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RESEARCH AND ANALYSIS

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Impacts of electric vehicles on the European high and extra high voltage power grid

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Abstract

The impact of electric vehicles on the electricity grid has been focused on by the literature in many facets, comprising considerations of the electricity system of a single household up to the highest voltage grid level. But each of these analyses is focusing on a single grid level. While the impact on the local level depends strongly on the specific environment and is consequently diverse, there is strong evidence that the impact on the highest grid level is non-critical. So far, there is no study considering several voltage levels together. Consequently, we analyzed here for the first time all voltage levels between 60 and 380 kV together for the European transmission grid and included, besides the load flexibilities from home charging, also the load from fast charging stations for the year 2050 with a completely replaced car fleet by electric vehicles. While the impact on the security of supply is rather marginal, with a slight increase of load shedding on some distribution grid nodes, the impact on nodal prices and greenhouse gas emission is—with up to 9%—more severe. When applying the model on the highest grid level alone, our results show significantly smaller impacts. These results endorse our comprehensive approach, which considers several grid levels and their comprehensive interactions—an isolated consideration of grid levels seems inappropriate for our research questions.

KEYWORDS
electric vehicles, Europe, fast charging, grid impact, industrial ecology, systems analysis

1 | INTRODUCTION

Plug-in electric vehicles (PEV) are a promising means of individual transportation of the future, providing locally emission-free, silent, and resource-flexible mobility (cf. Hawkins et al. (2013b) and Hawkins et al. (2013a))—however, depending on several framework conditions, such as a clean electricity provision (e.g., Garcia et al. (2018)). Even though a future car market without PEV seems unimaginable, their market share is hardly predictable (Gnann et al., 2018) and even very fast disruptional pathways are thinkable (Gómez Vilchez & Jochem, 2020). These fast market evolutions may impose country-specific impacts on the power system (e.g., Garcia et al. (2018)), which should be prepared far in advance as extensions of the power grid are very time consuming. Up to now, it is unclear how the existing power system that provides the backbone not only for the energy transition, but also for the electrification of transportation can cope with a high share of PEV and high charging rates at fast charging stations (FCS).

Consequently, our research question is on how the European transmission grid can cope with an accelerated penetration of PEV and corresponding FCS along the European highway. For answering this research question we modeled the endogenous commission of the transmission grid of core European countries and considered empirical charging data from home charging and fast charging of PEV. Therewith, the core contribution of our paper is unique in literature and contains the following three steps:

1. We consider empirically based load patterns of a high market penetration of FCS in Europe in an energy system model.
2. We consider the interactions between different grid levels above 60 kV within the European electricity system.
3. Based on this, we identify the impact from FCS on grid bottlenecks, load shedding, and the corresponding greenhouse gas emissions for the European electricity system.

The structure of the paper is the following. In Section 2, we identify the research gap for the European network considered. In Section 3, our methodology is explained before our data is described in Section 4. Section 5 provides the results and a short discussion before Section 6 concludes.

2 | RELATED WORK

When it comes to grid impacts from PEV, the current literature mainly focuses either on electrotechnical impacts on the decentralized level or on the highest voltage transmission grid. Only few studies try to incorporate both, but still without a convincing connection of both voltage levels (e.g., Crozier et al. (2020)). In the following, we provide an extraction of exemplary papers.

Most papers in this field study the impact from PEV on the energy system (i.e., power plants (Jochem et al., 2015; Xu et al., 2020; Wang et al., 2021) or electricity markets (Ensslen et al., 2018)) without considering electricity grids. Especially on the distribution grid level a plurality of studies, especially electrotechnical studies, exist. While some use more artificial grid and mobility data (e.g., Li et al. (2016)) others already focus on empirical evidence and use real data, assuming different charging patterns of PEV users (e.g., Xiang et al. (2016)). Qian et al. (2015) made a technical analysis on the impacts on the thermal ageing of power distribution transformers in a generic distribution network for the UK with real load demand data. Leemput et al. (2015) analyzed a Flemish urban distribution grid on two power levels and different charging strategies for residential households. They confirmed the hypothesis that FCS have a more severe impact on these low voltage grid levels compared to slow charging. González et al. (2019) analyzed the impact of FCS on the local electricity grid in the urban context of Cuenca, Ecuador. Salah et al. (2015) investigated the impact from PEV on substations in an example distribution grid in Switzerland. They conducted a simplified load flow analysis and found that up to a market share of 16% no substation comes to its power limits. For market penetrations of beyond 50% some substations might be overloaded. Similarly, Jochem et al. (2018) gave an overview of different German studies on the impact on distribution grids. Their core result is that until 30% market share of PEV most German distribution grids should not be jeopardized – unless in very unlikely cases of simultaneously charging at high charging rates (which would be avoidable by scheduling the chargings).

The impact on the transmission grid is often seen as less severe. One very first investigation of the German transmission grid was conducted by Hartmann and Özdemir (2011). However, they only considered the potential load increase on the national level without considering a real grid. Heinrichs and Jochem (2016) analyzed the German transmission grid with a nodal pricing approach and indicated that there are only marginal effects on the German transmission grid up to 2030 and 22 million PEV (50% market share). Hence, the highest voltage level of the transmission grid seems to be adequately dimensioned for these market shares. This is especially true if controlled charging is considered (cf. Crozier et al. (2020) and Staudt et al. (2018)). Furthermore, FCS for interim charging during the trip, which occurs mostly along highways, is not considered in many studies. Mu et al. (2014) is an example exception as they consider fast and usual (smart) charging for their analysis on a generic distribution system in the United Kingdom.

Concluding, a multi-country study, which is focusing on FCS along the highway and their impact on the distribution and transmission grid (60 until 380 kV level) is missing so far.

3 | METHOD

In order to analyze the impact of FCS for the future power system, the following challenges have to be addressed:

1. a consistent parametrization of the future power system in line with the projected PEV market penetration and their resulting time- and spatial-dependent load patterns and
2. an integrated modeling of the interconnected European power system, considering the grid connection of FCS on the high voltage distribution grid level.

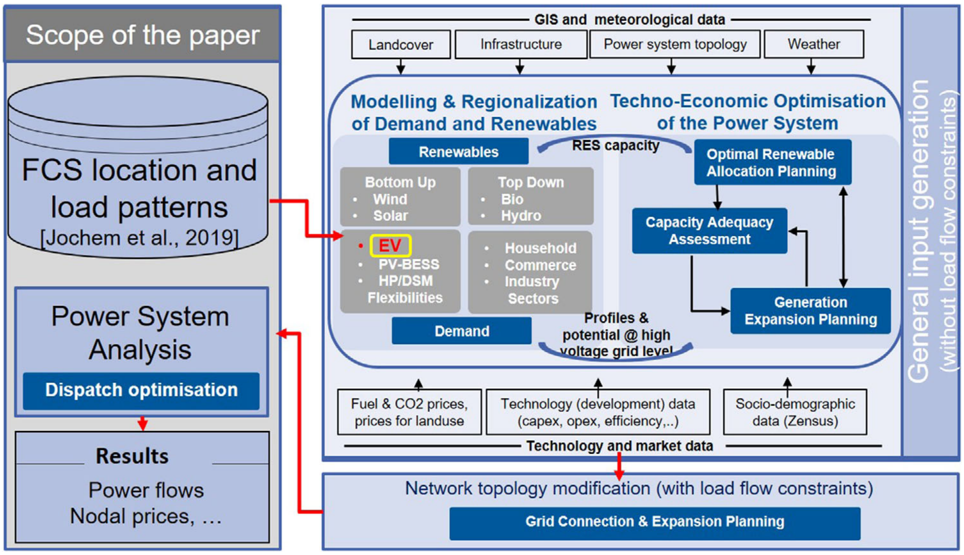

FIGURE 1 Our approach based on previous work on the European electricity network (Hartel et al., 2019; Ruppert et al., 2020) and the allocation of fast charging stations by Jochem et al. (2019)

For addressing the first issue of a consistent parametrization of the future power system we integrated the FCS related data based on Jochem et al. (2019) into a framework for modeling the development of the future power system (Hartel et al., 2019; Ruppert et al., 2020). As illustrated in Figure 1, this framework includes a tool chain for a techno-economic optimization of the power system based on hourly resolved renewables and demand profiles and potentials on the European high voltage distribution grid level.

In a first step, we included the FCS locations and load patterns in addition to the inflexible electricity demands of other sectors such as household, commerce, and industry and adjusted the PEV home charging demand accordingly. Regionalized on the high voltage distribution grid level the demand side includes a certain flexibility potential of other electricity consumers, such as heat pumps (on household and district heating level), home charging PEV, photovoltaic battery energy storage systems, and power-to-gas applications of the future power system. In combination with a detailed modeling of renewable potentials and their generation profiles we derived the configuration of the future power system based on a generation expansion planning in the next step, considering certain expansion targets for renewables on the one hand, and the security of supply for the expansion of conventional generators on the other hand. After running an optimal renewable allocation planning (cf. Slednev et al., 2018), we performed a capacity adequacy assessment to derive the capacity requirements for the following generation expansion planning of conventional generators (cf. Hartel et al., 2019). In the last step, we modified the network topology by running a transmission network expansion planning on top of the known expansion projects.

Once the parametrization of the future power system is known, the next challenge lies in handling the complexity arising from modeling the impact of FCS on the European power system. Considering a local injection of FCS on the high voltage distribution grid level, on the one hand, and a global balancing between demand and supply within transmission grid restrictions, on the other hand. Given the enormous dimension of the European high and extra high voltage distribution and transmission grid, a direct solution of the alternating current optimal power flow (AC-OPF) problem for modeling the FCS grid impact had to be discarded. Instead, we developed an approach for the power system analysis which includes a dispatch optimization considering grid restriction with a varying level of detail.

The goal of the linear model is to find a cost-minimal generator dispatch in a network such that the nodal demand is covered in each time step $t \in T$, covering 1 h. In this context the set of generators G comprises all dispatchable units which either provide or consume power within a directed graph of the electrical network, consisting of a set of nodes N and a set of edges Ω (all applied variables, parameters, and sets are provided in Table A1). Furthermore, the network is subdivided into three sub-systems: (i) transmission grid (TG), (ii) distribution grid (DG), and (iii) zonal grid (ZG), regarding the level of detail for modeling grid restrictions in different regions or at different voltage levels (cf. Figure 2).

The sub-systems either include a linear representation of the complex power flow restrictions following the DC approach with piecewise linear quadratic loss modeling (TG and DG) or a net transfer capacity (NTC)-based exchange modeling between zones (ZG). The link between the sub-systems is modeled based on auxiliary generators which are connected to the boundary node of both systems with switching signs, such that a load on one side corresponds to the generation on the other side and vice versa. In this context, the European power system (PS) references to the whole model, covering all power generation and demand in Europe, while the DC-OPF sub-system consists of all TG and DG associated nodes (buses), edges (branches), and generators (i.e., generators, flexible loads, and storages).

The main driver of the optimization is the nodal balance restriction, enforcing Kirchhoff's first law such that the sum of power generated or consumed from generators $p_{g,t}$ combined with the inflows and outflows $f_{nm,t}$ minus the transmission losses $l_{nm,t}$ equals the summed demand $P_{d,t}$ in

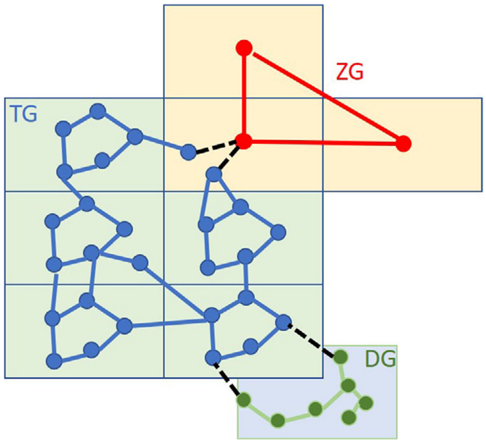

FIGURE 2 The considered sub-systems of the electricity grid: transmission grid (TG), distribution grid (DG), and zonal grid (ZG)

the node $n \in N$ and each time step $t \in T$.

$$\sum_{g \in G_n} p_{g,t} + \sum_{m \in \dot{}_n} (f_{mn,t} - f_{nm,t}) - \frac{1}{2} \cdot \sum_{m \in \dot{}_n^{TDG}} (l_{nm,t} + l_{mn,t}) = \sum_{d \in D_n} P_{d,t} \quad \forall n \in N, t \in T \tag{1}$$

It should be noted that the FCS demand added to the model is included in the set of consumers D with a fixed electricity demand and appears on the right-hand side of the nodal balance. Transmission losses are only considered on lines of the transmission and distribution grid, denoted by $\Omega^{TDG} = \Omega^{TG}_{AC380} \cup \Omega^{TG}_{AC220} \cup \Omega^{DG}_{AC110}$, while the loss of HVDC edges Ω^{TG}_{HVDC} is included in the generator efficiency (cf. Equations 4 and 5) and NTC-based exchanges between zones Ω^{ZG} are lossless. Based on the DC approach (Schweppe et al., 2013), Kirchhoff's second law is modeled for these sub-systems by coupling the line flow to the phase-angle difference, weighted with the branch susceptance.

$$f_{nm,t} = (\Theta_{n,t} - \Theta_{m,t}) \cdot \varphi_{nm} \quad \forall (n,m) \in \Omega^{TDG}, t \in T \tag{2}$$

Following Dos Santos and Diniz (2010), line losses are approximated by a quadratic convex function of phase-angle difference multiplied with the line conductance and a set of k equations is used to approximate this quadratic function with a piecewise linear function at k points.

$$\begin{aligned} l_{nm,t} \quad \geq \quad & -g_{nm} \cdot \left(\Delta\Theta^k_{nm}\right)^2 + 2 \cdot g_{nm} \cdot \Delta\Theta^k_{nm} \cdot |\Theta_{n,t} - \Theta_{m,t}| \\ & \forall (n,m) \in \Omega^{TDG}, t \in T, k \in K \end{aligned} \tag{3}$$

The transmission over HVDC lines within the transmission grid sub-system (start and end node element of N^{TG}) is modeled through a coupled generator ($g \in G^{HVDC+}_m$) load ($g \in G^{HVDC-}_n$) pair in both directions with a roundtrip efficiency for considering losses.

$$\sum_{g \in G^{HVDC+}_n} p_{g,t} = - \sum_{g \in G^{HVDC-}_m} p_{g,t} \cdot \eta_g \quad \forall (n,m) \in \Omega^{TG}_{HVDC}, t \in T \tag{4}$$

$$- \sum_{g \in G^{HVDC-}_n} p_{g,t} \cdot \eta_g = \sum_{g \in G^{HVDC+}_m} p_{g,t} \quad \forall (n,m) \in \Omega^{TG}_{HVDC}, t \in T \tag{5}$$

Flexibility in the sense of balancing demand and supply over multiple time steps is modeled following Ruppert et al. (2020), based on a general storage equation with losses neglected.

$$v_{s,t} = v_{s,t-1} + \sum_{g \in G^{inS}} p_{g,t} \cdot \eta_g - \sum_{g \in G^{outS}} \frac{p_{g,t}}{\eta_g} + \zeta^{in}_{s,t} - \zeta^{out}_{s,t} \quad \forall s \in S, t \in T \tag{6}$$

The energy level $v_{s,t}$ of a storage $s \in S$ at time step $t \in T$ results from its previous level, the external power inflow $\zeta^{in}_{s,t}$ or outflow $\zeta^{out}_{s,t}$ and the sum of charged and discharged power provided by connected generators $p_{g,t} \in G^S \subseteq G$. Besides modeling classical storage applications such as hydro pump storages and batteries, this equation might be used to model the flexibility of generators following a demand or generation profile by modifying the bounds on variables. That way, the load shifting potential of flexible demands, such as home charging PEV and distributed heat pumps (HP), might be modeled as described by Ruppert et al. (2020). The basic idea of this approach is to derive the bounds for the shifting from the profile itself, based on the assumption that a certain share of a specific load/generation profile might be shifted within a certain time range to a certain degree.

Furthermore, all generators, flows, and losses are restricted to upper and lower bounds, with the convention that generators with a positive feed-in into the network $p_{g,t} \in G^{+}$ are bound to a positive or zero lower bound and load processes $p_{g,t} \in G^{-}$ to a negative upper or zero bound vice versa.

$$x_t^{\min} \leq x \leq x_t^{\max} \quad \forall x \in \left\{ p_{g,t}, f_{nm,t}, \zeta_{s,t}^{\text{in}}, \zeta_{s,t}^{\text{out}}, v_{s,t} \right\}, t \in T \tag{7}$$

Finally, the objective function is defined based on a minimization of the linear variable generator dispatch cost:

$$\min_{p} \sum_{g \in G} \sum_{t \in T} p_{g,t} \cdot \left(\frac{c^{\text{fuel}}}{\eta_g} + \frac{\text{CO2}_f}{\eta_g} \cdot c^{\text{CO2}} + c^{\text{opex}} \right) \tag{8}$$

4 | SCENARIO DESCRIPTION AND DATA

The following case study is based on the aforementioned approach of integrating transportation related data concerning the PEV penetration into a framework for parametrizing a model of the future electrical network. Therefore, specific assumptions concerning the PEV load development are included into a general scenario setting for the development of the European power system. In this article, we provide a brief overview of the major scenario assumptions (cf. Section 4.1) and refer to Ruppert et al. (2020) for a detailed description of the grid related data, including the scenario definition, generation, and grid development as well as a unit parametrization. Furthermore, we briefly describe the data branches which were added to the case study in Ruppert et al. (2020), with the first branch containing all transport relevant data (cf. Section 4.2) and the second branch adding the distribution grid and own grid expansion measures to the grid data (cf. Section 4.3).

4.1 | Scenario description

With the scope of analyzing the PEV impact on the grid in central European countries until 2050, we model the development of the European power system with a focus on the central European countries and their transmission grid. While the countries in focus, i.e., France, Belgium, the Netherlands, Switzerland, Austria, Czech Republic, Poland, Germany, and Luxembourg, are modeled with a representation of their distribution grid for an in-detail analysis of the impact of decentral loads and generation, the internal grid restrictions of all other countries are neglected while their cross-border flows are limited to their NTC. The general scenario setting for this case study assumes a high share of renewables throughout Europe, with a target of a 85% in Europe in 2050 (90% Western Europe and Nordics, 80% Southern Europe, 70% Eastern Europe) and a path for the share of renewables in Germany of 65% (2030), 80% (2040), and 95% (2050), respectively. The scenario framework for the development of the different renewables and load types is derived from a combination of the “Distributed Generation” scenario of the Ten-Year Network Development Plan (TYNDP) 2018 (ENSTO-E, 2018) and the closely related C Scenario by the German Network Development Plan 2030 (50Hertz et al., 2019) in addition to own assumptions. Based on this scenario framework an optimal allocation planning of renewables (cf. Slednev et al., 2018) is computed, which provides the input for the generation expansion planning of thermal generators with an a priori stochastic capacity adequacy assessment (Hartel et al., 2019), considering 15 weather years. In this case study, we considered a European coal phase out and refer to Ruppert et al. (2020) for details concerning the generator expansion and dismantling planning. For the grid expansion beyond the known national plans and TYNDP projects, which reach until 2030, we run a cost-minimal optimization with the option to replace each branch by multiple new branches from 2025 onward in 5-year periods until 2050.

4.2 | Transport data

PEV are considered by two data sets. First, their usual chargings that occur mainly at home, work or other locations connected to lower grid levels in areas of high population densities. These chargings (which are characterized by low charging rates and might even provide some load flexibilities in the future) are already considered in the basic model (Hartel et al., 2019). This data is mainly based on a national data survey of conventional car usage (Nobis & Kuhnimhof, 2018). Second and new in this modeling is the consideration of fast charging along the highway. These charging stations are usually connected to higher grid levels (sometimes in regions of low population density), the charging power is considerably high, and the load

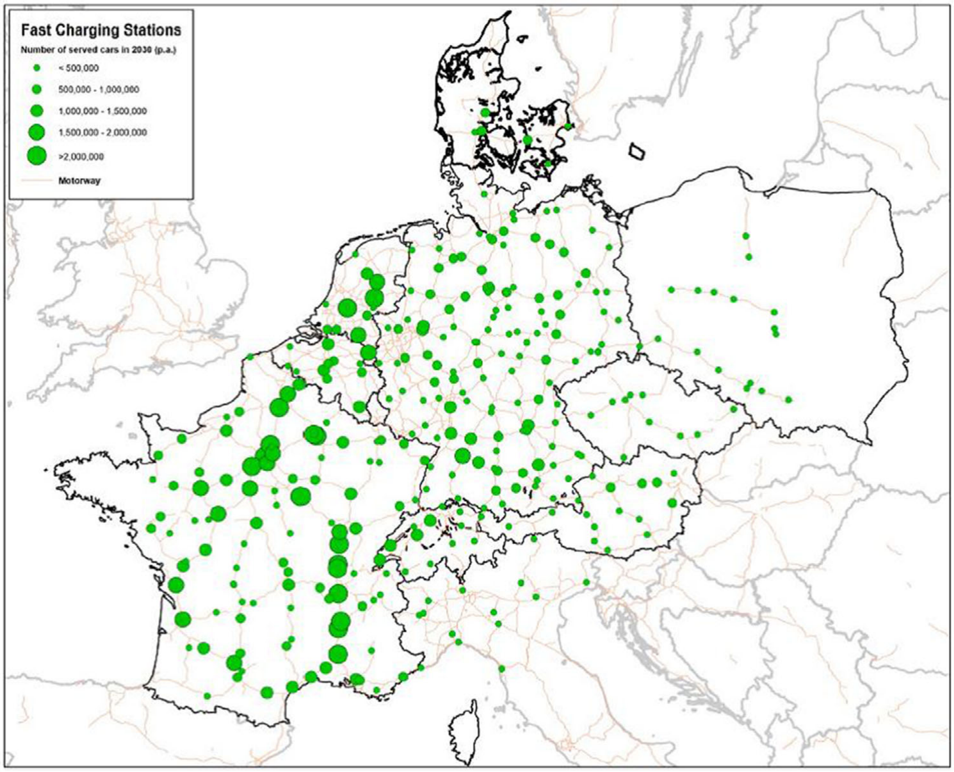

FIGURE 3 Minimal number of FCS locations along the European highways and their energy demand (Jochem et al., 2019). The underlying data are available in Supporting Information S1 and in the <S2-3_LocationOfFCS_VolumesBEV.csv> file of Supporting Information S2

flexibility (i.e., the willingness of users to charge later or at a lower charging rate) close to zero (Jochem et al., 2019). This may make their impact on the transmission grid more severe.

The transport related data contains day-time-dependent spatial load patterns of optimal allocated FCS along the European highway network based on Jochem et al. (2019) (cf. Figure 3). Jochem et al. (2019) base their analysis on the comprehensive European vehicle flow database ETISplus (Szimba et al., 2013). Furthermore, PEV-specific assumptions and scenarios for the market penetration of PEV (in line with the aforementioned market share of usual chargings) are made. The main assumptions are shortly explained in the following before the energy related data is outlined in further detail.

1. **Charging rate**: As fast charging technology is getting more advanced, average charging rates are expected to increase over time. Nevertheless, we assume an average charging rate of 150 kW for the whole time horizon.
2. **Vehicle range**: We take a very conservative approach here and assume 150 km range throughout the considered time horizon.
3. **Market penetration**: Our market share of PEV for 2030 is based on the current targets of the Federal Government (German Federal Government, 2019), which indicates up to 10 million PEV (25% market share) in Germany. For 2040 and 2050, we assumed a further rapid uptake of the PEV market, that is, 22 million PEV for 2040 (52% market share) and 40 million PEV for 2050 (close to 100% market share), which is in line with International Energy Agency (IEA) (2020). For all other countries the same market shares are assumed.

4.3 | Energy and power grid related data

The transmission grid of the above mentioned central European countries comprises the overhead line and cables of voltage levels above 200 kV of the interconnected AC network as well as the HVDC lines (cf. Figure 4). In contrast to the in-detail parametrization of the transmission grid, as described in Ruppert et al. (2020), the distribution grid used in this case study to cover the voltage levels between 60 and 200 kV is based on a generic grid generated from open street map data and parametrized with default values. In a previous study, Ruppert et al. (2020), this grid was used for regionalizing generators and loads with a connection to lower voltage levels, based on a shortest path solution to a transmission grid substation (Slednev et al., 2017).

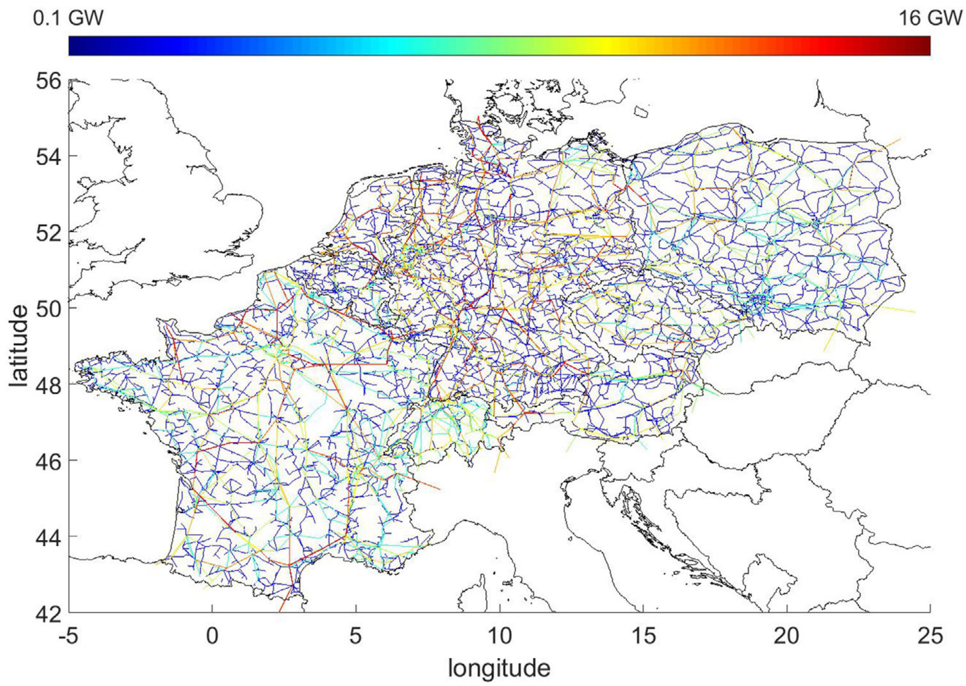

FIGURE 4 The considered European grid with thermal limits in GW

For a better representation of decentral generators and loads, we extend the regionalization approach by directly including the distribution grid into the system boundaries of the network model. In this context, we simplify the distribution grid in a way that all isolated parts of it, which are only connected to another grid through a single transmission grid substation, are reduced to a single node, leaving only those grids with a transmission function beneath the extra high voltage level inside the model. This reduces the number of nodes and branches in the modeled distribution grid to 19,052 nodes and 39,878 branches. Furthermore, these numbers already include a reduction to one bus per voltage level and substation and one branch per voltage level and edge, with parameters adjusted accordingly. In addition to the 3011 nodes and 7083 branches of the transmission grid the remaining European grid is aggregated to 21 zonal country nodes and 74 directed edges for modeling the NTC-based exchange flows between those nodes. Considering the generator representation, we chose an individual modeling of all existing and future thermal generators and hydro pump storages above 20 MW and aggregated all other renewable generators, storages, and flexible loads to one variable per type and node. Renewables such as onshore and offshore wind, rooftop, and ground-mounted photovoltaic, biogas as well as run of river are further aggregated to one single variable per node with zero variable cost and an hourly generation upper bound, resulting from the summed profiles. For biomass and seasonal hydro storages a certain flexibility in the sense of a shiftable generation between time steps is assumed. Following Ruppert et al. (2020) these generators are modeled based on the storage equation on the nodal level. The same approach is applied for flexible loads as described in Ruppert et al. (2020). In total we model 5801 thermal and renewable generators and 13,268 generators that are associated to a storage or a flexible demand or renewable generation (cf. Table A2 and Figure A1 in the Appendix).

Furthermore, we assume that the power flow between the transmission and the distribution grid is freely adjustable. This is realized by duplicating the buses on the lower voltage side of transformers connecting both grid levels such that both grid levels become independent, in the sense that Kirchhoff's second law does not apply. The exchange between these buses is afterward modeled based on auxiliary generators, as described in the previous section. The scope of this approach is to improve the regionalization of decentral supply and demand in a way that the impact of distribution grid flows on the transmission grid load is considered. Grid expansion in the distribution grid is simply realized by duplicating all branches of the current grid in 2050. Finally, the problem is solved for all 8760 h of a year, based on a rolling horizon approach, with an hourly optimization of the next 18 h with an overlap of 6 h, so that the last 6 h of the last optimization are discarded.

5 | RESULTS AND DISCUSSION

Overall, we found that even for a high penetration of PEV in 2050 (i.e., a complete replacement of the current car fleet) the impact of fast charging along highways on the central European electricity grid remains moderate. Although we didn't consider FCS installations within the endogenous planning of the installed generation (cf. Figure A1 in the Appendix) and transmission capacities in our grid, the changed load profile and distribution due to FCS had a low impact on the load shedding.

TABLE 1 Differences of load shedding for the two scenarios home charging (HC) and home charging plus fast charging stations (HC + FCS) as an indicator of the impact from FCS on load shedding (energy and power) in the considered DC-OPF sub-system (TG + DG nodes)

	Share in energy from load shedding [%]		Max. shedded load as share from max. load [%]	
Scenario	NoFlex	Flex	NoFlex	Flex
I HC	0.083	0.079	0.395	0.383
II HC + FCS	0.106	0.102	0.463	0.451
delta (II-I)	**0.023**	**0.023**	**0.068**	**0.068**

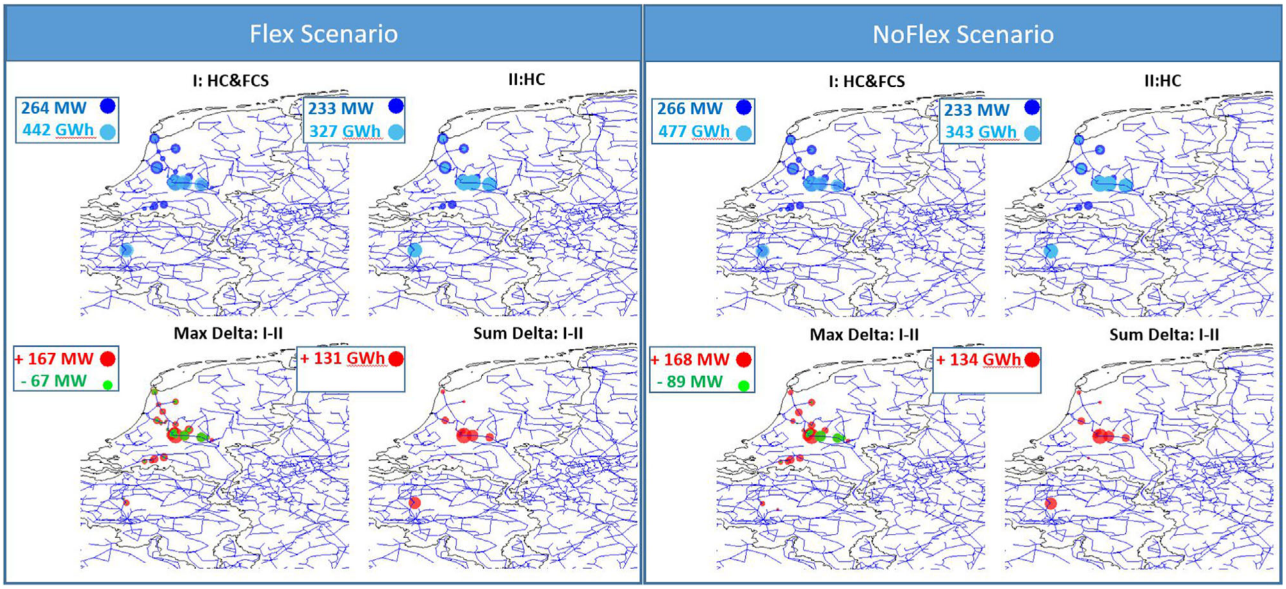

FIGURE 5 Differences in load sheddings of the two scenarios (HC and HC + FCS) with (left) and without (right) charging flexibility for HC given in maximum power (MW) and annual shedded energy (GWh) for 2050. The underlying data are available in Supporting Information S1 and in the <S2-1_Flex_Load_Scenario.csv> and <S2-2_Noflex_Load_Scenario.csv> files of Supporting Information S2

In the base scenario, where only home charging (HC) of PEV is possible, we found a slight imbalance between supply and demand in a few extreme situations, which was caused by bottlenecks in the distribution grid (cf. Table 1 and Figure 5). These shortages should not be overvalued because the distribution grid was not explicitly considered in the generation and grid expansion planning in previous steps for the modeling of the future power system. So in reality they might be identified beforehand and a grid extension would have solved the problem.

In case that a certain share of the PEV demand is shifted from home charging to fast charging along highways (HC + FCS), an increase of the load shedding is observed. However, the effect is moderate in terms of the additional needed power and energy (cf. Table 1 and Figure 5). The moderateness of the impact is mainly based on the somewhat (i.e., 1%) lower correlation of the load from FCS and the residual load compared to the HC Scenario (cf. Table A3 in the Appendix). Additionally, we calculated two further scenarios. While the Flex Scenario allows a flexible charging at home (i.e., the load from home charging as well as from heat pumps can be scheduled by our model within technical limits), the NoFlex Scenario considers these loads as stable (i.e., all chargings at home start as soon as vehicles are plugged-in). As expected, the introduction of flexibilities reduces the load shedding, while fast charging increases the imbalance in both scenarios (cf. Table A4 in the Appendix). Although these findings seem obvious, it should be noted that in case of an inflexible load, the fast charging profile shows a more favorable correlation with the (net-)load, resulting in a lower peak demand (cf. Table A5 in the Appendix). Without the congestions in the distribution grid, resulting from the more concentrated distribution, a lower load shedding could be expected in the NoFlex-HC + FCS Scenario. This is shown in model runs including only the (lossless) DC-OPF transmission grid (cf. Tables A6 in the Appendix). In this special case, without distribution grid congestions and load flexibility, fast charging leads to a slightly lower curtailment of renewables and lower CO_2 emissions.

Concerning the spacial distribution of the load shedding, we observe a small number of undersupplied substations, which belong to the Belgium and Dutch distribution grid with a similar distribution for the NoFlex and Flex Scenarios (cf. Figure 5). In total, fast charging leads to an increased load shedding for all affected substations, whereas the undersupply in a single hour might deviate in both directions, but with a higher magnitude of additional load shedding.

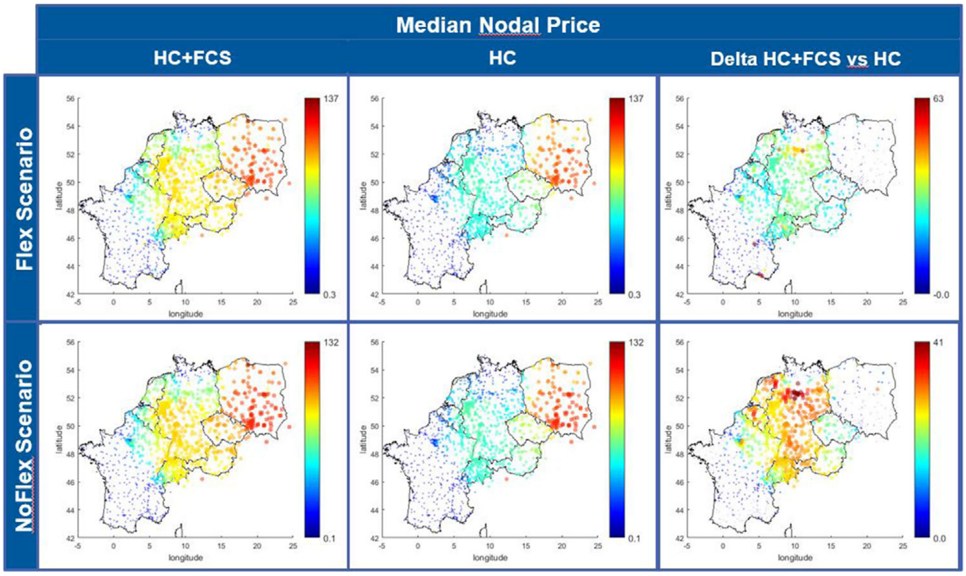

FIGURE 6 Nodal prices [€ per MWh] for the HC + FCS Scenario, the HC Scenario, and their differences in 2050 with (upper) and without (lower) flexible (i.e., controlled) home charging. The underlying data are available in Supporting Information S1 and in the <S2-1_Flex_Load_Scenario.csv> and <S2-2_Noflex_Load_Scenario.csv> files of Supporting Information S2

TABLE 2 Impact from fast charging on CO_2 emissions in megatons in 2050

Scenario	NoFlex	Flex
I HC	143.4	127.9
II HC + FCS	154.1	139.7
delta (II-I)	**10.6**	**11.8**

Besides load shedding, which indicates grid congestions in critical grid situations, the deviation in nodal prices might indicate grid congestions in less critical hours. A difference in nodal prices occurs already in the case of active grid restrictions. Figure 6 illustrates that FCS installations lead to a more congested network. Especially the core of the modeled grid region, comprising the Netherlands, Belgium, Austria, Switzerland, and most parts of Germany is affected by higher nodal prices. Due to an overall more congested grid, the balancing between regions with available low marginal cost generation such as renewables (northern Germany) or renewable and nuclear (France) and net-demand regions is limited. This finding holds for the NoFlex as well as for the Flex Scenarios (cf. Figure 6).

Considering that a shift from low to high marginal cost generation, due to increased grid congestions, coincides with a shift from low to high carbon-intensive generation in our system, the increase of the CO_2 emissions, shown in Table 2, is hardly surprising. A reduction of the renewables share of the total generation (from 77.06% to 76.62% in the NoFlex Scenario) in combination with a reduction of the nuclear generation share of the thermal generation (from 24.81% to 24.75% in the NoFlex Scenario), turned out to be the reason for this remarkable finding.

Concluding, we observed that fast charging along highways mainly increased the general level of congestions in the electricity network with only a moderate impact on critical congestions, which locally occurred for a few hours in the Netherlands and Belgium. The concentration of additional, non-flexible load in the distribution grid was found to be the main driver for these grid congestions. This finding is also supported by the observation of an overall moderate network load, even in the most congested hour, which is illustrated in Figure A2 in the Appendix.

These results show first insights into this complex issue. They are based on several assumptions and limitations. The main limitations are the following: Unlike the detailed parametrization of the transmission grid, including the characteristics of the existing branches and planned expansions as well as an additional endogenous expansion planning, a rather generic representation of the distribution grid is included. A more accurate parametrization of the existing distribution grid (including the load flexibility of PEV) and of the useful expansion options may influence the indicated congestions. Furthermore, the chosen DC-OPF approach with quadratic loss approximation is less restrictive than an actual N-1 secure AC modeling of the grid restrictions.

Further research may focus on integrating more detailed technological constraints (such as the controllability of chargings) or on how highly localized load increases may physically affect transformers and other hardware components or on whether different allocations of fast charging facilities can reduce the adverse effects on the power grid. Finally, other framework conditions (e.g., policies and legal aspects) as well as the user integration is still associated with high uncertainties and should be addressed in further research, too.

6 | CONCLUSIONS

Power demands for fast charging of PEV were found to be highly concentrated and might consequently jeopardize the electricity grid. Our analysis on an extreme scenario (i.e., minimal amount of FCS, no flexibility in charging, high market penetration of PEV, and an analysis of the distribution and transmission grid) leads, however, to a rather optimistic perspective. With the transformation of the power system, including the grid integration of high shares of renewables on the one hand and additional loads from an electrification of other sectors on the other hand, we found that critical bottlenecks in the corresponding reinforced grid infrastructure are hardly affected by fast charging. Considering only extra high voltage transmission grid restricts and an inflexible load, we even observed a small positive effect on the share of renewables due to fast charging, as the load patterns of fast charging and of the feed-in of renewables are positively correlated. By including the high voltage distribution grid restrictions, however, we found a negative grid impact of fast charging. Although no significant impact on potentially critical load situation was found, our observations indicate an overall increase of active grid restrictions, resulting in an increase of CO_2 emissions. Hence, from the current perspective, the higher grid levels of the future European electricity grid seem to be able to cope with high shares of PEV. Only on the local level, some shortages may occur—especially if the charging remains non-flexible. In order to consider these potential congestions in the future energy system, the representation of this impact from FCS on the high voltage distribution grid might play an important role in energy system models.

CONFLICT OF INTEREST

The authors declare no conflict of interest.

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DATA AVAILABILITY STATEMENT

The data that support the findings of this study are available in the supporting information of this article. Some data are, however, confidential. Therefore, not all research data are shared. There are further explanations in the supporting information.

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SUPPORTING INFORMATION

Additional supporting information may be found in the online version of the article at the publisher's website.

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APPENDIX: FURTHER DATA AND FIGURES

TABLE A1 Overview of sets, parameters, and variables from our model

Sets	
N	Set of nodes
Ω	Set of edges
$\Omega^{TDG}, \Omega^{TG}_{AC}, \Omega^{TG}_{HVDC}, \Omega^{DG}, \Omega^{ZG}$	Subsets of edges
Ω_n	Subset of edges with a connection to node $n \in N$
T	Set of time steps
G	Set of generators
$G^+, G^-, G^{HVDC^+}, G^{HVDC^-}, G^S$	Subset of generators
G_n	Subset of generators with a connection to node $n \in N$
D	Set of consumers with fixed electricity demand
D_n	Subset of consumers with a connection to node $n \in N$
S	Set of storages
K	Set of points for the piecewise linear loss approximation
Parameters	
$P_{d,t}$	Fixed electricity demand of consumer $d \in D$ in time step $n \in N$
φ_{nm}	Branch susceptance of edge $(n, m) \in \Omega^{TDG}$
g_{nm}	Branch reactance of edge $(n, m) \in \Omega^{TDG}$
$\Delta\theta^k_{nm}$	Phase-angle difference at point $k \in K$
η_g	Generator efficiency
x^{max}_t, x^{min}_t	Upper and lower bounds on variables $x \in \{p_{g,t}, f_{nm,t}, \zeta^{in}_{s,t}, \zeta^{out}_{s,t}, v_{s,t}\}$
c^{fuel}	Fuel price
$CO2_f$	CO_2 emission factor
c^{CO2}	CO_2 emission allowance price
c^{opex}	Variable operational expanses
Variables	
$p_{g,t}$	Power generated or consumed from generator $g \in G$ in $t \in T$
$f_{nm,t}$	Power flow on edge $(n, m) \in \Omega$ in $t \in T$
$l_{nm,t}$	Power loss on edge $(n, m) \in \Omega$ in $t \in T$
$\theta_{n,t}$	Phase angle of node $n \in N$ in $t \in T$
$\zeta^{in}_{s,t}, \zeta^{out}_{s,t}$	External power inflow to and outflow from storage $s \in S$ in $t \in T$
$v_{s,t}$	Stored energy in storage $s \in S$ in $t \in T$

TABLE A2 Numbers and capacities of generators of the considered grid levels

	Number			Capacity [GW]		
Generator type	**DG**	**TG**	**ZG**	**DG**	**TG**	**ZG**
Conventional	0	436	613	0	198.49	233.16
Non-shiftable renewables	4485	246	21	676.80	115.14	825.77
Storage generator	954	707	231	77.22	40.83	124.03
Storage load	954	688	231	77.22	37.27	124.03
Shiftable renewables	3925	185	29	18.57	1.35	55.75
Shiftable load	4855	467	42	49.26	7.99	42.04

TABLE A3 Model output: Electricity demand by PEV and correlation with load as well as with residual load: Fast charging leads to decreasing peak load by PEV—mainly because there is a negative correlation of fast charging load patterns and (residual) load

		Electricity demand by PEV				Correlation	
System	Scenario	Sum [TWh]	Max [GW]	Avg in Top1% [GW]	Avg in Top1% residual load [GW]	PEV and load [%]	PEV and residual load [%]
Euro-pean PS	I HC	366	106	89	82	55	41
	II HC + FCS	366	105	87	81	55	40
	delta (II-I)		−1.4	−2.0	−1.1	−0.09	−0.85
DC-OPF SS	I HC	197	59	49	44	52	35
	II HC + FCS	197	58	48	43	51	33
	delta (II-I)		−1.4	−1.5	−0.9	−0.49	−1.42

TABLE A4 Model output: Sum of load shedding [GWh] and maximum load shedding [MW] in 2050: The impact from fast charging increases the load shedding by about 430 GWh because of the grid bottlenecks identified by the CD-OPF sub-system. The European consideration increases the peak in maximum load shedding (for a few hours) considerably

		Sum of load shedding [GWh]		Maximum load shedding [MW]	
System	Scenario	NoFlex	Flex	NoFlex	Flex
European PS	I HC	1549	1452	6741	1262
	II HC + FCS	1976	1879	7107	1476
	delta (II-I)	427	428	366	214
DC-OPF SS	I HC	1532	1452	1303	1262
	II HC + FCS	1958	1880	1515	1476
	delta (II-I)	427	428	212	214

TABLE A5 Model output: Load and residual load for 2050: The relative difference in the (residual) load in the overarching European model equals the one from the DC-OPF sub-system; that is, the fast charging leads to smaller load peaks in both, the overall load and the residual load

		Load			Residual load		
System	Scenario	Sum [TWh]	Max [GW]	Avg in Top1% [GW]	Sum [TWh]	Max [GW]	Avg in Top1% [GW]
Euro-pean PS	I HC	3917	692	464	332	440	345
	II HC + FCS	3917	690	465	332	438	344
	delta (II-I)		−2.2	−1.2		−1.6	−0.8
DC-OPF SS	I HC	1848	330	309	118	215	182
	II HC + FCS	1848	327	308	118	213	181
	delta (II-I)		−2.2	−1.3		−1.6	−0.8

TABLE A6 Model output: Sum of load shedding [GWh] and CO_2 emissions as well as share of wasted electricity from renewables considering only the UHV grid for 2050

	Scenario	NoFlex	Flex
Sum load shedding [GWh]	I HC	638.5	0
	II HC + FCS	599.9	0
	delta (II-I)	−38.67	0
CO_2 emissions [Mt]	I HC	199.62	156.07
	II HC + FCS	199.28	156.32
	delta (II-I)	−0.34	0.26
RES waste [%]	I HC	8.09	4.87
	II HC + FCS	8.07	4.88
	delta (II-I)	0.02	0.01

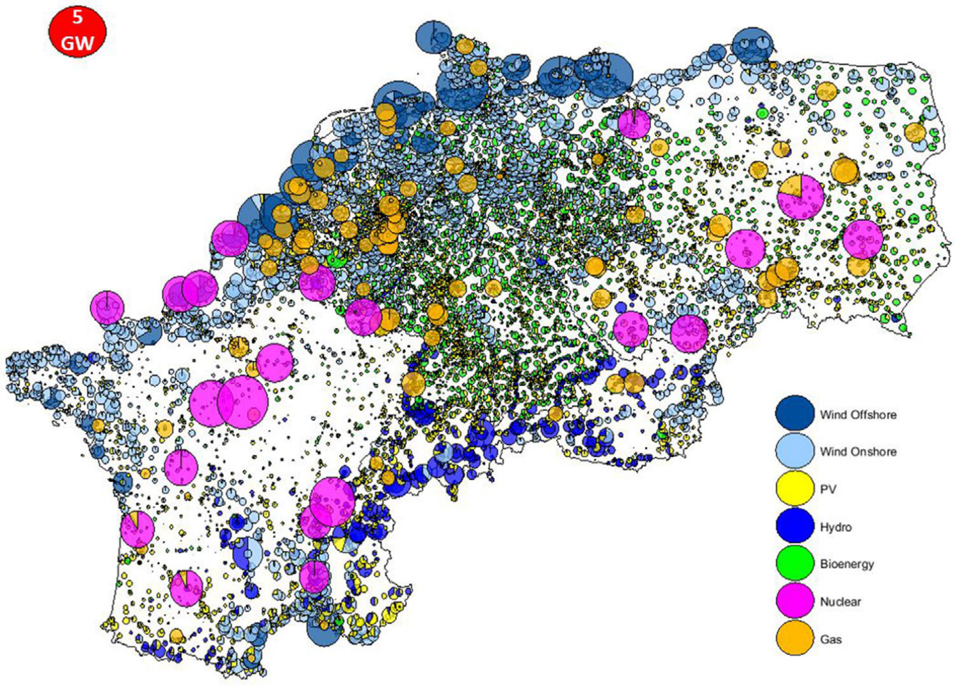

FIGURE A1 Installed capacities in our considered grid for 2050

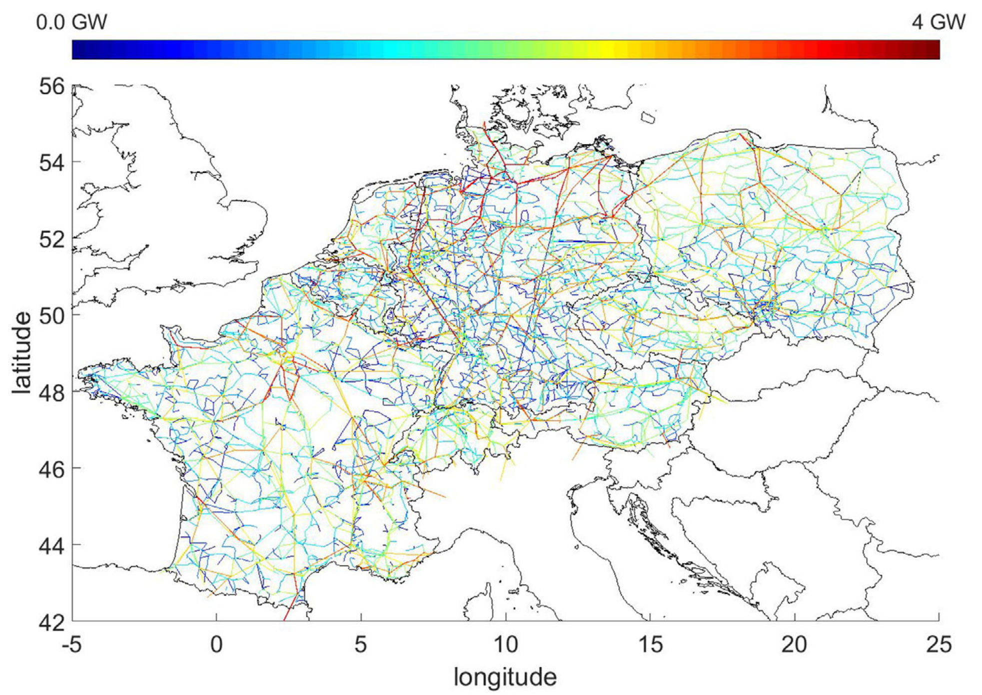

FIGURE A2 Power flow in hour with largest load shedding in 2050