Applied Energy 104 (2013) 642–652

Contents lists available at SciVerse ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

The role of grid extensions in a cost-efficient transformation of the European electricity system until 2050

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HIGHLIGHTS

- ▶ Determination of optimal generation capacities and transmission grid extensions.
- ▶ Iterative optimization with market model and load flow analysis.
- ▶ Grid extensions are crucial to achieve climate protection targets cost-efficiently.
- ▶ Grid extensions allow using most favorable sites for renewables in Europe.
- ▶ Grid extensions are mostly preferred to investments in storage units.

ARTICLE INFO

Article history:
Received 6 August 2012
Received in revised form 14 November 2012
Accepted 20 November 2012

Keywords:
Renewable energy
GHG reduction
Transmission grid
Power system optimization

ABSTRACT

A strong and intermeshed electricity grid allows the cost-efficient achievement of renewable energy targets by enabling the use of favorable sites and by facilitating the balancing of stochastic infeed from renewables and electricity demand. However, construction of new lines is currently proceeding slowly in Europe. This paper quantifies the benefits of optimal transmission grid extensions for Europe up to 2050 by iterating an investment and dispatch optimization model with a load flow based grid model. We find that large grid extensions, allowing the full exploitation of the most favorable RES-E sites throughout Europe, are beneficial from a least-cost perspective. If the electricity network were to be cost-optimally extended, 228,000 km would be built before 2050 (+76% compared to today). Only for sites located furthest from large consumption areas in Central Europe would the value of grid extensions not always outweigh its costs. Furthermore, the capacity of transmission lines connecting favorable RES-E sites with demand centers is cost-optimally dimensioned to almost entirely export all RES-E generation that exceeds local electricity demand. Only in periods with the highest infeed of fluctuating renewables, electricity is stored. When optimal grid extensions are impeded, storage investments are chosen to a larger extent.

1. Introduction and background

In an effort to fight global warming, many countries attempt to reduce CO_2 emissions in the power sector by significantly increasing the proportion of renewable energies in electricity production (RES-E). A highly intermeshed electricity transmission grid may contribute to a cost-efficient achievement of this target by enabling the use of the most favorable RES-E sites and by facilitating the integration of the stochastic infeed of fluctuating RES-E capacities and electricity demand.

In Europe, a large share of the renewable generation is expected to come from wind and solar power. However, the most favorable wind and solar sites are located far from load centers and have stochastic generation. Hence, additional transmission lines are needed to access these sites. Moreover, as wind speed, solar radiation and regional loads are 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 usage of storage options and regional resources, such as lignite in connection with carbon capture and storage. Although the need for transmission grid extensions in the transformation towards a low-carbon and renewable-based electricity system has been mostly accepted, the construction of new lines is often proceeding very slowly in areas with high population density (see e.g., [1]).

In this paper, we quantify the benefits related with optimal transmission grid extensions for Europe up to 2050 compared to

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http://dx.doi.org/10.1016/j.apenergy.2012.11.050

moderate interconnector extensions given that 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. The approach allows us to determine the optimal deployment of electricity generation technologies and transmission grid extensions from a system integrated perspective and to compare the results to a scenario with exogenous, moderate interconnector extensions.

Whereas the cost-efficient deployment of conventional and renewable technologies in the context of climate protection targets has been analyzed in various papers in recent years (e.g., [2–5]), the transmission grid is often not considered in economic optimization models (e.g., [5]). When considered, it is taken into account by exogenous transmission constraints (e.g., [2,4]) or treated in a context of a radial and not an intermeshed electricity network, implying that a consideration of load flows is not necessary (e.g., [3]).

To consider grid extensions in an intermeshed electricity network is challenging, as different characteristics and rules apply to commercial and physical electricity exchanges between two regions (see e.g., [6] or [7]). 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, 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 in time and have to be identified by load flow analysis.

One of the first attempts to integrate load flow analysis in electricity market models was undertaken by Schweppe et al. [8], who present an economic electricity dispatch model that includes a linearized Direct-Current (DC) load flow model. Applications of this approach can be found in [9] for the Austrian electricity system or in [10] for England and Wales. A European electricity market model including the transmission network via a DC load flow approach is presented in [11]. An earlier version of this model is also applied in [12] to analyze the impact of wind energy extension scenarios in 2020 on the European high voltage grid. The authors use an iterative approach to extend transmission lines based on differences in electricity prices between different nodes. Generation capacities are, however, treated exogenously. Models incorporating endogenous investments in generation and grid capacities are presented e.g., in [13–15]. Whereas in [13,14] the models are run on a low temporal resolution and applied to test systems with only a few technologies,[1] [15] present a model for the electricity and transmission system in Great Britain that is run with comparatively high temporal resolution and a large technological range.

For the large-scale optimization of the European power system, we use an iterative approach to analyze simultaneously optimal grid extensions and optimal generation capacity investments in the context of reaching climate protection targets. One major contribution of our analysis is to quantify to what extent grid extensions are cost-optimally preferred to other options in terms of meeting RES-E and CO_2 reduction targets and balancing fluctuating RES-E. These options include RES-E curtailment, larger use of storage units, generation options being located closer to consumption areas and/or larger shares of dispatchable RES-E. In addition, we quantify the economic effects of delayed interconnector extensions currently observed in Europe, e.g., due to long authorization procedures and opposition from the local population.

The remainder of the paper is structured as follows: In Section 2, we describe the simulation models and the iteration performed between them. Section 3 covers the scenario definitions and results of the scenario analysis. In Section 4, we draw conclusions and provide an outlook of further possible research.

2. Methodology

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

2.1. Electricity market model

We use a dynamic linear dispatch and investment model for Europe, incorporating conventional thermal, nuclear, storage and renewable technologies. The model is an extended version of the long-term investment and dispatch model from the Institute of Energy Economics (University of Cologne) as presented in [16]. Earlier versions of the model have been applied e.g., by [17,18]. For this analysis, the model has been extended by adding endogenous investments in renewable energy technologies. Table 1 provides an overview of the most important model sets, parameters and variables.

The objective of the model is to minimize total system costs, comprising investment, fix operation and maintenance, variable production and ramping costs (Eq. (1)). In addition, combined heat and power plants can yield revenues from the heat market, reducing the objective value.[2] While minimizing total system costs, the model has to ensure that hourly electricity demand within each market region is met (Eq. (2)) and that the peak demand (increased by a security margin) is guaranteed by securely available installed capacities (Eq. (3)).[3] In addition, net imports within the peak demand hour can contribute to this requirement. Eq. (4) formalizes a European-wide RES-E quota and Eq. (5) limits European-wide CO_2 emissions.

$$\min \quad TCOST = \sum_{y\in Y}\sum_{c\in C}\sum_{a\in A}\Big[dr_y\cdot\Big(AD_{y,c,a}\cdot an_a + IN_{y,c,a}\cdot fc_a + \sum_{d\in D}\sum_{h\in H}\Big(GE^{d,h}_{y,c,a}\cdot\Big(\frac{fu_{y,a}}{\eta_a}\Big) + CU^{d,h}_{y,c,a}\cdot\Big(\frac{fu_{y,a}}{\eta_a}+ac_a\Big) - GE^{d,h}_{y,c,a}\cdot hr_a\cdot hp_y\Big)\Big)\Big] \tag{1}$$

$$\text{s.t.}\sum_{a\in A} GE^{d,h}_{y,c,a} + \sum_{c'\in C} IM^{d,h}_{y,c,c'} - \sum_{s\in A} ST^{d,h}_{y,c,s} = de^{d,h}_{y,c} \tag{2}$$

$$\sum_{a\in A}\Big[\tau^{d,h}_{y,c,a}\cdot IN_{y,c,a}\Big] + \sum_{c'\in C}\Big[\tau^{d,h}_{y,c,c'}\cdot IM^{d,h}_{y,c,c'}\Big] \geqslant pd^{d,h}_{y,c} \tag{3}$$

$$\sum_{c\in C}\sum_{r\in A}\sum_{d\in D}\sum_{h\in H} GE^{d,h}_{y,c,r} \geqslant \omega_y\cdot\sum_{c\in C}\sum_{d\in D}\sum_{h\in H} de^{d,h}_{y,c} \tag{4}$$

$$\sum_{a\in A}\Big[\sum_{c\in C}\sum_{d\in D}\sum_{h\in H}\frac{GE^{d,h}_{y,c,a}}{\eta(a)}\cdot ef_a\Big] \leqslant cc_y \tag{5}$$

$$GE^{d,h}_{y,c,a} \leqslant av^{d,h}_{c,a}\cdot IN_{y,c,a} \tag{6}$$

$$\sum_{r\in A} sr_r\cdot IN_{y,e,r} \leqslant sp_{r,e} \tag{7}$$

$$\sum_{d\in D}\sum_{h\in H}\frac{GE^{d,h}_{y,c,a}}{\eta_a} \leqslant fp_{y,c,a} \tag{8}$$

Further important model equations bind the electricity infeed and/or the construction of technologies. Infeed and construction

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[1] [13] apply their model to a system with 7 existing and 11 possible future generating units. The simulation is done for a 10-year horizon, with each year consisting of 4 load levels. [14] present a case study for a 30 bus system, 6 generation firms and one dispatch period.

[2] The chosen representation of cogeneration plants neglects seasonalities of the demand for district heating. Process heat demand is, in contrast, rather constant throughout the year.

[3] We use a typical day approach, taking into account seasonal and hourly demand profiles, seasonal and hourly variability of wind speeds and solar radiation and seasonal inflow patterns of hydro storages. Within our analysis, we model 4 typical days to represent seasonal demand and RES-E infeed structures. In addition, days were divided into 6 slices, such that in total 24 dispatch periods per year are modeled.

Table 1
Model abbreviations including sets, parameters and variables.

Abbreviation	Dimension/ Unit	Description
Model sets		
$a \in A$		Technologies
$s \in A$	Subset of a	Storage technologies
$r \in A$	Subset of a	RES-E technologies
$c \in C$ (alias 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	€$_{2010}$/MW h$_{el}$	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
cc_y	t CO_2	Cap for CO_2 emissions
ef_a	t CO_2/ MW h$_{th}$	CO_2 emissions per fuel consumption
fc_a	€$_{2010}$/MW	Fixed operation and maintenance costs
$fu_{y,a}$	€$_{2010}$/MW h$_{th}$	Fuel price
$fp_{y,c,a}$	MW h$_{th}$	Fuel potential
hp_y	€$_{2010}$/MW h$_{th}$	Heating price for end-consumers
hr_y	MW h$_{th}$/ MW h$_{el}$	Ratio for heat extraction
$pd_{y,c}^{d,h}$	MW	Peak demand (increased by a security factor)
$sp_{r,e}$	km^2	Space potential
sr_r	MW/km^2	Space requirement
η_a	%	Net efficiency
$\tau_{y,c,a}^{d,h}$	%	Capacity factor
ω_y	%	Quota on RES-E generation
Model variables		
$AD_{y,c,a}$	MW	Commissioning of new power plants
$CU_{y,c,a}^{d,h}$	MW	Ramped-up capacity
$GE_{y,c,a}^{d,h}$	MW$_{el}$	Electricity generation
$IM_{y,c,c'}^{d,h}$	MW	Net imports
$IN_{y,c,a}$	MW	Installed capacity
$ST_{y,c,s}^{d,h}$	MW	Consumption in storage operation
TCOST	€$_{2010}$	Total system costs (objective value)

can be limited by the restricted hourly availability of plants (Eq. (6)), the scarcity of construction sites (Eq. (7)), the scarcity of the fuels used (Eq. (8)) and the existing political restrictions (such as nuclear phase-out plans). 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 inspections.[4] 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 $av_{c,a}^{d,h}$ 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 in RES-E infeed within a market region, several subregions per market region have been determined according to meteorological data (from [19]). We model 47 subregions for onshore wind, 42 for offshore wind and 38 for photovoltaic. Eq. (7) shows the space potential restrictions per subregion. For other technologies, the scarcity of the fuel rather than the scarcity of the construction site is crucial. For lignite and biomass, the fuel use is restricted to a yearly potential in MW h$_{th}$ (Eq. (8)). For biomass, different potentials apply for solid and gaseous biomass sources as well as for different cost classes.

In addition the model incorporates common elements of dispatch and investment models such as ramping constraints and storage level equations, as described in [16].

2.2. Modeling grid capacity extensions

Within the market model, commercial trades are limited by transmission grid constraints, represented by net transfer capacities (NTC) between market regions. By assuming provisional costs for additional NTC (€/MW) in a first step, the market model is able to consider NTC extension as an option to cost-optimally meet demand. In turn, NTC extension requires physical extension of the grid infrastructure. However, the 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 this data and to derive the actual costs related to a 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] Thus, the model includes also nodes in countries, which are not covered by the market model. As an example, the Balkan countries are represented by 15 nodes in order to take load flows in this region into account. Transmission lines between generation and load centers are included in an aggregated form and consider 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, the dispatch calculated within the market model is re-simulated within the transmission grid model in order to determine necessary grid upgrades. In the second step a stress test of the power system is performed to ensure that the resulting network is robust enough to cover demand under all realistic conditions, e.g., a long period of calm wind. We perform a stress test for extreme weather events, as in power systems with a high share of renewables, weather conditions have a larger impact on load flows than demand volatility.[7] Hourly Optimal Power Flow (OPF) simulations are performed, and the required amount of energy to be produced by each generator in order 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 accounts for n-1 contingencies) must be respected by the OPF algorithm. In the second step, the grid upgrade is determined on an hour-to-hour basis of the extreme event (lasting for 10 days). Therefore, in a third step, we calculate the extreme event situation over and over again with a reduced grid upgrade. The aim of the third step is to determine the cost-optimal grid upgrade by checking

[4] The infeed of storage technologies is additionally restricted by the storage level during a particular hour, influenced by seasonal, daily or hourly variations in water inflows to hydro plants or in solar radiation for 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 negligibly small variable costs for offshore wind and even smaller costs for onshore wind sites. Therefore, the model chooses offshore wind curtailment before onshore wind and photovoltaic curtailment.

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

[7] In order to determine the most extreme weather event that the power system would encounter, weather conditions of the past 30 years have been analyzed. Our experience is that, if the power system can cope with a long period of calm wind, it can cope with any other load situation. Such extreme situations can happen approximately every fifth year in its full length; however similar situations for shorter periods do happen once a year. Note also that the potential stress of the grid is purely based on thermal loading of the lines. Stress in terms of voltage issues, fast transients (such as ramping) and frequency control are not considered.

the need for each individual upgrade that was requested during step 1 and step 2.

From the results of this approach, the necessary grid upgrades in terms of physical capacity as well as associated costs are determined. These results serve as an input to calculate NTC extension costs between market regions, defined as the sum of the investments in extending tie-lines between regions and the partial costs of upgrading intra-regional lines. Intra-regional upgrades may be prompted by tie-line upgrades, allowing electricity to be transported and distributed within the region or even to act as a transit corridor to other countries. Another reason for upgrading lines within a region is because generation capacity tends to accumulate 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 then 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 sent again to the transmission grid model. The procedure is repeated 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. Fig. 1 depicts the iterative process.

We iteratively optimize combined generation and grid in subsequent decades. In the market model, we assume perfect foresight for the time horizon until 2070 (multi-period optimization). The market model covers every fifth year from 2010 to 2050 (i.e. 2010, 2015, 2020, etc). In addition, the model years 2060 and 2070 are included in order to account for long lifetimes of capital-intensive grid and generation capacities. While the market model is optimized over the entire period, the load flow calculations, in contrast, are simulated for each model year separately. When a robust level of NTC extension and electricity generation for a specific decade has been determined, NTC extension for this decade is fixed at the optimal level within the market model and the iterative process is repeated for the next decade.

3. Scenario analysis for the European electricity system

3.1. Scenario definition

We apply the approach described in Section 2 to optimize the transformation of the European electricity system[8] in order to reach an 80% RES-E share in electricity consumption and an 80% CO_2 emission reduction in 2050 (compared to 1990). In Scenario A, we analyze the cost-optimal deployment of generation and grid capacities from a system integrated perspective. We compare the overall cost-efficient system transformation in Scenario A to a scenario in which interconnector capacities are only moderately extended (Scenario B). In Scenario B, we assume that interconnector extensions are limited to projects that have already entered the planning phase today (based on [20]), but whose commissioning is assumed to be delayed.[9] Thereby, Scenario B takes into account that currently many grid extension projects are significantly delayed, often due to long and complex planning and authorization procedures for new transmission lines (especially when more than one country is involved) as well as by local opposition based on concerns about the environmental, health or visual impact of the project (see e.g, [1]). Still, these limited interconnector extensions imply a doubling of the present European cross-border capacities by 2050.

All other assumptions underlying the analysis are identical in both scenarios and presented in the Appendix. Assumptions include regional electricity demand, investment costs, fuel costs and economic-technical parameters of generation and grid technologies. In addition, information on spatial potentials of renewable energies and how they are determined can be found in [22–24]. In both scenarios, we model a step-wise transformation towards a low-carbon and mainly renewable-based electricity system, as illustrated in Table 2.

3.2. Scenario results

3.2.1. Cost-efficient development of generation and grid capacities (Sc. A)

Fig. 2 depicts the development of European generation capacities (left) and electricity generation (right) in Scenario A, when generation and grid capacities are cost-optimally extended. Major changes in the European generation capacity mix comprise significant investments in onshore wind capacities in the short term, offshore wind capacities in the medium term and solar (photovoltaics and concentrating solar power) capacities in the long term.

In the short term (to 2020), 120 GW of onshore wind capacities are deployed at favorable sites, primarily in the United Kingdom (full load hours (FLH) > 3700 h at best sites), France and Poland. In addition, offshore capacities increase by 47 GW, mainly driven by investments in Norway (FLH > 4400 h at best sites), the Netherlands, the United Kingdom and Ireland. In order to integrate such large amounts of wind energy into the power system, substantial grid enforcements in these countries are required. As far as

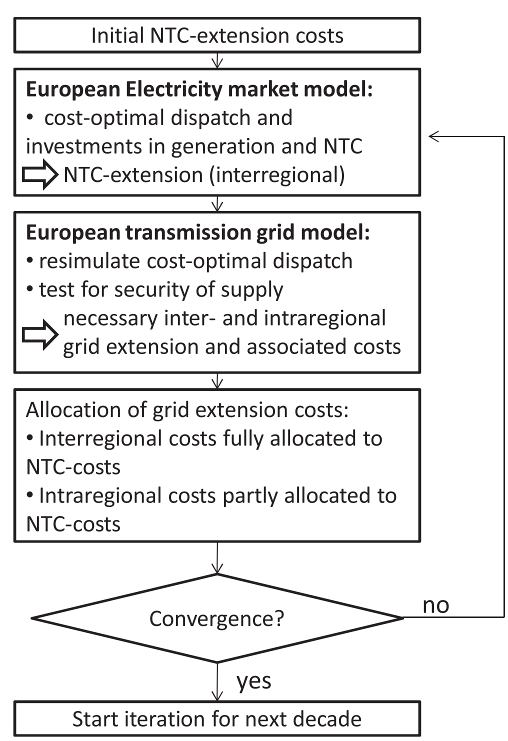

Fig. 1. Iteration process between market and transmission grid models.

8 The model covers all 27 countries of the European Union, except for Cyprus and Malta and includes Norway and Switzerland. In addition, North Africa is modeled as a satellite export region. RES-E imports from North Africa can be used to satisfy the European RES-E quota if this decreases total system costs. By assumption, only solar-based renewable sources can be deployed in North Africa.

9 An overview of the planned interconnection extensions (based on [20]) and the delayed interconnection extensions (as assumed in Scenario B) is provided in [21].

Table 2
RES-E and CO_2 reduction quotas (compared to 1990 emission levels) and historical data for 2008 (%).

	2008	2020	2030	2040	2050
RES-E quota (%)	21	34	50	65	80
CO_2 reduction quota (%)	6	20	40	60	80

interconnector capacities are concerned, especially cross-border capacities between Denmark and Germany and between Sweden and Germany are extended. Further grid upgrades take place to better integrate the Baltic power system.[10] In addition, German interconnectors with Belgium and the Czech Republic are enforced in order to supply Germany with low-cost baseload electricity after the German nuclear phase-out.[11] After 2020, additional onshore and offshore wind plants in Northern and Central Europe are constructed up to 2050. Furthermore, concentrated solar plants (CSP) are built in the Mediterranean region. Interestingly, CSP plants are mainly preferred to photovoltaic systems despite higher electricity generation costs. In electricity systems characterized by a high share of fluctuating renewables, CSP plants with integrated thermal energy storages have a high value, from a system perspective, because the storage permits electricity generation to shift to hours with low solar radiation [25]. Electricity storages are only constructed in countries with a large share of wind energy, e.g., in the United Kingdom and Ireland. Fig. 3 shows the partly aggregated regional electricity generation mix in 2050. From the left to the right, the first three bars highlight the favorable offshore wind generation potentials in the North Sea region. The four middle bars show a more diversified generation mix in the Central and Eastern European countries. In addition, it can be seen that the Central European countries are large importers of electricity in 2050. On the right, the regional electricity mix of the Mediterranean countries, comprising large shares of solar-based electricity, is displayed.

Further grid extensions are necessary in order to connect favorable wind sites in the North Sea region and large consumption areas in Central Europe before 2050. In addition, tie-lines from North Africa to Spain and Italy are constructed, entailing enforcements of the Italian (+ 21,000 km by 2050) and the Spanish network (+32,000 km) as well as of the Spanish-French interconnector (+28 GW_{th}). The French grid is also substantially upgraded (+27,000 km) due to increasing solar power generation in southern Europe and wind power generation in the Benelux countries. By 2050, total cost-optimal grid extensions throughout Europe amount to 228,000 km (+76% compared to today). An overview of European-wide grid extensions up to 2050 is provided in Fig. 4. On the right, grid extensions in the North Sea region (upper graph) and in the Mediterranean region (lower graph) are highlighted. In the North Sea region, the strong enforcement of the German-Danish interconnector ('1'; +24 GW_{th} by 2050), the north–south axis in Germany ('2') and the interconnector between the Netherlands and Belgium ('3'; +31 GW_{th} by 2050) are clearly marked. The lower graph highlights grid extensions between France, Italy and Spain, built to transport solar-based generation to Central Europe. In addition, Table 3 depicts the optimal transmission grid extensions per decade.

[10] Note that the Baltic electricity system is currently synchronized to the Russian and Belarus networks and not to the UCTE or Nordel system. The Baltic States currently import up to 15% of their electricity from Russia or Belarus. While the most important connections with Russia influencing the load flow (i.e. loop flows going via Russia) are taken into account in the modeling, Russia and Belarus are not included as market regions. Thus, the strong upgrades between the Baltic and the North-Western European countries may be overestimated.

[11] In the Czech Republic, 35% of the electricity generation in 2020 is from lignite. In addition, nuclear based generation plays an important role in both countries (24% of the generation in the Czech Republic and 27% in Belgium).

3.2.2. Drivers for grid extensions

Substantial grid extensions are beneficial for two reasons: First, a strong network enables the use of favorable RES-E sites as well as access to generation options restricted by natural (e.g., lignite) or political (nuclear) conditions throughout Europe. Second, grid extensions support the balancing of demand and fluctuating RES-E infeed. Fig. 4 and Table 3 indicate that for many transmission lines in Europe, the economic value of an extension clearly exceeds the costs. However, if differences in electricity costs between two regions are rather small or if distances to large consumption areas are long, a change in the regional electricity mix, rather than a grid extension, is optimal. In addition, when dimensioning a line, grid extension costs are measured against the costs of storage units and the opportunity costs of RES-E curtailment. For the European electricity system, we can draw the following conclusions regarding the influence of grid extension costs on the optimal electricity system development:

1. Electricity generation options with large comparative cost advantages are substantially deployed, even if it requires massive transmission grid extensions. This is, for example, the case for offshore wind in the Netherlands, Denmark-West and Ireland. These generation options are used until their full potentials are reached.
2. For electricity generation options remotely located from big consumption areas, investment costs associated with the transmission grid limit the cost advantage of electricity generation at favorable RES-E sites. This is, for example, the case for solar power imports from North Africa. The import option from North Africa is used only to a relatively small extent; the maximum import flow is reached in 2050 with 153 TW h. Similarily, the offshore wind potential in Norway is not fully exploited because of the long distances to major consumption areas in Central Europe.
3. While interconnector extension costs have little influence on regional capacity deployments, as far as the use of best sites is concerned, these costs highly influence to which countries the electricity is exported. An example is, whether wind-based electricity from the Netherlands should be primarily exported to France or to Germany.
4. Lines connecting favorable RES-E sites with demand centers are dimensioned to almost entirely export all RES-E generation that exceeds local electricity demand. Only in periods with very high RES-E infeed, is electricity stored or – to a rather low extent – curtailed. For example in Ireland, yearly RES-E generation in 2050 is nearly three times as high as local electricity demand. Therefore the interconnector to Great Britain is used to export electricity in all modeled time periods. In most periods the amount of wind generation exceeding local electricity demand can be fully exported. The additional wind infeed in periods with highest wind speeds is either curtailed (amounting to 4% of the yearly potential wind generation) or stored and then exported in times with lower wind generation (7% of potential wind generation).

3.2.3. Effects of sub-optimal interconnector extensions (differences between Scenarios A and B)

In the following, we analyze how moderate interconnector extensions affect the power system development, compared to the overall cost-efficient pathway, as determined in Scenario A. Thereby, we analyze the consequences of interconnection extension delays currently observed in Europe. Fig. 5 shows the differences in generation capacities (left) and electricity generation (right) between Scenario A and B on a European level. Overall, we find that the limitations in interconnector capacity extensions results in larger shares of generation options located near to

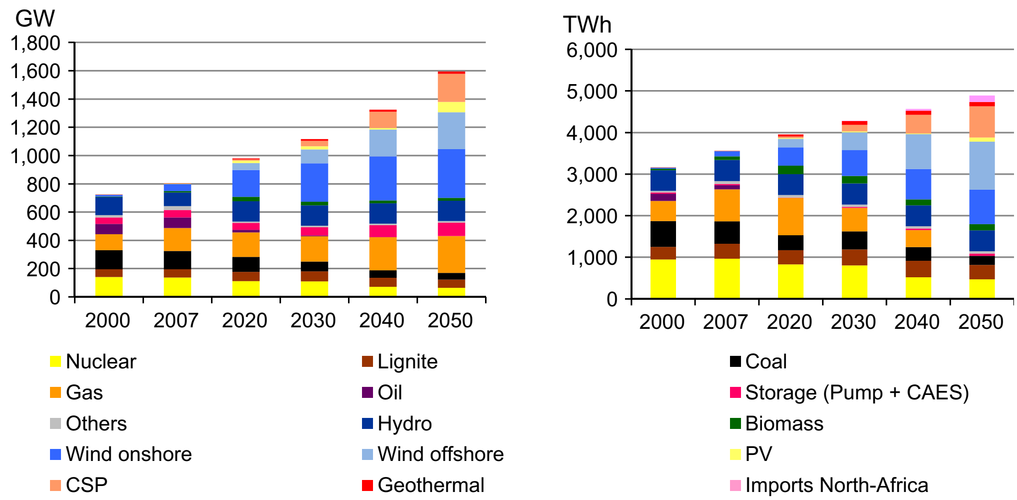

Fig. 2. Capacity (GW) and generation (TW h) development in Scenario A.

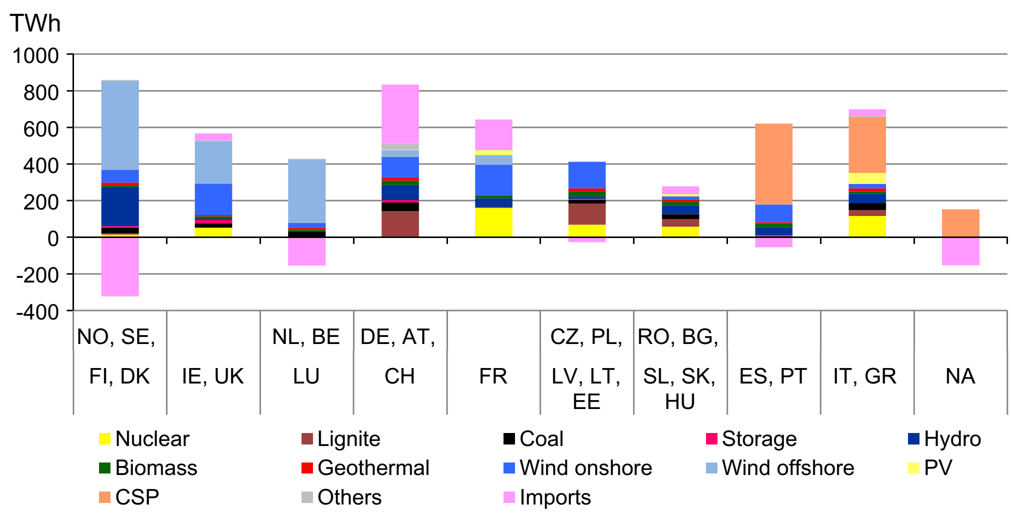

Fig. 3. Regional electricity generation mix in 2050 [Scenario A]. NO = Norway, SE = Sweden, FI = Finland, DK = Denmark, IE = Ireland, UK = United Kingdom, NL = Netherlands, BE = Belgium, LU = Luxembourg, DE = Germany, AT = Austria, CH = Switzerland, FR = France, CZ = Czech Republic, PL = Poland, LV = Latvia, LT = Lithuania, EE = Estonia, RO = Romania, BG = Bulgaria, SL = Slovenia, SK = Slovakia, HU = Hungary, ES = Spain, PT = Portugal, IT = Italy, GR = Greece, NA = North Africa.

consumption areas, as well as a greater amount of dispatchable renewables and storage units (including thermal energy storages incorporated in CSP plants). In addition, even with moderate interconnector extensions, significant intraregional grid extensions are required to reach the aforementioned RES-E and CO_2 reduction targets. By 2050, the transmission grid is extended by 500 GW. The total length of new lines is 111,000 km, representing a 37% increase compared to today's measure.

3.2.4. Effects on generation and capacity development

Major differences in the European capacity and generation mix occur with regard to offshore wind, solar technologies and electricity storage. Offshore capacities and especially offshore generation are lower in Scenario B, as the grid connection to the best offshore sites throughout Europe is limited. In addition, Scenario B is characterized by a larger amount of storage units which are commissioned in countries with large wind parks (on- and offshore). These storage units help to balance fluctuating wind infeed and demand and thereby also to increase the export possibilities to some extent. For the example of Ireland, in 2050 24% of the yearly potential wind generation is stored and consumed or exported during periods with lower wind infeed in Scenario B (compared to 7% in Scenario A). Furthermore, 8% of the potential yearly wind generation is curtailed (compared to 4% in Scenario A).[12] Additional CSP plants built in the Mediterranean countries in Scenario B replace lower solar-based imports from North Africa (−129 TW h compared to Scenario A). In addition, the capacity mix in Scenario B comprises 124 GW more photovoltaic capacity in 2050 than in Scenario A. More than one third is deployed in France due to the fact that wind energy imports from the Benelux countries, as well as solar power imports from Spain, are substantially hindered in comparison to Scenario A. Total capacities are also higher in Scenario B, mainly due to lower full load hours and a low capacity credit of photovoltaic power.[13] In contrast, a larger amount of gas capacities is deployed in Scenario A in order to ensure security of supply. Since electricity generation is more regionally concentrated at remote areas in Scenario A, more

[12] On a European level, RES-E curtailment in 2050 amounts to 20 TW h in Scenario A compared to 12 TW h in Scenario B (representing less than 0.5% of European RES-E infeed).

[13] For photovoltaics, we assume a capacity credit of 0% because peak demand in most European countries is during winter time and early evening hours, when no sun power is available.

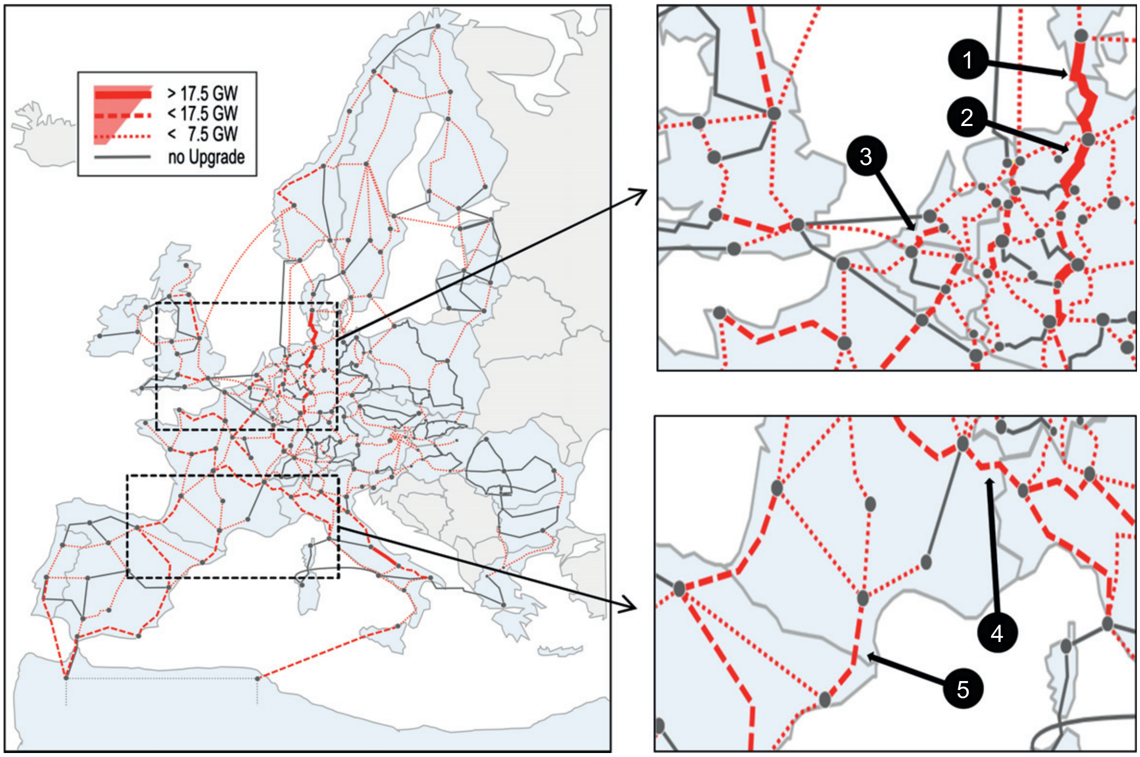

Fig. 4. Transmission grid upgrades by 2050 [Scenario A].

Table 3
Optimal transmission grid extension within Europe in Scenario A

	2010–2020	2020–2030	2030–2040	2040–2050
Thermal capacities HVAC (GW)	278	91	242	150
Thermal capacities HVDC (GW)	18	54	134	243
Line length (thousand km)	53	28	68	79

backup capacities are needed to ensure that demand can be met during peak hours.[14] With regard to electricity generation, generation options which are only available in some countries because of natural resource availabilities (lignite) or national political decisions (nuclear), can be better exploited in Scenario A where the European transmission network is more deeply intermeshed. In Scenario B, in contrast, technologies that are available in all countries (biomass, wind onshore, hard coal, photovoltaic) have higher generation than in Scenario A.

3.2.5. Effects on import and export streams

Regarding the regional distribution of electricity generation in Europe, national electricity mixes that are most influenced by limited grid extensions are the large importing countries in Scenario A – namely Germany, France and the United Kingdom – and the large exporting countries – Norway, the Netherlands, Denmark, Spain and Ireland. Germany and France, characterized by high electricity demands and located in central Europe, import 63% and 34%, respectively, of their demand in Scenario A. In Scenario B, imports are reduced to 14% in Germany and to 10% in France. To replace lower imports in Scenario B, e.g., Germany increases generation from offshore wind, biomass, lignite and photovoltaics. The largest net exporting countries in Scenario A remain net exporters in Scenario B, but to a lower extent (e.g., Norway 96 TW h instead of 270 TW h).

3.2.6. Effects on system costs and investment expenditures

Limited interconnector extensions, which impede physical and commercial trade flows between the large consumption areas and the best wind sites in Ireland, Norway and Denmark, are also especially costly for the European electricity system, as can be seen in Table 4. The table lists the ten interconnectors associated with the highest value of an additional extension – compared to the limited grid extensions in Scenario B – within the timeframe until 2050. Within the model, this value is represented by the marginal value associated with the interconnector extension limit. More precisely, this marginal value represents the variation of total system costs (million $€_{2010}$, net present value) resulting from a loosening of the NTC extension restriction by 1 MW. In the case of the interconnector between Ireland and the United Kingdom, an additional MW net transfer capacity, built within the time frame to 2050, would reduce total accumulated and discounted (5%) system costs by 2 million $€_{2010}$.

The influence of limited interconnector extensions on investment expenditures and on system costs can be seen in Tables 5 and 6, respectively. Table 5 depicts investment expenditures for conventional, renewable, storage and grid technologies, occurring in each decade until 2050 in Scenarios A and B. In both scenarios, renewable technologies have the biggest share, growing even larger over time. In contrast, investments in storage and grid technologies are relatively low through the time horizon to 2050 despite significant grid extensions, especially in Scenario A. Total investment expenditures increase in both scenarios (up to over 1140 bn. $€_{2010}$ in the decade 2040–2050) mainly due to the transformation to a low-carbon electricity system with mostly capital intensive technologies.

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

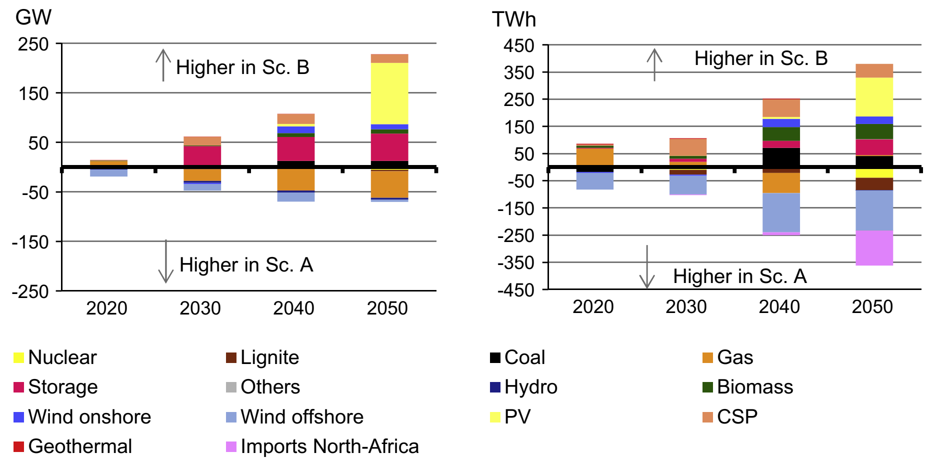

Fig. 5. Differences between Scenario B and A in generation capacities (GW) and electricity generation (TW h).

Table 4
Optimal (Sc. A) and restricted (Sc. B) NTC values in 2050 and marginal values of NTC extension limit in Scenario B (million $€_{2010}$, net present value).

From	To	Optimal NTC (GW)	Restricted NTC (GW)	Marginal (Mio $€_{2010}$)
IE	UK	8.89	1.88	−2.05
NO	DE	1.34	0.70	−1.81
DK-W	DE	26.11	2.42	−1.65
NO	UK	4.40	1.40	−1.58
NO	DK-E	0.24	0.00	−1.38
NO	SE	17.00	5.87	−1.36
NO	FI	3.56	0.97	−1.28
NL	BE	22.48	2.30	−1.25
RO	HU	2.94	0.60	−1.24
DK-W	DK-E	3.96	2.00	−1.11

Table 5
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	1142
	Scenario B	85	1034	15	29	1162
2010–2050	Scenario A	695	2422	39	213	3369
	Scenario B	671	2571	86	97	3426

In comparison to Scenario A, investment expenditures in Scenario B are especially high for renewable energies, as sub-optimal grid extensions hinder the use of favorable RES-E potentials. Furthermore, limited grid extensions in Scenario B impede the integration of fluctuating renewables. Therefore, storage capacities are built, especially in regions with high wind penetrations, resulting in almost 50 bn. $€_{2010}$ in additional 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 from now until 2050 are 57 bn. $€_{2010}$ higher in Scenario B. Table 6 shows the development of yearly fixed costs, variable costs and average system costs (generation and high voltage transmission grid) of electricity supply in Europe.

Table 6
Development of fixed, variable and average system costs until 2050 in Scenarios A and B.

		Fixed costs (bn. $€_{2010}$)	Variable costs (bn. $€_{2010}$)	Average costs ($€_{2010}$/MW h)
2010	Scenario A	65	75	47.1
	Scenario B	65	75	47.1
	Difference (B–A)	**0**	**0**	**0.0**
2020	Scenario A	108	115	65.6
	Scenario B	104	120	65.9
	Difference (B–A)	**−4**	**5**	**0.3**
2030	Scenario A	151	81	62.6
	Scenario B	155	82	63.8
	Difference (B–A)	**4**	**0**	**1.1**
2040	Scenario A	194	68	65.5
	Scenario B	199	69	66.7
	Difference (B–A)	**5**	**0**	**1.2**
2050	Scenario A	256	28	65.6
	Scenario B	264	30	67.9
	Difference (B–A)	**7**	**3**	**2.3**

In both scenarios, the share of fixed costs increases constantly over time, making up 90% of total costs in 2050. This development is caused by a changing capacity mix, which in 2050 mostly consists of renewable energies with low variable costs. Average system costs increase from 47.1 $€_{2010}$/MW h in 2010 to over 65 $€_{2010}$/MW h in 2020, mainly due to the challenging CO_2 emission target for 2020 and the increasing fuel costs.[15] In 2030, average costs are reduced, primarily due to the availability of CCS technologies and more advanced wind turbines. In the long term, higher fuel prices, emission reductions and RES-E targets cause higher costs, whereas the assumed cost reductions for advanced conventional and renewable technologies [see Tables A.2 and A.4] result in a cost decreasing effect. Cost differences between Scenarios A and B increase over time, since the consequences of limited grid extensions more severely influence production costs when RES-E shares are large. In 2050, average system costs are 2.5 $€_{2010}$/MW h (3.5%) higher than in Scenario B due to limited interconnector extensions.

[15] Before 2020, increasing fuel prices (see Table A.7) are one main driver for increasing average costs of electricity. Approximately 57% of the increase in average costs before 2020 is caused by increasing fuel costs. In the long-term, the amount of influence fuel prices have on average costs decreases due to the increasing RES-E share. In fact, less than 5% of the increase in average costs from 2010 to 2050 is caused by increasing fuel prices.

Table A.1
Net electricity demand in TW h_{el} and (potential heat generation in CHP plants in TW h_{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)
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)
United Kingdom	387.4	(68.1)	415.4	(68.6)	441.0	(69.0)	465.8	(69.3)

Table A.2
Investment costs of conventional and storage technologies in €$_{2010}$/kW.

Technologies	2020	2030	2040	2050
Nuclear	3157	3157	3157	3157
Nuclear Retrofit	300	300		
Hard Coal	1500	1500	1500	1500
Hard Coal – innovative	2250	1875	1750	1650
Hard Coal – CCS	–	2000	1900	1850
Hard Coal – innovative CCS	–	2475	2300	2200
Hard Coal – innovative CHP	2650	2275	2150	2050
Hard Coal – innovative CHP and CCS	–	2875	2700	2600
Lignite	1850	1850	1850	1850
Lignite – innovative	1950	1950	1950	1950
Lignite – innovative CCS	–	2550	2500	2450
OCGT	700	700	700	700
CCGT	1250	1250	1250	1250
CCGT – CCS	–	1550	1500	1450
CCGT – CHP	1500	1500	1500	1500
CCGT – CHP and CCS	–	1700	1650	1600
Pump storage	–	–	–	–
Hydro storage	–	–	–	–
CAES	850	850	850	850

Table A.3
Economic-technical parameters for conventional and storage technologies.

Technologies	η (*gen*) (%)	η (*load*) (%)	CO_2 factor (t CO_2/MW h_{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 – inno.	50.0	–	0.335	83.75	36.1	45
Hard Coal – CCS	42.0	–	0.034	83.75	97.0	45
Hard Coal – inno. 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 + 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

4. Conclusions and political recommendations

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

For this reason, under the assumed scenario framework, 228,000 km of transmission grid lines are built by 2050 given that generation capacities and the electricity network are able to be cost-optimally extended. Compared to today, this represents an increase of 76%. We find that in most cases, large grid extensions, allowing the full exploitation of the most favorable RES-E sites throughout Europe, are beneficial from a system integrated perspective. Only for those favorable sites located furthest away from large consumption areas in Central Europe, would the value of grid extensions not always outweight its costs. Furthermore, the capacity of transmission lines connecting favorable RES-E sites with demand centers is cost-optimally dimensioned to almost entirely export all RES-E generation that exceeds local electricity demand. Only in periods with the highest infeed of fluctuating renewables, electricity is stored. When optimal grid extensions are impeded, storage investments are chosen to a larger extent.

When interpreting our results, strength and limits of the chosen methodological approach need to be considered. We iterate a

Table A.4
Investment costs for renewable technologies in €$_{2010}$/kW.

	2020	2030	2040	2050
Biomass gas	2398	2395	2393	2390
Biomass gas – CHP	2597	2595	2592	2590
Biomass solid	3297	3293	3290	3287
Biomass solid – CHP	3497	3493	3490	3486
Geothermal (hot dry rock)	10504	9500	9035	9026
Geothermal (high enthalpy)	1050	950	904	903
PV ground	1796	1394	1261	1199
PV roof	2096	1627	1471	1399
Concentrated solar power	3989	3429	3102	2805
Wind onshore 6 MW	1221	–	–	–
Wind onshore 8 MW	–	1161	1104	1103
Wind offshore 5 MW (shallow)	2615	–	–	–
Wind offshore 8 MW (shallow)	–	2512	2390	2387
Wind offshore 5 MW (deep)	3105	–	–	–
Wind offshore 8 MW (deep)	–	2956	2811	2808

large-scale dynamic market model with a detailed model of the European high voltage grid transmission grid. Instead of modeling 8760 h, a typical day approach has been applied. This limited temporal resolution may lead to an underestimation of the need for flexible generation options. In addition, the deterministic nature of our approach neglects a variety of uncertainties inherent to long term system developments in general and to RES-E generation in particular. If uncertainty e.g., in investment costs, fuel prices and the stochastic nature of renewable infeed is considered, temporal, technological and regional investments, generation and power flows will vary from results of a deterministic approach (see, e.g., [26,27]). Furthermore, neglecting the stochastic nature of RES-E infeed leads to an underestimation of the additional system costs induced by RES-E targets [28]. Concerning the iterative process between the two models, one limit of our analysis is that the iteration 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 the costs and benefits of load-distant generation within countries is not part of the iterative process. Moreover, our approach only includes the high-voltage transmission grid and could be extended to lower voltage levels.

From a political perspective, three principal recommendations can be drawn from our results. First, a coordinated European RES-E plan of action is needed. We have shown that a RES-E deployment on favorable sites throughout Europe is cost-efficient, even when including costs for transmission grid extensions. Second, a European approach is also needed to foster transmission grid extensions. Areas of particular importance for a long term coordinated European plan for grid extensions have been identified in this analysis. Third, the massive increase in the share of fixed costs in the generation mix calls into question the current market design of the European power wholesale market.

Table A.6
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

Table A.7
Fuel costs in €$_{2010}$/MW h$_{th}$.

	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

Acknowledgments

This article is based on results from the study 'Roadmap 2050 – a closer look. Cost-efficient RES-E penetrations and the role of grid extensions' undertaken by the Institute of Energy Economics at the University of Cologne and Energynautics GmbH in 2011 (www.ewi.uni-koeln.de). Funding for the study was provided by the Gesellschaft zur Förderung des Energiewirtschaftlichen Instituts an der Universität zu Köln gGmbH, which is EWI's funding organization, and is gratefully acknowledged by the authors.

Appendix A. Appendix

The following tables present the most important assumptions underlying the scenario analysis. A detailed description of these assumptions can be found in [21] (see Tables A.1–A.7).

Table A.5
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 6 MW (deep)	–	–	5	152	25
Wind offshore 8 MW (deep)	–	–	5	160	25
Wind offshore 6 MW (shallow)	–	–	5	128	25
Wind offshore 8 MW (shallow)	–	–	5	136	25
Wind onshore 6 MW	–	–	5	41	25
Wind onshore 8 MW	–	–	5	41	25
Run-of-river hydropower	–	–	50	11.5	100

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