Industrial power grid fees in the age of the energy transition

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Content

1. Grid cost allocation models

1.1 Industrial grid fees are not aligned with climate objectives

The decarbonization of the industry will primarily be achieved through direct or indirect electrification of its processes. Low-carbon electricity offers indeed a promising path for the industry's transition to cleaner energy sources; however, it comes with its set of challenges.

Electrification often necessitates substantial investments in retrofitting or replacing existing industrial infrastructure and production equipment. This renewal can be costly and time-consuming, especially for heavy industries like steelmaking, cement or glass production, chemical manufacturing, and other applications where high temperatures are standard.

Besides the need for investment, a significant barrier to electrification are operational costs of electricity relative to fossil fuels. In Europe, electricity is more than twice the price of natural gas, the preferred energy source for industries due to its cost-effectiveness. The increased cost of electricity can raise concerns about the economic viability of electrifying industrial processes, especially for energy-intensive sectors.

The role of network charges in maintaining the stability of electricity costs for industrial consumers is essential, as they account for a significant proportion of companies' electricity costs. Unfortunately, Luxembourg's energy policy allocates a disproportionately high share of grid cost to the industrial sector than the residential sector. Over the last ten years, grid charges for industrial customers connected to medium (20kV) and high-voltage (65kV) grids have increased significantly more than those for residential customers and, more recently, have not been subject to the same aid mechanisms (price ceiling) applied to residential customers. This energy policy seems utterly detached from the government's climate targets to decarbonize industry by 55% by 2030 and bear a high risk for carbon leakage.

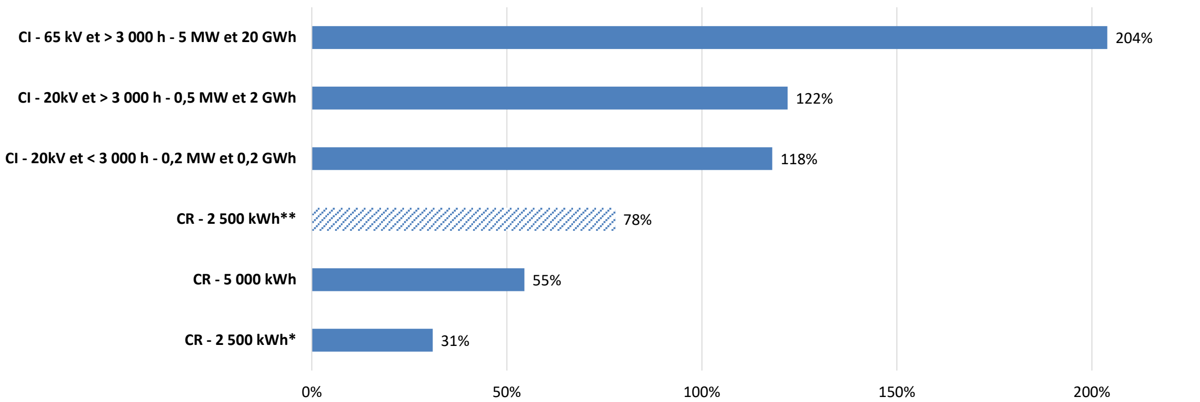

*Figure 1: Evolution of grid fees per type of customer Δ 2013 - Sep2023 [%]; CI: industrial clients, CR: residential clients. * Billed grid fees subsidized[1] for residential customers, ** grid fees without subsidies as a comparison (all data: source IRL)*

Figure 1 illustrates the changes in power grid fees per typical customer from 2013 to September 2023. Over this decade, the expenses associated with the power grid for industrial high-voltage customers have tripled by over 204%, while for both types of industrial medium-voltage customers, grid fees have seen a substantial doubling of their

[1] Grid fees for residential customers frozen at the 2022 level by the law of 23.12.2022.

costs, around +120%. In contrast, residential customers connected to the low-voltage grid have been relatively less affected, with their expenses increasing by only 31% to 55%.

This trend becomes even more noteworthy considering that, on the one hand, Luxembourg's industrial activity has been declining in the past decade, **leading to the release of industrial grid capacities**. On the other hand, the residential sector has put significant pressure on the power grid due to an extraordinary dynamic population growth of approximately +23% in the considered period.

Furthermore, it should be emphasized that Luxembourg's heavy industry has made significant efforts to reduce power consumption by improving energy efficiency and productivity. The overall power consumption of industrial customers exceeding 2 GWh/year decreased by 13% between 2012 and 2022[2]. During the same period, residential and all other professional customers (<2GWh/year) increased consumption by more than 10%, respectively 13%.

As grid costs are tied to voltage levels and, consequently, customer types, categories of customers who achieve the most energy savings face higher unit grid costs in proportion to their lower energy consumption. In other words, the more energy a customer saves, the more his remaining consumption must cover the regulated grid costs of his specific grid connection segment.

Another element that further widens the gap between industrial and residential grid costs is that grid design and expenses are primarily determined by the peak load the grid needs to accommodate. As power grids are complex systems, this design method simplifies by disregarding the actual load variability that grids must accommodate. Generally, we observe that the lower the voltage level, the greater the load variability. This diversity arises from varying consumption patterns at different grid levels. For instance, industrial consumers connected to higher voltage levels tend to exhibit more consistent consumption profiles, leading to lower load variability. In contrast, at the residential level, consumption is characterized by frequent switching on and off of multiple household appliances, irregular charging of electric vehicles, and the heating, cooling, or intermittent injection of solar power into the grid. These factors contribute to unpredictable and stochastic load spikes and peaks at the individual residential customer level. Aggregated over all residential customers, those spikes and peaks can thus cause load variabilities in the low-voltage grid that are difficult to approximate by a peak load approach.

Consider, for example, several households connected to the low-voltage grid in the same street of a residential area. The peak energy usage in each household may occur at different times of the day, reflecting the varied consumption habits of the residents. Consequently, the peak demand measured for the entire street may be significantly lower than the sum of the individual peaks of each house. This phenomenon is known as 'abundant peaks' or 'pointe foisonnée' in French. Extending this concept to the entire residential grid of a country, the measurable peak load of the residential grid at a specific moment in time, which determines its cost contribution share to the upstream grid levels, tends to be lower than what the grid may eventually need to withstand, namely the cumulative effect of all load spikes and peaks in the grid.

The above data and observations suggest that grid fees do not adhere to the **cost-causation or cost-reflectiveness principle**. This principle entails that the costs linked to a specific activity or service should be assigned to those who directly cause or benefit from that activity. Before the background of a weakening industrial sector and the demographic growth activity observed over the last decade, it is reasonable to assume that a significant portion of the costs associated with grid development at all voltage levels were **driven by the escalating demand within the residential sector**. This demand encompasses the need for a robust distribution of growing electricity consumption and a stable grid capable of accommodating the increasing volumes of solar power injected by private homes into the low-voltage grid and by wind power into the medium-voltage grid.

[2] Source: ILR, Chiffres clés du marché de l'électricité, année 2015; IRL, Chiffres clés du marché de l'électricité, année 2022, partie I

To bring it all together, the main factors driving grid costs in Luxembourg are identified at the low-voltage level associated with residential consumers. It is thus surprising that grid costs have risen the least for residential customers while they have increased most sharply for industrial customers. Furthermore, on top of this poorly equitable cost allocation model, residential customers benefited from subsidies at the end of 2022 to shield them from a substantial grid fee increase caused by a surge in energy prices following the conflict in Ukraine. While in Germany, for example, all power consumers benefited from such governmental aid, Luxembourg's industry was fully exposed to bear grid fee increases at the beginning of 2023 of up to 170%.

We **conclude** that the current grid cost allocation models determining the grid prices per tension level are increasingly becoming outdated. They do not sufficiently follow the cost-causation principle and disregard the industry's reliance on decarbonizing with electric power and the energy efficiency gains already realized by the industrial sector. By ignoring the vital principle of cost-causation, the current grid cost allocation models risk endangering a successful energy transition of society and the economy. On the one hand, the **missing price signals at the residential customer** level do not incentivize individuals to adopt more energy-efficient behavior and, on the other hand, businesses are disincentivized to electrify their production processes because of the disproportionally increasing operational costs compared to fossil energy.

1.2 Towards a cost causation-driven grid fee allocation model

This chapter will clarify the current grid cost allocation model and present four reform proposals to introduce the cost-causation principle at allocating grid costs among various voltage levels.

Figure 2 illustrates a simplified scheme of the main cost elements composing the maximum allowed revenue[3] (MAR) for the grid provider (the percentages in the diagram are illustrative; they vary annually). The MAR is annually fixed by the regulator (ILR) and represents, besides other services, the basic amount the grid operator can invoice to its customers. The MAR follows a voltage-level, specific cost allocation logic; all costs are separately accounted for at their origin; they are split into 220 kV (very high voltage), 65 kV (High voltage), 20 kV (medium voltage), 400 V (low voltage), and metering.

In other words, the grid provider's revenues per voltage level are determined by splitting the MAR according to their origin to the different voltage levels. For each voltage level, the specific costs (in €) are divided by the quarter-hourly measured simultaneous annual peak load of all withdrawals (in kW) in this grid level. The quotient obtained (in €/kW) is called 'stamp.' This reflects that network fees are distance-independent, i.e. network usage is settled independently of the distance between injection and withdrawal through the payment of this stamp. In general, this is a correct approach as grids are dimensioned for the peak loads and not for the energy transported.

The stamp of voltage level n serves as the basis to calculate each voltage level's (n, n-1 to n-3) cost contribution to the national peak load of this level according to its proportional load share to the peak. This cost-forwarding method from one voltage level, n, to the following downstream levels, n-1 to n-3, is called cost cascading.

This cascading model has a significant drawback for industrial customers: They often have an average of 5000-7000 hours equivalent grid usage time[4] (dividing the volume kWh by the peak capacity kW) as they seek to optimize production output. During the ¼h peak time of the year, the probability that they fully contribute to the peak is thus extremely high. However, low-voltage customers with an average of 800–1000 hours equivalent have a rather low probability of contributing to the ¼h peak. This leads to a much higher cost

[3] For the detailed composition of the MAR, refer to Règlement ILR/E20/22 du 26 mai 2020

[4] Grid usage time is obtained by dividing the volume drawn for them grid (in kWh) by the peak load (in kW); a full year has a maximum 8760 grid usage hours (365 days x 24 hours); see also chapter 2.1.i

allocation to the high- and medium-voltage grid consumers than low-voltage grid consumers.

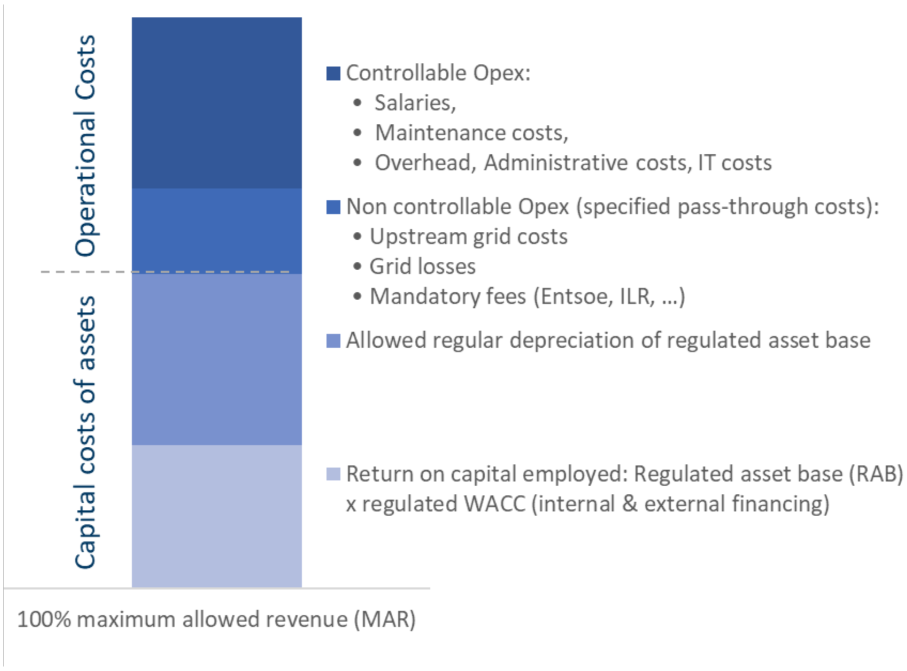

Figure 2: Simplified scheme of the main cost elements composing the maximum allowed revenue (MAR); the percentages in the diagram are illustrative. WACC: Weighted Average Cost of Capital

Within the above-described cost allocation and cascading model, we see five options to improve the fairness of grid fees per voltage level based on the cost causation principle:

i. **Reform the cost allocation key:** Currently, costs are allocated based on their point of origin, which means that any costs incurred for investments and operations at a particular voltage level are assigned to that same level. This may appear straightforward initially, but it becomes more complex, considering that voltage levels are interconnected. For example, reinforcements at the transport grid may be undertaken not because an increased capacity is needed at that same level but to accommodate more power in downstream voltage levels. Also, a development on the medium voltage may have the primary goal of helping evacuate injected volumes of renewable power at the low-voltage grid. Consequently, it's not uncommon for investments in higher voltage levels to be primarily aimed at meeting the needs of consumers connected to lower levels.

   Furthermore, the accurate allocation of grid costs is becoming increasingly important considering European energy policies, which focus on a blend of decentralized (local) energy generation and enhancing power grid reliability and supply security through expanded interconnection capacities among regional grid operators.

   In the past, the high-voltage (HV) grid primarily served to transmit power from centralized, large-scale power generation facilities to various categories of customers. All energy flows, whether generated or consumed, passed through the HV grid, contributing to its associated costs.

   However, it is now evident that decentralized energy generation and production, particularly from sources like photovoltaic (PV) and wind, will primarily occur at low-voltage (LV) and medium-voltage (MV) levels. Consequently, these energy volumes will not contribute to covering the costs of the HV grid. Nevertheless, decentralized energy production is highly dependent on weather conditions, necessitating a robust overall system that serves as a backup. Extensive interconnection capacities at the HV level provide these backup or reserve solutions. They ensure efficient energy transportation between countries and regions as needed to address weather-related intermittency.

As a result, the utilization rate of the HV grid is expected to decrease significantly. This raises the question of allocating higher grid transport costs to lower grid usage volumes. Additionally, there is a related question: who should bear the costs for grid security of supply and grid flexibility provided by HV interconnectors? Should it be the HV customers alone, or should all customers, including decentralized energy producers who benefit from these backup capacities for their "unreliable" power generators, share in these costs?

With the current cost allocation system, customers at the higher voltage level risk bearing most of these costs, even if the primary targeted beneficiaries are connected downstream. Therefore, instead of strictly attributing costs to their point of origin, we should consider reforming the cost allocation key to reflect the ultimate purpose of the cost better. Alternatively, customers at low voltage (LV) and medium voltage (MV) levels could be subject to an additional contribution to help cover the costs associated with the flexibility and backup services provided by the high voltage (HV) level.

Redefine the peak load moment used for the stamp. Currently, each grid voltage level is characterized by a single annual peak load moment in the system. This peak load moment determines the stamp of that voltage level and the proportional contributions of the downstream levels based on their load share at that specific moment in time. Electrical grids are complex networks with multiple interdependencies. A single peak load moment might oversimplify this complexity and result in inadequate cost allocations, as it could capture a non-representative moment of peak load share. This is particularly evident in the residential sector, given its abundant peak issues (see also Chapter 1.1). The measured annual peak load might occur when the residential sector's peak load share is exceptionally low or high, which would not be representative of its actual peak load contribution throughout the year. A more representative method might consist of multiple measurements around multiple annual peaks to understand better the grid level's usage and the proportional contributions of downstream grid levels at those moments. For example, the Belgian grid operator Elia considers the 11th annual or monthly peak to be a more representative level for calculating the stamp. Furthermore, as discussed in paragraph (i), redefining the stamp should consider the power grid reserves and flexibility functions provided by the HV grid for the entire community of national grid users, including consumers, prosumers, and producers.

ii. **Introduce hypothetical peaks:** A more equitable approach to seizing the investment and operational costs and distributing them more effectively to those who benefit from them could be to define a hypothetical future peak at each voltage level rather than relying solely on the annual peak load moment. This hypothetical peak could then be utilized within the existing cost allocation model to break down and cascade costs according to the different downstream voltage levels' hypothetical shares in that peak. This approach might sound adventurous at first sight, but after all, investments in the grid are typically made based on estimated potential future demand peaks. By relying on historical data and various usage projections, we can trust that these estimations of future peaks are reasonably accurate. In fact, they might provide a more accurate representation of grid usage compared to one single annual measurement, all while aligning better with the cost causation principle.

Reserved capacity-based peaks: A similar concept to the hypothetical peak could be applied if tariff models based on reserved capacity were introduced. The sum of all reserved capacities would then determine the peak demand (pointe non-foisonnée) at each voltage level. This approach would provide a more accurate representation of what grid level has the highest requirements, enabling more precise cost allocations, even if consumers would optimize their consumption and peak reservation.

In this model, it is essential to include prosumers and producers for the injection-related capacity needs at their respective voltage levels (LV and MV). The revenues generated from these sources could contribute to covering the costs associated with providing them the backup and flexibility of a robust HV grid (see also paragraph i. of this chapter).

iii. **Use overhead costs to balance effort sharing:** A final approach could consider using indirect costs, which do not have a single point of origin, to shift them to voltage levels with the highest cost causation shares. Examples of such costs include IT expenses, depreciation, and operational costs associated with office and administrative buildings, among others. A prerequisite for implementing this method is establishing a cost causation scheme to distribute overhead costs fairly. However, once such a scheme is in place, it can potentially overhaul the entire cost allocation method based on origin. Consequently, this final option can be used to initially reform the reallocation of overhead costs and then gradually reform the entire allocation process.

2 Grid tariff models

While the first chapter discussed the cost allocation models per voltage level, this current chapter focuses on the tariff models that determine the grid price at the customer level. First, we will explore the reformation needs of current tariff models, followed by propositions for alternative models.

2.1 Why do grid tariff models need an overhaul?

The energy transition across all sectors, including industry, is expected to at least double today's electricity consumption. This requires the energy sector to increase its share of low-carbon energy generation. In Luxembourg's current bidding zone, this translates to a greater incorporation of renewable energy sources, such as wind and solar power. Despite the growing cost-effectiveness of renewable energy production, the power market price is expected to remain higher than that of natural gas.

The share of variable renewable energies, such as wind and solar power, in the European electricity market presents an additional challenge: increasing fluctuations in electricity prices. Consequently, a prerequisite for the competitiveness of the energy-intensive industry in Luxembourg will be its ability to adapt to short-term fluctuations in electricity prices and leverage moments of low prices to its advantage. For example, companies could benefit from temporary low power prices to ramp up production during that period. Even companies whose production is less flexible could produce heat and cold to store for later consumption or store the cheap power directly in batteries or indirectly, for example, via hydrogen, for later use.

The ability to flexibly adjust demand to capitalize on power price volatility represents a way for the European industry to take advantage of the need to decarbonize by electricity. The industry needs to explore and employ all available strategies to narrow down the price gap between natural gas and electricity if it wants to stand a chance of competing internationally with counterparts who continue to have access to more affordable energy.

The guiding principle in designing new network tariffs for industrial customers should thus be to incentivize increasing demand flexibility while simultaneously dismantling existing barriers that currently hinder flexible power sourcing.

However, the current system of capacity-based pricing, calculated on the quarter-hourly measured annual peak load, along with the differentiated energy and capacity charges depending on the hours of annual usage, discourages demand flexibility. The current tariff scheme does not incentivize companies to increase demand flexibility. **The following three elements specifically disincentivize demand flexibility:**

i. **Grid tariffs that vary according to usage time:** The capacity and energy charges levels vary depending on whether a consumer has more or less than 3000 annual grid usage hours. Above this threshold, the energy charge is lower than below, while the capacity charge increases. The time of use, also referred to as 'usage duration of the annual peak power,' describes how many hours the customer would need to consume electricity at the highest power level, Pmax, to draw the annual energy volume W. At equal consumption volume W, customers with stable electricity consumption tend to have a lower Pmax, leading to a longer usage duration than those who prioritize flexible electricity consumption with occasional peak consumption periods. Although the capacity charge increases with longer usage times, the average network charge typically decreases with increasing annual usage hours.

   This design incentivizes customers to optimize for longer usage time with a flat profile rather than encouraging them to react to market price signals flexibly. So, even in an over-supplied grid, additional consumption is not incentivized; on the contrary, it may be heavily penalized financially (see next paragraph).

ii. **Capacity price that penalizes individual, single peak loads**: The grid fees consumers pay for an additional (marginal) consumption W varies significantly according to when the marginal power is drawn from the grid. When electricity is drawn below the company's individually quarter-hourly measured annual peak load, only the energy price is due. However, suppose the company is already consuming around peak load, and the increase in consumption entails a redefinition of the individual annual peak load to a higher level. In that case, a higher capacity charge is also due. In other words, the network charges incurred for increased consumption are much higher during these hours.

   According to economic logic, network fees should depend on the total grid load, which is the collective consumption profile of all customers, rather than the individual consumption profile of each customer. In a given network area, all customers should pay the same network fees at any given time when increasing their consumption because they all have the same impact on the limited network resource. The individual capacity price does not reflect this logic; it is not directly related to the network's load. As a result, industrial companies are not incentivized to take advantage of fluctuating electricity prices by temporarily consuming more electricity during low or even negative market prices, which would relieve the grid and contribute to the better integration of renewable energy.

iii. **Approximation of the capacity price (simultaneity factor):** The capacity price based on individual peak load consumption is intended to reflect the impact of individual consumption on the total grid load. The calculation method, described in Regulation ILR/E20/22 of May 16, 2020, Article 17 (3) and Article 18 (4), estimates the consumers' share in the maximum grid load. This estimation is made based on consumers' usage hours. It is based on the hypothesis that consumers with high usage hours contribute more to the maximum grid load than those with fewer usage hours. Therefore, consumers with high usage hours also pay a higher capacity charge corresponding to their approximated simultaneity factor.

In an energy system without demand-side flexibility and the injection of significant amounts of electricity into distribution grids, approximating simultaneity factors based on usage hours may provide plausible results. In future energy systems, however, the demand should adapt flexibly to changes in electricity prices and grid utilization. At the same time, decentralized generation is expected to increasingly feed into grids, particularly in distribution grids. This dynamic environment may result in inaccuracies if estimation methods are used to determine grid tariffs.

2.2 Grid tariffs that incentivize demand flexibility

The following paragraphs describe some propositions to eliminate the abovementioned drawbacks to help incentivize demand flexibility while promoting fair and equitable grid fee distribution among all industry consumers. It cannot be underlined enough that the decarbonization of industrial processes by switching to electricity will only occur if industrial consumers see a business case for the switch. Grid tariffs can contribute significantly to keeping electricity use competitive in the industry.

i. **Reform of the capacity price**. The capacity charges shall be reformed to reflect the consumer's real contribution to the network load more accurately. Currently, the capacity price is only based on one single individual peak load together with an estimation of its contribution to the network's peak load by an approximated simultaneity factor. This means it may penalize peak loads even if they relieve the local network, for example, when they offset generation-related peaks.

   In Belgium, for instance, the annual peak is determined not by one single peak but by the 11th peak drawn over a quarter-hour, and when it is drawn in potential peak load periods only, i.e., in the 5 pm-7 pm time slot, excluding weekends and only from January to March and November to December.

ii. **Rebates for industrial consumers, avoiding peak load periods in the network.** First, so-called peak load time windows shall be defined at the beginning of the year (see the Belgium example of the previous paragraph), during which consumers must not exceed their maximum load. Those time windows shall differentiate according to the time of the day and the season. Consumers whose annual peak load predictably occurs outside the defined time windows of the network's peak load, for example, during the weekend, at night, or in the summertime, shall be granted substantial grid fee rebates. Such rebates would encourage more demand flexibility outside peak load periods while reducing the risk of grid instability.

   For example, in Germany, energy-intensive industrial consumers whose maximum load contribution differs significantly from the simultaneous annual maximum load of all withdrawals from the grid are offered an individual grid free that can include a discount of up to 80% of the regular fee[5]. The reduced income of the grid operators is mutualized among all end consumers, but companies pay a reduced levy for energy volume consumed over one GWh. Such rebates stabilize the company's electricity costs in favor of the energy transition.

   Demand flexibility could further be encouraged in the future, by announcing dynamic, short-term suspensions of the statically predefined peak load time

[5] § 19 Abs. 2 der Stromnetzentgeltverordnung (StromNEV)

windows by the network operator when local peak generation occurs. This would allow the utilization of local surplus power instead of curtailment.

iii. **Reduce the weight of the energy charge in favor of the capacity charge.** The increasing trend towards auto-consumption calls for reducing the energy price component, favoring the capacity price component in grid tariffs. In an energy price-heavy grid tariff model, auto-consumers with high self-sufficiency often avoid contributing adequately to grid costs while remaining connected to the grid as a backup solution. Consequently, non-auto-consumers end up subsidizing the avoided grid costs of auto-consumers. To ensure fair and equitable cost distribution, adjusting the tariff structure to prioritize capacity charges can help incentivize all consumers to support the stability and sustainability of the grid.

The above three propositions align with the ILR's reserved capacity tariff model concept as foreseen for the low-voltage grid. At all voltage levels, the reserved capacity should, however, encompass the capacity for drawing from and injecting into the grid. Furthermore, the penalties foreseen by the model in case of exceeding the reserved capacity should be designed not to discourage demand flexibility. Penalties during the off-peak periods should thus be symbolic, while during the peak load periods, they should be calculated proportionally to the drawn power volume during the exceeding peak. At the same time, the penalties should be designed to prevent consumers from seeking to optimize grid costs by reserving lower capacities than they need. In other words, paying penalties while subscribing to an insufficiently high capacity cannot be less expensive than opting for a higher capacity subscription.

Another option is implementing a system where penalty charges progressively increase based on the energy consumed beyond the reserved capacity relative to the total annual energy consumption.

Ideally, penalty concepts should be applied at all voltage levels, including residential customers. However, since residential customers at the low-voltage level are generally less aware of their consumption patterns, and penalties are challenging to implement because of their low social acceptability, a different approach should be considered. As a standard practice, residential customers could be subject to an additional, undisclosed top-up fee on their reserved capacity, akin to a penalty for surpassing it. If they do not exceed their reserved capacity, they will receive a bonus payback or credit at the end of the year as an incentive. This approach converts a penalty into an incentive, aligning with the cost-causation principle while helping to cover grid costs.

3 Conclusion

The analysis of Luxembourg's electricity grid cost allocation and tariff calculation models presented in this paper reveals that the current energy policy disproportionately burdens the industrial sector compared to the residential sector in funding the impacts of the energy transition on the grids. In fact, the current cost allocation and tariff models remain rooted mainly in increasingly outdated electricity generation, transportation, and distribution models, which are ill-suited to address the challenges posed by the energy transition. They do not adhere to the cost-reflectiveness principle, which is essential for a fair transition, nor acknowledge the industry's reliance on competitively priced electricity supply to decarbonize its activities.

Without a reform towards a fairer burden sharing between the different customer types connected to the power grid, the achievement of a successful energy transition may be at stake: On one hand, residential customers lack the incentive to adopt more energy-efficient behaviors, and on the other hand, businesses are discouraged from intensifying their decarbonization efforts and may contemplate relocating to nations with more equitable legislation.

This document outlines the reasons for reforming the cost allocation and tariff models. It also presents multiple measures that can be taken to tackle the reform. However, we do not endorse any specific or particular combination of the presented reform measures to alleviate high network usage costs for industrial customers. The intricate interdependencies of these measures necessitate quantitative analyses and simulations to assess their ultimate impact on the network costs of different customer groups. The grid provider and the regulator are responsible for conducting these analyses. Nevertheless, we anticipate that the reform will address the disproportionately high network usage costs in the industrial sector and, in doing so, make a significant contribution to achieving the energy transition. Network tariffs must play a role in making electricity prices for industrial customers in Luxembourg competitive again compared to those in fellow Member States.

FEDIL - The Voice of Luxembourg's Industry

LUXEMBOURG OFFICE

7, rue Alcide de Gasperi
Luxembourg-Kirchberg
Telephone: +352 43 53 66-1

POSTAL ADDRESS
P.O. Box 1304
L-1013 Luxembourg