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Roadmap 2050 – a closer look

Cost-efficient RES-E penetration and the role of grid extensions

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1 EXECUTIVE SUMMARY

Motivation and methodology

The share of renewable energy sources (RES-E) in the European electricity mix has increased continuously in recent years and is supposed to become the most important source of electricity in 2050. This is meant to contribute to reducing CO_2 emissions from European power generation and to reduce the dependency of the European Union from imported fuels. Reaching high RES-E shares and low-carbon electricity generation in a cost-efficient way requires an optimal deployment of renewable resources throughout Europe. This practice implies important cost savings compared to reaching country-specific RES-E and CO_2 targets solely based on renewable resource deployment within the individual EU Member States (EWI (2010)).

However, leveraging geographic synergies for the deployment of RES-E in Europe requires electricity transports from often remotely located windy (Northern Europe) or sunny regions (Southern Europe) to the residential and industrial load centers. Furthermore, an extension of the electricity grid facilitates the integration of large fluctuating RES-E generation by potentially netting regional electricity loads and electricity feed-in from solar and wind power. Therefore, large scale penetration of renewable energies in Europe may be supported by – or even contingent on - an extension of transmission networks.

Although the necessity of grid extensions for transforming the electricity system towards renewable based generation has been mostly accepted, construction of new lines is progressing very slowly. Among other reasons, delays are mainly caused by long and complex planning and permission procedures for new transmission lines (especially when more than one country is involved) as well as by local opposition based on concerns about the environmental, health or visual impact of the project. Therefore, it is far from clear whether ambitious targets for grid expansion will, and can, be effectively reached in time.

In the context of these challenges posed by the European power system transformation until 2050, the Institute of Energy Economics at the University of Cologne (EWI) and Energynautics initiated the present study to analyze the cost-efficient system transformation and the role of grid extensions within this process. Funding for this study was provided by the Gesellschaft zur Förderung des Energiewirtschaftlichen Instituts an der Universität zu Köln gGmbH, which is EWI's funding organization, and is gratefully acknowledged by the authors.

Within this study, two scenarios were defined and simulated using a dynamic investment and dispatch model of the European power market covering fossil, nuclear, renewable and storage technologies. A combined optimization of the generation system and the high voltage grid is achieved by iterating the results of the European electricity market model with a European transmission grid simulation model. Both scenarios define a sequential transformation process to a low-carbon and high RES-E electricity system. The scenarios differ with respect to the assumptions made for the speed and the scope of potential interconnector extensions.

Scenario A represents the "Optimal Grid Extension" for which generation capacities and transmission grid costs are minimized without restrictions to grid extensions. Hence, Scenario A identifies a cost-minimal pathway to achieve the given targets for reducing CO_2 emissions and increasing RES-E-shares, considering both the generation and transmission part of the system. Within this scenario, transmission lines are extended whenever contributing to the minimization of total system costs. Among other results, this approach allows to determine to what extent the usage of load-distant RES-E sites (such as offshore wind in Northern Europe or solar-based generation in the Mediterranean) is beneficial when transmission costs are taken into account.

Scenario A does not only serve as a reference to which Scenario B can be compared, but also contributes to the ongoing discussion about the optimal pathway to reach ambitious climate protection targets in 2050. Moreover, it complements the various European roadmaps, especially by means of the applied methodological approach, through combined optimization of the generation and transmission system.

Scenario B assumes a moderate extension of European interconnectors. Specifically, interconnector extensions are assumed to be limited to projects which have already entered the planning or permission phase today (based on the ENTSO-E's Ten Year Network Development Plan), but whose commissioning is assumed to be delayed. Although limited, interconnector capacities increase by factor 2.5 compared to today within this scenario. By evaluating Scenario B we demonstrate the cost-minimal pathway to reach low-carbon and high RES-E targets within this framework.

By comparing Scenarios A and B we investigate the benefits of interconnector extensions beyond those already initiated. We analyze the differences with regard to the development of the European generation mix and transmission grid and calculate the implied cost differences.

Main findings of the scenario analysis

The two analyzed scenarios both show a cost-efficient transformation to a low-carbon and high RES-E European electricity system. Due to ambitious targets, the generation mix in both scenarios profoundly changes until 2050. In Scenario A, 1,217 GW of new grid capacity are built until 2050. The total length of new lines adds up to 228,000 km, which is an increase of 76% compared to today's 300,000 km. In Scenario B, new grid capacities until 2050 add up to 500 GW. The total length of new lines is 111,000 km, representing an increase of 37%.
In the following we present the main findings of the scenario analysis. In a first part we discuss results common to both scenarios. In a second part, we present the differences and benefits of optimal grid extensions.

Commonalities of both scenarios

- **Generation mix profoundly changes until 2050.**
  Due to ambitious targets, the generation mix profoundly changes until 2050 in both scenarios. Renewable energy capacities are primarily increased by onshore wind until 2020/2030, offshore wind mainly from 2030 onwards, and solar plants mainly after 2040. Fossil base and mid-load capacities decrease over time. Gas turbines serving as backup capacities are extended to ensure security of supply. Total installed capacities more than double until 2050 due to the low secured capacity of intermittent renewable technologies and an assumed increasing demand. In both scenarios, grid extensions allow for increasing interregional trade streams.

- **Electricity production is pushed towards the outer regions of Europe where conditions are best.**
  In our scenarios, wind offshore is primarily deployed in Northern Europe and solar power in Southern Europe. In addition, electricity flows from Eastern to Central Europe evolve from generation by wind onshore plants, biomass and non-renewable plants with low-variable costs (lignite and nuclear).

- **The cost-efficient achievement of RES-E targets differs significantly from current political action plans.**
  The National Renewable Energy Action Plans foresee a strong increase of photovoltaic capacity until 2020 (85 GW installed in Europe, of which 52 GW in Germany). In our cost-efficient scenarios no additional PV is installed until 2020. Instead, more onshore wind is deployed especially in France, Great Britain and Poland.

- **The transformation to a low-carbon and high RES-E European electricity system induces cost increases – which however can be limited by EU coordinated action.**

  In both scenarios, the average system costs per unit increase from 47.1 to 65.6-65.9 €$_{2010}$/MWh between 2010 and 2020. Reasons include increasing demand and rising fuel prices (assumption) and the realization of the RES-E and CO_2 reduction targets. In the long term, average system costs remain relatively stable due to cost reductions of renewables (assumption), the availability of CCS technologies (assumption) and the utilization of EU-wide synergies by using technologies at most favorable locations across Europe – the latter being enabled by significant and European-wide coordinated transmission grid extensions. Without EU-coordinated action, cost increases would be more pronounced.

- **The transformation leads to a capital-intensive electricity system.**

  In today's fossil fuel dominated electricity system, variable costs are about half of total system costs. In contrast, the cost structure of renewables comprises mainly capital costs. Large shares of generation from RES-E technologies in 2050 lead to an electricity system with about 90% capital costs. Within the next 40 years massive investments in capital intensive renewable as well as low-carbon conventional technologies are required to achieve the 2050 RES-E and CO_2 targets.

- **The fulfillment of the CO_2 reduction target until 2020 induces high costs.**

  CO_2 emissions are significantly reduced in both scenarios (by assumption), requiring strong CO_2 price signals. The short term transformation requires an accelerated construction of new power plants and leads to lower utilization and earlier decommissioning of existing power plants. The challenging CO_2 target in 2020 induces prices in the range of 50-55 €$_{2010}$/t CO_2. In the long run, the costs of CO_2 emissions level out at around 50 €$_{2010}$/t CO_2.

- **The cost-efficient and technically feasible solution comprises intraregional grid extensions in both scenarios.**

  Even though interconnector capacities are different, the intraregional transmission grid is significantly extended until 2050 in both scenarios in order to supply load centers with distant yet national RES-E generation. With more than 17,000 km of additional transmission lines in Italy, 10,000 km in France and 6,000 km in Germany, transmission grid extension appears to be one of the major challenges in both scenarios.

Benefits of increased transmission capacities

The optimal extension of transmission capacities enables the better usage of favorable technologies in Europe. From the scenario comparison the following benefits of optimal transmission grid extension are identified:

- **Optimal transmission capacity extensions enable the better use of favorable RES-E technologies.**
  In Scenario A (optimal transmission extension), favorable offshore wind sites are extensively used. In the short term, offshore wind power is deployed at particularly good locations in Ireland and Norway (about 4,000 full load hours). In the long term, wind offshore deployment also takes place in the Netherlands, Denmark and Great Britain (full costs 6-8 ct_{2010}/kWh in 2050). Furthermore, solar imports from North Africa (6-7 ct_{2010}/kWh in 2050) contribute to the fulfillment of European RES-E targets.
  In Scenario B (moderate transmission extension), less favorable offshore wind sites are deployed, e.g. in Germany, France and Sweden (full costs 8-11 ct_{2010}/kWh in 2050). In addition, more solar technologies are used in Southern and Central Europe, characterized by full costs between 7-13 ct_{2010}/kWh in 2050. Biomass capacities generate electricity in Central and Eastern Europe (full costs 5-17 ct_{2010}/kWh in 2050).

- **Optimal intermeshing of European market regions reduces the deployment of costly storage technologies.**
  In case of moderate transmission grid extensions, storage capacities enter the picture to integrate fluctuating RES-E. They are built in Northern Europe where large wind capacities are installed, e.g. Great Britain, the Netherlands and Poland (in total +55 GW storage capacities in 2050). In Southern Europe fluctuating PV generation is complemented by CSP facilities with integrated thermal storage units.

- **Optimal interconnection capacity extensions induce larger imports and exports.**
  Norway (270 TWh), the Netherlands (243 TWh) and Denmark (180 TWh) are the largest net exporting countries in Scenario A in 2050. In relative terms, exports from Denmark (324%), Norway (174%), the Netherlands (156%) and Ireland (134%) by far exceed 100% of their respective gross electricity demand. In contrast, the largest net exporting country in terms of gross electricity demand in Scenario B is Denmark with 68%.

- **Optimal transmission extensions include larger imports from North Africa.**
  Overall electricity imports from North Africa to Europe in 2050 amount to 153 TWh (3% of the gross electricity demand) in Scenario A compared to only 24 TWh in Scenario B. In Scenario B, only one HVDC transmission line between North Africa and Spain with a total capacity of 15 GW connects the North African transmission grid to Europe. Furthermore, a bottleneck can be identified between Spain and France (capacity restricted to 4 GW in 2050), such that the supply of large load centers in Central Europe with imports from

North Africa is limited. In any case, meeting North African electricity demand by supporting the building-up of a low-carbon electricity system there should have priority.

- **Enhanced interconnector capacities allow for balancing regional differences in load and supply.**
  Strong interconnectors alleviate the balancing of load and supply between countries, even during extreme local events (such as several days without wind power in a specific region). Consequently, in some countries optimal interconnector capacities reduce the need for intraregional transmission grid extensions. In Great Britain for example, total intraregional transmission grid capacities are 26 GW lower in Scenario A, when interconnectors to neighboring countries (e.g. Ireland and Norway) are optimally extended.

- **By optimally extending the transmission grid necessary investments can be lowered by 57 bn. €$_{2010}$ until 2050 (accumulated).**
  Utilizing the best European renewable sites with high full load hours means that lower investments need to be effected to reach the challenging targets. In Scenario B, additional 150 GW of RES-E capacities (approx. +6-7%) are installed in 2050 compared to the optimal extension scenario. Hence, higher investments (+150 bn. €) in RES-E plants are needed. On the other hand, as generation is located closer to load centers, less conventional back-up capacities are needed than in Scenario A.

- **A cost-efficient extension of the European transmission grid is one option to reduce the costs of the electricity system.**
  System costs are lower in the optimal grid scenario (Szenario A) and the difference to the moderate grid scenario (Szenario B) increases over time due to a larger benefit of a strong transmission grid in high RES-E systems. The benefit of optimal transmission grid extensions amounts to 10 bn. €$_{2010}$ in 2050. This corresponds to 2.4 €$_{2010}$/MWh lower average system costs (approx. 4%).

Conclusions and political recommendations

Our results show that within our framework ambitious RES-E and CO_2 emission reduction targets can be achieved, and that a cost-efficient regional distribution of generation capacities throughout Europe is possible. This holds true even with moderate interconnector extensions. However, additional interconnector and intraregional grid extensions - as determined in the optimal scenario - were found to entail additional cost savings.

Conclusions

- **An integrated European framework favoring a cost-efficient transformation is crucial.**
  In both scenarios, the transformation towards a low-carbon and mainly renewable based electricity system is realized within a framework favoring a cost-efficient electricity supply. In particular, this includes the possibility to deploy RES-E technologies on sites with high full load hours and to use CCS-technology, nuclear power (in some countries) and all other technically available generation options.
  With regard to renewable energies, the cost-efficient deployment of these options – as determined in our scenarios - leads to electricity mixes significantly differing from the ones EU Member States have specified in their NREAPs until 2020.

- **Scenario A makes better use of comparative cost advantages.**
  An extension of interconnector capacity is beneficial from an economic point of view whenever countries have comparative cost advantages of electricity supply. These arise due to different full load hours of fluctuating RES-E or due to generation options only available in some countries because of natural (e.g. lignite or biomass) or political (e.g. nuclear) restrictions. Our results show that in Scenario A generation options in countries with comparative cost advantages for RES-E production (e.g. Ireland for offshore wind) and for non-renewable generation with low variable costs (e.g. Czech Republic for lignite) can be better used through enhanced interconnector extension.

- **Benefits of transmission grid extensions are conservatively estimated.**
  Due to more pronounced learning curve effects of solar than of wind technologies, differences in electricity generation costs of these technologies diminish over time. The benefits of larger grid extensions in Scenario A, enabling e.g. a higher use of offshore wind instead of solar plants, are thus conservatively estimated. Also, the benefits of grid extensions in terms of balancing RES-E in-feed and demand are conservatively estimated due to the use of typical days. In addition, other benefits from grid extensions, e.g. an increasing potential competition, are not captured in the scenario results.

Political recommendations

- **Coordinated European action**
  Due to the fact that RES-E electricity generation costs broadly differ throughout Europe, it needs a coordinated European RES-E plan of action, such that regional benefits are optimally taken into account.
  A coordinated European approach is also needed to foster transmission grid extensions which were found to entail important cost savings in the generation sector by far exceeding the additional costs for the grid. In order to achieve the desired transmission grid extension, the following points need to be addressed: First a European regulatory framework should be provided stimulating the construction of new interconnection lines and guaranteeing the full recovery of investments. Second, a long term coordinated European plan for grid extensions should be envisaged. Areas of particular importance have been identified in this study. Third, the permission process for new transmission projects should be streamlined and harmonized across Europe.

- **Chronological sequence of investments**
  The cost-efficient RES-E target achievement implies the primary usage of mature technologies. The pathway is characterized by early investments in onshore wind. The subsequent technology in the medium and long term is offshore wind at favorable sites, mainly available in Northern Europe. Solar technologies may be an important part of a future high RES-E electricity system in the long term. We recommend that research funds are now established which ideally entail efficiency improvements and cost reductions for CSP and PV technologies, rather than large asset commitments in these technologies in the short and medium term.

- **Planning reliability**
  Huge investments in capital intensive generation and transmission grid capacities are necessary in order to reach ambitious RES-E and climate protection targets. Ensuring a reliable political and regulatory framework for investments is thus crucial. This includes reliable RES-E and long term CO_2-targets, which are essential to reach a cost-efficient capacity mix. The massive increase in the share of fix costs in the generation mix calls into question whether and how the market design for the European power market needs to be adapted. This seems to be particular relevant for investments in back-up capacities. Due to their very low utilization rates these capacities might rely on incomes from ancillary markets, ideally introduced and regulated on the basis of a European standard.

2 BACKGROUND AND PURPOSE OF THE STUDY

Electricity generation from renewable energy sources (RES-E) has been increasing continuously within the European electricity mix and is supposed to become the most important source of electricity in 2050. This is meant to contribute to reducing CO_2 emissions from European power generation and to reduce the dependency of the European Union from imported fuels. Reaching high RES-E shares and low-carbon electricity generation in a cost-efficient way requires an optimal deployment of renewable resources throughout Europe. This practice implies important cost savings compared to reaching country-specific RES-E and CO_2 targets solely based on renewable resource deployment within the individual EU Member States (EWI (2010)).

However, leveraging geographic synergies for the deployment of RES-E in Europe, requires electricity transports from often remotely located windy (Northern Europe) or sunny regions (Southern Europe) to the residential and industrial load centers. Furthermore, an extension of the electricity grid facilitates the integration of high RES-E shares by potentially netting regional electricity loads and electricity feed-in from solar and wind power. Therefore, large scale penetration of renewable energies in Europe may be supported by – or even contingent on - an extension of transmission networks.

Although the necessity of grid extensions for transforming the electricity system towards renewable based generation has been mostly accepted, construction of new lines is progressing very slowly. Many of the TEN-E (Trans-European energy networks) priority projects are significantly delayed, often up to 10 years and longer (MVV Consulting (2007)). Among other reasons, delays are mainly caused by long and complex planning and permission procedures for new transmission lines (especially when more than one country is involved) as well as by local opposition based on concerns about the environmental, health or visual impact of the project. Therefore, it is far from clear whether ambitious targets for grid expansion will, and can, be effectively reached in time.

In this context, the present study aims at analyzing the cost-efficient system transformation and the role of grid extension within this process. Two scenarios are defined and simulated using a dynamic investment and dispatch model of the European power market covering conventional, nuclear, renewable and storage technologies as well as grid extensions (based on net transfer capacities), and iterating the simulation results with a detailed model of the European transmission grid (high voltage). The two scenarios differ with respect to the assumptions made for the speed and the scope of potential interconnector extensions.

In Scenario A, we analyze how the European electricity system, including electricity generation along with the transmission grid, can be transformed to a low-carbon and mainly renewable based system by 2050 in a cost-efficient way. This approach allows determining to what extent the usage of load-distant RES-E sites is beneficial when transmission costs are taken into account. Decisions on transmission grid extensions are compared to storage options, curtailment of RES-E generation and the usage of load-near generation. Furthermore, the results comprise corresponding system development and associated costs. Scenario A serves as a reference to which Scenario B can be compared. On the other hand, Scenario A also contributes to the ongoing discussion about possible pathways to reach ambitious climate protection targets in 2050 and complements the various European roadmaps, especially by means of the applied methodological approach.

Scenario B shows the cost-minimal pathway to reach low-carbon and high RES-E targets in the presence of moderate transmission grid extension. Differences between the two scenarios show the benefit of optimal grid extensions determined in Scenario A.

The development of the European electricity system has been analyzed extensively in recent years. One group of European roadmaps analyzes the feasibility of RES-E shares of up to 100% in 2050 (e.g. EREC (2010), ECF (2010), Greenpeace (2010), PWC (2010)). However, they either ignore transmission grid considerations or assume an exogenous and often optimistic exptension over time. Another group studies load flows and grid investments in high RES-E scenarios (e.g. Greenpeace (2009), Tröster et al. (2011)), but takes the electricity generation capacities as exogenous parameters. Furthermore, a number of studies deal with large-scale integration of one particular RES-E technology, e.g. wind in EWIS (2007), EWEA (2009) or EWEA (2011b).

The present study builds on these separate analyses and takes an integrated approach, optimizing the overall European electricity system development until 2050, while comprising fossil, nuclear and renewable generation, storage as well as transmission of electricity.

3 SCENARIO DEFINITION

We analyze two scenarios for the European electricity generation and transmission system until 2050. Both define a sequential transformation towards a low-carbon and high RES-E electricity system. These targets are formalized as European quotas in terms of CO_2 reduction (with respect to the reference year 1990) and RES-E share. By applying European-wide instead of national targets, capacities are built on sites with the best potential throughout Europe in both scenarios. For the year 2050 the targets assumed in this study are:

- 80% reduction of CO_2 emissions in Europe
- 80% generation from RES-E in Europe

For both scenarios, targets are achieved with cost-efficient investment and dispatch decisions regarding RES-E, conventional, nuclear and storage technologies. By definition, they only differ with respect to the possible extent of interconnector investments. We are thus able to consistently analyze the benefit of optimal transmission grid extensions in the context of a pathway to a low-carbon and mainly renewable based electricity system.

Scenario A: Optimal transmission grid

Scenario A represents the "optimal transmission grid extension" for which generation capacities and the transmission grid are cost-optimally extended using an iterative approach. Hence, Scenario A identifies a cost-minimal pathway to reach prescribed CO_2 emission reduction and RES-E targets considering both the generation and transmission part of the system. Within this scenario, transmission lines are extended whenever contributing to the minimization of total system costs. For instance, this option is chosen when enabling the use of load-distant generation such as offshore wind from Northern Europe or solar-based generation from Southern Europe leading to an overall minimization of total system costs.

Scenario B: Moderate transmission grid

Scenario B assumes a moderate extension of European interconnectors. Specifically, interconnector capacities are assumed to be limited to projects which have already entered the planning or permission phase today, such that interconnector extension reaches a level as outlined in ENTSO-E's Ten Year Network Development Plan in 2050 (rather than in 2020). Although limited, interconnector capacities increase by factor 2.5 compared to today within this scenario. By evaluating Scenario B we demonstrate the cost-minimal pathway to reach low-carbon and high RES-E targets within this framework. A detailed description of the assumed transmission grid extensions in Scenario B is provided in section 6.2.1.

4 METHODOLOGY

In order to determine the cost-efficient development of generation units and the electricity grid (Scenario A) and to compare the results to the optimal electricity system under moderate grid extensions (Scenario B), two models are used in an iterative process: A European investment and dispatch model for electricity markets and an engineering model of physical electricity flows through the transmission grid. Section 4.1 describes the European investment and dispatch model for electricity markets (EWI), section 4.2 gives an overview of the engineering model of physical electricity flows (Energynautics) and section 4.3 explains the iterative process between the two models to determine the optimal investments in conventional, storage and renewable technologies as well as transmission grid extensions.

4.1 European electricity market model

A dynamic linear investment and dispatch model is used to compute the cost-minimal development of the electricity system for Europe including imports from North Africa.[1] The objective of the model is to minimize total system costs for the electricity supply of the exogenously defined electricity demand. Total system costs include investment costs, fixed operation and maintenance costs, variable production costs (which comprise fuel and CO_2-costs) as well as costs due to ramping requirements of thermal power plants.

This section provides first an introduction to the model, namely its technologies, regions and temporal resolution. Then, the data structure (in- and output overview) is described. The focus remains on the structural characteristics of the model, whereas the underlying assumptions (chapter 5) and the results are discussed in chapter 6 and 7.

Model overview

Figure 1 gives an overview of the model description by highlighting its major technological, regional and temporal characteristics. In the following these characteristics will be discussed in detail.

[1] The model used in this study is based on a long term investment and dispatch model for thermal, nuclear and storage of the Institute of Energy Economics presented in Richter (2011) – which is based on several other electrictity models developed by the Institute of Energy Economics since the 1990s, lately the one developed by Bartels (2009). Within this study the model has been extended especially with regard to renewable energy technologies.

Technologies	Regions	Temporal resolution
• Conventional power plants - carbon capture and storage (CCS) - combined heat and power (CHP) • Nuclear power plants • Storage technologies • Renewable technologies • Transmission capacities (NTC)	• Markets: EU-27 - including Norway and Switzerland - without Malta and Cyprus - satellite region North-Africa • Regions for renewable energies - 47 wind onshore - 42 wind offshore - 38 photovoltaic	• Development until 2050 - in 5-year-time-steps • Dispatch for 4 typical days per year - considering seasonal differences

FIGURE 1: OVERVIEW OF TECHNOLOGIES, REGIONS AND TEMPORAL RESOLUTION

Source: EWI / energynautics

Technologies

The model incorporates investment and generation decisions for all types of power plants: conventional power plants (potentially equipped with carbon-capture-and-storage (CCS) or combined-heat-and-power (CHP)), nuclear, storage technologies and renewable energy technologies (RES-E). For conventional power plants several vintage classes for hard coal, lignite and natural gas-fired power plants represent today's power plant mix. Storage technologies include pump-storage plants, hydro storage and compressed air storages (CAES). The renewable technologies are modeled with a high level of detail regarding their technological and economic characteristics. RES-E plants incorporated in the model are: photovoltaics (PV - roof and ground), wind (onshore and offshore), biomass (solid and gas), biomass CHP (solid and gas), geothermal, hydro (storage and run-of-river) and solar thermal plants (CSP). The extension of transmission capacities between model regions on NTC level is determined endogenously.

Furthermore, to account for technological process, several future plant developments of both conventional and renewable energy sources are modeled. Regarding conventional technologies, technological process is assumed to increase the net efficiency. The availability of CCS-technologies from 2030 onwards is another example for technological process of conventional technologies. For renewable energies the technological process is shown for the example of wind onshore: on average, existing onshore wind turbines are assumed to have a turbine capacity of 3 MW. For investments in new wind turbines the model has the option to install 6 MW turbines with higher full load hours due to higher turbine heights from 2010 to 2025. From 2030 onwards, investments in 8 MW plants are possible. The area required per MW is assumed to decrease as well.

Regions

The model covers all 27 European countries, except for Cyprus and Malta but includes Norway and Switzerland. These countries are defined as market regions where supply has to equal demand in each hour. North Africa is modeled as a satellite import region. RES-E imports from North Africa can be used to fulfill a European RES-E quota if this decreases total system costs. Transmission extension costs between North Africa and Europe are then taken into account.

In addition to the countrywise definition of market regions, Europe is split into regions for on- and offshore wind and solar resources (PV and CSP). The further disaggregation becomes necessary given the fact that the potential and full load hours of these technologies vary significantly on a relatively narrow spatial scale between Europe. Thus, 47 regions for wind onshore, 42 regions for wind offshore (shallow and deep water) and 38 regions for photovoltaic technologies have been determined, which are shown in Figure 2 and Figure 3 (regions are based on EuroWind (2011)). Note that only Southern Europe and North Africa are considered to offer enough potential for CSP plants since only direct solar radiance can be concentrated in these plants (IEA (2010a)).

Onshore	Offshore	
1		Austria
2 3	1/2	Belgium
4	3/4	Bulgaria
5 6		Czech Republic
7	5/6	Denmark-East
8	7/8	Denmark-West
9	9/10	Estonia
10 11	11/12	Finland
12 13 14	13/14	France
15 16 17	15/16	Germany
18 19 20	17/18	Great Britain
21 22	19/20	Greece
23		Hungary
24 25	21/22	Ireland
26 27	23/24	Italy
28	25/26	Latvia
29	27/28	Lithuania
30		Luxembourg
31 32	29/30	Netherlands
33 34	31/32	Norway
35 36	33/34	Poland
37 38	35/36	Portugal
39	37/38	Rumania
40		Slovakia
41		Slovenia
42 43 44	39/40	Spain
45 46	41/42	Sweden
47		Switzerland

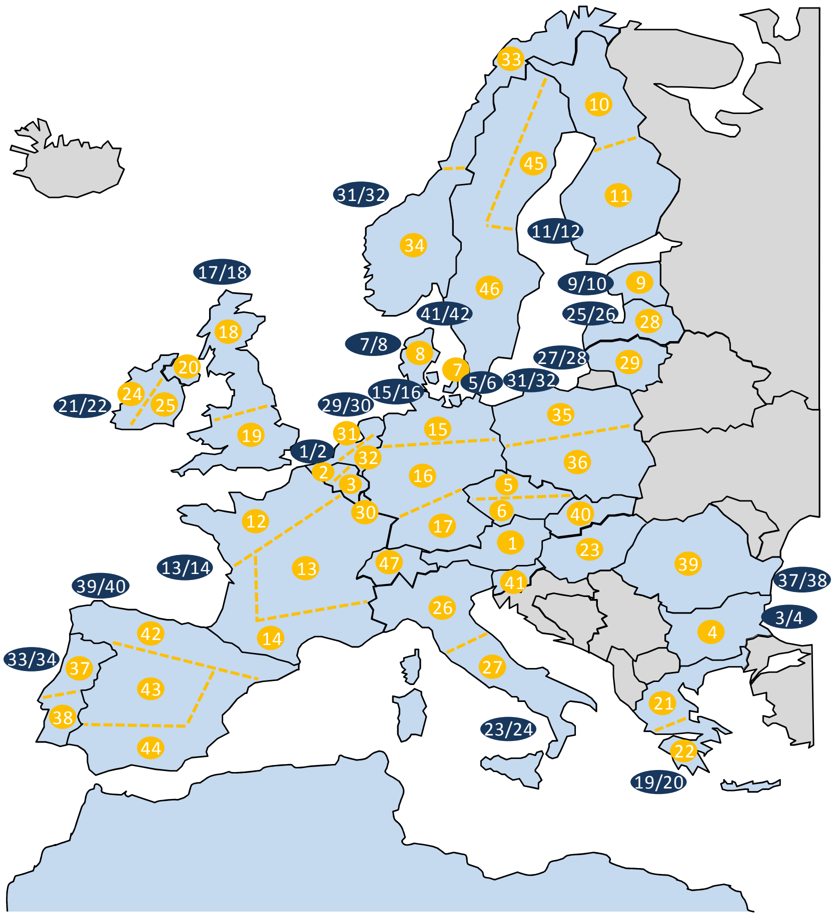

FIGURE 2: OVERVIEW OF MODELED WIND REGIONS

Source: EWI / energynautics

PV	CSP	
1		Austria
2		Belgium
3		Bulgaria
4		Czech Republic
5		Denmark-East
6		Denmark-West
7		Estonia
8		Finland
9 10 11		France
12 13		Germany
14		Great Britain
15 16	1	Greece
17		Hungary
18		Ireland
19 20 21	2	Italy
22		Latvia
23		Lithuania
24		Luxembourg
25		Netherlands
26	3	North-Africa
27		Norway
28		Poland
29 30	4	Portugal
31		Rumania
32		Slovakia
33		Slovenia
34 35 36	5	Spain
37		Sweden
38		Switzerland

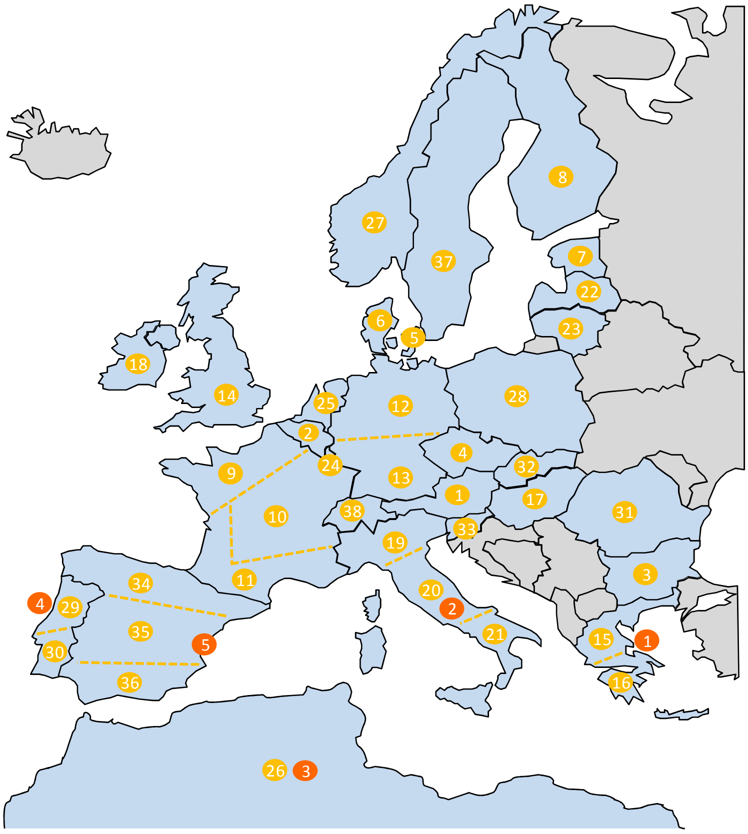

FIGURE 3: OVERVIEW OF MODELED PV AND CSP REGIONS

Source: EWI / energynautics

Temporal resolution

The model computes the optimal electricity mix and grid extensions in 5-year time-steps until 2050.[1] Within each model year, generation has to equal demand on four representative days accounting for seasonal differences.[2] As renewable energy resources are explicitly modeled in this study, a sufficiently high temporal resolution had to be chosen in order to appropriately reproduce volatile infeed-characteristics. Computation times as well as the sensitivity of temporal resolution on system composition were tested in order to find a suitable compromise on intraday resolution. As a result, days were divided into 6 slices.

[1] However, the model computes system development until 2070 in order to account for effects that result from different technology lifetimes when approaching the last years of the model.

[2] Each day can be subdivided into up to 24 hours. As for the yearly resolution, some kind of aggregation helps to limit computational time.

Data structure

The model results are influenced by assumptions concerning various input parameters. The basic structure of model in- and output parameters is illustrated in Figure 4. In the following the in- and output parameters are described in detail.

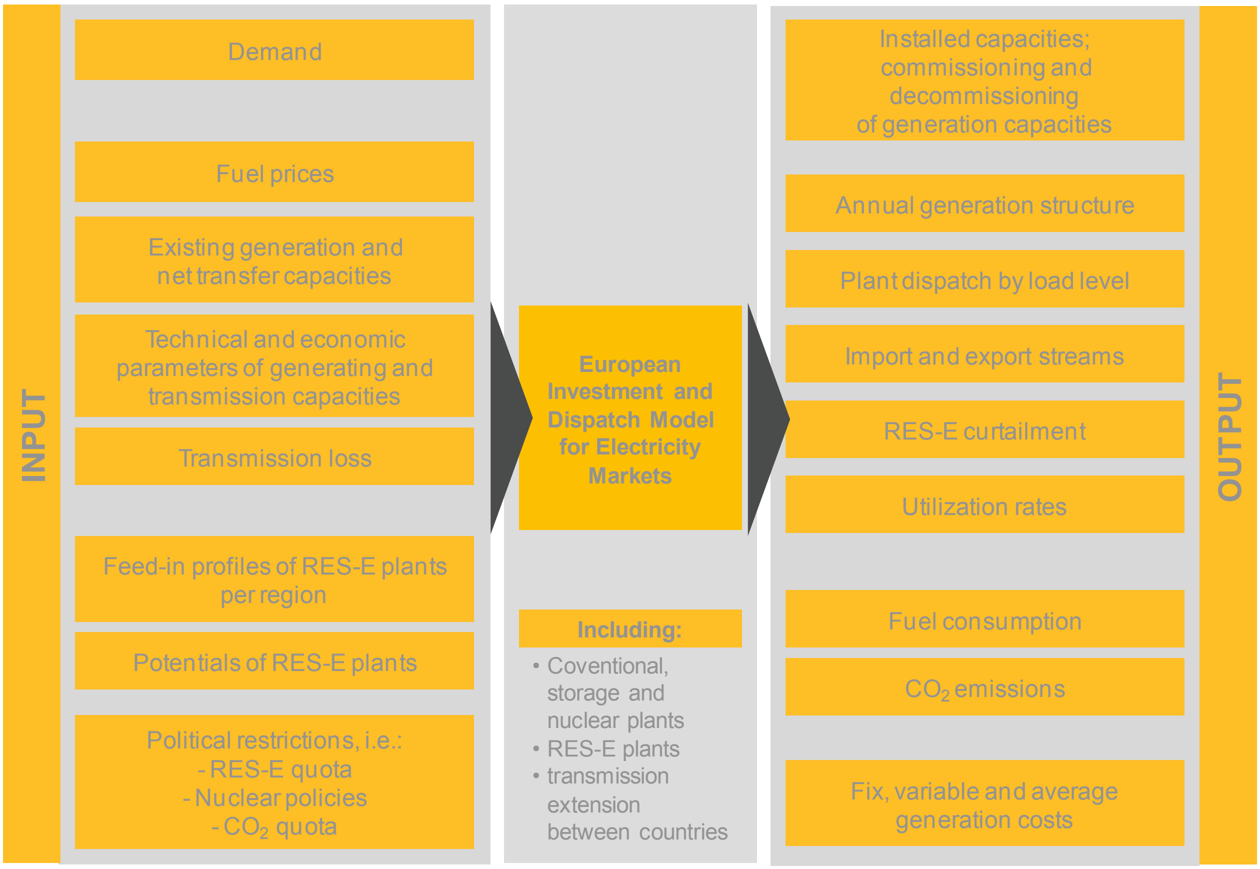

FIGURE 4: IN- AND OUTPUT-STRUCTURE OF THE MARKET MODEL

Source: EWI / energynautics

Input Parameters

The market model includes four groups of input parameters for the calculation: electricity demand, technology parameters (plants and transmission), RES-E potentials and feed-in profiles as well as political restrictions. Demand for electricity is defined exogenously on a yearly, daily and hourly basis. It includes net electricity consumption of end-consumers, transmission losses within model regions and other conversion losses in electricity grids. In contrast, consumption for storage operation, cross-border transmission losses and the power plant's own consumption are modeled endogenously. For the installed capacity needed to ensure enough back-up to the market an additional condition applies: in accordance with ENTSO-E's "margin against peak load" the model needs to provide additional back-up capacities to ensure security of supply.

Economic and technical input parameters define generation technologies and net transfer capacities. Economic parameters include investment costs, fixed operation and maintenance costs, fuel prices and costs due to ramping requirements of thermal power plants. Technical properties include net efficiency factors, ramping restrictions, technical lifetimes, minimal load fractions and CO_2-emission factors. Existing generation and transmission capacities per region are taken into account based on detailed information from EWI´s European power plant database. Net capacity for each installation is assigned to several vintage classes per technology in order to account for age specific properties such as efficiency factors. Transmission losses for imports are modeled based on average distances between regions (10% loss per 1000 km distance). RES-E specific input data include technical potentials either per market region (biomass, geothermal, solarthermal) or per wind or photovaltaic region. For intermittent RES-E technologies (wind, photovoltaics and solarthermal), regional and time-specific feed-in-profiles are assumed. These feed-in profiles represent the maximum possible feed-in of wind and solar technologies within each hour. Thereby the possibility of wind and solar curtailment can be endogenously chosen when needed to meet demand or when total system costs can be reduced due to lower ramping costs of thermal power plants.[1] Solarthermal plants are modeled as storage technologies since energy can either be directly produced at times when there is sun radiation or shifted to later hours via thermal energy storages incorporated in the plant.

Different political constraints can be applied to the model. In the context of this study three incentives are of particular interest: i) RES-E quota, ii) restrictions for nuclear energy and iii) European CO_2 policy. In this analysis a certain percentage of annual electricity demand has to be supplied from RES-E generation. Curtailed RES-E infeed does not contribute to the fulfillment of the RES-E quota. Regarding nuclear technologies, country-specific limitations, phase-out plans or investment bans for new plants are taken into account. In this study, an upper limit for CO_2 emissions in the European electricity sector is modeled. The limit is determined by the reduction of CO_2 emissions compared to the electricity system in 1990.

Output Parameters

The model results include: i) development of the generation and net transfer capacities, ii) dispatch decisions, iii) interregional trade flows, iv) fuel consumption, v) CO_2 emissions and vi) costs. The cost-optimal installed, newly commissioned and decommissioned generation and net transfer capacities are determined for each year. The optimal dispatch decision incorporates results on the annual generation structure, plant dispatch by load level, import and export flows, RES-E curtailment and yearly full load hours per technology. The costs are split into investment and fixed operation and maintenance costs, variable production and ramping costs.

[1] Wind sites are usually larger than solar sites and therefore transaction costs for solar curtailment are assumed to be higher than for wind sites. We use negligible small variable costs for offshore wind and even smaller ones for onshore wind sites. Therefore the model chooses offshore wind curtailment first.

4.2 European transmission grid simulation model

To physically analyze the transmission network we deploy a detailed model of the European extra high voltage grid developed by Energynautics using DIgSILENT's power system calculation tool PowerFactory.

The model covers the entire European transmission system of all ENTSO-E members. It consists of 224 nodes representing generation and load centers within Europe. Transmission lines between these centers are included in an aggregated form, considering both HVAC and HVDC lines. Figure 5 shows nodes and lines of the model for the year 2010.

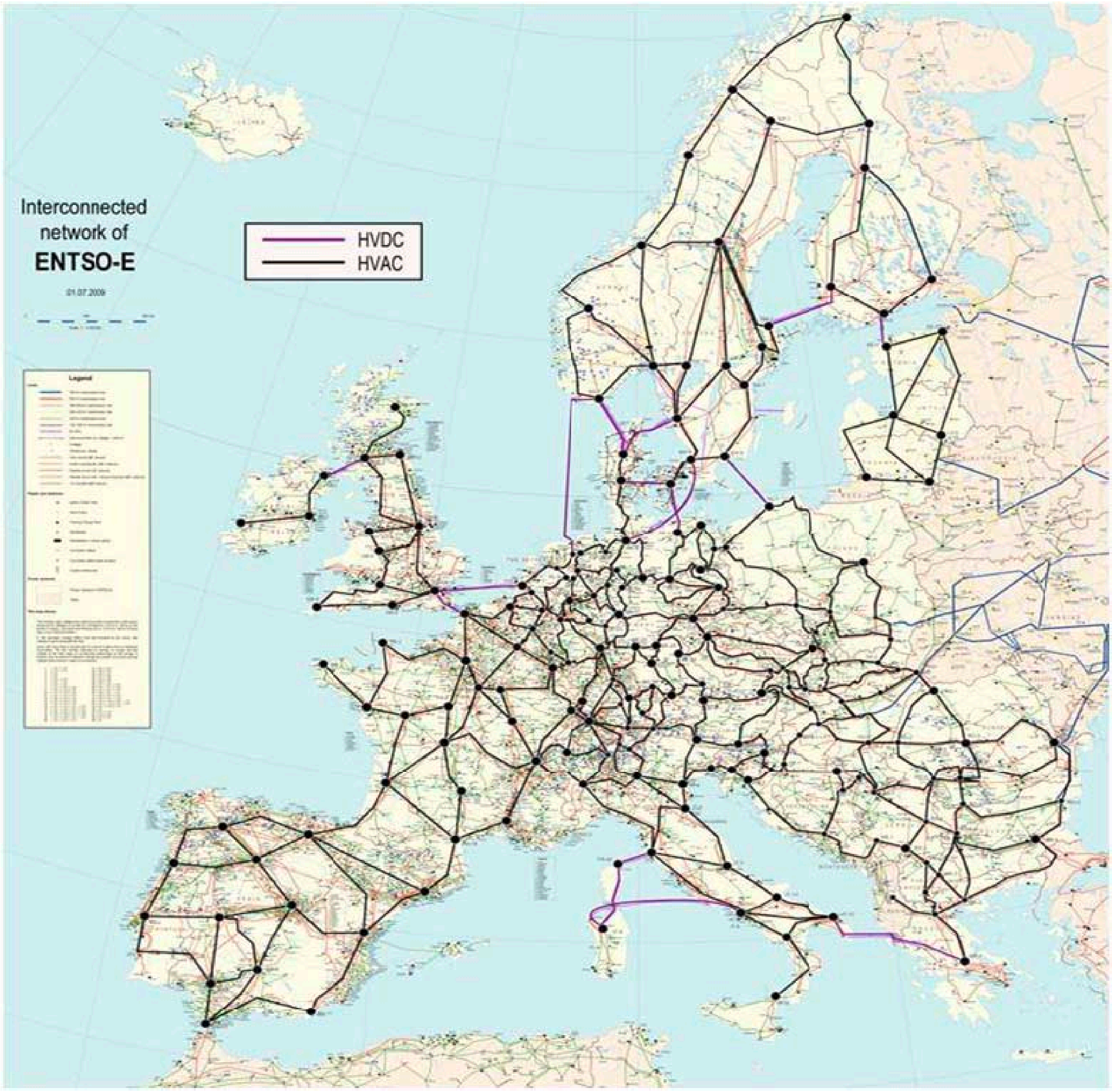

FIGURE 5: MAP SHOWING THE HIGH-VOLTAGE NETWORK MODEL OF EUROPE (STATUS 2010)

Source: EWI / energynautics (Reproduced with permission of ENTSO-E)

To identify the necessary physical grid upgrades for the electricity generation capacity mix determined within the market model and to determine the associated costs of grid extension, three steps have to be taken.

In the first step, detailed information on generation dispatch and customer load is taken from the results of the market model and integrated into the physical network model. Special attention is paid to the exact location and point in time of power in- and outputs, such that the resulting load flows within the power system can be analyzed. The dispatch calculated within the market model is re-simulated within the transmission grid model in order to determine necessary grid upgrades.

In the second step a stress test of the power system is performed to ensure that the resulting network is robust enough to cover demand under all realistic conditions. The most challenging condition was considered to be an extreme winter event characterized by high demand, low solar power production in most parts of Europe and low wind power production in Central and Northern Europe (as in January 1997). The installed capacities provided by the market model are assigned to the corresponding nodes in the grid model where generation and load are estimated. Hourly Optimal Power Flow (OPF) simulations are performed, and the amount of energy produced by each generator required to meet demand is calculated. In doing so, the maximum available generation at each node and the maximum line flow limit (specified as 80% of maximum thermal limit, and thus accounting for n-1 contingencies) must be respected by the OPF algorithm.

In the third step, the cost optimal grid upgrade is determined by checking the necessity of each individual upgrade that has been requested during step 1 and step 2. This last step is essential in order to minimize grid upgrade costs since some redundancy has most likely been built up during the process of adding network upgrades on a chronological hour to hour basis.

From the final results of this approach, the necessary grid upgrades in terms of thermal capacity as well as associated costs are determined. These results serve as an input to calculate NTC extension costs between market regions which are a sum of investments in tie-lines between regions and part of the costs of intra-regional upgrades. Intra-regional upgrades may be prompted due to upgrades of tie-lines, so that electricity can be transported and distributed within the region or even to act as transit corridor to other countries. Another reason for upgrading lines within a region is because of generation capacity built-up in areas with weak grids (such as remote wind locations). These upgrades are not linked to NTC extension and are therefore not considered when calculating NTC extension costs.

4.3 Combined optimization of the generation mix and transmission grid

Structural and locational changes in the power plant sector have been observed in recent years. Due to the different local conditions for renewable energies, future electricity generation is likely to take place far from large consumption areas which implies a significant increase in electricity exchange between regions. Therefore, transmission grids should be a major focus when analyzing the future development of the electricity system.

The cost-efficient development of electricity systems is usually determined by applying investment and dispatch optimization models for the specific electricity markets considering different scenarios (as described in chapter 3). However, difficulties arise when generation and grid shall be optimized jointly, which is mainly due to the fact that different characteristics and rules apply to commercial and physical electricity exchanges between two areas. Specifically, while a commercial trading activity with electricity (as modeled in the investment and dispatch decision) is a bilateral action between two countries, the physical settlement (i.e. the actual exchange of electrical energy) generally impacts the entire system.

Commercial exchange between two areas is constrained due to the presence of limited grid capacity. In a power system, Net Transfer Capacities (NTCs) provide a mean to quantify these limits for commercial trading at specific borders. According to ENTSO-E (2001a), NTC is "the maximum exchange program between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions". NTC is thus an important indicator to anticipate limited cross-border transactions.

Electricity market models used to analyze long term developments in electricity systems, such as the one deployed in this study (section 4.1), usually incorporate transmission grid constraints based on NTC between regions.[1] Under certain conditions, e.g. when distant renewable based electricity generation shall be integrated in the power system, the system considers NTC extension as cost-optimizing option (assuming provisional costs for additional NTC (€/MW) in a first step). In turn, NTC extension requires physical extension of the grid infrastructure. However, due to the previously mentioned differences between commercial and physical exchange, exact location and size of the grid extension needed to achieve the desired increase in NTC are initially unknown. We use the model of the European transmission grid (section 4.2) to determine these quantities and to derive the actual costs related to this particular NTC extension. It should be noticed that inter- as well as intraregional grid extensions are necessary for an increase in NTC. Both levels are considered by the model of the transmission grid and associated costs are allocated accordingly.

[1] Some market models try to integrate grid extension issues via direct-current or PTDF calculations (very few also consider alternating-current). Compared to the NTC approach, these methods cover additional physical aspects of grids. However, they are most often static and are only applied to small scale problems regarding temporal, regional or technological resolution. A good overview is provided in Groschke et al. (2009).

In the next step, the calculated costs of NTC extension are fed back to the market model which recalculates the system development. Due to a change of NTC extension costs, the optimal NTC and overall system development may now be different compared to the previous calculation. The new results from the market model are therefore passed again to the transmission grid model. This is where the iterative approach becomes apparent. The procedure is continued until the cost difference between two model runs becomes smaller than a threshold value. We are thus able to consistently optimize generation and grid extension at this point in time. Figure 6 gives an overview of the iteration process for the combined optimization of generation technologies and the transmission grid.

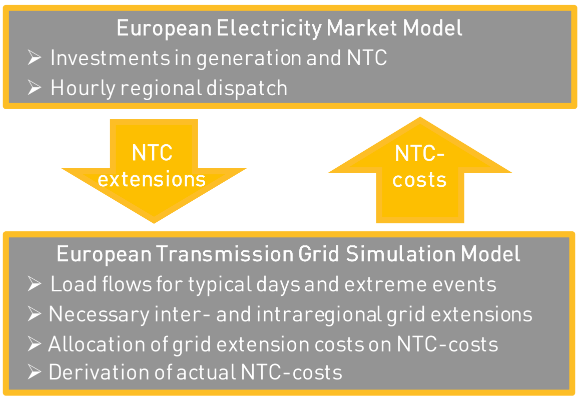

FIGURE 6: ITERATION PROCESS FOR THE COMBINED OPTIMIZATION OF GENERATION AND GRID EXTENSIONS.

Source: EWI / energynautics

As the system develops dynamically within the modeled timeframe, the iteration has to be repeated for subsequent time steps. While the market model calculates optimal development in 5 year intervals, we iteratively optimize combined generation and grid for each decade until 2050.[1] Time steps were chosen differently due to the massive computational burden.

[1] Note that the electricity market model is always run for the whole timeframe until 2070 in order to account for long lifetimes of capital-intensive grid and generation capacities. When the iteration process between grid and market model has been completed for a decade, grid investments until this point in time are fixed.

5 ASSUMPTIONS

In this chapter an overview is given of the major assumptions underlying the scenario analysis. The chapter is subdivided into six parts: demand parameters are discussed first, followed by technical characteristics of conventional, renewable, storage and grid technologies. The assumed development of fuel prices and assumptions concerning the political environment are provided subsequently.

5.1 Electricity demand and heat potential in co-generation

Electricity demand is primarily driven by economic and population growth. Furthermore, improvements in energy efficiency and the emergence of new technologies (such as electric cars) impact the development of the electricity consumption. In order to assess Europe's demand for electricity, Europe is divided into four regions with similar economic and population growth prospects, namely Western Europe, Southern Europe, Eastern Europe and Germany. Expected development is defined separately for each of these regions, such that an increasing demand for electricity and heat in Europe for the next decades up to the year 2050 is assumed. Table 1 presents an overview of the assumptions concerning the electricity demand growth rates.

TABLE 1: ASSUMPTION ON ELECTRICITY DEMAND GROWTH RATES

Region	Name	Countries	Assumptions	Growth rates [%]			
				2010-2020	2020-2030	2030-2040	2040-2050
I	"Western Europe"	FR, BE, NL, CH, AT, DK, NO, SE, FI, IE, LU	• slight increase of the population • stable GDP growth • high energy efficiency progress	1.25	0.65	0.6	0.55
II	"Southern Europe"	ES, IT, PT, GR	• increasing population • relatively high GDP growth	1.9	1.45	1.4	1.35
III	"Eastern Europe"	CZ, PL, BG, HU, SI, SK, RO, LV, LT, EE	• decreasing population • high GDP growth	1.95	1.2	1.15	1.1
IV	Germany	DE	• slight decline of the population • stable GDP growth • high energy efficiency progress	0.7	0.3	0	0

Source: EWI / energynautics based on IEA (2010b) and Capros et al. (2010)

Western Europe is expected to undergo a slight increase of the population and a stable GDP growth. Furthermore, a continuous electrification process is assumed, particularly in the transportation sector. Growth rates of electricity demand are thus positive. However, in the medium term the energy efficiency progress offsets the effects of GDP growth on the electricity demand. Southern Europe has higher GDP growth prospects and an increasing population that leads to higher growth rates of electricity demand. The energy efficiency offset is thus not as significant as in Western Europe. Eastern Europe in contrast has seen a decline in its population since the last decade. At the same time these countries belong to the group of European countries with the highest economic growth prospects. Hence, for the next decade we assume a high increase of electricity demand in Eastern Europe. Germany is listed separately from the other regions due to the fact that it is characterized differently regarding population, GDP and energy efficiency. In contrast to the other Western European countries, a slight decline in the population is expected. We assume that the energy efficiency progress will lead to an energy neutral growth of the German economy as from 2030. Based on the above discussed assumptions and numbers the resulting electricity demand per country and year is presented in Table 2.

Besides the electricity demand, Table 2 also reports values for heat demand, which are based on EURELECTRIC (2008) and Capros et al (2010). Similar to the electricity demand, an increasing potential for heat generation in CHP plants is assumed. However, growth rates are rather small for all European countries. Overall, the increase in process heat demand is expected to offset the slight decrease in demand for district heating due to energy efficiency improvements, mainly thermal insulation of buildings.

TABLE 2: FINAL ELECTRICITY DEMAND [TWh_{el}] AND (POTENTIAL HEAT GENERATION IN CHP PLANTS [TWh_{th}])

Country		2020		2030		2040		2050	
Austria	(AT)	65.3	(41.2)	70.0	(41.5)	74.3	(41.8)	78.5	(42.0)
Belgium	(BE)	92.6	(14.7)	99.3	(14.8)	105.4	(14.9)	111.4	(14.9)
Bulgaria	(BG)	32.0	(6.9)	36.0	(7.0)	40.4	(7.0)	45.0	(7.1)
Czech Republic	(CZ)	69.9	(55.1)	78.8	(55.7)	88.3	(56.4)	98.5	(57)
Denmark-East	(DK-E)	25.5	(36.5)	27.4	(36.7)	29.1	(36.9)	30.7	(37.2)
Denmark-West	(DK-W)	14.9	(18.2)	16.0	(18.4)	17	(18.5)	17.9	(18.6)
Estonia	(EE)	7.7	(1.4)	8.7	(1.4)	9.7	(1.4)	10.9	(1.4)
Finland	(FI)	96.6	(65.2)	103.6	(65.7)	110	(66.1)	116.2	(66.5)
France	(FR)	480.0	(31.6)	514.6	(31.8)	546.4	(32)	577.2	(32.2)
Germany	(DE)	567.0	(192.4)	584.2	(192.9)	584.2	(192.9)	584.2	(192.9)
Great Britain	(GB)	387.4	(68.1)	415.4	(68.6)	441.0	(69.0)	465.8	(69.3)
Greece	(GR)	65.2	(17.4)	75.3	(17.7)	86.5	(17.9)	99	(18.2)
Hungary	(HU)	40.1	(14.2)	45.1	(14.4)	50.6	(14.5)	56.5	(14.7)
Ireland	(IE)	28.1	(3.2)	30.2	(3.3)	32.0	(3.3)	33.8	(3.3)
Italy	(IT)	362.9	(169.2)	419.1	(171.7)	481.6	(174.1)	550.7	(176.5)
Latvia	(LV)	7.1	(6.5)	8.0	(6.6)	9.0	(6.7)	10.0	(6.7)
Lithuania	(LT)	9.9	(4.8)	11.1	(4.9)	12.5	(4.9)	13.9	(5.0)
Luxembourg	(LU)	7.6	(0.9)	8.1	(0.9)	8.6	(0.9)	9.1	(0.9)
Netherlands	(NL)	121.4	(114.3)	130.2	(115.1)	138.2	(115.8)	146	(116.4)
Norway	(NO)	118.7	(3.6)	127.3	(3.6)	135.2	(3.7)	142.8	(3.7)
Poland	(PL)	140	(93.3)	157.8	(94.4)	176.9	(95.5)	197.3	(96.6)
Portugal	(PT)	55.9	(13.9)	64.5	(14.1)	74.1	(14.3)	84.8	(14.5)
Romania	(RO)	49.8	(93.3)	56.1	(94.4)	62.9	(95.5)	70.1	(96.6)
Slovakia	(SK)	30.1	(17)	33.9	(17.2)	38	(17.4)	42.4	(17.6)
Slovenia	(SI)	16.3	(1.2)	18.3	(1.2)	(20.5	(1.3)	(22.9	(1.3)
Spain	(ES)	298.6	(59)	344.9	(59.9)	396.3	(60.7)	453.2	(61.5)
Sweden	(SE)	150.0	(29.3)	160.9	(29.5)	170.8	(29.6)	180.4	(29.8)
Switzerland	(CH)	65.4	(0.7)	70.1	(0.7)	74.5	(0.7)	78.7	(0.7)

Source: EWI / energynautics based on EUROPROG (2008) and Capros et al. (2010)

5.2 Economic and technical parameters of conventional power plants

This section reports the economic and technical parameters of conventional power plants represented in the model. Table 3 shows the assumed investment costs of established technologies as well as of newly developed power plant types that will be available in the future, such as CCS, new hard coal, lignite or gas power plants (based on Prognos/EWI/GWS (2010) and IEA (2010b)). These technologies are discussed in the following.

Hard coal: Conventional hard coal power plants are a mature technology and no further cost reduction can be expected. However, through the deployment of improved materials and processing techniques, future hard coal power plants (hard coal – "innovative") will be able to run at 700°C with 350bars of pressure, thus improving efficiency by about 4%-points to 50%. Whereas investment costs of this type of power plant are clearly above today's standard technology, costs decrease due to learning effects by around a third until 2050. If combined with CCS technology, investment costs of hard coal power plants are significantly higher. Coal power plants can also be built together with a heat module, which elevates costs but offers opportunities in the heat market.

Lignite: As for hard coal, an "innovative" as well as an "innovative CCS" technology becomes available in 2020 and 2030 respectively. The "innovative" technology uses a new system for drying lignite in a pressurized steam fluidized bed, which increases the efficiency of lignite-fired power plants by 3.5%-points to 46.5%. The investment costs for lignite-innovative power plants lie slightly above the investment costs of today's lignite power plants.

Gas: Both the open cycle (OCGT) and the combined cycle gas turbine (CCGT) are modeled. They are equally seen as mature technologies with constant investment costs. The CCGT can furthermore be equipped with a heat module (CHP) and/or a CCS technology, which raises the overall investment costs.

Nuclear: Nuclear plants are also mature plants with constant investment costs. Due to long planning and construction times, we assume that before 2025 only nuclear plants already under construction today, can be build. However, existing plants with a lifetime of 50 years can be retrofitted for 10 years.

CCS technology: By 2030, CCS is assumed to be commercially available and applicable to hard coal, lignite and combined-cycle gas power plants. As shown in Table 3, standard technology power plants as well as "innovative" power plants can be combined with CCS technologies. Moreover, a coupling of CCS and CHP is also available. Note that CCS power plants lose 4-8 percentage points in electrical efficiency compared to non-CCS plants, depending on the power plant type.

TABLE 3: INVESTMENT COSTS FOR CONVENTIONAL AND NUCLEAR POWER PLANTS [€2010/kW]

Technology	2020	2030	2040	2050
Nuclear	3,157	3,157	3,157	3,157
Nuclear Retrofit	300	300		
Hard Coal	1,500	1,500	1,500	1,500
Hard Coal - innovative	2,250	1,875	1,750	1,650
Hard Coal - CCS	-	2,000	1,900	1,850
Hard Coal - innovative - CCS	-	2,475	2,300	2,200
Hard Coal - innovative CHP	2,650	2,275	2,150	2,050
Hard Coal – innovative CHP and CCS	-	2,875	2,700	2,600
Lignite	1,850	1,850	1,850	1,850
Lignite - innovative	1,950	1,950	1,950	1,950
Lignite – innovative CCS	-	2,550	2,500	2,450
OCGT	700	700	700	700
CCGT	1,250	1,250	1,250	1,250
CCGT - CCS	-	1,550	1,500	1,450
CCGT - CHP	1,500	1,500	1,500	1,500
CCGT - CHP and CCS	-	1,700	1,650	1,600

Source: EWI / energynautics

Table 4 recaptures the technological options available to the system and shows their technological and operational characteristics, i.e. conversion efficiency, availability, operation and maintenance costs and technical lifetime.[1] For currently available technologies, efficiency assumptions are based on average specifications of power plant types in construction today. For "innovative" technologies, efficiency improvements are assumed due to the innovation described above. Note that CHP power plants have lower efficiencies in electric power production compared to non-CHP plants, but higher overall energy efficiencies.

The availability factor reported in Table 4 is the average of the four seasonal availability factors used in the model. It accounts for planned and unplanned shut-downs of the plants, e.g. because of revisions. For conventional and nuclear power plants, the availability factor determines also the contribution of a plant to the secured available capacity within each country. As described in

[1] In fact, a lot more technologies, reflecting several vintage classes for existing technologies, are modeled than shown in Table 4.

chapter 4.1, the peak demand plus an additional security margin has to be assured by securely available capacities at time of peak demand.

The fixed operation and maintenance (O&M) costs of CCS power plants comprise also the costs for transporting and storing the captured CO_2 underground. The technical lifetimes indicate the time period in which a newly built power plant can be used, except for the "Nuclear Retrofit" which is an option to extend the lifetime of existing nuclear power plants by 10 years (see above).

TABLE 4: TECHNO-ECONOMIC FIGURES FOR CONVENTIONAL AND NUCLEAR POWER PLANTS

Technology	Efficiency [%]	Availability [%]	Fix O&M costs [€$_{2010}$ /kW]	Technical lifetime [a]
Nuclear	33.0	84.50	96.6	60
Nuclear Retrofit	33.0	84.50	96.6	10
Hard Coal	46.0	83.75	36.1	45
Hard Coal - innovative	50.0	83.75	36.1	45
Hard Coal - CCS	42.0	83.75	97.0	45
Hard Coal - innovative CCS	45.0	83.75	97.0	45
Hard Coal - CHP	22.5	83.75	55.1	45
Hard Coal - CHP and CCS	18.5	83.75	110.0	45
Lignite	43.0	86.25	43.1	45
Lignite - innovative	46.5	86.25	43.1	45
Lignite – innovative CCS	43.0	86.25	103.0	45
OCGT	40.0	84.50	17.0	25
CCGT	60.0	84.50	28.2	30
CCGT - CHP	36.0	84.50	40.0	30
CCGT - CCS	53.0	84.50	88.2	30
CCGT - CHP and CCS	33.0	84.50	100.0	30

Source: EWI / energynautics

Table 5 depicts the assumed CO_2 emission factors for fossil fuel combustion, which describe the amount of CO_2 emitted per unit of primary energy consumed (tCO_2/MWh_{th}). While lignite fired power plants exhibit a CO_2 emission factor of 0.406 t CO_2/MWh_{th}, natural gas-fired power plants emit only 0.201 t CO_2 per MWh_{th}. CCS power plants are assumed to capture and store 90% of their CO_2 emissions.

TABLE 5: CO_2 EMISSION FACTORS FOR FOSSIL FUEL COMBUSTION [t CO_2/MWh_{th}]

Fuel	Hard Coal	Lignite	Natural Gas
CO_2 emission factor	0.335	0.406	0.201

Source: EWI / energynautics

5.3 Economic and technical parameters of renewable energy technologies

A large number of renewable energy technologies is implemented in the model, such as wind (on- and offshore), biomass (solid and gaseous), geothermal, photovoltaic (roof and open land installations) and run-of-river hydropower plants.[1] This section briefly introduces these technologies and highlights why they were chosen. The subsequent sections discuss their economic and technological characteristics in further detail.

Wind power: Wind power is continuously gaining significance in Europe. Installed capacity has risen exponentially from an accumulated 2.5 GW in 1995 to 75 GW in 2009 (EWEA 2011). Onshore installations so far represent by far the largest share (97%). In order to account for different possible options of wind power, the model includes different technologies on- and offshore. For onshore turbines, there are three sizes available at different times. 3 MW turbines represent the technology momentarily installed. No future investment is possible, and no investment costs are consequently listed for this type of turbine. Up to 2025, a 6 MW turbine can be built, and from then on only 8 MW turbines are considered, which are characterized by higher full load hours, lower specific costs and a lower space requirement per MW installed (km^2/MW). This development accounts for technological progress expected in the wind sector. Offshore wind is modeled very similarly, incorporating 5 MW turbines up to 2025 and 8 MW turbines from then on.

Photovoltaic (PV): PV utilizes panels (for instance amorphous or crystalline silicone) in order to convert solar radiation into electricity. As such, PV is directly influenced by solar radiation levels, with intermittencies occurring not only on daily (night-day), but also on a

[1] For run-off-river hydropower only existing power plants are considered. No new investments are possible in the model. Moreover the model includes hydro and pump storages, which are discussed in more detail in Section 5.4

narrower timescale (clouds). For PV two different types are considered: open field installations and panels mounted on rooftops.

Concentrating solar power (CSP): CSP plants focus the sun's rays on a fluid which transfers heat from a collector pipe to a heat exchanger. The thermal energy is then used to generate electricity in a steam turbine. In the model, CSP plants are combined with a thermal energy storage which enables the power plant to produce electricity in hours with no or low solar radiation. The assumed storage volume amounts to 8 hours.

Geothermal energy: Geothermal energy is represented with two technological options, one using the hot-dry-rock (HDR) process and the other one aiming at tapping hot groundwater reservoirs (high enthalpy). However, it should be noticed that potentials for high enthalpy resources in Europe are rather limited.

Biomass: Different biomass technologies account for gaseous and solid biomass fuels. Both options can be built with a heat-production unit (CHP) which increases both costs and overall efficiency of the plant.

Equivalent to the conventional technologies discussed in the previous section, plant characteristics have to be defined for renewable energies. The major difference compared to the conventional technologies is the fact that the availability of renewable energies in terms of regional potential is subject to large variations. An extra section is thus dedicated to this issue, placed after the subsections investment costs and techno-economic figures.

Investment costs of renewable energy technologies

Assumed investment costs including technology-specific learning effects are given in Table 6 for each renewable energy technology (based on Prognos/EWI/GWS (2010), EWI (2010), IEA (2010b), IEA (2010d)). Europe-wide, costs drop sharpest by about 30% for solar energy technologies, i.e. ground- and roof-mounted photovoltaics as well as concentrated solar power (CSP). For CSP only facilities including storage devices are considered which raises the investment costs but significantly increases the applicability of such installations.

For on- and offshore wind power a switch in technologies is assumed due to cost effects. As seen in Table 6, costs per kW for 8 MW turbines drop below 2020-level costs for 5 MW turbines for each site. Thus, until 2020, only 5 MW wind turbines are available, while from 2030 onwards, only 8 MW sites are installed on- and offshore. Learning effects in biomass technologies are only marginal as the power plant technology is, similar to already existing fossil fuel power plants, mature. Geothermal power plants see a slight decrease in investment costs.

TABLE 6: INVESTMENT COSTS FOR RENEWABLE ENERGIES [€2010 /kW]

Technology	2020	2030	2040	2050
Biomass gas	2,398	2,395	2,393	2,390
Biomass gas - CHP	2,597	2,595	2,592	2,590
Biomass solid	3,297	3,293	3,290	3,287
Biomass solid CHP	3,497	3,493	3,490	3,486
Geothermal (hot dry rock)	10,504	9,500	9,035	9,026
Geothermal (high enthalpy)	1,050	950	904	903
PV ground	1,796	1,394	1,261	1,199
PV roof	2,096	1,627	1,471	1,399
Concentrated solar power	3,989	3,429	3,102	2,805
Wind onshore 6 MW	1,221			
Wind onshore 8 MW		1,161	1,104	1,103
Wind offshore 5 MW (shallow)	2,615			
Wind offshore 8 MW (shallow)		2,512	2,390	2,387
Wind offshore 5 MW (deep)	3,105			
Wind offshore 8 MW (deep)		2,956	2,811	2,808

Source: EWI / energynautics

Techno-economic figures of renewable energy technologies

The same technological-economic characteristics as for conventional and nuclear power plant technologies are defined for renewable energy technologies (see Table 7). Biomass CHP power plants have a lower electric efficiency than non CHP power plants, but additionally produce heat. The fixed operation and maintenance costs for all renewable energy technologies are constant over time. While biomass and geothermal technologies have a technical lifetime of 30 years, all other renewable energy technologies are operated for 25 years.

As for conventional and nuclear power plants, the availability factor for dispatchable RES-E (biomass, geothermal) depicted in Table 7 corresponds to the average seasonal availability factors used in the model. For dispatchable RES-E, the availability factor also determines the capacity of a plant which is counted as securely available capacity at times of peak demand. Efficiencies and availabilities of fluctuating RE infeeds are left out in Table 7 due to the fact that these characteristics cannot be captured by a single number. In fact, the infeed from such non-dispatchable energy sources is modeled as power distribution. A more detailed discussion of how these technologies are represented in the model is provided in the following section. The contribution of fluctuating RES-E to securely available capacities is shown in column "secured capacity". This so-called capacity credit corresponds to the amount of electricity generation firmly available at the time of peak demand. For wind, this factor is assumed to be 5%, meaning that at least wind power generation amounting to 5% of all installed wind plants running at full capacity, is firmly available. This assumption can be made due to geographically diversified wind sites throughout Europe. For photovoltaics we assume a capacity credit of 0% because the peak demand in European countries is generally during winter time and at least in a part of the European countries during early evening hours, when no sun power is available. CSP technologies in contrast are modeled with integrated thermal energy storage and can therefore shift electricity generation to hours when no sun power is available. The assumed capacity credit for CSP plants is 40%.

TABLE 7: TECHNO-ECONOMIC FIGURES FOR RENEWABLE ENERGIES

Technology	Efficiency [%]	Availability [%]	Secured Capacity [%]	Fix O&M costs [€2010 /kW]	Technical lifetime [a]
Biomass gas	40.0	85	85	120	30
Biomass gas CHP	30.0	85	85	130	30
Biomass solid	30.0	85	85	165	30
Biomass solid CHP	22.5	85	85	175	30
Geothermal (HDR)	22.5	85	85	300	30
Geothermal	22.5	85	85	30	30
PV ground	-	-	0	30	25
PV roof	-	-	0	35	25
Concentrated solar power	-		40	120	25
Wind offshore 6 MW (deep)	-	-	5	152	25
Wind offshore 8 MW (deep)	-	-	5	160	25
Wind offshore 6 MW (shallow)	-	-	5	128	25
Wind offshore 8 MW (shallow)	-	-	5	136	25
Wind onshore 6 MW	-	-	5	41	25
Wind onshore 8 MW	-	-	5	41	25
Run-off-river hydropower	-	-	50	11.5	100

Source: EWI / energynautics

Renewable energy full load hours

Based on regional wind speed and solar radiation data potential full load hours were derived for each modeled wind and PV/CSP region (based on EWI (2010)). Figure 7 and Figure 8 depict the assumed potential full load hours for wind onshore and PV. The best sites for wind power with up to 3500 full load hours per year are located in northern Europe, especially in Great Britain, Ireland, Denmark, Norway and northern Germany. Good wind conditions can also be found in France, Spain and the Baltic states.

For solar technologies, potential annual power generation increases from North to South. The regions with the highest solar full load hours are located in Portugal, Spain, Italy and North Africa. Compared to wind power less full load hours can be reached since solar radiation is only present during daytime.

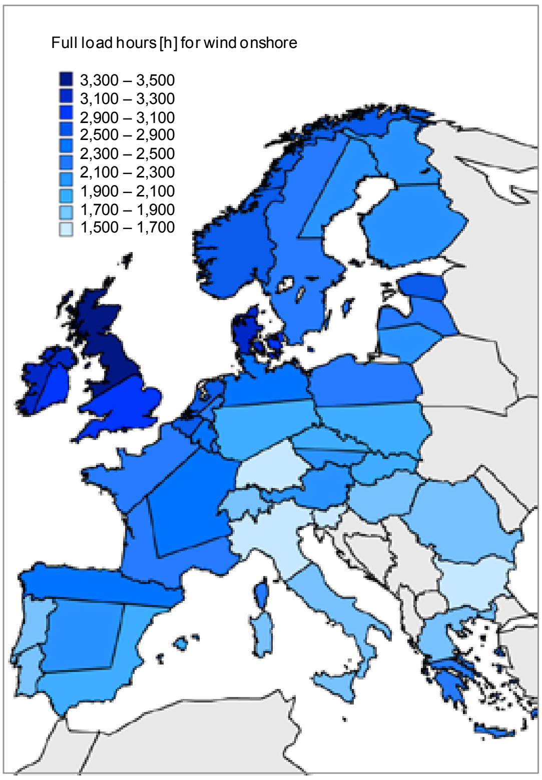

FIGURE 7: FULL LOAD HOURS FOR ONSHORE WIND [h]

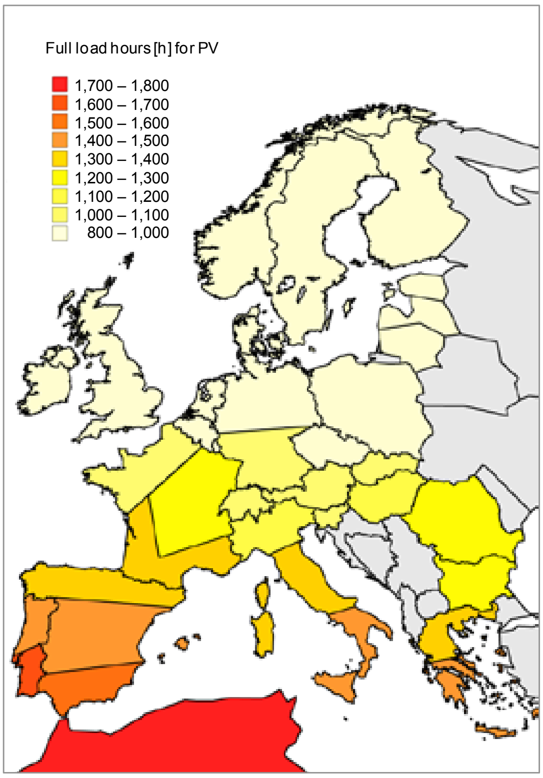

FIGURE 8: REGIONAL FULL LOAD HOURS FOR PV [h]

Source: EWI / energynautics

Wind onshore power density and relative wind onshore potential

Figure 9 depicts the wind onshore power density factor per region, which is defined as the single region's technical wind onshore potential in MW divided by the single region's land area in km². It can be seen, that the wind onshore potential in relation to the single region's land area is lowest in the north (Norway, Sweden and Finland) as well as in the south-east (Romania, Bulgaria and Greece), while the largest wind onshore power density can be observed in the regions Eastern Ireland, Southern Great Britain and the Eastern Netherlands. As the technical wind onshore potential does not comprise rural and industrial areas as well as forests, lakes, rivers, and mountains, the wind onshore power density factors is relatively low in Norway, Sweden, Finland, North-Italy and Switzerland. Figure 10 illustrates the classification of the single country's technical wind onshore potential in relation to the overall wind onshore potential of all countries. France, Germany, Poland, Great Britain and Spain offer by far the highest relative onshore wind potential.

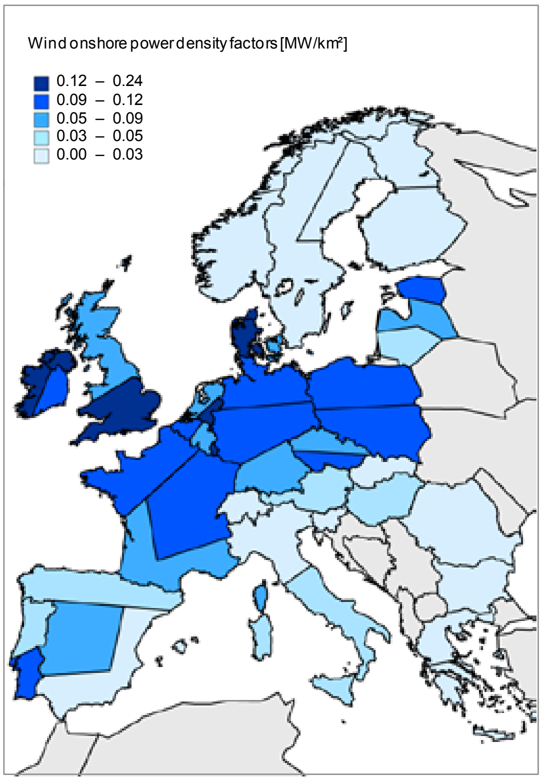

FIGURE 9: REGIONAL WIND ONSHORE POWER DENSITY FACTOR [MW/KM²]

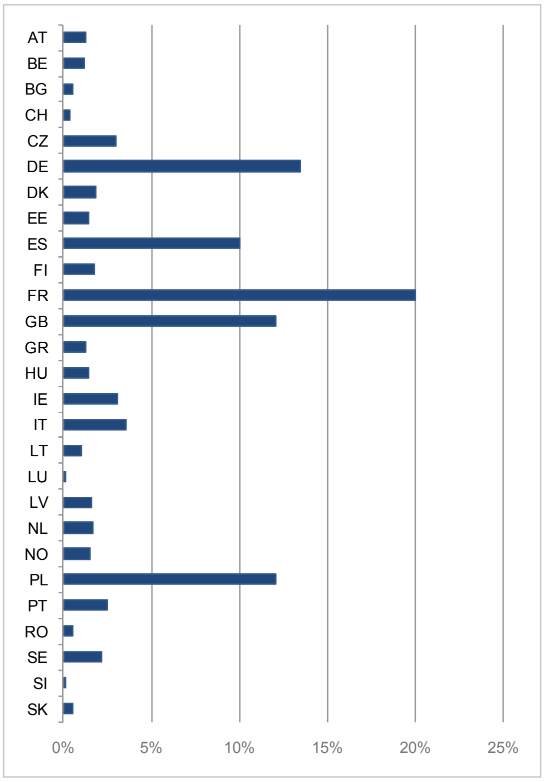

FIGURE 10: WIND ONSHORE POTENTIAL PER COUNTRY IN RELATION TO THE OVERALL POTENTIAL [%]

Source: EWI / energynautics

Bounds for biomass resources and relative potential

Upper bounds for biomass resources per country are presented in Figure 11. Here the single country's potential biomass electricity generation in 2050 is expressed in percentage of its electricity demand in 2010. The highest biomass resource potential in relation to the country's electricity demand can be found in the eastern European countries Hungary, Poland, Lithuania and Latvia, followed by Romania and Bulgaria.

Figure 12 illustrates the single country's biomass resource potentials, classified by the fuels biosolid and biogas. While biosolid includes energy crops, agricultural residuals, forestry, used wood and sewage sludge, biogas (low-cost) is produced from manure and biogas (high-costs) from silo maize. Moreover, also the single country's biomass potential in relation to the overall biomass potential of all countries is depicted. As can be seen, France, Spain and Germany offer the highest potential for biomass overall as well as for biosolid in particular.

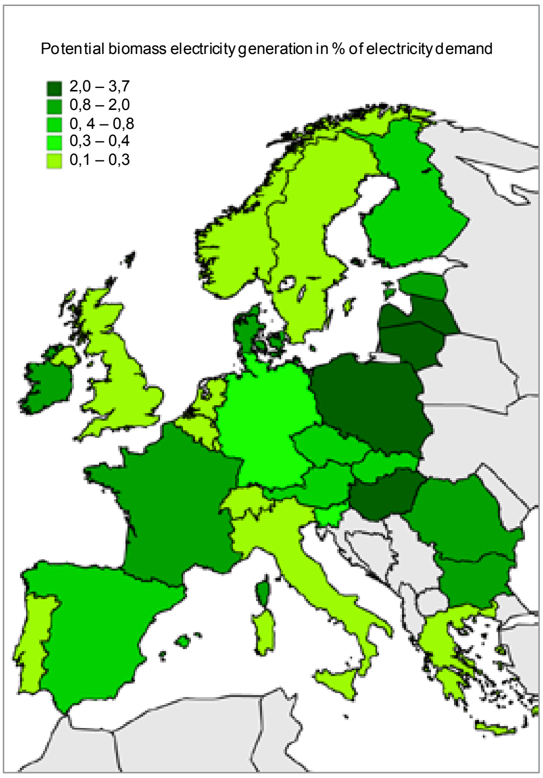

FIGURE 11: REGIONAL POTENTIAL BIOMASS SHARE OF DEMAND [%]

FIGURE 12: BIOMASS POTENTIAL PER COUNTRY IN RELATION TO THE OVERALL POTENTIAL [%]

Source: EWI / energynautics

Fluctuating renewable energy feed-in structures

Fluctuating renewable energy technologies are PV systems and wind turbines. In order to realistically represent the volatile infeed structures, full load hours are first broken down to typical days representing the four seasons of the year and then further to the 24 hours of each of these days. As such, the modeled infeed of a wind turbine or a PV system per hour is expressed in percentage of the rated power ($MW/MW_{inst.}$). Figure 13 displays four exemplary feed-in structures of wind and PV for two regions in Denmark and Spain. While the daily PV power generation typically peaks at midday when solar radiation is the highest, there is no clear pattern within the daily structure of wind power generation. Regional differences in the feed-in structures per technology are also due to differences in the assumed full load hours per region.

While the exemplary region in Spain has a higher amount of PV full load hours then the exemplary region in Denmark, the opposite is true for the case of wind power.

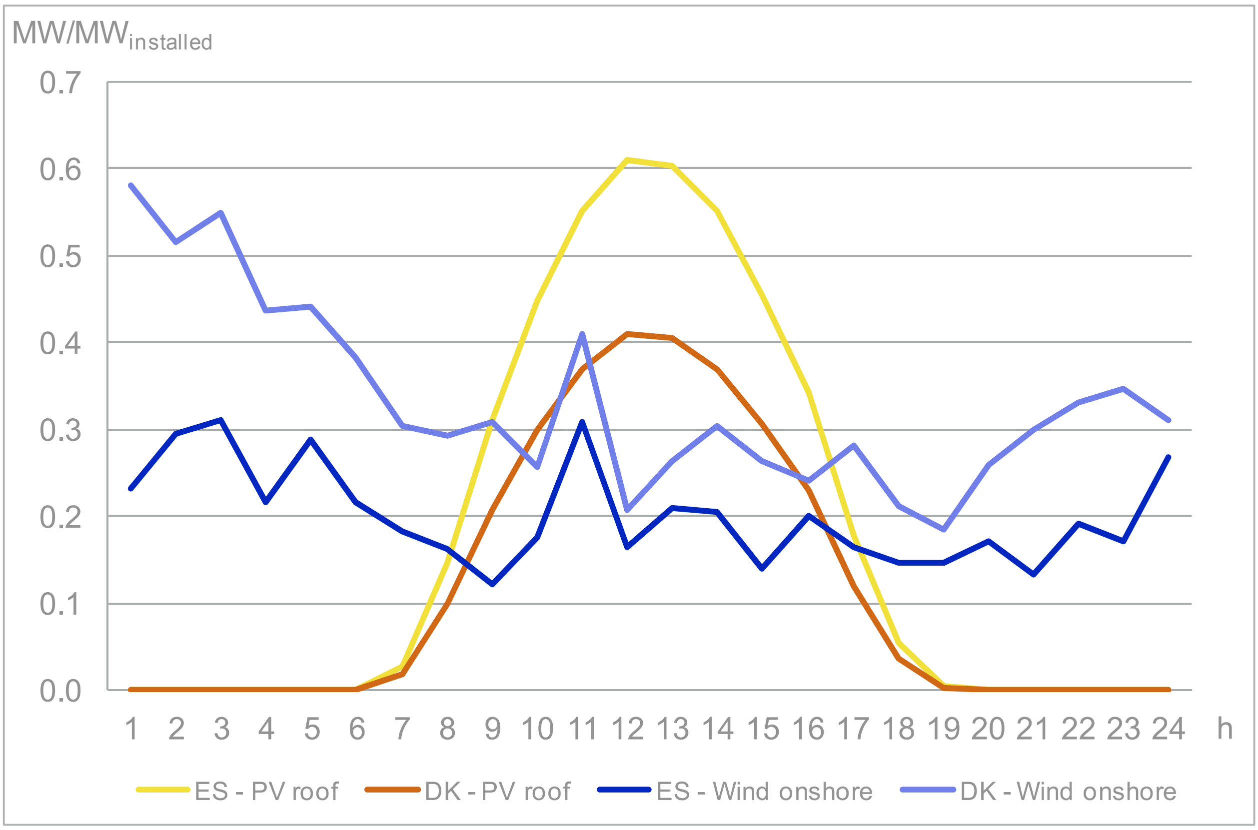

FIGURE 13: EXAMPLE FOR FEED-IN STRUCTURES OF WIND AND PV [MW/MW$_{inst.}$]

Source: EWI / energynautics

5.4 Economic and technical parameters of storage facilities

The market and grid integration of fluctuating technologies, such as wind and PV, is one of the major challenges for a generation mix characterized by a large share of renewable energy technologies. Storages can help to balance demand and intermittent RES-E infeed and therefore facilitate the integration of renewables. Several electricity storage technologies are considered in this study. The development of the economic and technical parameters for the different storage technologies is based on DLR (2010), Prognos/EWI/GWS (2010) and IFEU (2010).

Prevailing potentials of pump- and hydro-storages, which demand certain geographical conditions, are virtually exploited in Europe. Apart from the projects which are currently in the planning process, it is assumed that no further investments are possible. Table 8 recaptures the techno-economic parameters for storage technologies.

TABLE 8: TECHNO-ECONOMIC FIGURES FOR STORAGE TECHNOLOGIES

Technology	$\text{Efficiency}_{\text{turbine}}$ [%]	$\text{Efficiency}_{\text{load}}$ [%]	Volume factor	Availability [%]	Cap. credit [%]	Fix O&M [$€_{2010}$/kW]	Tech. lifetime [a]
Compressed Air Storage	0.86	0.81	8	95	50	9.2	40
Pump Storage	0.87	0.83	26	95	80	11.5	100
Hydro Storage	0.87	-	26	90	90	11.5	100

Source: EWI / energynautics

The efficiency factor of the turbine ($\text{efficiency}_{\text{turbine}}$) describes how much of the stored energy can be converted into electricity. The efficiency load factor ($\text{efficiency}_{\text{load}}$) accounts for the electricity losses in storage operation. The volume factor represents the ratio of storage size and the turbine capacity (e.g. 1 GW pump storage turbine has a 26 GWh storage basin). The availability factor shown in Table 8 corresponds to the average seasonal availability captured in the model and accounts for planned and unplanned shut-downs. The natural seasonal inflow into hydro-storage basins is an additional input parameter which is country-specific and therefore not depicted in the overview in Table 8. The capacity credit of hydro storage corresponds to its availability at peak load. The capacity credit of compressed air storages is assumed to be lower than for pump- and hydro-storage, since the volume factor is significantly lower.

5.5 Economic and technical parameters of grid technologies

The cost of grid upgrades depends on the type of technology, terrain, length and power rating of lines. The following assumptions have been made for High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC) transmission lines, based on ICF Consulting (2002), Oeding (2004), Lazaridis (2005), and Spahic (2009).

TABLE 9: TECHNO-ECONOMIC FIGURES FOR GRID TECHNOLOGIES

Technology	Grid Upgrade Costs [$€_{2010}$/kW/km]	Converter Costs [$€_{2010}$/kW]
HVAC (Overhead line)	0.4	-
HVDC (Cable)	1.5	150

Source: EWI / energynautics

The costs for both technologies were adjusted depending on the terrain of the region covered by the transmission line, allowing for up to 50% higher costs for lines crossing mountainous regions. Grid upgrade costs per kW and km are significantly higher for HVDC cables than for HVAC overhead lines. Moreover, for HVDC cables additional costs for the converter occur.

Investments in overhead lines using HVAC technologies are common practice in today's power systems as they depict the least-cost option for transmission capacity extensions. HVDC cables, in contrast, are so far only used for offshore connections between two territories, where cables need to be used, due to high compensation needs of reactive power demand of cables in HVAC systems.

In this study, investment priority is given to HVAC system upgrades, whereas the maximum upgrade per route is limited to a tripling of today's installed capacity. Any additional power would have to be transported via HVDC connections. Such onshore HVDC connections will most likely form an HVDC Supergrid overlaying the HVAC grid to transport high power over long distances. Since HVAC is a long-established technology, there is hardly any potential for price reductions. HVDC, in contrast, does provide some opportunities for cost reductions through market development, both for Line Commutated Converter (LCC) and Voltage Source Converter (VSC). However, since there are no reliable estimates of learning curves available for this technology, learning curves have been disregarded in this study for HVAC and for HVDC costs.

Overall, the analysis focuses on the transmission grid only. Thus no implications for the distribution grid are assessed. In general, the more decentralized a power system, the greater the need for distribution grid augmentation and thus the associated costs. Within the market model, the grid is represented by NTC-constraints, which simplify the technical characteristics of transmission systems. Power flows depend on the hourly dispatches of power plants, influenced mainly by regional demand patterns, regional weather conditions, variable costs of available power plants, economic im- and export streams and outages of power plants. A yearly NTC-value, as represented in the market model, is thus an average of net transfer capacities at different weather, demand and generation situations during this year. In addition, future NTC extensions in the market model are assumed to be the same in both directions, since directions of maximal NTC values can vary on an hourly basis and change fundamentally compared to today. Existing NTC-values are aligned for both flow directions within the optimal grid extension scenario (Scenario A), justified by the application of low cost reactive power compensation methods.

5.6 Development of fuel prices

Assumptions on fuel prices are mainly based on the World Energy Outlook 2010 (IEA (2010b)), and complemented by EWI expertise in various energy markets. Table 10 lists the assumed development of fuel prices together with historical prices. Regarding the different fuel types, the following aspects were taken into consideration:

After the price of oil peaked at 125 US$/barrel in 2008 it rapidly came down to values well below 70 US$/barrel. Since then the oil price has been subject to increase and is now at about 100 US$/barrel. In the long term, the oil price is expected to significantly increase until 2020 and at moderate rates from then on, such that it reaches 116 $€_{2010}$/MWh in 2050.

As for hard coal, trade market prices depend on production capacities, development of input factor prices to mining, transport infrastructure such as port facilities and coal demand. After 2008, when European import price levels for steam coal have been remarkably high, the world market price returned to a short period of lower price levels in 2009 due to decreasing demand. Starting in 2010 European steam coal import prices have rebounded and reached more than 120 US$/t in spring 2011 (CIF ARA basis). Import demand in Asia, especially in China and India, is projected to rise in the future which will support firm trade market prices. However, it is unlikely that prices rise strongly as coal production costs are relatively low compared to production costs of other fossil fuels and the amount of reserves will be sufficient to meet the increasing demand. Thus, we assume slightly rising prices on account of increasing material, transport and labor costs (IEA (2010b)).

Due to the low calorific value and high moisture content causing high transport costs per energy unit, there is no world trade market for lignite. We expect that better productivity offsets increasing cost factors (such as material, transport or labor costs). Consequently the prices are assumed to remain at the level of 2008.

The price of natural gas was historically closely linked to the oil price due to its substitutional relationship. However, it is expected that in the future gas markets will be more competitive and prices will be less influenced by oil price movements. Due to its characteristic of being a scarce resource, prices are assumed to increase from 28 $€_{2010}$/MWh_{th} to 35 $€_{2010}$/MWh_{th} in the long term.

Uranium prices have risen in recent years as new nuclear power plants were built, mainly in Asia and Eastern Europe. Simultaneously, increased prices motivated additional exploration of uranium mines. However, after the Fukushima disaster it generally remains unclear how the global trend regarding nuclear energy develops. Nuclear fuel prices were assumed to slightly decrease until 2020 and remain on a stable level after then.

Prices of biofuels (solid and gaseous) are defined country-specific thus accounting for the different potentials (as in section 5.3) and/or different agricultural conditions. Minimal and maximal values indicating the price range are given in Table 10. Similar to other fuels, biofuels are expected to become more expensive until 2050.

TABLE 10: ASSUMED DEVELOPMENT OF FUEL PRICES [€2010/MWhth OR AS REPORTED]

	2008	2020	2030	2040	2050
Nuclear	3.6	3.3	3.3	3.3	3.3
Lignite	1.4 (16.1 $_{2010}$/TCE)	1.4 (16.1 $_{2010}$/TCE)	1.4 (16.1 $_{2010}$/TCE)	1.4 (16.1 $_{2010}$/TCE)	1.4 (16.1 $_{2010}$/TCE)
Oil	44.6 (106.8 $_{2010}$/BOE)	99.0 (237.0 $_{2010}$/BOE)	110.0 (263.4 $_{2010}$/BOE)	114.0 (273.0 $_{2010}$/BOE)	116.0 (277.7 $_{2010}$/BOE)
Coal	17.28 (198.1 $_{2010}$/TCE)	13.4 (154.1 $_{2010}$/TCE)	13.8 (158.8 $_{2010}$/TCE)	14.3 (163.5 $_{2010}$/TCE)	14.7 (168.1 $_{2010}$/TCE)
Gas for power generation	25.2 (10.4 $_{2010}$/Mbtu)	28.1 (11.6 $_{2010}$/Mbtu)	31.3 (12.9 $_{2010}$/Mbtu)	33.2 (13.7 $_{2010}$/Mbtu)	35.2 (14.5 $_{2010}$/Mbtu)
Biosolid	15.0 - 27.7	15.7 - 34.9	16.7 - 35.1	17.7 - 35.5	18.8 - 37.5
Biogas	0.1 – 70.0	0.1 - 67.2	0.1 - 72.9	0.1 - 78.8	0.1 - 85.1

Source: EWI / energynautics

5.7 Political assumptions

Major political assumptions concern renewable energy targets, CO_2 emission reduction targets and nuclear policies within the individual countries.

We model a European-wide quota for electricity from renewable energy sources. This quota prescribes the minimum RES-E share of gross electricity consumption which has to be reached per year.[1] Since no country-specific RES-E targets are assumed, the European-wide target can be fulfilled by deploying RES-E on favorable sites throughout Europe. In 2020, 34% of Europe's gross electricity consumption is required to come from renewable energy sources, reflecting the single EU member states renewable energy targets for the electricity sector of their National Renewable Energy Action Plans (NREAPs). From then on a linear increase is assumed rising up to a target value of 80% in 2050 (see Table 11). As additional condition, no priority access of electricity generation from renewable energy sources is modeled. As such, wind and solar power electricity generation can be curtailed, if beneficial from an economic point of view. A European-wide CO_2 bound limits the emissions from power generation. 80% reduction has to be realized by 2050 with reference to the year 1990.

[1] The gross electricity consumption is determined endogenously in the model (electricity consumption of power plants and energy storages and grid losses for electricity imports and exports are determined endogenously). The quota-setting takes into account the assumed development of the endogenous components of gross electricity consumption.

TABLE 11: CO_2 REDUCTION AND RENEWABLE ENERGY TARGETS IN EUROPE [%]

[%]	2020	2030	2040	2050
RES-E Quota [in % of gross electricity demand]	34	50	65	80
CO_2 reduction quota compared to 1990	20	40	60	80

Source: EWI / energynautics

In order to achieve the RES-E and CO_2 reduction targets, imports of solar power from North Africa to Europe are possible but limited to a maximum amount of 200 TWh per year. This assumption is based on the consideration that North African solar power potentials will only partly be available for export to Europe, given the rising electricity needs of North Africa over the next decades. Out of the same reason it is assumed that the North African wind potential is used to cover the regional electricity demand and not available for exports.

An additional political assumption concerns the decisions on nuclear phase-outs in several European countries. Investments in nuclear plants are restricted to those countries which actively consider building new plants (IEA, 2010c).[1] In addition, due to long construction times of nuclear plants, investments before 2025 are restricted to those plants already under construction today.

[1] These assumptions do not include recent reconsiderations of nuclear policies after the Fukushima Catastrophe except for Germany where a faster nuclear phase-out was decided and is legaly binding.

6 SCENARIO RESULTS

This chapter presents results of the scenario analysis. Regarding the generation system, it describes the development of capacities, electricity generation, utilization times, import and export flows as well as CO_2 emissions. In addition, the development of the transmission grid until 2050 and system costs for electricity are presented. Section 6.1 covers the results of Scenario A and depicts thus the electricity system when generation and grid investments are chosen in a cost-minimizing way. The electricity system in the case of a moderate extension of interconnector capacities (Scenario B) is described in section 6.2. The results of both scenarios reflect the main political assumptions both scenarios have in common: to reach an 80 % RES-E and an 80 % CO_2-emission reduction target until 2050. A comparison and interpretation of the differences between the two scenarios is covered in chapter 7.

6.1 Scenario A: Optimal transmission grid

In Scenario A, the development of the European electricity system until 2050 results from a cost-minimizing optimization of generation and transmission technologies (see chapter 3). The following section deals with the scenario results for the European electricity mix (capacities, generation, utilization rate), trade flows between countries, the development of the transmission grid, CO_2 emissions in the electricity sector and system costs in Scenario A.

6.1.1 Capacities, generation and utilization

Capacities

Figure 14 shows the development of generation capacities in Europe until 2050. Overall, capacity increases due to a rising electricity demand and because of an increasing RES-E share. An increasing share of electricity generation from renewables requires a larger quantity of generation capacities because most renewables (especially wind and solar technologies) have lower full load hours than thermal or nuclear plants and because fluctuating renewables contribute less to capacity requirements from a security of supply point of view (low capacity credit).

Until 2020, the most remarkable change in the European capacity mix is a strong increase in onshore wind capacity (120 GW). The deployment takes place at favorable onshore wind sites, primarily in Great Britain (25 GW additional deployment until 2020), France (25 GW) and Poland (17 GW). In addition, European biomass capacities increase due to a deployment of 2.4 GW in Spain, 1.8 GW in France and 1.7 GW in Poland. Furthermore, thermal and nuclear plants which are decommissioned until 2020 are replaced by new plants. The most significant replacements concern lignite plants (12.8 GW in Germany and 3 GW in Poland) and nuclear plants (8.7 GW in France).

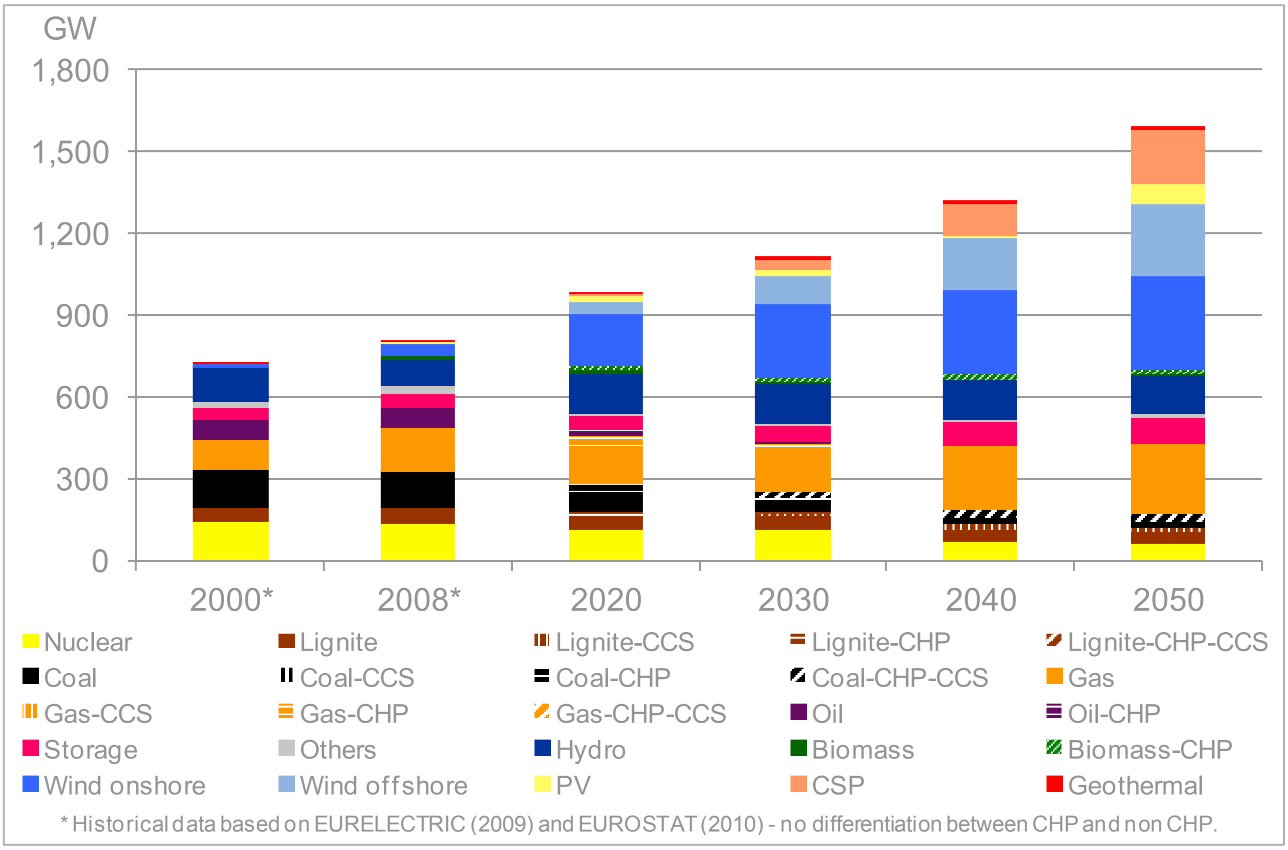

FIGURE 14: EUROPEAN CAPACITY MIX DEVELOPMENT UNTIL 2050 (SCENARIO A) [GW]

Source: EWI / energynautics

In the medium term (2020 to 2030), mainly onshore and offshore wind as well as concentrated solar power plants are built. The increase in onshore capacities essentially takes place in the same countries where a large increase is also observed until 2020: France (+29.9 GW), Germany (+16.1 GW) and Poland (+13 GW). Offshore wind turbines are installed in the Netherlands (+15 GW), Denmark (+13.4 GW), Great Britain (+10.3 GW) and Norway (+9.3 GW). Concentrated solar plants are built in regions with high yearly solar radiation: Spain (+28.9 GW) and North Africa (+1.5 GW). Regarding thermal power plants, the most significant development concerns coal plants equipped with CCS and CHP in Italy (+4.6 GW), Germany (+4.0 GW), the Netherlands (+3.9 GW), Romania (+2.2 GW) and Great Britain (+1.7 GW).

In 2050 the European capacity mix is dominated by onshore and offshore wind capacities as far as renewable energies are concerned and by gas-fired plants concerning conventional technologies. Countries with particular high installed onshore capacities are France (67.4 GW), Germany (47.4 GW), Great Britain (41.7 GW), Poland (40.1 GW) and Spain (35.5 GW). Offshore capacities are primarily located in the Netherlands (73.3 GW), Norway (61.5 GW), Great Britain (45 GW), Denmark (39.6 GW) and Ireland (13.6 GW). Between 2030 and 2050 CSP capacity expansion amounts to 80 GW in Spain, 70 GW in Italy, 32 GW in North Africa, and 19 GW in Greece, PV systems are primarily deployed in Italy (+32 GW) and France (+20 GW). Gas capacities are further expanded in France (+54.6 GW), Germany (+33.3 GW), Great Britain, Italy and the Netherlands (+11 GW each).

Electricity generation

Figure 15 depicts the development of the European gross electricity generation until 2050. The development is driven by all factors described above with regard to the European capacity mix. In comparison to the doubling of capacities during the modeled time frame, the increase of gross electricity generation is smaller (+33% from 2008 to 2050). Reasons are twofold: First, as already described above, RES-E plants (besides biomass and geothermal power plants) have lower full load hours compared to thermal or nuclear power plants. Thus a rising RES-E share leads to increasing capacities, regardless of demand developments. Second, also mentioned above, fluctuating RES-E have a low capacity credit. For this reason security of supply has to be ensured by sufficient securely available capacities. Since these capacities have usually very low full load hours, capacities with low investment costs are chosen. Since a large part of gas capacities are gas turbines built to ensure security of supply, the high capacity share of gas is not reflected in the generation mix.[1]

Regarding the electricity generation by RES-E plants in 2050, it is eye-catching that about 40% of total gross electricity generation is provided by wind power. Due to high full load hours of offshore wind sites, the largest part of wind generation comes from offshore sites even though more onshore capacities are installed. Photovoltaic in contrast is an example of a technology with comparatively low full load hours (even on favorable sites) and thus characterized by a significantly lower share in the electricity generation than in the capacity mix. Electricity imports from North African solar power plants contribute with 153 TWh to the European 2050 RES-E target of 80%.

[1] In 2050, no generation takes place in gas-fired power plants and the large share of gas capacities is only installed out of security of supply reasons. In reality, those plants would have very low full load hours during hours with high demand and hardly wind and/or solar infeed. Due to modeling the dispatch decisions for typical days (see Section 4.1), not all possible "extreme" weather events could be explicitly modeled within the investment and dispatch model. From a grid point of view, these situations have been tested for security of supply issues (see Section 6.1.4).

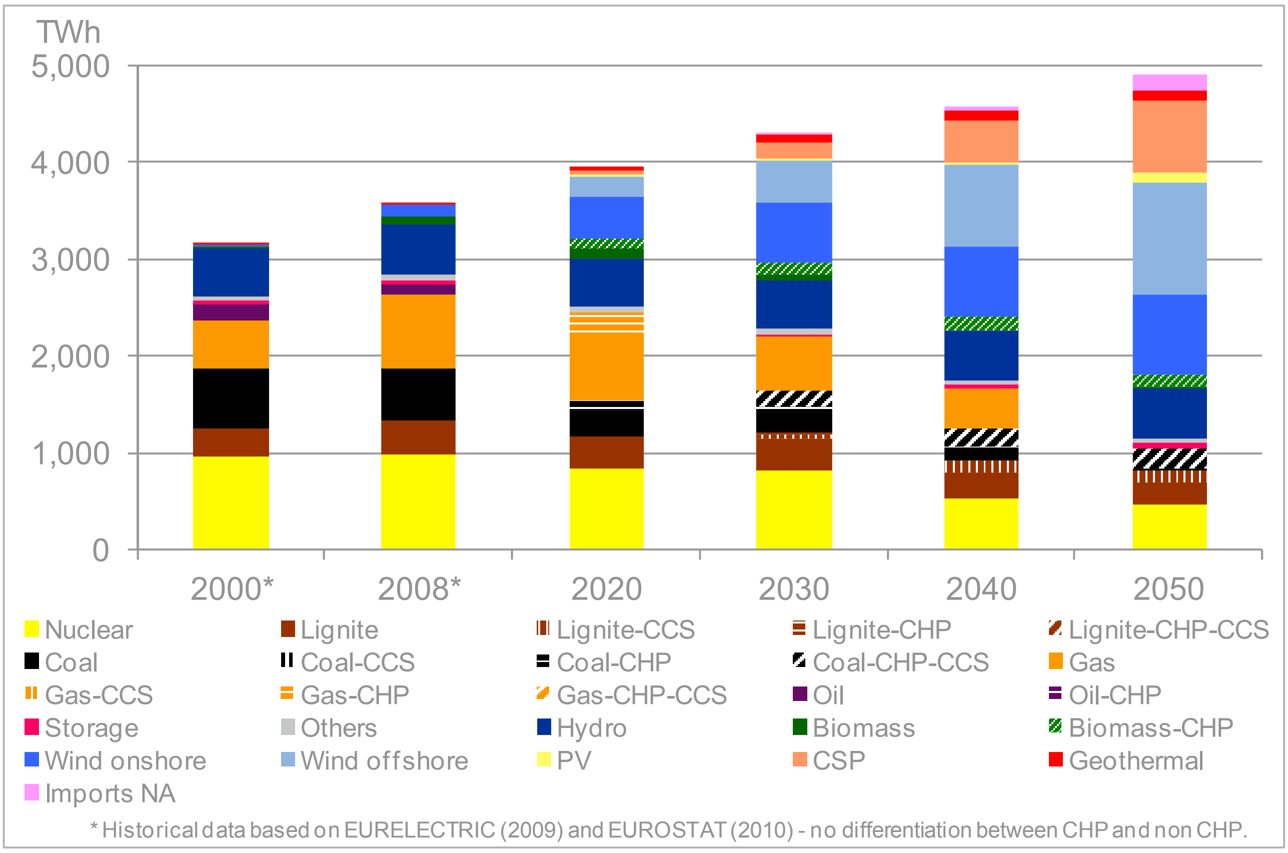

FIGURE 15: EUROPEAN ELECTRICITY GENERATION DEVELOPMENT UNTIL 2050 (SCENARIO A) [TWh]

Source: EWI / energynautics

Utilization

Figure 16 and 17 show the development of average utilization times of conventional and nuclear power respectively of renewable plants in Europe.

Considering conventional and nuclear plants it can be observed that the utilization of base load plants with low CO_2 emissions (lignite-CCS, coal-CHP-CCS and nuclear) is constantly high. Looking at the year 2020 gas-fired power plants have untypical high full load hours. The reason is that an ambitious 2020 CO_2-target has to be reached while CCS plants are assumed to be commercially available starting from 2030. For the same reason, the utilization of coal plants is untypical low in the short term. In the mid and long term full load hours of gas plants decrease because of increasing gas prices, capacity commissions of coal- and lignite- CCS-plants and the increase of gas capacity of which a large part is only built out of security of supply reasons, as discussed above. Coal generation in 2050 comes primarily from CHP plants, with the utilization of coal equipped with CCS (and CHP) power plants being twice as large as the one of coal plants (only equipped with CHP).

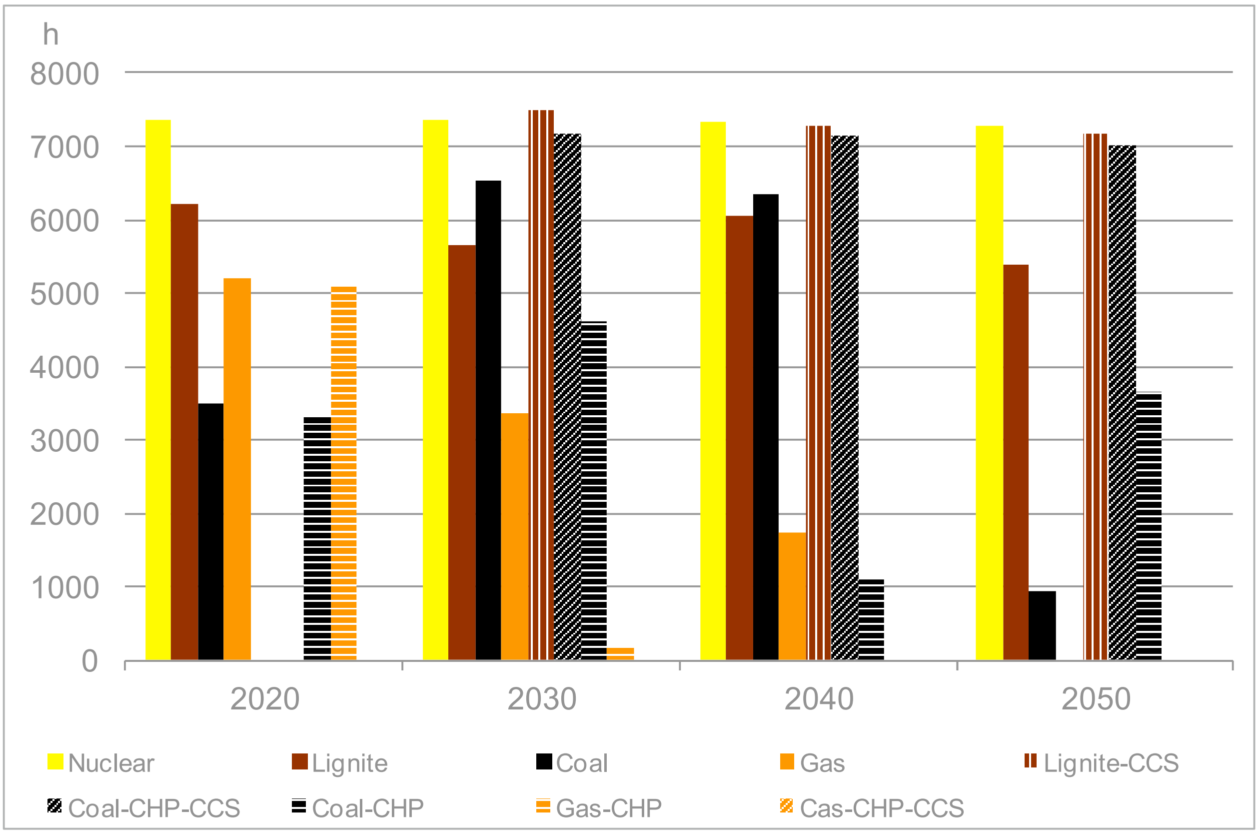

FIGURE 16: EUROPEAN AVERAGE UTILIZATION OF NUCLEAR AND CONVENTIONAL PLANTS (SCENARIO A) [h]

Source: EWI / energynautics

Full load hours of fluctuating renewable energy sources are lower than those of thermal and nuclear plants. In contrast, dispatchable RES-E capacities - biomass and geothermal plants - have relatively high full load hours. The full load hours of biomass-CHP and of geothermal plants - which also produce heat in cogeneration - are comparable to those of nuclear or lignite-CCS plants. Full load hours of on- and offshore wind slightly increase over time due to technological learning effects (see section 5.3), while full load hours of hydro plants remain constant since the inflow to hydro reservoirs and run-of-river plants is normalized to an average water year.

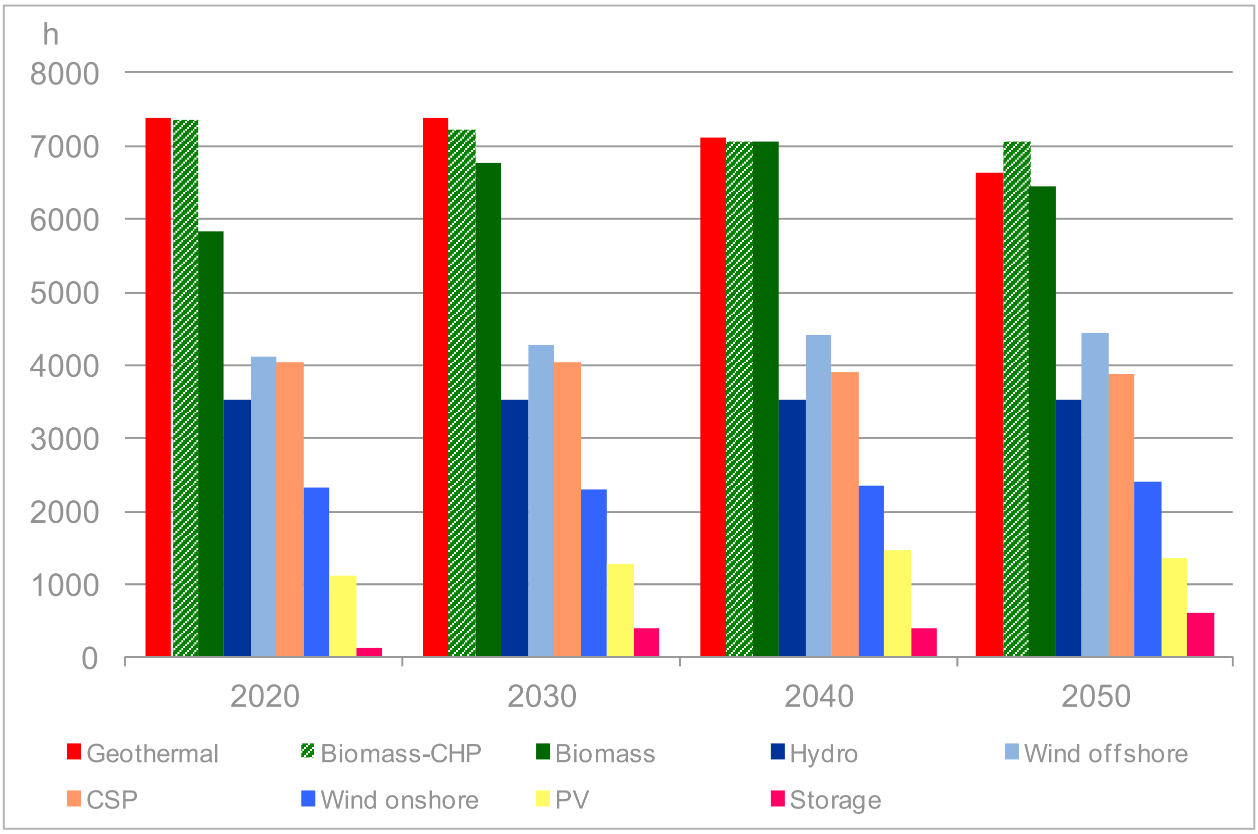

FIGURE 17: EUROPEAN AVERAGE UTILIZATION OF RENEWABLE PLANTS (SCENARIO A) [h]

Source: EWI / energynautics

6.1.2 Electricity trade flows

Figure 18 depicts European import and export trade flows in Scenario A for the years 2020 and 2050. It is important to notice that these trade flows are not identical to physical load flows described in section 6.1.3. Trade flows occur in the economic investment and dispatch model when contributing to the overall cost-minimizing solution, e.g. because a plant with lower variable costs can be dispatched in a neighboring country. The color patterns in Figure 18 indicate whether a country is a net-importing, a net-exporting or a self-sufficient country (defined as a country with yearly net imports in a range of +/- 10% of gross electricity demand).

Generally it can be seen that in both years the opportunity of trade is substantially used. Extensive transmission grid investments until 2020 and in the timeframe between 2030 and 2050 (see section 6.1.3) enable a deeper intermeshing of the European power markets compared to today. The trade flows in Figure 18 show that in both years also self-sufficient countries are characterized by considerable im- and export streams. Only in sum over the year, their imports equal more or less their exports.

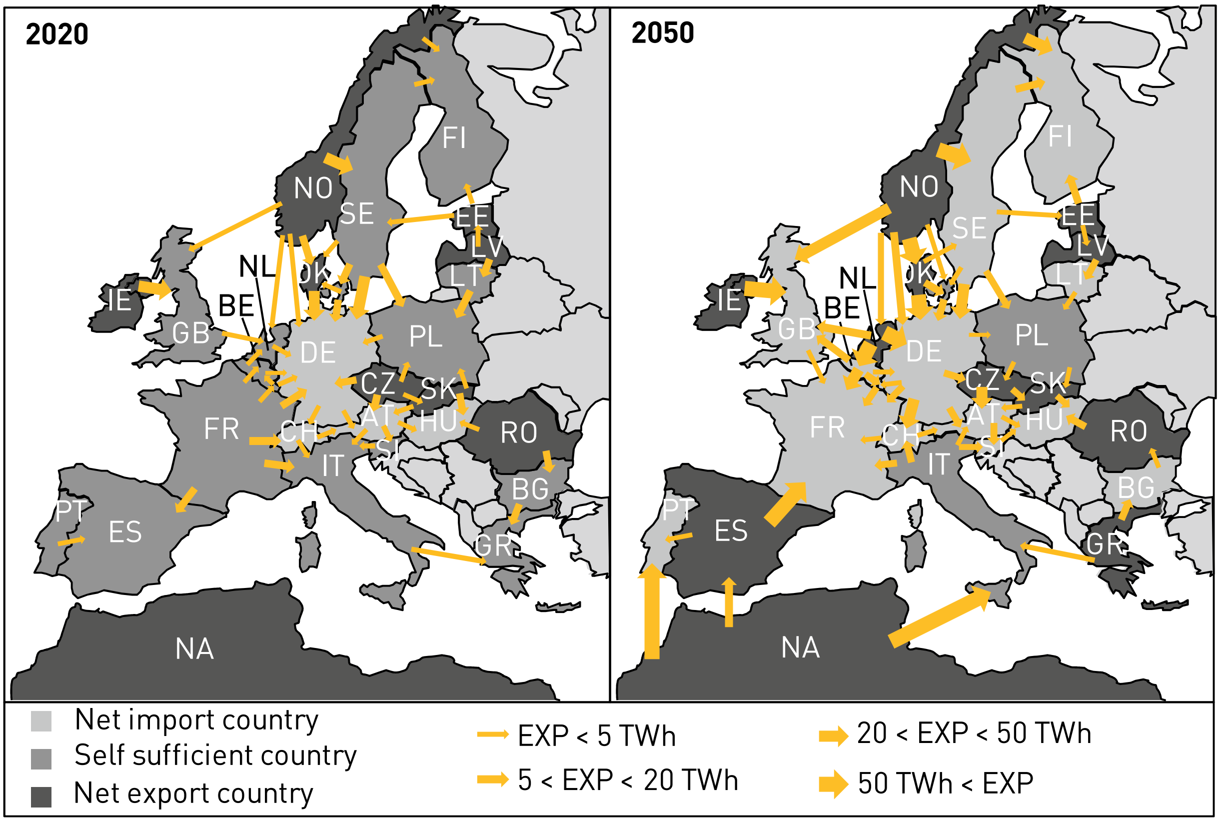

FIGURE 18: EUROPEAN IM- AND EXPORT STREAMS IN 2020 AND 2050 (SCENARIO A)

Source: EWI / energynautics

In the year 2020 most net importing countries are located in Central Europe (Germany, Switzerland and Austria). Net exporting countries are characterized by favorable potentials for renewables with comparatively low generation costs (i.e. hydro in Norway or wind in Ireland) or by conventional capacities with low variable costs (nuclear in France or lignite in the Czech Republic). Countries with net-imports within the range of +/- 10% of their gross electricity demand include Portugal, Spain, France, Great Britain, Italy and Poland. Those countries have favorable renewable potentials (and/or plants with low variable costs like nuclear in the case of UK and Spain) but also high electricity demand levels. The Spanish electricity mix in 2020 for example, comprises a large quantity of capacities with marginal or low variable costs: 24 GW onshore wind, 13 GW hydro, 7 GW nuclear, 13 GW solar (PV and CSP) and 5 GW storage capacities. Still, the Spanish demand in 2020 is among the five highest in Europe and hence capacities are mainly used for the domestic supply.

In 2050 a trade stream pattern from Europe's Northern, Southern and Eastern borders to the Central European countries can be observed. The largest net-exporting countries are mainly located in Northern Europe with large favorable wind potentials compared to their demand levels (Ireland, Norway, Denmark, the Netherlands, Estonia and Latvia) and countries with high full load hours for solar technologies in Southern Europe (Spain, Italy and Greece). Spain changes from a self-sufficient to a net-exporting country between 2020 and 2050, because of a significant deployment of solar technologies. Solar technologies have higher generation costs than onshore and offshore wind power plants on the best sites in Europe. Therefore, these plants are not deployed until 2020, when the European RES-E target can be fulfilled mainly by wind and hydro generation. With an increasing RES-E target, a rising European electricity demand and decreasing generation costs of solar technologies (cost reductions for PV and CSP are assumed to be higher than for wind technologies, see section 5.3), the role of solar technologies in Southern Europe becomes more important. Compared to 2020, the 2050 map shows significantly less countries with net-imports within a range of +/- 10% of gross electricity demand (only Poland and Italy).

6.1.3 European transmission grid

Between today and 2050, 1,217 GW new grid capacities are built adding up to a total length of 228 thousand kilometers (tkm). Figure 19 shows the transmission grid extensions in GW (capacity) and tkm (line length) within Europe until 2050. In the first decade, lines are built in HVAC technology, as this is the cheapest solution. In the long run HVDC technology is used to transport electricity with high efficiency over long distances from remote areas to the load centers in Central Europe.

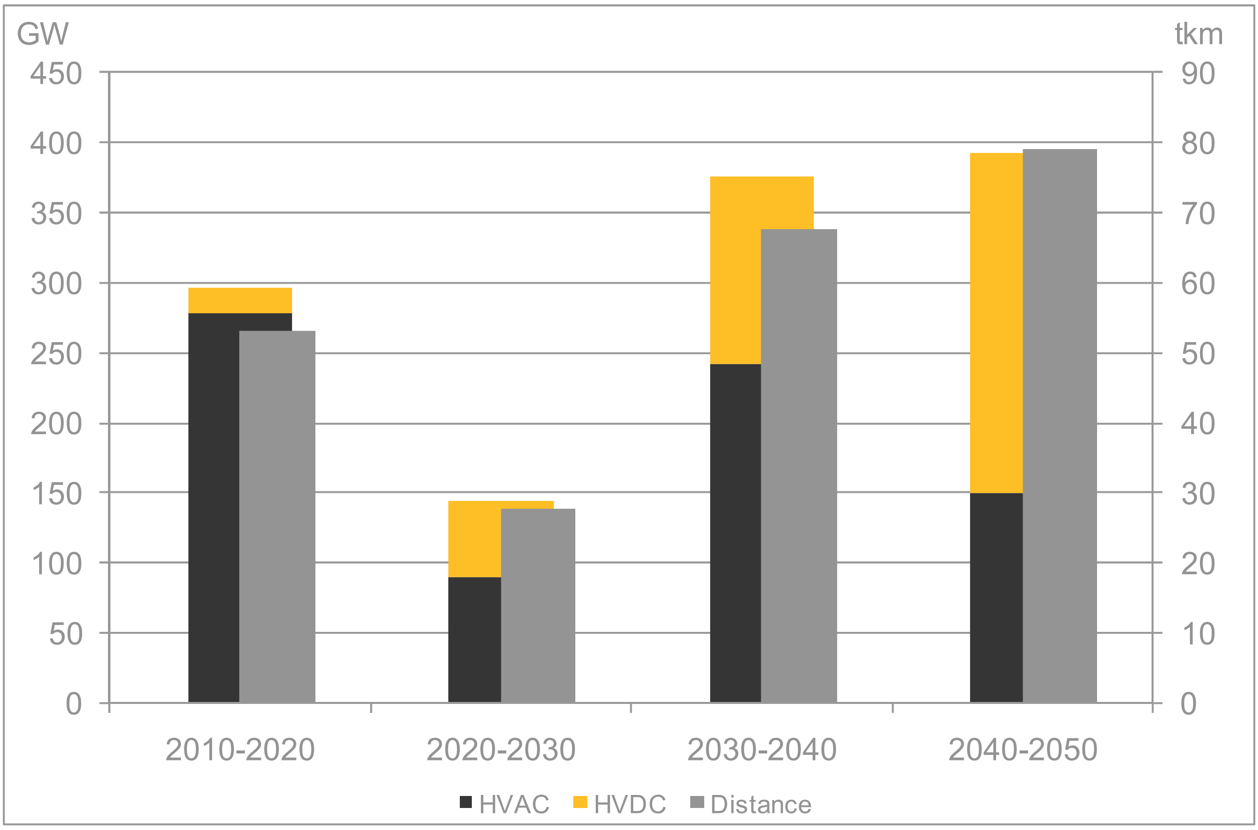

FIGURE 19: TRANSMISSION GRID EXTENTIONS WITHIN EUROPE – CAPACITIES [GW] AND LINE LENGTH [tkm] (SCENARIO A)

Source: EWI / energynautics

Until 2020, nearly 300 GW new grid capacities are built in Europe with a total line length of more than 53 thousand kilometers, mainly using HVAC technology. Only a small amount of transmission grid extensions until 2020 constitutes HVDC technology (+18 GW), which are primarily used offshore. As shown in Figure 20, which depicts the development of the transmission grid between 2010 and 2020, major upgrades are required all over Europe. Transmission grid capacities between Germany and Denmark as well as within Denmark need to be upgraded by 8 GW, driven by a major increase of wind power capacities in Denmark. Furthermore, a stronger link to the Nordic countries is needed as more electricity is imported from Germany. As nuclear power is phased out in Germany and coal-fired generation is considerably reduced due to the 2020 CO_2 reduction target, the transmission grid capacities in Germany are extended towards the neighboring countries, such as Belgium and the Czech Republic. To improve the integration of the Baltic power system, a new connection between Poland and Lithuania is established by 2020. Furthermore, the connection to Scandinavia is improved by building 4.4 GW HVDC links. As no imports from North Africa are expected until 2020, the Spanish transmission grid does not face a major upgrade until 2020. Only along the Mediterranean and between Spain and France further grid upgrades of 2.3 GW take place.

During the period from 2020 to 2030, the need for transmission grid upgrades is relatively low (Figure 21). Compared to the first decade, the transmission grid upgrades amount to around 150 GW, which represents only half the amount built in the previous decade. Major transmission grid upgrades until 2020 allow for essential load flows. The need for additional lines is also reduced because CCS technology becomes available in 2030, which is typically located close to load centers. As more and more offshore-wind resources in Germany and Denmark are deployed, transmission grid capacities in Northern Germany must be significantly increased, as well as the interconnection to Belgium and the Netherlands (Figure 21). To transport power from nuclear power plants to neighboring countries, the transmission grid in France is extended. During this decade, the first new connections to North Africa are built in order to import solar power. This also leads to the necessity to increase transmission grid capacities between Spain and France.

From 2030 to 2040, more than 67 thousand kilometers of new lines with a total capacity of more than 370 GW are built of which one third makes use of HVDC technology (Figure 19). During this decade offshore wind power and solar power capacities are significantly extended. As shown in Figure 22, major upgrades are needed in Central Europe to integrate wind power from the North Sea into the European power system. Upgrades of more than 10 GW are built between Denmark and Germany. Also, in Norway, Sweden and Finland the transmission grid is significantly extended. Due to an increase of solar capacities in Portugal and Spain and due to imports from North Africa, the transmission grid on the Iberian Peninsula is extended.

In the last decade investigated (2040 to 2050), another significant extension of transmission grid capacities is required when heading towards an electricity system with an 80% RES-E share. As shown in Figure 19, almost 400 GW of transmission grid upgrades in Europe are built, of which two-thirds are HVDC connections. The high share of HVDC is caused by the necessity to transport electricity from renewable resources over long distances to consumers. The necessary upgrades during this decade are shown in Figure 23. A new connection from North Africa to Italy is built, leading to the necessity to strengthen the transmission grid within Italy in the northbound direction. Also, in Spain and France many new transmission lines are constructed to transport electricity imported from North Africa towards the load centers in Central Europe. In Great Britain major upgrades take place in the area around London. Moreover, the HVDC connection to Belgium is upgraded by another 1.6 GW. Due to increasing installations of offshore wind power plants located in the North Sea off the coast of the Netherlands, upgrades of more than 12 GW (mainly HVDC) are necessary to integrate the rising wind power generation.

FIGURE 20: TRANSMISSION GRID UPGRADES FROM 2010 TO 2020 (SCENARIO A) [GW]

Source: EWI / energynautics

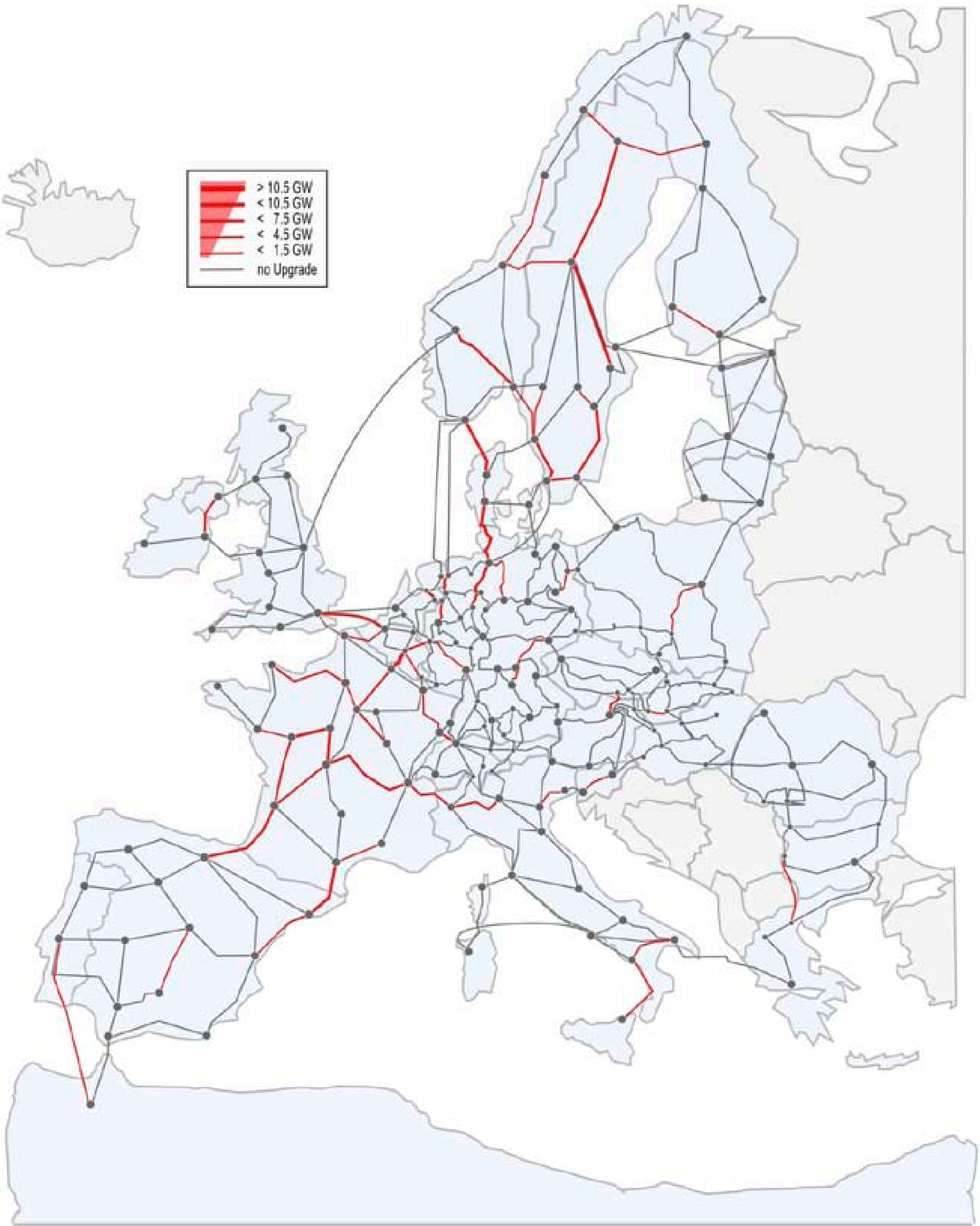

FIGURE 21: TRANSMISSION GRID UPGRADES FROM 2020 TO 2030 (SCENARIO A) [GW]

Source: EWI / energynautics

FIGURE 22: TRANSMISSION GRID UPGRADES FROM 2030 TO 2040 (SCENARIO A) [GW]

Source: EWI / energynautics

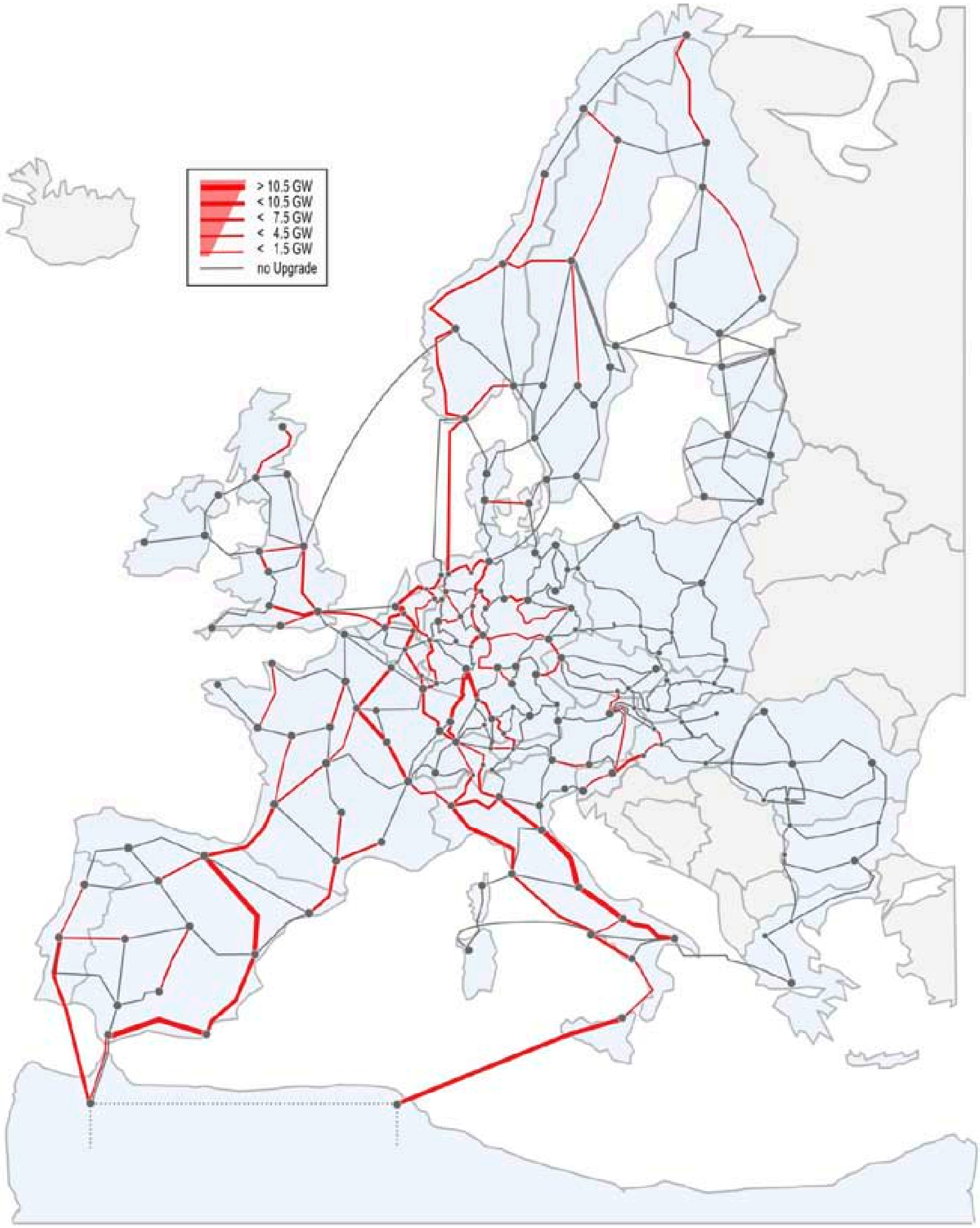

FIGURE 23: TRANSMISSION GRID UPGRADES FROM 2040 TO 2050 (SCENARIO A) [GW]

Source: EWI / energynautics

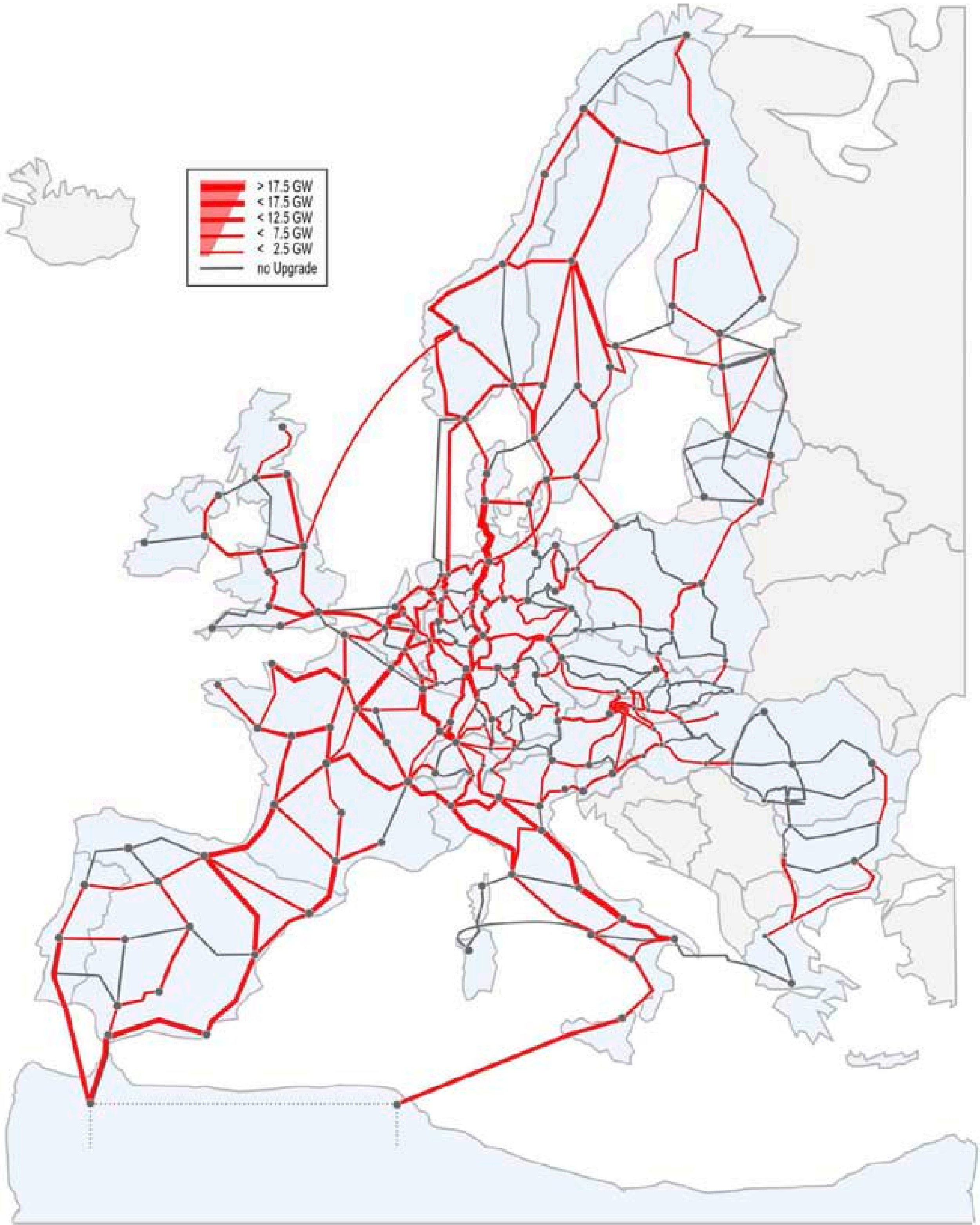

FIGURE 24: TOTAL TRANSMISSION GRID UPGRADES FROM 2010 TO 2050 (SCENARIO A) [GW]

Source: EWI / energynautics

6.1.4 CO_2 emissions in the electricity sector (including heat in co-generation)

As described in section 5.7, a European CO_2-reduction target of 20% in 2020 and 80% in 2050 compared to the CO_2-emission level in 1990 has to be reached.

As CCS-technologies are assumed to be commercially available only starting from 2030, the 2020 target is reached by an increasing RES-E generation and by a fuel switch of thermal power plants (increasing gas and decreasing hard coal generation). Countries contributing most to the 2020 CO_2 reduction target are Poland with a switch from coal to wind generation (60 mio. t CO_2 reduction compared to 2008), Great Britain with increasing wind and nuclear and decreasing thermal generation (65 mio. t CO_2 reduction compared to 2008) and Germany with increasing generation from gas, biomass and wind onshore plants which replace a part of Germany's coal generation (24 mio. t CO_2 reduction compared to 2008). Also Bulgaria and France contribute significantly to the 2020 target with a reduction of around 13-15 mio. t CO_2 compared to 2008 each. This reduction is driven by a replacement of coal in Bulgaria by biomass generation and in France by nuclear and wind onshore generation.

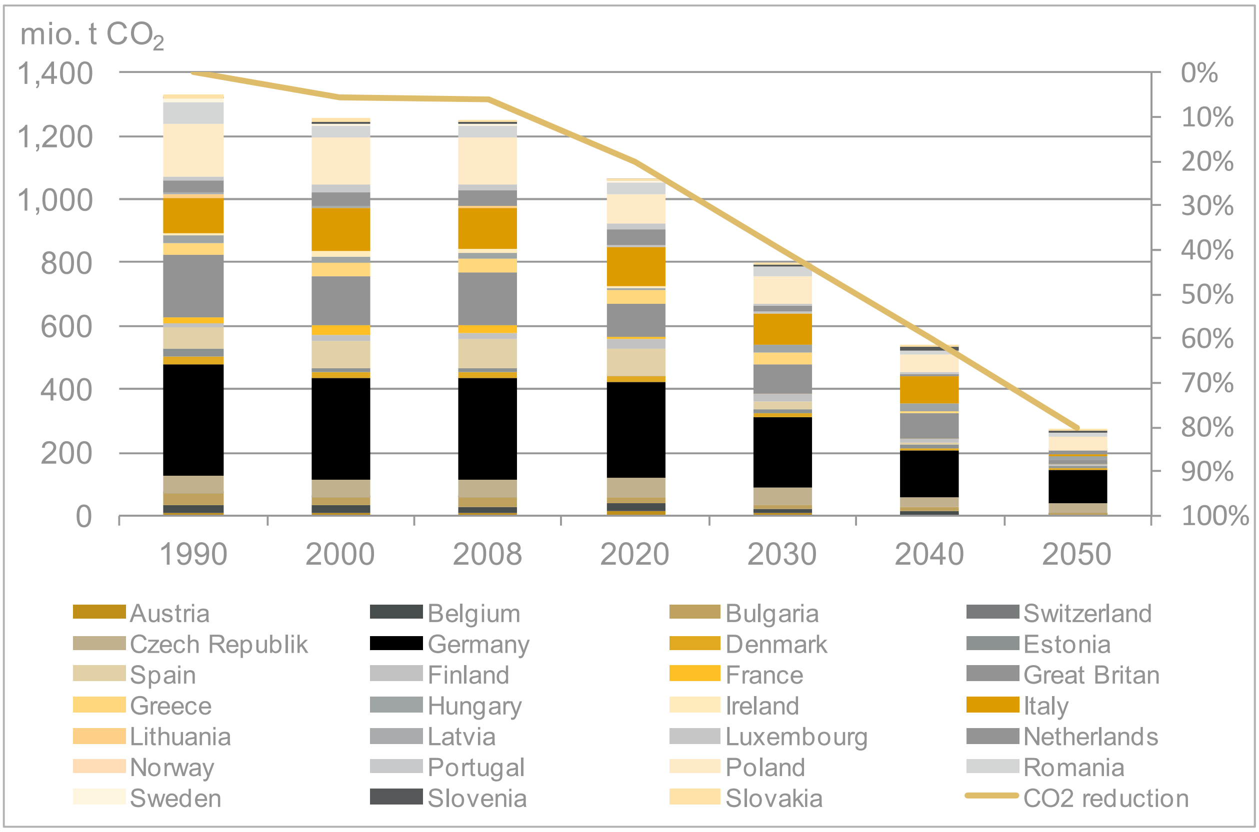

FIGURE 25: CO_2 EMISSIONS IN THE ELECTRICITY SECTOR (INCLUDING HEAT IN CO-GENERATION) PER COUNTRY (LEFT SIDE) AND CO_2 REDUCTION COMPARED TO 1990 (RIGHT SIDE) (SCENARIO A) [mio. t CO_2]

Source: EWI / energynautics

In 2050, 80% of the European electricity generation comes from RES-E power plants. An additional 10% of electricity is produced in nuclear plants and thus CO_2 neutral. About 7% of the European 2050 generation comes from CCS-plants (lignite and hard coal) and causes few CO_2 emissions. Lignite generation in non-CCS plants, which makes up 4.5% of European electricity generation, causes most of Europe's 2050 CO_2 emissions. On country levels, the European-wide 80% CO_2-reduction target is under-fulfilled in countries with lignite generation: Czech Republic (only 47% reduction compared to 1990), Finland (47% reduction), Hungary (69% reduction), Germany (70% reduction) and Poland (72% reduction). On the other hand, the European target is over-fulfilled in countries with favorable RES-E potentials and/or with nuclear capacities: Switzerland, Ireland, France, Latvia and Lithuania have a CO_2 neutral electricity generation in 2050.

As depicted in Figure 26, 57 mio. t CO_2 are captured and stored throughout Europe in 2050. About 20% of this amount is stored in Germany (lignite and coal-CHP plants), 14% in Italy (coal-CHP plants) and 12% in the Netherlands (coal-CHP plants).

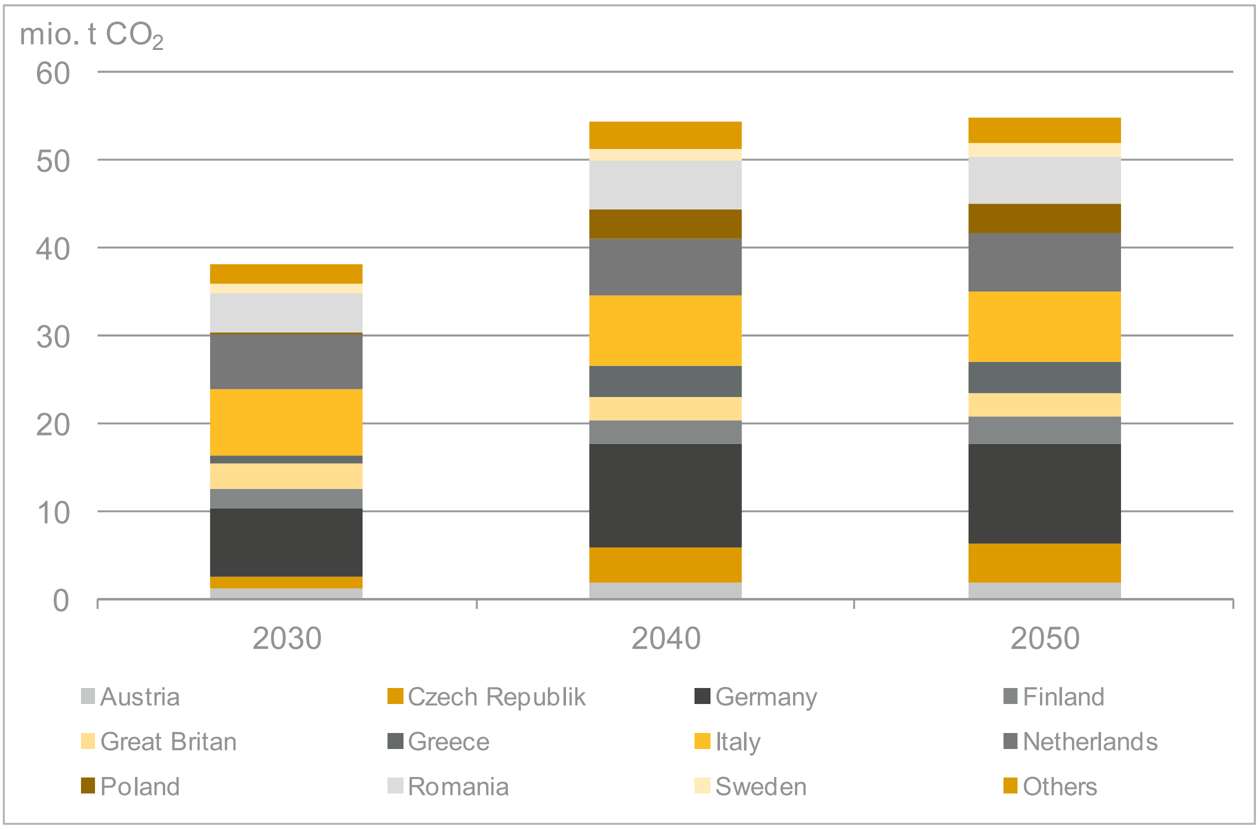

FIGURE 26: CAPTURED AND STORED CO_2 IN CCS-PLANTS PER COUNTRY (SCENARIO A) [mio. t CO_2]

Source: EWI / energynautics

6.1.5 Investments and total system costs

Figure 27 depicts the investment expenditures on conventional, renewable, storage and grid technologies, arising in each decade until 2050. The transformation of the electricity system requires significant investments, mainly in renewable technologies. The share of renewable energy investments grows over time while the investments in storage and grid technologies are relatively low throughout the time horizon until 2050.

The development of required investment expenditures is influenced by the development of total capacity commissions, the development of the technological mix and the development of the specific investment costs (per kW) of the commissioned capacities. The necessary investments increase in this scenario (up to 1,162 bn. €$_{2010}$ in the decade 2040-2050) due to the transformation to a low-carbon electricity system with mainly capital intensive technologies and due to the assumed increasing electricity demand. In the short term, investments are primarily needed to install gas-fired power plants (more than 50 GW in Europe until 2025) and wind parks at European coast lines. In the decade 2020-2030, investments in conventional power plants increase due to the replacement of several old nuclear power plants and the implied availability of CCS technologies. After 2030, further investments are needed for wind parks in Northern Europe and solar technologies primarily located in Spain and Italy.

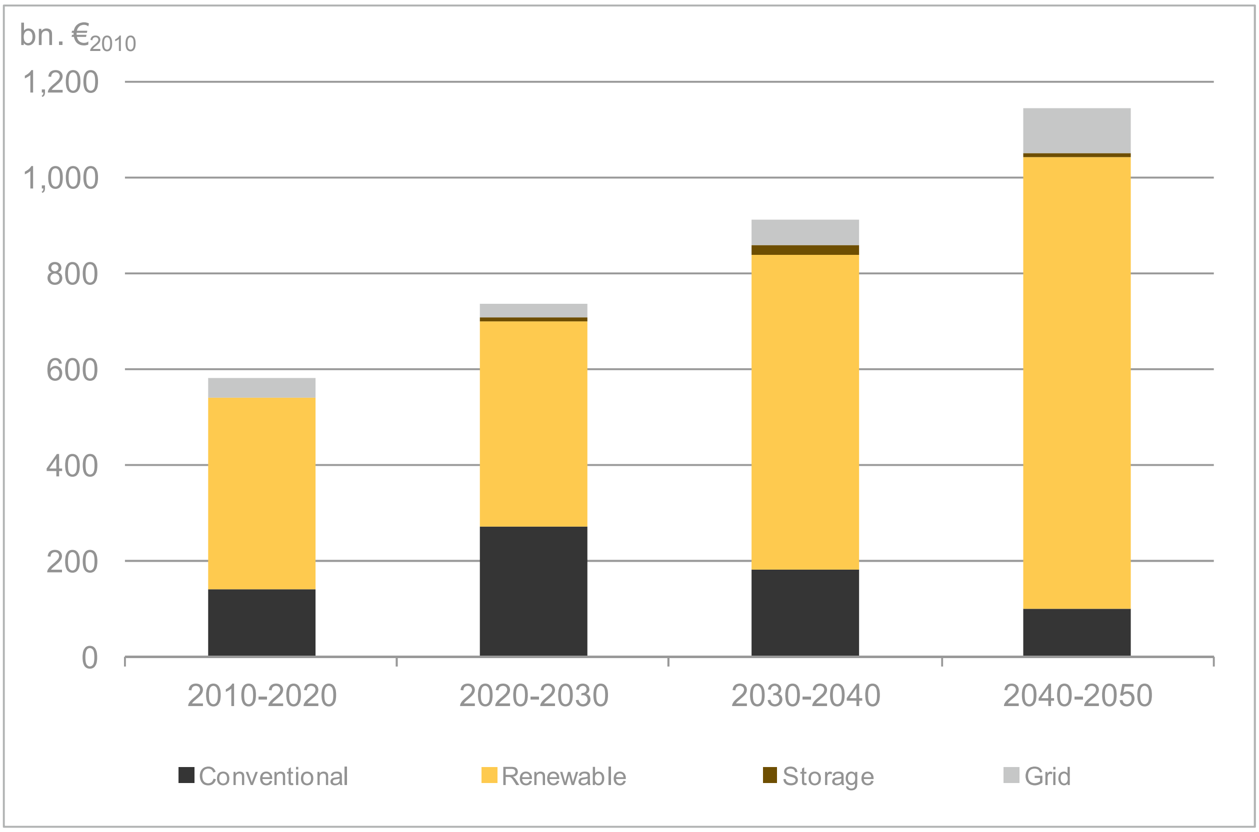

FIGURE 27: EUROPEAN INVESTMENT EXPENDITURES UNTIL 2050 (SCENARIO A) [bn. €$_{2010}$]

Source: EWI / energynautics

In addition to investment costs, fixed operation and maintenance costs as well as fuel and ramping costs arise. Figure 28 shows the development of fix costs (comprising annuitized investment as well as fixed operation and maintenance costs) and variable costs (fuel and ramping costs) in the years 2020, 2030, 2040 and 2050. In addition, the average system costs of electricity supply in Europe are depicted. Average system costs reflect the sum of investment (generation technologies and the high voltage transmission grid), fixed operation and maintenance as well as variable generation costs in relation to the total energy consumption of end users.

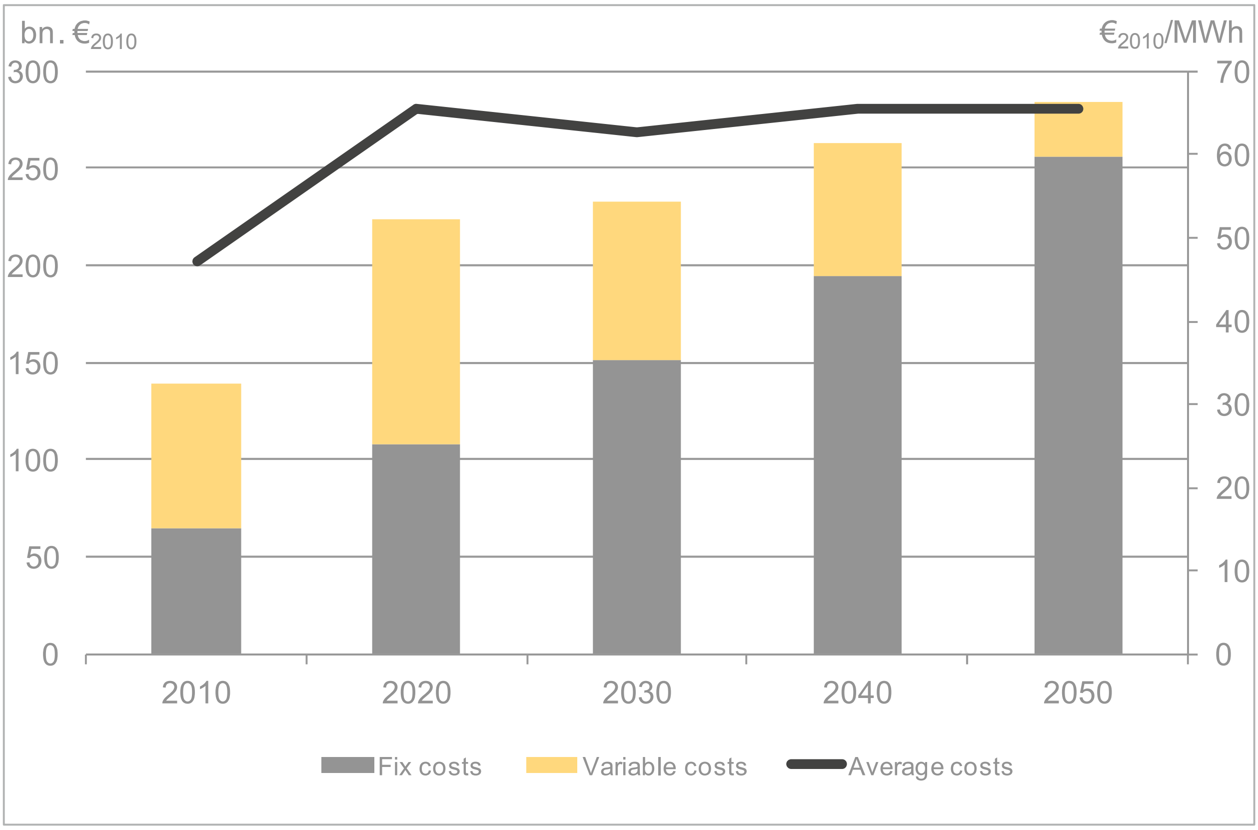

FIGURE 28: EUROPEAN FIX, VARIABLE AND AVERAGE COSTS UNTIL 2050 (SCENARIO A) [bn. €$_{2010}$]

Source: EWI / energynautics

It can be seen, that the share of fix costs increases constantly over time. This development is caused by a changing capacity mix which in 2050 is mainly based on renewable energies with marginal variable costs. In addition, in the long run a large share of conventional capacities only serves as back-up capacities out of security of supply reasons. Thus these capacities have high fix, but marginal variable costs. Hence, variable costs decrease over time despite increasing fuel prices. The average system costs increase from 47.1 in 2010 to 65.6 €$_{2010}$/MWh in 2020 due to the challenging CO_2 emission reduction target in 2020. In 2030, the average costs can be reduced primarily due to the availability of CCS-technologies and advanced wind turbines. In the long term, average system costs remain relatively stable. While higher fuel prices, higher CO_2 emission reduction as well as RES-E targets have a cost increasing effect, investment cost reductions for advanced conventional and renewable technologies (assumption) as well as the enhanced intermeshing of the European electricity system with large cross-border capacities have a cost decreasing effect. These opposite effects lead to relatively stable average costs of around 65 €$_{2010}$/MWh.

6.2 Scenario B: Moderate transmission grid

Although the necessity of transmission grid extensions for the transformation towards a low-carbon and renewable-based electricity system has been mostly accepted, construction of new lines is progressing very slowly in Europe. Especially cross-border infrastructure projects are often facing significant delays. According to an analysis of the European Commission (EC (2007)) and Buijs et al (2011), the top causes of delays are related to public acceptance issues, followed by technical issues, dependency on other projects, authorization procedures and terrain issues.

In order to analyze the impact of project delays on the cost-efficient transformation path towards a low-carbon and mainly renewable based electricity system, transmission grid capacities are only moderately extended throughout Europe until 2050 in Scenario B. Specifically, interconnector extensions are assumed to be limited to projects which have already entered the planning phase today (based on the ENTSO-E's Ten Year Network Development Plan (TYNDP)), but whose commissioning is assumed to be delayed. Assumptions regarding the delayed commissioning of interconnection extensions within Europe until 2050 (based on Net Transfer Capacities (NTC)) are derived from a detailed analysis of factors influencing the likelihood and the degree of project delays in a certain area:

- Population density
- Historical cases of public protest
- Type of terrain

Population density relates to public acceptance issues, i.e. the higher the population density of an area, the more likely the appearance of public protest against new transmission lines and thus the likelihood of project delays. A similar but separate issue is the existence of historical cases of public protest. Despite a low population density it has been historically difficult to gain public acceptance of transmission grid extension projects in certain regions in Europe, such as at the border of Spain and France. Therefore, the likelihood and the degree of project delays were assumed to be the higher the more pronounced the reported cases of public protest within a region. Also the type of terrain, which transmission lines are crossing, influences the construction progress, for example if the lines traverse mountainous regions or if access roads need to be built to reach the construction sites. Problems can also be encountered if the land is a nature reserve or a military zone. However, in relation to public acceptance issues, difficulties with regard to the type of terrain are less likely to cause delays in the project, since much of these problems ought to be already considered in the engineering design and permit planning process before the commencement of the project. For each geographic border within Europe, the above stated factors influencing the likelihood and the degree of project delays were assessed in order to determine a possible development of cross-border capacities throughout Europe until 2050.

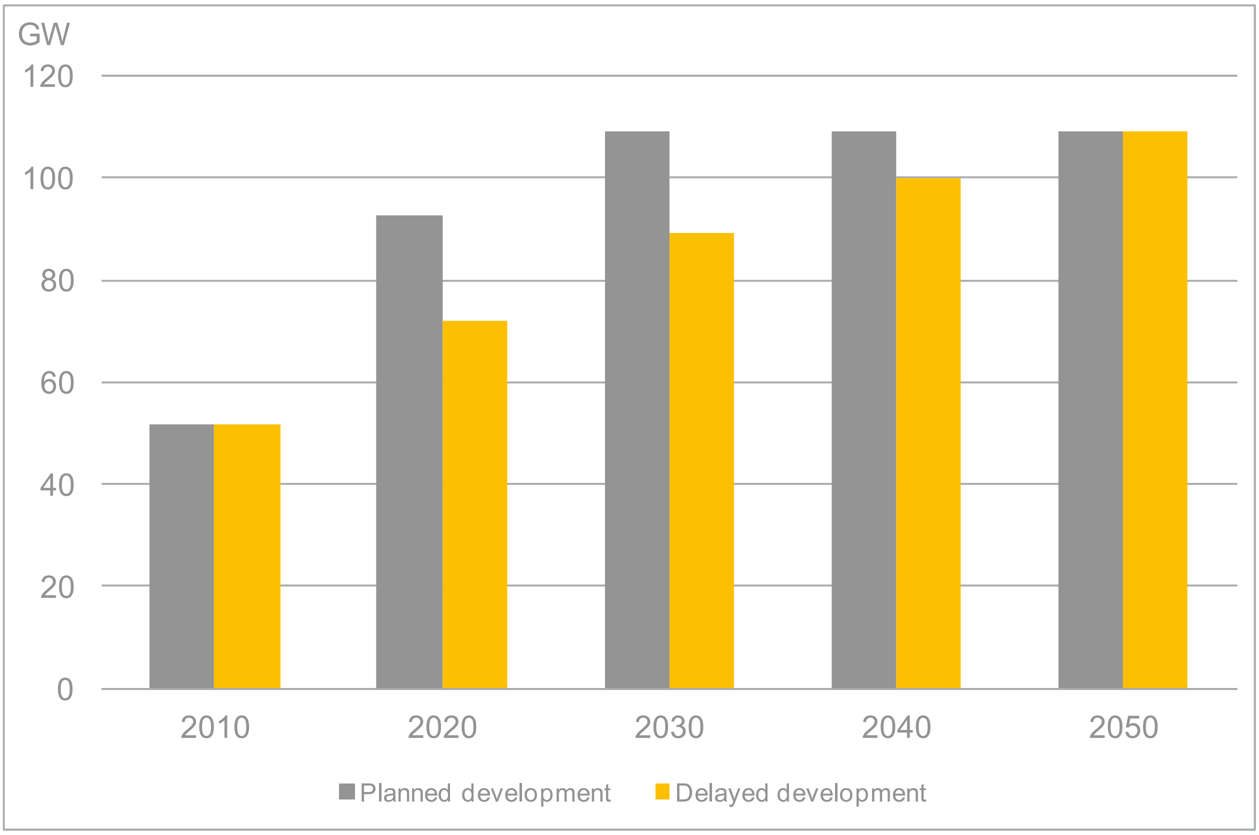

FIGURE 29: PLANNED AND DELAYED DEVELOPMENT OF TOTAL NET TRANSFER CAPACITIES IN EUROPE (SCENARIO B) [GW]

Source: EWI / energynautics

The chosen approach can be illustrated by a project listed in the ENTSOE's TYNDP which aims at increasing the power exchange capacity between Germany and Denmark West by 500 MW before 2020. In order to derive a plausible project delay the area is analyzed with regard to the factors population density, historical cases of public protest and type of terrain: Although the population density in this area is not as high as in a city, farmlands are prominent in the region. Moreover, there are several reported historical cases of local residents protesting against the construction of new transmission lines, a factor assumed to increase the likelihood of project delays. However, the terrain in this region is flat, open and easily accessible, so that the construction process should not encounter severe difficulties. Under consideration of all three factors the commissioning of the project (increase of the power exchange capacity between Germany and Denmark West by 500 MW) was assumed to be delayed by 10 years. As such, the project is assumed to be realized by 2030, and not as originally planned by 2020. Appendix A1 lists both the planned interconnection extensions (based on ENTSO's TYNDP) and the delayed interconnection extensions (as assumed in Scenario B) until 2050.

In an aggregated form this development of cross-border capacities is depicted in Figure 29. It shows the planned development of total net transfer capacities throughout Europe (based on ENTSO-E's TYNDP) and the delayed development of total net transfer capacities (as assumed in Scenario B).[1] As can be seen, total cross-border capacities within Europe are assumed to double within the next 40 years in Scenario B, reaching a total Net Transfer Capacity of 110 GW in 2050. Electricity imports from North Africa to Europe are assumed to be only possible via Spain, with an interconnector capacity of 5 GW in 2030 respectively 15 GW in 2050.

6.2.1 Capacities, generation and utilization

Capacities

The development of generation capacities in Europe until 2050 is displayed in Figure 30. The total capacity more than doubles (+120%) until 2050 and the total RES-E capacity even increases 6-fold until 2050.

Until 2020 primarily wind onshore capacities are added to the capacity mix. The bulk of wind onshore deployment takes place in France (+30 GW), Great Britain (+28 GW) and Poland (+18 GW). Moreover, overall biomass capacity increases by 23 GW, with additional capacities being primarily deployed in Germany (+7 GW), Spain (+3 GW), France (+3 GW) and Great Britain (+3 GW). Total capacity conventional power remains constantly high; however decommissioning nuclear power plants are partly replaced by lignite and coal power plants equipped with CCS technology as well as gas-fired power plants.

In the medium term (2020-2030) the observed capacity increase is mainly driven by additional wind on- and offshore as well as concentrating solar power plants. Additional wind onshore capacities are mainly deployed in France (+20 GW), Germany (+14 GW), Poland (+12 GW) and Great Britain (+10 GW) in the years between 2020 and 2030. Offshore wind capacities are primarily commissioned at favorable offshore sites in Great Britain (+17 GW), the Netherlands (+12 GW) and Norway (+12 GW). Additional capacities of concentrating solar power plants are largely deployed in Spain (+31 GW) and Italy (+15 GW). Moreover, storage capacities increase between 2020 and 2030, mainly due to the commissioning of compressed air energy storages in Great Britain (+21 GW), Ireland (+6 GW), Poland (+6 GW) and the Netherlands (+5 GW).

[1] Net transfer capacities in Figure 29 represent the average capacity of both directions.

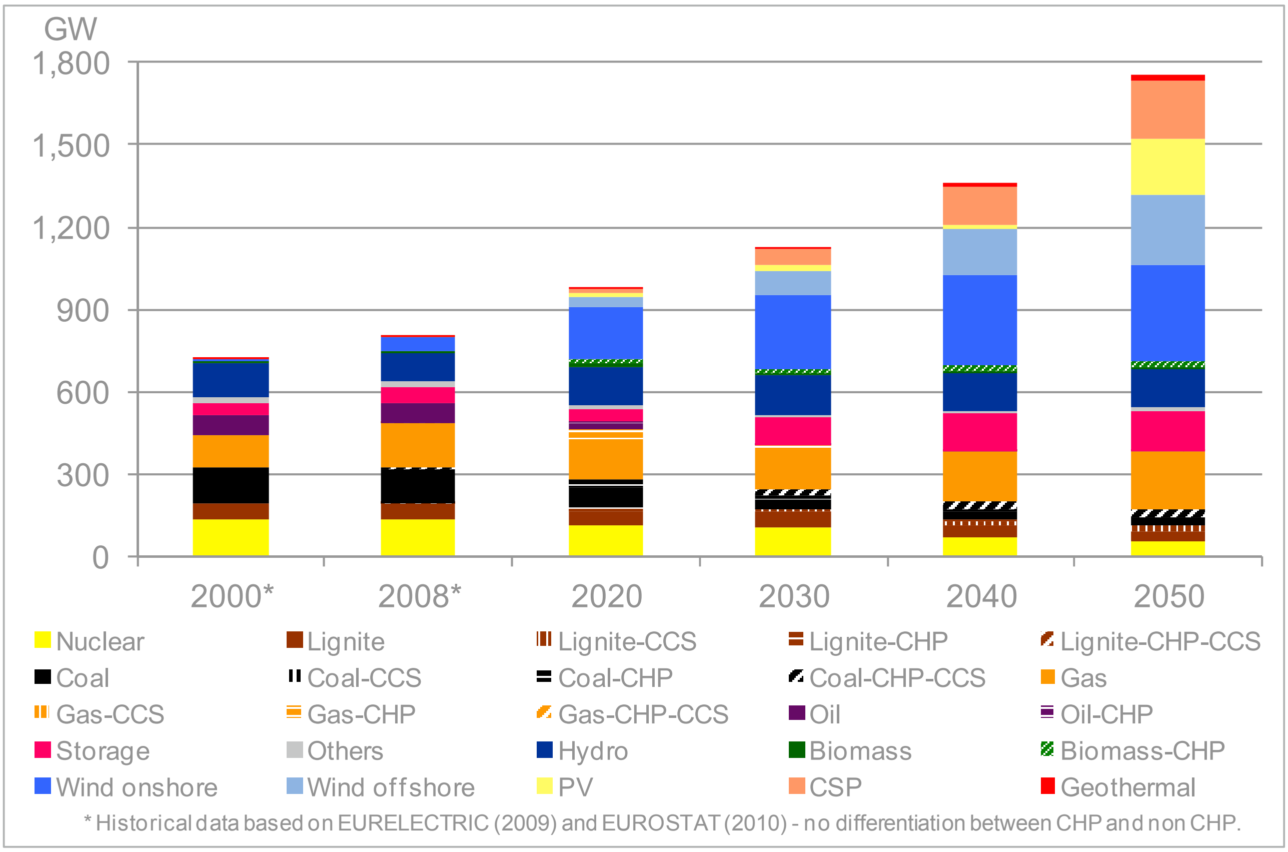

FIGURE 30: EUROPEAN CAPACITY MIX DEVELOPMENT UNTIL 2050 (SCENARIO B) [GW]

Source: EWI / energynautics

In 2050 the European capacity mix is dominated by wind and solar technologies (installed capacities: onshore wind 354 GW, offshore wind 256 GW, PV 199 GW, CSP 215 GW). Onshore wind capacities are primarily located in France (71 GW), Germany (48 GW), Great Britain (42 GW), Poland (42 GW) and Spain (35 GW). Countries with particularly high offshore capacities are Great Britain (90 GW), Germany (49 GW), the Netherlands (34 GW), France (28 GW) and Norway (26 GW). Compared to the European capacity mix in 2040, the mix in 2050 comprises significantly more photovoltaic and concentrating solar power capacities. Between these years, photovoltaic installations increase more than 10-fold to 199 GW by 2050, with the highest capacities being deployed in Italy (52 GW), France (51 GW), Hungary (16 GW), Austria (15 GW), Germany (13 GW) and Portugal (12 GW). Concentrating solar power plants are primarily located in Southern European countries, namely Italy (95 GW), Spain (94 GW) and Greece (27 GW) as well as in North Africa (6 GW). On the conventional side a significant increase in gas-fired power plants can be observed, primarily built to ensure security of supply.

Generation

Figure 31 depicts the development of the European gross electricity generation until 2050. This development is basically driven by the development of the European capacity mix which was previously described.

By 2050, 38% of total gross electricity generation is supplied by wind power. Due to their favorable characteristics regarding full load hours, offshore wind power plants make up the largest share. Given the large installed capacity, photovoltaic exhibits only a relatively small share of total gross electricity generation, as it is a technology with comparatively low full load hours. The relatively high share of CSP in comparison to photovoltaic electricity generation is due to the fact that CSP plants equipped with thermal energy storage achieve more full load hours than photovoltaic systems. Noticeably large gas capacities are built to ensure security of supply in times of high demand and/or low RES-E generation, whereas only limited amounts of electricity are actually produced.

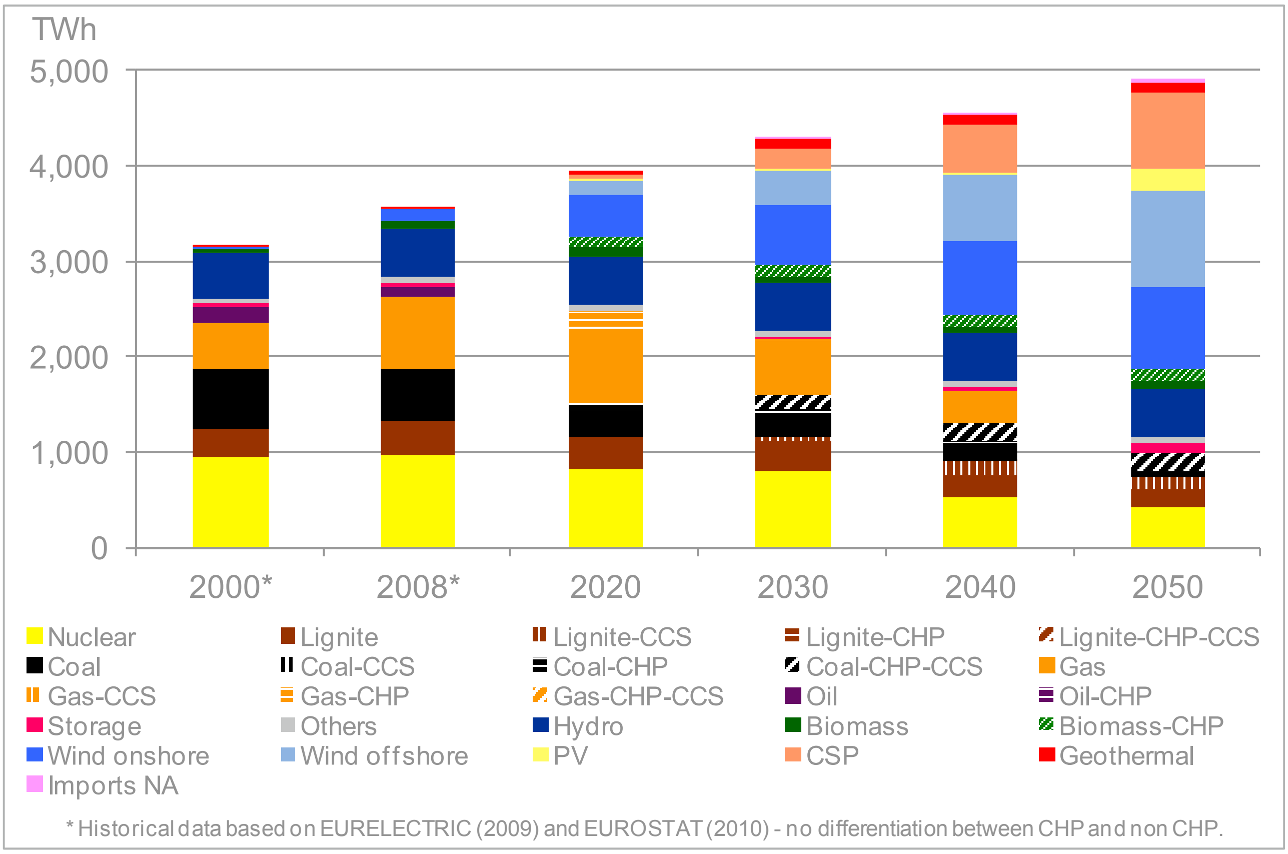

FIGURE 31: EUROPEAN ELECTRICITY GENERATION DEVELOPMENT UNTIL 2050 (SCENARIO B) [TWh]

Source: EWI / energynautics

Utilization

Figure 32 and 33 depict the average full load hours of thermal and nuclear respectively of renewable power plants.

Reducing CO_2 emission by 20% in 2020 depicts a challenging target for the electricity system. One key factor for achieving this target is the high usage of gas instead of coal power plants. Therefore, new gas-fired power plants are commissioned and older plants realize a high utilization. Increasing gas prices - especially compared to coal prices - lead to a decrease of realized full load hours of gas-fired power plants over time. The utilization of base-load plants with low CO_2 emissions (nuclear, lignite-CCS and coal-CHP-CCS) is constantly high.

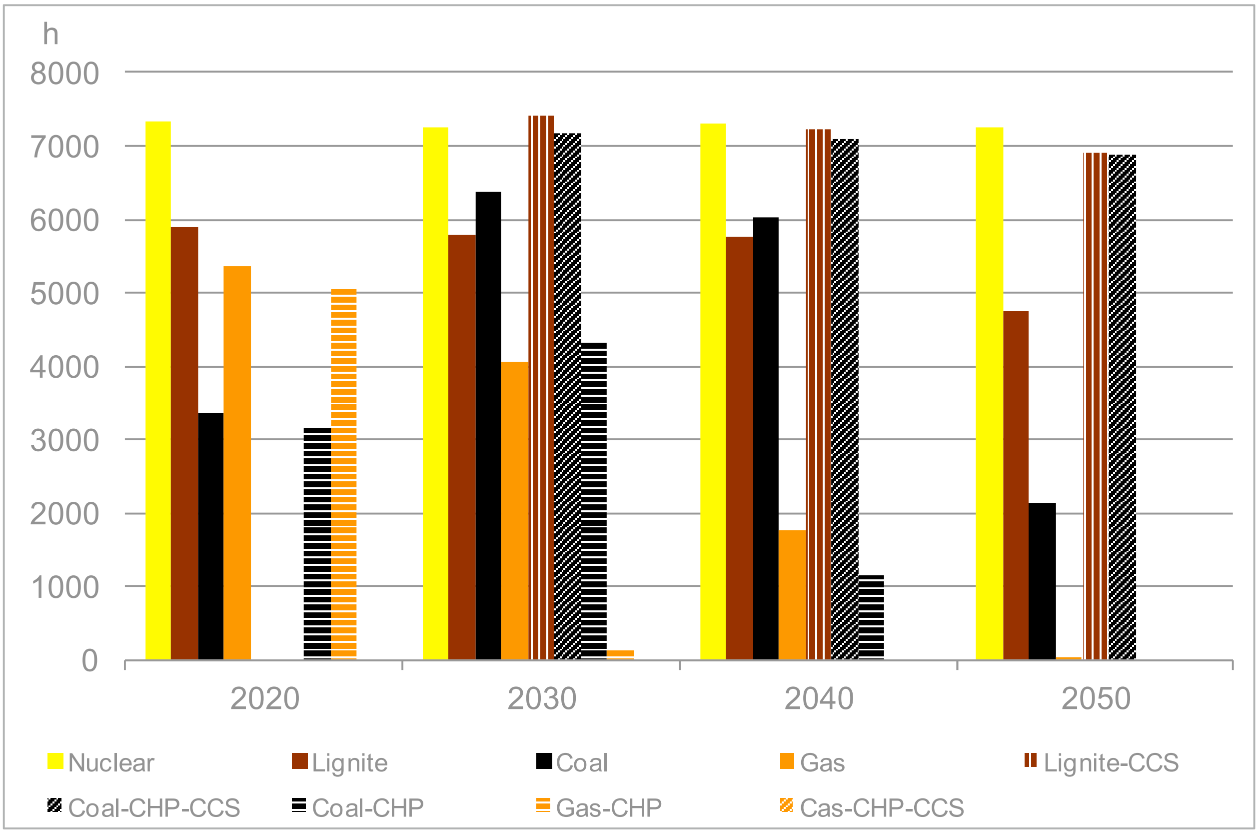

FIGURE 32: EUROPEAN AVERAGE UTILIZATION OF NUCLEAR AND CONVENTIONAL PLANTS (SCENARIO B) [h]
Source: EWI / energynautics

Compared to other renewable energy sources, biomass and geothermal-CHP plants have by far the highest full load hours. The number of full load hours of biomass, biomass-CHP and geothermal-CHP plants stays rather constant over time. On average, offshore wind turbines have higher utilization rates than onshore wind turbines due to higher wind levels offshore. The utilization of storage capacities increases over time as the share of fluctuating renewable electricity generation rises.

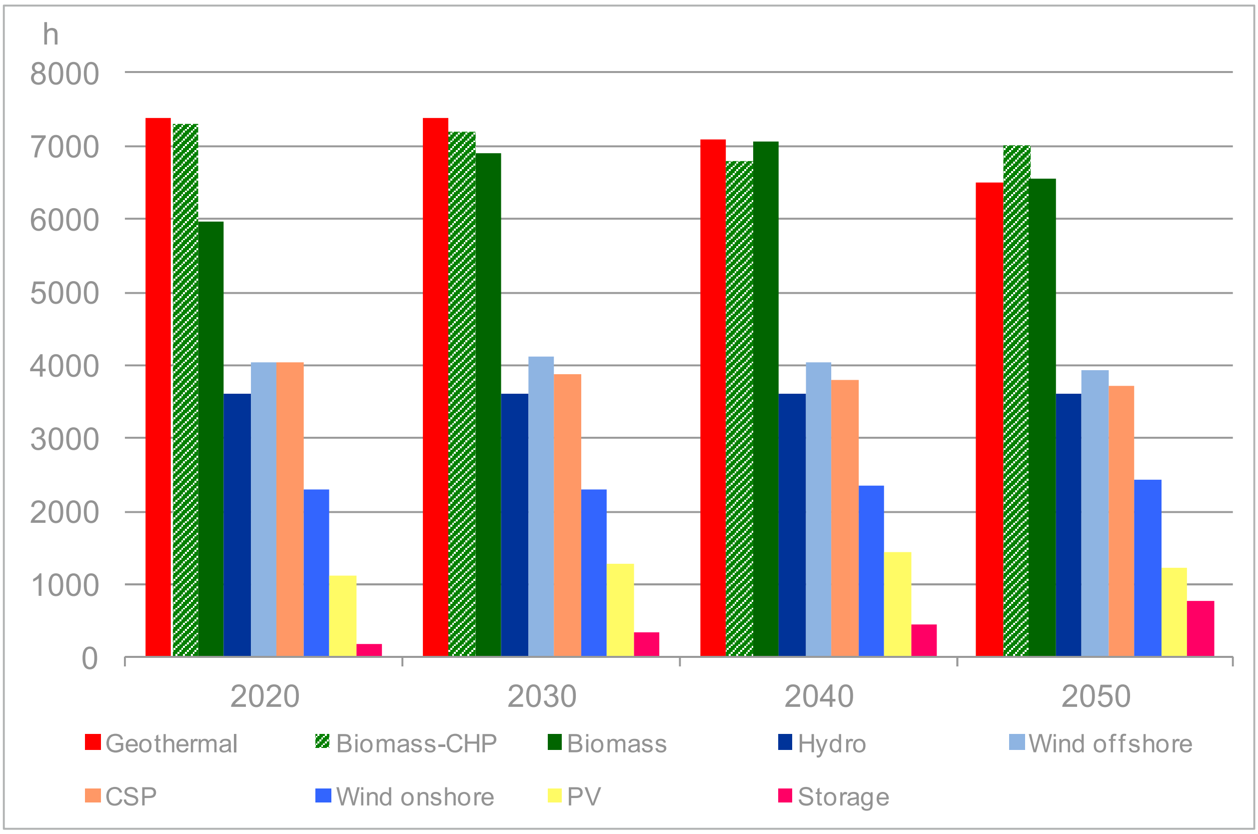

FIGURE 33: EUROPEAN AVERAGE UTILIZATION OF EUROPEAN RENEWABLE CAPACITIES (SCENARIO B) [h]

Source: EWI / energynautics

6.2.2 Electricity trade flows

Even though the transmission grid extension is only moderately extended, cross-border capacity is increased by a factor of 2.5 between 2010 and 2050 (see section 6.2). Figure 34 gives an overview of cross-border trade flows for the years 2020 and 2050. Besides an overall rise in electricity trading throughout Europe, it can be seen that some streams not only change in size, but also in direction.

Italy for instance, which is one of the major import countries in Europe since their moratorium on nuclear power after the Chernobyl accident in 1986, turns from a net importing country in 2020 (net imports amount to 10% of gross electricity demand) to a net exporting country in 2050 (net exports amount to 5% of gross electricity demand). This effect is mainly caused by the largely increased power generation from solar resources (CSP and PV).

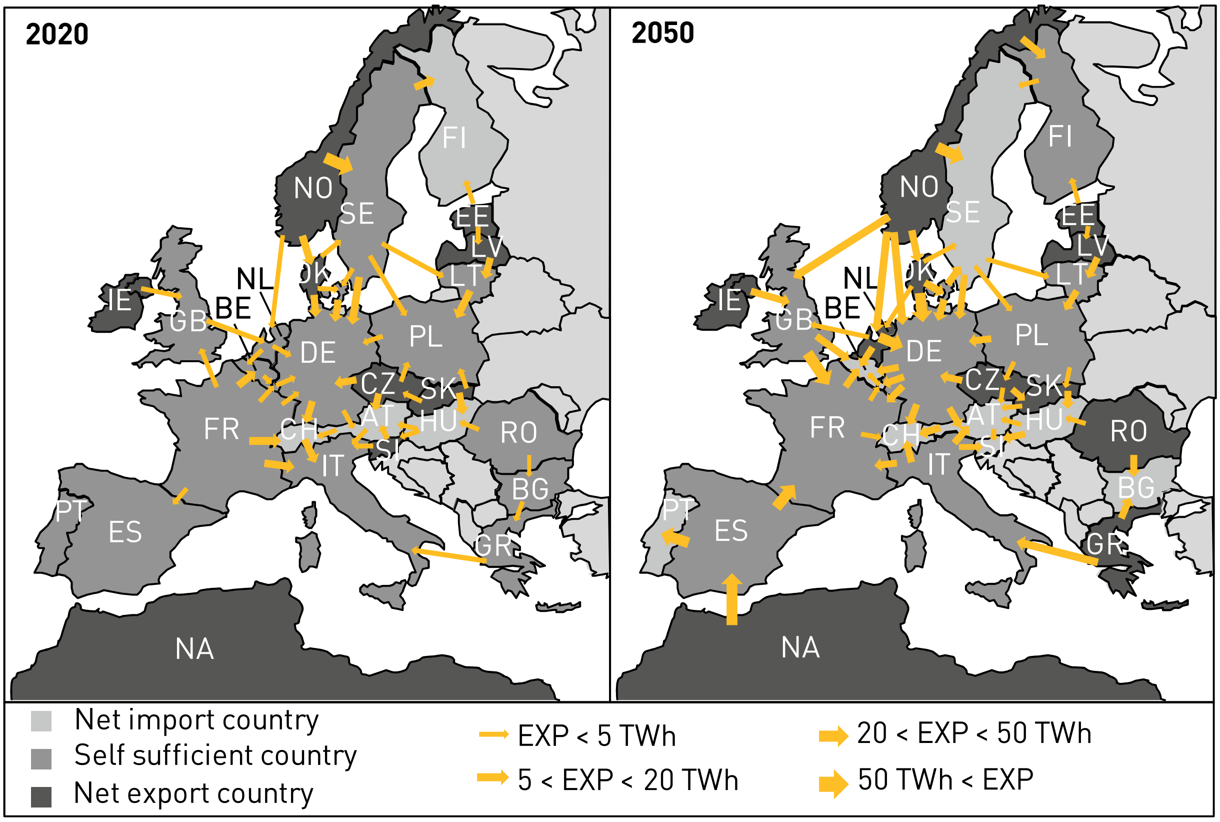

FIGURE 34: EUROPEAN IM- AND EXPORT STREAMS IN 2020 AND 2050 (SCENARIO B)

Source: EWI / energynautics

Another prominent example is France whose generation mix fundamentally changes in the course of time. In recent years, large amounts of nuclear energy caused export streams to all neighboring countries, a fact largely remaining unchanged until 2030. After that, nuclear power plants are decommissioned at the end of their lifetime and primarily replaced by wind turbines (on- and offshore) and PV systems as well as imports from Spain, Great Britain, Germany and Italy, thus causing trade flows to change in size and direction by 2050.

Generally it can be observed that in the long term countries characterized by extensive renewable energy potentials combined with comparably low generation costs become export countries. While electricity exports of countries in Northern Europe (including Ireland, Norway, the Netherlands, Denmark, Estonia and Latvia) are primarily based on wind power generation, exports of Southern countries (Spain, Italy and Greece and North Africa) are triggered by favorable potentials for solar energy technologies (CSP and PV). However, due to the moderate extension of cross-border capacities, favorable renewable potentials in Europe cannot be completely exploited. Nevertheless, there are significant changes in generation capacities, electricity production and trade flows.

6.2.3 European transmission grid

As described in section 6.2, a moderate increase of cross-border capacities between European countries is assumed in Scenario B. European cross-border capacities more than double over the next 40 years, reaching around 110 GW in 2050. In contrast to interconnector capacities, intraregional transmission lines are extended endogenously based on the cost-efficient development of the European electricity system (including generation and grid). In order to achieve prescribed targets and to ensure security of supply, not only interconnector capacities need to be extended, but also intraregional transmission lines. The development of the entire transmission grid is depicted in Figure 35.

Our results show that large intraregional extensions become necessary all over Europe. This is mainly due to the fact that large parts of the generation mix are transformed towards a low-carbon and mainly renewable based system. This includes the installation of large fluctuating RES-E capacities. Furthermore, demand for electricity is assumed to increase such that enhanced generation and transmission capacities become necessary. These capacities are generally commissioned at sites different to the ones deployed for today's power generation, entailing new lines and upgrades all over Europe. This development is particularly affected by the deployment of new remotely located RES-E generation sites that need to be connected to large load centers (which remain at the same locations).

An especially large increase of intraregional transmission grid capacities takes place in countries with large generation shares of fluctuating RES-E capacities and a mismatch between cost-efficient generation sites and large load centers within the country. An example in this scenario is Great Britain with large wind capacities in the Northern part and a high share of consumption in the area around London. Hence, the intraregional transmission grid is extended in Great Britain by 10,000 km until 2050. Another example in this scenario is Italy with solar technology installations in the Southern part due to higher solar radiation and load centers in Northern Italy (e.g. Milano) resulting in 18,000 km of grid extensions until 2050.

In general, for the cost-efficient achievement of the challenging political targets, intraregional transmission lines are significantly extended (by 85,000 km) until 2050 to enable the usage of load distant favorable RES-E sites and the balancing effects of a large transmission grid.

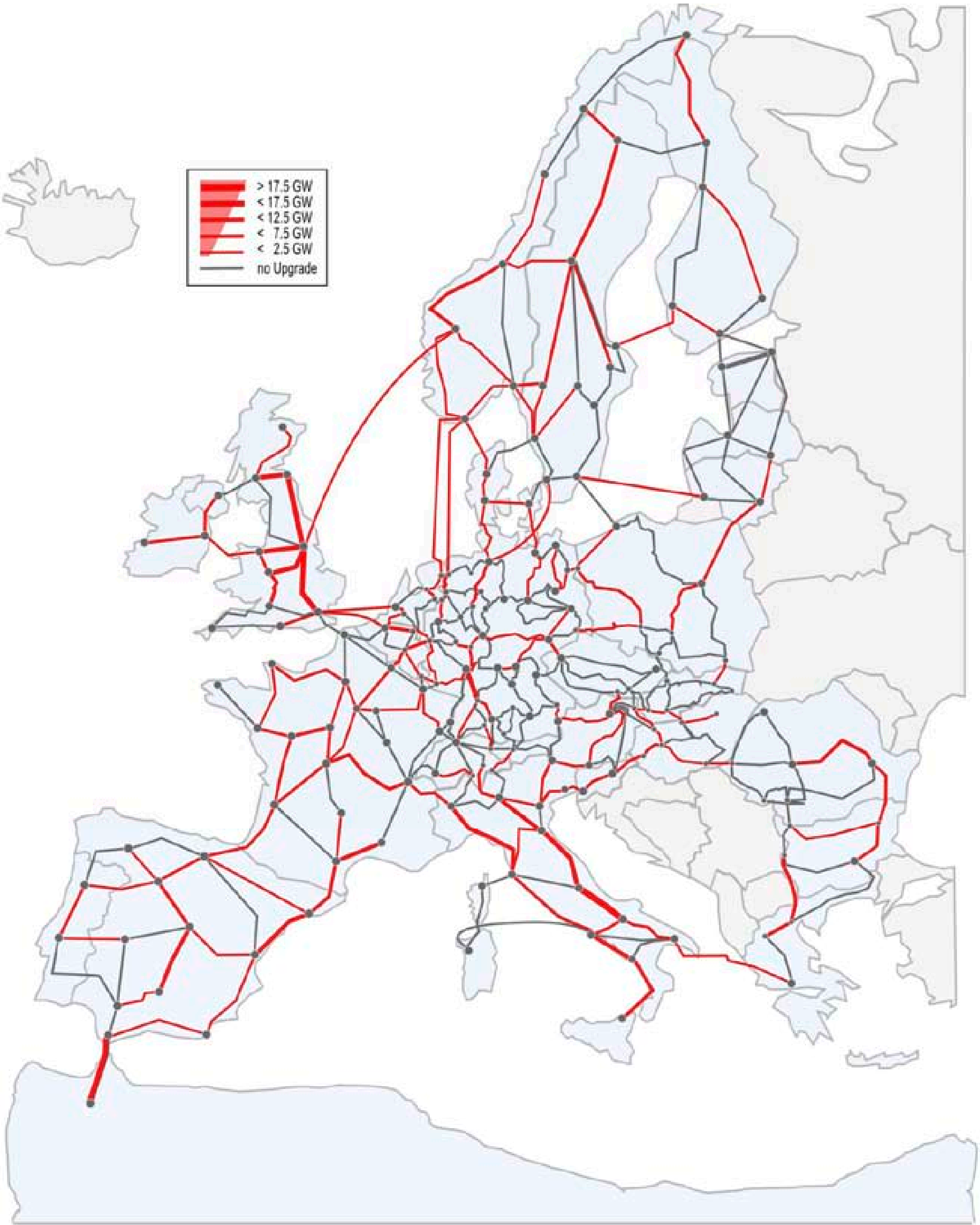

FIGURE 35: GRID UPGRADES FROM 2010 TO 2050 (SCENARIO B) [GW]

Source: EWI / energynautics

6.2.4 CO_2 emissions in the electricity sector (including heat in co-generation)

CO_2 emissions are limited by the CO_2 bound which is set to an 80% reduction target until 2050 compared to the 1990 values. Figure 36 shows the CO_2 emissions of the electricity sector (including heat in co-generation) as stacked bars indicating the total amount as well as each country's share. It should be noticed that the bound applies to total European emissions, such that one country is not obliged to meet the 80% reduction as long as another one can compensate. For instance, while Germany "only" reaches a 69% reduction, the electricity systems in Ireland, Lithuania, Latvia and Spain are CO_2 neutral in 2050, due to large amounts of wind respectively solar power generation. However, as can be seen from Figure 36 , almost all countries participate in the process of reducing CO_2 emissions to similar extends in order to reach the prescribed reduction target.

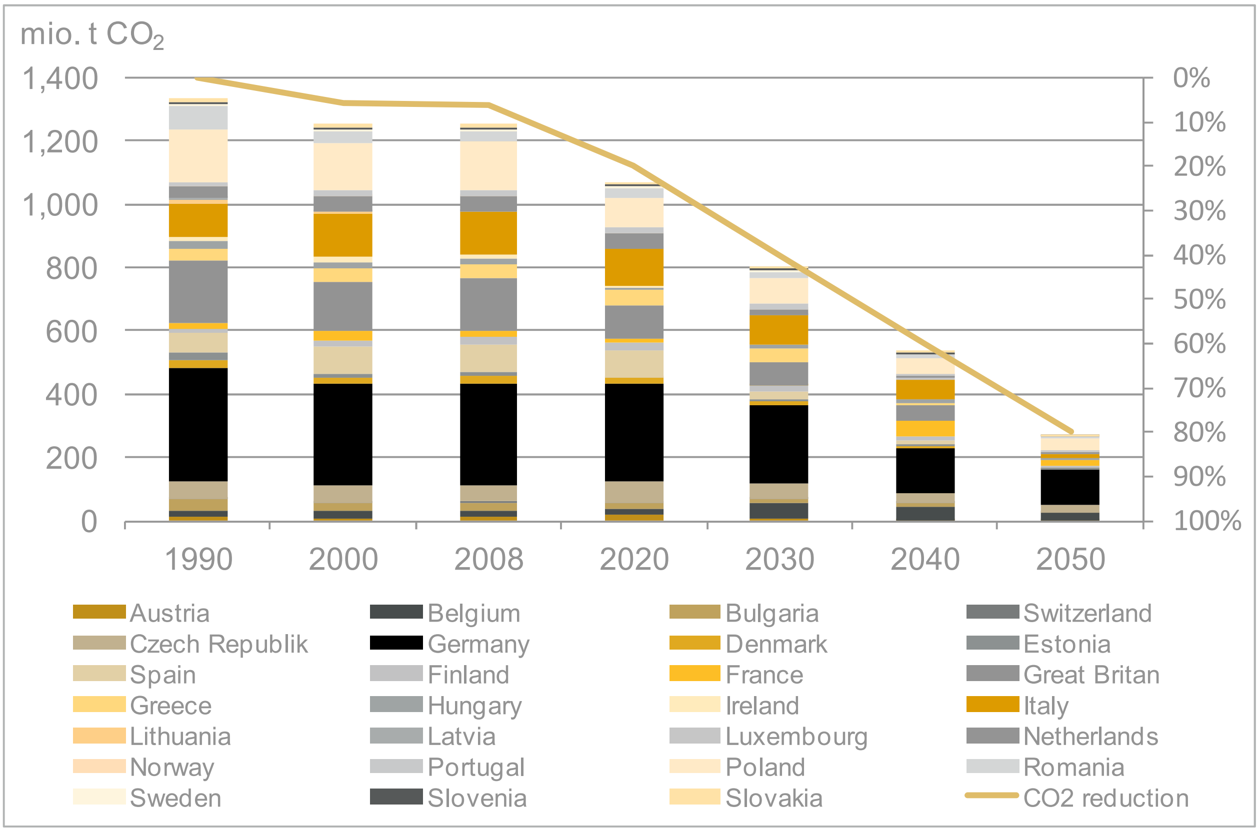

FIGURE 36: CO_2 EMISSIONS IN THE ELECTRICITY SECTOR (INCLUDING HEAT IN CO-GENERATION) PER COUNTRY (SCENARIO B) [mio. t CO_2]

Source: EWI / energynautics

Several technological options become available for CCS in 2030. As can be seen from the European capacity (Figure 30) and power generation mix (Figure 31), these options are utilized as a mean to reduce CO_2 emissions. Consequently, lignite and coal power plants are built in combination with CCS devices, which allow the system to avoid more than 50 mio. tons of CO_2 per year in 2050. This option is mostly realized in countries where fossil fuels are still used to produce power and heat, i.e. mainly in Germany, Italy and the Netherlands.

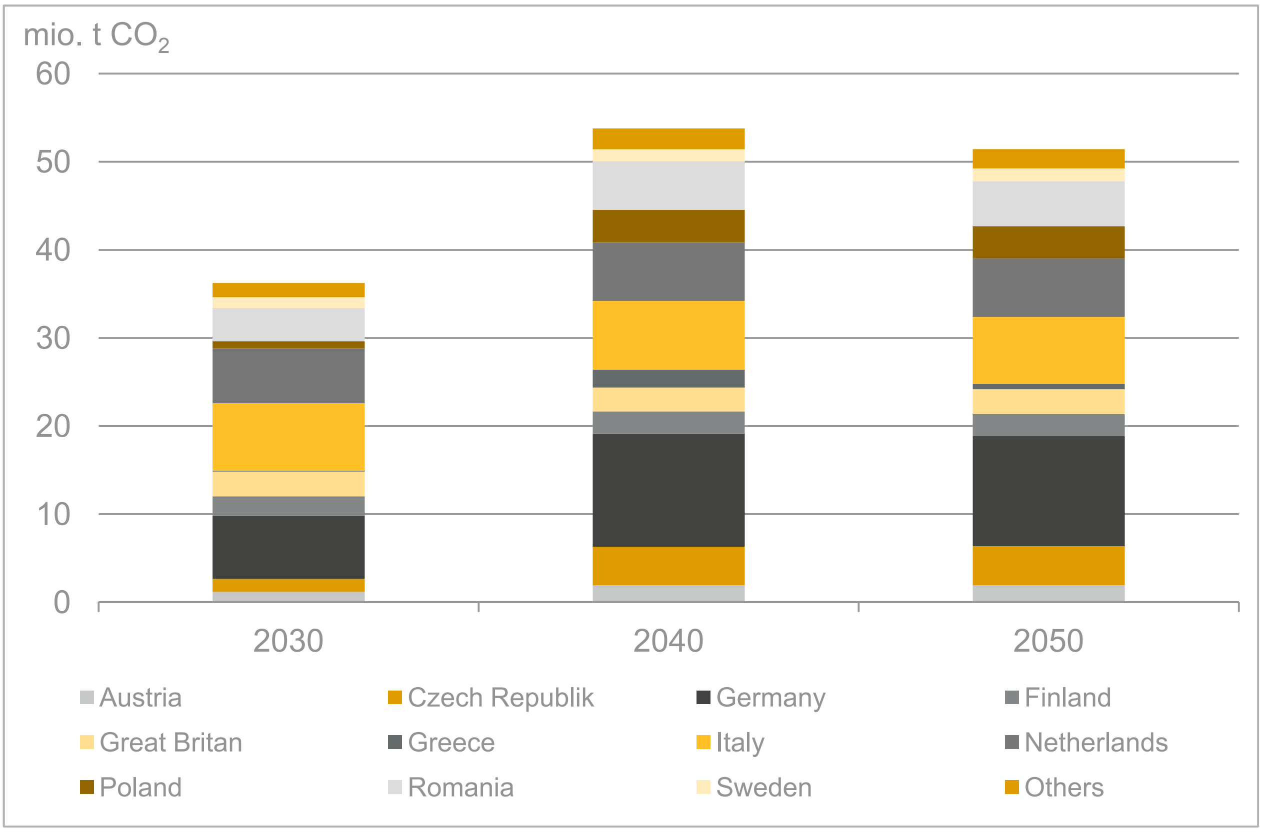

FIGURE 37: STORAGE OF CO_2 IN CCS-PLANTS PER COUNTRY (SCENARIO B) [mio. t CO_2]

Source: EWI / energynautics

6.2.5 Investments and total system costs

The development of total investment costs per decade until 2050 (in bn. €$_{2010}$) in Scenario B is depicted in Figure 38. Within the next 40 years massive investments in capital intensive renewable as well as low-carbon conventional technologies are required throughout Europe in order to achieve the assumed RES-E (80%) and CO_2 emission reduction (-80%) targets by 2050. Overall, an increase of investment costs can be observed, which is caused by an increasing necessity for investments in capital intensive renewable energy technologies. In contrast, investments in new storage and grid capacities constitute a comparatively small part of total costs. Investments in conventional technologies are more significant than those for storage and grid, but still less than those for renewable energy technologies. Moreover, they decrease in volume after 2030.

Total investment costs amount to more than 550 bn. €$_{2010}$ until 2020, of which around two-thirds (370 bn. €$_{2010}$) are necessary for renewable technologies (primarily wind onshore). The other third (150 bn. €$_{2010}$) accrues due to new thermal and nuclear capacities, primarily commissioned in Germany (lignite and gas), Great Britain and Italy (both gas) and France (nuclear). Investments in transmission grid capacities are comparatively small, due to two reasons. First, transmission grid capacities are only moderately extended, and second, transmission grid extensions have comparatively low costs.

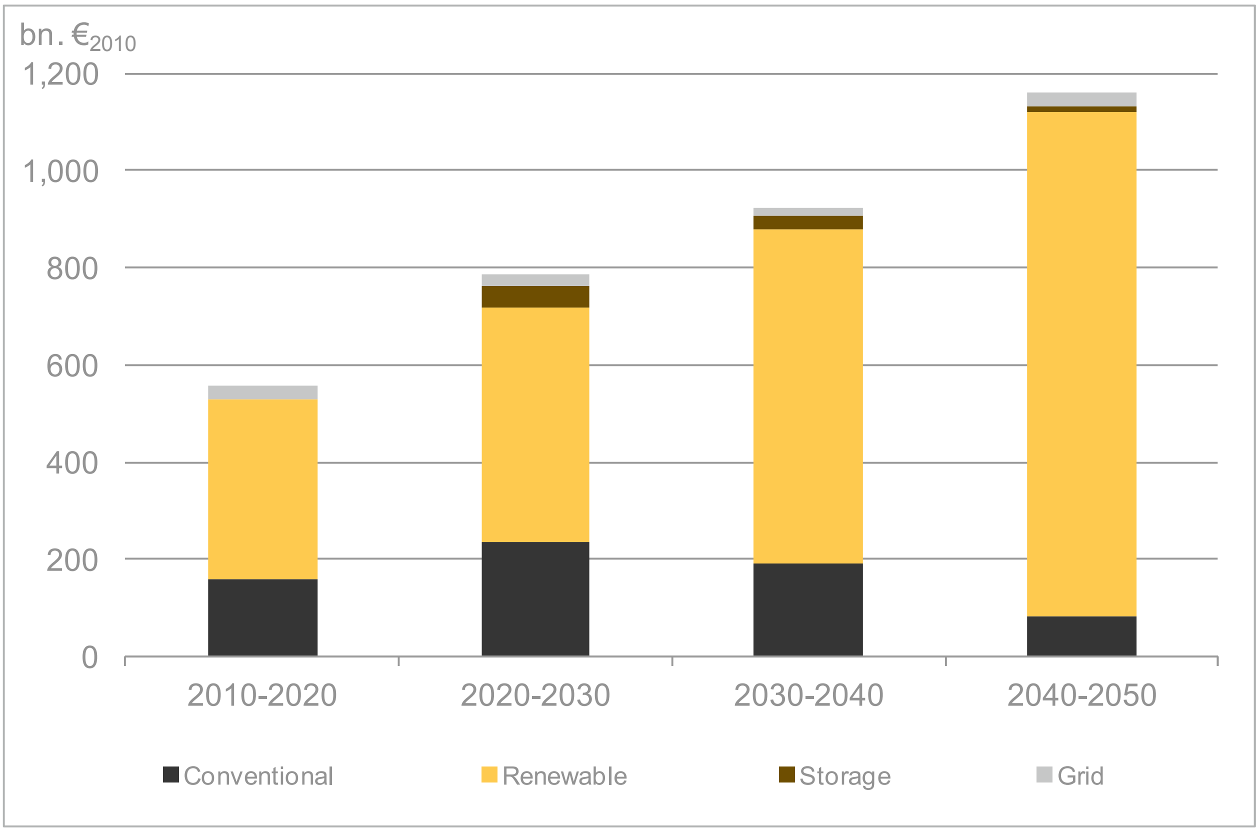

FIGURE 38: EUROPEAN INVESTMENT EXPENDITURES UNTIL 2050 (SCENARIO B) [bn. €2010]
Source: EWI / energynautics

Between 2020 and 2030 investments in renewable technologies increase both absolute and relative to investments in conventional technologies, primarily due to significant expansions of onshore wind (mainly in France, Germany, Great Britain and Poland), offshore wind (primarily in Great Britain, Norway and the Netherlands) and concentrating solar power (primarily in Spain and Italy). The largest part of investment costs for conventional plants (235 bn. €2010) originates from the commissioning of new nuclear (primarily in France), gas (primarily in Great Britain, the Netherlands and Sweden), coal (primarily in Belgium and Great Britain) and lignite fired power plants (primarily in Germany).

The years between 2030 and 2040 demand increasing investments of 920 bn. €2010, but with more than 1,150 the highest amount of investments incur in the last decade (2040–2050). Here, more than 1,000 bn. €2010 accrue due to the commissioning of RES-E technologies, namely new solar technologies (primarily in Italy, Spain and Greece), onshore wind (primarily in France, Great Britain and Poland) and offshore wind capacities (primarily in Great Britain, Germany and France). On the conventional side investment costs primarily incur due to the deployment of new gas-fired power plants.

Figure 39 depicts the development of annualized total costs (fix and variable) and average system costs for Europe until 2050. The rise in total system costs over time is caused by a significant increase in fix costs, reflecting the structural change of the European electricity system over the next 40 years, in which 80% of the European electricity demand will be supplied by capital intensive renewable energy and low-carbon conventional technologies in 2050. The average system costs rise from 47.1 €2010/MWh in 2010 to 67.9 €2010/MWh in 2050.

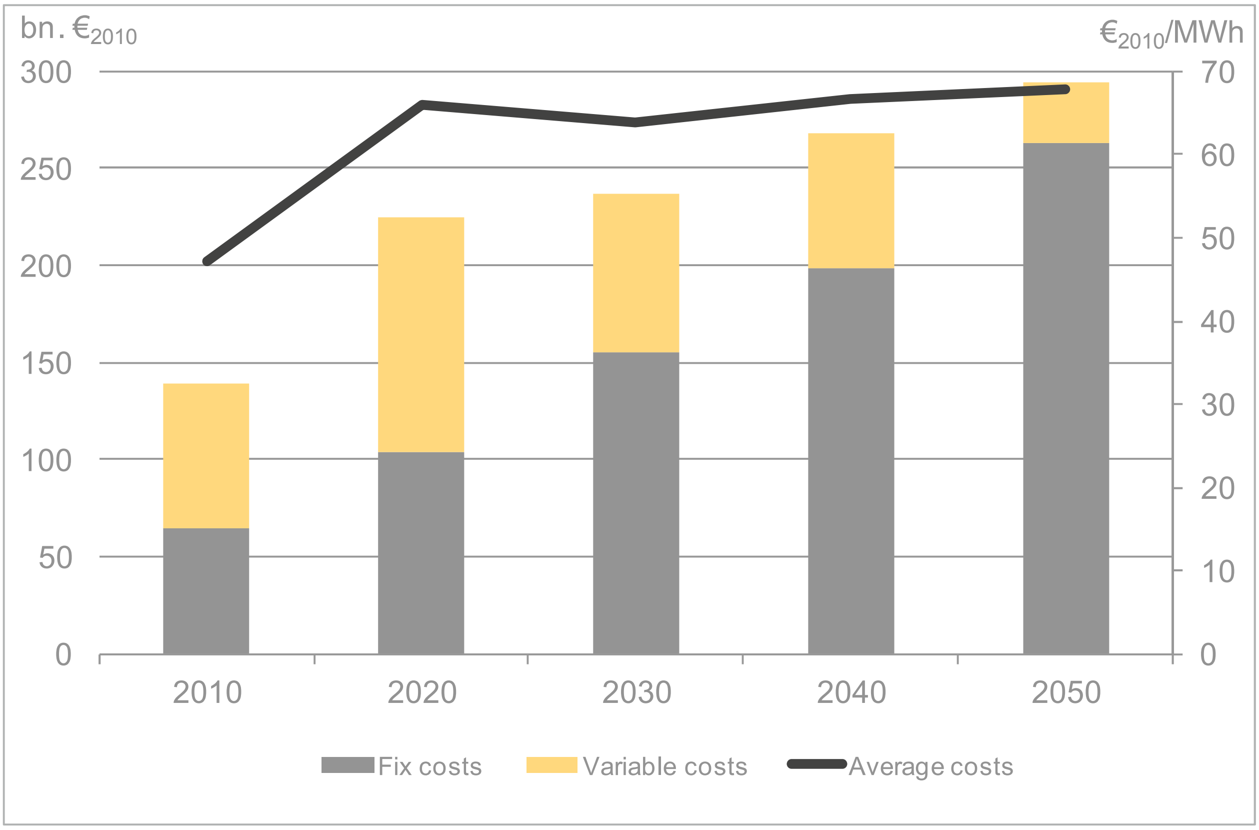

FIGURE 39: EUROPEAN FIX, VARIABLE AND AVERAGE COSTS UNTIL 2050 (SCENARIO B) [mio. €2010]

Source: EWI / energynautics

7 COMPARISON AND INTERPRETATION

Scenario A (optimal transmission grid) and Scenario B (moderate transmission grid) depict a cost-efficient path towards a low-carbon and high RES-E European electricity system until 2050. The framework of both scenarios is identical except for the possible extensions of interconnector capacities. Thus, many results are common to both scenarios. In the following, the commonalities of both scenarios are summarized first (section 7.1), before differences and benefits of optimal grid extensions are discussed (section 7.2).

7.1 Commonalities of both scenarios

- **Generation mix profoundly changes until 2050.**
  Due to ambitious targets, the generation mix in both scenarios profoundly changes until 2050. RES-E capacities are primarily increased by onshore wind until 2020/2030, offshore wind mainly from 2030 onwards and solar plants mainly after 2040. Fossil base and mid-load capacities decrease over time. Gas turbines serving as backup capacities are extended to ensure security of supply. Total installed capacities more than double until 2050 due to the low secured capacity of intermittent renewable technologies and an assumed increasing demand. In both scenarios, grid extensions allow for increasing interregional trade streams.

- **Electricity production is pushed towards the outer regions of Europe where conditions are best.**
  In our scenarios, wind offshore is primarily deployed in Northern Europe and solar power in Southern Europe. In addition, electricity flows from Eastern to Central Europe evolve from generation by wind onshore, biomass and non-renewable plants with low-variable costs (lignite and nuclear). Trade and physical flows develop accordingly, i.e. increasing volumes are transported over long distances from outer to inner European regions. Wind power from Ireland and solar power imports from North Africa are illustrative examples.

- **The cost-efficient achievement of RES-E targets differs significantly from current political action plans.**
  The National Renewable Energy Action Plans foresee a strong increase of photovoltaic capacity until 2020 (85 GW installed in Europe, of which 52 GW in Germany). In our cost-efficient scenarios no additional PV is installed until 2020. Instead, more onshore wind is deployed especially in France, Great Britain and Poland. Current European efforts which are

mainly based on national Member State's initiatives therefore differ from the cost-efficient pathway as determined in our scenarios.

- **The transformation to a low-carbon and high RES-E European electricity system induces cost increases – which however can be limited by EU-coordinated action.**
  In both scenarios, average system costs per unit increase from 47.1 to 65.6-65.9 €$_{2010}$/MWh between 2010 and 2020. Reasons include increasing demand and rising fuel prices (assumption) and the realization of the RES-E and CO_2 reduction target. In the long term, average system costs remain relatively stable due to cost reductions of renewables (assumption), the availability of CCS technologies (assumption) and the utilization of EU-wide synergies by using technologies at most favorable locations across Europe – the latter being enabled by significant and Europe-wide coordinated transmission grid extensions. Without EU-coordinated action, cost increases would be more pronounced.

- **The transformation leads to a capital-intensive electricity system.**
  In today's fossil fuel dominated electricity system, variable costs are about half of total system costs. In contrast, the cost structure of renewables comprises mainly capital costs. Large shares of generation from RES-E technologies in 2050 lead to an electricity system with about 90% capital costs. Within the next 40 years massive investments in capital intensive low-carbon conventional technologies are required to achieve the 2050 RES-E and CO2 targets.

- **CO_2 reduction target in 2020 induces high costs.**
  Especially in the short term, high investments and strong CO_2 price signals are required to transform the generation system in order to achieve challenging CO_2 emission reductions in 2020 and to bring the development on the right track towards the achievement of long term targets. The CO_2 emission reduction target for 2020 thus induces prices in the range of 50-55 €$_{2010}$/t CO_2 (slightly higher in Scenario B), whereas in the long run marginal costs of CO_2 emissions level out at around 50 €$_{2010}$/t CO_2 in both scenarios.

- **The cost-efficient and technically feasible solution comprises intraregional grid extensions in both scenarios.**
  Even though interconnector capacities are different, the intraregional transmission grid is significantly extended until 2050 in both scenarios in order to supply load centers with distant yet national RES-E generation. With more than 17,000 km of additional transmission lines in Italy, 10,000 km in France and 6,000 km in Germany, grid extension appears to be one of the major challenges in both scenarios.

7.2 Differences in the scenarios and benefits of increased transmission capacities

Differences and benefits regarding the European generation mix

Figure 40 shows the differences in the development of the electricity mix between Scenario A (optimal transmission grid) and Scenario B (moderate transmission grid) until 2050 on a European level. Figure 41 gives an overview of the generation by country in the target year 2050. The numerical data for all years are provided in the appendix.

- **Optimal transmission grid extensions enable the better usage of favorable RES-E technologies.**
  In case of an optimal transmission grid extension, favorable offshore wind sites are extensively used. In the short term, offshore wind power is deployed at particularly good locations in Ireland and Norway (about 4,000 full load hours). In the long term, wind offshore deployment takes also places in the Netherlands, Denmark and Great Britain (full costs between 6-8 ct_{2010}/kWh in 2050). Furthermore, solar imports from North Africa (6-7 ct_{2010}/kWh in 2050) contribute to the fulfillment of the European RES-E targets. In case of a moderate transmission grid extension, less favorable offshore wind sites are deployed, e.g. in Germany, France and Sweden (full costs between 8-11 ct_{2010}/kWh in 2050). In addition, more solar technologies are used in Southern and Central Europe, characterized by full costs between 7-13 ct_{2010}/kWh in 2050. In order to generate renewable low-carbon electricity, biomass generation (full costs between 5-17 ct_{2010}/kWh in 2050) is significantly extended in Germany and Eastern Europe: 20 TWh more in Germany, 12 TWh in Hungary, 5 TWh in Lithuania, 2 TWh in Romania and 1 TWh in Poland and Slovakia.

- **Optimal intermeshing of European market regions reduces the deployment of costly storage technologies.**
  In case of an optimal transmission grid extension the integration of fluctuating renewable energies such as wind or solar power succeeds through the possibility to transport available energy from one region to distant load centers. In case of only moderate transmission grid extensions, storage capacities enter the picture to integrate fluctuating RES-E generation. They are built in Northern Europe where large wind capacities are installed, e.g. Great Britain, the Netherlands and Poland. Overall, the difference in total storage capacity between both scenarios amounts to 55 GW in 2050. In Southern Europe fluctuating PV generation is complemented by CSP facilities with integrated thermal storage units.

- **The usage of load distant generation technologies leads to a stronger need for back-up capacities.**
  In case of an optimal grid extension, generation and consumption areas are largely geographically separated. To ensure local peak demands, open cycle gas turbines are installed close to consumption areas. In contrast, less peak capacities are needed in Scenario B (moderate transmission grid) due to the usage of nationally available capacities and the switch from wind to biomass and concentrating solar power plants (combined with thermal storage units). As such open-cycle gas turbines in Scenario A exceed installations in Scenario B by 53 GW in 2050.

- **While optimal transmission grid extensions enable the usage of cost-efficient RES-E generation to achieve the short term CO_2 reduction targets, more electricity is supplied by natural gas if the grid is only moderately extended.**
  In 2020 and 2030 wind offshore generation in Norway, Ireland and Denmark is largely substituted by natural gas generation close to load centers when transmission capacities are only moderately extended. In addition, in Scenario B coal and lignite capacities are utilized less in 2020 and 2030, in order to meet the CO_2 emission reduction target.

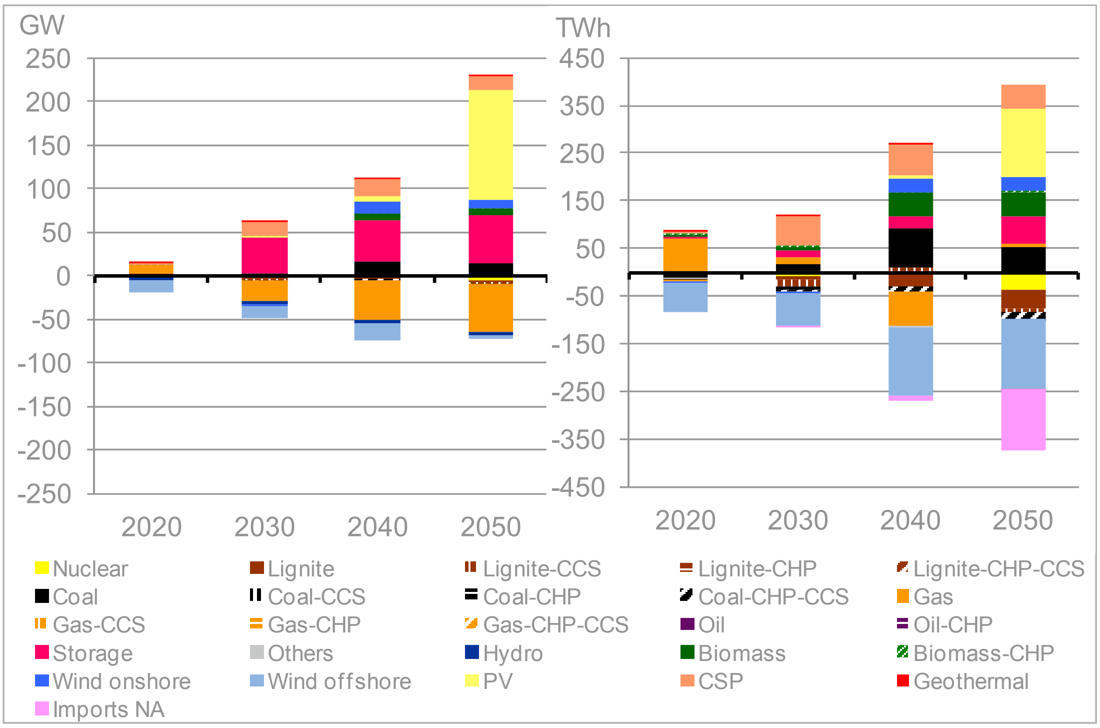

FIGURE 40: DIFFERENCES IN THE EUROPEAN ELECTRICITY MIX, SCENARIO B COMPARED TO SCENARIO A

LEFT: INSTALLED CAPACITY [GW], RIGHT: ENERGY PRODUCTION [TWh]

Source: EWI / energynautics

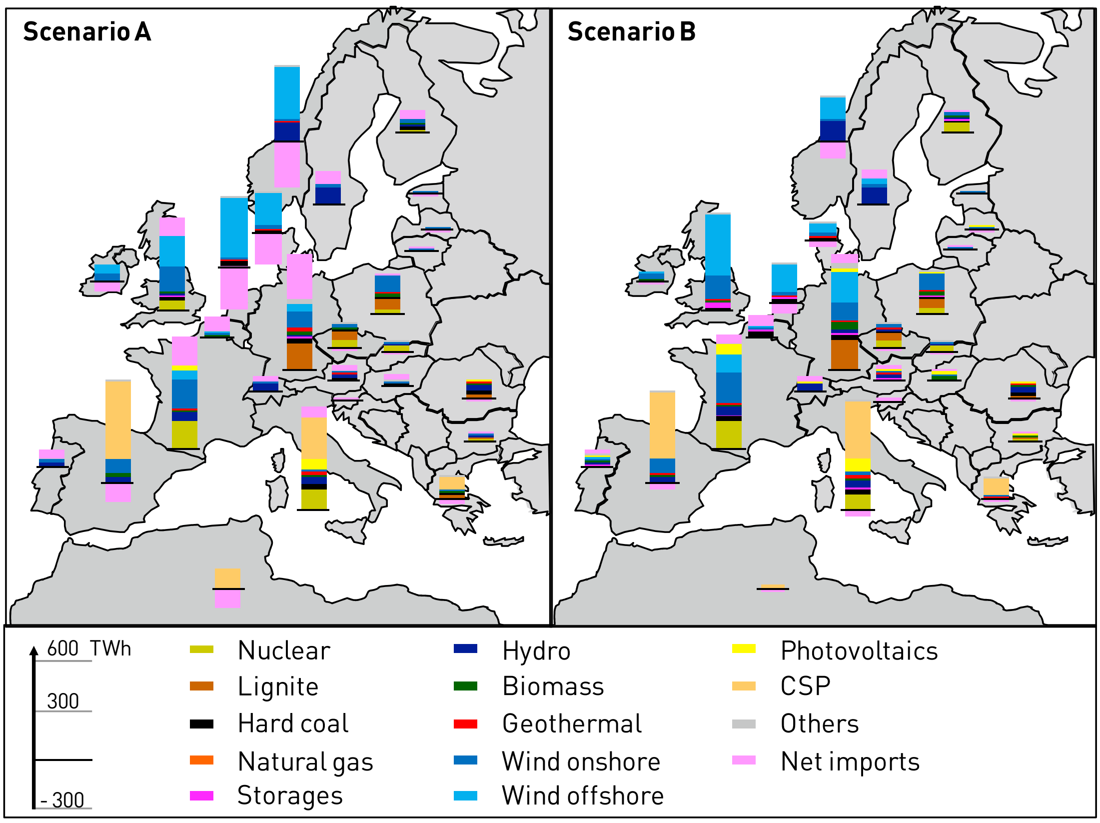

FIGURE 41: ELECTRICITY GENERATION BY COUNTRY IN 2050 [TWh]

Source: EWI / energynautics

Differences and benefits regarding the European trade flows

An overview of the European trade flows in the target year 2050 in Scenario A (optimal transmission grid) and Scenario B (moderate transmission grid) is provided in Figure 42. More detailed insights of the import/export balances for all countries are provided by Figure 43 depicting the net imports in the year 2050 of each country.

- **Optimal interconnection capacity extension induces larger exports in Northern European countries.**
  Norway (270 TWh), the Netherlands (243 TWh) and Denmark (180 TWh) are the largest net exporting countries in Scenario A (optimal transmission grid) in 2050. In relative terms, exports from Denmark (324%), Norway (174%), the Netherlands (156%) and Ireland (134%) by far exceed 100% of their respective gross electricity demand. In contrast, the largest net exporting country in relation to its gross electricity demand in Scenario B (moderate transmission grid) is Denmark with only 68%. Overall, Great Britain, France and Germany turn from "Net Importing Countries" to "Self-Sufficient Countries" (defined as countries with net imports in a range of +/- 10% of gross electricity demand) in Scenario B, due to lower imports from Northern European countries if the transmission grid is only moderately extended.

- **Optimal transmission grid extensions include larger imports from North Africa.**
  In Scenario A, overall electricity imports from North Africa to Europe in 2050 amount to 153 TWh (3% of Europe´s gross electricity demand) compared to only 24 TWh in Scenario B. In Scenario B, only one HVDC transmission line between North Africa and Spain with a total capacity of 15 GW connects the North African transmission grid to Europe. Furthermore, a bottleneck can be identified between Spain and France (capacity restricted to 4 GW in 2050), such that the supply of large load centers in Central Europe with imports from North Africa is limited. In any case, meeting North African electricity demand by supporting the build-up of a low-carbon electricity system there should have priority.

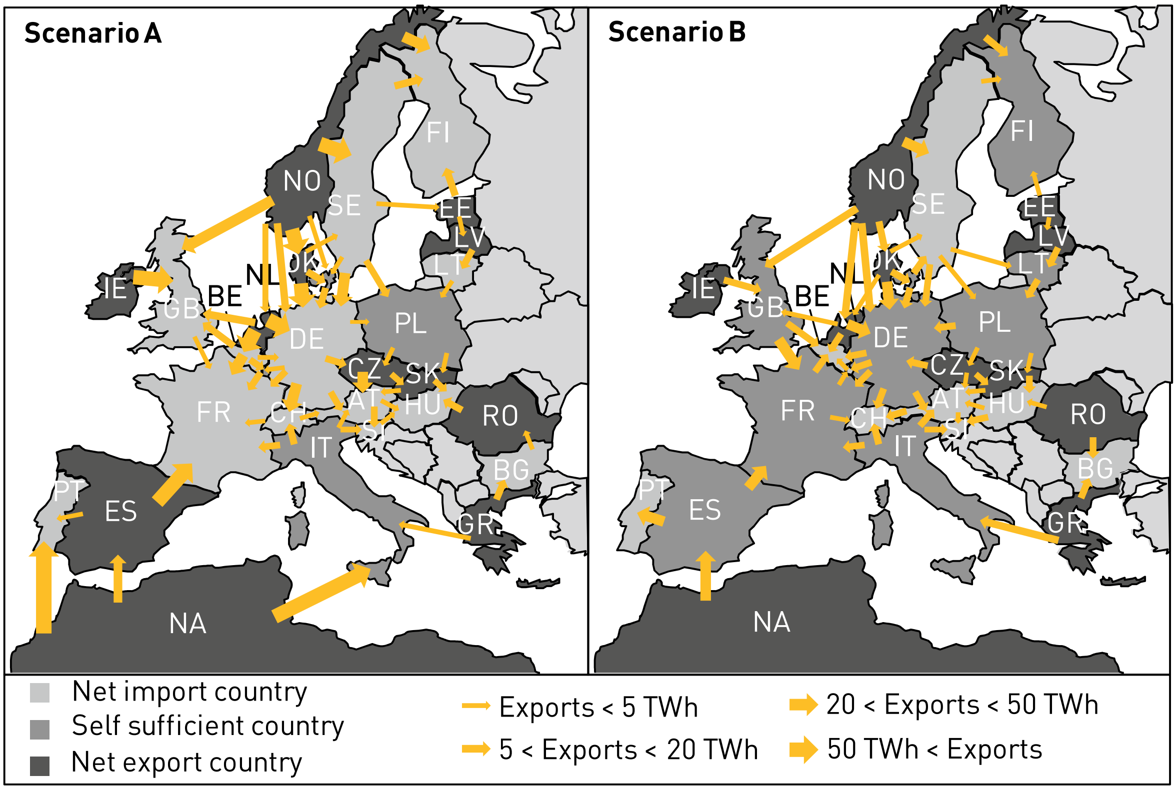

FIGURE 42: EUROPEAN NET IMPORTS IN SCENARIO A (LEFT) AND B (RIGHT) IN 2050 [TWh]

Source: EWI / energynautics

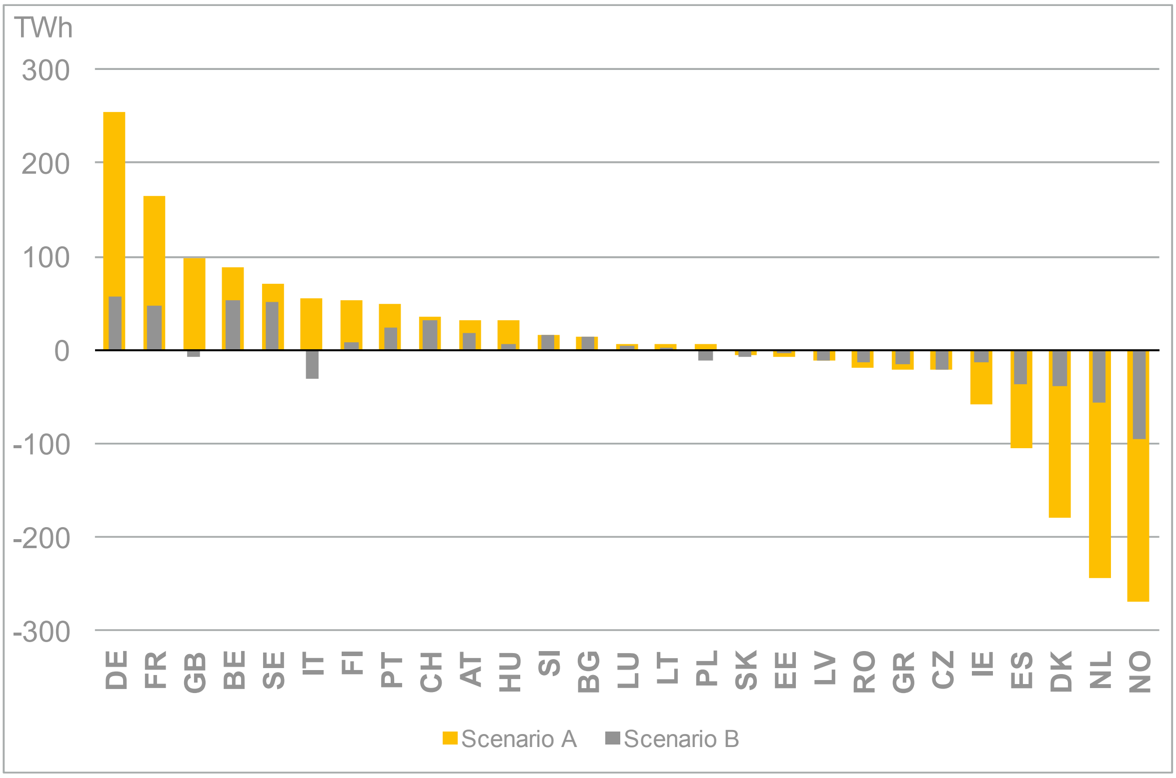

FIGURE 43: COMPARISION OF NET IMPORTS IN 2050 [TWh]

Source: EWI / energynautics

Differences and benefits regarding the transmission grid

The development of the transmission grid in Scenario A (optimal transmission grid) and in Scenario B (moderate transmission grid) is depicted in Figure 44. Optimal transmission grid extensions exceed the assumed moderate grid extensions in Scenario B by far.

- **Enhanced interconnector capacities allow for balancing regional differences in load and supply.**
  Strong interconnectors alleviate the balancing of load and supply between countries, even during extreme local events (such as several days without wind power in a specific region). Consequently, in some countries optimal interconnector capacities reduce the need for intraregional transmission grid extensions. In Great Britain for example, total intraregional transmission grid capacities are 26 GW lower in Scenario A, when interconnectors to neighboring countries (e.g. Ireland and Norway) are optimally extended.

- **The cost-efficient high RES-E and low-carbon electricity system requires more transmission grid upgrades than planned in the TYNDP.**
  It is cost-efficient to deploy wind and solar technologies at sites with highest wind speeds or solar radiation in Europe even considering the necessary upgrades of the transmission grid. Hence, in case of an optimal transmission grid extension wind power capacities are extensively deployed in Scandinavia and Ireland. To integrate the fluctuating wind power production, the transmission grid needs to be extended far more in these regions than indicated in ENTSO-E's TYNDP. Especially, lines within and between Norway, Sweden, and Denmark, and further towards Germany as well as lines within Ireland and towards Great Britain are extended significantly.

- **The Alps region becomes a critical point of the transmission grid.**
  In case of an optimal extension of the European power network, large grid capacity upgrades take place in the Alps region to allow the usage of favorable hydro storage sites and to transport electricity from North Africa via Italy to Central Europe.

- **Interconnector capacities between Spain and France are crucial for the assurance of security of supply in case of extreme events.**
  In electricity systems with a high share of fluctuating RES-E generation, the transmission system must be designed for the transport needs in case of extreme weather events, such as large solar generation in one European region and no fluctuating RES-E generation in another. Larger grid upgrades compared to the TYNDP are needed between and within Spain and France in order to allow for balancing effects and to transport electricity between Southern and Central Europe during extreme events.

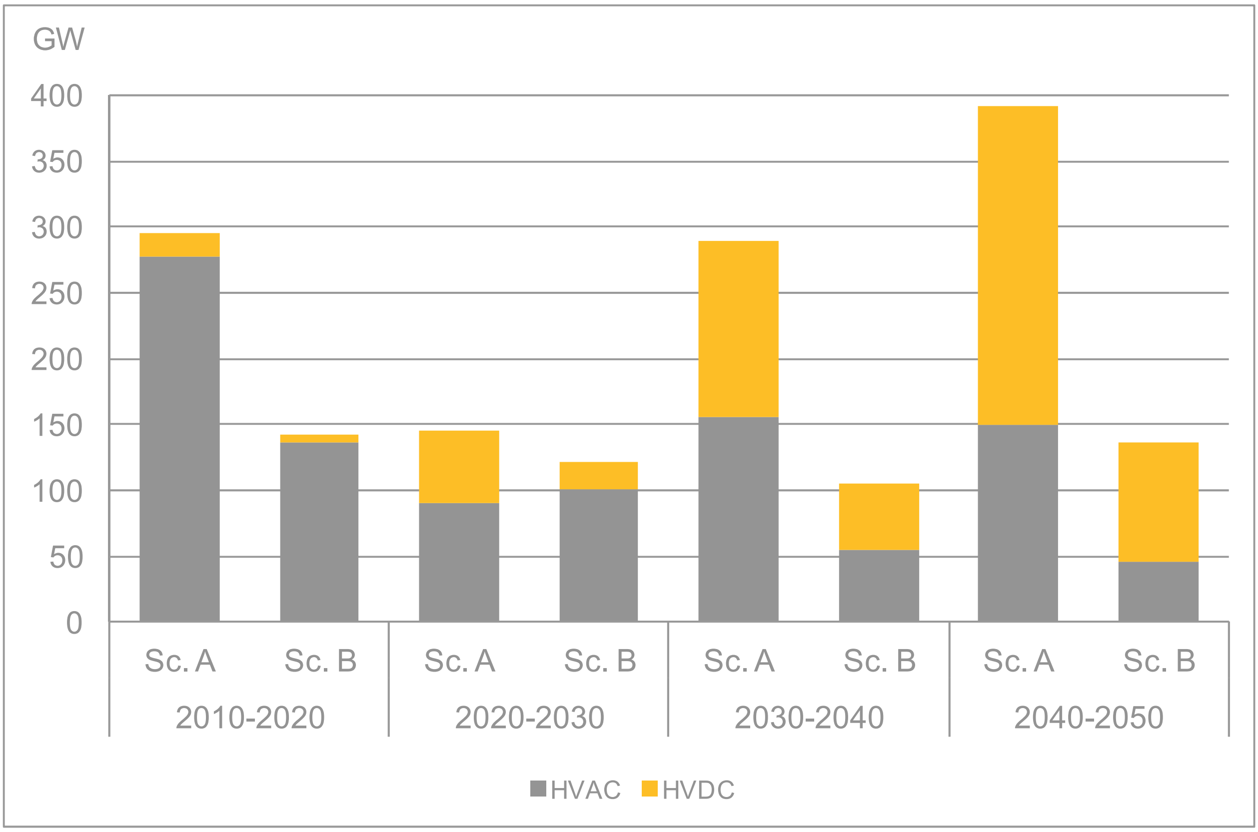

FIGURE 44: DIFFERENCES IN THE EXTENSION OF THE TRANSMISSION GRID [GW]

Source: EWI / energynautics

Differences and benefits in the achievement of the political targets

Figure 45 depicts the share of renewable energy generation in gross electricity demand per country in 2050. Overall it can be seen that differences between the countries are more pronounced in Scenario A (optimal transmission grid). Countries with favorable RES-E conditions contribute more to the achievement of the overall European RES-E target in Scenario A than in Scenario B due to the possibility of significant electricity exports to neighboring countries.

- **If interconnection capacities are optimally extended, best European wind sites in Denmark, Norway, Ireland and the Netherlands are extensively used to fulfill the European RES-E quota.**
  In both scenarios, export driven electricity generation is primarily observed in Denmark, Norway, the Netherlands and Ireland, which all exhibit a relatively large potential of favorable wind (on- and offshore) sites. In Scenario A, Denmark generates more than 215 TWh by renewable energy sources which represents nearly 400% of its gross electricity demand in 2050. Respectively, more than 422 TWh is generated by RES-E in Norway which represents 270% of its gross electricity demand in 2050. These shares fall to around 150% for both countries in Scenario B due to limited interconnection capacities to neighboring countries.

- **More domestically available renewable resources are deployed when interconnection capacities are limited.**
  The relative RES-E generation of all countries is more balanced in Scenario B than in Scenario A. This reflects higher usage of nationally available renewable resources and thus lower im- and export flows of renewable electricity across Europe to reach the prescribed RES-E targets when interconnection capacities are limited. In particular, wind power exports from Denmark, Norway, the Netherlands and Ireland are to a great extent substituted by increased national wind power generation in Germany, Great Britain, France and Sweden. Moreover, Greece, Italy, Portugal, Hungary and Bulgaria partly substitute electricity imports by increased solar power generation, while Lithuania, Hungary, Germany and Romania exhibit higher biomass-based electricity generation in Scenario B. As such, the European target of a 80% renewable energy share in gross electricity demand is achieved rather on a national than on an international level in Scenario B, where interconnection capacities are only moderately extended.

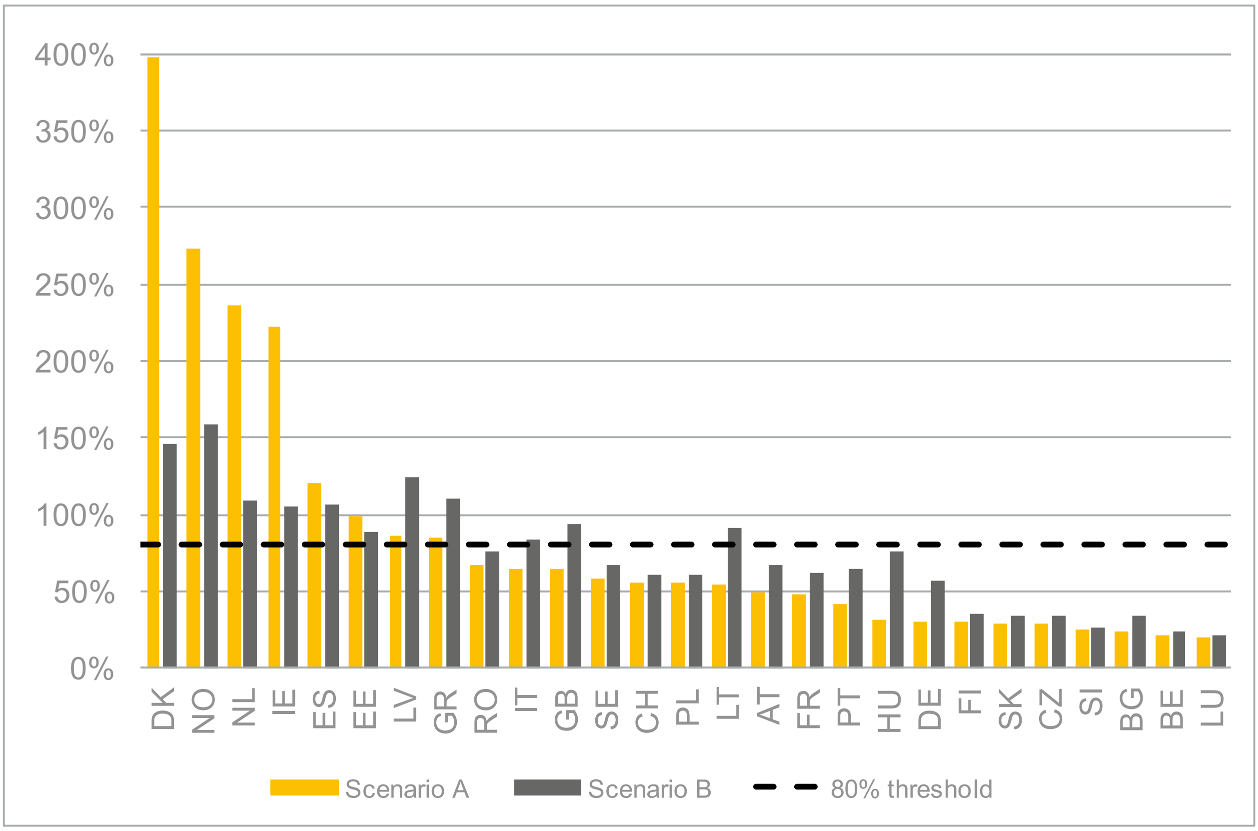

FIGURE 45: SHARE OF RENEWABLE ENERGY GENERATION IN GROSS ELECTRICITY DEMAND IN 2050 [%]

Source: EWI / energynautics

- **Optimal transmission capacity extensions enable the better usage of favorable technologies and hence the achievement of CO_2 reduction targets on a European level.**

  In Scenario A (optimal transmission grid), cost-efficient technologies at best European sites are deployed in order to achieve the challenging CO_2 reduction targets. The optimal extension of the transmission grid enables the necessary power flows in Europe and hence the usage of best technologies and sites. Therefore, the optimal extension of the transmission grid enables the achievement of challenging CO_2 reduction targets on a cost-efficient European level rather than on a national level in Scenario B (moderate transmission grid).

Differences and benefits regarding investments

Within the next 40 years massive investments in capital intensive renewable as well as low-carbon conventional technologies in both scenarios are required throughout Europe in order to achieve the assumed RES-E and CO_2 emission reduction targets by 2050. The differences of investment expenditures per decade between Scenario A (optimal transmission grid) and B (moderate transmission grid) is shown in Figure 46.

- **Necessary investments can be lowered by accumulated 57 bn. €$_{2010}$ until 2050 when the European transmission grid is optimally extended.**
  Utilizing the best European renewable sites with high full load hours means that lower investments need to be effected to reach the challenging targets. In Scenario B, additional 150 GW of RES-E capacities (approx. 6-7%) are installed in 2050 compared to the optimal extension scenario. Hence, higher investments (150 bn. €) in RES-E plants are needed. On the other hand, as generation is located closer to load centers, less conventional back-up capacities are needed than in Scenario A. Table 12 reports investments in conventional, renewable, storage and grid for both scenarios.

- **A lower than optimal extension of the transmission grid leads to almost 50 bn. €$_{2010}$ higher investments in storage technologies.**
  Due to the only moderate transmission grid extension in Scenario B, more storage technologies enter the picture to integrate fluctuating renewable energies into the European electricity system. The additional installation of in total more than 55 GW of storage capacities lead to almost 50 bn. €$_{2010}$ higher investments in Scenario B.

- **Larger geographic dispersion of load and generation sites leads to the need of additional investments in back-up capacities.**
  The share of remotely located fluctuating RES-E capacities, which are characterized by relatively low capacity credits, is higher in Scenario A. Therefore, more gas-fired power plants are commissioned to assure security of supply at times of peak-demand.

TABLE 12: INVESTMENTS IN CONVENTIONAL, RENEWABLE, STORAGE AND GRID IN SCENARIO A AND B [bn.€2010]

		Conventional	Renewable	Storage	Grid	Sum
2010-2020	Scenario A	141	398	0	43	581
	Scenario B	158	370	0	29	556
2020-2030	Scenario A	271	428	9	27	734
	Scenario B	236	482	43	25	786
2030-2040	Scenario A	182	656	22	52	911
	Scenario B	193	686	28	15	921
2040-2050	Scenario A	101	941	9	92	1,142
	Scenario B	85	1,034	15	29	1,162
2010-2050	Scenario A	695	2,422	39	213	3,369
	Scenario B	671	2,571	86	97	3,426

Source: EWI / energynautics

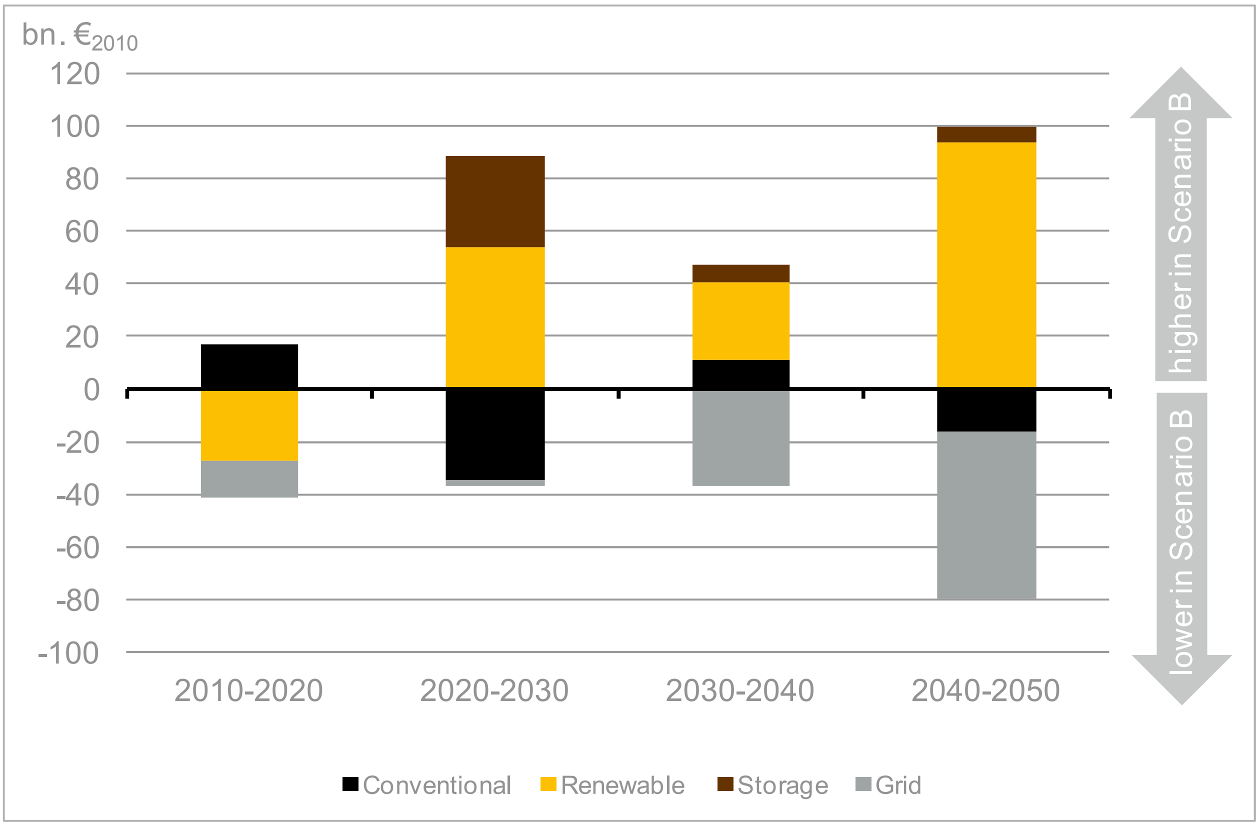

FIGURE 46: DIFFERENCES IN EUROPEAN INVESTMENT EXPENDITURES BETWEEN SCENARIO A AND B [bn. €2010]

Source: EWI / energynautics

Differences and benefits regarding the total system costs

Figure 47 depicts the differences of European fix, variable and average system costs between Scenario A (optimal transmission grid) and Scenario B (moderate transmission grid) in the years 2020, 2030, 2040 and 2050. Average costs refer to costs per unit electricity consumed. Average system costs reflect the sum of investment expenditures (generation technologies and the transmission grid), fixed operation and maintenance as well as variable generation costs in relation to the total energy consumption of end users.

- **Optimal transmission grid extensions facilitate the achievement of short and long term RES-E and CO_2 reduction targets.**
  In case of an optimal transmission grid extension, the short term RES-E and CO_2 targets are amongst others achieved by additional offshore capacities at best European sites. Hence, early investments are necessary which result in high fix costs in 2020. In case of an only moderate transmission grid extension, the connection of these offshore wind sites is limited and a higher usage of natural gas-fired power instead of coal plants occurs. This leads to significantly higher variable costs in Scenario B in the short term.

- **Optimal transmission grid extensions reduce total system costs by about 52 bn. $€_{2010}$ and lower average system costs.**
  Total system costs represent the accumulated discounted costs until 2050. While the cost-efficient transformation of Europe's electricity system in Scenario A (optimal transmission grid) leads to overall system costs of 3,605 bn. $€_{2010}$, they amount to 3,657 bn. $€_{2010}$ in Scenario B. As such, the additional costs of only moderate transmission grid extensions account for around 52 bn. $€_{2010}$. System costs are lower in the optimal transmission grid scenario and the difference to the moderate transmission grid scenario increases over time due to a larger benefit of a strong transmission grid in high RES-E systems. The benefit of optimal transmission grid extension amounts to 10 bn. $€_{2010}$ in 2050. This corresponds to 2.4 $€_{2010}$/MWh lower average system costs (approx. 4%).

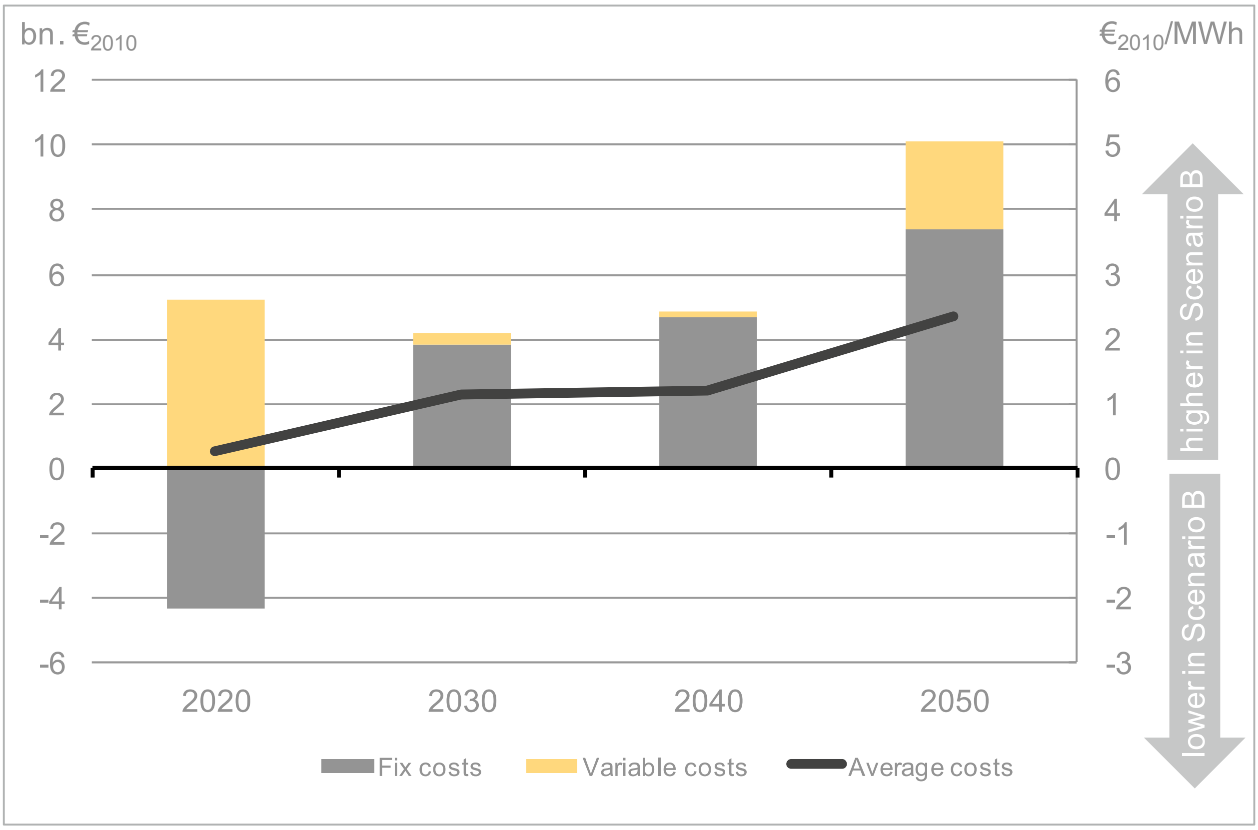

FIGURE 47: FIX AND VARIABLE COSTS [bn. €2010] AND AVERAGE COSTS FOR EUROPE [€2010/MWh]

Source: EWI / energynautics

8 CONCLUSIONS AND POLITICAL RECOMMENDATIONS

Increasing shares of RES-E in Europe's electricity generation mix and significant CO_2 emission reductions pose new challenges to the development of the European power system, asking for deliberate answers that have to be found to ensure a secure, reliable and economic electricity supply.

Reaching high RES-E targets in a cost-efficient way relies on the possibilities to use favorable sites throughout Europe. As these sites are often remotely located with respect to load centers, the combined optimization of generation technologies and electricity grid is crucial. Within this study we developed a tool that couples an economic model of the European electricity markets with an engineering model of the European high voltage grid. Two scenarios have been analyzed, showing the cost-efficient achievement of the assumed RES-E and CO_2 targets. By comparing these two scenarios, we have determined the benefits of optimal transmission grid extensions regarding the cost-efficient transformation of Europe's electricity system.

In the following sections we present the conclusions of our scenario analysis (section 8.1) and the political recommendations deduced from the results (section 8.2).

8.1 Conclusions

Our results show that within our framework ambitious RES-E and CO_2 emission reduction targets can be achieved and that a cost-efficient regional distribution of generation capacities throughout Europe is possible. This holds true even with moderate interconnector extensions. However, additional interconnector and intraregional transmission grid extensions – as determined in scenario A – were found to entail additional cost savings.

In both scenarios, the transformation towards a low-carbon and mainly renewable based electricity system is realized within a framework favoring a cost-efficient electricity supply. In particular, this includes the possibility to deploy RES-E technologies on sites with high full load hours and to use CCS-technology, nuclear power (in some countries) and all other technically available generation options. With regard to renewable energies, the cost-efficient deployment of these options – as determined in our scenarios - leads to electricity mixes which significantly differ from the ones EU Member States have specified in their NREAPs until 2020.

The transformation of the European electricity mix requires investments of about 3.400 bn. $€_{2010}$ in both scenarios. Due to only moderate grid extensions in Scenario B, additional 57 bn. $€_{2010}$ have to be invested in order to reach the RES-E and CO_2 emission reduction targets in 2050. Cost savings due to optimal grid extensions, rise with an increasing RES-E share up to yearly 10 bn. $€_{2010}$ in 2050. This corresponds to a system cost increase of 3.6% and an average cost increase of 2.5 $€_{2010}$/MWh.

The major reason for the cost savings realized in Scenario A is a better use of comparative cost advantages through optimal transmission grid extensions. Furthermore, a highly intermeshed electricity network helps to balance fluctuating RES-E generation and demand. It also increases potential competition. The benefit of comparative cost advantages is captured in-depth in the modeling approach. 47 onshore, 42 offshore and 43 solar regions have been determined based on meteorological data and account in detail for comparative cost advantages arising from different full load hours of fluctuating RES-E technologies throughout Europe. Apart from those, comparative cost advantages between different RES-E technologies are mainly influenced by their relative investment costs. The underlying assumptions for the learning curves of RES-E lead to a conservative estimation of potential benefits from transmission grid extensions. Due to more pronounced learning curve effects of solar than of wind technologies (see section 5.3), differences in electricity generation costs of solar and wind technologies diminish over time. While in 2010 the difference in generation cost between PV plants (ground) at favorable sites in Italy and an offshore wind turbine in Norway is 9 ct_{2010}/kWh, the cost difference decreases to only 2 ct_{2010}/ kWh in 2050. The benefit of a larger grid extension in Scenario A, enabling a higher use of offshore wind on sites in Norway instead of a higher generation from solar plants in the Mediterranean region, is thus conservatively estimated. Also, the benefit of transmission grid extensions with regard to balancing fluctuating RES-E in-feed is conservatively estimated within the market model due to the use of typical days. Moreover, increasing potential competition by enlarging the market through transmission grid extensions is not captured in the scenario results, which both reflect market outcomes under perfect competition.

Furthermore, transmission grid extensions are only one out of many elements contributing to the cost-efficient transformation process of the European electricity system. Further elements are e.g. the full market integration of RES-E and the assumed investment opportunities in all generation options including offshore and onshore wind, concentrated solar power, biomass, CCS, lignite, gas and nuclear plants (see section 5.2 and 5.3). Posing additional restrictions on the system, e.g. by assuming a phase-out of nuclear power in further European countries, by excluding the option of using CCS-technology, or by substantially limiting onshore expansion due to local resistance, induces additional cost. While one can argue whether or not the absence of one element might seem to be manageable, the absence of several elements would cause system costs to increase considerably.

8.2 Political recommendations

Based on the results of the two scenarios and their comparison, we provide in the following political recommendations on how to reach ambitious European renewable energy and climate protection targets in a cost-efficient way. These recommendations concern three main issues:

- Coordinated European action
- Chronological sequence of investments
- Planning reliability

Coordinated European action

The results of our study show that coordinated action among the EU Member States is essential when renewable energy and climate protection targets shall be reached in a cost-efficient way. Renewable resources are heterogeneously distributed within Europe, causing electricity generation costs to broadly differ across regions. In order to take advantage of those cost differences a **European RES-E plan of action** is needed, such that regional benefits are optimally taken into account.

A coordinated European approach is also needed to foster transmission grid extensions which were found to entail important cost savings in the generation sector by far exceeding the additional costs for the transmission grid. In order to achieve the desired large-scale extension of transmission capacities throughout Europe, the following points need to be addressed:

First a **European regulatory framework** should be provided stimulating the construction of new interconnection lines and guaranteeing the full recovery of investments. To this end, transparent and reliable mechanisms are needed. A legislative proposal to address cost allocation of cross-border or major technologically complex projects through tariffs and investment rules is envisaged to be brought forward by the European Commission by the end of 2011. To manage the grid regulation on a European level a European Regulatory Agency should be established. A first step towards such an agency with the mandate to regulate grid extensions within Europe was taken in 2010 with the formation of the Agency for the Cooperation of Energy Regulators (ACER).

Second, a **long term coordinated European plan for grid extensions** should be envisaged, similar to the TYNDP of the ENTSO-E, but going far beyond the program described, both with regard to the planning horizon and the liability of the submitted grid extension plans. Areas of particular importance for extension projects have been identified in this study.

Third, **the permission process for new transmission projects needs to be streamlined and harmonized** across Europe. Long, non-transparent and uncertain permission processes depict one of the main reasons for delays in the implementation of the projects at the moment. In addition, an improvement of public consultation procedures might enhance public acceptance of new transmission projects and thus accelerate the permission process.

Last, to be able to take advantage of physically integrated RES-E electricity generation through transmission grid extension, complementary market designs should be established. They should be harmonized and provide for the full market integration of RES-E generation. Moreover, harmonized market design should also address cross-border trading, such that increasing NTCs can be fully utilized.

Chronological sequence of investments

The cost-efficient achievement of RES-E target implies the primary usage of mature technologies. The pathway is characterized by early investments in onshore wind. Onshore wind turbines have already reached a mature level and have relatively low generation costs at good sites. Also biomass technologies are mature since the technology is the same as in conventional thermal plants. The cost range of biomass fuels is large. Low-cost biomass potentials can help to reach RES-E shares cost-efficiently even at low RES-E shares. However, onshore and low-cost biomass potentials are limited, such that other solutions have to be found. Offshore wind at favorable sites, mainly in Northern Europe, can be such a solution and contribute substantially to the achievement of high RES-E targets. Since the technology of the turbine corresponds to the turbines used on land, it is an equally mature technology. However, learning with regard to installation and maintenance of offshore plants is crucial.

As for today, solar technologies have comparatively high generation costs even on favorable sites. However, solar technologies can be an important part of a European high RES-E mix in the long term, if further substantial cost reductions are achieved. We recommend that research funds are now established which ideally entail efficiency improvements and cost reductions for CSP and PV technologies, rather than large asset commitments in these technologies in the short and medium term.

Planning reliability

In order to reach ambitious climate protection and renewable energy targets, huge investments in capital intensive generation and transmission grid capacities are necessary. Ensuring a reliable political and regulatory framework for investments is thus crucial.

Reliable RES-E targets are a precondition to achieve a cost-efficient transformation of Europe's electricity system until 2050. This is necessary in order to foster both, investments in renewable and in non-renewable power plants. Investments in both plant types will be suboptimal when the envisaged share of RES-E is unclear. In this case the development of future residual load curves and thus the optimal mix of peak-, mid- and base-load plants within the electricity system is uncertain.

Reaching CO_2-targets cost-efficiently requires **reliable long term CO_2-targets**. Investments in CCS-technologies, which can contribute significantly to reducing CO_2 emissions, are only commercially viable when CO_2 prices are high enough to make CCS-plants competitive. Uncertainty about future CO_2 prices thus hinders investments in CCS plants. Also, CCS-technology is still in the development phase. In the present study, we assume that CCS-technology is commercially available by 2030. In order to reach this CCS-option by 2030, investments in research and pilot projects are required today. Noticeably, reliability about future CO_2-targets is also necessary to reach a cost-efficient capacity mix of non-CCS plants (i.e. coal vs. gas investments).

Reliable returns of investments for back-up capacities are needed in order to assure security of electricity supply. In a renewable based electricity system, large amounts of electricity are supplied by technologies which are not securely available at times of peak demand. Thus, back-up capacities are needed in order to meet demand when intermittent renewables are not available. These capacities have very low utilization rates and might therefore rely on incomes from ancillary markets, ideally introduced and regulated on a European standard.

ABBREVIATIONS

a	annum (year)
bn	billion
BOE	barrel of oil equivalent
CAES	compressed air energy storage
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CHP	combined heat and power
CO_2	carbon dioxide
CSP	concentrated solar power
CSP-TES	concentrated solar power with integrated thermal energy storage
ENTSO-E	European Network of Transmission Operators for Electricity
EU-27	European Union
GDP	gross domestic product
GW	gigawatt
GWh	gigawatt hour
h	hour
HDR	hot-dry-rock
HVAC	high voltage alternating current
HVDC	high voltage direct current
kW	kilowatt
LCC	line commutated converter
Mbtu	million british thermal unit
mio	million
MW	megawatt
MW_{inst}	installed megawatt
MWh	megawatt hour
MWh_{el}	megawatt hour electric
MWh_{th}	megawatt hour thermal
NREAP	National Renewable Energy Action Plan
NTC	net transfer capacity
O&M	operation and maintenance
OCGT	open cycle gas turbine
OPF	optimal power flow
PTDF	power transfer distribution factor
PV	photovoltaics

RE	renewable energy
RES	renewable energy sources
RES-E	renewable energy sources for electricity
t	ton
TCE	tonne of coal equivalent
TEN-E	Trans-European Energy Networks
TES	thermal energy storage
TWh	terawatt hour
TWh_{el}	terawatt hour electric
TWh_{th}	terawatt hour thermal
TYNDP	Ten Year Network Development Plan
US$	US-Dollar
VSC	voltage source converter

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ATTACHMENTS

A.1 Assumed interconnector extensions in Scenario B

		NTC extension based on TYNDP [GW]				Assumed delayed NTC extension [GW]			
Export country	Import country	2010-2020	2020-2030	2030-2040	2040-2050	2010-2020	2020-2030	2030-2040	2040-2050
AT	CH		0.77						0.77
AT	CZ								
AT	DE	1.94	0.77					1.94	0.77
AT	HU	0.20				0.20			
AT	IT		2.63						2.63
AT	SI								
AT	SK	0.97					0.97		
BE	DE		0.89						0.89
BE	FR	0.30	0.97			0.30		0.97	
BE	GB	1.00					1.00		
BE	LU	0.40					0.40		
BE	NL								
BG	GR	0.97				0.97			
BG	RO	1.94						1.94	
CH	AT		0.77						0.77
CH	DE		0.77						0.77
CH	FR		0.20						0.20
CH	IT	0.97						0.97	
CZ	AT								
CZ	DE		0.97					0.97	
CZ	PL								
CZ	SK								
DE	AT	0.77	1.94					0.77	1.94
DE	BE		0.89						0.89
DE	CZ		0.97					0.97	
DE	CH		0.77						0.77
DE	DK-E	0.60				0.60			
DE	DK-W	0.50	0.97				0.50	0.97	
DE	FR								
DE	LU								
DE	NL	1.94					1.94		
DE	NO		0.70					0.70	
DE	PL	0.77	0.97			0.77		0.97	
DE	SE	0.60				0.60			
DK-E	DE	0.60				0.60			
DK-E	DK-W	1.40						1.40	
DK-E	NO								
DK-E	PL								
DK-E	SE	0.60				0.60			
DK-W	DE	0.50	0.97				0.50	0.97	
DK-W	DK-E	1.40						1.40	
DK-W	NL	0.70					0.70		
DK-W	NO	0.70				0.70			
DK-W	SE								

		NTC extension based on TYNDP [GW]				Assumed delayed NTC extension [GW]			
Export country	Import country	2010-2020	2020-2030	2030-2040	2040-2050	2010-2020	2020-2030	2030-2040	2040-2050
EE	FI	0.65				0.65			
EE	LV								
EE	SE								
ES	FR	1.60	1.20				1.60		1.20
ES	NA			4.40	10.00	0.30		4.10	10.00
ES	PT	1.80				1.80			
FI	EE	0.65				0.65			
FI	NO		0.97				0.97		
FI	SE	1.77				1.77			
FR	BE	0.30	0.97			0.30			0.97
FR	CH		0.20						0.20
FR	DE								
FR	ES	2.30	1.20				2.30		1.20
FR	GB	1.00					1.00		
FR	IT	0.60	1.00				0.60		1.00
FR	LU	0.20				0.20			
GB	BE	1.00					1.00		
GB	FR	1.00					1.00		
GB	IE	1.47				1.47			
GB	NL	1.00				1.00			
GB	NO	1.40					1.40		
GR	BG	0.97				0.97			
GR	IT	0.50					0.50		
GR	NA								
HU	AT	0.20				0.20			
HU	RO								
HU	SI	1.94				1.94			
HU	SK	2.91					2.91		
IE	GB	1.47				1.47			
IT	AT		2.63						2.63
IT	CH	0.97						0.97	
IT	FR	0.60	1.00				0.60		1.00
IT	GR	0.50					0.50		
IT	NA								
IT	SI		1.94					1.94	
LT	LV	0.20				0.20			
LT	PL	3.34				3.34			
LT	SE	0.70				0.70			
LV	EE								
LV	LT	0.20				0.20			
LV	SE								
LU	BE	0.20					0.20		
LU	DE								
LU	FR	0.20				0.20			
NA	ES			4.10	10.00			4.10	10.00
NA	GR								
NA	PT								
NA	IT								
NL	BE								
NL	DE	1.94					1.94		
NL	DK-W	0.70					0.70		
NL	NO	1.40					1.40		
NL	GB	1.00				1.00			
NO	DE		0.70					0.70	
NO	DK-E								
NO	DK-W	0.70				0.70			
NO	FI		0.97				0.97		
NO	GB	1.40					1.40		
NO	NL	1.40					1.40		
NO	SE	2.17				2.17			

Export country	Import country	NTC extension based on TYNDP [GW]				Assumed delayed NTC extension [GW]			
		2010-2020	2020-2030	2030-2040	2040-2050	2010-2020	2020-2030	2030-2040	2040-2050
PT	ES	1.80				1.80			
PT	NA								
PL	CZ								
PL	DE	0.77	0.97			0.77		0.97	
PL	DK-E								
PL	LT	3.34				3.34			
PL	SK								
PL	SE								
RO	BG	1.94					1.94		
RO	HU								
SE	DE	0.60				0.60			
SE	DK-E	0.60				0.60			
SE	DK-W								
SE	EE								
SE	FI	1.77				1.77			
SE	LT	0.70				0.70			
SE	LV								
SE	NO	2.17				2.17			
SE	PL								
SI	AT								
SI	HU	1.94				1.94			
SI	IT		1.94					1.94	
SK	AT	0.97					0.97		
SK	CZ								
SK	HU	2.91					2.91		
SK	PL								

A.2 Installed Capacities, Generation and Power Balance

In the following the key numbers regarding the electricity system of each country are reported. This includes the installed capacities by technology classes [GW], electricity generation by technology classes [TWh] and the power balance [TWh].

Austria	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	n.a.	0,60	0,60	0,00	0,00	0,60	0,60	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	n.a.	0,42	0,00	0,00	0,00	0,42	0,00	0,00	0,00
Coal-CHP	n.a.	0,75	0,50	0,25	0,00	0,75	0,50	0,25	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,79	1,15	1,23	0,00	0,71	1,15	1,15
Gas	n.a.	0,17	0,00	0,00	0,00	0,18	0,01	0,01	0,00
Gas-CHP	n.a.	1,90	0,63	0,00	0,00	1,90	0,63	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	n.a.	0,20	0,00	0,00	0,00	0,20	0,00	0,00	0,00
Storage	6,60	5,50	5,50	5,50	5,50	5,50	5,50	5,50	5,50
Hydro	5,41	8,22	8,22	8,22	8,22	8,22	8,22	8,22	8,22
Biomass	0,00	0,10	0,10	0,00	0,00	0,10	0,10	0,00	0,00
Biomass-CHP	n.a.	0,17	0,17	0,24	0,25	0,17	0,17	0,24	0,32
Wind onshore	0,97	3,45	3,47	3,93	4,43	3,45	3,47	3,93	4,43
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,03	0,01	0,00	2,42	0,03	0,01	0,00	15,83
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,25	0,56	0,57	0,82	0,25	0,56	0,57	0,82
Others	n.a.	0,15	0,15	0,15	0,15	0,15	0,15	0,15	0,15
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	5,52	2,21	0,00	0,00	0,00	2,27	0,00	0,00	0,00
Coal-CHP	n.a.	5,04	2,91	0,51	0,00	5,10	3,40	0,51	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	5,73	8,34	8,90	0,00	5,16	8,34	8,34
Gas	11,20	1,20	0,00	0,00	0,00	1,27	0,07	0,06	0,00
Gas-CHP	n.a.	12,45	0,85	0,00	0,00	12,32	1,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	1,24	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	3,00	3,00	3,21	0,00	2,29	2,29	2,68
Hydro	40,68	25,22	25,22	25,22	25,22	25,22	25,22	25,22	25,22
Biomass	4,63	0,61	0,60	0,00	0,00	0,59	0,61	0,00	0,00
Biomass-CHP	n.a.	1,24	1,26	1,80	1,80	1,25	1,25	1,80	2,36
Wind onshore	2,01	6,23	6,29	7,77	9,30	6,23	6,29	7,77	9,30
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,03	0,04	0,01	0,00	2,67	0,04	0,01	0,00	17,15
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	1,86	4,15	4,18	4,20	1,86	4,15	4,18	4,20
Others	1,78	0,76	0,76	0,76	0,76	0,76	0,76	0,76	0,76
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	59,41	65,25	69,97	74,28	78,47	65,25	69,97	74,28	78,47
Consumption in Energy Conversion	5,84	3,68	2,54	2,48	2,48	3,69	2,56	2,49	2,43
Own Consumption of Power Plants	5,84	2,09	0,95	0,88	0,89	2,10	0,96	0,89	0,83
Other	n.a.	1,59	1,59	1,59	1,59	1,59	1,59	1,59	1,59
Transmission Losses	3,45	3,10	3,10	3,10	3,10	3,10	3,10	3,10	3,10
Storage Consumption	0,54	0,00	4,16	4,16	4,46	0,00	3,19	3,19	3,72
Gross Electricity Consumption	69,23	72,04	79,78	84,03	88,52	72,05	78,82	83,06	87,72
Net Imports	4,86	15,18	28,99	32,45	32,44	15,13	28,58	32,12	17,71
Gross Electricity Generation	67,10	56,87	50,79	51,58	56,08	56,92	50,24	50,94	70,01

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Belgium	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2006*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	5,83	3,85	0,00	0,00	0,00	3,85	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	1,44	1,48	0,69	0,30	0,20	1,48	8,91	8,52	8,43
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,33	0,33	0,33	0,00	0,31	0,31	0,31
Gas	6,00	8,11	10,21	12,71	14,04	7,05	5,56	6,58	7,86
Gas-CHP	n.a.	0,80	0,27	0,00	0,00	0,80	0,27	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,57	0,04	0,02	0,02	0,02	0,04	0,02	0,02	0,02
Storage	1,31	1,31	1,31	1,31	1,31	1,31	1,31	1,31	1,31
Hydro	0,11	0,11	0,11	0,11	0,11	0,11	0,11	0,11	0,11
Biomass	0,13	0,58	0,11	0,11	0,11	0,58	0,11	0,39	0,43
Biomass-CHP	n.a.	0,32	0,34	0,34	0,34	0,32	0,32	0,35	0,34
Wind onshore	0,20	3,51	3,55	3,75	4,36	3,51	3,55	3,75	4,36
Wind offshore	0,00	0,73	0,73	1,89	1,86	0,73	1,89	1,89	1,86
PV	0,00	0,36	0,36	0,00	0,00	0,36	0,36	0,00	1,20
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	n.a.	0,20	0,20	0,20	0,21	0,20	0,20	0,20	0,20
Others	0,67	0,12	0,12	0,12	0,12	0,12	0,12	0,12	0,12

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	45,57	28,34	0,00	0,00	0,00	28,34	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	5,55	8,32	4,50	1,81	0,00	8,61	58,11	52,71	30,94
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	2,26	2,28	2,30	0,00	2,26	2,18	2,10
Gas	24,65	44,08	35,63	31,13	0,00	40,26	19,06	16,39	3,85
Gas-CHP	n.a.	4,49	0,00	0,00	0,00	4,49	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,41	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,51	0,51	0,66	1,37	0,51	0,56	0,87	1,06
Hydro	1,76	0,50	0,50	0,50	0,50	0,50	0,50	0,50	0,50
Biomass	3,99	2,99	0,75	0,75	0,75	2,99	0,76	2,79	2,88
Biomass-CHP	n.a.	2,35	2,37	2,37	2,37	2,35	2,37	2,37	2,37
Wind onshore	0,64	8,99	9,16	9,98	12,38	8,99	9,16	9,98	12,38
Wind offshore	0,00	2,96	2,96	8,35	8,60	2,96	8,34	8,35	8,60
PV	0,04	0,32	0,32	0,00	0,00	0,32	0,32	0,00	1,10
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	1,47	1,48	1,49	1,49	1,47	1,48	1,49	1,49
Others	2,34	0,65	0,65	0,65	0,62	0,65	0,65	0,65	0,65

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	82,64	92,49	99,17	105,28	111,22	92,49	99,17	105,28	111,22
Consumption in Energy Conversion	6,73	10,31	6,03	5,31	2,02	9,96	9,73	8,92	5,48
Own Consumption of Power Plants	6,73	8,52	4,24	3,52	0,23	8,17	7,94	7,13	3,69
Other	n.a.	1,79	1,79	1,79	1,79	1,79	1,79	1,79	1,79
Transmission Losses	4,26	3,84	3,84	3,84	3,84	3,84	3,84	3,84	3,84
Storage Consumption	0,43	0,71	0,71	0,92	1,90	0,71	0,77	1,20	1,47
Gross Electricity Consumption	94,06	107,35	109,75	115,35	118,97	107,00	113,51	119,24	122,00
Net Imports	10,60	1,39	48,67	55,39	88,59	4,56	9,96	20,99	54,09
Gross Electricity Generation	84,93	105,96	61,08	59,96	30,38	102,43	103,55	98,25	67,91

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Bulgaria	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	1,90	1,91	2,79	1,84	1,84	1,91	2,63	1,68	1,68
Lignite (incl. CHP)	3,18	3,58	2,52	1,56	1,36	3,64	2,62	1,66	1,46
Lignite-CCS	0,00	0,00	0,14	0,86	0,86	0,00	0,00	0,59	0,59
Coal	1,39	0,77	0,00	0,00	0,00	0,77	0,00	0,00	0,00
Coal-CHP	n.a.	0,05	0,02	0,00	0,00	0,04	0,02	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	0,36	0,00	0,00	0,44	1,58	0,00	0,00	0,40	1,98
Gas-CHP	n.a.	0,23	0,08	0,00	0,00	0,23	0,08	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,22	0,14	0,00	0,00	0,00	0,14	0,00	0,00	0,00
Storage	0,42	0,86	0,86	0,86	0,86	0,86	0,86	0,86	0,86
Hydro	1,38	2,12	2,12	2,12	2,12	2,12	2,12	2,12	2,12
Biomass	0,00	0,09	0,09	0,09	0,09	0,09	0,09	0,20	0,20
Biomass-CHP	n.a.	0,31	0,31	0,31	0,23	0,31	0,31	0,31	0,23
Wind onshore	0,04	0,18	0,15	1,71	1,92	0,18	0,15	0,00	1,92
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,01	0,01	0,00	0,00	0,01	0,01	0,00	4,15
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	n.a.	0,00	0,00	0,10	0,10	0,00	0,00	0,10	0,10
Others	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	15,77	14,02	20,51	13,50	13,50	14,02	19,33	12,32	12,18
Lignite (incl. CHP)	17,13	15,89	15,02	10,15	6,75	16,02	16,08	12,26	3,22
Lignite-CCS	0,00	0,00	1,07	6,44	6,44	0,00	0,00	4,48	3,82
Coal	6,05	0,00	0,00	0,00	0,00	0,78	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,02	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	2,36	0,00	0,00	0,17	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,00	0,01	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,28	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,36	0,34	0,00	0,00	0,00	0,21	1,19
Hydro	3,28	7,34	7,34	7,34	7,34	7,34	7,34	7,34	7,34
Biomass	0,00	0,69	0,69	0,69	0,69	0,69	0,69	1,48	1,15
Biomass-CHP	n.a.	2,29	2,29	1,64	1,66	2,29	2,29	1,64	1,66
Wind onshore	0,12	0,19	0,16	2,35	2,63	0,19	0,16	0,00	2,63
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,01	0,01	0,00	0,00	0,01	0,01	0,00	5,10
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,00	0,00	0,70	0,71	0,00	0,03	0,70	0,71
Others	0,06	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	28,63	31,95	36,00	40,36	45,03	31,95	36,00	40,36	45,03
Consumption in Energy Conversion	5,64	4,47	5,14	4,50	4,15	4,56	5,02	4,38	3,40
Own Consumption of Power Plants	5,64	2,99	3,66	3,03	2,67	3,08	3,54	2,91	1,92
Other	n.a.	1,48	1,48	1,48	1,48	1,48	1,48	1,48	1,48
Transmission Losses	4,67	4,20	4,20	4,20	4,20	4,20	4,20	4,20	4,20
Storage Consumption	0,26	0,00	0,50	0,47	0,00	0,00	0,00	0,29	1,65
Gross Electricity Consumption	39,20	40,62	45,84	49,53	53,38	40,71	45,22	49,23	54,28
Net Imports	-5,34	0,17	-1,65	6,18	13,63	-0,64	-0,72	8,78	15,26
Gross Electricity Generation	45,04	40,45	47,49	43,35	39,75	41,35	45,95	40,45	39,02

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Czech Republic	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	3,76	3,49	2,72	4,26	6,05	3,49	2,70	5,35	5,59
Lignite (incl. CHP)	8,84	6,39	6,26	4,13	4,13	6,52	5,65	3,51	3,51
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	1,78	0,91	0,18	0,01	0,00	0,91	0,18	0,01	0,00
Coal-CHP	n.a.	2,51	1,68	0,84	0,00	2,32	1,48	0,64	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,09	1,20	1,46	0,00	0,10	1,29	1,39
Gas	0,31	0,14	0,07	0,00	0,00	0,14	0,07	0,00	0,28
Gas-CHP	n.a.	0,37	0,12	0,00	0,00	0,37	0,12	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,12	0,07	0,00	0,00	0,00	0,07	0,00	0,00	0,00
Storage	1,15	1,15	1,15	1,15	1,15	1,15	1,15	1,15	1,15
Hydro	1,03	1,05	1,05	1,05	1,05	1,05	1,05	1,05	1,05
Biomass	0,05	0,63	0,06	0,06	0,06	0,63	0,08	0,10	0,24
Biomass-CHP	n.a.	0,45	0,49	0,50	0,51	0,45	0,49	0,50	0,51
Wind onshore	0,11	5,04	8,92	8,99	9,97	5,04	9,71	9,78	10,77
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,47	0,47	0,00	0,00	0,47	0,47	0,00	2,97
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,25	0,69	0,76	0,96	0,25	0,75	0,76	1,02
Others	0,42	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	26,55	25,70	20,00	31,34	44,48	25,70	19,87	39,33	40,41
Lignite (incl. CHP)	42,98	42,37	35,43	26,71	26,24	42,62	32,79	22,72	20,21
Lignite-CCS	0,00	0,00	12,95	23,19	22,70	0,00	15,18	26,87	25,63
Coal	5,79	1,14	1,18	0,03	0,00	1,01	1,16	0,02	0,00
Coal-CHP	n.a.	13,28	9,75	1,71	0,00	13,18	9,27	0,96	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,63	8,45	10,32	0,00	0,73	9,08	9,75
Gas	2,92	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,76	0,17	0,00	0,00	0,96	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,13	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,63	0,63	0,78	0,20	0,30	0,72	1,23
Hydro	2,38	2,73	2,73	2,73	2,73	2,73	2,73	2,73	2,73
Biomass	1,46	4,30	0,42	0,42	0,40	4,30	0,59	0,69	1,65
Biomass-CHP	n.a.	3,32	3,58	3,58	3,58	3,32	3,58	3,58	3,58
Wind onshore	0,25	10,80	17,59	17,79	21,03	10,80	19,72	19,93	23,17
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,01	0,46	0,46	0,00	0,00	0,46	0,46	0,00	2,99
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	1,85	5,11	5,64	5,70	1,85	5,51	5,64	5,70
Others	1,05	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	58,00	69,93	78,79	88,34	98,55	69,93	78,79	88,34	98,55
Consumption in Energy Conversion	8,91	10,58	10,27	11,40	12,63	10,60	10,16	12,16	11,86
Own Consumption of Power Plants	8,91	8,32	8,01	9,14	10,37	8,35	7,90	9,90	9,60
Other	n.a.	2,26	2,26	2,26	2,26	2,26	2,26	2,26	2,26
Transmission Losses	4,66	4,20	4,20	4,20	4,20	4,20	4,20	4,20	4,20
Storage Consumption	0,13	0,00	0,87	0,87	1,08	0,28	0,42	1,00	1,70
Gross Electricity Consumption	71,70	84,71	94,12	104,80	116,45	85,02	93,56	105,69	116,31
Net Imports	-11,47	-22,02	-16,53	-17,43	-21,53	-22,14	-18,36	-26,61	-20,76
Gross Electricity Generation	83,52	106,73	110,65	122,23	137,99	107,16	111,92	132,30	137,07

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Denmark	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	5,54	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	4,22	2,81	1,41	0,00	4,22	2,81	1,41	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,51	1,53	1,59	0,00	0,72	1,31	1,44
Gas	3,27	0,00	5,37	7,14	7,53	0,00	1,94	3,05	4,18
Gas-CHP	n.a.	2,16	0,73	0,00	0,00	2,16	0,73	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,80	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	0,00	0,00	0,00	2,24	2,84	0,00	1,06	2,55	2,75
Hydro	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01
Biomass	0,00	0,32	0,00	0,00	0,00	0,32	0,00	0,00	0,00
Biomass-CHP	n.a.	0,42	0,46	0,46	0,46	0,42	0,46	0,55	0,55
Wind onshore	2,80	4,90	5,73	6,07	6,49	4,90	5,82	6,15	6,58
Wind offshore	0,33	6,47	19,43	39,48	39,64	4,50	5,93	10,20	10,47
PV	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,95
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	n.a.	0,50	0,69	0,69	0,69	0,50	0,69	0,69	0,69
Others	n.a.	0,35	0,35	0,35	0,35	0,35	0,35	0,35	0,35
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	17,46	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	11,85	8,07	0,99	0,00	11,97	6,61	1,94	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	3,59	10,77	11,13	0,00	5,05	9,17	9,86
Gas	6,93	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	2,33	0,00	0,00	0,00	2,08	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	1,13	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,00	0,81	2,09	0,00	0,52	1,31	1,93
Hydro	0,03	0,05	0,05	0,05	0,05	0,05	0,05	0,05	0,04
Biomass	3,92	1,35	0,00	0,00	0,00	0,13	0,00	0,00	0,00
Biomass-CHP	n.a.	3,11	3,26	3,26	3,26	3,12	3,26	3,90	3,90
Wind onshore	6,93	13,52	17,34	18,87	20,86	13,52	17,71	19,25	21,24
Wind offshore	0,00	27,20	90,29	187,31	190,47	18,74	26,23	47,11	49,40
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,94
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	3,67	5,07	5,08	5,09	3,67	5,07	5,08	5,09
Others	0,00	1,85	1,85	1,85	1,74	1,85	1,85	1,78	1,75
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	33,37	40,45	43,38	46,05	48,65	40,45	43,38	46,05	48,65
Consumption in Energy Conversion	2,11	1,92	1,67	1,68	1,61	1,90	1,67	1,61	1,49
Own Consumption of Power Plants	2,11	1,42	1,17	1,18	1,11	1,40	1,17	1,11	0,99
Other	n.a.	0,50	0,50	0,50	0,50	0,50	0,50	0,50	0,50
Transmission Losses	2,36	2,16	2,16	2,16	2,16	2,16	2,16	2,16	2,16
Storage Consumption	0,00	0,00	0,00	1,15	2,98	0,00	0,74	1,87	3,61
Gross Electricity Consumption	37,85	44,53	47,20	51,04	55,40	44,52	47,94	51,69	55,90
Net Imports	1,46	-20,38	-82,31	-177,95	-179,29	-10,59	-18,41	-37,91	-38,26
Gross Electricity Generation	36,39	64,91	129,51	228,99	234,69	55,11	66,35	89,60	94,16

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Estonia	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	n.a.	1,17	2,05	2,05	2,05	1,26	0,94	0,94	0,94
Lignite-CCS	0,00	0,00	0,08	0,08	0,08	0,00	0,40	0,40	0,40
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	0,10	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,15	0,05	0,00	0,00	0,15	0,05	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,01	0,01	0,13	0,00	0,00	0,01	0,13	0,00	0,00
Storage	0,00	0,00	0,00	0,00	0,00	0,00	1,05	1,27	1,27
Hydro	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01
Biomass	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Biomass-CHP	n.a.	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06
Wind onshore	0,06	4,14	4,14	4,20	5,02	4,14	4,14	4,20	5,02
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02
Others	0,02	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	9,65	2,88	13,71	13,72	6,33	2,80	6,05	5,71	1,61
Lignite-CCS	0,00	0,00	0,57	0,56	0,54	0,00	2,66	2,70	2,58
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,01	0,01	0,00	0,00	0,00	0,00
Gas	0,70	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,04	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,00	0,00	0,00	0,00	0,89	0,94	0,98
Hydro	0,03	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02
Biomass	0,04	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Biomass-CHP	n.a.	0,42	0,42	0,42	0,42	0,42	0,42	0,43	0,43
Wind onshore	0,13	9,89	9,90	10,10	12,14	9,65	9,70	9,98	11,80
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,14	0,14	0,14	0,14	0,14	0,14	0,14	0,14
Others	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	6,99	7,70	8,68	9,73	10,85	7,70	8,68	9,73	10,85
Consumption in Energy Conversion	1,52	0,67	1,81	1,81	1,07	0,66	1,25	1,22	0,80
Own Consumption of Power Plants	1,52	0,29	1,43	1,43	0,69	0,28	0,87	0,84	0,42
Other	n.a.	0,38	0,38	0,38	0,38	0,38	0,38	0,38	0,38
Transmission Losses	1,13	1,02	1,02	1,02	1,02	1,02	1,02	1,02	1,02
Storage Consumption	0,00	0,00	0,00	0,00	0,00	0,00	1,27	1,34	1,40
Gross Electricity Consumption	9,64	9,39	11,50	12,56	12,94	9,38	12,22	13,31	14,07
Net Imports	-0,94	-3,96	-13,26	-12,42	-6,67	-3,65	-7,66	-6,61	-3,50
Gross Electricity Generation	10,58	13,35	24,77	24,98	19,61	13,03	19,88	19,92	17,57

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Finland	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	2,67	3,31	2,00	2,00	2,00	3,31	2,20	8,08	8,08
Lignite (incl. CHP)	1,22	1,00	1,20	0,98	0,98	0,67	1,34	1,12	1,12
Lignite-CCS	0,00	0,00	0,10	0,18	0,18	0,00	0,00	0,22	0,22
Coal	3,27	4,04	2,51	0,00	0,00	4,04	2,51	0,00	0,00
Coal-CHP	n.a.	0,73	0,48	0,24	0,00	0,73	0,48	0,24	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	1,40	1,54	1,77	0,00	1,29	1,50	1,56
Gas	2,65	0,76	3,46	5,52	7,86	0,76	1,44	2,17	3,48
Gas-CHP	n.a.	1,49	0,50	0,00	0,00	1,49	0,50	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	1,37	0,19	0,02	0,02	0,00	0,19	0,02	0,02	0,00
Storage	0,00	0,00	0,00	4,97	5,26	0,00	3,50	3,64	3,64
Hydro	3,10	3,10	3,10	3,10	3,10	3,10	3,10	3,10	3,10
Biomass	2,32	1,27	1,03	0,00	0,00	1,27	1,03	0,00	0,12
Biomass-CHP	n.a.	0,72	0,73	0,73	0,52	0,73	0,73	0,75	0,75
Wind onshore	0,11	2,61	5,57	5,61	6,12	2,61	5,77	5,81	6,32
Wind offshore	0,00	0,02	0,02	0,00	0,00	0,02	0,02	0,00	2,11
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,50	0,75	0,90	0,90	0,50	0,82	0,89	0,97
Others	n.a.	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	22,96	24,33	14,71	14,58	14,01	24,33	16,21	59,42	58,51
Lignite (incl. CHP)	5,20	7,17	6,85	6,38	5,46	3,96	7,67	6,00	1,91
Lignite-CCS	0,00	0,00	0,71	1,31	1,27	0,00	0,00	1,66	1,52
Coal	8,51	14,43	15,60	0,00	0,00	9,06	8,71	0,00	0,00
Coal-CHP	n.a.	5,27	1,49	0,00	0,00	5,27	1,43	0,08	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	9,93	10,62	12,25	0,00	9,41	10,24	10,25
Gas	11,25	0,00	0,00	0,00	0,00	0,00	0,00	0,06	0,00
Gas-CHP	n.a.	10,08	0,00	0,00	0,00	10,54	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,43	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,00	1,77	3,75	0,00	2,57	2,32	3,28
Hydro	17,11	13,96	13,96	13,96	13,96	13,96	13,96	13,96	13,96
Biomass	10,58	7,18	6,83	0,00	0,00	7,14	7,13	0,00	0,79
Biomass-CHP	n.a.	5,33	5,34	5,19	3,65	5,36	5,36	5,50	5,30
Wind onshore	0,26	5,71	11,64	11,78	13,54	5,71	12,23	12,38	14,14
Wind offshore	0,00	0,06	0,06	0,00	0,00	0,06	0,06	0,00	5,71
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	3,69	5,54	6,61	6,65	3,69	6,09	6,61	6,65
Others	1,14	0,97	0,97	0,97	0,91	0,97	0,97	0,97	0,97

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	82,61	96,60	103,58	109,97	116,17	96,60	103,58	109,97	116,17
Consumption in Energy Conversion	4,26	7,19	5,99	4,35	4,36	6,38	5,41	8,81	8,28
Own Consumption of Power Plants	4,26	6,13	4,93	3,29	3,30	5,32	4,34	7,75	7,22
Other	n.a.	1,07	1,07	1,07	1,07	1,07	1,07	1,07	1,07
Transmission Losses	3,33	3,00	3,00	3,00	3,00	3,00	3,00	3,00	3,00
Storage Consumption	0,00	0,00	0,00	2,52	5,36	0,00	3,67	3,31	4,68
Gross Electricity Consumption	90,21	106,80	112,58	119,85	128,90	105,99	115,66	125,09	132,14
Net Imports	12,77	8,62	18,96	46,68	53,44	15,94	23,86	5,90	9,17
Gross Electricity Generation	77,44	98,18	93,62	73,17	75,46	90,05	91,80	119,19	122,97

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

France	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2006*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	63,26	63,97	69,73	35,72	22,00	63,97	69,73	35,72	22,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	8,20	3,76	0,23	0,00	0,00	3,76	0,95	12,33	12,33
Coal-CHP	n.a.	0,16	0,11	0,05	0,00	0,16	0,11	0,05	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,01	0,01	0,00	0,00	0,00	0,00
Gas	1,10	0,00	0,00	33,50	54,59	0,00	1,08	24,11	42,68
Gas-CHP	n.a.	1,52	0,51	0,00	0,00	1,52	0,51	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	7,20	0,11	0,00	0,00	0,00	0,11	0,00	0,00	0,00
Storage	n.a.	4,30	4,30	4,30	4,30	4,30	9,13	9,13	9,13
Hydro***	20,81	20,87	20,87	20,87	20,87	20,87	20,87	20,87	20,87
Biomass	n.a.	0,87	0,79	0,00	0,00	0,87	0,79	0,00	0,00
Biomass-CHP	n.a.	1,85	1,99	2,08	2,09	1,98	2,06	2,16	2,17
Wind onshore	1,50	29,49	58,42	62,28	67,37	29,49	48,71	66,32	71,41
Wind offshore	0,00	0,00	0,00	2,35	14,95	0,00	0,00	14,95	27,52
PV	n.a.	0,27	0,26	1,48	20,15	0,27	0,26	3,28	50,99
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	n.a.	0,25	0,43	0,43	0,44	0,25	0,43	0,43	0,48
Others	n.a.	0,71	0,71	0,71	0,71	0,71	0,71	0,71	0,71

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	439,47	470,55	512,95	262,77	160,64	469,04	502,33	259,90	158,95
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	24,45	7,28	1,39	0,00	0,00	10,14	5,27	73,92	28,86
Coal-CHP	n.a.	0,30	0,43	0,00	0,00	0,07	0,41	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,06	0,06	0,00	0,00	0,00	0,00
Gas	21,92	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	3,11	0,00	0,00	0,00	3,54	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	5,89	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	1,35	1,69	1,69	4,26	3,70	6,31	5,96	8,00
Hydro	68,84	47,52	47,52	47,52	47,52	47,52	47,52	47,52	47,52
Biomass	5,89	5,59	5,14	0,00	0,00	5,19	4,86	0,00	0,00
Biomass-CHP	n.a.	13,63	13,99	14,66	14,70	13,67	14,03	14,72	14,76
Wind onshore	5,69	69,15	135,97	146,76	165,42	69,15	118,28	160,27	178,93
Wind offshore	0,00	0,00	0,00	8,24	52,38	0,00	0,00	52,38	96,51
PV	0,04	0,31	0,29	2,06	26,94	0,31	0,29	4,56	61,79
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	1,86	3,18	3,20	3,22	1,86	3,18	3,20	3,22
Others	3,86	3,75	3,75	3,75	3,75	3,75	3,75	3,75	3,75

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	433,32	479,97	514,64	546,37	577,17	479,97	514,64	546,37	577,17
Consumption in Energy Conversion	54,13	62,13	65,48	40,29	30,08	62,29	64,81	47,39	32,79
Own Consumption of Power Plants	54,13	48,12	51,48	26,28	16,07	48,28	50,80	33,38	18,78
Other	n.a.	14,01	14,01	14,01	14,01	14,01	14,01	14,01	14,01
Transmission Losses	32,92	29,62	29,62	29,62	29,62	29,62	29,62	29,62	29,62
Storage Consumption	1,89	1,87	2,35	2,35	5,92	5,13	8,84	8,34	11,23
Gross Electricity Consumption	522,26	573,59	612,10	618,63	642,79	577,01	617,91	631,72	650,81
Net Imports	-48,01	-50,81	-114,21	127,91	163,90	-50,94	-88,31	5,55	48,52
Gross Electricity Generation	576,03	624,40	726,31	490,72	478,89	627,94	706,22	626,17	602,30

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

****2000 data*

Germany	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	20,47	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	20,52	31,87	29,86	24,55	19,51	32,70	28,08	22,77	17,73
Lignite-CCS	0,00	0,00	1,68	5,06	5,06	0,00	2,22	8,51	8,51
Coal	27,60	14,20	5,54	0,00	0,00	14,20	7,87	2,33	2,33
Coal-CHP	n.a.	12,37	2,54	0,12	0,00	12,25	2,42	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	3,97	5,29	5,29	0,00	3,44	4,65	4,65
Gas	23,39	15,91	18,80	35,82	45,02	27,02	25,43	35,27	41,31
Gas-CHP	n.a.	9,24	4,37	0,02	0,00	9,24	4,37	0,02	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	6,26	0,65	0,38	0,13	0,00	0,65	0,38	0,13	0,00
Storage	5,71	7,89	7,89	7,89	7,89	7,89	7,89	7,89	7,89
Hydro	5,17	3,51	3,51	3,51	3,51	3,51	3,51	3,51	3,51
Biomass	3,39	5,43	3,32	0,03	0,03	5,43	3,90	3,12	3,12
Biomass-CHP	n.a.	1,22	2,43	2,96	2,97	1,73	2,52	3,07	3,07
Wind onshore	22,29	27,57	33,12	38,78	47,35	29,52	33,12	46,36	47,75
Wind offshore	0,00	0,04	0,04	8,57	10,19	0,04	4,70	23,99	48,93
PV	3,87	9,79	7,90	0,00	0,00	9,79	7,90	0,00	12,69
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,26	0,76	1,25	1,75	0,51	1,01	1,50	1,75
Others	5,61	5,70	5,70	5,70	5,70	5,70	5,70	5,70	5,70

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	148,50	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	150,62	153,94	152,03	131,93	108,02	156,23	145,91	107,41	106,49
Lignite-CCS	0,00	0,00	12,64	35,60	35,21	0,00	16,68	60,20	59,80
Coal	124,62	64,99	37,55	0,00	0,00	56,73	55,32	15,19	3,88
Coal-CHP	n.a.	20,36	12,29	0,52	0,00	14,68	8,88	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	28,89	38,46	36,64	0,00	25,01	33,50	32,15
Gas	75,92	103,67	83,02	55,74	0,00	180,60	146,34	82,34	0,00
Gas-CHP	n.a.	52,30	0,00	0,00	0,00	52,49	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	8,60	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	1,54	3,10	3,10	9,08	0,75	2,06	3,47	10,15
Hydro	26,96	12,92	12,92	12,92	12,92	12,92	12,92	12,92	12,92
Biomass	28,86	36,82	23,13	0,24	0,14	36,82	28,77	22,55	20,63
Biomass-CHP	n.a.	9,03	17,95	21,24	20,91	12,78	18,59	21,24	21,24
Wind onshore	40,57	51,68	68,04	86,43	101,49	55,15	68,04	98,05	102,56
Wind offshore	0,00	0,14	0,12	31,31	37,23	0,14	17,16	87,73	179,00
PV	4,42	9,80	7,92	0,00	0,00	9,80	7,92	0,00	12,61
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	1,92	5,61	9,25	12,93	3,74	7,44	11,08	12,93
Others	28,14	29,94	29,94	29,94	28,79	29,94	29,94	29,94	29,94

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	525,55	567,00	584,24	584,24	584,24	567,00	584,24	584,24	584,24
Consumption in Energy Conversion	53,52	53,43	46,54	40,13	31,89	59,97	53,72	43,76	34,13
Own Consumption of Power Plants	53,52	39,53	32,64	26,23	17,99	46,07	39,82	29,86	20,23
Other	n.a.	13,90	13,90	13,90	13,90	13,90	13,90	13,90	13,90
Transmission Losses	30,12	30,10	30,10	30,10	30,10	30,10	30,10	30,10	30,10
Storage Consumption	1,93	2,14	4,31	4,31	12,61	1,05	2,87	4,82	14,09
Gross Electricity Consumption	611,11	652,66	665,19	658,77	658,84	658,11	670,92	662,92	662,56
Net Imports	-20,10	103,61	170,04	202,08	255,47	35,34	79,92	77,30	58,26
Gross Electricity Generation	637,21	549,05	495,15	456,69	403,36	622,78	591,00	585,62	604,30

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Great Britain	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	10,98	9,57	8,26	8,67	7,48	9,57	4,24	1,19	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	28,44	18,10	15,13	14,71	14,30	18,10	8,20	7,78	7,37
Coal-CHP	n.a.	0,10	0,07	0,05	0,02	0,08	0,05	0,03	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	1,74	1,74	1,75	0,00	1,74	1,74	1,75
Gas	30,16	29,70	37,02	39,02	37,86	34,63	35,99	39,19	35,73
Gas-CHP	n.a.	3,81	1,27	0,00	0,00	3,81	1,27	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	5,90	2,44	0,16	0,00	0,00	2,44	0,16	0,00	0,00
Storage	2,74	2,74	5,46	14,01	23,28	2,74	24,03	39,29	51,40
Hydro	1,42	1,63	1,63	1,63	1,63	1,63	1,63	1,63	1,63
Biomass	1,21	1,38	0,48	0,00	0,00	1,43	0,53	0,00	0,00
Biomass-CHP	n.a.	0,49	0,89	1,15	1,15	0,53	0,89	1,19	1,15
Wind onshore	2,08	27,73	35,76	36,56	41,65	27,73	36,38	37,18	42,27
Wind offshore	0,39	10,88	21,00	27,74	45,06	10,88	28,01	60,05	90,05
PV	0,01	0,03	0,02	0,00	0,00	0,03	0,02	0,00	0,22
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,50	0,93	0,99	1,02	0,50	0,93	1,02	1,03
Others	1,38	0,54	0,54	0,54	0,54	0,54	0,54	0,54	0,54

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	52,49	70,38	59,74	62,92	52,42	70,38	31,21	8,32	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	125,32	46,09	94,91	90,97	11,18	45,64	52,16	42,31	0,00
Coal-CHP	n.a.	0,68	0,52	0,00	0,00	0,53	0,35	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	12,26	12,06	12,15	0,00	12,22	11,74	12,15
Gas	176,75	125,52	70,21	45,22	0,00	151,98	91,22	45,30	0,00
Gas-CHP	n.a.	25,97	0,20	0,00	0,00	26,27	0,31	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	6,10	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	1,80	2,90	10,65	13,33	1,53	8,98	13,39	30,29
Hydro	9,26	7,33	7,33	7,33	7,33	7,33	7,33	7,33	7,13
Biomass	10,05	7,49	2,04	0,00	0,00	7,78	2,68	0,00	0,00
Biomass-CHP	n.a.	3,41	6,23	8,07	8,07	3,74	6,24	8,38	8,07
Wind onshore	7,10	85,47	109,96	113,99	138,31	85,47	112,67	116,71	138,29
Wind offshore	0,00	39,23	75,69	102,53	174,35	39,23	101,77	228,61	343,68
PV	0,02	0,03	0,02	0,00	0,00	0,03	0,02	0,00	0,22
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	3,69	6,86	6,90	6,93	3,69	6,86	6,90	6,93
Others	2,29	2,85	2,85	2,85	2,68	2,85	2,85	2,74	2,61

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	341,56	387,38	415,37	440,98	465,84	387,38	415,37	440,98	465,84
Consumption in Energy Conversion	25,26	33,50	30,42	27,75	14,21	36,11	25,38	17,40	7,85
Own Consumption of Power Plants	25,26	26,86	23,78	21,12	7,57	29,48	18,75	10,77	1,21
Other	n.a.	6,64	6,64	6,64	6,64	6,64	6,64	6,64	6,64
Transmission Losses	28,20	25,38	25,38	25,38	25,38	25,38	25,38	25,38	25,38
Storage Consumption	1,28	2,50	4,06	15,05	18,87	2,12	12,73	19,03	43,05
Gross Electricity Consumption	396,30	448,76	475,22	509,15	524,30	451,00	478,85	502,79	542,12
Net Imports	11,02	28,82	23,51	45,67	97,54	4,55	42,00	11,05	-7,24
Gross Electricity Generation	389,37	419,93	451,71	463,48	426,76	446,44	436,86	491,73	549,36

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Greece	Historic	Scenario A				Scenario B			
Installed Capacity in GW	**2007***	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	4,81	5,92	4,60	0,11	0,11	6,88	5,64	1,15	1,07
Lignite-CCS	0,00	0,00	1,21	4,40	4,40	0,00	0,00	2,07	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,58	0,38	0,19	0,00	0,55	0,36	0,16	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,07	0,43	0,44	0,00	0,07	0,42	0,42
Gas	2,52	4,12	3,27	2,30	0,81	4,45	3,60	2,33	0,55
Gas-CHP	n.a.	0,06	0,02	0,00	0,00	0,06	0,02	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	2,43	0,11	0,00	0,00	0,00	0,11	0,00	0,00	0,00
Storage	0,70	0,70	0,70	0,70	0,70	0,70	0,70	0,70	0,70
Hydro	2,46	2,48	2,48	2,48	2,48	2,48	2,48	2,48	2,48
Biomass	0,04	0,06	0,06	0,04	0,04	0,06	0,06	0,05	0,10
Biomass-CHP	n.a.	0,17	0,17	0,17	0,16	0,17	0,17	0,18	0,18
Wind onshore	0,89	1,76	3,96	4,39	4,53	1,76	3,96	4,39	4,53
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,01	0,05	0,08	0,63	2,55	0,05	2,59	2,55	2,55
CSP	0,00	0,00	0,00	7,51	19,00	0,00	0,00	11,60	26,51
Geothermal	0,00	0,24	0,24	0,24	0,25	0,24	0,24	0,24	0,25
Others	0,03	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	33,36	28,65	21,10	0,85	0,39	30,42	30,52	8,67	0,00
Lignite-CCS	0,00	0,00	9,14	33,15	33,15	0,00	0,00	15,62	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	2,80	2,57	0,00	0,00	2,78	2,59	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,49	3,13	3,20	0,00	0,48	3,08	2,88
Gas	13,80	24,20	20,97	11,71	0,00	26,82	23,94	0,00	0,00
Gas-CHP	n.a.	0,41	0,03	0,00	0,00	0,44	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	9,99	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,29	0,18	0,00	0,00	0,00	0,00	1,05
Hydro	4,15	8,00	8,00	8,00	8,00	8,00	8,00	8,00	8,00
Biomass	0,19	0,41	0,42	0,27	0,25	0,41	0,42	0,39	0,63
Biomass-CHP	n.a.	1,22	1,21	1,21	1,21	1,23	1,21	1,21	1,21
Wind onshore	2,24	3,77	7,63	9,27	9,79	3,77	7,63	9,27	9,79
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,01	0,06	0,11	0,90	3,62	0,06	3,69	3,62	3,62
CSP	0,00	0,00	0,00	26,54	67,12	0,00	0,00	40,97	93,06
Geothermal	0,00	1,74	1,77	1,79	1,82	1,74	1,77	1,79	1,82
Others	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	56,65	65,21	75,31	86,54	98,96	65,21	75,31	86,54	98,96
Consumption in Energy Conversion	6,47	7,31	7,14	6,59	5,38	7,75	7,46	4,44	1,99
Own Consumption of Power Plants	6,47	5,61	5,43	4,88	3,67	6,05	5,75	2,74	0,29
Other	n.a.	1,71	1,71	1,71	1,71	1,71	1,71	1,71	1,71
Transmission Losses	4,54	4,09	4,09	4,09	4,09	4,09	4,09	4,09	4,09
Storage Consumption	0,36	0,00	0,41	0,25	0,00	0,00	0,00	0,00	1,46
Gross Electricity Consumption	68,02	76,61	86,94	97,47	108,42	77,05	86,85	95,07	106,50
Net Imports	5,61	5,32	13,19	0,43	-20,13	1,35	6,59	2,42	-15,58
Gross Electricity Generation	63,75	71,29	73,75	97,04	128,55	75,70	80,27	92,65	122,07

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Hungary	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	1,80	1,77	0,00	0,00	0,00	1,77	0,00	0,00	0,00
Lignite (incl. CHP)	0,97	0,87	0,91	0,91	0,91	0,83	0,98	0,98	0,98
Lignite-CCS	0,00	0,00	0,08	0,08	0,08	0,00	0,06	0,11	0,11
Coal	0,20	0,69	3,15	3,15	3,15	0,69	0,74	0,74	0,74
Coal-CHP	n.a.	0,01	0,00	0,00	0,00	0,01	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	4,50	1,53	1,96	2,80	3,92	1,59	2,07	3,33	5,31
Gas-CHP	n.a.	0,75	0,25	0,00	0,00	0,75	0,25	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,41	0,17	0,16	0,16	0,00	0,17	0,16	0,16	0,00
Storage	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Hydro	0,05	0,05	0,05	0,05	0,05	0,05	0,05	0,05	0,05
Biomass	0,40	0,34	0,00	0,32	0,32	0,34	0,01	1,91	1,91
Biomass-CHP	n.a.	0,74	0,75	0,75	0,57	0,74	0,74	0,74	0,57
Wind onshore	0,07	0,20	3,51	4,36	4,36	0,20	4,94	5,03	5,03
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	4,06	0,00	0,00	0,00	15,84
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,00	0,00	0,06	0,20	0,00	0,00	0,19	0,20
Others	0,02	0,04	0,04	0,04	0,04	0,04	0,04	0,04	0,04
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	14,82	13,00	0,00	0,00	0,00	13,00	0,00	0,00	0,00
Lignite (incl. CHP)	6,52	6,54	5,92	5,92	5,90	6,26	5,84	5,54	5,29
Lignite-CCS	0,00	0,00	0,57	0,57	0,58	0,00	0,45	0,75	0,80
Coal	0,57	0,92	22,52	21,34	4,20	1,36	4,98	4,87	1,43
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	15,18	8,39	7,67	8,08	0,00	8,67	6,63	6,71	0,00
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,36	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Hydro	0,21	0,23	0,23	0,23	0,23	0,23	0,23	0,23	0,23
Biomass	2,05	2,53	0,00	2,35	1,77	2,53	0,05	14,10	13,86
Biomass-CHP	n.a.	5,44	5,52	5,09	4,12	5,44	5,48	4,09	4,10
Wind onshore	0,21	0,27	5,60	7,16	7,16	0,27	8,53	8,78	8,78
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	4,88	0,00	0,00	0,00	18,70
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,00	0,01	0,44	1,47	0,00	0,03	1,42	1,47
Others	0,12	0,22	0,22	0,22	0,22	0,22	0,22	0,22	0,22
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	34,33	40,07	45,14	50,61	56,46	40,07	45,14	50,61	56,46
Consumption in Energy Conversion	5,71	4,31	5,10	5,02	2,50	4,36	3,22	3,21	2,18
Own Consumption of Power Plants	5,71	2,88	3,67	3,59	1,07	2,93	1,79	1,79	0,75
Other	n.a.	1,43	1,43	1,43	1,43	1,43	1,43	1,43	1,43
Transmission Losses	3,89	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50
Storage Consumption	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gross Electricity Consumption	43,93	47,88	53,74	59,13	62,46	47,92	51,86	57,32	62,14
Net Imports	3,90	10,35	5,47	7,74	31,91	9,94	19,42	10,62	7,27
Gross Electricity Generation	40,03	37,52	48,27	51,39	30,55	37,98	32,44	46,70	54,87

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Ireland	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	n.a.	0,16	0,06	0,00	0,00	0,16	0,06	0,00	0,00
Lignite-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	n.a.	0,45	0,05	0,00	0,00	0,45	0,05	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	n.a.	2,31	0,85	0,14	0,14	2,31	0,71	0,00	0,00
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	n.a.	0,53	0,13	0,00	0,00	0,53	0,13	0,00	0,00
Storage	n.a.	0,29	7,68	9,30	9,30	0,29	6,52	7,63	7,94
Hydro	n.a.	0,24	0,24	0,24	0,24	0,24	0,24	0,24	0,24
Biomass	n.a.	0,37	0,36	0,38	0,48	0,37	0,41	0,55	0,43
Biomass-CHP	n.a.	0,31	0,31	0,31	0,22	0,32	0,33	0,42	0,33
Wind onshore	n.a.	8,95	9,06	9,53	11,10	8,95	9,06	9,53	11,10
Wind offshore	n.a.	6,34	9,10	9,54	13,57	0,08	2,56	3,44	3,86
PV	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	n.a.	0,00	0,00	0,01	0,04	0,00	0,00	0,00	0,00
Others	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	2,79	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	5,23	0,00	0,16	0,00	0,00	0,66	0,15	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	16,07	2,86	0,53	0,00	0,00	4,18	0,52	0,00	0,00
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	1,73	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,27	2,80	3,59	4,83	0,23	2,99	3,95	9,52
Hydro	1,30	0,61	0,61	0,61	0,61	0,61	0,61	0,61	0,61
Biomass	0,16	2,27	2,43	2,52	3,13	2,27	2,43	2,43	2,41
Biomass-CHP	n.a.	2,16	2,18	2,09	1,54	2,16	2,18	2,18	2,19
Wind onshore	2,41	26,86	28,35	30,36	33,08	24,72	27,02	28,80	32,41
Wind offshore	0,00	25,06	36,06	37,99	57,29	0,29	10,10	13,87	14,99
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,00	0,00	0,05	0,33	0,00	0,00	0,01	0,01
Others	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	26,68	28,15	30,18	32,04	33,85	28,15	30,18	32,04	33,85
Consumption in Energy Conversion	1,45	0,70	0,48	0,41	0,41	0,89	0,48	0,41	0,41
Own Consumption of Power Plants	1,45	0,29	0,07	0,00	0,00	0,48	0,07	0,00	0,00
Other	n.a.	0,41	0,41	0,41	0,41	0,41	0,41	0,41	0,41
Transmission Losses	2,25	2,02	2,02	2,02	2,02	2,02	2,02	2,02	2,02
Storage Consumption	0,19	0,37	3,99	5,11	6,89	0,32	4,26	5,63	13,58
Gross Electricity Consumption	30,57	31,24	36,67	39,58	43,17	31,38	36,94	40,11	49,86
Net Imports	0,45	-28,85	-36,43	-37,63	-57,65	-3,74	-9,05	-11,74	-12,28
Gross Electricity Generation	29,69	60,09	73,10	77,21	100,82	35,12	46,00	51,85	62,14

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Italy	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	6,00	12,00	15,72	0,00	6,00	9,14	12,14
Lignite (incl. CHP)	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	n.a.	4,71	0,83	0,00	0,00	4,71	0,83	0,00	0,00
Coal-CHP	n.a.	0,09	0,07	0,05	0,03	0,06	0,04	0,02	0,00
Coal-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	n.a.	0,00	4,56	4,70	4,78	0,00	4,55	4,65	4,74
Gas	n.a.	51,72	41,20	33,38	16,68	45,89	35,37	27,56	11,91
Gas-CHP	n.a.	0,97	0,32	0,00	0,00	0,97	0,32	0,00	0,00
Gas-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	n.a.	13,93	4,26	0,15	0,00	13,93	4,26	0,15	0,00
Storage	n.a.	7,54	7,54	7,54	7,54	7,54	7,54	7,54	7,54
Hydro	n.a.	13,73	13,73	13,73	13,73	10,65	10,65	10,65	10,65
Biomass	n.a.	1,09	0,64	0,19	0,19	1,09	0,75	0,30	0,87
Biomass-CHP	n.a.	1,20	1,20	1,20	1,17	1,20	1,20	1,20	1,25
Wind onshore	2,70	4,85	5,66	10,35	10,35	5,66	10,35	10,35	12,84
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	n.a.	1,02	8,05	7,24	39,41	1,02	5,83	7,24	52,00
CSP	n.a.	0,00	0,60	30,20	70,20	0,00	15,19	55,19	95,19
Geothermal	n.a.	1,84	2,30	2,84	3,23	1,84	2,30	2,84	3,34
Others	n.a.	0,79	0,79	0,79	0,79	0,79	0,79	0,79	0,79

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	44,13	88,27	115,63	0,00	44,13	67,24	88,98
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	43,07	27,17	6,04	0,00	0,00	29,93	6,04	0,00	0,00
Coal-CHP	n.a.	0,64	0,39	0,00	0,18	0,44	0,30	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	33,12	34,14	34,77	0,00	33,09	33,78	32,75
Gas	172,70	288,13	255,60	219,48	0,00	253,70	223,90	155,97	0,00
Gas-CHP	n.a.	7,15	0,44	0,00	0,00	7,15	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	31,46	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	3,15	0,00	0,00	0,30	0,00	0,00	3,67
Hydro	47,23	41,49	41,49	41,49	41,49	41,49	41,49	41,49	41,49
Biomass	7,52	6,87	4,75	1,44	0,84	7,91	5,51	2,23	5,74
Biomass-CHP	n.a.	8,88	8,68	8,68	8,68	8,88	8,68	8,68	8,68
Wind onshore	4,86	5,83	7,19	14,48	14,48	7,19	14,48	14,48	20,30
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,19	1,36	11,53	10,46	55,58	1,36	8,41	10,46	72,78
CSP	0,00	0,00	2,05	103,64	240,92	0,00	52,12	189,39	326,66
Geothermal	5,52	13,61	17,01	17,41	17,65	13,61	17,01	17,41	17,65
Others	6,58	4,14	4,14	4,14	4,14	4,14	4,14	4,14	4,14

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	308,83	362,92	419,12	481,63	550,75	362,92	419,12	481,63	550,75
Consumption in Energy Conversion	22,27	38,38	40,04	40,26	21,13	35,19	36,82	31,77	18,24
Own Consumption of Power Plants	22,27	32,31	33,97	34,19	15,06	29,12	30,75	25,70	12,17
Other	n.a.	6,07	6,07	6,07	6,07	6,07	6,07	6,07	6,07
Transmission Losses	20,44	18,40	18,40	18,40	18,40	18,40	18,40	18,40	18,40
Storage Consumption	2,01	0,00	4,38	0,00	0,00	0,41	0,00	0,00	5,10
Gross Electricity Consumption	353,56	419,70	481,94	540,29	590,28	416,93	474,33	531,80	592,49
Net Imports	40,04	14,44	42,24	-3,32	55,93	40,84	15,06	-13,45	-30,32
Gross Electricity Generation	319,13	405,26	439,70	543,61	534,35	376,09	459,28	545,25	622,82

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Latvia	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	0,64	0,00	0,39	0,56	0,57	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,56	0,19	0,00	0,00	0,56	0,19	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,02	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	0,00	0,00	0,00	0,00	0,08	0,00	1,36	1,39	1,39
Hydro	1,56	1,54	1,54	1,54	1,54	1,54	1,54	1,54	1,54
Biomass	0,01	0,01	0,01	0,00	0,00	0,01	0,01	0,00	0,00
Biomass-CHP	n.a.	0,22	0,22	0,24	0,24	0,23	0,24	0,24	0,25
Wind onshore	0,03	4,43	4,82	4,82	5,72	1,43	4,27	5,29	5,58
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,06
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,09	0,09	0,09	0,09	0,09	0,09	0,09	0,10
Others	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	2,06	0,00	0,00	0,01	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,01	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,00	0,00	0,04	0,00	0,95	1,11	1,14
Hydro	3,11	6,91	6,91	6,91	6,91	6,91	6,91	6,91	6,91
Biomass	0,05	0,09	0,08	0,00	0,00	0,09	0,08	0,00	0,00
Biomass-CHP	n.a.	1,62	1,64	1,69	1,70	1,63	1,64	1,69	1,70
Wind onshore	0,06	9,41	10,34	10,35	11,99	3,01	9,12	11,11	12,05
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,06
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,65	0,66	0,67	0,67	0,63	0,66	0,67	0,67
Others	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	6,61	7,12	8,03	9,00	10,04	7,12	8,03	9,00	10,04
Consumption in Energy Conversion	0,39	0,10	0,10	0,10	0,10	0,10	0,10	0,10	0,10
Own Consumption of Power Plants	0,39	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Other	n.a.	0,10	0,10	0,10	0,10	0,10	0,10	0,10	0,10
Transmission Losses	0,80	0,72	0,72	0,72	0,72	0,72	0,72	0,72	0,72
Storage Consumption	0,00	0,00	0,00	0,00	0,06	0,00	1,36	1,58	1,63
Gross Electricity Consumption	7,79	7,94	8,84	9,82	10,91	7,94	10,20	11,39	12,48
Net Imports	2,52	-10,74	-10,79	-9,81	-10,40	-4,34	-9,16	-10,09	-10,05
Gross Electricity Generation	5,27	18,68	19,63	19,62	21,31	12,28	19,35	21,48	22,53

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Lithuania	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	1,18	1,18	0,00	0,00	0,00	1,18	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	2,36	0,00	0,37	0,54	0,86	0,00	0,21	0,38	0,48
Gas-CHP	n.a.	0,03	0,01	0,00	0,00	0,03	0,01	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,15	0,07	0,00	0,00	0,00	0,07	0,00	0,00	0,00
Storage	0,76	0,76	0,76	1,36	1,36	0,76	0,97	0,97	0,97
Hydro	0,08	0,12	0,12	0,12	0,12	0,12	0,12	0,12	0,12
Biomass	0,02	0,03	0,03	0,00	0,00	0,03	0,03	0,76	0,76
Biomass-CHP	n.a.	0,26	0,26	0,27	0,21	0,26	0,26	0,26	0,20
Wind onshore	0,05	0,09	3,43	3,46	3,46	0,10	3,13	3,16	3,16
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	2,25
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,00	0,00	0,05	0,07	0,00	0,01	0,05	0,07
Others	0,00	0,05	0,05	0,05	0,05	0,05	0,05	0,05	0,05
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	9,89	8,70	0,00	0,00	0,00	8,70	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	2,03	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,57	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,33	0,50	0,98	1,31	0,36	0,52	1,14	1,12
Hydro	0,99	0,40	0,40	0,40	0,40	0,40	0,40	0,40	0,40
Biomass	0,07	0,25	0,23	0,02	0,01	0,25	0,24	5,26	4,81
Biomass-CHP	n.a.	1,89	1,90	1,60	1,48	1,89	1,85	1,58	1,44
Wind onshore	0,13	0,14	6,80	6,89	6,89	0,15	5,95	6,03	6,04
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	2,20
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,00	0,01	0,36	0,50	0,00	0,06	0,33	0,50
Others	0,24	0,24	0,24	0,24	0,22	0,24	0,22	0,22	0,22
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	9,02	9,88	11,13	12,47	13,92	9,88	11,13	12,47	13,92
Consumption in Energy Conversion	2,12	1,46	0,59	0,59	0,59	1,46	0,59	0,59	0,59
Own Consumption of Power Plants	2,12	0,87	0,00	0,00	0,00	0,87	0,00	0,00	0,00
Other	n.a.	0,59	0,59	0,59	0,59	0,59	0,59	0,59	0,59
Transmission Losses	1,01	0,91	0,91	0,91	0,91	0,91	0,91	0,91	0,91
Storage Consumption	0,22	0,45	0,69	1,37	1,84	0,50	0,73	1,59	1,55
Gross Electricity Consumption	12,37	12,69	13,31	15,34	17,25	12,74	13,35	15,56	16,96
Net Imports	-0,96	0,74	3,22	4,85	6,42	0,75	4,10	0,58	0,24
Gross Electricity Generation	13,91	11,95	10,09	10,49	10,82	11,99	9,24	14,98	16,72

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Luxembourg	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,56	0,56	0,56
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,02	0,02	0,02	0,00	0,02	0,02	0,02
Gas	0,49	1,02	0,97	1,06	1,15	1,03	0,68	0,73	0,69
Gas-CHP	n.a.	0,07	0,02	0,00	0,00	0,07	0,02	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	1,10	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Hydro	0,03	0,04	0,04	0,04	0,04	0,04	0,04	0,04	0,04
Biomass	0,01	0,02	0,02	0,02	0,02	0,02	0,02	0,03	0,04
Biomass-CHP	n.a.	0,03	0,03	0,03	0,03	0,03	0,03	0,03	0,03
Wind onshore	0,04	0,47	0,47	0,49	0,57	0,47	0,47	0,49	0,57
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,02	0,03	0,00	0,00	0,00	0,03	0,00	0,00	0,06
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01
Others	0,01	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	4,05	3,68	1,62
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,12	0,12	0,12	0,00	0,11	0,11	0,11
Gas	2,40	6,82	3,84	3,56	0,00	6,69	3,16	3,13	0,14
Gas-CHP	n.a.	0,23	0,00	0,00	0,00	0,23	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Hydro	0,97	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18
Biomass	0,11	0,17	0,17	0,13	0,13	0,17	0,17	0,23	0,23
Biomass-CHP	n.a.	0,20	0,20	0,20	0,20	0,20	0,20	0,20	0,20
Wind onshore	0,06	0,94	0,95	0,99	1,26	0,94	0,95	0,99	1,26
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,02	0,02	0,00	0,00	0,00	0,02	0,00	0,00	0,05
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,09	0,09	0,09	0,09	0,09	0,09	0,09	0,09
Others	0,00	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	6,55	7,56	8,10	8,60	9,09	7,56	8,10	8,60	9,09
Consumption in Energy Conversion	0,04	0,79	0,48	0,45	0,09	0,77	0,81	0,77	0,27
Own Consumption of Power Plants	0,04	0,70	0,40	0,37	0,01	0,69	0,73	0,69	0,19
Other	n.a.	0,08	0,08	0,08	0,08	0,08	0,08	0,08	0,08
Transmission Losses	0,14	0,12	0,12	0,12	0,12	0,12	0,12	0,12	0,12
Storage Consumption	0,33	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gross Electricity Consumption	7,06	8,47	8,70	9,17	9,30	8,45	9,04	9,50	9,48
Net Imports	4,35	-0,19	3,16	3,90	7,31	-0,07	0,12	0,87	5,58
Gross Electricity Generation	3,56	8,66	5,55	5,27	1,99	8,53	8,92	8,63	3,90

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Netherlands	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,48	0,45	0,45	0,00	0,00	0,45	0,45	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	4,16	2,92	0,88	0,00	0,00	2,92	0,88	0,00	0,00
Coal-CHP	n.a.	1,11	0,74	0,37	0,00	1,11	0,74	0,37	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	3,89	4,07	4,17	0,00	3,85	4,13	4,17
Gas	15,67	4,68	10,75	19,67	19,65	3,49	6,68	10,76	10,76
Gas-CHP	n.a.	8,37	2,79	0,00	0,00	8,37	2,79	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,04	0,36	0,00	0,00	0,00	0,36	0,00	0,00	0,00
Storage	0,00	0,00	0,00	0,00	0,00	0,00	5,17	11,17	11,77
Hydro	0,04	0,04	0,04	0,04	0,04	0,04	0,04	0,04	0,04
Biomass	0,20	0,32	0,25	0,21	0,21	0,63	0,55	0,21	0,21
Biomass-CHP	n.a.	0,44	0,49	0,52	0,52	0,44	0,49	0,52	0,52
Wind onshore	1,64	4,61	4,86	5,48	6,02	4,31	4,86	5,48	5,96
Wind offshore	0,11	7,15	22,15	53,54	73,26	8,84	20,91	31,52	33,91
PV	0,05	0,06	0,01	0,00	0,00	0,06	0,01	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,35	0,85	1,10	1,10	0,50	0,85	1,10	1,10
Others	0,95	0,58	0,58	0,58	0,58	0,58	0,58	0,58	0,58

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	4,17	3,31	3,31	0,00	0,00	3,31	3,31	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	23,47	11,61	5,70	0,00	0,00	10,39	5,23	0,00	0,00
Coal-CHP	n.a.	7,43	3,39	0,00	0,00	7,07	3,39	0,04	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	26,94	28,63	28,84	0,00	26,94	28,59	28,84
Gas	63,43	7,96	6,29	5,37	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	52,92	0,00	0,00	0,00	51,46	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	2,07	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,00	0,00	0,00	0,00	1,14	7,19	9,68
Hydro	0,10	0,17	0,17	0,17	0,17	0,17	0,17	0,17	0,17
Biomass	6,64	2,24	1,60	1,41	1,41	3,90	3,30	1,41	1,41
Biomass-CHP	n.a.	3,20	3,46	3,63	3,63	3,20	3,46	3,63	3,63
Wind onshore	4,26	10,37	11,44	14,15	14,97	9,78	11,44	14,15	15,65
Wind offshore	0,00	29,00	98,28	243,38	338,29	35,80	91,53	140,72	154,60
PV	0,04	0,06	0,01	0,00	0,00	0,06	0,01	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	2,61	6,30	8,15	8,15	3,69	6,30	8,15	8,15
Others	3,48	3,04	3,04	3,04	2,88	3,04	3,04	2,89	2,79

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	109,15	121,40	130,18	138,20	145,99	121,40	130,18	138,20	145,99
Consumption in Energy Conversion	9,69	10,75	6,99	5,82	5,31	9,65	6,31	5,29	5,31
Own Consumption of Power Plants	9,69	8,32	4,56	3,40	2,88	7,22	3,89	2,86	2,88
Other	n.a.	2,42	2,42	2,42	2,42	2,42	2,42	2,42	2,42
Transmission Losses	4,66	4,19	4,19	4,19	4,19	4,19	4,19	4,19	4,19
Storage Consumption	0,00	0,00	0,00	0,00	0,00	0,00	1,62	10,27	14,02
Gross Electricity Consumption	123,50	136,34	141,35	148,22	155,49	135,24	142,30	157,95	169,51
Net Imports	15,85	2,44	-28,58	-159,71	-242,85	3,37	-16,97	-48,98	-55,41
Gross Electricity Generation	107,65	133,91	169,94	307,92	398,34	131,87	159,27	206,93	224,92

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Norway	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,07	0,07	0,07	0,00	0,07	0,07	0,07
Gas	0,66	0,46	4,44	5,04	5,04	0,46	0,98	0,58	0,58
Gas-CHP	n.a.	0,12	0,04	0,00	0,00	0,12	0,04	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	1,27	1,49	1,49	1,49	1,49	1,49	1,49	1,49	1,49
Hydro	27,63	28,25	28,25	28,25	28,25	28,25	28,25	28,25	28,25
Biomass	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Biomass-CHP	n.a.	0,10	0,11	0,11	0,11	0,10	0,10	0,11	0,11
Wind onshore	0,33	4,32	4,36	4,51	5,30	4,32	4,38	4,52	5,31
Wind offshore	0,00	17,65	26,93	46,71	61,47	10,00	22,29	25,24	26,30
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,05	0,05	0,05	0,05	0,05	0,05	0,05	0,05
Others	0,02	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,07	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,47	0,48	0,48	0,00	0,47	0,48	0,48
Gas	0,43	0,85	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,83	0,00	0,00	0,00	0,29	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	1,49	1,49	1,49	1,49	1,49	1,49	1,49
Hydro	27,63	111,70	28,25	28,25	28,25	28,25	28,25	28,25	28,25
Biomass	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Biomass-CHP	n.a.	0,72	0,11	0,11	0,11	0,10	0,10	0,11	0,11
Wind onshore	0,33	11,01	4,36	4,51	5,30	4,32	4,38	4,52	5,31
Wind offshore	0,00	79,35	26,93	46,71	61,47	10,00	22,29	25,24	26,30
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,36	0,05	0,05	0,05	0,05	0,05	0,05	0,05
Others	0,02	0,29	0,06	0,06	0,06	0,06	0,06	0,06	0,06
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	111,47	118,73	127,30	135,15	142,77	118,73	127,30	135,15	142,77
Consumption in Energy Conversion	5,72	1,70	1,58	1,58	1,58	1,56	1,58	1,58	1,58
Own Consumption of Power Plants	5,72	0,17	0,05	0,05	0,05	0,03	0,05	0,05	0,05
Other	n.a.	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53
Transmission Losses	10,24	9,21	9,21	9,21	9,21	9,21	9,21	9,21	9,21
Storage Consumption	0,42	0,00	0,81	0,97	1,35	0,00	0,81	0,81	5,45
Gross Electricity Consumption	127,84	129,64	138,91	146,91	154,92	129,50	138,91	146,75	159,01
Net Imports	-13,86	-75,47	-107,52	-197,70	-269,41	-39,84	-87,02	-94,27	-95,90
Gross Electricity Generation	142,67	205,11	246,43	344,61	424,32	169,34	225,93	241,03	254,91

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Poland	Historic	Scenario A				Scenario B			
Installed Capacity in GW	**2007***	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	1,00	2,58	3,27	0,00	2,25	4,59	4,59
Lignite (incl. CHP)	8,15	7,99	12,15	8,19	8,19	8,38	11,25	7,29	7,29
Lignite-CCS	0,00	0,00	0,33	1,65	1,65	0,00	0,64	2,35	2,35
Coal	20,63	12,11	1,53	0,15	0,00	12,11	1,53	0,15	0,00
Coal-CHP	n.a.	5,01	3,34	1,67	0,00	4,65	2,98	1,31	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,03	1,43	1,43	0,00	0,26	1,42	1,42
Gas	0,85	0,75	3,44	7,91	11,54	0,75	0,30	2,55	7,12
Gas-CHP	n.a.	0,68	0,23	0,00	0,00	0,68	0,23	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,00	0,28	0,00	0,00	0,00	0,28	0,00	0,00	0,00
Storage	1,76	0,00	0,14	0,01	0,70	0,00	0,00	0,72	2,24
Hydro	0,54	17,25	17,25	17,25	17,25	17,25	17,25	17,25	17,25
Biomass	0,07	2,18	1,69	0,36	0,24	2,17	1,77	1,35	1,80
Biomass-CHP	0,00	1,69	1,72	1,72	1,66	1,69	1,72	1,72	1,72
Wind onshore	0,30	5,85	10,55	14,78	15,10	6,78	10,55	14,78	15,36
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	6,22
PV	0,00	0,16	1,97	1,93	1,93	0,16	1,97	3,66	15,77
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	1,39	1,41	1,43	1,45	1,39	1,41	1,43	1,45
Others	0,00	0,57	0,57	0,57	0,55	0,57	0,57	0,57	0,54
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	0,00	0,00	7,36	18,36	23,32	0,00	16,03	32,68	32,68
Lignite (incl. CHP)	57,26	52,36	58,15	49,65	48,46	52,92	54,90	44,30	36,56
Lignite-CCS	0,00	0,00	2,36	11,73	11,49	0,00	4,52	16,66	16,31
Coal	83,91	12,33	9,51	0,90	0,00	10,67	9,31	0,74	0,00
Coal-CHP	n.a.	18,05	16,26	2,72	0,00	17,88	14,04	1,91	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,20	10,09	10,09	0,00	1,81	9,99	9,65
Gas	3,17	2,02	1,63	0,00	0,00	2,02	0,99	0,00	0,00
Gas-CHP	n.a.	3,39	0,00	0,00	0,00	3,64	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	2,32	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,53	0,92	1,65	3,47	0,66	2,12	4,31	7,52
Hydro	2,75	4,18	4,18	4,18	4,18	4,18	4,18	4,18	4,18
Biomass	3,46	2,53	2,21	0,35	6,22	2,63	2,87	2,39	7,23
Biomass-CHP	n.a.	12,45	12,60	12,88	12,88	12,45	12,88	12,88	12,88
Wind onshore	0,84	44,67	68,08	81,32	92,83	44,67	66,71	83,61	96,06
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	11,95
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	1,85	5,54	9,23	9,66	1,85	5,54	9,23	9,66
Others	2,47	0,41	0,41	0,41	0,39	0,41	0,39	0,39	0,39
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	117,47	140,03	157,77	176,88	197,33	140,03	157,77	176,88	197,33
Consumption in Energy Conversion	23,91	14,87	15,60	15,40	15,39	14,76	16,21	16,68	15,57
Own Consumption of Power Plants	23,91	8,81	9,54	9,35	9,34	8,71	10,16	10,63	9,52
Other	n.a.	6,05	6,05	6,05	6,05	6,05	6,05	6,05	6,05
Transmission Losses	12,69	11,42	11,42	11,42	11,42	11,42	11,42	11,42	11,42
Storage Consumption	0,30	0,73	1,28	2,32	4,88	0,92	2,99	6,10	10,64
Gross Electricity Consumption	154,36	167,04	186,07	206,01	229,02	167,13	188,39	211,08	234,97
Net Imports	-1,22	12,29	-3,32	2,54	6,04	13,17	-7,90	-12,20	-10,11
Gross Electricity Generation	156,18	154,75	189,38	203,47	222,98	153,96	196,29	223,28	245,08

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Portugal	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	1,78	1,75	0,72	0,14	0,14	1,75	1,94	1,36	1,36
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,28	0,32	0,32	0,00	0,28	0,32	0,32
Gas	2,56	3,83	3,81	7,29	8,41	3,24	2,29	5,13	5,19
Gas-CHP	n.a.	0,38	0,13	0,00	0,00	0,38	0,13	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	2,94	1,26	0,02	0,00	0,00	1,26	0,02	0,00	0,00
Storage	0,97	1,44	1,44	1,44	1,44	1,44	1,44	1,45	3,41
Hydro	4,05	4,03	4,03	4,03	4,03	4,03	4,03	4,03	4,03
Biomass	0,04	0,30	0,23	0,05	0,04	0,30	0,24	0,18	0,35
Biomass-CHP	n.a.	0,23	0,23	0,23	0,24	0,23	0,23	0,28	0,24
Wind onshore	2,14	4,16	6,91	8,57	8,70	4,70	6,91	8,57	8,81
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	2,31
PV	0,01	0,10	1,21	1,19	1,19	0,10	1,21	2,38	10,08
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,03	0,19	0,19	0,19	0,20	0,19	0,19	0,19	0,21
Others	0,35	0,11	0,11	0,11	0,11	0,11	0,11	0,11	0,11

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	11,20	10,81	5,07	0,97	0,00	11,42	14,08	9,87	4,36
Coal-CHP	n.a.	0,02	0,01	0,00	0,01	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	2,06	2,13	2,27	0,00	2,04	1,91	1,66
Gas	15,20	21,41	20,26	14,08	0,00	19,40	15,96	5,60	0,00
Gas-CHP	n.a.	2,77	0,00	0,00	0,00	2,77	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	4,15	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,14	0,01	0,70	0,00	0,00	0,72	2,24
Hydro	7,30	17,25	17,25	17,25	17,25	17,25	17,25	17,25	17,25
Biomass	2,13	2,18	1,69	0,36	0,24	2,17	1,77	1,35	1,80
Biomass-CHP	n.a.	1,69	1,72	1,72	1,66	1,69	1,72	1,72	1,72
Wind onshore	5,76	5,85	10,55	14,78	15,10	6,78	10,55	14,78	15,36
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	6,22
PV	0,04	0,16	1,97	1,93	1,93	0,16	1,97	3,66	15,77
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,19	1,39	1,41	1,43	1,45	1,39	1,41	1,43	1,45
Others	0,01	0,57	0,57	0,57	0,55	0,57	0,57	0,57	0,54

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	48,35	55,87	64,52	74,15	84,79	55,87	64,52	74,15	84,79
Consumption in Energy Conversion	2,23	4,09	3,33	2,31	0,82	3,95	3,80	2,33	1,19
Own Consumption of Power Plants	2,23	3,50	2,74	1,72	0,23	3,36	3,21	1,74	0,60
Other	n.a.	0,59	0,59	0,59	0,59	0,59	0,59	0,59	0,59
Transmission Losses	4,18	3,77	3,77	3,77	3,77	3,77	3,77	3,77	3,77
Storage Consumption	0,14	0,00	0,19	0,01	0,97	0,00	0,00	1,00	3,14
Gross Electricity Consumption	54,90	63,73	71,81	80,23	90,35	63,59	72,09	81,24	92,89
Net Imports	9,43	-0,37	9,12	25,02	49,20	0,00	4,78	22,39	24,53
Gross Electricity Generation	45,97	64,10	62,69	55,21	41,15	63,59	67,31	58,85	68,37

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Romania	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	1,30	0,00	0,00	0,00	1,00	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	4,18	3,11	2,65	1,26	1,26	2,93	2,36	0,97	0,97
Lignite-CCS	0,00	0,00	0,93	2,10	2,10	0,00	0,10	2,14	2,14
Coal	1,34	0,96	0,19	0,00	0,00	0,96	0,19	0,00	0,00
Coal-CHP	n.a.	0,90	0,60	0,30	0,00	0,90	0,60	0,30	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	2,19	2,47	2,47	0,00	2,21	2,46	2,46
Gas	2,76	0,00	0,00	0,18	0,18	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	0,89	0,30	0,00	0,00	0,89	0,30	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,72	0,19	0,00	0,00	0,00	0,19	0,00	0,00	0,00
Storage	0,00	0,00	0,00	0,00	0,45	0,00	0,00	0,00	2,19
Hydro	5,86	6,36	6,36	6,36	6,36	6,36	6,36	6,36	6,36
Biomass	0,00	0,02	0,06	0,08	0,43	0,02	0,04	0,58	0,91
Biomass-CHP	n.a.	0,80	0,80	0,80	0,74	0,78	0,78	0,81	0,74
Wind onshore	0,01	0,01	0,01	1,80	1,80	0,01	0,01	1,80	1,80
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	4,78	0,00	0,00	0,00	8,97
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,50	1,00	1,29	1,31	0,50	1,00	1,29	1,31
Others	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	11,23	0,00	0,00	0,00	7,34	0,00	0,00	0,00	0,00
Lignite (incl. CHP)	25,71	19,45	15,72	8,31	6,17	16,61	13,25	6,43	0,83
Lignite-CCS	0,00	0,00	7,03	15,79	15,84	0,00	0,75	16,15	13,78
Coal	0,11	0,00	1,11	0,00	0,00	0,00	0,29	0,00	0,00
Coal-CHP	n.a.	6,52	3,79	0,00	0,00	6,52	3,75	0,01	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	15,88	17,95	17,19	0,00	16,03	17,88	17,07
Gas	9,92	0,00	0,00	0,97	0,00	0,00	0,00	0,00	0,00
Gas-CHP	n.a.	6,55	0,40	0,00	0,00	6,55	0,27	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,70	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,00	0,00	0,03	0,00	0,00	0,00	0,85
Hydro	17,20	28,63	28,63	28,63	28,63	28,63	28,63	28,63	28,63
Biomass	0,02	0,13	0,41	0,58	3,09	0,13	0,29	4,29	5,29
Biomass-CHP	n.a.	5,90	5,46	5,46	5,35	5,73	5,46	5,46	5,46
Wind onshore	0,00	0,02	0,01	3,03	3,03	0,02	0,01	3,03	3,03
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	6,40	0,00	0,00	0,00	11,68
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	3,69	7,39	9,55	9,66	3,69	7,39	9,55	9,66
Others	0,06	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	41,78	49,77	56,08	62,87	70,14	49,77	56,08	62,87	70,14
Consumption in Energy Conversion	10,98	6,00	7,14	7,05	7,40	5,71	6,18	6,79	5,91
Own Consumption of Power Plants	10,98	3,25	4,39	4,30	4,65	2,97	3,43	4,05	3,17
Other	n.a.	2,74	2,74	2,74	2,74	2,74	2,74	2,74	2,74
Transmission Losses	7,19	6,47	6,47	6,47	6,47	6,47	6,47	6,47	6,47
Storage Consumption	0,00	0,00	0,00	0,00	0,05	0,00	0,00	0,00	1,21
Gross Electricity Consumption	59,94	62,24	69,68	76,39	84,05	61,95	68,73	76,13	83,73
Net Imports	-4,25	-8,65	-16,14	-13,89	-18,66	-5,92	-7,40	-15,31	-12,55
Gross Electricity Generation	64,96	70,88	85,82	90,28	102,72	67,88	76,12	91,44	96,29

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Slovakia	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	2,20	4,08	3,09	4,09	4,91	4,08	5,83	5,41	4,99
Lignite (incl. CHP)	n.a.	0,24	0,04	0,02	0,00	0,24	0,04	0,02	0,00
Lignite-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,39	0,26	0,13	0,00	0,38	0,25	0,12	0,00
Coal-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	n.a.	0,00	0,16	0,40	0,41	0,00	0,13	0,35	0,35
Gas	n.a.	0,39	0,39	0,00	0,00	0,39	0,39	0,00	0,00
Gas-CHP	n.a.	0,63	0,21	0,00	0,00	0,63	0,21	0,00	0,00
Gas-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	n.a.	0,04	0,00	0,00	0,00	0,04	0,00	0,00	0,00
Storage	n.a.	0,92	0,92	0,92	0,92	0,92	0,92	0,92	0,92
Hydro	n.a.	1,63	1,63	1,63	1,63	1,63	1,63	1,63	1,63
Biomass	n.a.	0,10	0,02	0,00	0,00	0,10	0,02	0,01	0,10
Biomass-CHP	n.a.	0,19	0,20	0,22	0,22	0,19	0,21	0,22	0,21
Wind onshore	0,01	0,00	1,97	1,97	1,97	0,00	1,97	1,97	1,97
Wind offshore	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	1,62
CSP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	n.a.	0,23	0,23	0,24	0,24	0,23	0,23	0,24	0,24
Others	n.a.	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	16,70	30,03	22,72	30,05	36,13	30,03	42,86	39,79	36,73
Lignite (incl. CHP)	2,21	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	2,46	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	1,94	1,50	0,00	0,00	2,16	1,64	0,23	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	1,20	2,84	2,88	0,00	0,98	2,58	2,58
Gas	1,61	2,64	2,22	0,00	0,00	2,50	1,83	0,00	0,00
Gas-CHP	n.a.	1,74	0,28	0,00	0,00	1,30	0,33	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,68	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,50	0,50	0,62	0,25	0,39	0,51	0,89
Hydro	4,24	7,34	7,34	7,34	7,34	7,34	7,34	7,34	7,34
Biomass	0,53	0,71	0,11	0,00	0,00	0,69	0,11	0,08	0,68
Biomass-CHP	n.a.	1,43	1,48	1,57	1,57	1,43	1,52	1,57	1,57
Wind onshore	0,01	0,00	3,71	3,71	3,71	0,00	3,71	3,71	3,71
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	1,77
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	1,70	1,72	1,74	1,76	1,70	1,72	1,74	1,76
Others	0,52	0,08	0,08	0,08	0,08	0,08	0,08	0,08	0,08

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	24,77	30,06	33,87	37,98	42,37	30,06	33,87	37,98	42,37
Consumption in Energy Conversion	3,43	4,51	3,67	4,17	4,78	4,48	5,64	5,14	4,81
Own Consumption of Power Plants	3,43	3,64	2,79	3,29	3,90	3,60	4,76	4,26	3,93
Other	n.a.	0,88	0,88	0,88	0,88	0,88	0,88	0,88	0,88
Transmission Losses	1,00	0,90	0,90	0,90	0,90	0,90	0,90	0,90	0,90
Storage Consumption	0,08	0,00	0,69	0,69	0,86	0,34	0,55	0,71	1,24
Gross Electricity Consumption	29,28	35,48	39,14	43,74	48,90	35,79	40,96	44,72	49,32
Net Imports	0,52	-12,15	-3,72	-4,10	-5,19	-11,70	-21,56	-12,90	-7,80
Gross Electricity Generation	28,96	47,62	42,86	47,84	54,10	47,49	62,53	57,63	57,12

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Slovenia	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	0,70	0,67	0,00	0,00	0,00	0,67	0,00	0,00	0,00
Lignite (incl. CHP)	n.a.	0,57	0,00	0,00	0,00	0,57	0,00	0,00	0,00
Lignite-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	n.a.	0,00	1,14	1,14	1,14	0,00	0,10	0,10	0,10
Coal-CHP	n.a.	0,06	0,04	0,01	0,00	0,07	0,04	0,01	0,00
Coal-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	n.a.	1,46	1,24	1,25	1,53	2,43	2,21	2,24	2,38
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	n.a.	0,01	0,00	0,00	0,00	0,01	0,00	0,00	0,00
Storage	n.a.	0,19	0,19	0,19	0,19	0,19	0,19	0,19	0,19
Hydro	n.a.	1,03	1,03	1,03	1,03	1,03	1,03	1,03	1,03
Biomass	n.a.	0,05	0,03	0,00	0,00	0,05	0,03	0,00	0,00
Biomass-CHP	n.a.	0,02	0,02	0,06	0,06	0,02	0,02	0,06	0,07
Wind onshore	n.a.	0,00	0,00	0,47	0,47	0,00	0,29	0,47	0,47
Wind offshore	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,44
CSP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	n.a.	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02
Others	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	6,27	4,93	0,00	0,00	0,00	4,93	0,00	0,00	0,00
Lignite (incl. CHP)	4,81	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,52	0,00	8,27	8,27	2,18	0,00	0,74	0,76	0,27
Coal-CHP	n.a.	0,21	0,21	0,00	0,00	0,20	0,20	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	0,48	8,66	7,87	8,27	0,00	15,39	14,03	12,89	0,00
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,02	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,08	0,00	0,00	0,00	0,08	0,00	0,09
Hydro	4,02	4,62	4,62	4,62	4,62	4,62	4,62	4,62	4,62
Biomass	0,29	0,36	0,22	0,00	0,00	0,36	0,21	0,00	0,00
Biomass-CHP	n.a.	0,16	0,16	0,47	0,48	0,17	0,17	0,47	0,48
Wind onshore	0,00	0,00	0,00	0,70	0,70	0,00	0,43	0,70	0,70
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,48
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,12	0,12	0,13	0,13	0,12	0,12	0,13	0,13
Others	0,00	0,01	0,01	0,01	0,01	0,01	0,01	0,01	0,01

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	12,81	16,27	18,33	20,55	22,92	16,27	18,33	20,55	22,92
Consumption in Energy Conversion	1,18	1,67	1,93	1,95	0,51	2,35	1,79	1,66	0,32
Own Consumption of Power Plants	1,18	1,38	1,63	1,65	0,22	2,05	1,50	1,36	0,03
Other	n.a.	0,30	0,30	0,30	0,30	0,30	0,30	0,30	0,30
Transmission Losses	0,81	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73
Storage Consumption	0,00	0,00	0,11	0,00	0,00	0,00	0,11	0,00	0,13
Gross Electricity Consumption	14,80	18,67	21,09	23,22	24,16	19,34	20,96	22,94	24,10
Net Imports	-1,60	-0,39	-0,46	0,76	16,05	-6,46	0,34	3,36	17,33
Gross Electricity Generation	16,40	19,06	21,55	22,46	8,12	25,80	20,62	19,58	6,77

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Spain	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	7,42	7,46	7,00	0,00	0,00	7,46	7,00	0,00	0,00
Lignite (incl. CHP)	1,93	1,79	1,64	1,22	1,22	2,79	2,35	1,94	1,94
Lignite-CCS	0,00	0,00	0,80	0,80	0,80	0,00	0,00	0,00	0,00
Coal	9,22	8,65	0,86	0,00	0,00	8,65	0,86	0,00	0,00
Coal-CHP	n.a.	0,06	0,04	0,02	0,00	0,06	0,04	0,02	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	25,44	7,98	11,13	8,21	7,55	7,87	7,87	10,27	9,72
Gas-CHP	n.a.	3,11	1,04	0,00	0,00	3,11	1,04	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	9,40	1,58	0,00	0,00	0,00	1,58	0,00	0,00	0,00
Storage	4,90	5,35	5,35	5,35	5,35	5,35	5,35	5,35	5,35
Hydro	13,76	13,10	13,10	13,10	13,10	13,10	13,10	13,10	13,10
Biomass	0,44	0,68	0,28	0,00	0,00	0,68	0,28	0,00	0,00
Biomass-CHP	n.a.	2,36	2,46	2,46	2,61	2,37	2,47	2,53	2,61
Wind onshore	14,13	24,37	26,44	34,42	35,48	24,37	26,44	34,42	35,48
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,67	3,50	3,44	0,00	0,00	3,50	3,44	0,00	0,00
CSP	n.a.	9,10	38,00	78,00	108,90	10,00	40,78	69,11	93,64
Geothermal	n.a.	0,25	0,75	0,82	0,93	0,25	0,75	0,82	0,93
Others	0,47	0,35	0,35	0,35	0,35	0,35	0,35	0,35	0,35

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	58,97	54,84	51,49	0,00	0,00	54,84	51,49	0,00	0,00
Lignite (incl. CHP)	0,00	12,17	8,69	8,69	0,00	14,00	15,06	14,45	0,00
Lignite-CCS	0,00	0,00	6,02	6,02	5,37	0,00	0,00	0,00	0,00
Coal	48,71	57,83	6,02	0,00	0,00	56,71	6,24	0,00	0,00
Coal-CHP	n.a.	0,00	0,08	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	121,56	56,95	43,24	4,31	0,00	56,53	23,55	0,00	0,00
Gas-CHP	n.a.	7,71	0,00	0,00	0,00	7,56	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	18,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,44	0,36	2,60	0,00	0,00	2,52	5,28
Hydro	26,11	26,03	26,03	26,03	26,03	26,03	26,03	26,03	26,03
Biomass	4,04	5,02	2,06	0,00	0,00	5,02	2,06	0,00	0,00
Biomass-CHP	n.a.	17,40	18,14	17,97	18,16	17,48	18,22	17,97	18,16
Wind onshore	32,20	46,04	51,30	77,68	81,16	46,04	51,30	77,68	81,16
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	2,56	5,19	5,11	0,00	0,00	5,19	5,11	0,00	0,00
CSP	0,00	36,69	153,21	314,49	439,07	40,32	164,44	278,66	377,51
Geothermal	0,00	1,85	5,54	6,07	6,15	1,85	5,54	6,07	6,15
Others	1,57	1,86	1,86	1,86	1,71	1,86	1,86	1,86	1,65

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	265,36	298,63	344,87	396,31	453,18	298,63	344,87	396,31	453,18
Consumption in Energy Conversion	18,85	23,94	16,55	6,89	5,53	23,96	14,63	6,44	4,99
Own Consumption of Power Plants	18,85	18,95	11,55	1,90	0,54	18,96	9,63	1,44	0,00
Other	n.a.	4,99	4,99	4,99	4,99	4,99	4,99	4,99	4,99
Transmission Losses	15,00	13,50	13,50	13,50	13,50	13,50	13,50	13,50	13,50
Storage Consumption	1,12	0,00	0,61	0,51	3,62	0,00	0,00	3,51	7,33
Gross Electricity Consumption	300,33	336,07	375,53	417,21	475,82	336,08	372,99	419,75	479,00
Net Imports	-11,04	6,51	-3,71	-46,28	-104,44	2,68	2,10	-5,49	-36,93
Gross Electricity Generation	313,75	329,56	379,23	463,48	580,26	333,41	370,89	425,23	515,94

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Sweden	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	9,06	9,50	6,61	0,00	0,00	9,50	6,61	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,13	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,44	0,30	0,15	0,00	0,44	0,30	0,15	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,73	0,88	0,91	0,00	0,74	0,86	0,89
Gas	0,55	0,28	6,67	10,43	14,54	0,28	6,69	11,37	14,87
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	4,30	0,49	0,00	0,00	0,00	0,49	0,00	0,00	0,00
Storage	0,00	0,09	0,09	5,29	5,29	0,09	0,09	5,73	5,73
Hydro	16,21	16,35	16,35	16,35	16,35	16,35	16,35	16,35	16,35
Biomass	2,09	1,03	0,02	0,00	0,00	1,03	0,02	0,00	0,00
Biomass-CHP	n.a.	0,17	0,17	0,19	0,19	0,17	0,18	0,19	0,19
Wind onshore	0,79	4,85	6,48	6,98	7,69	4,85	6,49	7,00	7,70
Wind offshore	0,00	0,16	0,14	0,00	0,00	0,16	0,14	0,00	8,20
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,40	0,40	0,40	0,40	0,40	0,40	0,40	0,40
Others	0,93	0,52	0,52	0,52	0,52	0,52	0,52	0,52	0,52
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	63,89	69,86	48,62	0,00	0,00	69,86	48,62	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,51	0,02	0,02	0,00	0,00	0,01	0,01	0,00	0,00
Coal-CHP	n.a.	3,23	0,94	0,06	0,00	3,23	0,88	0,26	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	5,32	6,19	6,29	0,00	5,37	5,99	6,29
Gas	0,60	0,00	0,00	0,00	0,00	0,00	0,00	0,98	0,00
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,87	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	0,03	1,19	2,01	0,00	0,16	4,41	6,31
Hydro	69,21	88,13	88,13	88,13	88,13	88,13	88,13	88,13	88,13
Biomass	11,18	0,05	0,11	0,00	0,00	0,03	0,08	0,00	0,00
Biomass-CHP	n.a.	1,24	1,22	1,32	1,32	1,27	1,25	1,32	1,32
Wind onshore	2,00	11,93	15,65	17,76	20,58	11,93	15,71	17,82	20,64
Wind offshore	0,00	0,41	0,36	0,00	0,00	0,41	0,36	0,00	22,19
PV	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	2,93	2,95	2,96	2,98	2,93	2,95	2,96	2,98
Others	0,66	2,75	2,75	2,75	2,59	2,75	2,75	2,75	2,75
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	128,65	150,03	160,87	170,78	180,41	150,03	160,87	170,78	180,41
Consumption in Energy Conversion	8,23	9,39	7,57	2,70	2,70	9,38	7,56	2,80	2,70
Own Consumption of Power Plants	8,23	7,31	5,49	0,63	0,63	7,31	5,49	0,72	0,63
Other	n.a.	2,07	2,07	2,07	2,07	2,07	2,07	2,07	2,07
Transmission Losses	10,99	9,89	9,89	9,89	9,89	9,89	9,89	9,89	9,89
Storage Consumption	0,07	0,00	0,05	1,69	2,87	0,00	0,22	6,29	9,00
Gross Electricity Consumption	147,93	169,30	178,37	185,06	195,87	169,30	178,54	189,76	202,00
Net Imports	-1,96	-11,26	12,25	64,70	71,97	-11,24	12,27	65,12	51,40
Gross Electricity Generation	150,04	180,56	166,11	120,37	123,90	180,54	166,27	124,63	150,61

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

Switzerland	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	3,22	1,17	0,00	0,00	0,00	1,17	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	0,07	0,00	0,00	0,00	0,00	0,67	0,67	0,67	0,67
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,01	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	7,32	4,43	4,43	4,43	4,43	4,43	4,43	4,43	4,43
Hydro	6,14	13,48	13,48	13,48	13,48	12,66	12,66	12,66	12,66
Biomass	0,00	0,58	0,08	0,08	0,11	0,58	0,08	0,08	0,10
Biomass-CHP	n.a.	0,06	0,06	0,06	0,04	0,06	0,06	0,06	0,04
Wind onshore	0,01	0,02	0,01	1,18	1,18	0,02	1,17	1,18	1,18
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,03	0,07	0,06	0,00	0,00	0,07	0,06	0,00	3,79
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,00	0,00	0,00	0,01	0,00	0,00	0,00	0,01
Others	0,17	0,39	0,39	0,39	0,39	0,39	0,39	0,39	0,39
Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	27,70	8,57	0,00	0,00	0,00	8,57	0,00	0,00	0,00
Lignite (incl. CHP)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Lignite-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coal-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas	0,75	0,00	0,00	0,00	0,00	4,74	4,66	4,58	0,00
Gas-CHP	n.a.	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Gas-CHP-CCS	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Oil (incl. CHP)	0,14	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Storage	n.a.	0,00	1,87	2,08	2,41	0,00	1,74	1,28	1,89
Hydro	37,94	43,77	43,77	43,77	43,77	43,77	43,77	43,77	43,77
Biomass	2,15	0,62	0,59	0,61	0,74	3,58	0,59	0,61	0,74
Biomass-CHP	n.a.	0,46	0,46	0,44	0,33	0,46	0,46	0,44	0,33
Wind onshore	0,02	0,02	0,01	1,87	1,87	0,02	1,86	1,87	1,87
Wind offshore	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
PV	0,03	0,07	0,06	0,00	0,00	0,07	0,06	0,00	3,95
CSP	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Geothermal	0,00	0,00	0,00	0,01	0,07	0,00	0,00	0,01	0,07
Others	0,24	2,05	2,05	2,05	2,05	2,05	2,05	2,05	2,05
Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	58,73	69,93	78,79	88,34	98,55	69,93	78,79	88,34	98,55
Consumption in Energy Conversion	2,12	8,91	10,58	10,27	11,40	8,91	10,60	10,16	12,16
Own Consumption of Power Plants	2,12	8,91	8,32	8,01	9,14	8,91	8,35	7,90	9,90
Other	n.a.	0,00	2,26	2,26	2,26	0,00	2,26	2,26	2,26
Transmission Losses	4,32	4,66	4,20	4,20	4,20	4,66	4,20	4,20	4,20
Storage Consumption	0,79	0,13	0,00	0,87	0,87	0,13	0,28	0,42	1,00
Gross Electricity Consumption	65,95	71,70	84,71	94,12	104,80	71,70	85,02	93,56	105,69
Net Imports	-1,14	-11,47	-22,02	-16,53	-17,43	-11,47	-22,14	-18,36	-26,61
Gross Electricity Generation	68,98	83,52	106,73	110,65	122,23	83,52	107,16	111,92	132,30

** Source: EURELECTRIC, Statistics and Prospects for the European Electricity Sector, 37th Edition EURPROG 2009*

*** Source: Eurostat Statistical Books, Energy - Yearly statistics 2008, 2010 edition*

, In the historic data the following types are aggregated: CHP and non-CHP in capacity and generation, Storage and Hydro in generation*

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