Comparing planning scales for a cost-optimal European power system
design in a renewable future

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Abstract
Negative effects of climate change, together with energy security considerations, are the cause of a
transition towards more renewable energy sources for electricity (RES-E) in the future European
power system. The intermittency of the two main sustainable technologies, wind and solar PV
power, causes problems for the current power system design and requires additional technical solu-
tions to maintain grid stability. This study researches the cost-optimal design for a future European
power system, for four geographical planning scales: National, Regional, in which three countries
on average are grouped, and Continental, in which 27 countries are all included in one optimisation.
These scenarios have been tested for increasing shares of RES-E in the generation mix: 20%, 50% and
80%. It is concluded that an increased share of RES-E inevitably leads to higher costs. When
the system is planned on a continental planning scale, the cost increase between 20% and 80%
RES-E integration is only €1.42, or 4%. When the system is planned on a national scale, the costs
would increase 23%, or €9.26, while the effect of moving to a regional planning scale is minimal:
only at 80% RES-E integration a significant cost difference, of 5%, was found. Furthermore, the
installed capacities, and subsequently the generation mix, was found to be heavily reliant on coal
and wind. The value of Electrical Energy Storage was found to be minimal and could be substi-
tuted by a strong transmission grid. However, as the planning scale increases, the interdependency
within European Member States increases accordingly: some countries have favourable conditions
for RES-E and become strong exporters, while other countries are left without domestic generation
capacity. Increased cooperation for power system planning has potential for a cost reduction, under
increasing shares of RES-E.

Keywords: Power system modelling, Intermittent renewable energy, Electricity storage, Grid
extensions, Power system planning scale

1. Introduction and background
The negative effects of anthropogenic climate change on ecosystems and societies are increas-
ingly substantiated by scientific evidence. The main cause is the emission of CO₂, from industrial
processes and combustion of fossil fuels (IPCC, 2014a). To mitigate climate change, the European
Union (EU) attempts to reduce emission levels, by defining national targets for the coming decades,
which eventually should lead to a fully renewable European power system (ECF, 2010). Energy se-
curity is a strong additional driver to decrease dependency on fossil fuels. Since domestic resources
are insufficient, 51% of European demand is imported. This import dependency threatens the se-
curity of supply, and might create market price fluctuations, which, subsequently, affects energy
affordability (European Commission, 2014). Renewable energy sources for electricity (RES-E) are seen as a possible solution for both problems (IPCC, 2014b; United Nations, 2015).

In Europe, particularly wind and solar PV are expected to play a significant role. They are abundant and already cost-competitive, or projected to reach that point within a foreseeable period (Edenhofer et al., 2010; Resch et al., 2008; Luderer et al., 2014). These two, intermittent sources differ from conventional, dispatchable generation technologies, on three different aspects. First, output from RES-E is uncertain, as forecast errors occur due to limited predictability of weather conditions. Secondly, favorable meteorological locations do not always correspond with demand centers, thus requiring large amounts of transmission capacity. This makes the transmission network susceptible to congestions and disruptions (IPCC, 2012). Finally, output from RES-E is variable, due to fluctuating weather conditions, which results in a low securely available capacity (capacity credit). To maintain grid stability during peak demand, the installed conventional generation capacity, which can be removed from the system, consists only of a small percentage of the added RES-E (Jägemann et al., 2013).

The integration of RES-E on electricity markets results in negative effects for other producers, among which the providers of backup capacity. Their full load hours (FLH) are reduced, average prices decline and a severe risk of negative prices emerges. This threatens the revenues and thus business case of conventional power plants. However, at the same time large amounts of backup capacity from dispatchable power plants are indispensable: electricity demand is relatively price-inelastic and demand and supply have to be balanced at all times to ensure grid stability, which cannot be done with RES-E (Scherer et al., 2012a; Ueckerdt, 2015).

Besides the EU sustainability targets, and ensuing installation of RES-E, the European aim has also been on a more joint energy policy. In February 2015 the Energy Union Package was adopted, which strives to integrate energy markets both physically, by increasing cross-border transmission capacity, and institutionally, by market coupling (European Commission, 2015). However, national governments remain hesitant to hand over autonomy regarding their energy sector to a more centralized institution (Helm, 2014). At the moment, only sustainability goals were set on a continental level, stipulated in the 20-20-20 goals (European Commission, 2010) Nonetheless, several options, to integrate RES-E in the current design, might benefit from an increased planning scale of the power system: when the intermittency of RES-E is spread over larger geographical areas, the average output remains more stable. This requires both strong transmission grids, as strategically located generation capacities. Additionally, the use of electrical energy storage (EES) could be used, to charge electricity in times of excess production, discharging it when demand exceeds supply. Finally, by finding the right balance between several generation technologies with distinguishing characteristics, a production profile more capable of following demand, can be created. If a system, containing all aforementioned options, were to be optimized, costs for RES-E integration can be kept minimal.

The benefits and technical properties of these solutions have been investigated before. The optimal mix between wind and solar PV for Europe was found, by different studies, to follow the seasonal load curve (Heide et al., 2010; Becker et al., 2014a), or to minimize balancing and storage needs (Heide et al., 2011). All studies concluded that, under increasing shares of RES-E, the required amount of solar PV increased as well, but that the majority of RES-E capacity was to come from wind. Optimization of EES in power systems was researched as well, and found to have potential in supporting highly renewable systems (Pleßmann et al., 2014). Especially pumped hydro storage (PHS) and hydrogen (H₂) were found to have acceptable costs for shorter storage durations (Samsatli and Samsatli, 2015; Steinke et al., 2013). However, he value of EES was not
fully compared to that of other complementary option. Finally, optimizations of the transmission
grid for Europe have been looked at. The total costs of increased grid capacities, sufficient to reach
almost unconstrained power flows, was found never to exceed 25% of the installation costs of RES-E,
required for a fully renewable system (Schaber et al., 2012b). Strong benefits of such an extensive
transmission grid on required backup capacity, storage capacity and eventually total system costs
were concluded upon. However, grid capacity would have to be increased strongly: increases of
between 76% and 400% are the result (Fürsch et al., 2013; Rodríguez et al., 2014; Becker et al.,
2014b).

The aforementioned options have also been studied in combinations (Bertsch et al., 2012; Zerrahn
and Schill, 2015; Brouwer et al., 2016; ECF, 2010). As was pointed out in the recent study by
Brouwer et al. (2016), these studies do not optimize over all different options available to find
a lowest system cost. Rather the effect of one of the options on the other are studied, where
exogenously given scenarios are used as input for at least one of the available options. This creates
a lack of understanding how different options relate to each other and which elements are valuable
to be included or excluded from future power system studies. Furthermore, these studies all look
at the optimal design from one planning scale: a central, European planner coordinates the whole
system. This scenario is unlikely to occur on short notice, but the effect of smaller planning scales
for optimization is overlooked.

This study applies a model to cost-optimize the European power system under increasing shares
of RES-E, for 20%, 50% and 80% of demand delivered from sustainable sources. Several power
system planning scales will be compared:

- A national scale
- A regional scale; with several countries grouped
- A continental scale

From the results it will be checked how these planning scales influence the total system costs,
the composition of these costs, installed capacities of different technologies and dispatch decisions.
Additionally the transmission network will be looked at, as well as import and export flows of
certain regions and countries. The share of domestic generation capacity will be used to determine
the energy dependency across Europe. A situation where no existing power infrastructure is present
is used as point of departure. By incorporating both RES-E, conventional generation technologies,
EES options and grid extensions in the cost-optimization, the value of each of these options, in
combination with others or by themselves, can be determined.

This paper is set out as follows: the model, used to simulate the described situation, is explained
in Section 2. The different scenarios, which will be compared, are elucidated in Section 3. Section 4
provides the results for the chosen scenarios. Section 5 shows the sensitivity for including or
excluding different options in the energy modeling process, as well as sensitivity to price variability
and another possible policy measure: CO$_2$ emission prices and caps.

2. Methodology

This investigation studies the EU, with the different Member States as separate nodes. Due to
geographical distances and insignificant demand, it was decided to leave out Malta and Cyprus,
but incorporate the centrally positioned Switzerland. A linear system cost optimization model
was constructed, where generation technologies, from three types of dispatchable power plants and two types of RES-E, several storage options and the cross-border transmission network were incorporated.

The model used historical demand data and RES-E production data from the year 2012, with an hourly resolution. The load was obtained from (ENTSO-E, 2015a) and corrected for missing values. The RES-E production data was taken from (Wijnja-Vlot, 2015) and aggregated per country. The model was run for a set of 52 days, picked from these datasets in such a way that all daily, weekly and seasonal patterns in both the production as demand data were preserved. In the Sections below the important elements of the model, choices and assumptions will be clarified. Incorporated generation technologies consist of wind power, solar PV power, a Combined Cycle Gas Turbine (CCGT), a hard coal plant and a biomass plant. For storage technologies the developing Flow Batteries (FB) and Hydrogen storage (H$_2$) were incorporated, as well as the more mature technology of Pumped Hydro Storage (PHS). The transmission lines were assumed of linear increasing costs per increasing capacity and length, were the length between countries is defined as the difference between geographical centers.

In the following the most important equations for the model are described. Table 1 shows the different sets, parameters and variables used in the model.

2.1. Costs modeling

As has been explained before, the objective of this model is to minimise total power system costs for Europe, $TC$. These costs consist of the sum of the fixed costs for all technologies, and the variable costs for all technologies (see Eq. 1).

$$\min \quad TC = FC + VC$$ (1)

The $FC$ can be defined as the total installed capacity of generation, storage conversion and storage capacity, multiplied by the fixed costs per capacity, for that technology. The interconnection costs have to be added as well, defined as the total transmission capacity installed, times the length and the fixed costs (see Eq. 2). Since fixed costs are made for the whole lifetime of a technology, and variable costs are calculated over shorter time spans, to make them comparable the time-cost-factor is introduced.

$$FC = \sum_{i \in G \cup E} \alpha_i \cdot \omega_i \cdot \sum_{n \in N} (IC_{i,n}) + \sum_{i \in S} \alpha_i \cdot \mu_i \cdot \sum_{n \in N} (IS_{i,n}) + \zeta \cdot \beta \cdot \sum_{n \in N} \sum_{m \in M_n} (\delta_{n,m} \cdot TR_{n,m})$$ (2)

The second element of the objective function consists of the variable costs per generation technology. These are calculated as the sum of all power output, multiplied by the variable costs for technology (see Eq. 3).

$$VC = \sum_{i \in G} \nu_i \cdot \sum_{n \in N} \sum_{t \in T} P_{i,n,t}$$ (3)

To guarantee a fair comparison, all costs have to be calculated over the same period of time. To do so, the runtime will be considered. This means that the fixed costs have to be brought back to hourly costs and multiplied by the number of hours of the run. This will be done by creating time-cost-factors (see Eq. 4 and Eq. 5). Herein the fixed costs will be divided by the lifetime in years for that technology and the average number of hours per year, multiplied by the hours of the run.

$$\alpha_i = \frac{R}{(\varphi_i \cdot Y)} \quad \forall i \in I$$ (4)
### Sets

<table>
<thead>
<tr>
<th>Notation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$G$</td>
<td>Set of considered generation technologies</td>
</tr>
<tr>
<td>$E$</td>
<td>Set of considered electrical storage conversion technologies</td>
</tr>
<tr>
<td>$S$</td>
<td>Set of considered electrical storage technologies</td>
</tr>
<tr>
<td>$I$</td>
<td>Set of considered technologies, where $I = G \cup E \cup S$</td>
</tr>
<tr>
<td>$N$</td>
<td>Set of considered nations</td>
</tr>
<tr>
<td>$M_n = {m</td>
<td>A(n,m) = 1, \forall n \in N, m \in N}$</td>
</tr>
<tr>
<td>$T$</td>
<td>Considered time steps</td>
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</tbody>
</table>

### Parameters

<table>
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<tr>
<th>Notation</th>
<th>Domain</th>
<th>Description</th>
<th>Unit</th>
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</thead>
<tbody>
<tr>
<td>$ED_{n,t}$</td>
<td>$n \in N, t \in T$</td>
<td>Electricity Demands</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$GP_{i,n,t}$</td>
<td>$i \in G, n \in N, t \in T$</td>
<td>Generation Potentials, maximal output per installed MW of generation technology</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$MC_{i,n}$</td>
<td>$i \in S, n \in N$</td>
<td>Maximum installable Capacities, limited by technical potential</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$\delta_{n,m}$</td>
<td>$n \in N, m \in M_n$</td>
<td>Distances between geographical centres per connection</td>
<td>(km)</td>
</tr>
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<td>$\omega_i$</td>
<td>$i \in G \cup E$</td>
<td>Fixed Costs generation and storage conversion technologies</td>
<td>(€/MW)</td>
</tr>
<tr>
<td>$\mu_i$</td>
<td>$i \in S$</td>
<td>Fixed Costs storage capacity technologies</td>
<td>(€/MWh)</td>
</tr>
<tr>
<td>$\zeta$</td>
<td></td>
<td>Fixed Costs transmission lines</td>
<td>(€/MWkm)</td>
</tr>
<tr>
<td>$\nu_i$</td>
<td>$i \in G$</td>
<td>Variable Costs generation technologies</td>
<td>(€/MWh)</td>
</tr>
<tr>
<td>$\varphi_i$</td>
<td>$i \in I$</td>
<td>Lifetimes generation and storage technologies</td>
<td>(year)</td>
</tr>
<tr>
<td>$\rho$</td>
<td></td>
<td>Lifetime transmission lines</td>
<td>(year)</td>
</tr>
<tr>
<td>$\alpha_i$</td>
<td>$i \in I$</td>
<td>Time-cost-factor to calculate fixed costs to hourly costs for all technologies</td>
<td>(/hour)</td>
</tr>
<tr>
<td>$\beta$</td>
<td></td>
<td>Time-cost-factor to calculate fixed costs to hourly costs for transmission lines</td>
<td>(/hour)</td>
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<tr>
<td>$R$</td>
<td></td>
<td>Specific considered hours of a run</td>
<td>(hour)</td>
</tr>
<tr>
<td>$Y$</td>
<td></td>
<td>Average number of hours in a year</td>
<td>(hour)</td>
</tr>
<tr>
<td>$\tau$</td>
<td></td>
<td>Transmission line efficiencies</td>
<td>(%/km)</td>
</tr>
<tr>
<td>$\gamma_i$</td>
<td>$i \in E$</td>
<td>Charging efficiencies</td>
<td>(%)</td>
</tr>
<tr>
<td>$\eta_i$</td>
<td>$i \in E$</td>
<td>Discharging efficiencies</td>
<td>(%)</td>
</tr>
<tr>
<td>$\vartheta_i$</td>
<td>$i \in G$</td>
<td>Percentage of production considered sustainable</td>
<td>(%)</td>
</tr>
<tr>
<td>$\varepsilon$</td>
<td></td>
<td>RES-E generation quota</td>
<td>(%)</td>
</tr>
<tr>
<td>$A(n,m)$</td>
<td></td>
<td>Adjacency matrix of neighbouring countries</td>
<td></td>
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</tbody>
</table>

### Variables

<table>
<thead>
<tr>
<th>Notation</th>
<th>Domain</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$TC$</td>
<td></td>
<td>Total power systems Costs</td>
<td>€</td>
</tr>
<tr>
<td>$FC$</td>
<td></td>
<td>Total Fixed Costs</td>
<td>€</td>
</tr>
<tr>
<td>$VC$</td>
<td></td>
<td>Total Variable Costs</td>
<td>€</td>
</tr>
<tr>
<td>$IC_{i,n}$</td>
<td>$i \in G \cup E, n \in N$</td>
<td>Installed Capacities of generation and storage conversion technologies</td>
<td>(MW)</td>
</tr>
<tr>
<td>$IS_{i,n}$</td>
<td>$i \in S, n \in N$</td>
<td>Installed Storage capacity technologies</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$TH_{n,m}$</td>
<td>$n \in N, m \in M$</td>
<td>Installed Transmission capacity between country $n$ and $m$</td>
<td>(MW)</td>
</tr>
<tr>
<td>$P_{i,n,t}$</td>
<td>$i \in G, n \in N, t \in T$</td>
<td>Produced Power</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$DP_{i,n,t}$</td>
<td>$i \in E, n \in N, t \in T$</td>
<td>Discharged Power</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$CP_{i,n,t}$</td>
<td>$i \in E, n \in N, t \in T$</td>
<td>Charged Power</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$SP_{i,n,t}$</td>
<td>$i \in S, n \in N, t \in T$</td>
<td>Power in Storage</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$IP_{n,m,t}$</td>
<td>$n \in N, m \in M_n, t \in T$</td>
<td>Imported Power, through transmission line between country $n$ and $m$</td>
<td>(MWh)</td>
</tr>
<tr>
<td>$EP_{m,n,t}$</td>
<td>$n \in N, m \in M_n, t \in T$</td>
<td>Exported Power, through transmission line between country $m$ and $n$</td>
<td>(MWh)</td>
</tr>
</tbody>
</table>
\[ \beta = \frac{R}{(\rho \cdot \gamma)} \]  

(5)

2.2. Power balance modeling

One of the major constraints is the power balance. In the power system the electricity demand has to be matched with the supply in any node. This can either be done by power generation, storage discharging or charging and import or export. The sum of all has to be equal to the demand in that country, at that time-step (see Eq. 6).

\[ E_{Dn,t} = \sum_{i \in G} P_{i,n,t} + \sum_{i \in S} (D_{P,i,n,t} - C_{P,i,n,t}) + \sum_{m \in M_n} (I_{P,m,n,t} - E_{P,m,n,t}) \forall n \in N \forall t \in T \]  

(6)

Furthermore, the goal of the model is to optimize under high levels of RES-E integration. To do so, the EU sets goals for the amount of electricity from sustainable sources. To be able to model this a variable is created that can be used to set a minimum of renewable energy, the RES-fraction. The constraint in the model prevents the share of RES-E supplied, compared to the total generation, to come below this fraction (see Eq. 7)

\[ \varepsilon \cdot P_{\text{generated}} \leq P_{\text{RES}} \]  

(7)

2.3. Power generation modeling

The generation output is always smaller than the installed capacity, multiplied by the generation potential per installed capacity, of that technology. For conventional generation this potential is equal to 1, for RES-E it depends on the weather conditions (see Eq. 8).

\[ P_{i,n,t} \leq GP_{i,n,t} \forall i \in G \forall n \in N \forall t \in T \]  

(8)

2.4. Electrical storage modeling

The amount of energy in storage is dependent on the energy in storage the time-step before, the charge and discharge, but also on the efficiencies with which electricity is charged and discharged (see Eq. 9). The energy in storage at the start, is the same as the stored energy in the end (see Eq. 10).

\[ SP_{i,n,t} = SP_{i,n,t-1} + \gamma_i \cdot C_{P_{n,t}} - \frac{1}{\eta_i} \cdot D_{P_{n,t}} \forall i \in S \cup E \forall n \in N \forall t \in T \]  

(9)

\[ SP_{i,n,t_{\text{max}}} = ST_{i,n,t_0} \forall i \in E \forall n \in N \]  

(10)

For storage technologies, no more electricity can be stored than the installed storage capacity (see Eq. 11). Also, no more electricity can be charged (see Eq. 12) or discharged (see Eq. 13) than the converter capacity.

\[ SP_{i,n,t} \leq IS_{i,n,t} \forall i \in S \forall n \in N \forall t \in T \]  

(11)

\[ DP_{i,n,t} \leq IC_{i,n,t} \forall i \in E \forall n \in N \forall t \in T \]  

(12)

\[ CP_{i,n,t} \leq IC_{i,n,t} \forall i \in E \forall n \in N \forall t \in T \]  

(13)
2.5. Transmission modeling

A simplified representation of electricity transmission between nodes was used, similar to the model by (Schaber et al., 2012a): the conservation of currents in each node of the network, Kirchoff’s first law, is respected, but the voltage law is excluded. The import in country $m \in M_n$ from country $n \in N$ is equal to the export in country $n \in N$ to country $m \in M_n$. In this transport there are some transmission losses, determined as a certain efficiency over length of line (see Eq. 14). Also, to assure that the model builds the same transmission capacity from the perspective of countries at both ends, these capacities have to be kept equal (see Eq. 15).

$$IP_{n,m,t} = \tau \cdot EP_{m,n,t} \forall n \in N \ \forall m \in M_n \ \forall t \in T$$  \hspace{1cm} (14)

$$TR_{n,m} = TR_{m,n} \forall n \in N \ \forall m \in M_n$$  \hspace{1cm} (15)

The total power transported between country $n$ and $m$ should never exceed the installed transmission capacity (see Eq. 16).

$$IP_{n,m,t} + EP_{n,m,t} \leq TR_{n,m} \forall n \in N \ \forall m \in M_n \ \forall t \in T$$  \hspace{1cm} (16)

2.6. Parameters used

The parameters needed for the described model consist mainly of cost parameters. The Capital Expenditures (CapEx) and Fixed Operations and Maintenance (FOM) for all technologies were used to calculate the costs per installed capacities. The Variable Operations and Maintenance costs (VOM) determine the costs of the dispatch decisions. For storage and transmission technologies the efficiencies were incorporated. This led to the parameters as depicted in Table 2, which are based on a wide range of reference studies. Additionally the technical potential of PHS per country was obtained from a report by Gimeno-Gutiérrez and Lacal-Aránguiz (2015).

Existing generation, storage and transmission capacities were obtained from (ENTSO-E, 2015b; Becker et al., 2014b). Aggregations had to be made in order to make the data compatible with the model. Future data was obtained from (Bruninx et al., 2015; Pfluger et al., 2011). Trends found in these researches were applied where exact figures were absent. In all investigated scenarios, for this paper, the demand and production data were used for 2012.

3. Policy scenarios European power sector

For the obtained model, several scenarios, with different power system planning scales, have been developed. These scenarios are cost-optimized for a 20%, 50% and 80% share of RES-E. Variables, subject to the optimization, are the installed capacities of generation and storage technologies, transmission line capacities between neighboring nodes and dispatch, curtailment, transmission flow, charge and discharge decisions. First, two reference scenarios were created, based on the currently installed capacities and those for 2050. Data was obtained from the ENTSO-E database and aggregated to match the used technologies for this research (ENTSO-E, 2015b). The share of RES-E in 2012 for Europe was roughly 15%, if run-of-the-river hydropower is disregarded (Eurostat, 2015). The scenario for 2050 was found capable of producing 45% of power from RES-E. For the 2015 scenario the capacity of PHS conversion and storage was kept at real world values, whereas FB and H2 were allowed to increase in order to use more of the available renewable power. Both reference scenarios give the bandwidth of current and expected system costs for RES-E integration. The policy scenarios, which incorporate options to decrease integration costs, are explained in the
Table 2: Overview of chosen generation technology parameters. CapEx = Capital Expenditures; FOM = Fixed Operation & Maintenance costs; VOM = Variable Operation & Maintenance costs; \( \eta \) = efficiency (fuel to electricity for power plants, charge/discharge for storage, transmission efficiency per 1000km for interconnection); Lifetime = average lifetime of the installed technology; Pollution = ton of CO\(_2\) emission per generated MWh. Figures were averaged from (Bertsch et al., 2012; Fürsch et al., 2013; ECF, 2010; Brouwer et al., 2016; van Staveren, 2014; Zakeri and Syri, 2015; Steinke et al., 2013; ENTSO-E, 2014; Schaber et al., 2012b,a).

<table>
<thead>
<tr>
<th>Generation technology</th>
<th>CapEx (( €/kW ))</th>
<th>FOM (( €/kW/yr ))</th>
<th>VOM (( €/MWh ))</th>
<th>( \eta ) (%)</th>
<th>Lifetime (yr)</th>
<th>Pollution (tCO(_2)/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind onshore</td>
<td>1080</td>
<td>34</td>
<td>0</td>
<td>100</td>
<td>25</td>
<td>0</td>
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<td>Solar PV</td>
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<td>27.50</td>
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<td>100</td>
<td>25</td>
<td>0</td>
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<td>CCGT</td>
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<td>20</td>
<td>46</td>
<td>60</td>
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<td>Coal plant</td>
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<td>28</td>
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<td>47</td>
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<td>90</td>
<td>84.5</td>
<td>35</td>
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<td>FB conversion</td>
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<td>0</td>
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<td>PHS storage</td>
<td>58</td>
<td>-</td>
<td>0</td>
<td>-</td>
<td>50</td>
<td>-</td>
</tr>
<tr>
<td>H(_2) conversion</td>
<td>1600</td>
<td>40</td>
<td>0</td>
<td>40</td>
<td>20</td>
<td>-</td>
</tr>
<tr>
<td>H(_2) storage</td>
<td>60</td>
<td>-</td>
<td>0</td>
<td>-</td>
<td>20</td>
<td>-</td>
</tr>
<tr>
<td>Interconnection line</td>
<td>1000</td>
<td>0</td>
<td>0</td>
<td>96</td>
<td>40</td>
<td>-</td>
</tr>
</tbody>
</table>

Sections below. For all scenarios with cross-border transmission, it is assumed that only neighboring countries can install interconnection capacity. All scenarios assume that a Transmission System Operator (TSO) is capable of designing the power system for the appropriate region - including the generation, storage and network design -, as well as making the dispatch decisions.

3.1. National planning, optimal dispatch

This first, national scenario (NAT) reflects the development under current policy the most: all nations plan their generation capacity, as if no cross-border transmission is possible, which ensures sufficient domestic generation capacity. They also have to fulfill the RES-E quota with their national generation portfolio. After the optimal design has been determined, the model is run again, while the currently installed transmission lines are added. This allows the optimization to transport electricity across borders in the dispatch phase, leading to a more optimal use of installed capacity. This scenario ensures national energy security, while finding an cost-optimal dispatch, charge/discharge, or storage planning, with existing interconnection capacity. It would need a national TSO, which, during the dispatch phase, cooperates with connected power systems.

3.2. Regional planning and dispatch

In the regional scenario (REG), both the installed capacities as the dispatch are planned from a regional perspective. There is, however, no transmission allowed between regions. The RES-E
quota has to be met within this regional scale as well, which allows, to a certain extent, to use more favorable locations. A regional TSO would be required, to coordinate the power flows within the region. This scenario ensures regional energy security, where interdependencies only exist with direct neighbors. The chosen regions are based on three different reasons:

- Already existing cooperation and official ENTSO-E regional groups. In this group the Baltic States, Scandinavia, the United Kingdom, Ireland and Continental Europe are seen as separate groups. As Continental Europe is still seen as a too large group it is split up as was done by other researches (see next item) (ENTSO-E, 2015a).

- In the research by Brouwer et al. (2016), Europe is divided in six regions. Compared to the current ENTSO-E groups, the British Isles have been grouped separately, Portugal and Spain form the Iberian Peninsula, France is a stand-alone node, Italy and the Alpine States (Switzerland and Austria) have been merged and the BeNeLux together with Germany is seen as one region. Eastern Europe is left out of this research, so an analysis of considered transmission lines is used to group these as well (see next item).

- In the current design, some countries are more grouped together and have significant capacities of interconnection already. From this an Eastern-European cluster of countries is determined, consisting of Poland, Czech Republic, Slovakia and Hungary. Two Balkan countries (Romania and Bulgaria) are merged with Greece, while the states around the Adriatic Sea are grouped with the Alpine States: Italy, Switzerland, Austria, Slovenia and Croatia.

In Figure 1 the grouped countries can be found.

### 3.3. Continental planning and dispatch

The continental scenario (CON) assumes one central planner, for all considered nodes. It determines the cost-optimal design in one run for the whole of Europe, with all options included. Both the planning, as the dispatch phase are optimized from this perspective. The RES-E quota is to be fulfilled on the European scale as well, which allows the optimization to use only the most favorable locations for wind and solar PV respectively. All available transmission connections are subdued to the optimization. A European TSO would be needed to coordinate the dispatch.

### 3.4. Central planning, country goals

The last policy scenario (CG) that will be compared, is a scenario in which both the installed capacities and dispatch phase are optimized from a central perspective, but where each country is required to have a minimal conventional generation capacity installed domestically, equal to the peak load during the considered period. This automatically ensures a spread of

![Figure 1: Overview of chosen regions and names for the grouped countries.](image)
installed capacities over countries, and a higher share of back-up capacity, leading to more national energy security.

4. Results

The main results from the different scenarios will be discussed in the following Sections, for different shares of RES-E integration. The differences in the overall optimization goal, total system costs, will be explained by the variations in power system design and dispatch decisions. The system costs have been calculated to system levelized cost of electricity (LCOE), by dividing them by total demand. The scenario names are abbreviated - NAT for national, REG for regional, CON for continental and CG for country goals - and for 20%, 50% and 80% RES-E integration levels, the numbers 20, 50 or 80 are added to the abbreviation, respectively.

4.1. System LCOE

The total system costs have been divided by the total demand over the considered period, in order to get more comprehensible values. The demand over the considered period was 420 TWh. Figure 2 shows the different system LCOEs. The effect of a more centralised planning level on system LCOE is unambiguously: when the planning scale increases, the cost decreases. The share of RES-E has a significant impact on the difference the planning scale makes: the effect grows stronger as shares of RES-E increase. An optimal CON20 design results in an electricity price of €37.50. The optimal price for a system planned on national level would result in €38.49; roughly 3% higher. Incorporating 80% RES-E, this difference dilates to 23%; €38.92 over €47.75. Noticeable here is the relatively small cost increase within the continental planning scenario: €1.42 or 4%. This implies that under optimal planning scale energy costs could remain around the same price as current levels, while integrating more electricity from RES-E than the European target for 2050.

Moving from a national to a regional planning level is hardly beneficial: costs for 20% or 50% RES-E are almost similar, while at 80% the regional scale saves €2.12 or 5%. This automatically shows that the benefit of the European scale over regional scales is still significant: around 17% or €6.72. Interestingly, the centrally planned scenario with regard for national energy security goals, the country generation quota scenario, performs worse than the national and regional planning scale for lower levels of RES-E. It only becomes beneficial for an 80% of RES-E requirement. The final remark is that increasing the planning for the European power system results in lower energy prices. However, the effect is smaller when less RES-E is required, or when additional constraints limit the degrees of freedom of the optimisation. Additionally it can be concluded that:

- The major part of the system LCOE, for lower levels of RES-E integration, is contributed by VOM from coal. As the share of renewables increases, the major share of costs is transferred to the fixed costs. Especially wind, coal and, in the 80% scenarios, solar PV, form a large share of the costs.

- The share of costs resulting from storage facilities is almost negligible: it forms less than 1% of the costs. The share of costs resulting from interconnection lines is almost negligible in the two restricted transmission scenarios, NAT and REG. For the CON and NGQ, especially at 50% and 80% RES-E integration levels, the transmission costs contribute between 4% and 7% of the system LCOE.
Figure 2: System LCOE for different scenarios. The costs for generation technologies have been split up in fixed costs (Investment) and Variable Operations & Maintenance (VO&M). Storage costs are divided in costs for conversion and costs for the storage facility.

Figure 3: Overview of installed generation and storage conversion capacities for each technology per scenario, for increasing shares of RES-E. Utmost left the current installed capacities are given for the reference scenarios, with 15% RES-E for 2015 capacities and 45% for 2050 capacities.
4.2. Installed generation and storage capacities

The installed generation and storage conversion capacities for different scenarios can be found in Figure 3. The red dotted line shows the peak load during the considered period. The installed capacities are shown for increasing levels of RES-E. For the reference scenario 15% RES-E integration corresponds with the 2015 scenario, while the 45% RES-E integration resembles the 2050 scenario. It was found that:

- The total installed capacity increases significantly as the RES-E integration share increases. The total installed capacity is always more than the peak load. The most extreme scenario is the NAT scenario, where for the NAT20 there is around 25% excess generation and conversion capacity, which increases to 68% at NAT80. The CON20 scenario has a higher excess capacity than the NAT20, but the CON80 is much lower with 57% excess capacity. Overall it can be seen that the integration of RES-E inevitably leads to more excess generation and storage conversion capacity.

- Wind is, in every scenario, the main contributor to RES-E shares. With lower integration levels of RES-E, coal forms the major part of installed fossil fuel generation capacity. The use of biomass is completely absent. In the NAT and REG scenarios the use of CCGT is rather stable, which means that the percentage of it in the fossil fuel generation capacity increases. In the 20% scenarios it only accounts for 15% of the conventional generation capacity, but has increased up to 33% in the highest RES-E integration scenario. However, in the CON scenario it completely disappears. It follows that more centralised planning scales allows for better utility rates of conventional power plants, so that the overall cheaper coal plants can be used more often instead of the more expensive CCGTs. This is a major reason for lower costs at higher planning scales.

- The installed capacity of solar PV is almost negligible for the scenarios with 20% or 50% RES-E integration. It is only used for the 80% scenarios. For the NAT80 and REG80 it forms 16% of the RES-E capacity, opposed to 9% for CON80 and at CG80 it is even insignificant. The more centralized the planning scale is, the less use for solar PV and the better the utilization of wind turbines. Since wind is overall cheaper than solar PV, this entails a cost reduction.

In all previously presented figures also the installed storage capacities were presented as well. For the CON scenario it is interesting to see that only PHS was used as storage option. The ratio of storage capacity divided by conversion capacity increases from 6.9 for CON20 up to 10.9 for CON80. This suggests that the storage is mainly used for long term storage. The maximum amount of PHS, due to a limited technical potential is 1669GWh. Around two thirds of this was used in CON80. In general, the increase of storage capacity is significant as the share of RES-E increases as well, often in the same country. The CON80 scenario has almost 1000GW of storage, which is an increase of over 200% compared to the CON20. Similar storage increases can be found in other scenarios as well. In REG80 even all technical potential for storage capacity was used. The more expensive H$_2$ is used for respectively the NAT80 and REG80 scenario. Apparently the need for storage is strong enough to substitute the, in some regions or countries, insufficient PHS with H$_2$ storage. The ratio between storage and conversion is even higher in these lower planning levels than in the CON80 scenario, both for PHS as for H$_2$. In most scenarios the installed capacities of both storage as conversion were in the same order of magnitude. From looking solely at the installed storage capacities a few interesting points can be distilled:
The influence of availability of storage on installed generation capacity is limited. Nonetheless, enormous amounts of storage are installed for every scenario where it is available.

The ratio between installed conversion and storage capacity suggests that most storage is used for longer periods of time.

In scenarios with insufficient storage capacity within reach, it proves to be beneficial to install the more expensive H\textsubscript{2} storage technology. Whenever the availability of transmission allows for the use of PHS this is always preferred over other storage technologies.

4.3. Generation mix

The comparison of generation mixes per scenario, as given in Figure 4, shows little anomalies given the installed capacities. The red dotted line in this Figure shows the total load over the considered period. Based on the installed capacities the generation mix meets the expectations.

From this Figure it can be concluded that:

- The share of power supplied by CCGT is negligible, even for the NAT, REG and CG scenarios, where it had significant shares of installed capacity. It can be concluded that the installed CCGT capacity is barely used and thus has few FLH. For situations with low FLH the LCOE of CCGT is lower than that of a coal plant, which explains the choice of CCGT over coal.

- The share of wind in CON20 is higher than the required power from RES-E. This suggests that a system optimum exists with more than 20% power from RES-E. To be precise, in CON20 37% of the power is generated from RES-E.

- The share of power from solar PV is marginal and ranges from only 6% in CON80 to 11% in NAT80. This corresponds well with the installed capacities and the average capacity factor for solar PV, compared to that of wind.
4.4. Transmission grid and power flows

The transmission grid installed can be split up in the distance it covers, dependent on which countries are connected, and the net transfer capacity of those lines. Figure 5 shows both the lengths and capacities per scenario, where upwards bars are the different capacities, and the downward bars depict the various lengths. The reference and NAT scenarios use the currently installed transmission capacities, and are therefore given in the same bar. It can be derived that:

- The currently installed line length is higher than that of an optimal scenario, but the installed capacity is lower than that of almost all optimization scenarios. The installed transmission line length stays roughly the same for different integration levels of RES-E. For REG80 it is even slightly lower than it is for REG20, suggesting less lines, but with greater capacity, are required as RES-E integration levels increase.

- The installed capacities increase significantly, as the share of RES-E increases. CON80 has three times more interconnection capacity than CON20, but also 7 times more installed capacity than is currently available. CG80 even has 8 times more installed capacity.

The lay-out and net importing or exporting countries are depicted in Figure 6, for two levels of RES-E integration in the CON scenario: CON20 and CON80. On the right side of the figure, the map of Europe shows average level of import or export of the considered countries, averaged over the three RES-E integration levels. First, as the share of RES-E increases, the capacity of the network connections increases, rather than that new lines are added. Only very few lines appear or disappear as a result of changing RES-E integration levels. Secondly, the amount of connections one country could have is not necessarily influential on the final installed capacity. France, Italy and Sweden all have more than five possible connections, but are not becoming more interconnected than countries with less connections.

In the European electricity grid no focal points emerge. Also, the countries that are strong net importers or exporters are connected more than others and with larger capacities to neighboring countries. For example Ireland, Denmark, which are large exporters are heavily interconnected. The Netherlands, Belgium and Austria, as large importers, are also connected to one or more transmission lines larger than 10GW. It is noticeable that large exporting countries often have large installed capacities of RES-E, while net importers mostly have domestic coal plants. Finally, from the import-export map it seems as if Central Europe depends on the outer regions for their electricity. These outer regions deliver the share of RES-E for the whole of Europe. This corresponds well with the theory that RES-E looks for the most optimal locations.

Figure 5: Installed transmission length and capacity per scenario. Both the REF and NAT scenario use currently installed capacities and lengths, which remain the same for increasing shares of RES-E and are given as the utmost left bar.
Figure 6: Overview of the installed network for the CON scenario with a 20% and 80% RES-E requirement (left side). On the right the net importing countries (as percentage of demand) and net exporting countries (as percentage of generation) can be viewed. The colors reflect the average over the different RES-E integration levels. In the table below the values per RES-E level can be found: negative values are net exporters, the value is the total exported power divided by the total domestic generation; positive values indicate net importers, the value is the total imported power divided by the demand.

5. Sensitivity analysis

Additionally to the scenarios, the model has been tested for differences in parameters and slightly different approaches. The varied parameters, and how they were altered, can be found in Table 3.

The most important findings from the sensitivity analysis are:

- The impact of chosen values for VOM are significant. A certain fuel price development might shift the equilibrium to the advantage of RES-E, especially compared with lower RES-E integration levels. If this is not accounted for in the planning phase impacts on the optimum can be significant. All increases in VOM prices result in a higher share of solar PV, while all decreases mainly result in slightly more CCGT over coal plants. When planning a power system the uncertainties, known fluctuations and future developments of fuel prices should be incorporated to determine an optimum.

- The impact of chosen values for CapEx is less extreme. Expected future technology costs are likely to lead to a higher share of solar PV. This share is deducted from wind capacity if prices for wind stay similar, but are more at the expense of coal capacity when prices for wind turbines decrease as is expected.
Table 3: Parameters variations investigated for the sensitivity analysis

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Variation applied</th>
<th>Underlying reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>VOM</td>
<td>+ &amp; - 25% &amp; 50%; Expected VOM 2050; BM -50%</td>
<td>Test the preference for certain generation technologies</td>
</tr>
<tr>
<td>CapEx</td>
<td>Expected CapEx 2050 RES-E/Solar PV/Storage</td>
<td>Test the system for the far away future, relation between wind and solar PV, is there need for FB or H₂</td>
</tr>
<tr>
<td>CO₂ emitted</td>
<td>Price of 25 &amp; 50€/tCO₂; Emission cap of -25% &amp; -50% to emitted in CON scenario</td>
<td>Test relation between use of coal or CCGT, maybe biomass</td>
</tr>
<tr>
<td>Complementary options</td>
<td>Without storage, without transmission, without both</td>
<td>Investigate value of different complementary options</td>
</tr>
<tr>
<td>RES-E share</td>
<td>90% and 100% RES-E share</td>
<td>Investigate the possibility of a fully renewable system and curiosity</td>
</tr>
</tbody>
</table>

- The result of an emission pricing system would lead to significant higher system LCOE, but also lead to higher RES-E integration levels as optimum: around 85% for a price of 25€/Mton and even 90% at 50€/Mton.
- An emission cap has no significant cost increase as result, but does increase the RES-E level. It suggests that higher RES-E levels can be achieved with emission cap policy without radical price increases.
- The absence of one or multiple elements from the optimisation shows small differences in the installed capacities, which are only slightly reflected in the generation mix. If storage is excluded significantly higher shares of CCGT are installed, while also a slight increase in solar PV is visible. For the exclusion of transmission the increase in CCGT is about similar, but the increase in solar PV is not visible. If both are absent the installed capacity increases in total, with the same patterns visible as for the exclusion of storage. Interesting to notice is that the exclusion of storage has thus the most influence on the required capacities per generation technology, but shows the least difference in system LCOE. If transmission is absent the effect is much more significant, reaching a cost increase of 23% for the CON80 scenario. It can be concluded that with a somewhat adjusted generation portfolio and mix the demand can be served at almost the same costs when no storage is used, but that the absence of transmission in the optimisation has a much larger impact on the resulting costs. The effect of transmission is concluded to be more important to the system than the effect of storage.
- A fully renewable power system is feasible, even at acceptable, but higher costs than a 50% scenario (about 23% higher costs). Such a system would consist of around 85% wind power and 15% solar PV in the generation mix, with an installed capacity of 90% wind power and 10% solar PV.
Sensitivity analysis - System LCOE

![Diagram showing sensitivity analysis of System LCOE. The bars represent deviations from the CON50 value for different changes in parameters. The blue vertical line represents the CON50 system LCOE, whereas the red, dotted line represents the system LCOE for CON80. Deviations are given for the 20%, 50%, and 80% RES-E scenario, except for the bottom two bars, which represent a 90% and 100% RES-E scenario.]

Figure 7: System LCOE resulting from sensitivity analysis. The bars all represent the deviation from the CON50 value, for several changes in different parameters. The vertical blue line represents the CON50 system LCOE, whereas the vertical red, dotted line represents the system LCOE for CON80. Deviations are given for the 20%, 50%, and 80% RES-E scenario, except for the bottom two bars, which represent a 90% and 100% RES-E scenario.

6. Discussion and conclusion

In this study, we modeled the European power system for a renewable future, for four different planning scales, under increasing shares of RES-E. The system costs were minimized with a fully linear cost-optimization model. Historical, hourly weather and demand data were used as input, from which 52 days were picked from the year 2012. The differences in costs, and underlying power system design, were presented for the four policy scenarios. The limitations of this study will first be discussed, followed by the main findings.

6.1. Research limitations

Due to choices and assumptions, some elements of the power system that have an influence in the real world were not included in this study. This poses certain limitations to the conclusions. The effects are:

- The amount of generation technologies is limited and even two often used technologies in the current power system have not been incorporated: nuclear and run-of-the-river hydropower. The choice to use biomass instead of Carbon Capture and Storage (CCS) technologies might also have influenced the results, seen that the characteristics of biomass apparently led to no usage of the technology at all. Also the exclusion of offshore wind turbines, considered
Figure 8: (a) Installed capacities resulting from sensitivity analysis. (b) Generation mix resulting from sensitivity analysis. The bars represent the share of total generated power per generation technology. All bars are given for a 50% RES-E integration level, except for the bottom two which represent a 90% and 100% integration level. The top bar shows the generation mix for a regular CON50 scenario.

with high potential for the current RES-E development, influences the costs and choices for technologies significantly.

- Prices for fuels and materials for all technologies were assumed inelastic. However, as the generation mix shifts to coal, or as a large share of wind turbines is needed these prices are likely to react, leading to different interdependencies between technologies.

- Based on the previous point, the only major system incorporated is the power system, although the power system is connected to a larger macro-economic system, which it influences and is influenced by.

- To model the power system many simplifications were applied in order to keep the model manageable. For the generation element tamping times, limits and costs have been ignored, as well as startup times and costs. The power balance also did not require spinning reserves. For the transmission section the network was considered a water-flow model, leaving out all kinds of technical transmission difficulties.

- The weather-data that was used as input for this study was found to show some inconsistencies, for which it had to be corrected. Since the model heavily relies on this input data, any inconsistency in the dataset devaluates the quality of the results.

- The aggregation per country leads to smoothing effects of extreme locations. This especially applies to large countries which can have very different weather patterns within. These are ignored as the average weather pattern per country was used as input.

- The point of departure for the model is a completely empty Europe, where all power system infrastructure can freely be placed. This does not take into consideration the existing infrastructure, lifetimes of those technologies and the route to get from current to optimal.
6.2. Main findings

The scenarios were tested for three levels of RES-E integration: 20%, 50% and 80%. Four options were incorporated in the optimization which are theoretically able to limit RES-E integration costs: distribution and mix of wind and solar PV, distribution and mix of backup capacity, electrical energy storage and interconnection capacity. From the results the following conclusions can be drawn:

- The biomass plant was not used at all in any scenario for a cost-optimal design. The specific costs of a biomass plant are too high and no situations were encountered in which these higher costs were justified.

- The main source of flexible generation was found to be the coal plant. When the system can be optimized most installed capacities will have many FLH. As FLH increase, technologies with high investment costs and low variable costs become relatively more attractive. Coal power plants fit this description. CCGTs have the ratio the other way around, they combine low investment costs with high variable costs. The result is a small share of CCGT that is marginally dispatched. The share of CCGT in the generation mix is negligible.

- The only form of storage, that was broadly applied, is PHS. Every scenario installed at least some and for NAT80 even 80% of the technically potential storage capacity was put into use. Other storage technologies were found to be used only sporadic. If the planning was performed on national scale and no technical potential for storage was available in that country, H₂ storage was used at the 80% RES-E integration level. For other scenarios the use of PHS increased as well with the increase of RES-E level. Apparently storage provides a solution at higher shares of RES-E.

- The transmission grid is not so much extended in length as more in capacity. This means that compared to the current network lay-out to a lesser extent new lines are build in an optimal scenario, but that the capacity should increase significantly. CON80 has around 7 times more transmission capacity than the reference scenario.

- Wind power is by far the main source of RES-E, especially at levels of lower RES-E integration. As this level increases, solar PV capacity is installed as well. The highest value found was for the NAT80 and REG80 scenario, were it formed 16% of installed RES-E capacity. The generated power from solar PV reaches 11% for the NAT80 scenario as a max. It can be concluded that for higher shares of RES-E solar PV power becomes increasingly important.

This research clearly shows a potential cost-reduction for the European power system, and finds that a more central planning scale is better capable of achieving that. The results suggest that it is possible to incorporate large shares of RES-E, while maintaining acceptable cost levels. Also without significant increase in RES-E integration levels, a cost reduction was found by optimizing, but the effect of planning scale is less present. The least cost increase for a system with higher shares of renewables in the energy mix was achieved with a central European planning scenario, where system LCOE only increases by 4% to get from a 20% RES-E integration to 80%. The overall lowest cost was also achieved by central coordination. However, this entails large increased capacities of transmission grid, as well as a growth in PHS capacity. Certain regions will become very dependent for their energy on neighboring regions and countries. Interestingly, a joint regional planning scale would have little benefit over the current national policy.
The feasibility of a more central planning scale is uncertain, as national energy policies are strongly aimed towards local energy security. It is recommended that the willingness of countries to cooperate is to be further researched. An additional topic of research would then be to determine which body is most appropriate to perform such a full system planning. Further research might also prove valuable for the option of DSM. It is regarded by policymakers as a valid option to deal with RES-E intermittency and already some research has been performed in that direction. It might prove to be complementary to options investigated in this study. Other questions that remain after this research regard the markets in which such a centrally coordinated system should operate. The economic feasibility of separate generation technologies was not looked at, while in the liberalized European power system private investors are only willing to participate if the business case is sound. Technical additions to this research are also suggested for further research. Especially including generation technologies that currently provide a fair share of the energy mix, like nuclear, run-of-the-river hydropower or offshore windturbines might give valuable insights as to how an optimal future power system might look like. Technical limitations of power transport are also recommended to be further researched, as the transmission network found to be beneficial for this study proved to be quite extensive. Simplifications in electricity flows might make transmission look disproportionately favorable.

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