Master Thesis "Energy Science"

Distribution tariff design considering electric vehicle loads

Capacity subscription model compared to dynamic day-ahead grid tariffs

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Summary

As part of reducing the emissions from personal transportation EV adoption is expected to rise dramatically in the coming decade. Whilst this has a positive effect on climate targets issues the current distribution networks for electricity were not built to accommodate the large rise in EV. This problem can be tackled in a number of different ways, such as by expanding network capacity, or including of storage at the distribution level. This thesis, however looks at price based incentives to mitigate the adverse effects of EV charging on distribution grids. In particular a restructuring of distribution grid tariffs was considered. Distribution grid tariffs are the tariffs paid by customers to distribution system operators (DSOs) for use and maintenance of the grid. Currently most customers connected to the low voltage distribution grid pay a flat rate for the grid tariffs. However, by restructuring these grid tariffs incentives can be provided in order to make sure EVs use the flexibility which exists in the charging sessions in order to limit congestion issues. In particular this study will look at public charging, that is charging points (CPs) connected to the distribution network and operated by a charging point operator (CPO).

Two particular proposals for grid tariff redesign were assessed. In the capacity subscription plus model (CAP+) the customer chooses a subscribed capacity, that is a power up to which the customer can freely use the grid. This subscribed capacity has options at a few different capacity sizes with associated costs. When the customer exceeds the subscribed capacity an exceedance fee has to be paid for each exceeded kilowatt-hour. The other considered option is a particular case of dynamic grid tariffs where the CPO pays differing prices for power used at particular times. How much power can be used at each time at the differing price levels is determined the day ahead. This tariff design bundles all CPs connected to the same transformer, thus the total power is what matters rather than the individual power of the CPs.

A perfect information model was constructed to find the optimal CPO behavior on a cost-wise basis under the different tariff designs (current, dynamic and CAP+). It is evident from the results that if the tariff design is left unchanged, and no alternative measures are taken to address the issue of transformer overloading due to EV charging at public charging points, problems are likely to occur. Introducing the CAP+ tariff design can mitigate part of this problem. But as the CAP+ tariff design focusses on individual usage peaks rather than the collective network peak which causes this transformer overloading it is not as effective at reducing transformer overloading as the Dynamic tariffs can be.

For the implementation of a tariff design more factors need to be considered, however. The regulatory authority (ACM) is responsible for accrediting a tariff design and considers factors such as non-discrimination, simplicity, transparency and more. In this regard the dynamic tariffs are more controversial as it requires technological capabilities and has a fairly complicated mechanic involving predicted transformer loads. Whether the advantages of the dynamic tariff design in terms of efficient network use, and thus overall costs reductions, outweigh the problems with current legislation and these regulatory principles is, in the end, a decision to be made by the regulator and is left outside the scope of this research.

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Contents

Abbreviations

ACM	**Authority for Consumers and markets**
CAP+	**Capacity subscription plus exceedance fee**
CEER	**Council of European Energy Regulators**
COA	**Charge-on-arrival**
CP	**Charging point**
CPO	**Charging point operator**
CPP	**Critical peak pricing**
CRI	**Cost-reflectiveness indicator**
CT	**Current tariff**
DSO	**Distribution system operator**
E.DSO	**European Distribution System Operators**
EU	**European Union**
EV	**Electric vehicle**
LMP	**Locational Marginal Price**
LV	**Low voltage**
PV	**Photovoltaic**
RO & SO	**Research objective & sub-objective**
TSO	**Transmission system operator**
V2G	**Vehicle to grid**

1 Introduction

The power system is rapidly changing, and with this the requirements for electrical distribution grids. Historically the requirements for electric distribution systems, in terms of the loads it was required to handle, were relatively fixed only gradually increasing with an increase in regular household electrical demand. But with an increase in adoption of distributed energy resources (DERs) these requirements are now changing quicker than ever. As much of the current infrastructure was built decades ago, it is not able to handle this sudden rise in demand and supply from rising technologies like electric vehicles (EVs) and photovoltaic (PV) systems (Henning et al., 2020). This is especially the case since these technologies are mostly located in low voltage distribution networks, these were built with households and other small consumers in mind, with relatively low and constant loads and no decentralized generation. Whereas previously almost all generation was centralized and connected to dedicated higher voltage sections of the grid. Of particular interest is the rise in electric vehicles (EVs). The share of EVs in the passenger car fleet has risen from just 1.63% at the end of 2018 to 3.84% in September 2021. (Netherlands enterprise agency, 2021). Home charging capacities of EV generally range from 3.6 to 11 kW(Henning et al., 2020), with public infrastructure exceeding even these values. This is relatively high compared to the typical household peak of about 4 kW (Henning et al., 2020). This puts a strain on the distribution grid which can lead to overloading of cables and transformers (Hu et al., 2015). This overloading causes thermal the temperature of transformers to rise, whereas transformers must be kept below specified temperatures otherwise the transformer wear and tear increases (Pérez-Arriaga & Knittel, 2016). Problems occur in particular when the peak in EV charging coincides with the regular household demand peak (Anastasiadis et al., 2019; Sadeghianpourhamami et al., 2018) which is likely in the case of uncontrolled charging of EVs (Gerritsma et al., 2019).

These congestion problems can be addressed in different ways. Most obviously the infrastructure can be upgraded to handle the increased demand. Upgrading this infrastructure would involve replacement of transformers and cables. This upgrading of the grid is both expensive and can only be done at a limited pace(Henning et al., 2020). Limited pace may be exacerbated skilled technical labor shortages in the electricity sector (ACM, 2022). The high costs for upgrading the transformer mean the most financially viable option for consumers is generally not upgrading the transformer capacity. The costs of upgrading the transformer generally outweigh the benefits from EV charging under higher transformer capacity limits (Brinkel et al., 2020). Another option may be the addition of storage at the distribution level, which if placed at crucial locations in the grid could be used to balance power flows (Matthiss et al., 2021). These batteries however are also costly and network operators are (in principle) not allowed to operate their own storage facilities (Proka et al., 2020). Another option is to use direct load control. This means part of the load such as energy intensive customer appliances can be managed by the DSO when required. In the case of EV this could be the restriction of charging power. This, however could cause discomfort to consumers requiring fast EV charging or the use of energy intensive appliances such as heating or cooling. In addition an adequate legal basis for this needs to be established. The final option is to use demand side management through price based incentives. This incentivizes customers to shift loads for monetary benefits providing choice to the customer to provide flexibility.

EVs in particular have been identified as a potential source for this flexibility (Askeland et al., 2020; Gerritsma et al., 2019; Hildermeier et al., 2019). Vehicles are stationary 95% of the time and generally only need about 10 % of the time in a day for charging (Hildermeier et al., 2019). This leaves a large amount of time when the high power rating of the EV is not in use. By shifting some of the charging loads away from peak hours, flexibility can be provided alleviating the aforementioned grid problems. However, EV owners are currently not incentivized to use the potential for this flexibility. One way incentivize the use of this flexibility for distribution grid stability is though price based incentives (Hildermeier et al., 2019). These price based incentives may be provided by altering the way customers pay for the distribution grid (D-Cision B.V. & Ecorys B.V., 2019).

The charges customers pay for the distribution grid are referred to as (distribution) grid tariffs. They exist for the distribution system operator (DSO) to cover the cost of efficient operation of the distribution grid. These costs are separate from the costs for the electricity itself which are paid to the electricity supplier and are what covers the cost of generation.

Distribution system operators (DSOs) charge customers for the delivery of electricity through local distribution grids. In the current situation customers with connection sizes from 1x10A to 3x25A, mostly households and small businesses as well as charging point operators (CPOs), pay the same flat fee for the complete grid service(Stedin, 2022). This provides no incentive to switch loads away from peak hours. Switching these loads away from peak hours would make for more efficient use of the network. In addition, when some customers have large flexible loads, such as EVs, these customers will use much more than the 4kW of calculation capacity which was used to calculate their current tariffs. This means the tariffs will become unreflective of the real costs caused by these customers (OTE, 2018). By changing the distribution tariffs the costs may be made more reflective as well as incentivizing efficient network use for EV charging.

Two tariff designs of particular interest are *capacity subscription models with (plus) exceedance fee (CAP+)* and *dynamic, day ahead grid tariffs (referred to as dynamic tariffs)*. Capacity subscription models, such as the one examined by (Henning et al., 2020) refer to the fee that is paid which allows for use of the network up to a certain power rating, thus a fee is paid for the agreed upon peak power consumption (€/kW) (the subscribed capacity). In this particular example exceedance of this subscribed capacity is allowed. That means the customer is allowed to exceed the load given by the subscribed capacity, however an exceedance fee is incurred per kWh (€/kWh) over the load which exceeds the subscribed capacity. This combination will thus be referred to as CAP+. Higher power capacities will be more costly thus incentivizing to take the lowest capacity subscription suitable to the situation. This CAP+ model may be relatively easy to implement and provide some amount of incentive for EV charging management as customers will not want to unnecessarily increase their subscribed capacity and incur the associated costs.

Dynamic grid tariffs, which can be used to mean a number of different options for tariff design. However, for the purpose of this thesis dynamic grid tariffs will refer to a fee per kWh for which a set of prices is established. For each time it is determined one day ahead how much power can be used at which fee, for instance the first 30 kW at lower fee, the next 25 at a middle fee etc. The amount of power is related to the expected "space" on the transformer, that is the expected amount of capacity available before causing transformer overloads. However, such tariffs may have greater issues in implementation as it requires IT for customer adaptation to these tariffs.

Many types of customers on the distribution grid exist, which can have vastly different load profiles. As mentioned before EVs in particular have been identified as a potential source of flexibility. Many EVs can be charged at home or at public charging points, operated by charging point operators (CPOs). The focus of this thesis will be on these CPOs as customers. The reason for this is twofold. First, it can be assumed CPOs have better technological capabilities to respond to price incentives than households and secondly CPOs, which operate public charging points for EVs will naturally locate themselves in places of high demand for EV charging. The choices for the tariff designs included, as well as the focus on CPOs as customers will be further elaborated on in section 3 on the scope of the thesis.

1.1 Scientific and social relevance

Literature exists looking at the separate effect of proposed *capacity subscription with exceedance fee (CAP+)* (Henning et al., 2020) and at the effect of dynamic grid prices. In the paper by (Henning et al., 2020) the CAP+ tariff design was looked at in the context of households. They showed that for this particular context the CAP+ tariff design would be more cost reflective and lead to less congestion than the current tariff design. However, in the case of households the CAP+ tariff design functions by shifting loads away from the peak of regular household use. The effect of a CAP+ model on fully flexible loads, such as public charging points has not been studied. Dynamic grid tariffs considered in literature tend to use more complicated marginal pricing methodologies based on a marginal price approach (Bergaentzlé et al., 2019; Huang et al., 2015; Li et al., 2014). This means the cost of delivering one additional kWh of energy at each location is calculated through modeling the power flows. These approaches however, have the issue that they requires extensive measurements and power flow calculations to determine prices. Furthermore this would lead to differentiation of price on the individual connection level. This results in challenges from a technical perspective as well as regulation which requires a degree of transparency and simplicity. This thesis will investigate a methodology to determine dynamic grid tariffs that focusses on probability of transformer overload, rather than marginal costs using one tariff per low voltage grid (grid connected to a single LV transformer). When this is done, a comparison can be made between this Dynamic grid tariff model and the CAP+ model proposed. This comparison will be done on a broader set of metrics taking into account the interests of different stakeholders including DSOs and customers as well as compliance to regulation.

As DSOs and stakeholders are currently considering a redesign of the tariff structure, this thesis aims to provide insight in the decision making process. Current tariff design has been identified as a barrier to the energy transition (OTE, 2018). A deeper look into these two options, especially considering the increase in connections of the customer type CPO (Elaad, 2021), provides information on the basis of which decisions can be made in both the short and long term.

1.2 Research goals

The primary goal of this research will be:

To evaluate the effect of capacity subscription and dynamic day-ahead distribution grid tariff designs from a customer (CPO), DSO and regulatory perspective.

1. *To obtain a complete overview of metrics on which a tariff design needs to be evaluated.*
2. *To create a set of evaluation parameters which can be used to evaluate the grid tariff designs on the basis of the metrics found in (1)*
3. *To develop a model to assess the effects of the tariff designs on quantitative metrics including congestion and CPO costs.*
4. *To analyze the considered tariff designs on the basis of the evaluation parameters (2) .*

In objective 1 a precise overview of metrics for assessing effects of the selected tariff on the customer, DSO and compliance with regulation are obtained. Next in objective 2 a set of evaluation parameters is constructed which is used to be able to evaluate the tariff design on the different metrics. These evaluation parameters are, as far as possible, concrete and applicable definitions based on the metrics found in sub-objective (SO) 1. When this is achieved the effect of the tariff design on quantitative metrics is modeled. These quantitative metrics include among others congestion and CPO costs. For this step it is also required to construct a methodology for determining the dynamic day-ahead grid tariffs. Finally these quantitative results are combined with qualitative assessment in objective four to be able finalize the evaluation according to the primary research objective.

2 Background and theory

The tariff designs are not created in a vacuum, rather the interests of the different stakeholders need to be taken into account. This background serves as an introduction to tariff design. First the legal and regulatory framework is presented to which tariff designs have to comply. Next an overview of tariff design is given. This includes the reason for tariff design, an explanation of current tariff design and an overview of design options. After this the section on tariff design is concluded with an overview of the two alternatives for tariff design considered in this thesis.

2.1 Legal and regulatory framework

DSOs operate in what are called natural monopolies. This means they effectively operate without direct competition as direct competition would not make sense for this kind of infrastructure since it would require a second, costly, parallel grid (Bergaentzlé et al., 2019). For this reason DSOs and TSOs are heavily regulated to avoid abuse of monopoly positions. This regulation is done by the regulatory authority. In the Netherlands this regulatory authority is the "Autoriteit Consument & Markt" (authority for consumers and markets, ACM). The tasks and responsibilities of the regulator are intwined in European and national legislation. From this a set of principles for tariff design arise. The sections below cover the European legislation which outlines the foundation of the tasks of the regulators and sates the details of the regulators tasks have to be contained within the national legislation. Next the applicable national legislation is covered and discussed in the context of the European legislation. Finally, the principles on which the actual regulation is founded are discussed. These principles are informed by the legislation and are important in this thesis as an alteration to the tariff design must comply to these principles to be approved by the regulator.

2.1.1 European legislation

The core of the EU legislation is encapsulated in the EU regulation on the internal market for electricity (EU regulation 2019/943, 2019), which outlines the rules for the electricity market in the EU. This regulation includes article 18 on charges for access to network, use of networks and reinforcement (i.e. grid tariffs). In paragraph one of the basic requirements for network charges are laid out. It is stated here that network charges (ie. Grid tariffs), shall be cost reflective, transparent, take into account the need for network security and flexibility and are applied in a non-discriminatory manner. Furthermore, these charges are not to include unrelated costs supporting unrelated policy objectives. These are some of the basic principles of tariff design, these principles are enforced by regulators. In section 2.1.3 the interpretation of these principles by regulators is expanded upon. Paragraph 18.1 of the regulation continues by stating the method to determine network charges shall neutrally support overall system efficiency over the long run through price signals. These price signals should not discriminate between production connected at the distribution (DSO) or transmission (TSO) level nor shall it discriminate against energy storage or aggregation. These network tariffs shall not create disincentives for self-generation, self-consumption or participation in demand response.

In article 18 of the regulation some more details are provided on the goals for tariff design. The idea of introducing time-differentiated tariffs has also been encapsulated in the regulation. It states that when smart metering systems have been implemented, regulatory authorities shall consider time-differentiated methodologies. These time-differentiated grid tariffs may be introduced reflect the use of the network, in a transparent, cost efficient and foreseeable way for the final customer. (Paragraph 18.7). This reflects the necessity of smart metering systems for time differentiation but also the assumption that time-differentiated methodologies may lead to more efficient network use. In paragraph 18.8 the necessity for the cost to provide incentives for the DSO to operate efficiently are stressed.

One thing to note is that in the basic principles of the regulation (Basic principles 39) it is clearly stated that non-discrimination also applies to non-discrimination against energy storage. This means tariffs should not be designed in such a way as to disincentive storage nor as an obstacle to improve energy efficiency.

The EU regulation does not instruct to use any particular tariff design. Rather it lays out the tasks of the regulators and provides them with a set of principles to be taken into account. However, the regulation does explicitly state that time differentiated tariffs should be taken into consideration. This is important when comparing tariff designs as non-time differentiated options also exist.

2.1.2 Dutch Electricity Law

In the Dutch framework considered in this thesis next to the European regulation the Dutch electricity law also applies. In the Dutch electricity law (*Elektriciteitswet 1998*, 1998) article 36 sub 1, the task of the regulator in setting tariff structures and conditions is further expanded on. It states that it has to set these tariffs taking into consideration:

a) A common proposal by the grid operators and a common consultation with representative market parties.
b) The importance of a reliable, sustainable, effective and environmentally sound operation of the electricity network
c) The importance of promoting the development of trade on the electricity market
d) The importance of effective operation of customers
e) The importance of quality of service from the grid operators
f) The importance of an objective, transparent and non-discriminatory enforcement of the energy balance in a cost-reflective manner
g) Ministerial rulings
h) The EU regulation 2019/943
i) The promotion of efficient network usage

Here h) refers to the regulation discussed above, and g) refers to the ministerial decree (Regeling inzake tariefstructuren en voorwaarden elektriciteit). This decree does not go into much further detail on the tariff design, only that differentiation should be made between transport dependent and independent tariffs. This refers to costs that are dependent on and independent of the actual amount of electricity transported. This thesis will focus on transport dependent fees in particular as the grid congestion is caused by transport of electricity. In addition, differentiation should be made between different categories of users. This does not impose limits on the considered tariff designs. Common proposal a) refers to the "tarievencode" (*Tarievencode Elektriciteit*, 2016) which provides the structure of the current tariff design in more detail. Currently proposals have been drafted to replace the Dutch electricity law and combine it with the equivalent law for gas into a new energy law. This is done for primarily two reasons, to implement parts of the 2019 Dutch Climate

Agreement and to comply with European legislation (Ministerie van Economische Zaken en Klimaat, 2021).

2.1.3 Regulatory principles

As mentioned before, the European and national legislation lay out the tasks and responsibilities of regulators. The regulators are responsible for setting or approving tariff designs. This is done on the basis of a set of regulatory principles which the tariff design should comply to. The council of European energy regulators (CEER) has provided their interpretation of what these principles consist of. In (CEER, 2017) these principles are collected. Here seven principles were identified, namely:

1) Cost reflectivity: To ensure efficient use of the network, tariffs paid by users should reflect the actual cost they impose on the network as far as practicable.
2) Non-distortionary: tariffs should be structured in such a way as to not distort access or use of the network. Distribution tariffs should not be structured in such a way as to create barriers for innovative solutions for consumers such as may be the case with flexibility and efficiency measures.
3) Cost recovery: Tariffs should be high enough as to that DSOs can recover efficiently incurred costs.
4) Non-discriminatory: Tariffs should be the same for equal network use and circumstances regardless of the user.
5) Transparency: Network tariffs should be structured and calculated is such a way as to be accessible to all customers. Methodologies of underlying calculations should be made available and explained.
6) Predictability: Network users should be able to estimate their network with a reasonable degree of accuracy as to provide them with the opportunity to make adequate investments in network usage. It is noted however that due to the changing nature of the energy system these network tariffs need to evolve. Indicating the delicacy of assessing these principles.
7) Simplicity: As much as possible tariffs should be easily understandable for consumers. For adequate adaptation to tariffs an understanding of the tariffs is required.

The European DSOs (E.DSO) hold a similar set of 7 principles (E.DSO, 2021), which are largely overlapping (cost-reflectivity, simplicity, non-discrimination, transparency). They however also stress implementability, fairness and efficient network use. With implementability refers to the technical possibility of implementing a tariff design, limits to which may for instance be the measuring equipment. Fairness is closely linked to cost-reflectiveness and non-discrimination, here E.DSO stress that only network costs should be recovered, not policy or environmental goals through the tariff design. Implementability and efficient network use are direct concerns for the DSOs themselves. In the process of setting the tariffs these differences between DSO and regulator incentives must be addressed.

2.1.4 Relevance to new tariff design

European and Dutch law lay out the foundations of both the tasks of the DSOs as well as the rules around how regulators may set the tariff methodologies. Whilst specific tariff designs are not prescribed, that being an explicit task of the regulator not the legislator, some principles are contained within the legislation. An example of this would be the prescription of transparency, non-discrimination and cost reflectiveness in article 36 sub 1f of the Dutch electricity law.

This legal framework does not show a strong preference for any tariff structure in particular. Regulatory authorities are given a high degree of freedom in determining these tariff structures. They are required however to take into account various aspects of methodologies and principles and have summarized the key principles as they see them themselves as well. These principles are not all reconcilable. Because of this, these principles need to be carefully weighed to make a correct decision.

An example of this would be fixed rates being extremely predictable and transparent, but for transport dependent costs they are less reflective of the costs caused by the customer. Capacity based tariffs may be more reflective but depending on the specific design can be unpredictable as a relatively short spike in power can result in high costs incurred. For this reason a framework for assessing the tariff designs on the regulatory principles has to be constructed. In that way the fit of a particular tariff design with these competing regulatory principles and the effectiveness in reducing the coincident peak needs can be assessed.

2.2 Overview of tariff design

This section provides an overview of grid tariff design options. The overview of grid tariff design options serves to provide insight into the place the considered options have within the broader context of tariff design, as well as to stipulate their inherit (dis)advantages.

2.2.1 Elements of tariffs

There are four drivers of costs in electrical grids (Reneses et al., 2013):

1) Energy: the costs associated with the amount of energy delivered at a specific time, for instance due to grid losses.
2) Capacity costs: Costs associated with the peak demand or potential to reach peak demand. Such as network investments due to congestion.
3) Connection costs: costs of connecting a customer to the grid
4) Consumer: Costs associated with the number of consumers, such as customer management costs.

These cost drivers have to be taken into account when designing an effective tariff as cost reflectivity needs to be taken into account. These costs have to thus be recovered in a tariff structure that takes into account the different underlying costs. However not all of these costs are dependent on the customers electricity consumption profile. For this thesis the consumer and connection costs will be disregarded as they are recuperated through separate fixed charges. Thus the focus will only be on energy and capacity costs. These are known as the transport dependent costs, as opposed to the transport independent consumer and connection costs.

Tariff design generally consists of a combination of up to three components: A flat rate depending on customer group (€/customer), capacity based rate (€/kW) and volume based (€/kWh) (CEER, 2017; Picciariello et al., 2015). These separate components are referred to as fees, the combination as tariff design. Capacity and volumetric charges can remain constant or change over time. In this latter case they are called time-varying. In addition they can also be spatially differentiated. In that case they are referred to as location specific or locational fees. Additionally these fees can be differentiated based on consumer type (e.g. industrial or residential). This differentiation between the consumer types can be done on the basis of connection size. Finally these fees may also change on some other criteria like a threshold in annual consumption for volumetric rate after which the fee (€/kWh) changes.

2.2.1.1 Flat rates fees

In flat rate an annual fee is paid. This can be done to cover costs only dependent on the amount of customers. Flat fees can be used to cover transport dependent costs, this however will be a crude approximation of the incurred costs from a customer as customer behavior is not taken into account . One advantage of fixed fees is that they are highly predictable, simple and transparent. Little incentive is provided however for efficient network use as customers are free to use up to the assigned limit (such as the physical connection limit).

2.2.1.2 Volume based fees

Constant volume, or energy, based fees involve a fee per kWh of electricity consumed. This provides an incentive for energy efficiency but not necessarily efficient network use as network costs are mostly driven by coincident peak loads (Govaerts et al., 2021). In the recent past it was easier to recover grid costs with volumetric tariffs than is the case today as inelastic customers have changed to elastic (net-metered) customers. (Schittekatte & Meeus, 2020) Volume based tariffs are simple to understand and transparent. The predictability is dependent on the predictability of overall energy use, since the tariffication is linear with energy. However true "bill shock" (an unexpectedly high bill) is unlikely due to the linear relationship with electricity use.

2.2.1.3 Capacity based fees

Fees may also be charged on the basis of the consumed (peak) power. One option is to have a contracted or subscribed capacity, that is a set capacity limit set beforehand by the user over which no exceedance is allowed. Alternatively the used capacity can be measured with fees charged afterwards for the actual use. A choice also has to be made on the timescale, charging for instance for an annual, monthly or weekly peak. Since network costs are largely driven by coincident peak demand this fee may be more cost-reflective than other volume or flat fees, especially when the individual peak coincides with the network peak. These capacity based tariffs thus provide incentives for limiting the individual peak, which may contribute to a reduction in network peak and thus more efficient network use. Capacity based fees may hover lead to unpredictability as relatively short but high peaks can lead to a large increase in costs if opted for actual measured peak. Alternatively the capacity may be limited in subscribed capacity fees leading to lower customer usage freedom.

2.3 Differentiation based on time and location.

The cost of supplying 1 kWh of energy is not the same at each time and location. For instance supplying 1 kWh at night in an uncongested urban area does not cost the same as would the same kWh during the day peak in a rural area (Reneses et al., 2013). Consequently customer location and time of day constitute cost drivers.

Differentiation on the basis of time is justified by the fact that network investments are largely driven by the coincident peak (Govaerts et al., 2021). This means a high proportion of costs are incurred during a limited amount of peak network usage time. Differentiation on the basis of time can thus increase cost reflectivity. In addition this provides incentives for more efficient network use. The differentiation on the basis of time can be static or dynamic. Static time-based differentiation refers to the case where the prices and times are fixed far ahead of time. Usually this means peak hours are identified (e.g. 17:00-20:00 daily) and fees are set higher during these hours for an entire year. These fees can be volumetric or capacity based. The differentiation on the basis of time may also be dynamic, however, changing over shorter periods of time. These tariffs can than for instance be announced the day before or close to real time. As the grid operator expects congestion to occur, fees may be set to a higher level.

Varying prices by location is motivated by costs that have been invested in the grid as well as costs of grid losses and congestion. As these cost drivers are localized issues, fees may be localized to reflect this fact (Reneses et al., 2013). This localization may be done on different scopes (referred to as granularity). This granularity can be at the level of a region, neighborhood or even at the specific line level.

One form of highly localized and time-varying fees are fees based on the locational marginal price (LMP). The LMP is defined as "the least cost to service the next increment of demand at that location consistent with all power system operating constraints" (Liu et al., 2009). This specificity of this location can be altered from zonal to nodes at the distribution level. This is known as the distribution locational marginal price (dLMP) which can be highly effective in reducing congestion from EV charging (Huang et al., 2015; Li et al., 2014). Calculating the dLMP requires complicated network modelling and is thus not very transparent. In addition it is not desirable to have different prices between neighboring connections, as would be the case with dLMP.

2.4 Combining components

When constructing a complete tariff design these separate fees are usually combined. Tariffs are designed to comply to regulatory principles and recover costs of efficient operation. Figure 1 shows an example of a mock tariff structure from Reneses et al. (2013). Here fees are differentiated by customer type, time of day and seasonally. This figure shows how different fees can exist

		Winter			Summer		
		Peak	Shoulder	Off-peak	Off-Peak	Shoulder	Peak
LV < 1 kV	$P^{*} = 1$	€/kW €/kWh €/customer					
	$P = 2$	€/kW €/kWh €/customer			€/kW €/kWh €/customer		
	$P = 3$	€/kW €/kWh €/customer		€/kW €/kWh €/customer		€/kW €/kWh €/customer	
MV > 1 kV and <33 kV	$P = 3$	€/kW €/kWh €/customer		€/kW €/kWh €/customer		€/kW €/kWh €/customer	
	$P = 6$	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer
HV > 33 kV and <72 kV	$P = 6$	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer
EHV >72 kV and <220 kV	$P = 6$	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer	€/kW €/kWh €/customer

* P number of time periods in the considered tariff. This table does not correspond to any existing tariff structure; it is only meant to show how a tariff structure could look like

Figure 1: Example of a tariff design overview taken from (Reneses et al., 2013)

simultaneously and can differ per customer type. The differentiation on the basis of customer type in this particular example is only done on the basis of the connection size and grid which the customer is connected to.

The tariff design example in Figure 1 shows a relatively straightforward combination of fees. The components are separately measured and charged for, albeit differentiated for the time of use by separating between peak and off peak times. Other options also exist for combining different fees and time differentiation. For instance one option for capacity subscription fees is to only limit usage within a certain number of (peak) hours. This frees the customer to be able to use as much capacity as is desired outside of peak hours thus focusing on net peaks whilst providing more freedom for individual peaks. Since network costs are driven by the coincident peak this model is more cost-reflective. The design is somewhat more complicated, requiring customers to keep track of time of use to a greater extend, still incurs the problems of bill-shock when not combined with an exceedance fee and in addition may lead to the formation of a new peak at the end of the limited time period. Of course this time period could still be fixed, or applied in a flexible manner.

An option for time-differentiated volumetric fees is to use a critical peak price (CPP). This means that the volumetric fee is significantly raised during a limited amount of hours in the year in which congestion occurs due to a particularly high (critical) peak.

2.5 Considered designs: Dynamic grid tariffs and CAP+

The current distribution network tariff (Current Tariff, CT) applied in the Netherlands for connections up to 3x80A is structured as a combination of different flat fees. Fist there are the transport independent fees (all in €/customer/year): the periodical connection fee ("periodieke aansluitvergoeding"), consumer fees ("vastrecht") and a fixed rate for measurements. In addition there are the transport dependent fees. This transport dependent fee is a flat fee for the capacity ("capaciteitstarief"). This is based on the assumed peak use rather than measured peak use (thus constituting a flat rate). This capacity fee is the same for connections from 1x10A up to 3x25A (Stedin, 2022). This thesis looks at alternatives to replace this transport dependent fee in particular. Replacing these transport dependent fees could improve both cost reflectivity and incentivize more efficient network use. To make this comparison a the flat capacity fee will also be considered as an option for tariff design.

The two tariff designs research in this thesis are capacity subscription models with an exceedance fee (CAP+) as well as dynamic grid tariffs. In the CAP+ tariff design the current transport dependent fees (the "capaciteitstarief") are replaced by a fee for the subscribed capacity. Here the customer choses one options within a menu of options for a subscribed capacity. For instance the menu can contain three choices, namely 5, 9 and 12 kW subscribed capacity. Whatever the choice of the customer, the subscribed capacity means that as long as the customer does not go over this capacity for one measurement period (e.g., 15 minute interval) no additional charges are incurred. When the customer does exceed this subscribed capacity, an exceedance fee is charged per kWh. This provides an incentive for the customer to spread out load as much as possible because reducing the individual peak demand means a lower capacity subscription can be taken whilst the exceedance also needs to be minimized. This capacity limit may be enforced during the entire day, or only at selected times. The CAP+ tariff design has been described in and investigated for household applications in (Henning et al., 2020). Figure 2 shows an illustrative example of the functioning of the CAP+ model. Under the current tariff design no limits would exist thus the example customer uses electricity at any rate. Under the CAP+ tariff design an exceedance fee would need to be paid over the amount of electricity (kWh) consumed above the subscribed capacity (5 kW). Thus under the CAP+ tariff design the customer shifts load in such a way as to not go over the 5kW subscribed capacity at any time.

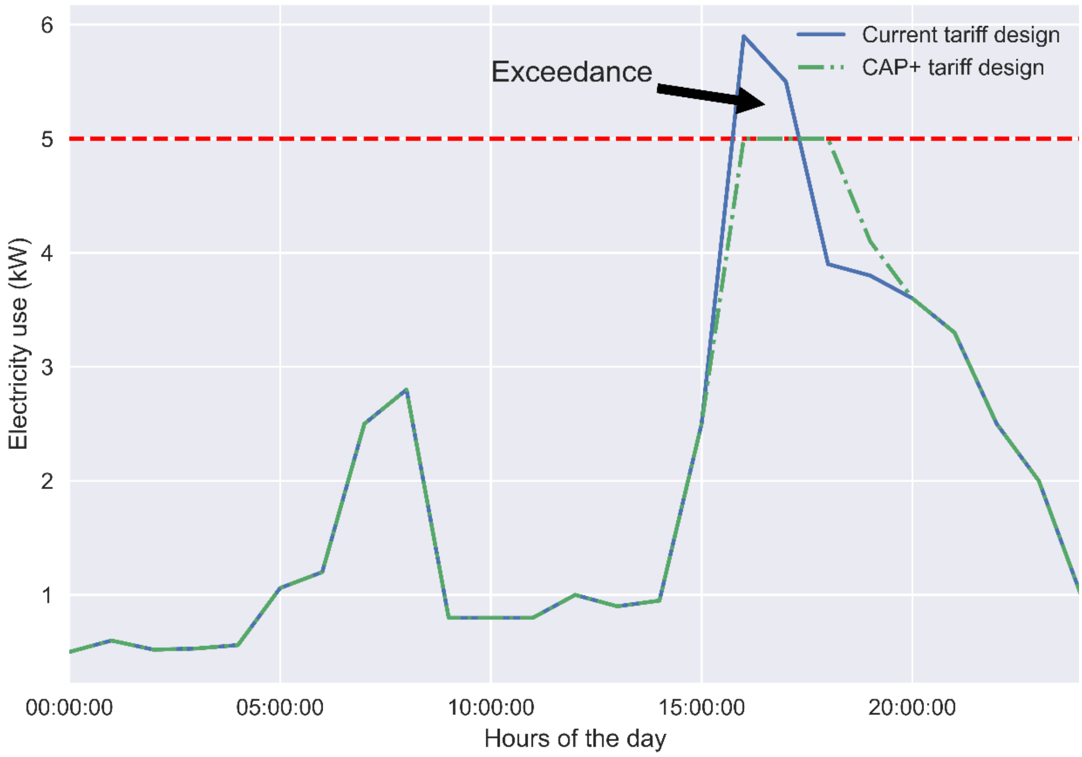

Figure 2:Overview of CAP+ tariff design. Exceedance refers to exceedance of the subscribed capacity, over the exceeded amount of electricity (kWh) an exceedance fee needs to be paid. Subscribed capacity of 5kW indicated by dotted red line

In the dynamic grid tariff design a time and location differentiated volumetric rate is applied (€/kWh). There are multiple rates for different levels of (expected) congestion. For instance a low, medium and high price. These prices are fixed per annum. When each rate has to be paid however is varying and is determined the day ahead. For each time interval of, say 15 minutes, it will be determined how much power is available to charge at the cheapest option and at subsequent levels. This will be done for all charging points combined. This means the connections with flexible loads, owned by the CPO, will be pooled and billed as if it were one connection. This leads to the advantage that the dynamic rates explicitly incentivize peak shaving of the collective peak, rather than individual peaks. This allows EVs which have little opportunity to (partially) delay charging to charge at the required rates whilst being compensated by charging sessions which do have this opportunity. Whether the collectivization of these rates is allowed within legislation is unclear, thus legislation may be required to be altered. The power available at each level needs to be determined the day ahead and thus be determined using predictions on the transformer loads rather than actual transformer loads. In Section 4.4 the methodology of determining price levels based on predicted transformer loads is further explained.

Figure 3 shows a theoretical example of the functioning of the dynamic tariffs, these values are not based on real values but purely illustrative. Without the dynamic tariffs, under the current tariff design the peak of EV load coincides with the peak in regular household use. In the figure we see that for most of the day the introduction of dynamic tariffs does not influence EV load. Here all the required EV load falls under the cheapest price level for the dynamic prices. However, in the late afternoon the regular consumption of electricity peaks and at the same time the EV load without dynamic tariffs peaks. Under the dynamic tariffs however a higher volumetric grid tariff (€/kWh) would have to be paid. This is indicated by the yellow and red colors. Under the dynamic tariffs this is avoided as much as possible to save costs. However this is not completely avoided, which may be due to some charging sessions having instant demand for charging. At the times when the EV load under the dynamic tariffs hits the red zone, the CPO would still not pay the highest tariff for all load at that time, rather the lowest price capacity gets filled first (if available), followed by the medium and finally the highest price. Later we see that when non-EV load drops more capacity is available at a lower price (green). Then the CPO increases its own EV load.

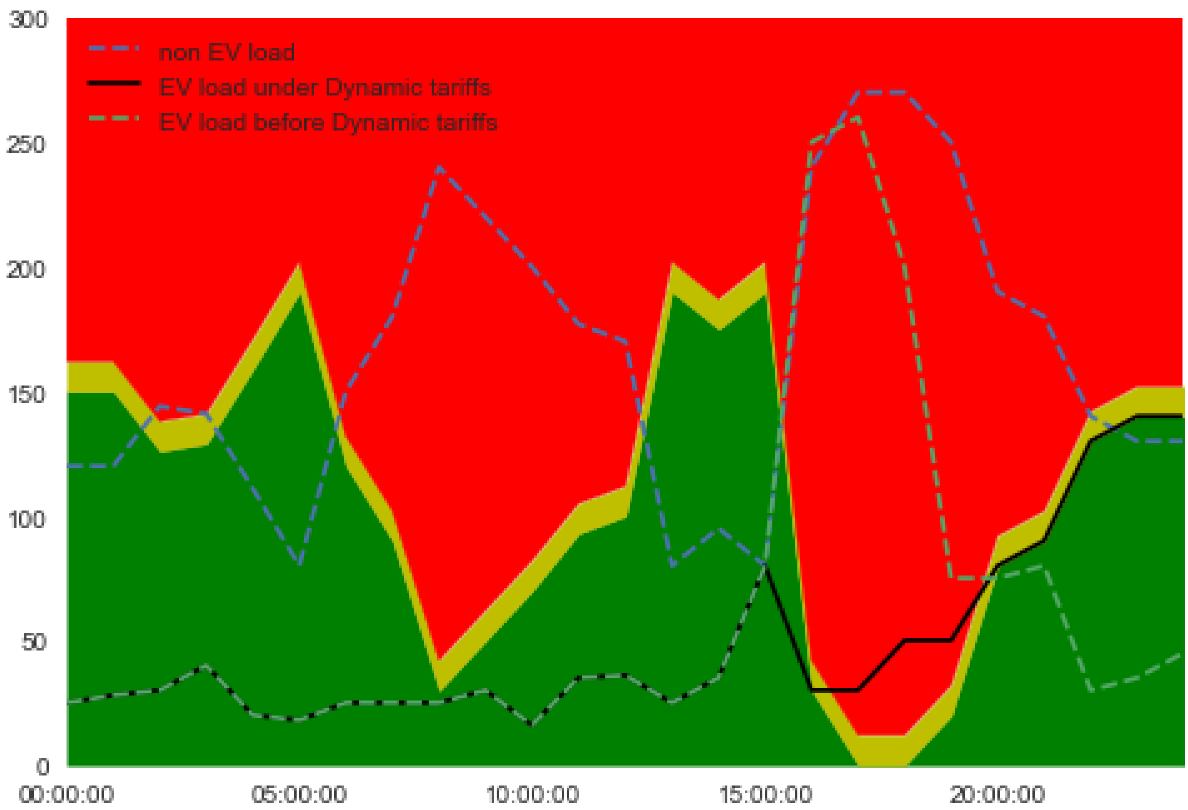

Figure 3: Theoretical example of functioning of Dynamic tariffs, without dynamic tariffs EV load coincides with the peak in regular consumption (non-EV load), with Dynamic tariffs this load shifts. Available capacity at the different price levels is shown. Green is the lowest price, yellow a medium price and red is the highest price.

2.6 Smart charging

In this thesis the grid impact of implementing a new tariff design is assessed. The reason why tariff design affects loads in the grid is because of customer responses to tariff based incentives. This thesis specifically looks at CPO responses to tariffs, based on altering EV charging patterns. This can be seen as a form of smart charging. In (Hildermeier et al., 2019) smart charging is defined as "Electric vehicle charging that can be shifted to times when the costs for producing and delivering electricity are lower, without compromising the vehicle owner's needs". Smart charging is considered to be a specific form of demand side management (García-Villalobos et al., 2014).

Smart charging objectives can vary and include: The reduction of grid impact by EVs, the minimization of energy costs, matching or matching of renewable energy generation (Bons et al., 2020). In this thesis the focus will be on reducing the grid impact as well as minimization of energy costs. Smart charging does not necessarily mean all of these goals are met or even improved upon.

The specific smart charging strategy for the EVs matters. In (Hilshey et al., 2013) it was shown that simple smart charging strategies, only allowing vehicles to charge after midnight, can actually increase rather than decrease transformer wear and tear. The concept of smart charging can be extended to include vehicle to grid (V2G) allowing for the injection of power into the grid by EVs(García-Villalobos et al., 2014).

3 Scope of thesis

As stated in the main research objective this thesis aims to assess new tariff designs from a CPO, DSO and regulatory perspective. This already indicates a limit in assessing the tariff designs as it focuses on one specific customer group, the CPOs/flexible load in LV distribution networks. However many complexities still exist, this section serves to define the scope of this thesis in terms of key assumptions and inclusions and exclusions on tariff design. This is broken up into three parts, choice of customer type, choice of included tariff designs and key modeling assumptions.

This thesis only considers CPOs as customers, the reason for this is twofold. First, as EV penetration is expected to rise, one of the factors that put serious pressure on the distribution grid is the charging of electric vehicles. A large proportion of this will be done through public charging points controlled by CPOs (Elaad, 2021). This means that this customer type needs to be considered when looking at new tariff design. Since CPOs only control flexible loads their demand profiles are significantly different to regular customers such as households. This means the ability to react to price-based incentives is stronger. However the loads also greatly exceed regular household loads. Furthermore, tariff designs focused on regular customers such as households may incentivize efficient network use by disincentivizing the use of flexible loads at peak times for inflexible loads (regular household use). However as CPs have only flexible loads, these incentives may not fit the CPOs load pattern well. For these reasons CPOs are a special case that require special attention in considering new tariff design.

For this thesis two new tariff designs were considered. These were compared to the current tariff design. As explained in section 2.2, many options for tariff design exist. As it is impractical to consider all these options two were selected. These options are the CAP+ and dynamic grid tariff designs. These options were chosen as they were already being looked into as potential options for grid tariffs. (FLEET, 2021; Henning et al., 2020). For Dynamic grid tariffs many alternatives exist. Dynamic grid tariffs could be structured in a time varying volumetric price (€/kWh) without allocating rising prices for the power used or via critical peak pricing (CPP), where relatively large fee is levied, only at times when congestion is expected (€/kWh). These, however, can induce so called shouldering effects (also known as peak after the peak) where charging is minimized up to the point the more expensive time period is over, after which a new peak forms. By using a layered pricing system (low, medium and high) for available capacity on the transformer at each time this problem is addressed. The choice was also made to assume pooling of connections, this means that the tariffs are levied over the combination all the CPOs connections behind a single transformer rather than individual tariffs for all connections. If the capacity was divided between the connections evenly this would result in inefficient network use as this would mean that the individual connections would be limited to a percentage of the available network capacity for lower prices. However if only a small percentage of CPs use their allotted share available cheaper capacity, for instance because not all CPs have a connected EV at that time, a large proportion of the transformers capacity would remain unused. However, it is not clear whether the legal and regulatory frameworks can accommodate for pooling of connections.

In modeling the main assumption is that CPOs aim only to minimize their own costs. There are two main reasons to only look at the CPOs costs and not the CPO revenues. Firstly, the CPO revenues are based on the specific pricing structure a CPO will use for its own customers. This is not readily available and may vary largely from CPO to CPO and also be influenced by the specific tariff design. In reality the aim of CPOs will not necessarily be to minimize costs but to maximize profits. However, it is likely that minimizing costs will, at least largely, coincide with maximizing profits. An optimal pricing structure for the CPO to charge its own customers will pass on some of the benefits of the smart charging to incentivize participation and to attract customers. It would be optimal for the CPO to pass on these benefits in a way that coincides with minimizing costs.

The second important assumption in modeling is the assumption of perfect information. The CPO will be assumed to have perfect knowledge of all required information (start times, departure times, electricity prices, etc.) and perfect capabilities to act on this. This is done as it avoids having to model behavioral aspects which can be highly dependent on a case by case basis. Lastly, in the modeling it was assumed that smart charging occurs with the goal of reducing energy costs including grid tariffs, however this smart charging is limited to grid to vehicle charging only, no V2G was allowed.

4 Methodology

This section outlines the methodology used to complete the main research objective. For this the sub-objectives (SO) 1-4 as defined in section 1.2 were used. Figure 4 shows a schematic overview of how the results from the different SOs are used in subsequent research objectives and to complete the main research objective. SO1 is the central starting point, here the requirements for tariff design from a CPO, DSOand regulatory perspective are identified these are the. These metrics found in the literature research and discussions with the thesis supervisors and are discussed in the theory section (2). These metrics have to then be formulated in a way that is applicable for this thesis. This is the formulation of the decision parameters (SO2). This requires the input from SO1 as it must first be known what precise metrics are included. How these metrics can be assessed may differ largely. For metrics which are to be assessed quantitatively, such as customer (CPO) costs and efficient network use, a model is set up (SO3). In SO4 the modeled results were collected, this feeds and analyzed using the decision parameters defined in SO2. This includes both the quantitative analysis where applicable, as well as a qualitative analysis on other metrics which do not lend themselves to a model based approach. Below, the overview of decision parameters is first discussed, followed by the model formulation and the methodology determination of dynamic grid tariff prices. Finally, the case study for assessing the effect of implementing new tariff designs is presented as well as the scenarios for tariff design to be modeled.

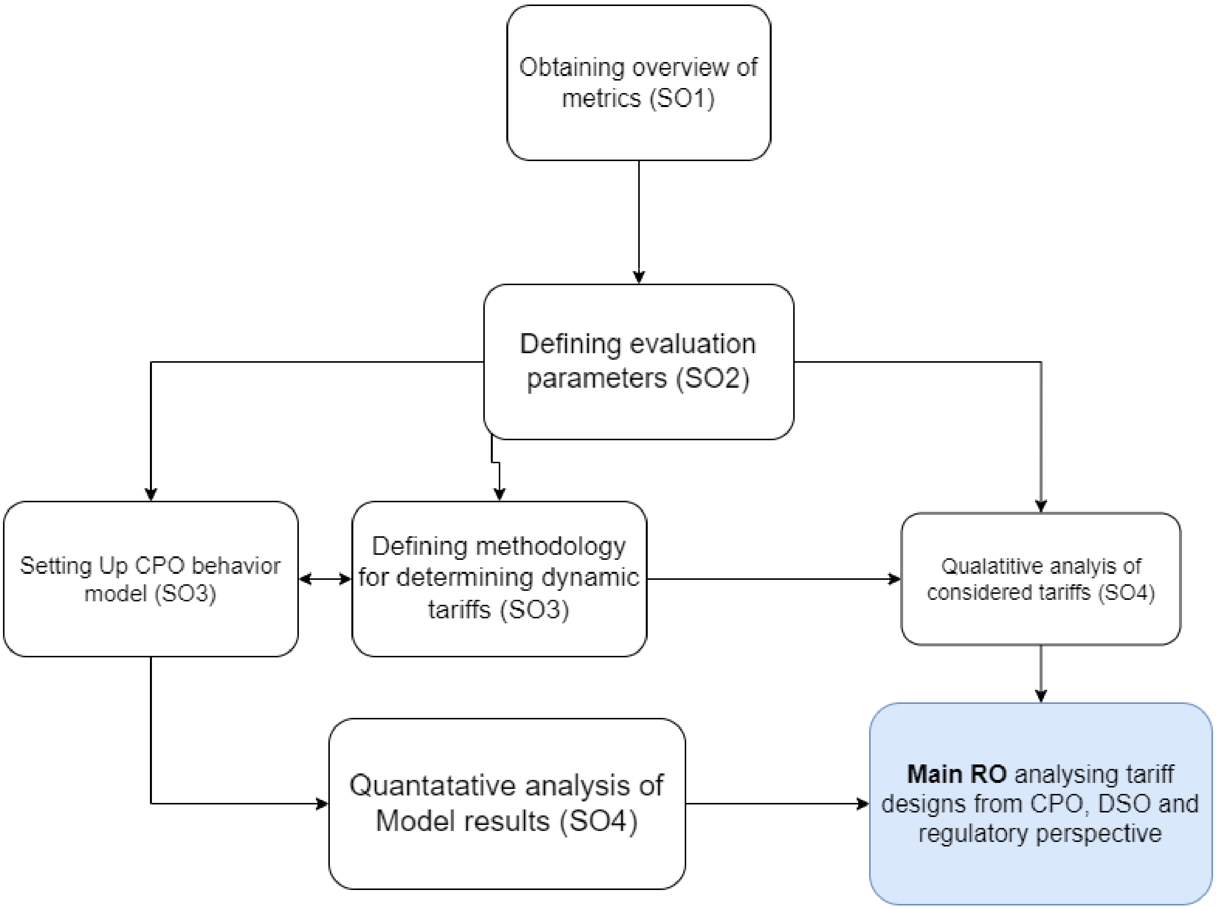

Figure 4: Overview of research structure

4.1 Definitions of evaluation parameters (RO2)

The final choice of tariff design should be made on the basis of the principles discussed in Section 2.1.3. However, as these principles are formulated in a general way, clear definitions need to be constructed in order to come to a complete evaluation. This evaluation will be done on the basis of modelled results and qualitative assessment. Listed below is an overview of the parameters used for the evaluation of the investigated grid tariff designs. Table 1 contains a brief version of this overview.

Table 1: Overview of decision parameters for grid tariff design selection with definitions used for this research

Parameter	Brief definition	Assessment method	Good practice	Bad practice
Efficient network use	Avoiding congestion issues	Load duration curve	Low peak value, few times (far) above rated capacity	High annual peak, often (far) above rated capacity
Cost reflectiveness	Costs to be reflective of costs inflicted	Cost reflectiveness indicator	Share of fees paid equal to share of costs induced. CRI ≈ 1	Far higher or lower fees paid compared to costs induced. CRI >> 1 OR CRI <<1
Predictability	Ability to accurately estimate network costs	Qualitative	Fixed or easily predictable with rough estimate of consumption profile	Large swings in costs possible with small changes to consumption profile
Simplicity	Total grid tariff costs easily understandable	Qualitative	Limited set of fees, fees easily understandable	Combination of many complicated, interdependent fees
Transparency	Openness about calculation of tariffs	Qualitative	Full method of calculation publicized with clear explanation via ACM	Method of calculation unavailable or calculation arbitrary
Non-distortionary	Avoids distorting decisions on market access	Qualitative, informed by electricity costs from model	Full ability to use grid infrastructure to follow market incentives	Strong limits to market access, even above network requirements
Non-discrimination	Equal circumstances lead to equal network costs	Qualitative, assess circumstances and costs	Clear separation between circumstances	Arbitrary separation based on non-consumption related parameters

Efficient network use is the first of the evaluation parameters that will be considered. This is because incentivizing efficient network use is the main reason for restructuring the grid tariffs. Efficient network use is defined as network use that results in few exceedances of the rated capacity of the infrastructure when alternatives for this network use exist. This will be translated to the lower investment costs incurred by the DSO which will be transferred to customers. Since network costs are largely driven by the coincident peak, the focus of efficient network use will be on the total load. For this purpose a load duration curve is constructed. A load duration curve shows an ordered graph of descending loads showing the amount of time the transformer undergoes a specific load. This load duration curve is then examined on the annual peak as well as the time and severity of exceedance of the rated transformer capacity. The load at the transformer under the different tariff design options will be the load determined using the idealized CPO behavior model which will be explained in detail below.

The principal indicator of a tariff's *cost reflectiveness* is built around the notion that the highest coincident peak is the primary driver of network investment costs. Hence, it will be necessary to first determine the contribution of the network user to the highest annual coincident peak. Cost reflectiveness would mean that this contribution to the annual peak should be in proportion with the costs paid by the CPO in relation to the total DSO revenue. This principle translates to the mathematical formulation in equation (1) below. This is the cost reflectiveness indicator (CRI). Here the grid tariffs paid by CPO refer to the total of grid tariffs paid by the CPO from all CPs connected to the transformer whilst total DSO revenue refers to the total in grid tariffs paid to the CPO by all connections behind the transformer, including households and other non-CPs, assuming that the revenue from non-CPs will equal the current revenue under the existing tariff design, with 340 households. The CPO load at the peak time is the total load of the CPO at the time at which transformer load is highest. This is the sum of loads at all charging points. The peak can be either the 15 minute timestep at which the transformer load is at its highest annual peak, or a broader definition can be taken. In this thesis two variants will be assessed. The first is a variant where the CRI is calculated for the annual peak only, meaning one 15 minute interval. In the second variant all 15 minute intervals where the load is at least 95% of this peak 15 minute interval load are taken into account. Loads are measured in kWh (average power per 15 minute interval), the CRI is a dimensionless quantity. A good result for this CRI is a value close to 1, as this indicates perfect allocation of costs. The input values for the cost reflectiveness indicator are found using the model results.

$$Cost\ reflectiveness\ indicator = \frac{Grid\ tariffs\ paid\ by\ CPO}{Total\ DSO\ revenue} / \frac{CPO\ load\ at\ peak\ time}{Total\ load\ at\ peak\ time} \quad (1)$$

Predictability refers to the ability of the customer to estimate their network costs. A tariff design will be deemed predictable if the total bill for network costs is either fixed in costs over time or can be accurately predicted based on a rough estimate of the consumption profile. This means the costs should not dramatically change when a customer slightly alters their behavior Predictability cannot be measured quantitatively, thus this parameter will be assessed qualitatively.

Simplicity and transparency also need to be assessed qualitatively. Simplicity is defined as understandability, which is a requirement for adequate adaptation of customer behavior to tariff designs. Transparency means the tariffs have to be calculated in a way that is accessible to all customers. Whilst these two are closely related some important differences exist. Simplicity is explicitly about the being understandable to the customer on how the bill is formed. This means that the set of fees is clear and how to total on the customer's bill follows from the fees is easy to understand. Good practice would be to have a limited set of fees. Transparency is about the calculation behind the rates. This calculation should be clear and made publicly available and clearly explained. The precise manner in which this will be done cannot be assessed, as this is outside the scope of this thesis. However there are differences between the tariff designs on how easy it is to communicate the underlying requirements for calculations, this will be taken into account.

The *non-distortionary* principle requires that "costs should be recovered in ways that avoid distorting decisions around access to and use of the network, and market offers" (CEER, 2020, p. 20). For the purpose of this thesis, distortive tariffs are those that over-incentivize customer responses beyond what is necessary for efficient network use. A *qualitative assessment* shall be made on whether the considered tariffs designs are distortive and to which extend. Whilst neither of the tariff designs considered include explicit prohibitions of access this access may still me distorted by the additional costs for grid tariffs. Thus the assessment will focus on the distortion to market access caused by the introduction of a new tariff design. Here, distortion to market access is taken to be a diminished ability to react to market prices, specifically day-ahead electricity market, prices. This assessment will be informed by the amount of extra electricity costs that the CPO incurs compared to the current tariff design where no restrictions other than the physical limit of the connection exists., These additional electricity costs will be calculated using the model described below. A qualitative assessment will then be made on what these additional electricity costs mean in terms of market distortion in addition to a qualitative assessment to what extent this is distortive.

Non-discrimination refers to equal network costs under the same circumstances regardless of user or the end-use of the electricity. Discrimination means unequal treatment under equal circumstances. Violation of this principle thus means that inequal treatment under equal circumstances happens. This means to asses compliance to the non-discrimination principle both the equality of circumstances and treatment must be assessed.

Not all of these principles are valued equally. Heavy emphasis will be placed on the efficient network use, as this is the main reason for considering a change to the grid tariffs. This does not mean the other parameters are not important. If serious issues persist in other parameters an option for tariff design will not be feasible. The exact weighing of the parameters is, in the end, however up to the interpretation of the regulator rather than an objective truth.

4.2 Idealized CPO behavior model

To assess the quantitative aspects of tariff design, a model is constructed to estimate the behavior of a CPO under differing tariff designs. First, a benchmark model is created to model the behavior of the CPO with the current tariff (CT) design in place. The loads resulting from CPO behavior are then added to the base transformer load, that is transformer load without EV charging, to obtain total transformer loads. Next two cases are considered with the new tariff structures, CAP+ and Dynamic grid tariffs in place.

The CPO will be assumed to minimize its owns costs. This is done as the assumption is made that this will be the same as maximizing profit. These costs include the day ahead price of electricity and the grid tariffs. Only costs which depend on the load variation over time are included. Fixed costs, such as taxes and operations and maintenance (O&M) will not be taken into account as they do not depend on the tariff design in place. Other costs and revenues such as those related to imbalance markets are placed outside the scope of this thesis.

4.3 Mathematical formulation of idealized CPO behavior model

For the CAP+ model the optimization is done for the individual grid connections, each grid connection is one Charging point (CP) with two power outlets. This can be done as no interdependencies exist between charging points. In the dynamic grid tariffs model, all charging points behind the transformer must be optimized in one session as the tariffs are interdependent as the specific dynamic tariff design considered for this thesis assumes pooling of connections to occur. The equations in this section are labeled with C, D, E and COA for CAP+, Dynamic, Electricity only and Charge-on-arrival.

4.3.1 Capacity subscription model

In the case of the capacity subscription model the optimization can be done for each charging point (with two power outlets) individually. The results of these optimizations for each charging point can further be used to calculate the total power and costs of the CPO for all CPs combined. In the CPO model the following parameters are introduced.

Definitions of parameters and variables:

$$\epsilon_{\text{exceedance}} = exceedance\ fee\ \left(\frac{€}{kWh}\right)$$

$$\epsilon_{\text{DA},t} = Day\ ahead\ electricity\ price\ at\ time\ t\ \left(\frac{€}{kWh}\right)$$

$$P_{\text{subscribed},o} = Subscribed\ capacity\ of\ option\ (kW)$$

$$p_{CP,t} = power\ at\ the\ charging\ point\ at\ time\ t\ (kW)$$

$$p_{n,t} = charging\ power\ of\ charging\ session\ n\ at\ time\ t\ (kW)$$

$$p_{\text{charge,max},n} = maximum\ charging\ power\ of\ charging\ session\ n\ (kW)$$

$$\epsilon_{\text{cap},o} = costs\ for\ with\ subscribed\ capacity\ option\ o\ (€)$$

$$\Delta t = timestep$$

$$b_{\text{cap},o} =\ binary\ variable\ to\ enumerate\ options\ (o)\ for\ subscribed\ capcity$$

$$c_{\text{cap}} = \text{Subscribed capacity costs (€)}$$

$$E_n = Energy\ demand\ for\ charging\ session\ n\ (kWh)$$

$$T_{0,n}, T_{\text{f},n} = start\ and\ end\ of\ connection\ to\ the\ CP\ for\ charging\ session\ n\ (timestep)$$

$$Options = set\ of\ options\ for\ subscribed\ capacities$$

There are three types of costs relevant for the optimization, the cost for electricity at the day ahead market, the costs for the subscribed capacity and the costs to be paid in exceedance fees (the costs for going over the subscribed capacity). This results in the objective function:

For CAP+ tariff the objective function becomes:

$$\text{Min} \sum_{t}^{T} \left(\epsilon_{\text{DA},t} * \; p_{\text{CP},t} * \Delta t \; + p_{\text{exceedance},t} * \epsilon_{\text{exceedance}} * \Delta t\right) + c_{\text{cap}} \; (C.5)$$

The costs for the capacity subscription are dependent on the chosen subscribed capacity. There are multiple options, each with an associated price, the CPO has the option to choose one of these options. This is done using a binary variable. Each option for the subscribed capacity can either be chosen (1) or not chosen (0). This results in the costs according to equation (C.2). However, only one subscribed capacity is allowed, not a combination of (smaller) subscribed capacities. This is fixed by the constraint in equation (C.3).

Capacity subscription fee constraints

$$c_{\text{cap}} = \sum_{o}^{Options} b_{\text{cap},o} * \epsilon_{\text{cap},o} \;\; (C.4)$$

$$\sum_{o}^{Options} b_{\text{cap},o} = 1 \;\; (C.3)$$

The costs for the electricity price is calculated using the power at the charging point at each timestep, this power is also required to calculate the costs for exceedance (see equation (C.6) below). The power at the one single outlet of the charging is the total power in all charging sessions at that outlet for a given timestep (C.4). The total at the charging point is the equal to the total of all (i.e. both) outlets at that charging point (C.5).

Power at CP constraint:

$$p_{\text{i},t} = \sum_{n}^{N} p_{i,n,t} \; \forall \; t, i \; (C.4)$$

$$p_{\text{CP},t} = \sum_{i}^{I} p_{i,t} \; \forall \; t \;\; (C.5)$$

The charging powers of each session are limited by the maximum charging power associated with that session, in addition charging powers cannot be less than zero (i.e. no V2G).

Minimum and maximum charging power constraint:

$$0 \leq p_{\text{charge},n,t} \leq p_{\text{charge,max},n} \; \forall \; n, t \; (C.6)$$

The charging power at the CP can than be combined with the power of the chosen subscribed capacity to obtain the exceedance power. The exceedance power is the power above the subscribed capacity. This is implemented using two inequality constraints, one to say it needs to be equal or larger than the difference between the charging power at the CP and the subscribed capacity (C.7) and one to make sure the exceedance power cannot be negative (C.8). This is done to avoid using logic operators. The exceedance power will always be as small as possible given that there are costs associated with the exceedance power, thus inequalities can be used instead of equalities.

Exceedance power constraint

$$p_{\text{exceedance},t} \geq \; p_{\text{CP},t} - \sum_{o}^{Options} b_{\text{cap},o} * P_{\text{cap},o} \; \forall \; t \; (C.7)$$

$$p_{\text{exceedance},t} \geq 0 \; \forall \; t \; (C.8)$$

Lastly, a constraint has to be introduced to make sure that the demanded energy for each charging session is being met. Otherwise all charging powers could just be left at zero, and no cars would be charged in the model. The energy must be charged within the time the EV is connected to the CP. The power constraint required to suffice in the energy demand given by equation (C.9).

Energy requirement constraint

$$\sum_{t=T_{0,n}}^{T_{f,n}} p_{\text{charge},n,t} * \Delta t = E_n \;\; \forall n \; (C.9)$$

This model is then optimized by varying the charging powers, exceedance power and binaries for the subscribed capacity selection within the constraints given by equations (C.2-C.9) above. The charging powers outside of the start and end time are set to 0.

The model is optimized by varying:

$$p_{\text{charge,n,}t} \forall \; n, t \in [T_{0,n} \, , T_{\text{f},n}]$$

$$p_{\text{exceedance},t} \forall \; t$$

$$b_o \; \forall \; o \;\; \in \text{Options}$$

Thus the model is optimized for charging power of each session at the times between the start and finish time of the charging session as well as the correct subscribed capacity, found via the subscribed capacity binaries.

4.3.2 Dynamic grid tariffs model

In the dynamic grid tariffs model two costs for the CPO need to be taken into account, first the costs of electricity at the wholesale market ($\epsilon_{DA,t}$) and secondly the costs of the dynamic grid tariffs, which are determined by the charging power within each level. Since the available power at each price level is determined for the entire set of CPs, this optimization has to be done for the entire set of CPs at once rather than per separate CP. This model uses many of the same parameters as the CAP+ model, however some new parameters are introduced:

Definitions of parameters and variables:

$$\epsilon_{grid,i} = Grid\ tariff\ \ at\ level\ i\ \left(\frac{€}{kWh}\right)$$

$$p_{\text{total},t} = total\ charging\ power\ in\ timestep\ t\ (\text{kW})$$

$$p_{\text{level},i} = charging\ power\ at\ price\ level\ i\ (kW)$$

$$p_{\text{charge},i,n,t} = charging\ power\ at\ price\ level\ i, of\ charging\ session\ n\ and\ at\ timestep\ t\ (kW)$$

$$P_{\text{available},i,t} = Available\ power\ to\ charge\ at\ price\ level\ i\ at\ time\ t(kW)$$

Under the dynamic grid tariff design considered for this thesis there are two types of costs. First the costs for the electricity prices at the day ahead market and secondly the costs in the dynamic grid tariffs themselves. The day-ahead electricity costs are dependent on the total charging power, the dynamic tariffs are dependent on the amount of power charged at that price level (there may be power charged at multiple price levels at once).

Objective function dynamic grid tariffs

$$Min\left(\sum_{t=1}^{T}\left(p_{\text{total},t} * \epsilon_{\text{DA},t} + \sum_{i}^{i=I} \epsilon_{\text{grid},i} * p_{\text{level},i,t}\right) * \Delta t\right)\ (D.1)$$

The power within each price level at which the CP charges is determined using the available power in each price level. This means the CPO cannot charge with a higher power for a certain grid tariff price than is available at that price level. The CPO will first charge at the cheapest price level when this is possible, given the objective function is to minimize costs. However the cheapest price level may not suffice at each timestep. When this happens a higher dynamic grid tariff (€/kWh) will be paid on part of the charged power. Overall the total power charged at all price levels combined must be equal to the total power charged at each time (D.2). The total power charged must also be equal to sum of all charging sessions at each time.

Power levels constraints:

$$p_{\text{total},t} = \sum_{i}^{I} p_{\text{level},i,t}\ \forall\ t\ (D.2)$$

$$p_{\text{total},t} = \sum_{n}^{N} p_{\text{charge},n,t}\ \ \forall\ n, t\ (D.3)$$

As mentioned before the CPO cannot charge at a certain price level above the available power at that price level. This is fixed by the constraints given in equations (D.4) and (D.5). The available powers within each level are calculated using the methodology explained in 4.4. These vary for each timestep and are influenced by other power use at the transformer, to avoid overload the transformer.

Price level availability constraints:

$$0 \leq p_{\text{level},1,t,} \leq P_{\text{available},1,t} \, \forall t \; (D.4)$$

$$0 \leq p_{\text{level},i,t} \leq P_{\text{available},i,t} - P_{\text{available},i-1,t} \; \forall \, t, i \; \in [1, I] \; (D.5)$$

The charging powers of each session are limited by the maximum charging power associated with that session, in addition charging powers cannot be less than zero (i.e. no V2G). This is the same for constraint as in the CAP+ model.

Minimum and maximum charging power constraint:

$$0 \leq p_{\text{charge},n,t} \leq p_{\text{charge,max},n} \; \forall \, n, t \; (D.6)$$

Lastly, a constraint has to be introduced to make sure that the demanded energy for each charging session is being met. For this we can again use the energy requirement constraint from the CAP+ model, repeated below for completeness (D.7).

Energy requirement constraint

$$\sum_{t=T_{0,n}}^{T_{f,n}} p_{\text{charge},n,t} * \Delta t = E_n \;\; \forall n \; (D.7)$$

This model is then optimized by varying the charging powers for each charging session within the connection and departure time from the CP. All other variables in this model (power at the different price levels, total power) are wholly dependent on these optimization variables.

The model is optimized using the variables:

$$p_{charge,n,t} \forall \, n, t \in [T_{0,n} \, , T_{f,n}]$$

4.3.3 Electricity price optimization only model

Besides the Dynamic grid tariffs and CAP+ tariff designs two baseline scenarios are included. The first is the electricity price optimization only model (later to be referred to as just electricity only), this refers to the optimization only being done on the day-ahead electricity prices and not the grid tariffs. Since the current tariff design consist of flat fees this is equivalent to optimization under the current tariff design. The second baseline scenario is a baseline scenario without smart charging, just using charge-on-arrival. This will be expanded upon below in section 4.3.4.

When optimizing for the electricity prices only the objective function becomes:

Objective function electricity price optimization only

$$Min \sum_{t=1}^{T} (p_{\text{total},t} * \epsilon_{\text{DA},t}) * \Delta t \ (E.1)$$

Here the total power is the sum of all powers from the charging sessions at any time:

Total power constraint:

$$p_{total,t} = \sum_{n}^{N} p_{\text{charge},n,t} \ \forall \ t \ (E.2)$$

The charging powers of each session are limited by the maximum charging power associated with that session, in addition charging powers cannot be less than zero (i.e. no V2G). Borrowing from the CAP+ and Dynamic models, this constraint is given in (E.3)

Minimum and maximum charging power constraint:

$$0 \leq p_{\text{charge},n,t} \leq p_{\text{charge,max},n} \ \forall \ n, t \ (E.3)$$

And finally, again, the required energy per charging session must be fulfilled, similar to the Dynamic and CAP+ models. This is given by equation (E.4)

Energy requirement constraint

$$\sum_{t=T_{0,n}}^{T_{f,n}} p_{\text{charge},n,t} * \Delta t = E_n \ \forall n \ (E.4)$$

Again, this model is optimized using the charging powers for the different charging sessions within the time the EV is connected to the CP.

The model is optimized using the variables:

$$p_{charge,n,t} \forall \ n, t \in [T_{0,n}, T_{f,n}]$$

4.3.4 Charge-on-arrival model

The charge-on-arrival model does not require optimization, rather it is a calculation based on the input data. In the charge-on-arrival model the EVs are charge at maximum power from the moment they arrive until they are full. This can be separately calculated for each charging session thus t=0 will be taken to be the time at which the EV connects in the equations below. Here the following parameters are introduced:

$$E_{charged,t} = Energy\ charged\ to\ the\ EV\ within\ charging\ session\ up\ to\ timestep\ t$$

At the start this charged power $E_{charged,0} = 0$, this then increases by the charging power for each timestep. This process is given by equation (COA.1)

$$E_{charged,t} = \sum_{\tau=0}^{t} \mathrm{p}_{\mathrm{charge},\tau} * \Delta t\ \forall\ t\ (COA.1)$$

The charging power is always the maximum possible without going over the energy requirement of the charging sessions. This is formulated in equation (COA.2).

$$p_{charge,t} = \min\left(p_{charge,max}, \frac{E_n - E_{charged,t}}{\Delta t}\right) \forall\ t\ (COA.2)$$

Here E_n is, again, the energy requirement of the charging session for which the charging powers are calculated. This equation means that the power that is charged at each timestep is equal to the maximum charging power, unless the maximum charging power makes the total charged energy larger than the required amount of energy. In that case the total power will be the power equal to the amount necessary to fulfill the rest of the demand within this timestep. After the energy requirement is fulfilled this equation reduces to 0.

4.4 Determining dynamic grid tariff prices

In addition to setting up the idealized CPO behavior model, the prices and available power in each price category for the dynamic grid prices must be determined. Available power per price category refers to the manner in which the dynamic grid tariffs are set up. In the dynamic grid tariff system there are multiple, in this case 3, price categories. At each time the CPO can consume a certain amount of power at the lowest price, a certain amount at the medium price and the rest at the highest price. These are referred to as price categories and thus have an associated available power. The goal of the dynamic grid tariffs is to precisely target transformer overloading by increasing costs when transformer overloads occur. This, however, runs into an issue. To provide the CPO with an opportunity to adapt to the prices the prices need to be determined and published in advance (in this case a 24 hour period is assumed). Because the prices need to be known in advance it is impossible to use real-time data. For this reason load predictions will be used. These load predictions are provided by the DSO and concern load predictions excluding EV load as the EV load will be determined by the CPO based on the pricing structure. The load without EV load will henceforth be referred to as non-EV load.

Load predictions are not 100% accurate but have some associated error. Using the load predictions provided and associated error the likelihood of exceedance of the transformer capacity can be determined. This likelihood will than increase with increased EV load from the CPO. This is illustrated in Figure 5**Error! Not a valid bookmark self-reference.** below, here μ indicates the predicted transformer load at a specific time, the actual transformer load is distributed around this prediction. This means for a certain predicted non-EV load a small chance of transformer overloading exists. When the CPO adds EV load at this specific time, the distribution shifts, this causes the probability of transformer loads exceeding the transformers rated capacity to increase. At specific thresholds for this probability of exceeding the transformer rated capacity the price will be increased. The CPO pays the lowest price when not risking transformer overloads above the threshold and increased prices when going above one or more of these thresholds.

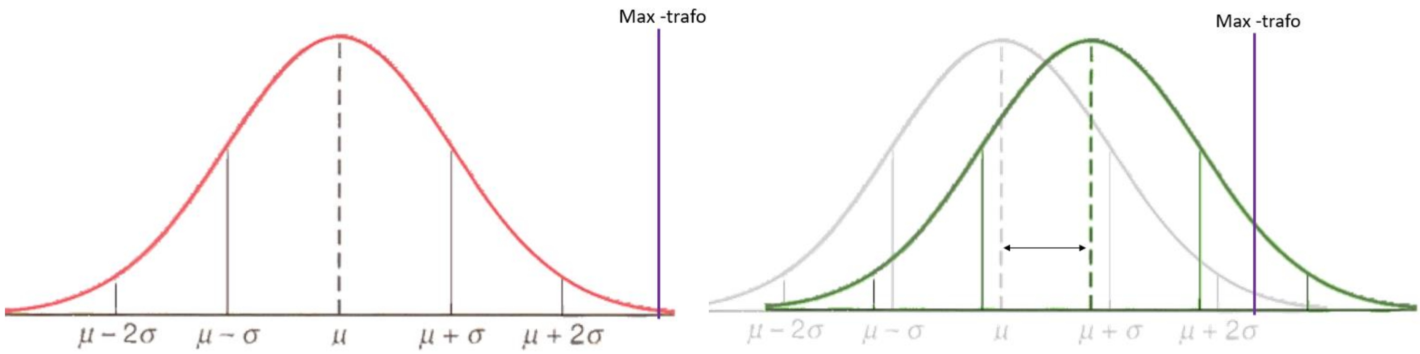

Figure 5: Illustration of methodology to determine the available power at different price levels for dynamic grid tariffs. A shift in predicted transformer load, caused by the introduction of EV load causes the chance of transformer overload to increase.

In this thesis dynamic grid tariff sets with three price levels were used. To calculate the available powers in this thesis a margin of 1% for the middle price and 5% for the high price was used. This means that when, given the prediction error, the probability of overloading exceeds 1% the price is raised to the medium price level. When the probability of overloading exceeds 5% the prices are raised to the high price. Figure 6 shows the available power at the three different price levels for a given week in December. Since non-EV load is much lower than the transformer rated capacity at all times power is available at all three price levels at all times.

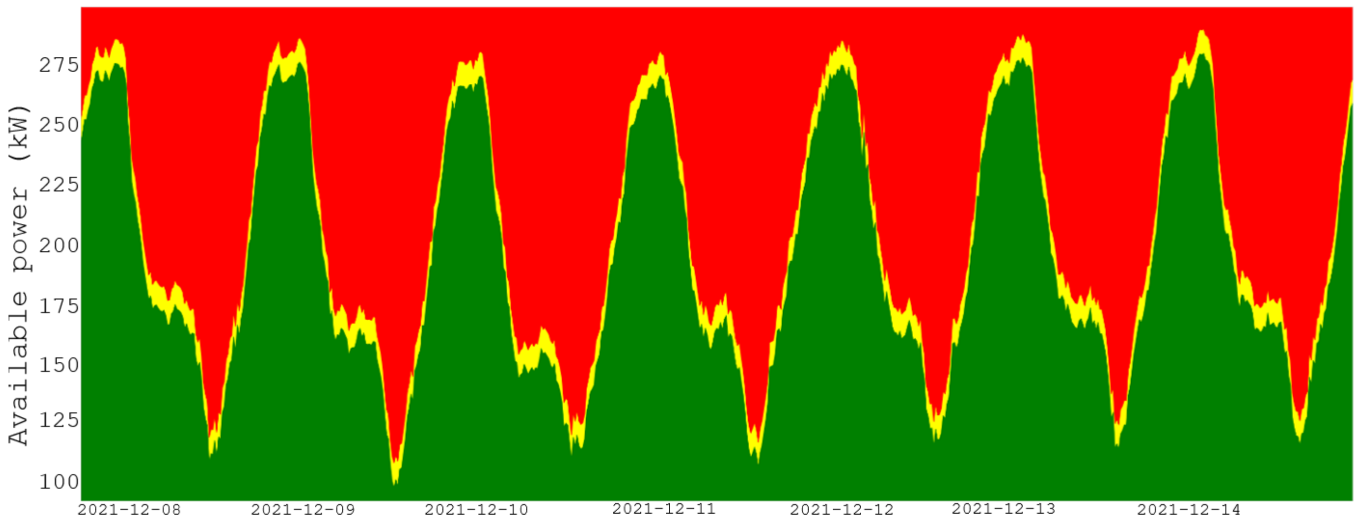

Figure 6: Overview of available power at low (green), medium (yellow) and high price levels for the dynamic grid tariffs. These available powers are additive meaning the CPO can use power in the low first, and add some of the medium price power. A CPO may charge 100 kW at, 15 kW at the medium and 50 at the high dynamic grid tariff price level at a specific time.

4.5 Case study and data overview

For assessing the effect of introducing a new tariff design a case study will be used. This case study will present an outlook on the effects of altering the tariff structure for CPOs on a distribution grid (single transformer, Floresstraat) in the Lombok neighborhood in Utrecht. The transformer is a 400 kVA transformer which currently is not experiencing congestion issues. In addition to charging infrastructure the transformer serves around 340 households, mostly built in the early 20th century. However with increasing EV penetration congestion issues may occur. For this reason an outlook is presented for a future scenario increased EV load. A total of 60 charging points (CPs), 120 outlets, were selected. This is expected to be reached between 2028 and 2040 (Elaad et al., 2021). The demand totals 537 MWh annually which is consistent with predictions made in (N. Brinkel et al., 2020) which assume 530 MWh of demand for full electrification of the car fleet. The charging data for these charging points contains all charging sessions within 2021, with the connection time, departure time, total energy required and the maximum power of the charging session. Table 2 presents an overview of data. All data used was real data from 2021. The increase in charging points is modeled using real data from other charging points within Utrecht not connected to this transformer in real-life. The choice to use 2021 was made because this is the most recent year for which full data exists and real data has the advantage of not requiring assumptions in generating profiles, which may lead to biases. In the modeling approach the assumption is made that 1 kW and 1 kVA is equivalent.

Table 2: Overview of data relevant to the case study

Input	Shortened description	Source
Electricity prices	Day-ahead prices from APX spot market, 2021	APX data, retrieved via Stedin from (EPEX spot, 2022)
Predicted transformer loads	Predictions of transformer loads excluding EV 24hrs in advance	Proprietary predictions from Stedin
Actual transformer load	Actual transformer loads excluding EV	Stedin data
Charging session data (Arrival times, departure times, energy requirements and charging point)	Data from multiple CPs from We Drive Solar in Utrecht area for 2020, selection of CPs was used	Stedin / We Drive solar (CPO and partner in FLEET project(FLEET, 2021)
CAP+ (subscription prices and exceedance fees)	Parameters for the CAP+ tariff design	Varied in different scenarios, see results
Dynamic grid tariff prices	Prices at the different levels for dynamic grid tariff prices	Varied in different scenarios, see results
Dynamic power availability	Availability of power at the different price levels at any time, based on predicted loads, 1% and 5% chance of overloading	Calculated using method discussed in 4.4

4.6 Modeling scenarios

In modeling a number of different scenarios for tariff designs were tested. These include the scenarios for the CAP+ tariff design (Table 3) and the dynamic tariffs (Table 4). In addition to these scenarios 2 baseline scenarios were taken into account. The first baseline scenario uses the electricity price optimization only model to assess the CPO behavior under the current grid tariffs, the second baseline scenario uses the charge on arrival model. The scenarios will be referred to as the electricity only and charge-on-arrival scenario respectively.

The CAP+ tariff designs used are based off of internal proposals within Stedin for the subscribed capacities, with corresponding prices and exceedance fees. These were further varies to assess the effect of changing the prices and exceedance fees. For the dynamic grid tariff varying sets of prices were chosen to investigate how differences in these prices affect the CPO behavior. In the dynamic pricing only the differences between the prices matters. In the modeling phase trial sets were used. These trial sets were later corrected to the values shown in Table 4. This was done on the basis of the total grid tariffs due for the CPO, these calculations can be found in section 5.4.

Table 3: Overview of CAP+ tariff design scenarios

Name	Subscription prices [5kW, 9kW, 12kW, 17kW] in (€/yr)	Exceedance fee (€/kWh)
CAP+ 1	[125, 225, 300, 425]	0.5
CAP+ 2	[125, 225, 300, 425]	0.1
CAP+ 3	[150, 200, 250, 300]	0.5
CAP+ 4	[150, 200, 250, 300]	0.1

Table 4:Overview of Dynamic grid tariff design scenarios prices shown are shown per price level of the dynamic tariffs [low, medium, high].

Name	Dynamic prices (€/kWh)
Dynamic 1	[0.017, 0.027, 0.047]
Dynamic 2	[0.017, 0.107, 0.207]
Dynamic 3	[0.017, 0.062, 0.162]
Dynamic 4	[0.017, 0.116, 0.416]

5 Results

The results section is divided along the lines of the evaluation parameters. Efficient network use will be discussed first, illustrated using load duration curves at the transformer. This is followed by an overview of how introducing a new tariff design affects costs for the CPO and related DSO revenues. In addition the cost reflectiveness is closely examined as well as the specific details of designing CAP+ and dynamic tariff structures.

5.1 Efficient network use

To examinate the efficiency of network use, the load duration curves at the transformer under the different options for tariff designs are examined. Load duration curves show the hourly load at the transformer over one year, ordered from high to low load rather than being ordered on a chronological basis.

First presented, is the load duration curve comparing the different tariff designs. For this the best performing CAP+ and Dynamic tariff design scenarios are presented, in combination with the charge-on-arrival and optimization on electricity prices only (Figure 7). Next an in depth analysis of the different CAP+ and dynamic tariffs is presented. The rated capacity of the transformer in the case study was 400 kVA (assumed to be 400 kW), this level is indicated with a horizontal red dotted line.

5.1.1 Comparing the tariff designs

Figure 7 shows the comparison between the four main scenarios. In all cases the rated transformer capacity is exceeded for a part of the year. What is evident is that differences exist in both the number of hours at which exceedance occurs as well as the maximum exceedance between different scenarios.

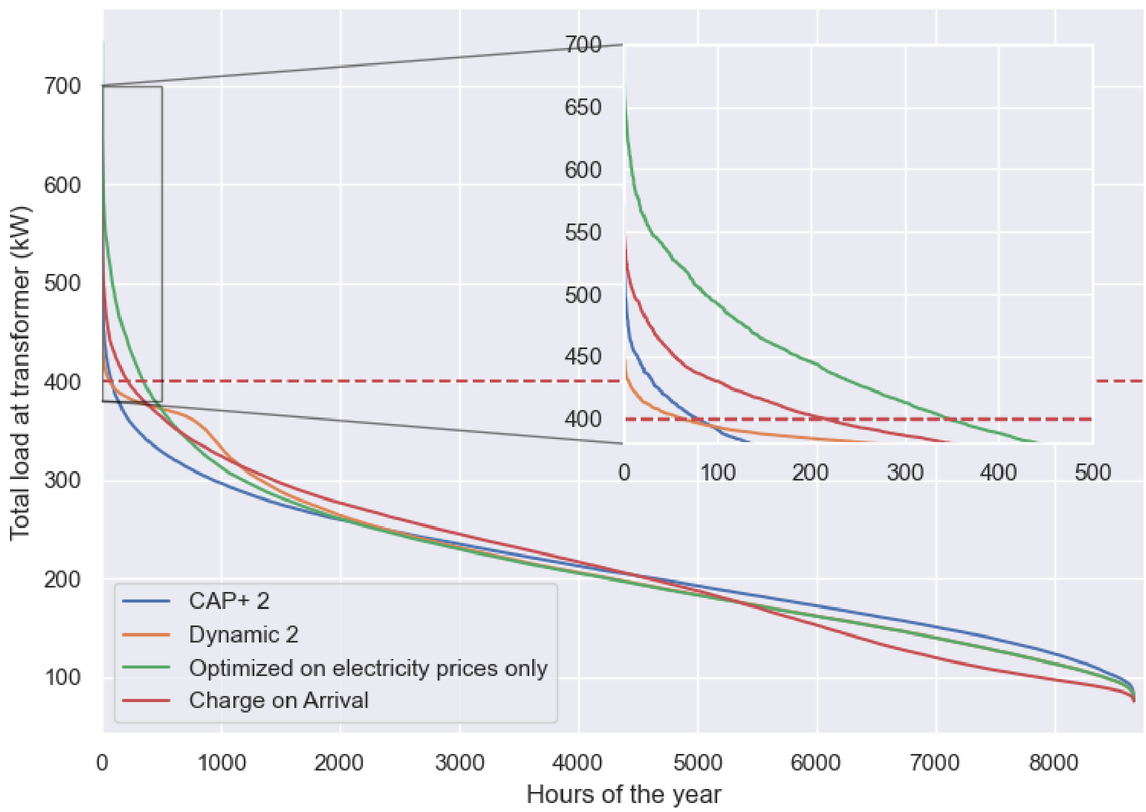

Figure 7: Load duration comparing different tariff designs options

When examining the two baseline scenarios (unoptimized charging and optimization on the electricity prices only), a clear distinction arises. Optimizing on electricity prises causes both a far higher maximum load as well as more frequent exceedance, peaking at nearly 750 kW as opposed to 575 kW for unoptimized charging. This difference is caused by the fact that when shifting the charging loads, all vehicles will, when possible, charge at the time of the lowest electricity prices in the electricity optimization only scenario. This causes greater allignment of charging sessions than that which would occur under charge of arrival where the allingment is purely based on the natural distribution of arrival times.

In both the CAP+ and dynamic tariff designs the number of hours when congestion occurs is drastically lowered compared to the baseline. This is because both incentivize limiting high loads. However, when looking at the peak hours a clear difference arises. The CAP+ model peaks at a far higher 572 kW as compared to 455 kW for the dynamic alternative. This translates to 143% and 114% of rated transformer load. The cause of this difference is to be found in the structure of the incentives. The incentives for dynamic tariffs are specifically aimed at the coincident peak of all loads at the transformer. This happens because in the dynamic tariffs the grid connections are pooled. Meaning they are treated as if they were a single connection for the dynamic grid tarif purpose. For this complete pooled set of connections the available power to charge at each level is communicated. This means the CPO can use the flexibility from longer charging sessions to ensure enough charging volume in one charging session. In addition the available powers are specifically set in order to incentivize grid use below the transformer rated capacity. In the CAP+ model, however, the incentives for limiting grid use are on the level of the individual connection. This means that, whilst for a single connections the CPO is incentivized to limit the peak to the subscribed capacity, the total coincident network peak can still be relatively high if all charging points reach the peak at the subscribed capacity at the same time.

5.1.2 Example of tariff design effect on daily charging pattern

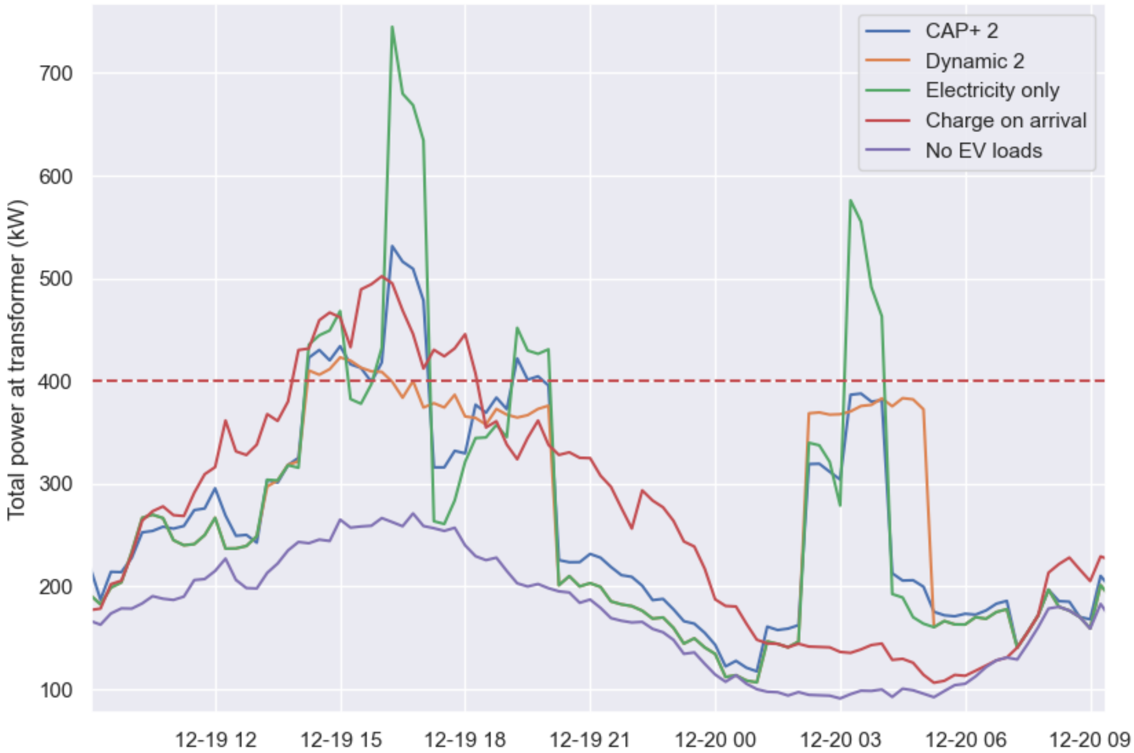

Figure 8: Example day showing the effect of introducing different tariff design on charging patterns. The day is taken from 9 AM to 9 AM, this is shown on the x-axis together with the data (MM/DD h).

Figure 8 shows an example of a day with heavy congestion, to provide a reference. Here the day is taken to be from 8:00am to 8:00am the next day which provides a better overview of shifting loads than if the calander day was used. The first thing to note is that, as expected, the range of arrival times for the EVs causes a spread of charging load, up to an extend, leading to a relatively smooth curve for the charge-on-arrival scenario. This curve does exceed rated transformer capacity at the peak by a significant amount between 14 pm and 17 pm as on this particular (sun)day many cars arrived at this moment. When optimizing for electricity prices significant peaks arise at times of low electricity prices and high numbers of connected EVs. The first of these peaks is at 16:30, coinciding with high non-ev load. The second peak is in the night to early morning. This peak does not coincide with high non-ev load and is likely caused by low electricity prices. Under the CAP+ tariff design the shape of the electricity only scenario is largely followed, however notably the peaks are lower. This is the case because a premium has to be paid when exceeding the subscribed capacities. However, especially at 17:00 the loads still allowed under the CAP+ tariff structure mean total transformer load still far exceeds the transformer rated capacity due to high non-ev loads. Under the dynamic tariff stucture this is not the case. Whilst the charging coincides perfectly with the electricity optimization only scenario for loads dropping below approximately 300 kW, a clear difference arises when exceeding these levels. When that happens the peak of the electricity only scenario is stumped resulting in a broader, but significantly lower peak at or somewhat below the rater transformer capacity. This can be seen most clearly with the nightly peak. Here the Dynamic 1 has a longer peak between 2:00 and 5:00 whereas the electricity only scenario peaks much shorter, between 3:00 and

4:00, but at 580 kW compared to 380 kW for the dynamic scenario respectively.This is because under the dynamic grid pricing the grid tariffs per kWh go up if the chance of transformer overload increases. Thus the prices go up if the total load at the transformer nears the transformer rated capacity. For this reason the CPO opts to not take advantage of the shorter time period with the lowest prices for electricity, but instead opts to charge the EVs for a longer period with low, but not the lowest, prices.

5.1.3 Dynamic tariffs

In Figure 9, seen below, the different dynamic tariff designs are more closely inspected. All of the dynamic pricing structures share the same overall shape for the majority of hours in the year. A steady increase is seen for most hours, followed by a rapid increase at around 300 kW and before platauing at 350kW and ending with an uptick above 400kW in the most high load hours of the year.

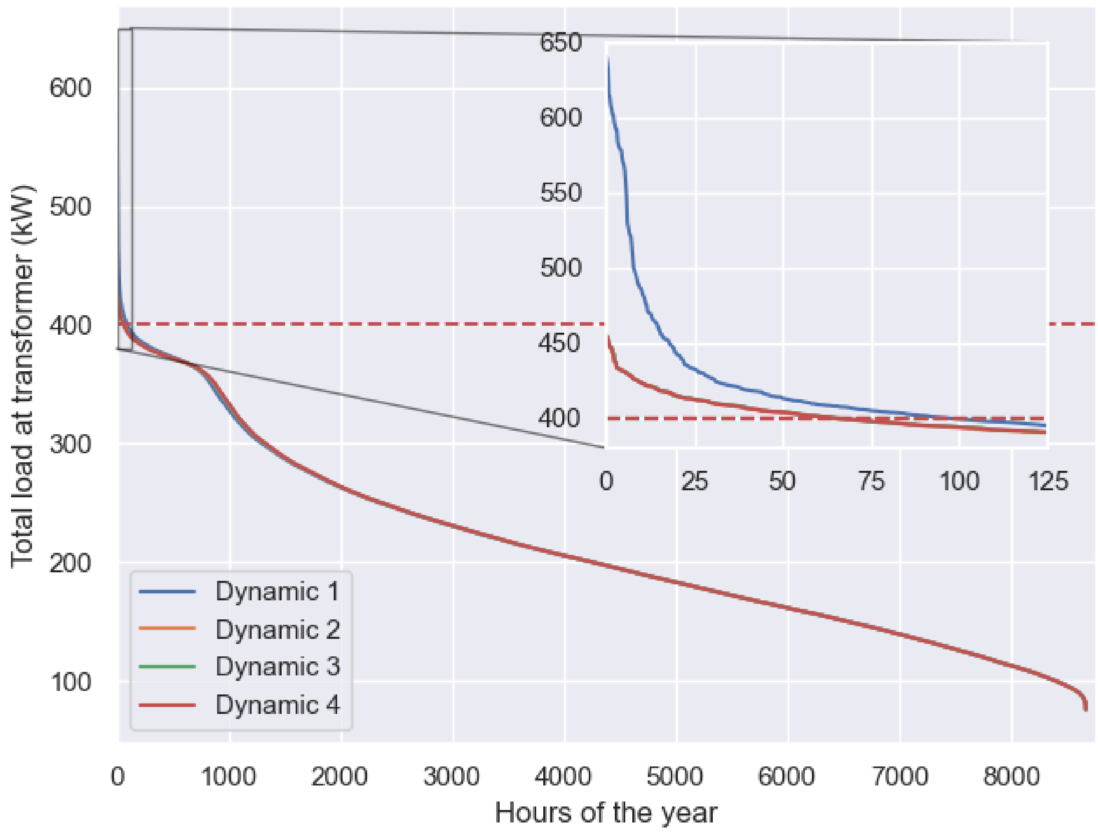

Figure 9: Load duration curve comparing different dynamic tariff design scenarios

This is the result of of the fact that the dynamic pricing structure only starts to affect charging behaviour when the transformer load is expected to be at or near the transformer's rated capacity. This is what explains the quick rise and than platauing of the load duration curve between 350 and 390 kW. The loads above these levels are priced higher, thus some of this load will be shifted to other times. Above this level, however, a split arises between Dynamic 1 and Dynamic 2, 3 and 4. Whereas 2, 3 and 4 almost perfectly coincide for the entire year Dynamic 1 shows a much higher peak. When looking at the set of prices in the different dynamic tariff designs it becomes clear why

Dynamic 1 diverges. In Dynamic 1 the price differences between the levels is the smallest. This means the least amount of incentives to limit charging when chance of transformer overloading is high are provided. This result of this is a shortcoming of incentives to reduce charging loads at a number of hours per year. This is the case because if the Day-ahead electricity prices have a swing larger than the dynamic price difference it becomes more interesting for the CPO to act on these electricity prices rather than limiting its grid tariff costs. When this shortcoming arises the transformer load peaks at a value which exceeds even the CAP+ tariff design discussed above. In the other scenarios which were considered, the incentives were large enough, further increase of these differences makes little to no difference.

5.1.4 CAP+ Tarriffs

The CAP+ tariff has two parameters which are subject to variation, the exceedance fee and the subscription fees. In Figure 10 the effect of these two parameters is shown. Whilst no large difference exist in the peaking value, significant differences exist in the number of hours at which the rated capacity is exceeded. CAP+2 performs best, followed by CAP+4, these two have in common that they are the CAP+ tariffs with the, comperatively, low exceedance fee of € 0.1/kWh. The reason why a low exceedance fee leads to a lower amount of hours with exceedance is that lower exceedance fees also cause lower subscribed capacities, this means an incentive to limit the loads at the level of the charging point (CP) starts at a lower load. This difference is further eleborated on in the intermezzo section on subscribed capacities below. Next, larger differences between the subscribed capacities also have a mitigating effect on the number of hours at which the transfomer load is exceeded. This can be explained via the same logic as the exceedance fees, higher differences provide a higher incentive for low subscribed capacities.

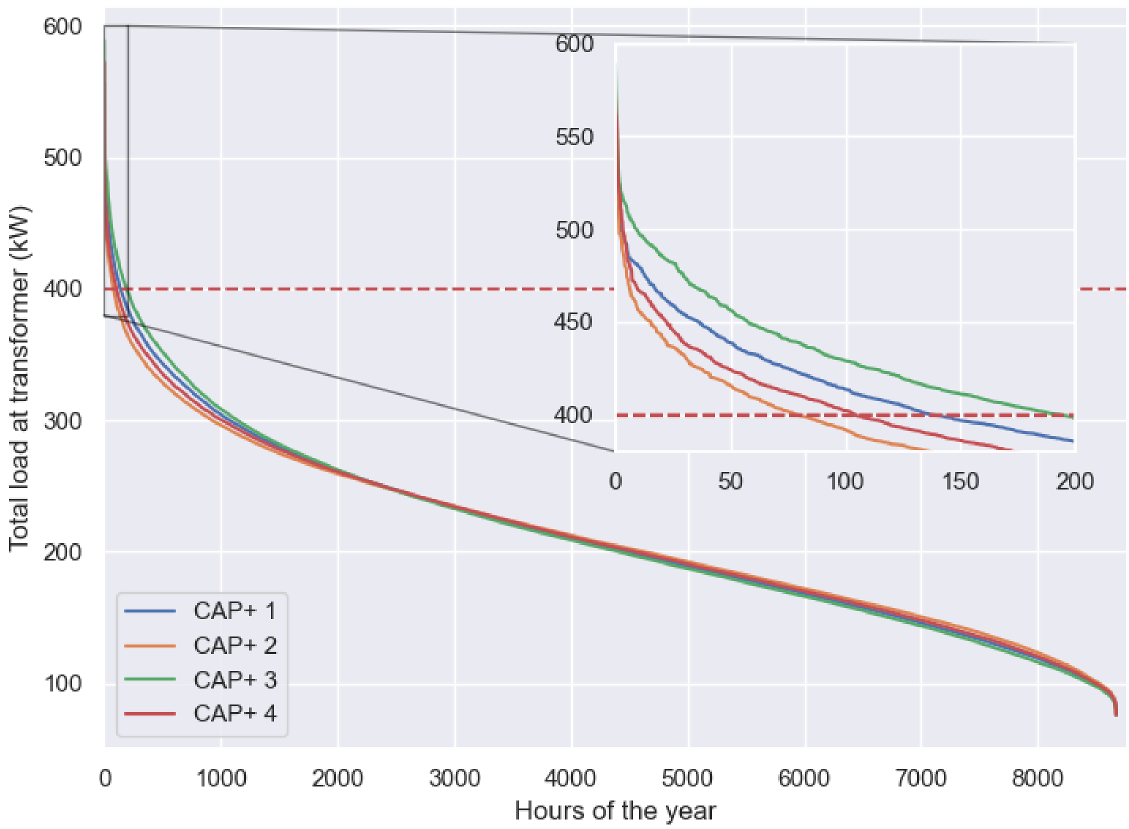

Figure 10: Load duration curve for different CAP+ tariff design scenarios

When looking at the overall shape of the load duration curves under the CAP+ tariffs no explicit tapering of loads is found near the transformer rated capacity. In fact, the load duration curves gradient steadily increases for loads higher than 250 kW. This means that, as discussed before, no interactions exist which specifically cause a dampening of loads with respect to the transformer rated capacity, rather the loads are only dampened by the individual subscribed capacities being lower than the full physical connection, being available under the current tariff design at no extra costs.

Intermezzo - Subscribed capacities

In the model the CPO was free to choose the subscription size which would lead to the lowest total costs (grid tariffs + electricity prices). The optimal solution for grid tariffs is shown in table Table 5.

Table 5: Overview of subscribed capacities opted for by the CPO under the different CAP+ tariff design scenarios. Total of 60 CPs considered

Tariff (subscription fees, exceedance fee)	5 kW	9kW	12kW	17 kW
CAP+ 1	13	21	23	3
CAP+ 2	25	30	5	0
CAP+ 3	5	22	25	8
CAP+ 4	18	36	4	2

Two trends become apparent here: first a steeper increase of fees per subscription size leads to lower chosen subscribed capacities. Secondly, a lower exceedance fee also leads to significantly lower chosen subscribed capacities. Both effects can be explained by the incentives which arise from the chosen combination. Firstly, higher differences between subscription fees mean that more costs are incurred when raising the subscribed capacity one level, thus more costs need to be incurred elsewhere in order to justify raising the capacity. Secondly the chosen subscriptions are also lower with a lower exceedance fee. This is because the penalty for exceedance is lower, thus the choice to occasionally exceed chosen capacity will be less costly which allows for, in general, lower subscribed capacities. Even though CP's are relatively large users of electricity in the LV distribution grid, especially compared to non-ev households, high subscribed capacities are not dominant. To understand why this is the case under the assumptions made in the model a simple calculation can be used. In order for a CP under the [125, 225, 300, 425] with exceedance fee 0.1 tariff structure to opt for a larger subscribed capacity, €100 in exceedance fees must be mitigated (in the case of the 5 to 9 kW expansion, the first two possible subscription sizes). This means 1000 kWh must fall under this exceedance fee. A kWh falls under the exceedance fee when the subscribed capacity is exceeded (i.e. 1 hour of 8 kW power consumption with a 5 kW subscribed capacity is 3 kWh under exceedance fees). This is a significant percentage of the approximately 9000 kWh/yr charged at the average CP within the contained set.

5.2 Cost overview

Besides efficient network use the costs paid paid by the customer, in this case the CPO are also very relevant. Here two types of costs are of importance, the grid tariff costs and the (day-ahead) electricity costs. The goal is to find the effect of introducing a new tariff design. This is why Figure 11 shows the additional electricity costs as compared to the electricity only scenario, which is the current tariff design with optimization on electricity prices in place. The dynamic scenarios show an asterisk. This is to indicate that the values for total grid cost per CP are subject to change. The values for the dynamic prices are easily adapted to recouperate costs at a different level. This is further expanded upon in section 5.4.

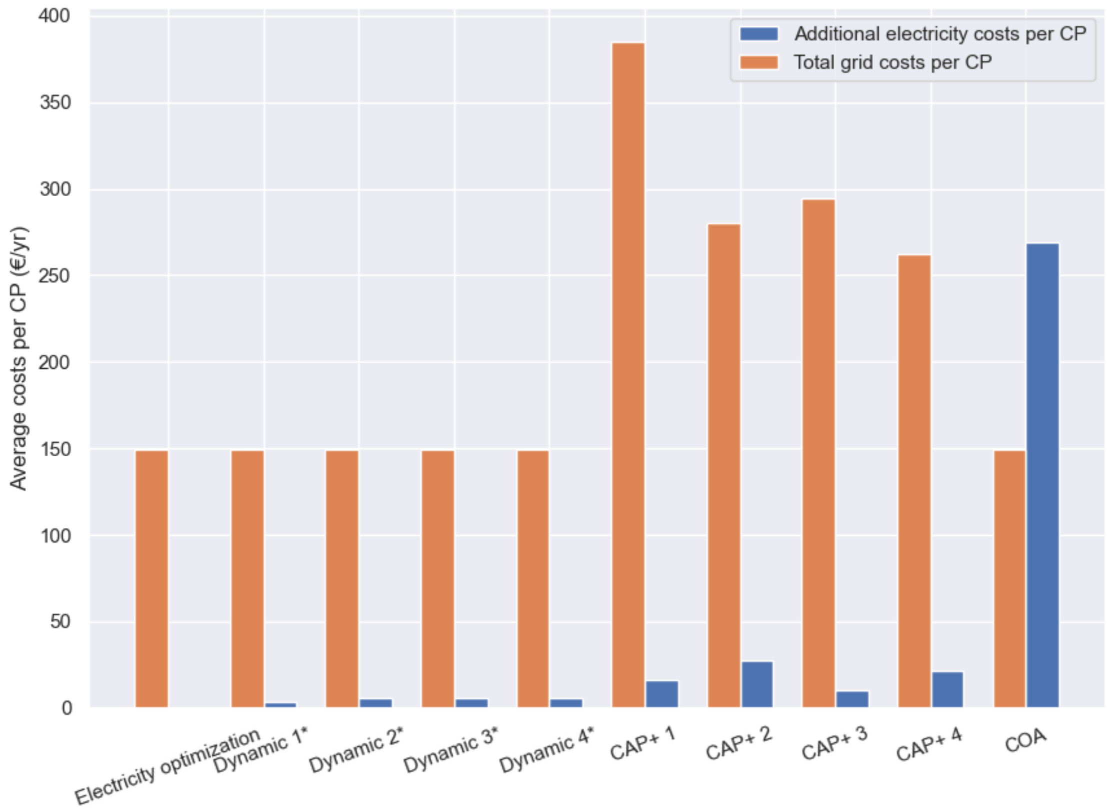

Figure 11: Overview of costs paid by the CPO in grid tariffs under differing tariff design scenarios as well as additional electricity costs compared to the current tariff design. The asterisks indicate that the grid costs for dynamic tariffs can be easily altered, see section 5.4 for full info.

Table 6: Overview of costs per CP paid by the CPO in grid tariffs and electricity costs under differing tariff design scenarios as well as additional electricity costs compared to the current tariff design.

	Total grid tariffs (€/yr)	Additional electricity costs (€/yr)	Total electricity costs (€/yr)	Total costs (electricity + grid tariffs) (€/yr)
Electricity price optimization	149.60	0.00	721.22	870.82
Dynamic 1	149.60	3.27	724.48	877.35
Dynamic 2	149.60	6.13	727.35	883.08
Dynamic 3	149.60	5.90	727.12	882.62
Dynamic 4	149.60	6.02	727.23	882.85
CAP+ 1	384.97	16.28	737.50	1138.75
CAP+ 2	279.90	27.33	748.55	1055.78
CAP+ 3	294.20	10.43	731.65	1036.28
CAP+ 4	262.57	21.47	742.68	1026.72
Charge-on-arrival	149.60	268.77	989.98	1408.35

In general we see the total costs for Electricity far outweigh the cost for grid tariffs, but the grid tariffs far outweigh the additional electricity costs caused by the introduction of a new tariff design. The additional electricity costs refer to the additional costs the CPO incurs in from electricity in the day-ahead market compared to the Electricity price optimization scenario. These costs are caused by the change in tariff design which incentivize the CPO to not always charge at full power whenever the day-ahead prices are lowest. Since the additional electricity costs are low this means this does not happen very often or happens only for small differences in electricity prices.

The CPOs costs for grid tariffs increase compared to the current tariff design for all the CAP+ models included, this is to be expected as CPs use a relatively large amount of electricity compared to regular households. Because CPs are relatively large users of electricity they require, on average, a larger subscribed capacity, this larger subscribed capacity means they have higher than average costs compared to average cost under the current tariff design. In the current tariff design all of users with connection sizes between 1x10A and 3x25A have the same grid tariff costs(Stedin, 2022), regardless of actual network use. Thus when this is differentiated, as is the case in the CAP+ model the larger users, such as CPs will have an increase in their grid tariffs. Because in the CAP+ model an exceedance fee needs to be paid on the electricity consumed at above the subscribed capacity, it is not always beneficial to charge the car at the maximum possible power when electricity is at its lowest price during the time period of the charging session. Thus sometimes some extra amount needs to be paid on the electricity to charge the car compared to the current tariff design. This varies between the specifics of the CAP+ design. A higher exceedance fee, as is applied in CAP+ 1 and CAP+ 3, causes the CPO to opt for higher subscribed capacities. These higher subscribed capacities means that the capacity to react to lower electricity prices is larger. This, in turn, leads to lower additional costs for electricity compared to when the CPO opt for smaller subscription capacities as is the case with lower exceedance fees. The costs for grid tariffs, however, are lower in CAP+ 2 and CAP+4, the scenarios with the lower exceedance fees. This is because of two reasons. First, the CPO opts for smaller subscribed capacities, leading to lower costs in subscription fees. Secondly, the costs for exceedance are lower with a lower exceedance fee as well. Furthermore, steeper price increases for the subscribed capacities lead to higher costs, both for the subscribed capacities themselves as well as higher costs from exceedance fees as exceedance fees need to be paid over a higher proportion of the consumed electricity, when opting for smaller subscription sizes.

In all scenarios for the dynamic tariff design the costs for grid tariffs equal the costs for grid tariffs under the current tariff design. This is however, not a coincidence but rather this is by design. The tariffs were calculated to precisely be at the level required to recuperate costs at the same rate as the current tariff design. These calculations are further explained in section 5.4. The reason for making the costs the same total costs in grid tariffs for CPOs under the Dynamic tariffs as under the current tariff design would be to make sure that the revenue for the DSO does not increase. This is necessary because the DSO can only recover costs at the level of efficient operation (CEER, 2017). However it is also possible to redistribute the costs from households to CPOs to an extent to make the grid tariffs more cost reflective (see sections 5.3 and 5.4).

Additional electricity costs are low under all dynamic tariff design scenarios. This is both compared to the total electricity costs as well as compared to the additional electricity costs under the CAP+ tariff design. This is the case because under the Dynamic grid tariff design the capacity to react to lower electricity prices is not set by an individual limit, as is the case under the CAP+ tariff design, but rather extra costs, in the form of the higher price levels in the dynamic grid tariffs, are only applied when the total load at the transformer reaches a certain threshold. This is much less often the case than the amount of times an individual charging point is limited by the subscribed capacity. Furthermore, Dynamic 1 has even lower additional electricity costs when compared to the other dynamic scenarios, this however is the case only because Dynamic 1 does not provide enough incentives to overcome the benefits of lower electricity prices when the transformer gets overloaded. This leads to high transformer loads, but does mean lower costs for electricity.

5.3 Cost reflectiveness

As discussed earlier, the grid tariffs should, as far as practicable, reflect the costs inflicted by the network use of the user. (CEER, 2017) The earlier defined metric of cost reflectiveness, the CRI formulated in equation (1), is used for this and shown in Table 7 below. Here the Max peak refers to the single time of year when the total transformer load is highest, the 95% peak takes into account all times when at least 95% of this peak value is reached.

Table 7: Cost reflectiveness of tariff design scenarios as calculated using the defined CRI, here Max peak refers to the single timestep in the year with the highest value transformer load, 95% peak refers to all values of at least 95% max being taken into account

	Max peak	95% peak
Dynamic 1	0.19	0.20
Dynamic 2	0.58	0.38
Dynamic 3	0.61	0.40
Dynamic 4	0.64	0.42
CAP+ 1	0.42	0.43
CAP+ 2	0.22	0.23
CAP+ 3	0.39	0.39
CAP+ 4	0.23	0.23
Electricity price only	0.23	0.23
Charge on arrival	0.34	0.35

The results of the cost reflectiveness analysis show that in each case the numbers are well below 1, thus indicating the CPO pays less in grid tariffs then would be consistent with perfect cost reflectiveness. This is expected due to the high loads associated with EV charging. For the Dynamic tariff design one note must be made, the costs for the dynamic tariffs can be relatively easily scaled, see section 5.4 below, and thus the results for the CRI can also be scaled accordingly. The decision on how to divide the costs, and alter the dynamic prices is left outside the scope of this thesis. For the CAP+ tariff design this is not the case, as the CAP+ tariff design is not easily adapted and the CAP+ tariff design is proposed to be applied to both households and CPOs equally. In addition the CRI for current tariff design, the electricity price only scenario, is much lower than 1. This is because optimization on electricity prices only results in high loads caused by EV at the peak times, especially when electricity is cheap.

Wilts the CRI for the CAP+ tariff design is virtually equal for the Max peak and 95% peak calculations this is not the case for the dynamic tariff designs. This is because in the dynamic tariff design the coincident peak is specifically charged at higher prices. This means that when the transformer gets overloaded, or more specifically the probability of overloading is sufficiently high, the prices go up for the CPO. The CPO will thus charge less causing them to be a smaller percentage of this peak. This effect is smaller for the 95% category than the max peak category.

The main result from this is that the dynamic tariff scenarios which function well as a means of increasing efficient network use (Dynamic 2, 3 and 4) are significantly more cost reflective compared to the current and the CAP+ tariff designs.

5.4 Calculate dynamic tariffs optimum

As mentioned before the dynamic tariff design scenarios shown in Table 4 are the values calculated to make the CPO precisely have the same total grid tariff costs under these dynamic scenarios as under the current tariff design. These calculations were done by first modeling the CPO behavior using trial sets for the dynamic tariff design. These trial sets can be found in Table 8. In the model only the difference between the different price levels matters, not the absolute values since the CPO saves on the price difference but always has to pay at least the amount corresponding to the lowest price level. As long as an flat increase is added to all price levels within the dynamic tariff scenario equally, no behavior change will occur.

To calculate the flat rate which needs to be added to the dynamic prices equation (2) is used. Here base CPO grid tariff costs refers to the CPO revenue using the trial values for the dynamic prices and the total charged energy is all charged electricity (kWh) from all EVs at all charging points for the year. The target CPO grid tariff costs is the total in grid tariff costs that the CPO has to pay in order for the DSO to recuperate the right amount of costs from the CPOs connections. For the purpose of the results presented above this target was set to be equal to the CPO costs under the current tariff design (€ 149.6 per CP, €8976.- in total). Alternatively equation (3) can be used to determine the total amount of grid tariffs the CPO would have to pay the cost reflective amount given by the defined CRI. By linearly increasing the amount the CPO has to pay the cost reflectiveness can be increased to perfect cost reflectiveness (CRI=1). Of course, increasing the grid tariffs for the CPO means that grid tariffs for other users will likely have to be decreased to comply to regulation (the DSO is not allowed to increase its own revenue from gird tariffs above a certain level).

In order for the DSO to recuperate the costs of efficient operation the trial dynamic tariff structures shown in Table 8 would not suffice. This can be seen in Figure 11 and

Table 6 where recuperated costs, the total revenue of the DSO from connections behind the transformer in question, are much lower compared to the current situation if the values for the trial dynamic tariff structures were taken. In order to get the right recuperation the dynamic tariffs will thus have to be adjusted. Luckily only the absolute difference between the different tariff levels matters in the optimization. For this reason if all levels were to be raised by the same amount the behavior of the CPO would not be altered under the assumptions within the model. In order to calculate the amount by which the tariffs have to be raised the following equation is used:

$$flat\ raise\ of\ dynamic\ fees = \frac{target\ CPO\ grid\ tariff\ costs - base\ CPO\ grid\ tariff\ costs}{total\ charged\ energy} \quad (2)$$

$$Target\ CPO\ revenue = \frac{CPO\ grid\ tariffs\ paid}{cost\ reflectiveness} \quad (3)$$

Table 8: Overview of dynamic grid tariff scenario trial values as used in the modelling phase.

Name	Dynamic prices (€/kWh)
Dynamic 1	[0.01, 0.02, 0.04]
Dynamic 2	[0.01, 0.1, 0.2]
Dynamic 3	[0.005, 0.05, 0.15]
Dynamic 4	[0.001, 0.1, 0.4]

Table 9 shows the results for the flat rate increase in dynamic grid on top of the trial values shown in Table 8 necessary to bring the total CPO grid tariff costs up to the level of the current tariff design, or perfect cost reflectiveness according to the CRI. For example, the trial set for Dynamic 1 [0.01, 0.02, 0.04] requires a flat rate increase of 0.007 €/kWh in order for the CPO to pay the same amount as under the current tariff design. Thus the dynamic prices would become [0.017, 0.027, 0.047].

Table 9: Price corrections to the Dynamic grid tariffs necessary to recuperate costs at the level of the current tariff design or perfect CRI. Flat rate increase all price levels (low, medium and high) in €/kWh

Dynamic tariff set	Current tariff design	cost reflective	cost reflective 95%
Dynamic 1	0.007	0.037	0.035
Dynamic 2	0.007	0.012	0.018
Dynamic 3	0.012	0.020	0.030
Dynamic 4	0.016	0.025	0.038

Using the corrections to the dynamic prices required for a cost reflective grid tariff total for the CPO provides another option for the costs for the CPO. This means the results as shown in Figure 11 would change significantly. Figure 10 below shows the overview of costs again, now including the option of cost-reflective grid tariffs for the CPO under the dynamic grid tariff design, this assumes cost-reflectiveness to only take into account the annual max peak.

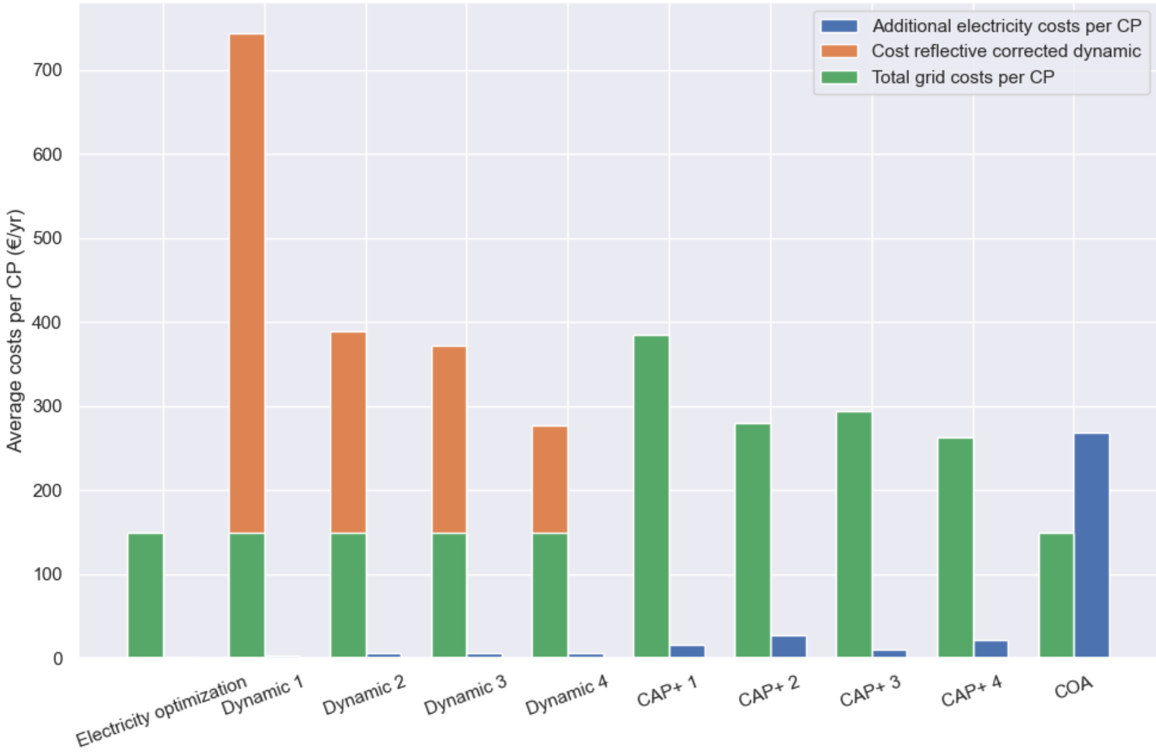

Figure 12: : Overview of costs paid by the CPO in grid tariffs under differing tariff design scenarios as well as additional electricity costs compared to the current tariff design. Now including the costs for the dynamic tariffs when correcting the dynamic tariffs for perfect cost reflectiveness.

When correcting the dynamic grid tariffs for perfect cost reflectiveness the total grid tariffs to be paid by the CPO rise significantly. However, large differences between the Dynamic 1 scenario and the other Dynamic scenarios exist. This difference is caused by the ineffectiveness of the Dynamic 1 scenario to reduce peak loads. Because the Dynamic 1 scenario leads to high peak loads a lot of extra tariffs need to be levied on the CPO in order to recuperate costs at a level that is reflective of the costs the CPO inflicts. This is because as the peak dramatically increases so do the eventual network costs as network costs are primarily driven by the highest coincident peak (Govaerts et al., 2021). For the other scenario's, Dynamic 2, 3 and 4, this is much less the case. As these specific designs for the dynamic grid tariffs are more effective at reducing the contribution of the CPO to peak transformer loads, they require less costs to be levied in order to be cost reflective as determined using the defined CRI. Whether to levy grid tariffs from the CPO at the cost reflective level, at the level of the current tariff design or at some level in between is a choice for the regulator and left outside the scope of this thesis. Raising the costs for CPOs means a redistribution of costs from households to the CPO as the revenue for the DSO is not allowed to increase above the level of the costs of efficient network operation (CEER, 2017).

6 Analysis of qualitative parameters

In addition to the quantitative analysis of the impact of alternative tariff designs, other factors need to be taken into account. These are the factors that were labelled in the overview of decision parameters section as parameters which would be assessed qualitatively.

predictability

Under the current tariff design *predictability* is optimal. There are no changes possible to the bill for grid tariffs to be received other than upgrading the physical connection and year-on-year marginal increases. Both the CAP+ and dynamic grid tariff designs will lead to a reduction in this predictability. This is due to the possibility (in both cases) that relatively minor changes in grid use at specific times can lead to a relatively large increase in the payments due for the grid tariffs. The CAP+ exceedance fee and the highest price in the dynamic pricing scheme have relatively high fees. This means that when these fees have to be paid the bill for the customer can go up by a relatively large amount with a relatively small change in the customers load profile. Thus the network costs are not easily estimated on the basis of a rough consumption profile. However, in both these cases the necessity to pay these relatively high, €/kWh, prices can be predicted and minimized to an extent. When these are minimized a these costs can go down significantly which increases the accuracy of the estimation based on the rough consumption profile.

In the case of the dynamic tariffs there is a secondary problem. The dynamic tariffs are based on the (predicted) loads from other non-CP connections. This means that, when the loads of the other connections significantly change, and this is taken into account when making the load predictions, the available powers at the price levels may change. This can alter the bill for the CPO significantly making it harder to predict the total network costs on the basis of a rough estimate of the consumption profile.

Simplicity

In addition to the predictability, the current flat rate for the grid tariffs is very simple to understand for customers and the manner of determining the fees is relatively transparent, as the full explanation is available online (Autoriteit Consument en Markt, 2021). Both the CAP+ and Dynamic grid tariffs are more complicated. The CAP+ tariff is more complicated for two reasons: it consists of two rather than one type of fee (subscription and exceedance) and, in addition, the exceedance fee being dependent on both momentary power consumption and subscribed capacity, somewhat more complicated for customers.

The dynamic grid tariffs are complicated by the pooling of different physical connections behind the same transformer and the inclusion of predicted transformer loads. Here pooling means treating the group of connections a CPO has behind a single transformer as if it were one connection, thus billing as one and allotting available power to the group rather than the physical connection if multiple CPOs are active with connections to the same transformer this will further be complicated. A manner of dividing the available power at each price level will have to be devised in this case. This will require active management and connectivity in order to properly adapt to. One major mitigating factor on this complexity is the targeting of the dynamic grid tariffs, because these are aimed specifically at CPOs or other flexible load operators. For this reason a higher level of understanding and technical capacities may be expected. Furthermore, requiring adaptation to the predicted grid use of other customers connected to the same grid means long-term planning is made more complicated as well under the dynamic tariff design.

Transparency

On transparency, both the CAP+ and Dynamic tariffs may have some issues. Both the determining of the exceedance fee and the precise manner of determining the available powers requires careful consideration, which may not always be easily linked to publicly available parameters. In the case of determining CAP+ a clear method of determining exceedance fees and subscription fees needs to be set up and made publicly available in order to be as transparent as possible. This is not yet done but should be feasible if implemented. For determining the available powers of the different dynamic pricing levels this becomes more complicated. The prediction algorithm and required data is more challenging to make publicly available and to explain well. In addition a prediction algorithm like this is more likely to be prone to large-scale updating which also makes transparency more difficult.

Non-distortion

In the current tariff no distortion occurs, the only limit to market access, that is the opportunity for a party to react to market incentives, is the physical limit of the connection. The CAP+ tariff design introduced limits to market access above these physical limits, whilst these limit the access to the market they only do this by increasing the differentiation between customers on their network use, thus imposing a limit stricter than the pure physical limit for some customers. In the case of the dynamic tariffs, market prices are clearly one of the factors which impact the dynamic grid tariff to be paid. However, the low amount of additional electricity costs incurred under the dynamic grid tariffs compared to the actual grid tariffs which need to be paid indicate that these incentives are provided in an efficient manner. If tariffs were too restrictive, higher additional electricity costs would have been expected as the CPO would shift loads more often than is strictly required for efficient network use under an overly strict dynamic tariff design.

Non-discrimination

Finally, non-discrimination is stressed as an important consideration in determining fees, this means that equal cases should be treated equally. In the case of dynamic tariffs flexible loads would be treated differently to household loads. This would be done under the assumption that public charging and household electricity use are sufficiently different and can thus be treated as a different case. Whether this is sufficiently the case is, in the end, a regulatory and legal discussion to be held.

This addresses well the difference between households and CPOs, however the locational dependency of the dynamic tariffs is not addressed within this. The available powers at each time are dependent on other use of consumers connected to the same transformer as well as previous grid investments of the DSO (a larger transformer means more available power to charge at low grid tariff costs). This difference in available powers can be compensated with lower base fees, however it does mean that the specifics of the dynamic pricing structure will change from location to location which may run into problems with legislation (primarily the non-discrimination principle) and is, in general, a regulatory choice whether this is acceptable.

7 Discussion

The analysis of grid tariff design models presented in this thesis was largely done on the basis of the presented model. When setting up the model a number of assumptions had to be made in order to assess the CPO behavior. This means an idealized version of effects is presented and real-life factors may alter the precise results. In addition, this thesis provides a case study for grid tariffs on future conditions on a transformer with a high share of public charging, results may differ somewhat if the setup of charging infrastructure behind a transformer is very different.

The most important assumption made in the model is the assumption of perfect information. The CPO is allowed to completely alter charging speeds in order to minimize its own costs, taking into account the entirety of available charging data. This means no measures will be taken to address uncertainties and avoid risks. In reality the CPO may decide to avoid certain risks. For instance, if the departure time of one of the CPOs customers is unknown an estimation must be made on this departure time. It is likely that the CPO will be conservative in this estimate as overestimating connection time leads to undercharging. This means if the CPO estimates a departure time of 8 am but the car leaves earlies, say 7 am, the car is left with a non-full battery. This would affect the CPOs business model as it would lead to a lower amount of kWh sold. In addition, not fully charging customers' cars will likely lead to dissatisfied customers. In addition some of the benefits may also be passed onto customers leading to an alternate goal for optimizing profits. However, it is likely that the benefits will be passed on in such a way that minimizing costs would still lead to the highest profits. This is the case as passing on benefits in a manner that would not lead to alignment of profits maximization and cost minimization would mean at some point the CPO would be better off increasing its own costs just to increase costs for the customer as well. This means in reality the CPO will limit the time at which charging needs to be finished rather than using the actual departure time. This in turn will lead to higher peak loads as more charging needs to happen in a shorter amount of time.

Whilst this assumption means the model outputs are no perfect representation of what real life results would be, the results do provide a useful starting point from which inferences can be made. The model provides an overview of what the CPO would do in an idealized case, meaning the real-life results are likely to mirror this with some amount of corrections. These corrections would differ under the different tariff designs and are discussed below.

In addition to perfect information, full participation of the CPOs customers in the smart charging is assumed. In reality nonfrequent users of the CPOs infrastructure may be excluded because of a lack of information or a lack of knowledge about the customer's demand profile. In addition the assumption was made that all EVs have the required technical capacities for smart charging, such as the possibility to delay charging sessions. Both these could be heavily influenced by policy decisions as policy makers can mandate charging standards and participation in smart charging.

For the CAP+ tariff design specifically, the effects of less than perfect information could be fairly large. The CPO has to make a decision on bandwidths. Without the specific demands known an element of uncertainty is introduced in picking the appropriate bandwidth. Overestimating the necessary bandwidth will lead to higher, but known, costs. Underestimating bandwidths could potentially lead to large sums of money to be owed in exceedance fees. In addition choosing a higher bandwidth allows more flexibility for the CPO, for this reason it is likely that in a real-life scenario the CPO would prefer larger but fixed costs insure a limit to expenses by opting for a higher bandwidth. As shown in the results section, higher bandwidths for the CPO lead to higher transformer peak loads. Overtime CPOs will learn to make better decisions on this, however the information they have will never be the perfect information assumed in this model.

In addition, the CAP+ tariff design is highly dependent on smart charging participation. If a significant part of the CPOs customers does not participate in the smart charging, for any reason, the CPO may be forced to opt for a higher bandwidth to accommodate these users. This would allow the CPO higher charging powers, even in customers that do participate in the smart charging. This reveals a further advantage of the dynamic tariffs; in the dynamic tariff design the CPO can use the flexibility of the participating customers to avoid power usage in higher price categories when part of the charging is done without load management.

Dynamic tariffs show clear advantages in efficient grid use and can result in lower costs for both CPO and DSO. However, questions are raised with respect to implementation, with dynamic tariffs requiring more complicated billing measuring and communications between CPO and DSO. In Furthermore, whether dynamic grid tariffs in this specific structure are the best option for achieving these advantages is not fully clear. Alternatively, financial incentives could be provided in other ways. Both the alternatives as well as the implementation should be areas of future research. Research on the technical implementation is already done within the FLEET pilot project (FLEET, 2021). Research into the legal aspects of implementing dynamic grid tariffs, such as the pooling of different physical connections, is still required. In addition, alternatives to the dynamic grid tariffs as presented in this thesis may be investigated.

When looking at alternatives for dynamic grid tariffs to provide the necessary incentives for efficient network use multiple options arise. Firstly, these options could include further grid tariff alternatives, such as fixed TOU or dynamic tariffs based on other measures than predicted transformer loads. It is not evident however, that grid tariffs are the best option for providing these financial incentives. The solution may also be found outside the grid tariffs, for instance with flexibility contracts or local flexibility markets. One example of this would be real-time auction the capacity available on the distribution transformer as proposed in (Philipsen et al., 2016). Working with flexibility contracts or a flexibility market means that the financial incentives do not have to be (fully) provided through the grid tariffs. This has the advantage that the grid tariffs can be more easily fit within the regulatory framework whilst efficient network use is incentivized through other means.

That being said, the EU regulation (REGULATION (EU) 2019/ 943) does explicitly state that "where member states have implemented smart metering systems, regulatory authorities shall consider time-differentiated network tariffs" (article 18.7). This indicates that some level of complexity in grid tariffs arising from time-differentiation should be allowed. Whether the specific design of dynamic tariffs presented in this should be implemented is, in the end, up to the regulator.

The dynamic grid tariffs presented in this thesis were investigated under the assumption that no V2G would occur and all CPs connected to the transformer are managed by the same CPO. Further research needs to be done on the best manner in which to integrate V2G into the tariff design and what the effect of this would be on the efficient network use. In addition a manner to determine how the available power per price level gets divided between multiple CPOs needs to be constructed and assessed.

In addition this thesis has shown indications of what is required in designing tariff designs according to the CAP+ and Dynamic grid tariff models. However the precise pricing of these models is something which needs to further worked out and is also a matter of regulatory decision. In the case of the CAP+ The results show that a higher exceedance fee does not necessarily result in more efficient grid use. The reason for this is best understood by looking at extreme values. An exceedance fee of 0 would mean that no incentives exist. An (practically) infinite exceedance fee means the chosen subscription will need to equal the annual peak usage. This means an optimum exists; careful consideration must be taken to find this optimum as this can significantly affect the effectiveness of the CAP+ tariff design. In the case of dynamic pricing this involves clear regulatory or political decision making, the most optimal incentives for efficient network use are found when using a (practically) infinite grid tariff for the higher cost power levels, this would maximize the incentive to only charge when power is available to charge at the lowest rate. However this comes with disadvantages such as market distortion, leading to higher electricity costs for the CPO. Setting the differences for the price levels to zero would negate the effect of dynamic grid tariffs, thus a middle solution needs to be found here as well. This is however a decision on what level of distortion is allowed from these grid tariffs, as well as how much these tariffs and available power may differ from location to location.

8 Conclusion

The objective of this research was to evaluate the effect of two proposed grid tariff designs from a customer (CPO), DSO and regulatory perspective. A model was constructed to investigate how charging patterns on public charging points would change as a result of the introduction of these new grid tariff designs. A future scenario with high EV adoption was assessed, the modelled results for this scenario were then analyzed to find the costs and benefits for the CPO and DSO. Furthermore compliance to principles on the basis of which regulators approve specific tariff designs was assessed.

The expected rise in EV adoption can lead to higher loads at the transformer level and that these loads can lead to transformer overloading. These high loads are likely to be exacerbated by CPOs using smart charging to respond to price fluctuations in the electricity market. Introducing a new grid tariff design can significantly limit transformer overloading by providing incentives for efficient network use. Both the CAP+ and dynamic tariffs, studied in depth in this thesis can provide such incentives. Whilst both provide incentives, differences in their effectiveness do exist. Dynamic tariffs, when well-designed, can provide stronger and more targeted incentives. Whereas CAP+ incentivizes a lowering of individual peaks of connections, it does not incentivize the limiting coincidence of these peaks. Dynamic grid tariffs specifically target the coincident peak of all connections at the transformer considering both EV and non-EV loads. Under this dynamic tariff design the flexibility of EVs is used to avoid congestion issues whilst allowing full utilization of the physical infrastructure as long as no grid issues arise.

Whilst these dynamic tariffs can have significant benefits over both the current and the CAP+ tariff designs, the implementation of such a tariff design is likely to be more difficult. Dynamic tariffs require more technical capabilities such as communications equipment and a higher level of understanding of how these grid tariffs work. In addition, these dynamic grid may not be fully compliant with legislation and regulation. Legislation on pooling of connections and on locational differences based on the behavior of other network participants may be required to be altered before this form of dynamic tariffs can be implemented.

The CAP+ design can lead to improvements on efficient grid use, but in designing the CAP+ tariffs careful consideration must be made as to align the incentives for efficient network use. An optimum for the exceedance fee in a CAP+ tariff design exists and a method should be constructed to carefully and transparently find this optimum.

A similar level of care should be taken in designing the dynamic tariffs, when the fluctuations in electricity prices overcome the incentive provided by the dynamic grid tariffs. Alternatively, exorbitant prices would incentivize efficient grid usage but may be unwanted because it reduces the option for the CPO to charge when it is required. This is a tradeoff that needs to be made by the regulator on the basis of the existing, or future, legal framework and principles that follow from this.

Overall, a shift in tariff design will be required to limit congestion issues arising from further EV penetration. CAP+ provides partial incentives but its effect may be limited. Dynamic grid tariffs should strongly be considered as an alternative. Further investigation should be done on the precise implementation and setup of these tariff designs and on the legal and regulatory status of these dynamic tariffs. Alternatively the CAP+ model, in combination with further incentives through flexibility markets or contracts can be set up, but this combination needs to be studied in further detail as well.

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