Flexibility options in European electricity markets in high RES-E scenarios

Study on behalf of the International Energy Agency (IEA)

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1 EXECUTIVE SUMMARY

The increasing electricity generation by renewable energy sources (RES-E) gives rise to various structural issues in international electricity markets. Electricity generation from wind turbines and solar systems depends on local weather conditions and therefore the hourly feed-in can be highly uncertain. In particular, the generation from wind turbines can change considerably from one hour to another due to altering wind speeds. Given a large deployment of wind and solar capacities, the residual load structure (electricity load subtracting fluctuating RES-E generation) is expected to be more volatile in future electricity systems. In addition, electricity systems need to be able to handle possible forecast errors concerning the generation from renewables. Therefore, flexible resources in mostly renewable electricity systems are needed to cope with the volatile residual load structure.

Variable electricity load structures are expected to have an increasing impact on the optimal capacity mix as thermal and nuclear power plants are technically restricted in their ability to change generation levels. Technologies with high ramp rate capabilities, such as gas-fired power plants, energy storage, demand side management, or flexible CCS plants will be needed. By definition, flexibility is the capability to balance rapid changes in renewable generation and forecast errors within a power system. Several options are available to provide flexibility and need to be comparatively evaluated to determine the cost-efficient mix of technologies.

In this study, the development of the European electricity markets until 2050 is simulated using a linear investment and dispatch optimization model for two scenarios, each differing in CO_2 emission costs. These calculations are supplemented with a more detailed analysis concerning the operational flexibility of the resulting power plant portfolio by using a European dispatch model for 8760 hours for selected years (2020, 2030, 2040 and 2050).

The effects of intermittent renewables on the cost-efficient capacity mix, required flexibility and electricity costs are analysed with a special emphasis on advanced CCS plants with flexible CCS units. Profits of flexibility options and potentially missing revenues from locked-in power plants are discussed, raising implications for system adequacy and market designs.

- **A high share of renewable generation profoundly changes the cost-minimum capacity mix, favouring gas-fired power plants due to less full load hours.**

  In the scenarios considered, renewables are deployed exogenously in order to achieve a share of 80 % of net electricity demand in 2050. This leads to a profound change in the optimal capacity mix, as realizable full load hours of base-load plants are reduced and more mid- and peak-load capacity is cost-efficient to achieve system adequacy.

- **Greater variability in the residual load significantly raises the need for flexibility in renewable power systems.**

  In 2050, the residual load duration curve, i.e. the number of hours a given load level is observed per year, is steeper (compared to 2020) for countries with high shares of fluctuating wind and solar generation. More hours with negative residual load (defined as the net electricity demand subtracting renewable generation without considering storage operations, imports and exports) occur during times of low feed-in of fluctuating renewables high levels of residual load still exist. Hence, approximately the same amount of securely available (mainly conventional) capacity has to be installed in 2050 as in 2020.

  Residual load is more volatile in terms of absolute amounts and frequency of changes in electricity systems with a high share of renewables. For example in the United Kingdom, positive as well as negative hourly changes of up to 40,000 MW could frequently occur due to a high share of wind generation in 2050. Other countries with high shares of fluctuating renewables still have to face changes of up to 25,000 MW from one hour to another (in 2050). The hours with the highest fluctuations appear in times of low residual load when generation from renewables is high.

  Due to the stochastic availability of wind and solar power, additional flexibility (apart from the need to balance volatile generation and demand) is needed to cope with potential forecast errors on short notice. Considering potential forecast errors of 10 % of the hourly-expected wind and solar generation[1], additional short-term flexibility (as in the capability to balance forecast errors within minutes) of 2,000 MW is often needed in 2020. However, the requirement increases over time due to the large deployment of wind and solar power. In 2050, the amount of short-term flexibility needed in countries with a high share of renewables is often larger than 8,000 MW.

- **Flexible gas-fired power plants could play a significant role in mostly renewable power systems due to low capital costs and technical operational flexibility.**

  In 2020, the required flexibility to dispatch generation and demand is mainly determined by the changes in load rather than generation from renewables. The supply of flexibility for short-term uncertainty does not pose a major challenge, as enough flexible capacity is available to balance forecast errors in hours with a potential need for additional generation. The requirement of negative flexibility supply is not a challenge due to the possible curtailment of wind generation. Naturally, ramping down thermal power plants (if possible, within technical restrictions) is most often cheaper than wind curtailment due to the reduction of fuel costs.

[1] The quality of short-term prediction of wind and solar feed-in has increased in recent years due to improved forecast models. As stated in ANEMOS (2011), relative forecast errors could be reduced on average from about 10 % in 2000 to 6 % in 2006 with further improvements achieved in recent years. However, relative forecast errors can still be significantly higher in single hours.

In 2050, the dispatch is strongly influenced by weather conditions and the resulting generation of fluctuating renewables. However, more flexible capacities (mainly gas-fired power plants) are installed to ensure system adequacy. Curtailment of wind generation is frequently used and storage is more often utilized to cope with hourly changes in residual electricity load. Regions with large capacities of concentrated solar power (CSP) with thermal energy storages, especially Italy and the Iberian Peninsula, benefit from their capability to smooth the residual load curve (by using the storage unit). Short-term uncertainty can be covered by sufficiently available and highly flexible gas capacities.

After becoming available in 2030 (by assumption), carbon capture and storage (CCS) technologies with flexible CCS unit provide flexibility are used in Scenario A (net capacities 2030 6.1 GW; 2040 and 2050 12.6 GW). However, the CCS unit is only switched off when costs of CO_2 emissions are low. In the high CO_2 price scenario, flexible CCS technologies are installed due to their relatively high contribution to system adequacy through being able to provide more generation (by switching off the CCS unit) compared to a conventional CCS plant.

- **The merit order of flexibility options is closely interrelated to the level of the residual load. The costs of flexibility increase over time and are especially high at high levels of the residual load.**

A merit order for flexibility options to increase or decrease power generation or curtailing demand corresponds with the usual merit order, i.e. the ranking of generation technologies by variable costs. Costs for flexibility are higher in 2050 compared to 2020 due to the increase of CO_2 prices, as well as mid-load capacities with relatively low variable costs being replaced by gas-fired power plants with high variable costs. Due to the more costly flexibility options and the increased need for flexibility, the overall costs of flexibility rise. The costs for providing short-term flexibility, however, correspond with the costs of conventional generation due to the dependency between the residual load and the availability of power plants to provide additional flexibility.

Thermal generation flexibility options are faced with the trade-off between dispatch generation and provision of positive flexibility. The costs of storages and demand side management are opportunity costs for plant operators that highly depend on a specific point in time, rendering an integration into an average ranking impossible. Storage operators maximize their profits by charging storages when electricity prices are low and discharging when high, while keeping capacity restrictions under consideration (so-called 'energy arbitrage'). For instance at peak demand, most power plants (including storages and demand side management) are already in use and thus positive flexibility can only be provided at high cost.

- **Peak-load plants cannot recover capital costs due to low utilization. Long-term power market design has to consider potential missing money of peak load plants to ensure system adequacy.**

  Considering the model environment (cost-minimization from a central planner perspective), the simulation results indicate that peak-load plants – specifically open cycle gas turbines – are not able to recover their capital costs in an energy only market with high competition, a high share of renewables and electricity prices that are purely based on short-term marginal costs. The simulation results also show that a substantial amount of peak capacity is still needed for situations with low feed-in of wind and solar technologies at times of high demand.

  Based on the model results, it is rather doubtful that sufficient investments, although required for peak demand, will be made. Further evaluations should be performed whether peak load capacities will be able to recover their capital costs within a few hours per year with sufficiently high electricity prices (above short-term marginal costs) or if the market design has to be adapted to ensure system adequacy.

2 BACKGROUND AND SCOPE OF THE STUDY

In recent years, many countries and governments have established policies to drive more renewable energy into the power market. This study sheds light on the various issues of flexibility in future power systems with significant amounts of non-dispatchable renewable energy capacities. For the purposes of this study, we assume a high penetration of renewable energy – 80 % of the net electricity consumption - in the European power system in 2050. The study does not predict whether this is a realistic outcome or not, but rather makes statements about the future power mix. The objective of the study is to model and discuss a potential situation in which power systems require increased flexibility services.

The increasing electricity generation from renewable energy sources gives rise to various structural issues in international electricity markets. Electricity generation of wind turbines and solar systems depends on local weather conditions, causing the hourly feed-in to be highly uncertain. Especially the generation from wind turbines can change considerably from one hour to another due to altering wind speeds. Given a large deployment of wind and solar capacities, the residual load structure (load subtracting fluctuating RES-E generation) is expected to be more volatile in future electricity systems. In addition to the hourly dispatch volatility, the availability of wind and solar power is stochastic and, even when considering advanced forecasting methods, the actual generation may differ from forecasted values. Forecast errors occur on short notice and backup capacities – which are able to provide such short-term flexibility - have to be available. Therefore, flexible resources in the electricity system are needed to cope with the volatile residual load structure.

Because power plants have technical restrictions concerning their ability to change generation levels, variable electricity load structures can be challenging for power systems. Therefore fluctuating residual load can affect the cost-minimal capacity mix. Flexible technologies with high ramp rate capabilities such as gas-fired power plants, storages or some demand side management processes can be used to realise the dispatch of generation and demand. Another option for providing flexibility is the installation of advanced CCS plants with flexible CCS units. By switching off their CCS units, these plants can provide additional generation on short notice and contribute to more flexibility, especially in power systems with high shares of CCS technologies.

The deployment of advanced CCS plants and other flexible resources in an optimal capacity mix depends on various parameters such as CO_2 and fuel prices, full load hours or required flexibility. An integrated analysis considering of all dependencies is necessary to identify which options are able to cope with the challenges of the increasing need of flexibility when given high shares of RES-E.

The scope of this study is to take a closer look at the effect of volatile generation of wind and solar technologies on the future electricity supply (dispatch of generation and demand) and the resulting role of flexibility options in Europe. Therefore, the flexibility requirements as well as the possible flexibility provision from conventional, storage technologies and demand side management (DSM) is further analysed. Special emphasis is placed on advanced CCS plants with flexible CCS units. The following research topics are further examined within this study:

- The impact of a high share of RES-E on installed capacities, generation mix, trade flows, CO_2 emissions and total costs of the electricity system.
- The requirements for dispatch and short-term flexibility and the fulfilment of these requirements by flexible resources including a cost-based ranking and estimations about potential revenues.
- The impact of an increasing share of renewable generation on potential revenues of flexibility options and "locked-in" fossil fuel plants.

Due to the structural changes in the European electricity markets, historical data cannot be used to analyse the possible future role of flexibility options, rendering an econometric analysis impossible. Hence, we simulate the development of the European electricity market in two scenarios ("A": low CO_2 prices; "B" high CO_2 prices) until 2050 using an investment and dispatch optimization model (DIMENSION). Calculations are supplemented with a more detailed analysis concerning the operative flexibility of the resulting power plant portfolio by using a European dispatch model for 8760 hours for selected years (2020, 2030, 2040 and 2050).

3 METHODOLOGY

A dynamic linear investment and dispatch model is used to compute the cost-minimal development of the electricity system for Europe.[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. First, this section provides an introduction to the model, namely its technologies, regions and temporal resolution. Following, the data structure (in- and output overview) is described. The focus remains on the structural characteristics of the model, whereas underlying assumptions and results are discussed in Chapter 4 and 5, respectively.

Overview

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. 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 (gas, liquid and solid), biomass CHP (gas and solid), geothermal, hydro (storage and run-of-river) and solar thermal plants. Furthermore, to account for technological progress, several future plant developments are modeled. The deployment of renewable capacities in Europe is exogenous in the analysed scenarios but generation of biomass, hydro, wind and solar plants is an endogenous decision in the model. Regarding conventional technologies, technological progress is assumed to increase the net efficiency or leads to the availability of CCS technologies from 2030 onwards. The model covers 13 European regions which are defined as market regions where supply has to equal demand in each hour. The model computes the optimal electricity mix in 10-year time-steps until 2050.[2] Within each model year, generation has to equal demand on twelve representative days accounting for seasonal differences. 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.

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

[2] 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.

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 1. In the following the in- and output parameters are described in detail.

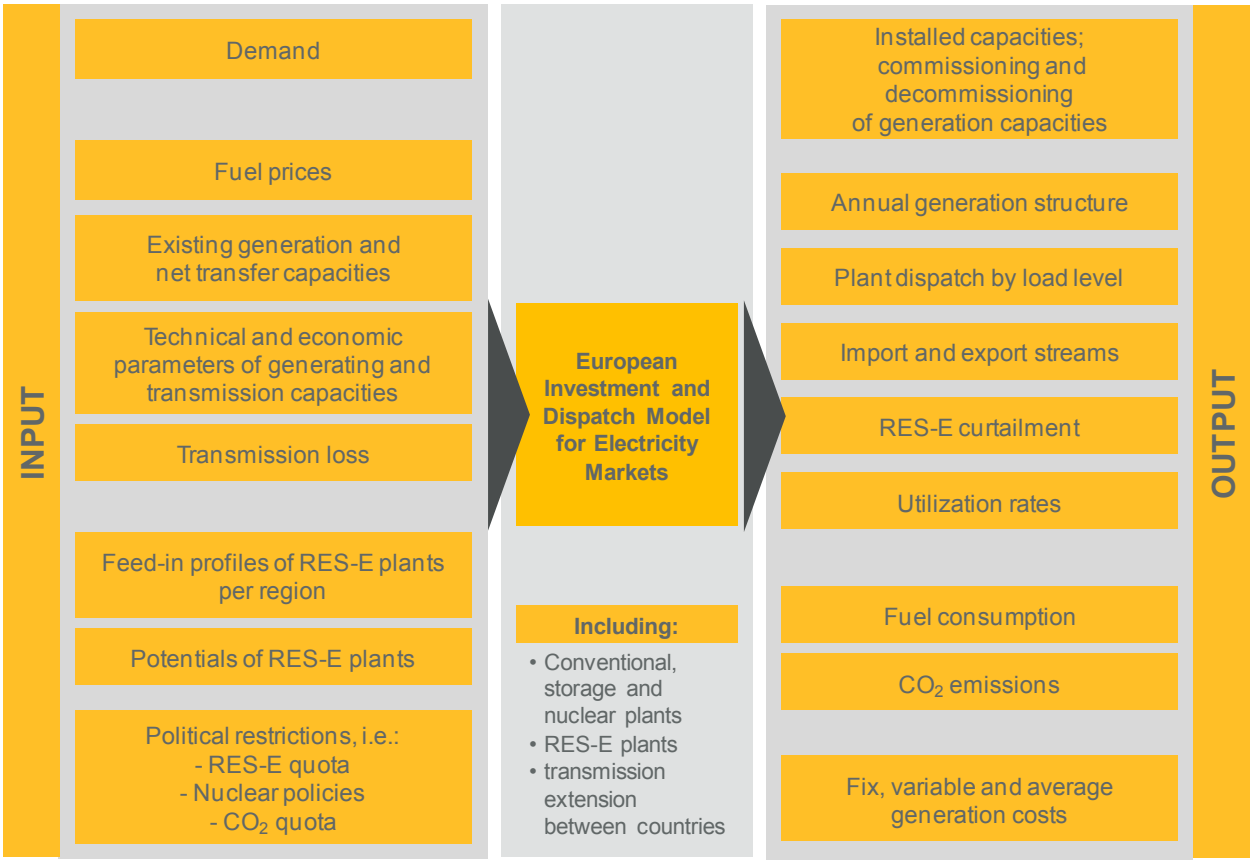

FIGURE 1: IN- AND OUTPUT-STRUCTURE OF THE ELECTRICITY MARKET MODEL (DIMENSION)

Source: EWI

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 plants' own consumption are modelled endogenously. For the installed capacity needed to ensure enough backup in the market an additional condition applies: in accordance with

ENTSO-E's "margin against peak load" the model needs to provide additional backup capacities to ensure security of supply.

Economic and technical input parameters define generation technologies. 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 (net). Transmission losses for imports are modelled 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 photovoltaic 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 option of wind and solar curtailment can be endogenously chosen when total system costs can be reduced due to a reduction of ramping costs of thermal power plants or in case of insufficient alternative flexibility.[1] Solarthermal plants are modelled 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 plants.

Output Parameters

The model results include: i) development of the generation, 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 capacity is 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 ASSUMPTIONS

In this chapter an overview of the major assumptions underlying the scenario analysis is given. Most relevant assumptions include: development of electricity demand and potential for heat in co-generation; economic and technical parameters of conventional, storage and renewable technologies; development of the European electricity grid and fuel prices.

4.1 Considered countries in the scenario analysis

Several countries were aggregated to regions, namely Ireland and the United Kingdom (UK), Spain and Portugal (IB), Norway, Sweden and Finland (SK), Slovenia, Slovakia, Romania, Bulgaria and Hungary (EE). Like the single countries, each region is treated as one market within the model. The considered countries are shown with a grey colouring in.

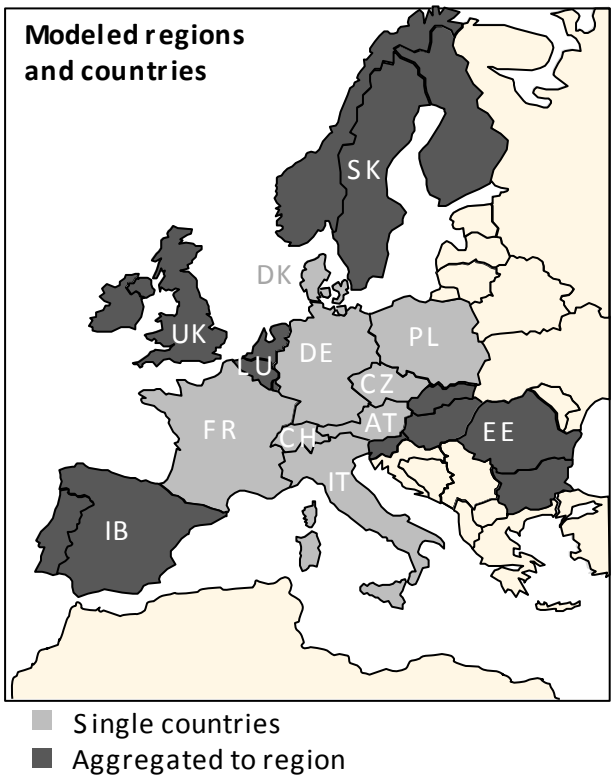

FIGURE 2: MODELED COUNTRIES AND REGIONS

Source: EWI

4.2 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 the scenarios, 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. However, in the medium term the assumed energy efficiency progress offsets the effects of GDP growth on the electricity demand. For Southern Europe higher growth rates of electricity demand are assumed due to an expected increasing population. 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 in the medium and long term. Hence, for the next decades a high increase of electricity demand is assumed in Eastern Europe. Table 1 reports the final electricity demand per model region in the scenarios.

Similar to the electricity demand, an increasing potential for heat generation in CHP plants is assumed (based on EURELECTRIC (2008) and Capros et al. (2010)). 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 1: 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)
BeNeLux	(LU)	221.6	(129.9)	237.6	(130.8)	252.2	(131.5)	266.5	(132.3)
Czech Republic	(CZ)	69.9	(55.1)	78.8	(55.7)	88.3	(56.4)	98.5	(57.0)
Denmark	(DK)	40.5	(54.7)	43.4	(55.1)	46.0	(55.4)	48.6	(55.7)
Eastern Europe	(EE)	151.9	(132.6)	171.1	(134.2)	191.8	(135.7)	214.0	(137.2)
France	(FR)	480.0	(31.6)	514.6	(31.8)	546.4	(32.0)	577.2	(32.2)
Germany	(DE)	567.0	(192.4)	584.2	(192.9)	584.2	(192.9)	584.2	(192.9)
Iberian Peninsula	(IB)	354.5	(72.9)	409.4	(73.9)	470.5	(75.0)	538.0	(76.0)
Italy	(IT)	362.9	(169.2)	419.1	(171.7)	481.6	(174.1)	550.7	(176.5)
Poland	(PL)	140.0	(93.3)	157.8	(94.4)	176.9	(95.5)	197.3	(96.6)
United Kingdom	(UK)	415.5	(68.1)	445.6	(68.6)	473.0	(69.0)	499.7	(69.3)
Scandinavia	(SK)	365.4	(98.1)	391.8	(98.8)	415.9	(99.4)	439.4	(99.9)
Switzerland	(CH)	65.4	(3.0)	70.1	(3.0)	74.5	(3.0)	78.7	(3.0)

Source: EWI based on EURELECTRIC (2008) and Capros et al. (2010)

4.3 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 are assumed to be available in the future, such as thermal power plants equipped with CCS, innovative hard coal, lignite or gas power plants (based on Prognos/EWI/GWS (2010) and IEA (2010a)). Table 4 recaptures the technological options available to the system and shows their technological and operational characteristics, i.e. conversion efficiency (net), availability, annual operation and maintenance costs, technical lifetime, minimum load and start-up times. For currently available technologies, net efficiency assumptions are based on average specifications of power plant types in construction today. For "innovative" technologies, efficiency improvements are assumed due to technical innovations. Note that CHP power plants have lower efficiencies in electric power production compared to non-CHP plants, but higher overall energy efficiencies.[1]

Nuclear: Nuclear plants can be seen as a mature technology for power generation and therefore constant investment costs are assumed in the scenarios. Due to long planning and construction times, the scenarios assume that before 2025 only nuclear plants already under construction are build.

Hard coal: Conventional hard coal power plants are a mature technology and no further cost reductions are assumed. 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 350 bars of pressure, thus improving net 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 net 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.

[1] Notes to Table 3: In fact, a lot more technologies, reflecting several vintage classes for existing technologies, than shown are modeled. The availability factor is an average of the four seasonal availability factors used in the model. It accounts for planned and unplanned shut-downs of plants, e.g. due to revisions. For conventional and nuclear power plants, the availability factor also determines the contribution of a plant to the secured available capacity within each country.

Gas/hydrogen: Open cycle (OCGT) and combined cycle gas turbine (CCGT) are both investment options. They are equally seen as mature technologies with constant investment costs. CCGT plants can furthermore be equipped with a heat module (CHP) and/or a CCS technology, which raises the overall investment costs. The model considers natural gas and hydrogen as a fuel option for OCGT and CCGT plants.

CCS technology: By 2030 CCS is assumed to be available and applicable to hard coal, lignite and combined-cycle gas power plants. As shown in Table 2, 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). Costs for transporting and storing the captured CO_2 underground (10 $€_{2010}$/t CO_2) are included in the listed fixed operation and maintenance (O&M) costs of CCS power plants.[1] Note that CCS power plants lose 9.5 or more percentage points in net electrical efficiency compared to non-CCS plants, depending on the power plant type. Flexible CCS power plants are able to switch off the CCS unit to increase power plant output and therefore offer short-term flexibility to the power system.[2]

Table 2 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 (t CO_2/MWh_{th}). While lignite-fired power plants exhibit 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 85 % of their CO_2 emissions.

TABLE 2: CO_2 EMISSION FACTORS FOR FUEL COMBUSTION IN THE POWER SECTOR [t CO_2/MWh_{th}]

Fuel	Nuclear	Oil	Hard coal	Lignite	Natural gas	Hydrogen
CO_2 emission factor	0	0.266	0.335	0.406	0.201	0

Source: EWI

[1] Assumption of full load hours to calculate the amount of captured and stored CO_2 were made according to common utilization rates.
[2] For a general discussion of CCS and Hydrogen technologies cf. Davison 2009. For a detailed discussion of the techno-economic figures cf. Finkenrath 2011.

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

Technology	2020	2030	2040	2050
Nuclear	3,157	3,157	3,157	3,157
Lignite	1,850	1,850	1,850	1,850
Lignite CHP	2,350	2,350	2,350	2,350
Lignite CCS	-	2,896	2,721	2,652
Lignite CCS (flexible)	-	3,041	2,842	2,764
Lignite - innovative	1,950	1,950	1,950	1,950
Lignite – innovative CCS	-	2,996	2,821	2,752
Lignite – innovative CCS (flexible)	-	3,145	2,945	2,867
Lignite – innovative CHP and CCS	-	3,396	3,221	3,152
Hard coal	1,500	1,500	1,500	1,500
Hard coal CHP	2,650	2,342	2,135	2,030
Hard coal CCS	-	2,349	2,207	2,152
Hard coal CCS (flexible)	-	2,459	2,298	2,236
Hard coal - innovative	2,250	1,904	1,736	1,650
Hard coal - innovative CCS	-	2,753	2,443	2,302
Hard coal - innovative CCS (flexible)	-	2,894	2,560	2,410
Hard coal – innovative CHP and CCS	-	3,191	2,842	2,682
CCGT	700	700	700	700
CCGT - CHP	1,000	1,000	1,000	1,000
CCGT - CCS	-	1,127	1,057	1, 030
CCGT – CCS (flexible)	-	1,189	1,109	1,078
CCGT - CHP and CCS	-	1,409	1,341	1,314
OCGT	400	400	400	400

Source: EWI and IEA

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

Technology	Net efficiency [%]	Availability [%]	Fix O&M costs [€2010 /kWa]	Technical lifetime [a]	Minimum load [%}	Ramp-up times [h]
Nuclear	33.0	84.5	96.6	60	45	48
Lignite	43.0	86.3	43.1	45	30	3-12
Lignite CHP	22.5	86.3	62.1	45	30	3-12
Lignite CCS	33.5	86.3	70.3	45	30	3-12
Lignite CCS (flexible)	32.9	86.3	71.6	45	30	3-12
Lignite - innovative	46.5	86.3	43.1	45	30	3-12
Lignite – innovative CCS	37.0	86.3	70.3	45	30	3-12
Lignite – innovative CCS (flexible)	36.4	86.3	71.6	45	30	3-12
Lignite – innovative CHP and CCS	20.0	86.3	89.3	45	30	3-12
Hard coal	46.0	83.8	36.1	45	30	1-6
Hard coal CHP	22.5	83.8	55.1	45	30	1-6
Hard coal CCS	36.5	83.8	59	45	30	1-6
Hard coal CCS (flexible)	35.9	83.8	60.2	45	30	1-6
Hard coal - innovative	50.0	83.8	36.1	45	30	1-6
Hard coal - innovative CCS	40.5	83.8	59	45	30	1-6
Hard coal - innovative CCS (flexible)	39.9	83.8	60.2	45	30	1-6
Hard coal – innovative CHP and CCS	20	83.8	78	45	30	1-6
CCGT	60.0	84.5	28.2	30	40	0.75-3
CCGT - CHP	36.0	84.5	40.0	30	40	0.75-3
CCGT - CCS	52.0	84.5	46	30	40	0.75-3
CCGT – CCS (flexible)	51.6	84.5	50.5	30	40	0.75-3
CCGT - CHP and CCS	33.0	84.5	57.9	30	40	0.75-3
OCGT	40.0	84.5	17.2	25	20	0.25

Source: EWI and IEA

4.4 Economic and technical parameters of renewable energies

A large number of renewable energy technologies is implemented in the model, such as wind (on- and offshore), biomass (gaseous, liquid and solid), geothermal, photovoltaic (roof and open land installations) and hydropower (run-of-river and hydro storage) plants. Assumed investment costs including technology-specific learning effects are given in Table 5 for each renewable energy technology (based on Prognos/EWI/GWS (2010), EWI (2010), IEA (2010a), IEA (2010b)). Assumed costs drop sharpest by about 30 % for solar energy technologies, i.e. ground- and roof-mounted photovoltaics as well as concentrated solar power (CSP). Modelled CSP facilities are assumed to have an included thermal storage device, which is the reason for higher investment costs than listed in other studies.

TABLE 5: 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 liquid	1,700	1,700	1,700	1,700
Biomass solid	3,297	3,293	3,290	3,287
Biomass solid CHP	3,497	3,493	3,490	3,486
Concentrated solar power	3,989	3,429	3,102	2,805
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
Wind onshore	1,221	1,161	1,104	1,103
Wind offshore	2,615	2,365	2,249	2,247

Source: EWI

The same technological-economic characteristics as for conventional and nuclear power plant technologies are defined for renewable energy technologies (see Table 6). Biomass CHP power plants have a lower electric efficiency (net) 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 can operate for 25 years.

As for conventional and nuclear power plants, the availability factor for dispatchable RES-E (biomass and geothermal) depicted in Table 6 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. The possible feed-in of non-dispatchable energy sources such as wind or solar power depends on a specific day and hour (power distribution). The contribution of fluctuating RES-E to securely available capacities is shown in column "secured capacity". For wind, this factor is assumed to be 5 %, meaning that wind power generation amounting to at least 5 % of all installed wind plants running at full capacity, is firmly available. For photovoltaics a capacity credit of 0% is assumed due to the fact that peak demand in European countries is generally during winter time and at least in a part of the European countries during early evening hours. CSP technologies in contrast are modelled 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 6: TECHNO-ECONOMIC FIGURES FOR RENEWABLE ENERGIES

Technology	Net 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 liquid	30.0	85	85	85	30
Biomass solid	30.0	85	85	165	30
Biomass solid CHP	22.5	85	85	175	30
Concentrated solar power	-	-	40	120	25
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
Run-off-river hydropower	-	-	50	11.5	100
Wind onshore	-	-	5	41	25
Wind offshore	-	-	5	128	25

Source: EWI

The deployment of renewable capacities in Europe is exogenous in the analysed scenarios but generation of biomass, hydro, wind and solar plants is an endogenous decision in the model. Figure 3 shows the assumed development of RES-E capacities in Europe until 2050. Until 2020,

the scenarios consider the implementation of the published National Renewable Action Plans (NREAP). After 2020, a large deployment of wind (on- and offshore) mainly in Northern Europe and solar power (PV and CSP) in Southern Europe is assumed. Data for single countries can be found in the appendix.

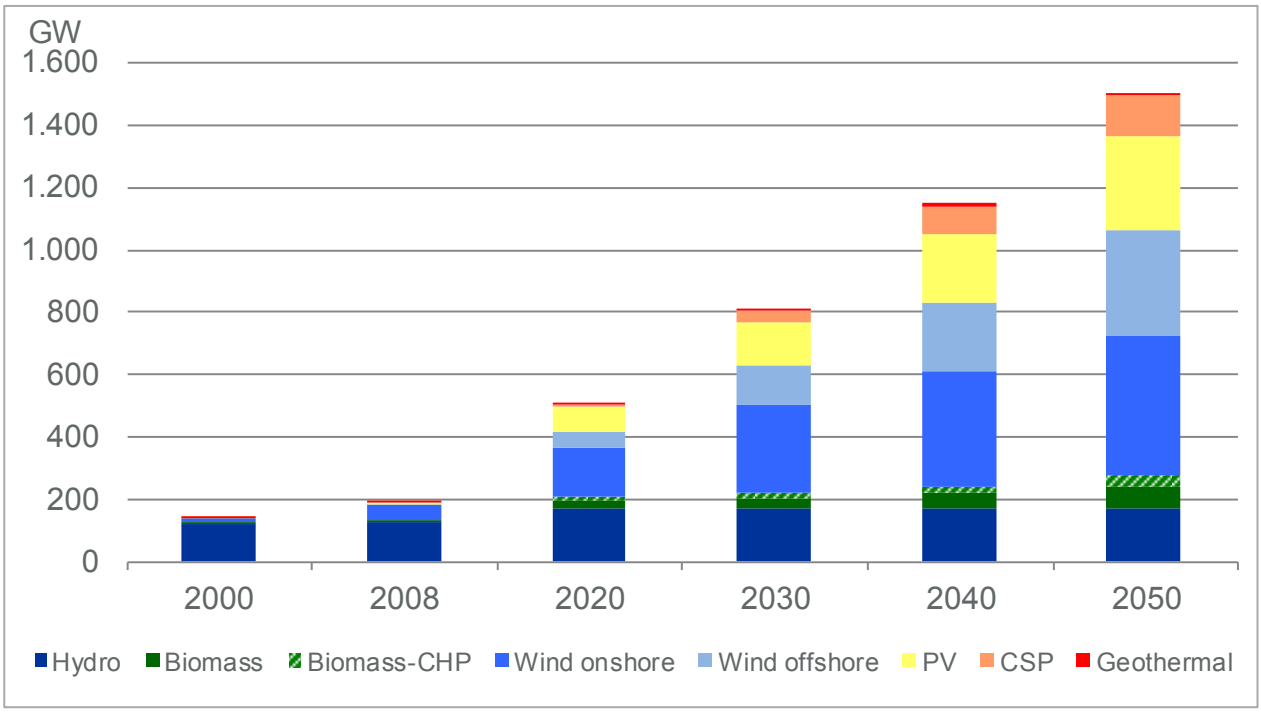

FIGURE 3: ASSUMED DEVELOPMENT OF RES-E CAPACITIES IN EUROPE UNTIL 2050 [GW]

Source: EWI

4.5 Economic and technical parameters of storages and demand side management

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 feed-in 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). The potential and the technical parameters of demand side management processes were determined and quantified for all European countries by applying the methods used in DENA (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 7 shows the

techno-economic parameters for storage technologies. The efficiency factor (net) of the turbine ($efficiency_{turbine}$) describes how much of the stored energy can be converted into electricity. The efficiency load factor ($efficiency_{load}$) 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 7 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 7. 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.

TABLE 7: TECHNO-ECONOMIC FIGURES FOR STORAGE TECHNOLOGIES

Technology	Net $efficiency_{turbine}$ [%]	Net $efficiency_{load}$ [%]	Volume fac. [-]	Availability [%]	Cap. credit [%]	Fix O&M [$€_{2010}$ /kWa]	Tech. lifetime [a]
Compressed air storage	86	81	8	95	50	9.2	40
Pump storage	87	83	26	95	80	11.5	100
Hydro storage	87	-	26	90	90	11.5	100

Source: EWI

Next to storage technologies, the model considers 28 different DSM processes differentiated per sector in each region. Table 8 gives an overview of all demand side management processes per sector. For each process technical figures and load characteristics as shown in Table 9 are assumed and similar processes aggregated. The criterion for aggregation is the balancing interval, i.e. the time in which the amount of demand reduction must equal the amount of demand increase including possible efficiency losses. Demand reduction and increase are subject to constraints, due to technical characteristics, current load, installed load or availability of a process.

TABLE 8: CONSIDERED DEMAND SIDE MANAGEMENT PROCESSES

Sector	Processes
Industry	aluminium-electrolysis, cement mills, paper machine, paper coating / calendaring, pulp refining, recycled paper treatment, electric arc furnace, chlorine-alkali-electrolysis (membrane), ventilation, compressed air
Service	medium and large water heaters (>30l), air conditioning, ventilation, cold storage houses, walk-ins / chillers / freezers
Domestic	refrigerator, freezer, washing machine, dryer, dish washer, medium and large water heaters (> 30 l), air conditioning, night storage heating, circulation pumps
Transport	e-mobility
Municipal	pumping, aeration
Others	heat pumps

Source: EWI

TABLE 9: TECHNICAL FIGURES FOR DEMAND SIDE MANAGEMENT

Technologies	Balancing interval [h]	Efficiency [%]	Availability [%]	Max. demand reduction [%]	Max. demand increase [%]	Cap. credit [%][1]
ventilation, compressed air, air conditioning, walk ins / chillers / freezers, refrigerator, circulation pumps, heat pumps	2	95	90	24-100	75-100	0
medium and large water heaters (> 30l), cold storage houses, freezer, pumping	4	95	90	100	50-100	2
dish washer	12	100	90	100	100	30
washing machine, dryer, night storage heating, e-mobility, aeration	24	100	90	25-100	25-100	30
aluminium-electrolysis, cement mills, paper machine, paper coating / calendaring, pulp refining, recycled paper treatment, electric arc furnace, chlorine-alkali-electrolysis (membrane)	8760	100	90	15-100	50	100

Source: EWI

[1] Considering uncertainty about deployment and usage of demand side management, the capacity credit increases over time and reaches this final values not until 2020 (industrial processes) or 2030 (all other processes).

In the scenarios, the development of DSM capacities is exogenously. The development is based on assumptions regarding the regulation or technical restrictions. Figure 4 shows the assumed development of DSM capacities per category (industry, service, domestic, transport, municipal and others) for Europe until 2050 in comparison to the technical potential in each year. A strong increase of DSM processes in the industry sector is assumed because technically energy-intensive industries can already provide short-term flexibility to the power sector.[1] The service and domestic sector are considered to develop more slowly and the installed DSM capacity will not to reach its full potential. The processes in the service and domestic sector are rather small and therefore less monetary gains can be achieved. Also, their utility might not be strictly a function of cost or profit but also of convenience. The technical and developed potential of e-mobility increases significantly until 2050.

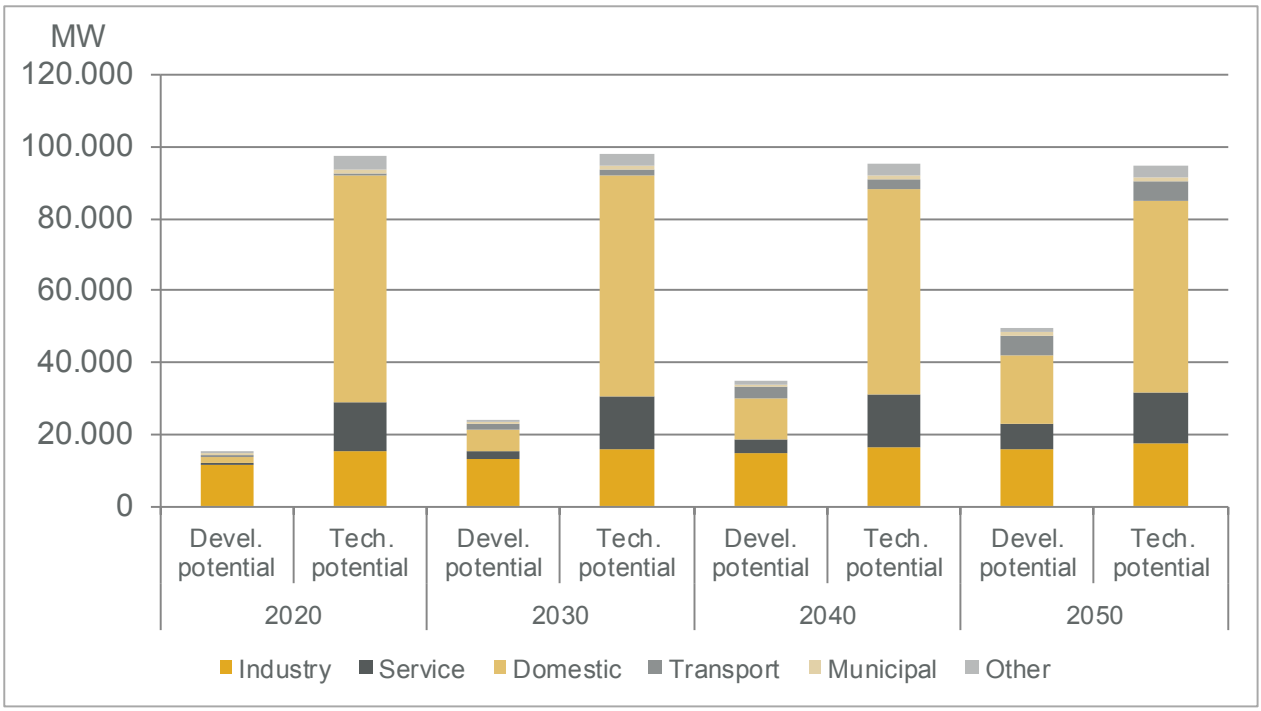

FIGURE 4: ASSUMED DEVELOPMENT OF DSM-CAPACITIES IN EUROPE UNTIL 2050 [MW]

Source: EWI

4.6 Development of the European electricity 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))

[1] Many energy-industries already offer balancing power.

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 the scenarios transmission grid capacities are strongly extended throughout Europe until 2050. The scenarios assume the deployment of the Ten Year Network Development Plan until 2050 (ENTSO-E, 2010). Figure 5 depicts the net transfer capacities between the modelled European regions in 2050.

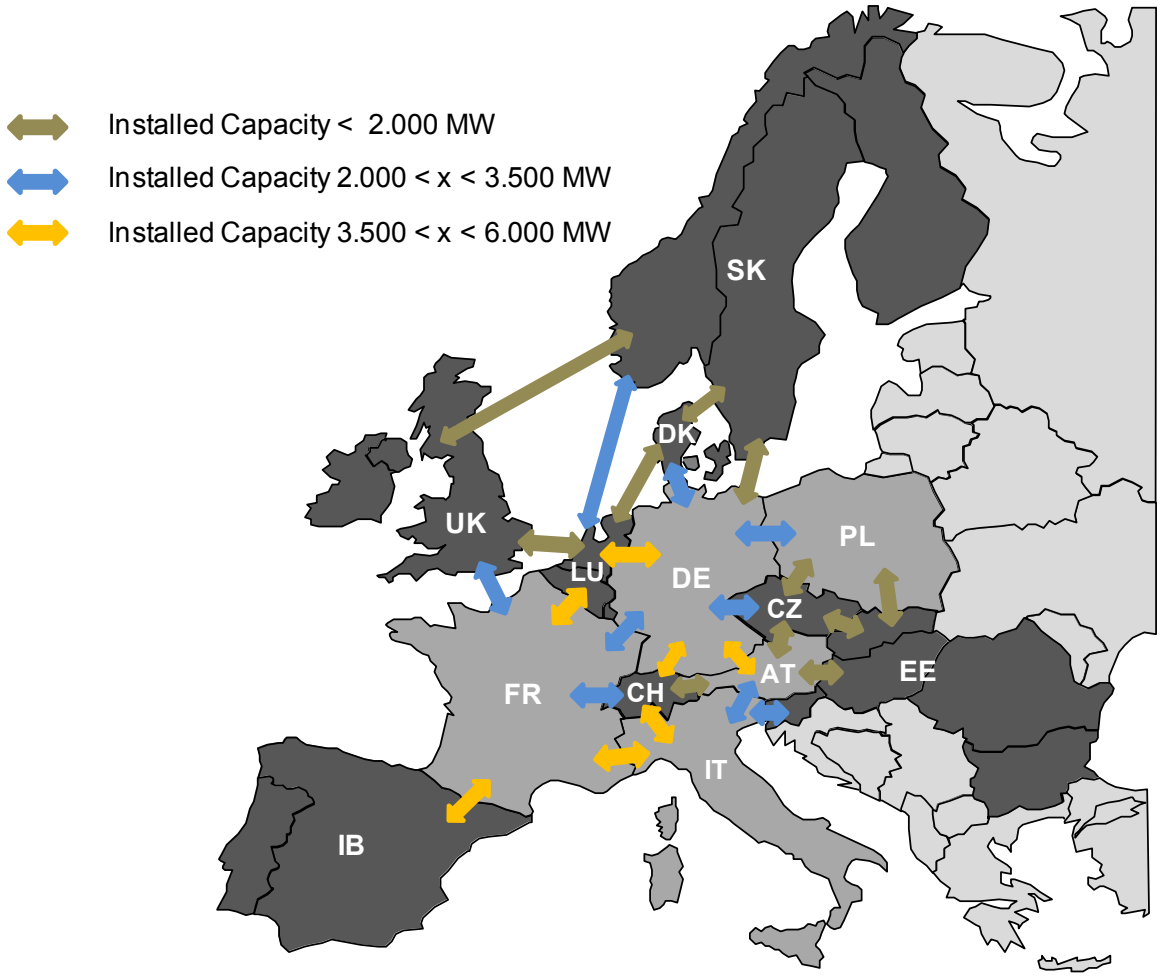

FIGURE 5: ASSUMED INSTALLED NET TRANSFER CAPACITIES BETWEEN EUROPEAN REGIONS IN 2050 [MW]

Source: EWI

4.7 Development of fuel prices

Assumptions on fuel prices are mainly based on the World Energy Outlook 2010 (IEA (2010a)), 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:

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.

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

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 labour costs (IEA (2010b)).

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. The future development of natural gas prices is highly uncertain – partly due to the exploration of shale gas in recent years. 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.

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 $€_{2010}/MWh_{th}$ in 2050.

Prices of **biofuels** (liquid, gaseous and solid) are defined country-specific thus accounting for the different potentials (as in section 4.4) 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 [€$_{2010}$/MWh$_{th}$]

	2008	2020	2030	2040	2050
Uranium	3.6	3.3	3.3	3.3	3.3
Lignite	1.4	1.4	1.4	1.4	1.4
Hard coal	17.3	13.4	13.8	14.3	14.7
Oil	44.6	99.0	110.0	114.0	116.0
Natural gas	25.2	28.1	31.3	33.2	35.2
Hydrogen	-	46.7	47.4	48.2	48.9
Bioliquid	53.2 - 94.3	57.1 - 101.1	61.8 - 109.4	61.8 - 109.4	61.8 - 109.4
Biogas	0.1 - 70.0	0.1 - 67.2	0.1 - 72.9	0.1 - 78.8	0.1 - 85.1
Biosolid	15.0 - 27.7	15.7 - 34.9	16.7 - 35.1	17.7 - 35.5	18.8 - 37.5

Source: EWI

4.8 Political assumptions

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

TABLE 11: CO_2 PRICE IN SCENARIO A AND B [€$_{2010}$/t CO_2]

[€$_{2010}$/t CO_2]	2020	2030	2040	2050
CO_2 price in Scenario A	22.6	31.8	40.9	50.0
CO_2 price in Scenario B	35.1	56.8	78.4	100.0

Source: EWI

[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 legally binding.

4.9 Flexibility requirement and options

The integration of renewable power generation requires a more flexible (positive and negative) power plant mix to balance the intermittent generation and demand. Electricity generation of wind turbines and solar systems depends on local weather conditions and therefore varies considerably from one hour to another. In particular, the generation from wind turbines can change quickly due to altering wind speeds. Given a large deployment of wind and solar capacities, the residual load structure (load subtracting fluctuating RES-E generation) is expected to be more volatile in future electricity systems. In addition to this hourly dispatch volatility, the availability of wind and solar power is stochastic and actual generation may differ from forecast values - even considering advanced forecast methods. In the analysis, we added an additional flexibility restriction so that the system has to be able to balance potential forecast errors of at least 10 % of expected wind and solar generation at all times. The quality of short-term prediction of wind and solar feed-in has increased in recent years due to improved forecast models.[1] However, relative forecast errors can still be significantly higher in single hours. However, several flexible technologies exist with different capital/operating cost structures, as well as technical restrictions, to facilitate the integration of intermittent technologies in the power system.

Positive flexibility options

In today's power systems, flexible technologies are already needed to balance electricity generation and changing electricity consumption. Moreover, power plant outages and demand forecast errors require sufficient short-term flexibility to achieve system stability. The majority of the required flexibility is currently provided by thermal power plants such as coal or combined cycle gas turbines which offer positive flexibility (within minutes) when operating in part-load. However, ramping processes of power plants - which are offline for more than 50 h (cold start) - require approximately 3-12 hours (depending on the technology) to fully ramp-up. The costs of offering flexibility depend on the specific characteristics, such as part-load efficiencies or fuel and CO_2 prices. An advantage of open cycle gas turbines is the ability to ramp up within 15-20 minutes from a cold start. As capital costs are relatively low compared to other thermal power plants, OCGT are ideal backup capacities. However, actual utilization costs are rather high as efficiency factors are substantially lower compared to combined cycle gas turbines. Naturally, storage technologies (e.g., pump storages, compressed air storages or batteries) are another option to quickly increase power generation in times with low renewable generation and high demand. However, storage technologies (with the exception of hydro storages) are usually not cost-efficient in today's power systems due to relatively high capital costs or low efficiency factors. Additionally, short-term flexibility could be provided by discontinuing the charging operation of storages to quickly meet electricity demand.

[1] As stated in ANEMOS (2011), relative forecast errors could be reduced on average from about 10 % in 2000 to 6 % in 2006 and further improvements were achieved in recent years.

Furthermore, the transition to flexible electricity demand could potentially play an important role in renewable power systems to balance electricity generation and demand. The characteristics and costs of demand flexibility strongly depend on the specific process (e.g., washing machine, e-mobility or industrial processes) in terms of capacity and potential interruption duration. Another option for providing flexibility is the installation of advanced CCS plants with a flexible CCS unit. By switching off their CCS units, these plants can provide additional generation on short notice (within 15 minutes). In renewable power systems, wind and solar power is curtailed when additional power generation cannot be integrated into the grid (e.g., situations with fully used cross border capacities and storages). In the case of negative forecast errors (less wind and solar power than expected), wind and solar capacities which reduced their generation based on the forecast (planned wind and solar curtailment) are able to increase their generation.

Negative flexibility options

Equivalent to the requirement of positive flexibility, negative flexibility is needed in power systems to scope with peaks of wind and solar generation. Due to negligible variable costs, wind and solar technologies feed into the grid when available and as a result conventional power plants need to ramp down. In the case of positive forecast errors (actual exceeds expected generation) of wind and solar power, the power plant mix has to be flexible enough to quickly adjust its generation. Operating thermal power plants (online plants) offer negative flexibility as their power output can be reduced, considering their specific characteristics. Other options are charging storages or increasing demand in DSM processes. Another cost-efficient option of providing negative flexibility can be the curtailment of wind and solar generation.[1] From a system perspective, it is cost-efficient to curtail wind and solar generation to achieve system stability or when total system costs can be reduced by lowering ramp-up costs of thermal power plants. Naturally, ramping down thermal power plants (if possible, within technical restrictions) is cheaper than wind or solar curtailment due to the reduction of fuel costs.

[1] The power generation by wind turbines can be quickly reduced by turning the blades (e.g., pitch control).

Table 12 lists potential positive and negative dispatch and short-term flexibility options for power systems.

TABLE 12: DISPATCH AND SHORT-TERM FLEXIBILITY OPTIONS.

positive	negative
Ramping of thermal power plants in part load operation	Thermal power plants in operation (ramping down)
Open cycle gas turbines able to start operation within 15-20 minutes	Storage technologies
Utilization of stored energy or stop of storage	Curtailment of wind power
Shifting through demand side management (reduction)	Shifting through demand side management (increase)
Utilization of previously curtailed wind power	
Switching off CCS unit to increase power output	

Source: EWI

5 SCENARIO RESULTS

In this chapter, selected results of the scenario analysis are presented. Section 5.1 provides an overview of the European electricity system development in both scenarios until 2050. It describes the development of capacities, electricity generation, RES-E curtailment, utilization times, import and export flows as well as CO_2-emissions in the power sector. Detailed numerical data can be found in the appendix. In section 5.2, the role of flexible resources in mainly renewable power systems is discussed. The changes of necessary flexibility due to a higher share of renewables are analysed. Regional dispatch realizations as well as flexibility options to balance possible forecast errors of wind and solar generation provide insight to a cost-efficient integration of fluctuating renewable energies. Based on the scenario results a cost-based ranking of flexible resources is provided in section 0. Finally, potential revenues and profits of flexible resources are estimated.

5.1 Overview of the electricity system development in Scenario A and B

5.1.1 Capacities, generation and utilization rates

- Capacities –

Figure 6 depicts the gross electricity capacities in Scenario A (left side) and in Scenario B (in comparison to Scenario A on the right side) for the years 2020, 2030, 2040 and 2050. As can be seen the capacity mix changes significantly – large deployment of renewables and decreasing base-load capacities - in both scenarios until 2050. The numerical data (net capacities) per country can be found in the appendix.

- Capacity mix changes profoundly in both scenarios until 2050.
  Due to the assumed RES-E deployment in the scenarios, the share of RES-E capacities increases 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 2030. The capacity of base- and mid-load plants decreases over time as fewer full load hours are achieved by these technologies. Also, the integration of fluctuating renewables requires more flexible technologies. Hence, the share of gas-fired capacities (open and combined cycle) serving as flexibility options and backup capacities increases.

- Total installed capacity more than doubles until 2050.
  Due to the low secured capacity of intermittent renewable technologies and an assumed increasing electricity demand, total gross capacity more than doubles by 2050.

- Higher CO_2 prices in Scenario B lead to more nuclear and CCS capacities.
  Nuclear plants are installed instead of coal power plants in Eastern Europe (1.5 GW in 2030), BeNeLux (4 GW in 2030) and the Czech Republic (1.5 GW in 2030). In France nuclear plants are built instead of gas-fired power plants (4 GW in 2030). The high CO_2 price leads to earlier and significantly larger investments in CCS plants. In 2030, additionally 30 GW of coal and gas-fired power plants are equipped with CCS units (Total capacity equipped with CCS in Scenario B – 2030: 80 GW and 2050: 94 GW).

- Given higher CO_2 prices in Scenario B, the value of electricity storage options increases (even more) to prevent curtailment of renewables.
  In Scenario A storage is already intensely used to prevent curtailment of renewables and therefore deployed in UK (13 GW in 2050), BeNeLux (2.5 GW in 2050) because of the large amounts of negative residual load. A higher CO_2 price increases the value of electricity as generation costs of fossil fuel based technologies are higher. Therefore, wind and solar curtailment is associated with higher costs and additional storage technologies are cost-efficient in Scenario B. These storage capacities are mainly deployed in UK (2 GW in 2050), BeNeLux (1 GW in 2050) and Poland (1 GW in 2050) to integrate the fluctuating wind power.

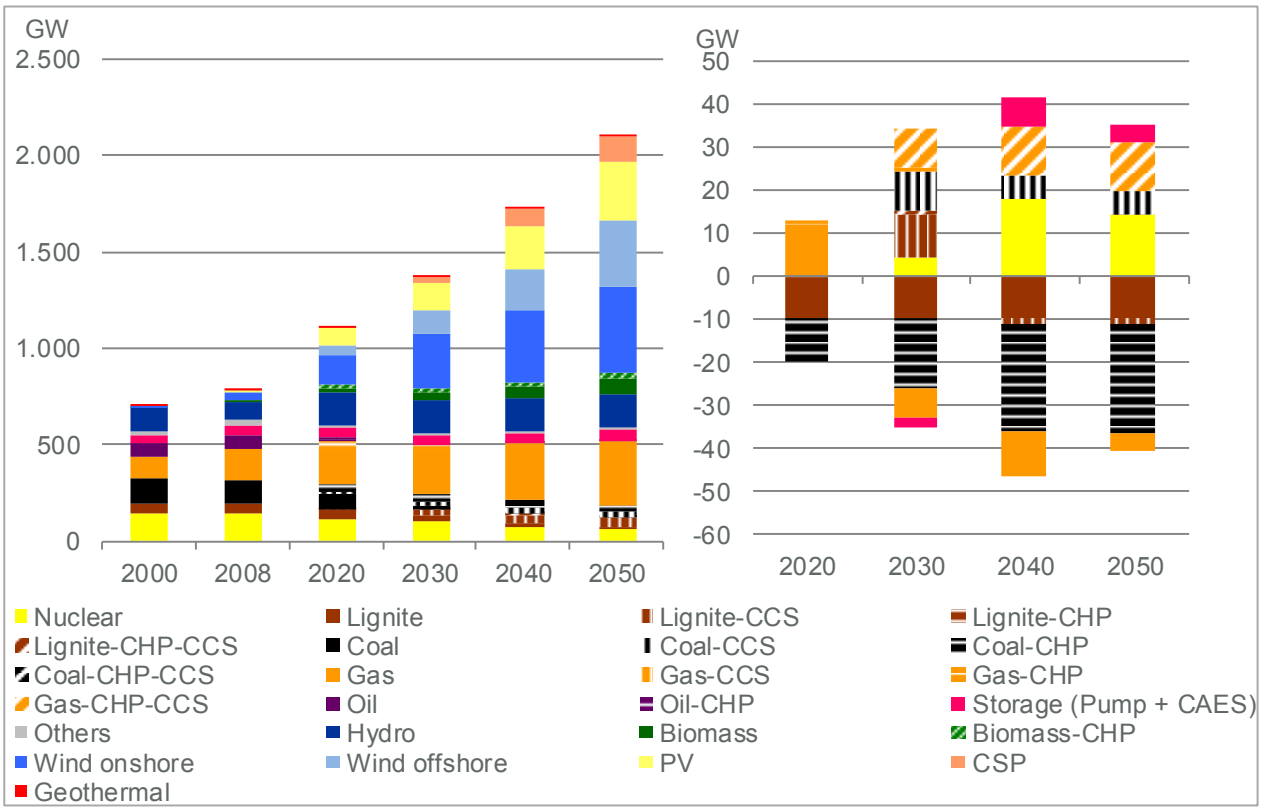

FIGURE 6: EUROPEAN GROSS CAPACITY MIX DEVELOPMENT UNTIL 2050 [GW]

IN SCENARIO A (LEFT) AND SCENARIO B (RIGHT)

Source: EWI

- Electricity generation –

Figure 7 depicts the gross electricity generation in Scenario A (left side) and in Scenario B (in comparison to Scenario A on the right side) for the years 2020, 2030, 2040 and 2050. In 2050 about 75 % of the gross electricity demand is provided by renewable energies. The numerical data (net generation) per countries can be found in the Appendix.

- RES-E share on gross electricity demand increases from 34 % in 2020 to 54 % in 2030 and to 75 % in 2050.

  In the short term (until 2020), hydro power (39 % of RES-E generation) and onshore wind (26 % of RES-E generation) are the most important renewable energy sources. Due to the assumed large deployment of on- and offshore wind turbines, more than 50 % of the renewable energy is provided by wind power in 2050. Solar technologies – mainly deployed in Southern Europe – generate about 22 % of the renewable energy.

- Higher CO_2 prices in Scenario B lead to a coal-to-gas switch supplemented by additional biomass generation in the short term (2020).
  In 2020, about 200 TWh of electricity are generated in combined and open cycle gas turbines instead of hard coal and lignite power plants. This includes 60 TWh of electricity generation in gas-fired CHP plants.

- Due to CO_2 prices of 100 €/ t CO_2 in Scenario B in 2050, almost all conventional generation takes place in nuclear or fossil power plants equipped with CCS in the long term.
  In Scenario B more than 470 TWh of electricity are generated in coal and gas-fired power plants equipped with CCS units in 2050. Some gas-fired power plants mainly installed to secure electricity supply with fewer full load hours operate without CCS units.

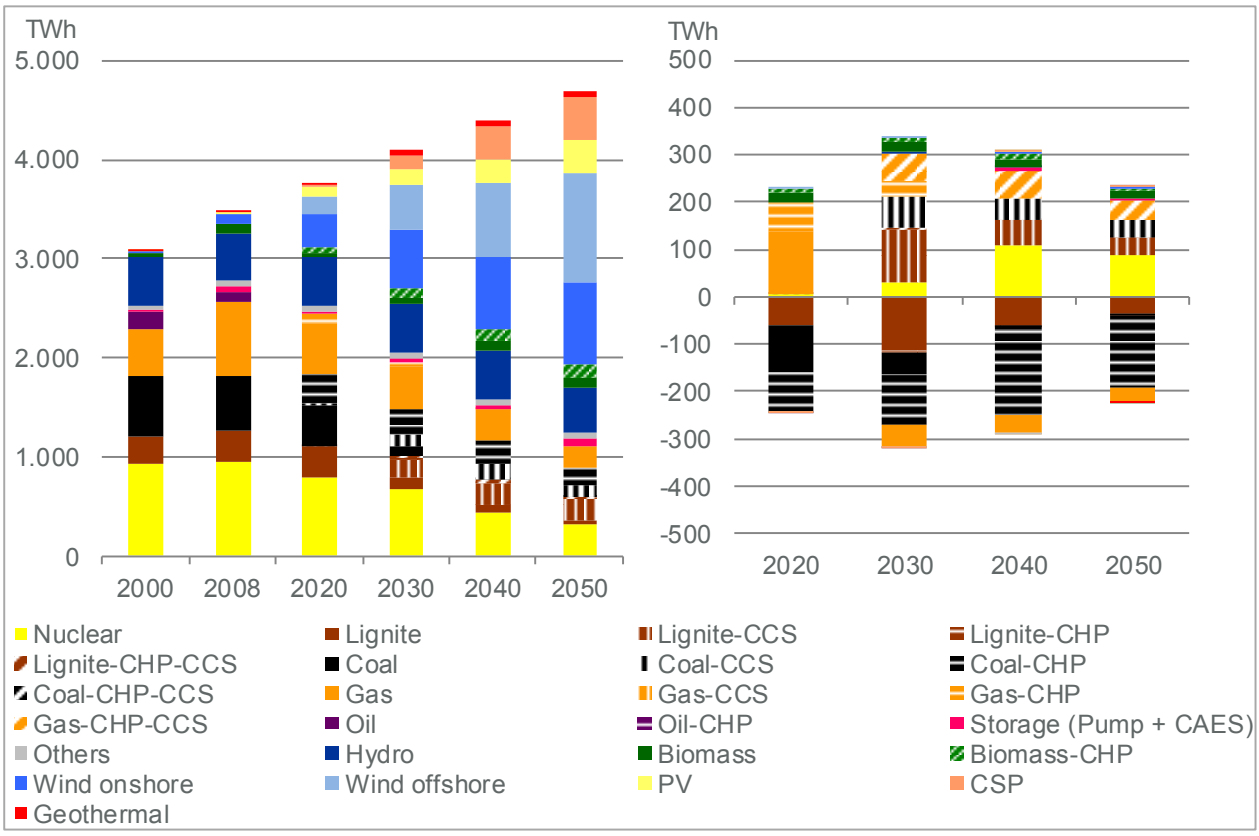

FIGURE 7: EUROPEAN GROSS ELECTRICITY GENERATION DEVELOPMENT UNTIL 2050 [TWh] IN SCENARIO A (LEFT) AND SCENARIO B (RIGHT)

Source: EWI

- RES-E curtailment –

Figure 8 depicts the amount of wind (on- and offshore) and PV curtailment in Scenario A (left side) and in Scenario B (in comparison to Scenario A on the right side) for the years 2020, 2030, 2040 and 2050. Wind and solar power are curtailed when not needed due to low demand, filled

storages and restricted transfer capacities or when total system costs can be reduced due to lower ramping costs of thermal power plants.

- Wind and solar curtailment is cost-efficient – especially in electricity systems with a high share of fluctuating RES-E.

  Marginal integration costs of fluctuating RES-E rise due to more costly dispatchable capacities in the system. More than 140 TWh of possible wind and solar generation which represents about 7 % of total wind and solar generation are curtailed in both scenarios in 2050: onshore wind mostly in UK (70 TWh) and Poland (12 TWh); offshore wind in UK (34 TWh), BeNeLux (5 TWh) and Denmark (4.5 TWh). Solar power is curtailed in France (3 TWh), Germany (2.7 TWh) and Poland (2 TWh).

- Additional storage capacities are cost-efficient in Scenario B.

  Due to higher CO_2 prices, the value of electricity generation is higher in Scenario B, due to higher variable costs of generation. Hence, the cost of wind and solar curtailment are higher and therefore some additional storage capacities are cost-efficient. Additional 4 GW of storage capacities (mainly in UK, BeNeLux and Poland) allow the usage of about 4-6 TWh additional wind power.

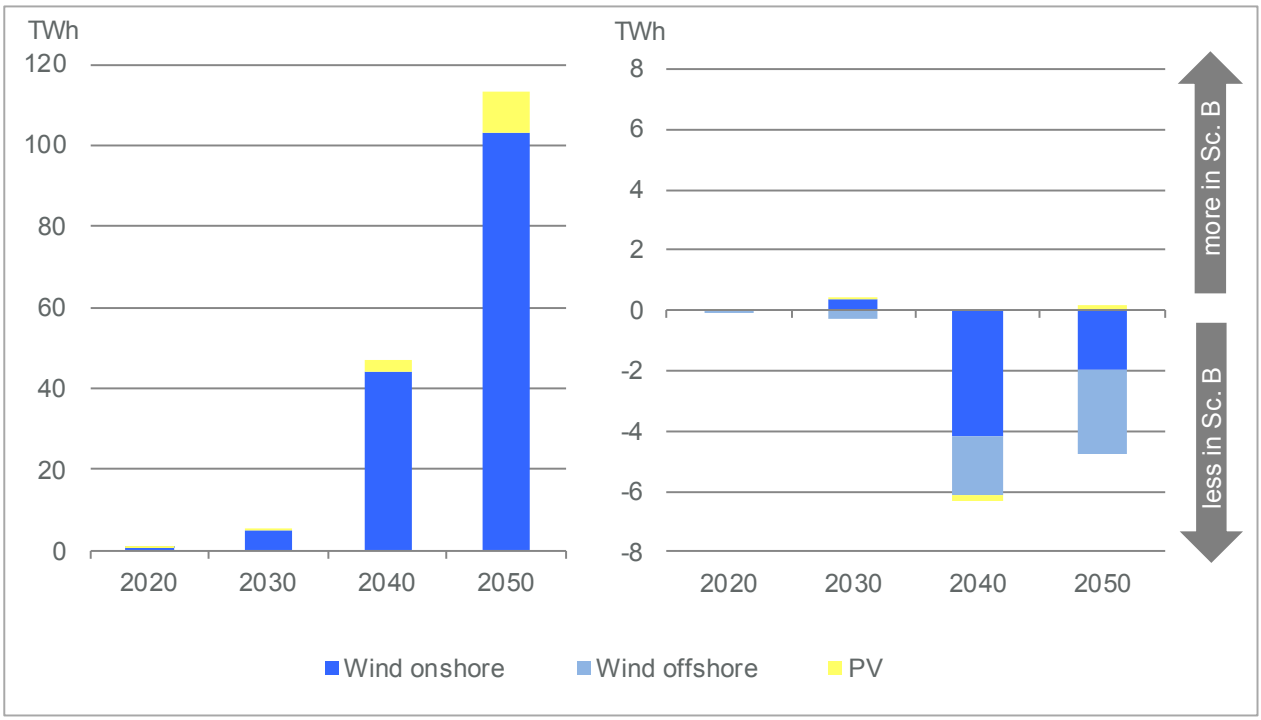

FIGURE 8: TOTAL EUROPEAN RES-E CURTAILMENT IN 2020, 2030, 2040 AND 2050 [TWh] IN SCENARIO A (LEFT) AND SCENARIO B (RIGHT)

Source: EWI

- Utilization –

Figure 9 depicts the European average utilization rates (full load hours) for nuclear and conventional power plants in Scenario A (left side) and in Scenario B (in comparison to Scenario A on the right side) for the years 2020, 2030, 2040 and 2050. Full load hours of renewable and storage technologies are shown in Figure 10.

- Utilization rates of all conventional power plants decrease over time in both scenarios.
  Apart from maintenance services, nuclear plants operate for more than 7000 hours at full load in 2020. However, the utilization rate decreases until 2050 to about 5000 operating hours at full capacity. Similar effects can be observed for lignite CCS and hard coal plants due to the further deployment of renewable energies.

- Higher CO_2 prices in Scenario B result in higher utilization rates of gas and biomass-fired plants in 2020.
  As CCS units are assumed to be not available in 2020, higher CO_2 prices in Scenario B lead to a coal-to-gas switch and additionally a higher utilization of biomass capacities with relatively high fuel costs (compared to other biomass resources).

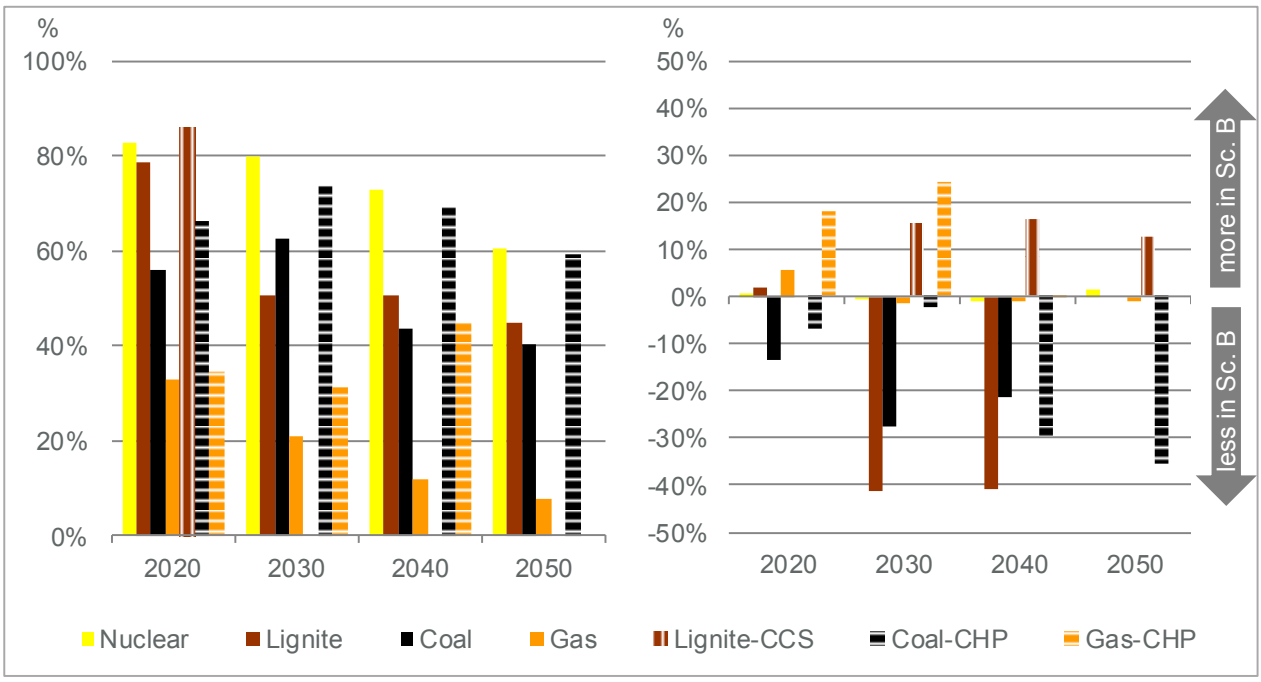

FIGURE 9: EUROPEAN AVERAGE UTILIZATION RATES OF NUCLAER AND CONVENTIONAL POWER PLANTS [%] (LEFT SCENARIO A AND RIGHT SCENARIO B)

Source: EWI

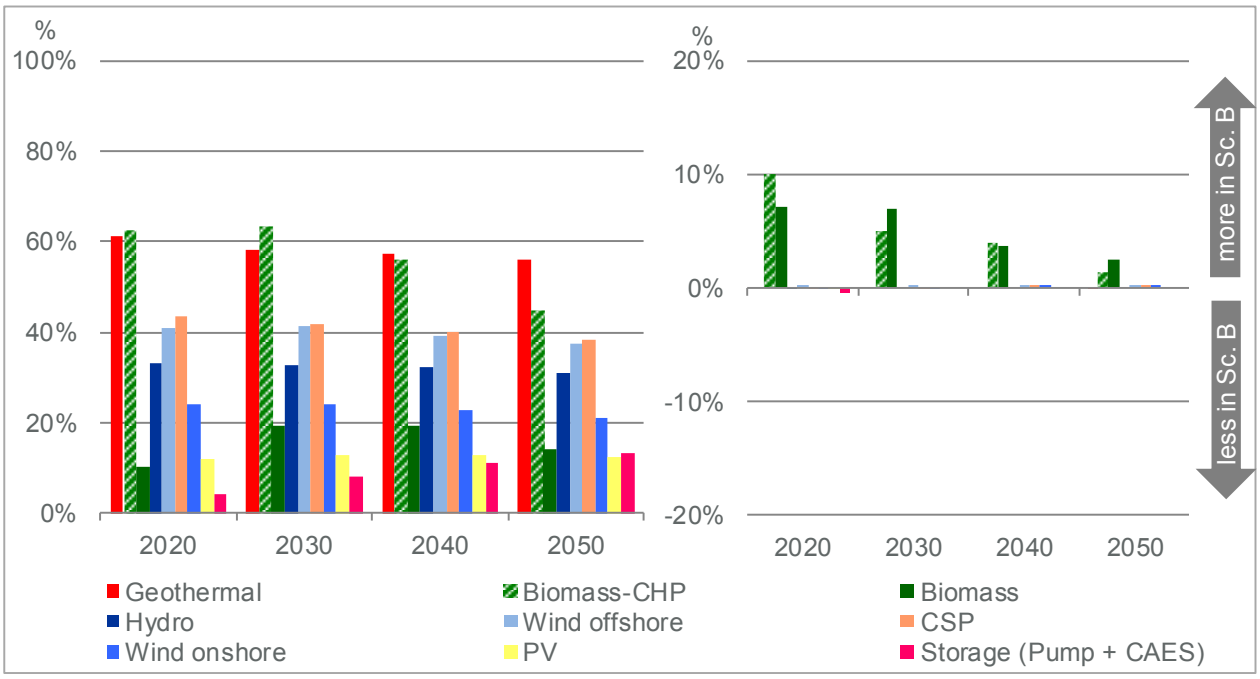

FIGURE 10: EUROPEAN AVERAGE UTILIZATION RATES OF RENEWABLE AND STORAGE CAPACITIES [%] (LEFT SCENARIO A AND RIGHT SCENARIO B)

Source: EWI

5.1.2 European trade flows

Figure 11 depicts European import and export trade flows in Scenario A for the years 2020 and 2050 (Scenario B in Figure 12). Trade flows occur when they contribute to the overall cost-minimizing solution, e.g. because a plant with lower variable costs can be dispatched in a neighbouring country. The colour patterns indicate whether a country is a net-importing, net-exporting or self-sufficient country (defined as a country with yearly net imports in a range of +/- 10 % of gross electricity demand).

- France and the Czech Republic are large exporters in both scenarios.
  France and the Czech Republic are well connected through net transfer capacities to their European neighbours. Due to the availability of nuclear power in both countries and lignite in the Czech Republic, these countries become large exporters.

- Higher CO_2 prices in Scenario B have little impact on import and export flows.
  As RES-E capacities are exogenous in both scenarios, renewable deployment does not react to the higher CO_2 prices. Considering the conventional power mix, higher CO_2 prices substantially change the optimal capacity mix but only to a small extent the spatial distribution. Hence, differences between net imports in Scenario B to Scenario A are lower than 5 TWh.

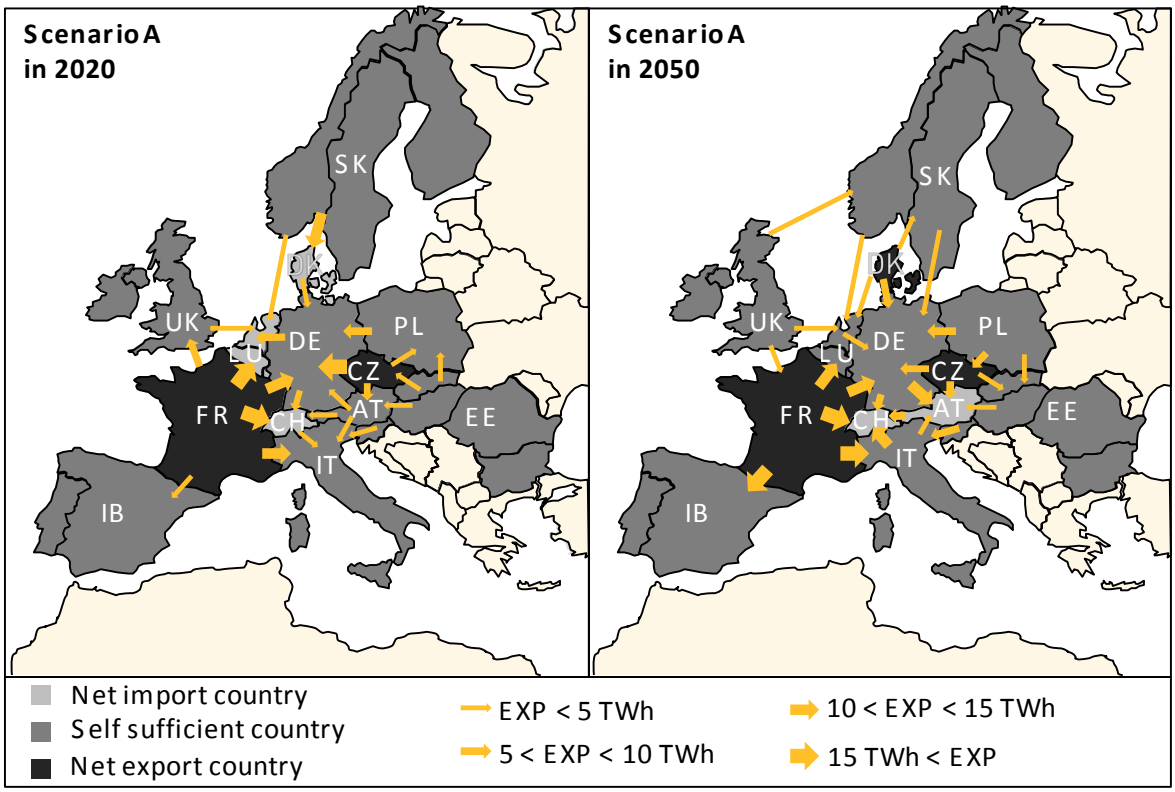

FIGURE 11: EUROPEAN IM- AND EXPORT STREAMS IN 2020 AND 2050 (SCENARIO A) [annual TWh]

Source: EWI

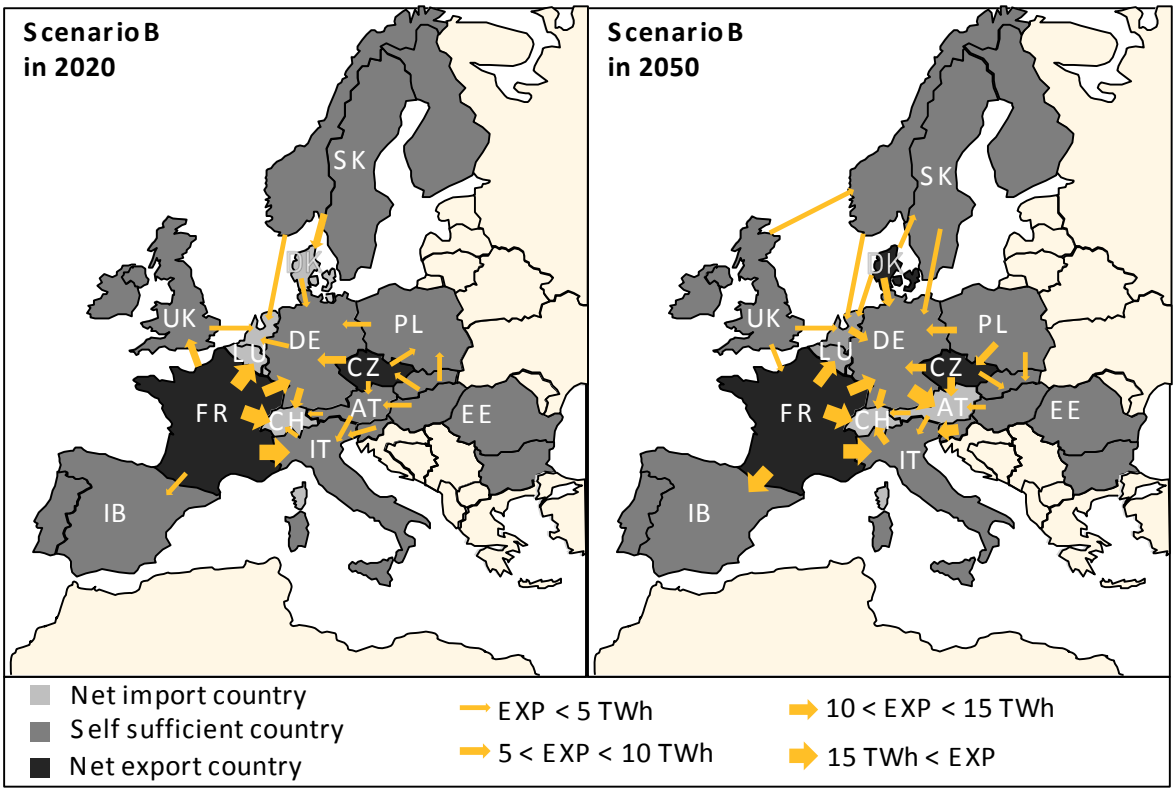

FIGURE 12: EUROPEAN IM- AND EXPORT STREAMS IN 2020 AND 2050 (SCENARIO B) [annual TWh]

Source: EWI

5.1.3 CO_2 emissions in the electricity sector

Figure 13 depicts the CO_2 emissions in the power sector in Scenario A (left side) and in Scenario B (in comparison to Scenario A on the right side) for the years 2020, 2030, 2040 and 2050. Figure 13 also shows the CO_2 reductions compared to the EU 1990 level (shown on the right axis). Figure 14 depicts the captured and stored CO_2 in CCS plants throughout Europe.

- Compared to 2008, CO_2 emissions increase slightly to 2020 but are substantially reduced after 2020.
  Mainly because of the assumed increasing electricity demand in Europe (section 4.1), more CO_2 is emitted in 2020 than today. Given the assumed RES-E deployment, CO_2 prices (22.6 €$_{2010}$/t CO_2) and the development of fossil fuel prices (gas and coal) the political target of 20 % CO_2 emission reduction compared to 1990 levels is not reached. Also, CCS is not an option based on the assumption that CCS is not available in 2020. After 2020, CO_2 prices increase further, more RES-E capacities are deployed and CCS becomes an option to avoid CO_2 emissions.

- About 5 % of the CO_2 emission reduction (2020-2050) is achieved by CCS units in lignite and hard coal power plants.
  Starting from 2030 about 20-30 mio. t CO_2 are yearly captured in CCS plants and stored underground.

- Higher CO_2 prices in Scenario B set strong incentives to reduce CO_2 emissions already in 2020.
  In 2020 the assumed CO_2 price of 35.1 €$_{2010}$/t CO_2 leads to fewer emissions (150 t CO_2) than in Scenario A. Compared to the level in 1990, 12.5 % reduction is achieved given the assumed scenario setting. To actually achieve the political target of 20 % reduction compared to 1990, CO_2 prices in the rage of 50-60 €$_{2010}$/t CO_2 would be needed (given the scenario setting).

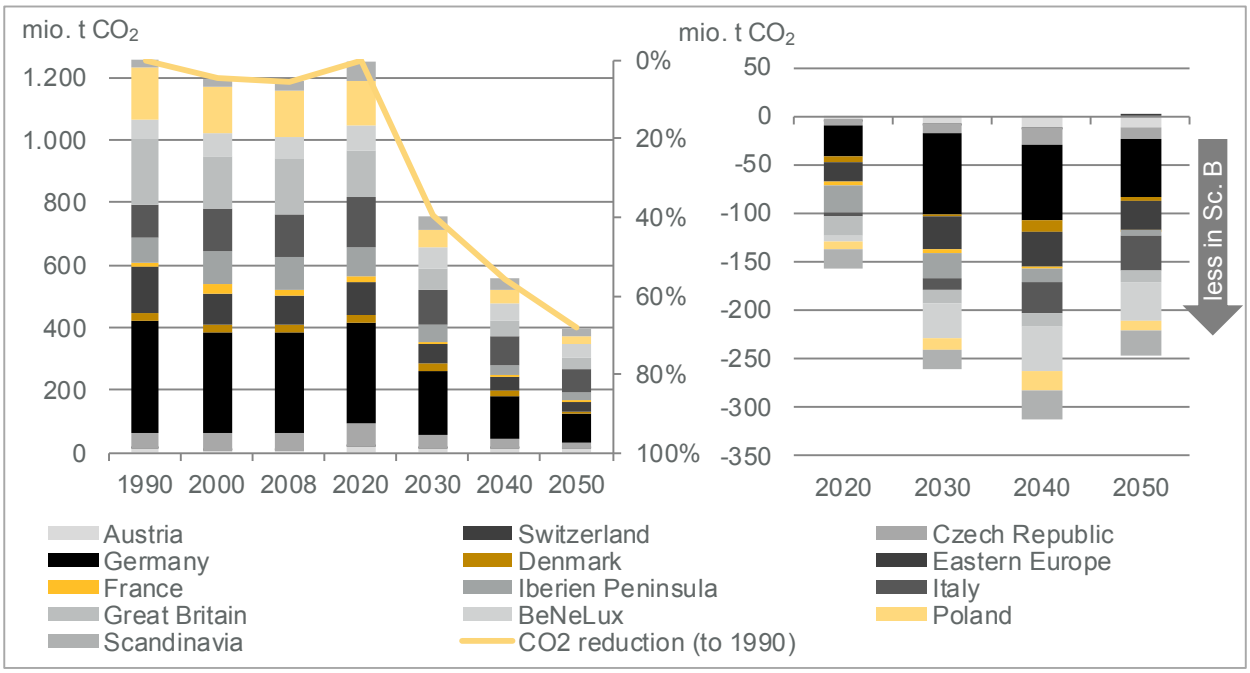

FIGURE 13: CO_2 EMISSIONS IN THE ELECTRICITY SECTOR PER REGION [mio. t CO_2]

(LEFT SCENARIO A AND RIGHT SCENARIO B)

Source: EWI

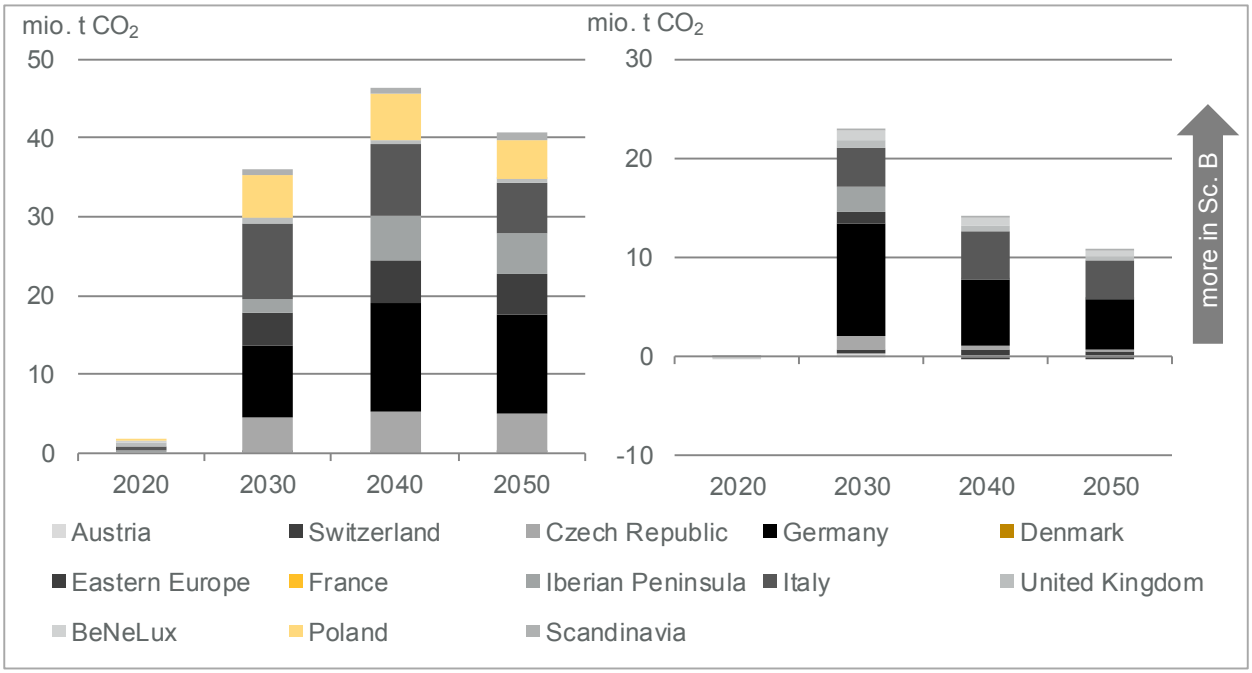

FIGURE 14: ABATEMENT OF CO_2 EMISSIONS THROUGH CCS UNITS [mio. t CO_2]

(LEFT SCENARIO A AND RIGHT SCENARIO B)

Source: EWI

5.1.4 Investments in conventional, renewable and storage technologies

Figure 15 depicts investments in conventional, renewable and storage capacities in Europe in Scenario A (left side) and in Scenario B (in comparison to Scenario A on the right side) for the next decades: 2010-2020, 2020-2030, 2030-2040 and 2040-2050.

- Due to the assumed deployment of renewable energies, large investment costs in RES-E capacities are incurred (same investments in both scenarios).
  Until 2050, more than 2,900 bn. €2010 investments in renewable capacities are needed to achieve the assumed deployment of RES-E capacities (in both scenarios).

- Higher CO_2 prices in Scenario B lead to larger investments in CCS plants in 2030. In the short term investments are hold off.
  Higher CO_2 prices set a strong incentive to invest in CCS plants. As CCS technologies are assumed to be available from 2030, investments are held off in 2020. In the long term additional storage investments take place.

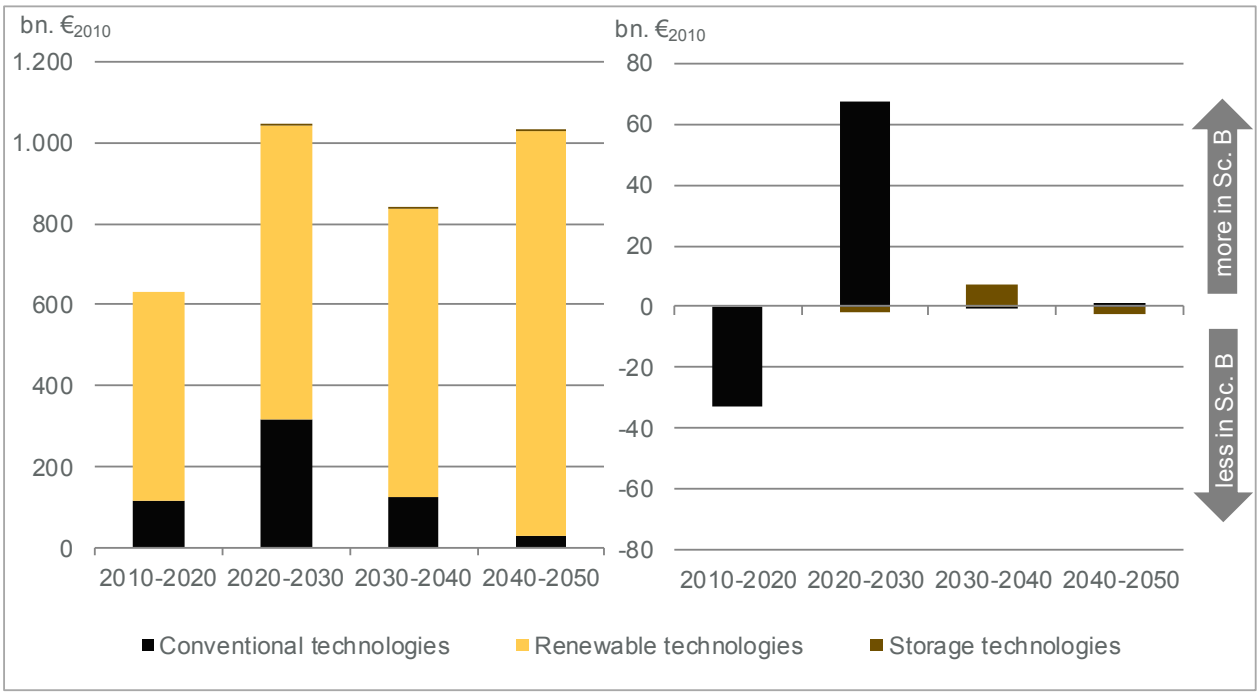

FIGURE 15: EUORPEAN INVESTMENT EXPENDITURES UNTIL 2050 [bn. €2010]

(LEFT SCENARIO A AND RIGHT SCENARIO B)

Source: EWI

5.2 The role of flexible resources in renewable power systems

In this section, the role of flexibility options is discussed in four steps: In the first step, we concentrate on the regional residual load (electricity load subtracting renewable generation) that has to be met by conventional power plants, storages, demand side management and electricity exchange between regions. The analysis shows that the residual load becomes more volatile due to the large deployment of fluctuating renewables. Thus, it becomes more challenging to meet electricity demand at all times. In the second step, we analyse the cost-efficient utilization of conventional power plants, storages, imports and exports, as well as RES-E curtailment to realise the dispatch of generation and demand – yet considering more extreme situations such as low wind availability and high demand. In the third step, an approach to develop a merit order of flexible resources is discussed. In the last step, the potential revenues of flexibility options, as well as the effects on revenues of locked-in power plants, are discussed.

5.2.1 Flexibility requirements: Volatility of electricity generation and demand

It is important to note that the residual load is defined as the regional electricity demand after subtracting the potential generation of renewable technologies. Thus, several balancing options are not considered, such as the utilization of storages, RES-E curtailment, imports and exports between regions. In particular, imports and exports play an important role (as discussed in Section 5.1) due to the large deployment of wind and solar technologies at the best European sites in combination with substantial cross-border extensions until 2050. First, we concentrate on the residual load duration curve of different regions to understand the challenges (e.g., ratio between peak and low demand) of a large deployment of renewables in the power sector. Second, we analyse the potential magnitude of (residual) electricity demand changes from one hour to another. The analysis indicates the extent of which flexible technologies (as well as dispatch management such as RES-E curtailment) are needed to balance generation and demand.

5.2.1.1 Development of the residual load duration curve

- Level of residual load –

By increasing the share of renewables in the European power system, the size and structure of the residual load changes, requiring generation from conventional and storage technologies. In this section, the need to provide flexibility in mostly renewable based power systems is shown by analysing the developments of residual load structures and the volatility of hourly changes within the residual load. Figure 16 to Figure 19 show the load duration curves for 2020 and 2050, i.e. the duration of particular load levels of the residual demand. For improved visualisation, the

load duration curves are separated by countries with a maximum residual load greater or less than 40 GW. The figures are the same for both scenarios, as identical development of renewables and load structures are assumed.

- The shape of the residual load duration curve changes up until 2050.
  Residual load duration curves for 2020 are rather flat with a slight negative slope. Therefore base and mid-load plants with relatively low variable costs are able to achieve a higher number of full load hours. In 2050, the slope level is steeper for countries with a high share of renewables. Due to the stochastic generation of wind and solar technologies, the residual load duration curve is not as smooth compared to today for countries with a large renewable share (e.g., United Kingdom in Figure 19). However, the shape of the residual load curve for the Iberian Peninsula and for Italy in 2050 is similar to the curves in 2020 due to their high shares of CSP generation. CSP smoothes residual load by utilization of its thermal storage and reduces the effects of fluctuating generation. As the potential for renewable energies is unequally distributed among Europe, countries in Northern Europe (wind power) and Southern Europe (solar power) become large exporters and countries in Central Europe import a substantial share of the electricity consumed. Thus, many hours exist with a negative residual load in countries with large wind and solar capacities.[1]

- Backup capacities are needed as high residual loads still occur in 2050.
  Due to an increase in overall demand (assumption) and low feed-in of renewables during certain hours, situations with high residual load still exist in 2050. The overall spreads of extreme values of residual load widen, e.g. for France the spread in 2050 is 140 GW, ranging from around -40 GW to +100 GW (+20 GW to +90 GW in 2020). This leads to the need for backup capacities or storages to cover the electricity load during peak hours, although these peak capacities are likely to realise only a few full load hours.

[1] The residual load curves shown in Figure 16 to Figure 19 are not adjusted for imports and exports.

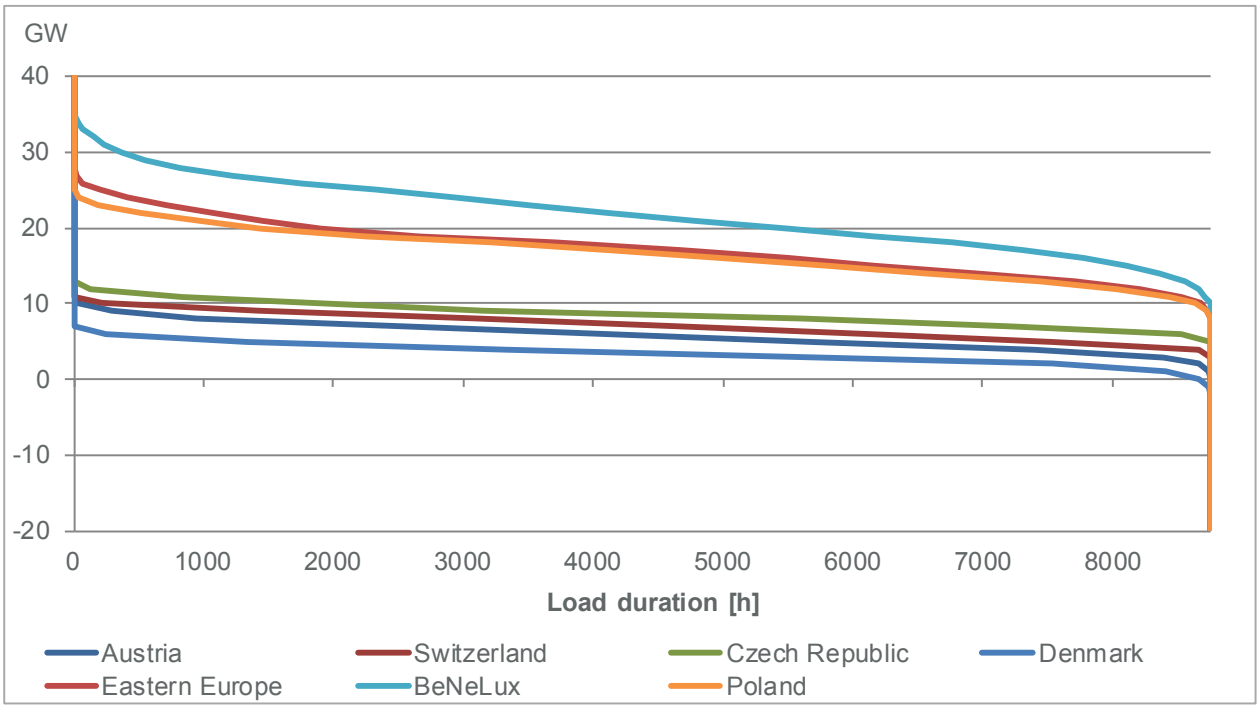

FIGURE 16: RESIDUAL LOAD DURATION CURVE IN 2020 (COUNTRIES LESS THAN 40 GW) [GW]

Source: EWI

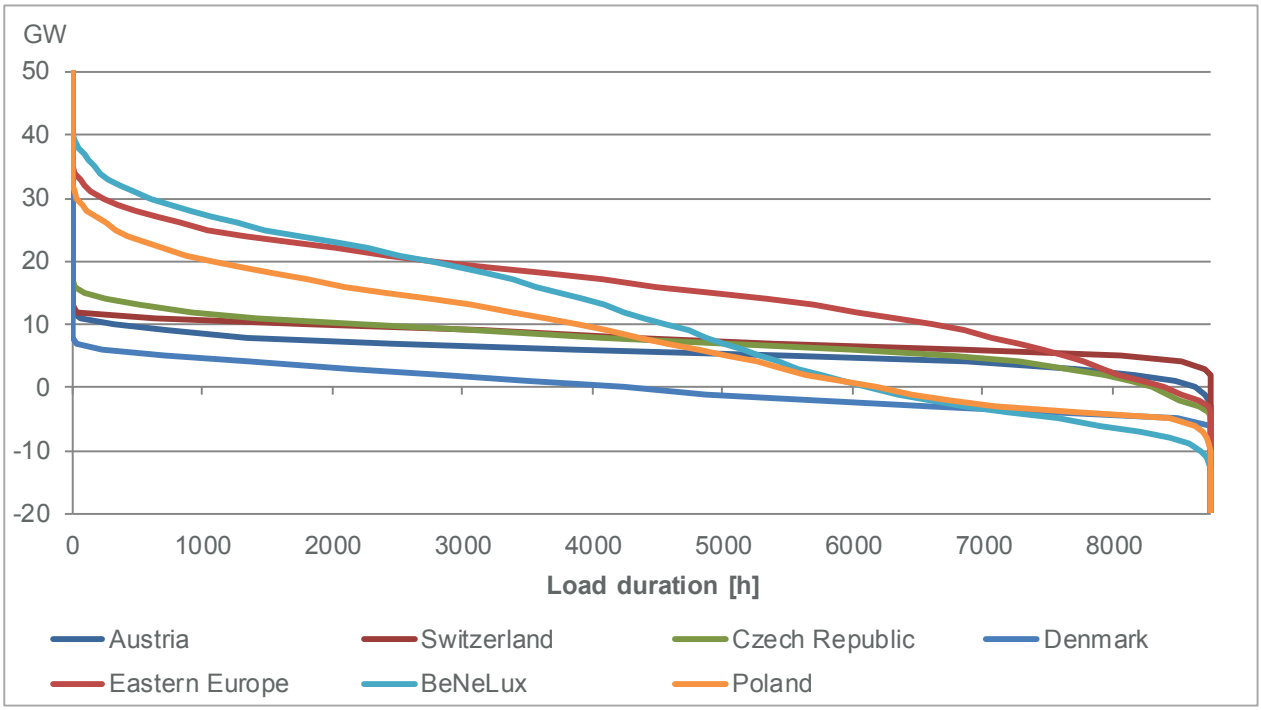

FIGURE 17: RESIDUAL LOAD DURATION CURVE IN 2050 (COUNTRIES LESS THAN 40 GW) [GW]

Source: EWI

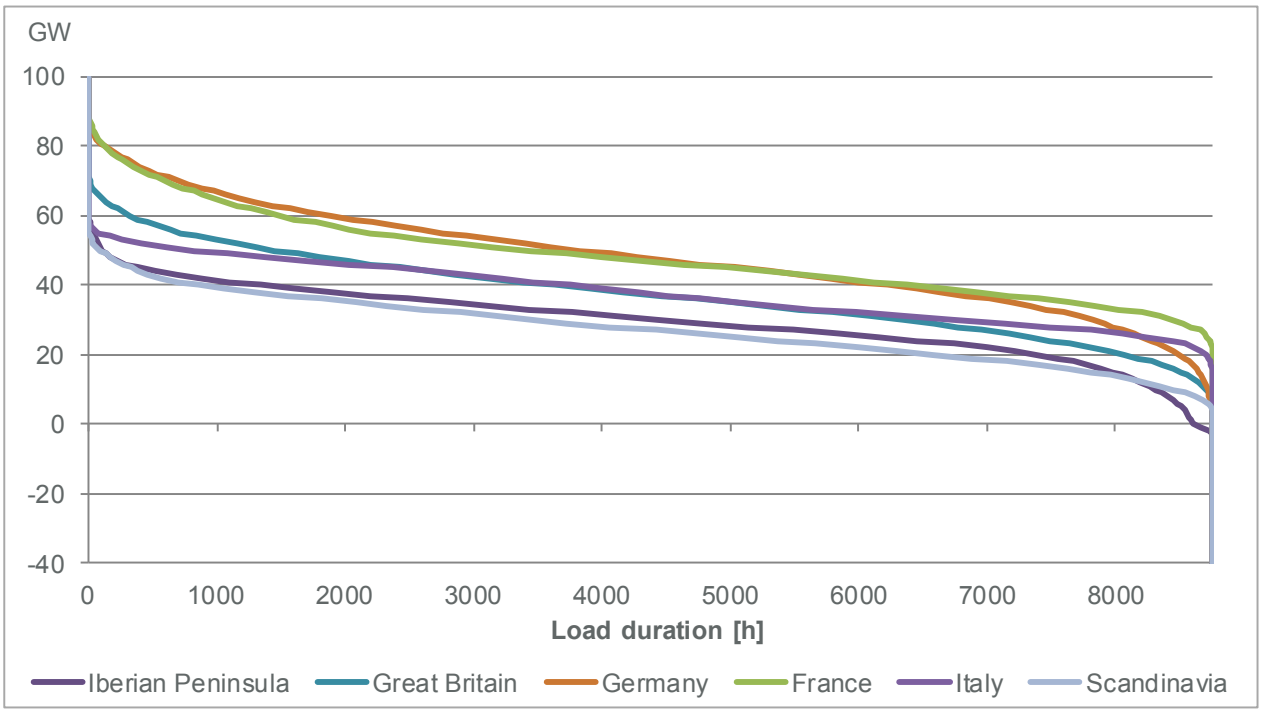

FIGURE 18: RESIDUAL LOAD DURATION CURVE IN 2020 (COUNTRIES GREATER THAN 40 GW) [GW]

Source: EWI

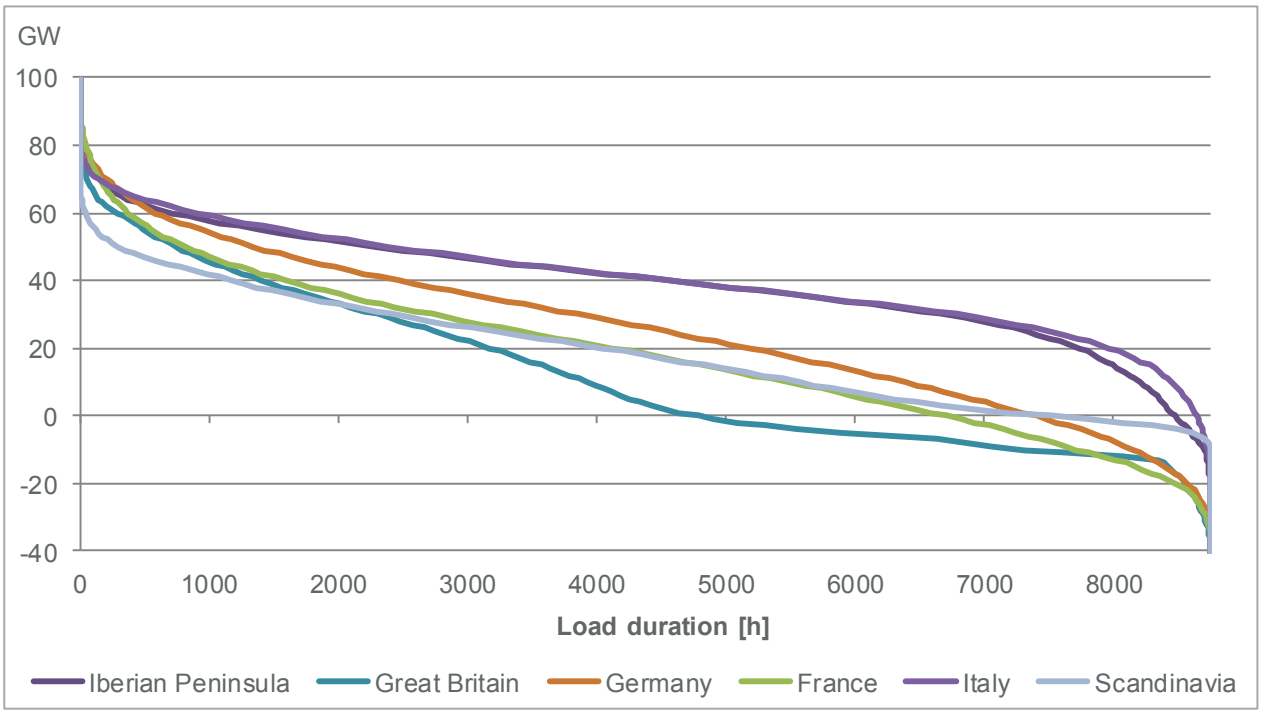

FIGURE 19: RESIDUAL LOAD DURATION CURVE IN 2050 (COUNTRIES GREATER THAN 40 GW) [GW]

Source: EWI

- Volatility of residual load –

The analysis of the residual load duration curve indicates how frequent different residual load levels occur during a year. It showed that, even considering a high share of renewable generation, large backup capacities are still needed in a mostly renewable power system. However, the previous analysis does not indicate the volatility of the residual load, i.e. hourly changes. To illustrate the volatility and the corresponding required flexibility of conventional power plants and storages, the change of the residual load from one hour to another is analysed dependent on the level of residual load. Figure 20 to Figure 23 show the residual load duration curves on the left side and the hourly changes in the residual load with respect to the residual load of the previous hour for selected countries in 2020 and 2050.

- Large changes in residual load occur more often due to the stochastic feed-in of renewables.
  Due to the stochastic generation of wind and solar technologies, the total number of hours indicating large changes in the residual load increases up until 2050. In 2020, only a few hours with an absolute change of more than 10,000 MW occur in any country. In 2050, all countries with residual load of more than 40 GW face hourly changes (positive and negative) greater than 10,000 MW.

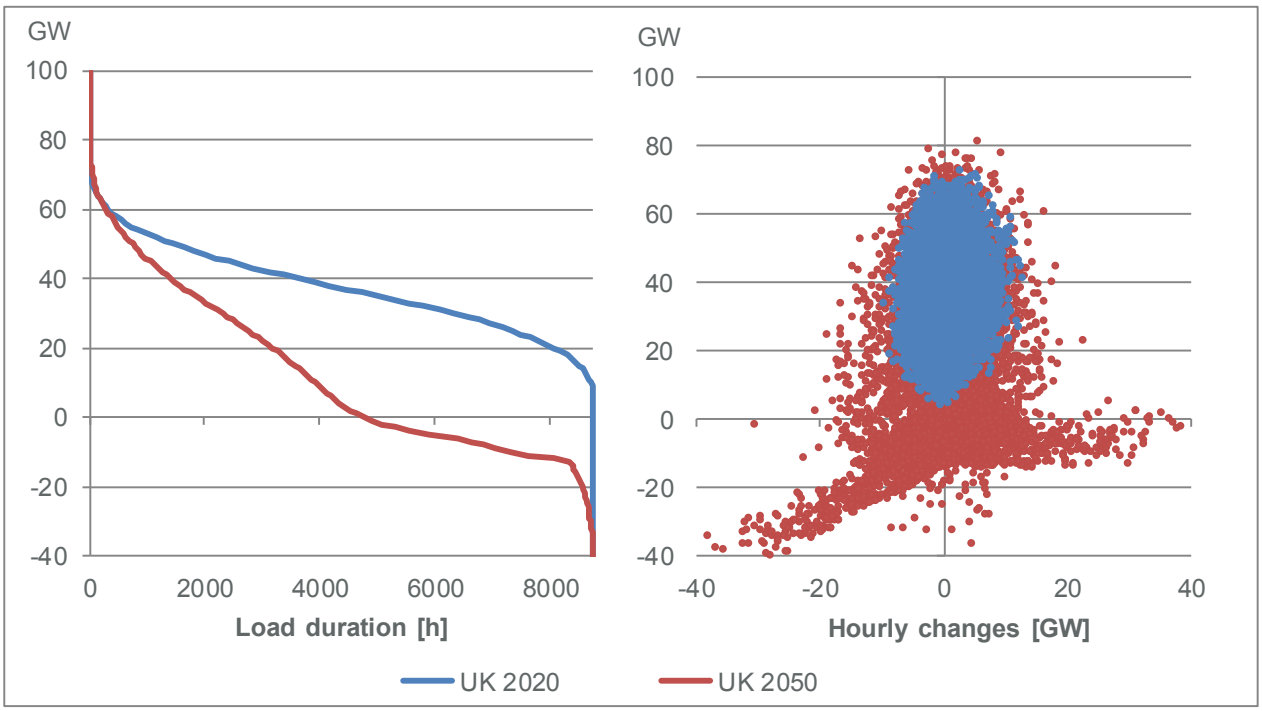

FIGURE 20: RESIDUAL LOAD CURVE (LEFT) AND CHANGE OF RESIDUAL LOAD (RIGHT) [GW] FOR THE UNITED KINGDOM IN 2020 AND 2050 *Source: EWI*

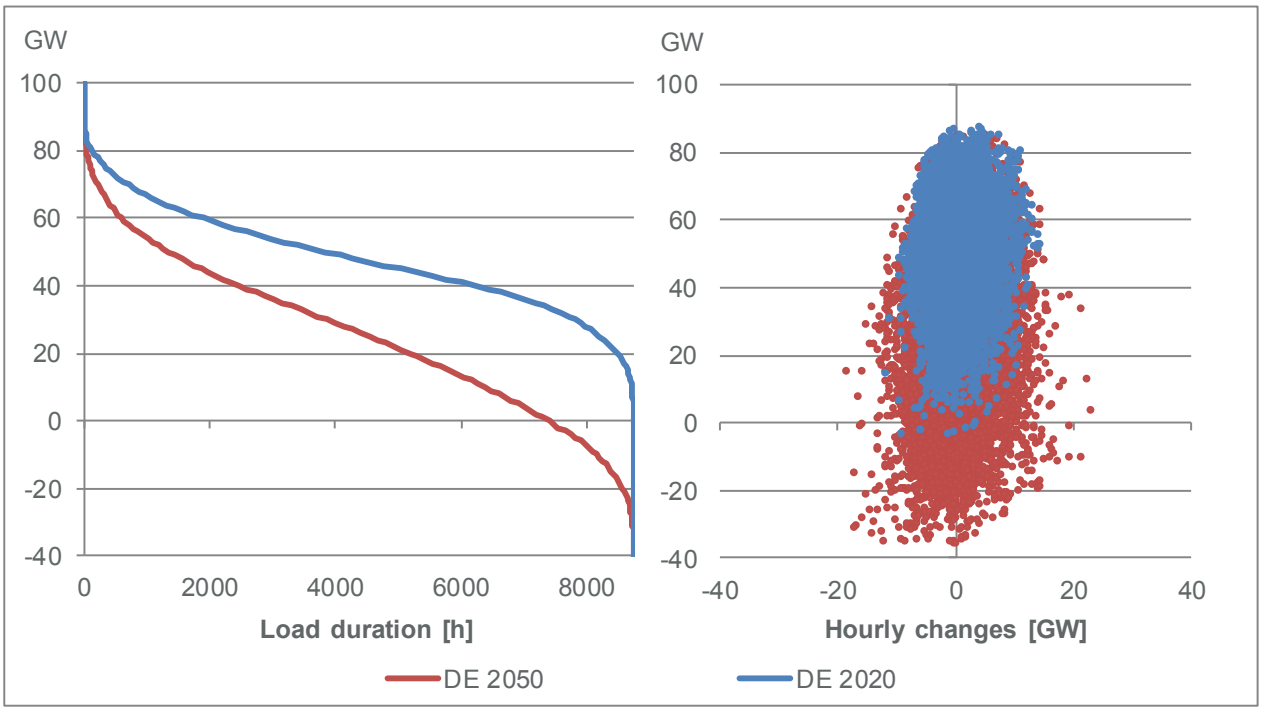

FIGURE 21: RESIDUAL LOAD CURVE (LEFT) AND CHANGE OF RESIDUAL LOAD (RIGHT) [GW] FOR GERMANY IN 2020 AND 2050 *Source: EWI*

- Hours with extreme changes occur more often in 2050.
  In countries with high demand and high penetration of renewables, fluctuations up to 40,000 MW (UK) in residual load occur often from one hour to another. The power systems in Germany, France, Scandinavia and the Iberian Peninsula still face hourly load changes of around 20,000 MW. Smaller countries like Denmark may have to deal with smaller changes in absolute amounts, but experience extreme hourly changes relative to their level of residual load.

- Significant hourly changes appear in situations of low or negative residual load.
  Hours with extreme changes in residual load from one hour to another coincide with situations of negative or low residual load due to the given high share of generation from renewables in these hours. In these situations, conventional power plants have to ramp up, use storages and adjust imports and exports in order to compensate for the changes in residual load.

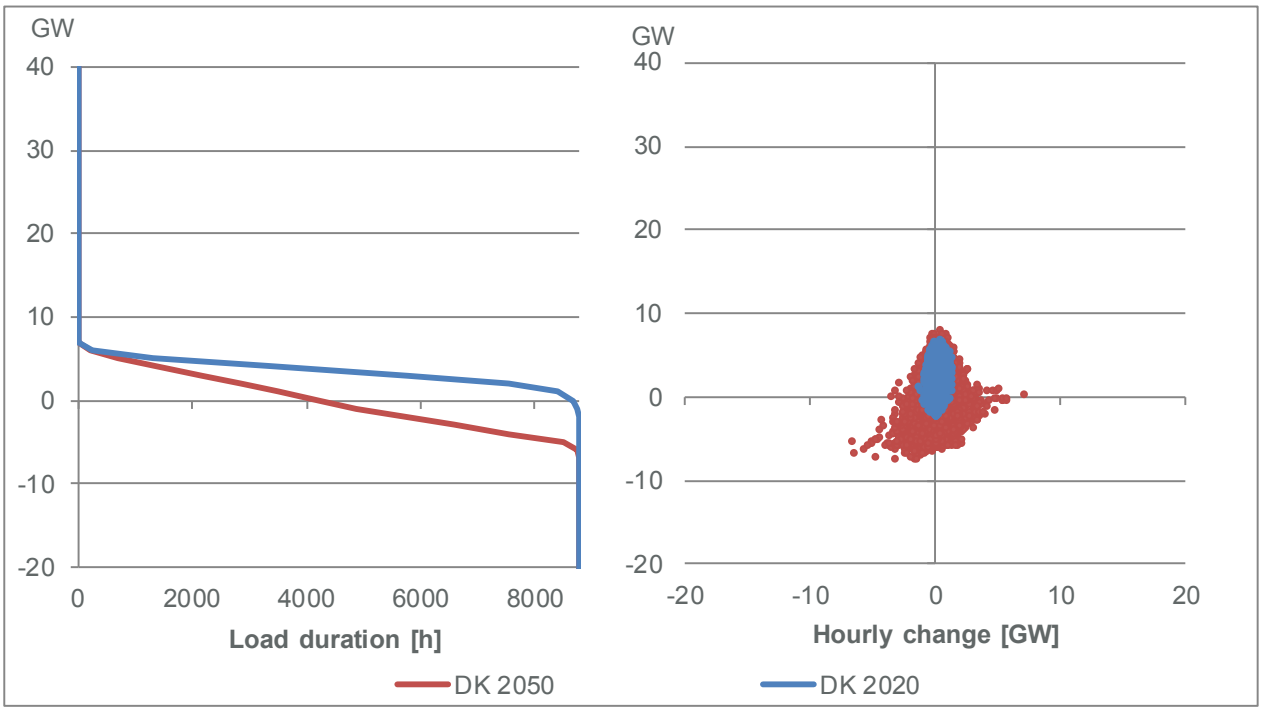

FIGURE 22: RESIDUAL LOAD CURVE (LEFT) AND CHANGE OF RESIDUAL LOAD (RIGHT) [GW] FOR DENMARK IN 2020 AND 2050 *Source: EWI*

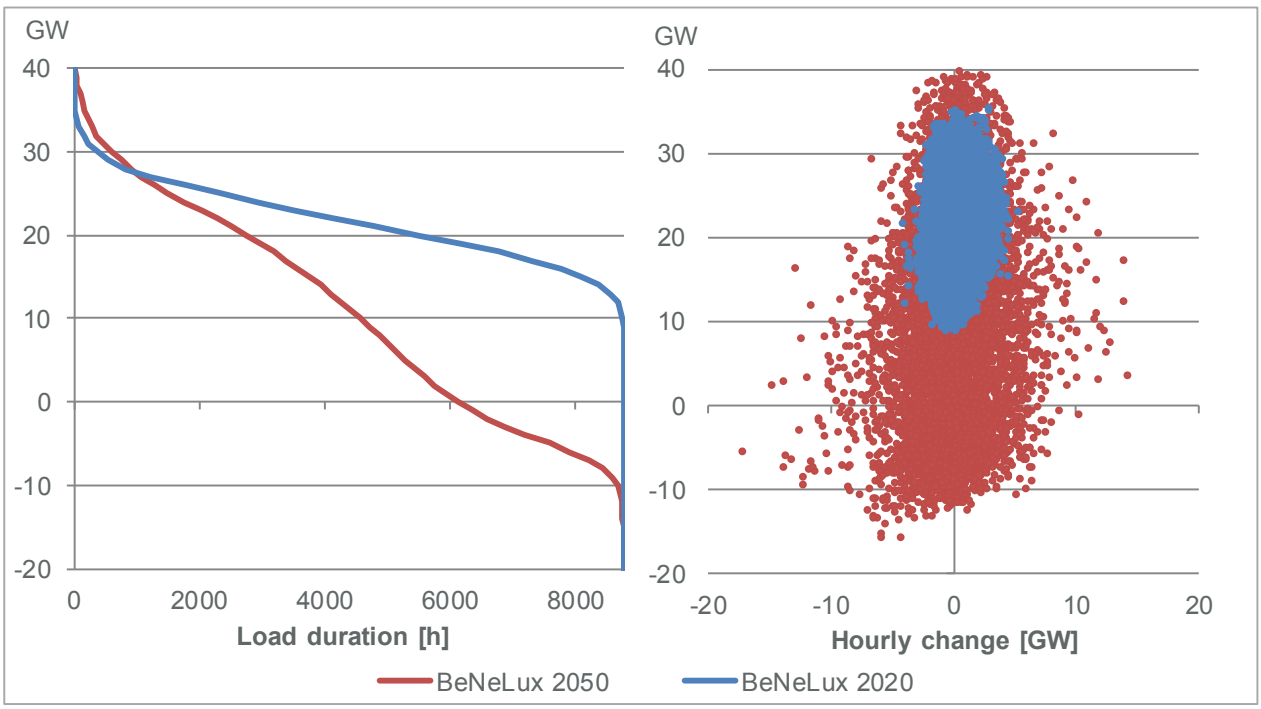

FIGURE 23: RESIDUAL LOAD CURVE (LEFT) AND CHANGE OF RESIDUAL LOAD (RIGHT) [GW] FOR THE BENELUX COUNTRIES IN 2020 AND 2050 *Source: EWI*

5.2.1.2 Changes in flexibility requirements

Uncertainty about the feed-in of renewables caused by forecast errors requires short-term flexibility in the power system to maintain system stability. The difference to the flexibility discussed in section 5.2.1.1 is that this provision is needed on short notice (t < one hour). The analysis assumes potential forecast errors of 10 % of the expected hourly wind and solar generation as stated in section 4.9. An increasing share of intermittent renewables increases the required provision of flexible resources in the medium and long term. In Figure 24 to Figure 27 load duration curves for the level of required flexible capacity (short term) dependent on the number of hours in a year are shown (i.e. 10 % of the hourly expected feed-in of intermittent renewables).

- Deployment of renewables requires a large share of flexible technologies in the short term.
  A more flexible power plant mix is necessary in the short term due to the large deployment of intermittent technologies. In particular in Germany, the Iberian Peninsula and the UK the required short-term flexibility exceeds 2,000 MW (approximately 2-4 % of peak demand) in more than 1000 hours in 2020.

- In 2050, a high amount of short-term flexibility is needed during the whole year.
  In 2050, the required flexibility exceeds 2,000 MW in more than 7,000 hours in France, Germany and the United Kingdom (Figure 25). Also, the maximal necessary short-term flexibility almost doubles from 2020 to 5050 (e.g., Germany – 2020: 5.5 GW and 2050: 11 GW). Thus, a more flexible power plant mix is necessary to integrate the intermittent renewable generation.

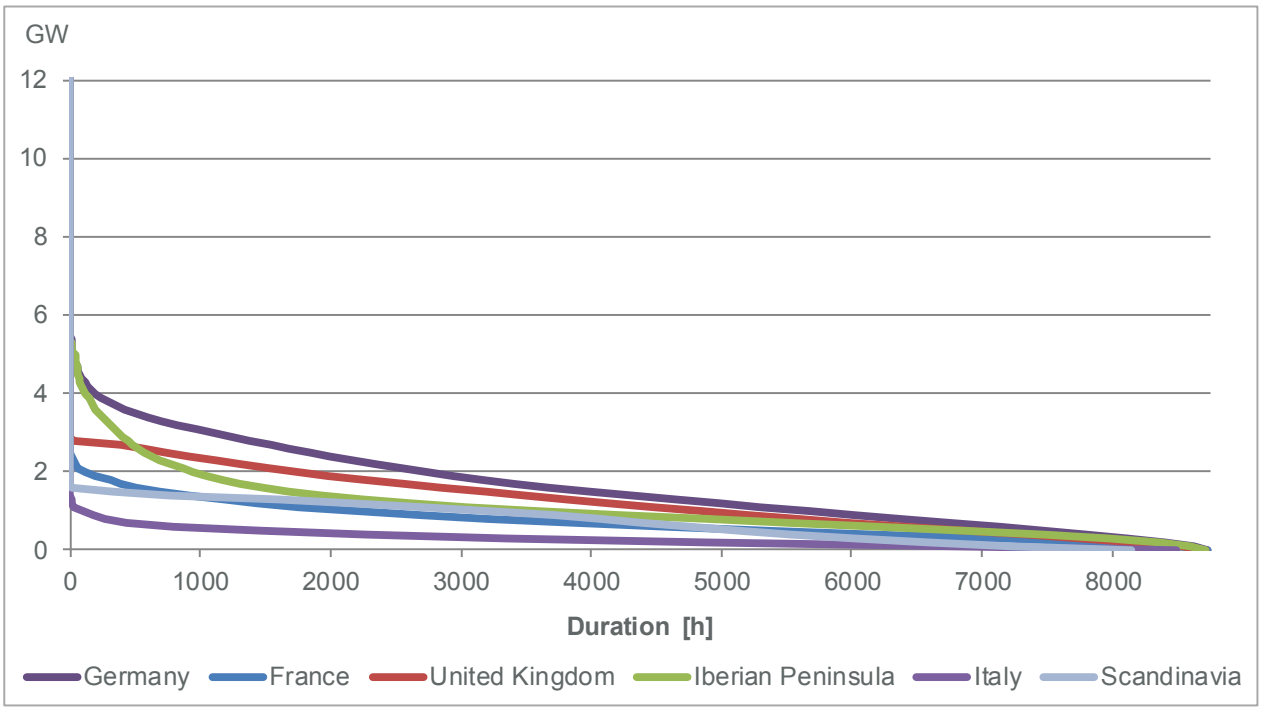

FIGURE 24: DURATION CURVE OF FLEXIBILITY REQUIREMENT IN 2020 [GW] (COUNTRIES WITH RESIDUAL LOAD GREATER THAN 40 GW) *Source: EWI*

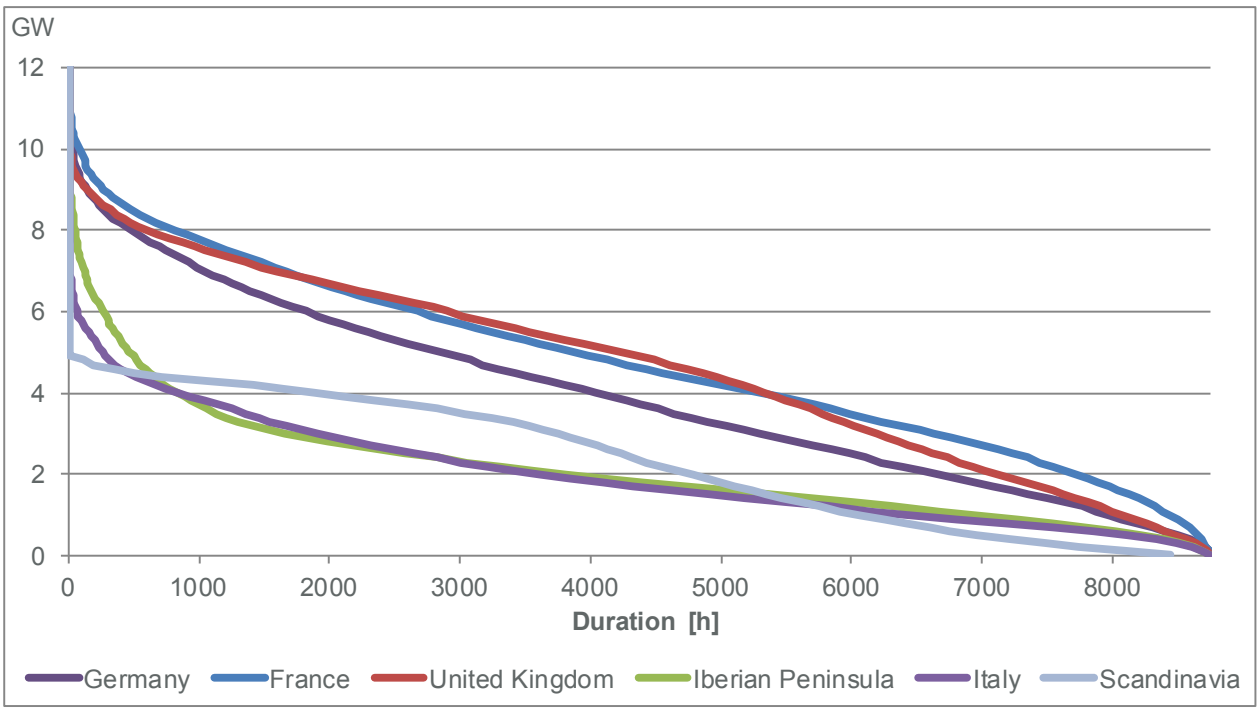

FIGURE 25: DURATION CURVE OF FLEXIBILITY REQUIREMENT IN 2050 [GW] (COUNTRIES WITH RESIDUAL LOAD GREATER THAN 40 GW) *Source: EWI*

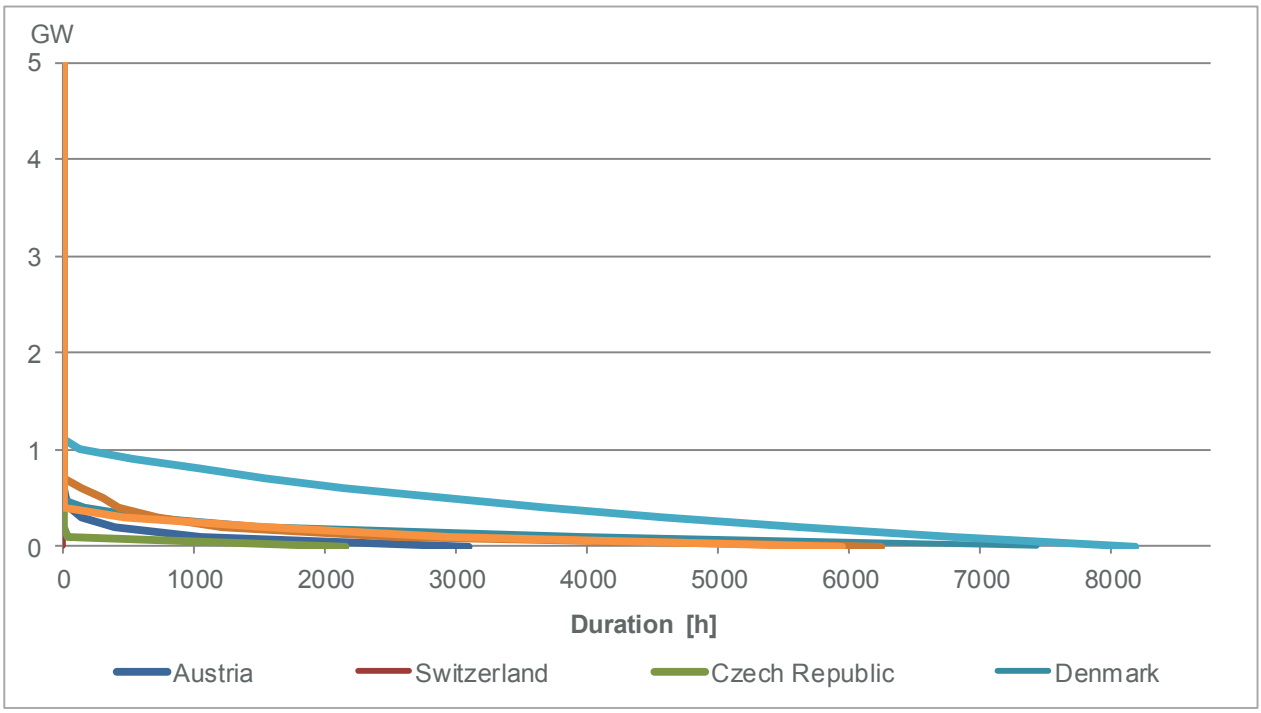

FIGURE 26: DURATION CURVE OF FLEXIBILITY REQUIREMENT IN 2020 [GW] (COUNTRIES WITH RESIDUAL LOAD LESS THAN 40 GW) *Source: EWI*

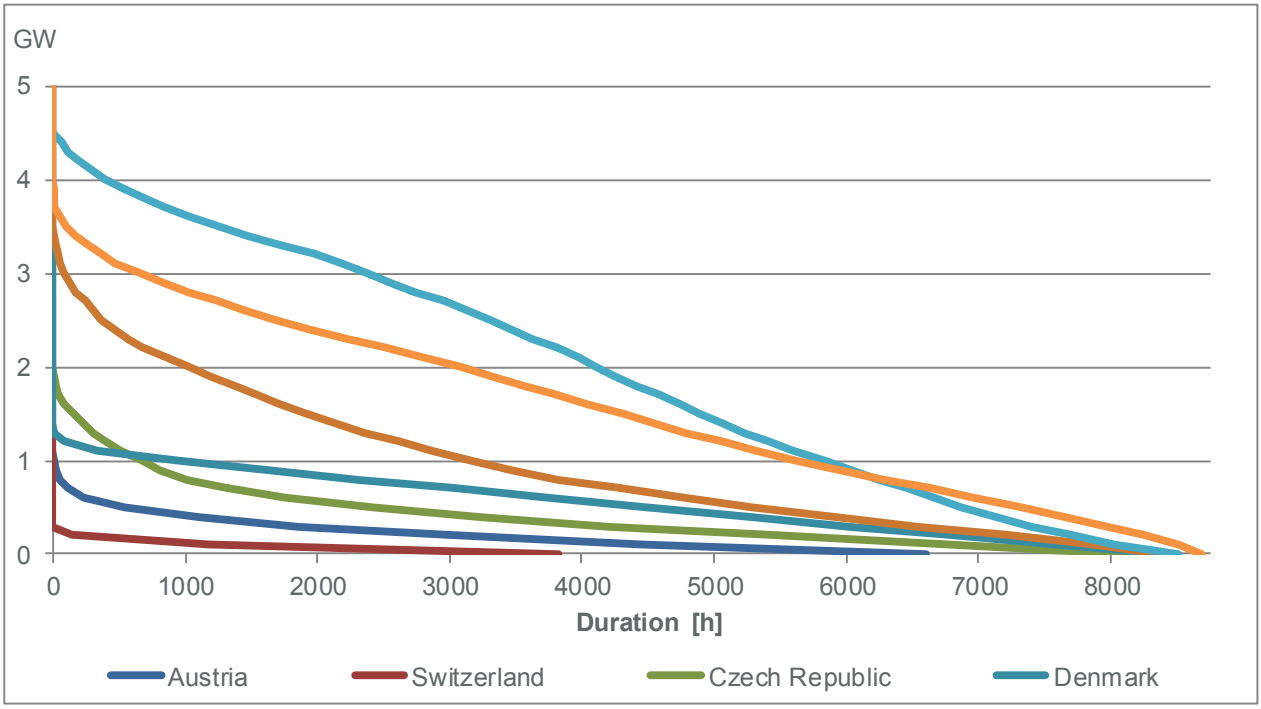

FIGURE 27: DURATION CURVE OF FLEXIBILITY REQUIREMENT IN 2050 [GW] (COUNTRIES WITH RESIDUAL LOAD LESS THAN 40 GW) *Source: EWI*

5.2.2 Dispatch realizations: Increasing challenges in European power systems

In this section, selected dispatch realizations in several countries in a winter and a summer week in 2020 and 2050 (Scenario A) are analysed. We focus on Scenario A, as similar effects can be observed in Scenario B. In a typical winter week, electricity demand is relatively high and strong winds are likely to occur. In summer, demand is relatively low and more solar energy is typically available. Furthermore, the hourly available short-term flexibility is analysed (in addition to operating power plants) to balance potential forecast errors.

5.2.2.1 Electricity system in 2020

- Dispatch realizations in 2020 –

Figure 28 to Figure 30 depict dispatch realizations in the UK, Iberian Peninsula and Poland for a winter week (January 5th to 11th) and Figure 31 to Figure 33 dispatch realizations in the UK, Scandinavia and Germany for a summer week (June 8th-13th). The figures show the gross electricity generation by fuel type, net imports and both gross and net electricity demand. The difference between gross and net electricity demand represents the transmission losses, the own consumption of thermal power plants, the charging of storage technologies and the catch-up effect of DSM processes. As transmission losses are proportional to the electricity demand (assumption), a comparison of net and gross electricity demand mainly indicates the operation of storages and DSM processes.

- At peak demand in winter, almost all available capacity is in use.
  High electricity demand in winter is met by additional generation of gas-fired power plants (CCGT and OCGT), storage technologies, hydro power, biomass resources (high cost) and demand side management by shifting electricity demand to hours with low demand. Such a situation occurs for example in the United Kingdom at Wednesday evening (Figure 28). Wind power contributes only 4,895 MW (32.5 GW installed in 2020) at relatively high demand (82,821 MW) – representing about 5.9 % of the gross electricity demand. Almost all backup capacities are used to serve the high demand.

- Hours with high shares of fluctuating renewables (> 50 %) already occur in 2020.
  Strong winds at relatively low electricity demand (Sundays) lead to situations where wind power contributes more than 50 % of the gross electricity demand in the UK in 2020 (Figure 28). As a result, coal and gas-fired power plants ramp down, but stay online (operate in part load) to cope with the daily peak demand at early evening.

- The volatility of the residual load is primarily influenced by the hourly electricity demand rather than the fluctuating feed-in of renewables in 2020.
  The residual load (electricity demand after subtracting fluctuating wind and solar generation) must be met by dispatchable power plants and storages. Even when considering the large deployment of wind and solar capacities and their fluctuating generation, the volatility of the residual demand is still predominantly influenced by the daily demand curve for most regions in 2020 (Figure 29 and Figure 30).

- Base-load technologies (nuclear and lignite plants) still run on maximum capacity in almost all hours in 2020.
  Nuclear and lignite plants still run at full capacity for the majority of the year (already shown in Figure 9 in section 5.1.1). This includes situations with relatively low electricity demand (for example on weekends) with large feed-in of wind and solar technologies. The integration of the intermittent renewables is mainly achieved by flexible hydro reservoirs in Austria, Scandinavia and Switzerland, gas-fired power plants in the UK, coal and gas-fired plants as well as imports and exports to neighbouring countries in Germany.

- Generation from PV panels fits today's demand curve because the electricity demand in the European electricity system has a midday peak when solar radiation is also highest,
  Based on the National Renewable Action Plan, 52 GW of PV panels are installed in the scenarios for Germany in 2020. As shown in Figure 33, the generation of solar panels fits today's demand curve. However, the generation from solar power drops in the afternoon when demand is still relatively high. The flexibility to integrate the fluctuating solar power into the electricity system is mostly provided by the neighbouring countries, as Germany tends to export electricity at midday and import in the early evening.

Winter week in 2020 (January 5th-11th)

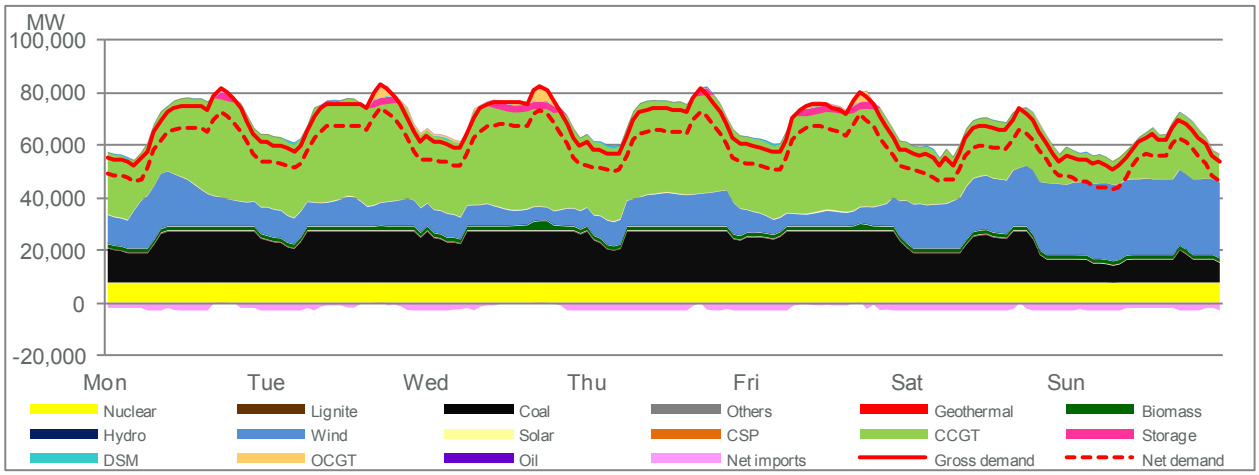

FIGURE 28: DISPATCH UK 2020 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

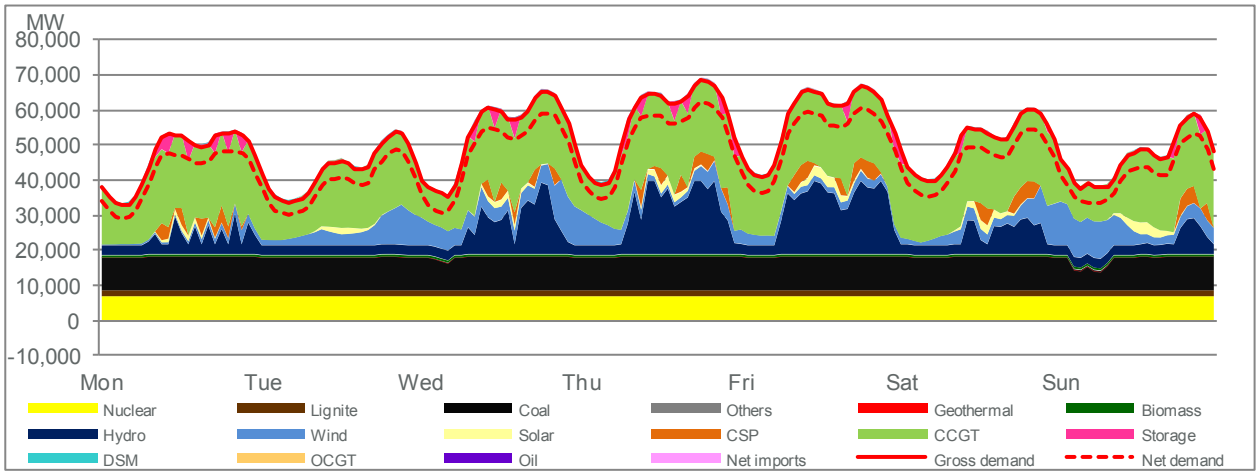

FIGURE 29: DISPATCH IBERIAN PENINSULA 2020 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

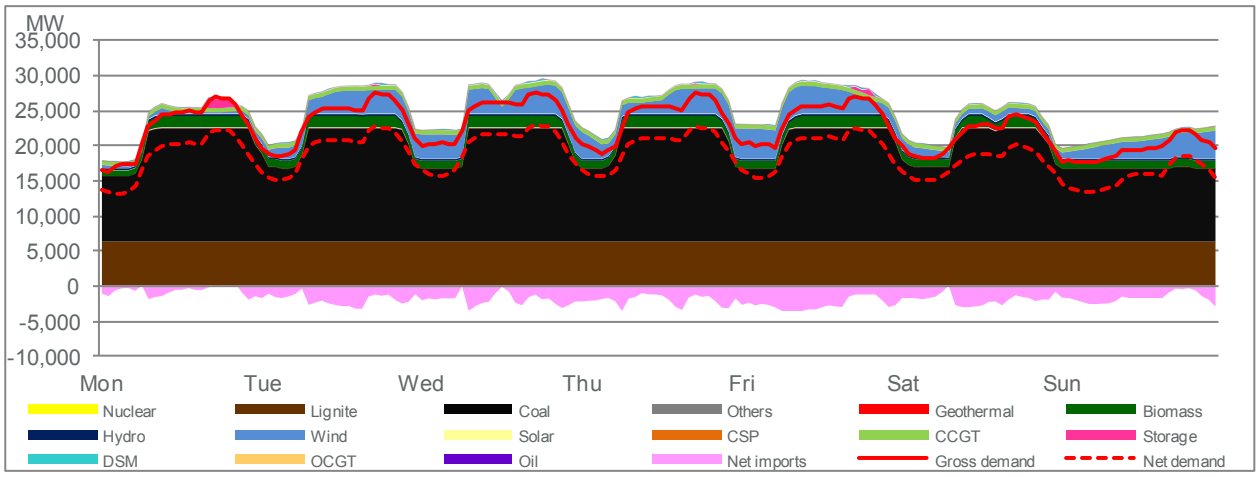

FIGURE 30: DISPATCH POLAND 2020 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

Summer week in 2020 (June 8th-13th)

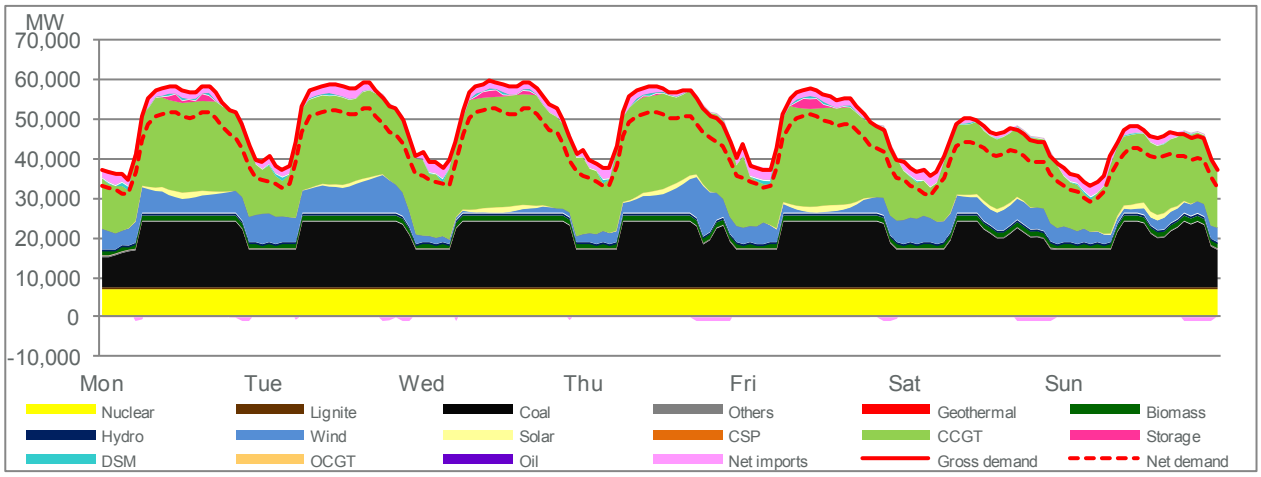

FIGURE 31: DISPATCH UK 2020 – SUMMER WEEK (JUNE 8th-13th) [MW] *Source: EWI*

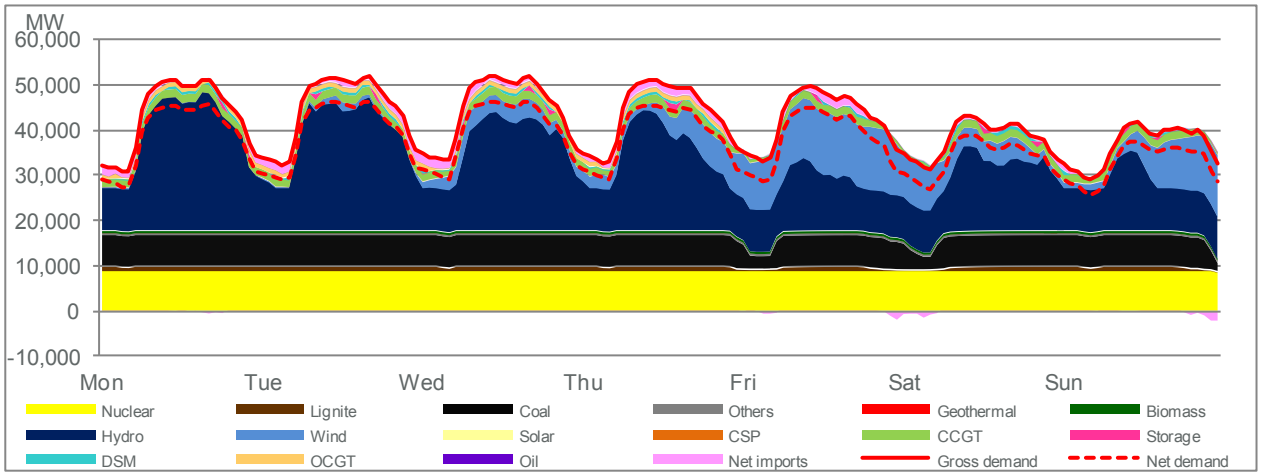

FIGURE 32: DISPATCH SKANDINAVIA 2020 – SUMMER WEEK (JUNE 8th-13th) [MW] *Source: EWI*

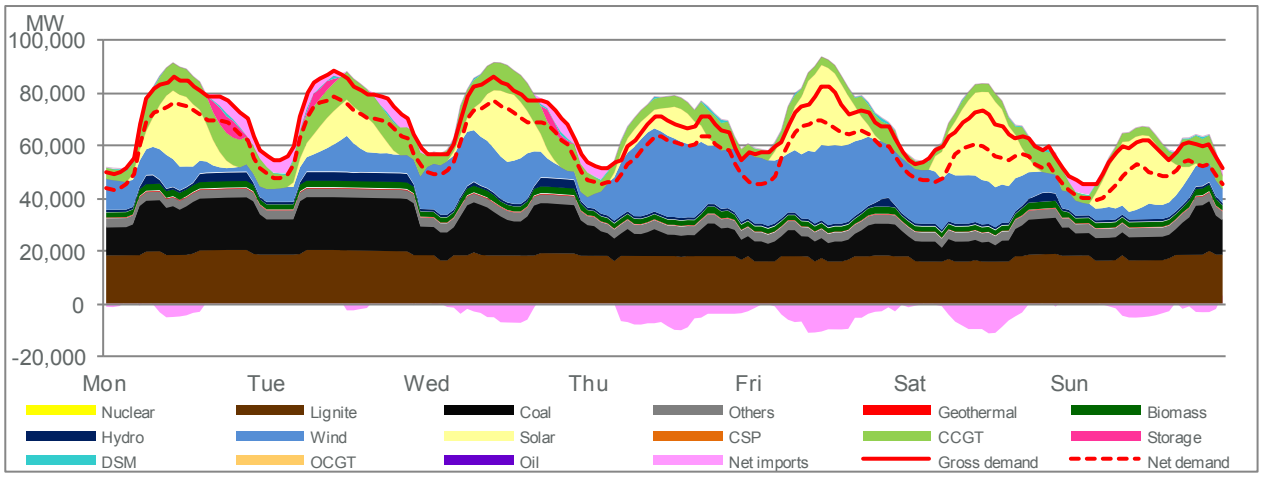

FIGURE 33: DISPATCH GERMANY 2020 – SUMMER WEEK (JUNE 8th-13th) [MW] *Source: EWI*

- Additional flexibility in 2020 –

Figure 34 to Figure 36 depict the additionally available short-term flexibility options during a winter week (January 5th-11th) in the UK, Germany and Iberian Peninsula. Figure 37 and Figure 38 display the available short-term positive flexibility options in the UK and Germany for a specific summer week (June 8th-13th). As described in Section 4.9, flexibility options include open cycle gas turbines, pump- and compressed air storages, thermal power plants in part load operation, DSM processes, planned wind curtailment and conventional power plants with flexible CCS units.

- The power plant mix offers enough positive flexibility to cope with eventual forecast errors for wind and solar energy in the short term.
  As thermal power plants, storages and demand side management are not in use when large feed-in of wind power is expected, many generation options are available to compensate potential forecast errors during these hours. In the analysis, mainly flexible gas-fired power plants (OCGT and CCGT), storages and other thermal power plants provide the positive flexibility needed.

- Short-term flexibility requirement is not a challenge in 2020.
  Given the assumed hourly flexibility requirement of 10 % of the actual generation from wind and solar power, the flexibility requirement is relatively low compared to the power demand in 2020. As shown in Figure 34, the flexibility requirement is on average 2,800 MW in the UK for a specific Sunday afternoon. However, due to the high wind availability more than 7,000 MW of open cycle gas turbines are available to balance potential forecast errors.

- The required flexibility to balance potential forecast errors of wind and solar power may already be high in the short term.
  Due to the large amount of installed solar systems in Germany in 2020 (assumption), the required short-term flexibility for forecast errors may already be relatively high compared to the hourly electricity demand. As shown in Figure 38, the 10 % short-term flexibility requirement (forecast error of 10 % for wind and solar power) translates to more than 5 GW of necessary positive flexibility.

Winter week in 2020 (January 5th-11th)

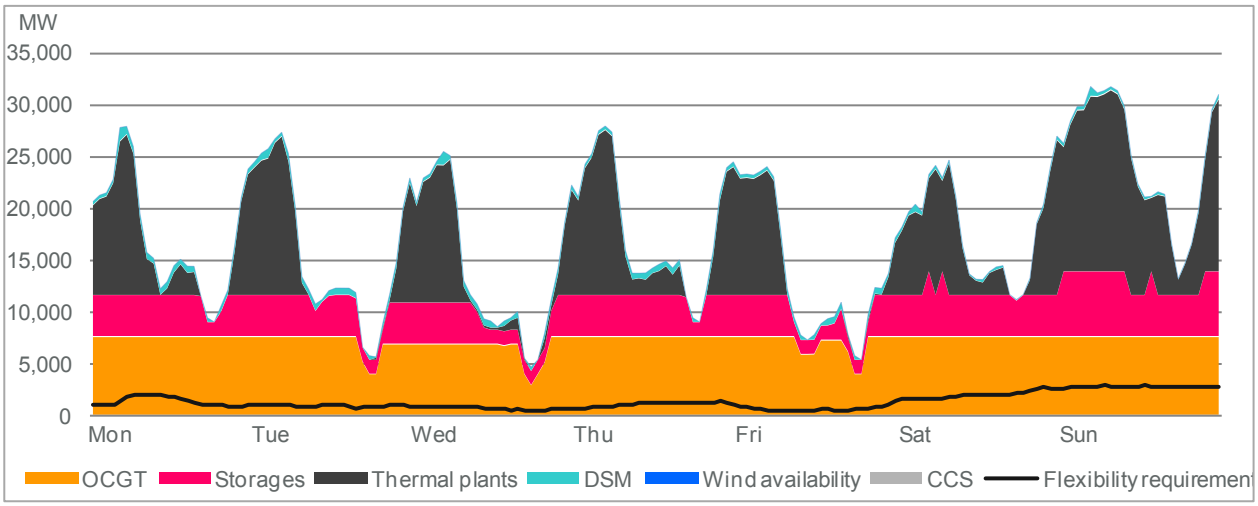

FIGURE 34: FLEXIBILITY OPTIONS UK 2020 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

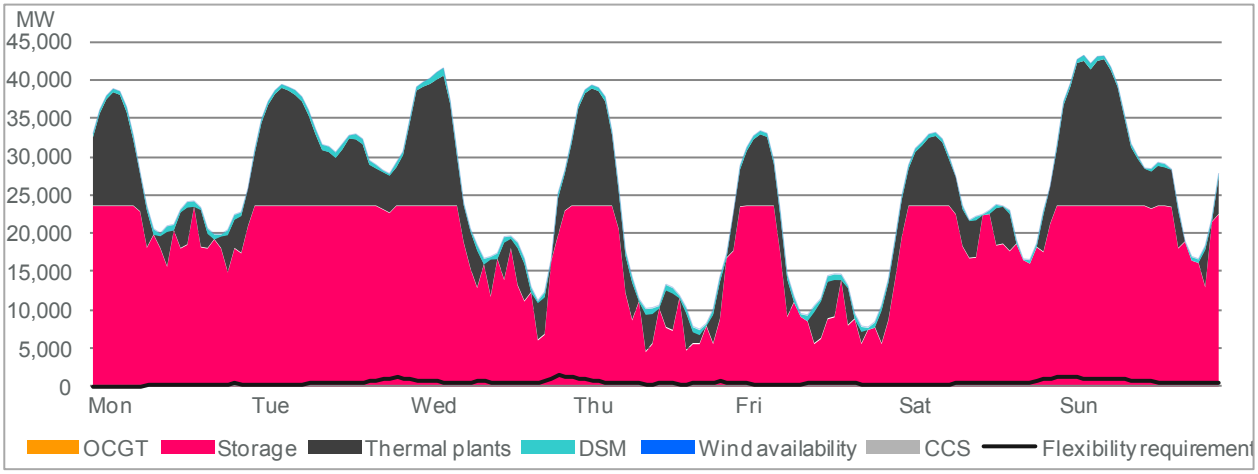

FIGURE 35: FLEXIBILITY OPTIONS IBERIAN PENINSULA 2020 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

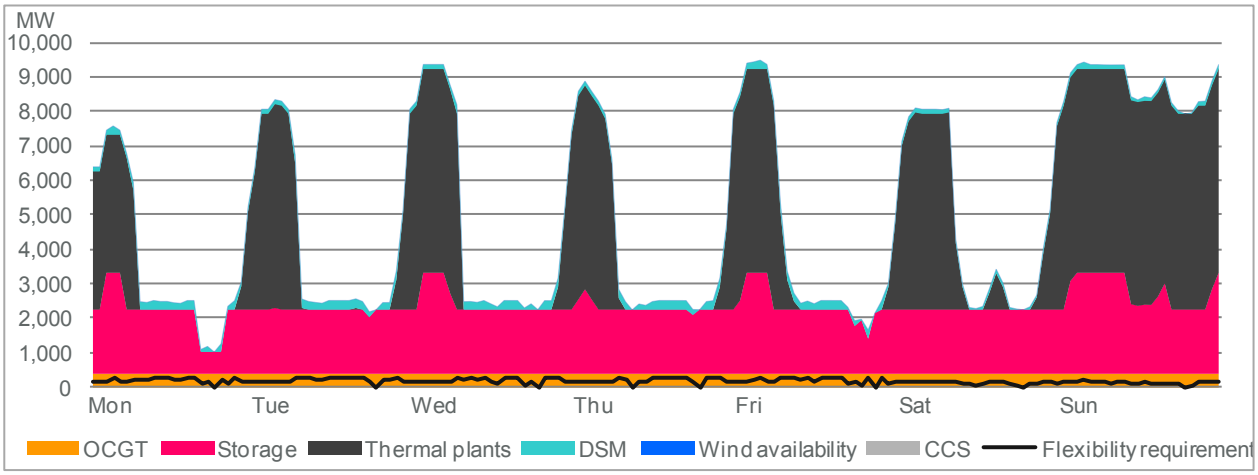

FIGURE 36: FLEXIBILITY OPTIONS POLAND 2020 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

Summer week in 2020 (June 8th-13th)

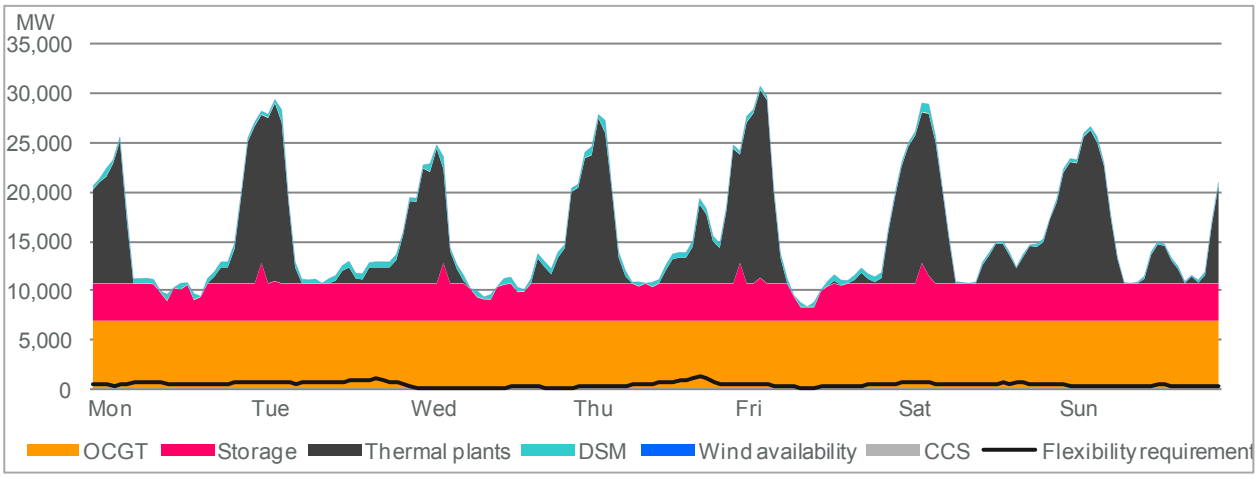

FIGURE 37: FLEXIBILITY OPTIONS UK 2020 – SUMMER WEEK (JUNE 8th-13th) [MW]

Source: EWI

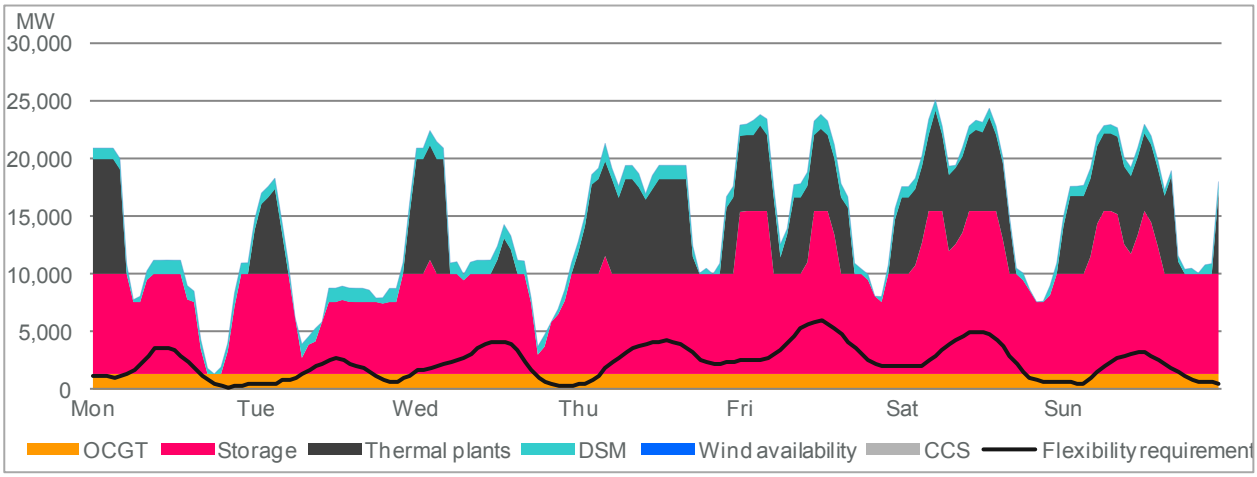

FIGURE 38: DISPATCH GERMANY 2020 – SUMMER WEEK (JUNE 8th-13th) [MW]

Source: EWI

As the generation from wind and solar systems may be under- or overestimated, sufficient positive as well as negative flexibility needs to be available to balance generation and demand for each hour. Figure 39 and Figure 40 depict the sum of negative flexibility options and the required flexibility (assumption) for the UK during a specific winter week (January 5th-11th) and for Germany during a specific summer week (June 8th-13th).

- Negative flexibility is mainly provided by thermal power plants (operating in part load), storages, wind reduction and demand side management.

  Given the high share of gas-fired power plants in the short term, negative flexibility can be easily provided by ramping down these power plants. Based on the assumptions concerning the deployment of DSM technologies, DSM processes also offer negative flexibility in the short term, in particular industrial processes on weekdays.

- Flexible wind power control is already cost-efficient in the short term.
  As shown in Figure 39, wind power control already plays an important role in the short term. On the Sunday morning of this week in the UK, thermal power plants (coal and combined cycle gas turbines) run at minimum load and therefore offer no additional negative flexibility. All available storages are charging and DSM processes run on full capacity and therefore cannot provide negative flexibility. However, wind curtailment offers a cost-efficient flexibility option.

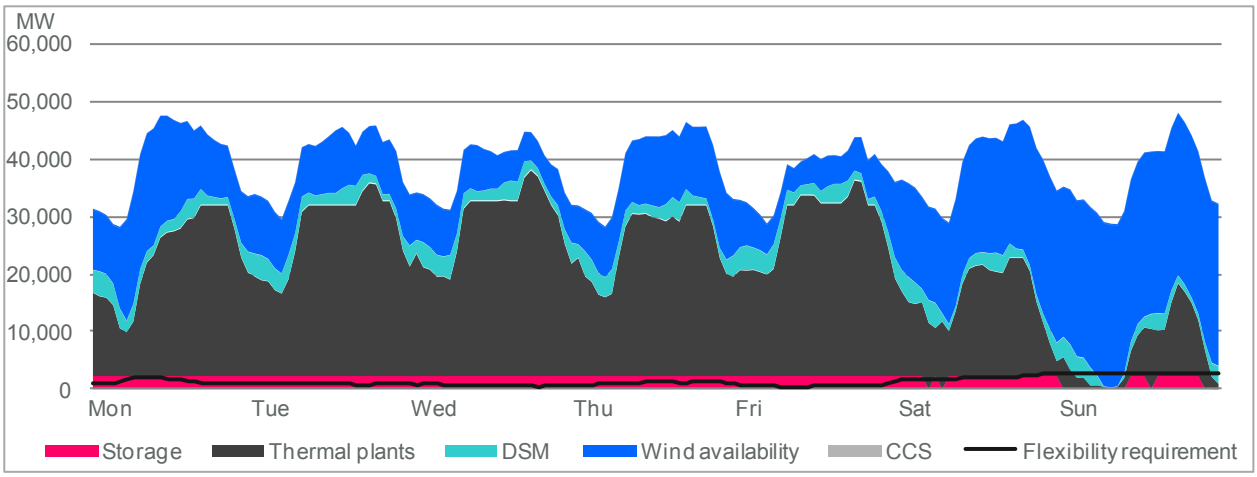

FIGURE 39: NEGATIVE FLEXIBILITY OPTIONS UK 2020 – WINTER WEEK (JANUARY 5th-11th) [MW]
Source: EWI

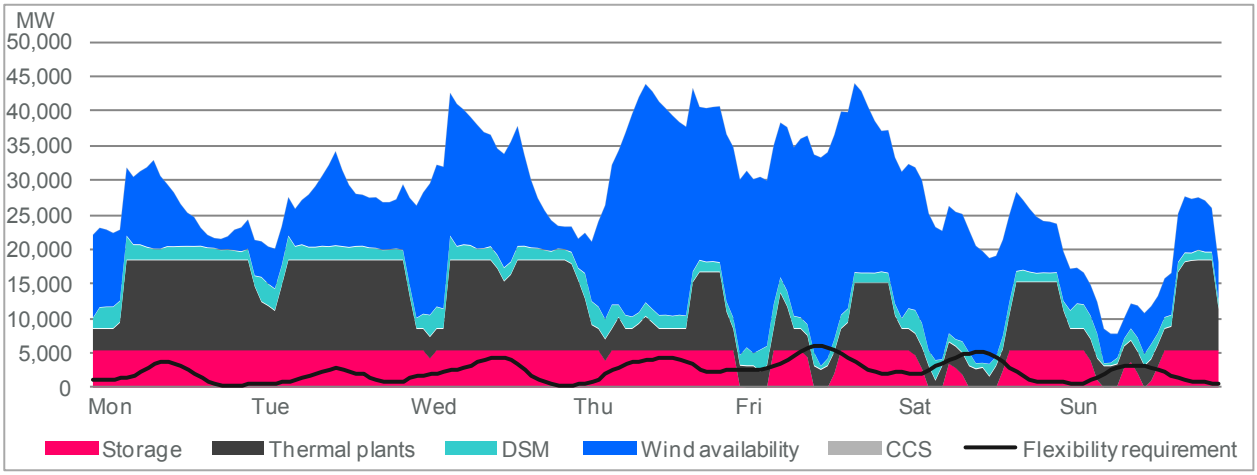

FIGURE 40: NEGATIVE FLEXIBILITY OPTIONS GERMANY 2020 – SUMMER WEEK (JUNE 8th-13th) [MW]
Source: EWI

5.2.2.2 Electricity system in 2050

- Dispatch realizations in 2050 –

Figure 41 to Figure 43 depict dispatch realizations in Poland, the Iberian Peninsula and Denmark during a winter week (January 5th to 11th) and Figure 44 to Figure 46 in the UK, Poland and Germany during a summer week (June 8th-13th). These figures show the gross electricity generation by fuel type and net imports as well as gross and net electricity demand. The difference between gross and net electricity demand represents transmission losses, own consumption of thermal power plants, charging of storage technologies and the catch-up effect of DSM processes.

- There are fundamentally different dispatch realizations in 2050 due to a strong dependence on weather conditions.
  As clearly seen in all figures, the dispatch of fluctuating generation and demand becomes more challenging in future electricity systems due to the large deployment of wind and solar technologies (assumption). One example of volatile wind generation is Denmark during a specific winter week (Figure 43). On some days, more than enough wind power is available and Denmark becomes a large exporter; whereas on others, electricity must be imported due to low wind availability.

- A more flexible power mix is needed to meet demand as the share of power generation from fluctuating renewables increases.
  Because weather conditions can quickly change, the power generation from wind turbines or solar technologies can increase or drop rapidly. As seen in Figure 41, wind power in Poland drops on Monday around midday from 13,134 MW – 7,592 MW – 3,804 MW – 1,860 MW within four hours and dispatchable plants (in this case OCGT and storages) are needed to substitute wind power.

- Challenging situations occur when given only minimum availability of wind and solar power in 2050.
  On the Wednesday of the specific summer week in the UK (Figure 44) only 240 MW of wind power are available around midday (more than 147 GW wind turbines installed on- and offshore in the UK in 2050). Hence, almost all dispatchable plants, storages and DSM processes as well as imports secure the electricity supply. A similar situation occurs during the winter week in Poland (Figure 41), on Monday around midday.

- Large amounts of wind power need to be curtailed in 2050.
  Wind curtailment takes place under the following conditions: electricity demand is satisfied, storages already in pump operation (or full), net transfer capacities at maximum capacity and

DSM processes at their maximum level.[1] In Denmark, during the specific winter week, more than twice as much wind power (> 13 GW) than net electricity demand (6 GW) is available on Wednesday afternoon. As storages are already in maximum charging operation and net transfer capacities are at maximum level, the additional wind power is curtailed. As shown in section 5.1.1, more than 100 TWh of wind and solar power in total are curtailed in 2050.

- In electricity systems with a large share of photovoltaics, concentrated solar power plants with thermal storages are able to provide flexibility by shifting generation to evening/night hours.

  As electricity demand is typically high around midday and late afternoon, the feed-in structure of solar technologies fits the demand quite well. However, at some point the residual demand structure is almost reversed due to the large solar feed-in around midday. CSP systems with integrated thermal storages provide flexibility by shifting generation to evening and night hours. This can be seen during the winter week of the Iberian Peninsula (Figure 42).

[1] For clarification, wind curtailment also takes place when ramp-up costs of thermal power plants can be avoided in order to minimise total system costs.

Winter week in 2050 (January 5th-11th)

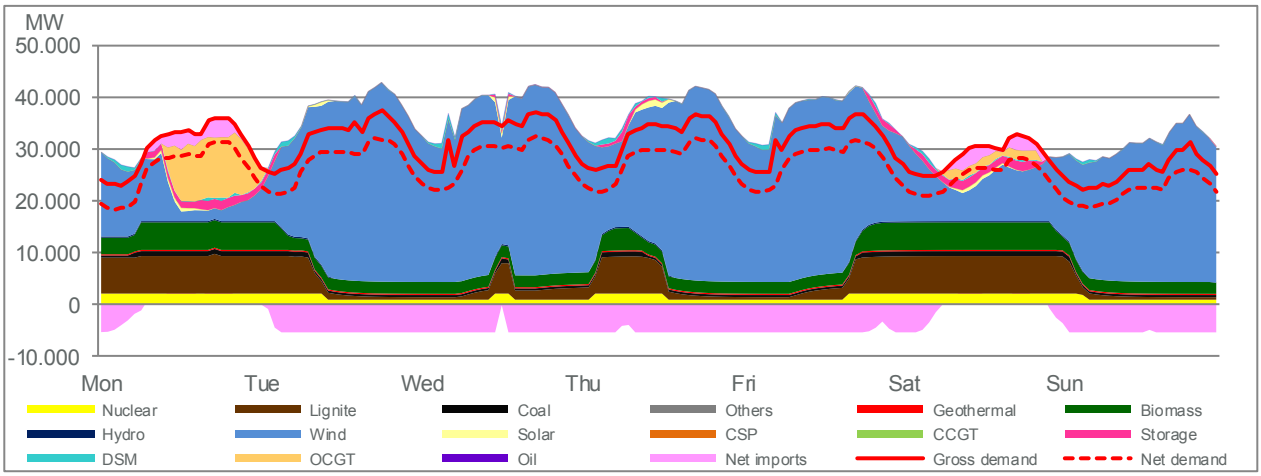

FIGURE 41: DISPATCH POLAND 2050 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

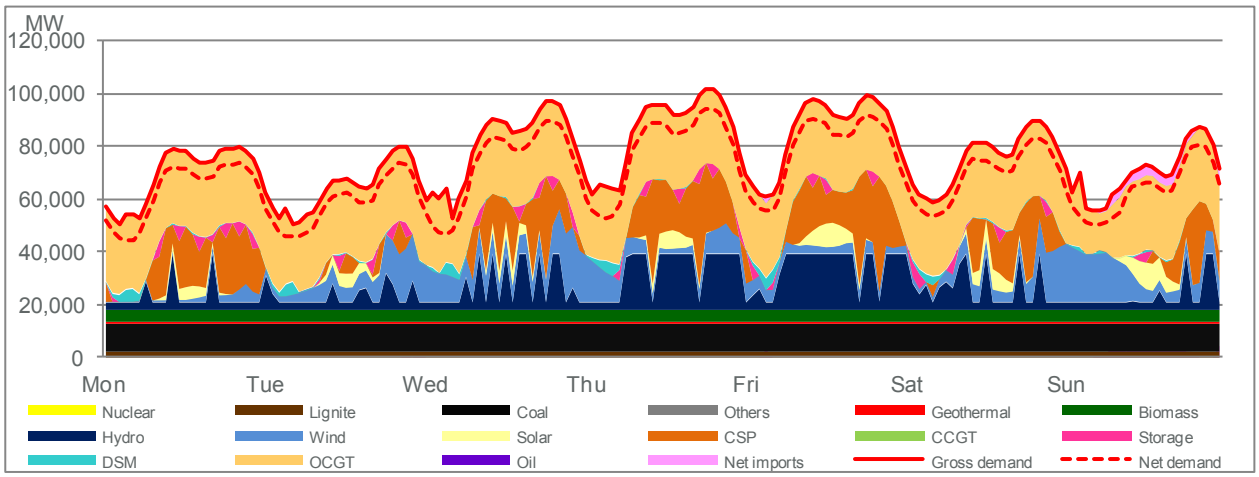

FIGURE 42: DISPATCH IBERIAN PENINSULA 2050 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

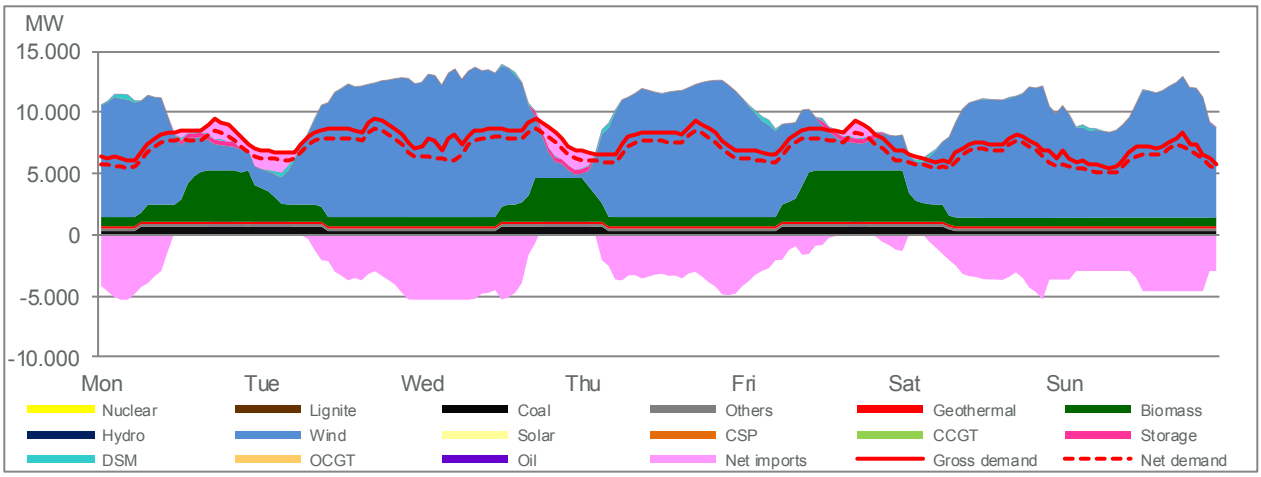

FIGURE 43: DISPATCH DENMARK 2050 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

Summer week in 2050 (June 8th-13th)

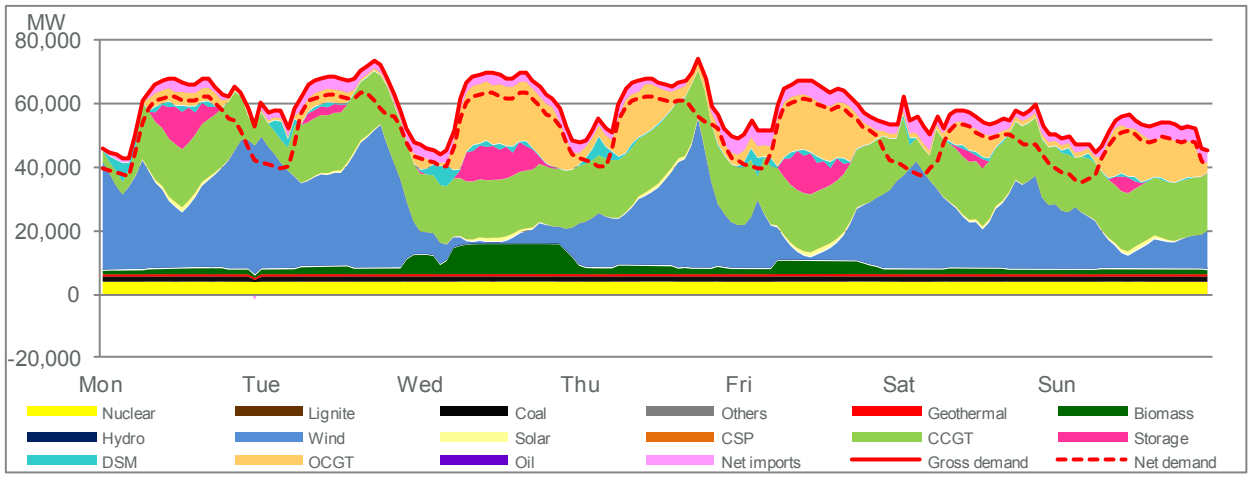

FIGURE 44: DISPATCH UK 2050 – SUMMER WEEK (JUNE 8th-13th) [MW] *Source: EWI*

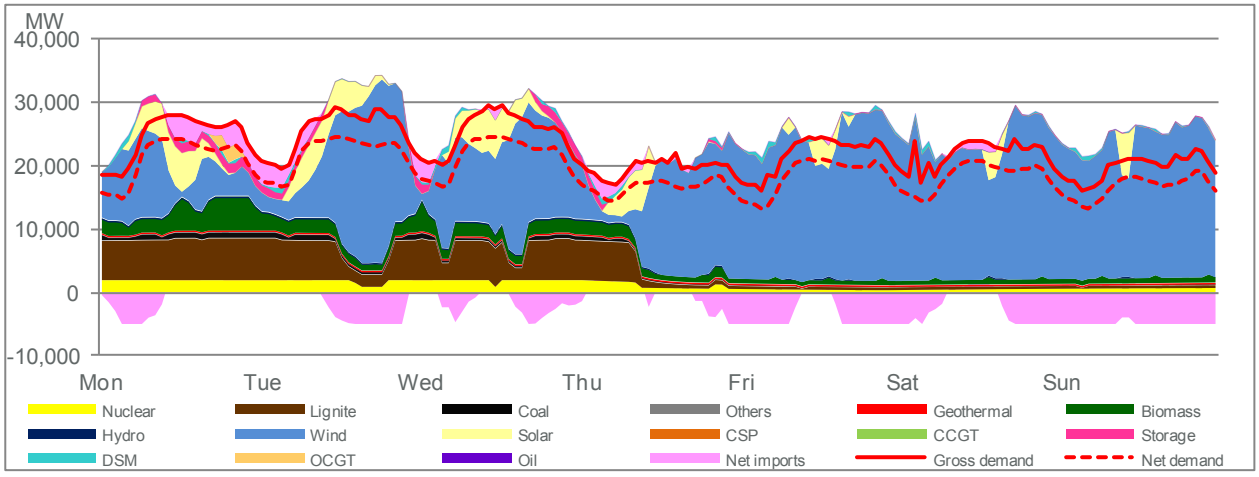

FIGURE 45: DISPATCH POLAND 2050 – SUMMER WEEK (JUNE 8th-13th) [MW] *Source: EWI*

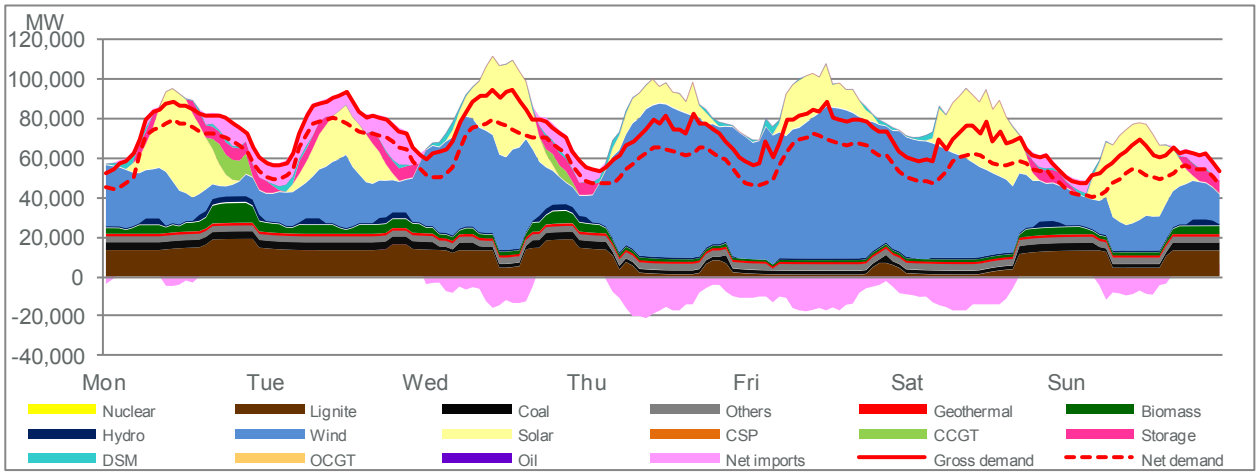

FIGURE 46: DISPATCH GERMANY 2050 – SUMMER WEEK (JUNE 8th-13th) [MW] *Source: EWI*

- Additional flexibility in 2050 –

Figure 47 to Figure 49 depict the additionally available short-term flexibility options during the same winter or summer weeks. As described in section 4.9, positive flexibility options include open cycle gas turbines, pump and compressed air storages, thermal power plants in part load operation, DSM processes, planned wind curtailment and conventional power plants with flexible CCS units. Negative flexibility can be provided by storages, thermal power plants in operation, DSM processes, wind curtailment and flexible CCS units.

- In the long term, open cycle gas turbines mainly serving as backup capacities for peak demand, also offer positive flexibility.
  As peak demand must be ensured by sufficient securely available capacity, open cycle gas turbines are built in both scenarios. As open cycle gas turbines are only used in situations with a high residual demand (after subtracting the fluctuating generation), these capacities are available to meet the flexibility requirement (as seen in Figure 47 or Figure 48). Hence, the provision of sufficient positive flexibility does not appear to be a major challenge for the electricity market.

- CCS plants installed with flexible CCS units offer additional short-term flexibility.
  Some CCS plants with flexible CCS units are built to ensure peak demand. These capacities also offer positive flexibility to the power system as seen in Figure 47 for the example of Poland. However, the utilization of other flexibility options is cost-efficient due to lower variable costs (in case of storages and DSM processes opportunity costs).

Winter week in 2020 (January 5th-11th) and summer week in 2050 (June 8th-13th)

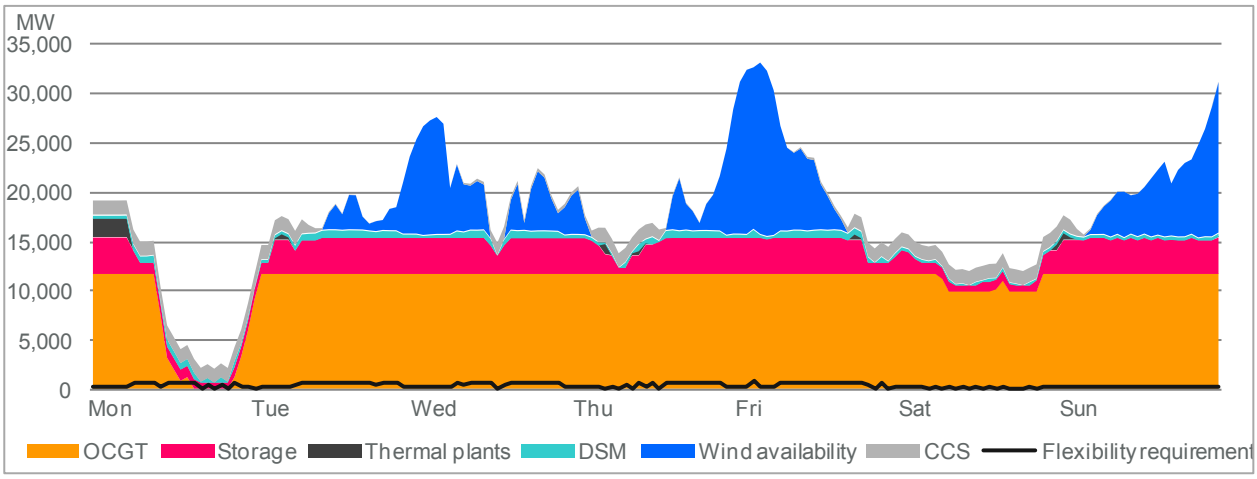

FIGURE 47: FLEXIBILITY OPTIONS POLAND 2050 – WINTER WEEK (JANUARY 5th-11th) [MW] *Source: EWI*

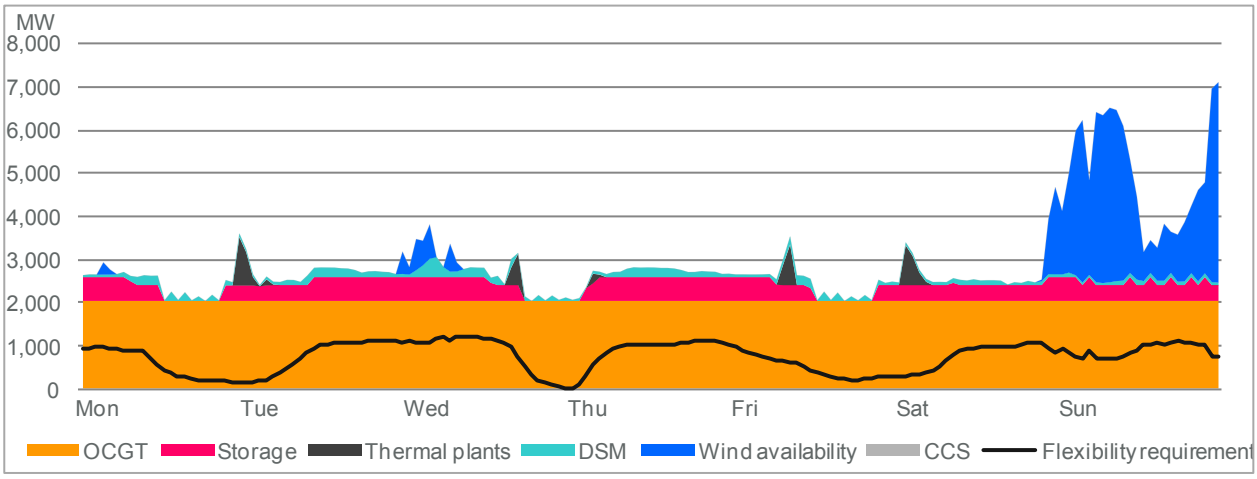

FIGURE 48: FLEXIBILITY OPTIONS DENMARK 2050 – SUMMER WEEK (JUNE 8th-13th) [MW] *Source: EWI*

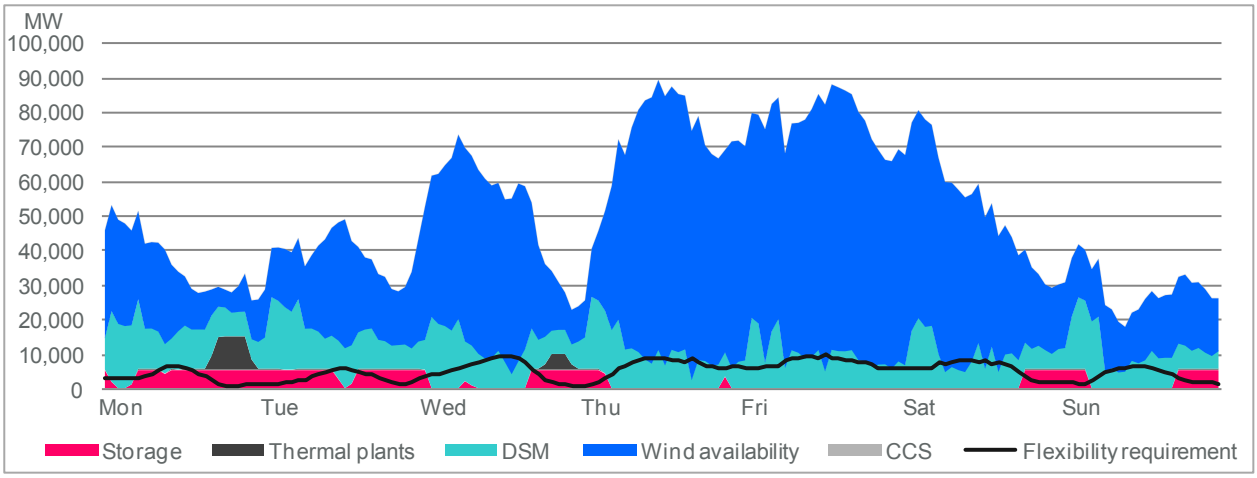

FIGURE 49: FLEXIBILITY OPTIONS GERMANY 2050 – WINTER WEEK (JUNE 8th-13th) [MW] *Source: EWI*

5.2.3 A closer look: the value of flexible CCS plants

Post-combustion carbon capture units in thermal power plants reduce both the power plant's efficiency and net power output due to the energy intensive process to capture CO_2 (Finkenrath 2011). However, it is technically possible to switch off CCS units on short notice and thus increase the output of the power plant. Therefore, power plants with flexible CCS units can offer short-term flexibility to the power market (Davison, 2009 or Martens et al., 2011).

As the future electricity generation is expected to be more volatile, due to a high share of fluctuating renewables, power plants with flexible CCS units might be cost-efficient as these plants can increase their power output when electricity demand is high and only limited wind and solar power is available (high electricity prices). As has been shown by Chalmers et al. (2009), considerable profits can be made by allowing a flexible operation of the capture plant in the case of high electricity and low CO_2 prices.

However, several flexibility options are available in electricity systems including open cycle gas turbines with large ramping capability and thermal power plants in part load operation, as well as storage technologies and demand side management processes. Therefore, the value of flexible CCS units can only be determined from a system perspective by comparing capital and variable costs of all flexibility options in different markets.

Flexible CCS units in thermal power plants are cost-efficient in Scenario A and sometimes in Scenario B, as these plants facilitate the integration of fluctuating renewable generation. The option of additional generation on short notice allows greater ramping of the residual demand and the possibility to balance forecast errors. In addition, flexible CCS plants contribute to ensure that peak demand can be met even considering hours with barely any renewable generation and high demand. In Scenario A, approximately 14-19 % of all CCS power plants are equipped with flexible CCS units. Due to higher CO_2 prices in Scenario B (2050: 100 $€_{2010}$/t CO_2), the option of flexible CCS plants is less attractive as a shutdown of the capture unit is associated with higher costs. Table 13 depicts the development of installed capacities of thermal power plants with CCS and compares the values to capacities with flexible CCS units.

TABLE 13: GROSS CAPACITY OF CCS TECHNOLOGIES (FLEXIBLE CCS) IN SCENARIO A AND B [GW]

	2030		2040		2050	
	total conventional capacity	of which with CCS (flexible CCS)	total conventional capacity	of which with CCS (flexible CCS)	total conventional capacity	of which with CCS (flexible CCS)
Scenario A (total)	494.5	51.1 (14 %)	500.5	78.4 (19 %)	509.2	78.4 (19 %)
- Austria	2.6	-	1.5	-	1.5	-
- BeNeLux	31.5	0.3 (0 %)	34.1	0.3 (0 %)	35.9	0.3 (0 %)
- Czech Republic	23.5	6.3 (24 %)	25.6	8.5 (32 %)	26.1	8.5 (32 %)
- Germany	83.0	10.0 (0 %)	83.4	20.3 (25 %)	80.9	20.3 (25 %)
- Denmark	3.9	-	3.6	-	3.1	-
- Eastern Europe	19.3	4.3 (0 %)	18.9	5.8 (0 %)	16.9	5.8 (2 %)
- France	87.9	-	86.6	-	85.6	-
- Iberian Peninsula	39.7	1.7 (0 %)	38.0	12.5 (2 %)	47.0	12.5 (2 %)
- Italy	53.4	15.2 (0 %)	53.9	15.2 (0 %)	54.8	15.2 (0 %)
- Poland	28.8	11.6 (49 %)	30.7	13.8 (49 %)	31.6	13.8 (49 %)
- United Kingdom	83.2	0.9 (0 %)	83.0	1.0 (0 %)	82.0	1.0 (0 %)
- Scandinavia	37.0	0.6 (0 %)	40.5	0.8 (13%)	43.1	0.8 (13 %)
- Switzerland	0.7	0.2 (0 %)	0.7	0.2 (0 %)	0.7	0.2 (0 %)
Scenario B	479.5	80.5 (0 %)	489.7	93.5 (2 %)	500.4	93.5 (2 %)
- Austria	2.3	-	0.8	-	0.5	-
- BeNeLux	31.4	2.5 (0 %)	33.8	2.5 (0 %)	35.4	2.5 (0 %)
- Czech Republic	22.5	6.6 (0 %)	24.3	7.4 (5 %)	24.8	7.4 (5 %)
- Germany	84.4	24.3 (0 %)	81.8	26.6 (4 %)	79.0	26.6 (4 %)
- Denmark	3.8	-	2.9	-	3.6	-
- Eastern Europe	20.4	5.8 (0 %)	18.8	5.8 (0 %)	16.8	5.8 (0 %)
- France	89.6	-	88.0	-	85.5	-
- Iberian Peninsula	38.6	6.6 (0 %)	37.7	13.1 (0 %)	46.7	13.1 (0 %)
- Italy	38.6	21.6 (0 %)	55.0	24.3 (0 %)	55.9	24.3 (0 %)
- Poland	25.3	8.1 (0 %)	25.7	8.7 (3 %)	27.0	8.7 (3 %)
- United Kingdom	84.5	2.6 (0 %)	79.3	2.6 (0 %)	81.0	2.6 (0 %)
- Scandinavia	37.0	0.8 (0 %)	40.5	0.9 (0 %)	43.1	0.9 (0 %)
- Switzerland	1.1	1.1 (14 %)	1.1	1.1 (14 %)	1.1	1.1 (14 %)

Source: EWI

As shown in the scenario analysis, balancing fluctuating generation and demand becomes more challenging in mostly renewable electricity systems. To illustrate the capability of flexible CCS units, Figure 50 depicts the dispatch realization in Poland during a December week in 2030 (Scenario A). Some lignite power plants, equipped with flexible CCS units, increase their output by switching off the CCS unit on Monday, Wednesday and Sunday afternoon to cope with low wind availability. CCS plants usually run in conjunction with an operating capture plant but CCS units are switched off to increase their power generation in about 260 hours of the year.

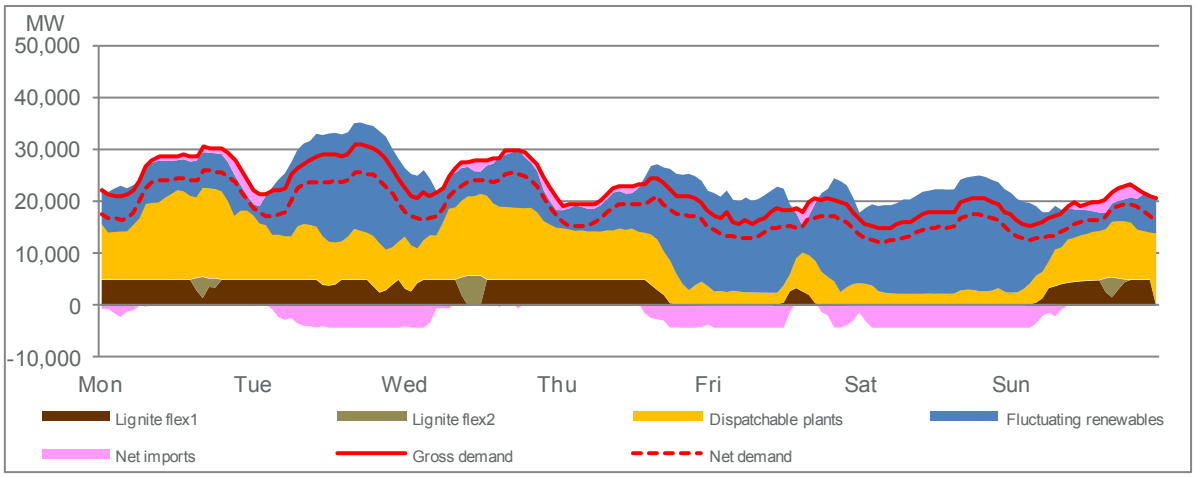

FIGURE 50: DISPATCH POLAND – DECEMBER WEEK 2030 [MW]

Source: EWI

The value of flexible CCS plants increases over time due to the further deployment of renewable energies. However, the scenarios assume increasing CO_2 emission prices and a large deployment of DSM processes. Thus, the flexibility option of CCS plants is less often used in the years 2040 and 2050. Table 14 shows the number of operating hours for CCS plants when CCS units are switched off.

TABLE 14: OPERATING HOURS OF CCS PLANTS WITH CCS UNIT SWITCHED OFF [h]

	2030	2040	2050
Czech Republic	6	2	6
Germany	-	50	30
Poland	264	196	143
Scandinavia	-	100	92

Source: EWI

For the example of Poland, flexible CCS plants run 196 hours in 2040 and 143 hours in 2050 with CCS units switched off. Figure 51 depicts the dispatch realization during a winter week in Poland in 2050 and shows that the capture unit is only shut down for a few hours on Wednesday afternoon. On other days, flexibility is mainly provided by other dispatchable plants such as biogas and storage, as well as demand side management processes. Based on the

scenario results, we conclude that flexible CCS units may be a cost-efficient way to provide flexibility in mostly renewable power systems. The profitability of flexible CCS technologies is discussed in Section 5.2.4 and then compared to other flexible technologies.

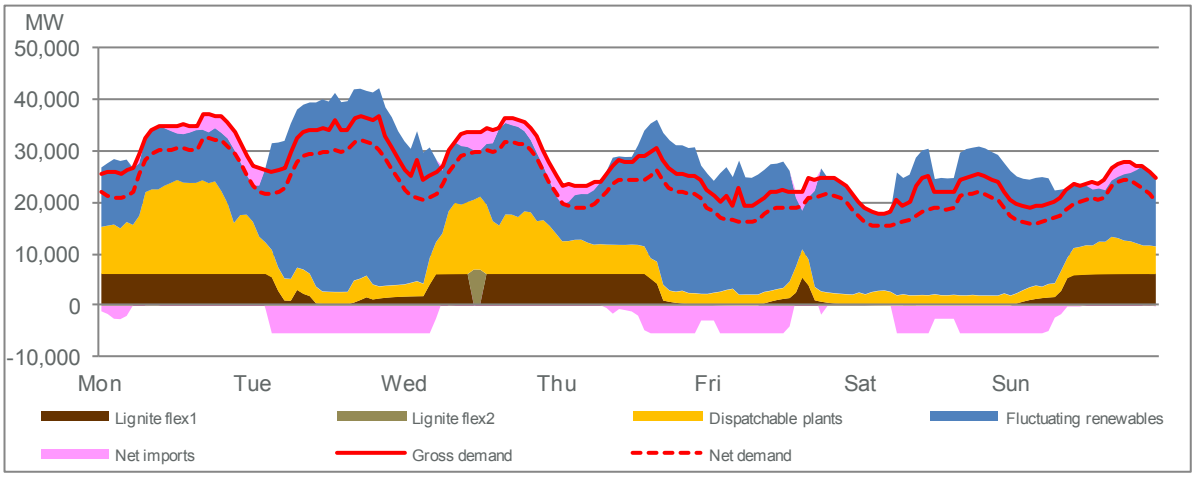

FIGURE 51: DISPATCH POLAND – DECEMBER WEEK 2050 [MW]

SOURCE: EWI

5.2.4 Costs of flexibility options: Merit order concept for flexible resources

In this section, we develop a merit order of flexibility options based on short-term marginal costs and discuss the influence of capital costs on the overall costs of different flexibility options. A merit order ranks the potential generation (from flexible technologies) in ascending order, according to their respective (short-run marginal) costs. As the flexibility of technologies highly depends on their status (e.g., thermal power plants on- or offline) and the specific hour (e.g., availability of demand side management), it is not clear a priori how to provide a general ranking of different flexibility options. Additionally, generation costs of storages or demand side management mainly represent opportunity costs rather than variable costs and therefore highly depend on the hours before and after the situation analysed. Thus, a merit order of flexibility can only be developed for a specific situation within the power sector (static concept) or as an average consideration with a certain inaccuracy due to information losses.

In the first step, we analyse the flexibility options in the two scenarios and rank them by short-term marginal costs for specific dispatch situations. As the available flexibility depends on the dispatch realization – as some capacities are already in use to meet electricity demand – we focus on different residual load levels to analyse extreme situations, such as high residual load levels in connection with a low availability of demand side management measurements. In the second step, we try to generalise the merit order approach to an average situation within the power sector under the consideration of the above discussed inaccuracy with regard to the status of thermal technologies or the availability of storage technologies. In the third step, we

discuss the influence of capital costs to rank flexible technologies based on their long-run marginal costs.

- Merit order of flexible technologies based on short-term marginal costs –

The analysis of specific hours allows a closer look at the availability of flexible resources in notable situations in regard to residual demand or required flexibility. Exemplarily selected hours in France and the UK are shown with the current production as well as the technical possible maximum and minimum generation in the following hour, depending on the availability of flexible resources (Figure 52 - Figure 55). This is supplemented by a merit order showing the costs of additional generation, i.e. the positive flexibility provision.

The costs of flexible power generation provided by thermal power plants are represented by variable costs. However, the costs of flexible power generation by storages or demand side management are opportunity costs. In this analysis, we estimate the opportunity costs of storages and demand side management using the marginal costs of the respective hour, as these represent the lower bound of additional generation costs. Imports are evaluated with the averaged marginal costs and weighted for the interconnector capacity of the (potential) export country.

- The costs of positive flexible power generation are correlated with the level of the residual load.
  In situations with high electricity demand and low feed-in of fluctuating renewables (as in the selected situations in Figure 52 - Figure 55), most capacity is already being used to meet electricity demand. Additional power generation can only be provided by technologies with comparatively high variable costs – often open cycle gas turbines.

- The costs of positive flexible power generation increase until 2050 due to higher fuel prices (assumption).
  The price for natural gas (assumed) has a strong impact on the costs of flexible power generation (positive), as open cycle gas turbines are often used to balance potential forecast errors of wind and solar generation. Hence, positive flexible power generation increases in the scenarios due to the increasing price (assumed) for natural gas (2050: 35.2 $€_{2010}$/MWh]. The resulting cost increase of positive flexibility can be observed by comparing the merit order in France in 2020 (Figure 52) and 2050 (Figure 53).

- A flexible operation of wind turbines (generation and curtailment) represents a cost-efficient option to provide positive and negative flexibility.
  Due to the large deployment of intermittent technologies (wind and solar power) in the scenarios, situations in which the available power generation from technologies with negligible variable costs exceeds the electricity demand occur more often. When

interconnector capacities are already fully used and storages operate at maximum capacity (charging operation), intermittent technologies can be quickly curtailed in order to achieve system stability. Moreover, the usage of planned curtailment of intermittent RES-E generation can reduce the need for positive flexibility. Situations with more wind or solar power than needed occur in both scenarios in the long term (demand met and interconnectors as well as storage capacities fully used). Naturally, ramping down thermal power plants (if possible, within technical restrictions) is cheaper than wind or solar curtailment due to the reduction of fuel costs. As depicted in Figure 55, large amounts of wind energy are available as positive flexibility in the UK in 2050.

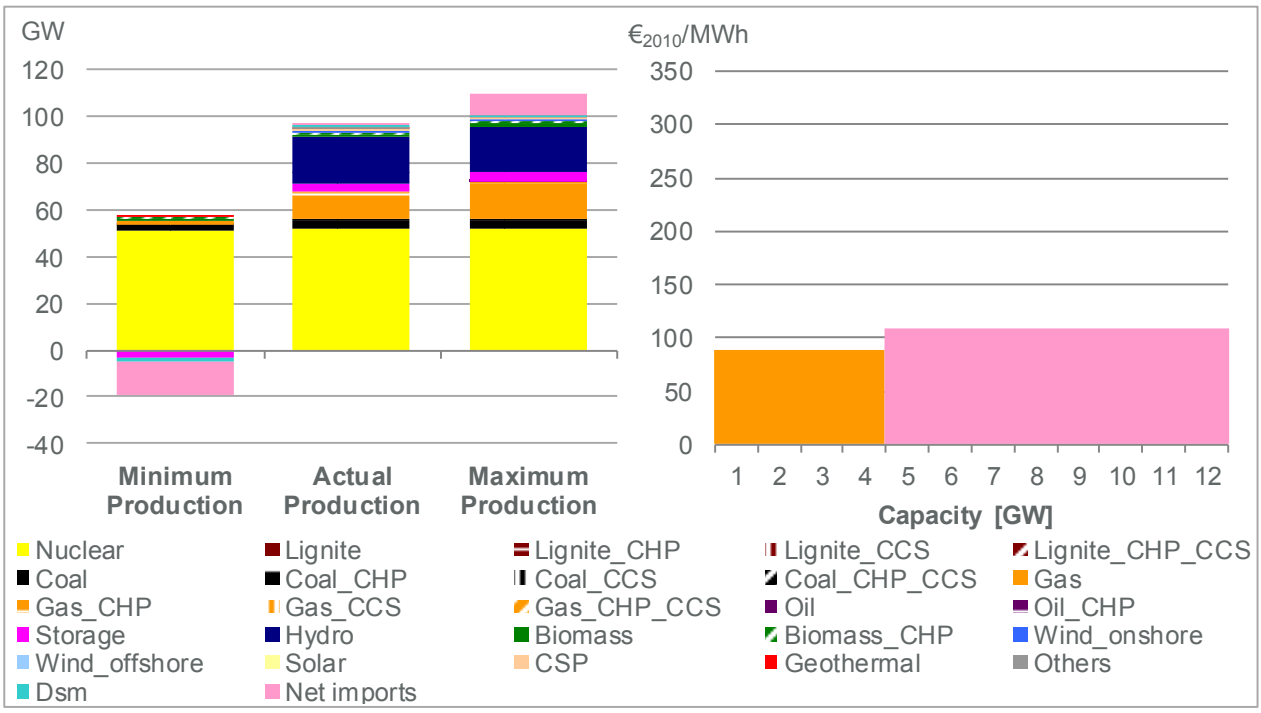

FIGURE 52: FLEXIBILITY OF POWER MIX (LEFT) AND MERIT ORDER FOR POWER INCREASE (RIGHT) [GW] HIGH RESIDUAL LOAD AT WINTER EVENING IN FRANCE 2020 *Source: EWI*

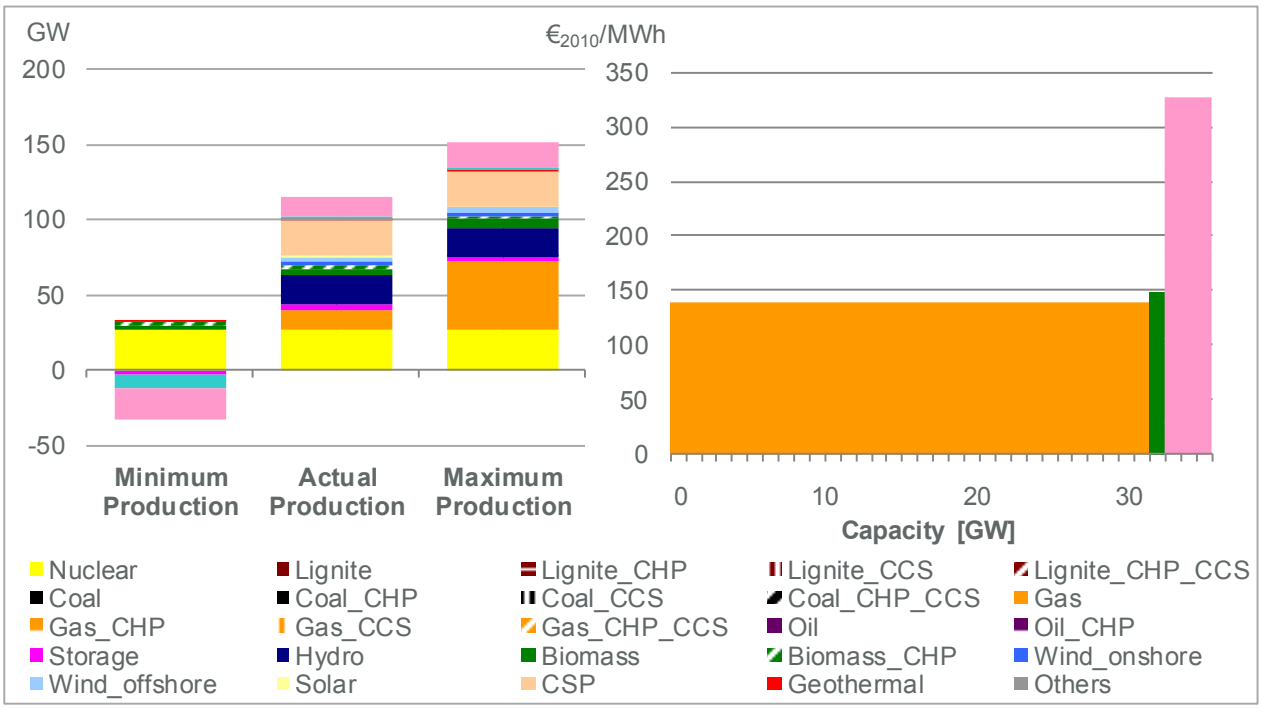

FIGURE 53: FLEXIBILITY OF POWER MIX (LEFT) AND MERIT ORDER FOR POWER INCREASE (RIGHT) [GW] HIGH RESIDUAL LOAD AT WINTER EVENING IN FRANCE 2050 *Source: EWI*

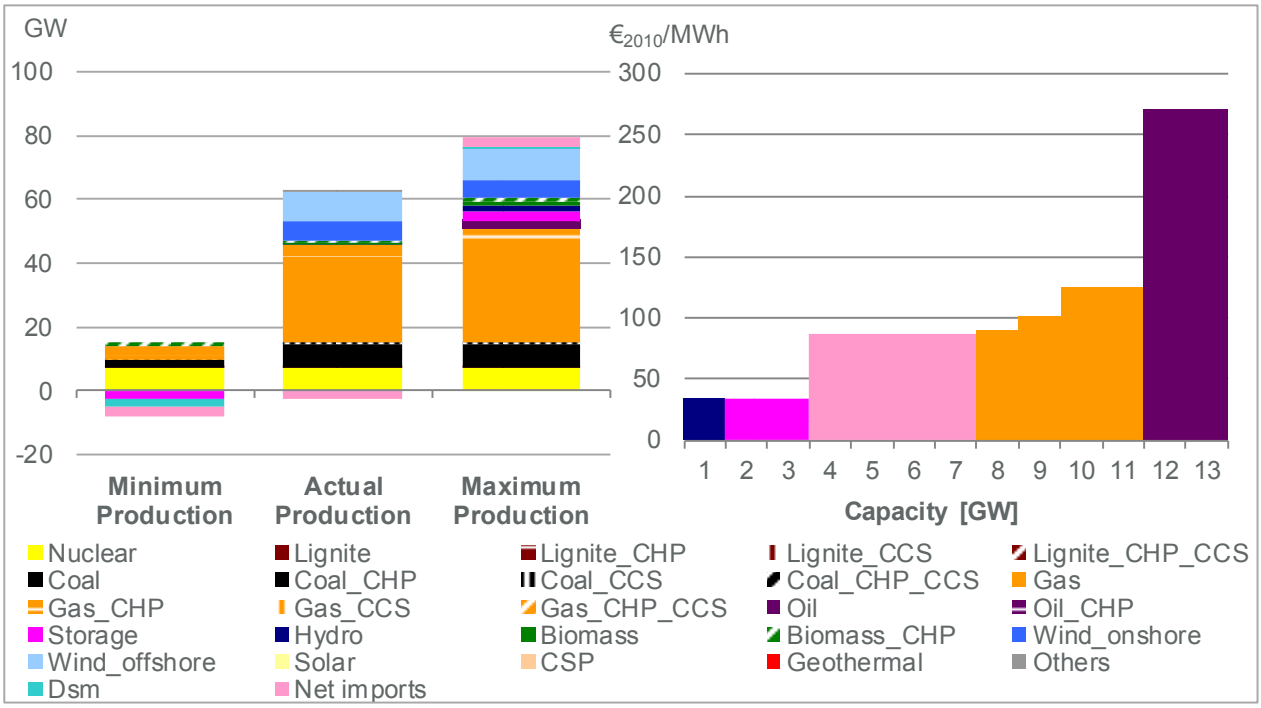

FIGURE 54: FLEXIBILITY OF POWER MIX (LEFT) AND MERIT ORDER FOR POWER INCREASE (RIGHT) [GW] HIGH RESIDUAL LOAD AT WINTER NIGHT IN THE UK 2020 *Source: EWI*

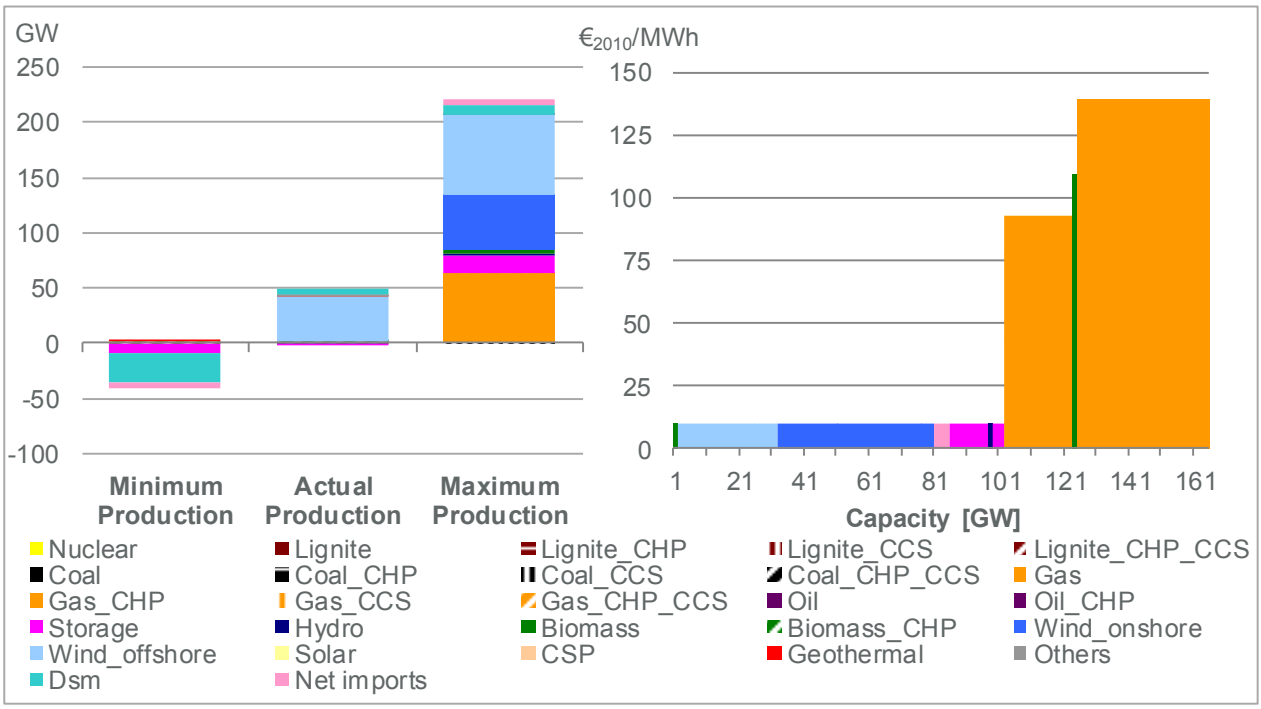

FIGURE 55: FLEXIBILITY OF POWER MIX (LEFT) AND MERIT ORDER FOR POWER INCREASE (RIGHT) [GW] HIGH RESIDUAL LOAD AT FALL NIGHT IN THE UK 2050 *Source: EWI*

- Average merit order of flexibility options -

In this part, the merit order for the specific situations analysed above is extended to a merit order for an average situation. However, a loss of information occurs as time dependencies such as part-load operations and ramping costs, as well as opportunity costs of storages, cannot be displayed. Hence, the option to operate at part-load for thermal power plants, storage technologies and imports is not considered in the following analysis. In Figure 56 and Figure 57, we compare installed capacities, flexibility provisions and costs of positive flexibility in the United Kingdom and Czech Republic in 2020 and 2050.

Both figures combine four individual graphs (2020 left and 2050 right). The lower graphs show a merit order for an average situation based on variable costs and installed capacities. As opportunity costs are not considered, storages, demand side management and imports are represented with zero variable costs. Moreover, the use of planned curtailment of intermittent RES-E generation is another option to provide flexibility (at zero costs). The upper graphs show the dispatch flexibility that is dependent on the residual load level. For each residual load level, running capacities can be identified at the abscissa and the positive flexibility at this residual load level is shown on the ordinate. Both graphs are scaled based on the installed capacity. Hence, it is possible to estimate flexibility costs from the merit order displayed in the lower graph.

- In the long term, the availability of positive flexibility increases in all countries.
  Dispatch flexibility increases in all regions in the long term due to the deployment of flexible gas-fired power plants instead of coal and nuclear power plants. Thus, the available positive flexibility at low levels of residual demand almost doubles before 2050, increasing even more at high residual load levels (Figure 56 and Figure 57).

- Flexibility costs increase in the long term; in particular in regions with a rather inflexible power plant portfolio.
  Due to a more flexible power plant portfolio in the UK in 2050, larger changes in residual load as well as potential deviations from forecasted dispatch realizations (based on forecasted demand and RES-E generation) are associated with lower costs than in 2020. The situation is different for the Czech Republic due to a higher share of (inflexible) nuclear and lignite CCS capacities in 2050 than in 2020.

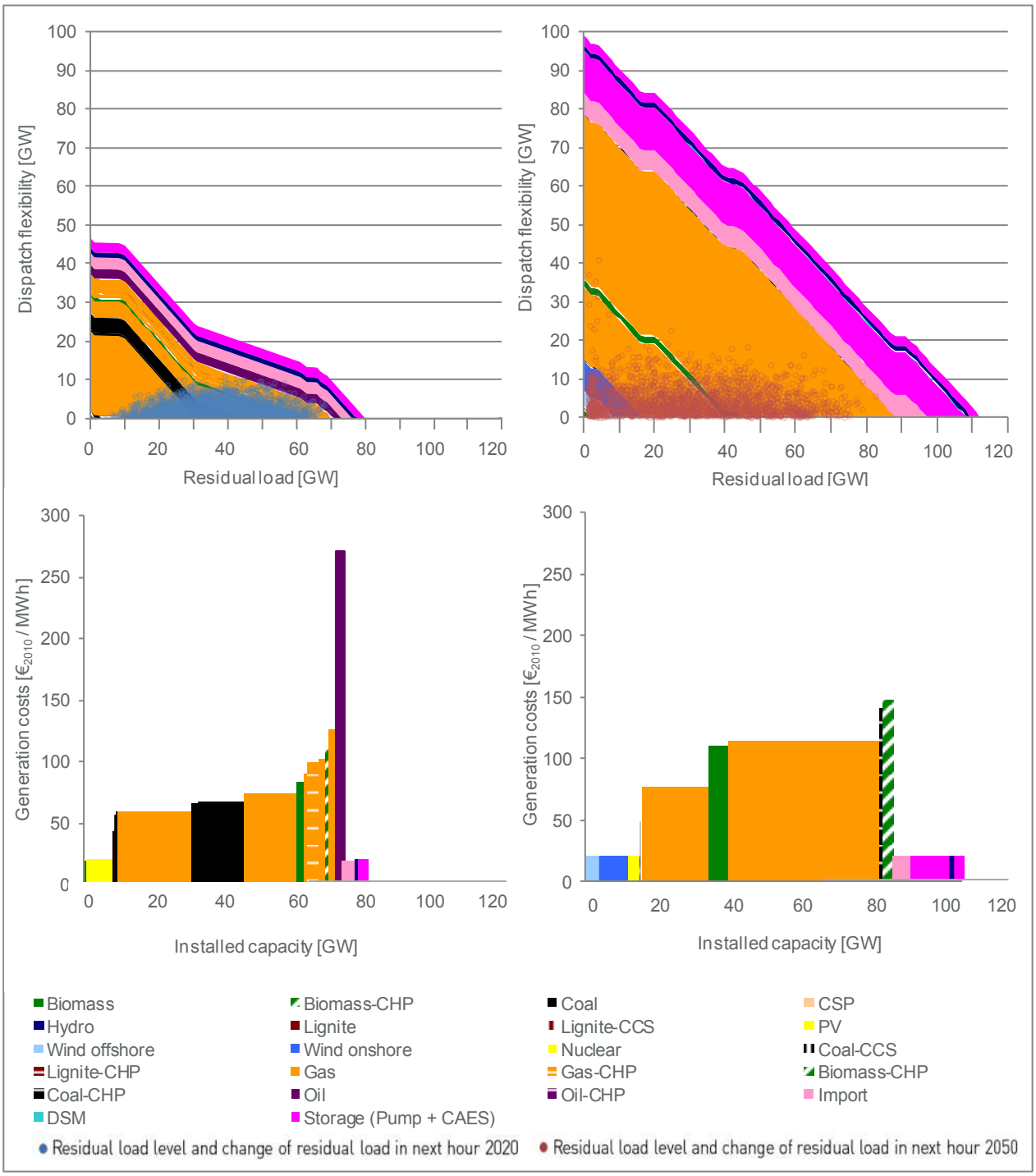

FIGURE 56: DISPATCH FLEXIBILITY AND COSTS FOR THE UK 2020 (LEFT) AND 2050 (RIGHT) IN SCENARIO A [GW]

Source: EWI

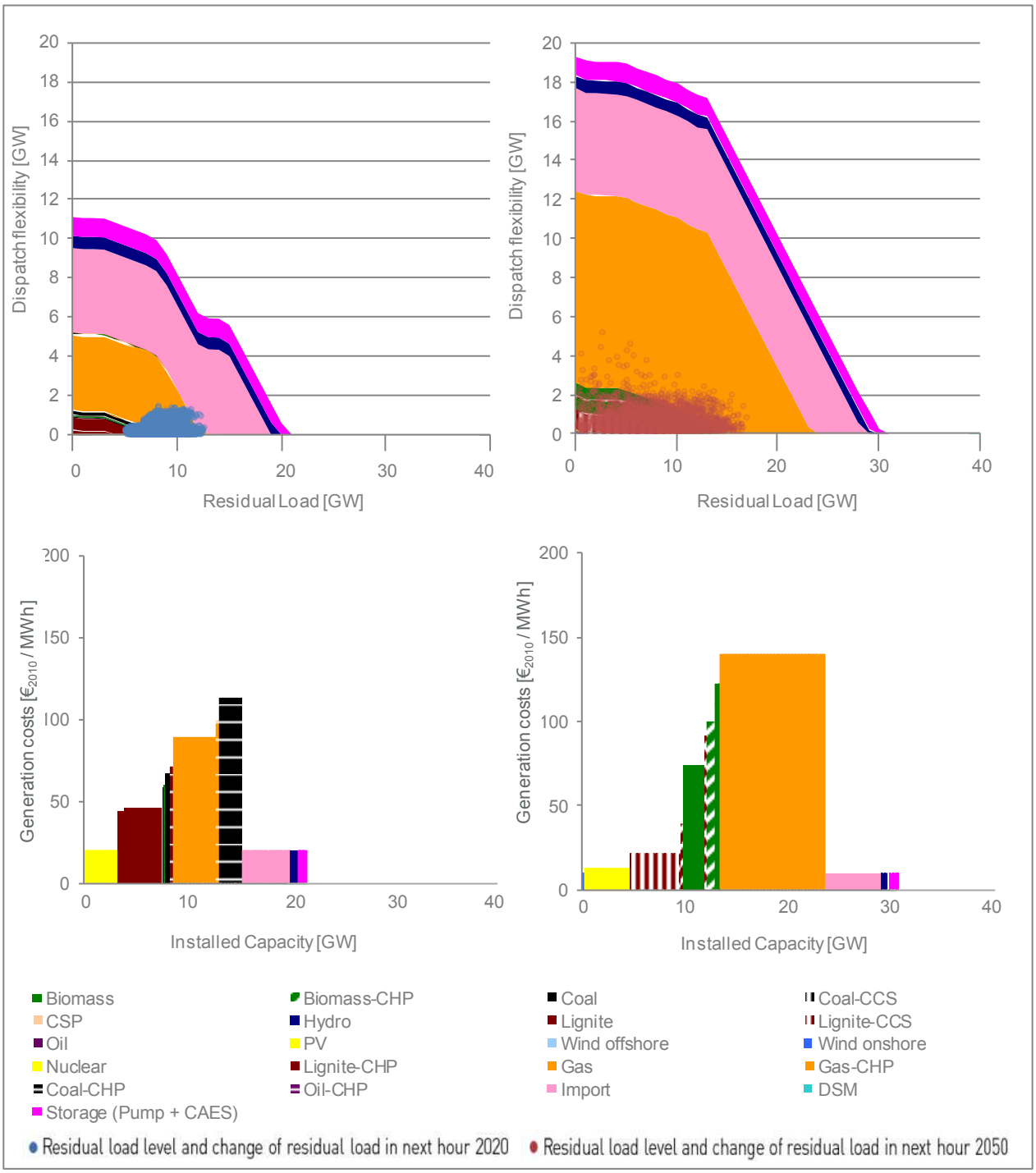

FIGURE 57: DISPATCH FLEXIBILITY AND COSTS FOR CZECH REPUBLIC 2020 (LEFT)) AND 2050 (RIGHT) IN SCENARIO B [GW]

Source: EWI

- Influences in the long term: investment decisions and affecting drivers-

Dispatch flexibility can be provided by many technologies with different capital to operating cost ratios. However, technologies are dichotomous with respect to their availability: in specific, they can either cover residual load or provide additional flexibility of short-term power generation.

The capacity mix has a significant influence on the actual availability and especially on the costs of flexibility. There are two main drivers for investment decisions: First, achievable full load hours are the main driver for investments as they reflect the relationship between capital and operating costs. Base-load technologies, such as nuclear or lignite power plants, are cost-efficient when a high number of full load hours are realised. However, the realization of full load hours is influenced by the level and structure of the residual load curve. Second, the amount of capacity necessary to meet peak demand (securely available capacity) is determined by the intended level of security. Hence, investment decisions also take the technology specific capacity factors – fraction of capacity which can be seen as securely available – into account.

Figure 58 and Figure 59 depict the relationship between annual full costs and achievable full load hours based on the residual load duration curve in France and Poland in 2020 and 2050. The upper graphs show the annual costs [T€$_{2010}$/MW] of electricity generation for different technologies as a function of full load hours achieved. These annual costs include capital, fixed operation and maintenance as well as variable costs. The lower graphs show the installed capacities as well as the regional residual load duration curve.[1] The graphs on the left side represent the results for the year 2020 and on the right for the year 2050.

- In both scenarios, open cycle gas turbines are the cost-efficient technology to provide short-term flexibility and security of supply.
  As discussed in Section 5.1, achievable full load hours of non-renewable technologies decrease over time. Hence, flexible technologies with relatively high capital costs have a comparative disadvantage to open cycle gas turbines (investment costs: 400 €$_{2010}$/kW). Thus, investments in storages, large coal or combined cycle gas turbines and flexible CCS plants are only cost-efficient if a high number of full load hours can be achieved.

[1] The residual load duration curve represents the actual load duration curve adjusted by intermittent renewable generation, storage operations as well as imports and exports.

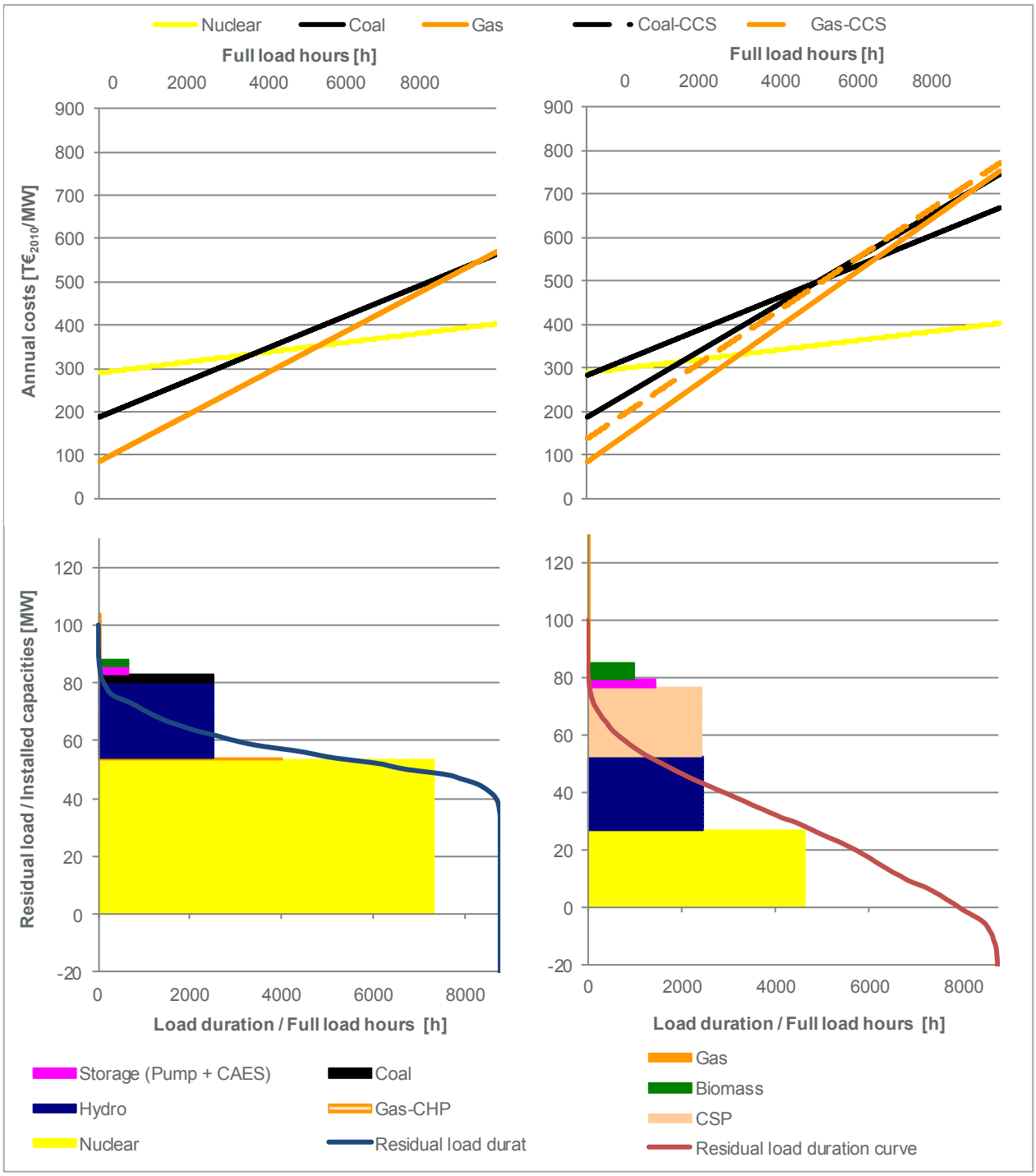

FIGURE 58: LONG TERM MERIT ORDER FOR FRANCE FOR SCENARIO A IN 2020 (LEFT) AND 2050 (RIGHT)

Source: EWI

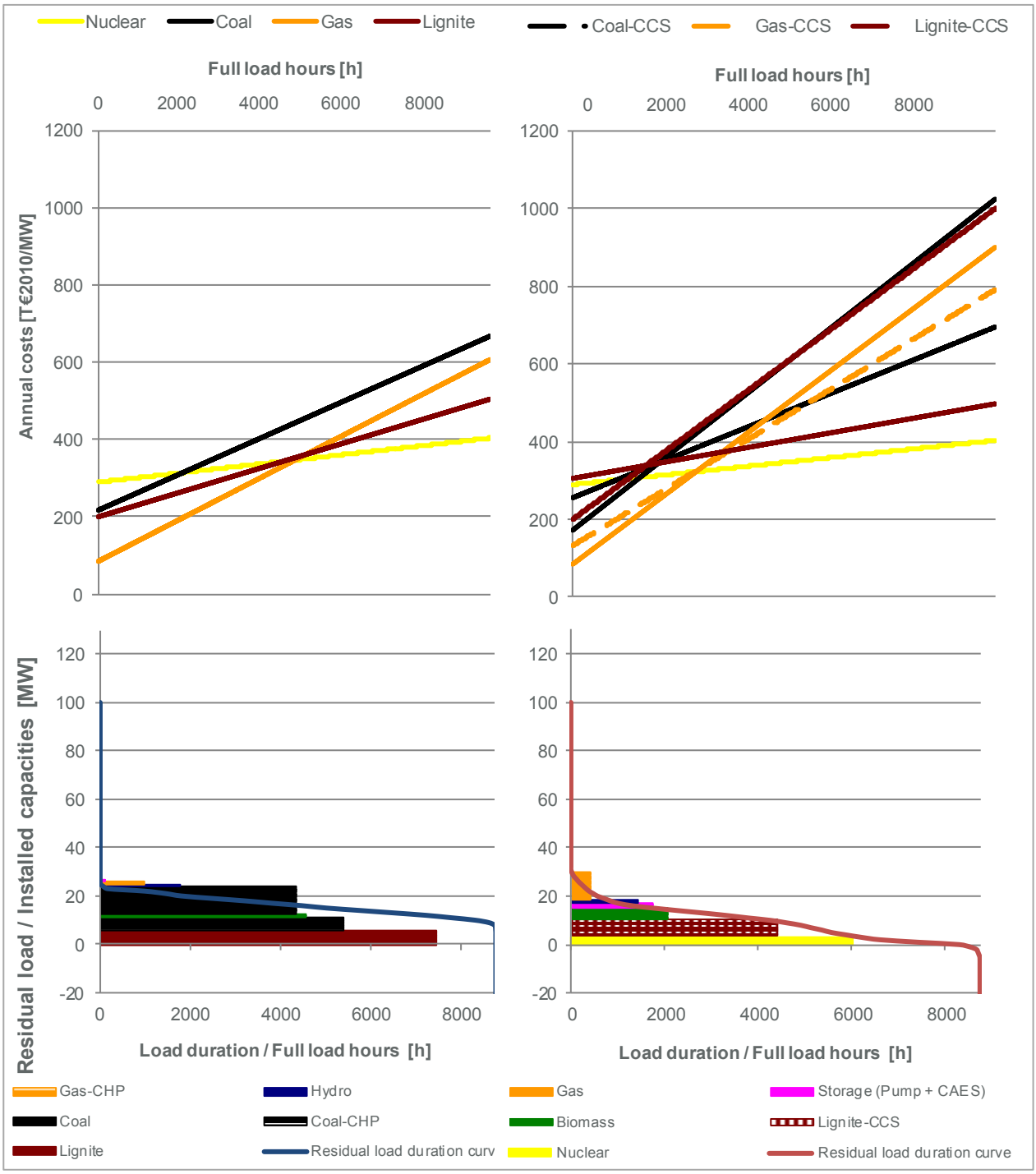

FIGURE 59: LONG TERM MERIT ORDER FOR POLAND IN SCENARIO B IN 2020 (LEFT) AND 2050 (RIGHT)

Source: EWI

5.2.5 Potential profits of flexibility options and "locked-in" power plants

The electricity market model used in this study optimizes investments and generation from a central planner perspective in order to minimize total system costs. This approach corresponds to welfare maximization in a competitive market under perfect information. Some technologies are able to realise profits due to capacity limits or fuel potential (e.g., limited hydro sites or biomass fuel restrictions). In this section, we analyse potential revenues, costs and profits of conventional and renewable technologies in several regions.

Potential revenues are estimated based on electricity prices that purely represent short-term marginal costs of electricity generation.[1] Investment costs are annualized over a depreciation time of 20 years (based on an interest rate of 5 %). Annual operation and maintenance costs occur independently of the actual usage. The reported accumulated discounted profits include revenues and variable, annual maintenance costs as well as investment costs over the technology-specific technical lifetime.

- Profitability of investments in Scenario A –

- Investments in base-load capacities (nuclear and lignite power plants) in 2020 are profitable in all regions.
  Given the scenario assumptions, investments in nuclear and lignite-fired power plants in 2020 are profitable in all regions. As discussed in Section 5.1, full load hours of nuclear and lignite power plants decrease over time due to the large deployment of renewable energies. However, due to relatively low variable costs (assumption), nuclear power plants still achieve more than 5000 full load hours in 2050 (more than 7000 hours in 2020) and lignite-fired plants run almost 4000 hours in 2050 (more than 6500 hours in 2020). Hence, investments in these technologies in 2020 are profitable – even considering the large deployment of renewable energies (shown in Figure 60).

- Mid-load capacities (hard coal and combined cycle gas turbines) can recover their capital costs.
  As for base-load capacities, achievable full load hours of combined cycle gas turbines and hard coal plants decrease over time. However, these plants can regain their capital costs due to increasing electricity prices – with particularly high prices occurring in hours with low wind and solar generation (due to the usage of open cycle gas turbines). Figure 61 shows the accumulated discounted profits of a few mid-load technologies in the United Kingdom, Italy and the BeNelux.

[1] To be precise, electricity prices are estimated on the basis of the dual variable of the equilibrium condition for power supply (power balance).

- Peak-load capacities (open cycle gas turbines) are not able to recover their capital costs with electricity prices that are purely based on short-term marginal costs.

  Open cycle gas turbines are deployed in all regions as backup capacities for situations when high demand in connection with low wind and solar feed-in occur. From a system perspective, these plants are the cost-efficient option to ensure peak demand due to relatively low capital costs. However, these investments are not profitable when electricity prices are purely based on short-term marginal costs (shown in Figure 62).

  To recover their capital costs, open cycle gas turbines would need additional revenues of about 600,000-700,000 €$_{2010}$/MW over their technical lifetime (which represents about 90-98 % of their capital and fixed operating costs). Under the consideration of about 230-1,200 operating hours over their technical lifetime, peak markups of 50-300 €$_{2010}$/MWh on electricity prices (that are purely based on short-term marginal costs; in hours OCGT are generating) are needed so open cycle gas turbines can recover their capital costs. It is not clear if such peak load markups will be provided in an energy-only market. Thus, further consideration should be given to the challenge of system adequacy in an environment which possibly does not trigger investments into secured capacity due to potentially missing revenues.

- Some renewable technologies (onshore wind and hydro) are profitable at the best European sites. However, most renewable technologies cannot regain their capital costs without additional payments.

  Given the assumed increasing fuel prices, decreasing capital costs of most renewable technologies and increasing prices for CO_2 emissions, investments in onshore wind turbines at the best European sites (in additional to large hydro plants) are already profitable in 2020. However, most investments in renewable energies in 2020 would need additional payments to be profitable (shown in Figure 63). This includes all photovoltaic capacities – even at the best European sites for solar power such as the Iberian Peninsula.

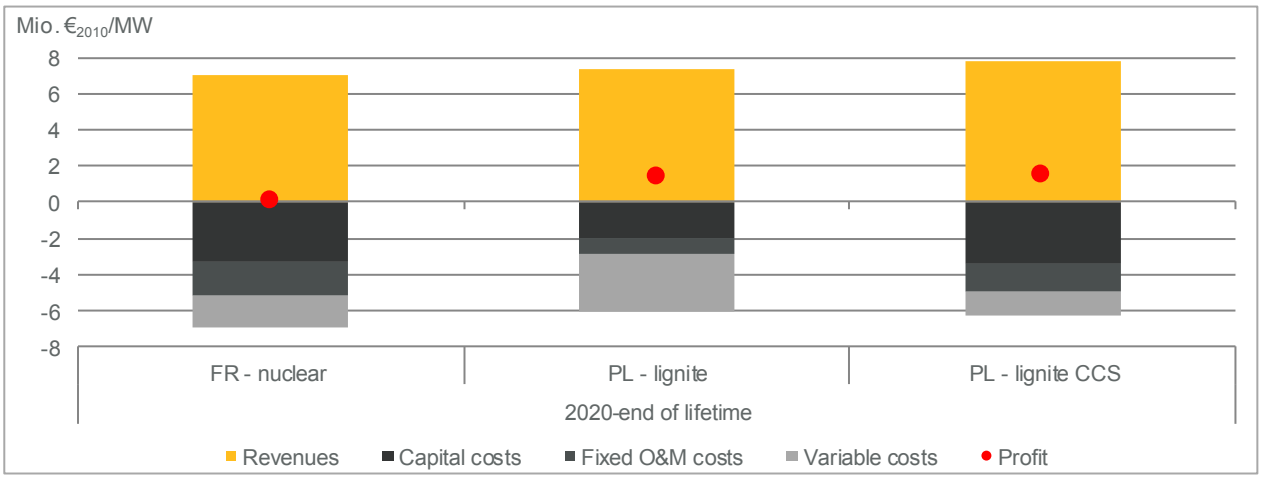

FIGURE 60: ACCUMULATED DISCOUNTED PROFITS OF BASE-LOAD CAPACITIES (SCEN A) [MIO. €$_{2010}$/MW]

Source: EWI

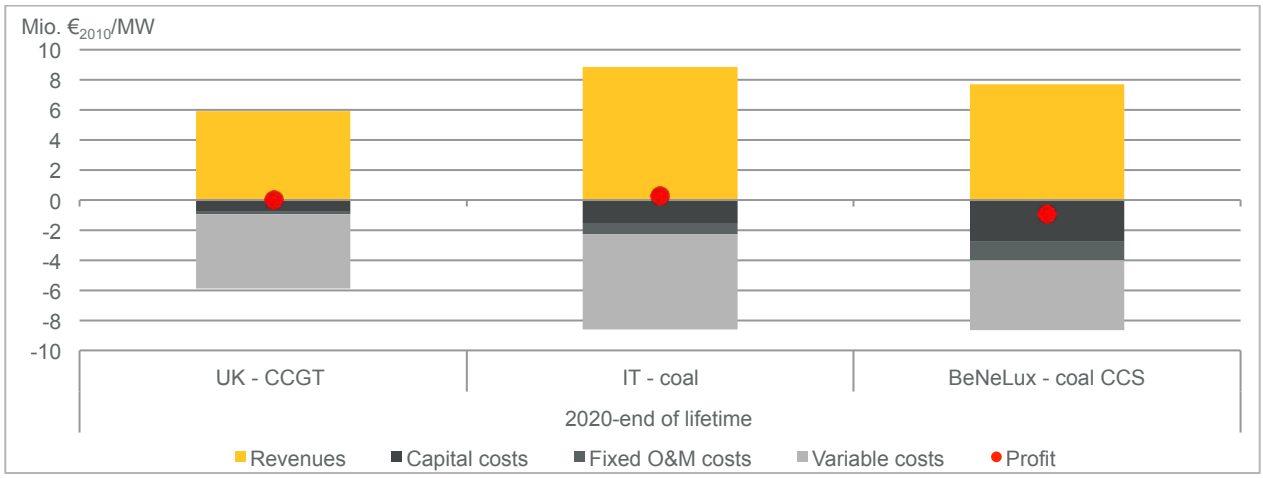

FIGURE 61: ACCUMULATED DISCOUNTED PROFITS OF MID-LOAD CAPACITIES (SCEN A) [MIO. €2010/MW] *Source: EWI*

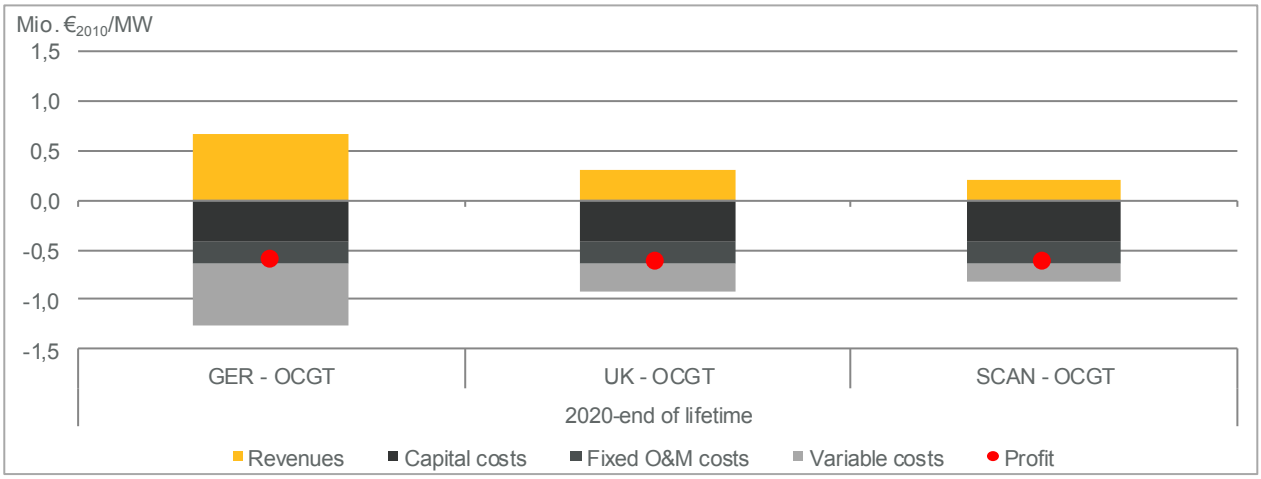

FIGURE 62: ACCUMULATED DISCOUNTED PROFITS OF PEAK CAPACITIES (SCEN A) [MIO. €2010/MW] *Source: EWI*

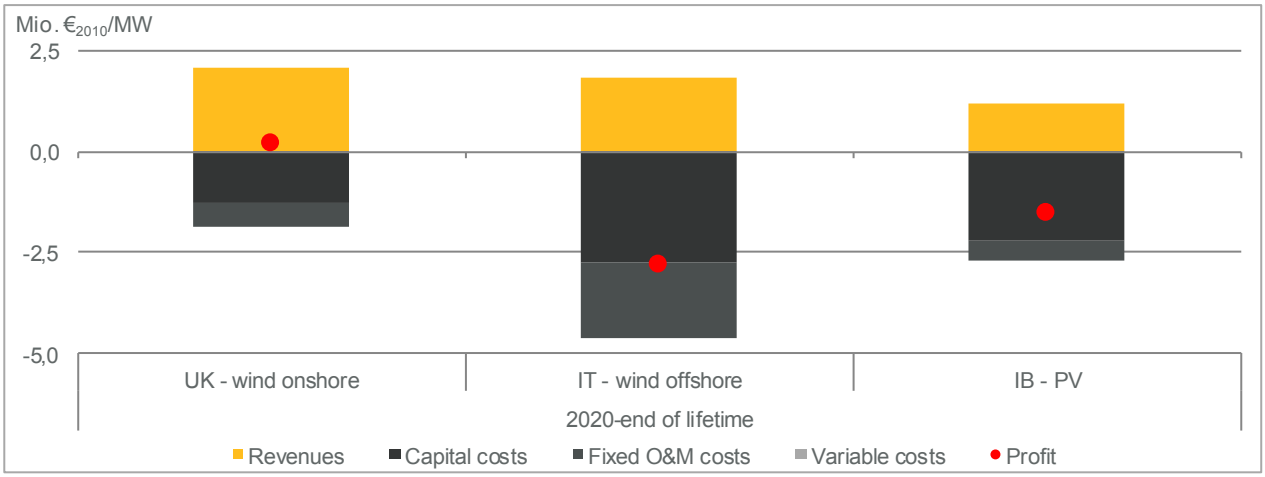

FIGURE 63: ACCUMULATED DISCOUNTED PROFITS OF RENEWABLES (SCEN A) [MIO. €2010/MW] *Source: EWI*

- Profitability of investments in Scenario B –

- "Locked-in" power plants, as well as investments in carbon intensive power plants, face low returns in the long term due to high CO_2 prices.
  Achievable full load hours of conventional power plants decrease over time due to the large deployment of renewable energies until 2050. If conventional generators also face a strong increase of CO_2 prices (Scenario B: 100 €/t CO_2 in 2050), carbon intensive power plants are not competitive in the long term due to relatively high variable costs. Figure 64 depicts the annual revenues in comparison to the specific costs [$€_{2010}$/MW] of a lignite-fired power plant constructed in Germany in 2020 in Scenario A and B (not discounted values). In the long term, such a lignite-fired power plant will only realise a few full load hours in Scenario B and thus investors would not be able to regain their capital costs given electricity prices that are purely based on short-term marginal costs.

- Due to higher CO_2 emission prices, CCS technologies are more often profitable in Scenario B than in Scenario A.
  In Scenario B, almost all lignite and hard coal-fired power plants are equipped with CCS units in 2050 due to high CO_2 emission prices. Due to the higher electricity prices in Scenario B, power plants equipped with CCS units are more often profitable than in Scenario A. Furthermore, lignite power plants with CCS units are highly profitable, as depicted in Figure 65.

- Renewable technologies that are only deployed at their best European sites – wind energy along the coastline of Northern Europe and solar power in Southern Europe – are profitable (even considering high CO_2 prices).
  The regional conditions for wind and solar technologies are heterogeneously distributed throughout Europe. Wind technologies are able to achieve more than 4000 full load hours at some sites along the coastline of Northern Europe and solar technologies more than 2000 full load hours in Southern Europe. Some of these technologies are profitable in the scenarios, with high CO_2 emission prices in Scenario B increasing their competitiveness. However, most renewable technologies are not able to regain their capital costs without any additional payments.

Most base- and mid-load technologies are profitable with electricity prices that are purely based on short-term marginal costs. However, peak load capacities which are built to ensure peak demand are not able to regain their capital costs in the analysed scenarios. The large deployment of open cycle gas turbines in both scenarios raises questions about whether or not investors are willing to invest in these technologies.

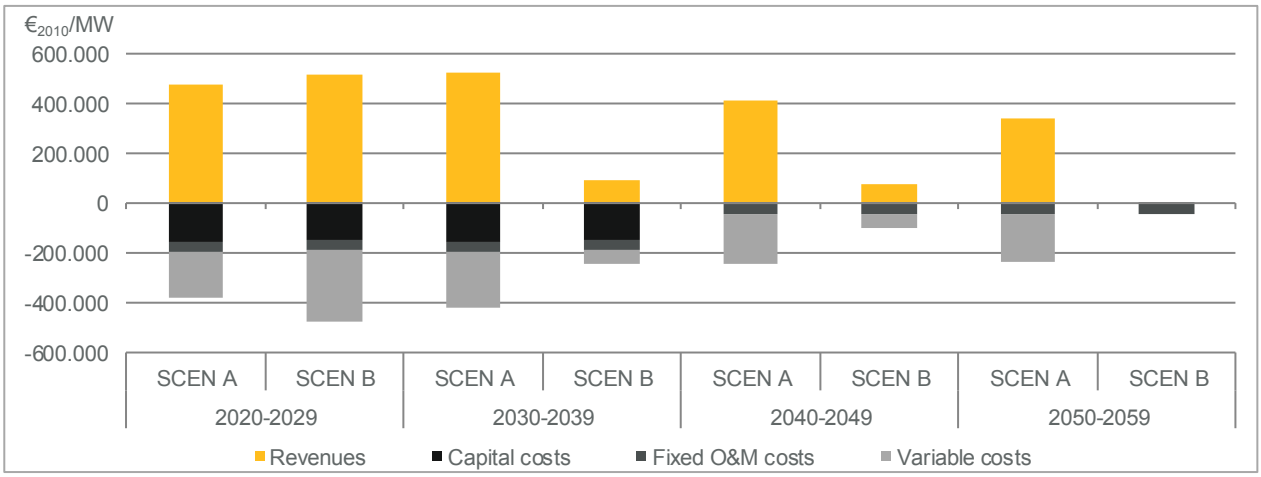

FIGURE 64: CASH FLOWS OF LIGNITE-FIRED PLANT IN GERMANY INVESTED IN 2020 [€2010/MW]. *Source: EWI*

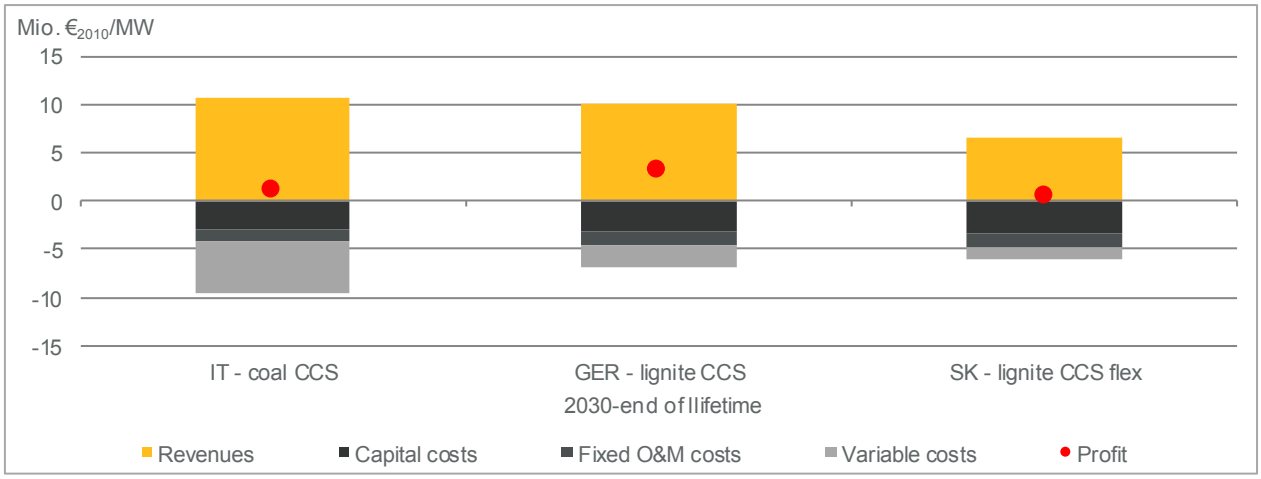

FIGURE 65: ACCUMULATED DISCOUNTED PROFITS OF CCS TECHNOLOGIES (SCEN B) [MIO. €2010/MW] *Source: EWI*

6 SUMMARY AND CONCLUSION

The scenario-based analysis of the effects of a high share of fluctuating renewables showed that regardless of CO_2 prices, the share of base- and mid-load capacities decreases, while the share of peak-load capacity (i.e., open cycle gas turbines) increases. This is explained by the reduction of realizable full load hours of non-renewable capacities rendering peak-load capacities the more cost-efficient option. For achieving system adequacy, peak-load capacities (serving as backup capacities) with relatively low capital costs are the cost-efficient complements to large amounts of intermittent renewables in an electricity system.

Under the consideration of technical capabilities, open cycle gas turbines offer more flexibility than other thermal plants. The share of intermittent renewables may increase and it may become more challenging to integrate the stochastic generation of intermittent renewables in the European electricity system until 2050. However, the simultaneous reduction of full load hours of non-renewables makes investments into open cycle gas turbines cost-efficient which can also provide the needed flexibility. Thus, under the condition of system adequacy, flexibility poses a challenge for neither dispatch realizations nor balancing forecast errors.

The costs for providing flexibility increase along with the overall production costs in the scenarios presented. Gas-fired power plants with relatively high variable costs are deployed due to less realizable full load hours of non-renewable plants. This shifts costs of flexibility even at relatively low residual load levels to more expensive technologies. Apart from storage, demand side management and imports, thermal power plants with flexible CCS units are another option to provide short-term flexibility due to their ability to switch off the CCS unit on short notice. Flexible CCS units in conjunction with coal power plants could be cost-efficient in markets with a high share of intermittent renewables, relatively low coal prices as well as relatively high CO_2 and natural gas prices.

Under the assumption of system adequacy, peak-load capacities suffer from missing revenues in an energy-only market with high competition, given a high share of renewables and electricity prices purely based on short-term marginal costs. It is rather doubtful that sufficient investments will be made, although they are required as backup capacities.

The resulting conclusions and insights from this study lay the groundwork for further analyses of how the necessary changes in power systems can be achieved. In particular, further consideration should be given to the challenge of system adequacy in an environment which possibly does not trigger investments into secured capacity due to potentially missing revenues. The advantages and disadvantages of compensation mechanisms for capacity in a situation where an energy-only market may not provide sufficient revenues for peak capacities have to be discussed.

ABBREVIATIONS

a	annum (year)
bn	billion
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
€	Euro
ENTSO-E	European Network of Transmission Operators for Electricity
GDP	gross domestic product
GW	gigawatt
GWh	gigawatt hour
h	hour
HDR	hot-dry-rock
kW	kilowatt
mio	million
MW	megawatt
MWh	megawatt hour
MWh_{el}	megawatt hour electric
MWh_{th}	megawatt hour thermal
NTC	net transfer capacity
O&M	operation and maintenance
OCGT	open cycle gas turbine
PV	photovoltaics
RES-E	renewable energy sources for electricity
t	ton
TWh	terawatt hour
TWh_{el}	terawatt hour electric
TWh_{th}	terawatt hour thermal
US$	US-Dollar

LIST OF FIGURES

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SOURCES

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APPENDIX

A.1 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	n.a.	0.60	0.60	0.00	0.00	0.60	0.60	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	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.	1.16	1.25	1.37	1.37	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	n.a.	0.18	0.00	0.00	0.00	0.18	0.00	0.00	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	0.45	0.45	0.44
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	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
Biomass	0.00	0.89	1.07	1.30	1.57	0.89	1.07	1.30	1.57
Biomass-CHP	n.a.	0.38	0.46	0.56	0.67	0.38	0.46	0.56	0.67
Wind onshore	0.97	2.58	3.47	3.93	4.43	2.58	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	0.32	0.32	5.00	9.00	0.32	0.32	5.00	9.00
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.20	0.28	0.34	0.00	0.20	0.28	0.34
Demand side management	n.a.	1.90	3.52	6.47	10.97	1.90	3.52	6.47	10.97
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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	5.52	2.41	0.00	0.00	0.00	1.88	0.00	0.00	0.00
Coal-CHP	n.a.	8.45	9.05	9.85	8.51	5.45	3.63	1.45	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	11.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-CHP	n.a.	9.15	3.06	0.00	0.00	11.43	4.38	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	3.32	3.02	2.08
Oil (incl. CHP)	1.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	n.a.	0.24	0.26	1.81	2.71	0.15	0.61	1.93	2.48
Hydro	40.68	39.97	39.97	39.97	39.97	39.97	39.97	39.97	39.97
Biomass	4.63	0.05	0.34	0.56	0.87	0.05	0.78	1.12	1.01
Biomass-CHP	n.a.	1.21	2.54	2.90	2.90	2.80	3.28	3.35	3.18
Wind onshore	2.01	4.89	6.59	7.46	8.41	4.89	6.59	7.46	8.41
Wind offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PV	0.03	0.34	0.34	5.34	9.62	0.34	0.34	5.34	9.62
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.01	1.01	1.40	1.69	0.01	1.01	1.40	1.69
Demand side management	n.a.	0.32	0.50	0.75	1.15	0.31	0.49	0.77	1.13
Others	1.78	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.79

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	3.36	3.41	3.55	3.55	3.27	3.56	3.34	3.14
Own Consumption of Power Plants	5.84	1.77	1.81	1.96	1.95	1.67	1.97	1.75	1.54
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	0.65	0.86	3.27	4.92	0.52	1.34	3.46	4.59
Gross Electricity Consumption	69.23	72.37	77.34	84.21	90.04	72.14	77.97	84.19	89.30
Net Imports	4.86	2.78	11.08	11.41	11.47	2.40	10.80	15.85	17.40
Gross Electricity Generation	67.10	69.59	66.26	72.80	78.57	69.75	67.17	68.34	71.90

** 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*

BeNeLux	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2006/2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	6.31	4.30	7.63	7.18	7.18	4.30	7.46	11.29	11.29
Lignite	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	5.60	4.30	3.70	1.88	0.00	4.30	3.70	1.88	0.00
Coal-CHP	n.a.	2.45	4.63	5.52	5.15	1.12	0.75	0.38	0.01
Coal-CCS	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	22.16	10.02	10.63	17.81	22.00	11.36	12.77	16.54	20.56
Gas-CHP	n.a.	9.23	3.08	0.00	0.00	9.23	3.08	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	1.92	1.92	1.92
Oil (incl. CHP)	0.61	0.40	0.02	0.02	0.02	0.40	0.02	0.02	0.02
Storage	2.40	1.31	1.31	1.31	3.81	1.31	1.31	1.98	4.78
Hydro	0.18	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Biomass	0.34	3.09	3.73	4.51	5.46	3.09	3.73	4.51	5.46
Biomass-CHP	n.a.	1.62	1.95	2.37	2.86	1.62	1.95	2.37	2.86
Wind onshore	1.87	6.13	9.54	11.54	13.97	6.13	9.54	11.54	13.97
Wind offshore	0.11	5.18	22.80	33.42	35.77	5.18	22.80	33.42	35.77
PV	0.08	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	n.a.	0.00	1.07	1.07	1.07	0.00	1.07	1.07	1.07
Demand side management	n.a.	3.44	6.97	11.78	18.56	3.44	6.97	11.78	18.56
Others	1.63	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26

Generation in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	49.74	31.64	52.24	43.36	41.76	31.64	52.22	68.02	64.84
Lignite	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	29.02	30.77	17.65	6.52	0.00	28.59	11.32	3.58	0.00
Coal-CHP	n.a.	17.53	30.22	30.85	26.14	8.10	4.76	1.20	0.01
Coal-CCS	0.00	1.82	1.37	1.00	0.85	1.81	1.44	1.02	0.85
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	90.48	19.23	8.98	10.42	10.66	25.32	12.92	11.18	9.43
Gas-CHP	n.a.	45.50	8.11	0.00	0.00	62.05	14.34	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	11.66	8.57	7.11
Oil (incl. CHP)	2.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	n.a.	0.76	2.16	2.79	5.74	0.73	2.03	3.43	6.69
Hydro	2.82	0.70	0.68	0.58	0.56	0.70	0.68	0.58	0.56
Biomass	10.74	1.03	1.44	2.35	3.32	0.64	1.35	2.43	3.47
Biomass-CHP	n.a.	5.49	6.21	6.51	6.51	5.79	6.29	6.51	6.51
Wind onshore	4.96	14.38	22.05	23.76	28.19	14.38	22.24	24.20	28.16
Wind offshore	0.00	20.88	91.76	131.55	139.82	20.88	91.80	131.64	139.66
PV	0.10	1.92	1.91	1.79	1.73	1.92	1.91	1.81	1.71
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.02	5.31	5.31	5.31	0.02	5.31	5.31	5.31
Demand side management	n.a.	0.89	1.36	1.90	2.63	0.89	1.35	1.90	2.67
Others	5.81	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	198.34	221.58	237.59	252.24	266.46	221.58	237.59	252.24	266.46
Consumption in Energy Conversion	16.46	13.03	13.89	12.27	11.27	12.71	13.12	12.03	11.25
Own Consumption of Power Plants	16.46	8.73	9.59	7.97	6.97	8.41	8.83	7.73	6.95
Other	n.a.	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29
Transmission Losses	9.06	8.15	8.15	8.15	8.15	8.15	8.15	8.15	8.15
Storage Consumption	0.75	1.96	4.38	5.82	10.75	1.91	4.19	6.72	12.16
Gross Electricity Consumption	224.61	244.72	264.01	278.47	296.62	244.36	263.05	279.14	298.01
Net Imports	30.79	36.80	-3.65	-4.81	9.82	25.86	5.97	-6.60	7.47
Gross Electricity Generation	196.13	207.91	267.66	283.28	286.81	218.50	257.09	285.74	290.54

** 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	4.93	5.48	3.65	3.49	3.39	7.02	5.19
Lignite	8.84	5.83	3.25	1.12	1.12	4.71	2.13	0.00	0.00
Lignite-CHP	n.a.	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.00
Lignite-CCS	n.a.	0.00	5.19	7.15	7.15	0.00	5.37	6.02	6.02
Lignite-CHP-CCS	n.a.	0.00	0.25	0.25	0.26	0.00	0.25	0.26	0.26
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	1.93	1.79	0.96	2.51	1.68	0.84	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	0.31	3.84	6.04	8.03	11.31	4.73	7.75	8.41	11.71
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	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13
Biomass	0.05	0.28	0.63	1.41	3.18	0.28	0.63	1.41	3.18
Biomass-CHP	n.a.	0.12	0.27	0.61	1.36	0.12	0.27	0.61	1.36
Wind onshore	0.11	0.74	5.85	9.89	16.71	0.74	5.85	9.89	16.71
Wind offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PV	0.00	1.70	3.56	6.48	10.11	1.70	3.56	6.48	10.11
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.24	0.35	0.50	0.00	0.24	0.35	0.50
Demand side management	n.a.	0.86	1.67	2.92	4.73	0.86	1.67	2.92	4.73
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	25.69	36.03	38.75	25.06	25.69	24.92	50.54	35.81
Lignite	42.98	41.63	11.46	4.52	3.92	35.40	1.24	0.00	0.00
Lignite-CHP	n.a.	0.00	0.00	0.00	0.00	1.69	0.00	0.00	0.00
Lignite-CCS	n.a.	0.00	28.67	33.62	30.87	0.00	38.28	36.48	32.08
Lignite-CHP-CCS	n.a.	0.00	1.69	1.68	1.76	0.00	1.71	1.76	1.77
Coal	5.79	3.43	0.76	0.02	0.00	2.79	0.48	0.01	0.00
Coal-CHP	n.a.	17.37	13.56	11.09	5.26	15.94	11.88	2.26	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	2.92	0.05	0.25	0.09	0.50	0.07	0.52	0.05	0.10
Gas-CHP	n.a.	0.69	0.34	0.00	0.00	0.49	0.60	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.	0.26	0.97	1.70	1.96	0.17	1.35	1.78	1.95
Hydro	2.38	3.13	3.13	3.12	3.05	3.13	3.13	3.12	3.04
Biomass	1.46	0.39	1.53	1.99	2.58	1.19	2.85	2.35	3.38
Biomass-CHP	n.a.	0.91	2.04	4.28	4.50	0.91	2.04	4.31	4.50
Wind onshore	0.25	1.29	10.19	17.20	28.08	1.29	10.19	17.20	27.96
Wind offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PV	0.01	1.66	3.48	6.20	9.50	1.66	3.48	6.26	9.42
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.02	1.22	1.74	2.47	0.02	1.22	1.74	2.47
Demand side management	n.a.	0.18	0.28	0.44	0.64	0.18	0.28	0.44	0.64
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	8.24	12.35	13.00	11.44	7.83	12.84	13.13	11.57
Own Consumption of Power Plants	8.91	5.98	10.09	10.74	9.19	5.57	10.58	10.87	9.31
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	0.54	1.64	2.81	3.37	0.41	2.16	2.92	3.37
Gross Electricity Consumption	71.70	82.91	96.97	108.34	117.56	82.36	97.99	108.58	117.68
Net Imports	-11.47	-19.79	-28.75	-28.86	-11.81	-13.84	-16.78	-30.59	-14.79
Gross Electricity Generation	83.52	102.70	125.72	137.20	129.37	96.21	114.77	139.17	132.47

** 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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	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	2.11	0.70	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	3.27	1.40	0.77	1.32	2.35	1.40	0.70	1.32	3.56
Gas-CHP	n.a.	1.43	0.00	0.00	0.00	1.43	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)	0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	0.00	0.00	0.42	0.42	0.42	0.00	0.50	0.50	0.50
Hydro	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	0.00	1.93	2.33	2.82	3.41	1.93	2.33	2.82	3.41
Biomass-CHP	n.a.	0.83	1.00	1.21	1.46	0.83	1.00	1.21	1.46
Wind onshore	2.80	2.62	3.79	3.96	4.36	2.62	3.79	3.96	4.36
Wind offshore	0.33	1.34	5.82	10.20	10.47	1.34	5.82	10.20	10.47
PV	n.a.	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	n.a.	0.00	0.25	0.25	0.25	0.00	0.25	0.25	0.25
Demand side management	n.a.	0.82	1.75	3.28	5.56	0.82	1.75	3.28	5.56
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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	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.	18.42	14.07	11.40	3.41	15.27	12.76	4.35	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	6.93	0.05	0.01	0.17	0.54	0.02	0.00	0.24	0.48
Gas-CHP	n.a.	0.26	0.00	0.00	0.00	0.99	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	0.36	0.42	0.46	0.00	0.42	0.48	0.53
Hydro	0.03	0.02	0.02	0.01	0.01	0.02	0.02	0.01	0.01
Biomass	3.92	0.84	1.35	2.01	2.52	1.60	1.76	2.55	2.80
Biomass-CHP	n.a.	0.93	3.66	4.36	4.44	3.72	4.37	4.37	4.40
Wind onshore	6.93	8.03	10.64	9.11	10.09	8.03	10.83	9.60	10.27
Wind offshore	0.00	5.72	24.18	40.10	39.58	5.72	24.34	40.87	40.41
PV	0.00	0.01	0.01	0.00	0.00	0.01	0.01	0.01	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	1.26	1.27	1.28	0.00	1.26	1.27	1.28
Demand side management	n.a.	0.10	0.19	0.36	0.62	0.10	0.19	0.36	0.63
Others	0.00	1.85	1.85	1.85	1.85	1.85	1.85	1.85	1.84

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	2.23	2.44	2.32	1.67	2.29	2.42	1.76	1.39
Own Consumption of Power Plants	2.11	1.73	1.94	1.82	1.17	1.79	1.92	1.26	0.89
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	0.10	0.71	0.97	1.29	0.10	0.79	1.05	1.40
Gross Electricity Consumption	37.85	44.95	48.68	51.50	53.77	45.00	48.75	51.02	53.60
Net Imports	1.46	6.99	-10.85	-21.39	-12.21	5.90	-10.98	-16.21	-9.95
Gross Electricity Generation	36.39	37.96	59.53	72.89	65.98	39.10	59.73	67.23	63.55

** 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*

Eastern Europe	Historic	Scenario A				Scenario B			
Installed Capacity in GW	2007*	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	7.20	7.63	6.18	7.76	6.74	7.63	7.82	11.21	10.19
Lignite	8.33	5.96	2.59	0.21	0.00	5.96	2.59	0.21	0.00
Lignite-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	3.06	4.27	4.29	0.00	4.32	4.49	4.49
Lignite-CHP-CCS	n.a.	0.00	0.59	0.60	0.62	0.00	0.59	0.62	0.62
Coal	2.93	2.41	0.19	0.00	0.00	2.41	0.19	0.00	0.00
Coal-CHP	n.a.	5.10	4.61	4.13	3.65	2.38	1.90	0.48	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	7.63	0.52	0.31	0.05	0.00	0.52	0.31	0.05	0.00
Gas-CHP	n.a.	1.67	0.00	0.00	0.00	2.50	0.83	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)	1.34	0.55	0.16	0.16	0.00	0.55	0.16	0.16	0.00
Storage	0.42	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
Hydro	7.29	13.51	13.51	13.51	13.51	13.51	13.51	13.51	13.51
Biomass	0.40	1.21	2.38	4.66	9.13	1.21	2.38	4.66	9.13
Biomass-CHP	n.a.	0.52	1.02	2.00	3.91	0.52	1.02	2.00	3.91
Wind onshore	0.12	6.46	10.92	18.46	31.19	6.46	10.92	18.46	31.19
Wind offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PV	0.00	1.07	6.00	20.00	31.03	1.07	6.00	20.00	31.03
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	n.a.	0.06	0.22	0.27	0.32	0.06	0.22	0.27	0.32
Demand side management	n.a.	3.12	6.49	11.07	17.33	3.12	6.49	11.07	17.33
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	58.51	56.06	45.36	54.58	46.39	56.07	57.43	80.13	69.95
Lignite	51.57	37.38	9.91	0.86	0.00	37.39	2.31	0.29	0.00
Lignite-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	22.60	30.36	28.25	0.00	31.08	29.18	25.86
Lignite-CHP-CCS	n.a.	0.00	4.04	4.07	4.20	0.00	4.12	4.22	4.23
Coal	9.19	3.21	0.80	0.00	0.00	4.25	0.52	0.00	0.00
Coal-CHP	n.a.	36.95	32.45	25.85	19.03	17.31	13.64	1.50	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	29.07	0.00	0.11	0.03	0.00	0.00	0.08	0.02	0.00
Gas-CHP	n.a.	5.46	0.00	0.00	0.00	17.65	4.38	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)	2.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	n.a.	0.13	1.12	2.01	2.34	0.05	1.48	2.32	2.34
Hydro	24.93	27.52	27.52	27.51	27.27	27.52	27.52	27.51	27.21
Biomass	2.60	3.34	9.72	13.49	12.51	6.03	12.31	14.88	13.97
Biomass-CHP	n.a.	3.94	7.71	15.05	18.61	3.94	7.71	15.12	18.61
Wind onshore	0.34	10.37	17.53	29.45	48.37	10.37	17.53	29.45	48.21
Wind offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PV	0.00	1.24	6.97	23.08	35.32	1.24	6.97	23.06	35.24
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.32	1.16	1.40	1.69	0.32	1.16	1.40	1.69
Demand side management	n.a.	0.62	0.95	1.42	1.99	0.61	0.97	1.43	2.00
Others	0.76	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31

Power Balance in TWh	2008**	2020	2030	2040	2050	2020	2030	2040	2050
Final Electricity Consumption	129.50	151.85	171.09	191.82	213.99	151.85	171.09	191.82	213.99
Consumption in Energy Conversion	25.77	16.47	19.30	20.92	19.75	15.46	19.71	20.02	18.97
Own Consumption of Power Plants	25.77	9.94	12.77	14.39	13.22	8.93	13.19	13.49	12.44
Other	n.a.	6.53	6.53	6.53	6.53	6.53	6.53	6.53	6.53
Transmission Losses	16.75	15.08	15.08	15.08	15.08	15.08	15.08	15.08	15.08
Storage Consumption	0.34	0.80	2.52	4.24	5.26	0.69	3.04	4.67	5.28
Gross Electricity Consumption	172.35	184.20	207.99	232.05	254.08	183.08	208.92	231.58	253.32
Net Imports	-5.17	-12.60	6.97	-11.81	-5.39	-8.92	6.20	-12.71	-8.73
Gross Electricity Generation	178.98	196.80	201.02	243.86	259.48	192.00	202.71	244.29	262.05

** 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	60.32	47.25	35.08	30.65	60.32	51.42	39.25	31.45
Lignite	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	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	0.23	0.00	0.00
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	0.00	0.00	0.00	0.00	0.00	0.00
Gas	1.10	18.32	36.49	48.67	52.25	17.59	33.93	45.70	51.32
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	4.30	4.30	4.30
Hydro***	20.81	28.30	28.30	28.30	28.30	28.30	28.30	28.30	28.30
Biomass	n.a.	2.10	3.03	4.36	6.29	2.10	3.03	4.36	6.29
Biomass-CHP	n.a.	0.90	1.30	1.87	2.69	0.90	1.30	1.87	2.69
Wind onshore	1.50	19.00	48.71	66.32	71.41	19.00	48.71	66.32	71.41
Wind offshore	0.00	6.00	16.32	36.72	62.06	6.00	16.32	36.72	62.06
PV	n.a.	4.86	18.82	36.89	62.35	4.86	18.82	36.89	62.35
CSP	0.00	0.54	4.05	16.20	27.38	0.54	4.05	16.20	27.38
Geothermal	n.a.	0.08	0.43	0.43	0.48	0.08	0.43	0.43	0.48
Demand side management	n.a.	14.97	29.20	54.54	93.03	14.97	29.20	54.54	93.03
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	440.53	335.95	221.61	142.33	440.61	360.37	238.35	146.32
Lignite	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	24.45	9.44	1.05	0.00	0.00	6.90	0.32	0.00	0.00
Coal-CHP	n.a.	1.13	0.63	0.11	0.00	1.00	0.25	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	21.92	0.74	6.78	8.77	2.41	0.48	1.39	4.27	1.52
Gas-CHP	n.a.	6.09	0.55	0.00	0.00	5.85	0.45	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.	2.84	3.93	5.71	6.19	2.64	4.44	5.47	6.42
Hydro	68.84	71.70	71.62	70.95	69.79	71.70	71.61	70.93	69.69
Biomass	5.89	1.37	3.40	6.38	6.31	2.06	3.12	5.55	6.84
Biomass-CHP	n.a.	6.61	8.82	10.21	11.01	6.70	9.22	10.28	11.00
Wind onshore	5.69	43.64	111.83	151.16	159.53	43.64	111.73	151.28	160.20
Wind offshore	0.00	18.77	51.01	114.54	192.93	18.77	51.04	114.49	192.55
PV	0.04	5.69	22.02	42.50	70.12	5.69	22.00	42.45	70.04
CSP	0.00	1.40	10.53	41.83	66.78	1.40	10.52	41.85	66.86
Geothermal	0.00	0.42	2.12	2.14	2.35	0.42	2.12	2.14	2.35
Demand side management	n.a.	1.89	3.29	5.42	8.88	1.90	3.29	5.43	8.90
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	39.88	34.33	28.56	24.29	39.70	35.42	29.27	24.53
Own Consumption of Power Plants	54.13	25.87	20.32	14.55	10.28	25.70	21.42	15.26	10.52
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	5.86	8.78	13.40	17.54	5.58	9.48	13.06	17.88
Gross Electricity Consumption	522.26	555.32	587.38	617.94	648.63	554.87	589.17	618.32	649.21
Net Imports	-48.01	-86.56	-70.23	-81.68	-104.04	-84.33	-87.87	-93.21	-107.76
Gross Electricity Generation	576.03	641.88	657.60	699.62	752.66	639.20	677.05	711.53	756.97

** 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*

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	20.52	20.50	14.16	10.96	6.80	13.70	7.36	4.16	0.00
Lignite-CHP	n.a.	5.34	2.99	0.88	0.00	5.34	2.99	0.88	0.00
Lignite-CCS	n.a.	0.00	8.25	16.71	16.71	0.00	17.86	19.94	19.94
Lignite-CHP-CCS	n.a.	0.00	0.18	0.86	0.87	0.00	0.85	0.88	0.88
Coal	27.60	14.20	5.54	0.00	0.00	14.20	5.54	0.00	0.00
Coal-CHP	n.a.	12.37	4.68	4.95	4.83	12.37	2.54	0.12	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	23.39	14.92	37.81	44.06	47.00	22.61	34.56	48.32	51.17
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	1.83	1.83	1.83
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	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31
Biomass	3.39	6.18	7.27	8.80	10.65	6.18	7.27	8.80	10.65
Biomass-CHP	n.a.	2.58	3.12	3.77	4.56	2.58	3.12	3.77	4.56
Wind onshore	22.29	35.75	43.26	52.34	63.33	35.75	43.26	52.34	63.33
Wind offshore	0.00	10.00	11.97	23.99	48.93	10.00	11.97	23.99	48.93
PV	3.87	51.75	62.62	75.77	91.68	51.75	62.62	75.77	91.68
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.30	1.01	1.50	1.75	0.30	1.01	1.50	1.75
Demand side management	n.a.	10.82	20.60	35.24	57.17	10.82	20.60	35.24	57.17
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	150.62	148.17	84.74	49.55	27.86	103.09	6.91	2.95	0.00
Lignite-CHP	n.a.	6.21	4.20	0.51	0.00	6.31	0.39	0.32	0.00
Lignite-CCS	n.a.	0.00	61.72	87.92	79.22	0.00	126.38	128.07	112.03
Lignite-CHP-CCS	n.a.	0.00	1.30	5.60	6.00	0.00	5.93	6.01	6.01
Coal	124.62	89.91	38.14	0.00	0.00	75.36	23.54	0.00	0.00
Coal-CHP	n.a.	45.68	32.36	33.99	28.43	41.31	18.26	0.65	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	75.92	76.41	84.18	66.48	33.72	139.58	106.11	84.22	41.93
Gas-CHP	n.a.	2.31	12.87	0.08	0.00	5.62	24.10	0.08	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	13.33	12.11	7.70
Oil (incl. CHP)	8.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	n.a.	3.57	7.03	9.12	14.76	2.70	7.34	10.74	14.42
Hydro	26.96	18.46	18.46	18.46	18.28	18.46	18.46	18.46	18.24
Biomass	28.86	7.30	17.59	16.72	15.31	12.36	24.52	25.02	19.71
Biomass-CHP	n.a.	16.81	21.39	21.86	22.32	19.42	21.44	21.86	22.32
Wind onshore	40.57	63.60	76.95	93.10	111.75	63.60	76.95	93.08	111.83
Wind offshore	0.00	32.00	38.30	76.78	156.28	32.00	38.30	76.78	156.22
PV	4.42	48.52	58.71	70.88	83.33	48.52	58.71	70.95	83.37
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	1.57	5.09	7.48	8.69	1.57	5.09	7.48	8.69
Demand side management	n.a.	2.38	3.59	5.02	7.28	2.35	3.55	5.05	7.33
Others	28.14	29.94	29.94	29.94	29.94	29.94	29.94	29.94	29.93

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	40.39	44.68	44.25	40.17	38.59	53.33	48.85	43.68
Own Consumption of Power Plants	53.52	26.49	30.78	30.35	26.27	24.69	39.43	34.95	29.78
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	7.35	13.39	17.74	27.86	6.12	13.77	20.02	27.42
Gross Electricity Consumption	611.11	644.83	672.40	676.32	682.37	641.80	681.44	683.20	685.44
Net Imports	-20.10	25.51	45.08	52.49	12.94	14.92	32.76	54.50	15.95
Gross Electricity Generation	637.21	619.32	627.32	623.83	669.43	626.88	648.68	628.70	669.49

** 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*

Iberian Peninsula	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	1.93	1.70	0.70	0.29	0.29	1.41	0.42	0.00	0.00
Lignite-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	0.88	1.36	1.36	0.00	1.12	1.35	1.35
Lignite-CHP-CCS	n.a.	0.00	0.33	0.39	0.39	0.00	0.33	0.39	0.39
Coal	11.00	10.41	1.44	0.00	0.00	10.41	1.44	0.00	0.00
Coal-CHP	n.a.	1.57	1.55	1.53	1.51	0.06	0.04	0.02	0.00
Coal-CCS	0.00	0.25	0.25	8.65	8.65	0.25	1.92	6.92	6.92
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	28.00	20.96	24.71	23.03	31.85	20.96	20.72	24.11	32.92
Gas-CHP	n.a.	3.48	1.16	0.00	0.00	3.48	1.16	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	2.28	2.28	2.28
Oil (incl. CHP)	12.34	2.84	0.02	0.00	0.00	2.84	0.02	0.00	0.00
Storage	5.87	6.38	6.38	6.38	6.38	6.38	6.38	6.38	6.38
Hydro	17.81	31.91	31.91	31.91	31.91	31.91	31.91	31.91	31.91
Biomass	0.48	1.47	2.12	3.05	4.40	1.47	2.12	3.05	4.40
Biomass-CHP	n.a.	0.63	0.91	1.31	1.88	0.63	0.91	1.31	1.88
Wind onshore	16.27	41.80	50.58	61.20	74.05	41.80	50.58	61.20	74.05
Wind offshore	0.00	3.08	3.72	4.50	5.45	3.08	3.72	4.50	5.45
PV	0.68	9.37	13.49	19.42	27.97	9.37	13.49	19.42	27.97
CSP	0.00	5.58	22.00	45.00	50.00	5.58	22.00	45.00	50.00
Geothermal	0.03	0.13	0.94	1.02	1.14	0.13	0.94	1.02	1.14
Demand side management	n.a.	9.21	19.39	37.75	65.66	9.21	19.39	37.75	65.66
Others	0.82	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	58.97	54.07	50.30	0.00	0.00	54.06	50.20	0.00	0.00
Lignite	0.00	12.04	2.39	1.05	0.91	10.08	0.48	0.00	0.00
Lignite-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	6.22	7.21	7.02	0.00	7.70	7.34	7.02
Lignite-CHP-CCS	n.a.	0.00	2.27	2.14	2.10	0.00	2.27	2.36	2.03
Coal	59.91	46.81	8.99	0.00	0.00	13.46	0.59	0.00	0.00
Coal-CHP	n.a.	11.22	10.90	8.69	4.88	0.44	0.28	0.07	0.00
Coal-CCS	0.00	1.70	1.70	39.76	35.00	1.74	12.94	32.59	29.72
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	136.76	56.12	74.96	28.67	30.57	95.13	51.96	30.93	32.69
Gas-CHP	n.a.	16.93	2.30	0.00	0.00	23.92	5.58	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	15.49	8.99	7.47
Oil (incl. CHP)	22.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	n.a.	1.53	2.87	5.80	7.33	1.46	3.34	5.56	7.16
Hydro	33.41	50.29	50.29	50.23	50.12	50.29	50.28	50.21	50.14
Biomass	6.17	0.29	1.65	8.46	11.88	0.42	8.95	8.50	12.09
Biomass-CHP	n.a.	4.74	6.82	9.72	13.99	4.78	6.88	9.90	13.86
Wind onshore	37.96	78.83	95.39	115.35	139.01	78.82	95.35	115.30	139.02
Wind offshore	0.00	6.37	7.71	9.33	11.27	6.37	7.71	9.32	11.28
PV	2.60	13.34	19.20	27.62	39.61	13.34	19.19	27.61	39.62
CSP	0.00	22.15	87.09	174.91	191.88	22.14	87.08	174.98	191.87
Geothermal	0.19	0.66	4.64	5.00	5.60	0.66	4.64	5.00	5.55
Demand side management	n.a.	1.27	2.20	3.74	6.12	1.36	2.23	3.74	6.13
Others	1.58	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	313.72	354.50	409.39	470.45	537.97	354.50	409.39	470.45	537.97
Consumption in Energy Conversion	21.07	17.94	16.78	20.44	19.86	15.43	19.91	19.51	19.35
Own Consumption of Power Plants	21.07	12.36	11.20	14.86	14.28	9.84	14.33	13.93	13.77
Other	n.a.	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Transmission Losses	19.18	17.27	17.27	17.27	17.27	17.27	17.27	17.27	17.27
Storage Consumption	1.26	3.40	6.19	11.81	16.32	3.40	6.88	11.48	16.10
Gross Electricity Consumption	355.23	393.11	449.63	519.98	591.42	390.59	453.45	518.72	590.69
Net Imports	-1.61	2.40	0.56	7.44	19.86	2.28	5.98	12.36	21.28
Gross Electricity Generation	359.72	390.71	449.08	512.54	571.56	388.31	447.47	506.36	569.41

** 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	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	n.a.	5.09	1.21	0.38	0.38	4.71	0.83	0.00	0.00
Coal-CHP	n.a.	5.98	5.96	6.03	6.01	5.76	5.74	5.72	5.70
Coal-CCS	n.a.	0.60	12.57	12.57	12.57	0.60	17.78	17.80	17.80
Coal-CHP-CCS	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	n.a.	42.60	24.78	30.77	31.87	42.39	20.90	23.90	25.00
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	2.33	2.33
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.	17.80	17.80	17.80	17.80	17.80	17.80	17.80	17.80
Biomass	n.a.	2.04	2.86	4.12	5.94	2.04	2.86	4.12	5.94
Biomass-CHP	n.a.	0.85	1.23	1.77	2.54	0.85	1.23	1.77	2.54
Wind onshore	2.70	12.00	21.84	36.91	53.15	12.00	21.84	36.91	53.15
Wind offshore	0.00	0.68	2.31	6.68	19.31	0.68	2.31	6.68	19.31
PV	n.a.	8.00	25.60	43.20	52.00	8.00	25.60	43.20	52.00
CSP	n.a.	0.60	12.00	30.00	50.00	0.60	12.00	30.00	50.00
Geothermal	n.a.	0.92	2.30	2.84	3.34	0.92	2.30	2.84	3.34
Demand side management	n.a.	7.05	14.94	26.40	42.80	7.05	14.94	26.40	42.80
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	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	43.07	30.93	8.60	2.10	1.35	25.93	2.13	0.00	0.00
Coal-CHP	n.a.	43.27	38.49	38.51	34.13	41.76	38.19	20.64	12.83
Coal-CCS	0.00	4.36	91.17	85.25	59.93	4.36	128.79	121.89	89.23
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	172.70	198.15	118.38	58.09	33.57	201.26	84.05	26.51	9.58
Gas-CHP	n.a.	4.59	0.59	0.00	0.00	6.06	0.87	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	13.63	8.78
Oil (incl. CHP)	31.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	n.a.	3.61	2.40	2.43	4.01	3.37	2.17	2.86	3.62
Hydro	47.23	43.38	43.38	43.38	43.37	43.38	43.38	43.38	43.38
Biomass	7.52	1.92	4.49	7.44	5.21	3.08	4.46	6.34	6.26
Biomass-CHP	n.a.	6.35	8.71	7.79	8.84	6.45	8.73	9.06	9.12
Wind onshore	4.86	17.07	31.07	52.51	75.62	17.07	31.07	52.51	75.62
Wind offshore	0.00	1.21	4.11	11.88	34.33	1.21	4.11	11.88	34.33
PV	0.19	10.82	34.64	58.45	70.34	10.82	34.64	58.45	70.34
CSP	0.00	2.04	40.80	101.82	168.43	2.04	40.80	101.89	168.65
Geothermal	5.52	5.01	12.29	15.12	16.60	5.01	12.29	15.12	16.60
Demand side management	n.a.	1.29	1.98	2.72	4.16	1.32	1.93	2.72	4.04
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	22.09	37.72	34.68	28.53	21.77	44.05	41.63	33.35
Own Consumption of Power Plants	22.27	16.02	31.65	28.61	22.46	15.70	37.98	35.55	27.28
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	6.32	5.34	6.13	9.77	6.03	4.96	6.71	9.11
Gross Electricity Consumption	353.56	409.74	480.57	540.84	607.44	409.13	486.53	548.37	611.60
Net Imports	40.04	15.56	3.69	20.58	20.95	16.15	6.81	21.80	27.81
Gross Electricity Generation	319.13	394.18	476.89	520.26	586.49	392.98	479.72	526.58	583.80

** 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	2.34	2.34	2.34	0.00	2.44	3.71	3.71
Lignite	8.15	6.47	5.43	0.97	0.47	6.01	4.96	0.50	0.00
Lignite-CHP	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-CCS	n.a.	0.25	9.88	11.77	11.77	0.25	6.43	6.98	6.98
Lignite-CHP-CCS	n.a.	0.00	0.42	0.44	0.45	0.00	0.42	0.45	0.45
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	2.69	1.02	5.01	3.34	1.67	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	0.85	0.45	3.30	10.18	13.49	0.45	3.74	10.30	14.06
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	1.41	1.41	1.41	2.00	1.41	1.41	2.64	2.64
Hydro	0.54	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Biomass	0.07	1.77	2.55	3.67	5.29	1.77	2.55	3.67	5.29
Biomass-CHP	0.00	0.76	1.09	1.57	2.27	0.76	1.09	1.57	2.27
Wind onshore	0.30	5.60	29.67	38.59	42.09	5.60	29.67	38.59	42.09
Wind offshore	0.00	0.50	7.00	13.72	26.89	0.50	7.00	13.72	26.89
PV	0.00	0.00	1.00	7.50	11.90	0.00	1.00	7.50	11.90
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.20	0.26	0.30	0.00	0.20	0.26	0.30
Demand side management	n.a.	2.30	4.67	8.24	13.38	2.30	4.67	8.24	13.38
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	16.59	14.92	14.01	0.00	17.32	24.70	22.41
Lignite	57.26	46.44	12.78	4.00	1.64	44.65	3.93	0.86	0.00
Lignite-CHP	n.a.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-CCS	n.a.	1.88	33.09	35.79	29.94	1.88	41.96	38.21	30.77
Lignite-CHP-CCS	n.a.	0.00	2.78	2.99	3.03	0.00	2.89	3.00	3.03
Coal	83.91	62.44	7.32	0.53	0.00	52.90	4.75	0.32	0.00
Coal-CHP	n.a.	27.30	21.12	15.95	5.23	27.20	20.17	5.70	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	3.17	0.00	2.29	6.81	8.53	0.00	2.77	4.17	5.53
Gas-CHP	n.a.	0.48	0.45	0.00	0.00	0.68	0.77	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.	0.38	2.33	2.90	3.86	0.18	2.53	4.12	4.59
Hydro	2.75	2.07	1.99	1.81	1.64	2.07	1.98	1.84	1.65
Biomass	3.46	2.67	6.74	8.33	9.06	8.15	9.02	10.82	10.80
Biomass-CHP	n.a.	5.74	8.14	11.88	13.24	5.74	8.23	11.91	13.24
Wind onshore	0.84	9.98	52.09	63.85	62.68	9.98	52.03	64.57	63.57
Wind offshore	0.00	1.26	17.55	34.17	66.77	1.26	17.53	34.19	66.62
PV	0.00	0.00	0.95	6.57	9.50	0.00	0.95	6.67	9.54
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	1.05	1.36	1.56	0.00	1.05	1.36	1.56
Demand side management	n.a.	0.41	0.73	1.15	1.74	0.42	0.74	1.16	1.77
Others	2.47	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	117.47	140.03	157.77	176.88	197.33	140.03	157.77	176.88	197.33
Consumption in Energy Conversion	23.91	17.80	18.16	17.59	15.61	17.33	19.29	17.65	15.75
Own Consumption of Power Plants	23.91	11.75	12.11	11.54	9.56	11.28	13.24	11.60	9.70
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	0.94	3.98	5.20	7.15	0.66	4.26	6.94	8.23
Gross Electricity Consumption	154.36	170.19	191.33	211.09	231.51	169.44	192.75	212.90	232.73
Net Imports	-1.22	-2.62	-8.77	-13.46	-10.49	3.05	-9.13	-12.31	-12.05
Gross Electricity Generation	156.18	172.81	200.11	224.55	242.00	166.40	201.87	225.21	244.77

** 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*

Scandinavia	Historic	Scenario A				Scenario B			
Installed Capacity in GW	**2007***	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	11.73	10.80	6.61	2.70	2.70	10.80	6.61	5.46	5.46
Lignite	1.22	1.09	0.86	0.08	0.08	1.01	0.78	0.00	0.00
Lignite-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	0.18	0.18	0.00	0.21	0.29	0.29
Lignite-CHP-CCS	n.a.	0.00	0.47	0.47	0.47	0.00	0.51	0.51	0.51
Coal	3.40	4.04	2.51	0.00	0.00	4.04	2.51	0.00	0.00
Coal-CHP	n.a.	4.26	3.87	3.48	3.09	2.34	1.95	1.56	1.17
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	3.85	11.89	20.61	32.34	35.33	13.90	22.45	31.49	34.48
Gas-CHP	n.a.	1.61	0.54	0.00	0.00	1.61	0.54	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)	5.67	0.67	0.02	0.02	0.00	0.67	0.02	0.02	0.00
Storage	1.27	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
Hydro	46.94	47.71	47.71	47.71	47.71	47.71	47.71	47.71	47.71
Biomass	4.41	2.04	2.93	4.22	6.08	2.04	2.93	4.22	6.08
Biomass-CHP	n.a.	0.87	1.26	1.81	2.61	0.87	1.26	1.81	2.61
Wind onshore	1.22	8.68	16.64	17.33	19.33	8.68	16.64	17.33	19.33
Wind offshore	0.00	10.18	22.45	25.24	36.61	10.18	22.45	25.24	36.61
PV	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.05	1.27	1.35	1.43	0.05	1.27	1.35	1.43
Demand side management	n.a.	6.62	10.59	16.79	26.11	6.62	10.59	16.79	26.11
Others	0.95	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76

Generation in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	86.85	74.71	36.66	15.75	13.93	79.31	39.55	31.68	27.81
Lignite	5.20	4.48	1.21	0.31	0.23	4.97	0.43	0.00	0.00
Lignite-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	0.43	0.36	0.00	0.45	0.58	0.45
Lignite-CHP-CCS	n.a.	0.00	2.95	3.05	3.09	0.00	3.13	3.11	3.14
Coal	9.09	10.69	7.67	0.00	0.00	10.66	6.17	0.00	0.00
Coal-CHP	n.a.	30.31	21.16	18.62	12.19	15.99	9.12	5.21	1.49
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	12.28	1.97	4.62	20.52	18.48	2.17	5.33	10.77	12.97
Gas-CHP	n.a.	3.91	0.81	0.00	0.00	7.26	1.38	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)	1.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	n.a.	1.45	2.49	2.63	2.84	1.47	2.49	2.71	2.95
Hydro	226.85	205.50	200.36	198.05	177.47	205.50	201.69	198.29	176.54
Biomass	21.76	4.19	6.03	8.68	12.49	4.19	6.04	12.99	16.61
Biomass-CHP	n.a.	0.10	0.74	3.17	7.59	2.48	5.40	9.00	11.03
Wind onshore	3.17	20.97	40.09	41.77	44.46	20.97	40.14	41.76	44.50
Wind offshore	0.00	45.55	100.42	112.89	163.43	45.55	100.43	112.88	163.35
PV	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.26	6.28	6.63	7.04	0.26	6.28	6.63	7.04
Demand side management	n.a.	2.70	3.11	3.72	4.71	2.71	3.14	3.76	4.78
Others	2.08	4.01	4.01	4.00	4.00	4.01	4.00	4.00	3.99

Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	322.73	365.36	391.75	415.90	439.35	365.36	391.75	415.90	439.35
Consumption in Energy Conversion	18.21	15.20	14.02	12.77	12.46	14.54	13.51	13.13	12.79
Own Consumption of Power Plants	18.21	10.53	9.35	8.10	7.78	9.87	8.84	8.45	8.12
Other	n.a.	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67
Transmission Losses	24.55	22.10	22.10	22.10	22.10	22.10	22.10	22.10	22.10
Storage Consumption	0.48	4.72	6.68	7.40	8.68	4.76	6.66	7.62	8.91
Gross Electricity Consumption	365.98	407.37	434.55	458.17	482.59	406.76	434.03	458.75	483.16
Net Imports	-3.05	-13.95	-13.42	9.83	2.50	-10.62	-10.00	6.90	-1.62
Gross Electricity Generation	370.14	421.32	447.97	448.34	480.10	417.39	444.02	451.85	484.78

** 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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	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	0.16	0.16	0.16	0.00	0.87	0.87	0.87
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	0.07	0.48	0.48	0.48	0.48	0.08	0.08	0.08	0.08
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	12.66	12.66	12.66	12.66	12.66	12.66	12.66	12.66
Biomass	0.00	0.46	0.84	1.66	3.24	0.46	0.84	1.66	3.24
Biomass-CHP	n.a.	0.18	0.36	0.71	1.39	0.18	0.36	0.71	1.39
Wind onshore	0.01	0.02	1.17	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	1.55	3.04	3.79	0.07	1.55	3.04	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	0.05	0.15	0.25	0.00	0.05	0.15	0.25
Demand side management	n.a.	0.68	1.38	2.42	3.93	0.68	1.38	2.42	3.93
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	8.56	0.00	0.00	0.00	8.56	0.00	0.00	0.00
Lignite	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lignite-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
Lignite-CHP-CCS	n.a.	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	1.18	1.07	0.84	0.00	6.33	6.24	5.05
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	0.75	2.85	3.06	2.54	1.73	0.57	0.48	0.34	0.27
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.	0.32	0.19	0.60	1.45	0.24	0.13	0.56	1.22
Hydro	37.94	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39
Biomass	2.15	0.08	0.80	1.42	0.83	0.12	0.89	1.52	1.05
Biomass-CHP	n.a.	1.18	1.13	1.23	1.19	1.18	1.13	1.23	1.22
Wind onshore	0.02	0.03	1.70	1.71	1.71	0.03	1.70	1.71	1.71
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	1.59	3.11	3.86	0.07	1.59	3.11	3.86
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.25	0.30	0.30	0.00	0.25	0.30	0.30
Demand side management	n.a.	0.18	0.25	0.34	0.49	0.18	0.25	0.34	0.49
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	65.42	70.15	74.47	78.67	65.42	70.15	74.47	78.67
Consumption in Energy Conversion	2.12	1.65	1.55	1.59	1.47	1.58	2.57	2.62	2.34
Own Consumption of Power Plants	2.12	0.92	0.83	0.86	0.74	0.85	1.85	1.90	1.61
Other	n.a.	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
Transmission Losses	4.32	3.89	3.89	3.89	3.89	3.89	3.89	3.89	3.89
Storage Consumption	0.79	0.62	0.52	1.17	2.51	0.51	0.43	1.12	2.19
Gross Electricity Consumption	65.95	71.57	76.10	81.12	86.54	71.40	77.03	82.10	87.08
Net Imports	-1.14	30.95	38.69	41.49	46.96	33.15	36.00	38.41	43.86
Gross Electricity Generation	68.98	40.63	37.40	39.62	39.58	38.24	41.03	43.68	43.22

** 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*

United Kingdom	Historic	Scenario A				Scenario B			
Installed Capacity in GW	**2007***	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	10.98	8.57	8.42	5.36	4.17	8.57	8.40	5.34	4.15
Lignite	0.00	0.16	0.06	0.00	0.00	0.16	0.06	0.00	0.00
Lignite-CHP	n.a.	0.08	0.08	0.08	0.08	0.10	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
Lignite-CHP-CCS	n.a.	0.00	0.12	0.15	0.15	0.00	0.16	0.17	0.17
Coal	28.44	18.55	0.88	0.41	0.00	18.55	0.88	0.41	0.00
Coal-CHP	n.a.	1.23	1.20	1.44	1.42	0.08	0.05	0.03	0.00
Coal-CCS	0.00	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	30.16	46.44	67.75	72.57	73.30	47.57	68.76	68.93	72.26
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	1.41	1.41	1.41
Oil (incl. CHP)	5.90	2.97	0.29	0.00	0.00	2.97	0.29	0.00	0.00
Storage	2.74	3.04	7.65	12.64	16.19	3.04	5.55	17.02	18.15
Hydro	1.42	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36
Biomass	1.21	3.08	4.43	6.38	9.18	3.08	4.43	6.38	9.18
Biomass-CHP	n.a.	1.32	1.90	2.73	3.94	1.32	1.90	2.73	3.94
Wind onshore	2.08	18.98	38.44	46.71	53.37	18.98	38.44	46.71	53.37
Wind offshore	0.39	13.55	30.57	63.49	93.91	13.55	30.57	63.49	93.91
PV	0.01	2.68	2.68	2.68	2.68	2.68	2.68	2.68	2.68
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.93	1.02	1.03	0.00	0.93	1.02	1.03
Demand side management	n.a.	12.31	24.65	46.75	80.56	12.31	24.65	46.75	80.56
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	62.98	58.23	30.98	21.39	62.98	57.82	30.86	21.41
Lignite	2.79	1.05	0.17	0.00	0.00	0.82	0.06	0.00	0.00
Lignite-CHP	n.a.	0.57	0.23	0.24	0.23	0.73	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
Lignite-CHP-CCS	n.a.	0.00	0.80	0.86	0.87	0.00	1.03	1.04	1.04
Coal	130.54	84.67	4.86	1.68	0.00	60.31	2.84	0.93	0.00
Coal-CHP	n.a.	8.85	7.64	8.07	6.85	0.55	0.34	0.10	0.00
Coal-CCS	0.00	4.63	3.87	2.81	2.31	4.66	3.86	2.86	2.33
Coal-CHP-CCS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas	192.81	141.06	127.21	97.41	77.01	158.87	123.73	94.63	74.34
Gas-CHP	n.a.	12.73	4.47	0.00	0.00	26.68	6.69	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	8.90	6.70	5.54
Oil (incl. CHP)	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage	n.a.	1.61	9.73	15.79	19.78	1.37	7.46	19.08	21.15
Hydro	10.56	4.26	4.02	3.08	2.63	4.26	4.00	3.12	2.64
Biomass	10.21	0.63	5.80	8.01	8.86	0.66	6.70	8.16	9.51
Biomass-CHP	n.a.	9.00	9.80	10.09	10.09	9.27	9.88	10.07	10.09
Wind onshore	9.51	61.77	123.14	121.43	103.02	61.77	122.54	123.94	103.44
Wind offshore	0.00	48.59	109.00	219.84	302.39	48.59	109.08	220.96	305.16
PV	0.02	2.31	2.28	1.94	1.66	2.31	2.27	1.96	1.67
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	4.58	5.03	5.06	0.00	4.58	5.03	5.06
Demand side management	n.a.	1.60	3.14	5.45	8.95	1.64	3.17	5.50	9.21
Others	2.29	2.85	2.85	2.85	2.83	2.85	2.85	2.85	2.83

Power Balance in TWh	**2008****	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Final Electricity Consumption	368.24	415.53	445.55	473.02	499.69	415.53	445.55	473.02	499.69
Consumption in Energy Conversion	26.71	24.67	18.07	15.48	14.11	22.84	18.60	15.75	14.39
Own Consumption of Power Plants	26.71	18.04	11.43	8.84	7.48	16.21	11.97	9.11	7.75
Other	n.a.	6.64	6.64	6.64	6.64	6.64	6.64	6.64	6.64
Transmission Losses	30.44	25.38	25.38	25.38	25.38	25.38	25.38	25.38	25.38
Storage Consumption	1.47	3.85	16.84	27.81	37.19	3.56	13.65	32.57	39.42
Gross Electricity Consumption	426.87	469.43	505.83	541.68	576.36	467.31	503.18	546.71	578.87
Net Imports	11.47	2.25	12.60	-2.72	-5.03	2.79	13.43	-0.17	-4.29
Gross Electricity Generation	419.05	467.18	493.24	544.40	581.40	464.52	489.75	546.88	583.16

** 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*