Impacts of restricted transmission grid expansion in a 2030 perspective in Germany

Final report
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Foreword

By contributing to the refutation of two persisting myths and by bringing more clarity on key future trends, this study shows that policy makers have various viable options open on the way towards high shares of renewable electricity (RES-E) in the power system. This positive message supports the implementation of the Energiewende in Germany and of the transition to renewables all over Europe. While the object of the analysis is the German power system, some of the conclusions can arguably be applied also to other countries with growing shares of variable renewables.

The first myth is that, in case of delays in the implementation of very ambitious transmission grid expansion plans, a general slowdown of investments in RES-E generation would be necessary in the coming years. Given the probability of such delays, this thesis would have heavy implications, if it were confirmed. But it is not: this study suggests that Germany can reach 72% RES-E by 2030, even if the transmission grid expansion is limited to those projects that were already under construction in December 2012. Importantly, the additional costs in case of such a heavily limited grid expansion are manageable: between 0.8% and 3% of the total power system costs, depending on the kind of RES-E technologies used, and on their geographical distribution within Germany. This finding is broadly in line with the results of other studies1 assuming (very) high shares of RES-E in the next decades, and comparing scenario with higher/lower transmission grid expansion. All found that higher transmission grid expansion reduces total system costs, but all also found that the cost difference is limited, ranging from close to 0% to circa 4% of total power system costs.

The second persistent myth is the idea that “wind should be built where it’s windy, and solar where it’s sunny”. That simplistic slogan reduces the complexity of the transition to renewables to only one dimension: the wind and solar resources. In the real world, there are a number of other relevant economic and non-economic factors, like the costs of land, of capital and of project development, the availability of skilled labour, the certainty of law, social acceptance, the strive for regional or national (partial) self-sufficiency, regional development concerns, etc. This study focused only on the impact of rapid/slow grid expansion and did not reproduce most of these “other factors”. Therefore, its findings are even more remarkable: a scenario with more wind where it is less windy (in the German case: more onshore wind in the South and less concentration of onshore and offshore wind in the North) is more robust against the probable risk of delayed grid expansion.

A further result that might seem surprising is that a delayed grid expansion in Germany is associated with slightly lower CO₂ emissions in 2030 than full grid expansion. The reason is that transmission grid expansion does not only favour the integration of wind and solar, but also the steady operation of inflexible, low marginal cost power plants, i.e. in 2030 Germany lignite. However, the difference is small: in all scenarios modelled, CO₂ emissions from the power sector are reduced to about one third of the 2011 level, thanks to the high shares of renewables.

This study should not be misinterpreted as suggesting that transmission grid is not important. As the authors repeatedly note, the assumption of perfect information, necessary to keep the complexity of the model at a manageable level, is of course not realistic: in the real world, suboptimal investments happen, and they are much more likely to happen in a power system with significant grid bottlenecks. Thus, the cost advantages of grid expansion cannot be fully reproduced in this model. Moreover, beyond the scope of the model, there are good reasons to pursue a strong expansion of the transmission grid: for instance, increasing the stability and the resilience of the power system and reducing the costs of providing important ancillary services. Furthermore, a strong grid – possibly even a slightly over-dimensional transmission grid in 2030 – will be a very good starting point for the further expansion of renewables in the following decades, and therefore in any case a good investment.

Four key policy conclusions can be drawn from this study:

1) **Transmission grid expansion in Germany should be implemented**, among other reasons because it is the cheapest way to integrate high shares of renewables and because it makes the power system more resilient.

2) However, even in case of very substantial delays in grid expansion, high shares of renewable electricity can be integrated in the power system, with only a moderate increase of total system costs (0.8% to 3% depending on the geographical distribution and generation profile of RES-E). Therefore, **possible uncertainties about the speed of grid expansion are no reason to slowdown the expansion of renewable generation**.

3) However, **such uncertainties may be a good reason to start steering the geographical distribution and the generation profiles of additional RES-E capacities**, taking into account the predictable transmission grid bottlenecks and favouring a balanced distribution of renewable generation within Germany, for instance more wind in the South and PV close to areas with strong daytime demand and low PV penetration, such as urban areas in the North.

4) In order to reach ambitious climate targets, **dedicated policies effectively able to reduce CO₂ emissions from the power sector need to be implemented**. This is even more important in case of rapid transmission grid expansion, in order to counterbalance the favourable effects it has on the use of lignite.

We at SEFEP, an organisation clearly committed to the support of public acceptance of transmission grid expansion, have commissioned this study with a true intellectual curiosity for its outcomes, and with the intention of promoting a well-founded debate on the potential effects of delay in transmission grid expansion, in Germany and other parts of Europe.

We are confident that this study, with its clear conclusions and by debunking some myths, will contribute to a more informed debate, and we would like to thank the authors and the Advisory Board for their precious work.

Raffaele Piria and Kristina Steenbock, Smart Energy for Europe Platform, August 2013
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Christian Nabe (Ecofys), Raffaele Piria (SEFEP).
Summary

Introduction
Action to meet Europe’s climate and energy security goals includes a significant increase in the proportion of renewable energy in the power system. Many studies assume a pre-requisite for this is large-scale development in the transmission grid. However, planning and construction of grid extensions tends to be a lengthy process with delays of several years common. The study reported here provides an answer to the basic question:

1. Can high shares of renewable energy be achieved in Germany even if transmission grid expansion turns out to be too slow or not feasible at the level assumed by other studies?

In addition, several supplementary questions are also addressed.

2. What is the magnitude of differences in total system cost if the grid expansion is delayed?
3. Which level of investment in flexibility options in the power system is optimal if transmission grid expansion is limited?
4. What is the impact of a delayed grid expansion on CO₂ emissions of the power sector?
5. What is the impact of a delay in transmission grid expansion on the curtailment of renewable energies?
6. To what extent do the answers to the aforementioned questions depend on the mix of renewable energy technologies employed?

Methodology
The core of the analysis is the application of a linear optimisation dispatch and investment model. The model minimises the total costs of electricity supply by optimising power generation from conventional and storage plants as well as optimising investment costs of the overall power generation mix. Investment decisions are made based on the principle of total cost minimisation.

The question addressed by this study relates to the German power system. However, Germany is an integral part of the European transmission system, so interactions with surrounding countries is an important part of the picture. This was modelled by simulating the whole system first with each country included as a copperplate i.e. perfect transmission through the country. Following this, the import and export flows were included as boundary conditions in a model of Germany that represents explicitly the regional distribution of renewable energies and the transmission capacities between different regions of Germany.

Five scenarios were modelled defined by different assumptions regarding the installed capacity of photovoltaics, onshore and offshore wind, two levels of grid development and additional potential for demand response. The type of renewable energy is important because the geographical distribution is
different. Other inputs to the model include the potential and costs for different storage or demand response options, costs of renewable generation capacity and basic assumptions such as fuel costs.

Results

The differences of results between scenarios are relatively small in all aspects. With restricted grid expansion, there is a higher capacity of gas generation and compressed air storage plants in the generation mix. This is to be expected as more transmission capacity brings more flexibility to the system. If this is restricted then other sources of flexibility are needed. The differences in capacity are also reflected in the differences in generation. Curtailment of wind in the L-scenarios (restricted development of the transmission grid) ranges from 1–4% of renewable generated energy.

Despite the differences in capacity and generation, total system costs are almost the same in the different scenarios. Carbon emissions are also very similar, within the bounds of normal variation of emissions. The scenarios with high reinforcement of the grid actually have slightly higher emissions as the conditions that favour renewable generation also favour lignite. Both technologies are high capital, low operating cost plants.

Conclusions

Based on the results of the modelling, the study gave the following answers to the questions mentioned before:

1. **High shares of renewable energy can be achieved, even if the grid expansion is substantially delayed.** A delayed grid expansion is not a show-stopper for large scale investments into renewable energies. The model results demonstrate how the power system would optimally adjust to this situation by investment in flexibilities. The answers to the following questions give more insight into the possible impacts of this delay.

2. **The analysis indicates that the scenario with more photovoltaics and onshore wind and less offshore wind is more robust against delays in transmission network expansion.** If transmission grid expansion is delayed (scenarios L), the total future system costs increase slightly. In scenario A-L (more offshore wind) the cost increase compared with scenario A-H amounts to about € 1.1 billion or 3% of total system costs. However, in scenario B (more onshore wind and PV), the cost increase associated to the delay in grid expansion is reduced by € 0.8 billion to about € 0.3 billion or 0.8%. In the real world, these cost differences will be higher, as market actors do not have perfect information about what happens in the future.

3. **If the transmission grid as a source of flexibility is limited, other flexibility options such as compressed air energy storage (CAES) and load shifting are employed.** For example an investment into about 5 GW of CAES appears to be cost optimal, if higher shares of offshore wind are assumed. If the renewable generation is based more on photovoltaics and onshore wind, the optimal CAES capacity is 2 GW. In all scenarios with restricted grid expansion, load shifting is employed to its maximum assumed potential. Under the given cost
assumptions, battery storage does not appear as a cost-optimal technology. However, this situation might change after 2030.

4. **In all scenarios modelled, CO₂ emissions from the power sector are substantially reduced to about a third of the 2011 level. The differences between the modelled scenarios are small and do not exceed annual variations of emissions in the past years.** A delayed grid expansion leads to slightly lower CO₂ emissions in 2030 than full expansion. Transmission grid expansion tends to favour technologies with high investment cost and low marginal generation cost, such as renewable energies but also lignite, as they benefit from the additional flexibility. As a consequence, further policy measures such as emission standards would need to be introduced to ensure a decrease in CO₂ emissions, as the assumed cost of CO₂ in 2030 (40 €/t) is not high enough to prevent an increased use of lignite. An intended delay of grid expansions as a measure of CO₂ reduction in the power sector does not seem to be appropriate, as the long-term effects of such a strategy would lead to higher costs and CO₂ emissions.

5. **Model results indicate levels of 1% curtailment of the renewable energy in 2030. If there are grid restrictions the curtailment of renewable energy will increase roughly twofold to fourfold from this level, depending on the employed renewable energy technology mix.** Curtailment reaches its maximum (15 TWh or roughly 4% of renewable generation) in the scenario where 25 GW of offshore wind generation cannot be transported to the load centres further south. Although curtailment of renewables as CO₂-free generation without variable cost appears as if it needs to be avoided, avoiding curtailment cannot be a goal by itself. It always needs to be balanced against other cost components and other options to avoid CO₂.

6. **The impact of the grid expansion delay on curtailment, CO₂ emissions and costs is generally higher when there is more offshore wind in the scenario.** This reflects the impact of spatially concentrated generation from offshore wind in the north, which cannot be transported to the south. The more evenly distributed renewable generation, the relevance of the transmission grid decreases. The more emphasis energy policy places on the exploitation of offshore wind resources, the more attention needs to be paid to avoiding delays in grid expansion.

The fact that the modelling results show relatively small differences between the scenarios could be interpreted in a way that conscious decision making on the renewable energy technology mix or transmission grid expansion has little significance. However, the small differences are also a result of the simultaneous optimisation of investment and dispatch with perfect information available. In reality, actors are facing insecure future framework conditions. This means that differences between scenarios will be higher in the real world. Hence robust, no regret decisions should be favoured.

Under the assumed investment cost digression scenarios, a more distributed renewable generation is achievable at a comparable cost level but appears to be more robust against
delays in grid expansion. We found that replacing 10 GW of the 25 GW of offshore wind with photovoltaics and onshore wind would have no disadvantages with respect to total system cost, CO₂ emissions and renewable energy curtailment. However, this does not mean that transmission grid expansion can be avoided by changing the renewable energy technology mix. Grid expansion is and remains a robust and relatively low cost flexibility option. Beside the aspects examined in this study, several technical and economic reasons, such as system stability and avoiding market power, make it inevitable to enforce the expansion of the grids to the planned level. This is especially true if a post-2030 perspective is assumed and future grid requirements are taken into account.
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1 Background goals of the study

A substantial increase in the share of renewable energy for electricity production is widely accepted as a "no-regret" measure to achieve Europe's climate, environmental protection and security of supply goals. This is driving the discussion on the appropriate future mix of renewable generation technologies and flexibility resources required to balance them. The discussion has recently been influenced by the large cost reductions and increasing penetration of decentralised photovoltaics systems.

Most studies and initiatives that look at European power systems based on large shares of renewable energies analyse the impact on the required transmission grid. They conclude that a massive expansion of the transmission grid is one of the decisive factors needed to allow the deployment of large amounts of renewable energies. While they show that an expansion and strengthening of the transmission grid is very important, these studies do not usually analyse the potential influence that decentralized flexibility options, such as decentralised storage, demand response and flexible generation, might have on transmission requirements. These decentralized flexibility options may become more important, if PV capacity continues to grow as prices decrease.

Key questions

This study answers a number of key questions related to the role of transmission grid expansion, decentralised flexibility options and the influence of the characteristics of different renewable energy technologies on both.

The main question of the study is:

1. Can high shares of renewable energy be achieved in Germany even if transmission grid expansion turns out to be too slow or not feasible at the level assumed by other studies?

An answer to this question is important to address the concerns that exploitation of renewable energy sources becomes difficult if the transmission grid is not extended substantially. It has even been argued that grid expansion is a necessary pre-requisite for further investments into renewable energies beyond a certain level and can be a show-stopper for renewable energies.

The following questions are relating to the consequences of delayed transmission grid expansion on a more detailed level. The answers to these questions will aid policy makers in making informed decisions about future policies towards regional flexibility options and transmission expansion.

2. What is the impact in terms of total system cost if the grid expansion is delayed?

The difference in cost has a high importance in the political debate on optimal deployment strategies of renewable energies. It is therefore crucial to understand the difference in total system cost, both investment and operational cost, if grid expansion is delayed.
3. What level of investment in flexibility options of the power system is optimal if grid expansion is limited?

By increasing the connection between different elements of the power system, grid expansion can be seen as a source of flexibility, bringing in more options to facilitate integration of renewable energies. If the transmission grid is not expanded as planned, this flexibility will be lost and other resources that provide flexibility might become more important. This trade-off is analysed in this study.

4. What is the impact of a delayed transmission grid on CO\textsubscript{2} emissions of the power sector?

Renewable energy is an important contributor to reduction in CO\textsubscript{2} emissions. The effect of transmission expansion delays on power generation, renewable energy curtailment and the resulting impact on CO\textsubscript{2} emissions is an important result of this study.

5. What is the impact of a delay in grid expansion on the curtailment of renewable energies?

If there is not enough flexibility in the system to accommodate all renewable generation, it needs to be curtailed. The curtailed energy has to be replaced either by energy from conventional sources or provided by additional investments in renewable energies. In the first case fuel costs and CO\textsubscript{2} emissions of the power system are increased while in the second case additional investment costs occur.

6. To what extend do the answers to the aforementioned questions depend on the mix of renewable technologies employed?

Generation from photovoltaics, onshore-wind and offshore-wind are likely to contribute the highest shares of renewable energy in the future energy mix. These have different supply characteristics as well as geographic distributions. These differences could change the answers to the previous questions.

1.1 Scope of the project

Geographic scope

The power system of Germany is the primary object of the analysis. As Germany is strongly connected to the surrounding power systems it is necessary to analyse the interactions of Germany with the surrounding ENTSO-E power system.
Technologies
Photovoltaics and onshore wind are the two most relevant renewable sources for Germany now, while offshore wind is expected to contribute in the future. All of these technologies are driven by the energy source (wind, solar) and are thus variable. Hydro, geothermal, biomass and biogas power plants also contribute to renewable energy generation but are less variable and are restricted by the available resource. Therefore, scenarios using a combination of photovoltaics, on-shore wind and off-shore wind are considered.

Different sources of flexibility are also taken into account. These include: load shifting options and decentralised storage (CAES, battery storage). The implementation of these technologies is determined by economic optimisation.

Target year and timespan of the analysis
The target year of the analysis is 2030. Investments are calculated in five year time steps from 2015 to 2030.
2 Methodology

2.1 Overview of requirements

In this study the methodology was chosen to take on the impacts of restricted transmission grid expansion on the German power system in 2030, considering the following requirements:

Interactions between Germany and the surrounding power system

The hourly load flows between Germany and the surrounding power system are important as they will allow the exploitation of some of the levelling effects of spatially distributed on-shore wind and providing reserve for the regional power system. Power flows to and from the German power system are limited by the interconnection capacities between Germany and the surrounding countries. We therefore model the surrounding European power system taking these interconnection capacities into account.

Different scenarios for the national power plant mix

The generation profiles and spatial distributions of different renewable sources are quite diverse and can have various impacts on the power system. Output from photovoltaics tends to be highest around noon. If the installed capacities exceed peak demand at noon, this can lead to oversupply during sunny noon hours, especially if additional wind power feeds into the system. Unlike photovoltaics, wind power generation does not have a clear diurnal pattern and the feed-in characteristic of wind generators allows to a higher degree the use of levelling effects using connections to other regions.

Generation from wind and photovoltaics has a limited ability to cover the system peak load. Storage and demand side management (DSM) options can shift the system peak load to avoid additional conventional power generation for backup. They also provide flexibility to the system to integrate the supply-driven renewable generation. The contribution from these flexibility options also needs to be taken into account for the optimisation of the generation capacity structure.

To take these requirements into consideration, we include the following elements in the analysis.

- Definition of renewable generation and transmission grid scenarios which show differences between the renewable energy technology mix and the level of grid expansion;
- Application of a combined dispatch and investment model, which calculates optimal, cost-minimising investments in conventional generation on a European level with a high temporal resolution (hourly); and
- Calculation of optimal dispatch and investments in the German power system.

The concrete steps of the analysis are described in more detail below.
2.2 Scenario definition

There are two scenarios with different renewable energy technologies in the generation mix and two scenarios with different levels of interconnection capacities. The renewable energy technology scenarios are labelled A and B. The renewable energy technology mix of scenario A is based on the German network development plan. Scenario B includes a larger proportion of photovoltaics and onshore wind and a smaller proportion of offshore wind.

Scenario “L” represents a “low” transmission grid with almost no additional expansions. Scenario “H” represents a “high” level of grid expansion, with HVDC overhead lines being in place. The numeric assumptions of the scenarios are discussed in Section 3.1.

An additional scenario is included with an increased use of DSM. In this study, DSM is represented as load shifting. In the additional scenario the share of shiftable load in the scenario B-L is increased from 5% to 10% of the load in a particular hour (scenario B-L 10%). The resulting combinations of the scenarios are depicted in Figure 1.

![Examined scenarios for Germany](image)

* B-L 10%: Scenario B with low interconnection capacity with 10% load shifting (instead of 5%)

Figure 1: Definition of five scenarios
2.3 Description of the applied optimisation model

We use an investment model as the main tool in this techno-economic analysis of the power system. It is a combined dispatch and investment model based on linear optimisation. Its main advantage is an investment decision based on full dispatch years. The resolution allows for the consideration of typical as well as extreme events and thus enables fundamentally sound investment decisions.\(^2\)

The model minimises the total costs of electricity supply by optimising power generation from conventional and storage plants as well as the investment costs of the overall power plant mix. Hence, no particular market design is assumed. Investment decisions are made based on the principle of cost minimisation and not based on expected returns from a power market.

The computation of dispatch and optimal investments evolves in five-year steps, beginning in 2015 and ending in 2050. This long-term perspective ensures a consistent development of the power plant mix over time. In this context, endogenous investment and decommissioning decisions can be taken in addition to exogenously given commissioning and plant shut-downs. Thereby, restrictions such as the technical life times are included.

Based on the available power plant capacities, 8760 consecutive hours of dispatch are modelled for each year. In each hour, the exogenously given residual load (demand less feed-in from renewable energies and less must-run generation from inflexible combined heat and power plants) has to be met through conventional production and electricity exchange. Thereby, also short-term inter-temporal constraints such as storage levels are taken into account.

Both in the investment and in the dispatch part, the model considers power plant technologies in terms of vintage classes. Within the vintage classes, plants of similar characteristics such as fuel type and age are grouped together. Their aggregated capacity is then dispatched as a single unit. The vintage classes are further characterized by specific technical and economic constraints. These include efficiency, fixed and variable costs of operation as well as annualised investment costs.

To enable the match of supply and demand, renewable energy curtailment options are implemented. Since renewable energies are assumed to receive market independent support payments, the curtailment option is only chosen if no cheaper way of balancing the system is feasible. In the case of oversupply, the typical ‘first choice’ flexibility is the international exchange between market zones. This exchange is limited by exogenously provided net transfer capacities (NTC) between the zones.

Further flexibilities on the demand and the supply side are storage technologies. In situations of oversupply, storage technologies increase the demand and store energy for high demand hours. In these high demand hours, the storage technologies are part of the supply side and reduce the demand for expensive peaking units. While the capacities of pumped-hydro storage are exogenously provided, the model can commission compressed air energy storage (CAES) endogenously. Furthermore, the model can invest in other flexibility options such as load shifting and batteries.

Figure 2 provides an overview on the inputs and outputs of the model.

\(^2\) A detailed description of the model can be found in Nicolosi (2012).
The main outputs of the model are the technology choices of the investment decision and the generation mix. These outcomes show on an aggregated level, how the system reacts to the increasing penetration of RES-E. These results come with the underlying investment and generation costs. Further dispatch outcomes are marginal costs of power generation and the exchanges between zones. Therefore the main advantage of the model compared to models which use only a limited number of type days is the greater temporal detail of these results which are available for every hour of the year. In particular the extreme hours can be analysed in detail.

2.4 Application of the model

For this project, we chose a two-step approach to solve the optimisation problem. The first step was the application of the combined investment and dispatch model on a European scale. Based on typical generation profiles, the power system of Europe and Germany was optimised to achieve a minimum-cost mix of conventional generation, storage and DSM options under a given set of technology-specific renewable energy installed capacities as well as transmission grid restrictions. An annual generation profile (8760 hours) for renewable energy in-feed based on a historic year was used to capture the variability and spatial correlation of renewable energies. As a result of this step, the
optimal power plant mix in the surrounding power system and the cross border flows were determined.

In the second step we optimised the technology mix in the German power system. Here, all parameters defined in the previous steps for the surrounding power system remained constant and only dispatch and investment within Germany was considered. To consider the impact of different degrees of transmission grid expansion on dispatch and investment, the zonal regional model of the German TSO was applied. In this model Germany is divided in 18 transmission grid regions by subdividing the regulation areas of the four German TSO as depicted in Figure 3.

![Figure 3: German network regions according to the Regional Model of the German TSO](image)

Based on the transmission grid information provided by the Platts Power Vision database as well as the network development plans, the net transfer capacities between the regions were determined. Transmission grid restrictions within the regions were not represented directly as restrictions in the optimisation model. However, the economic consequences of the integration of PV and other decentralized generation and storage options are taken into account by using results of the Dena distribution grid study (Dena 2012) as a reference study.
3 Main Assumptions

In this chapter, the main assumptions of the study are presented. Table 1 provides an overview of the most important input and output parameters of the study. Key input parameters will be discussed in the following sections. Assumptions which are not presented in the following sections can be found in a summarised format in the appendix.

Table 1: Input and output parameters of the model

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3.1 Definition of the scenarios

As described in chapter 2.2, we defined four scenarios with different combinations of transmission capacity scenarios and renewable energy mix scenarios.

**Transmission capacities**

The definition of the transmission capacity scenarios is based on the German Network Development Plan 2012 as well as the European Ten Year Network Development Plan (TYNDP) published by ENTSO-E in 2012. For scenario “H” we assumed, that all projects included in the TYNDP as well as in Scenario B 2022 of The German Network Development Plan are realised. For the “L” scenario we assumed that only projects which are currently (2012) in realisation phase will be available in 2030. Thus the difference between the two scenarios is substantial.

To reduce the complexity of the dispatch and investment modelling, grid restrictions are assumed to be non-existent (or a “copperplate”) both within each of the German regions and within each of the other European countries. However, the use of NTC as transfer capacities takes into account the fact that internal congestions restrict cross-zonal transfer capacities. Hence, this methodology ensures a realistic representation of the grid.

For the analysis of grid expansion cost we rely on results of studies which analysed cost on a detailed, project based level as described in the network development plan. Therefore, the copperplate approach does not compromise the accuracy of cost estimations.

**Renewable energy technology mix scenarios**

The renewable energy technology scenarios were selected so that they are realistic in the sense that they are acceptable as possible developments under certain framework conditions but also show noticeable differences in the calculated trade-offs. We expected that the variation of the shares of photovoltaics and off-shore wind would demonstrate the largest differences in the resulting trade-offs and focused on the variation of the shares of these technologies. We selected scenarios that lead to the same share of renewable energies of total power consumption in Germany. Section 3.4.1 describes the methodology we used to derive the scenarios with different shares of capacity for renewable energies in the German model regions as well as in Europe.

Figure 4 shows the capacities of different renewable energy technologies in the two scenarios. Scenario A is the base scenario used in the German network development plan 2012. For scenario B, a number of different sources were used. For on-shore wind the capacity is the same as the 2020 planning figures for on-shore wind of the federal states. Since the figure is very close to the

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4 In the German network development plan the base scenario is scenario B. The planning numbers for onshore wind of the Federal states were taken from scenario C of the 2012 network development plan.
maximum potential, the 2020 number is not increased further for the 2030 scenario. For photovoltaics, the assumed figure in this scenario equals the capacity installed at the end of 2012 with an annual increase of 3.5 GW. Both scenarios were calibrated to reach a penetration of about 72% renewable electricity in the mix, if the 2010 electricity net demand of 535 TWh is assumed to be constant. Hence, these scenarios have a higher ambition level than the current governmental targets for 2030.

Figure 4: The two scenarios for the renewable energy capacity mix in Germany (2030)

To derive the renewable energy capacity mix for the surrounding European power systems, the National Renewable Energy Action Plans (NREAP) were used. As the NREAP scenarios for the capacity mix define the plans for 2020, the numbers have been extrapolated to 2030 (see Figure 7). The extrapolation was calibrated to the goals of the EU energy roadmap for 2030 (“High-renewable energy case”), but considered the limitations of national renewable energy potentials. Hence, the 2030 scenarios take the results of the GreenX renewable energy potential studies into account.\(^5\)

To breakdown the German national renewable energy capacity mix to the regions, the 2020 plans of the federal states were used as a basis. Again, the 2020 numbers required an extrapolation, taking local potentials into account. Details of generation from these capacity scenarios are given in Section 3.4 below.

\(^5\) RE-Shaping D10 Report (2011)
3.2 Installed capacities of conventional power plants and technical lifetimes

The regional flexibility in power markets depends to a great extent on the existing power plant fleet. Figure 5 shows the assumed installed capacity of conventional power plants in the European member states, Norway and Switzerland.

![Figure 5: Installed capacity of power plants in European countries](image)

Technical lifetimes of power plants determine the existing installed capacity and the fleet of 2030. There is a big bandwidth of lifetimes of power plants, depending on their fuel and technical characteristics. The regional situation is often determined by political decisions.

Assumptions about existing power plants are derived from the Platts PowerVision database. It includes detailed information about each unit in the European electricity market. The date of first operation is given for each of the units. If published, the retirement dates of existing power plants are also taken into account. For most power plants, the retirement date is not yet settled. For these plants the assumptions shown in Figure 6 are used.
For nuclear power plants we assume a technical lifetime of 50 years. The second very long term investments are lignite fired power stations. We assume a technical lifetime of 45 years. In Eastern European countries like Poland, Czech Republic and Romania, these lifetimes have been passed, but most of the big power plants are either closed down or retrofitted after this time. Coal fired power plants are assumed to have a lifetime of 40 years. Gas-fired combined cycle power plants (CCGT) are expected to generate electricity for 35 years, gas turbines are assumed to close down after 30 years.

To reduce the complexity of modelling without losing accuracy, power plants are aggregated to age classes. Depending on the average date of first operation, these classes have different efficiency values in each region. For new power plants, limited technical progress is assumed: While CCGT plants are expected to reach efficiency values of up to 60%, lignite power plants do not exceed the value of 43% (see Figure 7). These assumptions are consistent with other studies.

Figure 6: Technical lifetimes of power plant categories

![Bar chart showing technical lifetimes of different power plant categories.](image)
3.3 Cost assumptions

3.3.1 Investment costs of conventional plants

The economic model takes into account the expected generation from renewable energy sources. If the residual load requires additional capacities of conventional power plants, investments are made depending on expected lifetimes, efficiencies, flexibility characteristics and necessary investment cost. Figure 8 represents the assumptions taken in this study.
Additionally, fixed operation and maintenance costs have to be taken into account for power plants that are ready to operate. These costs are high, especially for baseload installations like lignite and nuclear power plants as Figure 9 summarizes.

**3.3.2 Fuel costs**

To a large extent, the dispatch is determined by fuel costs and variable costs of operation. The assumptions for fuel costs are aligned with other studies and show increasing costs for coal and...
natural gas on the European market. In 2030 natural gas is assumed to cost 30 €/MWhth and coal is expected to cost 14.5 €/MWhth. The cost of uranium fuel is assumed to increase to 5 €/MWhth. The costs for lignite power plants stay at their very low level of 1.4 €/MWhth as they are determined mainly by variable mining costs of existing mines. Suppliers do not compete on an international market. An overview of fuel cost developments is given in Figure 10.

![Figure 10: Assumptions about the fuel cost development](image)

### 3.4 Generation of renewable energies

One main feature of the “Energiewende” is the expansion of renewable energy sources in the electricity system. As discussed previously two scenarios showing different expansion paths in Germany are used.

To allow an hourly simulation of generation dispatch, hourly values for renewable generation are required. The hourly generation pattern is based on wind and PV infeed data provided by the commercial data provider Eurowind for 2008, which is an average wind generation year for Germany. These generation time series are available with a spatial resolution of 2-digit postal codes and are aggregated by the selected region and scaled to the installed capacity.

#### 3.4.1 Wind energy

Wind energy is the most important source for renewable energy in Germany. In 2011, 8.1% of the electricity was generated in wind turbines. The technology developed rapidly, from an installed capacity of 18.4 GW in 2005 to 29 GW at the end of 2011. In the course of the year 2011, nearly 2 GW of new capacity was installed. In Scenario A, the installed capacity grows to 61.1 GW in 2030.
Scenario B applies higher expansion rates, with an installed capacity of 70.7 GW in 2030. The regional distribution of these capacities to the Germans region was based on the scenarios of the Federal states.

The assumed generation from wind turbines accelerates even faster. With growing hub heights and extended rotor diameters, the number of full load hours is increasing constantly. While in 2005 an average wind turbine reached nearly 1500 full load hours per year, this number increased to nearly 1700 h/a in 2011. These values are expected to grow further: According to BEE (2009) the German association of renewable energies assumes average full load hours of 2490 h/a in 2020, varying between 2000 and 4000 h/a, depending on the location. The dena grid study II gives an indicator of 2200 h/a for the year 2020. This study assumes 2300 h/a in for onshore wind in 2030. Depending on location and wind conditions, the full load hours are higher in regions close to the sea and at exposed places, which is taken into account.

Figure 11 shows the assumptions for all European countries. Islands like Ireland and the UK achieve the highest values, while countries with no or little coastline reach much lower numbers. The spread is about 1000 hours a year.

![Full load hours](image)

**Figure 11: Assumptions for average full load hours of wind energy in different European countries**

Offshore wind turbines are assumed to have higher full load hours because of better wind conditions in combination with higher hub heights and bigger rotor diameters. In this study 3800 full load hours per year is assumed.

The hourly structure of in-feed is derived from historical data from Eurowind, a weather data provider. In this study, time series of 2008 were used as this is an average year for in-feed of wind. Therefore, the hourly 2008 data for each region was weighted with the installed capacity of this region and aggregated to national wind curves for each European state, including Norway and Switzerland.
3.4.2 Photovoltaic

The number of photovoltaic installations in Germany is growing at a fast pace. In 2011, a new record of 7.5 GW new PV systems was installed. The potential generation from the installed capacity depends on the geographic location. Installations in Southern Germany reach higher full load hours than the ones in Northern Germany. In 2011, the average German PV installation achieved full load hours of 772 h/a. Technical progress is expected to enhance this number to an average about 950 h/a until 2030.

In other European countries, the number of full load hours depends on the latitude. Southern European countries like Spain and Portugal achieve higher values than Northern countries like the Scandinavian.

![Full load hours PV](chart.png)

**Figure 9:** Assumed full load hours for PV installations in 2030

The hourly structure of in-feed was derived from historical data delivered by Eurowind. To provide the correlation with the in-feed of wind, the same base year 2008 was used.

3.4.3 Biomass and other renewable energy sources

Other installations to make use of renewable energy are biomass power plants, concentrated solar plants, geothermal and tidal installations. The generation of electricity from biomass in Europe is expected to triple between 2010 and 2030. The main increases are expected to be in South Eastern Europe, while the generation of biomass plants in Germany is expected to double between 2010 and 2030, based largely on plants installed between 2010 and 2013.

Other sources of renewable energies are also assumed to be used, but only with a moderate technical progress. Plans for concentrated solar plants in Southern Europe and Northern Africa are not
expected to play a significant part in the European electricity market until after 2030. Geothermal and tidal power are also assumed to have a very limited role up to 2030.

3.4.4 CO₂ prices

Prices for carbon emissions are expected to rise in the future. The model leaves open, if the European Emission Trading Scheme is pursued after 2020 or if it is replaced by a carbon tax. In 2030, prices are assumed to reach 40 €/t of CO₂. A linear pathway was drawn from prices of 6 €/t in 2012 to 40 €/t in 2030.

3.4.5 Costs of Renewable energies

Costs assumptions for renewable energies were based on the assumptions of the study of Agora Energiewende. Detailed cost assumptions are presented in the appendix.

3.5 Other parameters

3.5.1 Demand for electricity

An important factor in determining the outcome of the power market is the demand for electricity. This demand depends on economic factors, on energy efficiency standards and on behaviour of energy users. For Germany, net demand is assumed to be at a constant level of 535 TWh. For the other countries, assumptions on the development of demand are based on different studies. The hourly structure of demand is derived from public data provided by ENTSO-E. The base year was again 2008 to be consistent with the wind and PV profiles.

3.5.2 Flexibilities from the demand side

With growing in-feed from intermittent renewable energies, the need for flexibility rises. One main source of future flexibility is the demand side. Only a few studies take demand response into account when they quantify future developments, mostly in sensitivity calculations, e.g. ECF Power Perspective 2030. The numbers in Figure 12 show the results of different studies as well as our assumptions on the shiftable demand in the peak hour of the country.
Most studies about DSM and Demand Response evaluate the technical potential. Different processes are examined and possible interruptions are quantified. In reality, the technical potential will not be deployed completely for a variety of reasons, e.g. contracts, labour rights, opportunity costs, behaviour, tariffs and costs.

In some countries, demand response is already part of the electricity market. This is reflected in the system adequacy forecasts. UCTE SAF (2009) shows expected demand response potentials in different EU states. Some studies generalise the results from pilot projects and scale them to national level. Torriti (2009) gives an overview about some of these studies.

The implementation of demand response depends on the industrial structure, of consumption profiles, technical equipment and adjustments in behaviour. The implementation might vary significantly in the European states because of different consumption patterns. This study takes a moderate approach towards future flexibility on the demand side. For all scenarios it is assumed that in 2030, 5% of the hourly demand can be shifted for up to two hours. As there is considerable insecurity about this number it was decided to calculate an additional sensitivity scenario. In this scenario, the shiftable share of the hourly demand is increased to 10%.

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6 Examples are Klobasa (2007), Stadler (2005) and VDE (2012)
This aggregated approach makes it possible to reflect the opportunities of demand response in our calculations without exact predictions about the development of future technologies and consumption behaviour. Similar to the dena grid study II, variable costs of load shifting are assumed to be 1 €/MWh. The investment cost was estimated to be 50 €/kW.
4 Model results

In this section, the results of the model runs are first given from a European perspective and then from the German national perspective. The implications of the results for the questions posed in Section 1 are discussed in Section 5.

4.1 European perspective

As discussed in Section 2, the optimisation of the European power markets and the detailed regional zones in Germany is solved in a two-step approach. First, a European model run identifies the hourly exchange values for all interconnectors. In the second step, the exchange values between Germany and the surrounding countries are taken as a model input for the optimisation of the German system. Figure 13 shows the aggregated exchanges in scenario A and B.

![Figure 13: Exchanges in scenario A and B in 2030](image)

In both scenario A and B, Germany continues to be a net-exporting country in 2030. The only interconnects with a net-import to Germany are Denmark, France, Poland and Sweden with the addition of Czech Republic in scenario B. The other countries are net-importers from Germany.
Also in scenario B, Germany remains a net-exporting country. The absolute net-exchange difference between scenario A and B is about 3 TWh which represents about 0.5% of the German consumption.

4.2 National perspective

4.2.1 Installed generation capacities

In the second step of the modelling approach the focus is on Germany. Investment and dispatch decisions take the constraints between the German regions into account and optimise the entire system accordingly. Additionally, they consider the cross border flows derived in the first step. Figure 14 shows the resulting generation and flexibility capacity in 2030.

Figure 14: Generation capacity in 2030 (*exogenous assumptions), lines indicating the change of capacities determined by the model
Total installed capacities

By scenario definition, the capacity mix is dominated by renewable generation capacity. The conventional generation capacity, which is necessary to provide energy in times of lower renewable energy infeed, represents only a fraction of the entire fleet.

The scenarios labelled L have more severe grid constraints. The model results show that more flexibility is needed when there are more grid constraints. This means that additional capacities are required in both conventional generation and flexibility options such as compressed air storage and load shifting.

With scenario A assumptions on the renewable energy technology mix, an additional capacity of 11 GW is needed, if no grid expansion could be realised. In scenario B, with more onshore wind and PV but less offshore wind the difference between the two transmission grid scenarios is reduced from 11 GW to 9 GW. In this scenario, the more evenly distributed renewable energies help to avoid local deficits and oversupply. These deficits and oversupply situations provide incentives for investment in power generation and flexibilities. These additional investments can be reduced if the renewable energy mix is changed.

Development of installed generation technologies

To better distinguish the differing results, Figure 15 shows a direct scenario comparison per generation technology. As hydro storage and pumped hydro are exogenous determined investments, the values are similar for all model runs.

![Figure 15: Direct comparison of generation capacity installed in 2030](image)
The figure shows that with restricted grid extensions (the L scenarios), more investments in gas fired technologies such as combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) is needed to provide the required flexibility.

For similar reasons, there are significant differences in investment in CAES. In this case, the contributions from different renewable technologies is also important as the higher offshore-wind capacities installed in scenario A produce power which cannot be transported to the load centres in the south. In this situation, 5.4 GW of CAES is part of the cost-minimising solution. In the B-L scenarios, CAES investments also appear to be economic. However, in these scenarios the installed capacity is less due to their more decentralised renewable energy distribution (2.3 GW).

**Coal and lignite**

Smaller effects can be observed in the lignite and coal capacity. While scenario A-H shows a slightly higher lignite capacity compared to all other scenarios, scenario A-L shows slightly less coal capacity. This is not surprising, since baseload technologies benefit from flexibility provided by the transmission grid as much as renewable energies do.

In the B scenarios, installed capacities of coal and lignite are similar. The more decentralised renewable generation in this scenario does not require use the transmission grid as much as in scenario A. Hence the differences between the high grid and the low grid case are reduced.

### 4.2.2 Power generation

The observations on the capacity side translate into the generation mix. Figure 16 shows the comparison of the generation mixes of the individual scenarios in 2030.
Total generation and curtailment of renewable energies

In scenario A-L, where a higher share of offshore wind is combined with a low grid expansion, a significant amount of curtailment (15 TWh) and the deployment of storage is necessary due to the grid constraints that occur with an increased generation from offshore wind. Curtailment and storage losses need to be compensated by generation from conventional power plants. Hence both effects lead to a higher overall generation compared to scenario A-H.

A similar pattern can be observed comparing scenario B-H and B-L. This comparison highlights the impacts of a reduced grid with a geographically more distributed renewable energies. Again, in the B-L scenario with higher grid restriction, conventional generation has to compensate an increased curtailment. However, in the B scenarios the demand for flexibility options is slightly lower than in the A scenarios. In this regard, geographical distribution of renewable energies can already be interpreted as one kind of flexibility option. To better distinguish the individual effects, Figure 17 shows the direct technology-specific scenario comparison.
Figure 17: Direct comparison of the generation mix

Differences in generation from gas, lignite and storage

The largest differences in the generation mix are differences of gas based generation, followed by differences of lignite-based generation. When grid constraints are limiting the transport of cheap lignite generation, lignite generation is replaced with gas. In the “A” scenarios with higher shares of offshore wind this effect is more pronounced compared to the “B” scenarios with more decentralised renewable generation.

Furthermore the higher usage of the flexibilities in the grid restricted scenarios can be observed by curtailment, the use of CAES and pumped hydro. Again, this effect is more pronounced in the “A” scenarios than in the “B” scenarios.

It can be concluded that the more constrained the grid, the higher the demand for alternative flexibilities. The differences are relatively modest between the scenarios. This lies primarily in the optimisation nature of the model. If the first best solution is restricted, the model by definition finds the second best solution. In reality, however, the assumptions of perfect information about the future are not applicable. For this reason, in the real world the differences between the two scenarios would arguably be larger.

Impact of flexibilities on lignite and renewable energies

The model results indicate that variable renewable energies and conventional generation with low marginal cost (such as generation from lignite plants) benefit from the same flexibilities, although they have very different specific CO₂ emissions. As both technologies have low variable generation
costs they are on the left side (in the lower part) of the merit order. In the cost-minimising economic dispatch they are dispatched with priority over other generation technologies such as coal and gas plants.

Flexibilities in the power system, such as storage, load shifting or grid expansion support the dispatch of both technologies. For renewable energies they help to align the generation with the load pattern. Conventional generation with low variable costs is typically inflexible, which is expressed with high startup costs and technical restrictions such as low ramp-rates and high minimum-up and minimum-downtimes. Flexibilities support these technologies keeping at a constant generation level and thereby minimising startup costs and technical restrictions. Therefore, the flexibility provided by less grid constraints lead to less curtailment and the use of cheaper conventional generation, while a tighter grid leads to more curtailment and higher costs in the investment and dispatch results.

4.2.3 Comparison of total cost

The corresponding total of scenario costs are shown in Figure 18. In this figure, all CAPEX and OPEX as well as costs of net exchange in 2030 are included and the annuitized investments in transmission and distribution grid infrastructure. Costs of existing assets such as depreciation of the grid as well as generation built before 2015 is not included in the total system cost figure.

![Figure 18: Overview of total power system costs in 2030](image)
Analysis of cost differences

The figure shows that the differences between the total costs of all scenarios are very small. The small cost differences can be attributed to the optimisation with perfect information, as discussed before. Nevertheless, the following two basic trends can be derived from the overall picture.

- Delayed grid expansion leads to slightly higher total costs. In case of a more decentralised deployment of renewable energies (scenario B), the difference between the two grid expansion cases is very small. It amounts to 0.8% additional total system costs. In case of a more centralised deployment of renewable energies with higher shares of offshore wind (scenario A), the difference is higher: the delayed grid expansion scenario leads to an increase in total system costs of 3.3%.

- Comparing A with B, one can see that the total costs are nearly identical in case of a high transmission grid expansion, but scenario A is by 2.6% more expensive in case of a restricted grid expansion.

However, a significant part of the total system costs are not an output of the model. For this reason, comparing the total system costs of scenarios A with scenarios B has a limited value, because their cost difference is largely due to the (exogenous) assumptions, for instance on the future costs of various technologies, notably offshore wind, onshore wind and PV. In this study, investment costs for renewables in both scenarios are assumed to be similar.

The difference of endogenous costs (model results such as OPEX of conventional generation and storage, CAPEX of conventional generation and storage and costs of net-exchange) between the H scenarios is relatively small (scenario A: € 9,623 million; scenario B: € 9,688 million). The L scenarios with a more constrained grid have the opposite order (scenario A: € 11,924 million; scenario B: € 11,068 million).

It is worth mentioning that also the H scenarios have inherent grid constraints since only the grid expansion measures defined in the grid development plan for 2023 are realised by 2030. At the same time, the grid expansion scenario L is really very limited and hardly different from the current situation. Moreover, it must be noted that also scenario B has a significant amount of offshore wind (15 GW) in 2030. This means that it includes a significant increase in generation from a geographically centralised source in comparison with today.

Beyond 2030

Another important consideration is that the year 2030 is not the end of the Energiewende. It is likely that further deployment of renewable energies after 2030 requires more flexibility of the power system. One important source of flexibility would be a stronger transmission grid than assumed here for 2030, even in the H scenario. Therefore, building transmission is basically a no-regret strategy, especially since actual construction is often slower than hoped for. If transmission materialises faster than expected, it is very likely that, within the next few years, this grid capacity turns out to be necessary. Additionally, transmission helps to prevent the manifestation of local market power. Other sources of flexibility would be new storage options which have not been considered in this study.
Among those are power-to-gas storage as well as all options which increase flexibility between the power sector and the heat and transport sector.

The proportion in the results shown in the previous Figure 18 can also be seen in the levelised cost of electricity (LCOE) as shown in Figure 19. The LCOE was calculated by dividing the total system cost as depicted in Figure 18 by the consumption in Germany (including net exports). As the consumption is assumed to be constant and net exports vary only slightly between the scenarios the LCOE values have the same proportions as the absolute cost.

![Figure 19: Levelised cost of electricity (LCOE) in Germany 2030](image)

*LCOE includes all cost 2015 – 2030 (but sunk cost) divided by consumption incl. net exports

### 4.2.4 CO₂ emissions

The different generation structure of the scenarios results in different CO₂ emissions. Figure 20 compares the calculated emissions for 2030 with historic emissions in Germany.
In all scenarios modelled, CO₂ emissions from the power sector are substantially reduced to about a third of the 2011 level, despite the total phase out of nuclear generation. The differences between the modelled scenarios are very small and do not exceed annual variations of emissions in the past years. A delayed grid expansion is associated with slightly lower CO₂ emissions in 2030 than the full grid expansion. As discussed before, grid expansion tends to favour technologies with low marginal generation cost, such as renewable energies but also lignite, as they both benefit from the additional flexibility.

Somewhat counter intuitively, the scenarios with more renewable generation due to less curtailment (A-H and B-H) also have higher CO₂ emissions. This is because in these scenarios, lignite generation is also higher for the reasons discussed above. This general effect is partly offset by the higher share of conventional generation in the scenarios with less network capacity, since the curtailed renewable energy amounts need to be compensated by fossil based generation.

As a consequence, in order to achieve ambitious climate policy targets, further policy measures such as emission standards would need to be introduced to ensure a decrease in CO₂ emissions. The assumed cost of CO₂ (40 €/t in 2030) is not sufficiently high e.g. to prevent an increased use of lignite. If carbon prices remain lower, the dedicated policies to reduce the use of lignite should be even stricter.

A deliberate delay of grid expansions as a measure of CO₂ reduction in the power sector is certainly not appropriate. As mentioned before, in a post-2030 perspective additional flexibilities of the power sector tend to favour technologies with low marginal generation cost, such as renewable energies but also lignite.
system would be required and grid expansion is one of them. Hence the long-term effects of such a strategy would lead to higher costs and CO$_2$ emissions.

4.3 Regional perspective

The distribution of renewable energy capacity and the ability of the system to distribute the energy, have effects on the regional marginal costs. Figure 21 shows the average regional marginal cost distribution in 2030 via colour coding.

If the network construction is restricted, as assumed in scenario L, the marginal cost divergence increases. In scenario A-L, with significant renewable energy capacity in the North of Germany, the marginal costs are significantly lower in the North and significantly higher in the South. This effect is less extreme if the renewable capacity is more distributed as in scenario B. Nonetheless, the effects of transmission constraints are visible.
The distribution of marginal costs in both H scenarios reflects the regional distribution of renewable energy generation. In scenario A, more renewable energy capacity is located in the north and in scenario B the renewable energy capacity is more distributed. In scenario B, the lower marginal costs associated with renewable energy are therefore distributed more widely than for scenario A.

To illustrate the congestion behaviour throughout the year Figure 22 illustrates congestion rent duration curves. Congestion rents are computed by adding volume-weighted marginal cost differences between the regions. Their absolute value indicates potential gains of a network operator, who could benefit from price differences with the application of a transmission tariff. They do indicate the magnitude of congestion but do not indicate congestion costs. Costs of transmission constraints are included in the operational costs of the power system. They represent the cost of the inefficiencies of the power plant least-cost dispatch due to the transmission constraints and therefore part of the operational cost differences as shown in Figure 18 (OPEX conventional and storage).

Figure 22: Congestion rent duration curves in 2030

It is important to mention that lower marginal costs do not necessarily translate into lower power prices in a certain region. What is more, in most European market designs, network restrictions do not influence wholesale electricity prices. To ensure a high market liquidity network restrictions are usually solved in a redispatch process, outside the market process.

Figure 22 shows the hourly aggregation of all congestion rents of all lines within Germany for all scenarios. One can clearly see that also both H scenarios have a significant amount of hours with
congestion. This stems from the assumption that only the NEP 2023 network is realised in 2030. However, the difference of the renewable energy technology mix is visible. Significant congestion rents or price differences occur only in a very limited number of hours (about 150). This number increases to about 700 hours if more offshore wind is used in the power generation mix (scenario A-H).

In the most constrained scenario (B-L) significant congestion occurs in more than 3000 hours. Approximately only half of the year would be entirely congestion-free. A more decentralised renewable energy distribution will reduce the congestion, roughly by about a third of the total congestion rent.

4.4 Impact of additional Load-shifting

Impact of load shifting on a European scale

To illustrate the role of demand flexibility for the future power system, a sensitivity analysis of scenario B-L was done, doubling the possible amount of load shifting. We expected to see a total cost reduction for the scenario, a decrease of curtailment as well as reduced congestion of the transmission grid.

As a first step, we performed a model run on the European scale. In this scenario, the load in all countries becomes more flexible. Hence, we assumed converging and effective European policies to unlock load shifting potentials. Another reason for a similar level of load shifting in Europe would be that coupled European power markets, including intraday and balancing markets, lead to an alignment of price incentives for load shifting. In this case, countries with higher shares of supply-driven renewables would export incentives for the system adaptation to other countries.

One observable difference in the modelling results of scenario B-L 10% compared to the scenario B-L is the higher net-export of Germany (see Figure 23).
The absolute value of net exports is slightly higher compared to the other two scenarios. In absolute terms, however, the differences are negligible. Another difference is the change of flows between Germany and the Czech Republic. In scenario B, the Czech Republic is a net exporter into Germany whereas with additional load shifting it becomes a net importer from Germany.

With respect to installed capacities, the assumed potential of load shifting is fully exploited. This leads to no observable differences in the installed generation capacities in Germany but to slightly reduced capacities in neighbouring countries.

**Impact of additional load shifting in Germany**

The analysis of the differences in total generation in Germany leads to little differences between scenario B and the load-shifting sensitivity scenario (see Figure 17).

Curtailment is at the same level and storage options are slightly less in use. The use of lignite, gas and coal plants slightly increases. This means that due to the increased flexibility of the system at almost no additional cost combined with the high penetration of renewables, German generation becomes more competitive compared to generation in the neighbouring countries. This leads to slightly increased exports.

However for one important reason the observable effects are not as strong as we expected them to be. An increased provision of flexibilities leads to saturation effects. This phenomenon which was also observed in other studies where an increased use of flexibilities beyond a certain level contributed only to a limited extent to the minimisation of cost.

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*Figure 23: Exchanges in scenario B compared to the scenario with load shifting*
In this study storage options with a limited storage time become less valuable for the power system. As load shifting is assumed to be a temporal restricted storage, the additional flexibility appears not help to reduce curtailment. Typically, in systems with high very penetration of renewables the importance of long-term storage increases.

In summary, the modelling results of the B-L 10% scenario show only small effects, but this might be caused by saturation effects. To further explore this issue, a more detailed study would be required to show which combinations of fixed cost, variable cost and load-shifting timespan would contribute to the minimum-cost solution. However, such a study would require the reduction of complexity on other parameters in order to keep it computationally feasible.
5 Conclusions

Answers to the questions raised in Chapter 1 are given by the results discussed above.

1. Can high shares of renewable energy be achieved in Germany even if transmission grid expansion turns out to be too slow or not feasible at the level assumed by other studies?

The answer to this question is: Yes, high shares of renewable energy can be achieved, even if the grid expansion is substantially delayed. A delayed grid expansion is not a show-stopper for large scale investments into renewable energies. The model results demonstrate how the power system would optimally adjust to this situation by investment in flexibilities. The answers to the following questions give more insight into the possible impacts of this delay.

2. What is the magnitude of differences in total system cost if the grid expansion is delayed?

According to the model results, if transmission grid expansion is delayed (scenarios L), the total future system costs increase slightly. In scenario A-L (more offshore wind) the cost increase compared with scenario A-H amounts to about € 1.1 billion, or 3% of total system costs. However, in scenario B (more onshore wind and PV), the cost increase associated to the delay in grid expansion is reduced to about € 0.3 billion or 0.8%. However in the real world, these cost differences will be higher, as market actors do not have perfect information about what happens in the future.

Certainly, the analysis indicates that the scenario with more onshore wind and PV and less offshore wind is more robust against delays in transmission network expansion.

3. Which levels of investment in flexibility options of the power system are optimal if grid expansion is limited?

If the transmission grid as a source of flexibility is limited, other flexibility options such as compressed air energy storage (CAES) and load shifting are employed. For example an investment into about 5 GW of CAES appears to be cost optimal, if higher shares of offshore wind are assumed. If the renewable generation is based more on onshore wind and PV, the optimal CAES capacity is 2 GW.

In all scenarios with restricted grid expansion, load shifting is employed to its maximum assumed potential. Under the given cost assumptions, battery storage does not appear as a cost-optimal technology. However, this situation might change after 2030.

4. What is the impact of a delayed transmission grid on CO₂ emissions of the power sector?

In all scenarios modelled, CO₂ emissions from the power sector are substantially reduced to about a third of the 2011 level.

The differences between the modelled scenarios are small and do not exceed annual variations of emissions in the past years. A delayed grid expansion leads to slightly lower CO₂ emissions in 2030.
than full expansion. Transmission grid expansion tends to favour technologies with high investment cost and low marginal generation cost, such as renewable energies but also lignite, as they benefit from the additional flexibility. As a consequence, further policy measures such as emission standards would need to be introduced to ensure a decrease in CO₂ emissions, as the assumed cost of CO₂ in 2030 (40 €/t) is not high enough to prevent an increased use of lignite. An intended delay of grid expansions as a measure of CO₂ reduction in the power sector does not seem to be appropriate as the long-term effects of such a strategy would lead to higher costs and CO₂ emissions.

5. What is the impact of a delay in grid expansion on the curtailment of renewable energies?

Model results indicate levels of curtailment of 4 TWh in 2030 in the case where optimal system adaptation and full grid expansion are implemented. This represents a share of 1% of the renewable energy. If there are grid restrictions the curtailment of renewable energy will increase roughly twofold to fourfold from this level, depending on the employed renewable energy technology mix. Curtailment reaches its maximum (15 TWh or roughly 4% of renewable generation) in the scenario where 25 GW of offshore wind generation cannot be transported to the load centres further south. Although curtailment of renewables as CO₂-free generation without variable cost appears as if it needs to be avoided, avoiding curtailment cannot be a goal by itself. It always needs to be balanced against other cost components and other options to avoid CO₂.

6. To what extent do the answers to the aforementioned questions depend on the mix of renewable technologies employed?

The impact of the grid expansion delay on curtailment, CO₂ emissions and costs is generally higher when there is more offshore wind in the scenario. This reflects the impact of spatially concentrated generation from offshore wind in the north, which cannot be transported to the south. The more evenly distributed renewable generation in scenario B, the relevance of the transmission grid decreases. The more emphasis energy policy places on the exploitation of offshore wind resources, the more attention needs to be paid to avoiding delays in grid expansion.

The fact that the modelling results show relatively small differences between the scenarios could be interpreted in a way that conscious decision making on renewable energy technology mix or transmission grid expansion has little significance. However, the small differences are also a result of the simultaneous optimisation of investment and dispatch with perfect information available. In reality, actors are facing insecure future framework conditions. This means that differences between scenarios will be higher in the real world. Hence robust, no regret decisions should be favoured.

Under the assumed cost regression scenarios, a more distributed renewable generation is achievable at a comparable cost level but appears to be more robust against delays in grid expansion. We found that replacing 10 GW of the 25 GW of offshore wind with onshore wind generation and PV would have no disadvantages with respect to total system cost, CO₂ emissions and renewable energy curtailment. However, this does not mean that transmission grid expansion can be avoided by changing the renewable energy technology mix. Grid expansion is and remains a robust and relatively low cost flexibility option. Beside the aspects examined in this study, several technical and economic reasons,
such as system stability and avoiding market power, make it inevitable to enforce the expansion of the grids to the planned level. This is especially true if a post-2030 perspective is assumed and future grid requirements are taken into account.
6 Bibliography

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### Electricity consumption

#### Total electricity consumption (in TWh) EU-27

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## Inputs for Infrastructure data Germany (existing plants)

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