Tagung Zukünftige Stromnetze | Future Power Grids Conference 2025

Conference Papers

https://doi.org/10.52825/zukunftsnetz.v2i.2598

Published: 28 Jul. 2025

Grid Fees in Transition

Variable Grid Fees as a Tool for Distribution Grid Congestion Management?

Niklas Jooß[1,*], Christoph Müller[1], and Andreas Weiß[1,2]

[1]Forschungsstelle für Energiewirtschaft e.V., Germany

[2]Technical University of Munich, Germany

*Correspondence: Niklas Jooß, njooss@ffe.de

Abstract. The reform of §14a of the German Energy Industry Act (EnWG) opens up the possibility for customers to choose variable grid fees for the first time. This legal adjustment enables distribution grid operators to design more flexible grid fees and to incentivise a potentially more efficient load management in the low-voltage grid. This paper includes a comprehensive analysis of the current design of variable grid fees and their congestion-relieving effect in the low-voltage grid. Particular attention is paid to the potential further development of grid charges towards a real-time pricing model that allows dynamic load control on the basis of real time grid utilisation. The results show that variable grid fee models can have impact on the stability and efficiency in the low-voltage distribution grid - both positive and negative. This work provides insights into the recent and possible future design of grid fees and their potential role in the energy transition.

Keywords: Variable Grid Fees, Dynamic Grid Fees, Congestion Management, Low-Voltage Distribution Grid

1. Motivation

The expansion of decentralised generation and the electrification of the heating and transport sectors will significantly change the stress on the distribution grids, especially in the low-voltage distribution level. The increase of components such as electric vehicles, heat pumps and stationary battery storage systems will lead to increased grid congestion. However, this increase also results in “flexibility potential”, that can be utilised through financial incentives for various services in the energy system and can therefore also contribute to relieve the distribution grid through a suitable incentive system.

Next to the costs of energy purchase, the grid fee accounts for the largest share of the total electricity price for private consumers [1]. The grid fee is the component of the electricity price that reflects the costs of grid operation and expansion. At present, household customers generally pay an annual basic charge with a fixed labour price. A redesign of the pricing system of the grid fees is intended to incentivise controllable consumption devices (control devices) to behave in a grid-friendly manner.

The reform of the §14a EnWG enables grid operators to temporarily limit the electricity consumption of controllable consumption devices if an overload of the grid is imminent and congestion-free operation is jeopardised [2]. In addition to a guaranteed grid connection for customers flexible consumption devices, the distribution grid operator also compensates the customers financially for the option of load reduction in cases of grid congestion. This financial compensation is achieved through selectable privileges in the context of grid fees. This includes “Module 3”, which can be selected from 1st of April 2025 and represents a static time-variable ‘time-of-use’ tariff (TOU tariff). With three different tariff levels, it is intended to incentivise controllable consumption devices to shift the load over time so that they relieve the grid. [3]

Previous studies investigated the design of variable grid fee concepts. In [4] are compared the effects of energy- and capacity-based grid fee tariffs, as well as TOU tariffs on six representative grids. The results show that TOU tariffs can lead to synchronization of flexible assets and thus lead to an increase of grid reinforcement costs. The study in [5] investigated the effect of energy- and capacity-based grid fee tariffs, as well as TOU tariffs and a dynamic tariff on the load demand in one low-voltage grid. The most effective grid fee concepts to decrease the peak load are the capacity-based tariff and the dynamic tariff. A possible concept for the further called ‘real-time pricing’ tariffs (RTP tariffs) is introduced in [6]. The grid fee tariff for households is adjusted based on the forecasted transformer load. The studies compares the effect of RTP tariffs with three varying transformer load forecast approaches. It is shown that the RTP tariff with the most dynamic forecast can effectively reduce grid congestions. The same model was used in [7] which analyzed the effect of TOU tariffs and RTP tariffs in representative grids in Germany. The study shows that TOU tariffs which are designed in advance to typical daily load profiles have no positive effect on the grid congestions. In contrast, RTP tariffs which are adjusted dynamically to the forecasted transformer load lead to congestion relief. In contrast to previous studies, this paper analyses the effect of real TOU tariffs introduced by German distribution grid operators and compares their effectiveness with a RTP tariff. Furthermore, this paper differs from previous studies by using the models of about 400 real low-voltage grids instead of using synthetic, representative grid models.

2. Methodology

This study analyses the effects of different grid tariff concepts on the grid load and the requirement for grid expansion in low-voltage distribution grids. In addition to the analysis of various TOU tariffs in accordance with §14a EnWG, the study compares the TOU tariffs with RTP tariffs, which are more dynamic and based on a local forecast of the grid load at the transformer.

These analyses utilise the ‘GridSim’ electricity grid and energy system model for distribution grids, which is being developed at Forschungsstelle für Energiewirtschaft e.V. (FfE). GridSim enables detailed bottom-up modelling of components and the simulation of the impact on the grid load via calculation of the load flows. For example, the household loads and corresponding driving profiles of the electric vehicles are generated using the at the FfE developed agent-based household load generator [8]. A detailed overview of the modeling and the simulation process can be found in [9].

In case of grid congestion, the simulation environment provides the option of resolving the congestion through conventional grid expansion. Resulting measures and grid expansion costs incurred can be analysed, as shown for example in [7] and [10], allowing the technical and economic assessment of grid relief measures.

In the following, the scenario framework of this paper is presented and the design of the analysed variable grid charges is described.

2.1 Scenario

The simulations and analyses utilise representative real low-voltage grids of a rural distribution grid operator from the ‘unIT-e²’ project. An overview and classification of the used low voltage grids can be found in [11].The allocation of photovoltaic (PV) systems, battery storage systems, electric vehicles and heat pumps as well as the share of market-oriented households follows scenario B of the scenario framework for the Electricity Grid Development Plan 2037/2045 (version 2025) [12] and was linearly interpolated between the given data samples. The resulting average installed capacities per household connection are shown in Figure 1.

For 2030, this means, for example, an installed PV capacity of around 6.3 kWp per house connection and a heat pump in around one in four buildings. With regard to flexibilization, approx. 15 % of households with flexibility are equipped with a dynamic electricity price and behave in a market-oriented manner. Of the market-oriented electric vehicles, approx. 7.5 % are bidirectional (bidi) and participate in arbitrage trading. In the 2045 “target system”, an average of 9.3 kWp of PV power is connected per house connection and approx. 1.45 electric vehicles with a charging capacity of 11 kW. Of these, around 15 % are bidirectional. The penetration of heat pumps increases to approx. 56 % of grid connection points. Overall, around 50 % of households are market-orientated.

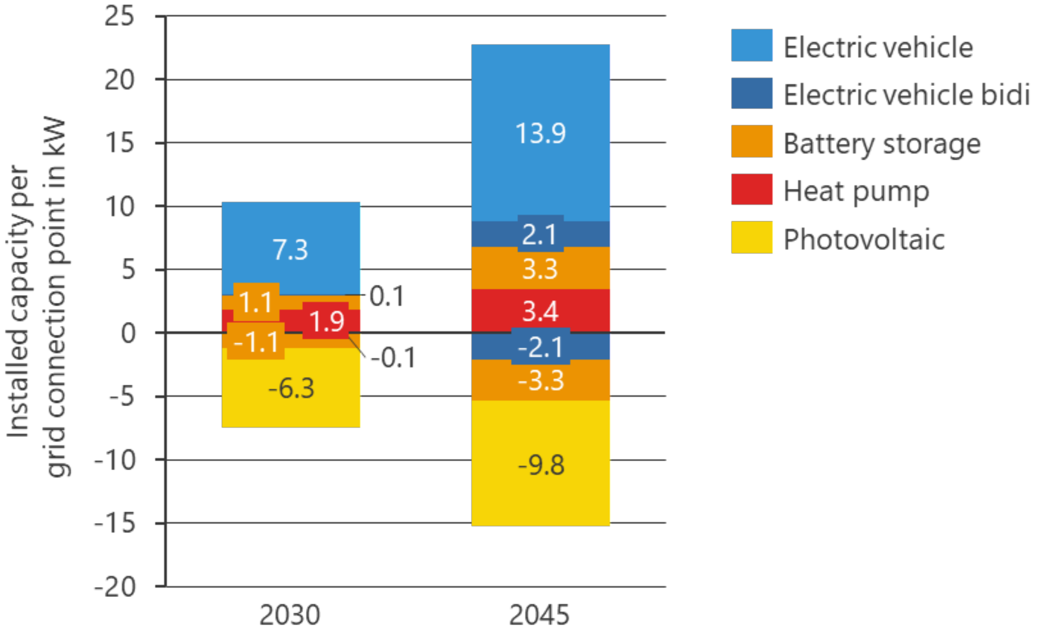

Figure 1. *Installed capacities per grid connection point for 2030 and 2045*

For market-oriented households with flexibility, the selection of Module 3 of §14a EnWG is anticipated, as they are likely operated by some sort of time-dependent optimization algorithm in order to maximise benefit from dynamic pricing. This results in a participation rate of approx. 15 % of the households in 2030 and 50 % in 2045. Day-ahead prices for 2030 and 2045 from the ISAaR energy system model developed at the FfE represent the future dynamic tariffs [13].

2.2 Variable grid fees

In addition to TOU tariffs in accordance with Module 3 of §14a EnWG, dynamic grid charges, calculated on the basis of the regional grid load, are also analysed in this paper and briefly presented below.

2.2.1 TOU tariffs

With the introduction of the TOU tariffs, the Federal Network Agency (BNetzA) has specified requirements for the design of the tariffs. The TOU tariffs must feature three tariff levels: a standard tariff, a high tariff and a low tariff. A standard consumer according to the standard load profile H0 must not be disadvantaged by the TOU tariffs and must pay the standard tariff on average. Additionally, the high tariff time window must be offered for a minimum of two hours per day and must not exceed twice the standard tariff. The low tariff, on the other hand, is to be set at between 10% and 40% of the standard fare. Furthermore, the TOU tariffs are to be offered in a minimum of two quarters. [3]

This paper analyses four variants for TOU tariffs, which are described in Table 1. Variants ID 1 and ID 2 are based on published grid fees from two grid operators. The variants ID 3 and ID 4 do not represent real modules and aim to incentivise flexible load to times of peak PV load. The average grid charge in Germany of 11.53 ct/kWh [1] represents the standard tariff.

Table 1. *Description of the analyzed time of use tariffs*

Tariff ID	Description
ID 1	Based on the grid fees of “Bayernwerk Netz” [14]
ID 2	Based on the grid fees of “LEW Verteilnetz” [15]
ID 3	PV-orientated grid fee
ID 4	PV-orientated grid fee with narrow NT time window at midday

In contrast to reality, the variable grid fees are not only allocated to individual quarters, but are valid for the entire year. This serves to further emphasise the effects on the grid, but also required caution in the evaluation of the data in the context of its realistic accuracy. All grid fee variants have a low tariff (LT) of around 10 % of the standard tariff (ST). The level of the high tariffs (HT), on the other hand, spreads more widely. In the case of PV tariffs, attention was devoted to the minimization of the gradients between ST and HT in order to avoid unwanted incentives. The price ranges for the three tariff levels are shown in Figure 2.

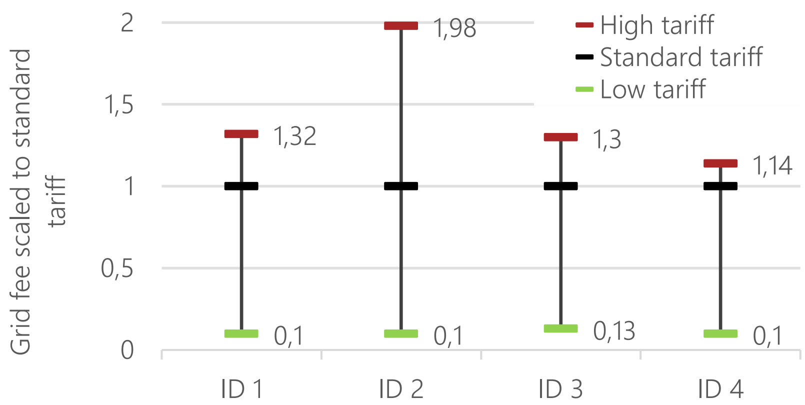

Figure 2. *Price range of the three tariff levels of the analysed grid fee variants*

The time windows for the individual tariff levels are shown in Figure 3. The LT time window for variant ID 1 is at night, while for the other tariffs it is at midday. Like tariff ID 1, grid tariff ID 2 has the HT time window in the evening hours, whereas grid tariffs ID 3 and 4 have the largest possible HT time window in order to achieve the highest possible relief effect by concentrating the consumption of flexibilities heavily in the PV curve.

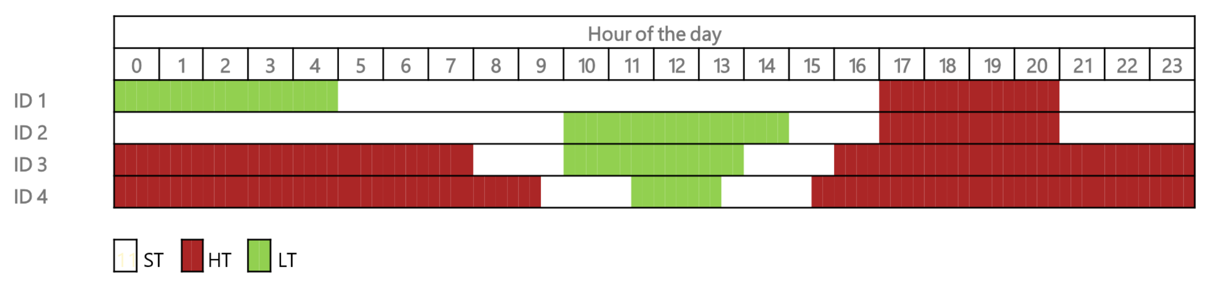

Figure 3. *Time window for the individual tariff levels of the analysed grid fees variants*

2.2.2 Real time pricing tariff

With more advanced digitalization in the distribution grids, grid fees may reflect the current grid situation even more precisely and be transmitted to grid users. RTP tariffs represent such a dynamic tariff structure.

A model of dynamic grid fees has already been applied by FfE in other publications, like in [6] and [7]. In this concept, an "aggregator" assigns a schedule for the consumers flexibilities. A grid fee tariff is allocated to the house connections one after the other by means of a check-in system. First, the local transformer utilization is forecasted. This forecast enables calculation of the grid fee for the first customer. After each check in by the customers, the grid fee is adjusted for the following customers. Each grid connection point, respectively house including different flexibilities, optimizes its schedule based on the allocated grid fee. The grid charge is thus calculated consecutively in each simulation step for all houses connected in a local grid.

If the forecast load-side transformer utilization exceeds 70 %, the grid fee is doubled and tripled from a utilization of over 95 %. In order to incentivize consumption in the event of feed-in overloads, the grid fee is set to 0 if the feed-in transformer load exceeds 70 % and to the negative standard tariff from 95 %. In order to influence the overall price and create incentives for load shifting, the price ranges of the grid fees must exceed the spreads of the day-ahead price. The analysis shows that the average price spread of the day-ahead price during a day is between 7 ct/kWh in 2030 and 9 ct/kWh in 2045 and the maximum price spread in both years is 20 ct/kWh. Therefore, doubling or tripling the assumed standard tariff of 11.51 ct/kWh is a sufficient scaling of the grid fee.

It should be noted that this check-in system results in each building and each customer seeing a slightly different grid fee, which consequently means that this system is not completely non-discriminatory. This circumstance is counteracted by a random distribution of the check-in sequence in each new grid congestion situation, whereby the non-discrimination is only reduced and not prevented.

The introduction of slightly different grid fees for each customer is crucial for an even distribution of load and thus for optimal utilization of the grid. A single dynamic grid fee for all customers, on the other hand, would result in too much load being shifted to times with lower grid fees. This would lead to new congestion.

3. Results

In this section, the short- and long-term effects of variable grid charges on the low voltage are analyzed with regard to the grid load and the resulting expansion costs, by comparison with a reference scenario, that does not provide variable or dynamic grid fees or other grid-relieving actions. Potential savings for consumers are highlighted as well as the grid load results per quarter in 2045. In none of the analyzed scenarios power reduction by the distribution grid operator in accordance with §14a EnWG was taken into account.

3.1 Short-term effects

To analyze the short-term effects, the results of the scenarios with the different grid fee concepts for the year 2030 are compared with each other. In the following analysis, lines and transformers are considered overloaded if in one timestep their nominal current, respectively power rating is exceeded. The allowed voltage range is ± 6 % of the nominal voltage. This corresponds to a common assumption in modelling, according to which ± 4% of the voltage band is reserved for the upstream grid levels (compare [16], [9] and [7]). The RTP check-in system proves to be the most effective in reducing grid congestion, as Figure 4 shows. The RTP check-in system has been demonstrated to relieve 3.5% of the congested grids in the Reference scenario, or 1.3% of all considered grids. In particular, the proportion of overloaded transformers is reduced, as the RTP tariffs have a positive effect on both load-related and feed-in-related transformer overloads.

Only TOU tariff ID 1 can provide relief in under 1 % of the analyzed grids. In all other variants with TOU tariffs, the proportion of grids requiring expansion increases slightly. Compared to the reference scenario, only line overloads can be slightly reduced in all TOU variants. For all other types of congestion, a small number of grids can be relieved or additional overloads occur in a small number of other grids.

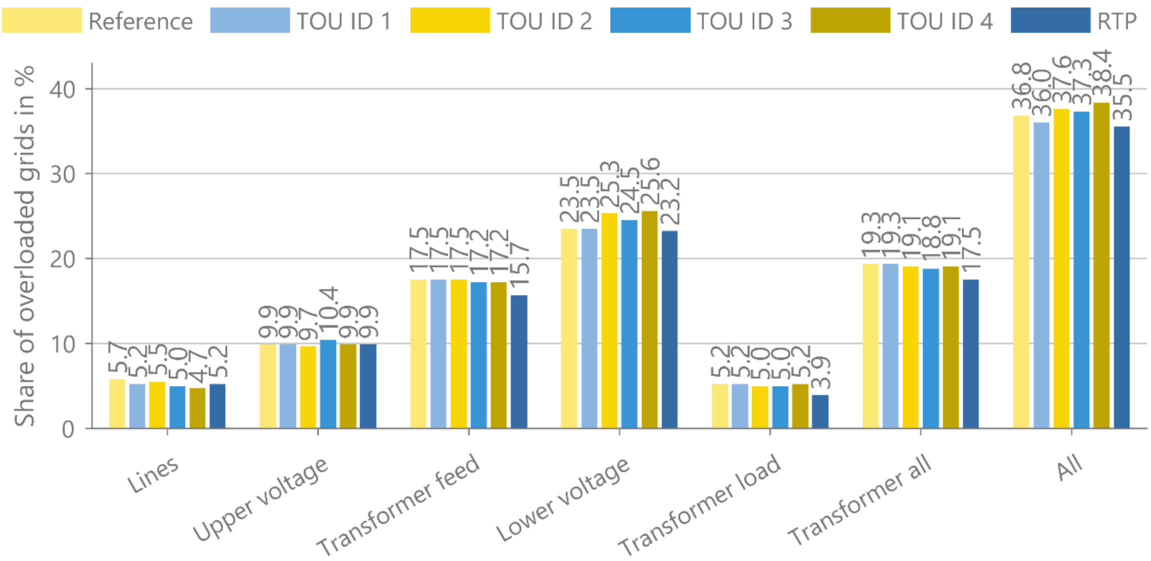

Figure 4. *Overloaded grids by type of congestion: scenarios with different grid fee variants in 2030*

Figure 5 shows the average expansion costs per grid for the different grid fee variants. The grid expansion is performed to achieve the cheapest solution to resolve congestions. Line congestions are dealt by adding parallel cables. Overloaded transformers are replaced by a conventional transformer or by a voltage regulated distribution transformer (VRDT) with higher power rating. In the reference scenario, the average expansion costs per local grid amount to almost € 12,000 by 2030. All TOU tariffs increase the expansion costs per local grid slightly. The lowest additional expansion costs arise with TOU tariff ID 1 with an increase of approx. 0.4 %. TOU tariff ID 4, which is adjusted to the PV generation peak, performs worst, with expansion costs increasing by approx. 3 %. The scenario with the RTP tariff reduces the expansion costs by approx. 3 % by 2030.

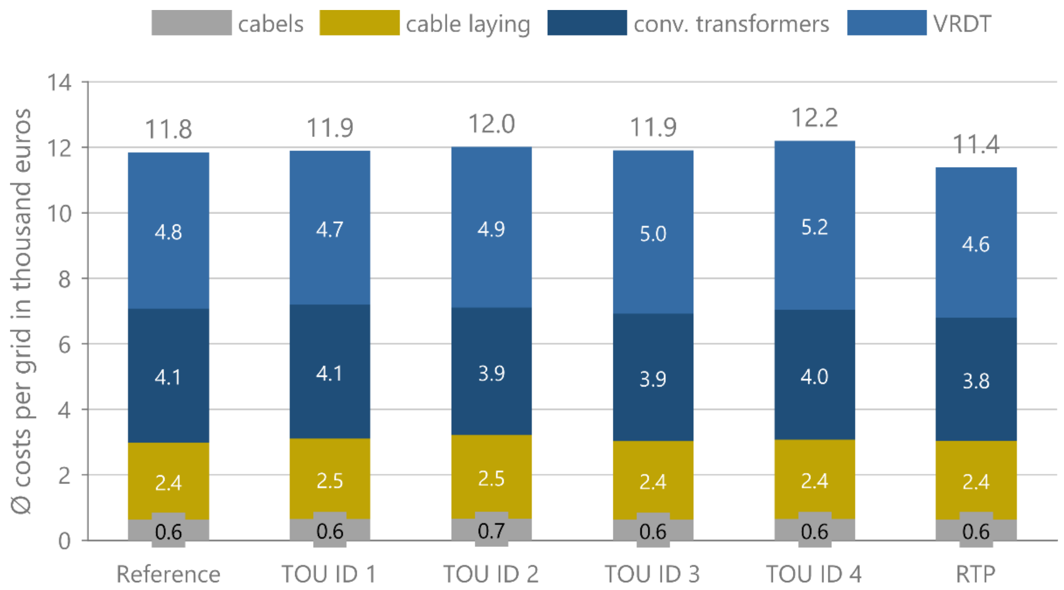

***Figure 5.** Average grid expansion costs per grid for the scenarios with different grid fee variants up to 2030*

The introduction of TOU tariffs therefore hardly leads to any reduction in expansion costs - and may even increase them in individual cases. Nevertheless, customers with TOU tariffs pay on average around 40 % less grid charges than in the reference case, as can be seen in Figure 6. Customers with TOU tariff ID 1 pay the least, although there are individual cases in which customers with a TOU tariff pay more than the standard tariff. It is important to consider that, in reality, the reduced grid fees will be considerably lower, as the TOU tariffs are only offered in individual quarters and not throughout the year as in the simulations.

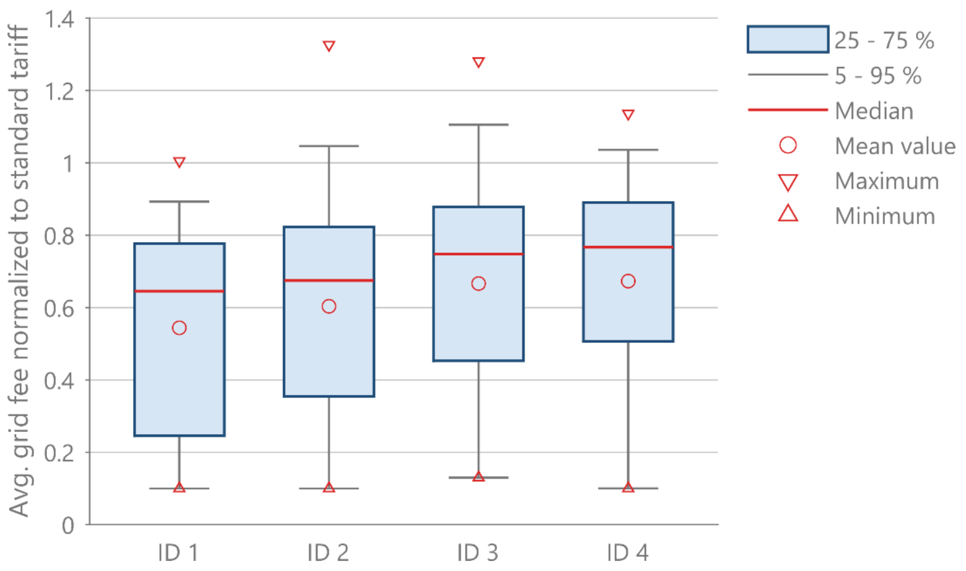

***Figure 6.** Average grid fee of customers with TOU tariff scaled to the standard tariff*

3.2 Long term effects

It is important to consider that in the scenarios analyzed, 'only' around 15 % of all households with flexibility will participate in these tariffs in 2030. To assess the "future viability" of the concepts, the reference scenario, scenario ID 1, ID 3 and the RTP scenario in the "climate-neutral" target grid 2045 are analyzed to quantify the overall grid expansion demand in the grids. For this purpose, todays grid topologies along with the flexibility penetration rates in 2045 (based on NEP scenario B), and the different grid fee concepts are simulated.

As presented in Figure 7, the proportion of overloaded grids is similar to 2030. However, at over 70 %, significantly more grids require expansion. Compared to the 2030 analysis, the RTP tariff model shows a significant reduction in the load on transformers and lines compared to the other scenarios.

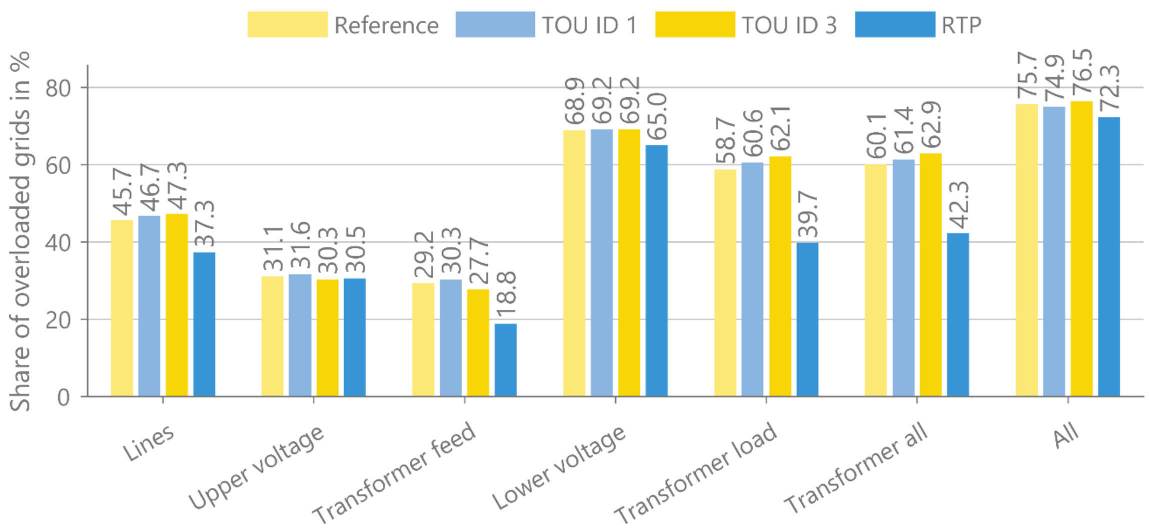

Figure 7. *Overloaded grids by type of overload: Scenarios with different grid fee variants in 2045*

This is also reflected in the grid expansion costs (compare Figure 8), according to which an average of € 52,200 is incurred per grid by 2045 in the reference case, € 58,900 in the ID 1 case, € 56,400 in the ID 3 case and € 37,500 for the RTP tariffs. The RTP tariff therefore shows an average cost saving of € 14,700 per local grid, which may justify the metering infrastructure required to implement this model. It should be considered that although the RTP tariff model is technically feasible in theory, it represents a very complex model to implement from a regulatory perspective, as it results in enormous redistribution effects regarding the grid fees.

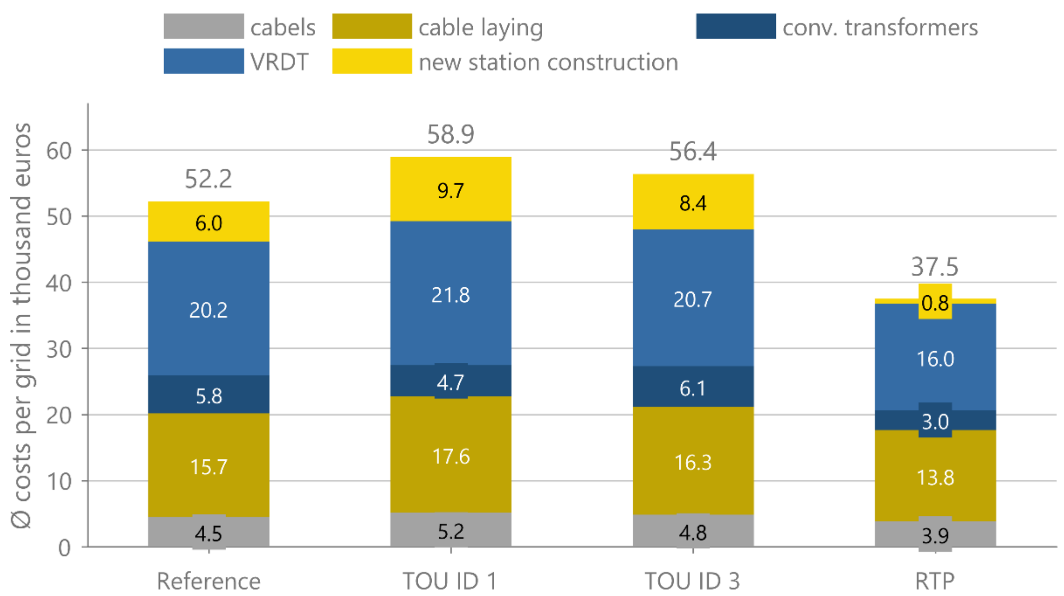

Figure 8. *Average grid expansion costs per grid for the scenarios with different grid fee variants up to 2045*

3.3 Grid overloads per quarter for 2045

The TOU tariffs in accordance with §14a EnWG Module 3 can only be offered on a quarterly basis, which is why the overloads are evaluated for each quarter. As the behavior in quarters one and four as well as two and three are similar, these are analysed combined. Overall, it is evident that the shift of loads into the low tariff time windows increases simultaneity and thus causes new overloads.

For TOU ID1, in the winter quarters Q1 and Q4, the heat pump loads in particular are shifted from midday (better COP) to the low tariff time window at night. As shown in Figure 9 this leads to fewer overloads at midday, but to a significantly higher proportion of overloads during the night, averaging up to 20 % of the grids. Overloads in the evening hours can be reduced slightly compared to the reference. In the summer quarters Q2 and Q3 (see Figure 10), more overloads result in the low tariff time window, but not as many as in the winter quarters. The feed-in-related overloads from PV systems also increase slightly, as loads that occur at times of low electricity prices in the midday period are also shifted to the low tariff time window.

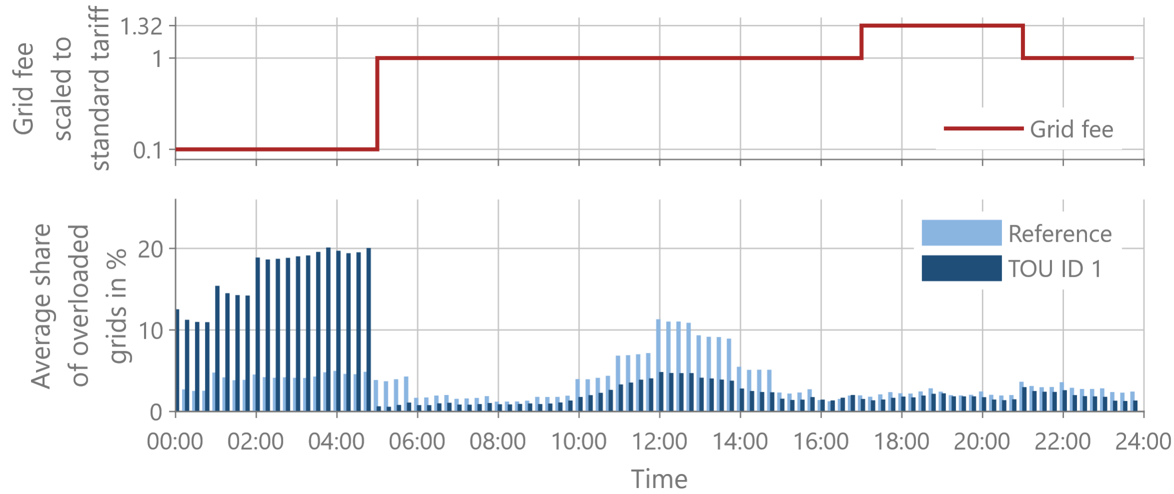

Figure 9. *Average share of overloaded grids per time of day for TOU tariff ID 1 in the quarters 1 and 4 of 2045*

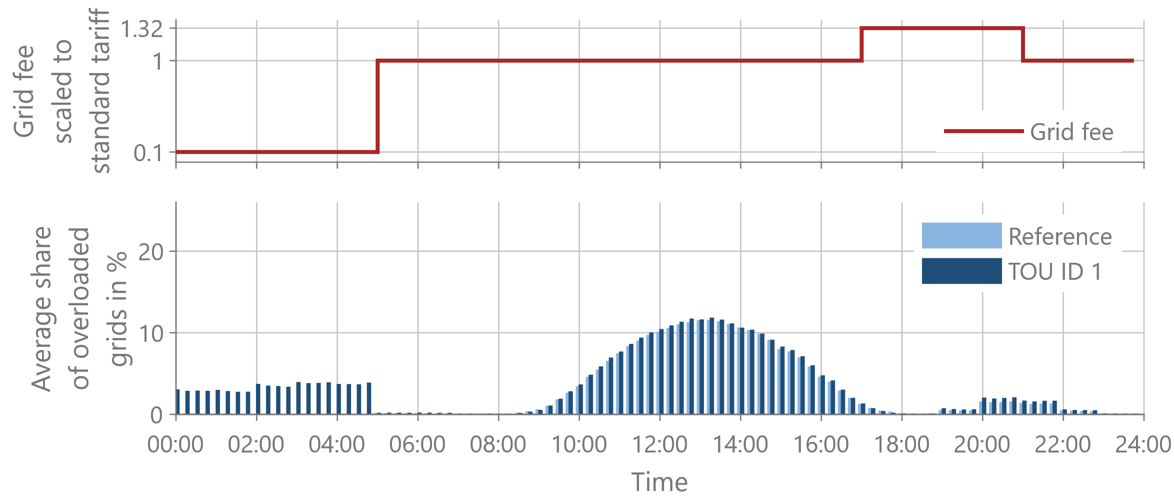

Figure 10. *Average share of overloaded grids per time of day for TOU tariff ID 1 in the quarters 2 and 3 of 2045*

Figure 11 shows that, with TOU ID 3 significantly more grids are overloaded at midday in the winter quarters Q1 and Q4, as loads are shifted into the low tariff time window. This reduces the overloads at night, as the total electricity price is cheaper at midday than at night due to the lower grid charge, despite lower exchange electricity prices. In the summer quarters, the number of overloaded grids in the low tariff window also increases slightly.

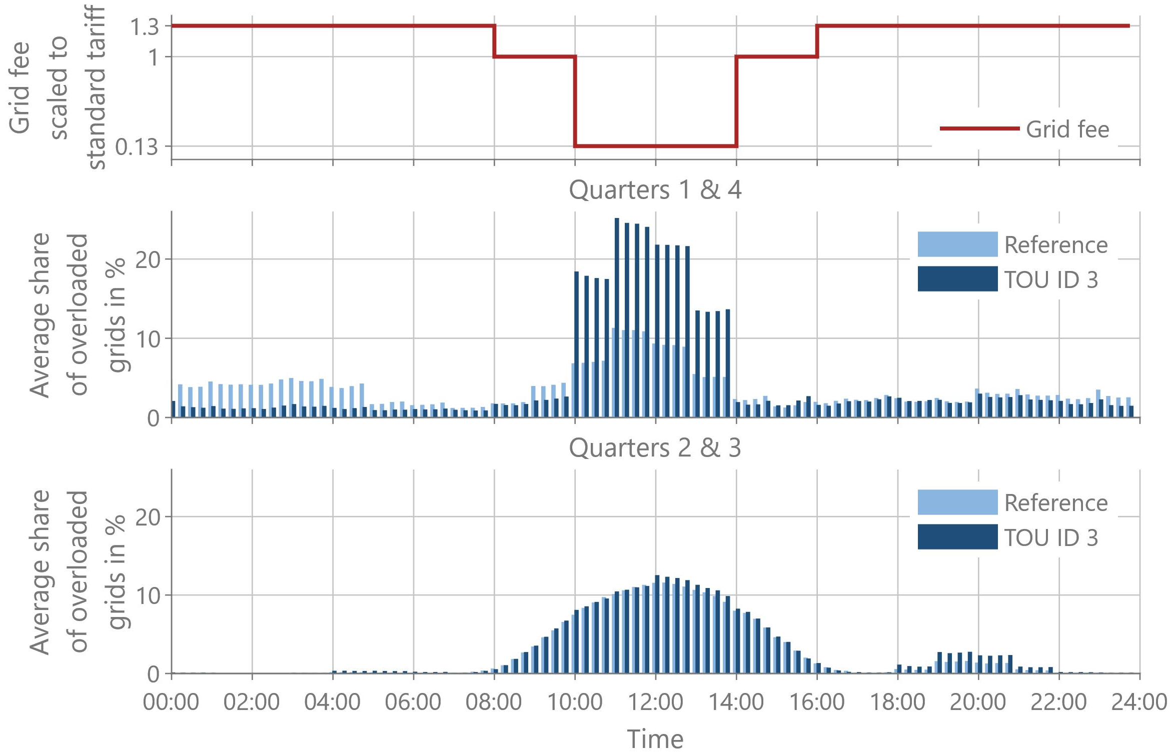

Figure 11. *Average share of overloaded grids per time of day for TOU tariff ID 3 in the quarters of 2045*

As presented in Figure 12, feed-in-related transformer overloads in Q2 and Q3 can be reduced, but on days with low PV generation, the load-influenced overloads increase and thus compensate for the relieving effect. Power dimming in accordance with §14a EnWG provides remedy.

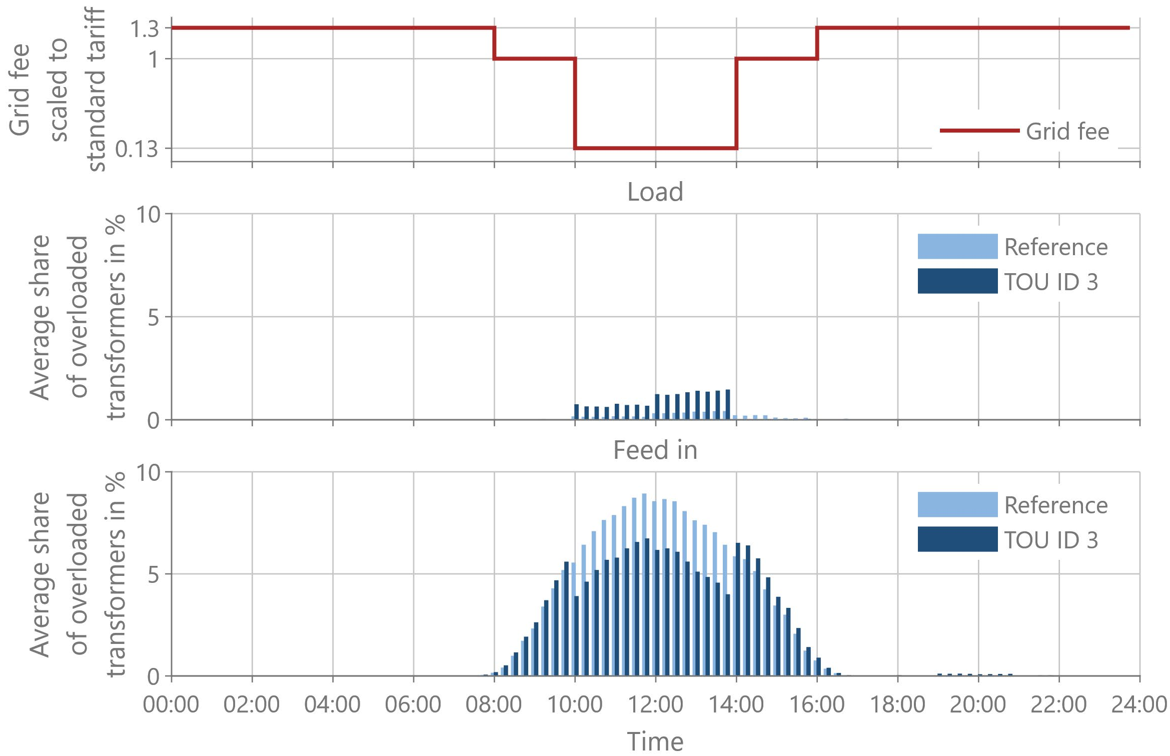

Figure 12. *Average share of overloaded transformers per time of day for TOU tariff ID 3 in the quarters 2 and 3 of 2045, by load and feed-in*

4. Conclusion

In this article, various grid fee tariffs and their potential grid relief effect are simulatively analyzed. The assessments reveal that TOU grid fee models only have minor impact on the grids in the short term up to 2030, but offer significant cost savings for end consumers. In the long-term comparison with regard to the target system in 2045, it becomes evident that TOU tariffs are no long-term solution, as with increasing participation rates, the result in additional congestion in the grid, whereby the “originators”, the participating flexibilities, are financially rewarded. The implementation of a dynamic RTP tariff, on the other hand, has a significant relief effect in the long-term and can significantly reduce grid expansion, especially reduce transformer expansion costs. Overall, the analyses provide arguments that Module 3 of §14a EnWG do not deliver a direct grid-relieving component - whereby an argument can be made against it, due to the additional loads in long-term. The analyses provide arguments in favor of a shift away from variable towards dynamic grid fee concepts, as these offer significant cost savings in terms of grid expansion.

5. Critical Review

The application of TOU tariffs throughout the entire year is a clear limitation of this study, which overestimates the financial benefit of variable grid fees and likely also the impact on the grid load. However, the analyses in section 3.3 provide insights into the grid overloads per quarter.

A 100 % pick rate of the Module 3 as a compensation for the control by the distribution system operator in according to §14a EnWG is assumed. Alternatively, Module 2 can be chosen, which provides a flat reduction of the grid fee by 60 % [3]. Therefore, based on the results from Section 3.1, it can be assumed that a majority of the households will choose Module 2. However, it should be noted that this requires a separate metering point for the respective controllable consumption devices. As a result, in the event of power reduction by the grid operator, it is not possible to distribute the available power among different controllable consumption devices [2]. Furthermore, contrary to the assumption in this study, customers without dynamic electricity tariffs might also choose variable grid fees (Module 3). Thus, it is very likely that there will be a mix of chosen grid fees, and the impact on the grids is overestimated.

Additionally, variable grid fees in their current design can only be selected in combination with power reduction by the distribution system operator according to §14a EnWG. Consequently, there is a de facto grid-relieving effect that was not examined in this paper. Analyses like in [7] show that power reduction is an effective instrument for relieving the grids. With permanent utilization and assuming minimal grid expansion, the expansion costs could be significantly reduced without overly restricting grid users.

Although RTP tariffs are effective in the simulations to reduce grid congestions, they are not completely non-discriminatory. The effect is only indirectly counteracted by the random assignment of the adjusted RTP tariffs, as described above, but non-discrimination cannot be guaranteed. Furthermore, RTP tariffs require high initial investments and, while technically feasible, are extremely complex from a regulatory perspective, as grid charges are determined at the local grid level, but the costs for grid operation and expansion are calculated for the entire grid area of a distribution system operator and would therefore have to be allocated in an extremely complex manner.

The last limitation worth mentioning, is that in the simulations, the grid is considered overloaded and needs to be expanded as soon as one limit value of a grid asset is exceeded for the period of just one timestep (15 min). In reality, this would be tolerable for a short period. Thus, overloads and expansion costs are likely overestimated.

Data availability statement

The grid data that support the findings of this study are not openly available due to reasons of sensitivity.

Underlying and related material

Examples of the household loads and the related driving profiles and thermal load profiles can be obtained from [17], [18], [19].

The modelling of mobility profiles is based on data from the following resources available in the public domain [20], [21].

Author contributions

The authors Niklas Jooß (N.J.), Christoph Müller (C.M.) and Andreas Weiß (A.W.) have performed the following roles according to the CRediT (Contributor Roles Taxonomy): Conceptualization (N.J.; C.M.), Data curation (N.J.), Formal analysis (N.J.; C.M.), Funding acquisition (A.W.), Investigation (N.J.; C.M.), Methodology (N.J.; C.M.), Project administration (A.W.), Software (C.M.), Resources (N.J.), Supervision (A.W.), Validation (N.J.; A.W.), Visualization (N.J.; C.M.), Writing – original draft (N.J.; C.M.), Writing – review & editing (N.J.; C.M.; A.W.)

Competing interests

The authors declare that they have no competing interests.

Funding

This paper was carried out as part of FfE's activities in the “unIT-e² – living lab for integrated e-mobility” project. The project is funded by the Federal Ministry of Economics and Climate Policy (BMWK). Funding reference: 01MV21UN11 (FfE e.V.)

References

[1] T. Schwencke: “BDEW-Strompreisanalyse Dezember 2024 - Haushalte und Industrie.” Berlin: Bundesverband der Energie- und Wasserwirtschaft e.V. (BDEW), 2024.

[2] “Beschluss zur Integration von steuerbaren Verbrauchseinrichtungen und steuerbaren Netzanschlüssen nach § 14a Energiewirtschaftsgesetz (EnWG) (BK6-22-300).” Ausgefertigt am 2023-11-27; Bonn: Bundesnetzagentur (BNEtzA), Beschlusskammer 6, 2023.

[3] “Beschluss zur Festlegung von Netzentgelten für steuerbare Anschlüsse und Verbrauchseinrichtungen (NSAVER) nach § 14a EnWG (BK8-22/010-A).” Ausgefertigt am 2023-11-27; Bonn: Bundesnetzagentur (BNetzA), Beschlusskammer 8, 2023.

[4] L. Kundert: “The Influence of Different Network Tariffs on Distribution Grid Reinforcement Costs.” Zürich: ETH Zürich, 2023. doi: https://doi.org/10.1109/PowerTech55446.2023.10202875

[5] D. Steen: “Smart charging of EVS under different grid tariff structures.” Göteborg: Chalmers University of Technology, 2022. doi: https://doi.org/10.1049/icp.2022.0882

[6] Y. Blume et al.: “Effects of variable grid fees on distribution grids with optimized bidirectional battery electric vehicles.” In: 6th Grid Service Markets Symposium (GSM); Luzern: Hochschule Luzern, 2022.

[7] Agora Energiewende and Forschungsstelle für Energiewirtschaft e. V. (2023): "Haushaltsnahe Flexibilitäten nutzen." Wie Elektrofahrzeuge, Wärmepumpen und Co. die Stromkosten für alle senken können.
[8] M. Müller et al.: "Development of an Integrated Simulation Model for Load and Mobility Profiles of Private Households." In: Energies, 2020, 13, 3843 Special Issue "Model Coupling and Energy Systems". Basel, Switzerland: MDPI AG, 2020. doi: https://doi.org/10.3390/en13153843
[9] M. Müller: "Netzintegration dezentraler Flexibilitätsoptionen mit Fokus auf ausgewählte Anwendungsfälle für bidirektionale Elektrofahrzeuge." Published by Technical University of Munich (TUM), audited by Wagner, Ulrich and Witzmann, Rolf: München, 2023. https://mediatum.ub.tum.de/1686443
[10] A. Weiß et al.: "Analyse methodischer Modellierungsansätze im Kontext von Verteilnetzsimulationen." In: IEWT 2021 - 12. Internationale Energiewirtschaftstagung; Wien: TU Wien, 2021.
[11] Y. Schulze et al.: "Anforderungen an aktuelle Verteilnetze und deren zukünftige Versorgungsaufgabe." In: 12. Internationale Energiewirtschaftstagung; Wien: TU Wien, 2021.
[12] Szenariorahmen zum Netzentwicklungsplan Strom 2037/2045, Version 2025 - Entwurf der Übertragungsnetzbetreiber. Berlin, Dortmund, Bayreuth, Stuttgart: 50Hertz Transmission GmbH, 2024.
[13] T. Kern: "Assessment of the Added Value of Bidirectionally Chargeable Electric Vehicles for the User and the Energy System." Submitted dissertation. Published by Technical University of Munich (TUM): München, 2022.
[14] "Preisblatt Netzentgelte Strom 2025." In https://www.bayernwerk-netz.de/content/dam/revu-global/bayernwerk-netz/files/netz/netzzugang/netzentgeltestrom/20241008_bayernwerk-preisblaetter-strom-2025-vorlaeufig.pdf. (Accessed on 12/2024); Regensburg: Bayernwerk Netz GmbH, 2024.
[15] "Preisblatt Netzentgelte Strom 2025." In https://www.lew-verteilnetz.de/lew-verteilnetz/fuer-netzkunden/uebersicht-ueber-netzentgelte. (Accessed on 12/2024); Augsburg: LEW Verteilnetz GmbH, 2024.
[16] "dena-Verteilnetzstudie - Ausbau- und Innovationsbedarf der Stromverteilnetze in Deutschland bis 2030." Berlin: Deutsche Energie-Agentur, 2012.
[17] "Synthetic Sample Electric Load Profile (Three-Phase) by Household Types (Germany)": http://opendata.ffe.de/dataset/synthetic-sample-electric-load-profile-three-phase-by-household-types-germany/; (Accessed on 02/2025); München: Forschungsstelle für Energiewirtschaft e. V. (FfE), 2020.
[18] "Synthetic Sample Mobility Profile by Household Types (Germany)": http://opendata.ffe.de/dataset/synthetic-sample-mobility-profile-by-household-types-germany/; (Accessed on 02/2025); München: Forschungsstelle für Energiewirtschaft e. V. (FfE), 2020.
[19] "Synthetic Sample Thermal Load Profile by Household Types (Germany)": http://opendata.ffe.de/dataset/synthetic-sample-thermal-load-profile-by-household-types-germany/; München: Forschungsstelle für Energiewirtschaft e. V. (FfE), 2020.
[20] "Mobilität in Deutschland 2017 – Datensatz"; Bonn: infas Institut für angewandte Sozialwissenschaft GmbH, 2019.
[21] M. Wermuth: "Kraftfahrzeugverkehr in Deutschland 2010 (KiD 2010) - Schlussbericht." Braunschweig: Verkehrsforschung und Infrastrukturplanung GmbH, 2012