The Impact of Variable Grid Fee Tariffs on the Electricity Costs of EV Users in Germany

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Keywords: EVs, § 14a EnWG, FLEXIBILITY MARKETING, SMART UNIDIRECTIONAL AND BIDIRECTIONAL CHARGING

Abstract

This paper investigates the impact of the 2023 framework of rules to § 14a of the Energiewirtschaftsgesetz - German Energy Industry Act, EnWG - (§ 14a framework) on electric vehicle (EV) users. The § 14a framework requires distribution grid operators (DSOs) to connect new heat pumps (HPs) and EV charging infrastructure (EVSE) while allowing them to reduce power drawn from HPs and EVSEs in case of grid overload. The DSOs are mandated to provide remuneration for these components. The study develops remuneration mechanisms in the form of variable grid fee tariffs together with DSOs, which are then implemented into an optimization model for the flexible marketing of EVs to analyse their effect on the EV charging behaviour and the total costs. The analysis reveals that the § 14a framework gives high flexibility in designing variable grid fee tariffs to meet the needs of the different distribution grids. These different tariffs enable flexible EV users to achieve substantial cost savings, thereby providing a strong incentive for the load shifting required by DSOs. This research fills a gap in understanding how the incentives outlined in the § 14a framework affect EV users.

1. Introduction

With the German energy transition, both the generation of volatile renewable energies and the electrification in the different sectors will continue to increase. For the transport sector, the transition from internal combustion-powered vehicles to electric vehicles (EVs) is a key aspect of the transition, reflected in the governmental goal of 15 million EVs in 2030, while for the building sector, it is the heat pump (HP) that replaces gas or oil-fired boilers [1], [2].

Due to this ramp-up of EVs and HPs in Germany, the distribution grids face the threat of grid overload and the need of relevant grid expansion [3]. To prevent potential grid issues by maintaining the ramp-up of EVs and HPs, an framework to the integration of controllable consumption devices in accordance with § 14a Energiewirtschaftsgesetz - German Energy Industry Act, EnWG - (§ 14a framework) was created in 2023 [4], [5]. This framework mandates that distribution grid operators (DSOs) must connect new HPs and EVSEs (controllable consumption devices, CCD) while also allowing them to reduce the power drawn from these components in case of a grid overload. While participation is required, operators of CCD will receive remuneration. All CCD operators are granted a remuneration, regardless of the power reduction they experience.
The Federal Network Agency (BNetzA) provides three options for the renumeration: a flat-rate grid fee reduction (Module 1), a flat-rate energy price reduction of the static grid fee (Module 2), and an optional time-variable grid fee tariff (Module 3). Module 1 is assigned to all CCD operators unless another module is selected. Module 2 offers an alternative to Module 1, providing a percentage reduction of the energy price of the static grid fee for the measured consumption of the CCD, requiring billing at a separate market location. The reduced energy price is 40 % of the DSO-specific energy price of the static grid fee, benefiting operators of high-consumption CCD, such as HPs in multi-family houses. Module 3 is an optional supplement to Module 1, offering additional saving potential for CCD operators. It is a static-time-variable grid fee tariff, which serves as an economic incentive for voluntary load shifting to further relieve the grid. There are three different price levels in these variable grid fee tariffs: the standard tariff level (ST), the low-pricing tariff level (NT), and the high-pricing tariff level (HT). The DSOs individually determine the time windows and levels for the NT, ST, and HT levels for their grid. The BNetzA provides framework conditions for the tariff design and one exemplary tariff. [5]

The impact of emergency shutdowns or power reduction of CCDs in different distribution grids according to the new § 14a framework has already been studied – partly in combination with variable grid fee tariffs [6], [7], [8].
In [6], the impact of the power reduction according to the § 14a framework (first draft) is analysed for different shares of EV penetration and maximal charging power for four different exemplary grids of the simbench data set. The paper reveals that the effect of the power reduction on the distribution grid varies depending on the grid type. Further, the impact on the EV user is analysed, demonstrating that the curtailment duration and frequency is the longest and highest in rural areas, with no great restriction in the individual mobility behaviour expected.
[7] also analyses the impact of the power reduction of flexible consumers (EVs and HPs) for three scenarios (‘today’,’ intermediate’, and ‘future’) for an exemplary grid of the simbench data set for one day. The authors demonstrate that

for 'today', the power reduction option of the § 14a framework can significantly reduce the grid congestion at the distribution level. For the 'future' scenario, however, the power reduction option prolongs the charging times of the EVs, resulting in higher simultaneities in total, which hinders the congestion measure from working.

In [8], the impact of variable grid fees as well as a power reduction according to the § 14a framework (draft version) for flexible consumers (EVs, HPs, home storage systems) for 2029 and 2035 are analysed for different grid types and extrapolated for Germany. Two types of variable grid fees with different grid fee designs are analysed: a variable grid fee tariff and a dynamic grid fee, based on the actual load in the distribution grid. For the dynamic grid fee, the power reduction option of the § 14a framework is included. However, the variable grid fee tariffs in this study do not correspond to Module 3 of the § 14a framework. The study shows that flexible consumers, optimizing on variable electricity prices, can stress the distribution grid. In combination with variable grid fee tariffs, however, the impact on the grid can be significantly reduced by only small reduction of the usable flexibility for the variable electricity prices. . The combination of variable electricity tariffs and variable grid fees is accompanied by the emergency power reduction of the § 14a framework in this study. It is shown that this combination allows prioritizing grids with a high demand for grid expansion and delaying grids with a lower demand for grid expansion with a only minor impact on the users.

All in all, the aforementioned literature review lacks studies addressing the remuneration mechanism of the new § 14a framework but focussing on the emergency power reduction option for the DSOs and the impact of this reduction on the grid and subsequent users.

As in [8], further literature analyses the impact of a variable grid fee tariff (not based on the § 14a framework, Module 3) on the grid and the users [9], [10].

In [9], the impact of different incentive-based grid fee tariffs (a power-related and a time-variable tariff with a peak price period of 16:00-21:00 and a low-price period of 9:00-13:00) on the distribution grid with flexible residential customers (including EVs, HPs, PV systems, and home storage systems) for one exemplary grid and one exemplary week is analysed. It is shown that the power-related tariff results in a more balanced load at the transformer while the time-variable tariff results in new higher load peaks, which makes emergency congestion necessary. However, in the exemplary week, all reduced loads could be recovered without loss of comfort for the users.

E-Bridge discussed and promoted variable grid fee tariffs for flexible grid customers in 2020 in [10]. The variable grid fee tariff consists of three levels but no fixed windows (which level is valid is communicated some hours in advance). The concept was tested in a field test from MITNETZ STROM and simulations of exemplary MITNETZ STROM grids. It was shown that the costs for both flexible and non-flexible consumers decrease, and less grid overload occurs.

In summary, the literature review lacks studies addressing the remuneration mechanism of the new § 14a framework on how the new variable grid fee tariffs can be designed from the DSOs and which impact these tariffs have on the CCD operators and the resulting load profile. This paper aims to fill this research gap. We focus on the EV users as one of the CCDs, as for HPs, Module 2 is often more beneficial [11].

Therefore, this paper addresses the impact of the remuneration mechanisms focusing on the variable grid fee tariffs according to Module 3 and the impact variable grid fee tariffs in accordance with the § 14a framework have on EV users. We answer the following three research questions:

1. How can variable grid fee tariffs in accordance with the § 14a framework be designed?
2. What cost reductions can be achieved for EV users? Which impact has the tariff design on EV users' cost reduction?
3. How does the charging behaviour change due to the variable grid fee tariffs? What shift occurs during the day?

The methodology and results chapters of this paper are structured as follows: First, the tariff design in accordance with the § 14a framework is displayed, followed by a case study to evaluate the cost reduction and load-shifting potential for these tariffs.

2. Methodology

The following methodology has been developed to assess the impact of the § 14a framework (see Figure 1).

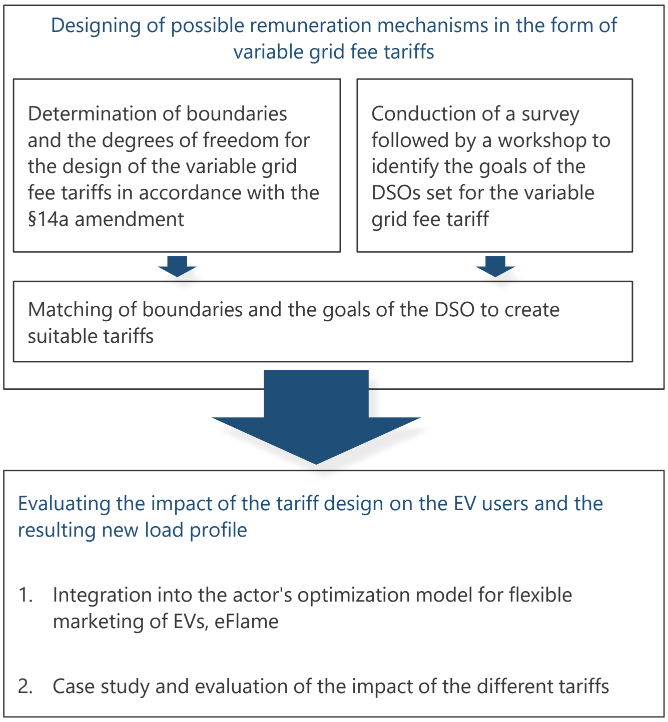

Figure 1: Methodology

In the first step, possible remuneration mechanisms in the form of variable grid fee tariffs are designed with the assistance of

DSOs. For the tariff design, first, the boundaries and the degrees of freedom for the design of the variable grid fee tariffs in accordance with the § 14a framework are determined. Then, a survey followed by a workshop with the DSOs is conducted to identify the different conditions in the distribution grids in Germany that lead to different load-shifting patterns required to support the grid and to identify the goals of the DSOs set for the variable grid fee tariff.

Bringing these two steps together, possible tariffs can be created in accordance with the goals of the DSOs. These variable grid fee tariffs are then implemented into the optimization model for flexible marketing of EVs, eFlame . The analysis then examines how the different variable grid fee tariffs impact the cost for EV users and which parameters in the tariff design impact the costs and the resulting load profile most.

2.1. *Tariff Design*

The BNetzA set the framework conditions for the design of the variable grid fee tariffs in accordance with the § 14a framework [4]. The boundaries (B1-B7) for the tariffs are displayed in the following:

- B1: The tariff must be valid for at least two quarters of the year
- B2: All levels (NT, ST, and HT) must be present at least once per day
- B3: The time window of the HT level must be at least 2 hours within one day
- B4: The level of the HT level must be less than or equal to 200 % of the ST level
- B5: The level of the NT level must be between 10 % and 40 % of the ST level
- B6: For the standard load profile H0, the grid fee over one year must be identical for the variable grid fee tariff and a constant grid fee tariff with only an ST level.
- B7: There are only the three levels NT, ST, and HT

It is not specified whether the tariff levels and time windows can differ over the course of a year, a month, a week, or daily.

In this current form, the mathematical problem resulting from these boundaries has many degrees of freedom which allow for a wide range of possible tariffs.

Therefore, in the next step, the goals of the DSOs for the grid fee tariff are identified by a two-step methodology: first, a survey is conducted, and then an interactive workshop is performed discussing the goals, the conditions in the different grids, and possible tariffs. The following design aspects, listed in Table 1, are used to cluster the information obtained.

In the last step, the boundaries of the BNetzA (B1-B7) and the goals of the DSOs are matched, creating suitable tariffs.

Both the survey and the workshop took place at the end of 2023. Therefore, the DSOs have not created their own variable grid fee tariffs at this time.

Table 1: Design aspects for the survey and the workshop with the DSOs

Design aspect	Description
Complexity	Includes number of variations within the tariff for the different days / quarters or the number of windows per day;
Required effectiveness	Determination of the extent of the desired shift: high load shifting desired or minimal impact on the users;
Location and length of HT/NT windows	Identification of grid-critical consumers or producers and grid-critical times such as long or short duration of the windows;
Critical target area	Determination of the target area/window of the desired shift: shifting load from the HT window to other times or shifting load into the NT windows from other times;

2.2. *Case study*

To evaluate the created variable grid fee tariffs, a case study for 2023 is performed in the optimization model eFlame (electric Flexibility assessment modelling environment).

The optimization model eFlame is an optimization model that is used for flexibility marketing for different components from the user's perspective in the energy system. Such components include EVs, HPs, stationary batteries, and industrial sites. The model can optimize the components' operation for several use cases, such as arbitrage trading, PV self-consumption optimization, FCR (Frequency Containment Reserve) trading, and peak shaving.[12], [13], [14]

This case study considers a household with an EVSE and an EV with variable electricity prices based on the Intraday Auction 2023. The parameterization is based on the unIT-e² project ([15] and [16]), as in [13] but updated for 2023; see Table 2. The parameters EV battery capacity, (dis-) charging power, EV consumption, household demand, state of charge (SOC), and max EV efficiency are set as in [13]. The electricity prices, grid fees, and tariffs are updated for 2023 with [17], and [18].

Three different charging strategies are considered: unmanaged direct charging, smart unidirectional, and smart bidirectional charging. Two hundred households are simulated with fitting EV profiles created by the household and EV generator, described in [19].

To evaluate the impact of the variable grid fee tariffs on EV users, scenarios with variable grid fee tariffs are compared to one scenario with a constant grid fee. The yearly costs and the cost savings compared to constant grid fees are analysed for the different grid fees. For the impact on the load profile, the charging profiles are aggregated, and the times of charging compared to the NT, ST, and HT windows are studied. To evaluate which parameters in the tariff design impact the costs and the resulting load profile most, the three different tariff designs are compared.

Table 2: Parametrization of the case study based on [13], [16], [17], and [18]

Parameter	Values
Electricity Prices	Intraday Auction Germany 2023 (quarterly hourly time series)
Constant grid fee, or ST level	9.52 ct/kWh
Levies	5.075 ct/kWh
Exemption from levies on the electricity fed back into the grid	3.71 ct/kWh
EV battery capacity	60 kWh
Maximum charging / discharging power	11 kW
Charging strategies	(1) direct, (2) smart unidirectional, (3) smart bidirectional charging
Charging efficiency	0.925
Discharging efficiency	0.92
Minimal SOC	0.31
SOC at departure	0.7
Average electricity demand household for 200 households	around 3000 kWh/a
Average yearly EV consumption for 200 EV profiles	around 2500 kWh/a

3. Results

In the first step, the design of the variable grid fee tariffs is presented in Chapter 3.1. The impact of these tariffs on the EV users and the resulting load profile are shown in Chapter 3.2.

3.1. Design of variable grid fee tariffs

As described in Chapter 2.1, the framework conditions of the BNetzA allow for high flexibility when designing the variable grid fee tariffs. To create realistic tariffs that fit the needs of the DSOs, a survey and a workshop were conducted to answer the design criteria ‘complexity’, ‘required effectiveness’, ‘location, and length of HT/NT windows’, and ‘critical target area’ (see Table 3). A total of nine representatives from seven DSOs took part in the workshop, covering different grid types, such as rural, mixed rural-urban, mixed rural-industrial, and urban areas.

Regarding the design aspect of ‘complexity’, all DSOs stated that low complexity is required. This is due to user acceptance, facilitating billing, and the lack of expertise in the field of designing variable grid fee tariffs for the DSOs. Therefore, a tariff should not be varied within one quarter and, if possible, be valid for the total year (one tariff for the total year or one tariff for part of the quarters and a standard tariff for the remaining quarters). Furthermore, only a few windows within a day are to be favoured, resulting in only one NT and one HT window. The design aspect ‘complexity’ greatly reduces the degrees of freedom of the BNetzA framework conditions.
The DSOs’ answers are ambivalent for the other design aspects and can be classified into three categories: urban grid areas, rural grid areas, and heterogeneous grid areas.
High effectiveness is required for urban grids with the HT window in the evening, when the peak load should be mainly reduced. For rural grids, an NT window at midday in summer, when a high share of PV generation is present, is relevant so that the load is shifted into the times of high PV generation to flatten the residual load. Low effectiveness is required for heterogeneous areas, such as a mix of rural and urban regions or large rural areas. As the evening peaks may not be at the same time in the whole grid, short and high HT windows in the evening may result in false incentives in some parts of the grid.

Based on the goals of the DSOs for the different grid types and the boundaries B1-B7 (see Chapter 2.1), the tariffs S1 to S3 are created, displayed in Table 4. The basis tariff is the exemplary tariff presented by the BNetzA [5]. In order to fulfil B6, the level of the HT window is calculated as the last free variable after keeping the other variables fixed.

S1 represents urban areas. Urban areas are mainly characterized by high load peaks in the evening. The tariff has, therefore, a short HT window with a high HT level to reliably pull the load out of the relevant evening hours. The tariff has the shortest possible high HT window, which causes a long and low NT window due to boundary B6.

S2 represents the heterogenous grid area. Here, a long HT window and a low HT level are required to not give false incentives in heterogeneous areas. S2 has the lowest HT level of all created tariffs with a relatively long duration. These two aspects result in the highest NT level (maximum of 40 % of the ST level) with small duration to fit boundary B6.

S3 represents rural areas. In rural areas, the sharp increase of decentral PV systems in the distribution grids results in a high generation peak at midday. Therefore, the tariff for the rural area is a midday PV tariff with a strong incentive to charge at lunchtime. The tariff has a rather long HT window, as rural areas are often also large grid areas, leading to heterogeneous characteristics regarding the peak time. Neither the HT nor NT levels are reaching the boundaries defined by the BNetzA (B4 and B5).

To summarize the results of the designing phase: The § 14a framework allows a high degree of flexibility in designing variable grid fee tariffs in order to meet the needs of the various

Table 3: Design aspects from the workshop with the DSOs

Design aspect	General	Urban	Rural	Heterogeneous grid area
Complexity	Low	-	-	-
Required effectiveness	Ambivalent	High		Low
Location and length of HT/NT windows	HT window: evening NT window: ambivalent Duration of HT window: ambivalent	NT window: at night Duration of HT window: short	NT window: at midday Duration of HT window: potentially long	Duration of HT window: long
Critical target area	Ambivalent	Shifting load from the HT window to other times	Shifting load into the NT windows from other times	

distribution grids. Different tariffs are developed depending on the distribution grid type.
The created tariffs are now evaluated in the case study.

Table 4: Created variable grid fee tariffs

Tariffs	NT window	HT window	NT-level % ST	HT-level % ST	Quarters
Basis	0-6am	5-9pm	25	136	4
S1 - urban	0-6am	6.5-8.5 pm	10	178	4
S2 - heterogeneous	1-5am	5-9pm	40	117	4
S3 - rural	10 am-2pm	5-9pm	25	171	2

3.2. *Cost evaluation for variable grid fee*

In the case study, the total costs for the average EV user (household + EV) are calculated with eFlame for the different charging strategies and variable grid fee tariffs for the year 2023 (see Figure 2). Unmanaged, direct charging is calculated only as a reference, as variable electricity prices will most likely not be used in combination with direct charging.

In the case of direct charging, the total costs increase by 13 €/a to 27 €/a, depending on the tariff, when shifting from constant to variable grid fees. This translates in a marginal cost increase of a maximum 2 % when compared to the total costs of 1430 €/a, as the EVs cannot react to the price signal.
With smart unidirectional charging, the cost savings from constant to variable grid fees range from around 40 €/a to 160 €/a. The cost reduction by the variable grid fee tariff is up to almost 200 €/a, but this leads to increased costs for electricity procurement, as the optimal times for purchasing electricity is not always aligned with the most favourable grid fee times.
For smart bidirectional charging, the cost savings from constant to variable grid fees range from 100 €/a to 255 €/a. These savings represent a significant reduction of up to 23 % compared to the constant fee. The cost reduction by the variable grid fee tariff is up to almost 315 €/a, but the costs for electricity procurement increase at the same time by a maximum of around 60 €/a. Additionally, in the case of bidirectional charging, the costs for levies change as the total purchased energy differs between the scenarios, albeit only slightly. In contrast, only the charging times change for unidirectional and direct charging.
In general, with direct charging, a slight increase in costs can be observed, while for smart charging, the costs decreases by shifting from a constant fee to variable grid fee tariff, with higher cost savings for bidirectional than for unidirectional charging.
To answer the research question of which impact has the tariff design on EV users' cost reduction, a more detailed look into the charging times is necessary. In Figure 3 (a), the average

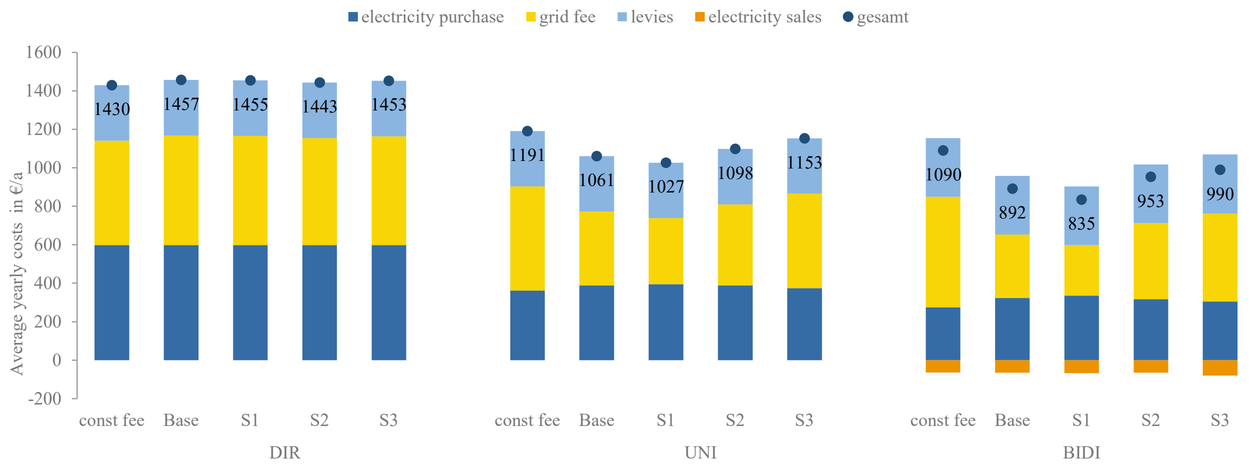

Figure 2: Average yearly costs for constant grid fee (const fee) and different variable grid fee tariffs (Base, S1, S2, S3) for a household with one EV for different charging strategies (direct charging (DIR), smart unidirectional charging (UNI), and smart bidirectional charging (BIDI)), split into electricity purchase, grid fee, levies and electricity sales.

share of charging energy of the different levels of grid fee for different variable grid fee tariffs and charging strategies are shown for a whole year.

In the case of a constant grid fee, only the ST level exists, resulting in 100 % of the charged and discharged energy being in the ST level for all charging strategies.

When introducing variable grid fee tariffs for direct charging, a significant share of HT level charging arises (15 % - 41 %), while only a small share of energy is charged in NT windows. The shares in the HT windows differ significantly between the variable grid fee tariffs. The highest share of ST level charging occurs for S3, as an NT and an HT level exist only for two quarters. To gain more insight into the S3-scenario, the shares of charged energy for only these two quarters are displayed in Figure 3 (b). For these two quarters, the share of HT window charging increases significantly for S3, resulting in the same share as in the Base- and S2-scenario, as they all have the same HT window length and position. S1 has a lower share, as the HT window duration is reduced from 4 to 2 hours. For the S3-scenario, a higher share of energy is charged in the NT window for direct charging, as the hours around midday correspond better to direct charging than charging in the early morning. The reason is that weekend midday charging occurs frequently as well as for non-commuters during the week.

For smart unidirectional and bidirectional charging, the share of NT-level charging increases significantly, and the share of HT-level charging is reduced to almost zero for all tariffs (with S1 and S3 providing the smallest shares with around 0.4 %). The Base-, S1-, and S2-scenarios provide a share between 78 % and 87 % of all charged energy in the NT window. The results for smart unidirectional and bidirectional charging are similar, with bidirectional charging occurring slightly more in the NT window and less in the HT and ST window, as more energy is charged in general and the option of discharging (into the household or the grid) exists. For S3, the charged energy for the two summer quarters is similar to the S1-scenario, with a higher share of NT charging than the Base- and S2-scenario. However, for smart charging, a part of the shifting occurs due to the variable electricity prices. Even with constant grid fee around 25 % to 40 % (total year for Base, S1, and S2, summer quarters for S3) of charging occurs in the NT-window-timeframe and less than 5% in the HT window-timeframe of the various variable grid fee tariffs. This demonstrates a link between the electricity prices for 2023 and the grid fee tariffs. Still, the shifting potential to the NT window increases greatly compared to only variable electricity prices by introducing variable grid fee tariffs.

In general, the share of charged energy in the NT window decreases in summer for tariffs with NT windows at night, as the low electricity prices at midday do not match the low grid fee at night. The effect is lower for S1, as the very low grid fee makes the window at night with a low grid fee more profitable than the window at midday with a low electricity prices and a standard grid fee.

The discharging energy for bidirectional charging is not shown in Figure 3. As grid fees are irrelevant for discharging, the optimization algorithm does not react to the different variable grid fee tariffs for discharging but only to the variable electricity price. However, for all variable grid fee tariffs, discharging occurs almost only in ST and HT windows, with the distribution between these two windows differing between the tariffs from a minimum of 36 % discharging in the ST window for the Base-scenario and a maximum of 58 % in the S1-scenario.

All in all, with smart charging, a significant shift from peak time (or standard time) charging to off-peak time charging occurs for all designed variable grid fee tariffs, leading to significant load-shifting behaviour of EV users when introducing variable grid fee tariffs, even though this effect occurs already partly by introducing the variable electricity prices from the year 2023.

Comparing the tariff design with the resulting load shifting and total costs, we see a high correlation between these aspects and

Figure 3: Average share of charging of the different levels of grid fee (NT, ST, HT) for constant grid fee (const fee) and different variable grid fee tariffs (Base, S1, S2, S3) for a household with one EV for different charging strategies (direct charging (DIR), smart unidirectional charging (UNI), and smart bidirectional charging (BIDI), (a) full year, (b) 2 summer quarters

the number of quarters, the NT window duration, and the NT window level. The highest impact is the number of quarters, as it greatly reduces the times when optimization based on the variable tariff is possible. With a shorter NT window duration, more charging situations occur during the ST level. Our findings for the summer quarters demonstrate the impact of the NT window times on the EV user.

4 Discussion and Conclusion

The integration of EVs, HPs, and renewable energies is challenging distribution grids, necessitating grid expansion and congestion management. In this context, the § 14a framework was introduced to provide DSOs with the emergency option to reduce the power demand of CCDs, with CCD operators being remunerated as compensation. This study focus on variable grid fee tariffs as one of the remuneration options and evaluates their impact on EV users' electricity costs and charging behaviour.

A two-step methodology is applied. First, variable grid fee tariffs in accordance with the § 14a framework with the help of DSOs are designed. Then, these tariffs are evaluated in the optimization model eFlame for flexibility marketing to determine how these tariffs impact the cost for EV users and the resulting load profile.

The analysis shows that the § 14a framework allows a high degree of flexibility in designing variable grid fee tariffs in order to meet the needs of the various distribution grids. Therefore, different tariffs are developed depending on the distribution grid type, for example, a tariff for high-load regions with a high peak-time window and a tariff for high PV generation regions with a low grid fee window at midday.
With the different variable grid fee tariffs, a cost decrease for smart charging can be observed, with a higher effect for bidirectional than for unidirectional charging. In contrast, a slight increase in costs occurs for direct charging, as the EVs cannot react to the price signal.
When smart charging is possible, charging occurs mainly in the NT windows, if it is available. Therefore, a significant load-shifting potential can be observed for all designed tariffs.

For the tariff design, the number of quarters with variable grid fees and the design of the NT window are essential for the EV user.

There are several limitations to the presented analysis, which should be listed here. Even though different charging and driving behaviour is considered, the parameterisation of the EV and the EVSE itself is not varied. Further, only variable electricity prices for 2023 are used (which shows a link to the designed grid fee tariffs). To get a holistic view, these two aspects should be varied in a further sensitivity study, considering also future years and how the results can be extrapolated to reflect Germany.
Moreover, only variable grid fees in accordance with Module 3 of the § 14a framework are analysed. However, Modul 3 is always combined with Module 1 in Germany. For an analysis of the § 14a framework in general, also Module 1 and 2 should be considered. The comparison done here corresponds to a comparison of Module 1 to the combination of Module 1 and Module 3.
Furthermore, possible power reduction measures from the DSOs and their impact on the EV user are currently not considered. These power reduction measures in different grid types should be included in further work. It is expected that for the different grid types, the number of hours with reduced power will differ, which might change which tariffs provide the highest cost benefit for the EV user.

In summary, DSOs can create suitable tariffs based on the § 14a framework, which results in a sufficient incentive for load shifting while offering significant cost savings for EV users.

5 Acknowledgements

The work described was conducted within the unIT-e² project, which is funded by the German Federal Ministry for Economics and Climate Action (BMWK) under the funding code 01MV21UN01.

We would like to thank Leon Berger for his work in his master's thesis, which provides the base of this publication.

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