What is a good distribution network tariff?—Developing indicators for performance assessment

Developing indicators for performance assessment

Hennig, R.J.; Ribo-Perez, D.G.; De Vries, Laurens; Tindemans, Simon H.

DOI
10.1016/j.apenergy.2022.119186

Publication date
2022

Document Version
Final published version

Published in
Applied Energy

Applied Energy 318 (2022) 119186

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

What is a good distribution network tariff?—Developing indicators for performance assessment

Roman J. Hennig [a,*], David Ribó-Pérez [b], Laurens J. de Vries [a], Simon H. Tindemans [c]

[a] Delft University of Technology, Faculty of Technology, Policy, and Management, Delft, 2600 GA, The Netherlands
[b] Universitat Politècnica de València, Instituto de Ingeniería Energética, València, 46022, Spain
[c] Delft University of Technology, Department of Electrical Sustainable Energy, Delft, 2628 CD, The Netherlands

ARTICLE INFO

Keywords:
Electric distribution networks
Tariffs
Distributed energy resources
Performance assessment

ABSTRACT

The adoption of distributed energy resources such as PV cells, electric vehicles and batteries in electric grids is increasing steadily. This brings new challenges for distribution networks. The current network tariffs were not designed for these types of usage and, in many cases, they are not adequate anymore. Thus, many new tariff frameworks have been proposed. In this paper, we focus on the question of how to assess whether a given tariff framework fulfills its objectives. We propose to use quantitative indicators for performance assessment. We give examples of indicators for common objectives and demonstrate how they can be derived from a cost-accounting methodology for distribution networks.

1. Introduction

The problem

The energy transition leads to an increasing penetration of solar photo-voltaic (PV) cells and high-power flexible loads, such as electric vehicles (EVs) and heat pumps in electricity networks. Users of these networks are charged a tariff for the cost of building and operating them. However, most tariffs were established in a time when power was generated in large, predictable generators and household loads were rather inflexible and easy to predict in aggregate. With the increasing penetration of variable renewable energy sources, distributed generation and high-power flexible loads, these preconditions are no longer true. Therefore, current network tariffs are outdated.

We need new tariffs that are able to deal with the current challenges, while also fulfilling the traditional objectives, such as cost-recovery and easy understandability for consumers. How to design such tariffs has been the subject of much debate recently. However, two important questions that have not received much attention in the literature are: how can we systematically assess whether a tariff fulfills the required objectives, and how can we estimate the trade-offs between different objectives when designing new tariffs? In this paper, we provide a framework to help answer these questions. We propose quantitative indicators for this purpose and demonstrate how they can be used in practice.

Difficulties in network regulation

Power system operation in Europe has been subject to *unbundling* since the 1990s, meaning that the processes of electric generation, transmission and distribution were no longer done simultaneously by the same vertically integrated utilities [2,3]. Generation has been opened up to competition among generators on power markets, while transmission and distribution are regulated monopolies. In most cases they are handled separately by distinct legal entities, the transmission/distribution system operators (TSOs/DSOs). The idea behind this process was that competition in power generation would be beneficial for consumers as markets were assumed to provide cost-efficient outcomes. But how can we ensure that network tariffs are also set in a way that leads to beneficial outcomes for transmission and distribution, given that networks are not subject to market competition?

The framework for tariffs in European countries is typically set by a National Regulatory Agency (NRA) [2]. This is done in consultation with network operators and other stakeholders, which include: electric utilities, consumer groups and special interest groups like smart charging, battery storage and PV companies. The regulator's objective is a tariff framework that recovers network costs at fair prices and that is acceptable to the involved stakeholders and the public.[1] Given the number of stakeholders involved in the discussion, it is clear that finding a tariff that satisfies everyone is a difficult task.

* Corresponding author.
E-mail address: r.j.hennig@tudelft.nl (R.J. Hennig).

[1] Once a tariff framework is agreed upon, it typically remains in place for the duration of a period of 4–7 years [1] Minor parameter changes within the framework can happen more often, e.g., on a yearly basis.

https://doi.org/10.1016/j.apenergy.2022.119186
Received 15 December 2021; Received in revised form 24 February 2022; Accepted 21 April 2022
Available online 7 May 2022

This is compounded by the problem that no theoretical optimum for network price regulation exists. Vogelsang [4] traces the history of the theoretical developments on network pricing and utility regulation. Since marginal cost pricing is not able to recover network costs, he ultimately comes to the conclusion that there is no strict optimum for price regulation. Rather, network pricing and utility regulation should be made for "practical application" and fulfill a list of desired objectives.

Objectives for network tariffs

There is some variation in the academic and regulatory literature on what the main objectives for network tariffs should be. Most sources agree that their primary function is to recuperate operating expenses and investments for the network operator. In addition, the most commonly cited objectives are CEE [5], Reneses et al. [6] and Eur [7]:

- They should give signals for efficient use of the network, i.e. ideally limit congestion. Congestion can be caused both by high load, and high feed-in from distributed generation;
- Tariffs charged to a given user should be reflective of the costs the user generates for network operation;
- They should not be *unduly* discriminating among users (more on this and the meaning of the word undue in Section 3.3);
- They should be easy to understand and predict by users and not change too much from one billing period to the next.

However, the specific choice of objectives and their relative weighting depends strongly on the context and the view of the stakeholders. Consumer groups and smart charging companies may place a higher value on consumer freedom and simple tariffs that do not restrict consumption too much, while network operators care more about the safe operation of the grid and keeping costs under control. Many such trade-offs and value judgements exist, and therefore discussions about new tariff systems can be quite contentious. There are many proposals for new tariff systems in the literature and ongoing national discussions, but there has not been much discussion about best practices for processes to decide on new tariff systems and objective evaluations of them.

Increased urgency for new tariffs

In recent years, installations of new distributed energy resources like PV cells, EVs, batteries and heat pumps have been strongly increasing [8,9]. These resources create new challenges for the grid, as they can draw or feed-in power at very high rates and at the same time, i.e., they can show strong simultaneity. This is because these resources follow the same drivers, e.g., sunshine in the case of PV cells, or low prices in the case of high-power flexible loads. This is contrary to traditional household loads, which typically had rather low average power with peaks that were spread out randomly over time. On the other hand, the flexibility of these new resources could also be used to resolve congestion in the distribution grid and even help with reducing problems at transmission level, if they receive the right incentives [10]. However, current grid tariffs typically do not provide incentives that align the use of flexibility with network objectives.

For example, the current tariff in the Netherlands is a standard fixed tariff that is the same for all households with a connection of up to 3 $\times$ 25 Ampere.[2] This was reasonable as long as the large majority of households were heated by gas and did not have EVs. It is a simple tariff, without any data transfer requirements, and variation in energy consumption between households was limited. However, this tariff does nothing to limit EV charging or PV feed-in when there are network problems. Furthermore, consumption profiles of users with and without these resources are now very different, so this tariff effectively subsidizes heavy consumers as they have to pay less relative to the energy they receive through the network and relative to the problems they cause for the network.

Performance assessment of network tariffs

In light of these difficulties, we propose a quantitative method for assessing the performance of tariffs with the help of indicators. The complete process of assessing a proposed new tariff is depicted in Fig. 1: first, objectives for tariffs are clearly identified. Second, indicators for assessing these objectives are agreed upon. Third, data is collected in real-world field trials or simulated and used in simulation environments. Lastly this data is processed in order to obtain the chosen indicators. The main advantage of this process lies not necessarily in providing exact performance scores, but rather in demonstrating the inherent complexities and trade-offs involved in tariff setting. This helps increase clarity and objectiveness of the discussions. The main contribution of this paper lies in proposing a sample of possible indicators for the main objectives and demonstrating a framework for their usage.

Contribution of this paper

Many studies have proposed new tariff frameworks to deal with the aforementioned challenges. Typically, studies focus on highlighting the benefits of these proposals with respect to how well they reduce network stress and discuss potential fairness issues. For example, the Utilities of the Future report [11] demonstrates how a tariff based on locational marginal prices at LV transformer level lead to cost optimal outcomes in the study system. They note that the resulting situation may not be fair, as users in a congested area are charged higher LMP's than users in not-congested areas. Furthermore, users who invest in flexible thermal loads bring down prices for everyone, while carrying the investment costs themselves. Thus, this setup also creates a "free-rider" problem. Schittekatte et al. [12] investigate the problem of "grid-defection" in some tariffs, where active users may invest in PV cells and batteries to avoid grid charges. They compute total system cost as a proxy for efficiency and allocation of sunk grid costs as a proxy for fairness. Neuteleers et al. [13] investigate fairness in terms of public perceptions. Ansarin et al. [14] look at total social welfare and wealth transfers, based on assumptions about the price elasticities of network users. Fridgen et al. [15] present a model for estimating the impact of different tariff systems in the specific case of residential micro-grids. They focus on total system cost, cost-allocation and network peak shaving services. Savelli et al. [16] propose a novel ex-ante dynamic network tariff and assess it in terms of cost-recovery and social welfare maximization, taking into account the network planning problem.

Many more examples of investigations like these exist, but what we found missing is a comprehensive assessment framework for general distribution networks, that looks at all of the main regulatory objectives and trade-offs between them. Brown et al. [17] present a score sheet of different tariff options for performance with respect to: simplicity, economic efficiency, adaptability, affordability and equity. However, the scoring of performance in this case is done based on the subjective judgement of the authors and not based on measured or simulated data.

In light of these gaps, the main contributions of this paper are:

- to propose indicators for the comprehensive assessment of the performance of tariffs with respect to a set of commonly used objectives;
- to develop a cost-accounting methodology for distribution networks including network cost factors and revenues from tariffs;
- to demonstrate the proposed framework in a case study.

Paper organization

The rest of the paper is organized as follows: Section 2 presents a conceptualization of a cost-accounting methodology for distribution networks and tariffs, Section 3 proposes indicators for the main regulatory objectives that tariffs are expected to fulfill and discusses connections and trade-offs between them, Section 4 presents a case study for the application of some of the indicators for a selection of tariffs, Section 5 gives a critical discussion of the approach, the limitations and remaining knowledge gaps and Section 6 concludes.

[2] https://www.energievergelijken.nl/energieprijzen/energierekening/capaciteitstarief.

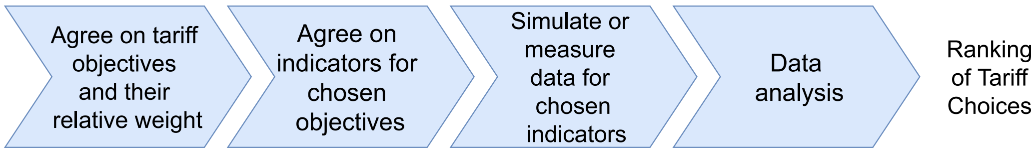

Fig. 1. Assessment process for network tariffs.

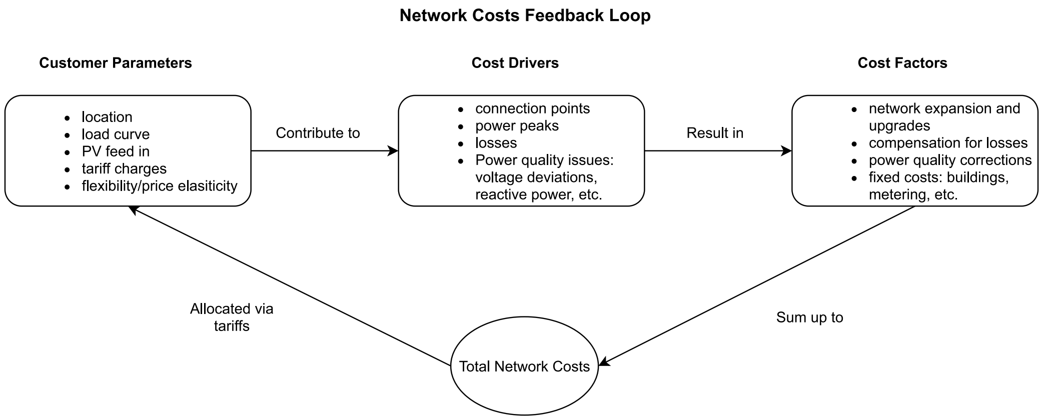

Fig. 2. Feedback between network costs and tariffs.

2. Tariff cost accounting methodology

In order to be able to evaluate the performance of network tariffs, we need to have a holistic picture of the determining factors of the costs that are allocated by them, the impact that the tariffs have on these costs and the manner in which they are allocated. To this end, this section introduces a proposed assessment framework for these issues. We begin by noting that there is a feedback in networks between the usage parameters of network users, network costs associated to these usage patterns and the tariffs by which the costs are allocated back to network users (see Fig. 2). We now discuss each of these topics in detail.

2.1. User parameters

We consider a set of network users $\mathcal{U}$. Each user $u \in \mathcal{U}$ has a power curve $P(u,t)$. Loads are represented as positive values of P and PV feed-in can be represented as negative values. For computations relevant to tariffs, we typically consider all times t in one billing period T, where T is most often taken to be one year and time is discretized in time steps Δt, the most commonly used choices for Δt being 5, 15 or 60 min.

The network tariff NT interacts with a user's power consumption in several ways: first, flexible loads are able to change their consumption profile based on the price signal π^{NT} that they receive from the tariff. The network tariff price combines with other price components to give the effective price seen by users. The implication of this is that a user's total power consumption profile can be a function of the network tariff: $P(u,t,\mathrm{NT})$. Thus, the tariff can be used to give incentives for efficient network usage.

Second, based on the realized power consumption of the user, the tariff charges are computed as presented in Section 2.3.

Lastly, performance indicators for the tariff can be computed based on the power consumption and contribution to network costs (Section 2.2), as described in Section 3.

2.2. Network costs

The costs of building and maintaining a distribution network are composed of several cost factors: asset and installation costs for grid infrastructure like transformers, power lines and switch gear, compensation for losses, repairs, power quality maintenance and fixed costs, e.g. for buildings and employees.

These cost factors can be related to cost drivers: number of connections and contracts, network peaks (which may necessitate network upgrades before the end of the designated lifetime of the upgraded assets), energy losses and power quality issues. The cost drivers in turn depend on the behavior of network users: power consumption and generation of existing users and siting choices of new property developments which require a network connection (see also Fig. 2).

In order to use the indicators proposed in Section 3, we need to have an estimate for how the network usage of users relates to the costs they incur for the network operator.

In the following, we base our assumption on a simplified model of a single neighborhood. We take into account only the losses and potential replacement of the LV transformer at which this neighborhood is connected to the grid. We use this to demonstrate how the proposed indicators can be applied in the real world or in more elaborate simulation studies that can include line losses, power quality issues and higher network levels.

Losses

For transformer losses, we follow the methodology given in [18]. Load-related losses, also called copper losses, grow quadratically in the loading of the transformer, multiplied by the nominal copper loss factor $P^{\mathrm{Tr}}_{\mathrm{cu}}$, which depends on the rated capacity of the transformer $P^{\mathrm{Tr}}_{\mathrm{RC}}$:

$$P^{\mathrm{Tr}}_{\mathrm{Loss}}(t) = \left(\frac{P^{\mathrm{Tr}}(t)}{P^{\mathrm{Tr}}_{\mathrm{RC}}}\right)^2 \times P^{\mathrm{Tr}}_{\mathrm{cu}} \tag{1}$$

The power at the transformer $P^{\mathrm{Tr}}(t)$ can be computed as the sum of power used of all households over this time step:

$$P^{\mathrm{Tr}}(t) = \sum_{u\in\mathcal{U}} P(u,t) \tag{2}$$

We compute the cost of losses using the energy price at the wholesale day-ahead market and a constant mark-up for transmission grid fees, taxes, and other transaction costs:

$$\mathrm{C}_{\mathrm{Loss}}(t) = \left(\pi^{\mathrm{WS}}(t) + \pi^{\mathrm{markup}}\right) \cdot P^{\mathrm{Tr}}_{\mathrm{Loss}}(t) \cdot \Delta t \tag{3}$$

Total losses for billing period T are obtained by summing over all times t in T:

$$\mathrm{C}_{\mathrm{Loss}}(T) = \sum_{t \in T} \mathrm{C}_{\mathrm{Loss}}(t) \tag{4}$$

Network upgrades due to peaks

An increase in network peaks may necessitate an upgrade of network infrastructure in order to avoid overloading of assets. This may also be triggered by feed-in peaks of distributed generation [19]. For evaluating tariff performance, it is therefore necessary to consider the impact of tariffs on flattening demand and feed-in peaks and to estimate how contribution to network peaks may be related to the costs required for these network upgrades.

Several methods for computing cost-causation with respect to network expansion exist in the literature [20–23]. Typically these are based on the idea of having a Reference Network Model (RNM), with respect to which cost differences due to new load or distributed generation are estimated.

In our simplified one-transformer model we follow a similar approach and assume that the transformer will have to be replaced once network load reaches 95% of the transformer's rated capacity. We define an indicator variable for whether or not this replacement happens in billing period T:

$$\mathrm{I}_{\mathrm{Repl}}(T) = \begin{cases} 1, & \text{if } P^{\mathrm{Tr}}(t) > 0.95 \cdot P^{\mathrm{Tr}}_{\mathrm{RC}} \text{ for any } t \in T \\ 0, & \text{otherwise} \end{cases} \tag{5}$$

Replacement before the end of the designated lifetime of the transformer results in a financial loss due to the foregone remainder of lifetime. This loss is proportional to the fraction of lifetime remaining and the sum of asset and installation cost:

$$\mathrm{C}_{\mathrm{Repl}} = \frac{T_{\mathrm{remain}}}{T_{\mathrm{Life}}} \cdot \left(\mathrm{C}^{\mathrm{Tr}}_{\mathrm{Asset}} + \mathrm{C}^{\mathrm{Tr}}_{\mathrm{Installation}}\right) \cdot \mathrm{I}_{\mathrm{Repl}}(T) \tag{6}$$

Where we multiplied by the indicator variable from Eq. (5), to ensure these costs are only taken into account when replacement is actually triggered.

This cost can be annualized for billing period T using the equivalent annual cost formula[3]:

$$\mathrm{C}_{\mathrm{Repl}}(T) = \mathrm{C}_{\mathrm{Repl}} \cdot \frac{r}{1-(1+r)^{-T_{\mathrm{Life}}}} \tag{7}$$

where r is the interest rate paid.

In our model, the total network cost of billing period T then consists of the sum of these factors and fixed costs:

$$\mathrm{C}^{\mathrm{Network}}_{\mathrm{Total}}(T) = \mathrm{C}_{\mathrm{Loss}}(T) + \mathrm{C}_{\mathrm{Repl}}(T) + \mathrm{C}_{\mathrm{Fixed}}(T) \tag{8}$$

More realistic models could take into account the costs for power quality corrections, line losses, replacements and higher network levels.

2.3. Network tariff structures

The total network costs are allocated to the end-users via recurring network tariffs (and one-off connection charges for new developments). The choice of these tariffs may in turn influence the behavior of network customers, i.e., their power consumption, thus closing the cost feedback loop (Fig. 2). It may, for example, give incentives in order to reduce total network costs $\mathrm{C}^{\mathrm{Network}}_{\mathrm{Total}}$ and fulfill other objectives, which are discussed in Section 3.

Network tariffs generally have three main components: fixed, volumetric and capacity based [5,24]:

- **Fixed component** π^{fixed}: typically paid on a monthly or yearly basis to recover recurring fixed costs. They can also be used to recover residual costs, which are defined as the difference between actual network costs and "the revenues collected through the application of allocation methodologies based on cost-causality" [25]. This difference exists in networks due to the difficulties in (or impossibility of) establishing a cost-function based on cost-causality [4].
- **Volumetric component** π^{vol}: to be paid per kWh of energy delivered. In the most general formulations, this can be time and location dependent. E.g., in Time-of-Use (ToU) tariffs, this component varies according to a fixed schedule each day. For Locational Marginal Prices (LMP), it can vary in near-real-time and location. Additionally, for some variants of contracted capacity tariffs, a volumetric fee may be applied to users when they exceed a certain power threshold. This is, e.g., the case for the proposed capacity subscription tariffs in the Netherlands [26,27] and Norway [28], which are also studied in the case study in Section 4. Therefore, our formulation of the volumetric component also includes a dependency on power demanded.
- **Capacity component** π^{cap}: payment associated to peak power drawn from the network. The idea behind charging for peak power is that this correlates more with the actual degree of network usage, as networks have to be designed to accommodate peak power and infrastructure investments are a major cost factor [6,12,29]. I.e., building a network that accommodates an additional 100 kW of peak demand may be much more expensive than delivering an additional 100 kWh of energy during non-peak hours. These payments can be applied to measured demand peaks, or by contracting a maximum capacity, which limits the maximum power available to the consumer or establishes a threshold to activate financial penalties, as described in the capacity subscription proposals cited above.

The network tariff NT is the set of parameters and functions π^{fixed}, π^{vol}, π^{cap}. When this tariff is applied to a users power usage $P(u,T)$, it yields a tariff charge π^{NT}:

$$\pi^{\mathrm{NT}}(u,T) = \pi^{\mathrm{fixed}}(T) + \sum_{t \in T} \pi^{\mathrm{vol}}(t, P(u,t)) \cdot P(u,t) \cdot \Delta t + \sum_{\tau \in T} \pi^{\mathrm{cap}}\left(\tau, \overline{P}(u,\tau)\right) \tag{9}$$

where $P(u,t) \cdot \Delta t$ is the energy consumed by the user u in the time step from t to $t+\Delta t$ and $\overline{P}$ is the peak power (measured or contracted) used as a basis for the capacity charge over time period τ. The accounting periods for peak power τ may, for example, distinguish between seasons or day and night time, similar to a ToU volumetric charge.

This tariff charge results in a cost for the user and a revenue for the network operator. Total network revenue TNR can then be computed as the sum of all revenues over the user set for a given tariff:

$$\mathrm{TNR}(T,\mathrm{NT}) = \sum_{u \in \mathcal{U}} \pi^{\mathrm{NT}}(u,T) \tag{10}$$

3. Objectives and indicators for network tariff performance

In this section we build on the network cost model introduced in the previous section to develop performance indicators for network tariffs. Besides recovering costs for network operation and sending signals for efficient network usage, tariffs are expected to ideally also fulfill a range of other objectives [1,5–7,30]. Among them: they should reflect the costs users are incurring on the network (cost-reflectiveness), they should be non-discriminatory between users, easy to understand (simplicity), not vary too much from one year to the next (stability) and easy to predict for users (predictability).

We formalize performance indicators (PIs) as sets of functions for a given network tariff NT:

$$\mathrm{PI} = \{\mathrm{PI}^{\mathrm{CostRec}}, \mathrm{PI}^{\mathrm{CostRefl}}, \mathrm{PI}^{\mathrm{CostEff}}, \mathrm{PI}^{\mathrm{NonDis}}, \mathrm{PI}^{\mathrm{Simpl}}\} \tag{11}$$

[3] See, e.g., https://xplaind.com/143298/equivalent-annual-costhttps://xplaind.com/143298/equivalent-annual-cost.

Table 1
A selection of possible performance indicators for the chosen objectives.

Objective	Possible indicators
Cost recovery	• Expected value and variance of expenses and revenues, based on plausible distribution of consumption patterns
Cost reflectiveness	• Tariff charges relative to individual contributions to short- and long-term marginal costs and fixed costs
Non-discrimination	• Difference of tariff charges for the same load curve in different pricing locations • Variations in tariff that are not explained by total consumed energy and personal peak
Cost-Efficiency	• Network operation and infrastructure costs • Other user costs: e.g., cost of charging EV at wholesale prices • Congestion management: peaks relative to network capacity, average loading of network assets
Simplicity	• Degree of temporal and spatial variation • Complexity score: 1. Fixed or flat volumetric tariffs; 2. vol. ToU with 2–3 time periods; 3. Capacity based or vol. ToU with >3 periods; 4. Mix of vol. and capacity, or near real-time. • Implementation burden score: 1. No change required; 2. Smart meters required; 3. Near real-time communication required; 4. New market platform required.

Where each of these sets consists of multiple indicators for the respective objective. We focus on the objectives of cost-recovery (CostRec), cost-reflectiveness (CostRefl), efficiency (CostEff), non-discrimination (NonDis) and simplicity (Simpl) here, as these are the most commonly found objectives. Given the abstractions involved in the cost model presented in the previous section, the numbers obtained from computing these indicators should be seen as indicative of relative performance, rather than precise values. The main advantage of the proposed framework is that it enables better understanding of the complexities and the principal trade-offs between performance with respect to different objectives. The choices of which indicators to use and how to weigh objectives relative to each other should be adapted to the specific context in which tariffs are investigated. In the following sections, we discuss each of these individually, with an emphasis on considerations for quantifying performance. A summary of the proposed indicators is given in Table 1.

Note that we do not have separate indicators for "fairness", which is also often cited as an objective for network tariffs. This is because "fairness" is an ambiguous term, which can have different meanings depending on the individual viewpoint. For example, for tariff setting it could mean charging users according to the costs they incur (cost-reflectiveness), charging everyone according to the same rules (non-discrimination), or even using tariffs for wealth redistribution purposes (equity concerns) to support vulnerable groups. Therefore, we use the more clearly defined concepts of cost-reflectiveness and non-discrimination here, while we consider equity concerns out of scope for this article.

3.1. Cost-recovery

Cost-recovery, i.e., financial sustainability of network operation [31], is a requirement, rather than merely a desired outcome. The network operator needs to recover costs to guarantee continued delivery of the service: "Cost recovery is the core objective of tariffs" [30].

An equality of revenues and costs needs to hold on average, across billing periods over the network under consideration. Due to the complexity of building and operating a network and setting charges on its use, revenues and expenses will not exactly balance out every year. Thus, we formalize this principle in terms of expected values:

$$\mathrm{E}\left[\mathrm{C}_{\mathrm{Total}}^{\mathrm{Network}}(\mathrm{NT})\right] \simeq \mathrm{E}\left[\mathrm{TNR}(\mathrm{NT})\right], \tag{12}$$

where we treat total network costs and revenues as random variables over different usage patterns of the user set $\mathcal{U}$. How to compute them for a given usage pattern was discussed in Section 2.

Eq. (12) leads us to define the performance indicators for cost-recovery as the (absolute) expected value and variance respectively, of the difference of costs and revenues:

$$\mathrm{PI}_{\mathrm{E}}^{\mathrm{CostRec}}\left(\pi^{\mathrm{NT}}\right) = \left|\mathrm{E}\left[\mathrm{C}_{\mathrm{Total}}^{\mathrm{Network}}(\pi^{\mathrm{NT}}) - \mathrm{TNR}(\pi^{\mathrm{NT}})\right]\right| \tag{13a}$$

$$\mathrm{PI}_{\mathrm{Var}}^{\mathrm{CostRec}}\left(\pi^{\mathrm{NT}}\right) = \mathrm{Var}\left[\mathrm{C}_{\mathrm{Total}}^{\mathrm{Network}}(\pi^{\mathrm{NT}}) - \mathrm{TNR}(\pi^{\mathrm{NT}})\right], \tag{13b}$$

Where the support of the random variables $\mathrm{C}_{\mathrm{Total}}^{\mathrm{Network}}$ and TNR is given by a range of plausible usage patterns across the user set of the network.

Note that better performance corresponds to a lower indicator value in this formulation, but this could be changed by adding a minus on the right side of the equation, if desired. While large deviations from a balanced budget are undesirable in any case, a large revenue shortfall may be potentially more severe than a large surplus, as it may threaten the financial stability of the network operator. To reflect this, it would also be possible to make the indicator asymmetric and penalize revenue shortfalls more than surpluses.

As demonstrated above, tariffs impact both sides of Eq. (12): they obviously determine the revenues from network charges. But on the other hand, they also can gives incentives for efficient network usage patterns that lead to lower overall costs, e.g., due to reduced losses and required network upgrades. Thus, when moving to a new tariff system, estimates should be made on how the new system influences both sides of the budget. This may lead to adjustments of the parameters of the new tariff system to avoid excessive revenue shortfalls or inflated prices. In order to reflect the uncertain nature of customer behavior patterns, it is beneficial to simulate this over a range of possible load patterns, e.g. based on different weather patterns or behavioral assumptions, in order to get a more robust picture.

As a side note, a good performance with respect to cost-recovery is also beneficial for the stability of tariffs over billing periods. The closer that revenues and costs are together, the less need there is for an adjustment of the parameters of the tariffs between billing periods. An example for a threat to stability is the so-called "death spiral" of distribution grids. It occurs, e.g., when grid tariffs only account for net consumption and active users can largely avoid them by investing in PV cells and/or batteries. In this case, the network operator would have to increase charges more and more in order to satisfy cost-recovery, which leads to highly instable tariffs (see, e.g., [12,32]).

Connections to other objectives

Cost-reflectiveness and non-discrimination: Eq. (12) imposes cost-recovery for the whole network. If network charges were also highly cost-reflective, this equation would hold not only for the network as a whole, but for all sub-parts of the network down to LV-feeders. For perfect cost-reflectivity, it could even hold for the single household level contributions (see Section 3.2). The degree to which cost-recovery varies over different neighborhoods may be seen as a form of cross-subsidy from areas where costs are over-recovered to those where they are under-recovered (note that these could also be intentional cross-subsidies in tariffs that are meant to subsidize certain groups of users, see e.g. [33]). On the other hand, if charges are perfectly cost-reflective at every sub-part of the network, they will likely also be highly discriminatory (see Section 3.3), as they would vary strongly by location.[4]

Cost-efficiency: As mentioned above, tariffs that give efficient price signals help to reduce the total cost side of the revenue balance. Thus, tariffs that give efficient signals score higher for cost-efficiency and they also need to recover fewer costs for the network operator (on average).

Simplicity: The simpler the tariff structure the easier it is to estimate total network revenue and to set charges such that total revenues equal total costs.

3.2. Cost-reflectiveness

According to EU law: "Charges applied by network operators for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, shall be cost-reflective (...)".[5] I.e., network charges should reflect the costs that a users network usage incurs for the network operator:

$$\pi^{\mathrm{NT}}(u,T) \simeq \mathrm{C}^{\mathrm{Contr}}(u,T), \tag{14}$$

The main difficulty in assessing cost-reflectiveness is to establish a cost causation function: how does a given usage profile by user u impact the total network costs $\mathrm{C}^{\mathrm{Network}}_{\mathrm{Total}}$? I.e., what is their cost contribution $\mathrm{C}^{\mathrm{Contr}}(u,T)$?

Network users contribute to the costs of building and operating the network in several ways (see also Fig. 2):

- Having a network connection: contributes to fixed costs and residual costs. A distribution network and a company managing it have to exist in order to supply users with electricity from wholesale markets. The costs for running this company include, for example: costs for owning and managing company buildings, employee wages and ancillary costs, maintenance costs of network infrastructure. Additionally, there is a one-off connection cost for new customers to build and maintain the physical connection to the network and set up a metering device.
- Consumption of energy: contributes to the short-term marginal cost of delivering energy through the network. Losses and power quality issues (e.g. voltage deviations) depend on the energy consumed by a consumer, their location and the total electricity flow in the network at a given time. E.g., thermal losses grow quadratically in the loading of an asset.
- Contribution to network peaks: contributes to the long-run marginal costs for investments in network infrastructure. Network assets have to be sized in order to safely supply the highest network peaks without failing. Thus, peaks are considered to be the main cost-driver for long-term investment decisions and replacement of assets which are at risk of being overloaded [5, 34].

Note that these contributions map approximately on the typical tariff components presented in section Section 2.3: fixed, volumetric and measured or contracted power (though personal power peaks generally do not align with network power peaks, see [29]). We now discuss each of these contributions in turn.

Contributions to fixed and residual costs

Since fixed and residual costs are driven by the need for having a network connection and are largely unrelated to short and long-term marginal costs, one obvious way of allocating contributions to fixed costs is to simply divide them evenly among all network users:

$$\mathrm{C}^{\mathrm{Contr}}_{\mathrm{Fixed}}(u,T) = \mathrm{C}_{\mathrm{Fixed}}(T) \cdot \frac{1}{n_{\mathcal{U}}} \tag{15}$$

where $n_{\mathcal{U}}$ is the number of users connected to the network. Some authors also discuss approaches to recover these costs by means that attempt to charge wealthier households more than less-wealthy households (see, e.g., [35]). However, this introduces distributional considerations unrelated to cost-reflectiveness. This can be identified as an additional objective for tariffs, but in the following we use Eq. (15) as the definition of the cost-reflective contribution to fixed and residual costs.

Contributions to short-term marginal costs

In the simplified network cost model introduced in Section 2.2, we use losses at the transformer as a proxy for short-term marginal costs. We allocate contributions to losses proportionally to power usage at each moment:

$$\mathrm{C}^{\mathrm{Contr}}_{\mathrm{Loss}}(u,t) = \mathrm{C}_{\mathrm{Loss}}(t) \cdot \frac{P(u,t)}{\sum_{u' \in \mathcal{U}} P(u',t)} \tag{16}$$

More elaborate models could also take into account power lines, higher network levels and power quality issues such as voltage support in short-term marginal costs. Furthermore, in realistic power flow models these costs also depend on a users location within the network.

It may be useful to define an auxiliary performance indicator to judge how well a tariff reflects these losses (or analogously for other short term marginal costs). This could, for example, be the Pearson correlation of tariff charges with contributions to losses:

$$\mathrm{PI}^{\mathrm{CostRef1}}_{\mathrm{Loss}}(\mathrm{NT}) = \mathrm{corr}\left(\pi^{\mathrm{NT}}(u,T),\, \mathrm{C}^{\mathrm{Contr}}_{\mathrm{Loss}}(u,T)\right) \tag{17}$$

Contributions to long-term marginal costs

A precise relation between contribution to peaks and contribution to long-term costs in networks is not possible. This is because the long-term cost function also depends on:

- other developments in the network, like demand growth and new connections,
- the prior situation in the network, i.e., the size and age of existing network assets,
- the planning of the network operator, which may or may not anticipate demand growth correctly,
- the location of the tightest constraint, i.e., whether it is at the LV transformer, a power line or an MV/LV substation. This would determine which peak contribution should actually be taken into account.

Furthermore, marginal costs are difficult to determine as network investment costs are typically step-functions: the marginal cost of adding additional demand is zero as long as the limit of safe operation with existing equipment is not reached, and it has a large jump once an additional unit of marginal demand pushes total demand over this limit. Lastly, a user's previous contribution to network peaks may also not necessary imply that the user will have the same peak contributions in the future. This could perhaps be resolved by treating a users load as a random variable, which is influenced by certain user parameters. Based on this, one could compute the most likely contribution to future network peaks.

[4] There are also discriminatory tariffs which are not based on cost-reflectiveness. For example volumetric net-metering [24] of PV owners: it makes cost-recovery harder as less revenues are obtained from them, it is not based on cost-reflectiveness and it is discriminatory in terms of price-per-kWh delivered through the network.

[5] See Article 18(7) of Regulation (EU) 2019/943.

However, a precise relation may also not be necessary in order to gain general insights into tariff performance. What is important here, is that network peaks are an important cost driver for network operators. Therefore, this should be reflected in the tariff. The degree to which we relate contribution to peaks to costs is a parameter that should be varied in a sensitivity analysis in order to obtain a more robust picture.

We approximate this relation by using the transformer replacement condition Eq. (5) to establish a degree to which a given consumer contributed to the replacement. Passey et al. [29] show, that in order to get a better estimate of a users true contribution to peaks one should take not just the single highest peak into account, but a range of peaks. This may better reflect the true nature of how often a given user contributes to critical or near-critical network peaks. Thus, we approximate this contribution by calculating the average contribution of each user to the n_{peaks} highest network peaks:

$$\mathrm{C}_{\text{Repl}}^{\text{Contr}}(u,T) = \mathrm{C}_{\text{Repl}}(T) \cdot \frac{1}{n_{\text{peaks}}} \sum_{t \in \mathrm{T}_{\text{peaks}}} \frac{P(u,t)}{P^{\text{Tr}}(t)} \tag{18}$$

where $\mathrm{T}_{\text{peaks}}$ is the set of the n_{peaks} highest network peak times. Note that the contribution in Eq. (18) is zero if the replacement condition Eq. (5) has not been met.

In analogy to Eq. (17), we define a performance indicator for the contribution to replacements as:

$$\mathrm{PI}_{\text{Repl}}^{\text{CostRefl}}(\mathrm{NT}) = \operatorname{corr}\left(\pi^{\mathrm{NT}}(u,T),\, \mathrm{C}_{\text{Repl}}^{\text{Contr}}(u,T)\right) \tag{19}$$

Total cost contribution performance indicators

Based on these contributions, we propose a combined performance indicator for cost-reflectivity as:

$$\mathrm{PI}_{\text{Total}}^{\text{CostRefl}}\left(\pi^{\mathrm{NT}}\right) = \operatorname{corr}\left(\pi^{\mathrm{NT}}(u,T),\, \mathrm{C}_{\text{Fixed}}^{\text{Contr}}(u,T) + \mathrm{C}_{\text{Loss}}^{\text{Contr}}(u,T) + \mathrm{C}_{\text{Repl}}^{\text{Contr}}(u,T)\right) \tag{20}$$

Note that the correlation coefficient here refers to the standard Pearson correlation. This coefficient tracks how strong a linear relationship between the two variables is. However, it does not measure the *slope* of the linear relationship. That is, a perfect linear relationship with a flat increase of variable y with x has the same coefficient as a perfect linear relationship with a very steep increase, both have a correlation coefficient of 1. On the other hand, perfect cost-reflectiveness would mean that cost contributions are exactly equal to tariff charges. Thus, an increase in cost contributions should be met by the same increase in tariff charges, i.e., the slope of the linear relationship would be 1. Thus, we propose as an additional indicator the slope of the linear regression function:

$$\mathrm{PI}_{\text{Slope}}^{\text{CostRefl}}\left(\pi^{\mathrm{NT}}\right) = \beta_1\,, \tag{21}$$

where β_1 is the linear coefficient of the regression function

$$\hat{\pi}_{\text{cost-contr}}^{\mathrm{NT}}(u,T) = \beta_0 + \beta_1 \cdot \mathrm{C}_{\text{Non-fixed}}^{\text{Contr}}(u,T) \tag{22}$$

and we include only non-fixed cost contributions in independent variable. Fixed costs in perfectly cost-reflective tariffs should be exactly equal to the offset parameters β_0.

Note that this indicator should always be assessed in conjunction with either the correlation coefficient, or the R-squared metric of the regression function. This is because non-linear relationships can also produce a slope coefficient close to 1 in linear regression, even though the true relationship is very different, see, e.g., [36].

Connections to other objectives Non-discrimination: There is a fundamental friction between these two objectives. Perfectly cost-reflective charges would be highly dependent on a user's location, time of usage and interruptibility of loads. Thus, they would be highly discriminatory.

Cost-efficiency: Theoretically, fully cost-reflective charges would send perfectly efficient price signals which could lead to highly efficient network outcomes. However, cost-reflective charges are not in themselves a sufficient condition for cost-efficient outcomes. In order for them to be effective, there also needs to be an abundance of price-elastic, flexible loads that can react to them, as well as a communication interface that reliably transmits price signals (and perhaps also control signals for interruptible loads), see Fig. 3.

Simplicity: As already discussed, fully cost-reflective charges would be strongly dependent on time, location and interruptibility. Thus, they would also be highly complex and require elaborate interfaces to be implemented.

3.3. Non-discrimination

Perhaps the biggest challenge with this objective is, to define what discrimination means, and when it may be permissible. For example, the Council of European Energy Regulators (CEER), in its summary of tariff design principles, states: "there should be no undue discrimination between network users" [5]. But what is *undue* discrimination and how can we distinguish it from *due* discrimination?

There are three main factors on which discrimination in tariffs charges can occur: time, location and flexibility of loads.

Discrimination based on time, e.g. in ToU or real-time tariffs, affect everyone equally and thus may be seen as *due* discrimination. However, there may be large differences in how well users can react to these varying prices. Thus, care should be taken to help vulnerable groups to adapt to these changes or offer easier tariffs for them.

Discrimination based on flexibility can occur when flexible loads (or generators) are charged differently than inflexible, must-run loads. In return, these loads may be curtailed in times of high network stress by the network operator. As flexible loads give up their right to run at any time and help reduce network problems, this may also be seen as *due* discrimination. However, again some users may be able to profit more from this than others (see, e.g., [37]). Thus, care should be taken to design tariffs in ways that do not lead to unintended wealth redistribution.

Discrimination based on location is more difficult to judge, as it depends strongly on the granularity of the variation in charges. Currently, many network operators apply "postage-stamp" pricing [7], whereby all consumers in the operating area are charged the same tariff, in analogy to the price of postage stamps for sending mail. In this approach there is no variation in location and therefore no discrimination based on location. On the other hand, problems related to network stress are typically highly localized. For example, the "Utility of the Future" report [11] shows how applying the same tariff system wide, or even at an MV substation level does nothing to resolve a localized network problem (p. 124 and following). Only applying an LMP-based tariff that targets the specific neighborhood feeder resolves this localized congestion problem. But does this mean that this is a *due* form of discrimination? Which feeders are congested and which not depends on factors that are outside of a user's control, like network planning failures by the operator or congestion due to a localized rise in energy consumption, e.g., because of a new commercial establishment or higher consumption of other users at the same feeder. Thus, this form of discrimination may be seen as *undue*. A further example is the distinction between rural and urban users: rural grids are typically spread out further and benefit less from economies of scale. Thus, costs for rural users will typically be higher. Furthermore, whether to live in an urban or rural area may be a choice that a user has some degree of control over, but then again it also may not be. Thus, a tariff that makes a general distinction between urban or rural may or may not be considered *due*. We do not make a judgement here on which forms of discrimination are *due* or not. The main point is that all of these considerations may be important when judging the degree of permissiveness of discrimination.

We propose the following performance indicators for non-discrimination:

Location-based discrimination

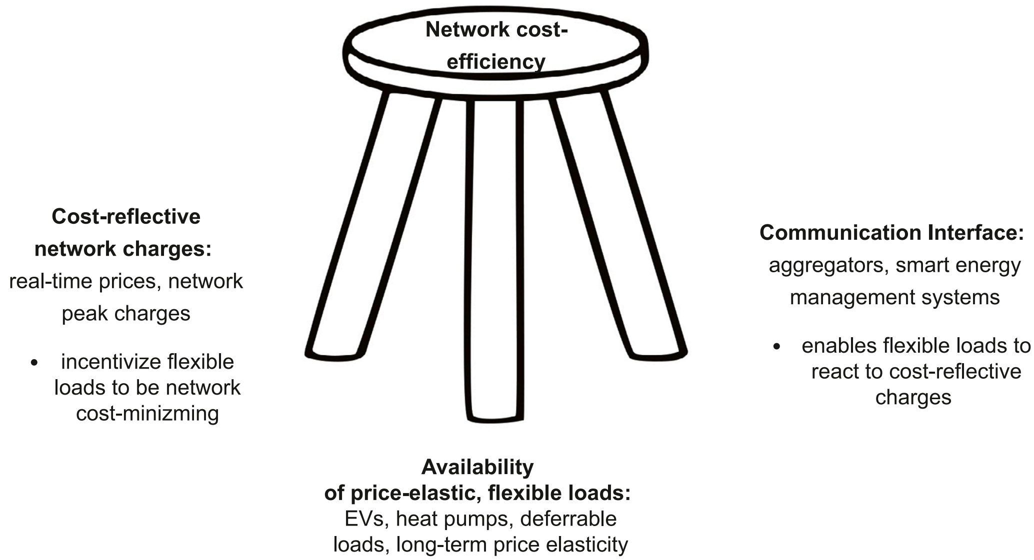

Fig. 3. 3-legged stool model for cost-efficiency in networks.

Due to the complexities related to location-based discrimination described above, we propose specific indicators for this issue. These are the maximum and average of differences in tariff charges for two different pricing locations a and b:

$$\mathrm{PI}^{\mathrm{NonDis}}_{\mathrm{loc,\,max}}\left(\pi^{\mathrm{NT}}\right) = \max_{\mathrm{u,\,loc_a,\,loc_b}} \left|\pi^{\mathrm{NT}}\left(u, T, \mathrm{loc_a}\right) - \pi^{\mathrm{NT}}\left(u, T, \mathrm{loc_b}\right)\right| \tag{23a}$$

$$\mathrm{PI}^{\mathrm{NonDis}}_{\mathrm{loc,\,avg}}\left(\pi^{\mathrm{NT}}\right) = \frac{1}{n_{\mathcal{U}} \cdot n_{\mathcal{L}}(n_{\mathcal{L}}-1)/2} \sum_{u,\,loc_a,\,loc_b} \left|\pi^{\mathrm{NT}}\left(u, T, \mathrm{loc_a}\right) - \pi^{\mathrm{NT}}\left(u, T, \mathrm{loc_b}\right)\right| \tag{23b}$$

where the set over which to find the maximum and average includes each observed or simulated user profile u for each price-location difference. I.e., this set is $\mathcal{U} \times \mathcal{L} \times (\mathcal{L}-1)/2$, where $\mathcal{L}$ is the set of distinct pricing locations and the factor of one half is added to avoid double counting.

General non-discrimination

In the most general sense, discrimination means that users are charged differently for using the network in a similar way. But as discussed above, it is difficult to define precisely what using the network "in a similar way" means. Arguably, the two parameters that perhaps best summarize how much a user uses the grid are their total energy consumption and peak load. Thus, one option to determine discrimination between users in a quick and rough way could be to look at the variance of charges per kWh of energy consumption and per kW of peak usage respectively:

$$\mathrm{PI}^{\mathrm{NonDis}}_{\mathrm{energy}}\left(\pi^{\mathrm{NT}}\right) = \mathrm{Var}\left(\frac{\pi^{\mathrm{NT}}(u,T)}{\sum_{t\in T} P\left(u,t\right)\cdot \Delta t}\right) \tag{24a}$$

$$\mathrm{PI}^{\mathrm{NonDis}}_{\mathrm{peak}}\left(\pi^{\mathrm{NT}}\right) = \mathrm{Var}\left(\frac{\pi^{\mathrm{NT}}(u,T)}{\overline{P}\left(u,T\right)}\right) \tag{24b}$$

Another option to measure discrimination indirectly could be to look at how much of the variance in network charges is explained by total energy use and peak load. This can be done by using the R^2-metric of a linear regression for network charges based on these two parameters:

$$\mathrm{PI}^{\mathrm{NonDis}}_{\mathrm{general}}\left(\pi^{\mathrm{NT}}\right) = R^2 \tag{25}$$

with the standard R^2-metric of the regression function:

$$\hat{\pi}^{\mathrm{NT}}_{\mathrm{energy,peak}}(u,T) = \beta'_0 + \beta'_1 \cdot \left(\sum_{t\in T} P\left(u,t\right)\cdot \Delta t\right) + \beta'_2 \cdot \overline{P}\left(u,T\right) \tag{26}$$

where we included apostrophes in the regression parameters to indicate that they are different from the ones used for the cost-reflectiveness regression function Eq. (22). Note however, that this indicator would not be well defined for a pure fixed charge, which has no relation to either energy consumption or peak load at all.

Connections to other objectives

Cost-efficiency: As explained in the discussion on cost-reflectiveness (Section 3.2), discrimination that is based on cost-reflectiveness may lead to efficient outcomes. On the other hand, there may also be discriminatory effects which are not based on cost-reflectiveness and thus do not lower network costs, like net-metering of PV cells.

Simplicity: Typically, simpler tariffs are less discriminating, as they tend to vary less. But it also depends on the viewpoint of what constitutes a discriminatory charge. E.g., an identical fixed charge for every user is a very simple tariff and it may be seen as non-discriminatory as everyone is charged the same. On the other hand, the charge-by-kWh and charge-by-peak measures (Eqs. (24a) and (24b)) for this tariff may be highly discriminatory.

3.4. Cost-efficiency

As previously discussed, network tariffs can give incentives for efficient network usage which reduces total costs for the network operator and hence reduces the charges that need to be recovered from network users. As demonstrated in the network cost model Section 2.2 and the discussion of cost-reflectiveness, Section 3.2, the main cost contributions which are under the control of users are those to short- and long-term marginal costs (e.g., contributions to losses and to network peaks). By lowering these costs, total network costs and costs per kWh of delivered energy can be reduced, which are two obvious choices for performance indicators:

$$\mathrm{PI}^{\mathrm{CostEff}}_{\mathrm{network}}\left(\pi^{\mathrm{NT}}\right) = \mathrm{C}^{\mathrm{Network}}_{\mathrm{Total}}(\pi^{\mathrm{NT}}) \tag{27a}$$

$$\mathrm{PI}^{\mathrm{CostEff}}_{kWh}\left(\pi^{\mathrm{NT}}\right) = \frac{\mathrm{C}^{\mathrm{Network}}_{\mathrm{Total}}(\pi^{\mathrm{NT}})}{\sum_{u,t} P(u,t)\cdot \Delta t}, \tag{27b}$$

On the other hand, perhaps minimizing network costs should not be the only objective. When tariff charges are applied that lead to minimal network costs, the total cost of energy consumption of all users may still be higher. This could occur, e.g., in a situation where the tariff disincentivizes consumption during times of low wholesale prices to restrain network peaks. Thus, another objective for cost-efficiency

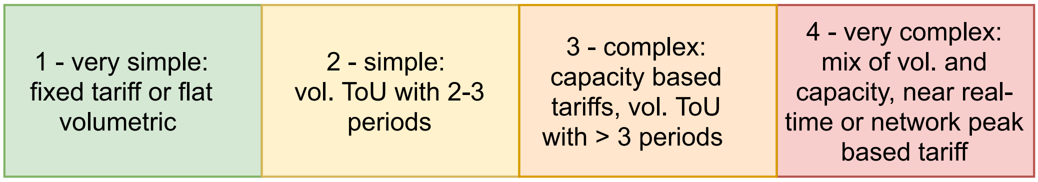

Fig. 4. Complexity score for the simplicity of tariffs.

could be to minimize total system costs, taking into account also the effective prices paid by users (Eq. (32)):

$$\mathrm{PI}^{\mathrm{CostEff}}_{\text{total system}}\left(\pi^{\mathrm{NT}}\right) = \mathrm{C}^{\mathrm{Network}}_{\mathrm{Total}}(\pi^{\mathrm{NT}}) + C^{\mathrm{Other}} \tag{28}$$

where other costs would mainly be made up of wholesale prices. In more elaborate schemes, they could also include foregone revenues from not being able to trade on other markets, e.g. balancing, due to restrictions of the tariff.

Since other costs are quite hard to obtain or realistically simulate, a middle ground may be to use congestion-management related measures to judge performance with respect to cost-efficiency. Ideally the tariff should lead to some flattening of peaks, so as to not threaten overloading of grid assets, but preferably the tariff should not restrict usage too much during times in which there is no network congestion, in order not to constrain users to make use of low wholesale prices during these times. Thus, possible performance indicators could be the size of peaks relative to the rated capacity of assets and the load factor of critical assets. The load factor is defined as average power divided by peak power. If it is close to 0, the load curve is dominated by large spikes and long times of comparatively low load. This indicates inefficient usage of assets. On the other hand, a load factor close to 1 may indicate that the asset is too often used at its limit and may have to be replaced soon. For the single transformer in our cost model, these indicators are obtained as:

$$\mathrm{PI}^{\mathrm{CostEff}}_{\mathrm{PeakSize}}\left(\pi^{\mathrm{NT}}\right) = \frac{\overline{P^{\mathrm{Tr}}(t)}}{P^{\mathrm{Tr}}_{\mathrm{RC}}}, \tag{29a}$$

$$\mathrm{PI}^{\mathrm{CostEff}}_{\mathrm{LoadFac}}\left(\pi^{\mathrm{NT}}\right) = \frac{\operatorname{avg}\left(P^{\mathrm{Tr}}(t)\right)}{\overline{P^{\mathrm{Tr}}(t)}}, \tag{29b}$$

These indicators have also been proposed by a study on tariff design for the European Commission [7]. Peak load has also been used in tariff assessment by Fridgen et al. [15]. They also proposed an indicator similar to the load factor, the "crest factor" which is defined as "the quotient of absolute peak to root mean square of all loads".

3.5. Simplicity and implementation burden

Users should be able to easily understand their network tariff in order not to be hit with unexpected charges and to be able to follow the price signals sent by the tariff in order to reduce impact on network costs. A highly cost-reflective tariff may not be effective in reducing costs if it is too difficult for users to adapt their usage to the price signal, or if the signal cannot reliably be transmitted. Therefore, it can be helpful to have a measure for how easy or difficult it is to understand the tariff.

Of course it is difficult to judge what users may consider simple or complex tariffs, as it strongly depends on traits of the individual users - e.g., their willingness and time availability to concern themselves with their network tariffs, or whether they have a smart homer energy management system, which can automatically follow price or control signals sent by the network operator. We propose a categorization based on 4 levels of increasing difficulty, as defined in Fig. 4. Based on this, we define a categorical indicator:

$$\mathrm{PI}^{\mathrm{Simpl}}\left(\pi^{\mathrm{NT}}\right) = \mathrm{I}_{\mathrm{Simpl}} \in \{1,2,3,4\} \tag{30}$$

Similarly, it is possible to define an indicator for the implementation burden of a tariff based on the infrastructure requirements that must be met in order for the tariff to be implementable. Many new tariff proposals like capacity subscriptions and highly variable time of use tariffs require at least smart meters. More advanced tariffs that send price or control signals in near-real time require a communication interface capable of transmitting these signals. And even more advanced solutions might require new market platforms between network operators and users (not considered in this study).

4. Case study

In this section we present a case study of tariff assessment to demonstrate how the proposed framework can be applied in practice. We keep the scope limited to a single neighborhood, four types of network tariffs and a selection of a few of the most important indicators, as this is intended only as a demonstration of the framework. We leave as future work an in-depth discussion of many different tariff variants, using a more comprehensive set of indicators and larger networks with multiple neighborhoods.

4.1. Model description

We developed the ANTS-model[6] (Assessment of Network Tariff Systems) to investigate the performance of tariffs. The model implements the network cost model presented in Section 2.

We account for the increasing penetration of distributed energy resources by separating users load into a flexible and inflexible component:

$$P_{\mathrm{total}}(u,t) = P_{\mathrm{flex}}(u,t) + P_{\mathrm{inflex}}(u,t) \tag{31}$$

Inflexible loads are "traditional" household loads like lighting, electric stoves and power outlets, which should be served at any given time. In our framework, these loads are not assumed to be able to respond to price or control signals. Flexible loads (or generation) include EVs, heat pumps and PV feed-in (which can be curtailed), and are assumed to be able to respond to price and control signals in near-real time. This responsiveness to external signals may be achieved through control by a Smart Energy Management System (SEMS) or an aggregator.

We assume that the effective price seen by these flexible loads is composed of different components, in euro/kWh:

$$\pi^{\mathrm{eff}}(t) = \pi^{\mathrm{NT}}(t) + \pi^{\mathrm{WS}}(t) + \pi^{\mathrm{other}}(t) \tag{32}$$

where π^{WS} is the whole-sale price in the electricity market and other charges may include, e.g. transmission fees and taxes.

A complicating factor is that network operators do not have precise information about how consumers respond to price and control signals. Even the loads that we consider inflexible here may, over the long run, have some elasticity of demand and the loads that are flexible may not at all times be able to follow external signals. Moreover, there is another category of devices that does not cleanly fall into either of these two categories: deferable loads with fixed power consumption profiles

[6] Publicly available at https://gitlab.tudelft.nl/rhenning/ANTS-model.

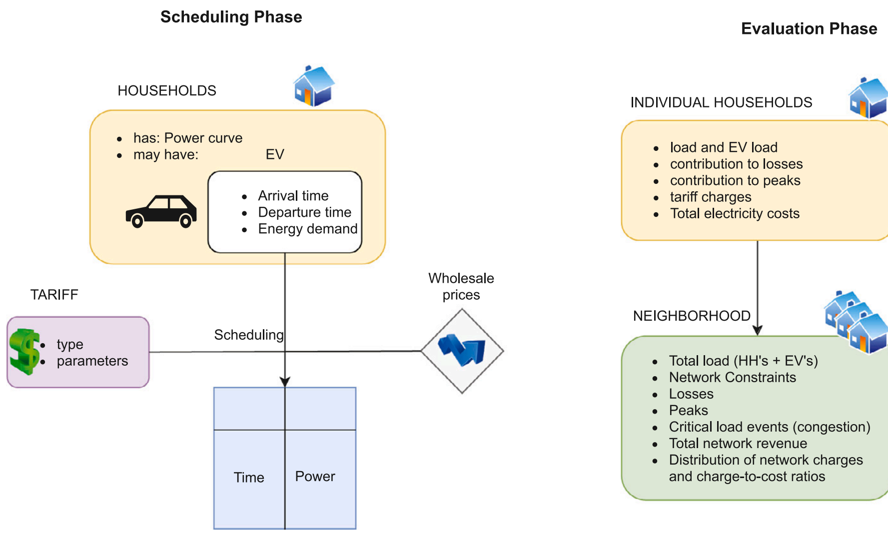

Fig. 5. Scheduling and evaluation phases in ANTS-model.

like smart dishwashers lie somewhere in the middle. These details could be included in future work.

For the purpose of demonstrating how the indicator framework developed in the previous sections can be applied in practice, we limit our analysis here to EVs as a proxy representation of flexible loads. Their scheduling is based on the tariff charge in combination with a wholesale market day-ahead price. We assume that they have perfect knowledge of wholesale prices and optimize charging over a 2-day time horizon. Their charging flexibility is limited by their driving behavior, which is represented as deadlines by which time a vehicle's battery must hold enough energy for a certain trip.

The model can be divided into two phases (see Fig. 5): in the first phase, EV charging is scheduled optimally, based on tariff signals and wholesale market prices. In the second phase, the proposed indicators are evaluated based on household load curves, the transformer loading and the given tariff charges. The model execution logic is presented in Appendix

Please note that the proposed cost-measures are strongly influenced by the existing situation at the given network location. Transformer replacement is triggered earlier if the LV transformer does not have a lot of headroom at the beginning of the simulation and the costs of losses also critically depend on the size of the transformer. Therefore, we sample over a range of existing situations with different transformer sizes for each EV scenario. Once a transformer upgrade has been triggered, we use the upgraded transformer size for loss computations and the initial transformer size for peak contributions.

4.2. Input data and parameters

For household load profiles (without EVs), we used the publicly available load profile generator by Pflugradt [38].[7] We simulated 50 German household load profiles for one year at a 15-min time resolution. For electric vehicle charging needs, we use parameters based on the 25 profiles derived by Verzijlbergh et al. [39]. For each tariff and EV number, we randomly draw out of the 25 profiles (up to a maximum of 25 EVs), and randomly assign the profiles to households. The random seed is reset for each tariff choice, so that the same values are used for each tariff in order to be able to compare results across tariffs. Wholesale market prices were obtained from the ENTSO-E transparency platform[8] for Germany in 2020.

[7] https://www.loadprofilegenerator.de/.
[8] https://transparency.entsoe.eu/.

Table 2
Parameter values for simulation case study. Note: For transformer sizes, only 100 kW and 160 kW are commercially available. The other sizes in 20 kW increments were added to simulate differing initial levels of congestion for computing averages and percentiles of the resulting indicators.

Parameter	Values
Number of households	50
Physical connection limit	17.3 kW
Number of EVs	0–25
n_{peaks} for peak contribution	10
Transformer	
Initial size	80, 100, 120, 140, 160 kW
Age	20 yrs
Lifetime	40 yrs
Replacement limit	95% loading
Upgrade size	2 times current capacity
Loss factor	10%
Costs	
Fixed	100 Euro
Loss markup per kWh	0.1 Euro
Transformer asset	10.000 Euro
Transformer installation	20.000 Euro
Interest rate	3%

For our computations of losses according to Eq. (1), we make the simplifying assumption that the loss factor is always 10% of the transformer size. This is larger then it generally is in real transformers (and in reality it also does not grow linearly with size), but in this way we can use the single transformer as a proxy for network losses in general. Network losses are generally around 5% of total power served [5], but since the first factor in Eq. (1) is mostly below 1, the second factor needs to be accordingly larger in order to approximate total losses closer to this percentage. We also assume costs for losses and transformer replacements to be a bit higher than is often done in the literature (e.g., in [23]), in order to account for the fact that we are omitting losses and replacements in lines and higher network levels. A summary of all main parameter choices can be found in Table 2.

Tariff choices

We chose four different tariff types for the assessment, which cover a range from very simple traditional tariffs to more complex newer tariff types:

- A fixed tariff with a charge of 250 Euro per customer per year, which resembles the "Capaciteitstarief" (capacity tariff) currently in place in the Netherlands.

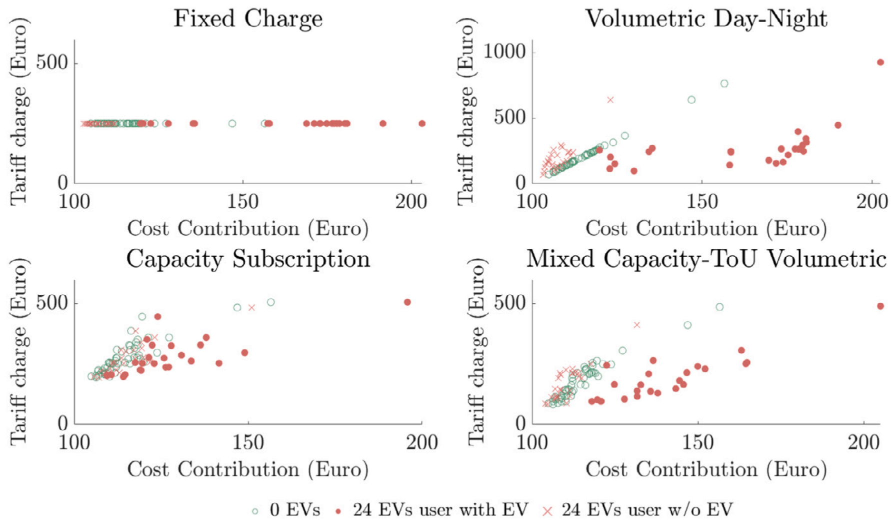

Fig. 6. Relation of tariff charges with cost contributions for different tariffs in a single model run with a transformer size of 120 kW. We show two situations: one with no EVs (green) and one where 24 households have an EV (red). Empty circles are households without EV, full circles are households with an EV. Note the different y-axis scale for volumetric day–night tariffs, as these can result in much higher charges than the other tariffs.

- A volumetric day-and-night tariff with a charge of 5 ct/kWh during day-, and 2.5 ct/kWh during night time.
- A capacity subscription tariff, as described in [26]. The possible subscription levels are at 2, 4, 8 and 17.3 kW, for a yearly charge of 192, 252, 480 and 900 Euro and a penalty of 0.5 Euro for every kWh of exceeding the subscribed capacity. This is inspired by values currently used in discussions for a new tariff system in the Netherlands, also used in [27].
- A mixed measured capacity and ToU volumetric tariff with parameters resembling the current distribution tariff for low-voltage users in Spain [40]: the measured capacity peak charge is 19.318 Euro/kW per year and the volumetric charges are 0.0559 ct/kWh from 12 am to 8 am, 1.7076 ct/kWh from 8 am to 10 am, 2 pm to 6 pm and 10 pm to 12 am, and 2.2658 ct/kWh from 10 am to 2 pm and 6 pm to 10 pm.

4.3. Results

For this case study we focus on results for cost-reflectiveness, efficiency and simplicity, to demonstrate how the methodology can work in practice. For each of these, we use indicators proposed in Section 3.

Cost-reflectiveness

In Fig. 6 we show an intermediate result from a single model run to provide insight in the way in which cost-reflectiveness and efficiency indicators are derived. The Y-axis shows the tariff charges for different network users, while the X-axis represents the contributions to the network costs of these individual users. We see that with a fixed tariff, (by definition) all users are charged the same, while the cost contributions differ widely, so cost-reflectiveness is zero. High cost-reflectiveness would be expressed in a linear relation between cost contribution and paid tariffs per household. For volumetric tariffs, there appears to be a strong linear relation between the two for users without EVs. This is understandable as these users do not contribute much to peak-related costs. Their main cost contribution comes from losses. Like the volumetric tariff charges, these are proportional to total energy consumption. The linear relation is weakened a bit by the fact that losses actually grow quadratic in line loading (Eq. (1)), and that the volumetric tariff has two different cost levels for day and night. When we go to a situation with many EVs, we can see that the linear relationship breaks down completely for volumetric tariffs. Users with EVs have much higher cost contributions now, as transformer replacement becomes necessary in this situation because of higher peaks. However, with this tariff, users are not charged according to their peak contribution. For the partly power based tariffs in the bottom row, we can see that the initial linear relationship between costs and tariff charges is not as strong. On the other hand, for higher EV numbers, these tariffs prevent the cost-contributions of most users from becoming very high. This is because these tariffs incentivize users to limit their maximal charging power, thus reducing network peaks and limiting the need for costly network upgrades.

In Figs. 7 and 8 we show the cost-correlation between tariff charges and cost contributions, which was identified as a performance indicator for cost-reflectiveness in Eq. (20). The random choice of EVs out of the 25 profiles and random assignment to households leads to some variability in results. Thus, we also show uncertainty bands that result from the sampling over different transformer sizes and EV profiles. This is particularly pronounced for the capacity-based tariffs, where for very low choices of EV numbers the correlation shows quite a large spread. This is due to the fact that at these low EV numbers costs are only due to losses in our model, and losses are proportional to volumetric consumption. Thus, the tariffs that charge based on maximal capacity have a much larger spread here. As in Fig. 6, we can see that:

- fixed tariffs have no relation between tariff charges and cost contributions whatsoever.
- volumetric tariffs perform quite well initially in a situation without EVs, but quickly deteriorate with higher EV numbers.
- capacity subscriptions and mix power-ToU volumetric tariffs do not start out quite as well as volumetric tariffs, but also do not drop off as much. Among these two, capacity subscriptions remain the more cost-reflective tariff at higher EV numbers.

Fig. 8 breaks down the results for users with and without EVs. We can see that in all cases, the performance of the tariffs for users without EVs remain quite stable, also once the network is becoming more congested due to EVs of other users. For EV owners, cost correlation drops off quickly in volumetric tariffs, and remains relatively stable for the capacity-based tariffs. Note that the total cost correlation in Fig. 7 may be worse than both the non-EV and the EV cost-correlation in Fig. 8. This is because while each of the two groups individually may have a near-linear relation in a result like the one shown in Fig. 6, they have different slope factors. Thus, the strength of the linear relation and consequentially the correlation, is worse for the combined results.

Efficiency In Fig. 9 we show another intermediate result to aid understanding of efficiency results: the highest-load part of the load-duration

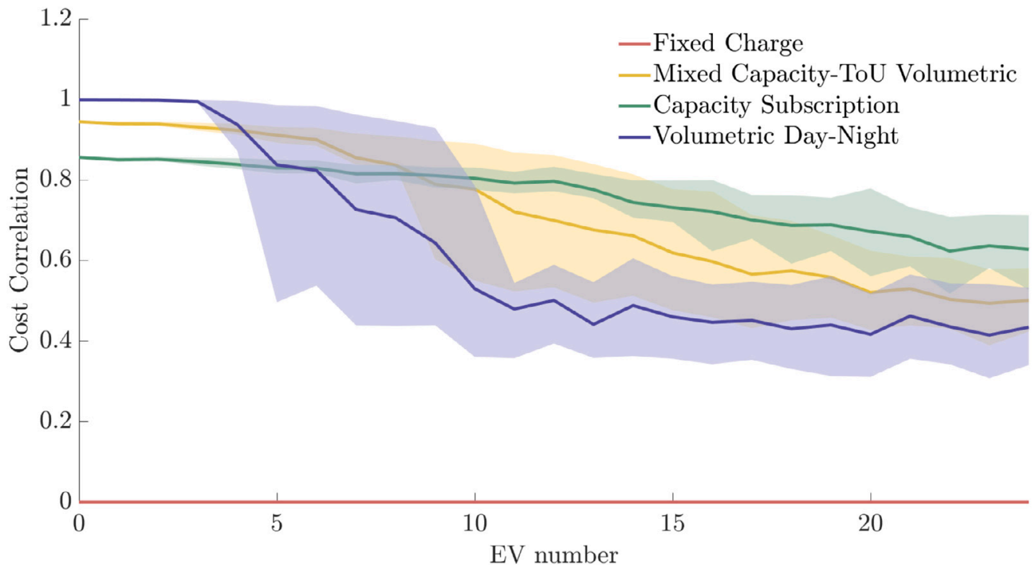

Fig. 7. Correlation coefficient between users cost contribution and their tariff charges for varying number of EVs with uncertainty bands from 20th to 80th percentile.

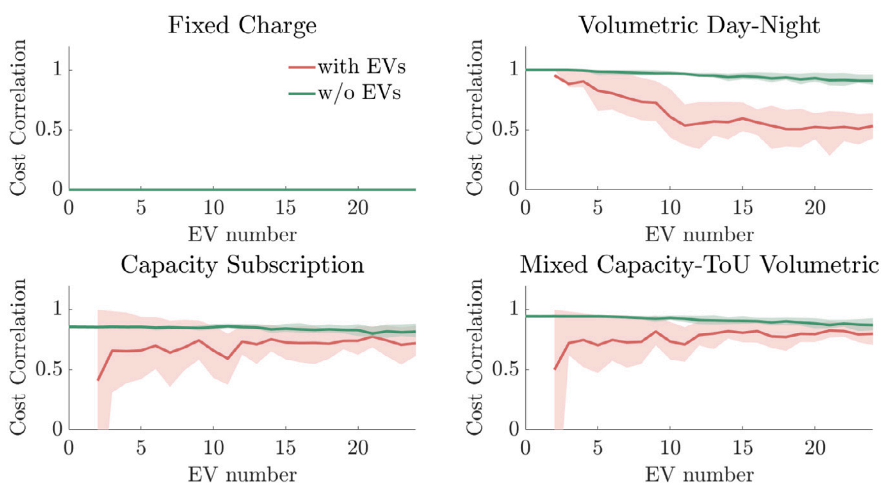

Fig. 8. Correlation coefficient between users cost contribution and their tariff charges, broken down by households with (red) and without (green) EVs with uncertainty bands from 20th to 80th percentile. Note: the difference to Fig. 7 is that here the correlation is computed separately for the households sets with and without EVs respectively. The line with EVs only starts at 2 EVs, as the correlation coefficient can only be computed for a set of at least 2 observations.

curve in model runs with a 120 kW transformer. We can see that fixed and volumetric tariffs do not limit high load peaks. The transformer gets overloaded at low numbers of EVs (around 8) already. The capacity-based tariffs again perform better: for the mixed tariff, overloading happens only at very high EV numbers. The capacity subscription manages to reduce peaks to below this transformer size, even up to very high EV numbers.

These insights translate directly into the performance assessment of efficiency with the indicators total network cost, peak size and load factor (Eqs. (27a), (29a) and (29b)). Capacity-based tariffs limit peaks (Fig. 10), which leads to more efficient network loading at higher EV numbers (Fig. 11). Thus, they also reduce the need for transformer upgrades and lead to lower network costs (Fig. 12).

Table 3 shows an example of "other costs" that could be taken into account for total system costs in Eq. (28). For EVs, one important consideration might be how much EV owners will have to pay for the charging of their vehicles under different tariffs. To investigate this, we look at the price of charging EVs at wholesale prices (for Germany in 2020) under different tariffs. The differences are low: for 24 EVs over the whole year, the difference between the smallest value for fixed charges and largest value for capacity subscriptions is 89 Euro. For EVs that drive only up to 30 km there is almost no difference at all. These EVs can easily fulfill their charging at the lowest prices also in the capacity-constrained tariffs, as they need only a few kWh every night. Only for heavy users with over 60 km driving distance per day there is a noticeable difference. At this amount, the constraints given by the capacity based tariffs restricts charging at the lowest price hours considerably. The resulting difference for a whole year of charging is still not very big: it is on average 25 Euro per year for heavy users. Note however that these results were obtained with wholesale prices in 2020. At the end of 2021, wholesale prices in Germany showed unprecedented spikes.[9] These prices spikes also led to bigger arbitrages between high and low price hours. This in turn would increase the differences in charging costs presented above.

Simplicity

Performance with respect to simplicity is assessed according to the complexity score in Fig. 4: the fixed tariff is the simplest one, the

[9] See, for example: "German energy prices hard to tame", 21.12.2021, Thomas Kohlmann for Deutsche Welle.

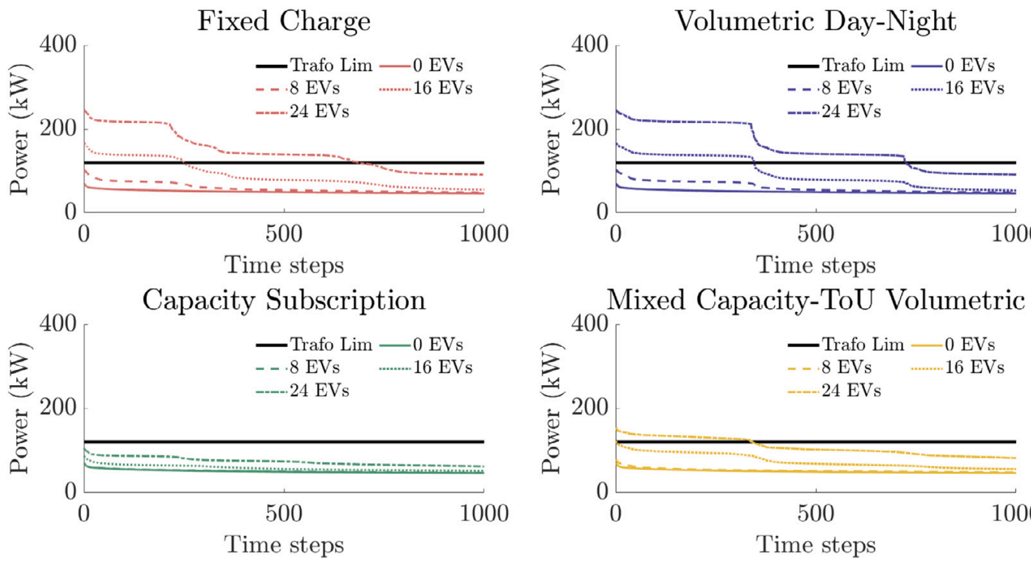

Fig. 9. The 1000 highest load time-steps of the load duration curve for selected EV numbers and transformer size of 120 kW.

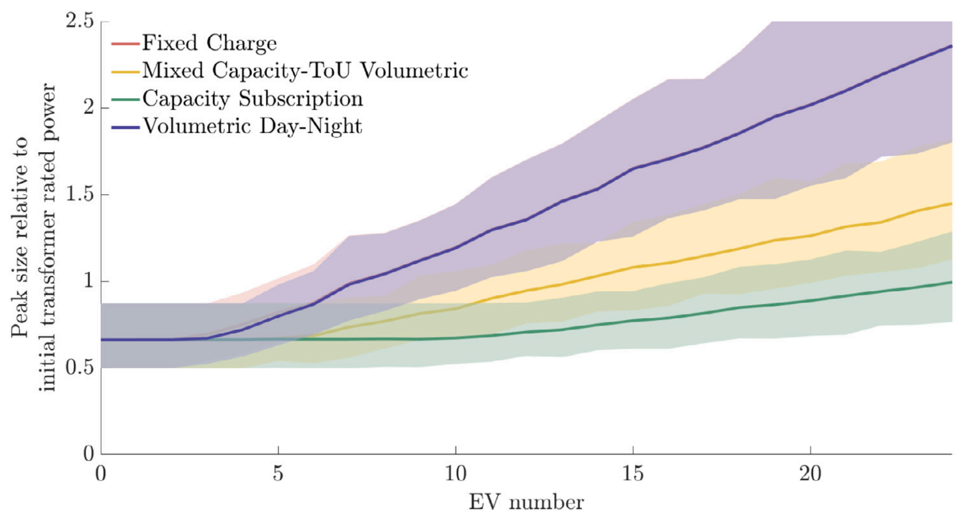

Fig. 10. Network peaks by tariff type relative to initial transformer size. Note: the spread in results is due to the range of different transformer sizes used and, for higher EV numbers, also due to the random selection of EVs.

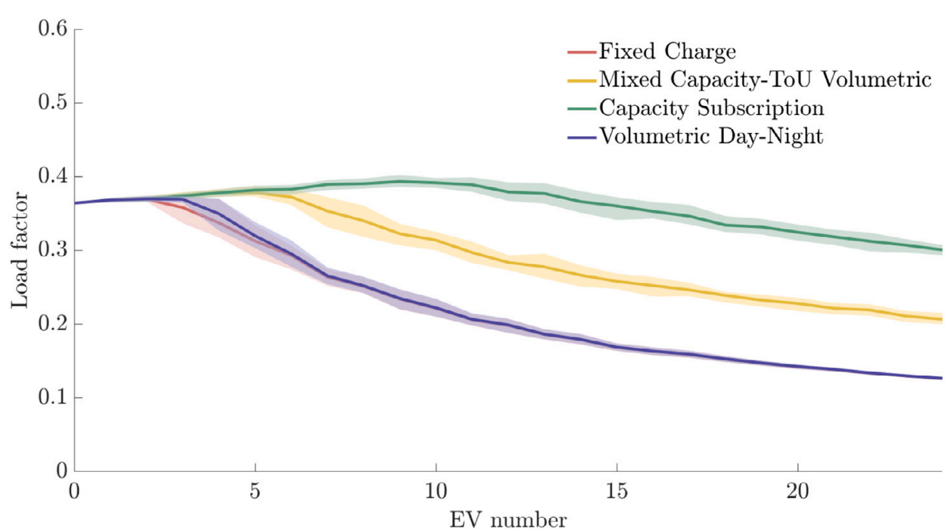

Fig. 11. Network load factor (average load divided by peak load) for different tariffs and varying number of EVs.

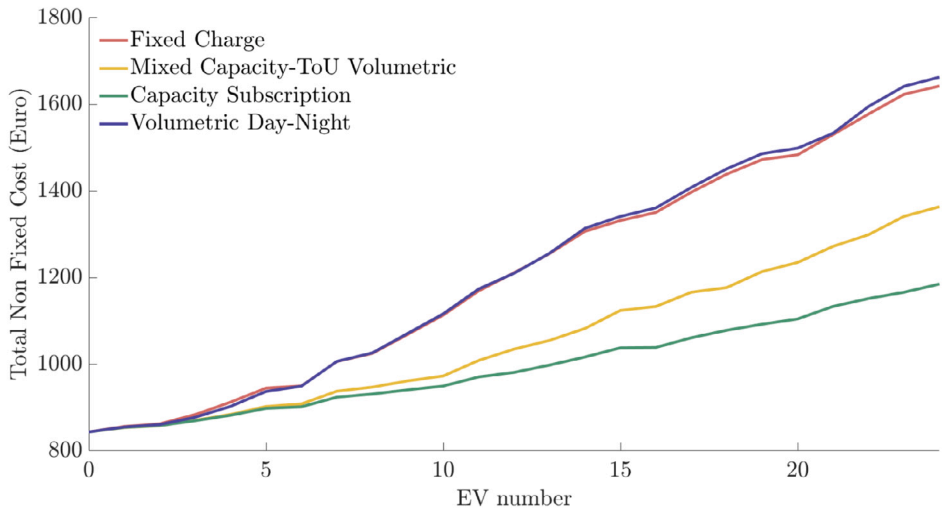

Fig. 12. Total non-fixed costs for different tariffs and varying number of EVs.

Table 3
Summed wholesale price costs in Euro for charging of all 25 EVs under different tariffs and average yearly charging cost per car by driving distance. The numbers of cars are 16 for lowest, 6 for medium and 3 for highest driving distance.

	Fixed Tariff	Vol. Day–Night	Cap. Subs.	Mix Cap.-ToU Vol.
Total for all EVs	1062	1090	1151	1117
<30 km per day avg.	16.2	17.2	16.7	17.0
30–60 km per day avg.	68.3	69.5	72.5	71.1
>90 km per day avg.	131	133	156	139

Table 4
Comparative assessment of the performance of the four tariffs relative to each other.

Tariff	Cost-refl. low EV	Cost-refl. high EV	Efficiency high EV	Simplicity
Fixed	– –	– –	– –	+ +
Vol. Day–Night	+ +	–	– –	+
Capacity subscription	+	+ +	+ +	–
Mixed Capacity-ToU Vol.	+/+ +	+	+	– –

volumetric day–night tariff the second simplest, capacity subscriptions the second most complicated and the mixed capacity-ToU tariff the most complicated.

Comparative assessment

Table 4 shows a comparative assessment of tariff performance for the four tariffs. We rank tariffs based on their relative performance to each other for the chosen indicators. For cost-reflectiveness, we look at both the situation with low and high EV numbers, as the results change considerably. For efficiency, according to our proposed indicators and the considerations in Fig. 3, a tariff can only lead to efficient network usage if there are also flexible loads that can react to the tariff signals. Thus, we assess efficiency performance only for high EV numbers (it would be the same for all tariffs at 0 EVs). We can see that both the volumetric and the fixed tariff score very badly for high EV numbers. Interestingly, these are two tariff systems that are still commonly used nowadays. This underscores the point made in the introduction: many current tariffs are outdated and not well suited to deal with grids where there is a high amount of flexible loads. In terms of efficiency and cost-reflectiveness, the capacity-based tariffs perform much better in grids with high amounts of flexible loads.

5. Discussion

This section critically reflects on the approach presented here. We discuss insights that can be drawn from this method, limitations and areas for future research.

5.1. Insights

What can we learn from the methodology described above? First and foremost, it clearly demonstrates the many complications in the process of tariff setting. There is no perfect solution that optimally meets all criteria and there are trade-offs between performance with respect to different objectives.

For example, one might wonder: the leading purpose of tariffs is to recover costs for the network operator in a cost-reflective way. So would it be possible to create a tariff, that uses a framework similar to the one presented here and allocates network costs solely based on cost-contributions? This tariff would score perfectly based on the cost-recovery and cost-reflectiveness indicators presented here. However, there are two major problems with it: first, the practical difficulty of calculating and allocating network costs. This is theoretically impossible, see [4] and Section 3.2. Even if this could be overcome, the framework presented here demonstrates another objection: such a tariff would score very badly in terms of non-discrimination and would also be extremely complex, as the relation between network usage and cost contributions is quite difficult to establish and would be hard to communicate to users.

There are many trade-offs like this in tariff setting. The proposed methodology helps to demonstrate and quantify them. A tariff is a complicated construct and its implications are not immediately obvious, while objectives and indicators are easier to understand. Thus, the assessment process laid out in Fig. 1 can clarify the underlying complexities and can lead to better understanding of the pros and cons of each tariff model.

Additionally, the methodology shows that tariff performance is highly context-dependent. The size and age of the existing infrastructure, the electricity wholesale market prices (for losses and user costs), the number of EVs and PV cells, the typical user load patterns and many other parameters have a strong influence on the performance assessment. Furthermore, the overall tariff performance depends on the weights of the different objectives relative to each other. This shows that there is no one-size-fits-all tariff system. The assessment should be done in consultation with all involved stakeholders and adapted to the local context. The case study also demonstrates that, especially in situations with increasing high-power flexible loads such as EVs, the performance of tariffs can change quickly. Thus, the urgency to change outdated tariff frameworks is growing.

In terms of the specific tariffs that we assessed in the case study, the methodology clearly showed that power-based tariffs are superior to fixed and volumetric tariffs for high numbers of EVs. On the other hand, they are also more complicated and may increase EV charging costs a little bit for heavy users. This further demonstrates the need for integrating this objective assessment with discussions among involved stakeholders.

The methodology can also be used to investigate specific concerns, like the impact of tariff proposals on a specific user group. For example, one might think that a capacity subscription tariff would be bad for EV owners. It restricts their charging power to the subscribed capacity, even when there is no congestion in the network. This might lead to higher costs for EV owners as they cannot make full use of the lowest-price hours at the wholesale market. However, our model shows that for most EV owners with a moderate driving range of up to 30 km per day, this effect is almost negligible and the resulting cost differences are less than a Euro per year (for wholesale prices in 2020 in Germany), assuming they are able to make use of smart charging. Only for very heavy EV use, above 60 km per day, does the capacity restriction make a significant impact. And for these users the price increase may also be justified by cost-reflectiveness.

5.2. Limitations

The indicator framework presented in Section 3 is of a general nature and therefore largely independent of the specific model implementation that is used.[10] However, in the case study presented here, there are many limitations in our current model. We only consider losses for short-term operational costs and transformer replacements for long-term investment costs. At the moment, we do not consider power quality issues like voltage deviations, line losses and replacements and higher network levels beyond the neighborhood LV transformer. This also prevents us from using more realistic network expansion models and power flow simulations. We only modeled EVs as a proxy for new kinds of high-power flexible loads, but future studies should also take into account heat pumps, PV cells and deferrable loads like smart dishwashers. The binary split of load into “flexible” and “inflexible” could be improved by considering the elasticity of demand of network users. Lastly, for consumer behavior, we assume that users optimize according to price signals. In reality they may respond in different ways.

Apart from the model, there may also be concerns about the *validity* of the indicators [41]: do they really measure what they are intended to? And are the indicators presented in Section 3 sufficient to judge performance of any tariff? It is an important step in the process to translate the chosen objectives into indicators, which can be obtained from measurements or simulations. It can be up for debate whether a given indicator really measures an objective. Therefore, indicators should ideally be agreed upon in a coordinated effort by all involved stakeholders. For example, there may be a concern by EV interest groups that capacity-based tariffs are too restrictive for EV owners and incur excessive costs for them. This could violate the cost-efficiency objective when taking into account not just network costs but related consumer costs as well, as in Eq. (28). In this case an indicator that measures the costs of charging EVs under different tariffs may be an obvious choice to add, as demonstrated in the case study.

[10] Though intermediate steps, such as cost contributions to short and long term losses, have to be adapted to the sepcific network cost model that is used.

5.3. Research gaps

Some limitations of the proposed methodology are inherent to the use of stylized models for complex technical systems. However, we also identified a number of areas where future research could make a significant improvement in terms of modeling:

- The combination of more sophisticated network expansion models with a feedback loop of network costs. Costs should be allocated back to consumers through tariffs, and the reaction of consumers to these tariffs should be taken into account for the expansion modeling.
- The use of more realistic power flow modeling in electricity networks to determine the cost-factors and cost-contributions.
- Implementation of advanced pricing mechanisms to resolve network congestion: locational marginal prices (LMP), dynamic tariffs, flex markets, smart curtailment solutions.
- Studies on consumer responsiveness to and understanding of different tariff types.

The indicator framework itself might also be improved by suggesting additional indicators for objectives which we did not treat in depth here, such as equity, third-party neutrality and incrementalism. The adaption to specific local contexts and concerns could also be an area for further research.

Lastly, an issue that has not received much attention in the literature is the political process of tariff setting. When a tariff system needs to be updated, there is a wide variety of stakeholders involved, each with their own objectives. This process often creates disagreements, and is difficult to understand for the public. How to come to an agreement in the face of these difficulties, and how to make sure that an acceptable compromise is produced? The governance and organization of this transition process is an important piece of the puzzle, which deserves further attention. The framework presented here may help with this process.

6. Conclusion

We propose quantitative performance indicators for the objective assessment of electricity network tariffs and a cost-accounting methodology for network costs. We demonstrated the benefits of evaluating tariffs with this methodology in a case study.

With the steady increase of distributed generation and high-power flexible loads, the urgency to improve tariffs is rising. For networks with high volumes of distributed energy resources, cost-reflectiveness and economic efficiency are particularly relevant performance indicators. However, cost recovery, non-discrimination and simplicity should not be neglected, as poor performance of any of these may lead to public or political resistance or failure of the tariff system to work as intended.

The proposed framework helps to understand the performance of network tariffs and the trade-offs between the different objectives of network regulation. This can improve the decision-making process for new tariff systems. Currently, this process is to a large degree based on subjective judgements and assumptions. With the presented methodology, which is as much as possible based on quantifiable indicators, the discussion can be moved to arguments about which objectives the tariff should fulfill and how to weigh the different objectives. It may be easier to agree on these questions, rather than immediately try to find agreement on a new tariff. Therefore, we recommend that stakeholders who are involved in tariff setting, agree on a set of objectives and indicators which can be assessed in simulations or real-world measurements.

The methodology demonstrates the complexities and trade-offs in tariff setting. As performance depends strongly on the context and the weighting of different objectives, there is no one-size fits all tariff. In future work, we plan to perform an in-depth study of the performance of tariffs in different European countries and to evaluate dynamic methods of congestion management.

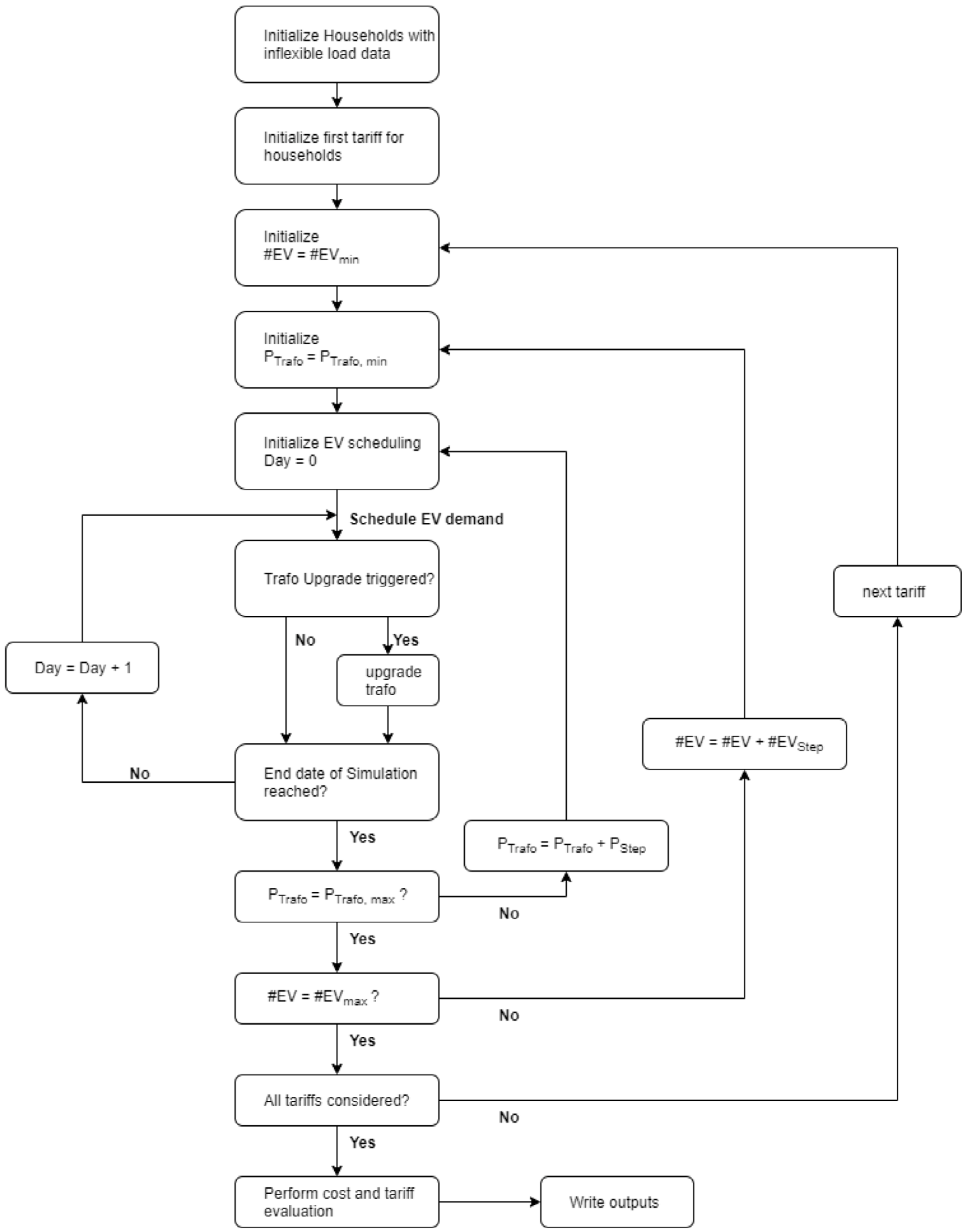

Fig. A.13. Model execution logic.

CRediT authorship contribution statement

Roman J. Hennig: Conceptualization, Methodology, Software, Data curation, Writing – original draft. **David Ribó-Pérez:** Data curation, Visualization, Writing – review & editing. **Laurens J. de Vries:** Writing – review & editing, Supervision. **Simon H. Tindemans:** Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgments

This work is part of the research program STEP-UP, which is partly financed by the Dutch Research Council (NWO) with project number 438-18-404. This work was supported in part by the Spanish public administration under grant FPU2016/00962. We thank Remco Verzijlbergh, Sigurd Bjarghov and Martijn Jonker for their input and critical feedback.

Appendix. Model execution logic

Explanation of steps (see Fig. A.13):

1. Load external household data and create household objects.
2. Load tariff parameters from tariff input file.
3. Load EVs at the given current EV number, from the minimum to maximum number in the given step size. EV profiles are loaded from an external file.
4. Set the transformer capacity to the given current capacity, from the minimum to maximum capacity in the given step size.
5. For each EV, schedule the charging based on required demand and optimized according to day-ahead wholesale prices and the tariff price signal.

6. If the sum of household load and all EV loads exceeds the current transformer capacity, a transformer upgrade is triggered.

7. Repeat scheduling for each day of the year.

8. Once the end of the year is reached, repeat steps 5–7 with the next higher transformer size. Store network indicators for each transformer size.

9. Once all transformer sizes have been used, repeat steps 4–8 with the next higher EV size. Store the averages and variances of network indicators over all transformer sizes.

10. Once all EV numbers have been used, apply the next tariff and repeat steps 3–9.

11. Once all tariffs have been considered, write output files (one for each tariff). Outputs can also be written at the household level if this option is chosen, as in the data for Fig. 6.

References

[1] Eurelectric. Network tariffs a EURELECTRIC position paper. Technical report, Eurelectric; 2016, URL: https://cdn.eurelectric.org/media/2012/network_tariffs_position_paper_final_as-2016-030-0149-01-e-h-5AF7DC88.pdf.

[2] Meeus L, Glachant JM. Electricity network regulation in the eu: the challenges ahead for transmission and distribution. Edward Elgar Publishing Ltd.; 2018, http://dx.doi.org/10.4337/9781786436092.

[3] Florence School of Regulation. Unbundling in the European electricity and gas sectors. 2020, URL: https://fsr.eui.eu/unbundling-in-the-european-electricity-and-gas-sectors/.

[4] Vogelsang I. Electricity transmission pricing and performance-based regulation. Technical report, CESIFO; 2005, URL: http://ssrn.com/abstract=741085.

[5] CEER. CEER paper on electricity distribution tariffs supporting the energy transition distribution systems working group. Technical report, 2020, URL: https://www.ceer.eu/documents/104400/-/-/fd5890e1-894e-0a7a-21d9-fa22b6ec9da0.

[6] Reneses J, Rodríguez MP, Pérez-Arriaga IJ. Electricity tariffs Vol. 16. London: Springer; 2013, p. 397–441. http://dx.doi.org/10.1007/978-1-4471-5034-3_8.

[7] REF-E AF-Mercados EMI, Indra Sistemas SA. Study on tariff design for distribution systems final report prepared for directorate-general for energy of the european commission. Technical report, European Commission; 2015, URL: https://ec.europa.eu/energy/sites/ener/files/documents/20150313Tariffreportfina_revREF-E.PDF.

[8] Jenkins J, Perez-Arriaga I. Improved regulatory approaches for the remuneration of electricity distribution utilities with high penetrations of distributed energy resources. Energy J 2017;38(3):63–91.

[9] Hoarau Q, Perez Y. Network tariff design with prosumers and electromobility: Who wins, who loses? Energy Econ 2019;83:26–39. http://dx.doi.org/10.1016/j.eneco.2019.05.009.

[10] Okur O, Voulis N, Heijnen P, Lukszo Z. Aggregator-mediated demand response: Minimizing imbalances caused by uncertainty of solar generation. Appl Energy 2019;247:426–37. http://dx.doi.org/10.1016/J.APENERGY.2019.04.035.

[11] MIT Energy Initiative and IIT Comillas. Utility of the future. Technical report, 2016, URL: https://energy.mit.edu/research/utility-future-study/.

[12] Schittekatte T, Momber I, Meeus L. RSCAS 2017/22 future-proof tariff design: recovering sunk grid costs in a world where consumers are pushing back. 2017, URL: http://hdl.handle.net/1814/46044.

[13] Neuteleers S, Mulder M, Hindriks F. Assessing fairness of dynamic grid tariffs. Energy Policy 2017;108:111–20. http://dx.doi.org/10.1016/j.enpol.2017.05.028.

[14] Ansarin M, Ghiassi-farrokhfal Y, Ketter W, Collins J. The economic consequences of electricity tariff design in a renewable energy. Appl Energy 2020;275(February):115317. http://dx.doi.org/10.1016/j.apenergy.2020.115317.

[15] Fridgen G, Kahlen M, Ketter W, Rieger A, Thimmel M. One rate does not fit all: An empirical analysis of electricity tariffs for residential microgrids. Appl Energy 2018;210:800–14. http://dx.doi.org/10.1016/j.apenergy.2017.08.138.

[16] Savelli I, De Paola A, Li F. Ex-ante dynamic network tariffs for transmission cost recovery. Appl Energy 2020;258:113979. http://dx.doi.org/10.1016/J.APENERGY.2019.113979, arXiv:1907.10086.

[17] Brown T, Faruqui A, Lessem N. Electricity distribution network tariffs principles and analysis of options. Technical report, 2018, URL: https://brattlefiles.blob.core.windows.net/files/14255_electricity_distribution_network_tariffs_-_the_brattle_group.pdf.

[18] Grond M. Impact of future residential loads on medium voltage networks (Master thesis), Delft University of Technology; 2011, URL: https://repository.tudelft.nl/islandora/object/uuid%3Aab64f05b-a58a-411d-b0dd-b5287302ca42.

[19] Picciariello A, Reneses J, Frias P, Söder L. Distributed generation and distribution pricing: Why do we need new tariff design methodologies? Electr Power Syst Res 2015;119:370–6. http://dx.doi.org/10.1016/j.epsr.2014.10.021.

[20] Sotkiewicz PM, Vignolo JM. Towards a cost causation-based tariff for distribution networks with DG. IEEE Trans Power Syst 2007;22(3):1051–60. http://dx.doi.org/10.1109/TPWRS.2007.901284.

[21] Li F, Tolley D, Padhy NP, Wang J. Framework for assessing the economic efficiencies of Long-run network pricing models. IEEE Trans Power Syst 2009;24(4):1641–8.

[22] Strbac G, Mutale J, Pudjianto D. Pricing of distribution networks with distributed generation. In: 2005 International conference on future power systems. 2005, p. 6. http://dx.doi.org/10.1109/FPS.2005.204260, pp.–6.

[23] Verzijlbergh RA. The Power of electric vehicles - exploring the value of flexible electricity demand in a multi-actor context. (Ph.D. thesis), TU Delft; 2013, p. 1–211. http://dx.doi.org/10.4233/uuid:47c8faa7-94de-40fe-8be7-fccec6ee07bb.

[24] Ansarin M, Ghiassi-Farrokhfal Y, Ketter W, Collins J. Cross-subsidies among residential electricity prosumers from tariff design and metering infrastructure. Energy Policy 2020;145:111736. http://dx.doi.org/10.1016/j.enpol.2020.111736.

[25] Batlle C, Mastropietro P, Rodilla P. Redesigning residual cost allocation in electricity tariffs: A proposal to balance efficiency, equity and cost recovery. Renew Energy 2020;155:257–66. http://dx.doi.org/10.1016/j.renene.2020.03.152.

[26] DNV G. Effective and cost reflective distribution tariffs. 2020, URL: https://www.dnv.com/Publications/effective-and-cost-reflective-distribution-tariffs-162913.

[27] Hennig R, Jonker M, Tindemans S, De Vries L. Capacity subscription tariffs for electricity distribution networks: Design choices and congestion management. In: International conference on the european energy market, EEM. 2020-September, IEEE Computer Society; 2020, http://dx.doi.org/10.1109/EEM49802.2020.9221994.

[28] Bjarghov S, Doorman G. Utilizing end-user flexibility for demand management under capacity subscription tariffs. In: International conference on the european energy market, EEM. 2018-June, IEEE Computer Society; 2018, http://dx.doi.org/10.1109/EEM.2018.8469832.

[29] Passey R, Haghdadi N, Bruce A, MacGill I. Designing more cost reflective electricity network tariffs with demand charges. Energy Policy 2017;109:642–9. http://dx.doi.org/10.1016/j.enpol.2017.07.045.

[30] ACER. ACER report on distribution tariff methodologies in europe. Technical report, ACER; 2021, URL: https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20D-Tariff%20Methodologies.pdf.

[31] Rodríguez Ortega MP, Pérez-Arriaga JI, Abbad JR, González JP. Distribution network tariffs: A closed question? Energy Policy 2008;36(5):1712–25. http://dx.doi.org/10.1016/j.enpol.2008.01.025.

[32] Manuel De Villena M, Gautier A, Ernst D, Glavic M, Fonteneau R. Modelling and assessing the impact of the DSO remuneration strategy on its interaction with electricity users. Electr Power Energy Syst 2021;126:106585. http://dx.doi.org/10.1016/j.ijepes.2020.106585.

[33] Borenstein S. The economics of fixed cost recovery by utilities. Electr J 2016;29(7):5–12. http://dx.doi.org/10.1016/j.tej.2016.07.013.

[34] Schittekatte T, Meeus L. RSCAS 2018/19 least-cost distribution network tariff design in theory and practice. 2019, URL: http://hdl.handle.net/1814/53804.

[35] Abdelmotteleb I, Gómez T, Chaves Ávila JP, Reneses J. Designing efficient distribution network charges in the context of active customers. Appl Energy 2018;210:815–26. http://dx.doi.org/10.1016/j.apenergy.2017.08.103.

[36] Anscombe F. Graphs in statistical analysis. Am Statistician 1973;27(1):17–21. http://dx.doi.org/10.1080/00031305.1973.10478966, URL: https://www.tandfonline.com/action/journalInformation?journalCode=utas20.

[37] Ribó-Pérez D, Heleno M, Álvarez-Bel C. The flexibility gap: Socioeconomic and geographical factors driving residential flexibility. Energy Policy 2021;153:112282. http://dx.doi.org/10.1016/j.enpol.2021.112282.

[38] Pflugradt N. Modellierung von wasser-und energieverbräuchen in haushalten. (Ph.D. thesis), Technische Universität Chemnitz; 2016, URL: http://nbn-resolving.de/urn:nbn:de:bsz:ch1-qucosa-209036.

[39] Verzijlbergh RA, Lukszo Z, Veldman E, Slootweg JG, Ilic M. Deriving electric vehicle charge profiles from driving statistics. IEEE Power Energy Soc Gen Meet 2011. http://dx.doi.org/10.1109/PES.2011.6039609.

[40] BOE. Resolución de 18 de marzo de 2021, de la comisión nacional de los mercados y la competencia, por la que se establecen los valores de los peajes de acceso a las redes de transporte y distribución de electricidad de aplicación a partir del 1 de junio de 2021. Report, Spanish Official Gazette; 2021, URL: https://www.boe.es/diario_boe/txt.php?id=BOE-A-2021-4565.

[41] Heale R, Twycross A. Validity and reliability in quantitative studies. Evid Based Nurs 2015;18(3):66–7. http://dx.doi.org/10.1136/eb-2015-102129, URL: http://ebn.bmj.com/.