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Flexibility in Europe's power sector - an additional requirement or an automatic complement?☆

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Abstract

By 2050, the European Union aims to reduce greenhouse gases by more than 80 %. The EU member states have therefore declared to strongly increase the share of renewable energy sources (RES-E) in the next decades. Given a large deployment of wind and solar capacities, there are two major impacts on electricity systems: First, the electricity system must be flexible enough to cope with the volatile RES-E generation, i.e., ramp up supply or ramp down demand on short notice. Second, sufficient back-up capacities are needed during times with low feed-in from wind and solar capacities. This paper analyzes whether there is a need for additional incentive mechanisms for flexibility in electricity markets with a high share of renewables. For this purpose, we simulate the development of the European electricity markets up to the year 2050 using a linear investment and dispatch optimization model. Flexibility requirements are implemented in the model via ramping constraints and provision of balancing power dependent of current renewables feed-in. We find that an increase in fluctuating renewables has a tremendous impact on the volatility of the residual load and consequently on the flexibility requirements. However, any market design that incentivizes investments in least (total system) cost generation investment does not need additional incentives for flexibility. The main trigger for investing in flexible resources are the achievable full load hours and the need for backup capacity. In a competitive market, the cost-efficient technologies that are most likely to be installed, i.e., gas-fired power plants or flexible CCS plants, provide flexibility as a by-product. Under the condition of system adequacy, flexibility never poses a challenge in a cost-minimal capacity mix. Therefore, any market design incentivizing investments in efficient generation thus provides flexibility as an automatic complement.

Keywords: Electricity, power plant fleet optimization, renewable energy, flexibility, market design

JEL classification: C61, C63, Q40

1. Introduction

By 2050, the European Union aims to reduce greenhouse gases by more than 80 %. The EU member states have therefore declared to strongly increase the share of renewable energy sources (RES-E) in the next decades. The vast majority of renewable energy is expected to come from wind and photovoltaics (PV). These sources, however, depend on local weather conditions, leading to an increase in stochastic electricity generation. Given a large deployment of wind and PV capacities, weather uncertainty results in two major impacts on electricity systems: First, the capacity mix must be flexible enough to cope with the volatile RES-E generation, i.e., ramp up supply or ramp down demand on short notice. Second, sufficient back-up capacities are needed to provide secure supply during times with low feed-in from wind and solar capacities. Otherwise, sharp decreases or increases in renewable production may lead to price spikes on the wholesale market and, if supply and demand do not meet, to potential black-outs. The provision of back-up capacity has been intensely discussed in the literature in recent years (for instance Cramton and Stoft (2008) and Joskow (2008)). Concerning flexibility, the discussion is rather new and previous literature is scarce. Lamadrid et al. (2011), an exception, argue that as volatility increases, additional incentives to invest in flexible resources should be implemented in market design. Meanwhile, the Californian system operator (CAISO) has already started to implement ramping products in market design to ensure flexibility (Xu and Threteway, 2012).

This paper analyzes whether there is a need for additional incentive mechanisms for flexibility in electricity markets with a high share of renewables.[1] One challenge of analyzing the role of flexibility in electricity markets is accounting for the possible contributions of all parts of an electricity system. First, the supply side is able to complement volatile RES-E generation with highly flexible gas-fired power plants or upcoming technologies such as power plants with a detachable carbon capture and storage unit. Second, the demand side can contribute flexibility by improving demand side management. Third, storages can restrain the volatility of the residual load for both the demand and supply side. Therefore, an integrated analysis of all flexibility possibilities is needed to answer the question of how an electricity system can adapt to an increasing share of renewables. From that, one can deduce whether flexibility requirements necessitate a special market design.

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[1]The discussion concerning the necessity of capacity mechanisms is beyond the scope of this paper.

For this purpose, we simulate the development of the European electricity markets up to the year 2050 using a linear investment and dispatch optimization model. We assume investments in renewable energies lead to an 80 % renewable share of total electricity generation in 2050. The model determines the cost-efficient capacity mix, ensuring adequate capacity and fulfilment of flexibility requirements.[2] These requirements result from load variation and the provision of balancing power, which are necessary due to the stochastic in-feed from renewables generation. Flexibility of power plants, however, is restricted by ramping and start-up constraints. Due to the importance of flexibility provision on short notice, the calculations are supplemented by using a dispatch model for 8760 hours for selected years (2020, 2030, 2040 and 2050). CO_2 emission costs may have effects on installed capacity (or generation) of base or peak load and storage capacities. Thus, impacts on the optimal capacity mix, flexible resources and flexibility provision are further analyzed by calculating an alternative scenario differing in CO_2 emission costs serving as a sensitivity analysis. The model results can be interpreted whether additional incentives for flexibility will be required or if flexibility will come as a complement given a competitive system.

Previous literature on integrated analyses of flexibility in electricity systems can be divided into static (dispatch only) and dynamic (dispatch and investment) analyses. In a static analysis, Denholm and Hand (2011) use a reduced-form dispatch model to analyze the effects of higher flexibility requirements on the capacity mix. They state that in an isolated system, flexible resources, i.e., elimination of must-run technologies, are crucial for the utilization of fluctuating renewable generation. A unit-commitment approach, focusing on the operational integration, is chosen in Ummels et al. (2006). These authors find that flexibility (in terms of ramp rates) does not pose a problem for the Netherlands in 2012. However, they identify the need for wind curtailment due to minimum load restrictions. Lamadrid et al. (2011) conclude from their analysis of an optimal dispatch with varying capacity and ramping cost configuration that there is a need for a market for ramping products. In a dynamic analysis, Möst and Fichtner (2010), Nicolosi (2010) and De Jonghe et al. (2011) analyze investment decisions under operational constraints to determine an optimal capacity mix. They find that operational constraints tend to change the optimal capacity mix compared to when only considering achievable full load hours from base-load to mid- or peak-load capacities. By comparing model runs with and without operational constraints, Nicolosi (2012) states that utilization rather than operational constraints determine the investments of peak load capacities. However, previous research neglects the ambitious renewable targets of the EU, especially in the long term when flexibility becomes a

[2]The objective of the model is to minimize total system costs of the electricity supply for 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 the ramping requirements of thermal power plants.

greater issue for the electricity system. Moreover, demand side reactions to high wholesale prices in case of low renewable production or to volatile wholesale prices in general have not yet been analyzed. We therefore contribute to this literature by considering the long-term developments in transitioning to a mostly renewable electricity system in Europe, especially with regard to an hourly, renewable-dependent provision of balancing power. The amount of balancing power was considered as 10 % of the current renewables in-feed in every hour. This is a rather high value and therefore a conservative benchmark because of the additional necessary flexibility provision. Furthermore, previously not considered flexibility options on the supply (flexible CCS plants) and demand (demand side management) side are considered.

We find that an increase in fluctuating renewables has a tremendous impact on the volatility of the residual load and therefore flexibility requirements. However, any market design that incentivizes investments in least (total system) cost generation does not need additional incentives for flexibility. Under the assumption of perfect competition the challenges of volatility and therefore flexibility are met by an increase in peak-load and a reduction in mid- and base-load capacities. Neither hourly load changes nor the provision of balancing power pose a challenge. Moreover, at every point in time of the simulation, the provision of balancing power is never a binding constraint, indicating excess flexibility provision. Therefore, the main trigger for investing in flexible resources are the achievable full load hours and the need for backup capacity. In a competitive market, the cost-efficient technologies most likely to be installed, i.e., gas-fired power plants or flexible CCS plants, provide flexibility as a by-product. Under the condition of system adequacy, flexibility never poses a challenge in a cost-minimal capacity mix. Therefore, any market design incentivizing investment in efficient generation provides flexibility as an inevitable complement.

The remainder of this paper is organized as follows: Section 2 presents the applied methodology and underlying assumptions. In Section 3, results with regard to the change in flexibility requirements and the adaption of the electricity system are analyzed. Section 4 concludes and discusses policy implications.

2. Methodology and assumptions

Due to the expected structural changes in electricity systems, historical data cannot be used to analyze the effects of a high share of renewables on the optimal capacity mix and on the future role of flexible resources. This renders an econometric analysis impossible. Nevertheless, an integrated analysis is necessary due to the possible contribution from all parts of the electricity system to flexibility. For this analysis, we apply the electricity market model (DIMENSION) of the Institute of Energy Economics at the University of Cologne, as presented in Richter (2011).[3] The model optimizes investments and generation of conventional, nuclear, storage and renewable technologies up to 2050.

2.1. Model description

The following table provides an overview of the most important model sets, parameters and variables.[4]

Abbreviation	Dimension	Description
Model sets		
$a \in A$		Technologies
$k \in A$	Subset of a	Technologies starting-up within 1h
$l \in A$	Subset of a	Technologies starting-up in more than 1h
$s \in A$	Subset of a	Storage technologies
$r \in A$	Subset of a	RES-E technologies
$f \in A$	Subset of a	CCS technologies with attached CCS unit
$g \in A$	Subset of a	CCS technologies with detached CCS unit
$w \in A$	Subset of a	Wind technologies
$m \in M$		DSM processes
$c \in C$		Countries
$e \in C$	Subset of c	Subregions
$d \in D$		Days
$h \in H$		Hours
$y \in Y$		Years
Model parameters		
ac_a	€$_{2010}$/MWh	Attrition costs for ramp-up operation
an_a	€$_{2010}$/MW	Annuity for technology specific investment costs
$av_{c,a}^{d,h}$	%	Availability
$de_{y,c}^{d,h}$	MW	Demand
dr_y	%	Discount rate
ef_a	t CO_2 /MWh_{th}	CO_2 emissions per fuel consumption
fc_a	€$_{2010}$/MW	Fixed operation and maintenance costs
$fu_{y,a}$	€$_{2010}$/MWh_{th}	Fuel price
cp_y	€$_{2010}$/t CO_2	Costs for CO_2 emissions
$pd_{y,c}^{d,h}$	MW	Peak demand (increased by a security factor)
η_a	%	Net efficiency
$\tau_{y,c,a}^{d,h}$	%	Capacity factor
$du_{y,c}^{d,h}$	MW	Acquired positive balancing power
$dd_{y,c}^{d,h}$	MW	Acquired negative balancing power
dv	%	Maximum deviation between RES feed-in and forecast
$ll_{y,m}^{d,h}$	MW	Lower limit of demand of DSM process
$ul_{y,m}^{d,h}$	MW	Upper limit of demand of DSM process
ml_a	%	Minimal load
su_a	hours	Inverse of start-up time
ac_a	hours	Accuracy of start-up representation
Model variables		
$AD_{y,c,a}$	MW	Commissioning of new power plants
$CU_{y,c,a}^{d,h}$	MW	Online capacity
$CUP_{y,c,a}^{d,h}$	MW	Capacity switched-on
$CDO_{y,c,a}^{d,h}$	MW	Capacity switched-off
$GE_{y,c,a}^{d,h}$	MW	Electricity generation
$IM_{y,c,c'}^{d,h}$	MW	Net imports

[3]See alsoEWI (2011), Nagl et al. (2011), Fürsch et al. (2012) or Jägemann et al. (2012).
[4]If not stated otherwise, MW are MW_{el}.

$\mathrm{IN}_{y,c,a}$	MW	Installed capacity
$\mathrm{ST}_{y,c,s}^{d,h}$	MW	Consumption in storage operation
TCOST	€$_{2010}$	Total system costs (objective value)

Table 1: Model abbreviations including sets, parameters and variables

The objective of the model (1) is to minimize discounted total system costs while meeting demand at all times:

$$\min \ TCOST = \sum_{y\in Y}\sum_{c\in C}\sum_{a\in A}\Bigg[dr_y \cdot \Bigg(AD_{y,c,a}\cdot an_a + IN_{y,c,a}\cdot fc_a \qquad (1)$$
$$+\sum_{d\in D}\sum_{h\in H}\left(GE_{y,c,a}^{d,h}\cdot\left(\frac{fp_{y,a}+cp_y\cdot ef_a}{\eta_a}\right)+CU_{y,c,a}^{d,h}\cdot\left(\frac{fp_{y,a}+cp_y\cdot ef_a}{\eta_a}+ac_a\right)\right)\Bigg)\Bigg]$$

Total system costs include investment, fixed operation and maintenance, variable production and thermal power plant ramping costs. Investment costs are annualized with a 5 % interest rate for the technology-specific depreciation time. Fixed costs occur for staff, insurance and maintenance. Variable production costs consist of costs for fuel and CO_2 , and depend on the emission factor and net efficiency of the several technologies. Ramping costs include costs of attrition and co-firing for start-up. Combined heat and power plants (CHP) are able to generate revenues from heat production and therefore reduce total costs.

The model balances demand and supply in every considered market for every hour of the year. In addition, peak demand (including a security margin) has to be met by secured capacity. Imports and exports can contribute fully to the balancing but only partly to the peak demand constraint. Further equations include constraints on electricity generation and technologies (such as general availability due to revisions or existing nuclear construction restrictions) storage level restrictions and net transfer capacities. All technologies are subject to an hourly availability, which allows us to model a fluctuating feed-in structure of renewable wind and solar technologies. For every hour and region, there is maximum feed-in derived from solar irradiation and wind speeds. The model therefore can decide not to use the full amount of RES-E generation available , i.e., curtail RES-E generation. The available feed-in of RES-E is calculated for every market via underlying subregions (47 for onshore, 42 for offshore and 28 for photovoltaics) to account for geographical patterns.[5] Within the investment model a typical day approach is used, capturing seasonal, weekly and daily patterns for demand and RES-E generation. In the detailed dispatch calculation, a 8760h time series is used.

[5]Cf. EWI (2011) for more detail.

2.2. Power plants with a detachable CCS unit

Flexible CCS plants have the option to switch off their capture unit and thereby increase power output, while simultaneously emitting more CO_2 . These units were modeled with the same constraints as conventional power plants, but with the possibility to switch between operation modes within one hour. This was implemented by adding a new technology g for every power plant f with a CCS unit, where g represents the share of capacity f whose CCS unit is switched off.[6]

The following constraint ensures that the total online capacity of technology f (CCS switched on) and its counterpart g (same technology with CCS switched off) does not exceed the total available capacity. By multiplying the ramped-up capacity of g with the fraction of the efficiencies of f and g, the increased net efficiency of power plants with switched-off CCS can be taken into account by:

$$CU_{y,c,f}^{d,h} + CU_{y,c,g}^{d,h} \cdot \frac{\eta_f}{\eta_g} \leq av_{c,f}^{d,h} \cdot IN_{y,c,f} \tag{2}$$

Additional modifications for power plants with a detachable CCS unit have to be made when modeling start-up behavior. These will be pointed out in the following subsection.

2.3. Start-up of thermal power plants

The maximum and minimum operational capacity in one point in time are dependent on the plants' statuses of the previous hours. Time periods are freely selectable and by considering more points in a given time period more realistic start-ups of power plants can be modeled.

Equation 3 makes use of the variables CUP and CDO, which symbolize capacity that was started and shut-down from the previous hour to the current one:

$$CU_{y,c,a}^{d,h} = CU_{y,c,a}^{d,h-1} + CUP_{y,c,a}^{d,h-1} - CDO_{y,c,a}^{d,h-1} \tag{3}$$

The restriction on the maximum online capacity of technologies with a flexible CCS unit (represented by f if CCS switched on, and g if CCS switched off) is similar to an ordinary power plant:

$$CU_{y,c,f}^{d,h} + CU_{y,c,g}^{d,h} = CU_{y,c,f}^{d,h-1} + CU_{y,c,g}^{d,h-1} + CUP_{y,c,f}^{d,h-1} - CDO_{y,c,f}^{d,h-1} \tag{4}$$

[6]The technical details of this process were taken from Davison (2009) and Finkenrath (2011).

As the online capacities of f and g belong to the same technology and since switching the CCS unit on and off can be done within one hour, the two can be combined.

The maximum start-up of capacities from one hour to the next depends on the overall available capacity, the capacity already in operation and the technology's start-up time (inverse of su_a). The model is taking into account the capacity that was started-up in previous hours:

$$CUP_{y,c,a}^{d,h} \leq \left(av_{c,a}^{d,h} * IN_{y,c,a} - CU_{y,c,a}^{d,h} + \sum_{i=h-ac_a}^{i<h} CUP_{y,c,a}^{d,t} \right) \cdot su_a \tag{5}$$

If power plants of one technology were starting-up in the previous hour, e.g., after all plants had been shut-down completely, then, under the assumption of a linear start-up trajectory, all plants are able to start-up with the same magnitude in all hours until reaching their maximum online capacity. On the contrary, if there was not any ramping activity in the previous hours, only the capacity currently not in operation is able to start-up. Parameter ac represents the accuracy of the modeling of start-up behavior ($0 \leq ac_a \leq \frac{1}{su_a}$).

The constraint has to be altered slightly for technologies with a detachable CCS unit by linking technology f with its counterpart g:

$$CUP_{y,c,f}^{d,h} \leq \left(av_{c,f}^{d,h} * IN_{y,c,f} - CU_{y,c,f}^{d,h} - CU_{y,c,g}^{d,h} + \sum_{i=h-ac_f}^{i<h} CUP_{y,c,f}^{d,t} \right) \cdot su_f \tag{6}$$

The restriction for shutting-down technologies can be enhanced analogously by replacing the original constraint with the following:

$$CDO_{y,c,a}^{d,h} \leq \left(CU_{y,c,a}^{d,h} + \sum_{i=h-ac_a}^{i<h} CDO_{y,c,a}^{d,t} \right) \cdot su_a \tag{7}$$

And equivalently for technologies with detachable CCS unit:

$$CDO_{y,c,f}^{d,h} \leq \left(CU_{y,c,f}^{d,h} + CU_{y,c,g}^{d,h} + \sum_{i=h-ac_f}^{i<h} CDO_{y,c,f}^{d,t} \right) \cdot su_f \tag{8}$$

2.4. Renewable-dependent provision of balancing power

Due to a high share of fluctuating RES-E, balancing power must be available to quickly balance power supply and demand if necessary. The quality of short-term prediction of wind and solar feed-in has improved in recent years due to improved forecast models. As stated in Giebel et al. (2011), relative forecast errors were reduced on average from about 10 % in 2000 to 6 % in 2006. However, in order to be able also to balance large forecast errors, high flexibility is nevertheless still needed (cf. Holttinen (2005) and Holttinen and Horvinen (2005)). The higher the value of the balancing power provision, the tighter this constraints gets for the electricity system. Therefore, as a conservative benchmark we chose 10 % of the renewables feed-in in every hour for the amount of positive and negative balancing power provision.

Constraint (9) was added to the model to ensure sufficient short term flexibility in order to increase production at all times. The parameter du represents the potential need for positive balancing power, which is set to 10 % of available wind and photovoltaic feed-in for each hour.

$$\begin{aligned} du_{y,c}^{d,h} \leq & \sum_{l \in A} \left(CU_{y,c,l}^{d,h} - GE_{y,c,l}^{d,h} \right) + \sum_{k \in A} \left(av_{c,k}^{d,h} \cdot IN_{y,c,k} - GE_{y,c,k}^{d,h} \right) + \sum_{s \in A} ST_{y,c,s}^{d,h} \\ & + \sum_{w \in A} \left((1 - dv) \cdot \left(av_{c,w}^{d,h} \cdot IN_{y,c,w} - GE_{y,c,w}^{d,h} \right) \right) \\ & + \sum_{f \in A} \left(GE_{y,c,f}^{d,h} \cdot \left(\frac{\eta_g}{\eta_f} - 1 \right) \right) + \sum_{m \in M} \left(ll_{y,c,m}^{d,h} - GE_{y,c,m}^{d,h} + ST_{y,c,m}^{d,h} \right) \end{aligned} \tag{9}$$

Several options for providing short-term flexibility exist. Technologies that need more than one hour to start-up (l) are limited to increasing their production by the amount of capacity currently in part load, i.e., online capacity minus current production. Technologies that are able to start-up within one hour (k) can increase production until reaching installed and available capacity. Storages consuming energy have the option (besides starting power generation) to stop filling their reservoir. Curtailed wind power can also be used to increase supply. The available capacity is restricted to 90 % of the expected and therefore curtailed power (to account for forecast errors). Another source of short-term power are plants with a CCS unit that can be switched off. The maximum additional production can be calculated by multiplying the fraction of both efficiencies (with and without CCS) minus one with the current power generation of plants with applied CCS. Finally, an available option for short-term flexibility is to reduce the power demanded by DSM processes, restricted by the minimum power demand (GE indicates decreasing and ST increasing regular demand).

The following constraint represents the need for negative flexibility where dd is equal to 10 % of expected feed-in by photovoltaics[7]:

[7]An underestimation of wind feed-in can be balanced by wind curtailment, thus there is no additional need for negative flexibility.

$$
\begin{aligned}
dd^{d,h}_{y,c} \leq & \sum_{l \in A} \left(GE^{d,h}_{y,c,l} - ml_l \cdot CU^{d,h}_{y,c,l} \right) + \sum_{k \in A} GE^{d,h}_{y,c,k} \\
& + \sum_{s \in A} \left(av^{d,h}_{c,s} \cdot IN^{s}_{y,c,a} - GE^{d,h}_{y,c,a} \right) + \sum_{w \in A} GE^{d,h}_{y,c,w} \\
& + \sum_{g \in A} GE^{d,h}_{y,c,g} \cdot \left(\frac{\eta_f}{\eta_g} \right) + \sum_{m \in A} \left(ul^{d,h}_{y,c,m} - ST^{d,h}_{y,c,m} + GE^{d,h}_{y,c,m} \right)
\end{aligned} \tag{10}
$$

Running power plants that cannot shut-down operation on short notice are only able to reduce production to minimum load. Highly flexible plants (e.g. gas turbines), on the contrary, can stop production completely. Storages can, in addition to reducing production, increase power consumption. An unexpected high feed-in by photovoltaics can also be balanced by reducing feed-in by wind turbines or even stopping production completely. Flexible CCS power plants that are not using their CCS units can switch-on CO_2 segregation and thus reduce efficiency and production. DSM processes can increase consumption until their maximum demand is reached.

All options discussed for positive and negative flexibility are summarized in table 2.

Table 2: Overview of flexibility options

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

2.5. Assumptions and scenario setting

Assumptions for the simulation include the regional electricity demand development, net transfer capacities between regions, capacities of existing power plants, technical and economic parameters for power plant investments as well as fuel and CO_2 prices. The scenario setting chosen for this analysis is only one possible development and should not be interpreted as a forecast. The assumptions are based on several sources such as Capros et al. (2010), Prognos/EWI/GWS (2010), IEA (2011), ENTSO-E (2011) and EWI (2011). The underlying assumptions used in the scenario analysis can be found in the Appendix A. Since CO_2 emission costs may have effects on installed capacity (or generation) of base or peak load and storage capacities, a sensitivity analysis with a higher CO_2 price is performed. The underlying assumption is that in Scenario

'A' CO_2 prices increase up to 50 EUR_{2010}/t CO_2 in 2050 and in Scenario 'B' up to 100 EUR_{2010}/t CO_2 in 2050. Table 3 depicts the assumed CO_2 emission prices from 2020 to 2050.

Table 3: Assumed CO_2 emission prices [EUR_{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

3. Results

In this section, the results from the analysis are presented. The impacts of an increasing share of RES-E on the residual load are discussed, with examples of selected European electricity systems up to 2050. Furthermore, it is shown how the system can adapt to the changing residual load and what an optimal capacity mix may look like.[8]

3.1. Impacts of an increasing share of RES-E

Based on simulation assumptions, the RES-E share on gross electricity demand in Europe 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 deployed 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. To illustrate the effects of such a high share of renewables, we focus on Germany and the UK. Both countries are chosen due to their geographical position within Europe. While Germany is well-connected to its neighboring countries, the UK only has few interconnections and is closer to an insular system. For Germany, the renewable technologies, i.e., wind and photovoltaics, are by assumption diversified, whereas the renewable capacities in the UK consist mostly of on- and offshore wind capacities, which leads to greater challenges due to the fluctuating nature of wind. In 2050, Germany has a renewable generation share of 61 % of gross electricity consumption, of which about 64 % is wind and 20 % pv. The UK has a renewable share of about 76 % with over 90 % wind.

Residual load

The high share of renewables has significant effects on the residual load, as shown for Germany and the UK in Figure 1.[9]

[8] Numerical data can be found in the Appendix B.

[9] Data source for 2011 load in Germany is ENTSO-E. Wind and photovoltaic generation data for 2011 is from the European Energy Exchange (EEX). For the UK, no data for the renewable feed-in was available.

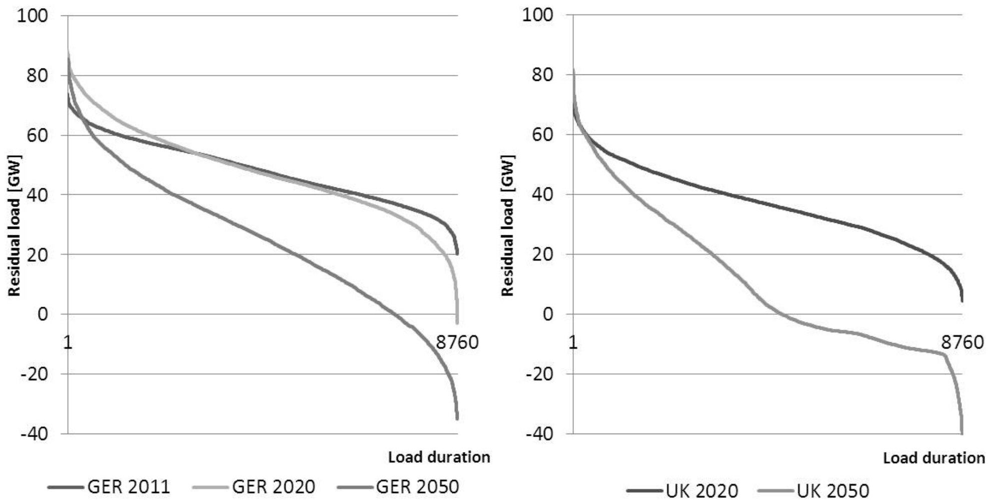

Figure 1: Residual load duration curve for Germany(left) and UK (right) [GW]

From the historical 2011 data to the assumed feed-in in 2020 the residual load duration curve for Germany changes slightly due to the assumed increase in electricity consumption and in deployed renewables. The residual load duration curves for Germany and the UK are steeper in 2050. The number of hours with negative residual load increases and occurs for nearly half the hours in the UK, where renewable electricity generation exceeds actual demand by up to 40 GW. Despite these developments, hours with high load levels remain. This means that achievable full load hours for conventional generation are reduced, but backup capacities for hours with high levels of residual load are still needed. The effects on the residual load depend on the installed renewable technology. In Italy and the Iberian Peninsula, for example, the shape of the residual load curve in 2050 is similar to the curves in 2020 due to the high shares of CSP plants with integrated thermal storages. CSP smoothes residual load by using its thermal storage unit and reduces the effects of fluctuating generation.

Volatility of residual load

The volatility of residual load is analyzed on an hourly basis. Figure 2 depicts the boxplots for Germany, 2011, 2020 and 2050 and for the UK in 2020 and 2050.

Two main developments can be identified. First, the extreme values grow larger with a higher share of fluctuating renewables. Still, 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 a residual load of more than 40 GW face hourly changes (positive and negative) greater than 10,000 MW. In countries with high demand and high penetration of renewables, hourly fluctuations up to 40,000 MW (UK) in residual load occur more often. The power

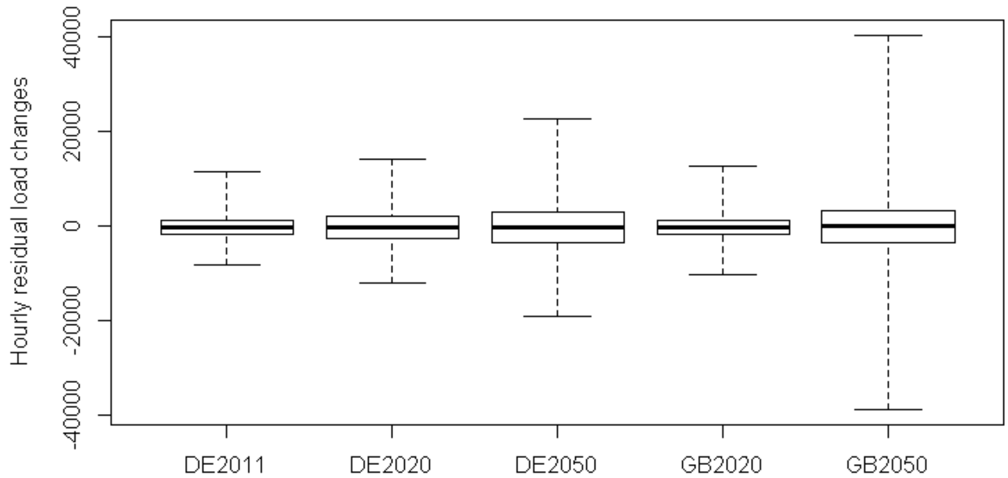

Figure 2: Box plot of hourly changes for Germany and the UK 2020 and 2050 [MW]

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 the residual load level. For the electricity system, large changes in times of low or negative residual load are especially challenging. Due to a high share of renewable generation in these hours, no conventional capacity is running and must therefore be started up. This requires sufficient flexible resources that are able to start up quickly. The second development is that there is a more widespread distribution of hourly changes. While in Germany the quartiles increase by about 50 %, in the UK these values double. Absolute hourly changes therefore increase tremendously, indicating an increased need for flexible resources to provide quick generation. This developments are also confirmed by analyzing means and standard deviation of positive and negative hourly changes as shown in table 4. The means change in the same manner as the analyzed quartiles. The standard deviation changes significantly, indicating more widely distributed hourly changes.

Provision of balancing power

Together with the higher feed-in of fluctuating renewables, forecast errors and therefore balancing power increase in absolute amounts as long as prediction is not improved. Figure 3 shows the duration curve of balancing power for renewables when 10 % of renewable generation must be provided as balancing power.

Table 4: Mean, maximum and standard deviation of hourly load changes for Germany and the UK

	Germany			UK	
	2011	2020	2050	2020	2050
Mean positive	2242	3083	4105	2345	4619
Standard deviation positive	2148	2572	3373	2229	4739
Max positive	11396	14106	22775	12545	40286
Mean negative	-1853	-2604	-3656	-1977	-4661
Standard deviation negative	1420	1922	2727	1724	4891
Max negative	-8016	-12069	-18984	-10186	-38631

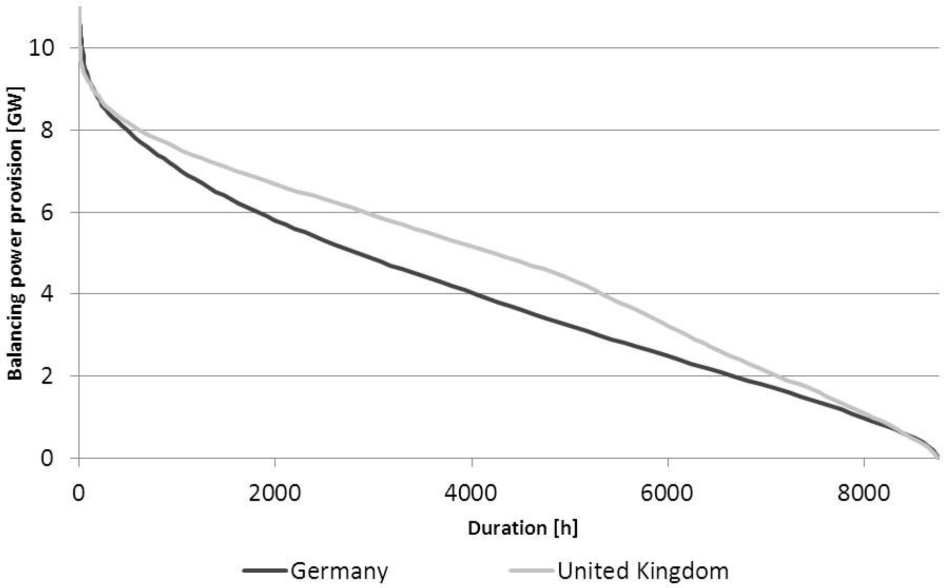

Figure 3: Required provision of positive balancing power in Germany and the UK 2050 [MW]

For Germany and the UK, up to 10,000 MW are needed as provision of balancing power only for renewables. Compared to current values (e.g. for Germany with around 2,000 MW for the tertiary reserve today) the provision is significantly higher in many hours. Therefore, flexible resources are constantly needed to provide balancing power to backup forecast errors or failures of RES-E.

3.2. Adaptation of the electricity system

The changing residual load leads to changes in the electricity system. This section describes the development of capacity, generation mix, CO_2 emissions and analyzes situations for the electricity systems with special requirements for flexibility.

3.2.1. Development of the capacity mix

The capacity mix changes significantly in both scenarios up to 2050 due to the large deployment of renewables and the decrease in base-load capacities. Figure 4 depicts the gross electricity capacities in

Scenario A for the years 2020, 2030, 2040 and 2050.

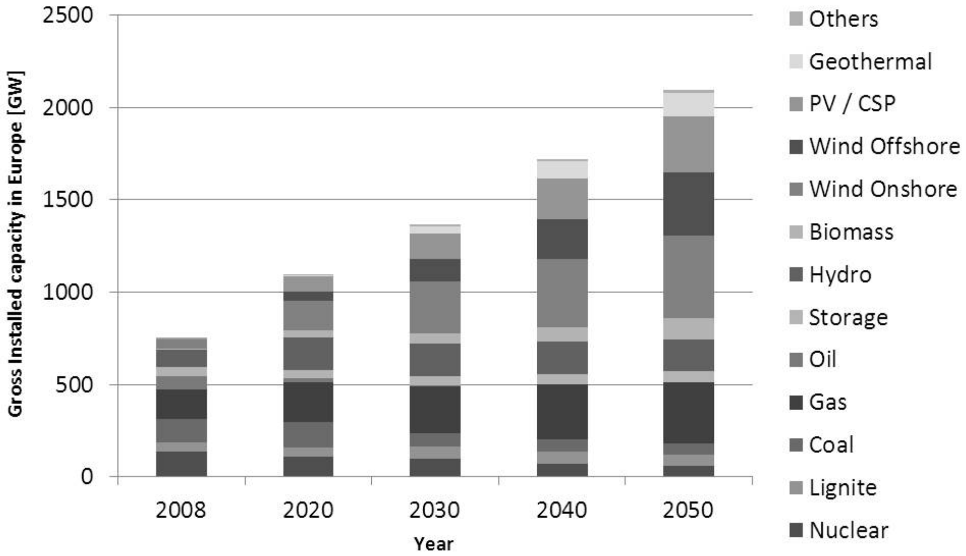

Figure 4: Development of European gross capacity mix up to 2050 [GW]

By assumption, RES-E capacities are primarily increased by onshore wind until 2020/2030, offshore wind from 2030 onwards and solar plants after 2030. The capacity of base- and mid-load plants decreases over time, as fewer full load hours are achieved by these technologies. Hence, the share of gas-fired capacities (open and combined cycle) increases. Due to the low secured capacity of intermittent renewable technologies and an assumed increase in electricity demand, total gross capacity more than doubles by 2050. Higher CO_2 prices in Scenario B lead to more nuclear and CCS capacities. However this has little effect and mostly peak load capacities are deployed. Storage is mainly deployed in countries with high amounts of negative residual load. In Scenario B wind and solar curtailment is associated with higher costs due to higher costs of fossil fuel generation, and making additional storage technologies cost-efficient.

3.2.2. Development of the electricity generation

Figure 5 depicts the gross electricity generation in Scenario A for the years 2020, 2030, 2040 and 2050.

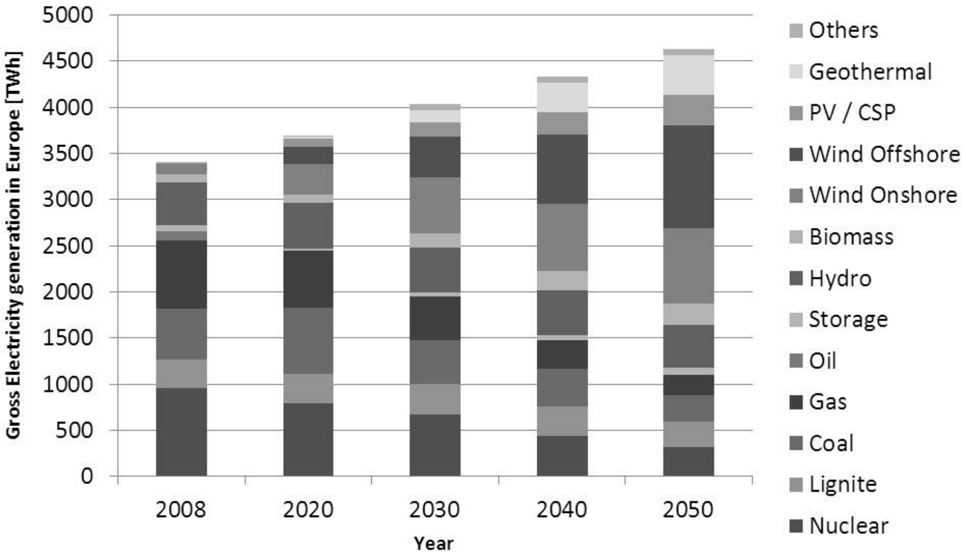

Figure 5: Development of European gross capacity generation up to 2050 [TWh]

Nuclear plants operate for more than 7000 hours at full load in 2020. However, the utilization rate decreases by 2050 to about 5000 full load hours. Similar effects can be observed for lignite CCS and hard coal plants due to the increased deployment of renewable energies. The availability of nuclear power or lignite capacities makes Czech Republic and France large exporters. 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 Scenario B, 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 from gas-fired CHP plants. More than 470 TWh of electricity is generated in coal and gas-fired power plants equipped with CCS units in 2050. However, as can be seen from figure 5, the amount of electricity produced from gas-fired power plants decreases. This is remarkable, especially given that the installed capacities are increasing. Due to CO_2 prices of 100 EUR/ 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. 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.

3.2.3. Fulfilling flexibility requirements

The changes in the capacity mix mainly stem from the reduction in realizable full load hours, rendering some base-load plants less cost-efficient than peak-load plants. However start-up and ramping constraints alter the capacity to a certain extent, as Nicolosi (2012) already showed. To analyze the flexibility of the system, we look further into the availability of positive and negative balancing power. Figure 6 shows the availability of positive balancing power for a summer week in Germany in 2020. The black line symbolizes the renewable-dependent provision, i.e. 10% of the feed- in from wind and photovoltaics.

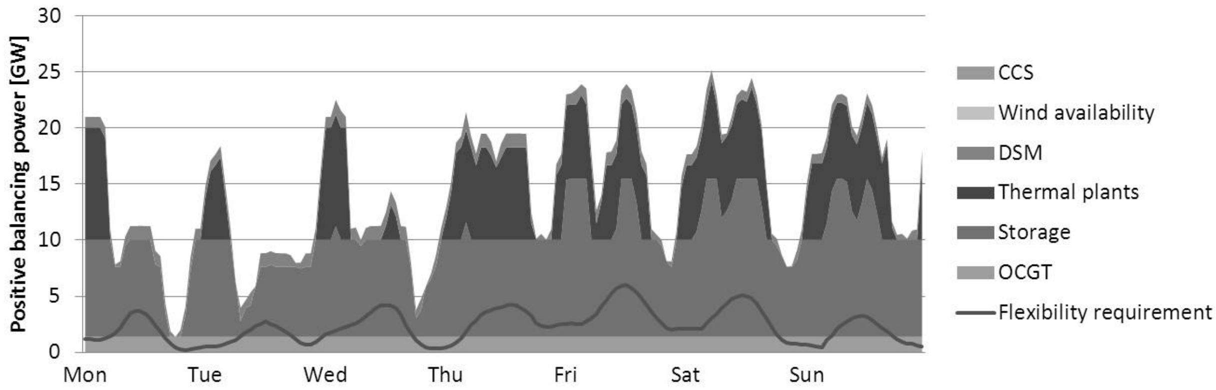

Figure 6: Availability of positive balancing power in June 2020 in Germany [GW]

During hours with high requirements, sufficient capacity for providing quick generation is available. Conventional generation is replaced by renewable generation, therefore capacities are idle and contribute to the availability of balancing power. Up to 2050, the availability of positive balancing power changes according to the source, i.e., there are more gas-fired power plants (OCGT) and less capacities in part-load.

Figure 7 shows the availability of negative balancing power in the same week as demonstrated before in Germany 2020.

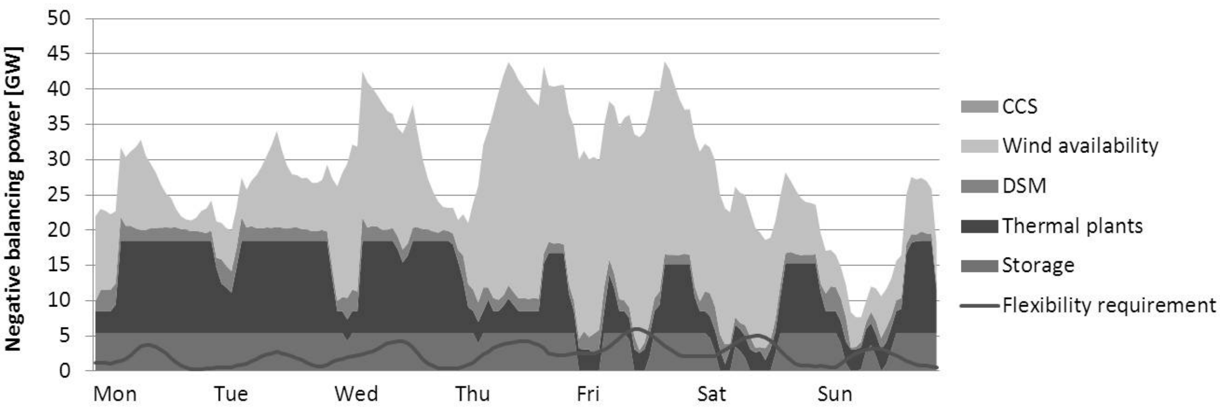

Figure 7: Availability of negative balancing power in June 2020 in Germany [GW]

Wind generation provides much flexibility within the short term as long as it can be curtailed. In times with low available capacities to provide negative flexibility, the demand for provision is also low. This is the reverse effect of the positive balancing power: In times with low feed-in, the availability is low, but barely any positive flexibility is needed since strong negative deviations can not occur. With the rising share of wind capacities and the possible curtailment, sufficient negative balancing power is always available.

As already indicated in the examples above, positive and negative balancing power requirements never pose any challenge in any country considered. The balancing power constraints are never binding, indicating that excess flexible resources are available at every point in time, even during hours with very high changes in residual load. System adequacy in peak load hours, however, is a stronger constraint for the solution. The flexible capacity, i.e., mainly open cycle gas turbines, are built to contribute to security of supply. The capacities are necessary to cope with the few hours of high residual load. For this, the cost-efficient technology is gas-fired power plants, with relatively low capital costs and high variable costs. At the same time, these power plants are highly flexible and can deal with every change in residual load. This finding is confirmed by the dispatch of the flexible CCS plants. Their CCS unit is only detached in times of peak load and low renewable feed-in rather than in hours with strong hourly load changes. In other words the actual investment decision to install a flexible CCS, rather than an ordinary CCS, is based on secured capacity and not on additional flexibility.

4. Conclusion

Electricity systems with a high share of renewables are confronted with an increasing requirement for flexibility. If the market does not provide sufficient flexibility and requires additional incentives, market design may be affected. In this paper, we analyzed this issue for the European electricity system. In an integrated system analysis, a linear investment and dispatch model is used to simulate the development of electricity markets in Europe up to 2050. The model was extended by including CCS power plants with a detachable CCS unit, constraints for the provision of balancing power provision depending on current renewable feed-in, demand-side reactions and ramping as well as start-up processes of conventional power plants.

The results of the integrated analysis show that achievable full load hours of conventional capacities are reduced as renewable generation increases. Depending on the fluctuating renewable share, the volatility of the residual load increases and significantly impacts the electricity system. In 2050, when, e.g. for Germany and the UK with 50 % and 70 % of fluctuating renewables respectively, the spread of hourly changes increase by 50 % in Germany and doubles in the UK. Extreme values of hourly changes occur more often and reach up to 40,000 MW in the UK due to the high wind penetration. In other countries with a more balanced renewable portfolio, values around 20,000 MW still occur. Provision of balancing power for forecast errors increase and, given a 10 % provision of renewables feed-in, reach over 10,000 MW in some hours.

The system adapts to the reduced achievable full load hours by adding more peak-load capacities, i.e., gas-fired power plants. Due to the relatively low investment costs, they serve as cost-efficient backup technologies. With higher CO_2 prices, the general case does not change: only more conventional capacity is equipped with CCS. Due to different storage investments in Scenario A and B, storages seem mainly to be built to prevent renewable curtailment, rather than to provide flexibility. This conjecture is confirmed by the fact that the provision of balancing power is never a binding constraint throughout the whole simulation. Therefore, at every point in time, excess capacity is able to ramp up within 15 minutes, allowing the electricity system to deal with any flexibility requirement. This finding is supported by the analysis of the utilization of flexible CCS power plants. The ability of these plants to provide generation in short time is only beneficial if renewable feed-in is low during peak-times - but not for the purpose of providing flexibility in hours with high volatility. Therefore, we conclude that the main trigger for investments in flexible resources such as gas-fired power plants or flexible CCS plants is system adequacy. Flexibility is a by-product of the cost-efficient adaptation to the reduced achievable full load hours under system adequacy.

Under the condition of system adequacy, flexibility never poses a challenge in a cost-minimal capacity mix. Therefore, any market design incentivizing investment in efficient generation thus provides flexibility as an automatic complement.

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Appendix

4.1. Appendix A - Model assumptions

Table 5: Net electricity demand [TWh_{el}] and potential heat generation in CHP plants [TWh_{th}]

		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

Table 6: Overnight investment costs [EUR_{2010}/kW]

	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
Compressed air storage	850	850	850	850
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

Table 7: Techno-economic figures for generation technologies [as indicated]

	Net efficiency [%]	Availability [%]	FOM costs [EUR_{2010}/kWa]	Lifetime load[a]	Minimum [%]	Ramp-up times [h]
Nuclear	33	84.5	96.6	60	45	48
Lignite	43	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	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	86.3	89.3	45	30	3 - 12
Hard coal	46	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	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	84.5	28.2	30	40	0.75 - 3
CCGT - CHP	36	84.5	40	30	40	0.75 - 3
CCGT - CCS	52	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	84.5	57.9	30	40	0.75 - 3
OCGT	40	84.5	17.2	25	20	0.25
Biomass gas	40	85	120	30	30	
Biomass gas CHP	30	85	130	30	30	
Biomass liquid	30	85	85	30	30	
Biomass solid	30	85	165	30	30	
Biomass solid CHP	22.5	85	175	30	30	
Concentrated solar power	-	-	120	25		
Geothermal (HDR)	22.5	85	300	30		
Geothermal	22.5	85	30	30		
PV ground	-	-	30	25		
PV roof	-	-	35	25		
Run-off-river hydropower	-	-	11.5	100		
Wind onshore	-	-	41	25		
Wind offshore	-	-	128	25		

Table 8: Fuel costs [EUR_{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	110	114	116
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

4.2. Appendix B - Detailed scenario results

Table 9: Gross installed capacities in Europe in [GW]

		Scenario A				**Scenario B**			
	2008	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	135	109	95	69	60	109	100	88	75
Lignite	51	45	29	15	9	36	20	5	0
Lignite-CHP	0	6	3	1	0	6	3	1	0
Lignite-CCS	0	0	32	48	48	0	42	46	46
Lignite-CHP-CCS	0	0	3	4	4	0	4	4	4
Coal	128	83	19	3	0	82	19	3	0
Coal-CHP	0	50	39	38	32	40	23	14	7
Coal-CCS	0	2	17	27	27	2	26	32	32
Coal-CHP-CCS	0	0	0	0	0	0	0	0	0
Gas	158	177	239	296	328	189	232	285	324
Gas-CHP	0	37	13	0	0	38	13	0	0
Gas-CCS	0	0	0	0	0	0	0	0	0
Gas-CHP-CCS	0	0	0	0	0	0	9	12	12
Oil	72	19	5	0	0	19	5	0	0
Oil-CHP	0	5	0	0	0	5	0	0	0
Storage (Pump + CAES)	50	47	52	57	64	47	50	64	68
Hydro	92	172	172	172	172	172	172	172	172
Biomass	9	29	39	55	79	29	39	55	79
Biomass-CHP	0	12	17	24	35	12	17	24	35
Wind onshore	49	160	284	368	449	160	284	368	449
Wind offshore	1	51	123	218	339	51	123	218	339
PV	5	82	138	222	305	82	138	222	305
CSP	0	7	38	91	127	7	38	91	127
Geothermal	1	2	11	13	15	2	11	13	15
Others	26	11	11	11	11	11	11	11	11

Table 10: Gross electricity generation in Europe [TWh]

	Scenario A					Scenario B			
	2008	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
Nuclear	955	794	665	442	321	799	695	552	409
Lignite	315	310	130	64	37	251	16	4	0
Lignite-CHP	0	7	5	1	0	9	0	0	0
Lignite-CCS	0	2	180	231	208	2	291	284	246
Lignite-CHP-CCS	0	0	19	24	25	0	25	25	25
Coal	543	407	104	12	1	308	57	5	0
Coal-CHP	0	290	252	232	167	207	145	47	16
Coal-CCS	0	15	120	157	120	15	186	200	154
Coal-CHP-CCS	0	0	0	0	0	0	0	0	0
Gas	747	512	444	308	223	643	401	275	194
Gas-CHP	0	111	35	0	0	174	66	0	0
Gas-CCS	0	0	0	0	0	0	0	0	0
Gas-CHP-CCS	0	0	0	0	0	0	60	61	44
Oil	91	0	0	0	0	0	0	0	0
Oil-CHP	0	0	0	0	0	0	0	0	0
Storage (Pump + CAES)	67	17	36	55	75	15	36	62	77
Hydro	466	497	491	487	464	497	492	487	462
Biomass	88	26	66	92	99	44	89	110	116
Biomass-CHP	0	67	94	117	134	78	101	125	138
Wind onshore	117	335	599	728	821	335	599	732	823
Wind offshore	0	180	444	751	1107	180	444	753	1110
PV	7	86	152	247	335	86	152	248	334
CSP	0	26	138	319	427	26	138	319	427
Geothermal	6	10	58	68	75	10	58	68	74
Others	67	57	57	57	57	57	57	57	57
DSM		14	22	32	49	14	22	33	50

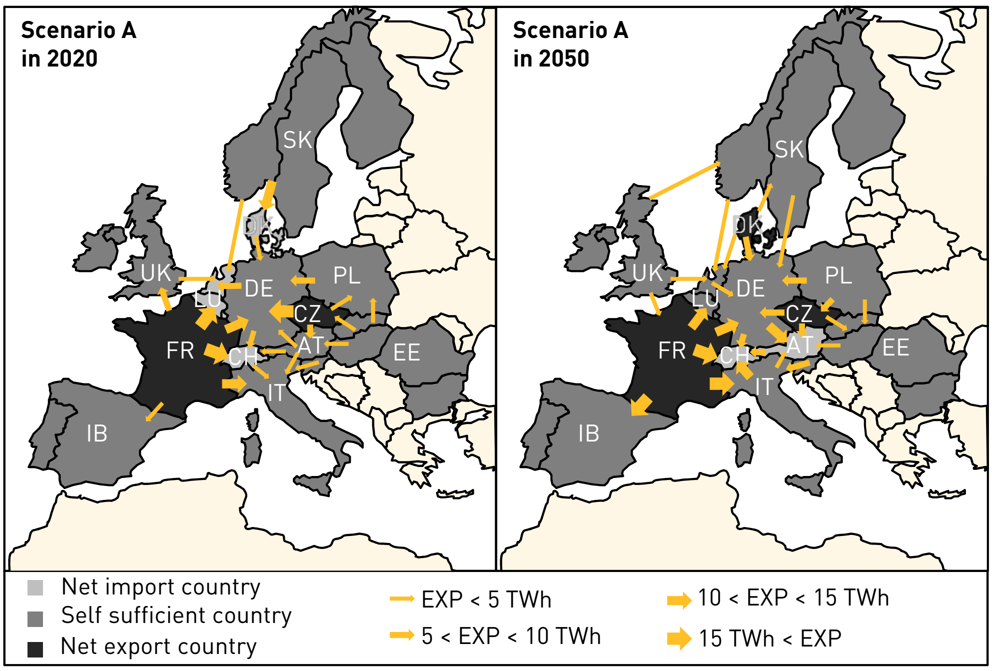

Figure 8: European import and export streams in 2020 and 2050 (Scenario A) [annual TWh]

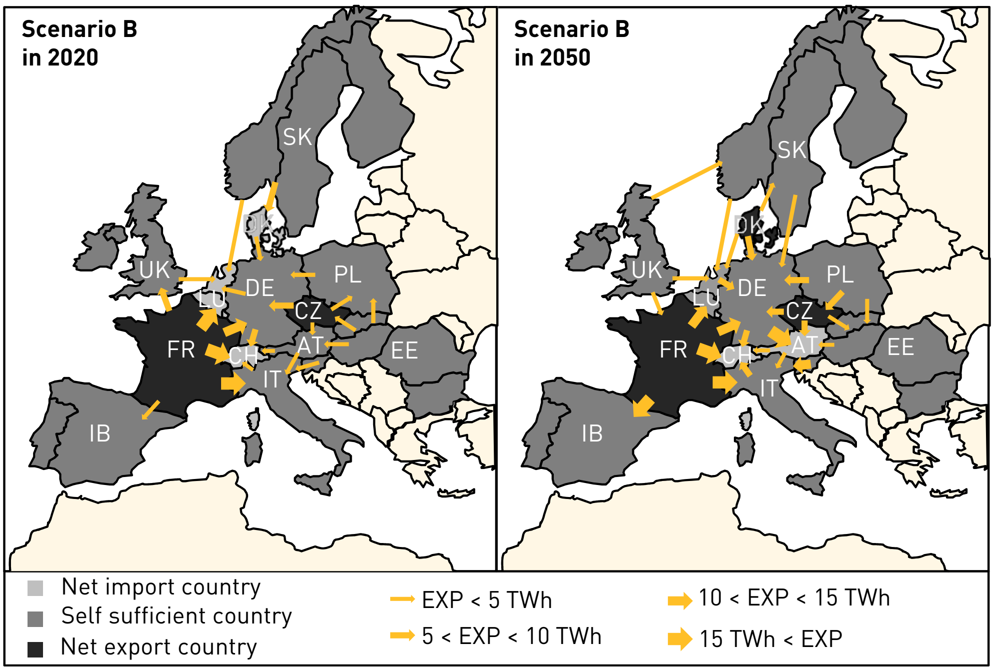

Figure 9: European import and export streams in 2020 and 2050 (Scenario B) [annual TWh]

Table 11: Renewable curtailment [TWh]

		2020	2030	2040	2050
Scenario A	Wind onshore	0.7	5.0	44.3	103.0
	Wind offshore	0.0	1.7	15.3	46.7
	Solar power	0.1	0.2	2.6	10.0
Scenario B	Wind onshore	0.7	5.4	40.1	101.1
	Wind offshore	0.0	1.4	13.3	43.9
	Solar power	0.1	0.3	2.4	10.2