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AUTOREN

Michaela Fürsch

Simeon Hagspiel

Cosima Jägemann

Stephan Nagl

Dietmar Lindenberger

Eckehard Tröster

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Michaela Fürsch[a,*], Simeon Hagspiel[a], Cosima Jägemann[a], Stephan Nagl[a], Dietmar Lindenberger[a], Eckehard Tröster[b]

[a] *Institute of Energy Economics, University of Cologne, Vogelsanger Strasse 321, 50827 Cologne, Germany*
[b] *Energynautics GmbH, Mühlstraße 21, 63225 Langen, Germany*

Abstract

As an attempt to fight global warming, many countries try to reduce CO_2 emissions in the power sector by significantly increasing the proportion of renewable energies (RES-E). A highly intermeshed electricity transmission grid allows the achievement of this target cost-efficiently by enabling the usage of most favorable RES-E sites and by facilitating the integration of fluctuating RES-E infeed and regional electricity demands. However, construction of new lines is often proceeding very slowly in areas with a high population density. In this paper, we try to quantify the benefits of optimal transmission grid extensions for Europe until 2050 compared to moderate extensions when ambitious RES-E and CO_2 reduction targets are achieved. We iterate a large-scale dynamic investment and dispatch optimization model for Europe with a load-flow based transmission grid model, in order to determine the optimal deployment of electricity generation technologies and transmission grid extensions from a system integrated point of view. Main findings of our analysis include that large transmission grid extensions are needed to achieve the European targets cost-efficiently. When the electricity network is cost-optimally extended, 228,000 km are built until 2050, representing an increase of 76% compared to today. Further findings include substantial increases of average system costs for electricity until 2050, even if RES-E are deployed efficiently throughout Europe, the grid is extended optimally, and if significant cost reductions of RES-E are assumed.

Keywords: Renewable energy, GHG reduction, transmission grid, power system optimization

JEL classification: C61, Q40, Q58, C63

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*Corresponding author
Email address: `Michaela.Fuersch@uni-koeln.de, +49 22127729321` (Michaela Fürsch)

1. Introduction

As an attempt to fight global warming, many countries try to reduce CO_2 emissions in the power sector by significantly increasing the proportion of renewable energies (RES-E). A highly intermeshed electricity transmission grid allows the achievement of this target cost-efficiently by enabling the usage of most favorable RES-E sites and by facilitating the integration of fluctuating RES-E infeed and regional electricity demands.

A large share of renewable generation is supposed to come from wind and solar power. However, most favorable wind and solar sites are located far from load centers and their generation is stochastic. Hence, additional transmission lines are needed to access these sites, and as wind and solar radiation is not entirely correlated within a large system a highly intermeshed electricity transmission grid reduces the need for back-up capacities. Electricity systems can also benefit from a more efficient utilization of storage options and regional resources such as lignite in connection with carbon capture and storage. 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 often proceeding very slowly in areas with a high population density.

In this paper, we try to quantify the benefits related with optimal transmission grid extensions for Europe until 2050 compared to moderate extensions when ambitious RES-E and CO_2 reduction targets are achieved. In order to analyze the role of grid extensions for the cost-efficient achievement of these targets, we iterate a large-scale dynamic investment and dispatch optimization model for Europe with a load-flow based transmission grid model. The approach allows us to determine the optimal deployment of electricity generation technologies and transmission grid extensions from a system integrated point of view and compare the results to a scenario with moderate grid extensions.

Main findings of our analysis include that large transmission grid extensions are needed to achieve the European targets cost-efficiently due to existing comparative cost advantages of RES-E sites throughout Europe, different policies regarding nuclear power and different local resource availabilities of lignite in connection with carbon capture and storage. Furthermore we find that the pathway towards a higher RES-E share envisaged in the National Renewable Energy Action Plans for 2020 substantially deviates from the cost-efficient pathway in our scenarios. Additionally, even considering a cost-efficient RES-E deployment throughout Europe, optimal grid extensions and significant capital cost reductions for RES-E technologies, we find that average system costs for electricity increase substantially until 2050.

The remainder of the paper is structured as follows: Section 2 provides a literature overview of approaches to integrate load flow analysis within electricity market models. Section 3 gives a short description of the simulation models and the iteration between them. Assumed input parameters are described in Section 4. Section 5 covers results of the scenario analysis. In Section 6 we draw conclusions and provide an outlook of further possible research.

2. Related literature and contribution of the current work

Integrated optimization models for renewable and conventional electricity generation technologies, developed to analyze optimal investment and dispatch decisions in the context of climate protection targets, have been applied in various papers during the last years. Palmer and Burtraw (2005) analyze the cost-effectiveness of different renewable energy policies based on an optimization model covering thermal and renewable energy technologies in 13 regions in the United States of America. DeCarolis and Keith (2006) develop a model including investment options in wind, storage and gas technologies as well as into HVDC transmission lines between five remotely located wind sites and one demand center. With this approach, the authors analyze the cost-effectiveness of wind power under a CO_2 reduction scheme and potential balancing effects of wind power on different sites.[1] Also Neuhoff et al. (2008) analyze the benefits of diversified wind locations. Their analysis considers investments into gas and wind capacities in seven regions in the United Kingdom. Ludig et al. (2011) determine optimal electricity mixes for reaching RES-E and CO_2 emission reduction targets in one region of Germany, by applying a long-term investment and dispatch model for renewable, thermal, electricity storage and carbon capture and storage technologies. Within these models, the electricity network is either not considered (Ludig et al. (2011)), taken into account by exogenous transmission constraints (Palmer and Burtraw (2005) and Neuhoff et al. (2008)) or treated in a context of a radial and not an intermeshed electricity network (DeCarolis and Keith (2006)).

Considering grid extensions in an intermeshed electricity network is challenging, because different characteristics and rules apply to commercial and physical electricity exchanges between two areas (see e.g. Wolak et al. (2004) or Groschke et al. (2009)). Specifically, a commercial trading activity with electricity as underlying is bilateral, whereas the physical settlement generally impacts the entire system. As such, in an intermeshed network, the exact location and size of transmission line extensions and thus the costs required to achieve a certain extension of commercial transfer capacities, are specific to the particular structure of the generation system at a certain point of time and have to be identified by load flow analysis.

[1] The model does not include a load flow analysis. Possible transmission line investments between five wind sites and one demand center form a radial and not an intermeshed network in which loop flows could occur.

During the last decades, attempts to integrate load flow analysis in electricity market models have been undertaken but remain challenging especially for large-scale problems due to computational constraints. One of the first attempts was undertaken by Schweppe et al. (1988), who present an economic electricity dispatch model including a linearized Direct-Current (DC) load flow model. Applications of this approach can be found e.g. in Stigler and Todem (2005) for the Austrian electricity system or in Green (2007) for England and Wales. Grid and generation capacities are exogenous in these simulations. Models incorporating endogenous investments in generation and grid capacities are presented e.g. in Roh et al. (2007) and Sauma and Oren (2006). Also Garcés et al. (2009) present an approach including cost-efficient endogenous transmission grid investments under consideration of network-constrained electricity trading. However, applications are so far limited to test systems with only a few technologies and on a low temporal resolution.[2] For large-scale problems with a high regional, temporal and technological resolution, investments into grid and generation capacities have to our knowlegde not been jointly optimized so far.

With our approach, we analyze the cost-efficient pathway to reach ambitious RES-E and CO_2 emission reduction targets considering investments in nuclear, thermal (possibly equipped with carbon capture and storage), renewable and storage technologies in 27 European market regions, 47 wind onshore regions, 42 wind offhore regions and 38 photovoltaic regions. In addition, an iteration of this large-scale economic model with a load-flow based transmission grid model allows determining grid extension costs for specific lines in a highly intermeshed network such as the European electricity system and thus to include grid investment options in the economic model (see Section 3). The approach permits analyzing the role of grid extensions in the context of reaching climate protection targets which so far has been neglected for real-world electricity systems with intermeshed networks. One major contribution of our analysis is to quantify to what extent and at which locations the option of grid extension is cost-optimally chosen and preferred to other options of meeting RES-E and CO_2 reduction targets and of balancing fluctuating RES-E, such as storages, RES-E curtailment, larger shares of dispatchable RES-E and generation options located closer to consumption areas.

3. Methodology

In the following we describe the electricity market model, the load-flow based grid model and the iterative process between the two models.

[2]Roh et al. (2007) apply their model to a system with 7 existing and 11 possible future generating units. The simulation is done for a ten-year-horizon, each year consisting of 4 load levels. Sauma and Oren (2006) present a case study for a 30 bus system, 6 generation firms and one dispatch period. Garcés et al. (2009) apply their model in a case study including 10 generation units and one dispatch period.

3.1. Electricity market model

We use a dynamic linear dispatch and investment model for Europe incorporating conventional thermal, nuclear, storage and renewable technologies.[3] Table 1 provides an overview of model sets, parameters and variables.

Table 1: Model sets, parameters and variables

Abbreviation	Dimension	Description
Model sets		
a		technology
c (alias c1)		region
d		day
h		hour
r	subset of a	RES-E technology
s	subset of a	storage technology
subc	subset of a	RES-E belonging to same subregion
y		year
Model parameters		
annuity	€$_{2010}$/MW	Annuity for technology specific investment costs
attc	€$_{2010}$/MWh$_{el}$	Attrition costs for ramp-up operation
avail	%	Availability of generation units
cobound	t CO_2	Bound for CO_2 emissions
dem	MW	Model demand
dsc	%	Discount rate
emissionfac	t CO_2 /MWh$_{th}$	CO_2 emissions per fuel consumption
fomc	€$_{2010}$/MW	Fixed operation and maintenance costs
fuelpotential	MWh$_{th}$	Fuel potential per year
fuelpr	€$_{2010}$/MWh$_{th}$	Fuel prices
heatpr	€$_{2010}$/MWh$_{th}$	Heating price for end-consumers
heatratio	MWh$_{th}$/MWh$_{el}$	Ratio for heat extraction
peak	MW	Peak demand (increased by a security factor)
potential	km^2	Space potential
space	MW/km^2	Space requirement of a technology
η	%	Net efficiency
ω	%	Quota on RES-E generation
τ	%	Capacity factor
Model variables		
C	MW	Installed capacity (net)
CADD	MW	Commissioning of new power plants (net)
CUP	MW	Ramped-up capacity (net)
G	MW	Electricity generation (net)
NIMP	MW	Net imports
S	MW	Consumption in storage operation
Z	€$_{2010}$	Total system costs (objective value)

[3]The model used in this analysis is an extended version of the long-term investment and dispatch model for thermal, nuclear and storage technologies of the Institute of Energy Economics (University of Cologne) presented in Richter (2011). The model is based on several electricity market optimization models; mainly the model developed by Bartels (2009). For this analysis the model has been extended especially with regard to renewable energy technologies.

This modeling approach, optimizing the total European electricity generation system and covering a large bandwidth of different investment options, is essential to take interdependencies between different technologies and regional characteristics - such as meterological and demand patterns - into account. From a system integrated point of view, the economic value of a technology depends on the hourly values of electricity infeed throughout the technical lifetime of the plant and on the value of its capacity. The value of electricity infeed in a particular hour is determined by the electricity demand in this hour and - given renewable energy and CO_2 reduction targets - by its contribution to the achievement of these targets. In addition, the value of electricity generation can be influenced by the demand from other markets, e.g. the heat market. At times of high heat demand, the value of electricity generation in co-generation mode can be high, even if demand for electricity is low. The value of capacity is determined by the contribution of an installed technology to security of supply requirements. However, the value of a technology always depends on the characteristics of the total system at a certain point of time: for example in a system with excess generation capacity, the capacity value of an additionally commissioned plant equals zero. Against these values, variable and fixed costs of each technology have to be compared. Within the model, this comparison of the value and the cost of each technology is formalized as follows:

$$
\begin{aligned}
min\ Z = \sum_{y,c,a} \Bigg[dsc(y) \cdot \Bigg[& CADD(y,c,a) \cdot annuity(a,y) + C(y,c,a) \cdot fomc(a) \\
& + \left[\sum_{d,h} G(y,c,a,d,h) \right] \cdot \frac{fuelpr(y,a)}{\eta(a)} \\
& + \left[\sum_{d,h} CUP(y,c,a,d,h) \right] \cdot \left[\frac{fuelpr(y,a)}{\eta(a)} + attc(a) \right] \\
& - \left[\sum_{d,h} G(y,c,a,d,h) \right] \cdot heatpr(y) \cdot heatratio(a) \Bigg] \Bigg]
\end{aligned} \tag{1}
$$

s.t.

$$\sum_{a} G(y,c,a,d,h) + \sum_{c1} NIMP(y,c,c1,d,h) - \sum_{s} S(y,c,s,d,h) = dem(y,c,d,h) \tag{2}$$

$$\sum_{a} \left[\tau(y,c,a,d,h) \cdot C(y,c,a) \right] + \sum_{c1} \left[\tau(y,c,c1,d,h) \cdot NIMP(y,c,c1,d,h) \right] \geq peak(y,c,d,h) \tag{3}$$

$$\sum_{r,c,d,h} G(y,c,r,d,h) \geq \omega \cdot \sum_{c,a,d,h} dem(y,c,d,h) \tag{4}$$

$$\sum_{a} \left[\left[\sum_{c,d,h} \frac{G(y,c,a,d,h)}{\eta(a)} \right] \cdot emissionfac(a) \right] \leq \sum_{c} cobound(c,y) \tag{5}$$

The objective function (1) includes fixed, variable production and ramping costs. In addition, combined heat and power plants can earn incomes from the heat market which reduces the objective value. The generated heat is remunerated by the assumed gas price (divided by the conversion efficiency of the assumed reference heat boiler) which roughly represents the opportunity costs for households and industries. Generation from combined heat and power plants is restricted by a maximum potential for heat generation in CHP plants specific to each region (see Section 4). Equation (2) is the power balance which has to be fulfilled within each hour in each market region. Equation (3) determines the value of capacity by prescribing a security of supply requirement: The peak demand (increased by a security margin) has to be met by securely available installed capacities. In addition, net imports within the peak demand hour can contribute to this requirement. Equation (4) formalizes the RES-E quota restriction and equation (5) limits European-wide CO_2 emissions.

Besides the equations determining costs and values of electricity generation technologies, important model equations bind the electricity infeed and/or the construction of technologies. Infeed and construction can be limited by a restricted hourly availability of plants (eq. 6), the scarcity of construction sites (eq. 7), the scarcity of the used fuels (eq. 8) and by political restrictions (such as nuclear phase-out plans).

$$G(y,c,a,d,h) \leq avail(c,a,d,h) \cdot C(y,c,a) \tag{6}$$

$$\sum_{r} space(r) \cdot C(y,c,r) \leq potential(subc) \tag{7}$$

$$\sum_{d,h} \frac{G(y,c,a,d,h)}{\eta(a)} \leq fuelpotential(a,c,y) \tag{8}$$

The hourly availability of dispatchable plants (thermal, nuclear, storage and dispatchable renewable plants such as biomass and geothermal plants) is limited due to unplanned or planned shut-downs e.g. because of revisions.[4] In case of dispatchable plants, the parameter *avail* in equation 6 takes into account these shutdowns. The hourly availability of fluctuating RES-E (wind and solar technologies) depends on hourly meteorological conditions and varies on a very narrow spatial scale. In this case, the parameter *avail* represents the (maximum possible) feed-in of wind and solar plants within each hour and is determined by wind speed and solar radiation data. This approach allows the possibility of wind and solar curtailment when needed to meet demand or when total system costs can be reduced due to lower ramping costs of thermal power plants.[5]

In order to account for the variations of RES-E infeed within a market region, several subregions per market region have been determined according to meteorological data (from EuroWind (2011)). For wind onshore we model 47 subregions, for wind offshore 42 and for photovoltaic plants 38 subregions. Within the model, these subregions are represented by different technologies. Advantages of this approach are twofold: First, regions clustered according to sun radiation data not necessarily overlap with those clustered according to wind speed data. For example, wind speed may vary significantly between the eastern and the western part of a country while sun radiation varies most on a north-south axis or vice versa. Second, this approach avoids the massive computational burden which would arise by modeling several regions per country as market region, implying that all variables multiply by the number of subregions. Equation 7 shows the space potential restrictions for technology groups corresponding to the same subregion. As an example, Germany is divided into three wind onshore regions (north, central and south). Thus, for Germany three groups of wind onshore technologies, representing these regions, are modeled. In addition, different technology classes account for technological learning processes. For the example of wind onshore, future available technologies are characterized by larger turbines and thus by lower costs per MW, smaller required areas per MW as well as by larger turbine heights and thus by higher full load hours. The installed capacity of all technologies belonging to the same subregion (e.g. all onshore technologies in northern Germany),

[4]The infeed of storage technologies is additionally restricted by the storage level in a particular hour which in turn can be influenced by seasonal, daily or hourly water inflows to hydro reservoirs or of sun radiation in the case of thermal energy storages in concentrated solar plants.

[5]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.

accounted with the respective areas required per MW, has to be smaller than the space potential per subregion.

For other technologies, the scarcity of the used fuels rather than the scarcity of construction sites is crucial. For lignite and biomass, the fuel use is restricted to a yearly potential in MWh_{th} (equation 8). For biomass, different potentials apply for solid and gaseous biomass sources as well as for different cost classes.

3.2. Modeling grid capacity extensions

The determination of the cost-efficient system development is based on the comparison of costs and values of all generation technologies in all regions. However, commercial trade flows and thus the use of some generation options, which would be beneficial from this comparison, are limited due to bottlenecks in the electricity grid. In the same way costs and economic values of different technologies in different regions are compared, the option of cross-border capacity extensions has to be evaluated from an economic point of view and compared to other options to meet demand, security of supply requirements and political targets such as a RES-E quota. However, as explained in Section 2, different characteristics apply to commercial and physical flows, leading to challenges regarding a joint optimization of the electricity grid and generation technologies. We therefore iterate the economic market model with an engineering grid model for Europe.

Within the market model commercial trades are limited by transmission grid constraints based on net transfer capacities (NTC) between regions. Under certain conditions, e.g. when distant renewable-based electricity generation shall be integrated in the power system, the system considers NTC extension as cost-optimizing option (assuming provisional costs for additional NTC (€/MW) in a first step). In turn, NTC extension requires physical extension of the grid infrastructure. However, exact location and size of the grid extension needed to achieve the desired increase in NTC are initially unknown. We use a detailed model of the European extra high voltage grid to determine these quantities and to derive the actual costs related to this particular NTC extension. The model covers the entire European transmission system of all ENTSO-E members and consists of 224 nodes representing generation and load centers within Europe.[6] Transmission lines between these centers are included in an aggregated form, considering both HVAC and HVDC lines. In order to determine the inter- and intraregional grid extensions necessary for an increase in NTC, three steps are taken within the transmission grid model.

In the first step, detailed information on generation dispatch and customer load is taken from the results of the market model and integrated into the physical network model. The dispatch calculated within the

[6]The model of the transmission grid was developed by Energynautics using DIgSILENT´s power system calculation tool PowerFactory.

market model is re-simulated within the transmission grid model in order to determine necessary grid upgrades. In the second step a stress test of the power system is performed to ensure that the resulting network is robust enough to cover demand under all realistic conditions, e.g. several weeks of calm wind. The installed capacities provided by the market model are assigned to the corresponding nodes in the grid model. Hourly Optimal Power Flow (OPF) simulations are performed, and the amount of energy produced by each generator required to meet demand is calculated. The maximum available generation at each node and the maximum line flow limit (specified as 80% of maximum thermal limit, and thus accounting for n-1 contingencies) must be respected by the OPF algorithm. In the third step, the cost optimal grid upgrade is determined by checking the necessity of each individual upgrade that has been requested during step 1 and step 2. This last step is essential in order to minimize grid upgrade costs since some redundancy has most likely been built up during the process of adding network upgrades on a chronological hour to hour basis.

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

The calculated costs of NTC extensions are fed back into the market model which recalculates the system development. Since NTC extension costs have changed, the optimal NTC and overall system development may now be different compared to the previous calculation. The new results from the market model are therefore passed again to the transmission grid model. The procedure is continued until the cost difference between two model runs becomes smaller than a threshold value. We find that after about 4 iteration steps per decade (4 calculations with the market model and 4 following calculations with the transmission grid model) hardly any changes in the generation system (electricity generation and NTC extension) occur. Figure 1 depicts the iterative process.

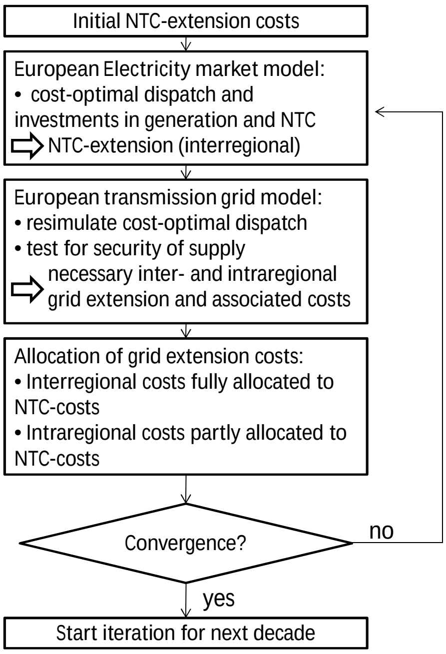

Figure 1: Iteration process between market and transmission grid model

As the system develops dynamically within the modeled timeframe, the iteration has to be repeated for subsequent time steps. While the market model calculates optimal development in 5 year intervals, we iteratively optimize combined generation and grid for each decade until 2050, due to the massive computational burden.[7]

4. Assumptions

In the following we present the major assumptions underlying the scenario analysis. Section 4.1 presents assumptions for the electricity demand and the potential heat generation in combined-heat-and-power plants. Sections 4.2, 4.3 and 4.4 summarize assumed technological and economic parameters for conventional and storage respectively RES-E and grid technologies. In 4.5 the assumed fuel price developments are presented.

4.1. Electricity demand and potential heat generation in CHP plants

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. We assume that demand growth is highest in Eastern European countries

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

because of a high GDP growth. The second highest growth is assumed for Southern European countries because of an increasing population and a relatively high GDP growth. Lower growth rates are assumed for Western/Northern European countries due to the assumption of a stable GDP growth and a high energy efficiency progress. For Germany we assume in addition a slight decline of the population such that demand grows only slightly until 2020 and remains on the 2020 level afterwards.

Based on these assumptions, Table 2 presents the resulting electricity demand per country and year. In addition, Table 2 reports values for heat demand which are based on EURELECTRIC (2008) and Capros et al. (2010). Growth rates for potential generation in CHP plants are rather small for all European countries. Overall, the increase in process heat demand is expected to offset the slight decrease in demand for district heating due to energy efficiency improvements, mainly thermal insulation of buildings.

Table 2: Net electricity demand in TWh_{el} and (potential heat generation in CHP plants in TWh_{th})

	2020		2030		2040		2050	
Austria	65.3	(41.2)	70.0	(41.5)	74.3	(41.8)	78.5	(42.0)
Belgium	92.6	(14.7)	99.3	(14.8)	105.4	(14.9)	111.4	(14.9)
Bulgaria	32.0	(6.9)	36.0	(7.0)	40.4	(7.0)	45.0	(7.1)
Czech Republic	69.9	(55.1)	78.8	(55.7)	88.3	(56.4)	98.5	(57.0)
Denmark-East	25.5	(36.5)	27.4	(36.7)	29.1	(36.9)	30.7	(37.2)
Denmark-West	14.9	(18.2)	16.0	(18.4)	17.0	(18.5)	17.9	(18.6)
Estonia	7.7	(1.4)	8.7	(1.4)	9.7	(1.4)	10.9	(1.4)
Finland	96.6	(65.2)	103.6	(65.7)	110.0	(66.1)	116.2	(66.5)
France	480.0	(31.6)	514.6	(31.8)	546.4	(32.0)	577.2	(32.2)
Germany	567.0	(192.4)	584.2	(192.9)	584.2	(192.9)	584.2	(192.9)
Great Britain	387.4	(68.1)	415.4	(68.6)	441.0	(69.0)	465.8	(69.3)
Greece	65.2	(17.4)	75.3	(17.7)	86.5	(17.9)	99.0	(18.2)
Hungary	40.1	(14.2)	45.1	(14.4)	50.6	(14.5)	56.5	(14.7)
Ireland	28.1	(3.2)	30.2	(3.3)	32.0	(3.3)	33.8	(3.3)
Italy	362.9	(169.2)	419.1	(171.7)	481.6	(174.1)	550.7	(176.5)
Latvia	7.1	(6.5)	8.0	(6.6)	9.0	(6.7)	10.0	(6.7)
Lithuania	9.9	(4.8)	11.1	(4.9)	12.5	(4.9)	13.9	(5.0)
Luxembourg	7.6	(0.9)	8.1	(0.9)	8.6	(0.9)	9.1	(0.9)
Netherlands	121.4	(114.3)	130.2	(115.1)	138.2	(115.8)	146.0	(116.4)
Norway	118.7	(3.6)	127.3	(3.6)	135.2	(3.7)	142.8	(3.7)
Poland	140.0	(93.3)	157.8	(94.4)	176.9	(95.5)	197.3	(96.6)
Portugal	55.9	(13.9)	64.5	(14.1)	74.1	(14.3)	84.8	(14.5)
Romania	49.8	(93.3)	56.1	(94.4)	62.9	(95.5)	70.1	(96.6)
Slovakia	30.1	(17.0)	33.9	(17.2)	38.0	(17.4)	42.4	(17.6)
Slovenia	16.3	(1.2)	18.3	(1.2)	20.5	(1.3)	22.9	(1.3)
Spain	298.6	(59.0)	344.9	(59.9)	396.3	(60.7)	453.2	(61.5)
Sweden	150.0	(29.3)	160.9	(29.5)	170.8	(29.6)	180.4	(29.8)
Switzerland	65.4	(0.7)	70.1	(0.7)	74.5	(0.7)	78.7	(0.7)

4.2. Conventional and storage technologies

For already existing power plant and storage technologies we assume that investment costs remain constant compared to today while learning effects lead to lower investment costs for new technologies. Through the deployment of improved materials and process techniques, future hard coal plants ("hard coal innovative") will be able to run at 700 degrees celsius and higher pressures (350 bars). The efficiency is assumed to increase by about 4 % points to 50 % due to these improvements. Investment costs are above today's standard technologies but are decreasing due to learning effects by around a third until 2050. Future lignite technologies ("lignite innovative") use a more efficient drying process and can therefore increase their efficiency to 48 %. Investment costs are just above todays state-of-the-art technologies. CCS-technologies are assumed to be commercially available by 2030 and applicable to hard coal, lignite and combined-cycle gas power plants. Due to long planning and construction times of nuclear plants we assume that before 2025 only nuclear plants already under construction today can be built. However, existing plants with a lifetime of 50 years can be retrofitted for 10 years at moderate costs (see Table 3). As also depicted in Table 3, standard and innovative technologies can be fitted with CCS and/or CHP technology. The investment costs of CCS technologies decrease until 2050. The investment costs of CHP plants also include additional costs for the grid and the extraction of heat. Due to the limited space potential pump storage and hydro storage plants are not an investment option.

Table 3: Investment costs of conventional and storage technologies in €$_{2010}$/kW

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

Table 4 shows the efficiency grades, CO_2 emission factors, technical availability, operational and maintenance costs and the technical lifetime for conventional plants. Efficiency grades are based on specifications of power plants currently under construction. For "innovative" technologies, higher efficiencies are assumed due to the described technical developments. CCS power plants lose 4-8 percentage points in electrical efficiency compared to non-CCS plants, depending on the power plant type. Moreover, higher operational and maintenance costs occur due to the additional costs for the pipe and storage system. Combined heat and power generation units have lower electrical but higher total efficiency grades. Operational and maintenance costs also include the costs for the heat extraction system.

Table 4: Economic-technical parameters for conventional and storage technologies

Technologies	$\eta(gen)$ [%]	$\eta(load)$ [%]	CO_2 factor [t CO_2 /MWh_{th}]	avail [%]	FOM costs [€$_{2010}/kW$]	Lifetime [a]
Nuclear	33.0	-	0.0	84.50	96.6	60
Hard Coal	46.0	-	0.335	83.75	36.1	45
Hard Coal - innovative	50.0	-	0.335	83.75	36.1	45
Hard Coal - CCS	42.0	-	0.034	83.75	97.0	45
Hard Coal - innovative CCS	45.0	-	0.034	83.75	97.0	45
Hard Coal - CHP	22.5	-	0.335	83.75	55.1	45
Hard Coal - CHP and CCS	18.5	-	0.034	83.75	110.0	45
Lignite	43.0	-	0.406	86.25	43.1	45
Lignite - innovative	46.5	-	0.406	86.25	43.1	45
Lignite - innovative CCS	43.0	-	0.041	86.25	103.0	45
OCGT	40.0	-	0.201	84.50	17.0	25
CCGT	60.0	-	0.201	84.50	28.2	30
CCGT - CHP	36.0	-	0.201	84.50	40.0	30
CCGT - CCS	53.0	-	0.020	84.50	88.2	30
CCGT - CHP and CCS	33.0	-	0.020	84.50	100.0	30
Pump storage	87.0	83.0	0.0	95.00	11.5	100
Hydro storage	87.0	-	0.0	90.00	11.5	100
CAES	86.0	81.0	0.0	95.00	9.2	40

The availability factor reported in Table 4 is the average of the four seasonal availability factors used in the model. It accounts for planned and unplanned shut-downs of the plants, e.g. because of revisions. For thermal, nuclear and storage power plants, the availability factor determines also the contribution of a plant to the secured available capacity at times of peak demand.

4.3. Renewable energy technologies

Table 5 gives an overview over the modeled renewable energy technologies and their assumed specific investment costs over time. The model includes photovoltaics (base and roof), concentrated solar power (CSP), wind onshore, wind offshore (deep and shallow water), biomass (solid and gas), hydro (run-of-river and storage) and geothermal power. Investment costs are assumed to decrease over time due to learning effects (based on on Prognos/EWI/GWS (2010), EWI (2010), IEA (2010a), IEA (2010b)). Europe-wide, costs drop sharpest by about 30% until 2050 for solar energy technologies. For CSP only facilities including thermal energy storage devices are considered which raises the investment costs but significantly increases the applicability of such installations. The assumed storage volume amounts to 8 hours - signifying that storing or generating electricity from stored heat is possible during eight consecutive hours at full capacity.

In order to account for different possible options of wind power, the model includes different technologies on- and offshore. For onshore turbines, there are three sizes available at different times. 3 MW turbines represent the technology momentarily installed. No future investment is possible, and no investment costs are consequently listed for this type of turbine. Up to 2025, a 6 MW turbine can be built, and from then on only 8 MW turbines are considered, which are characterized by higher full load hours, lower specific costs and a lower space requirement per MW installed (km^2/MW). This development accounts for technological progress expected in the wind power sector. Offshore wind is modeled similarly, incorporating 5 MW turbines up to 2025 and 8 MW turbines from then on.

Table 5: Investment costs for renewable technologies in €$_{2010}$/kW

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

The same technological and economic characteristics as for conventional and nuclear power plant technologies are defined for renewable energy technologies (Table 6). As for thermal, nuclear and storage power plants, the availability factor for dispatchable RES-E (biomass, geothermal) corresponds to the average seasonal availability factors used in the model and also determines the capacity of a plant which is counted as securely available capacity at times of peak demand. Efficiencies and availabilities of fluctuating renewable energy technologies are left out in Table 6 due to the fact that these characteristics cannot be captured by a single number. In fact, the infeed from such non-dispatchable energy sources is modeled as power distribution. As the yearly generation and feed-in structure of wind and solar technologies depends on local weather conditions, Europe was divided in 38 solar, 47 wind onshore and 42 wind offshore regions.[8] The contribution of fluctuating RES-E to securely available capacities at times of peak demand is shown in column "secured capacity". For wind, this factor is assumed to be 5%, meaning that at least the generation of 5% of all installed wind plants running at full capacity is firmly available in the peak demand hour. This assumption

[8]The regions are based on specific wind and solar data from EuroWind (2011). The wind and solar regions are not identical.

can be made due to geographically diversified wind sites throughout Europe. For photovoltaics we assume a capacity credit of 0% because peak demands in European countries are generally during winter time and in most European countries during early evening hours, when no sun power is available. CSP technologies in contrast are modeled with integrated thermal energy storage and can therefore shift electricity generation to hours when no sun power is available.

Table 6: Economic-technical parameters for renewable technologies

Technologies	Efficiency [%]	Availability [%]	Secured capacity [%]	FOM costs [€ $_{2010}/kW$]	Lifetime [a]
Biomass gas	40.0	85	85	120	30
Biomass gas - CHP	30.0	85	85	130	30
Biomass solid	30.0	85	85	165	30
Biomass solid - CHP	22.5	85	85	175	30
Geothermal (HDR)	22.5	85	85	300	30
Geothermal	22.5	85	85	30	30
PV ground	-	-	0	30	25
PV roof	-	-	0	35	25
Concentrated solar power	-	-	40	120	25
Wind offshore 6MW (deep)	-	-	5	152	25
Wind offshore 8MW (deep)	-	-	5	160	25
Wind offshore 6MW (shallow)	-	-	5	128	25
Wind offshore 8MW (shallow)	-	-	5	136	25
Wind onshore 6MW	-	-	5	41	25
Wind onshore 8MW	-	-	5	41	25
Run-of-river hydropower	-	-	50	11.5	100

4.4. Economic and technical parameters of grid technologies

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

Table 7: Economic-technical figures for grid technologies

	Grid upgrade costs [€ $_{2010}/(kW * km)$]	Converter costs [€ $_{2010}/kW$]
HVAC [Overhead Line]	0.4	-
HVDC [Cable]	1.5	150

The costs for both technologies were adjusted depending on the terrain of the region covered by the transmission line, allowing for up to 50% higher costs for lines crossing mountainous regions. Grid upgrade costs per kW and km are significantly higher for HVDC cables than for HVAC overhead lines. Moreover, for HVDC cables additional costs for the converter occur. Investments in overhead lines using HVAC technologies are common practice in today's power systems as they depict the least-cost option for transmission capacity extensions. HVDC cables, in contrast, are so far only used for offshore connections between two territories, where cables need to be used, due to high compensation needs of reactive power demand of cables in HVAC systems.

4.5. Fuel prices

Assumptions on fuel prices are mainly based on the World Energy Outlook 2010 (IEA (2010a)). Table 8 lists the assumed development of fuel prices (including transportation costs to the power plants) together with historical prices in €$_{2010}$. Regarding the different fuel types, the following aspects were taken into consideration:

After the price of oil peaked at 125 US$/barrel in 2008 it rapidly came down to values below 70 US$/barrel. Since then the oil price has been increasing. We assume that the oil price significantly increases until 2020 and at moderate rates from then on.

For hard coal, trade market prices depend on production capacities, development of input factor prices to mining, transport infrastructure 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 is projected to rise in the future which will support firm trade market prices. However, it is unlikely that prices rise strongly as coal production costs are relatively low compared to production costs of other fossil fuels and the amount of reserves will be sufficient to meet the increasing demand. Thus, we assume slightly rising prices on account of increasing material, transport and labor costs (IEA (2010a)).

Due to the low calorific value and high moisture content causing high transport costs per energy unit, there is no world trade market for lignite. We expect that better productivity offsets increasing cost factors (such as material or labor costs). Consequently prices (in €$_{2010}$) are assumed to remain at the level of 2008.

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

Uranium prices have risen in recent years as new nuclear power plants were built, mainly in Asia and

Eastern Europe. Simultaneously, increased prices motivated additional exploration of uranium mines. Nuclear fuel prices are assumed to slightly decrease until 2020 and remain on a stable level after then.

Prices of biofuels (solid and gaseous) are defined country-specific and thus account for the different potentials and/or different agricultural conditions. Minimal and maximal values indicating the price range are given in Table 8. Similar to other fuels, biofuels are expected to become more expensive until 2050.

Table 8: Fuel costs in €$_{2010}$/MWh$_{th}$

	2008	2020	2030	2040	2050
Nuclear	3.6	3.3	3.3	3.3	3.3
Coal	17.28	13.4	13.8	14.3	14.7
Lignite	1.4	1.4	1.4	1.4	1.4
Oil	44.6	99.0	110.0	114.0	116.0
Natural gas	25.2	28.1	31.3	33.2	35.2
Biomass (solid)	15.0-27.7	15.7-34.9	16.7-35.1	17.7-35.5	18.8-37.5
Biomass (gas)	0.1-70.0	0.1-67.2	0.1-72.9	0.1-78.8	0.1-85.1

5. Scenario Analysis for the European electricity system

5.1. Scenario definition

We apply the approach described in Section 3 to optimize the transformation of the European electricity system to reach an 80% RES-E share and an 80% CO_2 emission reduction (compared to 1990) in 2050. We compare this overall cost-optimal scenario (Scenario A) to a scenario in which interconnector capacities are only moderatly extended (Scenario B). The two scenarios only differ with regard to the possibilities of grid extensions, all other assumptions are identical. The effects of interconnector extension delays currently observed in Europe can thus be identified and analyzed. In both scenarios we model a step-wise transformation towards a low-carbon and mainly renewable-based electricity system, as illustrated in Table 9.

Table 9: RES-E and CO_2 reduction quotas [%]

	2010	2020	2030	2040	2050
RES-E quota [%]	-	34	50	65	80
CO_2 reduction quota [%]	-	20	40	60	80

Concerning the transmission grid extensions in Scenario B, we assume that interconnector extensions are limited to projects which have already entered the planning phase today (based on ENTSO-E (2010)), but whose commissioning is assumed to be delayed. Assumptions regarding the delays are based on factors influencing the likelihood and the degree of project delays in certain areas: Population density (relates to public acceptance issues), historical cases of public protest and type of terrain (e.g. mountainous regions, nature reserves, military zones etc.). An overview of the planned interconnection extensions (based on ENTSO-E (2010)) and the delayed interconnection extensions (as assumed in Scenario B) is provided in the Appendix. It should be noted that the purpose of Scenario B is not to create a "most-likely" scenario, but to show the influence of only moderate interconnector extensions compared to the overall optimal pathway in Scenario A. Intraregional transmission grid extensions in Scenario B are equally determined by load flow analysis within the grid model, however in contrast to Scenario A not in an iterative process but ex-post of the market model calculation.

5.2. Scenario results

In the following we present results for the cost-optimal deployment of generation and grid capacities (Scenario A) and discuss especially how much grid extension at which locations and at which point of time is beneficial from a system integrated point of view (Section 5.2.1). In Section 5.2.2 we analyze how moderate interconnector extensions are cost-efficiently substituted (Scenario B), e.g. by the choice of generation options located closer to consumption areas. Section 5.2.3 presents a comparison of costs and investment expenditures arising in both scenarios due to the transformation process of the European electricity system.

5.2.1. Cost-efficient development of generation and grid capacities

Figure 2 depicts the development of European generation capacities (left) and electricity generation (right) in Scenario A.[9] Generation capacities increase more than electricity demand not only because renewable plants have lower utilization times than conventional or nuclear plants but also because RES-E have a relatively low contribution to capacity requirements from a security of supply point of view. Major changes in the European generation capacity mix until 2050 comprise significant investments in onshore wind capacities in the short term, in offshore wind capacities in the medium term and in solar (photovoltaics and concentrating solar power) capacities in the long term.

[9] Values for the historical years are based on EURELECTRIC (2009) and EUROSTAT (2010) and do not include differentiations between CHP and non-CHP plants.

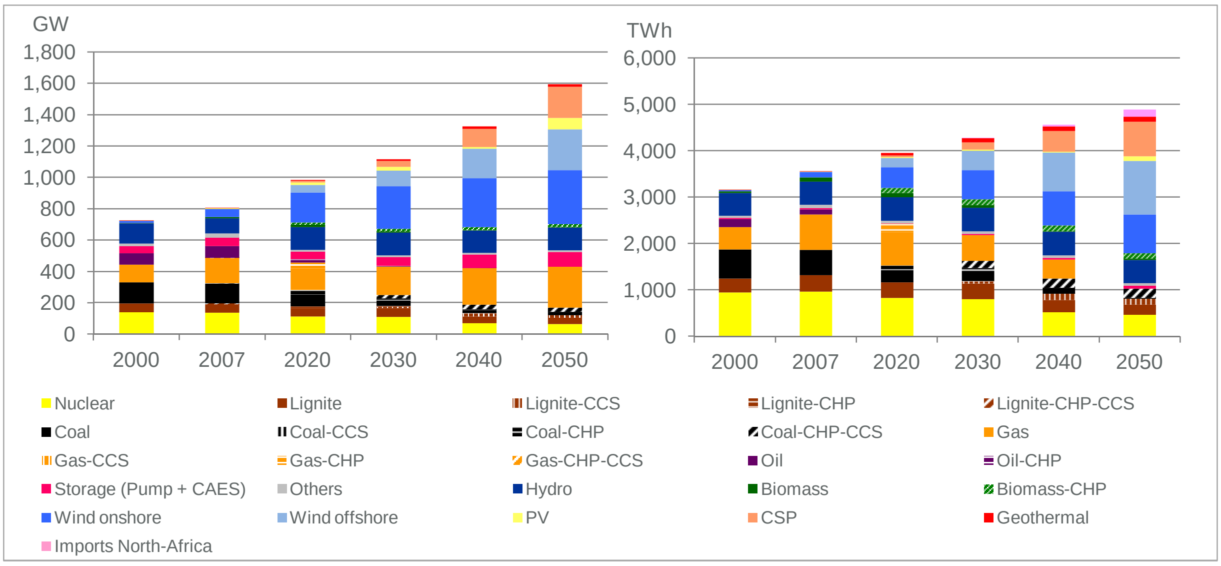

Figure 2: Capacity [GW] and generation [TWh] development in Scenario A

In the short term (until 2020) 120 GW wind onshore capacities are deployed on favorable sites, primarily in Great Britain, France and Poland. In addition, offshore capacities increase by 47 GW, mainly driven by investments in Norway, the Netherlands, Great Britain and Ireland. European biomass capacities increase by 16 GW. In the medium term (2020-2030), additional capacities mainly comprise onshore and offshore wind plants (constructed primarily in France, Germany and Poland as far as onshore wind repectively in the Netherlands, in Denmark, Great Britain and Norway as far as offshore wind is concerned). In additon, concentrated solar plants are constructed in Spain and North-Africa. Interestingly, CSP plants are preferred to photovoltaic systems despite higher electricity generation costs. CSP plants have a higher value from a system integrated point of view because they are modeled with an integrated thermal energy storage which permits to shift electricity generation to hours with low solar radiation.[10] Regarding thermal power plants, the most significant deployment concerns coal plants equipped with CCS and CHP in Italy, Germany, the Netherlands, Romania and Great Britain. In 2050 the European electricity mix is characterized by wind (on- and offshore) and solar (PV and CSP) technologies. In addition, mainly gas turbines ensure security of supply. Investments in solar capacities essentially take place between 2030 and 2050. At low European RES-E shares and at current investment costs, solar technologies have higher generation costs even on sites with the highest solar radiation, compared to wind on- and offshore technologies on best sites throughout Europe. However, with increasing RES-E targets, the potential for favorable wind sites is insufficient for achieving the

[10] A detailed analysis of the value of thermal energy storages in CSP plants can be found in Nagl et al. (2011).

predescribed shares. Therefore, the comparative cost advantage for RES-E generation of the Mediterranean countries arises in the long-term, when solar generation at favorable sites becomes cost-efficient compared to other RES-E generation options throughout Europe.

Overall, the cost-optimal regional and technological RES-E mix identified in this scenario substantially deviates from the pathway European Member States have defined in their National Renewable Energy Action Plans (NREAP) for the year 2020. The most noticeable deviations occur with regard to solar technologies which are cost-efficiently only deployed in the long term in southern countries but e.g. targeted in the German NREAP to reach over 50 GW in 2020.

The development of the European generation capacity mix is accompanied by substantial transmission grid investments until 2050, as depicted in Table 10.

Table 10: Optimal transmission grid extension within Europe in Scenario A

	2010-2020	2020-2030	2030-2040	2040-2050
Thermal capacities HVAC [GW]	278.05	90.55	241.5	149.55
Thermal capacities HVDC [GW]	17.617	54.097	134.015	242.677
Line length [km]	53,176	27,864	67,632	79,035

Until 2020, major upgrades take place between and within northern and central European countries, essentially in order to transport large amounts of wind energy. Especially, the grid between Denmark and Germany, within Denmark and between Scandinavia and Germany is extended. In addition, grid upgrades take place to further integrate the Baltic power system. Also, German interconnectors with Belgium and the Czech Republic are enforced, among other reasons in order to supply Germany with low-cost baseload electricity after the German nuclear phase-out. Also between 2020 and 2030, optimal grid extensions concentrate on the German-Danish interconnection in order to integrate the increasing wind offshore generation. In addition, an interconnector between North-Africa and Spain is constructed, which entails an enforcement of the Spanish-French interconnector. Also the French grid is substantially upgraded driven by increasing solar power generation in southern Europe and wind power generation in the Benelux countries. From 2030 onwards, HVDC lines are increasingly employed to transport electricity from renewable resources over long distances to consumers. Until 2050, total cost-optimal grid extensions amount to 228,000 km (+76% compared to today). Until 2050, lines in all regions are extended. Especially the north-south axis is enforced by major grid upgrades in Spain (+ 32,000 km), in France (+ 27,000 km), in Germany (+ 25,000 km) and in Italy (+ 21,000 km). Major interconnector capacity extensions especially take place between

Belgium and the Netherlands (+ 31 GW_{th}), Spain and France (+ 28 GW_{th}), Norway and Sweden (+ 25 GW_{th}) and Germany and Denmark-West (+ 24 GW_{th}). An overview of European-wide grid extensions until 2050 is provided by Figure 3.[11]

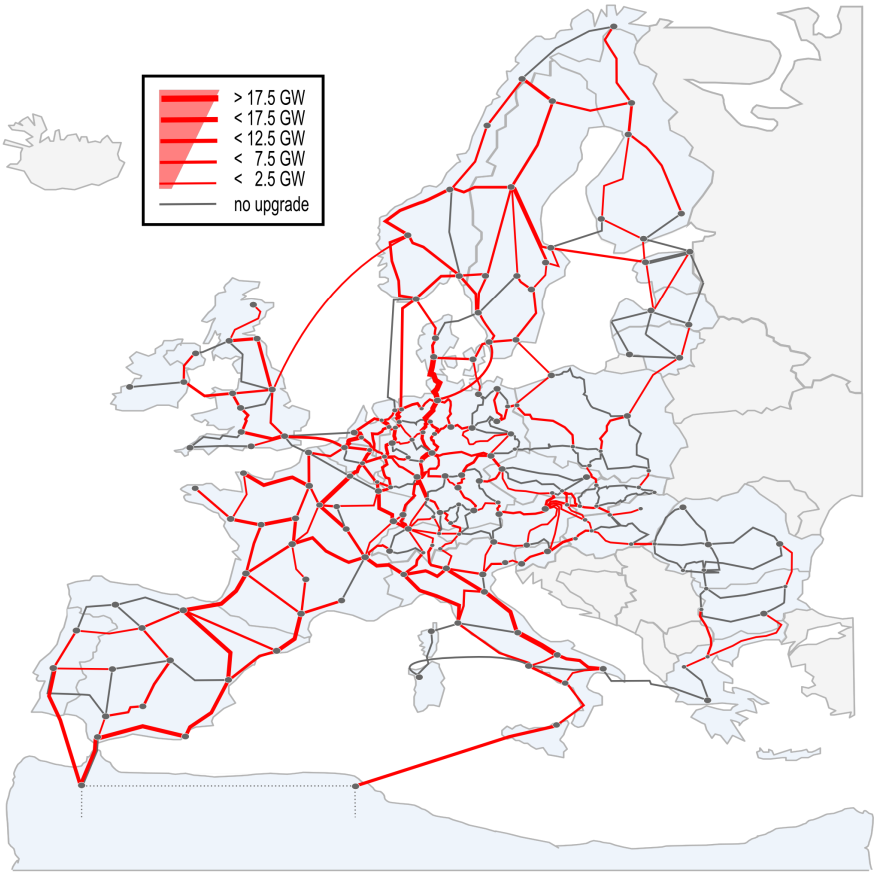

Figure 3: Transmission grid upgrade until 2050 [Scenario A]

Such substantial grid extensions are beneficial for two reasons: First, a highly intermeshed network can help to profit from comparative cost advantages of electricity supply from renewable energy sources. These advantages mainly arise because of different meteorological conditions, leading to substantial differences in generation costs. Also, generation options which are available only in some countries due to natural or political restrictions, can lead to comparative cost advantages. Lignite generation for example is restricted to countries with natural lignite resources because of high transportation costs. Second, an increasingly intermeshed network can help to balance demand and fluctuating RES-E infeed. Thus, the value of a grid extension is the higher the more pronounced electricity generation cost differences between regions are

[11] Note that some grid extensions in northern Europe could also be substituted by a North Sea Offshore grid which has however not been subject of this analysis.

and the more demand curves and/or fluctuating RES-E infeed are negatively correlated between different regions in the system (balancing effect). For the case of the European electricity system we find three main combinations of grid and generation investment choices depending on cost differences in electricity generation and interconnector capacities:

1. Electricity generation options with large comparative cost advantages are substantially deployed also if it requires massive transmission grid extensions. Often, these generation options are used until the respective potential is reached. This is for example the case for offshore wind in the Netherlands, in Denmark-West and Ireland. To which region this electricity is exported is however very sensitive to relative interconnector extension costs. For example, whether offshore wind from the Netherlands is mainly transported to Germany or to France via Belgium primarily depends on the relative interconnector extension costs.
2. For electricity generation options remotely located from big consumption areas, transmission grid investment costs can render cost-advantageous RES-E sites unfavorable compared to sites with higher electricity generation costs which require less grid investments. This is for example the case for solar power imports from North-Africa. This option is used only to a relatively small extent; the maximum import flow is reached in 2050 with 153 TWh. Because the cost-benefit of electricity generation from solar sources in North-Africa compared to European regions at the Mediterranean does not outweigh further grid investment costs, it is inefficient to build additional tie-lines enabling larger imports from North-Africa.[12]
3. When differences in electricity generation costs between two countries are small, relative import costs from a third country, induced by different interconnector investment costs, have a high influence on generation capacity deployments in those countries. The offshore wind deployment in Germany and France is for example very sensitive to relative import costs from the Netherlands. In this case, major investments in offshore wind do not necessarily take place in the region with lower electricity generation costs but in the region with higher import costs.

Summarizing, we find in this overall cost-minimizing approach that the option of grid extensions is substantially used in order to profit from comparative cost advantages for electricity generation. We find that favorable sites are used until their space potential is reached, if these regions are located close to large consumption centers. If however favorable sites are located far from demand centers, such as solar sites in

[12] By assumption, only solar-based renewable sources can be deployed in North-Africa. North African wind conditions are also relatively favorable, but not modeled within this analysis.

North-Africa and offshore sites in Norway, a full exploitation of the potential is not cost-efficient because of high transmission grid extension costs.

5.2.2. Effects of sub-optimal interconnector extensions

Figure 4 shows the differences in generation capacities (left) and electricity generation (right) between Scenario A and B on a European level (values above zero indicate that capacities respectively generation are higher in Scenario B). Overall, we find that the limitation of interconnector capacity extensions leads to larger shares of generation options located near to consumption areas, larger shares of dispatchable renewables and to an increased deployment of storages (both thermal energy storages incorporated in CSP plants and electricity storages). In addition, it is important to notice that even with a moderate interconnector extension, intraregional grid extensions required to reach the predescribed RES-E and CO_2 reduction targets are significant. Until 2050, the transmission grid is extended by 500 GW. The total length of new lines is 111,000 km, representing an 37% increase compared to today.

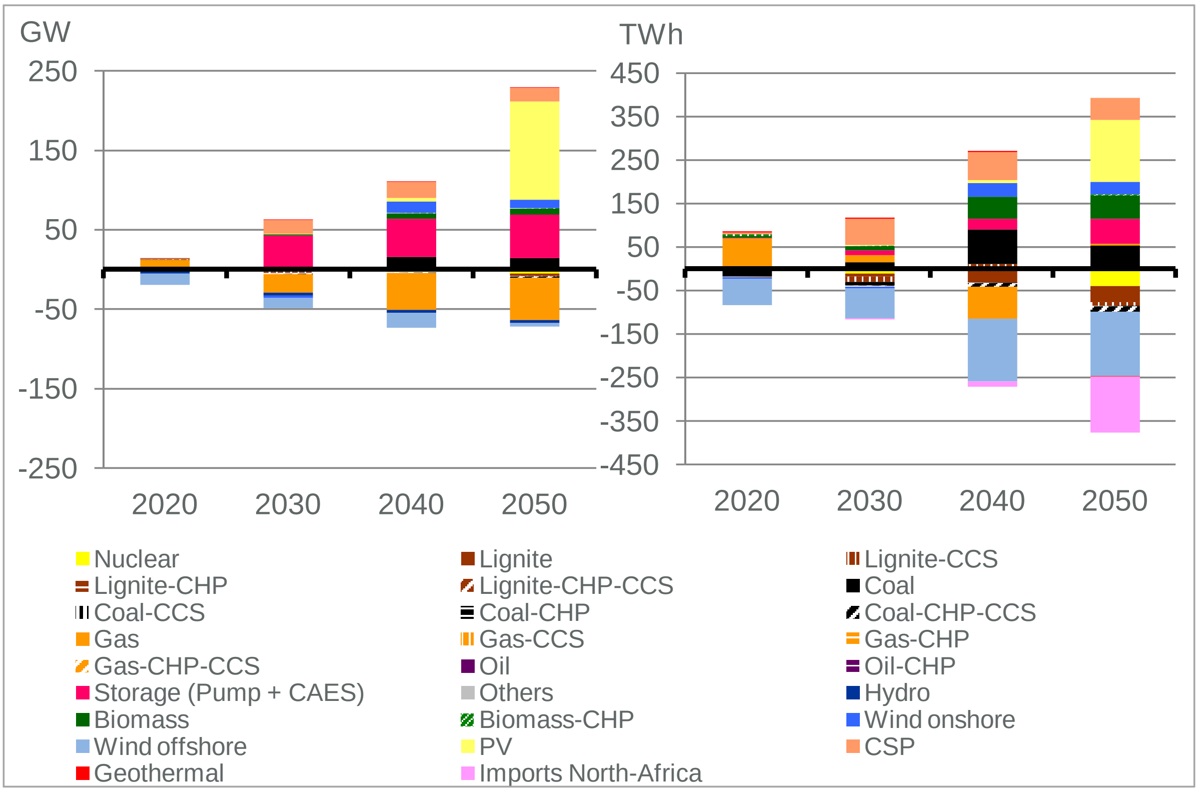

Figure 4: Differences between Scenario B and A in generation capacities [GW] and electricity generation [TWh]

Until 2020, the European capacity mix develops quite similar in both scenarios. Major differences occur only with regard to offshore wind and gas capacities. In Scenario A, the 2020 capacity-mix comprises 14 GW more offshore and 9 GW less gas capacities than in Scenario B. Reasons for the lower investments in offshore wind in Scenario B include lower interconnection capacities in comparison to the optimal path, especially between Germany and Denmark (-4.6 GW_{NTC}), between Germany and the Netherlands (-3.2 GW_{NTC}), between Germany and Sweden (-4.6 GW_{NTC}) and between Great Britain and Ireland (-5 GW_{NTC}). Between 2020 and 2030, differences become more apparent. In Scenario A, more offshore (13 GW) and more gas (24 GW) capacities are deployed. The additional gas capacities in Scenario A are gas turbines, needed to ensure security of supply. Since electricity generation is more regionally concentrated at remote areas in Scenario A, more backup capacities are needed to ensure that demand can be met during peak hours.[13] Scenario B is characterized by a higher capacity of concentrated solar power (17 GW) and especially by a large increase of storage capacities. While in Scenario A 10 GW storage capacities are deployed between 2020 and 2030, 51 GW are commissioned in Scenario B. The storage commissionings in Scenario B take place in countries with large wind parks (on- and offshore), namely Great Britain, Poland, the Netherlands and France. Due to limited grid extensions in Scenario B, a large part of the produced wind may not be used to satisfy local demand or to be exported to other countries during hours of high wind infeed. Storage units are deployed to shift electricity to hours of low wind infeed. The capacity mix in 2050 shows significant differences between the two scenarios. Most noticeable, 124 GW photovoltaic capacity is additionally installed in Scenario B compared to Scenario A. Also, the capacity mix in Scenario B comprises more storage (55 GW), CSP (17 GW) and coal (14 GW) capacities than in Scenario A. Due to low full load hours and a low capacity credit of photovoltaic power, total capacities are 158 GW higher in Scenario B than in A. The capacity mix in Scenario A comprises 53 GW more gas capacity (primarily built in order to ensure security of supply) and 4 GW more wind offshore capacity.

Taking a look at the differences in electricity generation between Scenario B and A, the additional generation of wind offshore plants in Scenario A compared to Scenario B is noticeable. In 2050, this difference is 148 TWh. This significant difference arises, although the European capacity mix comprises only 4 GW offshore capacity more in Scenario A than in Scenario B. The reason is, that the restricted grid extensions in Scenario B hinder the use of offshore sites with high full load hours, which are remotely located to load centers. In Scenario A, offshore wind plants can thus be located at better wind sites than in Scenario B. Furthermore, net imports in Scenario A are higher than in B, especially in 2050 (+129 TWh). In Scenario B, these imports of solar based generation from North Africa are also restricted compared to Scenario A,

[13]As peak hours occur simultaneously in many European countries, the contribution of exports to security of supply requirements is only small.

due to less grid capacities between North Africa and the European continent. Within Scenario B, only one HVDC transmission line between North Africa and Spain with a total capacity of 15 GW connects the North African transmission grid to Europe. Furthermore, a bottleneck can be identified between Spain and France (capacity restricted to 4 GW_{NTC} in 2050), such that the supply of large load centers in central Europe with imports from North Africa is limited. Higher generation in Scenario A is furthermore provided by nuclear and lignite plants. These generation options are only available in some countries because of natural resource availabilities (lignite) or national political decisions (nuclear). Thus, these generation opportunities, which are both characterized by low variable costs, can be better exploited in Scenario A when the European transmission network is more deeply intermeshed. In Scenario B in contrast, the generation by technologies available in all countries (biomass, wind onshore, photovoltaic) is higher than in Scenario A.

Lower grid extensions in Scenario B also lead to lower physical and commercial trade flows in the European system. Figure 5 shows the net imports in Scenario A and B in the year 2050.

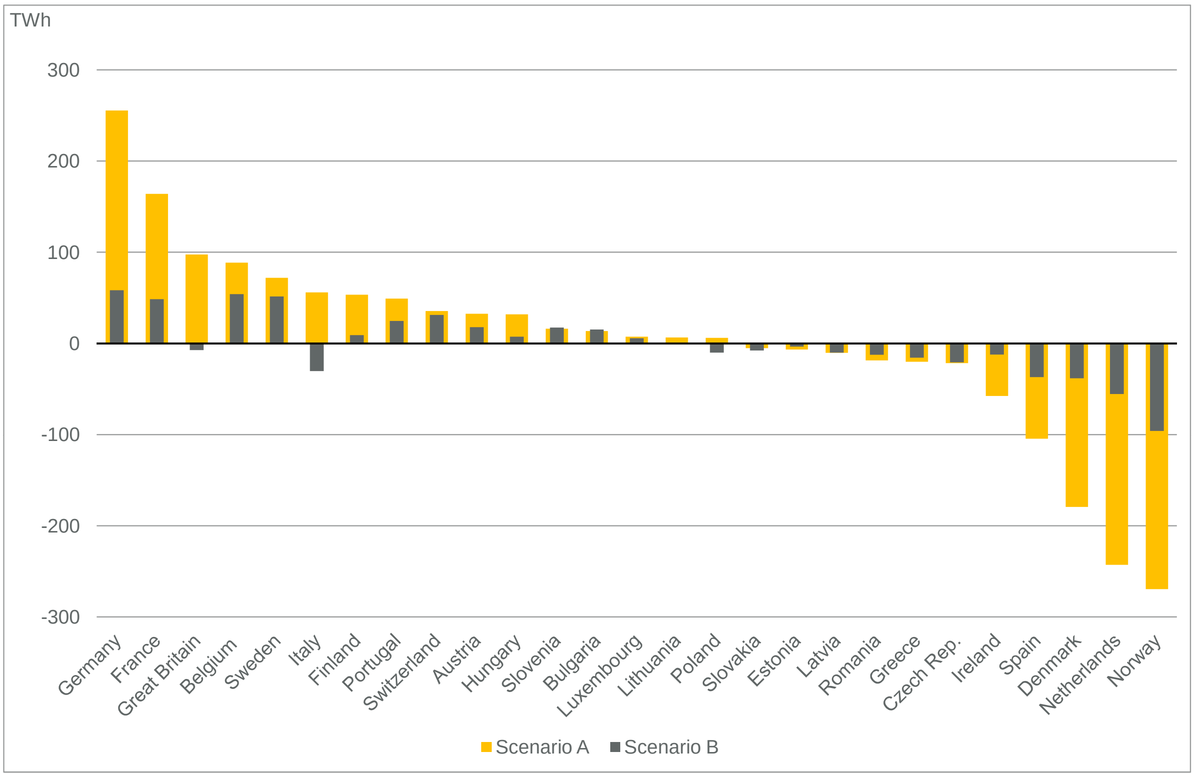

Figure 5: Comparison of net imports in 2050 [TWh]

In Scenario A, the largest net importing countries are Germany and France, both countries characterized by high electricity demands and located in central Europe. Great Britain, Belgium and Sweden also import large shares of their demand. These countries have neighboring countries with more favorable renewable potentials than in their own country, namely Ireland, the Netherlands and Norway. In Scenario B, due to lower transmission grid extensions, these countries have a substantially higher local production compared to Scenario A. For example in Germany, generation from wind offshore, biomass, lignite and photovoltaics is higher. Largest net exporting countries in Scenario A are Norway, the Netherlands, Denmark, Spain and Ireland. These countries are also net exporting countries in Scenario B but export less than in Scenario A.

5.2.3. Results for investment and costs

The transformation to a low-carbon and mainly renewable-based electricity system requires investments in conventional, renewable, storage and grid technologies. Table 11 depicts the investment expenditures arising in each decade until 2050 in Scenario A and B.

It becomes clear that renewable technologies take the largest share, which grows over time. In contrast, investments in storage and grid technologies are relatively low throughout the time horizon until 2050 - despite significant grid extensions, especially in Scenario A. Total investment expenditures increase in both scenarios (up to over 1,140 Bn. €$_{2010}$ in the decade 2040-2050) due to the transformation to a low-carbon electricity system with mainly capital intensive technologies and due to the assumed increasing electricity demand. In the short term, investments are primarily needed to install wind parks at the European coast lines. In the decade 2020-2030, the investments in conventional power plants increase due to the replacement of several old nuclear power plants and the assumed commercial availability of CCS technologies. After 2030, further investments are needed for wind parks in Northern Europe and solar technologies mostly in Spain, Italy and Northern Africa.

Table 11: Development of investment expenditures [bn. €$_{2010}$ in Scenario A and B]

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

In comparison to Scenario A, investment expenditures in Scenario B are especially higher for renewable energies, as sub-optimal grid extensions hinder the use of favorable RES-E potentials. Thus, in order to reach the RES-E targets in Scenario B, more RES-E plants with less full load hours than in Scenario A have to be built. Also, limited grid extensions in Scenario B impede the integration of fluctuating renewables. Therefore, storage capacities are built especially in regions with high wind penetrations, leading to almost 50 bn. €$_{2010}$ of further investments in Scenario B. Regarding conventional technologies, investment expenditures are lower in Scenario B, because less back-up capacities are needed. Overall, accumulated investment expenditures until 2050 are 57 Bn. €$_{2010}$ higher in Scenario B.

In addition to investment costs, fix operation and maintenance costs as well as variable production costs arise. Figure 6 shows the development of yearly fix costs (comprising annuitized investment as well as fix operation and maintenance costs) and variable costs (fuel, CO_2 and ramping costs minus remunerations for heat generated in CHP plants). In addition, the average system costs of electricity supply in Europe are depicted. Average system costs are calculated as the sum of all costs (generation and high voltage transmission grid) in relation to the energy consumption by end user. On the left hand side of Figure 6, the development within Scenario A is depicted, the right hand side highlights differences between Scenario B and A.

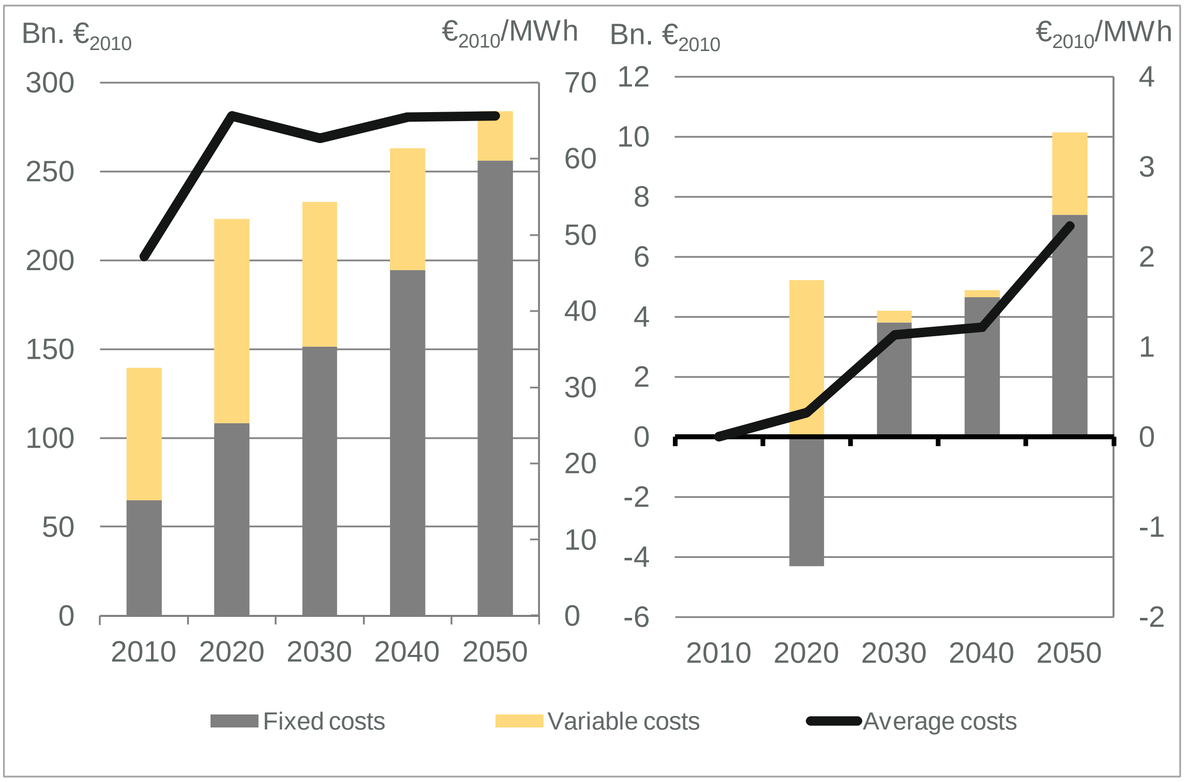

Figure 6: Development of costs in Scenario A [Bn. €$_{2010}$] and differences between Scenario B and A [Bn. €$_{2010}$]

It can be seen that the share of fix costs increases constantly over time and makes up 90% of total costs in 2050. This development is caused by a changing capacity mix which in 2050 is mainly based on renewable energies with low variable costs. In addition, in the long run a large share of conventional capacities mainly serves as back-up capacities characterized by high fix but low variable costs. For these reasons, variable costs in absolute terms decrease over time despite increasing fuel prices. In Scenario A, the average system costs increase from 47.1 in 2010 to 65.6 €$_{2010}$/MWh in 2020 mainly due to the challenging CO_2 emission target of 2020. In 2030, the average costs can be reduced primarily due to the availability of CCS-technologies and more advanced wind turbines. In the long term, higher fuel prices, higher emission reduction and RES-E targets lead to higher prices. The assumed cost reductions for advanced conventional and renewable technologies have a cost decreasing effect. These opposite effects lead to relatively stable average costs of 65 €$_{2010}$/MWh.

Costs in Scenario B are higher than in Scenario A, with the exception of fix costs in 2020. Higher fix costs in 2020 in the optimal scenario are mainly due to capital-intensive renewable technologies and grid investments until 2020 (see also Table 11 above). However, early investments in the grid infrastructure are cost-efficient from a system point of view - both in the short and the long term. Reasons why variable costs are higher in the restricted grid scenario are threefold. First, generation from lignite and nuclear power plants is lower. Second, in Scenario B biomass generation replaces a part of the wind generation in Scenario A. Third, variable costs in 2020 are higher because a larger share of gas generation is required in order to reach the 2020 CO_2 -target than in Scenario A. In Scenario A, the 2020 RES-E target is surpassed. Due to this additional RES-E generation, mainly from offshore plants, increased generation from lignite plants in Scenario A is possible without violating the CO_2 -target.

Differences in average system costs increase over time, since the consequences of limited grid extensions influence production costs more severely when RES-E shares are large. In 2050 average system costs are about 2.5 €$_{2010}$/MWh (3.5%) higher in Scenario B than in Scenario A. Overall cumulated discounted system costs until 2050 (not depicted in Figure 6) increase by about 52 bn. €$_{2010}$ due to limited transmission grid extensions in Scenario B. This amounts to an increase by 1.44%. Since the additional costs in Scenario B increase over time, the most significant cost differences are weighted least within this discounted cost difference.

6. Conclusions

We have shown that grid extensions are essential in order to reach high RES-E and CO_2 reduction targets in Europe in a cost-efficient way. Due to different meteorological conditions or local resource availabilities, generation cost differences throughout Europe are substantial - especially in the context of high RES-E targets. For example full load hours of solar and wind based technologies vary by factors up to 100% between most and least favorable sites throughout Europe.

For this reason, 228,000 km transmission grid lines are built until 2050 under the assumed scenario framework, when generation capacities and the electricity network can be cost-optimally extended. Compared to today, this represents an increase by 76%. We find that in most cases grid extensions allowing to fully exploit the most favorable potentials throughout Europe, are beneficial from a system integrated point of view. Only for those favorable sites located furthest north or south of large consumption areas in Central Europe, the value of grid extensions does not always outweigh its costs. We also find that grid extensions are mostly preferred to investments into storage units, which are deployed to a larger extent when interconnector capacities can only be moderately extended. Further findings include substantial increases of average system costs for electricity until 2050, even if RES-E are deployed efficiently throughout Europe, the grid is extended optimally, and if significant cost reductions of RES-E are assumed.

The approach of our analysis could be extended in several ways. First, the iterative approach is only based on capacities and costs for interconnectors between countries. Although transmission lines within countries are included in the transmission grid model, a consideration of costs and benefits of load-distant generation within countries is not part of the iterative process. Second, our approach includes only the high-voltage transmission grid and could be extended for lower voltage levels. The evaluation of grid extensions and generation capacity investments from a system integrated point of view, including these two aspects, provides an interesting area of further research.

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Appendix

Table 12: Abbreviations

Abbreviation	Description
DC	Direct current
CCS	Carbon capture and storage
CHP	Combined heat and power
CSP	Concentrating solar power
GDP	Gross domestic product
HVAC	High voltage alternating current
HVDC	High voltage direct current
NTC	Net tranfer capacity
NREAP	National Renewable Energy Action Plan
OPF	Optimal power flow
PV	Photovoltaic
RES-E	Renewable energy sources - electricity

Table 13: NTC extension based on ENTSO-E (2010) and assumed delayed NTC extensions [GW]

		Based on ENTSO-E (2010)		**Assumed delayed NTC extension**			
from	**to**	**2010-2020**	**2020-2030**	**2010-2020**	**2020-2030**	**2030-2040**	**2040-2050**
AT	CH		0.77				0.77
AT	CZ						
AT	DE	1.94	0.77			1.94	0.77
AT	HU	0.20		0.20			
AT	IT		2.63				2.63
AT	SI						
AT	SK	0.97			0.97		
BE	DE		0.89				0.89
BE	FR	0.30	0.97	0.30		0.97	
BE	GB	1.00			1.00		
BE	LU	0.40			0.40		
BE	NL						
BG	GR	0.97		0.97			
BG	RO	1.94				1.94	
CH	AT		0.77				0.77
CH	DE		0.77				0.77
CH	FR		0.20				0.20
CH	IT	0.97				0.97	
CZ	AT						
CZ	DE		0.97			0.97	
CZ	PL						
CZ	SK						
DE	AT	0.77	1.94			0.77	1.94
DE	BE		0.89				0.89
DE	CZ		0.97			0.97	
DE	CH		0.77				0.77
DE	DK-E	0.60		0.60			
DE	DK-W	0.50	0.97		0.50	0.97	
DE	FR						
DE	LU						
DE	NL	1.94			1.94		
DE	NO		0.70			0.70	
DE	PL	0.77	0.97	0.77		0.97	
DE	SE	0.60		0.60			
DK-E	DE	0.60		0.60			
DK-E	DK-W	1.40				1.40	
DK-E	NO						
DK-E	PL						
DK-E	SE	0.60		0.60			
DK-W	DE	0.50	0.97		0.50	0.97	
DK-W	DK-E	1.40				1.40	
DK-W	NL	0.70			0.70		
DK-W	NO	0.70		0.70			
DK-W	SE						
EE	FI	0.65		0.65			
EE	LV						
EE	SE						
ES	FR	1.60	1.20		1.60		1.20
ES	NA			0.30		4.10	10.00
ES	PT	1.80		1.80			

		Based on ENTSO-E (2010)		Assumed delayed NTC extension			
from	**to**	**2010-2020**	**2020-2030**	**2010-2020**	**2020-2030**	**2030-2040**	**2040-2050**
FI	EE	0.65		0.65			
FI	NO		0.97		0.97		
FI	SE	1.77		1.77			
FR	BE	0.30	0.97	0.30			0.97
FR	CH		0.20				0.20
FR	DE						
FR	ES	2.30	1.20		2.30		1.20
FR	GB	1.00			1.00		
FR	IT	0.60	1.00		0.60		1.00
FR	LU	0.20		0.20			
GB	BE	1.00			1.00		
GB	FR	1.00			1.00		
GB	IE	1.47		1.47			
GB	NL	1.00		1.00			
GB	NO	1.40			1.40		
GR	BG	0.97		0.97			
GR	IT	0.50			0.50		
GR	NA						
HU	AT	0.20		0.20			
HU	RO						
HU	SI	1.94		1.94			
HU	SK	2.91			2.91		
IE	GB	1.47		1.47			
IT	AT		2.63				2.63
IT	CH	0.97				0.97	
IT	FR	0.60	1.00		0.60		1.00
IT	GR	0.50			0.50		
IT	NA						
IT	SI		1.94			1.94	
LT	LV	0.20		0.20			
LT	PL	3.34		3.34			
LT	SE	0.70		0.70			
LV	EE						
LV	LT	0.20		0.20			
LV	SE						
LU	BE	0.20			0.20		
LU	DE						
LU	FR	0.20		0.20			
NA	ES					4.10	10.00
NA	GR						
NA	PT						
NA	IT						
NL	BE						
NL	DE	1.94			1.94		
NL	DK-W	0.70			0.70		
NL	NO	1.40			1.40		
NL	GB	1.00		1.00			
NO	DE		0.70			0.70	
NO	DK-E						
NO	DK-W	0.70		0.70			
NO	FI		0.97		0.97		
NO	GB	1.40			1.40		
NO	NL	1.40			1.40		
NO	SE	2.17		2.17			

		Based on ENTSO-E (2010)		Assumed delayed NTC extension			
from	**to**	**2010-2020**	**2020-2030**	**2010-2020**	**2020-2030**	**2030-2040**	**2040-2050**
PT	ES	1.80		1.80			
PT	NA						
PL	CZ						
PL	DE	0.77	0.97	0.77		0.97	
PL	DK-E						
PL	LT	3.34		3.34			
PL	SK						
PL	SE						
RO	BG	1.94			1.94		
RO	HU						
SE	DE	0.60		0.60			
SE	DK-E	0.60		0.60			
SE	DK-W						
SE	EE						
SE	FI	1.77		1.77			
SE	LT	0.70		0.70			
SE	LV						
SE	NO	2.17		2.17			
SE	PL						
SI	AT						
SI	HU	1.94		1.94			
SI	IT		1.94			1.94	
SK	AT	0.97			0.97		
SK	CZ						
SK	HU	2.91			2.91		
SK	PL						

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EWI is a so called An-Institute annexed to the University of Cologne. The character of such an institute is determined by a complete freedom of research and teaching and it is solely bound to scientific principles. The EWI is supported by the University of Cologne as well as by a benefactors society whose members are of more than forty organizations, federations and companies. The EWI receives financial means and material support on the part of various sides, among others from the German Federal State North Rhine-Westphalia, from the University of Cologne as well as – with less than half of the budget – from the energy companies E.ON and RWE. These funds are granted to the institute EWI for the period from 2009 to 2013 without any further stipulations. Additional funds are generated through research projects and expert reports. The support by E.ON, RWE and the state of North Rhine-Westphalia, which for a start has been fixed for the period of five years, amounts to twelve Million Euros and was arranged on 11th September, 2008 in a framework agreement with the University of Cologne and the benefactors society. In this agreement, the secured independence and the scientific autonomy of the institute plays a crucial part. The agreement guarantees the primacy of the public authorities and in particular of the scientists active at the EWI, regarding the disposition of funds. This special promotion serves the purpose of increasing scientific quality as well as enhancing internationalization of the institute. The funding by the state of North Rhine-Westphalia, E.ON and RWE is being conducted in an entirely transparent manner.