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The role of decentralised flexibility options for managing transmission grid congestions in Germany

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ABSTRACT

Decentralised flexibility options connected to the distribution grid can be used for congestion management in the transmission grid. Their potential contribution for the transmission grid in Germany is investigated in a scenario analysis for the years 2030, 2040 and 2050.

The model-based evaluation shows that until 2050, cumulative grid congestion increases significantly, which indicates that there is a significant need for grid expansion. Decentralised flexibility options can reduce the cumulative grid congestion of the transmission grid by around 15% in 2030 to around 10% in 2050 if decentralised flexibility options are operated not just in line with the power market, but also with a view to transmission grid requirements. In absolute terms, the benefit of the decentralised flexibility options increases over time.

However, decentralised flexibility options are only suitable in a few cases to fully resolve grid congestions on a certain power line which indicates that grid extension might still be necessary, especially in the long term. Yet decentralised flexibility can still have effects on operational grid management (short-term perspective) and grid expansion needs (medium- and long-term perspective). Therefore, creating a suitable policy framework for the use of decentralised flexibilities is a contribution to achieving climate protection goals.

1. Introduction

This paper analyses the contribution that decentralised flexibility options can make for the transmission grid in Germany. To our knowledge it is the first paper that analyses transmission grid effects of decentralised flexibility options, taking into account the overall decentralised flexibility potential and comparing different scenarios. For that purpose, we analyse how much decentralised flexibility can contribute to solving congestion problems in the transmission grid in different scenarios.

The expansion of renewable energies to achieve societal goals such as climate protection poses new challenges for the electricity system. In the distribution grids, where typically most solar and wind power plants are connected, conventional grid resources and their classic mode of operation are reaching their limits. Decentralised flexibility options applied in smart grids can help to improve both, grid operation and grid expansion planning.

Besides the distribution grid, renewables expansion also affects the transmission grid, as the location of generation changes and because renewables are characterised by more peaky load profiles. While the transmission grid and its expansion are an important infrastructure for the integration of renewables, especially in the German context, there is also a need to explore additional options that can complement transmission grid expansion and provide Transmission System Operators (TSOs) with a broader portfolio. This is necessary not the least in the face of continuous resistance towards and delay of transmission grid expansion.

Decentralised flexibility options, although connected to the distribution grid, can also be used for congestion management in the transmission grid. In this paper, the potential contribution of decentralised flexibility options for the transmission grid in Germany is investigated based on the electricity dispatch model “PowerFlex” and the grid model “OptGrid”. The analysis is conducted within a scenario analysis for the years 2030, 2040 and 2050.

The potential contribution of decentralised flexibilities to reduce grid congestion in the transmission grid is analysed by looking at the key figure of the change in the cumulative annual congestion of the entire grid. In 2030, the cumulative grid congestion of the transmission grid is

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reduced by around 15% and in 2050 by around 10%.[1] Our results show that decentralized flexibility options alone cannot eliminate all bottlenecks in the future power system.

The analysis has been performed within the project enera within the SINTEG programme funded by the German government.[2]

After a brief literature review in Section 2, Section 3 describes the methodology, including the potential for decentralised flexibility options, which is applied. Section 4 goes on to present the results and discussion, and Section 5 provides the conclusion.

2. State of the art

In this section, first we briefly look at relevant modelling approaches and second summarise relevant literature regarding our research question.

Consideration of energy system infrastructure plays an increasingly significant role in energy policy decision-making processes. For this reason, power system modelling is usefully complemented by transmission system modelling using network models. According to Pfluger (2013), there are four different approaches to represent grid constraints. The simplest network representation is the assumption that there are no bottlenecks in the underlying power system, so it can be represented as a copper plate: In this case, the model shrinks to a single node model, see e.g. Schaffner and Mihalic (2005). Using a transport model, bottlenecks between regions can be represented, but the existence of physical power flow principles is neglected: controllable power exchange is possible between regions represented by nodes, which is limited by net transmission capacity, cf. Nygard et al. (2011).

A more sophisticated approach is the DC model which usually defines the real power grid with its substations and power lines. Using Kirchhoff's laws and making three assumptions e.g. described in Van den Bergh et al. (2014), the AC load flow equations can be simplified such that the reactive power flows are negligible and only the active power flows need to be modelled in a linearised way.

Without these simplifications the nonlinear AC load flow equations for active and reactive power flows have to be represented in the model, as for example described in Farrag et al. (2019). However, the increased accuracy entails longer simulation times.

Regardless of the basic modelling approach, according to Hobbie et al. (2022) there are two different model formulations for resolving existing congestion through redispatch: In the soft constraints approach, line congestion is allowed but penalised by high costs. In the hard constraints approach, line utilisation is limited by the constraint of not exceeding the maximum line capacity. According to Hobbie et al. (2022), both model formulations have advantages and disadvantages, so it depends on the question or the individual case which paragraph should be used.

The amount of curtailment and redispatch in the electricity system is an indicator for insufficient grid capacities (Bundesnetzagentur, 2022). A classic approach to solve this is grid expansion. However, different alternatives exist. In line with the expansion of renewables they have received increased attention both in practice and in the literature. This includes both options outside the network as well as innovative technologies within the network.

Kemfert et al. (2016) analyse transmission planning in Germany (Netzentwicklungsplan) and conclude that there is overinvestment in transmission capacity. They argue that investment needs could be significantly reduced through integrated optimisation of generation dispatch and transmission investments. In their model, rather than assuming the current German uniform-pricing scheme, they apply a nodal-pricing regime. In this regime, the difference between costs of electricity supply at each node are reflected and congestions are taken into account in operational decisions of market participants (Eicke and Schittekatte, 2022). Also, investment decisions are influenced by this approach (Leuthold et al., 2008). For the European electricity system Neuhoff et al. (2013) have shown that nodal pricing can lead to operational cost reductions in Europe between 1.1% and 3.6% in comparison to uniform pricing (Neuhoff et al., 2013).

This leads to the question of which options exist that can react to signals that mirror grid congestion and act as an alternative to grid investment. One flexibility option to relieve grid congestion is demand response (Siano 2014). It can be provided by industrial consumers (Paulus and Borggrefe, 2011; Shahnewaz Siddiquee et al., 2021) as well as EVs (Beyazit et al., 2022) and heat pumps (Sperber et al., 2020). Through changing of peak loads the grid can be relieved and necessary expansion can be postponed or reduced (Siano 2014). Another option to relieve the grid are stationary battery storage systems. They can be applied to relieve the grid through storing of renewable excess generation (van Westering and Hellendoorn, 2020) or feed-in if demand exceeds generation (Navon et al., 2023).

At the transmission grid level, there is also a discussion about grid optimisation measures by implementing innovative technologies in the power grid. There is a range of options available which are rated and analysed for example in Consentec (2021) and ENTSO-E (2021).

At the distribution grid level, alternatives to conventional grid expansion are discussed under the label of smart grids (Kakran and Chanana, 2018), which includes the use of decentralised flexibility options by the distribution system operator for network management purposes (Davarzani et al., 2021).

Using decentralised flexibility options connected to the distribution grid for network management purposes at the transmission grid level is less widespread yet and has received less attention in the literature, in terms of both what effects can be achieved and how it can be implemented. Studies either focus on specific decentralised options or include renewable curtailment. Some results for Germany and Europe have been presented in the following publications.

Frontier Economics (2017) find that the potential of decentralised flexibility is geographically dispersed, and it is also relatively favourably located in relation to the transmission grid congestion, especially when compared to the location of the centralised flexibilities. They conclude that decentralised flexibility can make a relevant contribution to reducing redispatch costs and that this effect will increase over time with a changing generation mix from fossil fuels to renewables. However, they include renewables connected to the distribution grid and their curtailment in their definition of decentralised flexibility, so that nothing can be said about the specific effect of other options like demand-side management that are used to facilitate the integration of renewables.

Kolster et al. (2020) also include renewables in the decentralized flexibility potential (both upward and downward flexibility) and point out in their results that the main potential that is used is the curtailment of wind power plants.

Staudt et al. (2018) also find a significant effect on redispatch costs. They do not include the range of decentralised options but focus on the effect of the flexibility that can be provided by electric vehicles. Loschan et al. (2023) analyse the potential of EV fleets to reduce redispatch needs in Austria. They find that redispatch needs can be reduced by 25% by establishing EV as a redispatch measure. Klempp et al. (2021) come to similar conclusions for a combined analysis of heat pumps and electric vehicles.

A study by Moradi-Sepahvand et al. (2023) analysed in a similar way the effects of coordinated expansion planning of transmission grids and four active distribution grids. This joint planning approach led to a reduction of expansion planning costs in distribution and transmission grids. They assume that the impact of more active distribution grids would be even larger.

[1] In absolute terms, the benefit of the decentralised flexibility options increases over time from 2030 to 2050.

[2] https://projekt-enera.de/

Ruppert et al. (2020) extend the scope beyond Germany to study decentralized flexibility in the transmission grid in the central European area. In their analysis for 2030, decentralized flexibility can significantly reduce load shedding due to grid congestions.

Besides these techno-economic studies, the question of which role decentralised flexibility options can play as an alternative to transmission grid expansion and how this is perceived by various actors, has also been used as an example for political struggles around system technologies in the energy transition (Andersen et al., 2023).

3. Methodology: approach, scenario framework and model description

In this section, after a brief description of our general approach, we present the models used (3.4 and 3.6) and the relevant associated input data (3.2; 3.3; 3.5) for more details on the data see the appendices).

3.1. Overall approach

3.1.1. Overall approach of the analysis

This paper analyses the contribution that decentralised flexibility options can make for the transmission grid in Germany. For that purpose, it analyses the resolution of congestion through redispatch of decentralised flexibilities.

Due to our modelling approach, we do not identify all redispatch which has to take place to release all grid congestions. That is why – rather than looking at overall redispatch as an indicator – we focus on another key figure – the cumulative annual congestion of the entire grid – to get an overview of the overall state of the grid before and after the implementation of decentralized flexibility to eliminate bottlenecks.

If decentralised flexibility options do not completely resolve the bottlenecks, bottlenecks remain in the grid, and further measures would have to be taken to resolve them, e.g., conventional redispatch. This analysis does not explore how the remaining congestion can be resolved in a cost-optimal manner. If further bottlenecks remain in the network, then according to our terminology there is a further "need for network expansion", although this could also be resolved by other measures. Thus, the term "network expansion demand" is used in a broader sense.

For the analysis, we differentiate between four different scenarios, which are introduced in Section 3.1.3. With the help of the scenarios, we analyse the effect of decentralised flexibility in a range of different future configurations and how it develops over time (2030, 2040, 2050).

For each scenario and scenario year we analyse the effect of decentralised flexibility on transmission grid congestion by comparing a reference scenario ("ref") where decentralised flexibility is not used for transmission grid management with a scenario ("flex") where decentralised flexibility is "switched on". Comparing these two scenario types regarding the grid congestion for each scenario year provides us with the potential role of decentralised flexibility in the transmission grid.

In the following sections, we present the overall modelling approach and its limitations, while Sections 3.4 and 3.6 present the two models in more detail.

3.1.2. Overall modelling approach

To examine the possible maximum contribution of decentralised flexibility options to mitigate grid overloads we use a three-step modelling approach.

The first step is to determine the market outcome, i.e. the cost-optimal deployment of all players in the energy market to meet demand in each hour of the scenario year, using the dispatch model "PowerFlex" (Koch et al., 2015; Koch et al., 2017; Ritter et al., 2019; Syranidou et al., 2022; Gils et al., 2019; Ritter et al., 2021; Hobbie et al., 2022). The optimisation problem is set up for the entire scenario year in hourly resolution, so that there is perfect foresight. Its regionalised result, the use of renewable and conventional power plants, storage facilities and other flexibility options, represents the netted node feed-ins.

In a second step, these hourly net node loads are used to load the German high and extra-high voltage grid in the "OptGrid" model (Raventós et al., 2022; Hobbie et al., 2022).

In the case of load flow and redispatch calculations, there are no year-round constraints, so the optimisation problem can also be solved on a rolling basis. The foresight is 48 h. Intertemporal restrictions for storages and flexibility options are considered via specific constraints (Equation 3 and Equation 13).

In order to get an idea of the extent of the network bottlenecks, we use the optimisation model "OptGrid" as a load flow simulation: In this configuration it represents a DC power flow calculation, which is to be understood as a simplified form of the AC load flow calculation, compare Van den Bergh et al., (2014). As a result, we obtain the associated hourly line congestions and overloads for the assumed German extra-high voltage grid.

In a third step, the line overloads are reduced by subsequent optimisation by resorting to various redispatch options – in this case only decentralised flexibilities. The optimisation is formulated as cost minimisation: Line congestion is assigned high penalty costs, whereas redispatch options compete at significantly lower costs. This creates an incentive to resolve congestion as completely as possible. This way of modelling redispatch corresponds to the "soft constraints" approach as described in Hobbie et al., (2022): The optimisation problem does not become infeasible if not all congestions can be removed. In the case of this project, the problem formulation with soft constraints is required because the aim is to investigate what contribution decentralised flexibilities could make to removing bottlenecks and it cannot be assumed that decentralised flexibility options are able to remove all bottlenecks.

Chapter 3.4 presents the problem formulation for the dispatch model "PowerFlex" in more detail as does chapter 3.6 for the redispatch model "OptGrid". The first step presented above is covered by the market model (chapter 3.4), steps 2 and 3 are covered by the load flow and redispatch model (chapter 3.6).

3.1.3. Limitations

The model formulation of the redispatch model OptGrid used in this project works well to show how much flexibility options can contribute to reducing existing line congestion. However, only decentralised flexibilities are permitted as redispatch options – and these are not capable of completely resolving the existing bottlenecks. In reality, the remaining bottlenecks would be eliminated in the short term by further redispatch options, and in the longer term also by grid optimisation, grid reinforcement or grid expansion measures. Since we only focus on the feasibility – i.e., the contribution of decentralised flexibilities – we do not specify any redispatch costs as key figures, but only make statements about the remaining or resolved congestions in [MWh] or in [h/a].

The model used in the project is only conditionally suitable for determining grid expansion requirements. This is due to two reasons: First, from an optimisation perspective, there is no incentive to focus on reducing high network congestion rather than minor congestion. In reality, there should be a difference in that high congestion must be eliminated while minor congestion can sometimes be accepted. This could be addressed, for example, by quadratically incorporating network congestion into the objective function. Second, there is also no incentive to completely eliminate congestion on a single power line to the detriment of other lines. In reality, this would be tantamount to abandoning a grid expansion project. Mixed-integer model formulations would have to be used here. Alternatively, the grid expansion investment option could be activated in the OptGrid model and compete with the redispatch options. However, this would require the problem to be set up over the entire scenario year rather than rolling over each 48-hour period, as is currently the case. Statements about the resulting grid expansion requirement should therefore be understood as estimates.

All models used in this project are deterministic. Uncertainty is not included in our models and analysis. In the context of renewable expansion, flexibility is needed to deal both with the variability and uncertainty of renewables. We do model the variability of renewables, which is reflected in the renewable generation profile. Using decentralised flexibility also to deal with uncertainty would increase its effect.

In our analysis, decentralised flexibility is only used for the transmission grid. In reality, it will also be used for the distribution grid, and the two grid levels will compete for these resources, which overall will reduce the effect of this flexibility on the transmission grid.

3.2. Scenario framework

The scenarios developed are intended to depict potential future developments of the energy system. Each scenario describes an energy system that differs from the other scenarios in the characteristics of relevant input data (such as electricity demand and installed generation capacities in the power plant park). Decentralised flexibility options are thus applied in different settings.

The "Enera Best Case" and "Enera Worst Case" scenarios depict a particularly advantageous or particularly obstructive development of the energy system for the application of decentralised flexibility options. For this purpose, the parameters that can be assumed to have a major influence on the benefits were specifically varied in these scenarios. On the one hand, there are developments that increase the need for flexibility, such as the expansion of fluctuating electricity generation or the increase in new electricity applications. On the other hand, there is the available potential of decentralised flexibility and the cost development of innovative grid resources that can be drawn on to cover the flexibility demand. Finally, there are parameters that have a negative influence on the benefits of the enera solution. These are, for example, centralised flexibility options such as pumped storage power plants or load management in industry, which are in competition with decentralised flexibility options.

In addition to these two generic scenarios, two climate protection scenarios from the literature were used (Repenning et al., 2015). These scenarios are climate protection scenarios that describe a reduction of 80% (Climate Protection Scenario CP80) or 95% (Climate Protection Scenario CP95) of German greenhouse gas emissions compared to 1990. These scenarios have also been updated and revised to include the decisions to phase out coal in Germany in accordance with the provisions of the Coal Phase-out Act. Eliminated capacities for coal-fired power plants were compensated for by natural gas-fired power plants.[3]

The following figure provides an overview of the scenarios and their characteristics in the relevant dimensions. The dimension "expansion of renewable energies & new electricity consumers" shows the flexibility demand triggered by it. The dimensions "potential increase in decentralised flexibility" and "cost reduction of new resources" describe the scope of the available decentralised flexibility options. The dimension "potential increase in central flexibility" describes the competitive situation with decentralised flexibility options..

The "Enera Best Case" scenario is particularly strong in the dimensions that show a high need for flexibility on the one hand and favour the application of the enera solution on the other. If, for example, there is a particularly high fluctuation in electricity generation and the associated grid load, this can be reduced by decentralised flexibility and innovative resources. Centralised flexibility, on the other hand, which competes with the enera solution, is low in this scenario.

The "Enera Worst Case" scenario contrasts with the "Enera Best Case" scenario. The demand for flexibility triggered by fluctuating electricity feed-in and new electricity consumers is weakest in this scenario. At the same time, the development of decentralised flexibility is comparatively low and innovative grid resources are comparatively expensive. Furthermore, competition from centralised flexibility options is high.

The scenarios "CP80" and "CP95" are positioned between the two scenarios "Enera Worst Case" and "Enera Best Case", with a gradation of their characteristics in the scenario framework. Regarding the transformation of the electricity system, the following gradation results: "Enera Worst Case" scenario (weakest transformation) –> "CP80" scenario –> "CP95" scenario –> "Enera Best Case" scenario (strongest transformation).

3.3. Decentralised flexibility options

In the definition used here, decentralised flexibility options are connected at the distribution grid level and consist of the following technologies:

- **Load management:** Demand side flexibility (time shifting of loads) is considered for private households, the commercial, trade and services sector, smart charging of electric vehicles and smart operation of heat pumps.
- **Battery storage:** In combination with a rooftop PV system, battery storage is installed as generation-related flexibility.
- **Biogas and sewage gas plants:** Biogas and sewage gas are continuously produced via microbiological processes in the fermentation and digestion towers of the plants. Power generation from biogas and sewage gas can be made more flexible by means of a gas storage facility and appropriately sized combined heat and power plants (CHP). These plants thus serve as daytime storage facilities.
- **Natural gas CHP with heat storage:** Up to now, natural gas CHP units have usually been installed at a larger heat sink (e.g., swimming pool, hotel, hospital / nursing home or apartment building). There they are used in a heat-controlled manner. To make their operation more flexible, a heat storage tank and, if necessary, an increase in CHP output is required.

The share of electricity demand that can be made flexible differs by sector but increases for all sectors from 2030 to 2050. The lowest share is assumed for private households and the highest share for heat pumps (Table A.6). The assumed load shifting period is one hour for the commercial, trade and services sector, six hours for smart charging of electric vehicles, twelve hours for private households and one day for the smart operation of heat pumps. The resulting load-manageable electricity consumption at distribution grid level is shown in Table A.7. For the load management potential and its temporal and spatial distribution we have used input data documented in Heitkoetter et al. (2021). In a first step the spatial resolution is done for aggregated values, e.g., annual demand or installed capacities. In a second step these values are multiplied with a normalised profile in hourly resolution, e.g., hourly demand profiles or profiles on availability of flexibility.

The expansion of battery storage systems correlates with the installed PV capacity. In the "Enera Worst Case" scenario, 10% of the installed PV systems are equipped with a battery in relation to their output, in the "Enera Best Case" scenario this ratio is 35%. This range results from the ratio of rooftop PV systems to ground-mounted PV systems and from the ratio of rooftop PV systems that are equipped with a battery. The ratio always refers to the installed PV capacity. In the "Enera Worst Case" scenario, a ratio of rooftop PV systems to ground-mounted PV systems of 50% to 50% is assumed, in the "Enera Best Case" scenario it is 70% to 30%. The share of rooftop PV systems equipped with a battery is 20% in the "Enera Worst Case" scenario and increases to 50% in the "Enera Best Case" scenario. The storage capacity of the batteries is 1.6 times the charging and discharging capacity according to the German Grid Development Plan for Electricity (50 Hertz - 50 Hertz Transmission et al., 2018). The assumed overall flexibility from battery storage systems at distribution grid level is shown in Table A.8.

The installed CHP capacity of biogas and sewage gas plants remains constant at 4 GW across all scenarios and scenario years, but the flexibility of the plants increases over time. This development is based on the enera scenario framework including the following assumptions:

[3] After the Russian invasion of Ukraine, this assumption would need to be revisited.

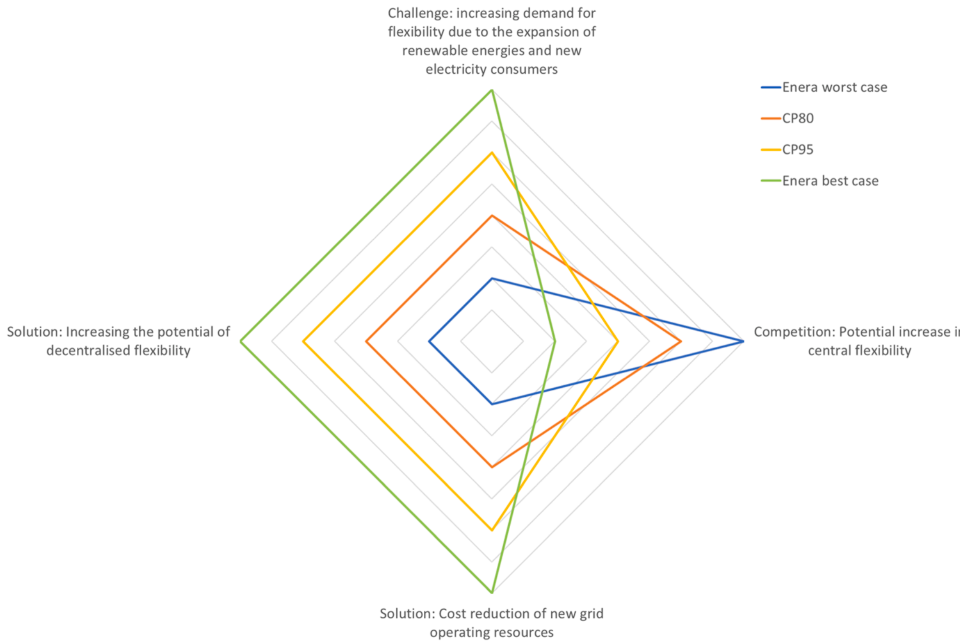

Fig. 1. Overview of the characteristics of the enera scenarios.

- Electricity generation from biogenic gases is reduced from around 32 TWh today (UBA – Umweltbundesamt, 2023, p. 10) to 16 TWh in 2050. The use of cultivated biomass, such as maize silage, decreases, on the one hand for climate protection and nature conservation reasons, and on the other hand it is assumed that biomass is increasingly in demand from other sectors and therefore less biomass is available for electricity production. The fermentation of biowaste and sewage sludge is expanded as far as possible and compensates for part of the decline in biogas production from cultivated biomass. The scenario framework of the current national grid development plan assumes a decline in electricity generation from biomass to 6 TWh by 2045 (50 Hertz - 50 Hertz Transmission et al., 2023, p. 70).
- The electrical CHP capacity remains constant at 4 GW despite the declining biogas volume. At the same time, the possibility of gas storage is gradually increased from 6 h in 2030 to 9 h in 2040 and 12 h in 2050. As a result, the biogas and sewage gas CHPs can be used increasingly flexibly, and the full-load hours decrease from 6000 h in 2030 to 5000 h in 2040 and 4000 h in 2050. The scenario framework of the current national grid development plan assumes a decline in full-load hours for electricity generation from biomass to 3000 h by 2045 (50 Hertz - 50 Hertz Transmission et al., 2023, p. 72).

The installed capacity of natural gas CHP decreases from 4 GW in 2030 to 3 GW in 2040 and 2 GW in 2050. The flexibility of the plants is the same in all scenarios: the thermal storage capacity is four times the maximum heat demand and the CHP is dimensioned for 4000 full-load hours. The assumed overall flexibility from CHP engines at distribution grid level is shown in Table A.9.

3.4. Electricity market model "PowerFlex"

The PowerFlex electricity market model is a fundamental dispatch model that uses thermal power plants, electricity feed-in from renewable energies, pumped storage power plants and flexible electricity consumers in a cost-minimising way to cover electricity and district heating demand. The temporal resolution is one hour, so that each scenario year contains 8760 time steps. The temporal resolution of the individual parameters is formed with a normalised base profile from a specific weather year. The mathematical formulation of the model was first described in Koch et al. (2015). The PowerFlex model was used in several model comparison projects (Gils et al. 2019; Syranidou et al. 2022; Ruhnau et al. 2022).

An overview of the variables and parameters used in this section can be found in the following table:

Thereby, the running index $\boldsymbol{t}$ refers to the temporal resolution of each variable, being evaluated in steps of $\Delta \boldsymbol{t} = \boldsymbol{1h}$ respectively in this model.

The objective function to calculate the total dispatch costs $\boldsymbol{TC}$ includes the marginal costs $\boldsymbol{MC}_s$ of all electricity generation technologies (including fluctuating renewable energies, that have very low technology specific marginal costs) multiplied by their hourly electricity generation $\boldsymbol{S}_{s,t}$ as well as the variable costs of the flexibility $\boldsymbol{VC}_f$ options multiplied by their hourly use.

Equation 1: Objective function of the market model

$$\boldsymbol{TC} = \sum_{s,t} \boldsymbol{S}_{s,t} \bullet \boldsymbol{MC}_s + \sum_{f,t} (\boldsymbol{P}^{out}_{f,t} + \boldsymbol{P}^{in}_{f,t}) \bullet \boldsymbol{vc}_f$$

The load constraint ensures that the sum of electricity generation from all supply technologies $\boldsymbol{S}_{s,t}$ as well as the use of all flexibility op-

Table 1
Variables and parameters for the PowerFlex model.

$\boldsymbol{TC}$: Total Costs	$\boldsymbol{MC}_s$: Marginal Costs of electricity generation technology $\boldsymbol{s}$	$\boldsymbol{S}_{s,t}$: Electricity generation supply by electricity generation technology $\boldsymbol{s}$ per time $\boldsymbol{t}$
$\boldsymbol{vc}_f$: Variable Costs of flexibility option $\boldsymbol{f}$ $\boldsymbol{l}_t$: Electricity demand / load per time step $\boldsymbol{t}$ $\boldsymbol{SL}_{f,t}$:Storage level of flexibility option $\boldsymbol{f}$ at time $\boldsymbol{t}$	$\boldsymbol{P}^{in}_{f,t}$:Storage charging of flexibility option $\boldsymbol{f}$ per time $\boldsymbol{t}$ $\boldsymbol{e}^{in}_f$:Charging efficiency loss parameter of flexibility option $\boldsymbol{f}$ (value between 0 and 1)	$\boldsymbol{P}^{out}_{f,t}$:Storage discharging of flexibility option $\boldsymbol{f}$ per time $\boldsymbol{t}$ $\boldsymbol{e}^{out}_f$:Discharging efficiency loss parameter of flexibility option $\boldsymbol{f}$ (value between 0 and 1)

Table 2
Variables and parameters of the PowerFlex model.

$l_{n,t}^{market}$: Net market load of nodal load n at time t	$S_{s,t}^{market}$:Net electricity market supply by electricity supply position s per time t	$D_{s,t}^{market}$:Net electricity market demand by electricity demand position d per time t
$n_{s,n}$:Connection factor matrix between supplier position s and grid node n (value between 0 and 1)	$n_{d,n}$:Connection factor matrix between demand position d and grid node n (value between 0 and 1)	$F_{t,v}$:Flow on power line v at time t
$df_{n,v}$:Power transfer distribution factors of node n and power line v	$O_{t,v}$:Overload on power line v at time t	$c^{overload}$:Cost of overload
$F_{t,v_{dc}}^{dc}$:Flow on DC power line v_{dc} **at time** t	c^{dc} :Cost of usage of DC power lines	C_v :Capacity of power line v
$C_{v_{dc}}$:Capacity of DC power line v_{dc}	$n_{f,n}$:Connection factor matrix between flexibility option f and grid node n (values between 0 and 1)	$n_{v_{dc},n}$:Connection factor matrix between DC corridor/power line v_{dc} and grid node n (values between 0 and 1)
$X_{f,t}$:**Use** of flexibility option f at time t	$c_{f,t}^{flex}$: Cost of usage of flexibility option f at time t	

tions including storage charging $P_{f,t}^{out}$ and storage discharging $P_{f,t}^{in}$ corresponds to the electricity demand to be covered for each time step. Demand side management is modelled as a storage where load increase corresponds to storage discharge (and load reduction corresponds to storage discharge).

Equation 2: Load constraint

$$l_t = \sum_s S_{s,t} + \sum_f P_{f,t}^{out} - \sum_f P_{f,t}^{in}$$

The storage constraint defines that storage charging $P_{f,t}^{in}$ and discharging $P_{f,t}^{out}$ depend on the respective storage level $SL_{f,t}$ and its upper and lower limits. Efficiency losses can be considered for both charging (parameter e_f^{in} as value between 0 and 1) and discharging (parameter e_f^{out} as value between 0 and 1).

Equation 3: Intertemporal storage constraint for the use of flexibility options

$$SL_{f,t} = SL_{f,t-\Delta t} + P_{f,t}^{in} \bullet e_f^{in} - \frac{P_{f,t}^{out}}{e_f^{out}}$$

The focus of the model is on Germany, but all 35 ENTSO-E member countries except Iceland and Cyprus are considered. The level of detail is high for Germany, the other countries are mapped in a more aggregated way. Each country represents a node that is connected to its neighbouring countries via interconnectors. Within a node, a uniform market area without network bottlenecks is assumed. The maximum exchange capacities between the countries (Net Transfer Capacities, NTC) are specified as hourly profiles in both directions.

The individual power plants are mapped in detail in the model using technical and economic parameters. Thermal power plants in Germany with an installed electrical capacity greater than 100 MW are mapped block by block and with an individual efficiency. Smaller thermal power generation plants are grouped by technology and year of construction and characterised with the help of type-specific parameters. For pumped storage power plants, parameters for mapping the pumps and reservoirs are stored in addition to the turbines. The use of pumped storage power plants is determined endogenously as part of the overall optimisation.

Biomass power plants that use biogas, wood or vegetable oil are represented in the model via technology aggregates as part of the thermal power plant park. The electricity supply from fluctuating generators (run-of-river, onshore and offshore wind, photovoltaics) is specified in hourly resolution. The model decides endogenously on the use for load coverage. Surpluses can also occur in this process.

For CHP plants, both the relevant properties of the plant in condensing mode (efficiency, maximum electrical output) and the properties in CHP mode (efficiency in CHP mode, maximum electrical output in CHP mode and thermal output of heat extraction) are stored. For each CHP plant, the share of condensing operation and the share of CHP operation are calculated in the model as part of the optimisation.

The annual electricity demand is exogenously specified and results from the electricity demand of the end-use sectors. In the model, the electricity demand is divided into an inflexible share with a predefined hourly load profile and a flexible share resulting from the electricity demand of new consumers, such as e-mobility or heat pumps.

Assuming complete foresight, the minimum-cost use of thermal power plants, pumped storage power plants, battery storages and demand side management as well as the electricity feed-in from renewable energies and the electricity exchange with neighbouring countries are determined within the framework of linear optimisation, considering technical and energy-economic constraints.

3.5. Network topology and regionalisation of input data and market results

3.5.1. Network topology and degree of expansion of the German transmission network

The degree of expansion of the German transmission grid used for the modelling process corresponds to the confirmed Grid Development Plan Electricity 2030 (version 2019) by the Federal Network Agency (BNetzA – Bundesnetzagentur, 2019). The transmission grid shown in Fig. 2 is composed with specific data for line capacities, line resistance and length of lines of the static grid model of the transmission system operators[4] (today's grid) supplemented by all grid expansion measures which are also added to the initial grid of the grid development plan and the confirmed expansion measures for the target grid 2030. The data for the grid expansion measures are taken from the project profiles in the annex to the grid development plan (50 Hertz Transmission GmbH; Amprion GmbH; TenneT TSO GmbH; TransnetBW GmbH 2020). To simplify matters, parallel lines from the same voltage level were combined. The transmission grid used in the modelling includes 316 grid nodes and 502 line connections, of which seven are HVDC corridors and 495 AC lines in the voltage levels 220 kV and 380 kV. Furthermore, there are 15 DC cables that connect the offshore wind farms directly to a converter station at an AC node. The combination of all offshore lines in one point in the North Sea as well as the Baltic Sea is just a matter of graphical representation. The distribution of electricity generation is proportional to the connected capacity of the wind farms.

In addition, 36 cross-border AC lines connecting Germany with its neighbouring countries in the European grid interconnection are considered. In some cases, Germany is connected to a neighbouring country via several lines. In the case of several lines, the hourly power exchange determined in the dispatch is distributed among them in proportion to the maximum transmission capacities of the individual lines.

3.5.2. Regionalisation of decentralised flexibility options to nodes in the German transmission grid

The Germany-wide potentials of decentralised flexibility options are first spatially distributed along the NUTS-1 level "Bundesland" (number: 16) and the NUTS-3 level "Landkreis" (number: 401) up to the LAU level of the municipalities (number: around 12,500). Afterwards, the basic

[4] Data is available on: https://www.jao.eu/static-grid-model

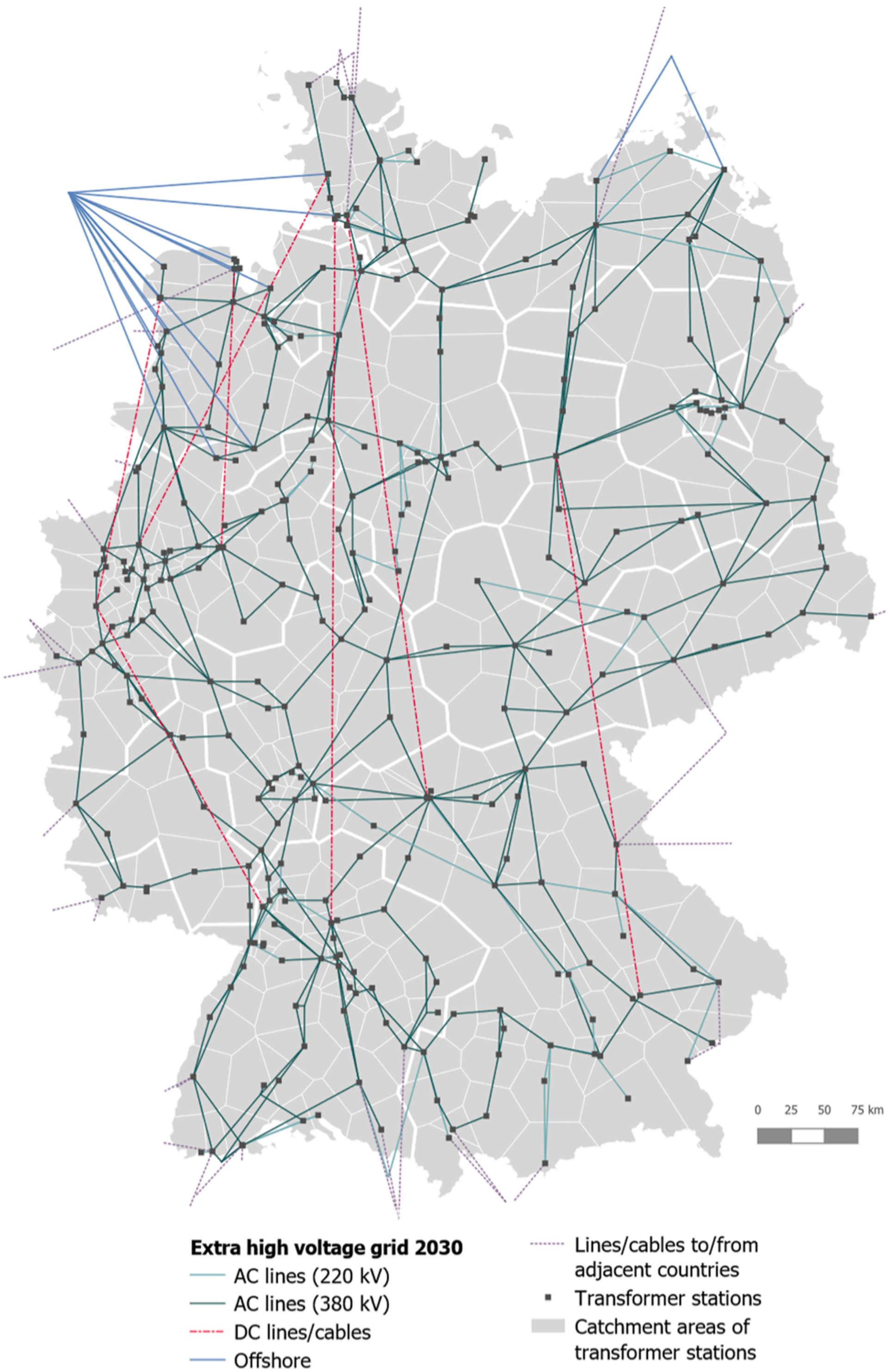

Fig. 2. Grid topology of the German transmission grid 2030.

parameters describing the potentials of the decentralised flexibility options, such as installed capacities of CHP plants and batteries, as well as sector-specific electricity consumption that can be flexibilized, are assigned from the municipality level to the nearest substation in the transmission grid (number: 316) and aggregated there. Finally, the complete set of flexibility parameters and profiles, including charging, discharging and storage capacities, is added proportionally to the basic parameters per flexibility option and grid node. This top down approach is further evaluated and compared with other transmission models in Raventós et al. (2022).

As a result, the potential of decentralised flexibility options is regionalised for all scenarios as shown for "Enera Worst Case 2030" and "Enera Best Case 2050" in Fig. 3. It becomes clear that the available potential of decentralised flexibility options increases over the course of the scenario.

Furthermore, it becomes apparent that the average charging capacity of decentralised load management technologies is in part significantly higher than their average discharging capacity. They are therefore particularly well suited for short-term absorbing RES feed-in peaks combined with medium-term power output or load reduction. Loading

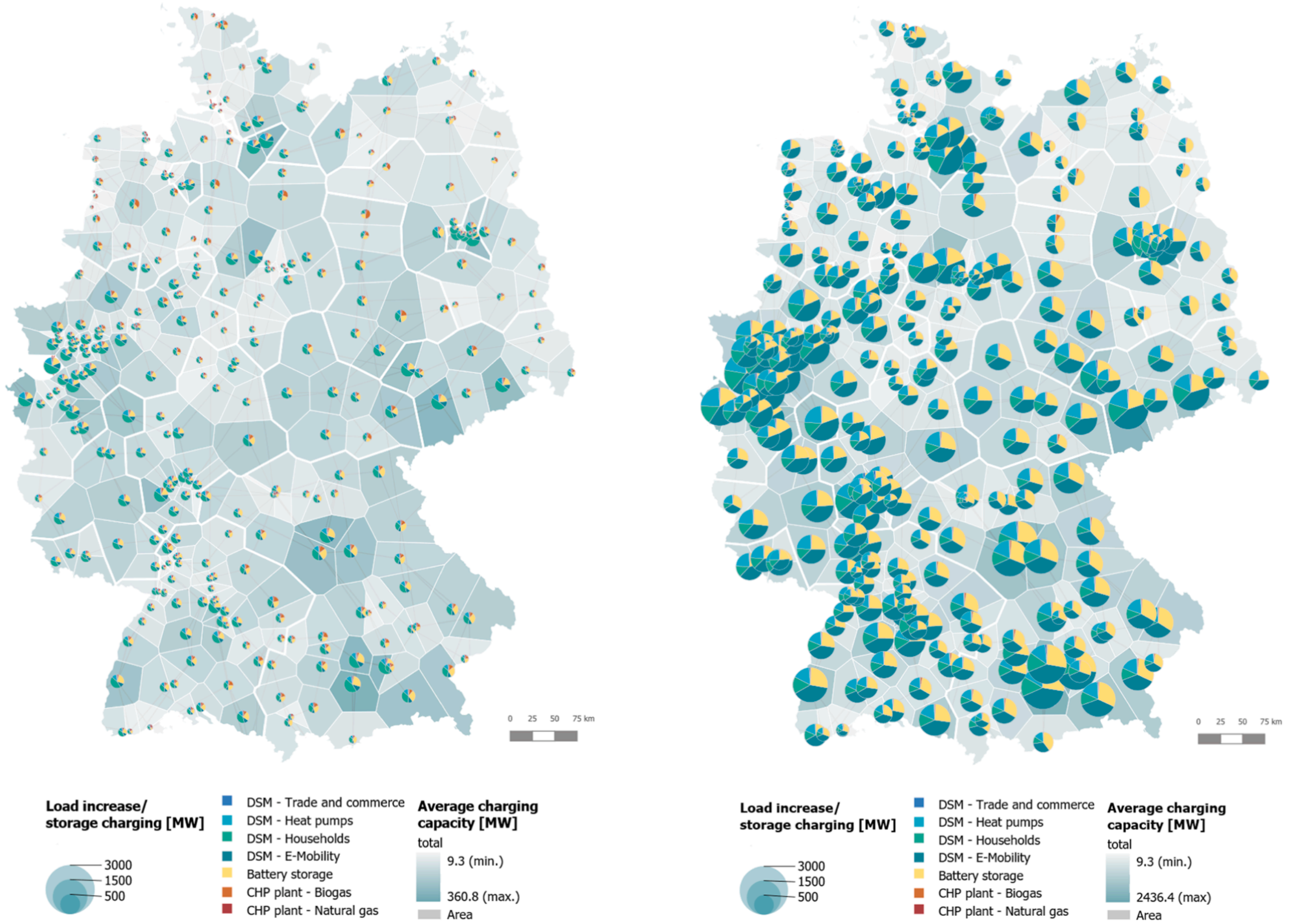

Fig. 3. Available potential of decentralised flexibility options per transmission grid node for mean charging power in the "Enera Worst Case 2030" scenario (left) and in the "Enera Best Case 2050" scenario (right).

and unloading balance each other out over all time steps, so that the use of each flexibility option takes place symmetrically over the entire modelling period.

3.5.3. *Regionalisation of load and renewable energies*

The federal state-specific distribution key for electricity demand is taken from the Grid Development Plan Electricity 2030 (version 2019). Within the individual federal states, regionalisation is conducted down to the level of municipalities using the following distribution keys:

- For selected large industrial electricity consumers, the electricity demand from steel production (25 TWh), aluminium production (10 TWh), chemical industry (42 TWh), cement production (2 TWh) and paper production (19 TWh) is directly allocated to individual production sites based on the list of delivery points benefiting from the special compensation regulation in the Renewable Energy Sources Act (EEG) (§ 64 ff) yearly published by the Federal Office of Economic Affairs and Export Control.[5]
- For all other electricity consumers (private households, tertiary sector, heat pumps and electromobility as well as large industrial consumers from other sectors), the population distribution is used as the distribution key.

The resulting regionalisation of electricity demand is shown in Fig. 4. The load centres in the Ruhr area and in the Hamburg and Berlin conurbations become evident. In addition, there are predominant network nodes with large industrial consumers, such as in Salzgitter, Leuna, Burghausen, Ludwigshafen and Saarland.

The federal state-specific distribution keys for PV, onshore wind, biomass and run-of-river generation are also taken from the Grid Development Plan Electricity 2030 (version 2019) from scenario C 2030. Within the individual federal states, regionalisation is conducted down to the level of municipalities using the following distribution keys:

- Photovoltaics:
  1. 70% rooftop PV systems: distribution by population
  2. 30% ground-mounted PV systems: municipality area
- Onshore wind, biomass and run-of-river: update via the plant inventory according to the current market master data register.

For offshore wind, the nationwide electricity generation is first divided between the North Sea and the Baltic Sea. For the scenario year 2030, the breakdown is 78% (North Sea) and 22% (Baltic Sea) (50 Hertz - 50 Hertz Transmission et al., 2018, p. 35), for the scenario years 2040 and 2050 it is 86% (North Sea) and 14% (Baltic Sea) (50 Hertz et al., 2020, p. 62). Based on these ratios, the electricity generation from offshore wind is distributed to the respective transmission grid nodes using the reported line capacities of the submarine cables and offshore lines through which the offshore wind lines are connected to the transmission grid (cf. Chapter 3.5.1) (50 Hertz - 50 Hertz Transmission et al., 2019, pp. 71–77).

[5] https://www.bafa.de/EN/Home/home_node.html

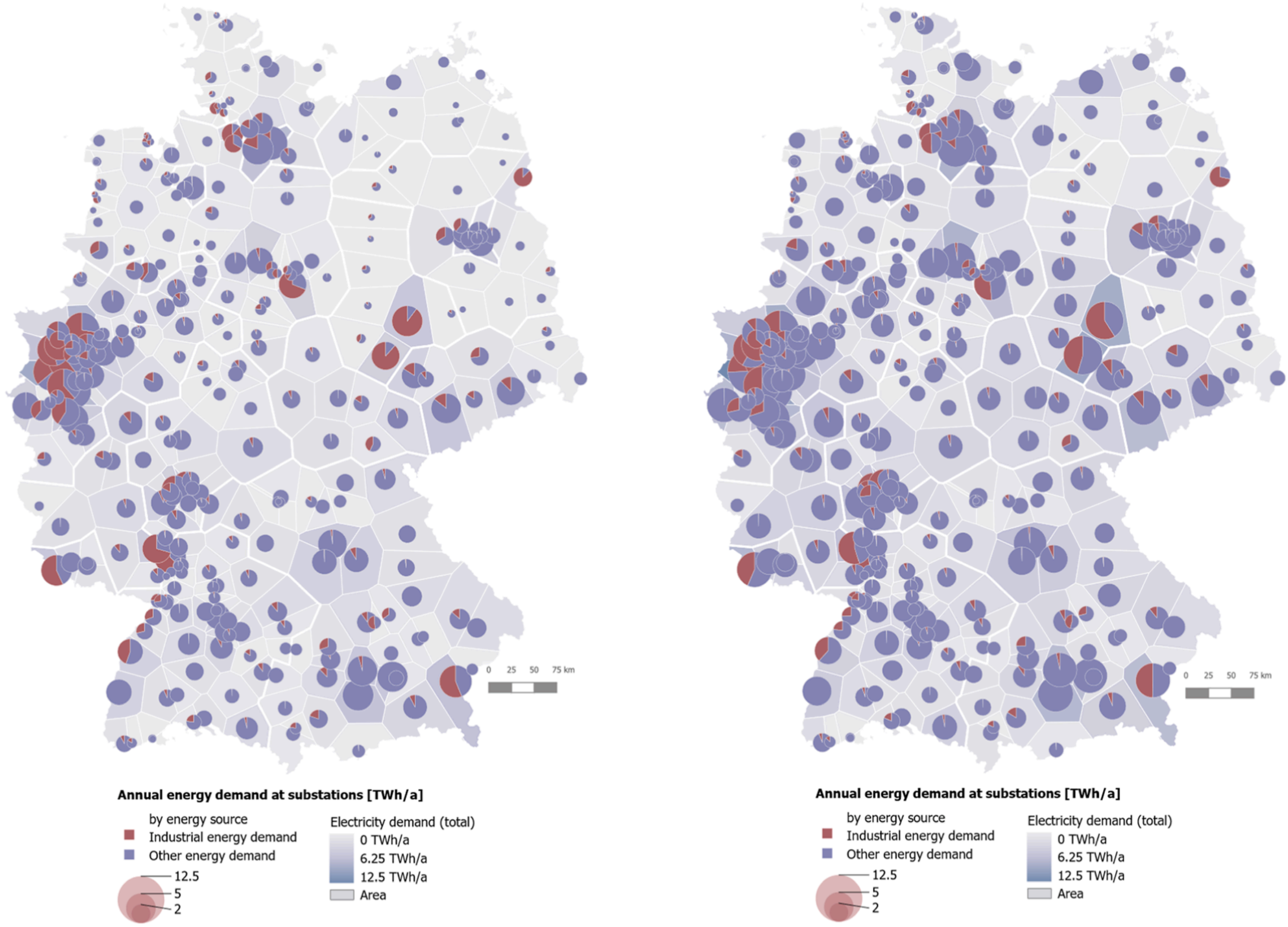

Fig. 4. Regionalised electricity demand per transmission grid node in the scenarios "Enera Worst Case 2030" (left) and "Enera Best Case 2050" (right).

The resulting regionalisation of fluctuating renewable energies is shown in Fig. 5. Here, the northern German feed-in nodes of wind and the southern German feed-in nodes of PV and run-of-river become evident.

The residual load remaining at the individual transmission grid nodes, which is the difference between electricity demand and fluctuating RES-E generation, gives a first impression of the transport task of the transmission grid (Fig. 6). It becomes clear that at the northern German transmission grid nodes, due to the high electricity feed-in from onshore wind turbines and, particularly at the 15 AC nodes with converter stations for DC cables from offshore wind turbines, the RES feed-in exceeds the electricity demand, so that the residual load becomes negative. Only in the catchment areas of Bremen, Hamburg and Berlin does a positive residual load remain. In contrast, in southern Germany and the Ruhr region, the residual load is almost universally positive, as the electricity demand is higher than the local supply of RES electricity. Only in isolated rural regions in southern and western Germany, which have some wind power generation, is the residual load negative.

Over time, from 2030 to 2050, it also becomes clear that this effect tends to intensify: in the east in particular, RES-E generation increasingly exceeds electricity demand significantly, and the regions in the west and south, which have a positive residual load in 2030, increasingly show this trend in 2050. In central Germany, some regions switch from residual producers to residual demanders and vice versa.

3.6. *Grid model "OptGrid"*

As described in chapter 3.1.2, the regionalised results of the energy market model "PowerFlex" are the essential input to start congestion studies using the load flow or redispatch model "OptGrid". The methodology used for regionalisation and redispatch is evaluated in (Raventós et al., 2022) and (Hobbie et al., 2022). An overview of the variables and parameters used in this section can be found in the following table:

These results can be imagined as hourly ($\boldsymbol{t}$) netted nodal ($\boldsymbol{n}$) loads of all demands ($\boldsymbol{d}$) and suppliers ($\boldsymbol{s}$) of energy (incl. the import and export flows on the cross-border interconnection points) where $\boldsymbol{n}_{s,n}$ and $\boldsymbol{n}_{d,n}$ indicate the connection of suppliers (s) and demand positions (d) to grid nodes (n):**Equation 4: Formation of the resulting net nodal load based on the market model dispatch results**

$$l_{n,t}^{\text{market}} = \sum_{s,d} (S_{s,t}^{\text{market}} \bullet \boldsymbol{n}_{s,n} + D_{d,t}^{\text{market}} \bullet \boldsymbol{n}_{d,n})$$

OptGrid in its basic configuration is a tool to do a simplified load flow calculation by using the DC-load flow approach. As for example described in Van den Bergh et al. (2014) and Flachsbarth (2013), if three assumptions are made, the nonlinear AC load flow equation can be reduced to a linear problem, where the calculated matrix of power transfer distribution factors $\boldsymbol{df}_{n,v}$represents the grid topology and the line parameters of the three-phase power grid. In general, the flow on a certain power line $\boldsymbol{v}$ at time $\boldsymbol{t}$ can be described as follows:

Equation 5: Formation of line flows

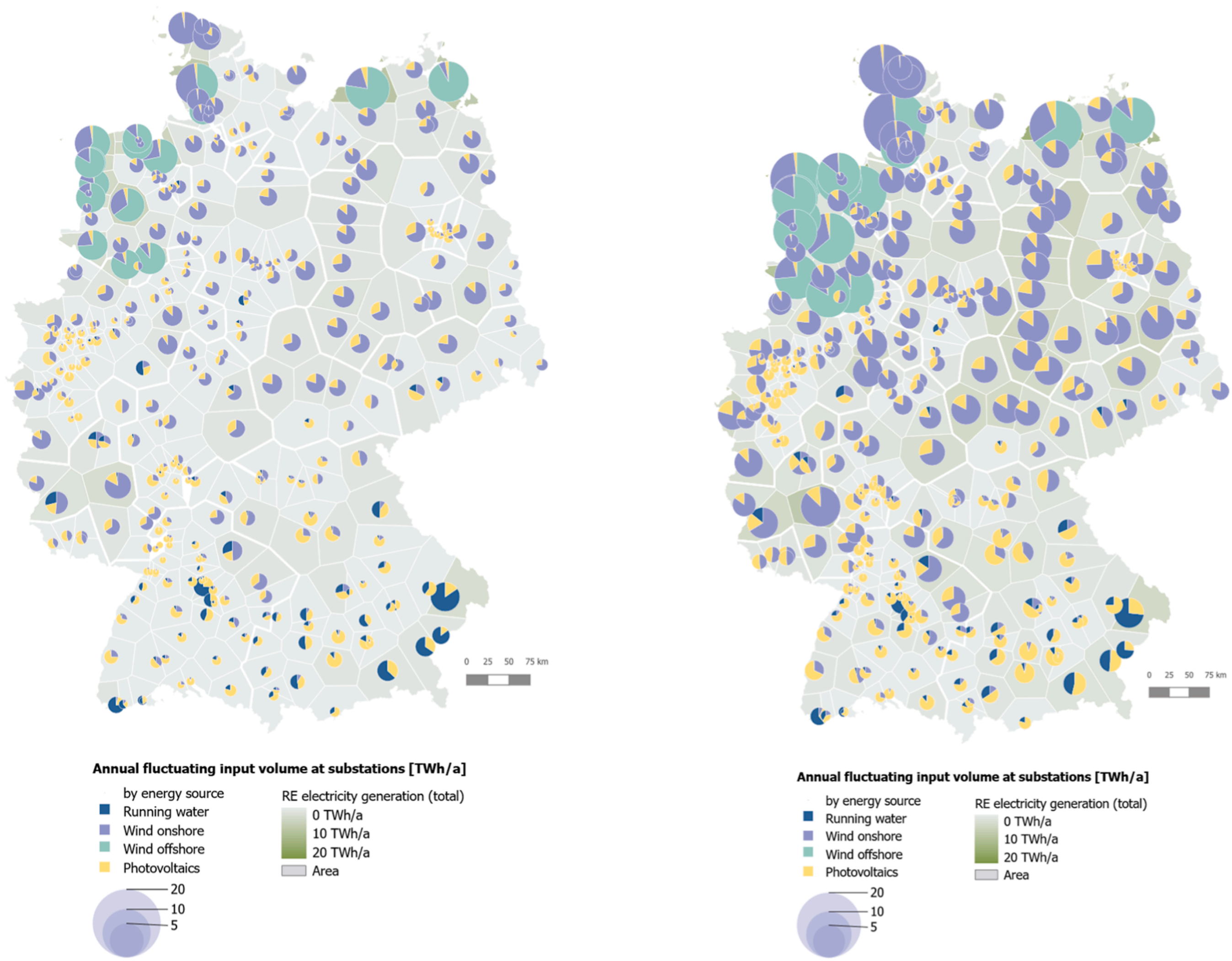

Fig. 5. Regionalised RES-E supply per transmission grid node in the scenarios "Enera Worst Case 2030" (left) and "Enera Best Case 2050" (right).

$$F_{t,v} = \sum_{n} - l_{n,t} \bullet df_{n,v}$$

Furthermore, the restriction is needed that the sum of net loads over all nodes is zero for each time step:

Equation 6: Sum of all net nodal loads is zero for each time step

$$0 = \sum_{n} l_{n,t}^{\text{market}}$$

If, additionally, DC power lines are part of the power grid under consideration, we extend our model to an optimisation problem where the grid congestion will be reduced by using DC power lines. Grid congestion leading to overload on AC power lines, can be reduced through redirecting available load through DC power lines. This is represented by the load flow model.

The netted market loads $l_{n,t}^{\text{market}}$ must be now extended by the inflows and outflows of the DC corridors, where $n_{v_{\text{dc}},n}$ indicate the connection of the DC corridor v_{dc} to a certain node n as well as the assumed direction of the power line, yielding $l_{t,n}^{\text{lf}}$.

Equation 7: Formation of the resulting net nodal load based on the market model dispatch results and the dispatch of the DC corridors

$$l_{t,n}^{\text{lf}} = l_{n,t}^{\text{market}} + \sum_{v_{\text{dc}}} n_{v_{\text{dc}},n} \bullet F_{t,v_{\text{dc}}}^{\text{dc}}$$

For the load flow model, the overload costs occurring in AC power lines v_{ac} and the costs of redistribution through DC power lines v_{dc} are regarded, yielding the load flow objective function $V_{\text{obj}}^{\text{lf}}$. Overloads incur high penalty costs while the deployment of DC lines incurs minimal costs:

Equation 8: Definition of the objective function for the load flow model

$$V_{\text{obj}}^{\text{lf}} = \sum_{t,v_{\text{ac}}} O_{t,v_{\text{ac}}} \bullet c^{\text{overload}} + \sum_{t,v_{\text{dc}}} |F_{t,v_{\text{dc}}}^{\text{dc}}| \bullet c^{\text{dc}}$$

For this purpose, the overloads $O_{t,v_{\text{ac}}}$ of the AC power lines must now be defined:

Equation 9: Formation of line overloads

$$O_{t,v_{\text{ac}}} = \begin{cases} F_{t,v_{\text{ac}}} - C_{v_{\text{ac}}} & \text{if} \quad F_{t,v_{\text{ac}}} - C_{v_{\text{ac}}} > 0 \\ 0 & \text{else} \end{cases}.$$

The capacity of the AC power lines $C_{v_{\text{ac}}}$ might be reduced by a safety margin τ to reasonably satisfy the $(n-1)$ grid security requirements. The use of the DC corridors is restricted to their maximum capacity:

Equation 10: Restriction of the use of DC corridors to their maximum capacity

$$|F_{t,v_{\text{dc}}}^{\text{dc}}| \leq C_{v_{\text{dc}}}$$

In the next step (redispatch model), the use of flexibility options and storage can be integrated into this cost minimisation problem in the

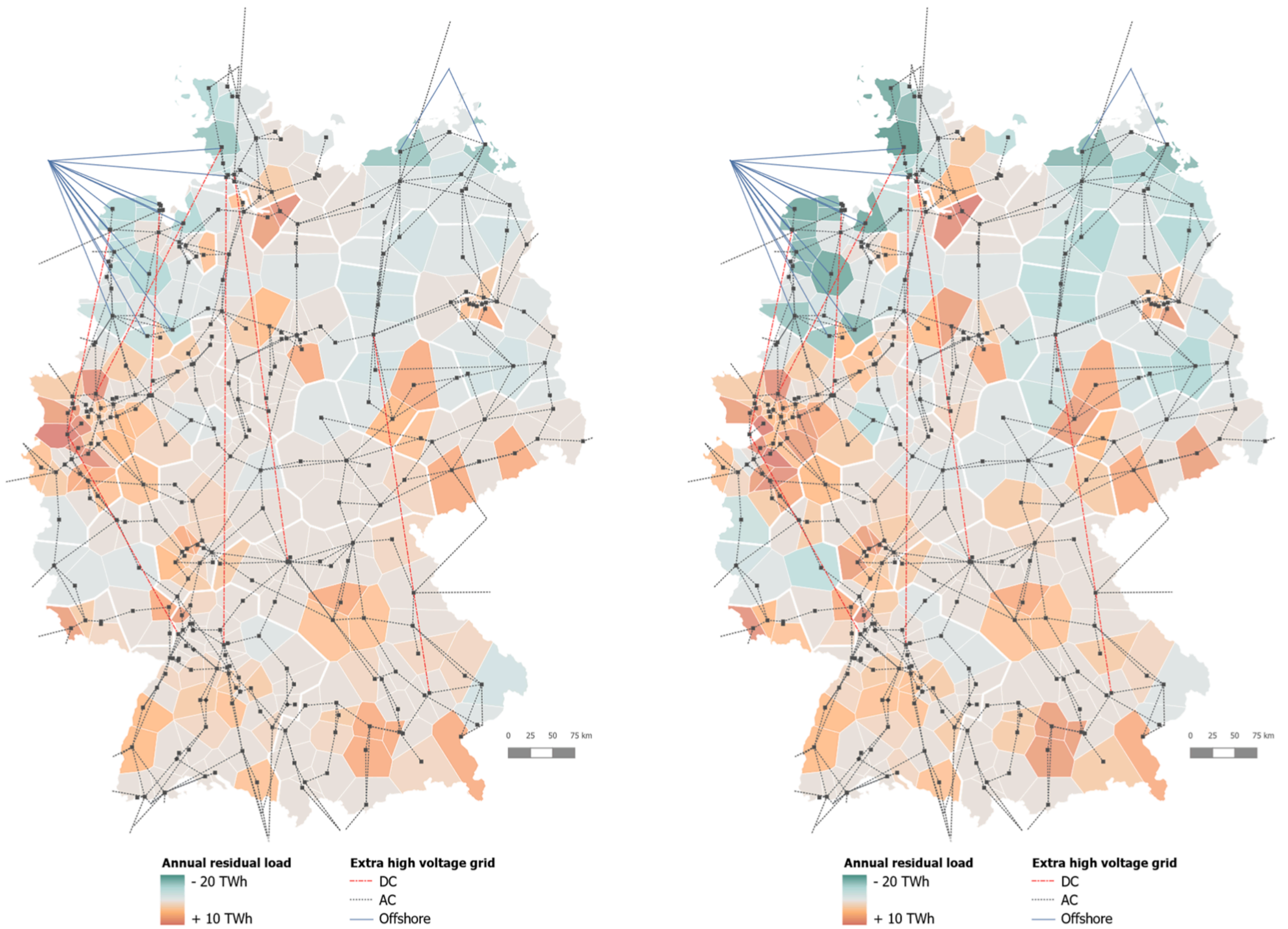

Fig. 6. Remaining residual load per transmission grid node in the scenarios "Enera Worst Case 2030" (left) and "Enera Best Case 2050" (right).

same way as the use of DC corridors: they can be used at market prices to reduce the congestion of the power grid. To achieve a maximum grid-serving effect of the decentralised flexibilities, the penalty term for line congestion was set significantly higher than the costs of using the DC corridors or decentralised flexibility options which are modelled as storage. The redispatch model netted load $l^{r}_{n,t}$ is now extended by the use of flexibility options $X_{f,t}$ (Equation 11). The costs are adopted in the redispatch model objective V^{r}_{obj}, where the costs for the flexibility options are added accordingly (Equation 12). Of course, the intertemporal storage constraint already introduced in the market model must be met again (Equation 13).

Equation 11: Formation of the resulting net nodal load based on the market model dispatch results, the dispatch of the DC corridors and the dispatch of flexibility

$$l^{r}_{n,t} = l^{market}_{n,t} + \sum_{v\_dc} n_{v_{dc},n} \bullet F^{dc}_{t,v_{dc}} + \sum_{f} n_{f,n} \bullet X_{f,t}$$

Equation 12: Definition of objective function for the redispatch model

$$V^{r}_{obj} = \sum_{t,v_{ac}} O_{t,v_{ac}} \bullet c^{overload} + \sum_{t,v_{dc}} |F^{dc}_{t,v_{dc}}| \bullet c^{dc} + \sum_{f,t} |X_{f,t}| \bullet c^{flex}_{f,t}$$

Equation 13: Intertemporal storage constraint for the use of flexibility options

$$SL_{f,t} = SL_{f,t-\Delta t} + X_{f,t}$$

The minimization of the full redispatch model objective function V^{r}_{obj} leads to the minimal cumulative overload of all AC power lines and across all time steps.

4. Results and discussion

4.1. Grid congestion indicators

All indicators of grid congestion are based on the calculated grid overload on a single power line. A line is considered overloaded when its utilisation exceeds 70% of the thermal line capacity. The capacity limit is thus reduced by a safety margin, which is intended to consider several aspects that are not represented in detail in the load flow optimisation. These aspects include in particular the (n-1) criterion, by which the failure of a network resource is to be intercepted, as well as the line load due to reactive power.

Taking into consideration the cumulative grid overload, our calculations show that, in the long-term perspective up to 2050, a grid expansion will be required that significantly exceeds the current target grid planning, irrespective of the scenario[6]: The determined grid congestion shows a need for action in all scenarios. The cumulative grid overload after having optimised the use of the DC corridors is around 40 TWh in the reference scenario for "Enera Worst Case 2030" and increases to up to 400 TWh in the reference scenario for "CP95 2050". The fact that there is a further considerable need for grid expansion is also

[6] All scenarios are based on the approved target grid from the confirmed Grid Development Plan for Electricity 2030 (version 2019).

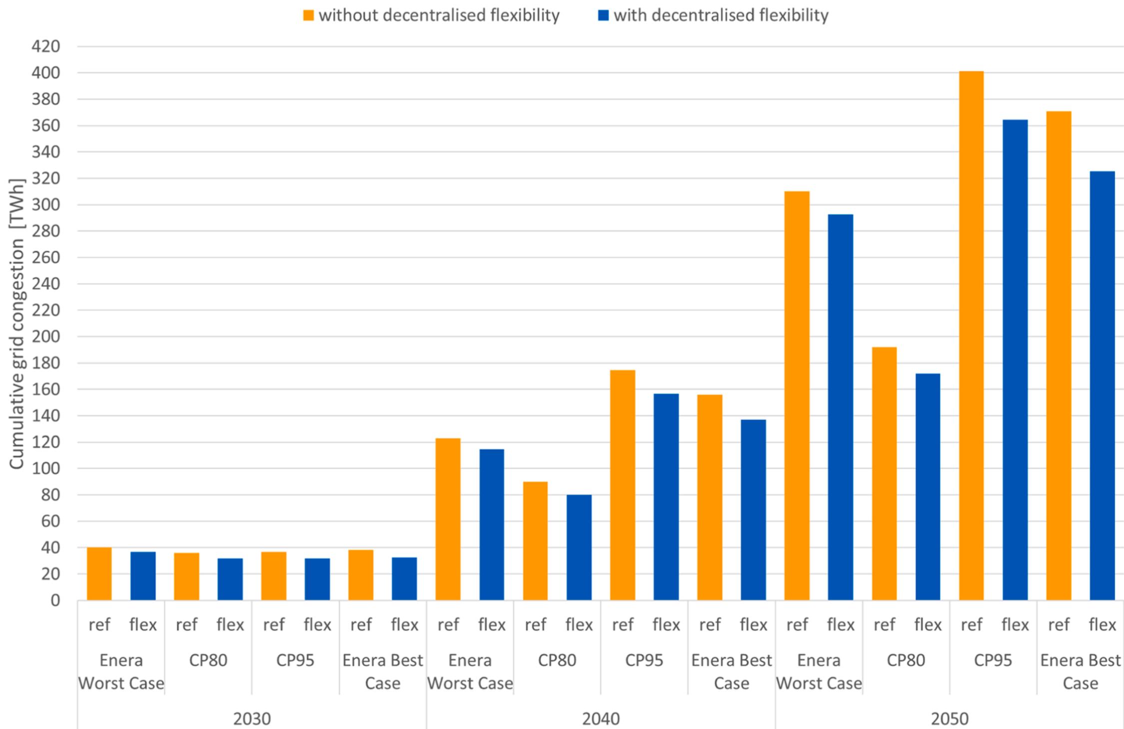

Fig. 7. Cumulative grid congestion in the enera scenarios before ("ref") and after ("flex") the transmission grid-serving use of decentralised flexibility.

shown by the results of the first draft of the Grid Development Plan for Electricity 2035 (version 2021), in which the planning horizon was extended by 5 years compared to its predecessor (50 Hertz - 50 Hertz Transmission et al., 2021).

With the transmission grid-serving use of the decentralised flexibility options, the cumulative grid congestion can be reduced by 8% ("Enera Worst Case" scenario) and 16% respectively ("Enera Best Case" scenario) in 2030, which corresponds to 3 TWh and 6 TWh respectively (Fig. 7). In the scenario year 2040, the percentage difference between the two scenarios decreases to some extent and the reduction ranges between 7% and 12%. This corresponds to a reduction in cumulative grid congestion of 9 TWh ("Enera Worst Case" scenario) to 19 TWh ("Enera Best Case" scenario). In the scenario year 2050, the cumulative grid congestion decreases to a value that is between 6% and 12% lower than in the scenarios without decentralised flexibilities. Thus, line congestion in the amount of 18 TWh ("Enera Worst Case" scenario) to 46 TWh ("Enera Best Case" scenario) can be balanced and avoided by decentralised flexibilities.

The decentralised flexibility options contribute more to the reduction of line congestion throughout the "Enera Best Case" scenario than in the "Enera Worst Case" scenario, as, among other things, the available flexibility potential is highest in the "Enera Best Case" scenario.

The ratio of the number of overloaded power lines approximates the number of power lines to be reinforced. Fig. 8 below shows the number of congested lines in the enera scenarios before ("ref") and after ("flex") the transmission grid-serving use of decentralised flexibility.[7]

Over the period from 2030 to 2050, the number of lines that are congested in at least one hour of the year doubles from around 150 lines to around 300 lines. The congestion of the grid increases significantly and is also distributed spatially (see next section). Please note, however, that the problem formulation of the optimisation in this project does not create an incentive to keep the number of congested lines low.

Although not explicitly incentivised, in 2030 the transmission grid-serving use of decentralised flexibility completely avoids line congestion. This is the case for 14 lines (Enera Worst Case scenario) to 21 lines (Enera Best Case scenario). In 2040, this effect is also seen for 15 lines (Enera Worst Case scenario) to 23 lines (CP95 scenario). The situation is different in 2050: in the "CP95" and "Enera Best Case" scenarios, overload can only be completely avoided for 2 lines, while in the "Enera Worst Case" and "CP80" scenarios it is 14 and 11 lines, respectively.

The use of decentralised flexibilities thus has the potential to substitute single grid expansion requirements, at least for a transitional period. By explicitly including the maximum grid congestion in the objective function, the number of lines that are not congested would certainly increase.

To get an idea of the intensity of overloads on a single power line, it is of interest to analyse the maximum line overloads over all timesteps on a single power line. In the following figure, the maximum line congestion in the enera scenarios before ("ref") and after ("flex") the transmission grid-serving use of decentralised flexibility is shown as a box plot graphic for all AC lines (Fig. 9). In 2030, both the upper whisker and the upper half of the box with the range of values between the median and the third quartile can be significantly reduced by using decentralised flexibility. In the years 2040 and 2050, this effect weakens and is finally no longer present in the scenarios "CP95 2050" and "Enera Best Case 2050". This also underlines the thesis that grid expansion could be reduced in the short to medium term through the grid-serving use of flexibility or that delays in grid expansion could be compensated for. In the long-term perspective until 2050, the maximum line congestion due to the use of decentralised flexibilities does not decrease with the modelling approach chosen here.

4.2. Spatial grid results

The spatial resolution also shows the extent of the need for grid expansion in the German transmission grid (Fig. 10). Bottlenecks extend in particular in a north-south direction. Bottleneck regions are located where offshore and onshore wind energy is fed into the grid in the north-

[7] The transmission grid in Germany used in the modelling is composed of 495 three-phase lines and 7 HVDC corridors (cf. Chapter 3.5.1).

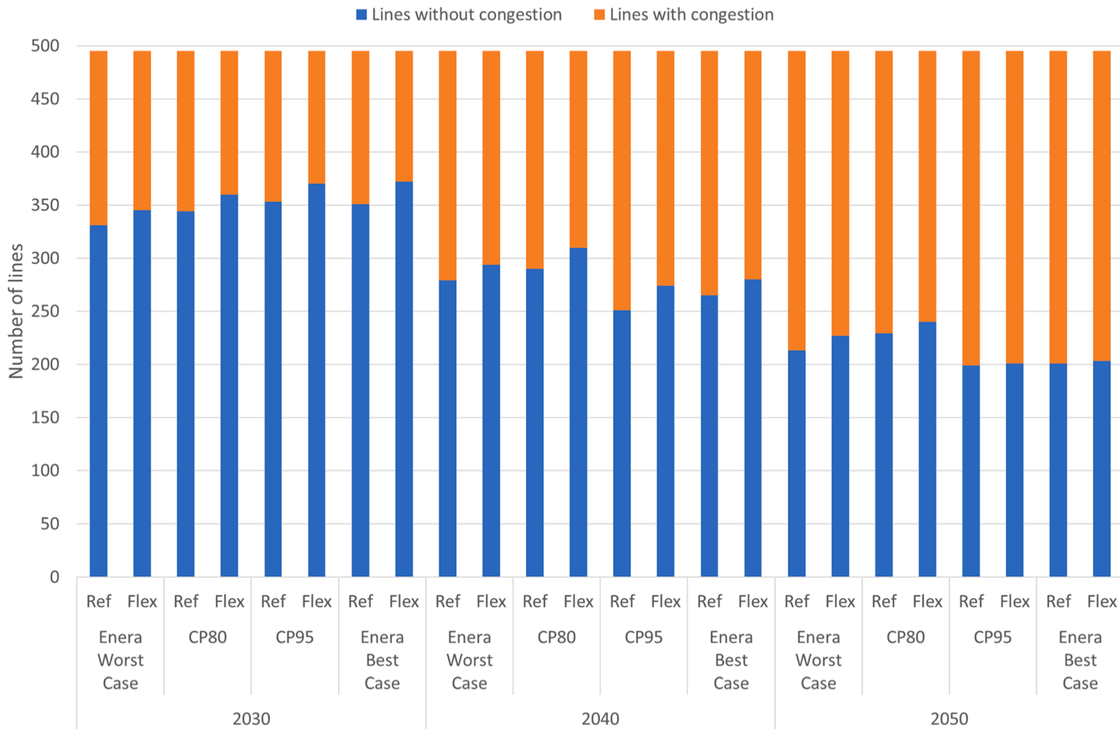

Fig. 8. Number of congested lines in the enera scenarios before ("ref") and after ("flex") the transmission grid-serving use of decentralised flexibility.

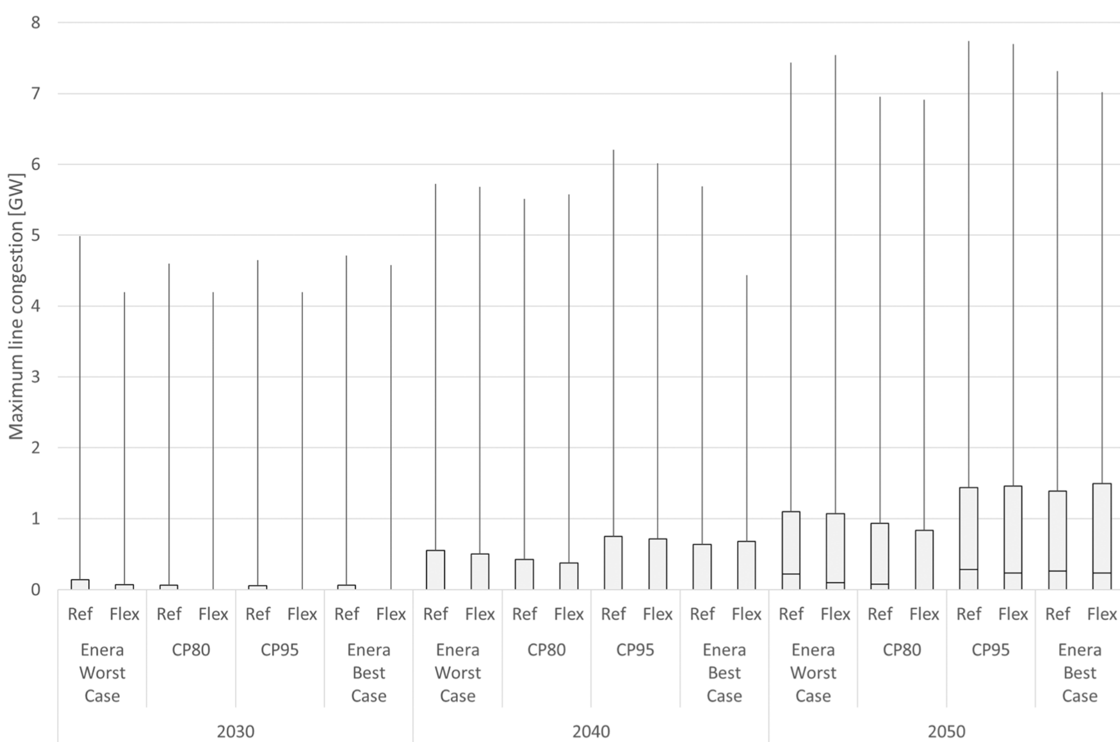

Fig. 9. Box plot of the maximum line congestion for all AC lines in the enera scenarios before ("ref") and after ("flex") the transmission grid-serving use of decentralised flexibility.

west of Germany, near interconnection points to neighbouring European countries and near the southern German load centres.

The HVDC corridors cannot be overloaded due to the modelling approach, so they appear as "grey dashed" lines in all maps below.

This figure is supplemented by Fig. 11, which also refers to the scenarios "Enera Worst Case 2030" and "Enera Best Case 2050", however, does not show the cumulative annual line congestion, but rather the number of hours in a year in which congestion occurs on the respective line. On the one hand, this illustrates the extent to which the number of hours with line congestion on the individual lines increases between 2030 and 2050.

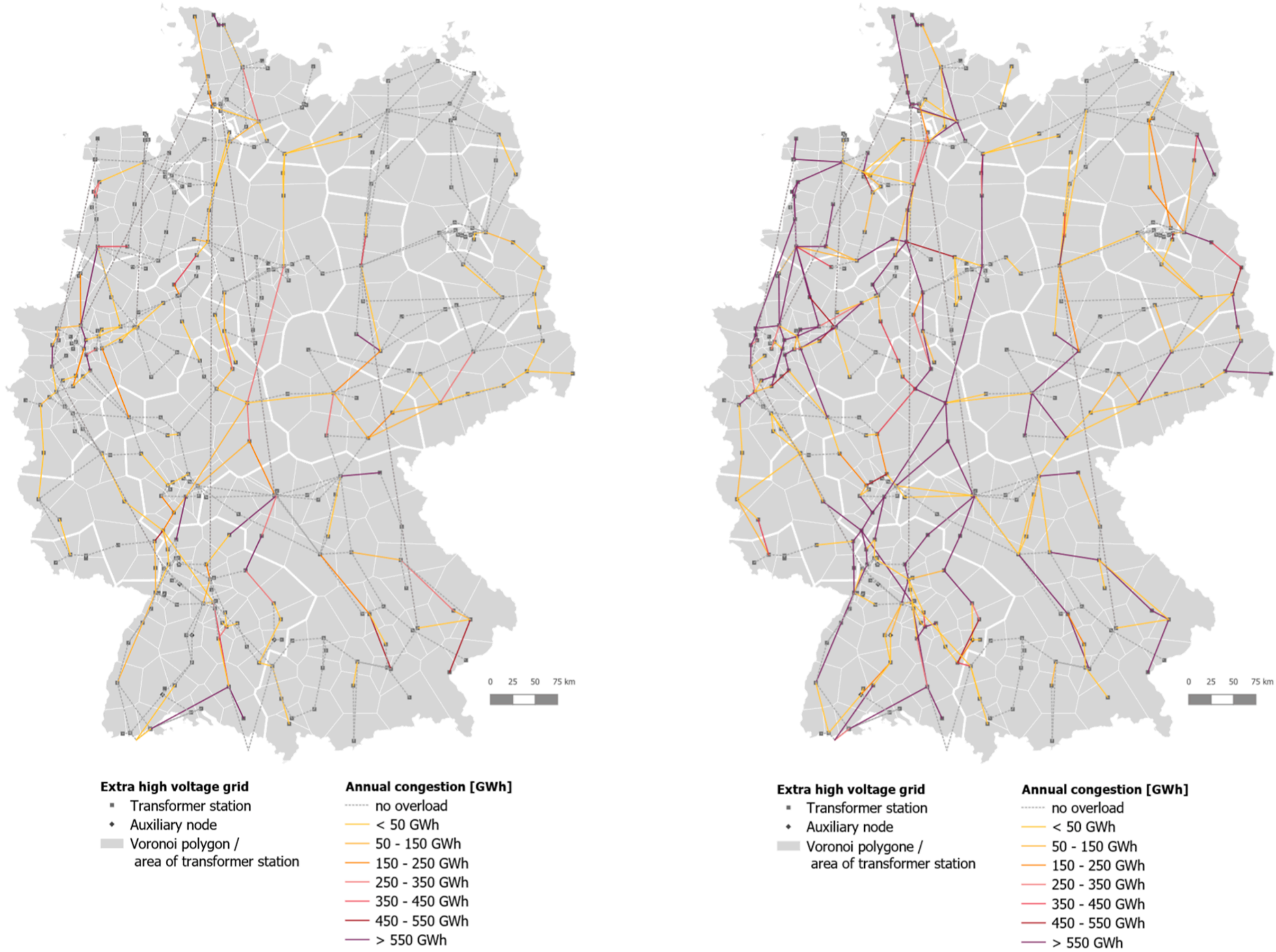

Fig. 10. Spatial resolution of the cumulative grid congestion on the individual lines in the reference scenarios "Enera Worst Case 2030" (left) and "Enera Best Case 2050" (right).

However, this key figure can also be used to estimate whether it is expedient to eliminate the bottleneck in the long term and permanently by expanding the grid or whether alternative measures could be used to minimise the line congestion. If bottlenecks occur on a line in only a few hours of a year (yellow lines in Fig. 11), these could be resolved with flexibility options, provided that sufficient flexibility potential is available in the spatial vicinity of the grid bottleneck. Decentralised flexibility options thus become part of the redispatch measures. As the number of congested hours increases, it becomes increasingly unlikely that the use of decentralised flexibility options could resolve this bottleneck in the long term.

Especially in the early scenario years, it becomes clear that the congestion on the lines only occurs in a few hours. In later scenario years, the number of overloaded hours on many lines increases. This indicates that, at least in the short and medium term, decentralised flexibility options represent a possibility to buffer delays in grid expansion or to reduce its urgency. In the long term, on the other hand, the option of grid optimisation or grid expansion will become increasingly necessary.[8]

[8] As a rule of thumb, a punctual line overload of maximum 140% in less than 4 consecutive hours can be coped with by the line material. In addition, load flow control measures can reduce the overload of individual line strands by distributing the load to less utilised line strands.

The third key figure shown in Fig. 12 is the maximum congestion on the AC lines for the scenarios "Enera Worst Case 2030" and "Enera Best Case 2050" without the use of transmission grid-serving flexibility. This key figure is usually used for dimensioning the grid expansion requirement where these extreme situations are decisive, not the cumulative annual overloads. To be able to save grid expansion with decentralised flexibilities, the maximum line congestion must be lowered from one expansion stage to the next lower expansion stage, so that one circuit can be saved.

Fig. 13 shows the decrease in cumulative annual line congestion because of the grid-serving use of decentralised flexibility for the scenarios "Enera Worst Case 2030" and "Enera Best Case 2050". It shows the difference in cumulative line congestion between the respective reference scenario ("ref") without decentralised flexibility and the flexibility scenario ("flex") with the grid-serving use of decentralised flexibility. Although not explicitly stimulated, the maximum line congestion decreases due to the use of decentralised flexibilities. It can be assumed that the effect would be significantly strengthened by a stronger incentive in the objective function (e.g., within the framework of a quadratic optimisation).

The annual use of decentralised flexibilities at the grid nodes can also be seen. On the one hand, the graph illustrates that the decentralised flexibilities are activated at the grid nodes between which there is a bottleneck. As expected, the amount of flexibility used goes hand in hand with the amount of reduction in line congestion. It can also be seen

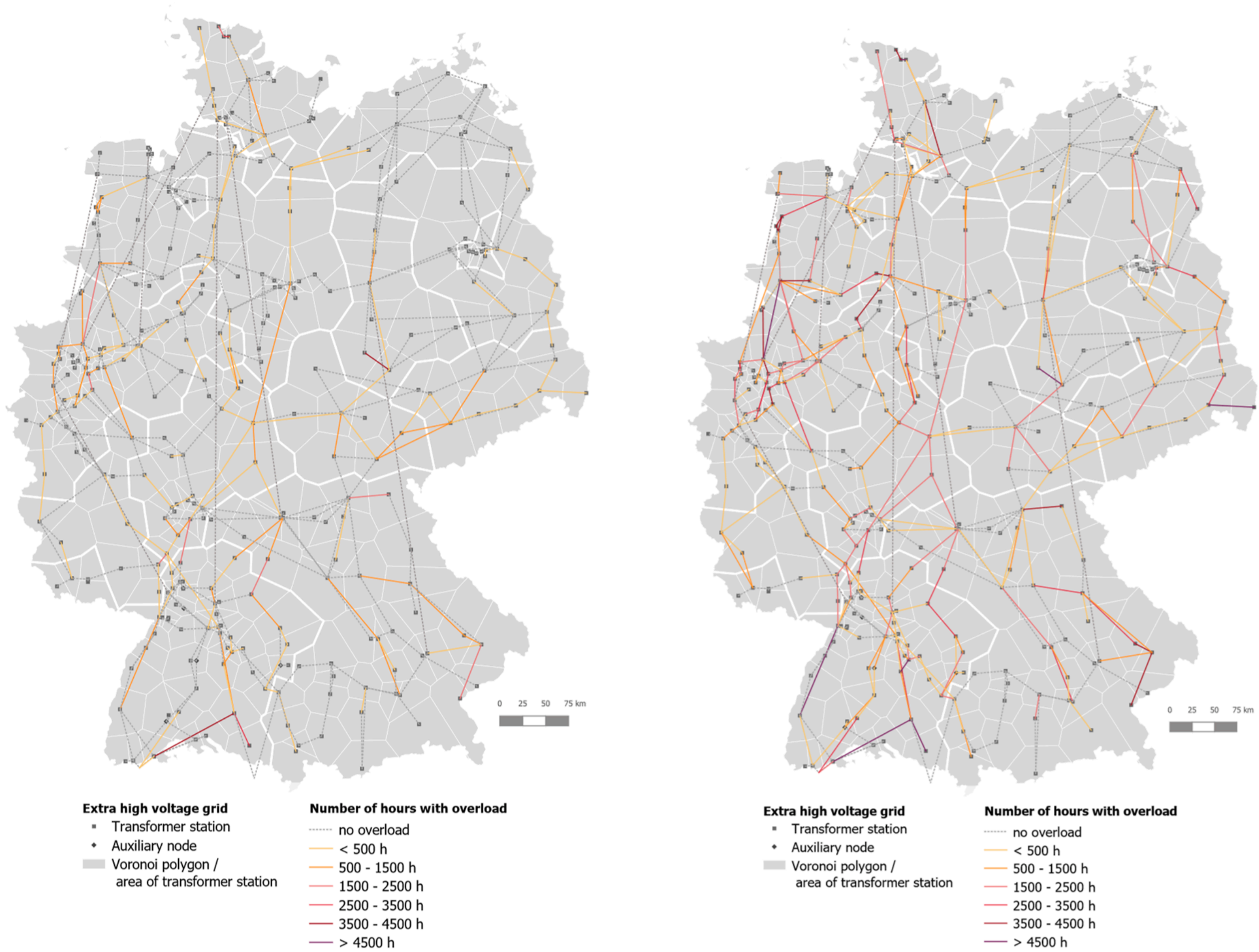

Fig. 11. Number of hours with grid congestion on the individual lines in the reference scenarios "Enera Worst Case 2030" (left) and "Enera Best Case 2050" (right).

that a reduction in demand at one node must lead to an increase in demand at the substation at the other end of the bottleneck: the two circles upstream and downstream of a bottleneck correspond to each other.

Furthermore, the cumulative line congestion is mainly reduced on lines that also have a high cumulative line congestion. These lines often run from north to south, or they are lines located at network nodes that are connected to neighbouring countries via interconnectors. As an example, individual lines with a comparatively high reduction in cumulative line congestion are marked in red in Fig. 13.

The pattern evident in the "Enera Worst Case 2030" scenario continues and intensifies in the "Enera Best Case 2050" scenario. The high cumulative line congestion in the north-west of Germany, which is associated with the increase in electricity feed-in from offshore wind energy, is also reduced using flexibility.

The utilisation of the decentralised flexibility potential available for use in the transmission grid in the "Enera Worst Case 2030" and "Enera Best Case 2050" scenarios is shown in Fig. 14. Typically, around 25% of the available decentralised flexibility potential is used to reduce congestion in the transmission grid. The flexibility potential is used particularly strongly in the eastern part of Schleswig-Holstein and in the western part of Germany. Here, the potential utilisation is around 30%, while in the eastern part of Germany it is only around 20%.

In order to be able to classify the potential utilisation, we refer again to Fig. 11: The congested lines are not congested in every hour of the year, but on average in 600 h/a in 2030 (i.e. in 7% of all hours), in 900 h/a in 2040 (i.e. in 10% of all hours) and in 1300 h/a in 2050 (i.e. in 15% of all hours). The potential for decentralised flexibility is available every hour of the year, but it is only used at the times and places where it can also help relieve congestion. Both restrictions result in low utilisation of flexibility potential, although it is fully used at times and locations of grid congestion.

4.3. The role of decentralised flexibility options in the transmission grid

What do the presented results mean for the role of decentralised flexibility in the transmission grid? The increasing decentralisation of the generation structure leads to increasing congestion in the transmission grid. Decentralised flexibility options can relieve the grid to some extent.

The extent to which the reduction of cumulative grid congestion affects grid expansion demand cannot be answered with certainty using the modelling approach used here, as the approach does not provide an incentive to limit high congestion to as few lines as possible.

However, even when considering the limitation in the modelling approach, it is evident that the long-term need for grid expansion can only be partially avoided, if at all, with decentralised flexibility options. Further measures are required to increase the transmission capacity of the power grid, and conventional grid expansion is a proven solution to relief grid stress. Indicators for the adequacy of grid expansion needs are the number of congested lines and the maximum line congestion levels.

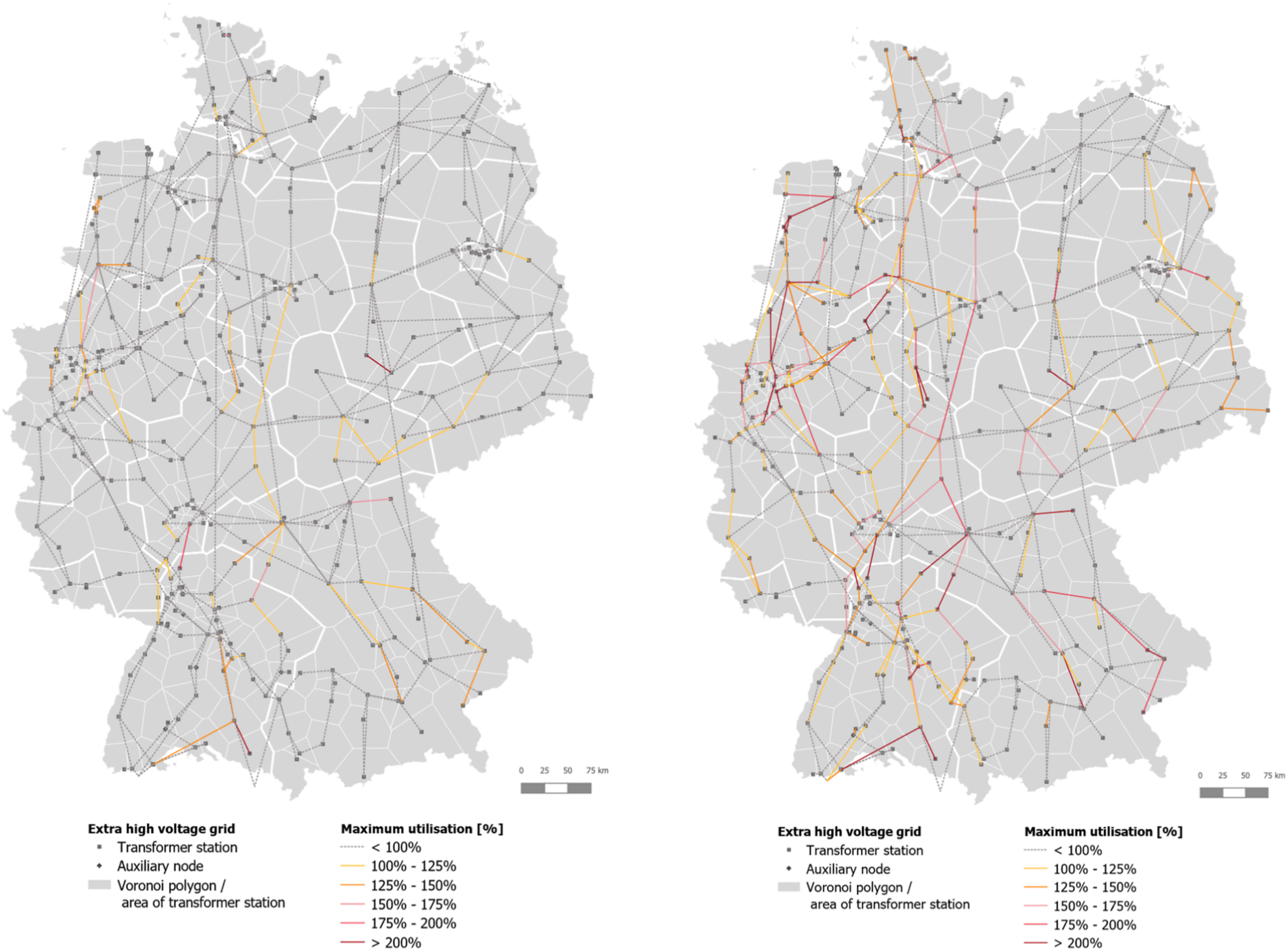

Fig. 12. Maximum congestion on the individual lines in the reference scenarios "Enera Worst Case 2030" (left) and "Enera Best Case 2050" (right).

Yet decentralised flexibility can still play a role. The effects demonstrated in this analysis can be exploited for the transmission grid in the following ways. Decentralised flexibility can have effects on operational grid management (short-term perspective) and grid expansion (medium- and long-term perspective):

- Short-term: The first task, which will become increasingly important in the future, is to replace redispatch of thermal power plants. It is inefficient to eliminate grid bottlenecks through grid expansion. Temporary or minor grid bottlenecks can be better resolved by redispatch or equivalent measures. When grid-serving deployment of decentralised flexibility is stimulated, it reduces RES curtailment and the need for positive and possibly negative redispatch from dispatchable power plants. With increasing shares of renewable energies, decentralised flexibilities become more valuable, especially if they are located close to net feed-in nodes.
- Medium-term: Based on the first role, a second role for decentralised flexibility options can consist in providing a certain degree of freedom in the technology mix used for grid expansion planning. It opens the possibility in grid expansion planning of increasingly adding technical developments to the conventional grid expansion (e.g., components for load flow control such as Static Synchronous Series Compensators (SSSC) or phase-shifting transformers).
- Long-term: Finally, decentralised flexibility options could also reduce uncertainty for an efficient transformation path of the electricity system. There is a temporal coupling between renewable expansion and grid expansion. However, the planning phase of the construction of a wind farm is significantly shorter than the planning phase of a grid expansion project. As a result, there is uncertainty about the regional interaction of renewable feed-in and transmission grid capacity. This coupling can be somewhat reduced by using other flexibility options, such as decentralised flexibilities. As a result, the transformation path for the expansion and conversion of the transmission grid remains more variable, and it is still possible to react to changes in both renewable expansion and electricity demand. This leads to more certainty about the required grid expansion.

These effects can be achieved by the various flexibility options with different intensities and at different times, depending on the characteristics and limitations of the flexibility potentials, but above all depending on their location. In contrast to the market-serving use of decentralised flexibility, in the grid-serving use of flexibility, loading and unloading always balance out in each time step and across all grid nodes, as is also the case with redispatch. This results in a simultaneous use of opposing flexibility options, which, however, takes place spatially at different grid nodes. If flexibility options are also part of possible redispatch measures in the future, then combinations such as reduction of electricity generation before the grid bottleneck and load reduction after the grid bottleneck or load increase and reduction of RES regulation (both before the grid bottleneck) can also be formed.

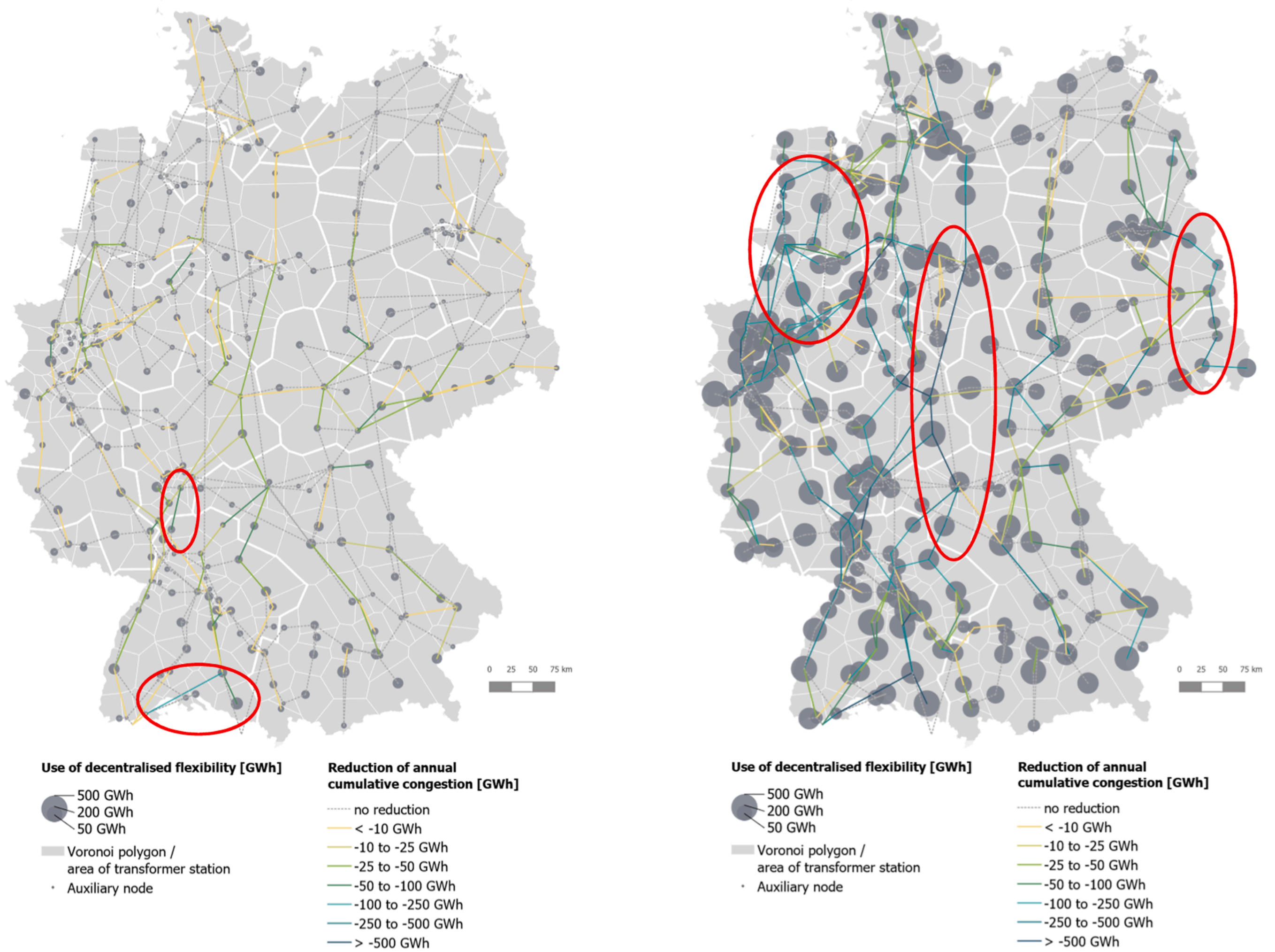

Fig. 13. Reduction of the cumulative congestion on the individual lines through the transmission grid-serving use of decentralised flexibility in the scenarios "Enera Worst Case 2030" (left) and "Enera Best Case 2050" (right).

5. Conclusion

This paper analyses the contribution that decentralised flexibility options can make for the transmission grid in Germany. For that purpose, we analyse how much decentralised flexibility can contribute to solving congestion problems in the transmission grid in four scenarios for the years 2030, 2040 and 2050.

The model-based evaluation shows that in the long-term perspective up to 2050, cumulative grid congestion increases significantly, which indicates that there is a significant need for grid expansion. In our case study, decentralised flexibility options can reduce the cumulative grid congestion of the transmission grid by around 15% in 2030 to around 10% in 2050 if decentralised flexibility options are operated not just in line with the power market, but also with a view to transmission grid requirements. In absolute terms, the benefit of the decentralised flexibility options increases over time from 2030 to 2050.

The decentralised flexibility options contribute more to the reduction of line congestion throughout the "Enera Best Case" scenario than in the "Enera Worst Case" scenario, as, among other things, the available flexibility potential is highest in the "Enera Best Case" scenario.

Even when considering the limitation in the modelling approach used here, it is evident that the long-term need for grid expansion can only be partially avoided, if at all, with decentralised flexibility options. Further measures are required to increase the transmission capacity of the power grid, and conventional grid expansion is a proven solution to relief grid stress.

However, even if decentralised flexibility options do not substitute for grid expansion in the long term, this analysis shows that decentralised flexibility options used to serve the grid can be an important building block in the long term for resolving grid congestions.

- Short-term effects: Reduction of the need for redispatch and RES balancing. A load or generation peak is temporarily stored before a grid bottleneck and balanced behind the bottleneck. This makes the netted nodal profiles more even. In the modelling, this effect is shown by the decrease in line congestion.
- Medium-term effects: Regarding the required grid expansion, the use of decentralised flexibilities can be integrated into the grid expansion planning. This can, for example, compensate for delays in grid expansion for a certain time, or delays can be accepted to better coordinate the construction of single projects. In the modelling, this effect is shown by the decrease in line congestion.
- Long-term effects: If decentralised flexibility potentials are available in spatial proximity and in sufficient amounts in the event of an existing grid bottleneck, this could also reduce grid expansion in the long term. The costs incurred in the event of a line congestion for the grid-serving use of flexibilities must then be weighed against the investment option in a grid expansion measure - analogous to redispatch. This is particularly interesting if the overload only occurs in a few hours per year or only to a small extent.

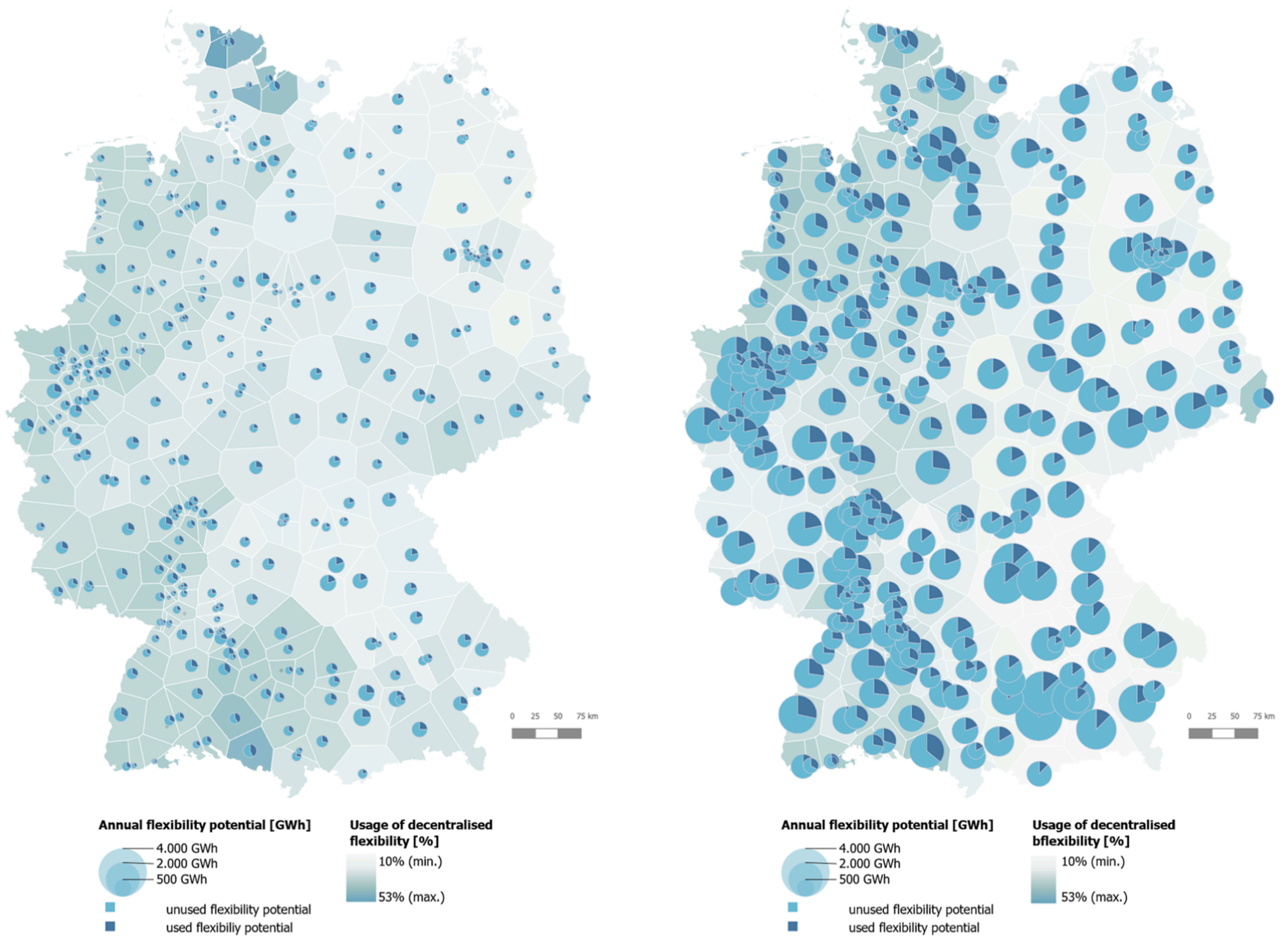

Fig. 14. Use of the decentralised flexibility potential available for use in the transmission grid in the scenarios "Enera Worst Case 2030" (left) and "Enera Best Case 2050" (right).

In terms of the debate on whether the future power system will be centralised or decentralised, the analysis provides an example of how the two perspectives can be combined.

In terms of policy measures, it is important to provide effective policy measures for both short-term and medium- and long-term transmission capacity expansion needs. Policy makers should not only focus on driving the (important) conventional grid expansion needs, but also look at measures that can compensate for delays in classical grid expansion or replace grid expansion. Here, policy should, as far as possible, exploit the potentials that are available at comparatively low development costs, including the decentralised flexibility analysed in this contribution. The analysis points to several areas where an effective regulatory framework is needed.

First, the regulatory framework needs to enable the development of decentralised flexibility options in the first place. Second, a regulatory framework is needed that makes the decentralised flexibility options analysed attractive and accessible to grid operators and sets incentives for appropriate grid-serving operation. Third, the regulatory framework also needs to enable coordination between the use of this flexibility in the market and for the grid, as well as coordination of decentralised flexibility between distribution and transmission system operators. Finally, as we have outlined, decentralised flexibility can only make a limited contribution to replacing grid expansion but can help to deal with the uncertainty in this process. This also needs to be reflected in the regulatory framework, for example by valuing the reduction of uncertainty in the regulation of grid operators.

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CRediT authorship contribution statement

Bauknecht Dierk: Conceptualization, Funding acquisition, Investigation, Methodology, Supervision, Writing – original draft, Writing – review & editing. **Koch Matthias:** Conceptualization, Data curation, Formal analysis, Funding acquisition, Investigation, Methodology, Software, Supervision, Validation, Visualization, Writing – original draft, Writing – review & editing. **Flachsbarth Franziska:** Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Software, Validation, Writing – original draft, Writing – review & editing. **Vogel Moritz:** Writing – original draft, Writing – review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Annex A. Data of scenario framework

Table A.3
Scenario framework for the year 2030.

	Enera Worst Case scenario	Scenario CP80	Scenario CP95	Enera Best Case scenario
Installed capacity for electricity generation	**237 GW**	**237 GW**	**241 GW**	**241 GW**
Lignite	9 GW	9 GW	9 GW	9 GW
Coal	8 GW	8 GW	8 GW	8 GW
Natural gas	34 GW	34 GW	29 GW	29 GW
Biomass	6 GW	6 GW	6 GW	6 GW
Run-of-river	6 GW	6 GW	6 GW	6 GW
PV	74 GW	74 GW	76 GW	76 GW
Wind onshore	70 GW	70 GW	78 GW	78 GW
Wind offshore	15 GW	15 GW	15 GW	15 GW
Other	6 GW	6 GW	6 GW	6 GW
Pump storage	10 GW	10 GW	10 GW	10 GW
Electricity demand	**542 TWh**	**505 TWh**	**483 TWh**	**504 TWh**
Conventional demand	492 TWh	443 TWh	391 TWh	391 TWh
Electromobility	7 TWh	18 TWh	22 TWh	28 TWh
Power-to-Heat	17 TWh	20 TWh	40 TWh	54 TWh
Power-to-Gas	0 TWh	0 TWh	7 TWh	7 TWh
Grid losses	26 TWh	24 TWh	23 TWh	24 TWh

Source: Authors and Repenning et al. (2015) for scenario CP80 and CP95

Table A.4
Scenario framework for the year 2040.

	Enera Worst Case scenario	Scenario CP80	Scenario CP95	Enera Best Case scenario
Installed capacity for electricity generation	**230 GW**	**238 GW**	**277 GW**	**309 GW**
Lignite	0 GW	0 GW	0 GW	0 GW
Coal	0 GW	0 GW	0 GW	0 GW
Natural gas	35 GW	35 GW	28 GW	28 GW
Biomass	4 GW	4 GW	4 GW	4 GW
Run-of-river	6 GW	6 GW	6 GW	6 GW
PV	74 GW	84 GW	90 GW	96 GW
Wind onshore	75 GW	80 GW	114 GW	140 GW
Wind offshore	30 GW	24 GW	30 GW	30 GW
Other	5 GW	5 GW	5 GW	5 GW
Pump storage	10 GW	10 GW	10 GW	10 GW
Electricity demand	**562 TWh**	**554 TWh**	**643 TWh**	**684 TWh**
Conventional demand	489 TWh	427 TWh	374 TWh	374 TWh
Electromobility	20 TWh	53 TWh	73 TWh	80 TWh
Power-to-Heat	26 TWh	48 TWh	71 TWh	83 TWh
Power-to-Gas	0 TWh	0 TWh	94 TWh	114 TWh
Grid losses	27 TWh	26 TWh	31 TWh	33 TWh

Source: Authors and Repenning et al. (2015) for scenario CP80 and CP95

Table A.5
Scenario framework for the year 2050.

	Enera Worst Case scenario	Scenario CP80	Scenario CP95	Enera Best Case scenario
Installed capacity for electricity generation	**237 GW**	**237 GW**	**241 GW**	**241 GW**
Lignite	0 GW	0 GW	0 GW	0 GW
Coal	0 GW	0 GW	0 GW	0 GW
Natural gas	35 GW	35 GW	28 GW	28 GW
Biomass	4 GW	4 GW	4 GW	4 GW
Run-of-river	6 GW	6 GW	6 GW	6 GW
PV	75 GW	121 GW	130 GW	147 GW
Wind onshore	78 GW	85 GW	150 GW	190 GW
Wind offshore	45 GW	32 GW	45 GW	42 GW
Other	6 GW	6 GW	6 GW	6 GW
Pump storage	10 GW	10 GW	10 GW	10 GW
Electricity demand	567 TWh	565 TWh	682 TWh	770 TWh
Conventional demand	502 TWh	420 TWh	375 TWh	375 TWh
Electromobility	31 TWh	80 TWh	106 TWh	133 TWh
Power-to-Heat	34 TWh	65 TWh	76 TWh	110 TWh
Power-to-Gas	0	0	125 TWh	152 TWh
Grid losses	28 TWh	28 TWh	34 TWh	38 TWh

Source: Authors and Repenning et al. (2015) for scenario CP80 and CP95

Table A.6
Share of load-manageable electricity consumption at distribution grid level.

	Enera Worst Case scenario	Scenario CP80	Scenario CP95	Enera Best Case scenario
Electromobility				
2030	50%	60%	60%	70%
2040	60%	70%	70%	80%
2050	70 &	80%	80%	90%
Heat pumps				
2030	60%	70%	70%	80%
2040	70 &	80%	80%	90%
2050	80 &	90%	90%	100%
Households				
2030	4%	6%	6%	8%
2040	6%	8%	8%	10%
2050	8%	10%	10%	12%
Commercial, trade and services sector				
2030	3%	6%	6%	9%
2040	6%	9%	9%	12%
2050	9%	12%	12%	15%

Source: Authors and Repenning et al. (2015) for scenario CP80 and CP95

Table A.7
Resulting load-manageable electricity consumption at distribution grid level.

	Enera Worst Case scenario	Scenario CP80	Scenario CP95	Enera Best Case scenario
Electromobility				
2030	3 TWh	7 TWh	8 TWh	11 TWh
2040	12 TWh	25 TWh	30 TWh	41 TWh
2050	21 TWh	46 TWh	49 TWh	77 TWh
Heat pumps				
2030	8 TWh	11 TWh	20 TWh	31 TWh
2040	13 TWh	26 TWh	37 TWh	48 TWh
2050	17 TWh	36 TWh	46 TWh	74 TWh
Households				
2030	5 TWh	7 TWh	6 TWh	8 TWh
2040	8 TWh	9 TWh	8 TWh	10 TWh
2050	11 TWh	11 TWh	10 TWh	12 TWh
Commercial, trade and services sector				
2030	4 TWh	6 TWh	6 TWh	9 TWh
2040	7 TWh	9 TWh	8 TWh	11 TWh
2050	11 TWh	12 TWh	11 TWh	14 TWh

Source: Authors and Repenning et al. (2015) for scenario CP80 and CP95

Table A.8
Dimensioning of battery storage systems at distribution grid level.

	Enera Worst Case scenario	Scenario CP80	Scenario CP95	Enera Best Case scenario
Share of installed PV power with a battery storage system	10%	15%	25%	35%
Charging and discharging capacity of the batteries				
2030	7 GW	11 GW	19 GW	26 GW
2040	7 GW	13 GW	22 GW	33 GW
2050	8 GW	18 GW	33 GW	52 GW
Storage capacity of the batteries				
2030	12 GWh	18 GWh	30 GWh	42 GWh
2040	12 GWh	20 GWh	36 GWh	54 GWh
2050	12 GWh	29 GWh	52 GWh	82 GWh

Source: Authors and Repenning et al. (2015) for scenario CP80 and CP95

Table A.9
Dimensioning of flexibility from CHP engines at distribution grid level.

	Enera Worst Case scenario	Scenario CP80	Scenario CP95	Enera Best Case scenario
Installed capacity of CHP engines				
2030	8 GW	8 GW	8 GW	8 GW
2040	7 GW	7 GW	7 GW	7 GW
2050	6 GW	6 GW	6 GW	6 GW
Thermal capacity of heat storages				
2030	20 GWh	24 GWh	28 GWh	32 GWh
2040	20 GWh	27 GWh	30 GWh	33 GWh
2050	24 GWh	26 GWh	28 GWh	30 GWh

Source: Authors and Repenning et al. (2015) for scenario CP80 and CP95

Annex B. Input data and results of the electricity market model “PowerFlex”

Input data.

- Electricity demand profiles (hourly resolution)
- RES feed-in profiles (hourly resolution)
- Demand-side flexibility profiles (resolved hourly)
- Techno-economic parameters of the thermal power plant fleet (e.g., electrical capacity installed, efficiency, fuel prices, CO_2 prices)
- Techno-economic parameters of storage power plants (e.g., storage capacity, efficiency)
- Techno-economic parameters of flexible consumers and electromobility (e.g., storage capacity, efficiency)
- Techno-economic parameters of grid-connected heat generators based on renewable energies (e.g., capacities, efficiency)

Results

- In hourly resolution:
  - Utilisation profiles of storage facilities, power plants and flexible consumers, heat generators
  - Electricity prices
  - Fuel mix
- As an annual sum:
  - Hours of use of storage facilities, power plants and flexible consumers
  - Fuel mix
  - Emissions by energy source
  - Integrated or surplus amount of fluctuating RES electricity

Annex C. Considered HVDC corridors and grid nodes for offshore wind farms

The HVDC corridors considered in the transmission grid are:

- DC1: Emden/East - Osterath (A-North)
- DC2: HVDC link Osterath - Philippsburg (Ultranet)
- DC3: Brunsbüttel - Großgartach (SuedLink)
- DC4: Wilster/West - Bergrheinfeld/West (SuedLink)
- DC5: Wolmirstedt - Isar (SuedOstLink)
- DC21b: Wilhelmshaven 2 - Uentrop
- DC25: Heide/West - Polsum (or Kusenhorst)

The offshore wind farms in the North Sea and Baltic Sea are connected to a total of 16 grid nodes:

North Sea

- Schleswig-Holstein (2 grid nodes): Heide/West and Büttel
- Lower Saxony (9 grid nodes): Inhausen, Wilhelmshaven, Unterweser, Halbemond, Emden/East, Emden/Borsum, Diele, Dörpen/West and Cloppenburg
- North Rhine-Westphalia (3 network nodes): Hanekenfähr, Westerkappeln and Wehrendorf

Baltic Sea

- Mecklenburg-Western Pomerania (2 network nodes): Bentwisch and Lubmin

Annex D. Input data and results of the grid model “OptGrid”

Input data.

- Netted nodal loads (hourly resolution)
- PTDF matrix for the three-phase network
- Network topology AC and DC
- Technology-specific flexibility profiles per transmission grid node (hourly resolved potential limits)
- Transmission capacity of the DC corridors

Results.

- In hourly resolution:
  - Utilisation and congestion of the individual lines in the AC grid
  - Utilisation of the DC corridors
  - Node- and technology-specific deployment profiles of decentralised flexibility options
- Based on this, the following key figures are formed and evaluated in the further course:
  - Cumulative grid congestion
  - Cumulative and maximum utilisation of the individual lines as well as the number of hours in which grid congestion occurs
  - Reduction of the cumulative congestion on the individual lines through the transmission grid-serving use of decentralised flexibility
  - Use of the decentralised flexibility potential available for use in the transmission grid.

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