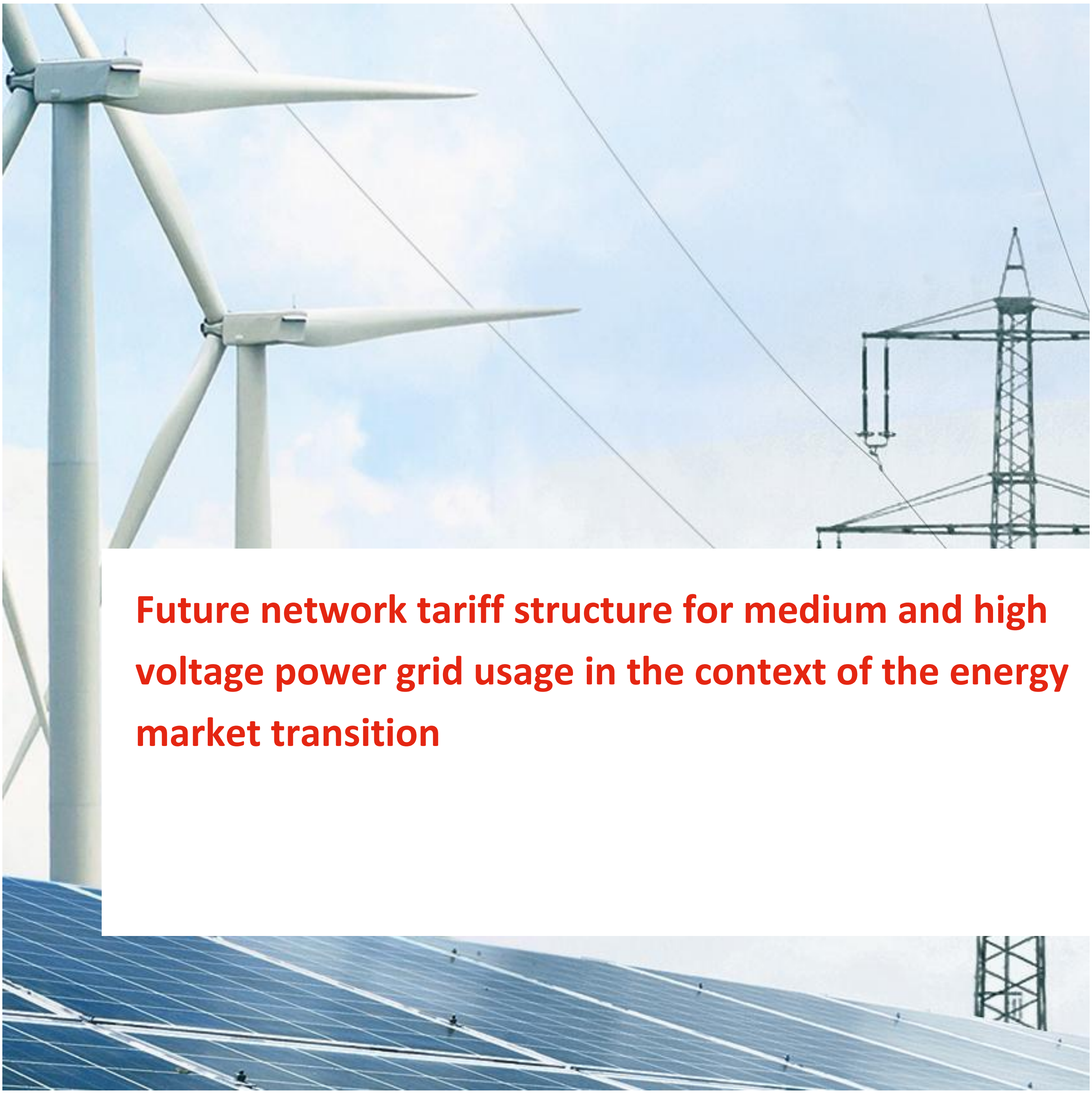

# Future network tariff structure for medium and high voltage power grid usage in the context of the energy market transition

**Study**

commissioned by

Creos Luxembourg

6th March 2025

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# Content

# 1 Introduction

Creos Luxembourg S.A., the electricity transmission system operator (TSO) and largest electricity distribution system operator (DSO) of Luxembourg, has commissioned a study on the future tariff structure for medium, high and very high voltage power grids in Luxembourg. The objective of the study is to analyse options for further development of the tariff structure, taking into consideration a number of challenges associated to today's tariff structure and to developments of the general conditions affecting network tariffs, for instance:

- Fundamental questions on the objectives of network tariff design related to both the refinancing and incentivising function of network tariff charges.
- A general discussion on the adequacy of cost allocation to customers at different voltage levels.
- The fact that the cost cascading mechanism in today's network tariffs is based on the quarter-hourly maximum load values of each network level, causing network tariffs to be sensitive to fluctuations of this parameter.
- The observation that the model of load simultaneity that is applied in order to split the tariff structure into two segments for customers with usage hours below and above 3.000 h/a can deliver erratic results, particularly for voltage levels with a low number of end customers connected directly to that voltage level. More fundamentally, it appears questionable if the assumptions underlying the simultaneity function are still appropriate.
- Discussions taking place in Luxembourg (as well as in other countries) about the aim to deliver more appropriate incentives to network users with respect to self-consumption and to the provision of flexibility with various purposes, aiming at an economically efficient implementation of the energy transition.

The study identifies possible development options for the future network tariff structure and assesses them with respect to the aforementioned questions and a defined set of criteria. Creos, together with the other DSOs of Luxembourg, as well as the regulatory authority ILR took part in the discussions throughout the study. The considerations and deliberations presented here provide a basis for discussion on the specific design of a future tariff system.

The detailed discussion about specific reform options is launched by a definition of the objectives and evaluation criteria for such a reform in Chapter 6. Specific tariff design evaluation criteria are derived based on a discussion of fundamental objectives of network tariff design. Chapter 3 covers the cost cascading mechanism – a step that provides the basis for the final tariff calculation. This chapter provides a qualitative and quantitative analysis for different variants of cost cascading mechanisms and evaluates them according to criteria that reflect the objectives for the future tariff system. Chapter 4 discusses the objectives, design options and effects of generation-side charges and provides an overview on the application of generation-side charges in other countries. The full range of design options that affect consumer-side network charges is addressed in Chapter 5 which covers connection charges, base prices, the simultaneity function and its alternatives as well as options for the capacity-based component. Chapter 6 provides an outlook on how network charges can provide incentives for network-oriented flexibility use especially through time-dependent network charges. The study's conclusions are summarised in Chapter 7.

# 2 Objectives and evaluation criteria for network tariff reforms

## 2.1 Fundamental objectives of network tariff design

There is obviously a vast variety of possibilities to design a network tariff. In order to find an appropriate solution within this variety of options, any tariff reform has to be driven by objectives that are desired to be met. The major challenge with the task of designing an appropriate network tariff arises from the fact that there are always conflicts between the objectives. One reason for this is that there are two fundamental functions of network tariffs that are, in principle, contradictory to each other, namely the incentive function and the refinancing function:

- **Incentive function**: Network charges are expected to create incentives for network users in a way that network users meet efficient investment and operation decisions regarding their generation, consumption and/or storage equipment. To meet this objective, network charges would have to reflect the direct impact of each individual decision of a network user on network cost as precisely as possible. This would, among others, require charges to be highly situation-dependent, which may be hard to fulfil in practice. A typical example of a network charge coming close to this requirement is a charge to be paid for “shallow connection cost”, i.e. the cost associated with providing a network connection to an individual network user. For the majority of network cost, it is however not possible to determine exactly the share of network cost caused by a single investment or operation decision of an individual network user.
- **Refinancing function**: Network tariffs are expected to be designed and calculated such that network cost (as far as approved by the regulatory authority) are fully covered. This objective could, in principle, be met easily by introducing a single and uniform price component e.g. based on energy consumption, which could be calculated by dividing total network cost by total energy consumption. However, a simple approach like this may lead to a cost allocation among network users that is not considered appropriate and fair. Therefore, even when only looking at the aspect of the refinancing function, there are typically multiple sub-objectives that are related to the cost allocation among network users, leading to conflicts that can only be resolved by trading off between

The fact that these two fundamental objectives are contradictory to each other can be shown easily when looking at the typical cost structure of networks. Network costs are, to a major part, fixed costs in a sense that they do not depend on individual decisions of individual network users. Therefore, once a network has been built, the marginal cost associated with individual decisions of network users are almost negligible, except for the case that such decisions cause network congestion that has to be resolved by costly measures. As a consequence, network charges based on marginal cost might appear desirable with respect to their incentives but would not at all lead to full refinancing of network cost. On the other hand, network charges that allow for full coverage of network cost can create incentives that are at least inefficient or possibly even adverse in a sense that they impose unnecessary barriers on certain types of network use. An important example of this effect are barriers to the provision of demand-side flexibility that are caused by charges related to maximum power demand of a consumer within a year: Such a price component can create a significant cost burden when there are few opportunities for flexible consumers throughout a year to provide flexibility by increasing their consumption as compared to their normal maximum demand.

For the reasons discussed above, it is generally not possible to design network charges such that they ensure full coverage of cost and, at the same time, provide efficient incentives (and avoid inefficient ones) under all circumstances. It would be an illusion to believe that this fundamental conflict can be overcome by designing a **cost-reflective** tariff which is typically required by legal and regulatory frameworks both on EU and national level. The problem is that it is not possible to define cost-reflectiveness in a way that would satisfy requirements to incentives and cost coverage at the same time. If cost-reflectiveness is interpreted such that network charges should reflect direct cost impact of individual decisions of network users, it might lead to efficient incentives, but not ensure cost coverage. If, on the other hand, cost-reflectiveness is rather interpreted in a way that average, typical cost effects of network users' decisions are reflected, the resulting charges would not create efficient incentives under all circumstances. For example, typical volumetric charges that have to be paid for withdrawal of energy can cause adverse incentives in situations in which additional consumption would be beneficial for the system and would not cause any network congestion or even reduce network congestion. As a conclusion, cost-reflectiveness can only be understood as a guiding principle to achieve a cost allocation accepted as fair, but not as a clear design principle that leads to an undisputedly optimal tariff design.

Against this background, we consider it sensible to following three guiding principles in order to arrive at a tariff design that strikes a reasonable balance between the fundamental objectives discussed above:

1. As far as **incentives for decisions with impact on network cost** are desired and appropriate, such elements should be designed so as to reflect marginal cost as precisely as reasonably possible. Examples for such tariff elements can be connection fees reflecting individual shallow connection cost (see above) as well as dynamic time-of-use charges reflecting network congestion cost. Such elements typically cover only a (small) part of total network cost.
2. The remainder of cost has to be recovered by **charges serving primarily the refinancing function**. These charges should be designed such that they create as little as possible adverse incentives. For example, as mentioned above, network charges should create as little as possible barriers to opportunities of market-oriented provision of demand-side flexibility.
3. Within the remaining scope for solutions, tariff design typically has to strike a balance between certain desired distributional effects and the attempt to follow a more or less "universal" cost allocation principle. Examples for desired effects can be low charges for industrial customers[1] facing strong international competition, or low charges for vulnerable customers. Of course, there will always be conflicting interests with respect to such cost allocation effects. From an economic point of view, it can be rational to align cost allocation with the price elasticity of customers. This principle which is referred to as "Ramsey pricing" in literature would mean that costs are preferentially allocated to those network users who have little price elasticity, e.g. are supposed not to change their behaviour significantly or even to leave the country in case of increasing power prices. Legally however, the scope for applying this principle is limited by non-discrimination requirements. Ultimately, in the political or regulatory debate, tariff design has to be accepted as fair by all relevant

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[1] In Germany, for example, industrial customers with more than 10 GWh annual consumption and more than 7000 usage hours can apply for a substantially reduced network charge. These exemptions from charges are refinanced by the other grid users via a levy. This special arrangement for reduced network charges was historically based on the argument that a steady load profile is beneficial to the operation of the network. The provision is currently under revision. For more information see *https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK04/BK4_71_NetzE/BK4_71_Ind_NetzE_Strom/BK4_Ind_NetzEntg_Strom.html*

stakeholders. In this debate, the principle of cost-reflectiveness is often referred to as a desirable guiding principle. However, as discussed above, it should be kept in mind that in case of controversial discussions on different cost allocation options, this principle often provides only weak guidance.

We will discuss later on in this report how these guiding principles apply to several tariff design decisions that require relevant trade-offs, e.g. with respect to the introduction of time-of-use charges and the way in which capacity-based tariff components are designed.

## 2.2 Tariff design evaluation criteria

Based on the above discussion of fundamental objectives of network tariff design, we primarily discuss the reform options examined in this study with respect to the incentives to network users they create as well as the appropriateness of the resulting cost allocation. Apart from this, we will put particular emphasis on the question of how tariff design impacts the stability of the level of tariffs over time. Additionally, we will address a number of basic requirements that are typically placed on the design of network charges, including objectivity, complexity and transparency of tariffs.

### 2.2.1 Incentives

As discussed in section 2.1, the first step of assessing a proposed tariff design reform option should be to analyse if the very purpose of the proposed tariff components is to create specific incentives to network users. This is, for instance, the case for time-of-use network charges that aim at providing incentives towards a costumer behaviour that leads to relieving network congestion. In such cases, the assessment should address both the questions if it makes sense to provide the proposed incentives and if the proposed tariff design is able to create these incentives in a satisfactory way. We discuss this further in chapter 6.

In a second step, any tariff design options, including those that do not primarily serve to provide specific incentives, should be analysed with respect to the risk of (unintendedly) creating inefficient or even adverse incentives. In this respect, we consider it particularly important to look for potential barriers related to market-oriented[2] use cases of demand-side flexibility. Even if the use of market-oriented flexibility is not a direct objective in the sphere of networks tariffs, it should be impacted as little as possible by network charges because the provision of demand-side flexibility to the market will be of high importance for the further development of energy transition. This aspect relates in particular to tariff components that create an incentive for an even power consumption profile, like fixed or capacity-based charges. We will discuss potential adverse incentives both with respect to the dimensioning of such tariff components and to their precise definition.

### 2.2.2 Appropriateness of cost allocation

Appropriateness of cost allocation is a criterion that relates primarily to the refinancing function of network charges (cf. section 2.1): As far as network charges do not serve to provide specific incentives, they are simply necessary to cover network cost, and to this end, the question has

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[2] All mechanisms that contribute to balancing supply and demand in the system. This includes transactions between market participants, including the implementation of contractual supply obligations, the management of balancing groups or the utilisation of price signals on the wholesale market through trading on the electricity exchange or through bilateral trading transactions. Additionally, the mechanisms of system balancing fall under market-oriented flexibility use.

to be answered which allocation of cost among (groups of) network users can be considered acceptable, fair and economically efficient (as for example reflected by the thoughts about "Ramsey pricing"). This challenge has to be met both for cost allocation across network levels (by cost cascading) as well as for the design of tariff components.

One approach to determining cost allocation principles that are accepted as fair is to analyse cost drivers of network cost and to try to match them to the indicators that are typically used for tariff calculation like the yearly amount of energy taken from the network or the maximum power of energy withdrawal within one year. Such analyses of network cost drivers have shown that a large part of network cost is driven by the structure of a network rather than by energy withdrawal by its users. Network structure in this context means the number and locations of the connection points that have to be served within a given area.[3] However, certain parts of network cost are also driven by the capacity requirements of network users and by the amount of energy transported. These findings can be helpful when figuring out reasonable solutions for cost allocation across network levels and across network tariff components.

In this sense, with respect to the cost cascading mechanism, we will analyse a number of variables that could be used as indicators for splitting cost to customers in a given network level and to customers in lower network levels. We will evaluate for each of these potential variables if their use could be justified and how they would impact quantitative results of cost cascading.

With respect to the design network tariff components, the findings about network cost drivers can provide a certain guidance as to how tariff components should be dimensioned in relation to each other. However, besides this guidance, it is quite important to also assess the incentive effects that certain types of tariff components can have, be it intended or unintended. We will discuss this more deeply in chapter 5.

### 2.2.3 Stability over time

Besides the criteria discussed above, a relative stability of tariffs over time also holds value both from network operators' and from customers' point of view and, more generally, from the perspective of transparency of tariffs. Stability of network tariffs can be impacted by different influence factors:

- **Network cost** can change from year to year. As far as such fluctuations on the cost side are not (partly) compensated by additional financing sources like public subsidies, they have to be reflected by variation of tariff levels. However, network cost typically do not fluctuate strongly but rather develop smoothly. Exceptions from this rule can be caused by strong external shocks like the price crisis at the European power market 2021-2023 which has, among others, caused congestion management cost in Germany to rise extremely in short time (which has an impact on tariffs that Creos has to pay to the German TSO Amprion).
- **Cost cascading** could lead to unstable cost allocation results among network levels if the variables used for cascading are subject to fluctuations from year to year. We will discuss how sensitive different possible variables are with respect to changes in network customers' behaviour.

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[3] For studies with cost driver analysis see a 2018 Study for the German Ministry for Economic Affairs and Climate Action (*https://www.bmwk.de/Redaktion/DE/Publikationen/Studien/optionen-zur-weiterentwicklung-der-netzentgeltsystematik.html*) as well as a 2021 study for the Swiss Federal Office of Energy (*https://www.bfe.admin.ch/bfe/de/home/versorgung/stromversorgung/bundesgesetz-erneuerbare-stromversorgung.exturl.html/aHR0cHM6Ly9wdWJkYi5iZmUuYWRtaW4uY2gvZGUvcHVibGljYX/Rpb24vZG93bmxvYWQvMTA1MTM=.html*)

- Similarly, the stability of **tariff components** can also be impacted by fluctuations of the variables used to calculate the components. The sensitivity of this impact can depend on the concrete principles of tariff calculation. For example, it appears that the principle of a simultaneity function applied in Luxembourg today causes relatively strong sensitivity of tariff components with respect to fluctuations of the customers' consumptions profiles.

### 2.2.4 Objectivity, complexity and transparency

These evaluation criteria cover a number of basic requirements, some of which are met by all design options that are seriously considered such as compliance with EU and national legal framework, application of a non-discrimination principle and the objectivity of the calculation of individual charges. With respect to some other aspects, the options evaluated in this study might differ, especially regarding the effort and complexity that is associated to the practical implementation of the different design options.

Effort and complexity of different cost cascading variants mainly depend on how readily the data for the variables used in the cascading mechanism is available. Some data is measured or collected by the network operators anyway, while the input data for some variants has to be generated by more or less complex calculations. Additionally, if a combination of variables is chosen for allocating cost to network levels, this can further increase complexity of the mechanism.

Effort and complexity of different combinations of tariff components mainly depend on the mechanism through which the breakdown of cost into tariff components takes place. In the current system, this allocation is based on the simultaneity function, which requires parametrisation. Alternatively, the cost recovered by each tariff component could be determined by fixed revenue shares. The complexity of this approach depends on how these shares are determined and adjusted over time.

The complexity of both cost cascading and tariff calculation determines not only the complexity and effort for the network operator but also influences the transparency of the calculation. Even if all options for the calculations are objective and non-discriminatory, a low complexity increases transparency for network users and other stakeholders like the regulator in comprehending the calculations. Another factor for transparency is the availability of data if stakeholders try to understand not only the methods but also the quantitative results of the tariff calculation mechanisms. Some of the data used in the calculation variants discussed in this report may can be taken from public sources, while other data are not available to third parties.

Transparency affects the perceived fairness and acceptance of the resulting allocation of cost to the network levels.

# 3 Cost cascading mechanism

## 3.1 Background and Motivation

The allocation of network cost in Luxembourg's electricity networks currently takes place vertically from the upper to the lower network levels. The allocation of cost to network levels via the cost cascading mechanism takes place in two stages:

In the first step, the cost of each asset is allocated to the voltage level to which the asset technically belongs. This principle of determining cost per voltage level is very common and basically undisputed. However, there are calls for potentially deviating from this principle in particular cases. The idea is to allocate costs of some of the assets based on the cause of the corresponding expansion need of the network. Specifically, some stakeholders in Luxembourg argue that the need for an upgrade of the EHV network to the 380 kV level is mainly caused by developments on the lower network levels. The proposed approach to allocate such cost elements directly to the lower levels would however constitute a paradigm shift that would require a complex and ambiguous allocation of transport requirements to network levels. It should be kept in mind that it is not possible to allocate (parts) of network assets to specific groups of network users in an unambiguous and objective way. Consequently, once this approach was applied to specific assets, this would likely open up a discussion about how to allocate network assets to user groups for more or less any of the network assets. We therefore tend to recommend maintaining the allocation principle applied so far, i.e. based on the technical characteristics of the network assets. This principle provides an unambiguous allocation key of cost to network levels.

In the second step, the cost determined for the individual network levels are cascaded down from the upper to the lower levels. This mechanism of top-down cost cascading reflects in a generalized way the fact that for the supply of customers at lower levels, the higher levels up to the EHV level are also needed. This is not only the case for the top-down transport of energy, but also for providing ancillary services for the whole system and for enabling power market access to customers on any network levels. Figure 3.1 illustrates the vertical top-down cascading mechanism in which the cost allocated to each network level in the first step are partly borne by the customers connected to that network level and partly cascaded downwards. In the current system the cost is cascaded downwards according to the annual peak load values at each level plus decentral generation in the underlying network levels, i.e. based on the gross peak loads. The cost borne by the network users on each level is calculated by the ratio of that level’s peak load value and the sum of peak load values of the downstream network levels. The cascading variable, i.e. in this case the gross peak load, is thus decisive for how much of the cost is cascaded how far downwards. Depending on how the values of the cascading variables on the individual levels relate to each other, the costs are cascaded downwards to a higher or lower degree.

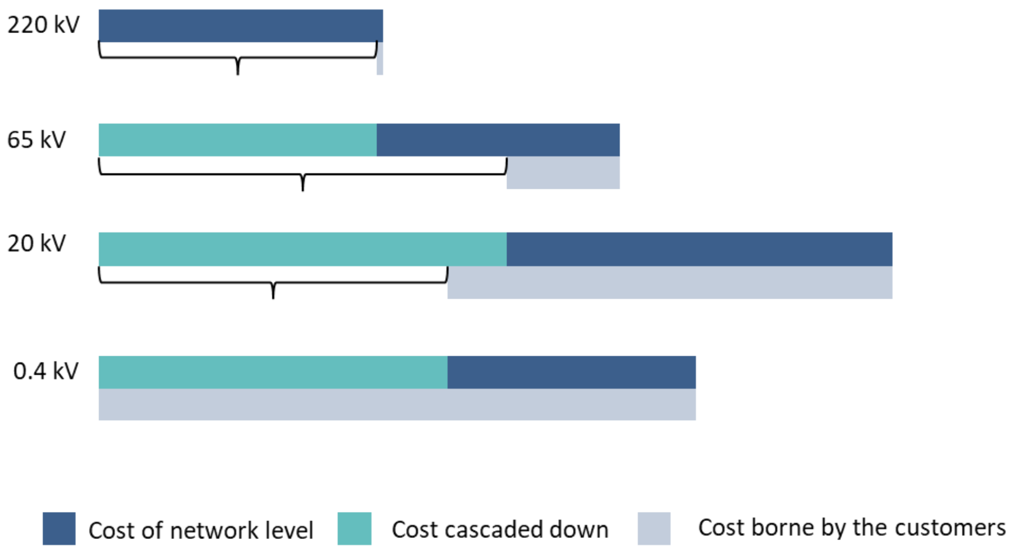

*Figure 3.1* *Schematic illustration of the cost cascading mechanism (approximately representing the 2022 cost allocation to each network level and the resulting cascading mechanism)*

The stability of the cost cascading variable over time affects the stability of network tariffs as it determines the allocation of cost to each network level, which are then used as a starting point to calculate components. *The annual peak load value* is determined by a single point in time in the year *and is* susceptible to one-off effects*.* The fact that annual peak load value is subject to fluctuations was the initial motivation for the exploration of alternative options for the cascading variable.[4] The following evaluation of different variables also covers questions of cost reflectiveness, complexity and transparency and evaluates the quantitative effects on the distribution of costs to the network levels.

## 3.2 Variants of cost cascading mechanisms

Based on the considerations in the previous section, which prompt an examination of the suitability of current cost cascading variable, the alternatives analysed are presented below.

In this study, the current cost cascading mechanism with the annual peak load plus decentralised energy generation (i.e. the gross peak load per network level) serves as the reference case. Peak load is used as the sole cascading variable not only in Luxembourg, but also in other countries like Germany and Belgium. An examination of the implementation of network tariff systems in further countries reveals that cost cascading mechanisms can be based on variables other than or in addition to the annual peak load.[5] In Switzerland the cost cascading depends on a mix of two variables – the gross annual consumption and peak load values.[6] The cost cascading mechanism in Austria also considers both annual consumption and peak load values.[7] In the

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[4] In order to mitigate this effect Creos currently uses averages and linear forecasts.

[5] Norway and France which also serve as benchmarks in the country research for this study allocate cost across network levels differently, i.e. by marginal cost (FR) and as part of the allowed revenues per voltage level (NO) (see Acer (2023)).

[6] Cost cascading depends 30% on gross annual consumption and 70% annual average of the monthly peak load values. See Stromversorgungsverordnung (StromVV) Articles 15 and 16. *https://www.fedlex.admin.ch/eli/cc/2008/226/de*

[7] See Systemnutzungsentgelte-Verordnung (SNE-V) Article 3. *https://www.e-control.at/bereich-recht/verordnungen-zu-strom/-/asset_publisher/tiRyh5zzUOU7/content/systemnutzungsentgelte-verordnung-sne-v-1*

Netherlands the cost allocation towards the higher and medium network levels is based on power and towards the lower voltage level on energy volumes.[8]

Given that peak load is not the only practically applied option for a cascading variable, a number of alternatives are examined in this study. The gross peak load currently used in Luxembourg is compared with the net maximum load to illustrate the effect of the differentiation between gross and net values[9]. Based on examples from other countries, consumption quantities are examined as possible variables. Finally, variants are considered that are based on a network planning perspective and thus take into account capacity variables that influence network dimensioning. The specific alternative variables for the cost cascading mechanism evaluated in this study include:

- Reference: today's mechanism both based on 2022 and 2023 consumption data
    - → Based on peak load of the downstream network level, as measured at the upper network level, plus decentralised energy feed-in
- Variant 1: Net peak load values based on 2022 consumption data
    - → Based on peak load of the downstream network level, as measured at the upper network level
- Variant 2: Net annual consumption based on 2022 and 2023 consumption data
    - → Based on the amount of energy transport from the upper to the lower network level, as measured at the upper network level
- Variant 3: Gross annual consumption based on 2022 and 2023 consumption data
    - → Based on the amount of energy transport from the upper to the lower network level, as measured at the upper network level, plus decentralised energy feed-in on lower network levels
- Variant 4: Connection capacities based on two approaches to quantify capacity demand of LV customers, i.e. 27 kVA and 1 kVA, alternatively
    - → Based on the contractually agreed connection capacities required by end consumers on current and all lower network levels
- Variant 5: Transformer capacities based on 2022 technical data
    - → Based on the contractually agreed connection capacities required by end consumers on current network level and the transformer capacity connecting the current and downstream network level

Further elucidation pertaining to the cost cascading mechanisms, with particular reference to the distinction between end consumers and downstream network levels, can be found in the ensuing sections.

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[8] See Acer (2023): *https://www.acer.europa.eu/news-and-events/news/acer-publishes-its-latest-report-how-electricity-network-tariffs-are-set-europe*

[9] In the context of cost allocation, the terms 'net' and 'gross' refer to the exchange between network levels. It is important to note that self-consumption by end consumers is never included.

### Reference

As previously stated, the reference case can be interpreted as a cost cascade based on gross annual peak loads per voltage level, determined by adding profiles of (measured) net peak loads and decentralised energy generation. From the load profiles determined in this way, annual peak load for each level results from the maximum value of the respective profile. In order to ascertain the total peak load, including decentralised generation, for the purposes of cost cascading, it is necessary to divide this figure into two parts: firstly, the maximum load of the customers connected to the respective network level; and secondly, the maximum load of the downstream network levels. The maximum gross load of the downstream network levels is derived from the sum of the maximum decentralised energy generation and feed-in from the upstream network level, minus the load of the customers and the grid losses of the respective network level.

### Net peak loads

In Variant 1, annual peak loads are utilised for cost cascading in a manner analogous to the reference case. The key difference between the reference case and this variant lies in the treatment of decentralised energy generation from downstream network levels. In Variant 1, peak loads are directly determined based on the sums of the measured load profiles of the end consumers and the load resulting from the grid losses. Decentralised generation is not taken into account here. Consequently, the variable used for cost cascading at a certain network level is identical to the peak load actually measured at the upper network level.

### Net annual consumption

Cost cascading via net annual consumption resembles the approach of net annual peak loads, but rather than employing the annual peak load, the overall annual energy consumption per voltage level is utilised. Similar as with the net annual peak load approach, transports to downstream network levels are only taken into account as they take place, i.e. influenced by the extent of simultaneous decentralized energy generation at those levels. Unlike net peak loads, which are based on the actual peak loads measured at the upper network level, Variant 2 considers the actual amount of energy transport from the upper to the lower network level, as measured at the upper network level.

### Gross annual consumption

Contrasting with net annual consumption, using gross annual consumption as a determinant for the cost cascade does not account for decentralized energy generation at downstream network levels. Consequently, the gross annual consumption at downstream network levels consists of the measured annual consumption by the end consumers at the respective network levels, plus network losses.

### Connection capacities

Variant 4 differs from annual peak loads and annual consumption in that it focuses on the connection capacities required by end consumers. For each network level, the capacity utilized by the end consumers is calculated as the total of the contractually agreed connection capacities of all end consumers at that network level. For low-voltage consumers without load metering, two sub-variants are assumed. In Variant 4.1, each unmeasured consumer is assumed to have a contractual connection capacity of 27 kVA. This reflects a typical value of technical connection capacity. In Variant 4.2, a capacity value of only 1 kVA is attributed to each unmetered consumer. This approach takes into account that compared to other network levels, on the low voltage level there is only a small degree of simultaneity of the individual consumption profiles, which is also taken into consideration in the dimensioning of the network. The second sub-variant therefore reflects the network dimensioning requirements more realistically. The connection capacity of the downstream network levels in both variants is determined by the total of the connection capacities of all end consumers connected at those levels.

### Transformer capacities

Variant 5 also employs the connection capacity at each network level to determine cost cascading for end consumers. However, in contrast to Variant 4, the connection capacity of the downstream network level is not derived from the sum of the connection capacities of the end consumers. Instead, the determinant for the cost cascading from the upstream to the next downstream network level corresponds to the transformer capacity between two voltage levels.

## 3.3 Quantitative Results

The quantitative analysis of the variants described above is based on 2022 cost allocation to each level before cascading.[10] Although 2023 data would be more up-to-date, that data was subject to adaptation as the projected cost of ancillary services charged to the transmission system operator were corrected within the same year. To test for sensitivity of certain variants, both the 2022 and the 2023 consumption profile data was used for the cascading variable. This analysis therefore isolates the effects of the cascading variable by keeping the cost constant which in reality also vary from year to year. It illustrates the effect of different cost cascading variables on the cost distribution.

In the reference case the cascading mechanism leads to a share of 0,6% of cost that are borne by customers on the 220 kV level, 9,8% by customers on the 65 kV level, 38,3% by customers on the 20 kV level and 51,3% by customers on the 0,4 kV level. In Variant 1, representing cost cascading based on net annual peak load values, a higher share of cost would remain in the 220 kV and the 65 kV network level as compared to the reference case. This is due to the fact that the net peak load value is the peak load actually measured at the upper network level, i.e. the load values are lower than gross load due to decentralized generation. This shows that the (very) high voltage network users benefit from today’s approach of cascading based on gross load values. With increasing decentralised generation on the 0,4 kV and 20 kV levels, this effect will further intensify.

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[10] It is not the aim of this analysis to replicate the actual tariff calculation 2022 exactly, but to illustrate the effects of using different cost cascading variables.

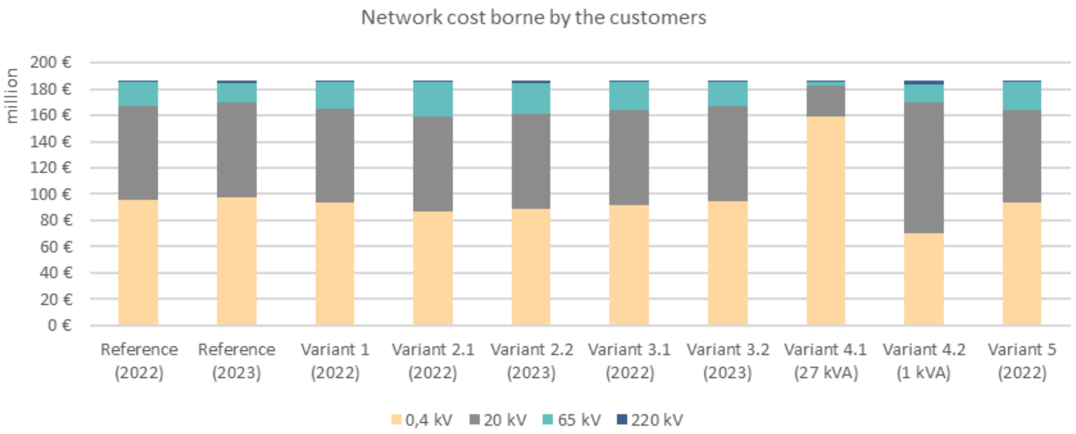

*Figure 3.2* *Distribution of cost borne by the customers of each network level after cost cascading with different variables based on 2022 cost data.*

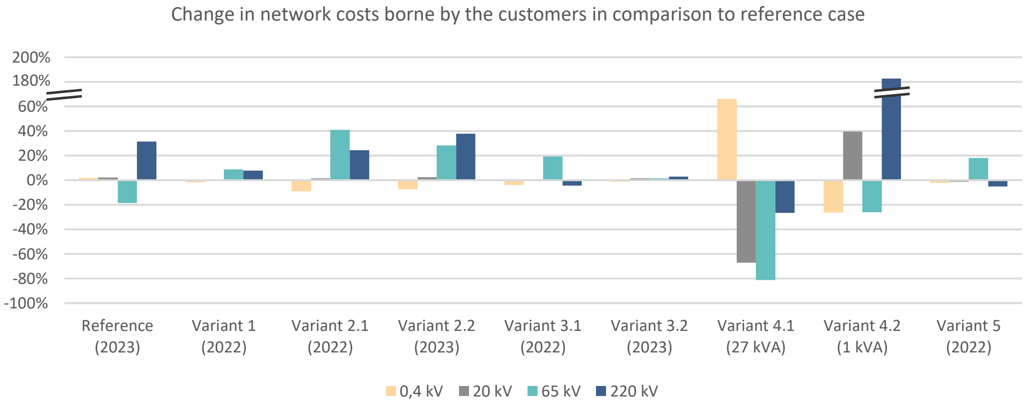

*Figure 3.3* *Relative change of cost borne by the customers of each network level after cost cascading with different variables compared to the reference case (2022).*

Variant 2 which is based on net annual consumption leads to a significantly higher proportion of cost borne by the two highest network levels. The effect is similar to the one observed for Variant 1. However, a net value for consumption is a cumulative value over the year and will always be affected by the decentralized generation of energy, while the peak load values are only affected by the amount of decentralised generation at the time of peak load.

A further remarkable result that can be observed both for Variants 2 and 3 is caused by a change of the status of a decentralised generation plant on high voltage level between the years 2022 and 2023. This plant has formerly been treated as a normal generation plant feeding into the network. From 2023 on, it has been treated as a self-generation plant of one of the high voltage level customers. As these energy amounts no longer appear in the annual consumption values, the cascading value for the high voltage level has decreased, so that a lower share of cost is allocated to customers on this network level. Self-consumption can reduce both the annual consumption values (these energy volumes are no longer drawn from the network) and peak loads (especially if the self-supply is not supply-dependent or self-consumers even out their peak load with energy storage). Self-supply is not measured explicitly as it does not utilise the network, and therefore it cannot be factored into the cost cascading.[11] Decentralised generation on the other hand can be considered in the cost cascading (see Variants 1 and 2) but is not taken into consideration when gross values are utilised. If there is no or only little decentralized generation, a cascading with gross values leads to exactly or approximately the same results as cascading with net quantities. The quantitative analyses based on current data for Variant 3 with 2023 data for gross annual consumption leads to very similar results as for the reference (based on 2022 data). However, if the two variants are compared based on data for the same year, it turns out that variant 3 would lead to a different cost distribution than the reference approach. The cost borne by the 0,4 kV and the 20 kV level are slightly higher in the reference case while the cost borne by the 65 kV level are noticeably lower compared to cost cascading applying the gross annual consumption (compare Figure 3.4 and Figure 3.5).

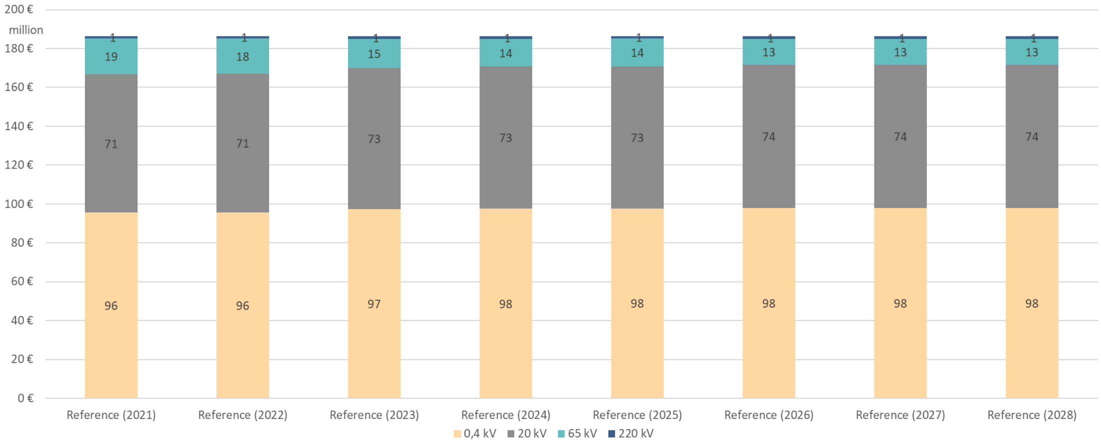

*Figure 3.4* *Distribution of cost borne by the customers of each network level after cost cascading applying the reference approach for different years (and on 2022 cost data).*[12]

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[11] The issue of the refinancing contribution of self-suppliers is however taken into account in the design of the network tariffs.

[12] In the estimations on future development of peak loads provided to us by Creos, the annual peak loads develop proportionally on all network levels across years so that the results of the cost cascading mechanism are the same for all three years 2026-2028.

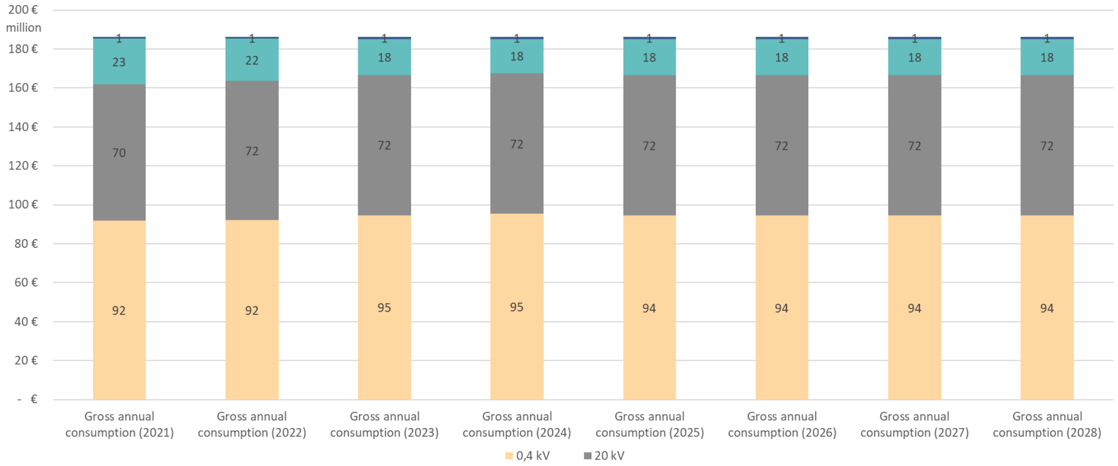

*Figure 3.5* *Distribution of cost borne by the customers of each network level after cost cascading applying the gross annual consumption approach based on consumption data for different years (and on 2022 cost data).*[13]

Variants 4 and 5 relate to variables that are based primarily on a network planning perspective and take into account capacity variables that influence network dimensioning. Variant 4.1 which allocates the cost based on individual connection capacities leads to a significant redistribution of costs from the upper levels to the lowest network level. The shares of cost allocated to the high and medium voltage levels are more than halved compared to the reference case. This variant however ignores the fact that the usage of the network on the lowest voltage level is characterised by a low degree of simultaneity of the individual load profiles. This is also reflected in the dimensioning of the network, which is why it would be difficult to argue why a technical capacity of 27 kVA per low voltage level network user should be assumed when cascading cost via the connection capacities. Variant 4.2 considers the low degree of simultaneity by setting the low voltage level connection capacity to 1 kVA per customer. This variant leads to the greatest distortions compared to the reference as the cost allocated to the low and high voltage level are significantly reduced while the cost allocated to the medium voltage level increases considerably and the very high voltage level is allocated almost three times the cost compared to the reference. In contrast to variants 4.1 and 4.2, in Variant 5 the downstream network level capacity is derived not from the sum of connection capacities of end consumers, but from those of directly connected transformers. No assumption needs to be made about the connection sizes of the low-voltage users. This leads to a cost allocation that is much closer to the reference, only the share of cost allocated to the high voltage level rises noticeably.

In the next step, the evaluation of the quantitative results will be complemented by the evaluation criteria of cost reflectiveness, complexity and transparency in order to draw a conclusion on the adequacy of the current mechanism and identify possible reform options.

## 3.4 Evaluation

The variants for the cost cascading mechanism will be evaluated according to the criteria introduced in section 2.2. As the cost cascading mechanism allocates cost to network levels as a

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[13] In the estimations on future development of gross annual consumption provided to us by Creos, the gross annual consumption develops proportionally on all network levels across years so that the results of the cost cascading mechanism are the same for all three years 2025-2028.

whole and the variables used for the cascading mechanism are determined for the entire customer collective, the incentives for individual customers do not play a significant role at this stage. Therefore, the incentive criterion is not relevant for the evaluation of the cost cascading mechanism and the different variants will be evaluated according to the criteria of the appropriateness of cost allocation, stability over time and objectivity, complexity and transparency.

### Cost cascading with peak load

Peak load is clearly a driver of network cost. However, it is not the only one - network cost are also structure-driven and partly even energy-driven. The widespread assumption that network cost are largely proportional to the simultaneous peak load in a network area can be called into question. The peak network load is neither the dominant nor a proportional driver of network cost. The network infrastructure costs are not driven primarily by the capacity requirements of the network users, but by the structure of the network, i.e. the locations of the network connection points and the distances between these points. These structural conditions result in variables such as the required cable length and the number of transformer stations required, which in turn have a significant influence on network cost. Of course, the costs of the network assets like lines and transformers are also dependent on capacity requirements. However, this dependency is not a proportional relationship. Therefore, cost cascading based on peak load is a possible, but not necessarily the most appropriate solution.

The peak load value per voltage level is prone to fluctuations - this is one of the reasons why alternative variables for cost cascading are examined in this study. The stability of the results of this approach could be increased by using averages of monthly or annual peak load values or the $x^{th}$ highest value instead of the maximum value from the quarter-hour with the highest load per voltage level.[14]

In the mechanism currently applied in Luxembourg, the cascading variable considers decentralised generation in such a way that gross peak load values are used for cost cascading. This approach yields a higher level of stability over time than cost cascading based on net values would do, particularly in the face of future increases in decentralised generation.

The main challenge when using the peak load is calculating the required values. The peak load values (and the decentralised generation) have to be derived via a comparatively complex calculation creating a considerable effort for Creos as these values cannot be directly measured. This complexity adversely affects the transparency of the current cascading mechanism. Additionally, the data and the calculations for deriving it are not published and cannot be reconstructed by stakeholders.

### Cost cascading with net annual consumption

Even if it is not the dominant cost driver, network costs are at least partially driven by energy consumption**.** Moreover, to a certain extent, consumption is correlated to peak load and might therefore be used as a proxy for peak load. However, net consumption is less correlated to peak load than gross consumption. Since net annual consumption considers the actual amount of energy measured at the transition to the downstream network level, it is directly impacted by decentralised generation. As decentralised generation decreases the measured net annual consumption, this leads to a reduced allocation of cost towards the lower network levels, as decentralised generation mainly takes place at the lower network levels. Cost cascading based

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[14] In order to mitigate fluctuations Creos already uses averages and linear forecasts.

on net consumption therefore constitutes a rather questionable approach since the capacity requirements of customers do not decrease in proportion to the increase in decentralised generation.

The effort of application of this cascading variable is lower compared to cost cascading with the annual peak loads. To calculate net annual consumption, energy withdrawals must be netted with decentralised generation. The data on decentralised generation per voltage level is currently not published. Therefore, the calculation would not be comprehensible to third parties today. However, if the relevant data was publicly available, the effects on the cost allocation could be understood with manageable effort and this variant would pose a more transparent approach compared to the reference case base on peak load values.

### Cost cascading with gross annual consumption

As discussed above, network costs are at least partially driven by energy consumption. Part of the cost for ancillary services passed on by the upstream transmission system operator Amprion are directly energy dependent. The gross annual consumption is more closely correlated to the peak load and can be considered an acceptable proxy. If no decentralised generation existed, the gross and net annual consumption would be identical. The gross annual consumption is not lowered by decentralised generation on the same grid level. If increasing decentralized generation leads to a reduced utilisation of the upstream network levels and any reductions in peak load, these effects are not taken into account by the gross energy consumption value. This can be considered an appropriate approach for cost cascading because the upstream network levels are still required to maintain the usual level of security of supply, even with a high penetration of decentralised generation.

In terms of stability over time, gross consumption appears similarly appropriate for cost cascading as gross peak load values or even more appropriate because it appears less prone to fluctuations than annual peak load. Still, it can still be subject to one-off effects in single years. The stability of this variable can be increased by using averages over several years.

A key advantage of this variant is the simplicity of the calculation. Cascading with gross annual consumption requires very little data and allows for a low level of complexity of the cost cascading mechanism. Furthermore, transparency of this approach is also very high as the data for gross annual consumption per network level is already published. Thus, the results of cost cascading based on this approach can be understood with little effort.

### Cost cascading with connection/ transformer capacity

As discussed above, a relevant cost driver for the network is its structure. It is therefore not only the maximum network load but also structural factors that are responsible for the dimensioning of the network. This leads to the consideration of using a relevant network planning parameter for the cost allocation. Capacities of user connections and transformers reflect that network costs are not primarily driven by actual use of the network, but by its dimensioning that is based on the capacity requirements of network users and underlying network levels.

However, the appropriateness of connection capacities as a cost allocation key depends on how the simultaneity of consumption profiles is taken into account. Especially on low voltage level, **connection capacities** will be considered a fair allocation key only if the low degree of consumption simultaneity on this level is reflected properly. A variant like variant 4.1 that ignores the low simultaneity of consumption in the low voltage level by summing up technical connection capacities of its individual users and thereby allocating a large share of cost to this level would be difficult to justify.

This problem could be avoided by using a combination of connection capacities at end consumer level and **transformer capacities** for the underlying network level as allocation keys (see Variant 5). In that case, the customer connection capacities on the low voltage level are not included in the calculation for cost cascading. Transformer capacities are already dimensioned according to the usage behaviour of low-voltage customers, therefore no assumption on the degree of simultaneity must be made during the cost cascading calculations.

These variants present a very stable alternative as connection and transformer capacities are very stable over time compared to the other variables discussed so far. Furthermore, cascading based on connection and transformer capacities requires very few data that is already available leading to low complexity. However, if the cascading solely utilizes **connection capacities**, the capacities to be applied for the low-voltage level must be determined and it must be plausibly justified what degree of simultaneity was assumed. This challenge does not arise when **transformer capacities** are used as allocation keys for the underlying network level, which makes this variant preferable. Currently the data on capacities per network level is not published. However, if the data was made available, the effects on the cost allocation could be understood with little effort.

## 3.5 Conclusions

Analyses of cost drivers show that network cost are not only driven by the peak loads but are also structure-driven and partly even energy-driven. The cost allocation via the cascading mechanism therefore does not necessarily have to be based on the maximum annual loads. Instead, several alternative variables can be argued. In order to fully reflect the fact that network cost is driven by several factors, a combination of cascading variables could be applied. However, this would increase the complexity of the calculation and thus reduce transparency.

The current approach based on (gross) peak load is still an acceptable solution. However, other allocation keys would be justifiable, as well, especially gross consumption or a combination of connection and transformer capacities. Among the candidates, utilising gross annual consumption has the advantage that the required data is already available and can be expected to be more stable over time than the annual peak load. The calculation would be considerably less complex. Additionally, the data is even publicly available allowing stakeholders to understand the effect of the cascading variable on the cost allocation across network levels. However, as was shown in section 3.3, a change towards cost cascading based on gross annual consumption would lead to a different allocation of cost to network levels. It would tend to allocate a higher share of cost to higher voltage levels. Concluding from these considerations, the advantages of a possible shift towards this alternative, particularly a simplification of cost cascading and an increase in transparency and stability, has to be weighed against the disadvantage of causing a non-negligible redistribution of cost allocation.

# 4 Generation-side charges

## 4.1 Objectives, design options and effects of generation-side charges

Luxembourg's network tariff system currently does not include any network charges to be paid on the generation side. However, a discussion has been raised about the potential introduction of producer-side network charges, motivated by thoughts about overall contributions to refinancing network cost: If producers made a contribution to financing network cost, consumption-side charges could be reduced accordingly. Possible further motives for the consideration of introducing producer-side charges include setting incentives for location and dispatch decisions.

Analogous to the analysis of consumption-side charges, a fundamental distinction must first be made between connection-based and energy-injection-based charges. In this respect, the design of generation-side charges affects which effects such charges could have, both intended and which unintended.

The dispatch decisions of producers are considerably more price-sensitive than the dispatch decisions of most consumers. Therefore, **charges based on energy injection** could have a strong impact on the dispatch of generation plants. As network charges inevitably require approximations, there is a high risk that such charges would not accurately reflect the cost effects in the network for any individual case, so that producers could be driven to meet economically inefficient dispatch decisions. In extreme cases, plant operators could decide not to generate electricity, even if this would be economically advantageous overall. For this reason, injection-based charges for power producers do not appear advisable.

**Connection-based charges** are levied independent of the actual dispatch of a generation plant. They can be designed either as capacity prices (paid periodically) or as one-off connection charges. The effect on producers would, in principle, be similar, but the financing contribution towards recovering network cost would increase more quickly with one-off connection charges than with capacity prices, as connection charges can be viewed as an advance payment on periodical network charges.

When network charges for producers are taken into consideration, the effect of producers' participation in the refinancing of network cost has to be carefully considered. Renewable energy and CHP plants are typically subsidised. Therefore, especially if those subsidies are determined by tender, producers will include their contribution to the network cost into their bids. Their share in bearing the network cost will then be refinanced via these subsidy systems. In the end, the cost is not borne by the producers but redistributed to the funding sources of support schemes for renewable energies and other subsidised technologies.

Producers that are not subsidised and additionally face international competition would be confronted with additional cost burden due to producer-side network charges and in turn have a competitive disadvantage compared to international competitors that are not subject to such charges. Therefore, it is important to analyse if there exist similar charges in the markets relevant for these producers. Since Luxembourg shares a bidding zone with Germany, network charges for producers in Germany would be particularly relevant to be taken into consideration. In Germany, producers do not pay network charges, and certain non-volatile decentralised producers even pay negative charges (for more details see section 4.2). Given this finding, creating an additional cost burden for producers in Luxembourg by introducing producer-side network charges would need to carefully consider the effect on how the additional costs are passed on by the producers and whether they create a competitive disadvantage compared to international competitors which is especially relevant as Luxembourg shares a bidding zone with Germany where no network charges are levied for producers.

## 4.2 Country research

In other European countries, generation-side network charges are not uncommon (see Table 4.1). However, the structure and level of these charges vary greatly. For those countries where there exist injection charges (or some other charge to include producers in the refinancing of certain cost) these will be described in more detail below.

*Table 4.1 Injection charges in the European countries that serve as a benchmark in this study*[15]

| | |
|---|---|
| **Germany** | None (in some cases even negative charges) |
| **Belgium** | Energy-based charge related to cost for ancillary services, except for Brussel region |
| **France** | Energy-based injection charge on the transmission level |
| **Netherlands** | Small lump sum fee for administrative costs |
| **Austria** | Energy-based injection charge for producer > 5 MW |
| **Switzerland** | None |
| **Norway** | Energy-based injection charges |

### Germany

Until 2020 decentralized volatile energy generation, i.e. supply-dependent renewables paid negative network charges (called avoided network charges). The concept of avoided network charges assumes that decentralised feed-in reduces the amount of electricity drawn from the upstream network and hence its use, resulting in the medium to long-term saving of network infrastructure cost. The operators of the decentralised generation plants receive the resulting savings as a fee. Since the actual avoidance contribution cannot be determined, the fee otherwise payable by the upstream network operator is used. The arguments that decentralised feed-in leads to a reduced upstream infrastructure requirement are increasingly being challenged. Nowadays this concept is only applied non-volatile decentralised generation below the 220 kV level. From 2023, new decentralised generation plants will no longer benefit from avoided network charges.[16]

### Belgium

Even though producers in Belgium are charged with an energy-based tariff, this is not considered as an injection tariff. The argument is that this tariff is related solely to cost for ancillary services such as black start and reserves. The level of the tariff is determined by a 50/50 split of those costs between withdrawal and consumption with a cap.  The cap for the injection-

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[15] For more information on the application of injection charges across European countries see the Acer (2023) Report on Electricity Transmission and Distribution Tariff Methodologies in Europe 2023: *https://www.acer.europa.eu/electricity/infrastructure/network-tariffs*

[16] For more information on the concept of avoided network charges in Germany see: *https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK08/BK8_06_Netzentgelte/67_vermNetzentG/BK8_vermNetzentg.html*

based tariff is derived from a benchmark of injection charges in other European countries.[17] In 2020-2023 this tariff was 0,62 €/MWh., for 2024-2027 it increases to 1.05 €/MWh.[18]

### France

In France producers on the transmission level pay energy-based Injection charges. The Injection tariff Is calculated by dividing the cost linked to losses (on the national network associated with electricity exports and under the Inter TSO Compensation) by the energy injected on network levels above 150 kV. This calculation currently results in a tariff of 0.23 EUR/MWh that is due on the high and very high voltage levels.[19] Additionally, producers (as well as consumers) on all voltage levels have to pay a management fee for the management of customers records.

### Netherlands

Producers in the Netherlands are charged with a lump sum tariff that contributes to covering administrative costs. This is not considered to be an injection charge by the national law. A more substantial injection charge is not applied with reference to risks of distortions in cross-border competition. In 2022 this lump sum tariff was 12,478.96 Euro on the very-high voltage level and 2,760 Euro on the high voltage level.[20]

### Austria

Producers are subject to injection-based charges for grid losses. The tariff for network losses is derived by dividing the sum of all costs for network losses by the volumes withdrawn and injected. The resulting tariff component is published in paragraph 6 of the network charges ordinance (SNE-V) and is currently 4.68 EUR/MWh.[21] In Austria producers with more than 5 MW installed capacity are subject to network charges to cover cost for system services. This tariff is published under § 9 of the SNE-V and is currently 1.40 EUR/MWh.

### Norway

In Norway the tariff for producers is composed of a charge for infrastructure cost, a surcharge for system service cost and an injection charge for marginal losses. The first two components are lump sum payments calculated on the basis of a 10-year moving historical average of production. This is so that the charges do not affect short-term generation and long-term capacity investment decisions. The producer's annual individual charge is based on the average production from past years, i.e. the tariff is not dependent on the producer's generation in the year it is charged. The fixed feed-in tariff rate for 2022 is set at 0,99 EUR/MWh and the surcharge for system operating costs of 0,2 EUR/MWh.[22] The injection charge that covers marginal losses is

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[17] Benchmarking study on injection tariffs commissioned by the Belgium TSO Elia: *https://www.google.com/url?sa=t&source=web&rct=j&opi=89978449&url=https://www.elia.be/-/media/project/elia/elia-site/public-consultations/2023/20230214_annexe1_bijlage1-siapartners_elia_dynamic-and-injection-tariffs-benchmark.pdf&ved=2ahUKEwiSqsHvqcKHAxUCA9sEHagaD-YQFnoECBYQAQ&usg=AOvVaw3WLflgBbw2DbLyuduVBNrX*

[18] Belgian tariffs on the transmission level: *https://www.elia.be/en/customers/invoicing-and-tariffs*

[19] Injection tariff on the transmission level in France: *https://www.services-rte.com/files/live/sites/services-rte/files/documentsLibrary/Understanding_the_tariff_TURPE_6_Consumers_and_Generators__4945_en*

[20] 2022 transmission level tariff calculation in the Netherlands: *rekenmodule-tarievenbesluit-tennet-2022.xlsx*

[21] Current Austrian ordinance on network charges : *https://www.ris.bka.gv.at/GeltendeFassung.wxe?Abfrage=Bundesnormen&Gesetzesnummer=20010107&FassungVom=2024-01-01*

[22] Calculated with 1 NOK = 0.08 EUR. For the 2022 tariff in Norway, see: *https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/tariff/tariff-booklet-2024.pdf*

calculated for consumers and producers alike and depends on the time and hourly amount of energy withdrawal or feed-in. The calculation of the energy component considers a marginal loss rate based on projected load flows and the area energy price.[23]

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[23] Further details on the Norwegian energy-component can be found here: https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/tariff/tariff-booklet-2024.pdf .

# 5 Consumer-side network charges

The current network tariffs in Luxembourg are based entirely on consumer-side network charges. This chapter will systematically structure and analyse the design options for a tariff system like that. Such a system can be characterised by a variety of tariff components, which can be designed in a wide range of different ways. Figure 5.1Figure 5.1 shows a categorisation of possible consumer-side tariff components that differentiates between one-off payments and components that are paid periodically) and between components with different reference values like power vs. energy.

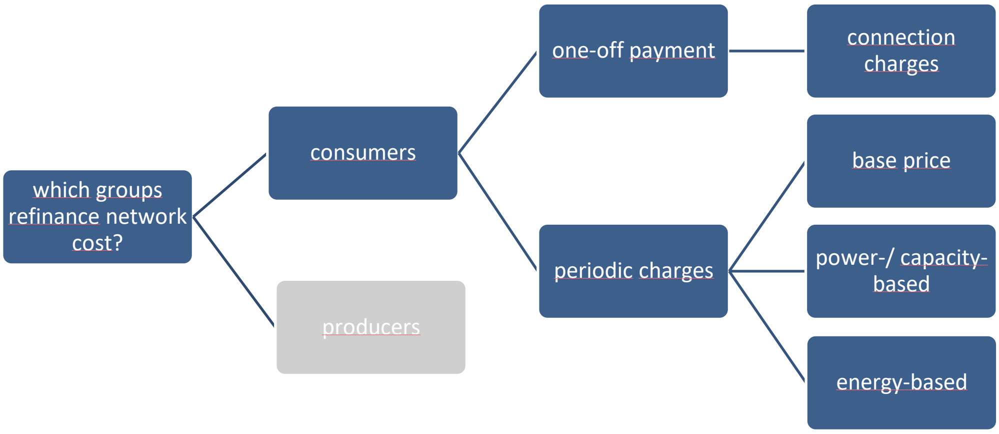

*Figure 5.1 System for categorising different types of network charges*

**One-off payments** are typically connection charges, i.e. charges that are levied when a network connection is first installed or when an existing connection is expanded. These payments will be discussed in section 5.1.

**Periodic charges** are the recurring network charges that are levied monthly or annually and that can be differentiated by the basis on which they are charged (energy, capacity or base prices irrespective of energy-use and capacity). A base price that each customer on a voltage level is charged uniformly is currently not levied in Luxembourg. This type of periodic charge will be discussed in section 5.2. Energy-based tariff components are usually charged on the amount of energy withdrawn from the network. Capacity prices can refer to different reference values, depending on which definition of capacity is chosen in the respective tariff system. In this study we will focus on contractual capacity, measured capacity (hereinafter referred to as power) and reference capacity (discussed in detail in section 5.5). Periodic charges in Luxembourg's current tariff system consist of an energy-based component and a power based-component. The procedure for calculating the tariff components per network level comprises two steps. In the first step, the network costs of the level under consideration, including the costs passed on from higher levels (i.e. the cost allocation resulting from the cost cascading), are divided by the simultaneous maximum annual load of the collective of end consumers and underlying network levels. The resulting costs per unit of power and year are referred to as the *stamp* (or *timbre* in Luxembourg). This approach assumes that the simultaneous annual peak load is the main driver of the network costs and that costs are approximately proportional to the annual peak (however, as was discussed in chapter 3, these assumptions are only partially tenable). In the second step, the *timbre* is converted into power and energy-based charges. This conversion is based on a so-called ‘simultaneity function’, with the aid of which the tariffs for usage hours below and above 3,000 usage hours are determined.

The simultaneity function constitutes the starting point for the following analysis of the periodic network charges that will be broken down into three steps. Section 5.35.2 takes an in-depth look at the currently applied simultaneity function and discusses, besides questions regarding the practical application of the function, the fundamental question whether the theoretical basis for its application is tenable. Section 5.4 examines the effects of applying fixed revenue shares instead of the simultaneity function to determine tariff components and the distributional effects such a change would entail. The different options for the reference parameter of the capacity-based tariff component are considered in section 5.5.

## 5.1 Connection charges

In addition to the periodic network charges, network operators can charge one-off contributions to construction cost to partially cover network reinforcement costs resulting from the construction or expansion of network connections. The addressees of these charges are the connection users. The basis for the calculation is the network connection capacity contractually agreed with the customer. These so-called deep connection charges are not usually seen as part of the network tariff system but concern the same cost sphere as the network tariffs. It relates to costs for the expansion of the network during the construction or expansion of a network connection.

Connection charges in general can be classified into three categories reflecting the scope of cost that they reflect (see Figure 5.2.). The *deep* connection costs are to be distinguished from the so-called *shallow* connection costs, which relate to the connection line and associated connection facilities used exclusively by the individual customer.

| | |
|---|---|
| **Shallow connection cost** | • cost of the connection itself but not related to the rest of the network and its infrastructure |
| **Specific deep connections cost** | • cost for reinforcing/ restructuring the network that can directly be linked to the new connection |
| **Lump-sum deep connections cost** | • a more general allocation of cost that are caused by new connections in the network on average |

*Figure 5.2 Differentiation of connection cost by their scope*

In the tariff system currently applied in Luxembourg, only shallow connection charges are levied. Deep connection charges reflect the fact that the costs associated with the construction and operation of a network component are largely determined at the time of the construction decision and can only be influenced to a limited extent afterwards. It gives network users a strong incentive to carefully plan the contractual capacity of new connections or connection expansions according to anticipated capacity demand.

Even though deep connection charges can provide partial coverage of network reinforcement or restructuring costs it should be noted that the contribution of this one-off charge to the refinancing of network cost would be comparatively small.[24] Given that this type of charge is based on contractual capacity and is levied once when the connection is constructed or expanded the height of this charge is limited. Additionally, this type of upfront payment potentially poses unintended barriers to the connection of new network users, especially if initial degree of utilization is low. Deep connection charges can be a tool to balance out the incentives that are created when a capacity-based component is introduced with the contractual capacity as its basis. This creates an incentive for customers to continually optimise their contractual capacity (more on this in section 0). In this case a deep connection charge can counteract this incentive as it is due each time the capacity is extended. However, as will be discussed in section 5.5 a capacity price based on reference capacity is better suited to reduce barriers to flexibility use than a component based on contractual capacity. In case the reference capacity model is adopted we see no necessity to introduce deep connection charges.

**Excursus on unused contractual capacity:**

In the current system where customers pay shallow connection cost and a power-based capacity component, there exists no incentive to adjust the contractual connection capacity once agreed with the network operator if the customer's demand for connection capacity decreases[25]. The network operators, on the other hand, have an interest in ensuring that permanently unused contractual connection capacity is freed up again, as this means that the existing network can be better utilised and less network expansion is needed. Therefore, during this study the question arose how consumers can be provided an incentive to return unused capacity.

One option is to introduce a very limited charge for contractual capacity, i.e. a tariff component based on contractual capacity. Even a small amount should trigger the incentive for all customers to return capacity that is no longer required.[26] This approach introduces an incentive for all customers to review the dimensioning of their contractual capacity but requires a provision on how often the contractual capacity may be adjusted.

Alternatively, if the case of unused contractual capacity only pertains to individual customers, the network operator could approach these specific customers offer to buy the unused capacity back. The returned capacity could be priced at the residual value of the shallow connection charge or a small, fixed amount if this residual value is zero. This approach is advisable if action is to be taken against unused capacity on a case-by-case basis.

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[24] In Germany, for example, there is a provision that deep connection charges above the low voltage level should not be higher than an annual power-based payment in the sense that the deep connection charge is an advance payment on future network charges.

[25] However, there is a minimum network charge to be paid irrespective of whether the maximum capacity ordered by the customer is utilised for connection exceeding 9000 kW. See: *https://www.creos-net.lu/fileadmin/dokumente/downloads/fr_description_fact_utilisation_reseau.pdf*

[26] In section 0 we will discuss why we do not consider a tariff component based on contractual capacity to be a suitable core element for a future tariff scheme that reduces barriers for flexibility use. Therefore, at this point we propose only a minor tariff on contractual capacity for the sole purpose of incentivising the return of unused capacity.

## 5.2 Base prices

A base price is a tariff component that is levied for each metering or connection point at a uniform amount per connection level. An example for the application of a base price per connection[27] can be found in the network tariff of the Swiss transmission system operator Swissgrid.[28]

A periodically charged base price per connection is suitable for reflecting the cost effects of network users' connection decisions that are structure related. If part of the structure-driven cost are recovered through a base price other charge component could be relieved of refinancing purely structure-driven cost. Since this tariff component is independent of a user's energy consumption it leads to a stronger participation of self-suppliers in refinancing of network cost which could be deemed desirable from a cost distribution perspective. It should be noted however that given the usually large heterogeneity of users, even within a single voltage level, a uniform base price could result in considerable redistribution when newly introduced.

In contrast to capacity- or power-based tariff components, a base price does not create barriers to flexibility use for existing network users. It does however have a negative impact on investment decisions in consumption technologies that are designed for low usage hours. This especially applies to highly flexible consumption units. Furthermore, a base price affects location decisions within a country in case it differs between locations (which does not apply in case of Luxemburg where network tariffs are uniform across network operators). However, the effect on location decision also includes the choice between domestic and foreign locations and, in the case of large consumers, the number of network connection points utilised. Due to its effects on investment decisions, a base price is also not free of flexibility barriers and therefore does not present an optimal solution.

## 5.3 The foundation and future of the simultaneity function

At the beginning of this chapter, we have to establish the fact that the simultaneity function is used to determine the level of the periodic charges, i.e. the power- and energy-based price. The model was adopted in Germany at the turn of the millennium and applied to the Luxembourg network tariff system in a very similar way.  This model is based on the assumption that, statistically speaking, consumers with higher usage hours have a higher degree of simultaneity than consumers with lower usage hours. Degree of simultaneity in this context means the ratio between the load of a customer at the moment of the network level's annual peak load and the maximum individual load of that customer (which does not necessarily occur at the same time as the network level's peak load).

As this simultaneity function can only approximately reflect the actual individual contributions to total maximum load, the position of the two straight line segments of the functional form must be parameterised in such a way that the sum of the products of the individual maximum loads and the resulting degrees of simultaneity result in exactly the simultaneous maximum load of the level, given the individual loads and usage hours of the consumers of a level. This is the

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[27] To calculate the base price, each connection point is weighted via a factor by setting the proportion of energy withdrawn in relation to the sum of the energy injected and withdrawn. For the calculation of the weight see: *https://www.google.com/url?sa=t&source=web&rct=j&opi=89978449&url=https://www.swissgrid.ch/dam/swissgrid/customers/topics/tariffs/Factsheet-Netznutzung-de.pdf&ved=2ahUKEwifp5jD6auIAxU-8AIHHYEEIkQQFnoECBMQAQ&usg=AOvVaw1dx42cwCLgB6c_MbizGmwA*

[28] For the amount Swiss base price on the transmission network level see: https://www.swissgrid.ch/en/home/customers/topics/tariffs.html

task of the grid operators when calculating the annual charges. To achieve this goal, the grid operators can adjust two parameters of the function, namely the degree of simultaneity at zero usage hours per year and the degree of simultaneity at 3,000 usage hours[29] per year. In general, however, it must be ensured that the two straight line segments intersect at 3,000 hours and that the degree of simultaneity assumes the value 1 at 8,760 usage hours (see Figure 5.3 for the 2023 parametrisation).

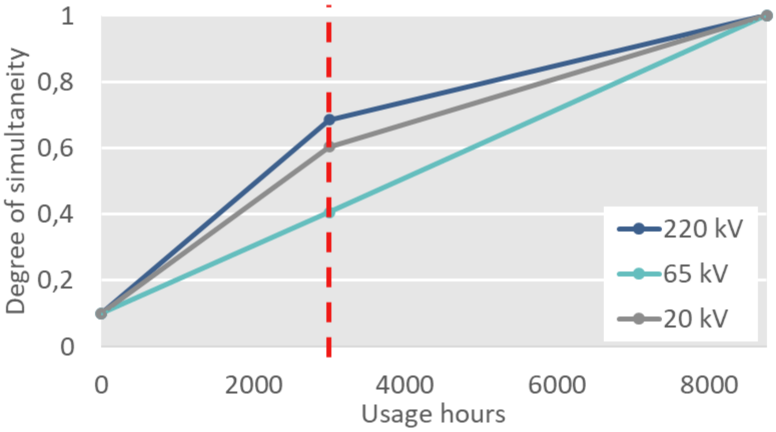

*Figure 5.3 2023 simultaneity functions for the 20, 65 and 220 kV voltage levels*

To determine whether an application of this simultaneity function is still justified in the future, the core assumption that consumers with higher usage hours have a higher degree of simultaneity than consumers with lower usage hours must be reviewed. Such review appears important for several reasons. Firstly, the model of the simultaneity function is highly generalised, as the actual degrees of simultaneity of the individual consumer withdrawal profiles vary greatly around the assumed function. Secondly, today's consumers can increasingly influence their usage hours or their degree of simultaneity, for example through self-supply or by utilising flexibilities. Thirdly, practical problems arise when applying the model to network levels with only a few customers. Overall, the suitability of this model is increasingly being called into question.

On the **220 kV level** there is only one large customer that has to bear the network cost allocated to customers of this level. The application of a complex model such as the simultaneity function does not appear necessary in this very specific case.

On the **65 kV level** there are roughly 50 customers. This number is not large enough to provide a stable basis for the parametrisation of a function that maps the relationship between two variables. Consequently, the function is very susceptible to fluctuations in the data base and therefore the parametrisation is unstable. This poses a practical problem as it threatens the stability of tariffs over time when changes in the usage hours of individual customers affect the shape of the function and thereby the tariffs as a whole. Figure 5.3 shows that the 2023 parametrisation of the simultaneity function on the 65 kV level is almost a straight line. This leads to tariffs for both segments below and above 3,000 usage hours that are practically identical. If

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[29] The value for the usage hours that differentiate between customers with high and low usage hours is chosen at the discretion of the network operator parametrising the tariffs.

there is no differentiation between the two segments, the simultaneity function loses its purpose and a uniform tariff for all customers on this voltage level could be derived more simply.[30]

The **20 kV level** in contrast has more than 8,000 customers. This provides a data basis large enough for a stable parametrisation of the simultaneity function.

Figure 5.4Figure 5.4 depicts the simultaneity function actually applied and the customer data on the 20 kV level. It is clearly recognisable that there is no particularly strong correlation between the usage hours and the degree of simultaneity. If the relationship between these variables is modelled by a simultaneous regression of both parts of the curve under the constraints that the y-value at 8760 usage hours is 1 and that the lines have the same y-value at 3,000 usage hours, the bend in the resulting function (blue line) is less pronounced than in the simultaneity function that is currently applied, and the coefficient of determination of the model resulting from the regression is very low indicating a weak correlation of the two variables. This suggests that the approximation by two straight lines is not better than the approximation by a single straight line which would mean uniform tariffs for users below and above the 3,000-usage-hours mark. Furthermore, the analysis of the 2023 data provides only a snapshot. With increasingly flexible grid users and growing self-supply, the already weak correlation will likely further decline in the future. It thus appears quite questionable if the core assumption of a direct correlation between the duration of use and the degree of simultaneity can be upheld.

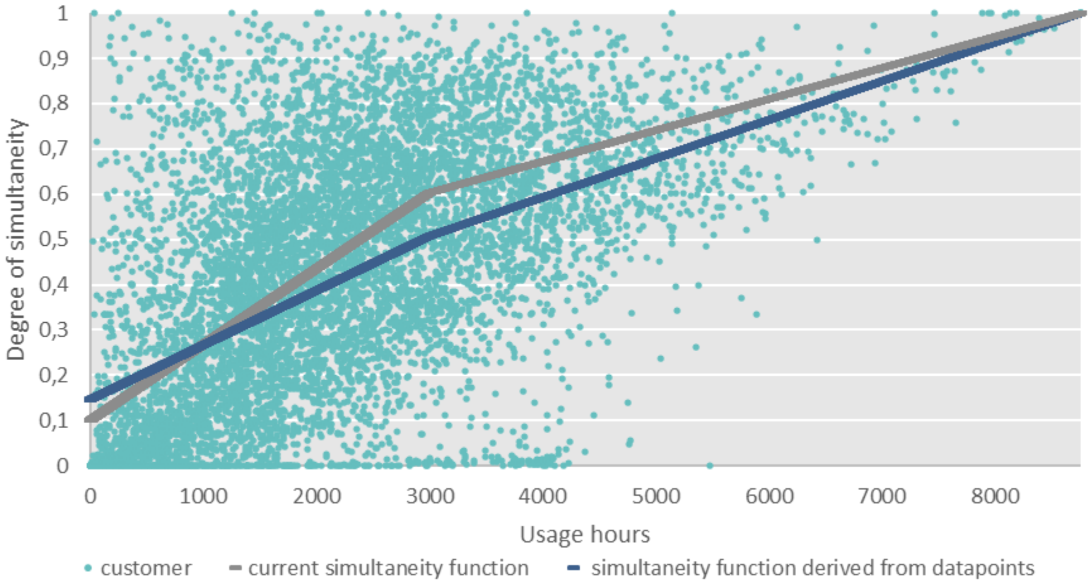

*Figure 5.4 Simultaneity function and customer data point (both 2023) and a simultaneous regression of both parts of the curve based on the customer data*

Given that on all voltage levels that are the subject of this study the application of the simultaneity function poses conceptual and operational challenges, we do not see convincing arguments that would justify a continued application of the simultaneity function in the future. Looking ahead to the topics discussed in the course of this chapter, it should also be noted that the application of the simultaneity function is conceptually part of a tariff system with a power-based component. In a system without a power-based component, i.e. a component based on

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[30] In the 2025 tariffs there is differentiation between the two segments leading to different tariffs below and above 3,000 usage hours. This volatility furthers the argument that the simultaneity function is not a stable concept, and its application should be reconsidered.

the users' annual peak load, the link to the degree of simultaneity is lost and the application of the simultaneity function would no longer make sense conceptually. On the low voltage level that is not subject of this study, no simultaneity function is applied. The new tariff system on that level that will be introduced in 2025 will include a capacity component based on a reference capacity (more on this concept in section 0). For the reasons discussed above, it appears recommendable not to use the simultaneity function on any voltage level anymore. An alternative for breaking down the network cost that are borne by customers on a given level into tariff components can be to apply fixed revenue shares as discussed in the next section.

## 5.4 Fixed revenue shares of tariff components

If the network costs are not transformed into a *timbre* and then broken down into tariff components based on the usage hours of the customers as it is currently the case, the conversion of cost to tariff components can be achieved by defining fixed revenue shares for each of the components. This simply means that a certain share of network cost is allocated to each tariff component. For example, if 50 % of the network of a certain voltage level are intended to be recovered from the energy-based component, then half of the cost would have to be divided by the projected energy consumption of the respective level to calculate the energy-based tariff component in Euros per kWh.

Any departure from the current system of calculating network tariffs will lead to changes in the tariffs and consequently to changes of the network charges born by individual customers. It can be seen as a potential objective in the context of such a structural reform to minimise these distributional effects in order to achieve best possible acceptance of the reform. On the other hand, certain distributional effects may appear well justified if the new tariff system leads to a cost distribution that is considered to be fairer than the status quo was. The following analysis will illustrate the effects of different sets of fixed revenue charges on individual customers and groups of customers in comparison to today's tariff system.

### 5.4.1 Analysed options of fixed tariff shares

In the analysis presented in the sections below, the power- and energy-based tariff components calculated on the basis of today's simultaneity function model will serve as a reference case that will be compared to different variations of fixed revenue shares for these two components. The reference case is modelled based on the 2022 tariffs (see Table 5.1).[31] The effect of the simultaneity function can be seen for the 220 kV and 20 kV level where the ratio between the power- and the energy-based components varies distinctively above and below 3,000 usage hours. On the 65 kV level the simultaneity function in the shape of almost a straight line leads to tariffs that are almost identical for the two sections.

*Table 5.1 Reference tariffs on the 20, 65 and 220 kV level based on the 2022 tariff*

| | < 3.000 h | | > 3.000 h | |
|---|---|---|---|---|
| | €/kW | ct/kWh | €/kW | ct/kWh |
| 220 kV | 5,54 | 1,08 | 28,83 | 0,30 |
| 65 kV | 10,49 | 1,07 | 10,18 | 1,08 |
| 20 kV | 20,93 | 3,51 | 82,92 | 1,44 |

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[31] The reference tariffs applied here are not identical to the actual 2022 tariffs as they are based on a simplified calculation, they are however very close to the level of the 2022 tariffs.

The different revenue share variations whose effects on 65 kV and 20 kV level customers will be examined are as follows:

- 10 %/90 % shares of the power-based and energy-based component respectively: modelling a very low share of the power-based component similar to the current tariff structure on the 65 kV level
- 40 %/60 % shares of the power-based and energy-based component respectively: modelling a relatively balanced allocation to tariff components, similar to the current tariff structure on the 20 kV level
- 80 %/20 % shares of the power-based and energy-based component respectively: modelling an extreme case with a very high share of the power-based component

The tariffs resulting from the application of fixed revenue shares to the revenues generated from the reference tariff and based on the energy consumption and annual peak loads from 2023 customer data are listed in Table 5.2.

*Table 5.2 Tariffs resulting from the application of fixed revenue shares*

| | **10% power / 90 % energy** | | **40% power / 60 % energy** | | **80% power / 20 % energy** | |
|---|---|---|---|---|---|---|
| | €/kW | ct/kWh | €/kW | ct/kWh | €/kW | ct/kWh |
| 220 kV | 3,88 | 1,05 | 15,54 | 0,70 | 31,07 | 0,23 |
| 65 kV | 6,25 | 1,16 | 25,02 | 0,77 | 50,04 | 0,26 |
| 20 kV | 11,03 | 3,41 | 44,11 | 2,27 | 88,23 | 0,76 |

### 5.4.2 Effects on the 65 kV level

On the 65 kV level, the case with a low revenue share of the power-based component (10%) and a high share of the energy-based component (90%) leads to the least overall redistributions compared to today‘s tariff system as this ratio is close to the revenue shares generated from the current tariff components (see Figure 5.5).

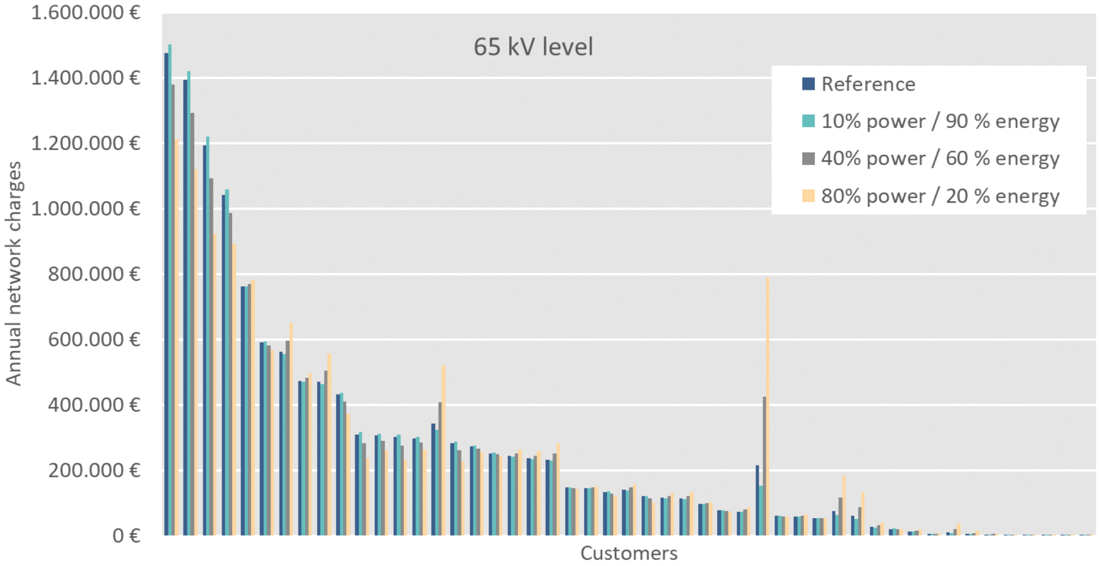

*Figure 5.5 Annual network charges for customers on the 65 kV level for the reference and different fixed revenue share cases*

Looking at the individual customers, a low revenue share of the power-based component leads to marginal increases for some customers and more pronounced decreases in network charges for some others. The high decreases occur for customers with lower absolute amounts of charges; the overall revenues generated from all cases stays the same. However, if the revenue share of the power-based component was increased, the distortions would increase (see Figure 5.6). Currently customers with low usage hours benefit from the low share of the power-based component. This would clearly change in cases with higher revenue shares of the power-based component.

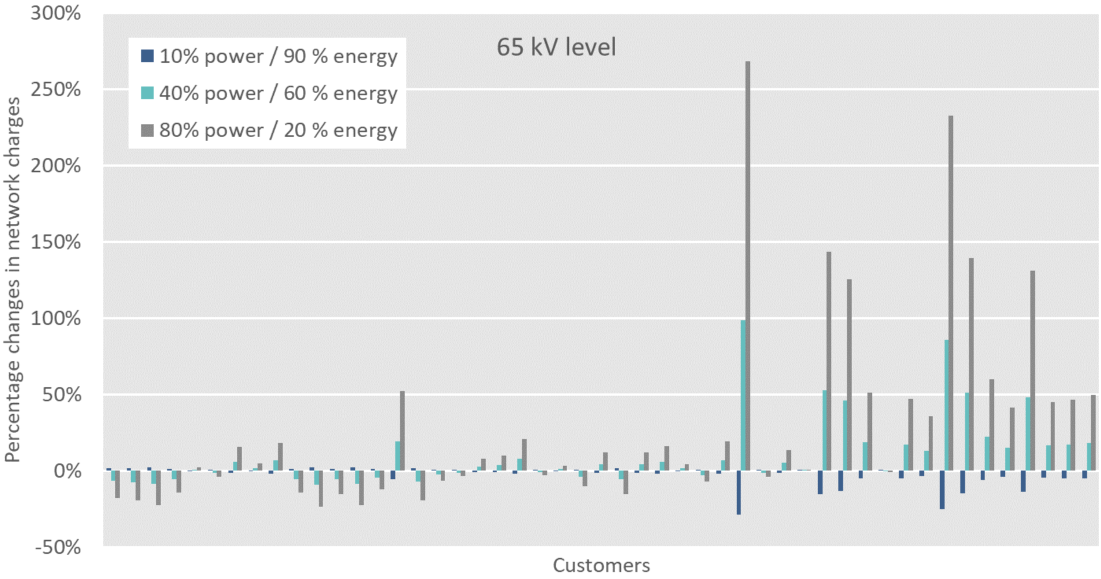

*Figure 5.6 Relative changes in annual network charges for customers on the 65 kV level for different fixed revenue share cases compared to the reference*

### 5.4.3 Effects on the 20 kV level

On the 20kV level, there are more than 8,000 customers. Therefore the effects of fixed revenue shares on individual network charges cannot be depicted in the same manner as for the small customer collective on the 65 kV level. The effects will instead be illustrated with the aid of exemplary customers. The characteristics of the exemplary customers are summarised in Table 5.3. The parametrisation of these exemplary customers does not aim necessarily to reflect the average customers on the network level but instead illustrate the range of effects on network charges for different revenue shares on different types of customers.

*Table 5.3 The characteristics of the exemplary customers on the 20 kV level*

| Characteristics | Short name | Max. annual load [kW] | Energy [kWh] | Usage hours | Type of customer |
|---|---|---|---|---|---|
| Business - high usage hours - large connection capacity | Business large | 480 | 3.000.000 | 6.250 | |
| Business - high usage hours - large connection capacity - with self-supply | Business large – self supply | 480 | 1.500.000 | 3.125 | 50% self-supply |
| Business - low usage hours - small connection capacity | Business small | 80 | 128.000 | 1.600 | |
| Business - low usage hours - small connection capacity - with self-supply | Business small – self supply | 80 | 64.000 | 800 | 50% self-supply |

Across the exemplary customers a 40 %/ 60 % ratio of revenue shares of the power- and energy-based component possibly yields results closest to today's system for customers without self-supply (see Figure 5.7). Customers with high usage hours benefit from a low share of the energy-based component. Customers with low usage hours see rising network charges with an increasing revenue share of the power-based component, even more so if they are self-suppliers.

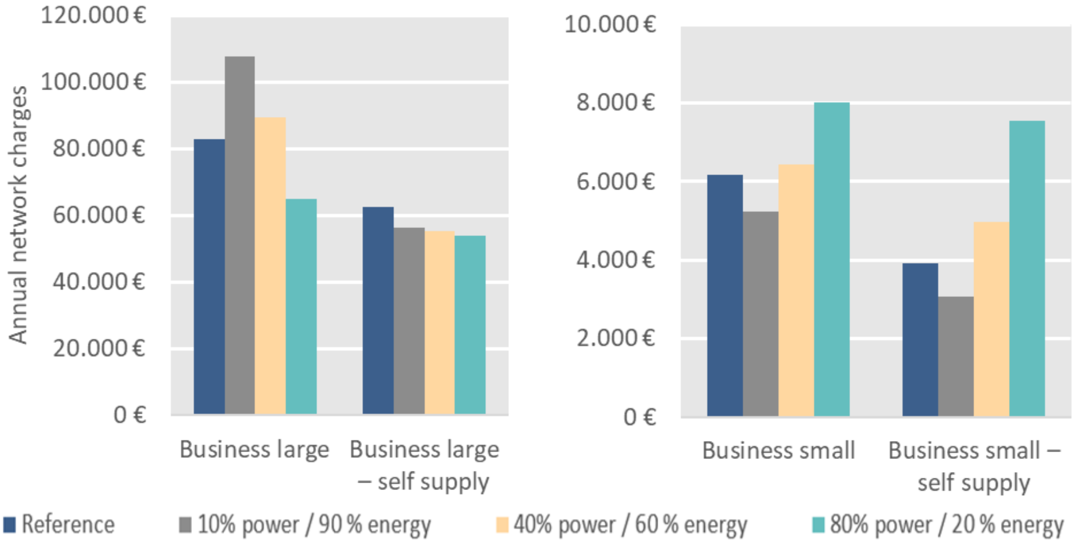

*Figure 5.7 Annual network charges for exemplary customers on the 20 kV level for the reference and different fixed revenue share cases*

While the exemplary customers provide a general indication of the effects on certain customer groups, the effects on the individual customers were also analysed. On the 20 kV level it is surprising that two thirds of the customers have power values below 50 kW. These capacities appear very low for 20 kV customers, and it could be questioned in how far these customers are connected to the "correct" network level and in how far they should be considered relevant for evaluating effects of reform options. When comparing the effects of the of 40 %/ 60 % revenue shares of the power- and energy-based component on both the absolute and relative changes in annual network charges, the small customers are faced with high relative changes in network charges but low absolute changes (see Figure 5.8). However, even without the unusually small customers there remain chases with high relative changes (>60 %) in network charges (Figure 5.9).

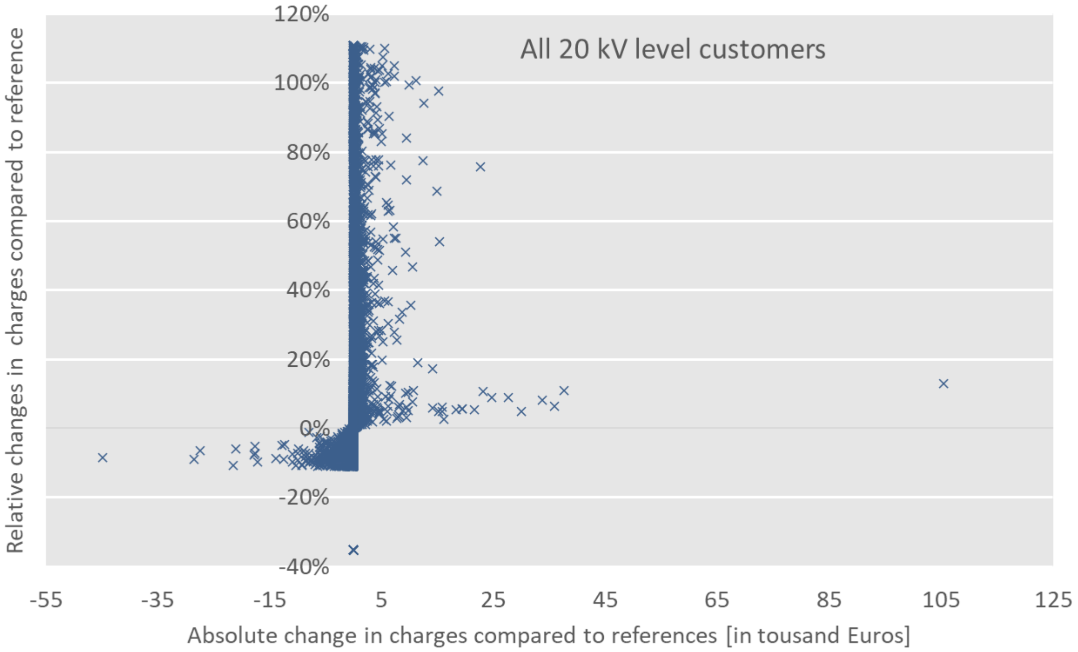

*Figure 5.8* *Relative and absolute effects on annual network charges of 40 %/ 60 % revenue shares of the power- and energy-based component for all 20 kV level customers*

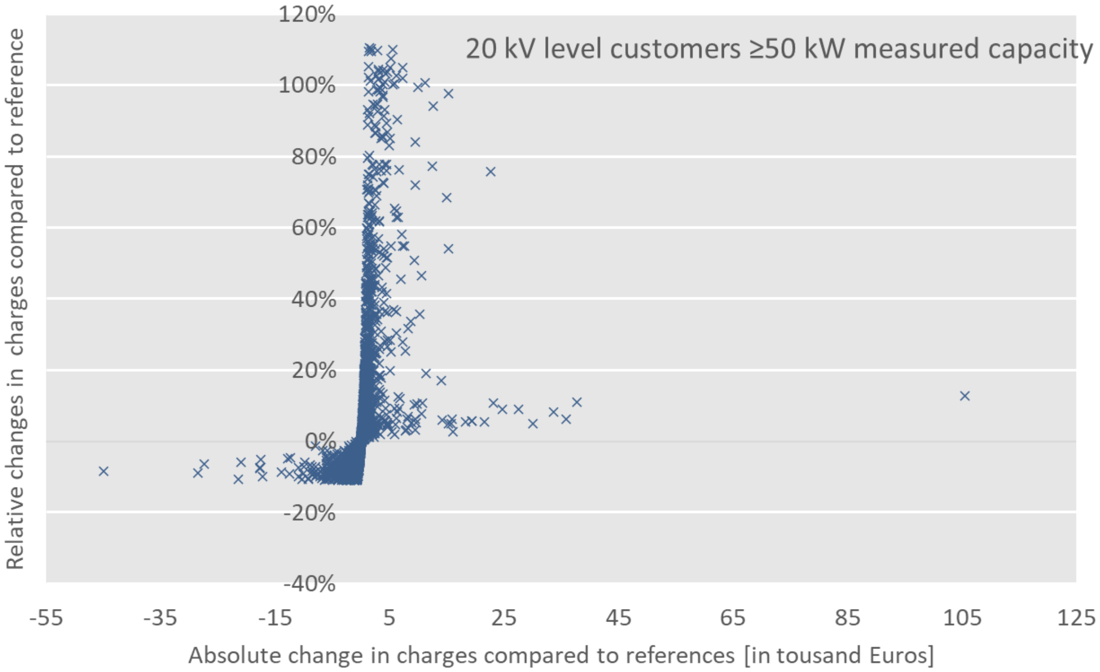

*Figure 5.9* *Relative and absolute effects on annual network charges of 40 %/ 60 % revenue shares of the power- and energy-based component for 20 kV level customers ≥ 50 kW power*

If the tariff calculation is decided to be changed from the application of a simultaneity function towards fixed revenue shares, the distributional effects shown above would have to be assessed for acceptability. A possibility to mitigate these effects would be to spread the change over several years through a gradual transition into a new system, adapting the tariffs in the two segments of the simultaneity function successively to the uniform tariffs that would result from a chosen ratio of fixed revenue shares.

### 5.4.4 Conclusions

On the 65 kV level, the 2022 tariff shows hardly any difference between the two sections of the simultaneity function.[32] The resulting tariffs are therefore already very similar to the ones resulting in one of the cases of fixed revenue shares. Applying a tariff that has a very low revenue share of the power-based component and a very high share of the energy-based component leads to only small changes. With regard to cost allocation, a small power-based component leads to a burden on consumers without own generation facilities that could possibly be considered unjustified. A future increase of the revenue share of the power-based component on the 65 kV level could be considered appropriate if a greater revenue share from the power-based component is sought to increase the contribution to the refinancing of network cost by self-suppliers. On the other hand, the currently small power-based component leads to low flexibility-inhibiting effects.

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[32] In the 2025 tariffs there is differentiation between the two segments leading to different tariffs below and above 3,000 usage hours. This volatility furthers the argument that the simultaneity function is not a stable concept, and its application should be reconsidered.

On the 20 kV level, applying fixed revenue shares leads to more redistribution effects than on the 65 kV level even if the fixed revenue shares are chosen similar to the revenue shares generated by the current tariff (40 %/60 % split of revenue shares of the power- and the energy-based component). This is not surprising as currently the tariff components significantly differ above and below 3,000 usage hours. In the parametrisation of fixed revenue shares on this level it has to be considered that there are many unusually small customers connected to this level. This includes considerations which effects on these customers are deemed acceptable and in how far fixed revenue shares might create an incentive for these customers to connect to the low voltage level. Any transition towards fixed revenue shares could be introduced gradually to spread the redistribution effects over several years by successively bringing the tariffs in the two segments of the simultaneity function closer to the uniform tariffs from fixed revenue shares.

It should be noted for both the 20kV and the 65 kV level that a power-based component that makes up a substantial share of the revenues strongly involves customers with low usage hours and/ or self-supply in the refinancing of the network cost but at the same time creates barriers to flexibility use. Options for mitigating these barriers while allocating a substantial share of revenues to the power-based component will be discussed in section 5.5.

## 5.5 Options for the capacity-based component

Currently the capacity component of the network tariff is based on **measured capacity/ power-based**, e.g. the customer’s maximum power demand defined by the highest quarter-hourly electricity consumption within the billing period. This design along with the incentives set by the simultaneity function create an incentive to reduce individual peak consumption and thus to strive for an even consumption profile which – at least in the past – has been considered desirable from a network perspective but affects the use of flexibility. If a consumer's maximum measured capacity in a calendar year up to that point is exceeded as a result of an increase in power, under the current tariff system an increased payment of the capacity component is due, regardless of whether this excess occurs again in the same year or not. The power-based component can create a particularly high barrier for consumers for whom opportunities to utilise their flexibility only occur occasionally (e.g. in the event of negative electricity market prices). In addition, the power-based component has a fundamentally questionable incentive, as the individual power peak of a consumer does not usually coincide exactly with the time of the maximum load of a grid or grid area. Still, the power-based component provides an ever-increasing incentive over the course of a year not to exceed the maximum power reached so far in the year, even if such an excess does not even lead to a critical (and therefore long-term dimensioning-relevant) grid load at many points in time.

At first glance, a potential solution to the flexibility barriers caused by the power-based component might be a capacity component that is charged based on the **contractual connection capacity**. The reference value for the capacity-based component does not change depending on the actual electricity consumption and cannot be adjusted to fluctuating demand at short notice. This means that the capacity-based component also plays no role in short-term utilisation of flexibility. The contractual connection capacity cannot be adjusted during the year in order to fulfil the basic idea of this tariff component. Nevertheless, customers must be permitted to adjust the reference value, i.e. the contractual capacity, at certain intervals (e.g. annually). The shorter this period is chosen, the more pronounced the incentive for grid users to adjust it frequently on the basis of short-term demand forecasts, so that the effect of a capacity-based component would approach that of the withdrawal-dependent power-based component. As a result the capacity-based component does not impede the flexibility provision in the short-term, but in the medium-term there is an incentive to set the contractual capacity as low as possible, leading to restrictions for the provision of flexibility later on. Against this background it would make sense to combine a capacity-based component with a deep connection charge as a one-off payment that would have to be paid each time the contractual capacity is increased. This would counterbalance the incentive for customers to modify contractual capacity too frequently. In summary, the introduction of a tariff component based on contractual capacity instead of measured power would modify but not eliminate the barriers to flexibility use that are caused by the incentive to strive for an even consumption profile.

Instead, a capacity component based on a **reference capacity** could offer a solution for a component that is still based on measured values, leading to an at least weak incentive for even consumption profile while allowing for flexibility uses without significantly affecting the capacity price paid. Such a tariff component will be introduced in Luxembourg on the low voltage level starting 2025.The reference capacity on which the capacity price is charged is defined as a level of capacity that covers a large part of a customer's demand but is allowed to be exceeded. This needs to be combined with a surcharge on the energy-based price for power consumed in excess of the reference capacity. Without a surcharge all customers would choose a reference capacity of zero and pay no capacity price, but only the energy-based component. In this case, the network charges would not create any barriers to the use of flexibility. However, the refinancing of network cost would solely be based on energy-based prices which significantly decreases the refinancing contribution of self-suppliers and customers with low usage hours (for the discussion of the refinancing function of network charges see Chapter 2) and would not reflect the fact that part of the network cost is structure-driven. On the other hand, if the surcharge on the energy withdrawn above the reference capacity is very high, customers have an incentive to choose a reference capacity that reflects their maximum annual load to avoid the surcharge, which would lead back to today's system with a power-based component and its downsides for flexibility use. Based on these considerations, it becomes clear that a system based on reference capacity requires a balancing of the capacity price and the surcharge (compare Figure 5.10).

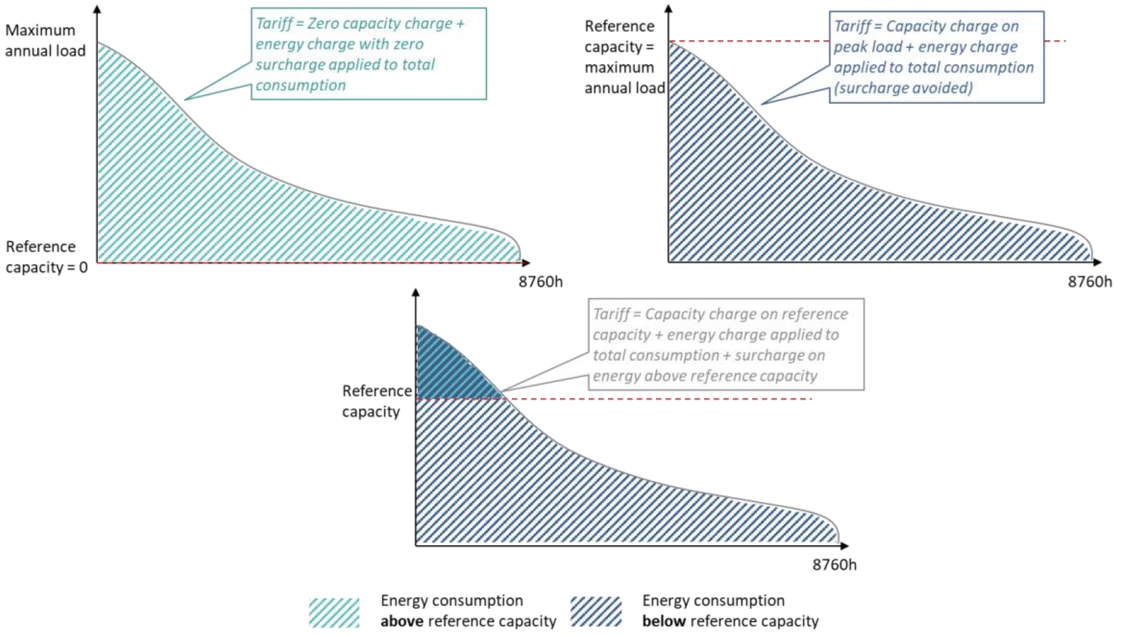

*Figure 5.10 Schematic approach to the reference capacity applied to an exemplary duration line of consumption*

On the low voltage network level, the network operators have committed to calculating for each customer the individual level of reference capacity that yields the lowest total network charges, given the past consumption profile of the customer. If customers have to choose their reference capacity levels themselves, it would be rational for them to follow that same approach, thus minimising the total network charges. We assume in the following that customers would follow this approach, be it by doing the necessary calculations themselves or by delegating this to a service provider.

The energy-component without surcharge does not affect the choice of reference capacity as it is levied on the total energy consumption. Only the amount of energy on which the surcharge is levied additionally depends on the choice of reference capacity. On the other hand, the ratio between the capacity component and surcharge plays an important role in the effect of the reference capacity model. As was illustrated by the extreme cases depicted in Figure 5.10 a high capacity price combined with a low surcharge leads to the choice of a low reference capacity while a high surcharge in relation to the capacity price leads to the choice of a high reference capacity.

These interdependences should be taken into account when parameterising a tariff based on a reference capacity component and an energy-component plus surcharge. As was established in section 5.2, a system with a capacity component that is not based on the maximum annual load does not make sense alongside the application of the simultaneity function (whose future application is also questionable from a conceptual perspective). Accordingly, in the future tariff for the low voltage network level fixed revenue shares are applied for the energy-based component on the one hand and the capacity-based component and surcharge on the other hand. Even though the surcharge is levied on the energy-consumption the theoretical analysis has shown that the surcharge and the capacity-based component are interconnected through choice of the reference capacity. This is why it makes sense to apply the revenue shares in this way (see Figure 5.11).

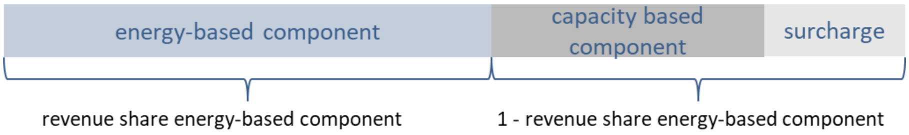

*Figure 5.11 Fixed revenue shares in a tariff system with a reference capacity-based component*

If we apply the revenue shares derived in the previous step (a 10 %/90 % split of the energy- and the capacity-based component on the 65 kV level and a 40 %/60 % split on the 20 kV level) as our starting point for the following analysis, we can identify the effects on the choice of reference capacity.[33]

Starting from the perspective of an individual customer, Figure 5.12 depicts the capacity price and the surcharge on energy consumption that an exemplary 20 kV level customer would have to pay depending on the reference capacity the customer chooses. The reference capacity is expressed in relation to the annual peak load, i.e. ranging between 0% and 100%. The resulting curves of payments at different levels of reference capacity represent different levels of

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[33] This analysis shows only the first step of the iteration in parametrising actual tariffs with reference capacity. In this step the customers chose a reference capacity based on the capacity price and the surcharge. However, this does not automatically ensure the refinancing of the network cost, therefore must follow an iteration adjusting the level of the tariff components and the consequent choice of reference capacities until an equilibrium is found.

surcharges. The energy price is neglected here, as this charge is the same for every case. For a zero percent surcharge it can be seen like in Figure 5.10 that the customer would choose a reference capacity of zero to minimize the network charges. With increasing surcharges, the optimal reference capacity increases. Given the relatively low usage hours of this customer's profile, the customer would choose a relatively low reference capacity compared to its annual peak load. For surcharges above 100% the customer's optimal reference capacity would be in the range of 30-50% of its annual peak load.

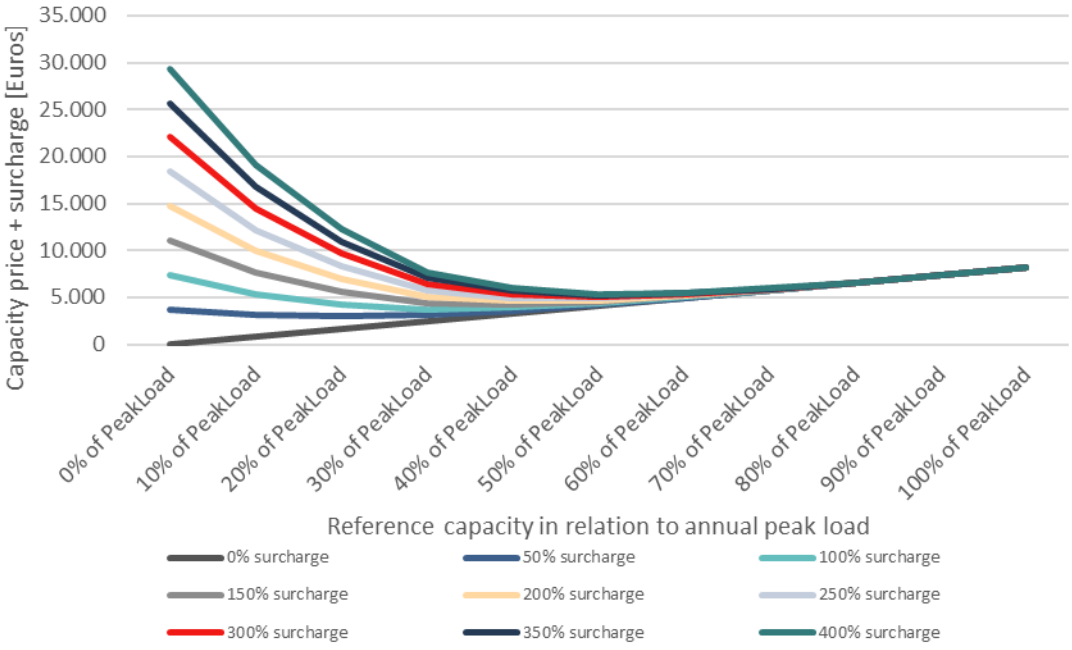

*Figure 5.12 Capacity price and surcharge paid by an exemplary 20 kV customer (with circa 1,750 usage hours and 325 MWh energy consumption) given different levels of surcharges and depending on the reference capacity the customer chooses in relation to its annual peak load*

Figure 5.13 depicts how many customers on the 20 kV level would choose a certain level of reference capacity (in relation to their peak load) for a range of surcharges. Other than in Figure 5.12 that relates to a single customer, Figure 5.13 only shows the optimal choice of reference capacity for a given surcharge. It shows that with very high surcharges, i.e. surcharges of more than 200 % on the energy price, the majority of customers would choose a reference capacity of at least 50 % of their annual peak load. Surcharges below 100 % lead to 0 kW reference capacity as the optimum for most customers meaning customers pay a surcharge on every kWh of energy consumption and no capacity price. This is due to the high ratio between capacity price and energy price (see Table 5.2).

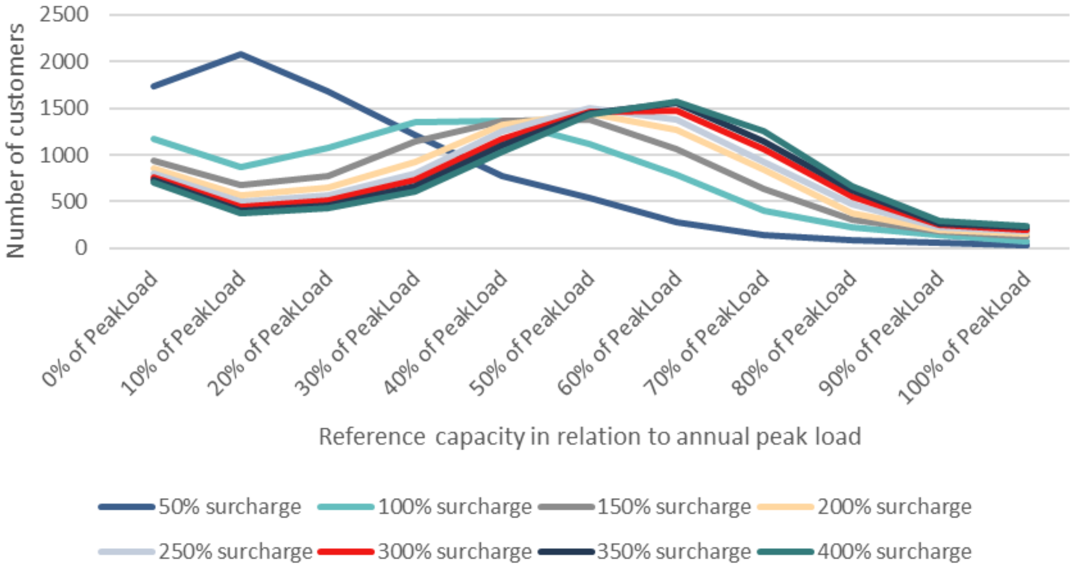

*Figure 5.13 Number of customers on the 20 kV level that would choose a specific reference capacity in relation to their annual peak load for different levels of surcharges*

On the 65 kV level the perspective of an individual customer depicted in Figure 5.14 shows that given the initial tariff (low ratio of capacity- and energy-based component) and the customer’s high usage hours, the customer will choose a reference capacity between 50 % and 70 % of its annual peak load for surcharges of 10% and more on the energy component.

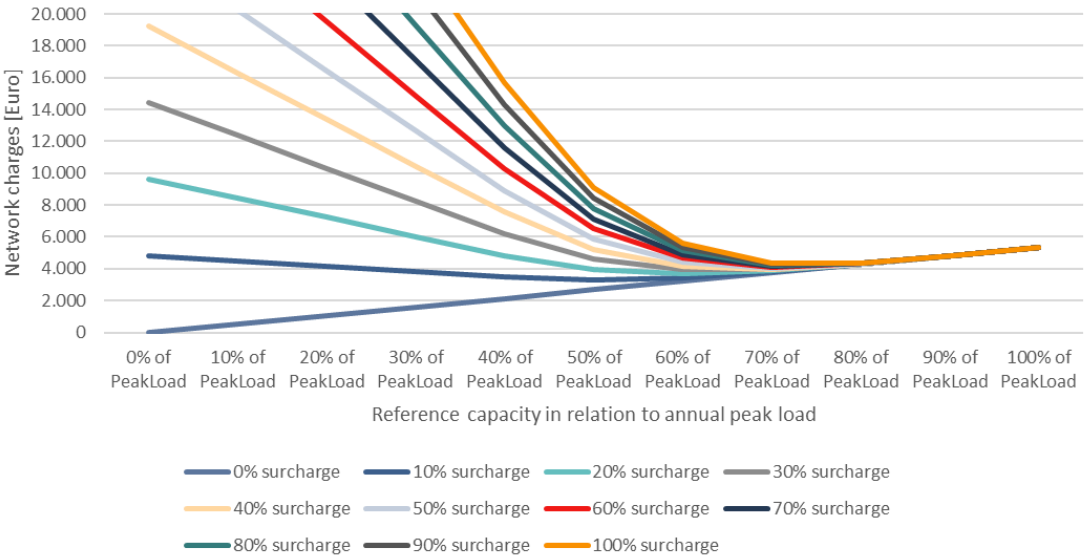

*Figure 5.14 Capacity price and surcharge paid by an exemplary 65 kV customer (circa 5000 usage hours and 4,000 MWh energy consumption) given different levels of surcharges and depending on the reference capacity the customer chooses in relation to its annual peak load*

Figure 5.15 depicts how many customers on the 65 kV level would choose a certain level of reference capacity (in relation to their peak load) for a range of surcharges. Again, it can be seen that the higher the surcharge, the higher is the optimal choice of reference capacity in relation to the annual peak load. Unlike on the 20 kV level, customers would choose relatively high reference capacities even at much smaller surcharge levels. This is due to the fact that the ratio of capacity charge to energy charge (see Table 5.2) is very low and the usage hours of the customers are typically higher on 65 kV than on 20 kV level.

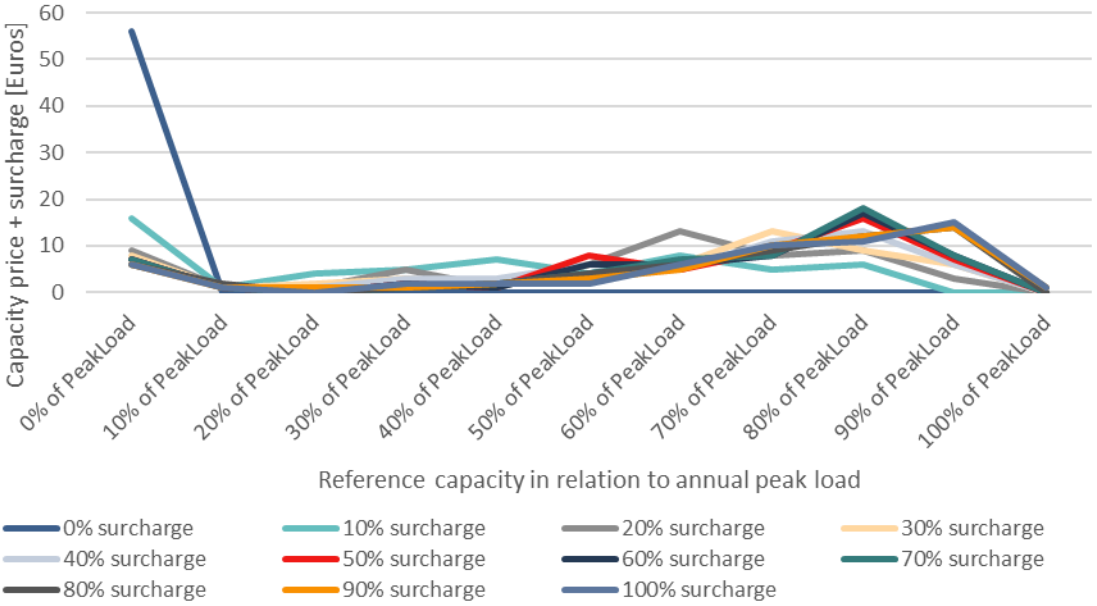

*Figure 5.15 Number of customers on the 65 kV level that would choose a specific reference capacity in relation to their annual peak load for different levels of surcharges*

The quantitative analysis illustrates the interdependence between all three components of a tariff with reference capacity: the capacity-based component, the energy-based component and the surcharge. The wide range of optimal reference capacities in relation to the customers' annual peak loads shows that the reference capacity should be considered solely as a calculation parameter for network tariff billing and not as a technical parameter that is relevant for the dimensioning of the network. In particular, the reference capacity should not be interpreted as an indicator for the maximum power demand expectation of a customer. Depending on the parameters mentioned above, customers can be incentivized to choose a reference capacity that is considerably below their maximum power.

Given the objectives for a target model discussed in chapter 2, a reference-based capacity component can be considered as a promising option for a future medium and high voltage network tariff as this component creates clearly less barriers to flexibility use than a conventional power-based tariff component. This could also be achieved by a tariff system with a strong emphasis on energy-based charges, however the reference-capacity-based component additionally offers the possibility of charging a capacity component to ensure a fair share of network cost being allocated to network users with low usage hours and self-suppliers. Thus, this model allows to strike a better trade-off between a substantial capacity component and the avoidance of critical barriers for flexibility use. This trade-off can be calibrated via the combination of the capacity component and the surcharge which affect the reference capacity that customers will choose to minimize their network charges.

## 5.6 Conclusions

In this chapter we have identified the conceptual and operational challenges stemming from the application of the simultaneity function as a basic element of the network tariff. In conclusion, there appear no convincing arguments that would justify the future application of this element. The alternative of applying fixed revenue shares for the allocation of cost to tariff components simplifies the tariff calculation and unlinks it from the concept of simultaneity. However, any such changes to tariff calculation will entail distributional effects across different types of customers. Even if these effects are accepted because they would lead to a fairer distribution of the refinancing of network charges, any changes from the status quo have to be justified and more fundamental changes that lead to considerable redistributions might have to be introduced successively in more than one step in order to spread the effects over several years.

Further, the barriers to flexibility use created by the power-based component were addressed in a discussion on the options for a suitable design for a capacity-based component. Any departure from a power-based component strengthens the arguments for abolishing the simultaneity function. Conceptually it could be shown that a reference capacity model offers a solution that avoids critical barriers for flexibility use while ensuring that a substantial share of the network cost is refinanced by a capacity component so that network users with low usage hours and self-suppliers participate appropriately in the refinancing. In conclusion, a tariff system with a reference capacity component appears to be a viable option for the higher voltage levels.

# 6 Outlook: Incentives for network-oriented flexibility use

## 6.1 Objectives of and instruments for network-oriented flexibility use

As discussed in section 2.2.1, there exist design options of network tariffs that have the explicit purpose of providing specific incentives to network users. Time-dependent network charges are a very prominent example of such design options, being actively discussed in Luxembourg as well as in many other European countries. The objective of time-dependent charges is to set incentives for network users to adapt their behaviour in a way that is considered beneficial for the electricity system as a whole. Typically, these incentives are primarily focused on flexibility demand of the grids, aiming at mitigating network congestion by reducing the loading of network elements at critical bottlenecks, or by improving the voltage situation in order to avoid violation of permitted voltage limits. This objective can be addressed both as a means for curative congestion management in cases of acute congestion as well as for preventive congestion management aiming at reducing the probability of acute congestion.

Besides these objectives that are network-oriented in a narrow sense, time-dependent charges are sometimes also discussed as a means to support electricity market price signals by amplifying them. Although it may not appear straightforward at a first glance that network charges should be used to support market price signals, this can potentially be justified by the fact that network charges, due to their refinancing function, can be seen to distort market price signals in certain situations. Eliminating these distortions in cases where the market has a strong demand for flexibility use can have an effect that is similar to an amplification of market price signals. However, in the following, the focus is on the objectives of network-oriented flexibility use in a narrow sense as discussed in the previous paragraph.

Naturally, network charges can only provide incentives to those network users that pay these charges. In Luxembourg, at present, network charges are only paid by network users who withdraw power from the network, i.e. by consumers and – as far as there are no special exemptions – by operators of storage devices. Therefore, as long as this design aspect remains unchanged (cf. chapter 4), the dispatch of generation units cannot be influenced by this type of incentives. Time-dependent network charges are thus primarily a means to incentivise network-oriented use of demand-side and/or storage-side flexibility. This can be an important instrument for network congestion management particularly (but not only; see below) in cases where congestion is mainly caused by demand and storage behaviour. This is why, for example, network-oriented use of the flexibility of charging devices for electric vehicles is strongly discussed (and in some countries already used) as a means to manage low voltage network congestion caused by simultaneous use of these devices. But demand-side flexibility can also contribute to the mitigation of generation-driven network congestion, e.g. by reducing local network loading in situations of strong infeed from PV installations. In general, it is important to be aware that network congestion can take place at different network levels and can be caused by different drivers. Therefore, flexible demand connected to a certain network level can be valuable for the management of different cases of network congestion at the same time. For example, network-oriented flexibility provided by e-mobility charging can be beneficial for low voltage network congestion management, as mentioned above, but can also contribute to management of congestion at the medium, high or extra high voltage levels. Depending on the existence and extent of network congestion at different network levels, it can therefore require some form of coordination to use demand-side and storage-side flexibility for network-oriented purposes in the best possible way.

The concept of incentivising network-oriented flexibility use by the means of time-dependent network charges has a number of advantages in comparison to other instruments of network congestion management. Among others, price-based mechanisms have the advantage that it remains up to the network users to decide themselves if and to what extent they provide their flexibility as a reaction to a specific price signal. This allows them to decide about their behaviour based on their own preferences, for example by refraining from providing flexibility in single cases where they have an immediate need to use electricity. Furthermore, network-oriented price signals can easily be coordinated with market-based price signals by simply adding up these two signals. This type of price-based coordination is very common in other sectors of the economy, too, where each part of a supply chain provides its own price signals.

On the other hand, price-based instruments for congestion management have the disadvantage that network operators cannot precisely predict in each case if the changes of behaviour due to the price signals are sufficient to completely eliminate congestion. For this reason, it will remain necessary to establish additional instruments, allowing network operators to initiate targeted changes in consumption behaviour (or storage operation) to fully eliminate a network congestion. One important instrument for congestion management is the well-known concept of redispatch of generation units and curtailment of renewable generation. This instrument will clearly continue to be relevant in the future. However, it is not appropriate for congestion management that is based on demand-side flexibility, mainly because the consequences of a curtailment of demand differ fundamentally from the consequence of a curtailment of generation units (which can be remunerated relatively easily by case-by-case payments).

Therefore, especially for network congestion that is primarily demand-driven, further instruments will be needed. An example of such instruments can be a curtailment mechanism for flexible consumption devices similar to the one that has been introduced in Germany recently, based on article 14a of the German energy act (§ 14a EnWG). This instrument allows network operators to temporarily reduce power consumption of these devices within certain defined limits in cases of congestion on the low voltage level or the medium to low voltage transformer level. As a compensation for these potential curtailments, the owners of these devices are granted a reduction of network charges (instead of receiving case-by-case payments, which would be rather difficult). Besides this type of mechanism, other instruments like market-based procurement of flexibility from consumers and storage operators are also discussed in several countries. One critical aspect of these discussions relates to the problem that such markets can provide disincentives aiming at a strategic behaviour that increases the extent of congestions, especially if congestion can well be anticipated.

It is not a task of this report to fully discuss the options for such non-price-based instruments for network-oriented use of demand-side flexibility. Most important for the purposes of this report is to raise awareness that time-dependent network charges will not be sufficient as a sole instrument for congestion management in the future. There will rather be a need to establish further instruments like the ones mentioned above. However, this finding should not lead to the conclusion that time-dependent network charges are not useful. On the contrary, they can be seen as a particularly user-friendly and easy-to-coordinate instrument to reduce the probability of acute network congestion, i.e. as a means for preventive congestion management, especially with respect to demand-driven cases of congestion. We therefore consider it quite likely that in the future, a mix of several instruments will yield optimal results regarding efficient preventive and curative congestion management, including time-dependent network charges.

## 6.2 Design options for time-dependent network charges

If time-dependent network charges are decided to be introduced as an instrument for (mainly preventive) congestion management, decisions on a number of design options will have to be met, the most important of which are discussed below:

- **Network level, place and type of congestion:** Time-dependent network charges are intended to reflect the probability or intensity of network congestion to incentivise changes of consumer behaviour such that congestion is relieved. To design charges that fulfil this objective, a decision has to be made in the first place as to which cases of congestion should be taken into consideration for this purpose. It is obvious that, for example, low voltage network congestion driven by e-mobility charging has completely different characteristics than high voltage congestion driven by feed-in of large wind or solar power plants. As discussed above, it is even possible to use flexibility from the same source to relieve different cases and types of congestion. This however requires some form of coordination, e.g. by determining priorities as to which case of congestion is most important to be relieved at which point in time, or by adding up time-dependent price signals that address different cases of congestion that are to be handled in parallel.
- **Lead time of determining time-dependent charges:** Depending on the predictability of congestion, it has to be decided at which lead time and for which duration the levels of time-dependent charges are set. For instance, congestion caused by renewables infeed can only be predicted one or few days in advance at acceptable accuracy, so that time-dependent charges focusing on such congestion would have to be fixed at short notice, e.g. day-ahead. In this case, the charges would typically be called “dynamic” or “real-time” charges. In contrast to this, demand-driven congestion can be predicted with longer lead times, so that charges would not have to be that dynamic.
- **Granularity in time and price levels:** Time-dependent charges can be designed at a wide range of granularity options, ranging from two-step tariffs with only few price changes per day down to quarter-hourly prices from a continuous bandwidth of possible price levels. This decision is also dependent on the type of congestion that is focused, as well as on the role of potential unintended effects like new load peaks right after abrupt reductions of price level.
- **Granularity in location:** Depending on the type and location of congestion that is focused, time-dependent charges have to be differentiated by location to a certain extent.
- **Level of price spread:** The spread between the lowest and highest price levels of a time-dependent network charge determines the strength of the incentives provided to network users. Ideally, it should be determined such that an economically efficient amount of flexibility is allocated by network users to relieve the congestion that is targeted. Taking into account that flexibility is also of great value for market-oriented purposes and should therefore not only be used for network-oriented purposes, it becomes obvious that this is a challenging design decision.
- **Network charge component that sends the price signal:** In principle, any component of network charges that is based on measured values like energy withdrawal or maximum annual power demand can be designed in a time-dependent manner. However, with a view to comprehensibility and clarity of incentives, we consider it recommendable to select the energy-based charge component to send the time-dependent price signal.

These considerations show that most of the required design decisions depend strongly on the types and locations of network congestion that are intended to be relieved, besides other factors like the ability of network users to react dynamically to price signals as well as prerequisites regarding overall electricity tariff structures and metering equipment. It is therefore not possible to design a universally applicable time-dependent network charge system that yields optimal results under all circumstances. Rather, time-dependent charges have to be designed in a targeted way, taking into consideration the aforementioned factors. For this reason, we consider it crucial to first analyse the need for demand-side contributions to network congestion management before deciding if and which time-dependent network charges should be introduced.

## 6.3 Prerequisites for incentivising network-oriented flexibility use

The most important prerequisite for the introduction of time-dependent network charges is that it is possible to determine cases of existing congestion or at least a certain likelihood of upcoming congestion on which the design of the charges can be focused. If there are no such cases, it would be useless to incentivise changes of consumer behaviour from a network operation point of view. In that case, flexibility of consumers – as far as consumers do not prefer to use it for their own purposes – should rather be provided for market-oriented purposes e.g. by taking it into account in day-ahead or intraday trading at the power market.

With regards to network congestion in Luxembourg, Creos and the other network operators involved in this study have signalled that there are no significant cases of congestion today that would require the use of demand-side flexibility for congestion management. Furthermore, it is not yet possible to figure out cases of congestion that are likely to become relevant in the near future. Based on these findings, for the time being, it does not appear recommendable to design a concrete system of time-dependent network charges for the medium, high and extra high voltage levels.

To substantiate these findings, we have analysed aggregated residual load profiles for different voltage levels in order to find out if there are significant peaks. Residual load profiles net the decentralised feed-in of renewables with the load. The average daily residual load profiles based on 2023 load data are shown in Figure 6.1 for the medium voltage, Figure 6.2 for the high voltage and Figure 6.3 for the extra high voltage level, in each case including the load of the underlying voltage levels.

The figures show that at all of these voltage levels, the average residual load profiles appear relatively smooth. Even more important, significant parts of the fluctuations between minimum and maximum residual load at the medium, high and extra high voltage levels are driven by fluctuations at low voltage level. Aggregated residual load profiles of customers connected to the medium, high and extra high voltage levels are thus even smoother, partly showing hardly any fluctuations, at all.

Therefore, even if it would appear sensible to provide incentives for smoothening the residual load profiles also in a situation without congestion – which we would consider questionable, anyway – there would not be a reasonable basis for such incentives in the upper voltage levels.

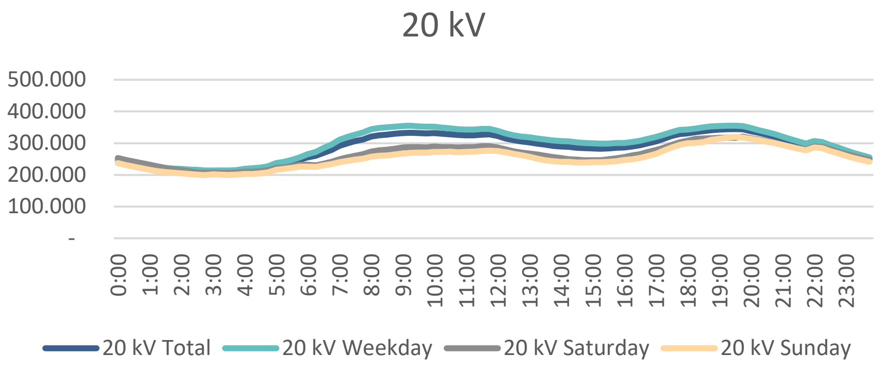

Figure 6.1 *Cumulative daily residual load profile of the 20kV voltage level (2023 data) differentiated by total, weekday, Saturday and Sunday values*

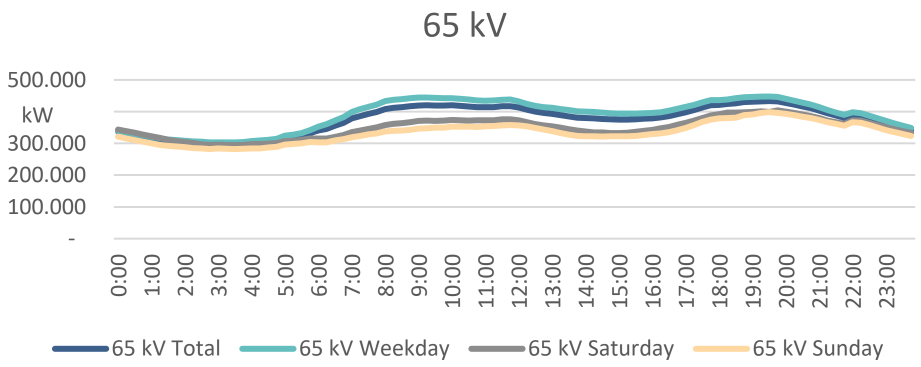

Figure 6.2 *Cumulative daily residual load profile of the 65kV voltage level (2023 data) differentiated by total, weekday, Saturday and Sunday values*

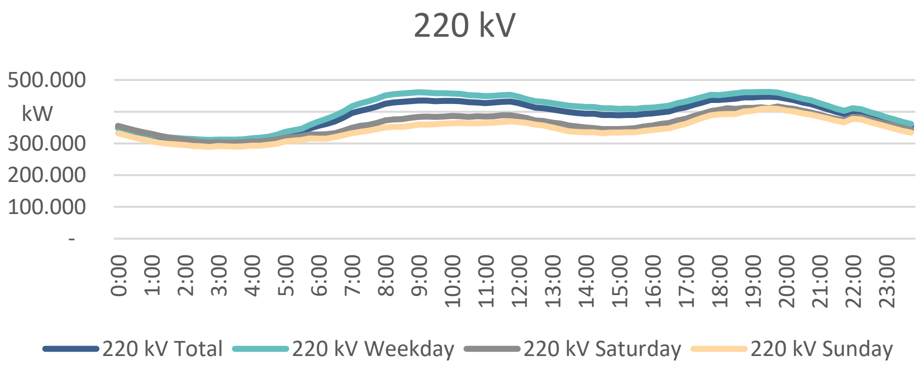

Figure 6.3 *Cumulative daily residual load profile of the 220kV voltage level (2023 data) differentiated by total, weekday, Saturday and Sunday values*

## 6.4 Conclusions and outlook

Based on the findings discussed above, we do not see an urgent need to introduce time-dependent network charges on the medium, high and extra high voltage levels in Luxemburg in the near future. It does not even appear sensible to develop a design for such charges prophylactically and only introduce it at a later stage since it is not possible from today's perspective to figure out precisely which cases of network congestion will become most relevant in the future and which design of time-dependent charges would optimally fit for that purpose.

However, in principle, we consider time-dependent network charges a valuable instrument that can incentivise network-oriented changes of consumer behaviour in a consumer-friendly way that allows for relatively simple coordination with other instruments for flexibility use. Therefore, we recommend observing the future development of network congestion over the next years and to re-evaluate periodically the general demand for congestion management and the potential benefits of demand-side flexibility provision based on time-dependent network charges.

# 7 Conclusion

As pointed out at the beginning of this study, it is generally not possible to design network charges such that they ensure full coverage of cost and, at the same time, provide efficient incentives (and avoid inefficient ones) under all circumstances. This fundamental conflict cannot simply be overcome by designing a cost-reflective tariff. Therefore, on the one hand, at least those tariff elements that are intended to provide relevant incentives for network customers' decision that have a strong impact on network cost should be designed so as to reflect marginal cost as precisely as reasonably possible. On the other hand, the remaining cost has to be recovered by charges serving primarily the refinancing function of network tariffs. These charges should be designed such that they create as little as possible adverse incentives. Within the remaining scope for solutions, tariff design typically has to strike a balance between certain desired distributional effects and the attempt to follow a more or less "universal" cost allocation principle.

Regarding the discussions on the allocation of network cost via the **cost cascading mechanism**, analyses of cost drivers show that network cost are not only driven by the peak loads but are also structure-driven and partly even energy-driven. The cost allocation via the cascading mechanism therefore does not necessarily have to be based on the maximum annual loads. The current approach is still an acceptable solution. However, other allocation keys would be justifiable, as well, such as a key based on gross annual consumption. This variant has the advantage that the required data is already available and can be expected to be more stable over time than the annual peak load. The calculation would be considerably less complex. Additionally, the data is even publicly available allowing stakeholders to understand the effects of the cascading variable on the cost allocation across network levels. However, when considering a shift towards this alternative approach, the resulting cost allocation to network levels that is different to the cost allocation resulting from the current method has to be evaluated. Such a shift would tend to allocate a higher share of cost to higher voltage levels.

A discussion has been raised about the potential introduction of **producer-side network** charges, motivated by the objective to involve producers in the refinancing of network cost and to reduce consumption-side charges accordingly. As there is a high risk that such charges cannot be designed precisely enough to be truly cost reflective and thus could lead to economically inefficient dispatch decisions, injection-based charges for power producers do not appear advisable. Connection-based charges would not imply this risk, but their refinancing contribution would be limited. In any case producers will try to pass on these additional costs, either via the electricity price (this however is limited by competition especially in a shared bidding zone with Germany where no such charges exist for producers) or via higher demand for support in the case of RES producers for example.

A main focus of this study was placed on reform options for the **consumer-side network charges**. First, we discussed the option of refinancing purely structure-driven network cost via a **base price**. In contrast to capacity- or power-based tariff components, a base price does not create barriers to flexibility use for existing network users. It does however have a negative impact on investment decisions in consumption technologies that are designed for low usage hours. Therefore, a base price is also not free of flexibility barriers and therefore does not provide an optimal solution.

Given that on all voltage levels that are the subject of this study the application of the **simultaneity function** poses conceptual and operational challenges, we do not see convincing arguments that would justify a continued application of the simultaneity function in the future. The alternative of applying fixed revenue shares for the allocation of cost to tariff components would simplify the tariff calculation and unlink it from the concept of simultaneity. However, any such changes to tariff calculation will entail distributional effects across different types of customers. Even if these effects are accepted because they would lead to a fairer distribution of the refinancing of network charges, any changes compared to the status quo have to be justified, and changes that lead to considerable redistributions might have to be introduced successively in more than one step in order to spread the effects over several years.

Additionally, the barriers to flexibility use created by the power-based component lead to a discussion on the options for a suitable design of a **capacity-based component**. Any departure from today's approach of a power-based component would strengthen the arguments for abolishing the simultaneity function. Conceptually it could be shown that a reference capacity model offers a solution that avoids critical barriers for flexibility use while ensuring that a substantial share of the network cost is refinanced by a capacity component so that network users with low usage hours and self-suppliers would participate appropriately in the refinancing of network cost. A tariff system that is similar to the one that will be introduced in 2025 on the low voltage level appears to be a suitable solution for the higher voltage levels as well. In case the reference capacity model is adopted we see no necessity to introduce **deep connection** charges.

Regarding incentives for network-oriented flexibility use, we do not see an urgent need to introduce **time-dependent network charges** on the medium, high and extra high voltage levels in Luxemburg as long as there are no clear cases of network congestion that these charges could address. However, in principle, we consider time-dependent network charges a valuable instrument that can incentivise network-oriented changes of consumer behaviour in a consumer-friendly way, and that allows for relatively simple coordination with other instruments for flexibility use. Therefore, we recommend periodically re-evaluating the general demand for congestion management and the potential benefits of demand-side flexibility provision via time-dependent network charges.