Assessing the Impacts of Market-Oriented Electric Vehicle Charging on German Distribution Grids

Birgit Schachler*, Anya Heider*, Tim Röpke*, Florian Reinke† and Carsten Bakker‡
* Reiner Lemoine Institute gGmbH, Berlin, Germany
{birgit.schachler, anya.heider, tim.roepcke}@rl-institut.de
† 50Hertz Transmission GmbH, Berlin, Germany
florian.reinke@50hertz.com
‡ Elia, Brussels, Belgium
carsten.bakker@elia.be

***Abstract*—Market-oriented charging, based on real-time electricity prices, was in a previous study shown to benefit the integration of variable renewable energy sources (VRES) by significantly reducing market-driven curtailment. In this study, we assess the impact of market-oriented charging of electric vehicles (EVs) on medium-voltage (MV) and low-voltage (LV) grids in Germany and compare it to an uncoordinated charging. The analyses are conducted on synthetic grid topologies for a 2030 scenario with 10 million passenger cars.**

We show that market-oriented charging has different effects on the assessed grid types. In photovoltaics (PV)- and wind-dominated grids, as well as load-dominated suburban and rural grids, a minor increase in load-driven grid issues is observed, predominantly due to wind-feed-in driven charging peaks in the winter. Feed-in curtailment, however, is slightly reduced, which can mainly be attributed to a reduction of PV curtailment. In urban grids, on the other hand, market-oriented charging results in a significant increase in the number and degree of load-driven grid issues.

As urban grids only make up around 7 % of German MV grids, the impact for entire Germany is found to be moderate. Assuming load-driven grid issues could be solved by a curtailment of charging demand, it is found that market-oriented charging results in an increased curtailment of only 0.7 % of the total charging demand. A sufficiently high benefit in overlaying grid levels could thus outweigh the drawback of increased stress on urban grids.

I. Introduction

To reach carbon-neutrality in the mobility sector, the share of EVs will significantly increase [1]. This poses challenges for distribution system operators (DSOs), as EV charging increases stress on the grid and may require network expansion or reinforcement [2]. On the other hand, due to their long standing times and large cumulated battery capacities, EVs can constitute a flexibility option that can help with their grid integration as well as the integration of VRES [3].

One possibility to utilise the synergies of EVs and VRES is exposing EVs to real time electricity prices [4]. In a study conducted by the transmission system operator Elia Group, it was shown that market-oriented charging can significantly reduce market-driven VRES curtailment and is thus beneficial for the overall operational costs of the power system [5]. However, some studies critically note that market-oriented charging may lead to high simultaneities of charging, that can induce severe grid issues in distribution grids [1], [2], [6]. Therefore, not only systemic effects should be considered in the assessment of this charging strategy, but also impacts on the distribution grid.

So far, few studies evaluate the impact of market-oriented charging on distribution grids [6]–[9]. While [8] and [9] respectively analyse the impact on a single LV grid, only the distribution grid studies [6] and [7], conducted for the German federal states Baden-Wuerttemberg and Hesse, evaluate the effects of market-oriented charging on a larger set of differently characterised LV, MV and high-voltage (HV) grids. In [7], solely an increase in the simultaneity of charging is assumed, without further explanation. In [6], on the other hand, to draw conclusions on how the simultaneity factors used in conventional grid planning are impacted, the change in the maximum positive and negative residual load with regard to uncoordinated charging is analysed. They find that the maximum positive residual load is significantly increased, especially in urban and suburban grids. In these, it rises to up to 150 % in MV grids and up to 170 % in LV grids. The impact on rural grids is much smaller with an increase of up to 120 %. The maximum negative residual load, signifying a reverse power flow, is at times increased by up to 5 % and decreased by up to 2 %.

However, only considering the impact on worst cases falls short on providing insights on frequency and duration of newly arising grid issues - factors that become important when assessing the potential of temporal flexibility options as an alternative to conventional grid expansion. This study therefore focuses on time series based analyses. Instead of grid expansion costs, the necessary curtailment of feed-in as well as demand to solve arising grid issues is determined. It is used to analyse at what times market-oriented charging, in contrast to uncoordinated EV charging, is beneficial or adverse for distribution grids and to give an indication as to whether grid integration of VRES is aided. It is further used to evaluate the potential of a flexibility measure where DSOs are allowed to curtail charging demand for up to two hours per day, as is currently possible for heat pumps (HPs), to avert grid issues due to EV charging.

Our analysis builds upon the study by Elia Group [5] that assessed the benefit of market-oriented charging for the overall electricity system. They considered a 2030 scenario with 10 million electric passenger cars and around 90 GW of PV and 80 GW of wind onshore capacities, based on a scenario from the network expansion plan (NEP) (version 2019) [10]. We use representative, synthetic MV distribution grid topologies including underlying LV grids, representing the entirety of German MV grids, to address the following research questions:

- How does market-oriented charging influence overloading and voltage issues in MV and LV grids compared to uncoordinated charging?
- Can market-oriented charging provide a meaningful flexibility to facilitate the integration of renewables into MV and LV distribution grids?

The following Section II provides details on the used scenario framework and distribution grid topologies, as well as on how grid issues and necessary curtailment to solve these are determined. The results are presented in Section III and discussed in Section IV. The paper concludes with a summary of the main results in Section V.

II. Methodology

Two scenarios are evaluated in this study: one with an uncoordinated charging of EVs and one with a market-oriented charging. Section II-A describes the general scenario framework used for both charging scenarios as well as the regionalisation of generation capacities and loads, necessary for distribution grid analyses. Details on the regionalisation of EV demand are given in Section II-B along with further information on the two considered charging strategies. Afterwards, the analysed grid topologies are presented in Section II-C, followed by details on how the impact on grids is determined in Section II-D.

A. Scenario framework

As this study builds upon a study conducted by Elia Group [5], we use the same general scenario framework, which is formed by the *B-2030* scenario taken from the German network development plan [10]. The underlying assumption is a renewable penetration able to serve 65 % of the load in a moderate sector coupling scenario. In order to convey a faster increase of EV penetration, the scenario framework is adjusted by considering 10 million instead of 6 million passenger cars. Table I presents the Germany-wide generator capacities and consumption of loads relevant to MV and LV grids.

TABLE I: Germany-wide scenario framework

Installed generator capacities in GW				
Solar	Wind onshore	Run-of-river	Other RES	Gas
91.3	81.5	5.6	7.3	35.2
Annual consumption of loads in TWh				
EVs	HPs	P2M	P2H	Conventional
22.3	18.2	0.3	10.0	476.0

The displayed values include all voltage levels and are Germany-wide. To obtain highly spatially resolved data for the relevant grid levels, we assume the same proportional geographic and grid-level-specific distribution of generation and load as in the *NEP 2035* scenario developed in the *open_eGo* research project [11].

Sector coupling elements were not considered in the *open_eGo*-scenario and therefore require special treatment. The allocation of EV demand is further explained in Section II-B. HPs are assumed to be predominantly installed in households. Their demand is thus allocated to households, proportionally to the demand of the respective household. Power-to-methane (P2M) units are assumed to be located at biogas plants. To retrieve location-specific data, the state-wise installed capacities of P2M plants from [10] are allocated to biogas plants proportionally to the respective biogas plants' capacity. Power-to-heat (P2H) includes both industrial and district heating appliances. Industrial appliances are assumed to be located in the HV level and thus not further considered. District heating appliances, on the other hand, can be connected to both the HV and MV level. We assume the same share of district heating appliances in the MV in 2030 as today. The appliances are allocated to areas that are due to their high load density well suited for district heating.

Dispatch and demand time series of the regionalised units are obtained by taking Germany-wide time series for the different types of generators and loads from [5] and proportionally scaling them with the respective installed capacity of generators or annual consumption of loads. In [5], a European electricity market model is used to determine the dispatch of generators and P2X-units. As charging demands of both analysed scenarios vary over time, this results in differing generator dispatches determined by the market model.

B. Electromobility demand

Germany-wide electromobility demand time series for both charging scenarios are as well obtained from [5]. In [5] a transportation model to generate individual driving behaviour of EVs is used. The model utilises historical mobility data from Germany published in [12]. The data include information on start and end times of trips, purpose of trips, and distance traveled. Output of the model are the electric consumption and available time slots for charging throughout the day of each modelled EV. Further, information on the type of charging location is given. In the transportation model it is distinguished between three types of charging locations - home, work and public - whereas for public charging it is further distinguished between slow and fast charging. This is relevant to account for different probabilities for charging opportunities as well as different available charging powers. As an example, the availability of home charging stations is assumed to be highest with 80 % and lowest for public charging stations with only 20 %. Concerning charging powers, public charging stations are assumed to mainly consist of 11 kW and 22 kW chargers, while charging stations at home and work are assumed to mainly consist of 3.7 kW chargers.

The charging demand in case of uncoordinated charging is obtained by assuming that each EV is plugged in immediately after arriving at a charging point and charged with the maximum power available. For the market-oriented charging the generated time slots of possible charging times of each individual EV are combined with a European market model to determine optimal periods to charge the vehicle, with the goal to minimize electricity costs for charging.

The resulting average charging demand for entire Germany in both charging scenarios is shown in Fig. 1. It can be seen that market-oriented charging leads to a shift of the charging demand away from evening hours to night time hours and noon. The Germany-wide peak load of EV

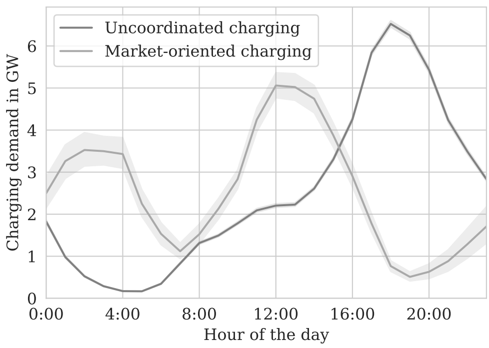

Fig. 1: Average charging demand in entire Germany in case of uncoordinated and market-oriented charging

charging is nearly tripled through market-oriented charging, from 9.4 GW to around 26.7 GW. The Germany-wide total peak load, on the other hand, is slightly decreased.

As distribution grid analyses require data in high spatial resolution, the provided Germany-wide data is regionalised. To this end, first, the Germany-wide demand is allocated to each NUTS 3 region according to [13]. Afterwards, the regionalisation inside each NUTS 3 region is conducted by determining potential charging sites for each considered type of charging location based on geographical data. Each possible charging site is assigned an attractivity that is later used to determine which charging station charging demand is allocated to. The approach taken to identify potential charging sites for each type of location and to determine their attractivity is as follows:

a) Home charging: The allocation of home charging stations is based on the number of apartments in each 100 x 100 m grid inside the respective NUTS 3 region given by Zensus 2011 [14]. In every grid cell, the total number of registered apartments is determined. The cell with the highest number of apartments receives the highest attractivity.

b) Work charging: The allocation of work charging stations is based on the area classification obtained from OpenStreetMap (OSM) [15] using the *landuse* key. Work charging stations are allocated to areas tagged with *commercial*, *retail* or *industrial*. The attractivity of each area depends on the size of the area as well as the classification. Commercial areas receive the highest attractivity, followed by retail areas. Industrial areas are ranked lowest.

c) Public charging (slow): The basis for the allocation of public charging stations are points of interest (POI) from OSM. POI can be schools, shopping malls, supermarkets, etc. The attractivity of each POI is determined by empirical studies conducted in previous projects.

d) Fast charging: The basis for the allocation of fast charging stations are the locations of existing petrol stations obtained from OSM. The locations are ranked by the traffic volume of streets within a 900 m radius.

Once potential charging sites are determined, the charging demand is allocated to specific sites taking into account the attractivity as well as the distribution of charging rates from [5].

C. Distribution grid topologies

1) Modelling of grid topologies: The utilised grid topologies are generated using the open-source software *ding0* [16], [17], developed in the research project *open_eGo* [11]. *ding0* is a tool that synthesizes MV and LV grid topologies for Germany based on highly spatially-resolved data of electricity demand, land use, demography and generation capacities (see [18] for further details). The resulting dataset comprises over 3,300 MV grids with underlying LV grids.

The aim of the *open_eGo* project was to determine grid expansion needs due to the expansion of renewables. Therefore, the focus lay on rural and suburban areas. Grid topologies in urban areas can currently not be modelled with *ding0*, due to a lack of data. As the inclusion of urban areas is essential for the evaluation of the impact of EVs on the grid, urban grids are modelled separately in this study, based on highly load-dominated grids modelled with *ding0*. The approach taken for urban grids is described in Section II-C4.

In *ding0*, MV networks are modelled as open ring topologies, considering historically load-oriented development and current planning principles for distribution networks. In the generation of the MV topologies it is distinguished between suburban and rural areas. Grids in suburban areas are usually equipped with underground cables at a voltage of 10 kV, whereas grids in rural areas predominantly consist of overhead lines at a rated voltage of 20 kV. The methodology to synthesize MV grid topologies is thoroughly described in [16]. An exemplary synthetic MV grid topology is shown in the Appendix in Fig. 8. LV networks are modelled as radial topologies based on reference grids from literature [19], [20]. Further information is given in [11].

2) Update grid topologies to status quo 2018: The grid topologies modelled with *ding0* are generated using a data basis of the year 2015. In order to obtain grid topologies that better reflect the current state of distribution grids in Germany, the grids are updated with respect to PV, wind and biomass capacities, as these have changed most significantly in the past years. For this, installed capacities per federal state (NUTS 1 region) for the year 2018 are taken from [21] and inside each state regionalised based on the spatial distribution in the *open_eGo* scenario *NEP 2035*.

The integration of new generators may require an expansion of the grid. Grid expansion needs are evaluated using the two design cases, heavy load flow (HLF) and reverse power flow (RPF), currently applied by DSOs. For this, simultaneity factors as stated in [22] are used. Arising grid issues are determined through a non-linear power flow analysis and afterwards checking compliance with allowed loadings and voltage deviations as explained in Section II-D. The grids are expanded using the automated grid expansion methodology implemented in the open-source software *eDisGo* [23] and thoroughly described in [22].

3) Identification of representative grids using clustering: As simulating the total number of over 3,300 MV grids is beyond the scope of this study, a spatial complexity reduction yielding a representative subset of the grids is conducted. For this purpose, the k-medoids algorithm is used to identify clusters of similar networks [22]. Out of each cluster one grid serves as a representative further detailed analyses are conducted on. The result of the clustering is a set of 15 MV grids with underlying LV grids, representing the entirety of rural and suburban German distribution grids.

The features used to create the clusters should reflect the pursued purpose of the clustering. In this study, the clustering is used to determine impacts on the distribution grids from adding 2030 scenario assumptions on additional generation capacities and loads to a 2018 grid status. Therefore, the grids are clustered based on the following four independent features that are considered to have the largest impact on arising grid issues and are in line with the approach taken in the dena study Integrated Energy Transition [24]:

- Expansion of PV from status quo 2018 to 2030,
- Expansion of wind onshore from status quo 2018 to 2030,
- Peak load of HPs,
- Peak load of EV charging.

4) Assumptions for urban grids: As stated before, urban grids can currently not be modelled with *ding0*. Therefore, the most heavily load-dominated, non-urban representative grids determined through the clustering serve as a basis to analyse the impact on urban grids. The capacities of PV and wind, as well as demand of HPs and EVs are adapted to better reflect typical values of urban grids.

Regarding generator capacities, it is assumed that wind capacities in urban areas are negligible, while there will be a moderate expansion of PV until 2030. To determine mean PV capacities in urban grids, the installed capacities of the cities Bremen, Berlin and Hamburg, given in the *B-2030* scenario [10], are used and assumed to be equally distributed per area, amounting to an average PV capacity per MV grid of around 2 MW.

On the demand side it is assumed that the share of HPs in urban areas can be neglected due to the high specific heat demand that makes these areas more suitable for district heating. The mean EV demand in urban areas is obtained using the regionalisation of EV demand from [13]. It is found to be by a factor of 4.3 higher than the EV demand in the used load-dominated, non-urban representative grids, resulting in large charging station capacities. It is assumed that within the service area of an LV grid, 50 % of the total charging station capacity is connected to the MV side of the MV-LV station.

5) Considered representative grids: Through the clustering, 15 representative grids are determined, representing the entirety of German MV grids in rural and suburban areas. To evaluate the impact of the two charging scenarios on different types of grids, the 15 representative grids are categorised by whether they are PV-, wind- or load-dominated. Grids not clearly dominated by either are categorised as *Other*. Due to their diversity, they are not separately discussed in this study but included in the results for entire Germany. Further, the three most load-dominated, non-urban grids serve as a basis for urban grids, resulting in a total of 18 representative grids.

Table II displays the number of representative grids used for detailed analyses of each grid type as well as the share of each grid type of the entirety of the over 3,300 MV grids. It shows, that load-dominated (non-urban) grids make up the largest share of grids. Wind-dominated grids only make up around 7 % of the MV grids in Germany, as a large share of the total wind capacity is connected to the HV level.

TABLE II: Number of representative grids and share per grid type

	Number of repr. grids	**Share of grids represented**
PV-dominated	4	22.9 %
Wind-dominated	3	6.7 %
Load-dom. (non-urban)	4	53.0 %
Urban	3	6.6 %
Other	4	10.8 %

The most important features of the four grid types discussed in more detail are presented in the Appendix in Table IV. To obtain results for the entirety of German MV and LV grids, results for the representative grids are scaled up by the number of grids they represent.

D. Evaluation of grid issues and necessary curtailment

To assess the impact of market-oriented charging on the MV and LV grids and compare it to uncoordinated charging, arising voltage and overloading issues are determined for both charging scenarios. This analysis is based on annual time series in hourly resolution. Afterwards, the necessary curtailment of load and feed-in to solve arising grid issues is determined. It is used to evaluate if grid issues are load- or feed-in-driven and serves as an indicator for flexibility need within the grids.

Grid issues arising from additional load and distributed generation are determined by conducting a non-linear power flow analysis and afterwards checking compliance with voltage requirements and technical guidelines regarding equipment loading. The power flow analysis is conducted using the open-source software *PyPSA* [25]. The secondary side of the HV-MV-station is set to be the slack bus. All other buses are modelled as PQ buses, where active and reactive load and feed-in are given.

Using equipment loading and voltage deviations obtained through the power flow analysis, overloading and voltage issues are determined by applying allowed load factors and voltage deviations stated in [22]. The allowed equipment load factors reflect that the (n-1) principle applies for consumers connected to the MV grid. Concerning allowed voltage deviations used to identify voltage issues, the allocation of the allowed voltage deviation of ± 10 % takes into account that the majority of loads is connected in the LV and therefore reserves a larger voltage band in the LV for the load case. In the reverse power flow case a larger voltage band is reserved for voltage rise in the MV grid.

The necessary curtailment of load and feed-in to solve arising grid issues is determined by iteratively lowering the demand respectively feed-in in steps of 5 % and after each iteration step rechecking for grid issues as described. Grid issues in the LV are solved first, followed by issues at MV-LV stations and finally issues in the MV, as the curtailment of loads and generators in the lower voltage levels can already solve or reduce grid issues in the MV grid. Grid issues within the MV and LV are solved starting with the issue farthest away from the respective station, as again solving grid issues at one point in the grid can already solve or lower problems upstream.

TABLE III: Change in maximum positive and negative residual load per grid type. Values above 100 % indicate an increase in the maximum residual load in the market-oriented charging scenario.

Grid type	**Max. positive residual load**	**Max. negative residual load**
PV-dominated	87 % - 100 %	85 % - 98 %
Wind-dominated	58 % - 91%	98 % - 100 %
Load-dom. (non-urban)	96 % - 105%	-
Urban	111 % - 183%	-

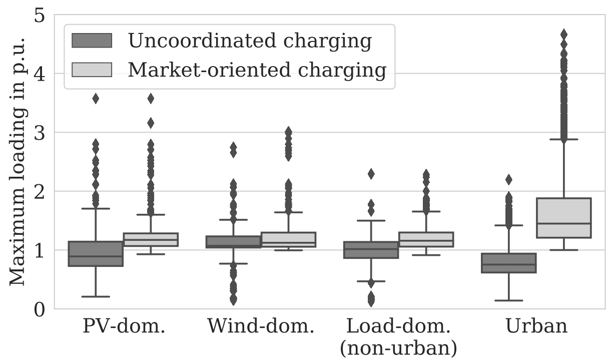

Fig. 2: Maximum loading of lines and transformers. Only components that are overloaded in one of the two charging scenarios are included.

III. Results

A. Impact on residual load and maximum loading of components

Table III gives the change in maximum positive and negative residual load (total demand minus feed-in in MV and underlying LV grids) between the uncoordinated and market-oriented charging scenario for the different types of grids differentiated in this study. Maximum values in the uncoordinated charging scenario serve as the reference. Thus, values above 100 % signify an increase in maximum residual load in the market-oriented charging scenario, whereas values below 100 % indicate a decrease. While market-oriented charging mainly decreases the maximum positive residual load in generation dominated grids, it is largely increased in urban grids. In load-dominated (non-urban) grids, both an increase as well as a decrease can be observed. Concerning the maximum negative residual load, signifying the maximum reverse power flow, Table III shows, that it is as well decreased in generation-dominated grids. The decrease is with up to 15 % in PV-dominated grids generally higher than in wind-dominated grids, where it can only be diminished by up to 2 %. As in load-dominated non-urban and urban grids the demand is always higher than the infeed, the residual load is always positive.

The influence of the different charging behaviours on single grid components is visualised in Fig. 2. It shows the maximum loading of all components that are overloaded in either one of the two scenarios. In case of urban grids it can be seen, that the maximum loading of components is significantly increased. Also, an increase in the number of overloaded components can be seen, indicated by the increased amount of data points with maximal loadings above 1 p.u.. Both the number of overloaded components and the maximum loading serve as an indicator for grid reinforcement needs if no other flexibility options can be utilised. For PV- and load-dominated (non-urban) grids, we can also observe an increase in the number of overloaded components and maximum loading, though not as significant as in urban grids. For wind-dominated grids, we find that the maximum loading does not significantly change as it is for most components in these grids reached due to high feed-in and only slightly impacted by the shift of charging demand into times of high feed-in.

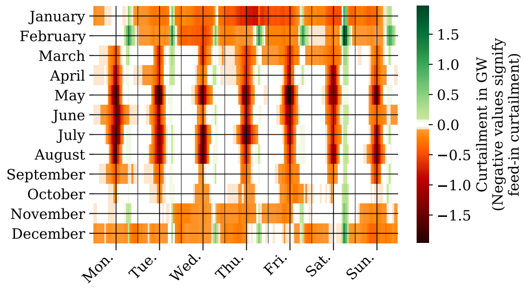

Fig. 3: Necessary curtailment of charging demand and feed-in of VRES to solve grid issues in the German MV and LV grids in the uncoordinated-charging scenario. Weekday labels signify noon of the specified day.

B. Necessary curtailment to solve arising grid issues

The temporally resolved necessary curtailment to solve grid issues can visualise the need for flexibility within a grid. Fig. 3 shows the necessary curtailment in all German MV and LV grids induced by new consumers and infeed from distributed generators in case of uncoordinated charging. It can be seen that load-driven grid issues predominantly occur during evening hours, most severely in the winter. During summer months, charging demand curtailment is mainly observed in urban grids. Feed-in driven grid issues mainly occur in summer around noon due to high PV feed-in and in winter due to high wind feed-in.

Through market-oriented charging, EV demand is shifted away from times of high residual load to times with high VRES infeed, characterised by low electricity prices. The resulting difference in the necessary EV charging curtailment between market-oriented and uncoordinated charging in urban and wind-dominated grids is shown in Fig. 4. It is scaled to the respective EV peak charging demands in the market-oriented charging scenario to enhance comparability. The figure shows that market-oriented charging reduces grid issues during evening hours in both urban and wind-dominated grids. This is also true for the other grid types not shown here. Overall, market-oriented charging decreases the charging demand during evening hours to such an extent that grid issues are almost fully diminished.

However, at other times, a severe increase in necessary EV charging curtailment can be observed that is due to high simultaneities of charging events. These events mainly occur during night hours in winter months with high wind feed-in and in summer around noon, predominantly on weekends,

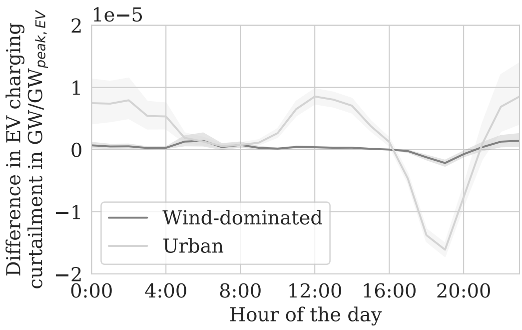

Fig. 4: Average difference in EV charging curtailment between market-oriented and uncoordinated charging in urban and wind-dominated grids. Negative values signify a higher curtailment in case of uncoordinated charging.

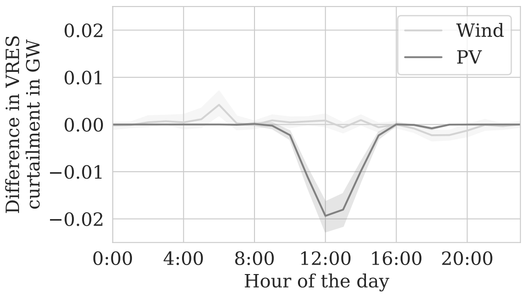

Fig. 5: Average difference in VRES curtailment between market-oriented and uncoordinated charging in the German MV and LV grids. Negative values signify a higher curtailment in case of uncoordinated charging.

with high feed-in from PV. Besides being characterised by a high feed-in, these are times when many people are assumed to be at home with a high availability of charging opportunities.

The high charging simultaneities result in more severe grid issues in urban grids than in wind-dominated grids, as the higher specific EV charging curtailment in urban grids in Fig. 4 shows. In wind-dominated grids, it can be observed that through market-oriented charging the necessary EV charging curtailment is mainly increased during the night, while it is not increased in times around noon. Therefore, it can predominantly be attributed to wind-feed-in driven charging peaks. In PV- and load-dominated (non-urban) grids, PV-feed-in driven charging peaks also generally result in less necessary charging curtailment than wind-feed-in driven charging peaks.

Besides resulting in less necessary charging curtailment, PV-feed-in driven charging peaks also result in a higher reduction of VRES curtailment than wind-feed-in driven ones, as can be observed in Fig. 5 by the larger reduction of PV curtailment. However, in total, the reduction of necessary VRES curtailment to solve grid issues through market-oriented charging, though observable in all grids with feed-in driven grid issues, is only minor, as shown in Fig. 6. The reductions can almost entirely be attributed to a reduction of PV curtailment in the LV level. On the load side, an increase in necessary EV charging curtailment of around 12 % can be seen that can mainly be attributed to urban grids, while in

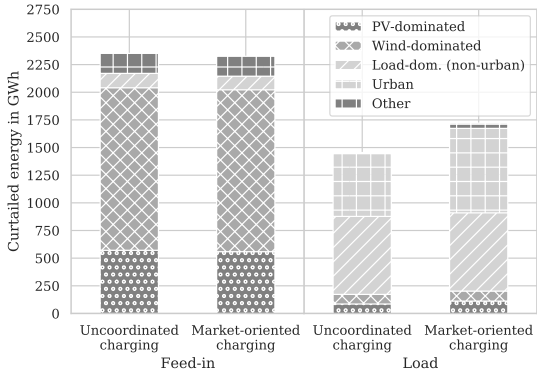

Fig. 6: Total necessary curtailment of charging demand and VRES feed-in to solve grid issues in the German MV and LV grids differentiated by type of grid.

the other types of grids, necessary load curtailment does not increase significantly.

C. Probability of charging interruption events

According to § 14a EnWG, German DSOs are entitled to control EV charging. The details of this are however still under discussion. In the case of heat pumps, DSOs currently have the means to interrupt electricity supply for two consecutive hours and a total of no more than six hours per day (cf. § 7 BTOElt) to avoid critical grid loads. We therefore further analyse how often EV charging at all modelled charging points needs to be curtailed for up to two hours and more than two hours. This analysis indicates whether any of the two charging strategies would be better suited for DSOs to avoid grid issues through the measure of curtailing EV charging demand for up to two hours.

Fig. 7 presents the results of this evaluation for load-dominated grids, differentiated by season. Summer months comprise June, July and August, and Winter months December, January and February. It shows that the probability of necessary charging interruptions of more than two hours is near 0 % in the summer and transition months for both charging scenarios. In the winter months, however, the probability of these events increases and lies around 7 % in case of uncoordinated charging. Through market-oriented charging, the probability of necessary charging interruptions of more than two hours is reduced and lies around 4 %. These effects can as well be observed in the other grid types, though in PV- and wind-dominated grids the probabilities of charging interruptions are generally smaller, while in urban grids they are generally higher. Here, also in the summer a considerable probability of necessary charging interruption can be observed with up to 15 % in case of uncoordinated and 7 % in case of market-oriented charging.

IV. Discussion

The results show that uncoordinated charging mainly leads to grid issues during evening hours when EV charging demand coincides with high conventional electricity demand. This effect becomes even more severe in the winter months with an additionally high electricity demand of HPs. Through market-oriented charging, EV charging is shifted away from these times, which almost entirely diminishes

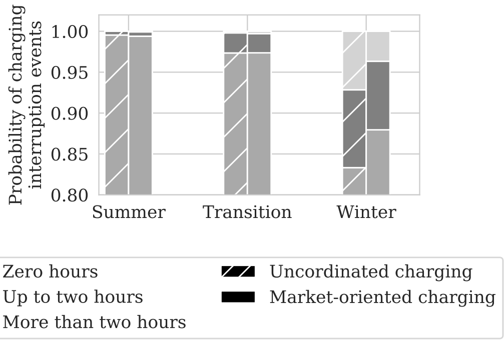

Fig. 7: Probability of charging interruption of zero, up to two and more than two hours for load-dominated grids, differentiated by season.

grid issues during the evening hours. At other times, however, market-oriented charging leads to high charging peaks that result in more severe grid issues than in the case of uncoordinated charging. The highest charging peaks occur during night hours in winter months with high wind feed-in and on summer weekends around noon with high PV feed-in. During these times, many people are assumed to be at home and to have charging opportunities, wherefore the potential of shifting charging into those times is high.

In urban grids the charging peaks result in a significant increase in the number of overloaded lines and transformers, their maximum loading and the necessary EV charging curtailment to solve load-driven grid issues, while in the other types of grids only a small increase in these values can be observed. As urban grids make up around 7 % of the German MV grids, the overall impact can be considered moderate, with an increase of the Germany-wide necessary charging demand curtailment of only 0.7 % of the total charging demand.

There are different reasons for the higher impact of market-oriented charging on urban grids. For one thing, in the other types of grids some grid expansion was already conducted due to the expansion of renewables. Therefore, these can take up more additional load than the urban grids. The state of the urban grids, however, holds the largest degree of uncertainty in this study, as highly load-dominated suburban grids are used as a basis for their modelling. Another reason is that the ratio of EV demand and conventional electricity demand in urban areas is assumed to be up to four times higher than in the other types of grids. Therefore, a doubling or tripling of the charging peak power, as it can at times be observed in case of market-oriented charging, will more likely lead to higher peaks of the total electricity demand, even though charging is shifted away from peak load times of conventional electricity demand. Further, in the other types of grids, high charging peaks can be levelled out by VRES infeed to some degree.

The potential of levelling out charging peaks proves to be higher for PV-feed-in driven charging peaks than for wind-feed-in driven ones, as both PV generators and charging stations are to a large extent connected to the LV. In contrast, wind generators are predominantly connected to the MV and HV levels. Wind-feed-in driven charging peaks thus result in generally higher residual loads in the LV than PV-feed-in driven ones, leading to the higher observed necessary charging curtailment.

This effect also diminishes the levelling effects of EV charging and wind feed-in in the MV, thus limiting the potential of reducing wind feed-in curtailment and helping the integration of wind generators. Further, increases in wind feed-in curtailment can at times be observed. This can be explained by the temporal shift in charging demand in the market-oriented charging scenario. It leads to a shift from home to public and work charging, which in turn results in a spatial shift of EV charging. A possible explanation for why the spatial shift leads to an increase in mainly necessary wind curtailment is that wind generator sites are predominantly located in rural areas, whereas through the shift of charging from home to work and public charging, charging is moved into suburban parts of the grid.

In total, necessary wind-feed-in curtailment is not reduced through market-oriented charging. PV curtailment can be slightly reduced by around 3 %. Thus, the impact of market-oriented charging on the reduction of VRES curtailment due to grid restrictions in the MV and LV is only small. However, it has to be noted that it does significantly reduce market-driven VRES curtailment.

When looking at the probability of charging interruption events in both scenarios it can be observed that market-oriented charging, on average, decreases the probability that charging needs to be interrupted for more than two hours. Thus, if DSOs were allowed to curtail EV charging for up to two consecutive hours, as is currently possible in case of HPs, it would more often lead to solving load-driven grid issues without requiring further measures. In both scenarios charging interruptions of up to two hours only showed to be sufficient to solve load-driven grid issues in the summer and transition months in PV-, wind- and load-dominated (non-urban) grids. In the winter months and in urban grids in all seasons, additional measures would be required. It has to be noted, though, that the determined time spans of EV charging curtailment might be overestimated due to the applied methodology of determining the curtailment need. In this process, all charging stations behind an overload or in the same feeder with voltage issues are curtailed equally. Curtailing single charging stations to a higher degree might lead to a reduction of time spans single charging stations are curtailed. This is, however, not further investigated in this study.

On the whole, both uncoordinated and market-oriented charging come with benefits and drawbacks. On the one hand, market-driven VRES curtailment can significantly be reduced through market-oriented charging, thus reducing CO_2 emissions and further the need for temporal flexibility provision. On the other hand, market-oriented charging leads to charging peaks of up to three times as high as observed in uncoordinated charging. While the impact on load- and feed-in-driven grid issues in PV-, wind- and load-dominated (non-urban) grids is only minor, load-driven grid issues in urban grids increase significantly in number and degree, thus significantly increasing the need for spatial flexibility provision, if no other measures can be taken.

Furthermore, the here considered EV penetration of 10 million passenger cars can only be considered an intermediate stage. To reach carbon neutrality, the number of EVs is expected to further increase. This needs to go along with an expansion of renewables. The analyses conducted in this study showed that grids with only small capacities of VRES are most negatively affected by market-oriented charging. Furthermore, it was found that PV-feed-in driven charging peaks lead to less severe grid issues and have a higher potential of reducing VRES curtailment due to grid restrictions. Therefore, the spatial distribution of VRES and the share of PV will significantly impact whether the benefits or drawbacks of market-oriented charging will be predominant.

V. Conclusion

In this paper, the impacts of market-oriented charging of EVs on MV and LV grids in Germany were evaluated for a 2030 scenario with 10 million passenger cars and compared to an uncoordinated charging. It was thereby differentiated between different types of grids - PV-dominated, wind-dominated, load-dominated (non-urban) and urban grids.

The analysis showed that the impact of market-oriented charging differs significantly between the different types of grids. In urban grids, charging peaks induced by market-oriented charging led to a significant increase in the number and degree of load-driven grid issues, thus significantly increasing the need for spatial flexibility provision. In the other types of grids, however, the impact of charging peaks was not as significant. The smallest impact was seen in wind-dominated grids where feed-in driven grid issues predominate for both uncoordinated and market-oriented charging. In total, the Germany-wide necessary curtailment of EV charging demand to solve load-driven grid issues was only increased by 0.7 % of the total charging demand.

Besides a difference in the impacts of charging peaks on different grid types, a difference between wind-feed-in and PV-feed-in driven charging peaks was observed. PV-feed-in driven charging peaks on average led to less additional grid issues and a higher decrease of VRES curtailment. In total, however, the reduction of VRES curtailment due to grid restrictions in the MV and LV was negligible. Grid integration of VRES is thus not considerably improved through market-oriented charging. On the other hand, market-driven curtailment was in a previous study [5] shown to be significantly reduced by market-oriented charging, decreasing the need for temporal flexibility.

As a flexibility measure, the possibility to curtail charging demand for up to two consecutive hours, as is currently possible for HPs, was analysed. It was shown that market-oriented charging generally decreases the probability of interruption events lasting longer than two hours.

It can be concluded that both uncoordinated and market-oriented charging come with benefits and drawbacks. Further evaluations should analyse which of these benefits economically outweigh the drawbacks. For a holistic analysis, this should include the consideration of different flexibility options and all voltage levels. Further analyses could also focus on measures to avoid high charging simultaneities through market-oriented charging, e.g. by adding a local component to the coordinated charging algorithm while keeping it beneficial for the overall power system.

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APPENDIX

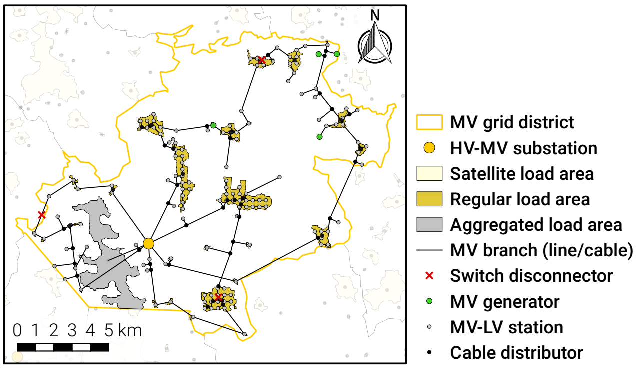

Fig. 8: Exemplary synthetic MV grid topology

TABLE IV: Characteristic parameters of representative grid topologies in 2030

	Installed generator capacities in MW	
	PV	Wind
PV-dom.	53.3 - 92.7	2.3 - 6.9
Wind-dom.	22.8 - 89.3	103.8 - 174.1
Load-dom. (non-urban)	7.3 - 22.1	-
Urban	1.9 - 2.1	-
	Annual consumption of loads in GWh	
	Conventional (incl. HPs)	EV
PV-dom.	65.2 - 210.0	2.8 - 13.3
Wind-dom.	64.7 - 171.4	3.4 - 7.2
Load-dom. (non-urban)	91.5 - 363.2	4.9 - 11.0
Urban	120.8 - 247.0	19.9 - 47.0