MARKET ENABLING INTERFACE TO UNLOCK FLEXIBILITY SOLUTIONS FOR COST-EFFECTIVE MANAGEMENT OF SMARTER DISTRIBUTION GRIDS

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Methodology for dynamic distribution grid tariffs

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Abbreviations and Acronyms

Abbreviation	Meaning
5 Ds	Digitization, decentralization, decarbonization, deregulation and democratization
ACER	The European Union agency for the cooperation of energy regulators
ACH	Air changes per hour
BRUGEL	L'autorité bruxelloise de régulation dans les domaines de l'électricité, du gaz et du contrôle du prix de l'eau – Brussels capital region regulator for gas, electricity, and water
COP	Coefficient of performance
CWaPE	Commission Wallonne pour l'énergie – Walloon energy commission
DA	Day-ahead
DAM	Day-ahead market
DER	Distributed energy resources
DG	Distributed generation
DNR	Distribution network reconfiguration
DR	Demand response
DSO	Distribution system operator
DUR	Danish utility regulator
EEG	Erneuerbare-Energien-Gesetz – Renewable energy sources act
EnWG	Energiewirtschaftsgesetz – Energy act
EU	European Union
EUR	Euro
EV	Electric vehicle
HP	Heat pump
HV	High voltage
KPI	Key performance indicator
NVE-RME	Norwegian energy regulatory authority
Ofgem	UK office of gas and electricity markets
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt-hour
LP	Linear program/ linear optimization problem

LV	Low voltage
MV	Medium voltage
NIE Networks	Northern Ireland electricity networks
NOK	Norwegian krone
NRA	National regulatory authorities
p.u.	Per unit
PV	photovoltaic generation
RC	Reverse cycle
RES	Renewable energy sources
SO	System operator
TOU	Time of use
TSO	Transmission system operator
UMEI	Universal market enabling interface
VREG	Vlaamse regulator van de elektriciteits- en gasmarkt -Flemish regulator for energy and gas markets

EUniversal
UMEI

Executive Summary

The EUniversal project, funded by the European Union, aims to develop a universal approach on the use of flexibility by Distribution System Operators (DSO) and their interaction with the new flexibility markets, enabled through the development of the concept of the Universal Market Enabling Interface (UMEI) – a unique approach to foster interoperability across Europe.

The UMEI represents an innovative, agnostic, adaptable, modular and evolutionary approach that will be the basis for the development of new innovative services, market solutions and, above all, implementing the real mechanisms for active consumer, prosumer, and energy community's participation in the energy transition. In this way, an effective, market-based and future-proof ecosystem can be realized. The EUniversal approach will be implemented and tested in three multi-scale demonstrations (i.e. Germany, Poland and Portugal) to demonstrate its universality.

The anticipated project outputs are becoming increasingly important since in recent years the energy landscape has experienced substantial changes. Digitization, decentralization, decarbonization, deregulation and democratization (often referred to as the 5Ds) leave their mark on the energy transition. An important finding in this respect is that energy is more renewable and, moreover, is generated in a small-scale and distributed manner. As these developments reach momentum, these changes lead to several challenges and opportunities from a grid management point of view. Decentralized, renewable energy production and electrification of heat and mobility can increase the complexity of operating the electricity system (e.g. supply peak demand at times when there is no local production) and could impose additional investments.

As a consequence, flexibility in distribution grids is becoming a key aspect in a renewable-dominated electricity smart system. EUniversal aims to provide the necessary tools to identify, quantify and provide flexibility services directly to the distribution grid. Besides this direct provision of flexibility, the flexibility can be triggered by a price or tariff signal indirectly. This deliverable sheds light upon the latter, the use of indirect flexibility signals, in the form of dynamic grid tariffs, to activate and incentivize end- consumers to provide their flexibility as a service to the distribution system.

The current grid tariff structures were laid out in a time when the energy provision was still rather unilateral and renewable energy and self-production were not yet broadly applied. Furthermore, consumers were assumed to be rather unresponsive to more dynamic grid tariffs or other price signals. As this passive consumer role is evolving towards more active participation, consumers can provide significant flexibility potential from an electricity system point of view. In this context, the review of grid tariff design will be reconsidered in this report and specific attention is given to the application to the EUniversal German demo.

A qualitative assessment of the main aspects defining grid tariff designs, complemented with a European benchmark analysis performed for a selection of countries forms the basis for acquiring first insights. It becomes apparent from the analysis that currently most tariff designs rely upon a volumetric charge. However, a distinct (planned) shift towards capacity-based tariff designs and the implementation of time-varying tariffs is identified as a manner to increase cost-reflectivity. Discussion to include more flexibility from the grid user focus on the introduction of more dynamic tariffs to reflect grid constraints.

The findings from the qualitative analysis have led us to orient the discussion of grid constraints towards three potential implementations. In particular, the reflection of the system peak or the grid state can be static (which means that the grid status is not considered in the tariff), event-based (focussing on certain peak-events) or dynamic (continuous representation of the grid state). The further analysis, based upon the different design dimensions considered (i.e. distribution of grid costs,

spatial variability, consumer variability, time variability, tariff driver, symmetry, dynamic element, billing trigger and granularity), has resulted in 5 tariff designs for this assessment;

1. Static grid tariff: capacity-based tariff where the congestion risk is identified ex-ante based on historical data analysis. Based on a combined seasonal and time-of-day analysis of the cumulative load profiles within the grid, five different tariff periods have been defined and used as temporal (time of day and seasonal) differentiation elements in the design of this static grid tariff..
2. Event-based binary grid tariff: capacity-based tariff where the congestion risk is determined day-ahead. One tariff is applied for the entire day with a distinction between a low and high tariff depending on the anticipated grid state.
3. Event-based gradual grid tariff: capacity-based tariff where the congestion risk is determined day-ahead. One tariff is applied for the entire day with a distinction according to 5 rate heights depending on the anticipated grid state.
4. Dynamic binary grid tariff: volumetric tariff where the congestion risk is determined day-ahead. An hourly differentiation is applied with a distinction between a low and high tariff depending on the anticipated grid state.
5. Dynamic gradual grid tariff: volumetric tariff where the congestion risk is determined day-ahead. An hourly differentiation is applied with a distinction according to 5 rate heights depending on the anticipated grid state.

For these tariff designs, a quantitative assessment is made of the entailed impact on the grid operators (in function of relieving grid congestion, redispatch need and cost recovery) as well as on the end-consumer (viewed in function of the invoice impact). The quantitative assessment (which makes use of a grid model provided by the German DSO Mitnetz Strom, load profiles stemming from different connected loads including variations of flexible assets, a unit commitment model for energy pricing, and a flexibility model for interpreting the end-customer's potential reactions to the received tariffs) enables the definition of initial congestion instances, and expected reductions in those congestions due to each of the implemented tariffs.

Considering the performance of the different grid tariff designs in function of the key objective, i.e. relieving distribution grid constraints and answering to a redispatch need, the quantitative results indicate that, overall, all selected grid tariff designs achieve good results. The static grid tariff (tariff 1) performs well in mitigating the cases with the highest congestion, as can be shown by the resulting reductions in expected congestion instances (in terms of voltage and line flow limits) within the different feeders. This makes us conclude that an individual capacity trigger, with an economically acting consumer, can already reduce the aggregated local or system peak. In comparison to the second and third tariff, which also contain a capacity trigger in the grid tariff design, it can be observed that overall, the performance (in function of mitigating grid congestion) is slightly less. So, despite the fact that the consumers, similarly to tariff 1, receive an individual incentive to reduce the need for capacity, the effect on the grid state and congestion cases is less. When the period of registration of the capacity usage is too long (e.g. a day) the local trigger to reduce the individual need for capacity is less. To conclude the analysis, tariffs 4 and 5 contain a high level of granularity and perform better in terms of reducing high congestion risk situations and in parallel show a higher responsiveness to the redispatch signal as well.

From a grid operator perspective, cost recovery needs attention. In particular, the rate height of the different grid tariff designs is set based on the initial residential demand and does not account for the reaction of the residential demand on this signal. Hence, if the tariff signal causes a shift in consumer behaviour to lower tariff periods, this also impacts the cost recovery of grid operators. This effect is particularly observed in the event-based tariff designs where certain rates apply for the entire day and the measurement basis is daily. These tariff designs require a more extensive feedback loop to establish steady-state rate heights. Static tariffs and dynamic tariffs need less precaution to set the rate height in function of recovering the allowed revenue by the DSO.

From the perspective of the consumer, access to flexibility can really provide significant benefits in terms of grid costs reduction. Particularly, the event-based tariff designs could potentially lead to a considerable cost reduction.

1 Introduction

1.1. Grid operation

As the energy transition gains traction, we can identify multiple challenges and opportunities impacting the grid operation. These issues are related to the need for security of supply, the technical and economic implications of expanding distributed renewable energy sources, the ongoing need for rational use of energy, but also the growing need to use electricity grid infrastructure in general, and the limited capacity of electricity networks in particular, more efficiently.

Large-scale integration of **decentralized renewable energy production** such as photovoltaic generation (PV) and installation of new loads such as electric vehicle charging infrastructure can make the power system more complex to operate and may necessitate either additional investment towards network reinforcements and/or use of flexibility for avoiding distribution network voltage limit violations and thermal overload issues. The network, in particular, must be able to meet peak demand from consumers even when no local production is available, while also accounting for:

- The possibility of inverse (injection) flows in the grid during low off-take and high production periods. In this case, it may be necessary to adjust the protection in substations to allow transport to the higher voltage levels;
- The variability of renewable energy sources, which can negatively affect voltage and power flow management and lead to unwanted voltage variations and/or congestions; and
- A larger simultaneity on the local grid (especially for PV), as when a large volume of PV electricity is produced, this peak production is produced simultaneous in neighbouring PV installations.

The **electrification trend** of mobility and heat demand also has an impact on the power grid. It is projected that the low-voltage network may be unable to handle circumstances in which everyone seeks additional electricity at the same time. The higher simultaneity factor of loads such as electric vehicle charging leads to large peaks during certain parts of the day. Several studies suggest, for example, that the increased demand of electric vehicle (EV) charging sites and the growing integration of heat pumps might result in increased distribution network investments, to decrease the risks of congestions and, in general, increase the networks' capacity.

This effect, however, can be reduced by using flexibility, or the **active participation of the consumer**, in grid operation. Given the growing trend of digitalization and the availability of real-time sensing and data collection, innovation opens up new prospects for network management techniques. This allows for more efficient operation of power grids, which may result in network investments being postponed or avoided.

1.2. Grid tariff design

Generally, the design of a distribution grid tariff follows three steps. Initially, the total allowed revenue for the distribution grid operator is to be set. Due to the monopolistic nature of the electrical system, where grid operators could otherwise take advantage of their position and set grid tariffs too high, a revenue cap is necessary. This exercise is in most cases performed by the national regulator. The second aspect of the distribution grid tariff design is the actual determination of the tariff design and thus how the allowed revenue is recovered from the grid users. This step is followed by the actual computation of the rate height, which is the actual rate value of the different components of which the tariff is composed.

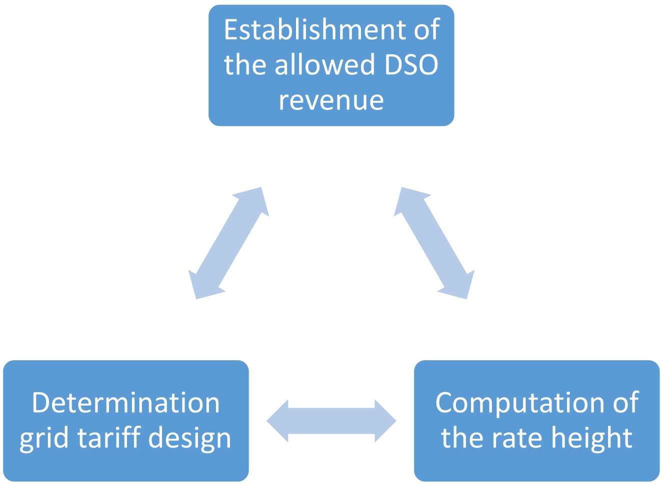


Figure 1: Grid tariff design methodology

Even though the proposal presents these three steps sequentially, in practice, they are actually somewhat contemporaneous rather than being strictly sequential, as visualised in Figure 1 [1]. For instance, the tariff structure design is the starting point, but the cost drivers that are specified in the second stage will determine its final design. Additionally, each rate computation procedure must be modified multiple times in response to its impact on demand patterns (e.g., the computed tariff rates can entail behavioural change of the grid user, enforcing adjustments in the tariff design to accommodate the new consumption profiles).

In this deliverable, the definition of the allowed revenue is out of scope. Particular attention is paid to the definition of the grid tariff design and the resulting rate height.

Grid tariff designs were established when energy provision was still largely unilateral, and renewable energy and self-production were not widely used. Consumers were assumed to be rather passive and insensitive to price signals. Furthermore, because of a lack of digital meters on the consumer's side, the available methods for the settlement of the grid usage were limited as well. As a result, at low voltage, grid fees are commonly made up of a fixed grid charge and a grid tariff based on active energy offtake (€/kWh).

Given recent trends and anticipated changes in grid operation, the existing design of the grid tariffs for end-users on the low voltage grid can be questioned:

- As a result of the current tariff design, residential end-consumers are given too few incentives to deal rationally with available network capacity. The volumetric billing basis (i.e. €/kWh) provides little motivation to act following grid requirements.
- Current rates result in cross-subsidies. In particular, grid users with a large net-offtake in kWh partially cover the costs of grid use for end-consumers with a very low net-offtake in kWh. Additionally, grid users with a relatively flat off-take profile partially cover the costs of grid use for consumers with a large peak off-take.
- The system peak in the network determines a substantial portion of the costs for system operators. This is the peak power that is simultaneously required (or produced) by all end-consumers within the same grid segment. Current grid tariffs for end-users on the low voltage grid do not reflect this system peak usage of the grid and associated costs.

- Active consumers or prosumers can become valuable assets for the energy system if given the correct signals and opportunities. Tariffs dedicated to resolve network issues, for example, could be a more cost-effective alternative than grid investments to alleviate grid congestion.

Hence, in this paradigm shift, grid tariff designs need to be reconsidered. According to ACER, network tariffs have two key objectives: (1) they should incentivise DSOs to build and operate the networks optimally and efficiently and (2) they should provide economic signals to trigger an efficient usage of the network by the network users [2].

1.3. Grid tariffs as part of a DSO set of measures

To ensure the development and the stable operation of transmission and distribution grids, system operators (SOs) can use a toolbox of mechanisms. In this context, grid tariffs are part of a bigger framework of mechanisms which can be implemented to obtain sufficient flexible volume to resolve certain challenges and issues for SOs. This framework of mechanisms is depicted in Figure 2, and consists of technical solutions (e.g. network reconfiguration), rule based mechanisms and connection agreements, tariff based solutions and market based solution. These mechanism have been studied in more detail in the framework of deliverable D5.1 of the EUniversal project [3].

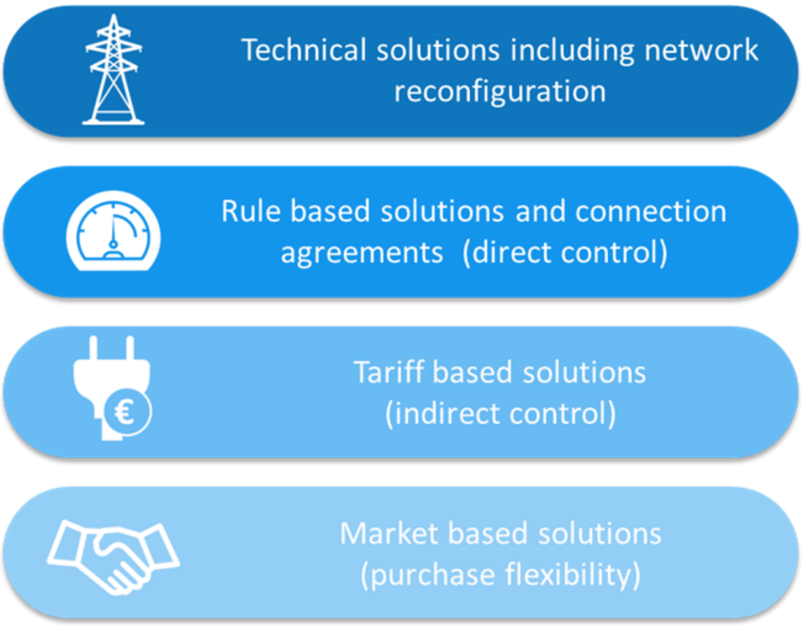


Figure 2: DSO set of measures for congestion management

As shown in Figure 2, **tariff-based solutions** are complemented by three other groups of mechanisms to support the SOs in maintaining a reliable grid operation and mitigating grid congestions.

Technical solutions refer to the flexibility resources owned by the DSO which can contribute to the management of congestion. Distribution Network Reconfiguration (DNR) is a direct congestion management strategy that the DSO implements in various time frames. To alter the network topology, the DNR integrates the control of tie and sectionalising switches, as well as changing the status of some normal-open and normal-closed switches, changing transformer taps, and establishing the control of linear regulators.

Rule-based mechanisms and **flexible connection agreements** rely upon technical regulations. Network operation and the risk for grid congestion is considered by a mandatory provision of flexibility (e.g., a direct control action) or by adapting the connection capacity in a flexible manner. In the latter case FSPs agree to have their connection curtailed in some periods (e.g. demand could be temporarily reduced during periods of load peak demand or generation could be curtailed to avoid generation peaks) [3].

The group of **market-based solutions** assumes a direct procurement and activation of flexibility following a market-based procedure. This mechanism assumes that flexibility providers, voluntary and explicitly participate in a procurement procedure for a grid service. Multiple market-based solutions exist to support SOs, amongst others, tendering procedures, auctions and continuous trading.

Flexibility may not be acquired through a single mechanism, but through a combination of methods. These mechanisms must be meticulously constructed to work in tandem, offer consistent investment signals, and maximize the value of all resources.

1.4. Approach and structure

By creating the Universal Market Enabling Interface (UMEI), a novel strategy to promote interoperability throughout Europe, the EUniversal project, funded by the European Union, aims to create a universal approach to the use of flexibility by distribution system operators and their interaction with the new flexibility markets.

The UMEI stands for an innovative, agnostic, adaptable, modular, and evolutionary approach that will serve as the foundation for the creation of new innovative services, market solutions, and, most importantly, the implementation of practical mechanisms for active customer participation in the energy transition (such as from consumers, prosumers, and energy communities).

One of the main objectives of the EUniversal project is incentivise flexibility via appropriate market-based mechanisms to solve existing constraints in DSOs grids. The UMEI will be deployed to encourage the supply of flexibility services and to connect distribution system operators' active system management with electricity markets. As elaborated in deliverable 5.1 of the EUniversal project [3], DSOs have access to various alternatives to solve grid problems as also explained in the previous section.

This deliverable provides a deep dive into one of these mechanisms, the dynamic network tariffs. Given the changing context and anticipated changes in grid operation, defined previously, regulators and DSOs within the different EU Member States are reviewing the distribution grid tariff design. This deliverable develops recommendations for a future-proof grid tariff design, given the changing context of the energy system.

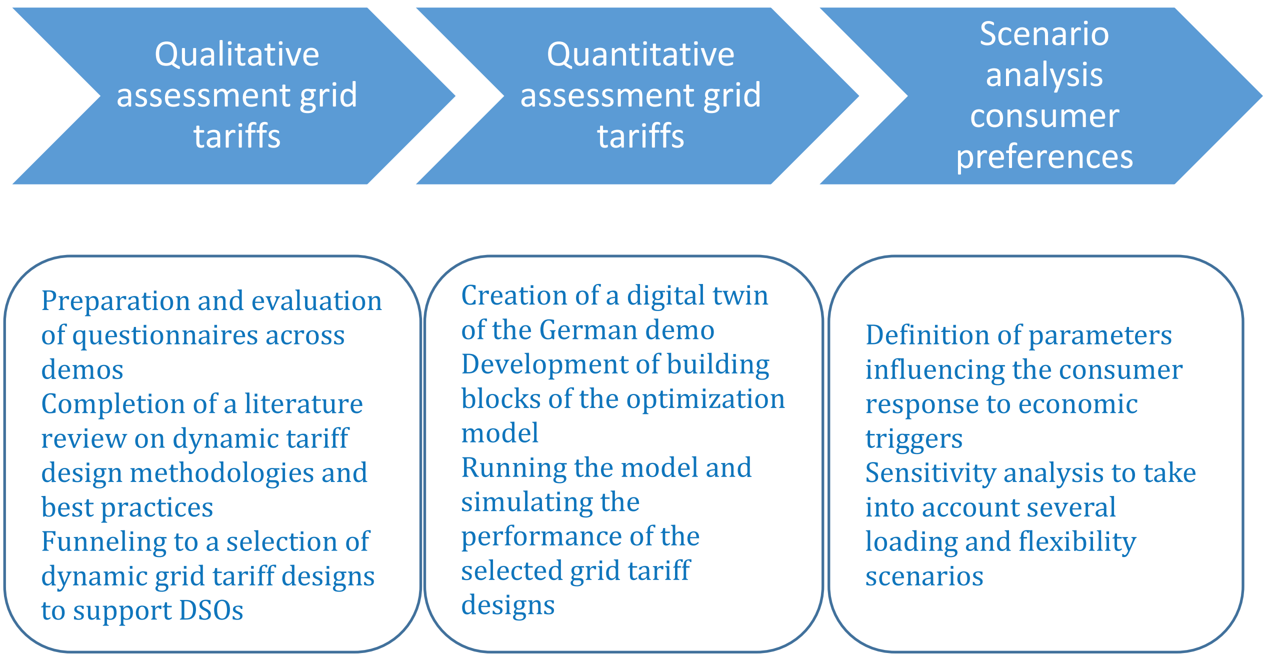


Figure 3: Three-step approach to evaluate alternative dynamic distribution grid tariffs

As visualised in Figure 3, in the first instance, a qualitative assessment of grid tariff designs provides the background that constitutes the base for the further analysis. This qualitative analysis incorporates the conceptual framework of establishing grid tariff designs, shedding light on the different design dimensions, as well as provides a review of dynamic tariff design methodologies and best practices across EU Member States. Particular attention is paid to the Member States represented in the EUniversal project. Via a dedicated questionnaire, insight is gathered on the common practices and anticipated reforms. The results from this questionnaire are complemented with a literature review and market survey of other relevant EU grid tariff practices.

The completion of the qualitative assessments of grid tariff designs leads to an educated, funnelled decision process to define grid tariff designs which can address congestion issues. Subsequently, a simulation environment is developed, representing a digital twin of the German demo within the EUniversal project. This simulation environment is used to assess the impact of different tariff designs on end-consumers on the one hand and on the overall power system on the other hand, assessing the effects of the introduced tariffs on alleviating network congestions and voltage issues.

2 Qualitative assessment grid tariff design

2.1 Dimensions grid tariff design

To determine which tariff designs may address the aforementioned issues, different grid tariff dimensions come into play. A tariff design is shaped by nine factors: grid cost distribution, spatial variability, consumer variability, time variability, tariff driver, symmetry, dynamic element, billing trigger and granularity of measurement. Figure 4depicts those factors.

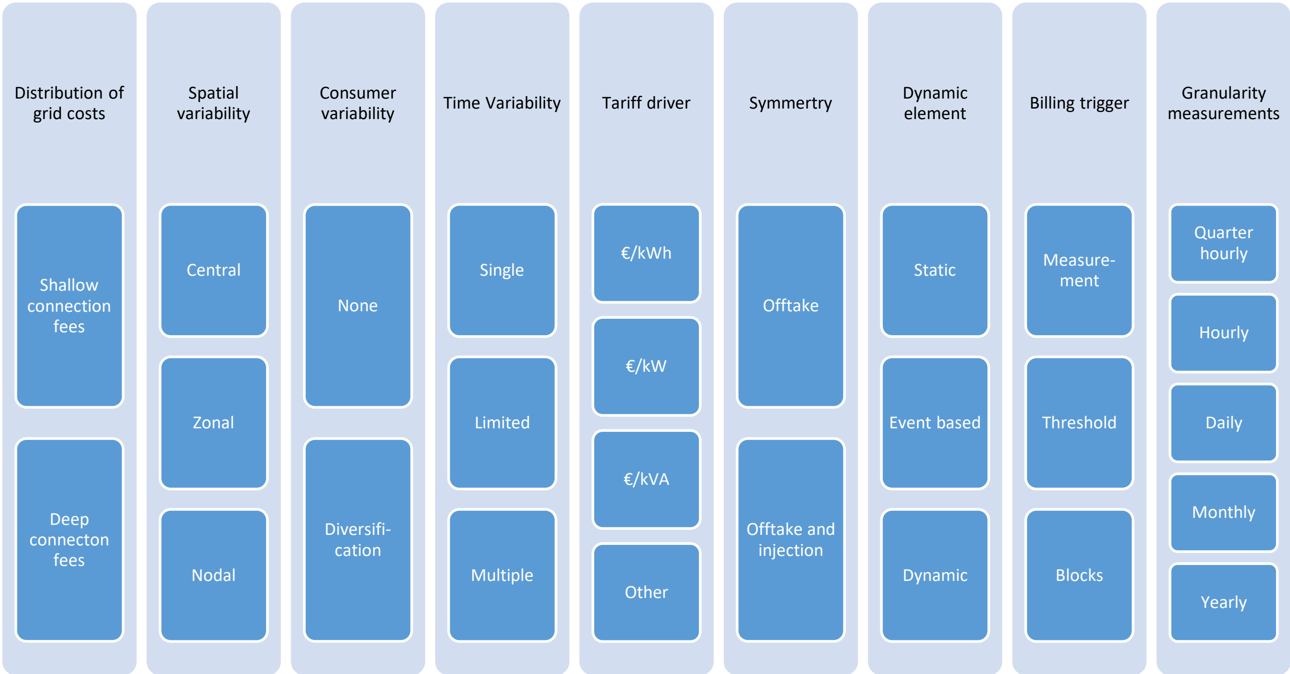


Figure 4: Dimensions of grid tariff designs

2.1.1 Distribution of grid costs

Grid tariffs and the cost of establishing a grid connection cannot be considered independently. The initial network connection and the related connection charges decide how much of the potentially incurred costs will be covered by new customers and how much costs will be socialized. If the connection fee does not cover all network reinforcement expenditures, the remaining costs must be recovered through periodic distribution grid rates. Figure 5 depicts the principle of distribution of the permissible income of distribution system operators, with a distinction made between a '**deep**' and a '**shallow**' determination of the connection tariff. More information on the distinction between deep and shallow connection charges, the advantages and disadvantages of both approaches and the current practices in different EU countries can be found in [3].

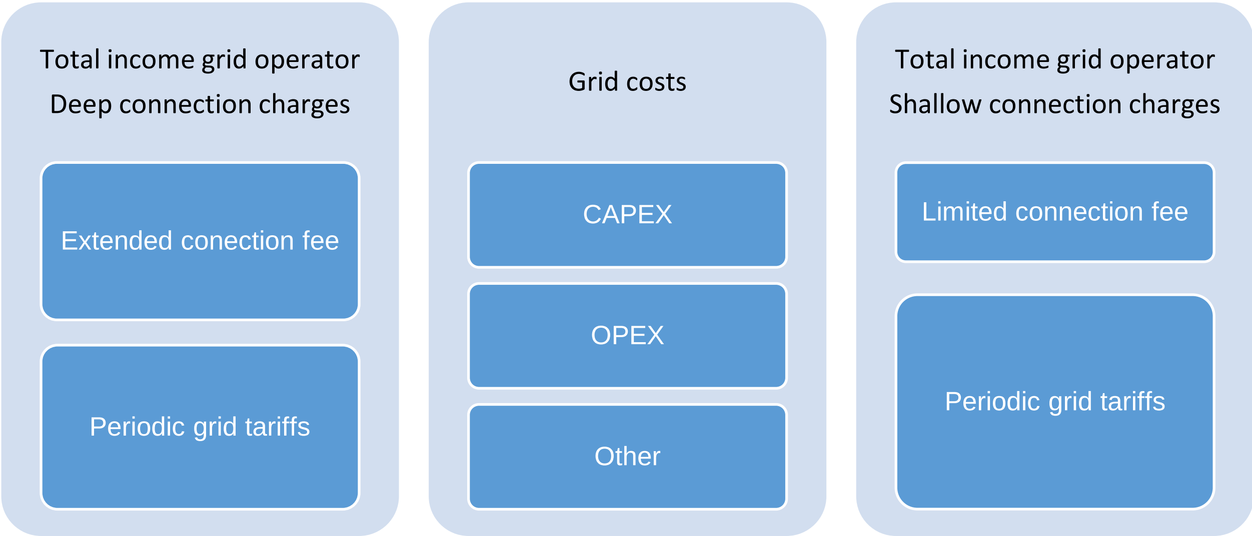


Figure 5: Distribution of grid costs

2.1.2 Spatial variability

The aspect of location specific tariff signals requires specific attention. In particular, there are locational variations in the cost of serving grid users across the distribution and transmission networks. Furthermore, the need to send signals about capacity constraints may differ between areas. The local variation of grid tariffs can, for example, be driven by user density, the distance from generation, the distance from substations and technical characteristics of network assets.

For the characterisation of the geographical differentiation implemented, we consider an adapted approach of the energy pricing mechanisms, which can include network usage charges (to various degrees, depending on the method). Spatial differentiation, in the context of grid tariffs, can be divided into nodal tariffing, zonal tariffing and central tariffing. In **nodal** tariffing, network losses and grid congestions are reflected in the tariffs at each node. **Zonal** tariffing aggregates nodes into zones with uniform pricing. Hence, no distribution grid differentiation can be implemented within a zone, and it entails considering only congestions between the zones. Grid congestions inside a zone are managed by redispatch **Central** tariffing assumes that all grid users are exposed to a uniform tariff. In this context, locational differences (and thus transmission and distribution constraints) are neglected.

2.1.3 Consumer variability

The types of end consumers and consumer-specific tariffs are gaining importance given the increasing level of end-customer involvement and the introduction of collaborative concepts (e.g., energy communities). Grid tariffs can respond to these trends by providing advanced differentiation depending on the consumer type (e.g., large off-take versus low off-take), the anticipated engagement (e.g., flexible grid user versus non-flexible grid user) and the manner of organization (e.g., energy community).

2.1.4 Time variability

Grid tariffs can be fixed without considering time variability. The resulting **'single'** tariff is valid regardless of the timing of consumption (e.g. time of day, season and it being during the week or weekend). Besides single tariffs, tariffs can be determined using a time dimension as a diversifying factor. This time dimension can rely upon **'limited'** variability e.g. common practiced differentiation between peak and off-peak tariffs). Tariff designs can incorporate an increased interpretation of this time granularity and utilize **'multiple'** time periods to define a customized rate height.

Time-varying tariffs can be implemented for both capacity-based and energy-based grid tariffs (see section 2.1.5). TOU tariffs offer grid operators an alternative mechanism for reducing grid costs by encouraging consumers to reduce their energy or capacity usage during periods of high demand.

TOU tariffs can be considered in a static or dynamic manner. Static TOU tariffs refer to tariffs for grid use that are different during predetermined (fixed) periods. A fixed rate must be calculated for each of these tariff periods. An illustration of a static TOU tariff is shown in Figure 6. This figure shows the manner in which a TOU tariff with four distinct tariff blocks (i.e. 04:00 – 10:00, 10:00 – 16:00, 16:00 – 22:00 and 22:00 – 04:00) is applied to an hourly consumption profile of a consumer. In the example, a different rate height is applied to each of the time blocks (represented by different colour groups), which is fixed for the entire year.

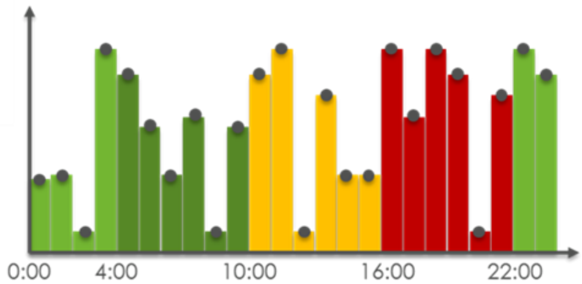
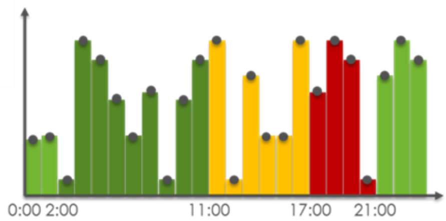


Figure 6: Illustration of static TOU tariff

In the case of dynamic rates, the timing of the time intervals may vary from day to day (or even more often). Alternatively, the rates applicable to the different time intervals (e.g., hourly) may also be dynamic, i.e., changing from one rate period to another. This could lead to the implementation of real-time pricing, such as hourly changing prices, where the hourly rates are calculated dynamically. An illustration of a dynamic TOU tariff is shown in Figure 7. As illustrated on the left side, the previously mentioned tariff blocks from Figure 6 are dynamically adapted. Hence, depending on external signals perceived, like for example grid congestion triggers, the timing of the tariff blocks is shifted in time from one day to another. The red tariff, for example, is no longer valid from 16:00 – 22:00 (as seen in Figure 6) but is applicable from 17:00 – 21:00.

The change in rate intensity is illustrated on the right-hand side. In this interpretation the definition of the time blocks remain the same (compared to Figure 6) but the rate height applicable to each time block is calibrated in a day to day manner, representing an external trigger. For illustrative purposes, to visualise the increase or decrease of the rate height the colour intensity is altered (e.g. in comparison to Figure 6, the time block of 16:00 – 22:00 has become more expensive).

Dynamic TOU tariff (changing time intervals)



Dynamic TOU tariff (changing rate intensity)

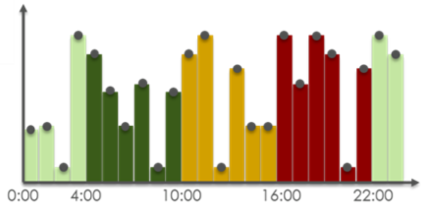


Figure 7: Illustration of dynamic TOU tariff

A number of aspects must be considered when developing time-varying distribution grid tariffs.

- For tariff designs to transmit correct signals, grid congestion must be accurately predictable, ahead of real-time, which is rarely the case today.
- Structural distribution network congestion is likely to compromise service continuity, given the typical configuration of the grid. It could also be a sign of a network that is not properly dimensioned, requiring additional investment to achieve an increased network capacity.
- Addressing a structural network capacity shortfall by systematically shrinking renewable generation (including through tariff signals) is incompatible with the goal of sustainable generation support, which is to maximize renewable production.
- Where grid congestion is present in the electricity system, tariff designs captured far ahead of real time, can be imperfect alternatives to dynamic tariff schedules. It is more complex and less effective to set tariffs too far from the moment of delivery.

2.1.5 Tariff driver

Applying a certain tariff driver is a critical factor for establishing future-proof tariff design variations. The vast majority of tariff designs rely upon (a combination of) a capacity factor and/or a volumetric factor. These factors can be complemented by a fixed charge, based on a multitude of aspects (e.g., connection, number of household members or types of assets). An overview of the possible tariff drivers can be consulted in Table 1.

Table 1: Overview of tariff drivers

Tariff driver	Parameter
Fixed amount	€/connection
Capacity	
Technical	€/kVA connection capacity
Contracted	€/kVA contracted capacity
Measured	€/kW capacity registered
Volumetric	€/kWh

The grid usage can be, to some extent, invoiced using a **fixed amount** per connection point (€/day, €/month, €/year). A fixed tariff driver is a straightforward and reliable approach to bill end-users for grid expenditures made by the DSO. There is, however, no incentive to adjust demand in response to what is desired from a grid operation perspective.

The inclusion of a **capacity-**based tariff driver can be performed by reflecting upon 1) the connection's technical maximum power (kVA), known as connection capacity, 2) the contractually specified access to capacity (kVA), and/or 3) the measured capacity (kW).

For both the grid user and the system operator, fixed or pre-contractual capacity tariffs based on connection capacity or contracted capacity provide the advantages of simplicity, stability, and predictability. Because some grid expenses are set in the short term but are also dependent on long-term capacity to some extent, it may be preferable to recover costs through fixed or pre-contracted capacity tariffs. However, these tariff drivers expressed in kVA, are often based on historical decisions, in the case of connection capacity, and do not reflect the actual usage of the grid.

When using a grid tariff based on the registered peak power, grid operators charge consumers based on the actual (peak) capacity that consumers use. Depending on the time range in which the peak consumption is observed and determined, many design versions can be constructed (i.e., annual, monthly, or daily basis). When it comes to designing tariffs, one of the most crucial decisions to make is how capacity is interpreted. This decision can, among other things, affect the cost distribution across different customer segments.

Volumetric grid tariffs are based on the grid user's real energy usage. This factor, reflecting upon the volumetric energy consumption (and/or injection), can be billed at a fixed rate, as well as on a static or dynamic TOU basis. Volumetric tariffs have advantages in terms of user acceptability since this is a common practice, known by the grid users. However, there are also a few disadvantages. A volumetric tariff driver can leave the system operator with revenue unpredictability. Furthermore, it can promote inefficient grid use (i.e. high capacity - low energy flow), leading to an unnecessarily heavy and expensive grid infrastructure.

2.1.6 Symmetry

A grid tariff design can include parameters reflecting the **offtake and/or the injection** of electricity. An offtake tariff is applied by all Member States (which can be complemented, at instances, by other forms of tariffs, such as injection tariffs, as addressed shortly). However, looking at the exclusive implementation of an offtake tariff can bring significant advantages with respect to the integration of distributed RES, and the induced simplicity of the tariff. Indeed, a single offtake charge can improve the clarity and simplicity of the tariff for the consumer, enabling a better understanding of the tariff, and as a result, a more informed reaction to the tariff. In other words, due to this simplicity, the reaction to offtake tariffs (e.g., through shutting down of appliances) and the consequences of such reactions for the consumer are rendered relatively intuitive, which can enhance the uptake of such tariff-induced load shifting/shaving reactions at the consumer level (in particular, in a manual control environment.

When a network user connected to the distribution grid pays distribution tariffs for injection or the ability to inject, there can be an injection charge. This charge encompasses situations in which only a portion of the distribution costs is levied or only a few network users are impacted. Currently, about a dozen Member States have applied some interpretation of a distribution tariff for injection [2]. An injection charge could stimulate the consumer to increase the level of self-consumption. Furthermore, large volumes of injections could entail voltage issues, a proportionate contribution to the grid costs caused via an injection charge can therefore be defended.

There are also some important nuances and side effects tied to injection charges. An application of an injection charge can influence the roll-out of RES and can create distortions in the national and crossborder wholesale market [2]. Furthermore, the grid costs induced by producers are, to a large extent, recovered through other means (e.g. connection charges) and the grid costs incurred are largely covered by the withdrawal of electricity. Often regulatory prescriptions also do not foresee nor allow the application of injection tariffs. Finally, from a consumer point of view, the application of an injection charge increases the number of tariff triggers and increases complexity to deduct the desired behaviour. For example, in a manual control environment it can become intricate to respond accordingly.

2.1.7 Dynamic element

The extent to which the tariff design develops a link with the registered system peak at the local level is examined in this dimension. In particular, this factor provides the possibility to reflect upon the risk of congestion issues at the electricity grid. It is worth noting that the system peak can be measured at several points throughout the electricity grid (e.g. local feeder, transformer, substation, etc). The stronger the tariff may influence rational network use at the local level, the more the system peak is monitored on a smaller scale, i.e. closer to the effective network user.

Three implementation methods can be considered, i.e. static, event-based or dynamic grid tariffs. **Static grid tariffs** are set in advance and are maintained for a longer duration (e.g. for one year or over the course of the tariff regulation period which is multi-year). Hence, the actual grid state and risk of congestion issues are not reflected in a static grid tariff. We note here that a static tariff does not mean that the tariff rates are constant, but rather that the rates are calculated beforehand (e.g., for each time of use, when considering the temporal dimension) over a period of time., Those rates are not changed over the course of that period.

Event based grid tariffs refer to tariff designs where the charging of grid usage is elevated, by exception, in certain peak periods, reflecting the risk of congestion issues on the grid. These event-based grid tariffs are characterised by their limitedness in occurrence throughout the year, meaning that the elevated charging is not a common practice. In their application, the rates can be calibrated statically (fixed rate heights for certain congestion events) and dynamically (re-calculation of the rate height for each anticipated occurrence of a congestion event).

Dynamic grid tariffs imply that consumers are charged different rates depending on the dynamically computed grid state during each time period., This provides a very close link to the grid state and the risk of congestion in the setup of the tariff rates, as in this design, the rates of the tariff are re-calculated in a dynamic manner based on the dynamically changing grid state. In other words, dynamic grid tariffs allow capturing anticipated congestions in a future time period (the length of which can vary) and reacting to them through adjusting the tariff levels with the goal of preventing or mitigating their occurrence.

2.1.8 Billing trigger

The dimension of the billing trigger refers to the applied factor that causes the rate level to change. A distinction can be made between the three methodologies, illustrated in Figure 8.

The tariff design can rely on **actual measurements,** where the billed costs depend on the changing pace of the relevant measured volumes (e.g. offtake). This implies that every action of the consumer has a 1-on-1 invoice impact. Particularly, every modification of the billed volume taken by the consumer leads to an adapted contribution to the grid costs.

Instead of volume dependent tariff design, a **threshold** can be implemented to define the trigger for the change in rate. In particular, every measured magnitude, which can be both energy or capacity, below the threshold is billed at a certain rate. Crossing the threshold induces a higher tariff rate. The threshold interpretation can be modified by the design decisions made in the other tariff dimensions. For example, the granularity of measurement or the inclusion of TOU triggers can lead to a different understanding of which volumes should be billed at the exceeding tariff rate (e.g. only the volume of that particular quarter for which the threshold is exceeded or the volume for the entire day).

For the consumer, the threshold approach is more easy to understand, facilitating a more intuitive action (e.g., to aim to stay below the threshold). As there is a dual rate interpretation (i.e. below and over the threshold), there are lower incentives for using flexibility, especially when flexibility volumes are not enough to bring down the consumption pattern below the threshold. In particular, the action of the consumer is defined by the 'distance' from the current position towards the threshold. If the consumers' measured volume is below the threshold, there is a lower trigger to alter its behavior.

When the number of thresholds is raised, the tariff design is set in **blocks**. This implies that a combination of multiple thresholds defines the applicable rate height. Due to the increased rate possibilities, the incentives for triggering a consumer action are amplified. Also, this tariff design can be adapted depending on the other features. Combined with other differentiating factors (e.g. time-variation and/or dynamic block definitions), this can be perceived as complex by the consumer. An example of the use of blocks is given in Figure 8, in which the hourly capacity or energy (depending on the tariff driver) would be charged according to one of three prices corresponding to the green (low price), yellow (medium price) and red (highest price) in the figure, depending on the area where the actual measurements fall into.

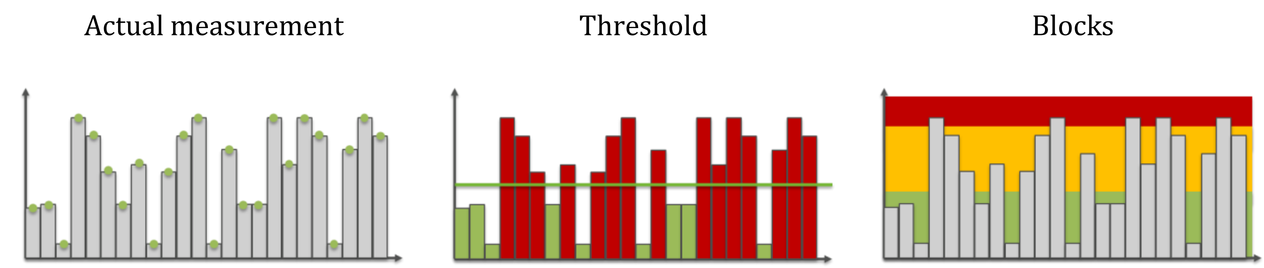


Figure 8: Illustration of billing trigger

2.1.9 Granularity measurements

Within this dimension, a distinction is made given the granularity over which the data is recorded. This can be done on a **quarter-hourly, daily, monthly** or **yearly** basis. This dimension is inextricably linked to the available measuring equipment.

To reflect the capacity usage (both a capacity charge and a volumetric charge with a reflection to capacity), quarter hourly measurements of the actual consumption are advised. Measuring on a more aggregated level (i.e. hourly, daily, …) would significantly reduce the steering effect.

2.2 Common practices

The European practices in the field of grid tariff design were briefly examined in deliverable D1.1 of the EUniversal project in the context of answering the question *"Which regulatory flexibility mechanisms are currently in place and how do they look like?"* [4]. Several countries were examined in deliverable D1.1: Belgium, Germany, Norway, Poland, Portugal, Spain and the UK are included because of their involvement in the EUniversal project. France and the Netherlands were covered as important developments on new network users, impact studies and regulations are ongoing in these countries.

In the light of this deliverable, we will provide a deep dive into the topic of dynamic grid tariff designs and complement the aforementioned list of countries with: Austria, Northern Ireland and Denmark. The information included in this benchmark comes from questionnaires performed within the EUniversal project, complemented with desk research. More details are given for the grid tariff design in Germany, as the quantitative analysis presented in Chapter 3will be done for a scenario based on the German EUniversal demonstrator.

Following the deep dive into German grid tariff designs, a review of EU practices is performed. Attention is paid to EU countries who finalised a redesign of grid tariffs or are in the midst of reformation.

2.2.1 Grid tariffs in Germany

The German distribution grid transmits power at three voltage levels: high , medium and low [5]. The high voltage grid serves primarily population centres (via transformer substations) and energy-intensive industries connecting at a voltage range of 60 kV up to 220 kV. The medium voltage grid provides electricity service to regional substations and large consumers, e.g., factories or hospitals at a voltage range of 6-60 kV. The low voltage grid serves households and small consumers connecting at 230 V or 400 V.

German authorities have decided to implement smart meter roll-out until 2032. Less than 5% of residential customers are equipped with smart meters [6]. That is to say that the smart meter infrastructure is not wide-spread at low-voltage level. For now, the German Energy Industry Act requires that customers with a yearly consumption of over 6.000 kWh are provided with smart measurement systems (when technically possible). The requirement also applies to generators with an installed capacity above 7 kW. However, these requirements leave the majority of German households unaffected today since, most households have a lower yearly consumption. The lack of sufficiently granular metering equipment at the household level is currently a barrier for implementing more cost-reflective tariff designs.

Regulated budget and cascading

The first step in the procedure to calculate grid tariffs is the determination of the **regulated budget**. The regulated budget in Germany is established by the regulator, who is responsible for determining the calculation method [7].

A core element of the incentive regulation is a regulatory period of five years. The Bundesnetzagentur (regulatory authority) determines in advance the maximum revenue the network operator may receive on a year to year basis during these five years. This requires extensive data collection and assessment to determine the costs of network operation. The audited costs for the operation of the network, as well as an efficiency benchmarking of network operators, and quality elements for the security of supply provide the basis for determining the allowed revenues. The operator can freely employ and invest this predetermined revenue amount (budgetary approach).

For the duration of the regulatory period, a network operator's actual costs and revenues are decoupled. By setting a fixed amount of revenue, the network operator has an incentive to increase productivity and lower costs to increase its potential profits or reduce possible losses. If the network operator manages to lower its costs under the set amount of revenue, it can keep the additional profit during the regulatory period as a bonus for especially cost-effective management.

A second step in the procedure to calculate grid tariffs is the allocation of the regulated budget to the different groups of grid users (e.g. depending on the voltage level), the so-called **cascading principle**. The methodology applied to perform the cascading of the regulated budget is determined by the regulator.

The procedure for determining the charges is governed by the StromNEV [8]. The calculation is based on cost element, cost center and cost unit accounting.

- Cost element accounting (§§ 4-11 StromNEV): The costs incurred within the period under consideration are allocated to the individual cost elements. A distinction is made between costs equal to expenses and imputed costs.
- Cost center accounting (§§ 12-14 StromNEV): The cost elements are assigned to the place where they are incurred. Direct costs are allocated directly and overhead costs by means of a distribution key.
- Cost unit accounting (§§ 15-21 StromNEV): After the costs have been allocated to the cost centers (grid and transformer levels), the grid charges are calculated as part of cost unit accounting, which determines the network charges. The grid charges are determined top-down for each individual network or transformer level.
  First, the specific annual costs in €/kW of the highest operated grid or transformer level are determined. They result from the division of the total costs of the level and the simultaneous annual maximum load of the level. The simultaneous annual peak load is seen as the major cost driver. Then, these are transformed into four charge items using the simultaneity function.
  In the next step, the total costs of the level are reduced by the direct network charge revenues of the level. The remaining cost amount of the level is passed on to the downstream grid or transformer level. The costs of the downstream network or transformer level thus consist of the original costs of this level and the costs passed on. This process is repeated in each grid and transformer level until the costs of the grid are completely covered by the charges of the lowest operated grid or transformer level.

Current grid tariff design

The grid tariff for residential grid users consists of a fixed term and a volumetric term (i.e. €/KWh). The fixed fee is less than 30% of the total network charge for the average customer. For most residential grid users, a flat rate is applied to the volumetric charge. Time-differentiated day/night tariffs have been used in the past by DSOs to charge for the consumption of residential grid users (i.e., applied to the volumetric term). This type of tariffs, however, are the exception rather than the rule. They are not much used today. In addition, it is worth noting that the decision to include time-differentiated tariffs is at the discretion of each DSO. The tariff drivers are set on a yearly basis and published by the system operator to enhance transparency. Pursuant to §19 of the StromNEV [8], certain end-consumers have the option of receiving lower individual network charges from the local system operator. Operators of electricity distribution networks shall charge a reduced network charge to those suppliers and final consumers in the low-voltage range with whom they have concluded network use contracts if, in return, the network-serving control of controllable consumption devices that have a separate metering point is agreed with them (§14a EnWG) [9].

Reformations

Reformation of grid tariffs has been studied in Germany [10]. Time-varying network tariffs, combined with intelligent energy management of consumers with flexible assets were considered in a pilot operated by Mitnetz Strom. In the implementation of this pilot, the network operator transmits time-variable network tariffs and available network capacities (the capacity the DSO reserves for every grid user) via interfaces. The energy management system performs a fully automatic optimization considering the needs of the consumer. The main advantage of this method is not requiring a direct control for congestion management by the network operator.

The main lessons learned from the study are:

- The concept of time-variable network tariffs in combination with a reservation system of the system operator represents an easy-to-implement and effective means to support the success of the energy transition in the distribution network.
- The technical feasibility of the concept was demonstrated in pilot applications.
- The developed method, when adequately implemented, can offer the potential to avoid the need for direct control by system operator.
- Change in regulation is required for implementation.

After the successful completion of the first pilot project, Mitnetz Strom is planning the timely further development beyond its network area. The factual discussion at federal level and in the respective state's political context is required to support and further promote the concept of time-variable network tariffs.

2.2.2 Grid tariffs in other European countries

In the majority of EU countries, the grid tariff design is primarily based on a volumetric term (kWh), often accompanied by a fixed term and a power term (kW or subscribed connection capacity). According to the ACER report on grid tariffs in Europe, six European countries attributed a larger weight to capacity charges (i.e. CZ, ES, IT, NL, PT, SK) [2].

In **Belgium**, the responsibility of the distribution tariff design is assigned to the regional regulatory entities (i.e. VREG for Flanders, BRUGEL for Brussels Capital Region and CWaPE for Wallonia). Until recently, all regions predominantly depended on a volumetric term in the distribution grid tariff.

In 2018, a study was carried out on the initiative of BRUGEL to document the establishment of the 2020-2024 tariff methodology [11]. Particular attention was paid on the implementation of capacity pricing in the Brussels Region. The study concluded that the implementation of a capacity-based tariff structure should make it possible to achieve the energy transition at the lowest cost, in particular by greatly reducing the need to reinforce the distribution network by 2030.

Consequently, the tariff methodology for the regulation period 2020-2024 in the Brussels Capital Region foresees a capacity charge in addition to a volumetric charge. Low voltage consumers equipped with a digital meter are charged for the actual usage of capacity (€/kW/month), complemented with a volumetric charge. Low voltage consumers without peak measurement due to the lack of a smart meter, are billed based on the connection capacity (€/year). For these consumers, a threshold is set at 13kVA, where consumers with a connection capacity below this threshold are billed significantly less. This latter group of consumers is also exposed to volumetric charges.

In the context of a new clearing house and data platform (called Atrias), BRUGEL is examining the introduction of time differentiation in the reformed tariff design. This exercise should be finalised in function of the new tariff methodology for the next regulation period starting from 2025.

In 2020, the Flemish regulator (VREG) published the electricity and natural gas distribution tariff methodology for the regulation period 2021-2024, containing a significant reformation of the tariff structure starting from January 1, 2022 [12]. The timing was later postponed to July 1, 2022. In short, the redesign of the tariff structure presents a significant shift from a volumetric tariff term to capacity-based components (in kW). The Flemish regulator claims that network expenses are primarily driven by network capacity. Thus, capacity-based tariffs more properly reflect the generation of costs than volumetric tariffs. Capacity-based tariffs can encourage efficient grid use, such as minimizing peak loads that may necessitate grid expansion.

In detail, the new grid tariff consists of both a capacity and a volumetric signal, visualised in Figure 9. The capacity signal is composed of a €/kW charge which is invoiced on the averaged 12-month peak measurements. In this manner a single high peak demand during a certain month only counts for 1/12th in the invoice but is carried for 12 months. To guarantee a fair contribution from all grid users, a minimal capacity volume of 2,5kW per month is assumed. Hence, if the capacity peak during a month does not exceed the 2,5 kW threshold this minimal capacity is charged to the grid user.

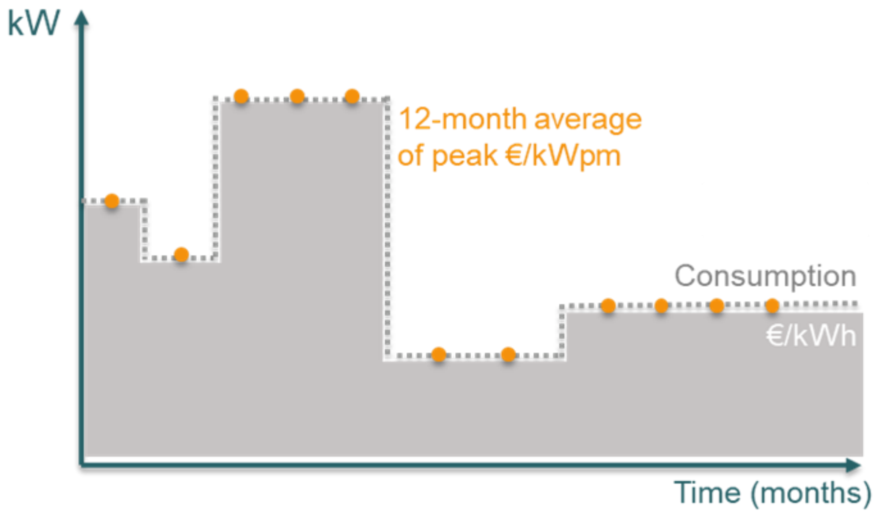


Figure 9: Illustration of reformed grid tariff in Flanders

The volumetric charge is expressed as a €/kWh charge for every unit of energy consumed. The volumetric charge is considered, in combination with the capacity signal, in order to maintain an incentive towards a rational use of energy. Furthermore, grid users understand the manner in which the grid costs are invoiced since they are used to this in the current grid tariff design. Thus, the adaptation of the new grid tariff is facilitated. The grid costs within this tariff design are distributed via a ratio of 80% to the capacity charge and 20% to the volumetric charge. As part of a follow-up analysis, the integration of TOU signals and/or more dynamic interpretation of the reformed grid tariff design will be examined by the Flemish regulator.

As for the Walloon region, the current network tariffs (which are still volumetric based tariffs) are valid until 2023. No specific measures are currently envisioned for the next period (2024-2028).

In **Norway**, the current regulation gives DSOs a large degree of freedom regarding how to design tariffs. In general, tariffs for households and small commercial customers mainly consist of a fixed- (NOK[1]/year) and an energy charge (NOK/kWh). Customers with an installed capacity exceeding a set limit usually have a capacity charge (NOK/kW) in addition to the fixed and energy charge. The smart meter roll-out was completed at the beginning of 2019 and all smart meters provide quarter-hourly measurements. This facilitates the introduction of adapted grid tariff designs.

The Norwegian energy regulatory authority, NVE-RME, suggested a transition to a tariff design based on precontracted capacity in 2017. In particular, it was suggested to rely upon a subscribed level of power consumption and a per-kWh overspending component during hours when the consumer exceeded the subscription threshold. However, stakeholders were sceptical, believing that such a

[1] Norwegian krone

tariff design would be too complicated for customers to comprehend and difficult to implement. DSOs have expressed a desire to have the ability to incorporate alternative interpretations, such as metered capacity and time-of-use.

Currently, the grid tariff is in a transition phase and RME presented a revised proposition in 2022. In the current proposition, the grid tariff is expected to introduce a measured capacity approach (€/kW), a subscribed capacity (€/kW) or a fuse size approach (€/kVA) [13]. The capacity charge can have a supplement when the available capacity is expected to be constrained, to allow for critical peak pricing or time-of-use pricing. Changes will be phased in gradually. The regulator RME foresees 5 years for the changes to be incorporated.

For **Polish** households and small consumers at LV level, the distribution network tariff consists of a fixed and volumetric component. Larger consumers at low voltage level and grid users at medium and high voltage levels are charged a volumetric and monthly capacity-based tariff. A temporal distinction between peak and off-peak is implemented for all grid users. MV and HV grid users can extend this with an additional time block. A reform to more dynamic tariffs is foreseen as part of Poland's Electromobility Development Plan [14], [15].

Low voltage network users in **Portugal** are charged a tariff with volumetric and contracted power components to recuperate the use-of-system network charges. For higher voltage levels, the power term is based on both contracted capacity and peak capacity consumption [16]. LV consumers are exposed to three time differentiating tariff periods. For MV and HV consumers there is an additional fourth tariff block defined. These consumers are exposed to seasonal diversifying tariffs. Two seasons are present in the energy tariff component of MV and HV customers in Portugal.

In **Spain**, capacity and energy tariffs are used. The new reformed grid tariff design from 2021 consists of an energy charge, differentiating between 3 time periods (i.e. peak, medium and off-peak), and a capacity charge, differentiating between 2 time periods (i.e. peak and off-peak), illustrated in Figure 10.

Additionally, for non-residential consumers, there is a penalty when the actual capacity usage exceeds the contracted power. Furthermore, for certain applications and technologies, specific grid tariffs or certain exemptions are applicable (e.g. public EV charging and energy sharing in renewable energy communities).

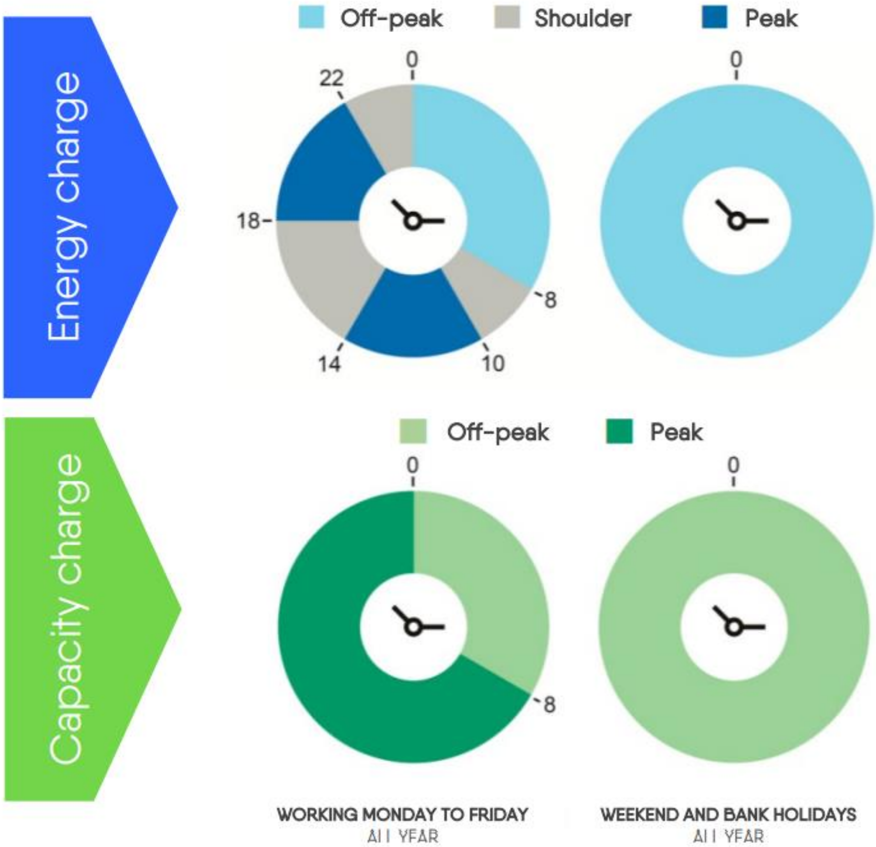


Figure 10: Spanish grid tariff design [17]

Following the new grid tariff design, grid users are advised to use more capacity (e.g. in function of EV charging) during off-peak hours.

The **UK** grid tariff for residential grid users consists of fixed and volumetric terms. Grid users connected to extra high-voltage networks are subjected to nodal pricing of grid costs. Note that the office of gas and electricity markets (Ofgem) differentiates between two types of charges for distribution grid tariffs: residual charges and forward-looking charges. The former refers to fixed network costs (sunk costs). The latter is expected to reflect operational costs while giving signals for efficient network use to grid users. Residual charges may be recovered via the fixed term, while the volumetric and the capacity terms (if implemented in the future) could be used as forward-looking charges [18]. The UK plans to have temporal granularity in the capacity component of future tariffs.

France has a time-of-use differentiation implemented in volumetric and capacity terms for customers who subscribe to a capacity above 36kW (i.e. over 10 million LV grid users). In particular, the capacity component of the tariff changes along 2 or 3 daily periods and 2 seasons. The application to small customers was discussed in the last tariff consultations (2019- 2020) but postponed for further consideration. Currently, residential grid users can be invoiced based on a single tariff, a day/night tariff or a tariff differentiated by four periods for the volumetric term [19].

In the implementation of the time of use tariff, to prevent a simultaneous reaction to a changing tariff period, different time of use windows are applied for each MV circuit. French retailers are free to set the time differentiation for the electricity offering, which can be based on the same time differentiation as the grid tariff or a different one. However, most retailers replicate the time windows of the grid tariff allocated to the client by the DSO.

In the **Netherlands**, grid users are allocated to predefined categories, the so-called capacity bands, based on their connection capacity. The grid tariff for residential grid users is largely based on a capacity charge (i.e. technical connection capacity, in €/kW) which was introduced in 2009. The current tariff structure presents a static relationship with the system local peak. In particular, the grid tariff is dependent on the connection capacity and not the manner in which capacity is actually used. Furthermore, the rate height of the capacity bands is not dependent on the system peak, hence no dynamic relationship is established in the tariff design. The grid tariff does not change throughout the year.

A reformation of the grid tariff is expected for 2023-2025 and will aim to increase cost reflectivity. The revision might include the following changes:

- Shift to a capacity-based tariff that reflects actual capacity use rather than the technical connection capacity.
- Introduction of time-varying tariffs, based on the experiences with the current capacity-based tariff.

In **Austria,** the grid tariff implemented consists of a mix of volumetric, capacity and fixed terms. The tariff distinguishes between three types of residential grid users: users with load profile metering, users without load profile metering and interruptible users with load profile metering. The tariff varies during the day (peak/off-peak) and between seasons (summer/winter). In general, time-differentiated charges are mainly applied to users with load metering and interruptible contracts.

A new tariff design is expected to be introduced by 2024, just after completing the smart meter roll-out. In this new reform, the NRA is planning to introduce various changes:

- Simplification of network charges by implementing one connection charge (merging admission and provision charges into one) and dropping the metering charge (which refers to measuring load and peak)
- Introduce a capacity charge for all residential consumers
- Eliminate the annual flat rate for reasons of cost reflectivity (i.e. a fixed fee provides no signal)

The NRA is working on a modernization of the interruptible tariff, which expects to give grid operators the possibility to use flexibility from interruptible consumers. Currently, interruptible tariffs in Austria diverge from the common concept. Consumers with certain predefined flexibility assets and under contractual agreement within this tariff can get interrupted at a specific hour during the evening. This hour is predefined limiting potential uses of flexibility. In the future, the new interruptible mechanism will allow the grid operator to use flexibility when it is really needed by allowing for a more dynamic allocation of curtailment periods. This mechanism is open to residential grid users.

In **Northern Ireland**, the distribution tariffs are primarily volume-based with approximately 74% of distribution revenue recovered from unit (kWh based) charges [20]. The Utility Regulator is undertaking a review process of the distribution tariffs charged by NIE Networks [21]. In the call for evidence, published in June 2021, the regulator queried views on five key topics: 1) identification of the drivers of change (e.g. DER and EVs), 2) appropriate tariff reform options, 3) approaches to managing the transition, 4) consumer engagement and 5) other challenges and risk specific for Northern Ireland. In the received responses, a support for the transition of distribution tariffs away from volumetric kWh based charges to peak demand charges can be deducted. The Utility Regulator is considering the different views received and translating these into action points.

The tariffs in **Denmark** are mostly volumetric (energy-based). For an average household (approximately 4 MWh annual consumption) the volumetric term accounts for ¾ of the grid tariff. The lack of a capacity term in combination with the current distribution of costs reduces the incentive given to consumers to use flexibility during peak hours (when congestions are observed in the grid). This situation is acknowledged by the Danish Utility Regulator (DUR) and the Danish Energy Agency.

The Danish energy agency and the Danish transmission system operator for electricity and natural gas, Energinet, are working together to develop a new tariff design that includes more time-differentiated tariffs on both the DSO and TSO levels, as well as a fixed power-based component at higher voltage levels. The sector has been working on a new tariff design (Tarif model 3.0) [22].

In Tariff Model 3.0, time differentiation of the variable kWh tariffs is the starting point for all customer categories. The idea is that the tariff signals must reflect that it is precisely the sum of many consumers' consumption during the busiest hours that determines the electricity network's need for capacity and thus the network's costs. Furthermore, a power payment is introduced for larger customers (B-high, A-low and A-high customers).

The formal proposition is provided to DUR. DUR must then approve or decline the new tariff approach. Hence, a change in the tariff design is expected soon.

2.3 Selection of grid tariff designs

A key property of a grid tariff is its ability to incentivise action through a price signal. However, the design should also provide opportunities to grid users to adapt their behaviour in terms of their needs and willingness to pay for the network service. A fixed pricing structure, for example, does not provide incentives to shift consumption. This entails missing the opportunity for grid users to benefit from their flexibility in terms of reduction in their electricity bills, and for system operators to benefit from that flexibility in terms of efficient network use and potentially differed investments. Hence, tariff design needs to evolve.

A future-oriented distribution grid tariff design needs to account for the challenges generated by new energy solutions such as, amongst others, distributed generation (DG), demand response (DR), electrification of transportation with electric vehicles (EV), storage, and energy efficiency approaches. At the same time, it must be comprehendible for grid users if we want them to be able to deduct the best behaviour and act accordingly. In addition, it must allow DSOs to recover the cost of providing network services while respecting overall design principles.

As shown in Section 2.1, different dimensions define the tariff design. Historically, not much variation exists in tariff design, and the vast majority of European grid tariffs rely predominantly on a static, volumetric term (see section 2.2). Furthermore, dimensions such as time variability, spatial variability and dynamic triggers are not yet widely implemented. Relying heavily on a static volumetric term, without any time variation or dynamics, to recover network costs is not a sound strategy in the long term. First, the signals sent to consumers may not be adequate to motivate efficient grid utilization. Second, while the volumetric term may be sufficient to recover short-term network costs, it cannot fully address the main cost driver for DSOs. Indeed, in the long-term, network costs largely depend on peak power (availability and utilization of network capacity).

Hence, from a **distribution grid point of view**, in order to reflect the grid costs and the grid state in the tariff design, the inclusion of a power term in the tariff design is recommended. As highlighted in the European benchmark, Section 2.2, the capacity term is not used in most surveyed countries but its use is being considered by NRAs and DSOs.

In addition to the availability and utilization of network capacity, also the simultaneity of this peak power with the system peak is a driver of grid costs and an indicator of potential network congestions. This is illustrated in Figure 11. In particular, it is not so much the individual peak power that drives the risk of congestion but rather the coincidence with the aggregate of the individual peak demands or the system peak.

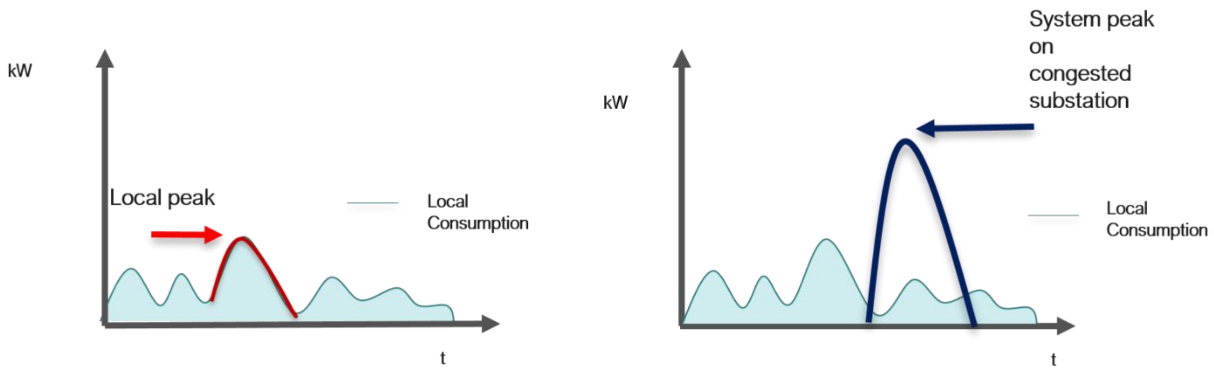


Figure 11: Local (left) versus system (right) peak power

From a **TSO point of view**, in the specific case of Germany, grid congestions are mainly characterised by a high infeed of renewable production (particularly by wind). In contrast to the distribution grid level (where grid costs are driven by a need for capacity), the usage of grid capacity might not be the best-suited indicator for congestions at higher voltage levels. In particular, the longer the distance to the grid user (i.e. more grid infrastructure is used to transport and distribute the electricity) the less capacity matters, hence volumetric signals could be better suited. This is due to the fact that congestion induced by RES-production connected to the higher voltage levels could be mitigated (by increasing the consumption for example) by a large number of grid users connected to the underlying grid infrastructure. Thus, depending on the relevant characteristics of the grid infrastructure from source to consumer and the relevant congestion risk for the different grid components consumers' flexibility can be activated.

2.3.1 Evaluation of distribution grid tariff dimensions

Thus, in order to design grid tariffs which serve the objective of congestion management at the distribution level, two key aspects are particularly relevant, i.e. the reflection of capacity (contained in the **tariff driver** dimension) and the reflection to the system peak (contained in the **dynamic element** dimension).

Considering the dimension of '**dynamic element**', the reflection to the system peak or the grid state can be static (in which case, the tariff rates do not dynamically change based on the dynamically changing grid state), event based (in which tariff rates are adapted based on anticipated occurrence of peak-events) or dynamic (in which the tariff rates are dynamically adapted to mirror the state of operation of the grid). While the event-based and dynamic interpretation have the potential to mitigate grid congestions since a reflection is made to the grid state, this can potentially be less apparent for the static interpretation[2]. In order to incorporate the grid state in a static or fixed tariff design, time differentiation is required. In this context, extensive data analysis of historical behaviour and grid analysis provides the direction points to diversify the static tariff. More specifically, insight into the appearance of a system peak during the day/week/month/etc. drives the definition of tariff blocks in time (e.g., pricing risky time slots at a more expensive rate). This link between the static interpretation and the **time variability** is displayed in Figure 12.

Due to the construction of the general project objective, the characteristics of the German EUniversal demo and other assumptions considered, some design choices have already been made for certain tariff dimensions. These dimensions are defined ex-ante.

This is the case for the '**distribution of grid costs**'. The choice of the initial network connection and the associated connection costs determine how much of the possible costs to be incurred will be covered by the new customers and which share will be socialized. If the connection cost does not cover part of the necessary network reinforcement costs, these costs must be recovered through the periodic distribution grid tariffs. Within this study, the interpretation of grid costs is considered unchanged from current practices and remains a shallow fixing of connection fees.

Furthermore, due to the size of the German demo, no **consumer varying** tariff incentives are considered. There are diversifying characteristics assigned to the consumers, differentiating for example between flexible and non-flexible consumers, but this has no impact on the tariff signals received.

[2] We note that static tariffs, when based on accurate predictions of future loads, can have the potential of also mitigating anticipated grid tariffs, as will be shown in Section 3.2. However, as the improvement in predictions by virtue of approaching real-time operation is not taken into account in the static tariff designs (as would be the case in dynamic tariffs) this exposes static tariff designs to possible large forecast errors, which can provide an inaccurate foresight of the grid operation, and hence, an inaccurate design of the tariff's temporal differentiation and defined rates. Hence, forecast errors can have a direct impact on the performance of static tariffs and their ability of alleviating congestions

The **symmetry** dimension refers to the implementation of injection tariffs in the overall grid tariff design. The inclusion of an injection component into the grid tariff design for LV consumers receives less regulatory support as it would influence the roll out of RES. Moreover, this increases the number of tariff triggers and increases complexity, making the tariff design more complex to interpret by the consumer and less intuitive to drive the desired behaviour. Hence, the analysis focusses on the offtake side.

The **granularity** dimension refers to the level of detail in which the data is recorded. This can be done on a quarter-hourly, daily, monthly or yearly basis. This dimension is strongly related to the available measuring installation. In order to reflect upon the grid usage (both in capacity terms as in volumetric terms), quarter-hourly measurements of the actual consumer behaviour are advised. Measuring on a more aggregated level (i.e. hourly, daily, …) would mute the steering effect.

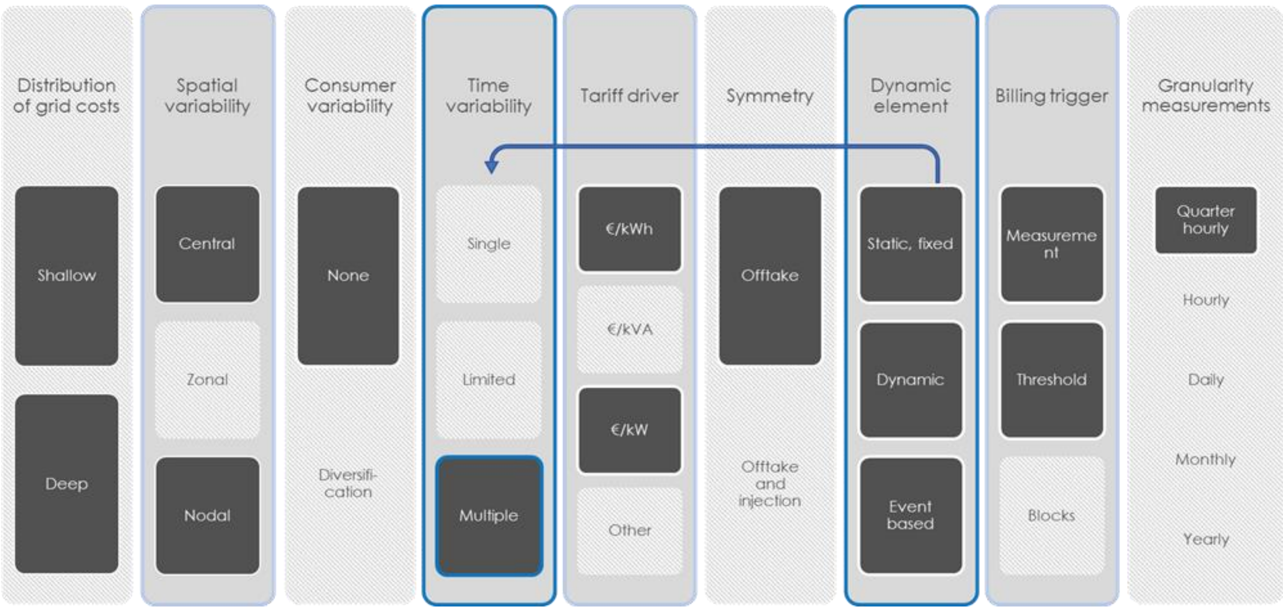


Figure 12: Interpretation of the tariff dimensions in function of mitigating grid congestion

The remaining dimensions, i.e. **spatial variability, tariff driver, and billing trigger** are still to be decided. Certain design choices entail a specific interpretation of some dimensions while other design choices leave more room for flexibility. The steps taken in the design process of these remaining dimensions are displayed in Figure 13 and are elaborated in more detail in the next sections. Subsequently, the resulting grid tariff designs are described.

Static time based

Starting with the static interpretation of a distribution grid tariff, illustrated as the first building block in Figure 13, it is assumed that the risk of grid congestion is considered in the definition of different time blocks. In particular, occurrences of grid congestion throughout the year are analysed and used to draw generic conclusions on the statistical probability of grid congestion for different time definitions (e.g. seasonal effects, week/weekend effects and time of day effects). Hence, this assumes a data interpretation layer and some degree of averaging risk of grid congestion. As the averaged behaviour and risk of congestion are not different from one node to another, a spatial variation in the static tariff design does not add any value. Hence, a central approach is considered.

The averaged interpretation of grid congestion may result in insufficient identification of certain individual risks of congestion. Hence, it is recommended to apply a capacity charge as the main tariff driver in order to provide a local incentive to the consumer to consider the individual capacity demand. In this manner, the consumer is motivated to limit the individual peak power and consequently reducing the risk and severity of a coinciding system peak.

For the final tariff dimension, the use of actual measurements is chosen instead of a threshold since the latter would induce a higher level of complexity, making the tariff design less intuitive for the consumer to act upon.

Event-based

The second interpretation considers the translation of the risk of congestion into a 'peak event'. In the tariff design a reflection is made to the grid state, and when the grid is anticipated to be at a congested state, a peak price is applied. Compared to the static interpretation, where the risk of congestion is considered on a yearly basis, the timing of forecasting in this interpretation is much more granular and closer to the actual delivery of electricity. In order to accurately define if a peak event is triggered, a day-ahead classification of the grid congestion risk is required. Due to the higher granularity and the fact that the potential congestion risks are not averaged over a longer period, the risk estimate can change from one feeder to another (i.e. a day with a peak event at one feeder does not necessarily entail a peak event at another feeder). Thus, to avoid that all grid users across all the different feeders are unnecessarily impacted by one peak event, a nodal differentiation is recommended, which in the context of this study refers to the feeder-level.

The identified peak events, which define the tariff design, are triggered by a synchronous demand for peak power by the connected grid users. Consequently, a capacity-driven tariff design, expressed in a €/kW tariff, is advised to trigger an adequate response from the consumers.

Finally, following the same reasoning as with the static interpretation, the actual measurements are used as the billing trigger.

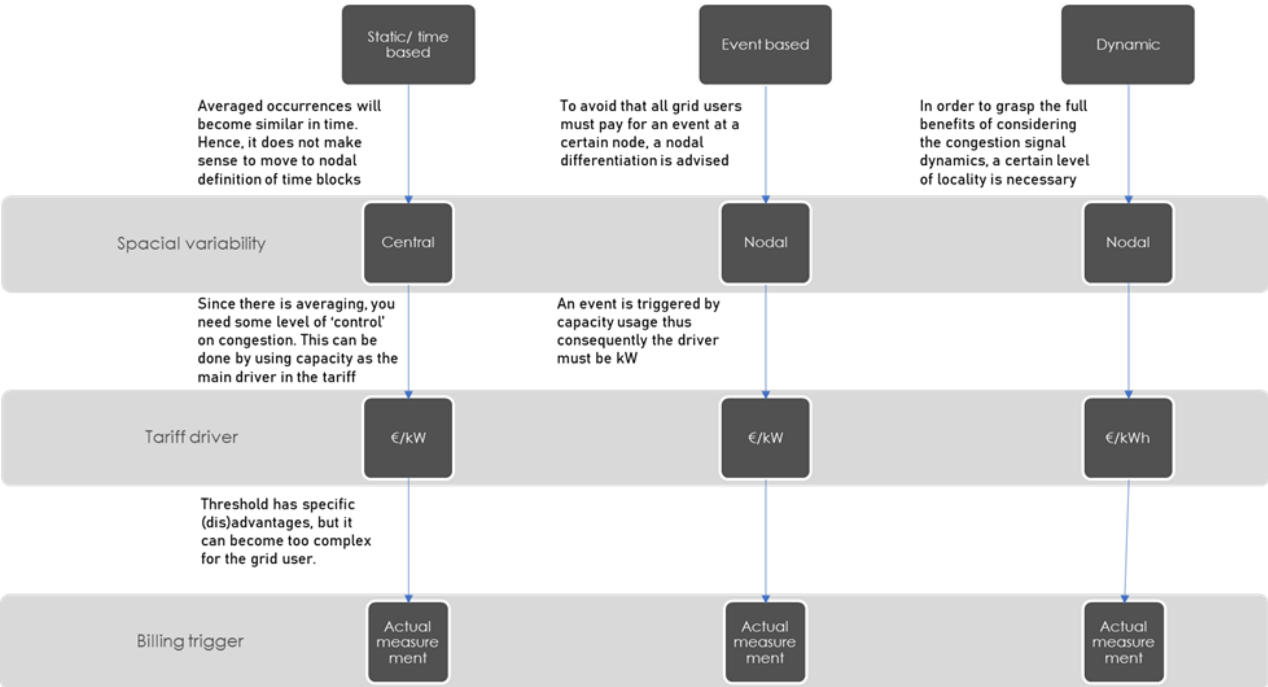


Figure 13: Design choices and selection grid tariffs

Dynamic

The last building block, denoting the dynamic interpretation of the grid state, refers to the intensive and automatic link between the risk level of grid congestion and the rate level of the tariff, making the distribution tariff increasingly expensive as the risk of grid congestion increases. It is this dynamic link between the grid state and the tariff rate which can enable this tariff design to mitigate dynamically changing congestion conditions. In order to grasp the full benefits, generalisations on a central grid level (i.e. no spatial variability is implemented) are discouraged. A nodal interpretation, where the grid state is dynamically defined for each feeder is more appropriate.

The close link between the grid state and the tariff rate allows for both the volumetric and the capacity charge to be possible implementations. In particular, it is assumed that the high granularity in rate height provides sufficient directions to consumers to adapt their behaviour in function of the risk of grid congestion, regardless of the tariff driver applied. In practice, there is no differentiation between the kW and kWh tariff driver given the hourly dimension of the dynamic tariff design. Hence, for the further analysis, a volumetric tariff driver is assumed.

For this dynamic volumetric grid tariff design, the actual measurements are used as the billing trigger.

2.3.2 Resulting distribution grid tariff designs

2.3.2.1 Static grid tariff design

The static grid tariff design (i.e. for further reference **tariff design 1**) is characterized by the design choices made and explained in the previous section. An important feature of the static tariff design is the choice of the static time-of-use periods in order to reflect the grid state. For this exercise, historical data analysis is performed on aggregated demand and injection flows in order to assess the potential risk of congestion throughout the year. Furthermore, it is evaluated if this risk can be generalized for certain periods in the year (e.g. seasons or months) or time slots during the day (e.g. hourly distinctions).

This data analysis, applied to the different consumers within the German demo, resulted in the following interpretation of time differentiation:

- There is a higher correlation of the identified aggregated system peaks for the months of October up to and including March. We see the same correlation for the months of April up to and including September. Hence, from a 'system peak'-point of view, which is considered a factor to influence the risk of congestion, a distinction is made between the winter-months and summer-months.
- Looking at the average behaviour on a weekly basis, no particular distinction can be made between weekdays and weekend days. Hence, this is not maintained as a diversifying factor in the static tariff design.
- Analysis of the average day profile in the winter months enabled to deduct three distinct time blocks during the day. A particular high peak demand (on an aggregated level) could be derived during the timeslot 17:00h – 1:59h. This average peak demand was more moderate during the time slot between 7:00h and 16:59h. A low system peak demand was visible during the hours 2:00h until 6:59h[3].
- For the typical average day in summer months, the variation of the day profile resulted in the definition of two time blocks, differentiating between a moderate and low peak demand. No

[3] Note that the average day profile between 02:00 to 03:00 shows an average peak in Figure 14, but this is to a certain extend due to the characteristics of certain individual profiles (e.g. accumulation heating). Furthermore, the TOU differentiation of this one-hour block will make the time periods difficult to track and complicates the static TOU definition.

high system peak demand was registered within the average day profile. The moderate peak demand is registered during the hours 10:00h until 00:59h. The low peak demand is recorded in the time slot 01:00h – 9:59h.

The average day profiles in summer and winter months are shown in Figure 14 and Figure 15.

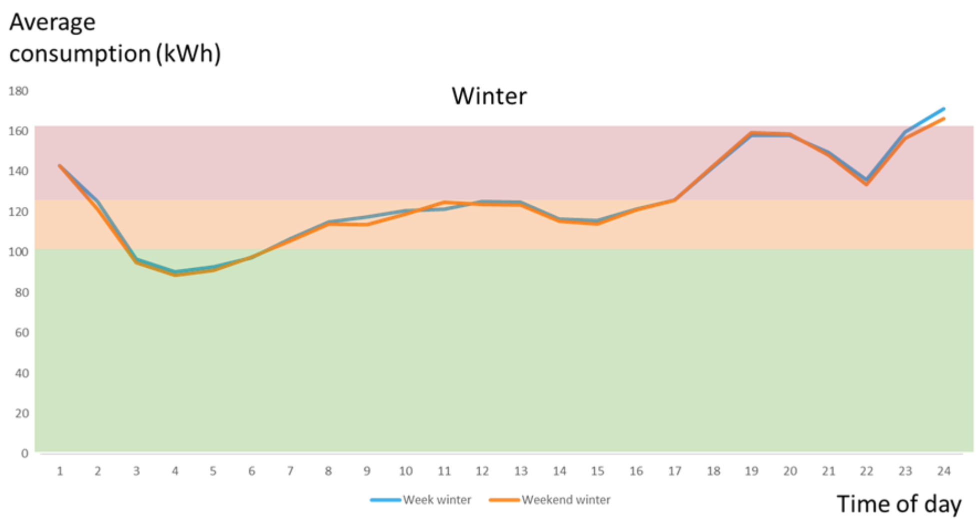


Figure 14: Average day profile in winter months

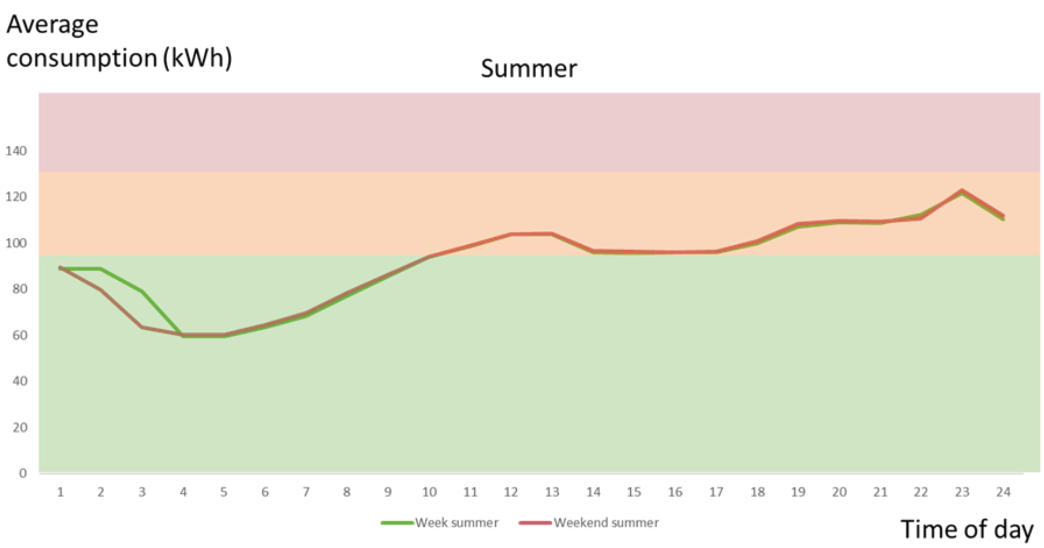


Figure 15: Average day profile in summer months

Based on this analysis, five different time of use periods have been identified, to be reflected in tariff design 1. An overview of these defined time of use periods is provided in Table 2.

Table 2: Definition of static time of use periods

summer	Medium	10:00 - 00:59
summer	Low	1:00 - 9:59
winter	High	17:00 - 1:59
winter	Medium	7:00 - 16:59
winter	Low	2:00 - 6:59

The applicable tariff for each of these time blocks is dependent on the anticipated system peak and the regulated budget to be distributed. In particular, if the expected system peak is high, a higher tariff rate is applied. In parallel, if the anticipated system peak is moderate or low, the rate height is respectively moderate and low. An illustrative example of this principle, where the rate height is linked to the predefined static time blocks, is provided in Figure 16 and Figure 17, depicting the hourly rates.

For each of the static time of use blocks, the consumed power (i.e. kW demanded from the grid) of the individual consumer is defined to establish the grid invoice. This individual peak demand within each static time block is multiplied by the applicable rate height, defined for each time block.

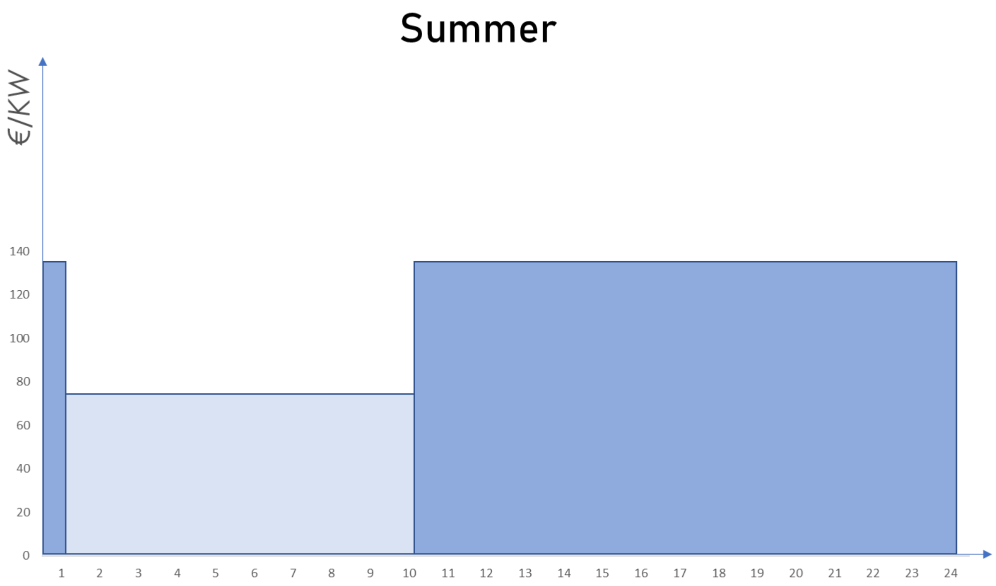


Figure 16: Illustrative example of static tariff design summer months

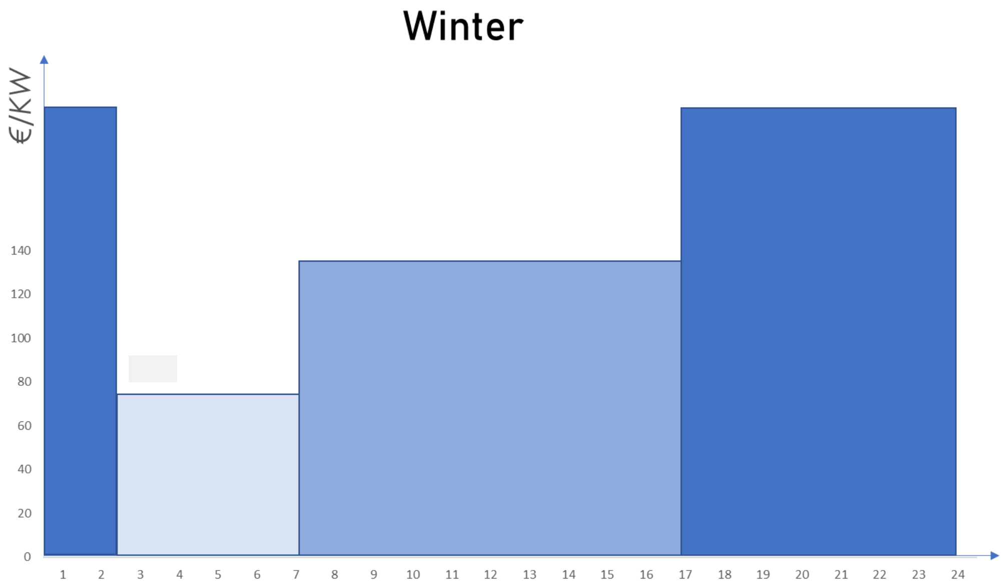


Figure 17: Illustrative example of static tariff design winter months

2.3.2.2 Event-based grid tariff design

The second interpretation considers the translation of the risk of congestion into a 'peak event'. In this context, the definition of the risk of congestion is not based on historical data analysis but relies on an analysis closer to real time, i.e. day-ahead. In particular, in a day-ahead manner, the risk of congestion is determined, which provides much more room for variability than within the static tariff design where a typical winter day or summer day is considered non-variable.

In this tariff design, the day-ahead definition of the risk of congestion is determined for the full day. In practice, a forecast is made of the individual demand profiles for the next day and aggregated for every feeder. This data on the offtake side is complemented with the forecasted need for redispatch on the injection side. In this manner, an integrated view on the risk of congestion on both the offtake and the injection sides is established. Stemming from this forecast, two potential elaborations for the final tariff design are considered.

In a **first interpretation** (i.e. for further reference **tariff design 2**), a day can be classified according to three indices.

- i) The next day can be considered at a congestion risk 1 if, for minimum one of the hours of the next day, an offtake-related congestion is forecasted.
- ii) If none of the hours of the next day seems to be prone to offtake nor injection related congestion, the day is classified as 0.
- iii) A congestion risk index of -1 is applied when at least one of the hours of the next day is considered to be at risk for injection related congestion (and no offtake congestions are expected during the other hours that day).

This is illustrated in Figure 18, where, as an example, for day 1 an offtake-driven congestion is anticipated, for day 2 no congestions are expected and for day 3 a high infeed of RES is expected.

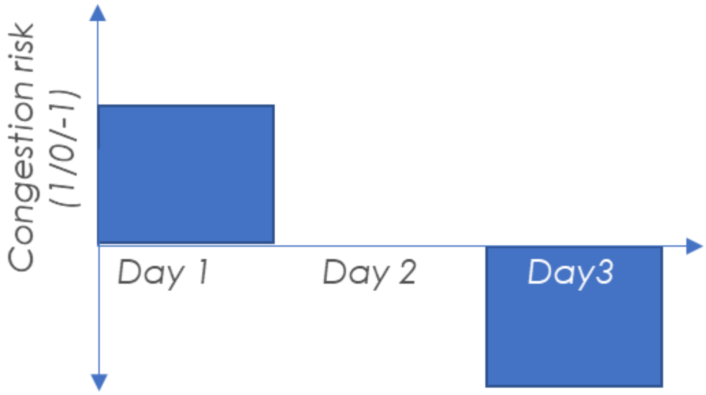


Figure 18: Illustration daily classification of congestion risk

To establish the tariff design accordingly, each congestion risk indices (i.e. 1, 0 or -1) is linked to a specific capacity tariff. Consequently, three rate heights can be defined which correspond to the congestion risk, where the offtake-driven anticipated congestion (1) is billed as the highest capacity tariff. On the opposite side, an injection-driven congestion (-1) is billed at the lowest rate. Days for which no congestion risk is identified (0) are billed at the standard capacity tariff. This is illustrated in Figure 19.

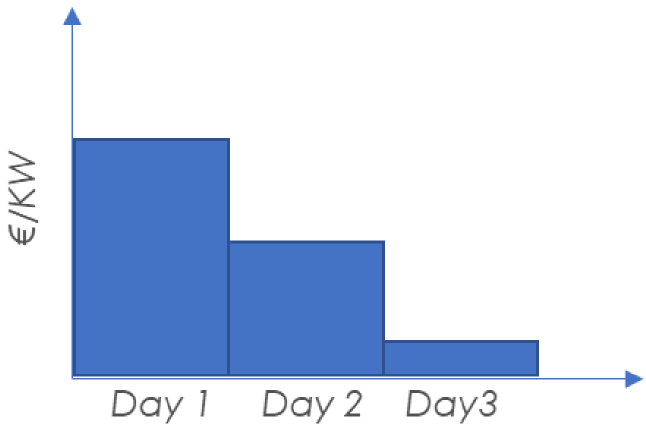


Figure 19: Illustration event based grid tariff design

In the current analysis within the German demo, we see that the grid user characteristics (e.g. distribution of PV technology) entail that no injection-related congestion risk could be identified for the simulated year at the low-voltage distribution level for the grid considered in our analysis. Hence, a binary signal differentiating between 0, for no congestion risk, and 1, for offtake driven anticipated congestion, suffices. For the distinction between the binary signal the technical grid parameters are listed in Table 3.

The congestion signal is obtained from evaluating the voltages measured at all nodes and the current of all branches downstream from a feeder. Voltages are in per unit (p.u.) values and have as reference the feeder voltage node. The current flowing in each branch is compared to the respective rating of the branch; the resulting metric is the occupancy ratio of the branch. To determine a congestion signal at the feeder level, the node with the lowest voltage and the branch with the highest occupancy ratio determine the state of congestion of the network.

Table 3: Conditions for the binary signal and definitions for "low" and "high" congestion risk

Congestion Risk	Voltage (p.u.)	Occupancy Ratio (current/branch rating)
Low	≥0.96	<0.60
High	<0.96	≥0.60

In Table 3, it should be understood that if either voltage falls below 0.96 p.u. or if the occupancy ratio rises above 0.60, the congestion risk will be considered "high". Either threshold, if triggered, will determine the heightened state of congestion.

In order to define the actual grid invoice for each grid user, the used capacity needs to be determined. Given the daily interpretation of the tariff design, the maximum used capacity is defined over the course of day as well. In practice, the grid user receives an indication of the applicable capacity tariff for the next day (which is one of two potential values; high or low tariff) and this tariff applies to the highest peak consumed during that day.

Depending on the forecasted congestion for the next day, the applicable tariff changes from one day to another. Hence, this day to day variation in tariff height defines the variability of this tariff design. The tariffs can be communicated to the consumers via different feedback channels. This is however out of scope of the current report.

Alternatively, a more gradual interpretation of the event-based tariff design is considered (i.e. for further reference **tariff design 3**). In particular, instead of a classification according to two indices (being 1 and 0), the risk of congestion is considered gradually, reflecting the voltage level on the local grid. This leaves room for a more gradual billing of the risk of congestion to the final consumer, providing more gradual signals to the consumer to alter their behaviour.

Table 4 provides a summary of the congestion rating classes and their conditions of voltage and branch occupancy ratio. For the practical interpretation to define the actual congestion rating, the evaluation of either (not necessarily both) of these criteria at a given period will classify the rating of that period. The most restrictive condition sets the rating. For example, if at a certain period, the lowest voltage is 0.93 p.u. and the highest occupancy rate is 56%, the congestion rating is A. Conversely, if at another feeder the lowest voltage is 0.98 p.u. and the highest occupancy ratio is 48%, the congestion rating for that feeder is C.

For event-based (i.e. capacity) tariffs, the signal attributes one rating to characterize the state of congestion of a feeder for one day. The congestion rating for one day corresponds to the worst hourly rating measured that day (where A is the worst).

Table 4: Conditions for the gradual signal and definitions for staged congestion risk

Congestion Risk	Voltage (p.u.)	Occupancy Ratio (current/branch rating)
E	<1.00	>0.00
D	<0.97	>0.40
C	<0.96	>0.45
B	<0.95	>0.55
A	<0.94	>0.65

In line with the previous elaboration of the tariff design, each stage of the congestion risk is linked to a specific capacity tariff. Consequently, 5 rate heights are defined which correspond to the congestion risk. This is illustrated in Figure 20.

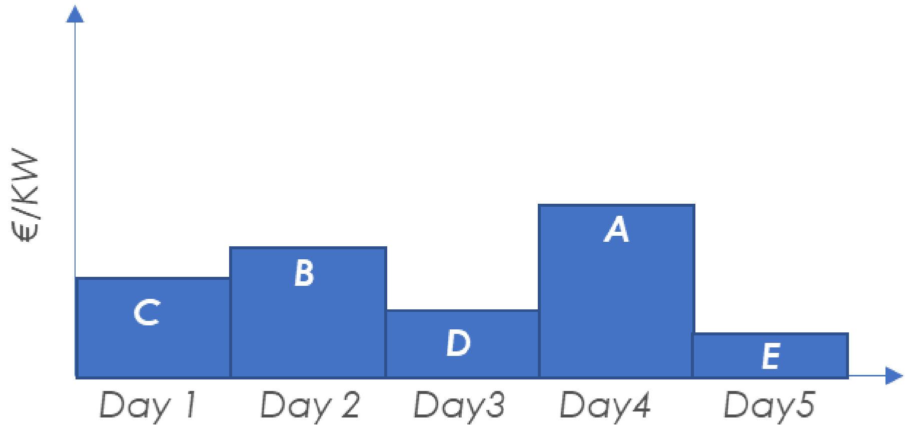


Figure 20: Illustration of gradual event-based grid tariff design

For the definition of the grid invoice, the respective rate height is multiplied by the maximum peak usage of that day.

2.3.2.3 Dynamic grid tariff design

Moving from a daily definition of the congestion risk in the event-based tariff design, this dynamic tariff design relies upon a day-ahead forecast of the hourly congestion risks. More variability is introduced by setting the congestion risk more granularly (i.e. hourly instead of daily indices) and the rate height is more modular. In particular, the distribution tariff is made increasingly expensive as the risk of grid congestion increases.

Looking into the dynamics of the grid tariff design, this tariff refers to the intensive, more granular and automatic link between the hourly-set risk level of grid congestion and the rate height of the tariff. In parallel to the event-based grid tariff designs, two alternative approaches are considered in the analysis. The **first** considers the congestion signal in a binary fashion as described in Table 3, i.e. a low or high risk of congestion (i.e. for further reference **tariff design 4**). An illustrative example is provided in Figure 21.

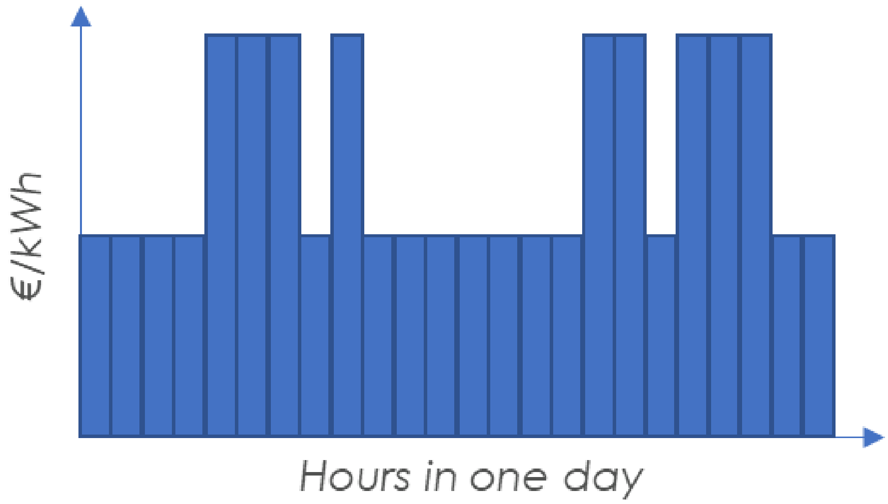


Figure 21: Illustration binary dynamic grid tariff design

Alternatively, a more gradual interpretation of the congestion risk is considered (i.e. for further reference **tariff design 5**), following the methodology as described in Table 4. . Every hour the risk of congestion is rated from A to E. Hence, every hour, the rate height of the grid tariff could be set at one of five levels. This is illustrated in Figure 22.

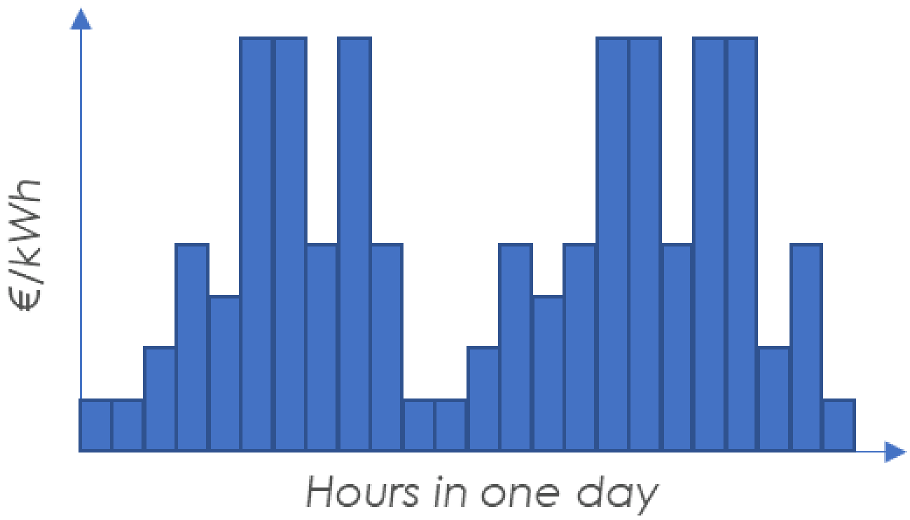


Figure 22: Illustration gradual dynamic grid tariff design

This implementation foresees a volumetric charge in the tariff design. Hence, the total energy consumed is the basis on which the grid invoice is calculated.

2.3.3 Redispatch incentive

As previously described, the high-voltage and medium-voltage network of the electric grid is confronted with injection related congestions (high wind). Furthermore, the number of grid users able to respond to a certain need for TSO congestion services is larger in comparison to the distribution grid (i.e. only the grid users connected to a particular feeder can mitigate congestions happening on this feeder).

This has an effect on the manner of implementing a redispatch incentive in the tariff design. Particularly, the use of capacity triggers is not the best signal for congestions at higher voltage levels, in contrast to the distribution grid level (where grid prices are driven by a requirement for capacity). Volumetric signals, in that respect, may be more appropriate.

Hence, in this analysis, the different dynamic grid tariff designs are complemented with a volumetric term which reflects the need for redispatch at the TSO level.

3 Quantitative assessment of grid tariff design

The objective of our analysis is to assess the impact of the selected grid tariff designs on the distribution network in function of congestion mitigation and the response to redispatch signals. To assess the performance and the manner of reaching these objectives, a quantitative assessment is elaborated. This section deep dives into the developed methodology, shedding light on the deployed models, the assumptions considered, and the key performance indicators used to benchmark and evaluate the grid tariff designs. The chapter concludes with an elaboration of the results and a sensitivity analysis.

3.1 Methodology

3.1.1 Deployed models

For the impact assessment for the tariffs, a simulation environment is set up. The simulation environment implements an open loop of four building blocks. The first model, denoted system model, represents the electricity system in a clustered fashion. The second model represents the distribution network (noted as "Network model" in Figure 23). This model is followed by a building block which defines the applicable tariffs, designated in Figure 23 as the "Tariff model". Finally, the flexibility model represents the residential demand on the level of individual households. All models are put in sequence to quantify the impact of the tariffs.

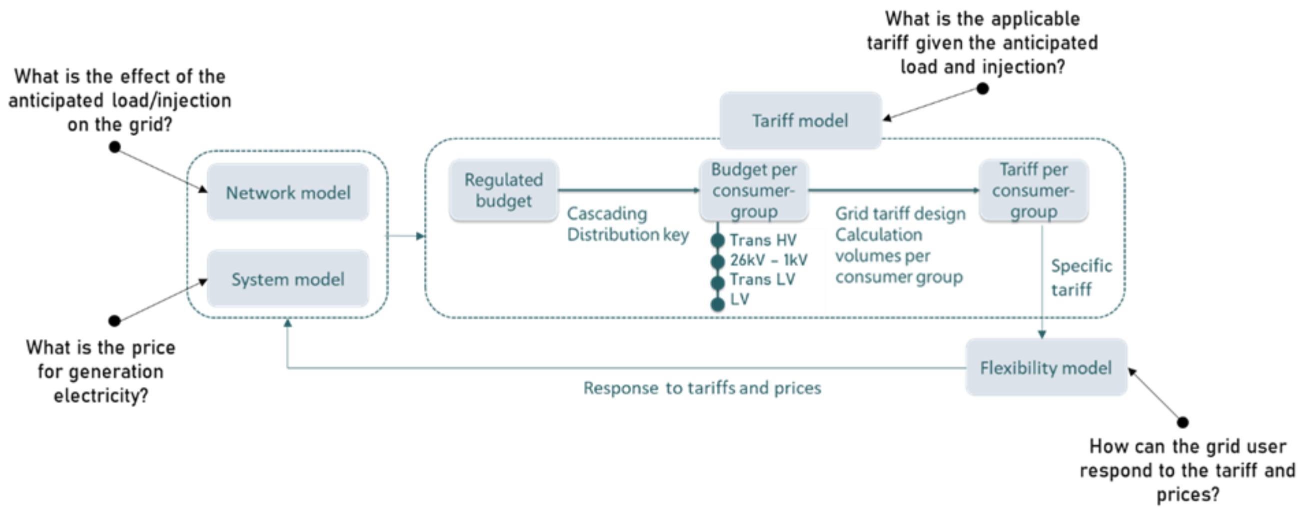


Figure 23: Visualisation modelling environment

The goal of this open loop is to assess different tariffs on their effectiveness to reduce network congestion. Residential households are first subjected to the combination of a commodity price signal (which is the output of the system model) and to a reference flat grid tariff (which comes from the tariff model module), and adjust their initial scheduled consumption in order to minimize costs (this is done in the flexibility model module). We calculate the state of congestion of the network by running the power flow equations on the network taking into account the adjusted schedules of the household (in the network model module). We consider all steps until the establishment of the network congestion state in the first iteration of the loop. The second (and last) iteration of the loop then begins. Tariff rates are then set after the state of congestion is known and are a function of this state of congestion. Consumers now react to the new grid tariff signals and adjust their schedule once more.

The state of congestion is then again recalculated. This marks the end of the second iteration. By measuring the difference of the states of congestion at the end of the first and second loop, we can determine the effect of the tariff designs on the state of congestion.

3.1.1.1 System model

A clustered unit commitment model is used to support the system model. The model's general goal is to commit and dispatch generation units at the transmission level to meet the aggregated demand profile at the lowest possible cost. The generation assets are grouped according to technology, which implies an abstraction from individual ownership or units. All associated expenses for the operation, including variable costs for fuel, emissions, maintenance, start-up, and shut-down, are taken into consideration by the clustered unit commitment model. Additionally, the model takes into account the efficiency levels of the various generation technologies. Intertemporal ramping restrictions, minimal stable operating points, and maximum capacities are included to account for the corresponding technological limitations. The maximum capacity is discounted to account for scheduled maintenance.

An aggregated hourly profile, depicting the irradiance or wind speeds, is used to supply RES with information about the availability of solar and wind power. Storage systems also track their state of charge over the model horizon while taking charging and discharging efficiency into account. Demand can be limited if there is not enough supply. Because it is substantially more expensive than any other technique, load shedding is only used as a last resort. The system model does not explicitly model price-responsive demand flexibility. It is presumptively represented in the demand profile of the model's re-run (i.e. the second loop as is explained above), as will be showcased in the flexibility model building block.

The model is deployed in a deterministic way based on a demand profile with hourly resolution. 8760-time steps are simulated altogether. Price profiles that depict the relevant prices in the neighbouring countries for the specified hour are used to estimate import and export exchange with neighbouring countries. The available transfer capacity also places a cap on the import and export capacities. The system model assumes that Germany is a copper plate with no internal congestion because the operational aspects of the network are not included in this part of the model environment [4]. With the model we are running a day ahead mechanism where the unit commitment model will give a balanced solution. Deviations that happen afterwards are taken into account in the next time stages. Future deviations can be taken into account using probabilistic formulations, but this is out of the scope of the current work.

The system model's output is a cost-effective schedule to fulfil the demand. An hourly pricing profile can be produced based on the marginal cost brought on by the scheduled technologies. The marginal cost profile is taken to be a rough estimate of the price that would appear on an electricity market when considering truthful bidding at marginal unit costs. The hourly marginal cost coming from the system model is taken as the energy component charged to all residential consumers in our simulations.

3.1.1.2 Network model

The four-stage tariff evaluation loop assesses the impact of a tariff design in providing congestion services for the DSO and the TSO. For the DSO, mitigation of distribution network congestion is considered, and for the TSO, redispatch of LV-connected flexible resources is considered for reducing curtailment of renewable generation in the transmission network. For the definition of the first part,

[4] Note that network congestions in the distribution network are considered in the network model, described in section 3.1.1.2. The redispatch mechanism aims to account for congestions on the transmission level.

the distribution network congestion, a network model along with power flow calculations are used, as described in Deliverable 8.1 of the EUniversal project, see Figure 24 [23].

Multiple factors make the LV distribution grid a complex environment. Limited non-real-time measurement sites, highly stochastic profiles due to unpredictable end consumer behaviour, and a largely unknown grid topology (e.g., the phase connectivity of single-phase connections is often unknown) define the uncertainty entailing LV grids. However, it is critical to have a precise understanding of when and where there is a significant risk of congestions to set appropriate tariff rates in order to prevent those risks.

The network model takes into consideration nodal load profiles for performing power flows. The network model uses statistical and artificial intelligence techniques to calculate the probability density of voltage and current levels at all nodes in a LV network, given the available data and taking into account all unknown variables (e.g. the LV grid layout, historic and recent grid and connection profile measurements, weather forecasts and information on the flexible assets, as available to the DSO).

The network model outputs the nodal voltages and line loadings which are used for defining a day-ahead LV congestion forecast and asset headroom calculation. It defines the risk for congestion, per feeder and transformer, per quarter hour time step and for the next 48h. In our particular exercise, the congestion signal has a 1h-time step and can be predicted for a time horizon as large as the optimization runs, which considers 36 hours, of which the first 24 hours are kept.

Congestions that can be identified by the network model are overvoltage, undervoltage, overcurrent and transformer overloading. However, the actual occurrence of these congestions depends on the grid considered and result from running the network model for a certain (part of a) distribution grid. In the current German demo, for example, the congestions identified are under voltage, and line loading.

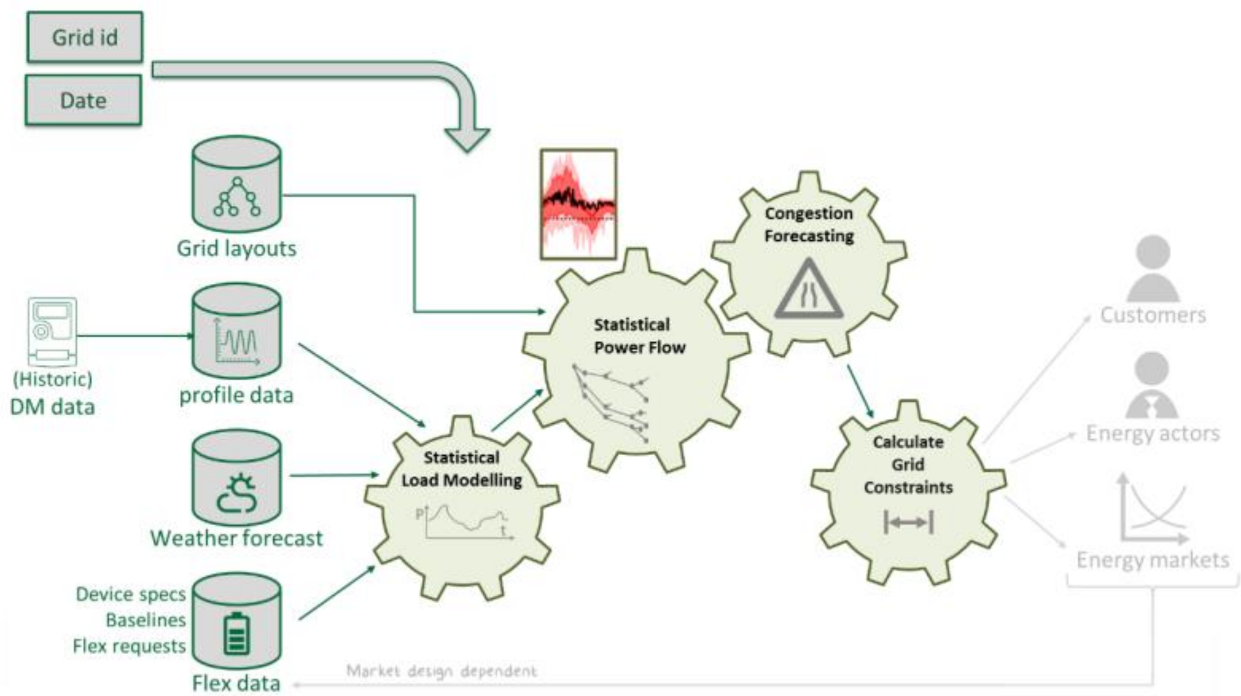


Figure 24: Illustration of the network model [23]

3.1.1.3 Tariff model

For each of the selected tariff designs, the rate height is defined. This rate height is calculated via the methodology described in Figure 25. First, the yearly regulated budget is defined by considering the current practice of billing distribution grid costs to the LV consumers within the demo (i.e. flat volumetric rate). This flat rate is applied to the reference calculation volume which is the yearly consumption of electricity (yearly kWh-volume).

In the tariff model, the resulting yearly regulated budget is re-distributed on the basis of the respective calculation volume, specific for each tariff design. This calculation volume is the parameter based on which the costs are distributed and it is the total anticipated yearly volume applicable for the tariff design in scope.

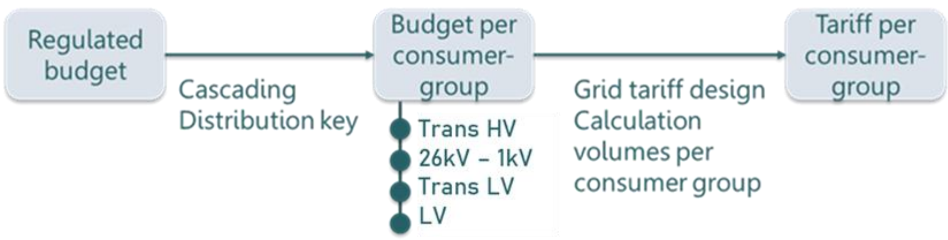


Figure 25: Calculation methodology for the tariff rate

The level of the rates for all tariffs is fine-tuned to guarantee that the revenue obtained from each tariff approached, as close as possible, the revenue recovered from the flat volumetric rate currently in practice.

3.1.1.4 Flexibility model

The consumer flexibility model simulates the decision-making or control algorithm in a residential household. The decisions have an impact on how flexible devices are used, i.e., adjusting demand over time to achieve an economic or technological goal. Each home seeks to reduce its overall costs in this situation, including grid tariffs and energy prices.

Residential load profiles have changed in recent years. Households are increasingly featuring, within their energy asset portfolios, solar photo-voltaic cells on their rooftops capable of generating electricity during the day, battery systems storing energy for later use when not required, and a set of flexible and smart appliances that, by virtue of their adjustable loads, enable demand response. Households, therefore, have the means to react to price incentives by shifting part of their energy use to more favourable hours of the day. In the same way, introducing targeted grid tariffs will conceivably also provoke households to adjust their energy use. The flexibility model captures this dual response of households to price and tariff signals by adjusting their energy needs over the course of the day.

The model is formulated as a rolling horizon linear optimization problem (LP), performed at an hourly resolution for a whole year. We use a rolling horizon technique, which means that the model is run over a horizon of 36 hours, the first 24 hours' findings are kept, and the model then advances to evaluate the next day. The key objective is to ensure the continuity of the results for batteries and heat pumps. By initializing the respective variables in the first hour of the following day as the solution in the last hour of the present day, intertemporal restrictions, such as the energy stored in the battery and the indoor temperature maintained by the heat pump, are reflected.

Below we describe the full problem formulation, which includes every type of flexible technology observed to exist in the Mitnetz customer data (i.e. German demo). As we implement the model on each customer, we adapt the problem formulation by removing the appropriate variables, terms and constraints relating to assets not present in the considered household composition.

$$
\begin{aligned}
\min_{V,d^{HP},s,d^F,\delta} \quad & \textstyle\sum_{t=1}^{T}(\lambda_t^{\text{off}} + \tau_t^{TSO,off} + \tau_t^{DSO,off})V_t^{off} - (\lambda_t^{in} + \tau_t^{TSO,in} + \tau_t^{DSO,in})V_t^{in} \\
\text{s.t.} \quad & V_t^{off} - V_t^{in} = D_t + d_t^{HP} - i_t^{PV} + s_t^{ch} - s_t^{dis} + \textstyle\sum_{sf} d_{sf,t}^F, \quad \forall t \\
& 0 \le V_t^{off} \le V^{max,off}, \quad \forall t \\
& 0 \le V_t^{in} \le V^{max,in}, \quad \forall t \\
& V_t^{in} \le i_t^{PV} + s_t^{dis}, \quad \forall t \\
& i_t^{PV} = C^{PV} P_t^{PV}, \quad \forall t \\
& (\ldots), \quad \textit{(heat pump constraints, linear)} \\
& \delta_{sf,t}^{up} - \delta_{sf,t}^{down} = D_{sf,t}^{I} - d_{sf,t}^F, \quad \forall t \forall sf \\
& 0 \le \delta_{sf,t}^{up} \le \Delta_{sf,t}^{up}, \quad \forall t \forall sf \\
& 0 \le \delta_{sf,t}^{down} \le \Delta_{sf,t}^{down}, \quad \forall t \forall sf \\
& \textstyle\sum_{t=1}^{T} \delta_{sf,t}^{up} \le FER_{sf}, \quad \forall sf \\
& \textstyle\sum_{t'=1}^{T'} \delta_{sf,t'}^{down} = \sum_{t'=1}^{T'} \delta_{sf,t'}^{up}, \quad \forall sf \\
& \textstyle\sum_{t=1}^{T} \delta_{sf,t}^{down} = \sum_{t=1}^{T} \delta_{sf,t}^{up}, \quad \forall sf \\
& d_{sf,t}^F \ge 0, \quad \forall t \forall sf
\end{aligned}
$$

Sets

t	time step in hours. $t = 1, \ldots, T$.
t'	recorded time step. Subset of t. $t' = 1 \ldots T'$
sf	flexibility asset. sf = {electric boiler, electric vehicle, general flexibility}

Decision Variables

V_t^{off}	offtake volume from the grid at hour t [kW]
V_t^{in}	injection volume to the grid at hour t [kW]
d_t^{HP}	heat pump consumption at hour t [kW]
s_t^{ch}	charged volume to battery at hour t [kW]
s_t^{dis}	discharged volume to battery at hour t [kW]
$d_{sf,t}^F$	activated flexible volume of flexible asset sf at hour t [kW]
$\delta_{sf,t}^{up}$	upward flexible volume of flexible asset sf at hour t [kW]
$\delta_{sf,t}^{down}$	downward flexible volume of flexible asset sf at hour t [kW]

Parameters

T	Time horizon, selected as T = 36 hours [h]
T'	Recorded time horizon. T' = 24 hours [h]
λ_t^{off}	offtake market price of electricity [EUR/kWh]
λ_t^{in}	injection market price of electricity [EUR/kWh]

$\tau_t^{TSO,off}$	offtake volumetric redispatch grid tariff [EUR/kWh]
$\tau_t^{DSO,off}$	offtake volumetric grid tariff [EUR/kWh]
$\tau_t^{TSO,in}$	injection redispatch grid tariff [EUR/kWh]
$\tau_t^{DSO,in}$	injection volumetric grid tariff [EUR/kWh]
D_t	consumer demand load at hour t [kW]
i_t^{PV}	solar PV production at hour t [kW]
$V_t^{max,off}$	offtake upper limit [kW]
$V_t^{max,in}$	injection upper limit [kW]
$D_{sf,t}^{I}$	initial flexibility schedule of asset sf at hour t [kW]
$\Delta_{sf,t}^{up}$	upward flexibility upper limit of asset sf at hour t [kW]
$\Delta_{sf,t}^{down}$	downward flexibility upper limit of asset sf at hour t [kW]
C^{PV}	maximum Capacity of solar PV system [kW]
P_t^{PV}	capacity factor of solar PV system at hour t
FER_{sf}	cumulative energy requirements of flexible asset sf over time horizon T [kW]

The objective function of a consumer faced with capacity driven tariff designs is shown in the formulation below:

$$\begin{aligned} \min_{V,V_{\text{Peak}}} \quad & \textstyle\sum_{t=1}^{T}(\lambda_t^{\text{off}} + \tau_t^{TSO,off})V_t^{off} - \sum_{t=1}^{T}(\lambda_t^{in} + \tau_t^{TSO,in})V_t^{in} + \tau^{C,DSO}V_{\text{Peak}} \\ \text{s.t.} \quad & V_{\text{Peak}} \geq V_t^{off}, \quad \forall t \end{aligned}$$

All other constraints featured in the problem formulation for the volumetric tariff design seen previously remain unchanged in this formulation for capacity tariffs.

Decision Variable

V_{Peak}	peak hourly offtake volume in [T] (36 hours) [kW]

Parameter

$\tau^{C,DSO}$	offtake capacity grid tariff [EUR/kWh]

In the flexibility model, productions from PV panels are considered not curtailable, so the power is injected back into the grid in case of excess. Loading shedding is not allowed, so demand respond restricts to load shifting. Load shifting can lead to losses e.g. in form of thermal losses in case of earlier heating, or electrical losses due to the efficiency of a battery cycle. The flexibility of smart appliances (e.g. dish washer, washing machine, etc.) is described by applying a flexibility band of 10% (the possibility to increase or decrease from default profiles). We add limits on the shiftable energy to better represent the number of cycles per day and the energy content of a cycle. Electric vehicles are modelled following a similar approach following the underlying idea of availability for charging, respectively absence. The consumption of a heat pump is based on a reverse cycle (RC) model for heat in representative residential houses. The ambient temperature follows an hourly time series. The flexibility of the heat pump is captured by a temperature band in the house. The state-of-charge dynamics of the battery are tracked via an energy balance, where the efficiency of charging and discharging is taken into consideration.

There are three characteristics of the flexibility model which frame the interpretation of the results.

- It is assumed that the household responds in a rational manner, i.e., the consumer purely reacts to price and tariff signals;
- The rational response and activation of flexibility in the household is considered to be automated and can be fully employed (within the limits defined by the inherent technology);
- The household has perfect foresight within the day on all aspects, including the production from PV panels, the demand, and the development of the tariff and price signal.

These assumptions represent the most ideal setting, so the flexibility usage is an upper bound. It is these assumptions that support the execution of a sensitivity analysis in the final stage of this study to get an idea of the robustness of the different tariff designs.

3.1.2 Assumptions

3.1.2.1 Definition of congestion signal and redispatch signal

In this section, we first define **offtake congestion** for the case study based on the German demo. Congestion in the distribution network is defined based on the nodal voltage (in per unit) and thermal line loading (in percentage of the line power capacity).

Based on ex-ante data analysis for the nominal congestion definition, we observe no congestion incidents for any of 39 feeders for 1 year of simulation. The line parameters can be observed in Figure 26. Note that feeders 7, 30, 33 and 39 have significantly high cumulative line resistance compared to other feeders.

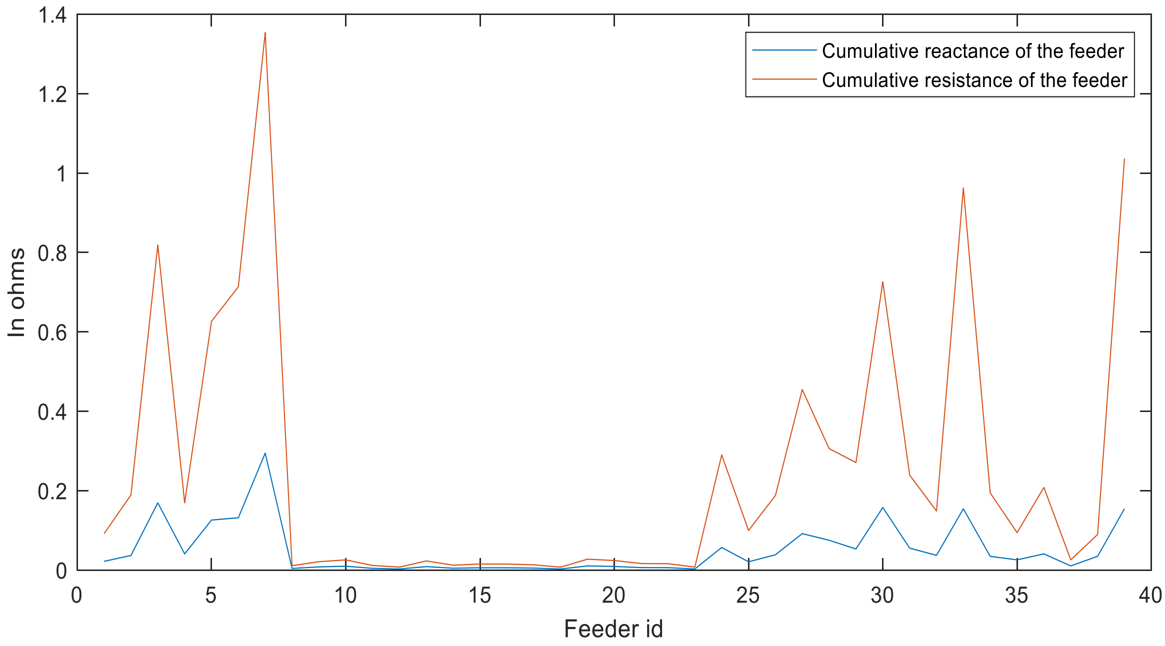


Figure 26: Variation of line parameters over 39 feeders.

Analysis of the mean loads shows that feeders 7, 30, 33, and 39 have a mean load of more than 24 kW, see Figure 27. In addition, the peak loads on each of the feeders are shown. Feeders 3, 7, 30 and 33 have peak load of more than 100 kW.

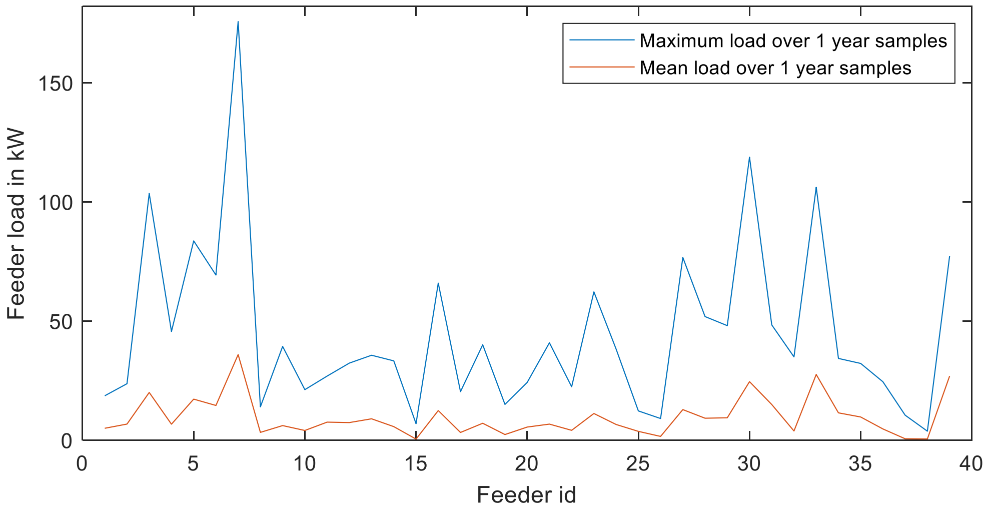


Figure 27: Variation of mean and maximum peak loads over 39 feeders

In order to analyse congestion events, we redefine the characterisation of congestion. The allowable band of operation for voltage and line loadings are made more restrictive. The nodal voltage range is changed to [V_{min}', V_{max}'], where V_{min}' > V_{min} and V_{max}'< V_{max} where V_{min} and V_{max} denote the original minimum and maximum voltage ranges. Similarly, the maximum allowable line loading is reduced from 100% of its capacity. In accordance with the reduced thresholds in the definition of congestion depicted in Table 3, in the numerical evaluation we denote network as congested if (i) thermal loading exceeds 60% of line rating, and (ii) voltages lie outside the [0.96,1.04] pu voltage range. The restrictive ranges defining congestion are motivated by volt-watt and volt-Var inverter control which pre-emptively corrects network issues. These adapted congestion limits are used as a proxy to mirror future scenarios in which the increase in baseloads renders network capacity more limited and risk of congestions more frequent.

Based on the adapted definition of grid congestion, a statistical power flow is performed to gather the nodal voltages and line loadings. The simulations for the German demo are performed for 1 year with hourly samples and yield the following congestion incidents.

Table 5: Congestion incidents observed

Feeder id	Number of congestion incidents	Percentage of incidents among all feeders
3	2	1.8
6	1	0.9
7	**13**	**11.9**
28	1	0.9
30	**7**	**6.4**
33	**84**	**77.1**
39	1	0.9

From Table, we observe that more than 95% of congestion incidents are happening in only 3 feeders, with more than 77% of the total congestion incidents observed in feeder 33. More detailed analysis of feeder 33 enables determining the instances in which voltage and thermal congestions are occurring and whether these incidents are correlated. From the analysis, we can observe that thermal congestions often appear with a voltage issue in the distribution network.

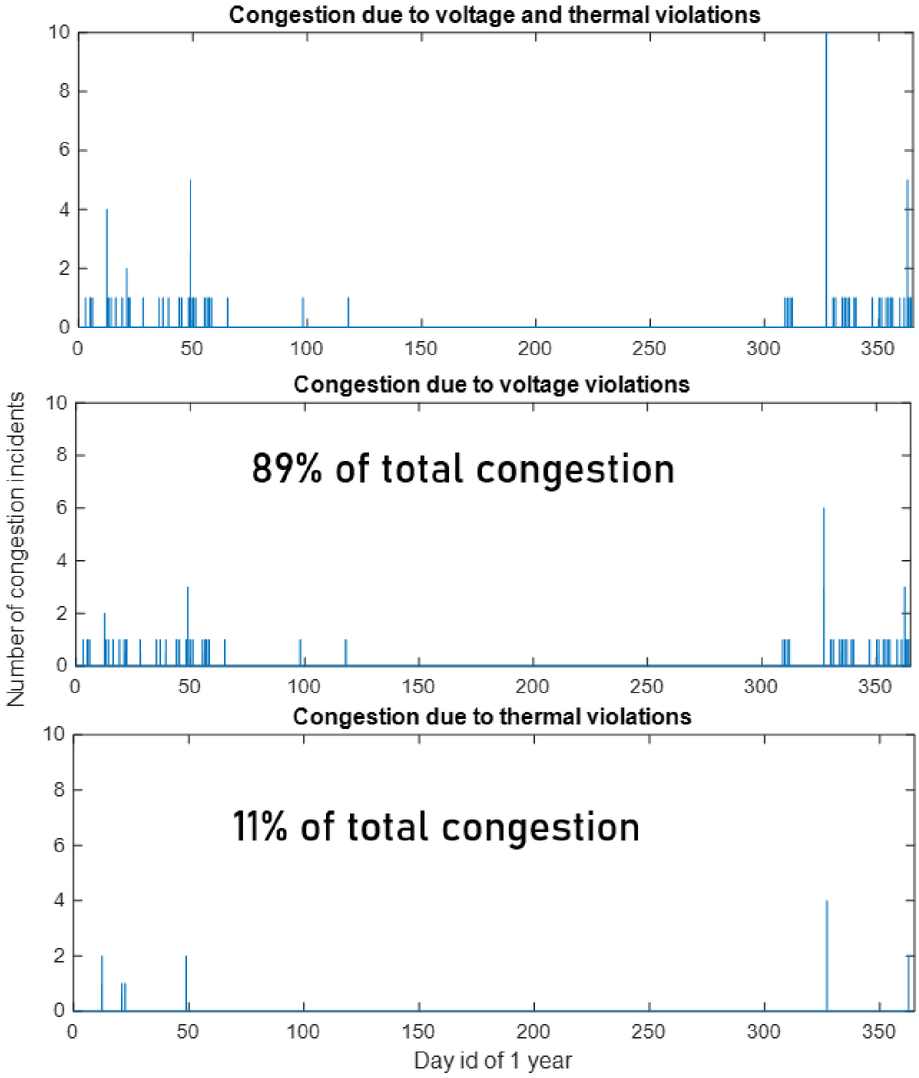


Figure 28: Congestion incidents in feeder 33

We analyse the congestion instances at the feeder level for generating a congestion signal which is going to be integrated into the proposed tariff designs. We observe that[5]:

- Locationality: More than 95% of the (restrictive) congestion is happening at only 3 of the 39 feeders
- Characterisation congestion: 89% of the distribution network congestion is caused due to voltage violations and 11% due to thermal violations,
- Seasonality: Winter nights have the maximum number of congestions happening. 96.33% of the identified (restrictive) congestions happen from January to March and October to December.
- Time of day: 86.3% of the congestions happen between 9:00 pm to 4:00 am.
- Dependency of congestion incidents on the line parameters and the load in the feeder: The feeders with high congestion incidents tend to have a high cumulative feeder resistance and

[5] It should be noted that the times and seasonality of occurring congestions are highly dependent on the connected loads. The current profiles are highly heat-driven and have limited integration of PV and EVs. As the penetration of PV and EVs will increase, the congestion characteristics will also change.

reactance. The feeder with the highest number of congestion incidents has a significantly higher load than the mean load met by all the other feeders.

In the further analysis, there are two manners in which the risk of congestion incidents is considered:

- Binary congestion signal: in this mechanism, congestion signal is 1 whenever a voltage or line limit violation is observed. The congestion signal remains 0, otherwise. The states have been previously defined in Table 3.

Gradual congestion signal: the congestion signal can have more than two states (other than 0 and 1). Such a signal can be used to denote the severity of congestion. The states have been previously defined in Table 4.

Besides distribution grid congestion, also **transmission-related congestions** are considered. In Germany, the transmission system operator generates a redispatch signal aiming to improve the stability of the grid and the energy system. This schedule-based congestion management has been updated in October 2021, also referred to as Redispatch 2.0 [24]. The new regulations apply to all installations over 100 kW. This includes installations that were previously unaffected by feed-in management requirements and those that are currently on a fixed renewable energy act - Erneuerbare-Energien-Gesetz (EEG) feed-in tariff. The goal of redispatch 2.0 is to prevent grid congestions in the transmission network at a low cost while ensuring curtailment of generation is also minimized.

Figure 29 and Figure 30 show, respectively, the performed processes in the day-ahead and intra-day timeline for Redispatch 2.0. These figures detail the activities, and responsibilities of different entities in the power system along the different time steps. The Redispatch 2.0 process starts 36 hours before real-time operation and ends 15 minutes before the actual activation.

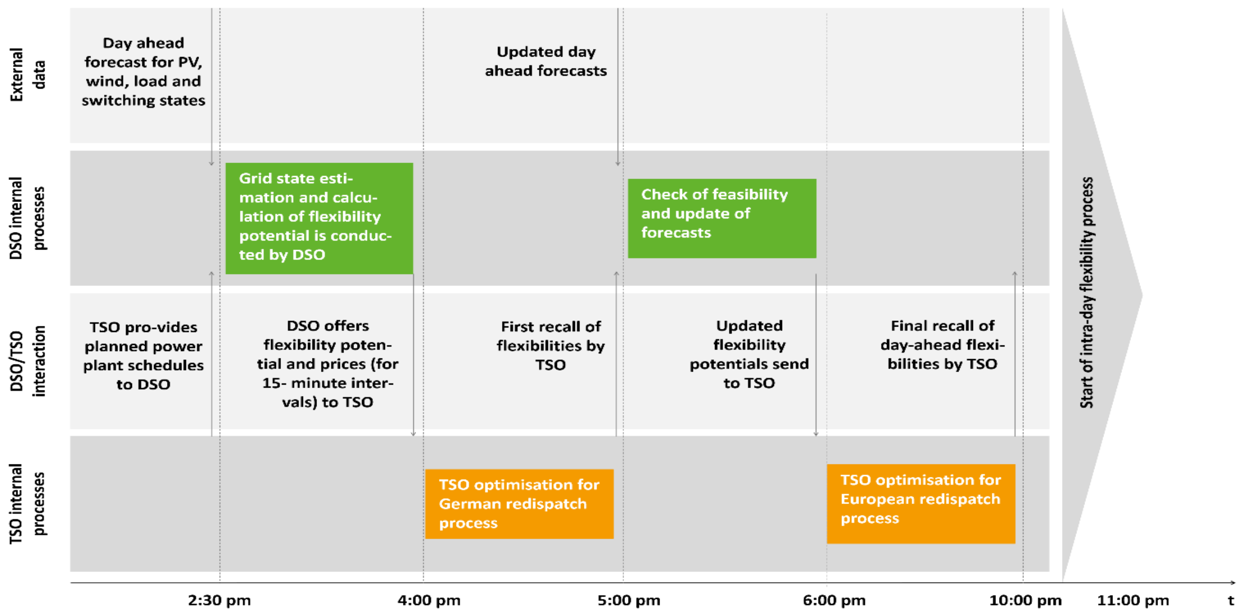


Figure 29: Day-ahead timeline for Redispatch 2.0 [25]

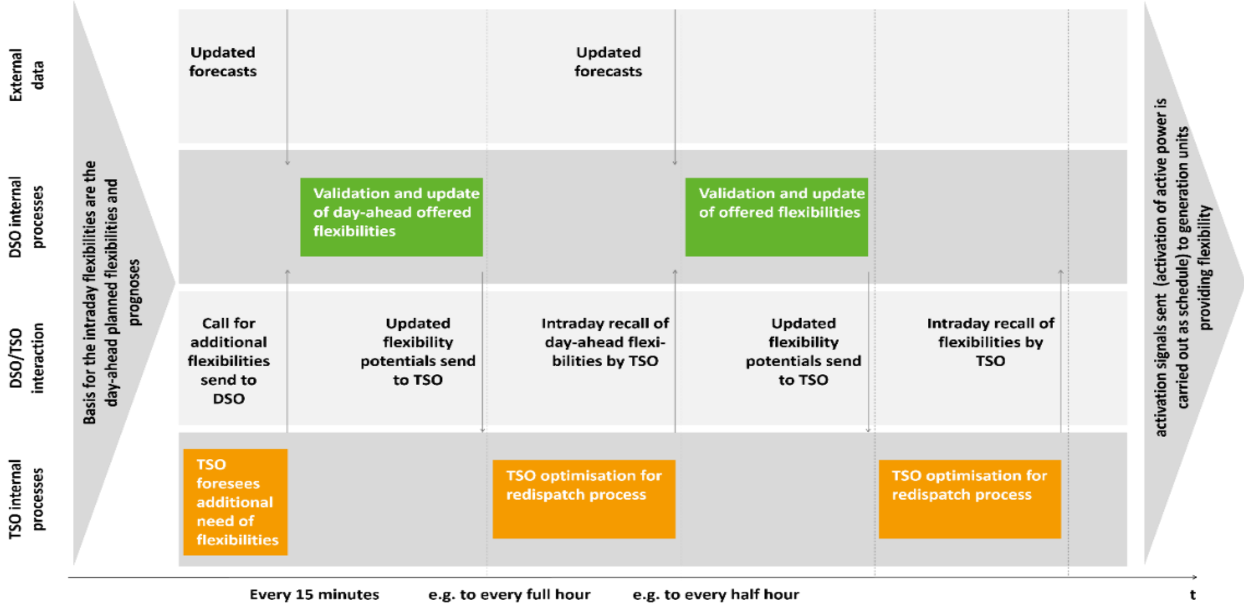


Figure 30: Intraday timeline for Redispatch 2.0 [25]

In this analysis, we utilize the redispatch signal generated by the TSO. We used the reports on relief measures to calculate a redispatch signal [26]. These reports log incidents where in the transmission network was adjustment to power feed-in needed and which line bottlenecks occurred. The incidents are time stamped, and we extracted from the set of incidents the hours of the year that were affected by a redispatch on some location on the grid. We then constructed our redispatch signal considering these hours. We observe, for the year 2020, that during 8.38% of the time the redispatch signal is active, there being 736 hours where the redispatch mechanism was initiated. Figure 31 shows the histogram of redispatch incidents for the year 2020, spread across an average day[6]. From the figure it becomes apparent that most incidents are recorded during the late morning – early afternoon, coinciding with the sun radiation peak.

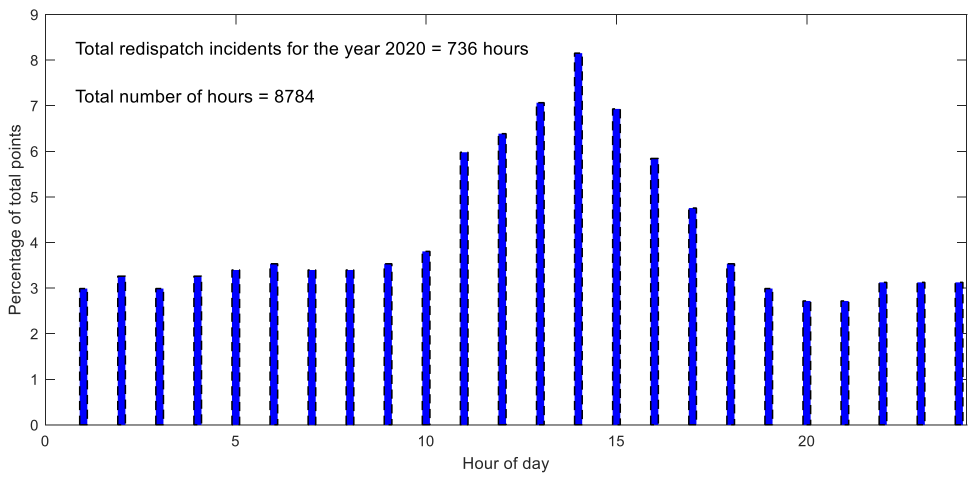


Figure 31: Average daily spread of the Redispatch signal for 2020 [26]

For the purpose of this study, it is assumed that the Redispatch 2.0 mechanism is extended to LV grid users as well. In particular, the registered redispatch signal is considered to determine if an

[6] It should be noted that at this time the former Redispatch regulation still applied as Redispatch 2.0 started October 2021.

adaptation of the consumption profile of low voltage consumers (in function of an increase in consumption) is desired.

In the methodology, the need for adaptation is considered via translating the redispatch signal to a binary signal (either 0 or 1). Consequently, if the binary signal is 1, an adapted (in this case, increase of) consumption is desired. Hence, the grid tariff is adapted accordingly to drive the behavioural change. Alternatively, if the binary signal is 0, no need for flexibility is considered for solving grid congestions at TSO-level, entailing no impact on the distribution grid tariff applied.

Given the split identification of the distribution grid congestion risk and the need for redispatch, there is a potential risk of conflicting signals for certain moments in time. For example, there can be a need for redispatch identified, indicating a request to increase the consumption level, while the local distribution grid can, however, already be rated at a higher congestion risk. In order to take the risk of conflicting signals from the transmission and distribution grid into account, a **hierarchical structure** is defined in the model environment. Consequently, when, for a certain feeder, a high congestion (in a binary application) or a congestion rating of A, B or C (in a gradual application) is identified for the next day, the redispatch signal is ignored. It is assumed in this case that the redispatch need is answered by another grid location.

3.1.2.2 Rate height of different tariffs

Reference grid tariff

For the reference grid tariff, the current practiced distribution tariff is considered. Low voltage consumers are exposed to a volumetric, flat tariff, α, that is charged every hour of the year.

$$C_0 = \alpha \sum_t V_t$$

The flat rate α takes the value of 0.0546 Euro/kWh. Knowing the annual consumption of each customer in the network, we can calculate the overall revenue to the DSO. In the tariff designs studied, the rate heights were determined in such a way that their cost matched the cost C_0 of the reference flat tariff.

Each tariff design is composed of two terms: a redispatch term, and a distribution grid tariff-specific term.

Redispatch term

The redispatch term applied for tariff 2, 3, 4 and 5 is a function of the redispatch signal ρ (binary) and the congestion state δ (also binary). Tariff 1, not being dependent on a congestion signal, is the sole exception and only considers the redispatch signal.

The redispatch term is represented by the following expression:

$$\Sigma_t\big(\gamma(1-\bar{\delta}_t\rho_t)\big)V_t,$$

where γ is the tariff height, $\bar{\delta}_t$ is a binary signal taking the value 1 when congestion is low in time period t, and ρ_t is a binary signal taking the value 1 when the redispatch signal is active. The summation is over every hour of the year, and V_t is the hourly offtake volume at time t. The choice of the binary triggers would remove this term from the tariff in case the congestion signal is on (i.e., equal to 1) and the state of the distribution network is at low congestion risk. This would then constitute a reduction in perceived tariff incentivizing additional consumption.

The redispatch signal is presented as a volumetric trigger. Based on the available data on the need for redispatch, weighted against the state of the local network (in order to identify the potential 'room' to answer to the redispatch signal), and the potential effect on the DSO costs and revenues, the rate height was defined at 0,022 €/KWh.

Tariff design 1: Static grid tariff

This first tariff design is considered "static" because it does not consider the state of congestion of the network in a dynamic fashion. Instead, the risk of congestion is identified ex-ante (i.e. year ahead), filtered from historical data on expected consumption and injection. As a result, five different tariff periods are defined. Each day is divided into 2 or 3 blocks (in the summer and winter, respectively). Each block is then affected by a tariff α, which we describe as high (H), medium (M) or low (L). The tariff-specific term is capacity-based.

Peak volumes $V_{d,i}^{P}$ are measured for each block, to which the corresponding tariff α_i is applied, where i can capture either the high (H), medium (M) or low (L) state, and d is the index capturing the day

The cost for tariff 1 is described by:

$$C_1 = \sum_t (\gamma(1-\rho_t)V_t + \sum_d \left(\alpha_H V_{d,H}^P + \alpha_M V_{d,M}^P + \alpha_L V_{d,L}^P\right)$$

The required DSO revenue is assigned to each of these five tariff periods, based on the measured peaks in the selected periods. This calculation leads to the definition of the appropriate tariff rate for each tariff period, as displayed in Table 6.

Table 6: Rate height tariff design 1- static grid tariff

Season	tariff period	hours	Symbol	Tariff	Unit
summer	Medium	10:00 - 00:59	α_M	0,109	€/kW
summer	Low	01:00 - 09:59	α_L	0,053	€/kW
winter	High	17:00 - 01:59	α_H	0.328	€/kW
winter	Medium	07:00 - 16:59	α_M	0,109	€/KW
winter	Low	02:00 - 06:59	α_L	0,053	€/kW

Note: as tariff 1 requires no evaluation of the state of congestion, the redispatch cost is only a function of the redispatch signal.

Tariff design 2: binary event-based grid tariff

The tariff-specific term is capacity-based. Within this capacity tariff with a binary congestion signal, the congestion signal is high on days, d, where at least one hour is congested (resulting in $\delta_d = 1$, and

$\bar{\delta}_d = 0$). These days are billed at a higher peak rate, β, to incentive consumers to reduce the peak consumption. This is complemented with a base rate, α, applied to the peak volume observed on days where the risk of congestion is low (resulting in $\delta_d = 0$, and $\bar{\delta}_d = 1$).

Tariffs are applied to the peak consumption V_d^P measured on day d, for every day of the year.

$$C_2 = \sum_t \left(\gamma(1 - \bar{\delta}_t \rho_t\right) V_t + \sum_d \left(\alpha \overline{\delta_d} + \beta \delta_d\right) V_d^P$$

Simulations in the tariff model considered the balancing exercise between providing a sufficient tariff spread to yield sufficient consumer response and, on the other hand, obtaining a total tariff revenue that approaches the regulated budget originally defined. This analysis has led to the resulting rate heights in Table 7.

Note that this higher rate is applied to peak volume, regardless of whether the peak volume and the congestion risk coincided in the same hour of the day or not.

Table 7: Rate height tariff design 2 - binary event-based grid tariff

Rating	Symbol	Tariff	Unit
Low	α	0,053	€/kW/day
High	β	0,109	€/kW/day

Tariff design 3: gradual event-based grid tariff

The tariff-specific term is capacity-based. This capacity tariff classifies the state of the network into 5 ratings, from A to E (A being the most congested state). The rating for day d is defined as the highest state of (hourly) congestion observed in that day.

$$C_3 = \sum_t \left(\gamma(1 - \bar{\delta}_t \rho_t\right) V_t + \sum_d \left(\alpha_E \delta_{E,d} + \alpha_D \delta_{D,d} + \alpha_C \delta_{C,d} + \alpha_B \delta_{B,d} + \alpha_A \delta_{A,d}\right) V_d^P$$

Only one δ term is non-zero in any given day. As an example, if the state of congestion of day d has rating D, $\delta_{D,t} = 1$, all other terms $\delta_{A,d}$, $\delta_{B,d}$, $\delta_{C,d}$ and $\delta_{E,d} = 0$, and tariff α_D is applied.

The simulations of the tariff model, while compared to the target regulated budget, yielded the rate levels described in Table 8.

Table 8: Rate height tariff design 3 - gradual event-based grid tariff

Rating	Symbol	Tariff	Unit

E	α_E	0,008	€/KW/day
D	α_D	0,197	€/KW/day
C	α_C	0,809	€/KW/day
B	α_B	1,468	€/KW/day
A	α_A	2,029	€/KW/day

Tariff design 4: binary dynamic grid tariff

This tariff design consists of a volumetric tariff component with a binary congestion signal. Hence, there is a base rate, α, applied when congestion is "low" (i.e, ., $\delta_t = 0$, and $\bar{\delta}_t = 1$), and a "premium" rate, β, when congestion is anticipated to be high (i.e, ., $\delta_t = 1$, and $\bar{\delta}_t = 0$),. This rating is set in an hourly fashion.

$$C_4 = \sum_t (\alpha\, \bar{\delta}_t + \beta\delta_t + \gamma(1 - \bar{\delta}_t\rho_t))V_t.$$

The applicable rate heights are described in Table 9

Table 9: Rate height tariff design 4 - binary dynamic grid tariff

Rating	**Symbol**	**Tariff**	Unit
Low	α	0,032	€/kWh
High	β	0,763	€/kWh

Tariff design 5: gradual dynamic grid tariff

The last tariff design considers a volumetric trigger with a reflection to a gradual congestion signal. This congestion signal classifies the state of the network into 5 ratings, from A to E (A being the most congested state). This tariff design considers an hourly differentiating rate height based on the relevant state of the network. At any given hour t, the rating determines the tariff.

$$C_5 = \sum_t (\gamma(1 - \bar{\delta}_t\rho_t)V_t + \sum_t (\alpha_E\delta_{E,t} + \alpha_D\delta_{D,t} + \alpha_C\delta_{C,t} + \alpha_B\delta_{B,t} + \alpha_A\delta_{A,t})V_t.$$

Similarly to tariff design 3, only one δ term in C_5 can be non-zero in any given time. The different rate heights for each of the grid ratings is described in Table 10.

Table 10: Rate height tariff design 5 - gradual dynamic grid tariff

Rating	Symbol	Tariff	Unit
E	α_E	0,014	€/KWh
D	α_D	0,340	€/KWh
C	α_C	1,399	€/KWh
B	α_B	2,540	€/KWh
A	α_A	3,510	€/KWh

3.1.2.3 Energy component of the electricity price

In reality, (residential) consumer may choose among different energy suppliers and different contract types to obtain the most beneficial contracts for the energy component. In our analysis, we have assumed that an identical energy component is charged to all residential consumers for the energy offtake from the grid. It is approximated by the hourly marginal cost coming from the system model (as explained in section 3.1.1.1) as we assume that consumers will increasingly have access to more dynamic prices. This thus means that, aside from one of the grid tariffs explained in the previous section, the residential consumers in our analysis will also act according to hourly, dynamic prices.

3.1.2.4 German demo network characteristics

The German demonstration considers the LV Grids of the German DSO Mitnetz Strom. For the purpose of this study, four pilot regions were ultimately selected in the grid regions of Brandenburg, West Saxony and South Saxony, the area of operation of Mitnetz Strom. These four pilot regions consisted of a wide diversity of feeders and a variety of generation technologies and flexible applications connected. A simplified visualisation of the German demo network is provided in Figure 32.

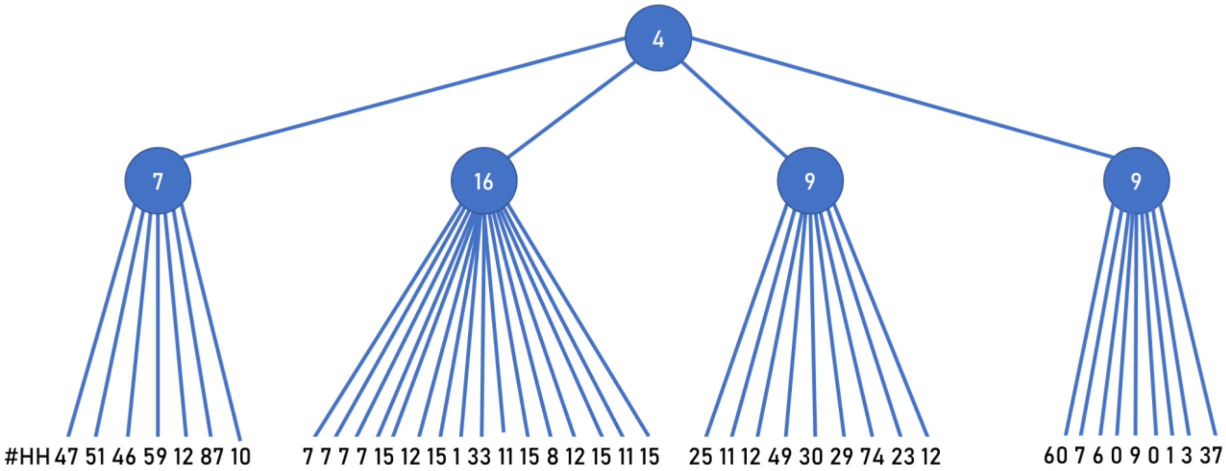


Figure 32: Simplified visualisation of the German demo LV network

A more detailed description of the German demo network and the respective technical characteristics is provided in the following table.

Table 11: Technical description of the selected German LV grid

Substation	1	2	3	4
Number of feeders connected	7	16	9	9
Number of households connected	312	191	265	123
Number of PV installations	31	0	34	3
Number of heat storage units	10	178	12	1
Number of heat pump systems	7	0	3	6
Number of CHPs	2	0	0	0
Number of EVs	0	0	0	8
Number of batteries	2	0	7	1

3.1.2.5 Grid user assumptions

For each of the households connected to the different feeders within the German demo, the yearly (thus, accumulated) electricity consumption is known. However, this is not sufficient to describe the grid user behaviour in detail. In particular, every household has a different consumption profile in terms of energy consumption, peak demand and connected capacity, relevant, among other things, to establish the response to grid tariffs and energy components. That is why the definition of a more granular grid user behaviour is essential to provide a good proxy of the different household behaviours within the demo. For this purpose, 'typical' end-user groups are defined. As 'typical' end-user groups, it was opted to use the Eurostat categories to classify consumers, as seen in Table 12 [27]. For each Eurostat customer category, both a 'non-prosumer' and a 'prosumer' variant exist.

Table 12: Eurostat household categories

Eurostat household categories
Band-DA (Very small): annual consumption below 1 000 kWh
Band-DB (Small): annual consumption between 1 000 and 2 500 kWh
Band-DC (Medium): annual consumption between 2 500 and 5 000 kWh
Band-DD (Large): annual consumption between 5 000 and 15 000 kWh
Band-DE (Very large): annual consumption above 15000 kWh

The known statistical distribution of the Belgian households across the different consumer categories is used to approximate the statistical representation of the different Eurostat household categories in the German LV-demo. An overview of the statistical distribution across the consumers, prosumers and all households is provided in the next table.

Table 13: Statistical distribution across household categories assumed in the analysis

Statistical distribution	DA	DB	DC	DD	DE
Consumers	3%	19%	62%	9%	7%
Prosumers	30%	9%	46%	6%	9%
All households	8%	18%	59%	8%	7%

Within each of the Eurostat categories, a dataset of distinctive consumer consumption profiles was consulted. The profiles in this dataset were mapped with the known yearly consumption data of the households within the German demo as well as the availability of energy technologies (as described in the previous section). In this manner, it is assured that there is a good mapping and approximation of the individual household behaviour within the German demo.

3.1.2.6 Definition of household flexibility

The household configuration is modified reflecting the household composition and energy needs of each of the 1157 households in the Mitnetz network.

The flexibility considered in the flexibility model (see Section 3.1.1.4) is characterised by the underlying flexible technologies assumed. In this analysis, distinct sources of flexibility are defined which sum up the total flexible volume, in particular;

- Electric vehicles
- Heat pumps
- Electric heaters
- Generic flexibility, a.o. smart appliances
- Electric batteries

For **electric vehicles**, the charging profiles used in this study are based on data about the charging of an electric vehicle, linked to the distribution of the arrival times at a certain charging location, the distribution of the distance covered, and other parameters including properties of an electric vehicle (such as, storage capacity, charging capacity, consumption per distance travelled,). Furthermore, we assumed a typical battery with a range of 300-400 km and an energy content of 75kWh. We assume that 75kWh is the maximum charge that an electric vehicle can demand.

The EV data is based on the data provided via Pecan street [28]. This information, describing a typical profile, is then renormalized according to the size of the anticipated battery. The flexibility is described in terms of charging sooner or later.

The number of EVs assumed in the analysis is mapped to the technical characteristics of the German demo whereas the data in Table 11is considered to model the total EV flexibility volume.

It is assumed that the **heat pumps** are all installed in the same building type. This building is a detached house that was built after 2012 and has underfloor heating. This property is defined in two zones, the day zone and the night zone. The day zone is 132 m^2 and contains areas where the inhabitants are present during the day. The night zone is 138 m^2 and contains the other areas such as bedrooms and attic. The building has an average U-value of 0.3 W/m^2K and a ventilation rate of 0.4 ACH. This building is modelled as a network of thermal resistances and capacities, as described by [29]. The user behaviour of the homes is based on the model described by [30]. This user behaviour is aggregated to an average user by averaging the effective lower limit for the indoor temperature and averaging the hot water demand, as described in [31]. The model of the building, heat pump and hot water tank was verified against a detailed building simulation model by [31] .

The model, therefore, consists of a state-space representation of the network of thermal resistances and capacitances. This represents the dynamic behaviour of the building with underfloor heating. A lower limit and an upper limit are imposed on the temperatures of the day zone and of the night zone, which are determined by the thermal comfort requirements of the users. The heat pump then meets these comfort requirements. It supplies heat with a coefficient of performance (COP) that is calculated every day on the basis of the average supply temperature of the heating and the average outside temperature.

The heat pump also provides domestic hot water. This is stored in a 250-litre water vessel that must be kept between 50°C and 60°C. The heat pump has a lower COP when providing domestic hot water than when supplying heat to the underfloor heating system.

The model can be used to optimize the electricity demand of the home. In the event that the heat pump does not take variable rates into account, the heat pump minimizes its energy consumption. In the case of variable rates, the flexibility of the building structure and the hot water tank can be used to save costs.

The number of heat pumps assumed in this analysis is aligned with the German demo, included in Table 11.

In addition, **electrical heaters** for heating and domestic hot water are considered. These are continuous electric boilers that produce during the day and night according to the needs of the end-user.

The profiles used for these devices are based on data obtained via Pecan Street [28]. We hereby assume that 201 German households within the demo use electrical heaters to heat their house via electricity (see Table 11).

Finally, every individual household is assigned a certain volume of **generic flexibility** to cover miscellaneous sources of flexibility not considered in the previous technologies (e.g. dishwasher, dryer, washing machine, refrigerator and freezer). In this analysis, it is assumed that the generic flexibility sums up to 10% of the electricity consumption in each time period [32].

Subsequently, in order to allocate flexibility to the different individual households and entailing consumption profiles, a number of preconditions for the residential demand model have to be taken into account. These preconditions relate to the different households and their individual characteristics. An additional step that is necessary before the different scenarios can be simulated consists of mapping the different sources of flexibility to the individual households while respecting the penetration levels for the different energy technologies described in Table 11. A two-part approach is used for this: first an elimination process is used to exclude less likely combinations (for example, a household within the day-ahead (DA) end-user group is less likely to own a heat pump or an EV). The remaining combinations are then optimized to best match the distribution of the different end-user groups, the known yearly electricity consumption and the assumptions of the flexibility resources. This results in a detailed overview of the household configurations.

3.1.3 Key Performance Indicators

In the quantitative assessment, a number of key performance indicators (KPIs) are calculated. These KPIs allow a quantitative review of the selected grid tariff designs in terms of benefits, concerns and efficiency. Table 14 provides an overview of the relevant KPIs. The KPIs are calculated for the short term.

Table 14: KPI's to assess the system impact

	KPI	Description	Unit
1	Effect of tariff design in reducing offtake related congestion with respect to base case	The impact is assessed based on quantification of instances: • Number of congestions mitigated • Number of shifted congestions • Number of new congestion instances • Number of unresolved congestion events	Relative change compared to the reference tariff
2	Effect of tariff design in reducing injection congestion and answering to redispatch signal	The impact is assessed based on the quantification of the number of redispatch signals mitigated compared to the total number of redispatch signals sent.	Relative change compared to the reference tariff
3	Grid cost recovery	Percentage deviation in total income from grid tariffs compared to reference	Relative change compared to reference tariff
4	Individual tariff impact	Total costs per consumer, including the energy component, grid component, taxes and levies, calculated for a full year per use case.	€/ year

3.2 Impact assessment

In this section, the results of the quantitative assessment are presented. To analyse the performance of the different tariff designs and to enable a good comparison basis, particular attention is paid to 3 feeders out of the 39 feeders within the German demo. These 3 feeders are selected since they contained the most congestion events (given the redefined congestion thresholds defined in Section 3.1.2.1), Furthermore, these feeders are some of the most populated ones. Below we present a table describing the relative percentage of congestion events and the number of residential customers per selected feeder. Together they represent more than 95% of all congestion events.

Table 15: (Relative) Congestion incidents and number of customers for the three selected feeders

Feeder id	Congestion incidents	Percentage of incidents	Number of customers
7	13	11.9%	99
30	7	6.4%	87
33	84	77.1%	76

For these three feeders, a more in-depth insight in the results of the KPIs is provided. The feeder with the ID33 presented the highest share of congestion events. Hence, the KPIs results for this feeder are particularly interesting to consider the effect of the tariff designs and to draw conclusions on the effectiveness of the selected tariff designs to reduce grid congestions.

3.2.1 KPI1 Reducing offtake-related congestion

The first KPI considers the effect of each tariff design on reducing offtake-related congestion with respect to the reference tariff. The reflection of the reduction of grid congestion is considered in function of the number of hours the grid is operated following certain grid characteristics, classified according to five predefined stages. The technical characteristics of these grid stages are summarized in Table 16.

Table 16: Technical characteristics of the considered grid stages

Grid stages	Voltage (p.u.)	Occupancy Ratio (current/branch rating)
E	<1.00	>0.00
D	<0.97	>0.40
C	<0.96	>0.45
B	<0.95	>0.55
A	<0.94	>0.65

The optimisation exercise captures each individual consumer's response to the different grid tariffs sent. The effects of the tariffs (through consumer reactions) on grid congestions are shown in Table 17 and

Table 19 for the feeders 33, 7 and 30respectively. In those tables, an overview is provided of the number of hours during which the distribution grid is in a certain grid state (i.e. rating from A – E, where A is to be considered the worst rating as seen in Table 16).

Table 17: Identification of the grid state for the selected grid tariffs for feeder 33

Number of hours	**Reference**	**Tariff 1**	**Tariff 2**	**Tariff 3**	**Tariff 4**	**Tariff 5**
	Flat volumetric grid tariff	**Static grid tariff**	**Event--based binary grid tariff**	**Event--based gradual grid tariff**	**Dynamic binary grid tariff**	**Dynamic gradual grid tariff**
E	8258	8343	8329	8362	8220	8298
D	409	377	396	371	479	394
C	82	38	31	25	56	64
B	9	2	3	1	5	4
A	2	0	1	1	0	0

Table 18: Identification of the grid state for the selected grid tariffs for feeder 7

Number of hours	Reference	Tariff 1	Tariff 2	Tariff 3	Tariff 4	Tariff 5
	Flat volumetric grid tariff	Static grid tariff	Event--based binary grid tariff	Event-based gradual grid tariff	Dynamic binary grid tariff	Dynamic gradual grid tariff
E	8507	8677	8611	8659	8440	8471
D	240	79	139	98	299	257
C	8	2	8	1	18	30
B	3	1	1	1	2	1
A	2	1	1	1	1	1

Table 19: Identification of the grid state for the selected grid tariffs for feeder 30

Number of hours	Reference	Tariff 1	Tariff 2	Tariff 3	Tariff 4	Tariff 5
	Flat volumetric grid tariff	Static grid tariff	Event-based binary grid tariff	Event-based gradual grid tariff	Dynamic binary grid tariff	Dynamic gradual grid tariff
E	8691	8709	8709	8711	8689	8735
D	57	45	43	42	59	19
C	9	5	7	6	11	5
B	2	1	1	1	1	1
A	1	0	0	0	0	0

From the overview tables, it can be distinguished that the static tariff (i.e. tariff design 1) performs surprisingly well in mitigating the cases with the highest congestion. This is remarkable given the fact that this grid tariff design consists of a year-ahead definition of the tariff periods based on historical data. Hence, the day-ahead forecast of congestion is not considered to set the rate height. One main reason behind the good performance of tariff design 1 is that the analysis assumes accurate foresight, i.e., that accurate predictions of future loads and the future grid operational state is available year-ahead, which would face practical challenges as several dynamic variations can take place between the time of prediction and real-time operation that would otherwise impact the performance of this tariff. In other words, had the loads and grid conditions closer to real time been different than the anticipated ones (i.e., in the case of relative forecast errors, which typical to occur in practice), the static tariff's performance would have decreased, as it would have been originally designed for a setting that differed from the one that took place in real-time. Indeed, one main disadvantage of tariff design 1, is that it does not allow the incorporation of the improvement in predictions/forecasts when approaching real-time operation in adapting the tariff design and rate heights (a feature only possible in dynamic tariffs). Hence, when large forecast errors take place, an inaccurate estimate of the grid operation status would exist at the time of design of the static tariff (in terms of temporal differentiation and defined rates), which would impact tariff design 1's ability of preventing future congestions. However, on the other hand, when an accurate estimate of future load profiles exits (or, alternatively, an accurate view of the occurrence of typical congestions within the grid on a yearly basis), the results of tariff design 1 indicate that data analysis, to set the tariff periods in function of historical occurrences of grid congestions and their anticipated evolutions, could be sufficient to relieve the cases with the highest congestion. It should also be noted that the static grid tariff design consists of an individual capacity trigger. This means that all consumers automatically receive an individual incentive to reduce the need for capacity during predefined peak-periods (e.g. winter months between 17:00 - 1:59h) when the rate height is set high. Consequently, the individual responses (by activating flexibility during these tariff periods) of the consumers entail a reduced simultaneous system peak on feeder level. Indeed, as this is a capacity trigger, the optimization at the consumer level (in reaction to the tariff) would aim to reduce peaks and spread them out. As this formulation measures 2 peaks per day in summer, and 3 in winter, the tariff exerts considerable control over load schedules, relatively more so than one peak measurement per day, or volumetric tariff designs, which are pointwise, and where time periods are independent from each other.

In comparison to the second and third tariffs, which also contain a capacity trigger in the grid tariff design, it can be observed that, overall, the performance (in function of mitigating grid congestion) is slightly lower (even though this should not be considered as a one-to-one comparison with tariff 1, as tariff 1 assumes perfect foresight, as previously explained). Hence. although consumers, similarly to tariff 1, receive an individual incentive to reduce the need for capacity, the effect on the grid state and congestion cases is lower. A reason for this can be found in the manner in which the time aspect is defined in the respective tariff designs. In particular, in tariff design 1, different time blocks are defined in a day for which the rate height varies, following the principle of TOU, and within each period the use of capacity is defined. In contrast, in tariff designs 2 and 3, the rate height is set for the full day without time variation, just as the use of capacity is defined over the course of the entire day. When the period of registration of the capacity usage lacks sufficient granularity, the local trigger to reduce the individual need for capacity is reduced. This can be explained by a practical example. If a consumer is exposed to an event-based tariff as in tariff 2 or 3, and reaches a maximum capacity need of 6kW during one quarter of that day, he/she will be billed for this 6kW. Consequently, if this consumer manages to remain below 6kW during the other quarters of that day, he/she will not experience an invoice impact. Moreover, the consumer does not perceive any incentive to limit the need for capacity, below the 6kW of this example, during the other quarters of that day. If we transpose this effect to the feeder level or system level, the reduction of the synchronous system peak by tariffs 2 and 3 can be lower. The aggregate of all individual capacity usages can still be considerable regardless of whether the individual peak moment (the 6kW in our example) coincides with the system peak demand, due to the fact that we do not incentivise peak reduction during the other times.

With tariff designs 4 and 5, even more time granularity is implemented in the tariff design. Both tariffs assume an hourly time granularity. While we see comparable results to the other tariffs for the high congestion cases (i.e. ratings A and B) for all feeders, we can observe that for some feeders (e.g. feeder 7 as featured inTable 17, Table 18and Table 19) the grid state is shifted from E to D and even C. Hence, this means that the risk of congestion for these feeders for certain moments in time is slightly increased but still below the high congestion risk rating. This does not mean that the effectiveness of dynamic grid tariffs in function of relieving grid congestion is reduced. As explained above, these results can partly be explained by the assumptions taken in our analysis, i.e. if grid congestions would be less predictable than assumed in our current analysis, the more dynamic tariffs where the congestion risk is determined day-ahead would perform better. In addition, the results can also partly be explained due to the higher responsiveness of the individual consumers to a redispatch signal sent. Due to the fact that the grid state is evaluated every hour as well as the resulting distribution grid tariff, the coordination between the redispatch signal and the distribution grid tariff is improved. While in other tariff designs (e.g. tariff design 2 and 3) the grid state is defined on a daily basis, where the highest congestion risk for one hour defines the risk for the entire day, in the dynamic tariff only the hours which are rated at the highest congestion risk are subject to a higher tariff rate. This is further explained in the next section (i.e. KPI2 reducing injection congestion).

Finally, on the differentiation between the interpretation of the congestion risk, i.e. considering a binary or gradual grid state, no significant differences could be filtered from the analysis. From the analysis, it becomes apparent that the distinction is more manifested in the actual invoice impact of the consumer (where a gradual interpretation, entailing a gradual rate height shows fewer tariff shocks) than in the performance with respect to reducing grid congestions.

3.2.2 KPI2 Reducing injection congestion

In this parameter, the effectiveness of the different tariff designs in fulfilling the need for redispatch is considered. The impact is assessed based on the quantification of the number of redispatch signals mitigated compared to the total number of redispatch signals sent.

Data analysis of the redispatch signal yields that the signal is active for 736 hours in the year (see section 3.1.2.1). Simulations of the effect of redispatch on the initial, reference, situation shows that answering to the redispatch signal would lead to an increase in congestion events on the local grid if the grid state is not considered. The isolated effect of the redispatch signal on the number of congestion events is shown in Table 20. To assess the impact of the proposed grid tariff designs on the effectiveness in reducing the need for redispatch, the results in Table 21 can be consulted. The quantitative results show that the reflection of the grid state in a daily fashion, meaning that the next day is considered a peak day once one hour is classified as high congestion risk, leads to more redispatch signals to be neglected. This is due to the fact that if for one hour a congestion risk is considered, no redispatch signal can be answered during the remaining hours of that day, while, in practice, there might still be hours with sufficient grid capacity to answer the redispatch need. In contrast, the dynamic tariff designs, which entail an hour-by-hour assessment of the grid state, prove to be more welcoming of the redispatch signal. The neglect of the redispatch signal is decreased from 84 occurrences in an event-based tariff design to 11 occurrences in a dynamic tariff design.

The static grid tariff does not consider the actual distribution grid constraints in any manner. Hence, the coordination between the distribution grid rating and the need for redispatch cannot be assessed.

Table 20: Number of congestion events by implementing redispatch signal

Number of hours	Reference	Reference
	No redispatch signal considered	Redispatch signal considered
E	8258	8220
D	409	432
C	82	95
B	9	10
A	2	3

Table 21: Effectiveness of the selected tariff designs in reducing redispatch need

Number of hours	Reference	Tariff 1	Tariff 2	Tariff 3	Tariff 4	Tariff 5
	Flat volumetric grid tariff	Static grid tariff	Event-based binary grid tariff	Event-based gradual grid tariff	Dynamic binary grid tariff	Dynamic gradual grid tariff
Redispatch signal active	736	736	736	736	736	736
Redispatch signal is active	NA	NA	652	652	725	725
Redispatch signal is neglected	NA	NA	84	84	11	11

3.2.3 KPI3 Grid cost recovery

In this section, we discuss the manner in which the different grid tariff designs affect the cost recovery for the DSO. Cost recovery refers to the fact that DSOs ought to be able to effectively recover their costs. DSOs may recover costs through connection fees and regulated services in addition to imposing tariffs for using the distribution system. While in the case of inelastic demand the revenues can be directly calculated, under the assumption of large volumes of flexible demand grid cost recovery can be affected. In particular, the incomes from the grid tariff for the operators might differ from the initial expected incomes as consumers change their behaviour according to the applied tariffs. Hence, the manner in which tariffs are set and how consumers are responding to the different tariffs affect the total costs recovered via the payment of grid costs by the individual consumers.

As mentioned in Section 3.1.2.2, all parameters within each tariff design were finetuned with the aim that the revenue of each tariff approaches the revenue from the reference flat rate. Hence, measures were taken in the methodology to guarantee a sufficient level of cost recovery. However, as already indicated in the qualitative assessment, the setting of the rate height is not a strict sequential step following after the establishment of the tariff design. These two components (i.e. rate height and tariff design), complemented with the establishment of the allowed revenue, are to be performed rather simultaneously, entailing an iterative feedback-loop.

In Table 22 and Table 23 the different tariff designs are compared in function of the revenue obtained by the grid operator, in absolute and relative terms, respectively. As shown in these tables, the static tariff has performed the best in approximating the allowed revenue of the DSO, with a relative cost recovery of 101%. This is a logical result of the static definition of periods as well as fixed allocation of rate heights within these time blocks. In particular, it is known in advance how many hours of the year are qualified as peak tariff periods, and how many hours of the year are considered moderate or low tariff periods. Thus, the applicable calculation volumes within each of the time blocks can be assessed with more certainty, entailing a higher stability in the cost recovery.

Table 22: Absolute cost recovery for the selected tariff designs

Grid costs	Reference	Tariff 1	Tariff 2	Tariff 3	Tariff 4	Tariff 5
	Flat volumetric grid tariff	Static grid tariff	Event-based binary grid tariff	Event-based gradual grid tariff	Dynamic binary grid tariff	Dynamic gradual grid tariff
33	13 203.95	13 052.24	12 293.29	12 716.79	14 705.85	13 164.02
7	17 197.03	16 656.44	9 502.78	11 243.66	16 787.62	15 329.22
30	11 767.38	12 743.91	6 413.74	7 226.63	11 385.35	9 716.40
Total	42 168.36	42 452.59	28 209.81	31 187.08	42 878.82	38 209.64

Table 23: Relative cost recovery for the selected tariff designs

Relative grid costs	Reference	Tariff 1	Tariff 2	Tariff 3	Tariff 4	Tariff 5
	Flat volumetric grid tariff	Static grid tariff	Event-based binary grid tariff	Event-based gradual grid tariff	Dynamic binary grid tariff	Dynamic gradual grid tariff
33	100%	99%	93%	96%	111%	100%
7	100%	97%	55%	65%	98%	89%
30	100%	108%	55%	61%	97%	83%
Total	100%	101%	67%	74%	102%	91%

Event-based tariffs (i.e. tariff 2 and 3) are shown to impact the cost recovery severely. In total terms, the recovered budget amounts to only 67% and 74% of the initial DSO costs to be recovered in the reference scenario. It can be argued that this shows a higher response from the consumers (to adjust their load profiles) to the capacity tariff. The optimization exercise performed by each individual consumer tries to reduce peaks, regardless of the grid state that day. This is due to the daily capacity trigger in the tariff design, which entails that consumers perceive a positive invoice impact at each reduction of the maximum capacity usage on a daily basis. Hence, in all tariff periods (i.e. peak day and off-peak day in the binary implementation and day ratings from A – E in the gradual interpretation) consumers will limit the capacity usage which in its turn reduces the calculation volumes for the budget recovery. This indicates that a capacity trigger can influence the cost recovery to a large extent and might necessitate a more elaborate feedback-loop in order to reach a steady-state rate height.

In contrast to the event-based tariffs, the dynamic tariffs (i.e. tariff 4 and 5) approach the allowed revenue rather well. The binary and gradual interpretation of the grid state obtain a cost recovery of, respectively, 102% and 91% of the initial budget. The improved performance compared to the former two tariffs 2 and 3 is mainly due to the higher, i.e. hourly, granularity of the tariff design. In the event-based tariff designs, there are in fact only 365 measurement points during the year which are considered to establish the grid invoice. In this context, with a slight effort of the consumer, the consumer can obtain a lower capacity usage which triggers a lower grid invoice. In the dynamic tariff designs, 8.760 measurement points define the total invoice for the consumer. Hence, if the consumer can reduce the consumption during one hour of the day, he/she is required to do the same effort in the consecutive hours because every hour is considered a separate billing period. Consequently, the total effect on the calculation volumes is lower, leading to a very moderate impact on the cost recovery.

Analysing the effect between the different feeders, Table 22 and

Table 23 provide a more in-depth analysis of three exemplary feeders on the redistribution of the regulated budget. The results show that feeders which are exposed to a higher congestion risk (and thus higher tariffs), e.g. the feeder with ID 33, experience fewer issues to recover the required budget. Even with event-based tariffs implemented, feeder 33 shows a cost recovery of 93% and 96%, which is particularly higher than the average of 67% and 74% for these tariffs, when considering the total budget. This is due to the fact that the exposure to more peak events leads to a higher number of peak tariff days, which, in its turn, increases the contribution to the collected grid costs.

This also shows that the choice of the tariff design impacts the distribution of grid costs across the different consumers. The location of being connected to the distribution grid will define the magnitude in which the consumer contributes to the grid costs. Consumers connected to rather congested feeders will be exposed to particular higher grid costs than consumers connected to feeders with spare capacity. This effect of redistribution based on the locational differences is often a topic of discussion from the perspective of fairness and non-discrimination amongst grid users.

With all tariffs, it is possible to achieve the same cost recovery level as within the reference tariff. This would require adapted values of the tariff, entailing an iterative approach taking into account the response of the tariff setting to the response of the consumers. This action-reaction chain then leads to stable grid tariffs but this optimisation is out of scope of this study (amongst others due to the extensive computing time).

3.2.4 KPI4 Individual tariff impact

The final KPI considers the viewpoint of the grid user. In particular, the impact of the selected grid tariff designs on the total anticipated grid invoice is assessed. In this manner, we can establish whether certain grid tariff designs, although they might perform well from a DSO perspective (i.e. when measured through KPIs 1 – 3), may cause tariff shocks for certain grid users, as, in that case, this would limit their implementation potential.

As the total grid invoice is dependent on an interplay of different aspects (e.g. total consumption, maximum capacity usage, available flexibility and availability of own production), it is not possible to assess this KPI on an aggregated level. In order to facilitate an educated assessment of the invoice impact, typical consumers are defined. Moreover, from the full set of grid users, three grid users are selected which map with predefined characteristics, being;

- A standard consumer without own production or a significant volume of flexibility.
- A consumer without own production but with a more than average consumption and volume of flexibility, such as a heat pump owner.
- A prosumer with own PV production.

In Table 24, we provide a detailed look into the impact on the total yearly grid invoice for the different consumer types in absolute and relative terms.

Table 24: Total grid invoice for certain types of consumers (in €) for the selected tariff designs

Grid invoice	Reference	Tariff 1	Tariff 2	Tariff 3	Tariff 4	Tariff 5
	Flat volumetric grid tariff	Static grid tariff	Event-based binary grid tariff	Event-based gradual grid tariff	Dynamic binary grid tariff	Dynamic gradual grid tariff
Consumer without flex	286.16	285.87	286.54	283.32	286.18	273.79
		-0,10%	0,13%	-0,99%	0,01%	-4,32%
Consumer with HP	652.43	537.64	361.18	459.56	618.45	757.79
		-18%	-45%	-30%	-5%	16%
Consumer with PV	213.60	174.02	118.86	138.58	210.91	192.80
		-19%	-44%	-35%	-1%	-10%

A consumer with average consumption, without access to a large volume of flexibility, perceives no distinct differences in the total grid invoice. Only in the last tariff design there is a slight decrease of the grid costs to be paid by the consumer, but this is rather due to a coincidence of a cheaper tariff period with the non-flexible consumption of the consumer.

For the large consumer with access to flexibility, in this case, a HP, the grid costs in the reference scenario are considerably higher due to the volumetric billing of grid costs. Moving to a capacity-driven grid tariff design entails significant benefits for this type of consumers. Particularly, the event-based tariff designs imply a considerable cost reduction (i.e. 45% and 30% depending on the implementation of a binary or gradual signal). HPs are appliances with large electricity consumption, spread over a long period where the maximum peak demand is moderate. This indicates a reason as to why the capacity-based tariff designs are preferred by this type of consumer.

The consumer with PV shows similar results on a relative scale to the consumer with an HP installed. In absolute terms, the order of magnitude of the total grid costs is lower. Table 24 also visualises that the event-based tariffs provide significant cost reduction opportunities over all of the consumer types. This corroborates the statements made in section 3.2.3 on the cost recovery challenges of these grid tariff designs.

3.3 Sensitivity analysis

In this section, we consider several scenarios where customers have increasingly higher volumes of flexibility (and where appropriate the anticipated increase of load), prompted by the energy transition, in order to test the robustness of the quantitative results found during the impact assessment (i.e. section 3.2). In particular, as described in the introduction of this deliverable, multiple challenges and opportunities are increasingly impacting the grid operation. Via this sensitivity analysis we aim to capture the effect of increasing the amount of flexibility in the consumption profiles (amongst others due to the increased electrification of heat and mobility) on the medium to longer run. The sensitivity analysis has the following aims:

1. To quantify the effect of increasing volumes of flexibility (and where appropriate the anticipated increase of load) on the congestion of the network, and;
2. To quantify the effectiveness of an adapted tariff design in reducing congestion in each of the flexibility scenarios.

For the elaboration of the sensitivity analysis we focus on the implementation of tariff 5, being the dynamic gradual tariff design. From the impact assessment it became apparent that this tariff design provides a good approach to tackle both DSO and TSO congestion risks. Furthermore, the impact on the consumer invoice as well as on cost recovery of the DSO could be kept within bounds. Given the future outlook of the sensitivity analysis, anticipating for mid- to long run scenarios, it can be assumed that grid users will have better access to smart meters and automated control devices to anticipate the hourly grid tariffs in the best possible manner.

We focus our simulations on feeder ID 33, being the feeder presenting the highest number of congestion events, defined as the number of hours classified in ratings A,B and C.

3.3.1 Selection of flexibility scenarios

The core of the sensitivity analysis considers the quantification of the consequences of taking steps in the energy transition, viewed from the grid user. In particular, we consider multiple scenarios with differing volumes of flexibility devices which are compared to the scenario presented in Section 3.2, representing the current practice. This latter scenario is, in the remainder of this section, designated as the “main scenario”.

The sensitivity analysis captures one scenario in which customers offer less flexibility than within the main scenario. An interplay of different factors can lead to a reduced or delayed provision of flexibility by the grid user (e.g. price elasticity, risk aversion and lack of supporting technologies). Hence, this scenario is developed to grasp a worst-case perspective on the performance of the selected tariff 5. The worst case scenario is complemented with three scenarios where consumers are expected to offer higher volumes of flexibility and/or have access to more flexible devices. The scenarios are summarized in Table 25: Flexibility scenarios studied in the sensitivity analysis. In the definition of the scenarios, we consider flexible assets to be either heat pumps, electric heaters and electric vehicles. Higher general flexibility percentages indicate that consumers have a higher willingness to shift their load, by actions that reflect a higher elasticity or energy-conscious behaviour on the part of the consumers themselves, or any so-configured (minor) smart appliances (that exclude those defined as flexible assets).

Table 25: Flexibility scenarios studied in the sensitivity analysis

Flexibility Scenarios	Description
Low	3% general flexibility of demand, no flexible devices
Main Scenario	10% general flexibility, current portfolio of flexible devices*
15 Flex	15% general flexibility, current portfolio of flexible devices*
More Devices	10% general flexibility, double the number of flexible devices*
High	15% general flexibility, 20-25% of customers have flexible devices

*The current portfolio of devices on feeder 33, as summarized in Table 17.

3.3.2 Effect of flexibility on the congestion of the network

In a first instance we assess the effect of the varying volumes of flexibility and adapted portfolios of flexible devices on the operation of the grid. In particular, the effect on the occurrence of grid congestion is considered. We compare the status of the distribution network, under the assumption of a reference tariff, for all the predefined scenarios, by looking at the number of hours classified into the congestion rating states E to A. Table 26 shows the number of hours by congestion rating under several flexibility scenarios. Flexibility increases across scenarios from left to right. Recall that the 'main scenario' considers the grid operation, and entailing risk on congestion, as elaborated in section 3.2.

Table 26: State of congestion across flexibility scenarios

Flex Scenarios	Low	Main	15 Flex	More Devices	High
Rating for Reference	3% flexibility, no devices	10% flexibility, current portfolio	15% flexibility, current portfolio	10% flex, double the number of devices	15% flexibility, 20-25% of customers have devices
Activated Annual Flexibility (kWh)	2 764	20 163	21 692	32 985	82 781
E	8 480	8 258	8 198	7 089	6 503
D	264	409	441	657	612
C	13	82	106	513	291
B	1	9	11	190	172
A	2	2	4	**313**	**1182**

Flexibility is commonly stated as a key facilitator of the energy transition and important asset in the operation of our electricity grids. In this context, we would expect a positive effect on the grid state at increasing levels of available flexibility. However, as shown in Table 26, by gradually increasing the portfolio of flexible assets, the additional consumption of these new assets burdens the distribution network rather than that their flexibility mitigates congestion risks. As a consequence, we see an increased number of higher congestion risks, with ratings A, B and C becoming increasingly populated, as the number of flexible devices increases.

This is due to the increased load brought by the new flexibility devices, while network capacity (and definition of congestion ratings) is kept the same. Note in particular that, for the scenarios with highest flexibility, the number of hours in rating A increase dramatically. This indicates that the network is now confronted with significantly more load, and tightly used network capacity.

It must, however, be pointed out that the ratings scale, as shown in Table 16, was calibrated for the main scenario, which did not see any congested hours within the standard definitions of voltage and power limitations (i.e. considering the typical congestion-defining limits being nodes with less than 90% of rated voltage of the reference node, and line flows approaching or surpassing the 100% capacity rate of the power lines of the network). With the higher loads seen in the scenarios of higher flexibility, a recalibration of the rating scale could now adhere to the standard definitions of congestion. Figure 33 illustrates the effect of higher loads brought by the high-flexibility scenarios on the distribution network.

Figure 33 shows the most congested hour of the year observed for each flexibility scenario. The x-axis displays the occupancy rate of the most-loaded power line in the distribution network below the feeder-level, while the y-axis represents the largest nodal voltage drop with respect to the reference node. As showcased through this plot, as the number of flexible devices stepwise increases (i.e. moving from the current number of devices in the blue, orange and yellow dots to an increased number of devices in the purple and red dots), the most congested hour shifts further to the bottom right. This means that the worst nodal voltage drops and the occupancy rate of the busiest line increases. Crucially, for the two scenarios with increased numbers of flexible devices, the most congested hours are very heavily congested, with voltage dropping below 0.90 p.u. and power exceeding 100% of line power rating.
Consequently, the results in Figure 33 are not to be interpreted as if the least flexibility available, the better for the system, as it is not the increase in flexibility (i.e. hovering over the blue, orange and yellow dots) that gives rise to significant increasing congestion issues. It is rather the increased loading of the network due to the additional connection of electric loads (i.e. the shift to the purple and red dots) which is entailing a higher risk on congestion. In fact, when comparing similar loading conditions with and without using the inherent flexibility, it is intuitive that the risks of congestions would be significantly higher when the flexibility of the additional flexible assets is not provided to the system. To conclude, the added flexibility by the new flexible assets and the improved ability to shift energy consumption to better times during the day, in the 'more devices' and 'high' scenarios, is not able to completely cover the induced disadvantage of the added load stemming from the flexible devices (e.g. EVs and HPs). One of the main takeaways here is that, although the flexible devices have a huge flexibility potential, there might still remain a need for network investments to accommodate the growth in loads, depending on the local circumstances. The flexibility at the consumer side can be explored to solve congestion instances on the medium run. However, on the longer run, a heavy-loaded system with continuous structural congestions, would require an increase in network capacity, as flexibility alone – under those circumstances – cannot resolve all congestions. If the available flexibility is however exploited in an efficient manner, via dynamic distribution tariffs or other flexibility mechanisms, these flexible devices can contribute to relieving their own impact and reduce the investments required for upgrading the distribution system.[33]

Figure 33, the figure showing the most congested hour, serves as a visual representation of the effect the additional flexible assets have on network congestion. The more flexibility there is, the more load there is on the network, and the higher the number of congestion events.

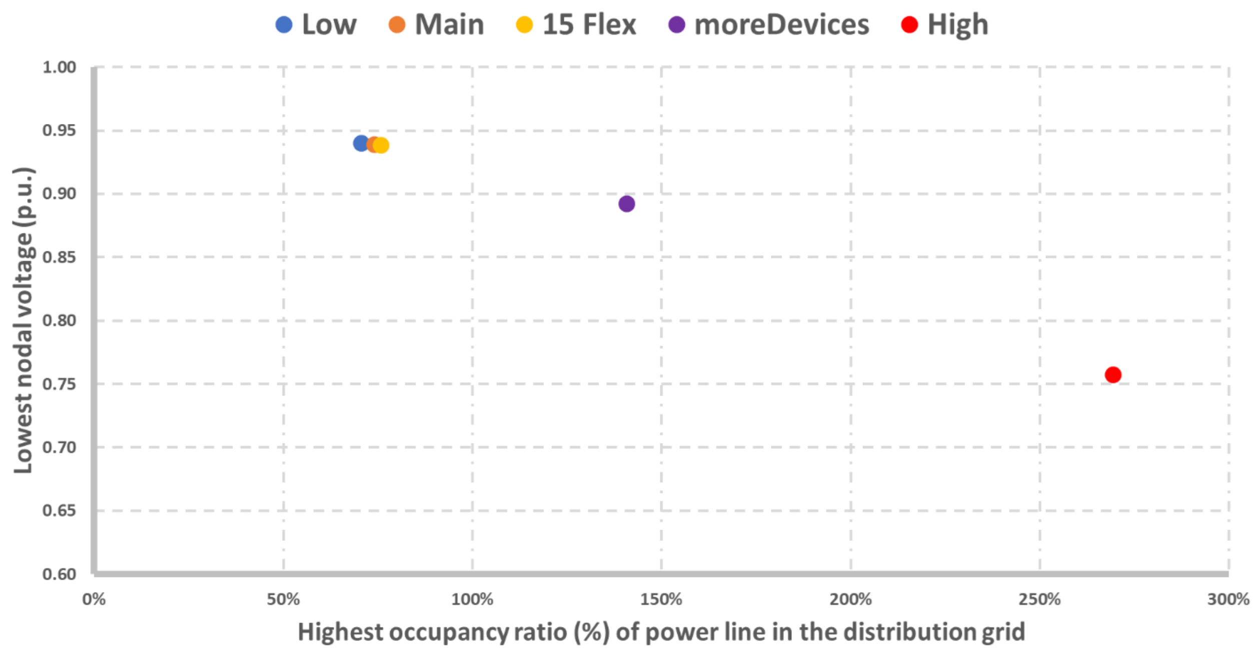


Figure 33: Most congested hour across flexibility scenarios

3.3.3 Effect of flexibility on the effectiveness of a dynamic grid tariff

A second glance at the sensitivity analysis provides an indication of the effectiveness of a gradual dynamic grid tariff design (as described in section 2.3). We established that, in future scenarios, with the introduction of more flexible devices, the load on the distribution network increases, leading to more congestion issues. These findings are made under the assumption of the current practiced grid tariff (i.e. reference, flat and volumetric grid tariff). The objective of this part of the analysis is to measure how well the dynamic tariff 5 manages to reduce congestion in the network.

We evaluate the performance of tariff 5 across the different flexibility scenarios by looking at the relative change of the number of hours of each congestion rating. The expectation of this analysis is to investigate whether tariff 5 can succeed in reducing higher shares of congested hours as the number of flexible devices increases.

Table 27 - Table 31 show a comparison between the number of hours classified by congestion rating for the reference tariff and tariff 5, under the different flexibility scenarios.

Table 27: Congestion state reduction – 'low' flexibility scenario

Low	Reference	Tariff 5	Relative variation
E	8480	8538	0.7%
D	264	212	-19.7%
C	13	7	-46.2%
B	1	2	100.0%
A	2	1	-50.0%

Table 28: Congestion event reduction – 'main' scenario

Main Scenario	Reference	Tariff 5	Relative variation
E	8258	8298	0.5%
D	409	394	**-3.7%**
C	82	64	**-22.0%**
B	9	4	**-55.6%**
A	2	0	-100.0%

Table 29: Congestion event reduction – '15 flex' scenario

15% Flex	Reference	Tariff 5	Relative variation
E	8198	8299	1.2%
D	441	384	**-12.9%**
C	106	74	**-30.2%**
B	11	3	**-72.7%**
A	4	0	-100.0%

We observe across all results in Table 27 - Table 31 that tariff 5 is effective at reducing the number of hours from the most congested states, particularly in the scenarios where a significant volume of flexibility is provided without impacting the portfolio of flexible devices (i.e. scenario 'main' and '15 flex'). In the first 3 scenarios, where the available flexibility is gradually increased, we see that the effectiveness of tariff 5 in reducing the number of congestion events, increases under a moderate increase in flexibility. This is particularly clear when comparing scenario '15 flex' with the main scenario, where the relative variation in '15 flex' is consistently higher (in magnitude) in ratings D, C,B and A than in the main scenario. This suggests that under moderate increases in flexibility, tariff 5 can take advantage of the increased flexibility to reduce congestion in the distribution network. In the scenario of 'low' flexibility, there are few congested hours ranked A, B or C, so any interpretation on the relative variation between tariff 5 and the reference must acknowledge the low numerical representation of instances of ratings C, and more especially, B and A.

Table 30: Congestion event reduction – 'more devices' scenario

More Devices	Reference	Tariff 5	Relative variation
E	7089	7144	0.8%
D	657	602	-8.4%
C	513	512	-0.2%
B	190	190	0.0%
A	313	312	-0.3%

Table 31: Congestion event reduction – 'high' flexibility scenario

High	Reference	Tariff 5	Relative variation
E	6503	6703	3.1%
D	612	478	-21.9%
C	291	188	-35.4%
B	172	120	-30.2%
A	1182	1271	7.5%

When the flexibility increase is due to an increase of flexible devices, such as in the two last scenarios (i.e. the 'more devices' and 'high' scenario), the increased load in the network renders tariff 5 (under its current calibration) to be less effective at reducing congestion than in the previous scenarios. Although there is more flexibility available, the additional load stemming from the flexible devices leads to more occurrences with congestion risks. The additional load needs to be met during the course of the day (given the characteristics of the flexibility), leading to more hours with an A; B or C rating which cannot be mitigated by using the additional flexibility in combination with a dynamic tariff.

Tariff heights are calibrated by anticipating the number of congested hours expected in the year, so as to recover the tariff revenue to the DSO. If congestion is higher than expected by virtue of increased load, the revenue will be higher than anticipated, as more hours will be priced at higher tariff rates. This means that to succeed, DSOs must accurately anticipate the congestion of their network, and price volumetric (and capacity) rates according to their forecast.

Table 32 shows the cost recovery of the reference tariff and tariff 5 across different flexibility scenarios. For the calculation of the recovered budget, the tariff rates as calibrated in section 3.1.2.2 are considered. In this table we see reflected that, as many more hours are classified as having rating A, B and C in the 'more devices' and 'high' scenarios, the occurrence of higher rate heights is increasing. Consequently, the grid invoice for the consumers becomes increasingly expensive. We see from Table 31 and Table 32 that consumers pay the highest peak tariffs (at stage A) in order for them to match the required load during the day.

Consequently, the recovered budget as a DSO is undue. This could fuel the discussion that tariff heights must be calibrated for each network, following a good anticipation of the load and flexibility expected on the network. However, given the available network capacity, at a certain future scenario, the consequential additional load makes it unable to render a tariff outcome in the calibration exercise. Despite necessitating a recalibration of tariff rate heights and congestion thresholds, if network loads are too high, tariff 5 will be unable to resolve congestion effectively, and the network will simply have to be upgraded to be able to handle higher loads.

Table 32: recovery cost gap across scenarios

Flexibility Scenarios	Reference cost (€)	Tariff 5 cost (€)
Low	10 771	11 819
Normal	13 204	13 164
15 Flex	13 235	19 590
more Devices	15 698	21 798
High	18 643	141 985

4 Conclusions/recommendations

4.1 Integrated conclusions on grid tariff design

General design issues

A grid tariff design must allow DSOs to recover the cost of providing network services while respecting overall design principles (e.g. cost reflectivity, non-discrimination, simplicity and non-distortion). There exists a consensus by different stakeholders and in the literature on these regulatory design principles that grid tariffs should observe. However, despite that these principles provide guidelines on how grid tariffs should be designed, there is still room for interpretation. Which principles need to be considered and the relative importance of these can be argued to differ. To complicate the assessment exercise, it is important to note that these principles may be conflicting and the fulfilment of all of these principles or objectives might become complex. This entails a complex balancing exercise where the importance of the regulatory principles needs to be weighed. An example, particularly relevant for this analysis, is the conflict between simplicity and transparency from the perspective of the grid user on the one hand and cost-reflectiveness and economic efficiency from the DSO perspective on the other hand. While tariff designs based upon a fixed tariff driver score the maximum points on simplicity and transparency, there is absolutely no link to the cost drivers of the DSO nor does it provide sufficient incentives for rational grid usage. On the other hand, dynamic tariff designs which incorporate a real time signal to drive rational grid usage and reflect potential grid congestions have to forgo transparency and simplicity. Moreover, the consideration of certain design principles influences the performance of the grid tariff design in other aspects. For example, often economic efficiency is difficult to achieve if the customers cannot respond to the tariff signals due to limited understanding of the tariff signals or how to best act upon them. The regulator could use approaches based on multi-criteria analysis to weigh the different objectives and determine how to balance these competing principles.

The qualitative analysis has shown that grid tariffs can be defined by a multitude of components (e.g. tariff driver, time variability, granularity and dynamic element). Also, the interaction between these different tariff components gives rise to a complex balancing exercise. The interplay between these different components within a grid tariff design can influence the performance of the overall tariff design on the regulatory design principles. Furthermore, the effectiveness of certain tariff components is tied to the design choices made in other tariff dimensions. For example, if the tariff design contains a capacity trigger (i.e. €/kW used capacity) to maximise the cost reflectivity of the tariff design, the performance of this regulatory design principle is influenced by the granularity in which this usage of capacity is measured (for example, quarter-hourly versus monthly).

Another aspect which complicates the optimal definition of the grid tariff design is the presence of contextual factors which influence the consumer response and in parallel the performance of certain grid tariffs. Moreover, it is complex to identify the interplay between the grid tariff and potentially other signals for the end consumer (i.e. commodity price and commercial flexibility request). Certainly, since these contextual factors are also in full transition (e.g. elaboration of dynamic price contracts).

Furthermore, a future-oriented distribution grid tariff design needs to account for the challenges generated by new energy solutions like distributed generation, demand response, electrification of transportation (EVs) and heat (HPs), storage, and energy efficiency approaches. Hence, we should consider and anticipate the adaptations brought by the energy transition and develop grid tariff designs which can adjust flexibly if the context demands. The changing consumer context stresses the importance of the somewhat contemporaneous nature of the three building blocks of grid tariff design, being the allowed revenue, the grid tariff design and the rate height. In particular, each rate computation procedure must be modified multiple times in response to its impact on demand patterns (e.g., the efficient-promoting computed tariff rates can entail behavioural change of the grid user, enforcing adjustments in the tariff design to accommodate for the new consumption profiles).

Reflection grid constraints

In this study we provide particular attention to the consideration of grid constraints in the distribution grid tariff design. As elaborated, the reflection of the system peak or the grid state can be static (meaning that it is not existing), event-based (focussing on certain peak-events) or dynamic (continuous representation of the grid state). Hovering over the qualitative and quantitative assessment it becomes apparent that each of these implementations comes with certain advantages, disadvantages and prerequisites.

The **static** implementation of the grid constraints in the distribution tariff entails a lack of a direct and dynamic link to the anticipated day-to-day grid congestion. To accommodate for the inertia, historical data is used to define fixed time blocks as a proxy for the anticipated grid congestion. For the grid user, this is a very simple and easy to understand tariff scheme. There is only one tariff driver influencing the behaviour which enables the grid user to easily deduct the desired behaviour. Moreover, due to the fact that the time blocks and entailing tariff are known year-ahead and remain constant for a long period (i.e. only seasonal difference between summer and winter months), transparency and tariff stability are improved. Grid users can compute a better estimate of the total grid invoice. Additionally, owing to the time variation implemented, the total grid invoice impact is limited. Consumers can anticipate the peak time way ahead because this is the same for every day during the season (winter or summer) and the duration of the peak periods is limited so this gives consumers time to shift to a better moment, hence less effect on total invoice.

Although it was expected that the performance on the level of answering to grid constraints would be limited (due to the fixed interpretation of the grid state), the static tariff delivered surprisingly good results in mitigating grid congestions. This can be attributed to the tariff driver and time variability implemented and the predictability of the timing of peaks. As a result, every consumer is automatically given an individual incentive to use less capacity at predetermined peak times during certain hours of the day. Due to the consumers' responses (i.e. activating flexibility during these tariff times), the synchronous system peak on the feeder level is lowered. Hence, we can conclude that if the tariff blocks are set in the correct manner, based on extensive data analysis, the anticipated averaged definition of peak periods can lead to a considerable reduction of grid constraints. Lessons learnt on changing electricity consumption profiles, behavioural changes and integration of RES and flexible technologies can further optimize the definition of the static periods. Certainly, with the roll-out of smart meters and more detailed measurement equipment, leading to increased availability of data, the static periods can be further optimised to consider potential grid congestions way ahead. Another improvement can be to set the static periods for certain grid infrastructure separately. For example, data analysis on the feeder level could entail the creation of dedicated peak times and tariff blocks. In this case, locational differences can be incorporated to set the static tariff periods. However, it should be noted that with the increase of differentiating factors, the performance on other regulatory design principles, like simplicity and transparency, can be impacted (e.g. consumers will be exposed to other peak hours and tariff blocks when they move).

A downside of the static tariff design is the fact that, given the static definition of grid constraints, during certain peak hours flexibility will be activated, however, it might not be necessary. On the other hand, if flexibility is needed outside the previously defined peak hours, it is not visible in the tariff design, hence the grid user will not act.

In the **event-based** grid tariff designs, the grid user is notified day-ahead of the potential congestions, defined on a daily basis. This increases the simplicity and clarity of the tariff for the grid user.

Consequently, the deduction of the 'best behaviour' is improved. However, due to the fact that the congestion indicator is set for the entire day, the level of influence of the grid user is very limited. In order for the grid user to benefit from the tariff spread between low and high peak days or A-E ratings, he is required to shift high capacity usage over to the next day. Only a very small portion of flexible consumption can be shifted from one day to another (e.g. battery) or we are intervening in the comfort level of consumers. Nevertheless, the implementation of a daily peak pricing incentivizes consumers to reduce the maximum daily peak demand regardless of the applicable tariff period. In particular, every reduction of maximum daily peak demand entails a reduction in the grid invoice.

Given the capacity-based expression in the tariff design, which is the main cost driver of using the distribution grid, there is a trigger for rational grid usage. Furthermore, this tariff design entails a good combination of a local trigger (capacity driver) with a congestion signal (rate height is set by the day-ahead congestion signal). The local capacity trigger could already mitigate certain low voltage congestions, entailing that fewer days will be qualified as high tariff periods.

A consequence of the daily definition is the fact that this tariff design seizes excess flexibility. Flexibility can be expected for the full day even when this is not necessary in the context of grid congestion. For example, the entire day can be considered a 'peak day' due to one hour having a risk of congestion. This affects the response to a redispatch signal but also commercial market requests for flexibility. On the other side, once the maximum capacity of the day is reached, every price arbitrage action for other purposes (e.g. answering to a commercial flexibility request or in function of dynamic price contracts) below that threshold is possible without an invoice impact for the grid user.

The daily definition of the tariff trigger can be seen as the maximum level of granularity when manual control is implemented. Hence in a manual control environment, particularly the case in the first years of the smart meter roll-out, before mass market penetration of smart, supporting technologies, this is the most advanced tariff design practically implementable for residential consumers.

Finally, to conclude on the possible tariff periods (i.e. binary or gradual), it can be noted that, the result show no particular effect on the performance of the grid tariff designs nor on the volume of flexibility offered. This is due to the daily definition of the tariff period and the fact that the technical characteristics of most flexible technologies do not foresee a shift in behaviour from one day to another. Thus, the opportunity to benefit from the tariff spread between off-peak and peak periods on one hand and the A-E rating on the other hand cannot be reaped, leading to no significant differences between the two approaches.

It should also be noted that if automatic control devices are largely deployed, new ramp up and ramp down events will occur under binary tariff periods. This could be avoided with more gradual approaches.

Finally, the **dynamic** tariff designs introduce an hourly granularity into the grid tariff. Such tariff designs can become rather complex for the grid user due to the variety of signals perceived. Not only is he exposed to an hourly changing tariff but, in the gradual definition, to 5 different tariff stages.

This hourly changing tariff trigger is very demanding for the consumer. Certainly, in a manual control environment, a significant amount of effort is needed from the grid user to assess the different hourly rate heights for the next day and deduct the best behaviour. The latter is a very complex exercise since a lot of consumption appliances cover multiple hours once turned on. A grid user can decide, for example, to turn on the washing machine at the cheapest hour of the day, however, due to a high peak tariff applied in the next hour the overall cost for running the washing machine is higher than in the reference case. Hence dynamic tariffs assume there is automated control equipment which performs this optimization exercise in the background.

In the implementation of this tariff design, a volumetric tariff driver is foreseen. However, since the rate height is set every hour, reflecting the hourly grid state, there is a consideration of capacity included. In this context, rational grid usage is considered. One should always create a reflection to capacity. Thus, if a volumetric tariff driver is chosen, this impacts the other design choices in order to reflect upon capacity usage in another manner. With a daily definition of the volumetric tariff trigger, for example, there is no incentive to limit the capacity request during the day. This can lead to additional offtake congestions. Hence, from the perspective of the rational grid usage and reflection of cost drivers of the DSO, the hourly tariff dimension is required when implementing a volumetric trigger.

The hourly definition of the tariff coincides with the time definition of dynamic price contracts. Hence, consumers, or automated technologies commissioned, perform an economic trade-off which does not only considers the grid tariff but also the applicable commodity price. The resulting aggregated hourly signal and consequent consumer response can have an impact on the performance of the dynamic grid tariff. For example, a high price arbitrage potential in the context of dynamic energy price (e.g. in function of high RES on the market) could still lead to high levels of consumption during certain hours regardless of the anticipated grid congestion risk and peak tariff applied. Certainly, as there is no daily trigger or threshold defined to stay below a certain capacity.

Also, the coordination between the flexibility request of the TSO (in function of redispatch) and the objective to reduce grid congestion of the grid tariff is improved via the hourly granularity. There is more room to respond to the redispatch signal since there is an hourly assessment of the DSO grid congestion state. Hence, the grid state is only valid for the respective hour and does not captivate the entire day.

With regard to the differentiation in defining the grid congestion based on a binary signal or gradual signal, it is to be noted that with the binary setting, the tariff spread is more exposed and clear for the consumer and might induce a higher response. With the gradual approach, the rate jumps between the different stages will define the performance. Consumers might not perceive the rate jump from one stage to another to be sufficient to adapt the behaviour.

4.2 Tariff design as a solution for grid constraints

As stated earlier, tariff designs are part of a larger portfolio of measures available to the DSO to accommodate grid congestion risks. In this section, we provide concluding remarks and attention points when considering tariff designs as a solution to limited grid capacity.

In the case of dynamic tariffs, the timing of the tariff blocks may change from day to day (or even more often) for example to reflect a local or system peak. Notably, ex-ante cost determination provides strong signals to grid users for when it is best to restrict grid usage. However, it does not guarantee that the reaction of the grid users will be effective when capacity is scarce since it is based on predictions. For tariff designs to transmit correct signals, grid congestion must be accurately predictable, ahead of real-time, which is rarely the case today.

With regards to residential consumers, the principles of simplicity and predictability can be questioned when an extensive reflection of the grid state is implemented. Also, grid tariffs can become more volatile and harder to predict. However, the growth of automated control and other innovations are likely to address this gap in the future.

The time-varying price signals have the risk to be counterproductive if they are set by default for every grid user and any grid location without differentiation. If generalized they could influence customer behaviour in a way that is not necessary the correct one to solve the local needs or grid congestion and seize flexibility which could serve other purposes (e.g. system needs). In parallel, the approach to define the system peak benefits from differentiation. In particular, the more the system peak is measured on a smaller scale, i.e. closer to the effective grid user, the stronger the tariff can give direction to rational network use at local level. But this involves a high level of complexity, measurements, locational differentiation….

Addressing a structural shortage of network capacity through a systematic shrinkage of the renewable generation (including through tariff signals) is contrary to the goal of sustainable generation support, which aims to maximize renewable production. Given the typical structure of the electricity grid, persistent distribution network congestion is likely to jeopardize the continuity of service. It may also be an indication of a non-optimally dimensioned network. Where grid congestion is a structural feature of the system, tariff designs that are captured far ahead of real time are imperfect alternatives to dynamic tariff schedules.

Furthermore, the effectiveness of dynamic grid tariff designs is influenced by contextual parameters, like dynamic commodity prices for example. The two signals perceived by the grid user are not always aligned since they are reflecting scarcity on different levels. While an energy price measures scarcity in the wholesale market at the system level, the (dynamic) grid tariff aims to reflect scarcity on the grid. There are two sources of interference with the signal from the energy component, i) opposing price signals (e.g. higher grid costs due to peak hour definition), or ii) threshold for consumption. The latter, capacity threshold, inhabits more potential to mute market signals which is aggravated when the threshold or tariff signal comprises a longer period (e.g. yearly defined).

5 External Documents

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Annex I – Questionnaire implementation grid tariff

1. Regulated budget and cascading

Please indicate the laws, grid codes or technical norms where the aspects are regulated. If English versions are available, please use this version. If not, reference the documents in the language available.

1.1 Regulated budget

1) Which entity is in charge of calculating the regulated budget?

The first step in the procedure to calculate grid tariffs is the determination of the regulated budget. Usually, this value is established by the regulator responsible for determining the calculation method, but other entities might be in charge of the calculation.

☒ DSO	☐ Regulator	☐ Other, please specify

Please explain:

Corresponding document/norm:

2) Is the regulated budget published? Please provide the link to the information.

1.2 Cascading principle

1) Which entity is in charge of defining the methodology for cascading[7]?

A second step in the procedure to calculate grid tariffs is the allocation of the regulated budget to the different groups of grid users (e.g. depending on the voltage level).

☐ Methodology determined by regulator	☐ Methodology determined by DSO and approved by regulator	☐ Methodology determined by DSO without supervision of regulator	☐ Other (please specify)

Please explain:

Corresponding document/information:

2) What is the basis for differentiating in function of cascading?

Normally this is based on voltage level but other methods can be applied.

[7] The principle whereby grid costs are divided on the basis of load flow data between consumers connected to that network level (e.g. voltage level based) and the connected lower networks or voltage levels.

☐ None	☐ Different for generation and demand	☐ Different according to voltage level
☐ Locational differences (e.g. nodal, urban/non-urban)	☐ Other (please specify	

Please explain:

Corresponding document/information:

3) What is the distribution key implemented across the different cascading levels (e.g. voltage levels)

☐ Distribution depending on energy offtake	☐ Distribution depending on number of grid users	☐ Other (please specify)

Corresponding document/information:

2. Distribution grid tariff design

2.1 Current practices

1) Which tariff driver(s) is (are) applied for invoicing distribution grid connected grid users?

☐ €/kWh	☐ Fixed € amount	☐ € / kW
☐ €/kVA	☐ Other (please specify)	

Please explain:

Corresponding document/information:

2) If there are multiple tariff drivers, please specify the ratio in which the grid costs are attributed to the different tariff drivers.

Please explain:

3) Is time variation implemented in the distribution grid tariff design?

☐ No time variation, one tariff for all time periods	☐ Limited variation, tariff which differentiates between day and night	☐ Multiple time periods	☐ Other (please specify)

Please explain:

Corresponding document/information:

4) <u>What is the granularity in which the tariff driver is set?</u>

☐ 15 min	☐ Daily	☐ Weekly
☐ Monthly	☐ Yearly	Other (please specify)

Corresponding document/information:

5) <u>Is there a differentiation across grid users?</u>

☐ No	☐ Differentiation depending on voltage level	☐ Differentiation depending on order of magnitude of energy consumption	☐ Other (please specify)

Please explain:

Corresponding document/information:

6) <u>Are locational signals implemented in the distribution grid tariff</u>

☐ No	☐ Nodal signals	☐ Zonal signals	☐ Other (please specify)

Please explain:

Corresponding document/information:

7) <u>Is a dynamic element present in the current distribution grid tariff design?</u>

We refer to the aspect of e.g. changing time blocks, changing tariffs,.., in order to reflect the grid state in the grid tariff design.

☐ Static grid tariffs	☐ Dynamic grid tariffs

Please explain:

Corresponding document/information:

8) Are the grid tariffs equal for generation and demand, please specify?

☐ Yes	☐ Different for generation and demand	☐ Other (please specify)

Please explain:

Corresponding document/information:

2.2 Transparency

1) How are the distribution grid tariffs published and where can the tariffs be consulted by grid users?

Corresponding document/information:

2.3 Reformation

1) Have the current practices regarding grid tariff design been assessed via a (pilot)project or study? Please provide the link to these studies.

Corresponding document/information:

2) What where the lessons learned? What are the positive and negative aspects linked to the current practice of grid tariff design?

Corresponding document/information:

3) Are steps taken to reform the current grid tariff design? Is this documented? Who is taking action in this regard?

Corresponding document/information:

4) What are the expected reformations scheduled with regard to distribution grid tariff design?

Corresponding document/information:

3. Link to other stakeholders

1) Is there an alignment between the TSO and DSO grid tariffs? Are for example the design, tariff drivers and incentives send to the consumers aligned in order to get a uniform signal to the end consumer or are they rather defined separately? Please specify.

Corresponding document/information:

2) Which stakeholder invoices the grid tariffs to the grid user?

☐ Supplier	☐ TSO and DSO separately	☐ DSO invoices both transmission and distribution tariffs	☐ Other (please specify)

Corresponding document/information:

3) How are the transmission and distribution grid tariffs displayed for the grid user?

☐ Displayed separately on the invoice	☐ Displayed in a combined manner	☐ Other (please specify)