Revenue-Based Allocation of Electricity Network Charges for Future Distribution Networks

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***Abstract*—This paper investigates the economic implications that high penetrations of distributed energy resources (DER) have in future distribution networks, and proposes a novel scalable scheme for the assignment of use of network charges based on individual participant nodes' revenue. For validation purposes, a techno-economic simulation is proposed to understand how power and revenue flows will change. A year-long high-resolution quasi-static time series (QSTS) simulation, two price schemes, four trading environments, and four DER allocation methods from the literature are used to study economic benefits for individual participants and the supplier. Testing is performed using the IEEE 33-bus and 123-bus networks, and an Irish urban medium voltage feeder. Revenue flow is presented as an indicator of which participant nodes are profiting more from grid usage, and therefore should be responsible for greater network charges, this is validated against traditional and alternative schemes. Important reductions in use of network charges are seen especially by participant nodes with a higher PV generation-to-load and self-consumption rates. The proposed method is only relevant when dynamic tariffs are in place and/or local trading is enabled. Ultimately, results suggest that the income from network charges received by the supplier is increased when dynamic tariffs are used.**

***Index Terms*—Allocation of network charges, distribution network planning, distributed energy resources, local electricity markets, resource allocation.**

I. Introduction

GOVERNMENTS and regulators are showing an increasing interest in the transformation of the electricity sector towards one that uses the existing infrastructure more efficiently, includes renewable energy sources, evolves towards a high penetration of distributed energy resources (DER) and is fair with its participants [1]. This translated into multidisciplinary studies for planning of distribution networks. The literature offers different DER allocation methods that shed light on how future grids will distribute generating resource amongst participants [2]–[4]. Multiple market environments are proposed for the local trading of energy resources [5]. Studies present the simultaneous analysis of technical and economic constraints [6]–[8] trying to reduce the negative technical effects of local energy markets. Framed in this, the authors found a gap in the literature corresponding to an effective simulation-based comparison of these different proposals.

Furthermore, while there is significant research on the technical and economic considerations around the large-scale implementation of new technologies in the electricity sector for individual participants, the implications for grid operators have been passed over. Technical losses, paired with operation, investment and maintenance of transmission and distribution networks represent costs that traditionally have been transferred to the end user [9], and with the evolution of the sector, must be reformulated. These costs are expected to change with the introduction of new technologies because aside from power flows, revenue flows are expected to change once distribution networks achieve high penetration of DER. This is explained by the stochastic nature of energy demand and generation plants that use non-dispatchable renewable sources, changing energy policy and price schemes, and the possible trading environments with different rules allowing or restricting local trading.

The research community highlighted from an early stage the necessity and potential benefits of modifying network charges for the electricity sector as a response to new developments [10]. The economic implications of DER installations considering existing network charges methodologies has been explored [11], [12]. As discussed in [13], it is possible to consider the supplier as an active participant that must take a portion of network charges. Nonetheless, after a review of the literature, the authors did not find alternatives for the fair allocation of network charges.

Investigating industry and technical reports from national and supranational entities, it was found that tariff methodologies across Europe are the responsibility of each national regulatory authority, and they are periodically amended [9]. The tariffs are currently calculated based on energy flow, installed power, fixed charges or a combination of these. Most European countries allocate charges for energy consumption, and an increasing number of them allocate also for energy injected to the grid [14]. However, no novel methodologies are being considered for the allocation of charges between users [9]. This is the case not only for Europe: while 44% of the price paid on average by end users in the United States comes from network charges, there are no alternative methodologies proposed for their calculation and allocation [15]. The opportunity for more sophisticated tariff structures has been noted [14] and it was highlighted that any structural changes in these should be well publicised to minimise negative impacts to end users [16].

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The fair assignment of network charges is a paramount topic for grid operators, it is important to address how these will be calculated and distributed amongst users. Accordingly, this paper offers a novel methodology for the fair assignment of use of network charges based on individual participant nodes' revenue. Pairing energy offers and requirements obtained from power flow simulations with different trading environments and price schemes result in revenue flows. These can be translated into grid usage, and subsequently, use of network charges.

It is expected that users with DER often acting as generators (i.e., not acting as a traditional load or generating for self-consumption, but actively exporting) will see an increase in charges, while those that make a less intensive use of the network (e.g., through local generation for self-consumption) will see a reduction in charges. Moreover, as noted in [16], the change in the distribution of these charges can impact positively or negatively users without DER as well (e.g., if a single user installs DER for its consumption, his charges will be reduced, while the rest of the users will see an increase). Nonetheless, adjusting charges to users that decrease/increase their use of the grid can translate into increased social welfare, while encouraging users to become active participants, without affecting the interests of the supplier.

This methodology also presents an important tool that makes possible an effective comparison of potential DER distributions, price schemes and trading environments. The main contributions of the paper are:

- Presenting a novel formulation for the fair assignment of use of network charges that is based on revenue (an indicator of which participant nodes are using the grid more intensively), and validating it against traditional and alternative assignments.
- Performing a high resolution long-term technical-economic simulation of multiple scenarios with different DER distributions, price schemes and trading environments to identify the behaviour of future individual revenue flows.
- Making use of the proposed use-of-network charges assignment methodology to carry out an effective comparison of the studied scenarios and issue recommendations based on the results.

The remainder of this manuscript is structured as follows: Section II presents the methodology and mathematical formulation, Section III presents the details for the techno-economic simulations performed as part of this study, as well as the assumptions and limitations of this work. Results are displayed in Section IV and the paper is closed with conclusions and recommendations in Section V.

II. Methodology

A techno-economic simulation of a distribution network is proposed. An overview of the proposed methodology is presented in Fig. 1. It is important to note however that in real scenarios only the economic balancing and assignment of use of network charges would be necessary, as all preliminary steps would be performed contrasting real energy requirements, offers

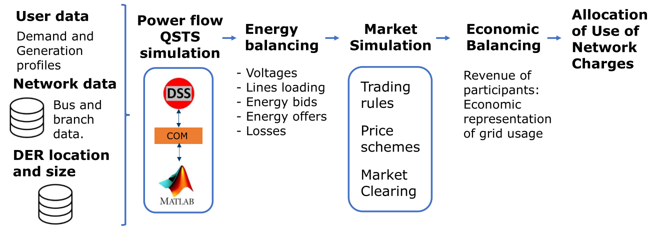

Fig. 1. Overview of the proposed methodology: simulation of electricity distribution network and assignment of use of network charges.

and prices particular to that case, framed in the applicable trading and market clearing rules (i.e., the power flow and market simulations are not required in real applications, only for validation in this paper).

First, using the distribution network data, together with demand and generation profiles simulated, and state-of-the-art DER allocation methods selected from the literature, a year-long high-resolution quasi-static time series simulation (QSTS) will be performed to obtain power flows and energy offers/requirements. Performing a power flow simulation, node voltages, loading of lines, losses, energy bids and offers can be calculated. Second, the energy offer/requirement of each participant node in each time step will be run through different price schemes and trading environments to match buyers and sellers, and identify transacted prices. Note that for the purpose of this study, participants represent non-dispatchable loads and generation resources, this means that there is no need for optimal power flow simulations, and the market clearing can follow the bids and offers resulting from the AC power flow calculations. This is possible because no flexible resources are considered as discussed ahead in Section III-D.

For applications of this work, information sharing between the supplier and trading platforms is necessary. It is required for the supplier (or any potential entity in charge of use of network charges calculation and allocation) to have access to individual revenue information. In cases where the supplier is trading directly with the user, the information is already available (e.g., as part of the smart-metering scheme and relevant princing scheme). Alternatively in case of a hypothetical local trading scenario (e.g., as defined later in Section III-C), it is possible to either share the revenue of participants with the supplier, or fully take control over the assignment of use of network charges to later aggregate and settle with it.

A. Revenue-Based Allocation of Network Charges

The traditional allocation of network charges consists of distributing the charges amongst participants based on their total energy import over a long span (in the order of months). Keeping the granularity selected for this problem, and without losing generality, (1) shows that the traditional charges $\Omega_{i,t}^{trad}$ for participant i are the result distributing all costs for the time step t. Operation, maintenance and investment costs (grouped in Φ_t^{supl}), plus technical losses (these last obtained multiplying losses $\Gamma_{m,t}$ in every line m by the electricity price offered by the supplier $\alpha_{supl,t}^{sell}$) are divided amongst participants for each time step t. The distribution is made based on the participant's active energy import $\epsilon_{i,t}$ relative to that of all users $\sum_{j \in N} \epsilon_{j,t}$. Note that $\epsilon_{i,t}$ is active energy import only when greater than zero.

$$\Omega_{i,t}^{trad} = \left(\sum_{m \in L} \left(\Gamma_{m,t} \times \alpha_{supl,t}^{sell} \right) + \Phi_t^{supl} \right) \times \frac{\epsilon_{i,t}}{\sum_{j \in N} \epsilon_{j,t}}$$
$$\epsilon_{i,t} \geq 0 \, \forall i, \, j \in N, \, \forall t \quad (1)$$

With the large-scale adoption of smart-metering schemes it is now possible to evaluate grid usage in near-real time (i.e., it is possible for the supplier to access consumption patterns with enough granularity). Using (2) it is possible to include an alternative way to distribute network charges: not only quantifying energy import, but also energy export over shorter spans (in the order of minutes). The active energy offer/requirement from participant node i is represented by $\epsilon_{i,t}$, it is modelled as import when positive and export when negative. The alternative distribution of network charges $\Omega_{i,t}^{alt}$, equivalent to net metering, is therefore computed as the participant's fraction of the total active energy (either import or export) using the absolute value.

$$\Omega_{i,t}^{alt} = \left(\sum_{m \in L} \left(\Gamma_{m,t} \times \alpha_{supl,t}^{sell} \right) + \Phi_t^{supl} \right) \times \frac{|\epsilon_{i,t}|}{\sum_{j \in N} |\epsilon_{j,t}|} \quad (2)$$

The active energy $\nu_{i,supl,t}$ transacted between participant nodes i and the supplier must be calculated first as in (3): it is the difference between the active energy (either import or export) and active energy $\nu_{i,j,t}$ transacted with every other participant j. The price $\alpha_{i,supl,t}$ at which the participant i will trade with the supplier is obtained using (4), a binary variable $\mu_{i,t}$ which depends on whether the transaction is for purchase or sale and corresponding supplier buy $\alpha_{supl,t}^{buy}$ and sell $\alpha_{supl,t}^{sell}$ prices for the time step. Finally, it is possible to compute the revenue $\Psi_{i,t}$ for each participant node i. This is done by adding the resulting income or spend of each transaction with other participant nodes and the supplier at the respective price using (5).

$$\nu_{i,supl,t} = \epsilon_{i,t} - \sum_{j \in N} \nu_{i,j,t} \quad (3)$$

$$\alpha_{i,supl,t} = \left(\alpha_{supl,t}^{buy} \right)^{(1-\mu_{i,t})} \times \left(\alpha_{supl,t}^{sell} \right)^{(\mu_{i,t})} \quad (4)$$

$$\Psi_{i,t} = \sum_{j \in N} \left(\nu_{i,j,t} \times \alpha_{i,j,t} \right) + \nu_{i,supl,t} \times \alpha_{i,supl,t} \quad (5)$$

At last, network charges $\Omega_{i,t}^{rev}$ of each time step (i.e. technical losses, plus operation, investment and maintenance charges) will be calculated and distributed amongst participant nodes depending on the absolute value of their revenue $\nu_{i,j,t}$ respective to that of all others using (6). This is the proposed and preferred methodology as it captures not only individual usage patterns (both consumption and excess), but local energy trading, dynamic pricing from the supplier and congestion concerns indirectly (i.e., when the grid is congested, local trading prices are expected to increase due to supply/demand balancing, and

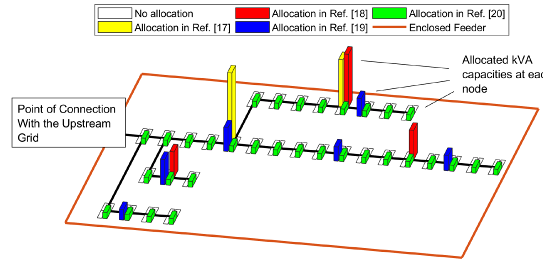

Fig. 2. Comparison of installed capacities given selected DER allocation methods for the test network 1, IEEE 33-bus radial distribution network.

this is reflected in higher network charges).

$$\Omega_{i,t}^{rev} = \left(\sum_{m \in L} \left(\Gamma_{m,t} \times \alpha_{supl,t}^{sell} \right) + \Phi_t^{supl} \right) \times \frac{|\Psi_{i,t}|}{\sum_{j \in N} |\Psi_{j,t}|} \quad (6)$$

There are different views on whether generation units must be subject to use of network charges. It can be argued that traditional generators provide a service required by final users and in this unidirectional paradigm it is reasonable to allocate them in one end or the other (i.e., in any case these would be paid by the end user). However, the appearance of DER is making the flows of revenue and electricity change, therefore the use of network charges must be calculated also for users with DER capabilities exporting energy, as this represents another type of service. This is reflected in the absolute value of the revenue in (6) and is one of the highlights of this work compared to traditional and alternative allocation of charges.

B. DER Allocation Methods

Size and location of DER is expected to impact the flow of energy and subsequently revenue between participant nodes and the supplier, to account for this, the authors performed an extensive review of allocation papers in the literature. Over the more than 60 potential publications, four papers were selected to represent hypothetical scenarios for high penetration of DER in the IEEE 33-bus network [17]–[20]. These methods were selected because they have a large penetration of DER and do not present voltage or line-loading issues as discussed in [20]. Fig. 2 presents an overview of installed capacities for generation across this test network's topology.

The IEEE 123-bus network is not present in most DER allocation papers. Considering that the proposed methodology is designed for participants that can be either consumers or prosumers (i.e., there is no exclusive generation participant), one of the allocations proposed in [21] was selected for this purpose.

Similarly, following the review of common practices for distribution system allocation rules found in [22], two rules of thumb were selected to represent future high penetration scenarios for the case study: allowing the installation of 15% of the distribution transformer kVA rating and the installation of 15% of the peak load of the studied node. To complement this, the local rule for allocation particular to the case study in [23] was selected for investigation. A summary of selected DER allocation methods can be found in Table I.

TABLE I
DER ALLOCATION METHODS SELECTED

Network Studied	DER allocation method	Participants with DER	Total DER [kW]
Test Network 1 IEEE 33-Bus	Ref. [17]	6/32	3,500.3
	Ref. [18]	3/32	3,427.4
	Ref. [19]	5/32	3,000.0
	Ref. [20]	32/32	3,389.8
Test Network 2 IEEE 123-Bus	Ref. [21]	5/91	1,050.0
Case Study: Urban Feeder	15 % Transf. Rating	45/52	691.5
	15 % Peak Load	52/52	257.2
	Ref. [23]	45/32	2,280.0

C. QSTS Simulation

To ultimately study the flows of revenue and determine the resulting assignment of use of network charges, it is important as input to have an energy balance that represents future conditions in a distribution network. In current practices the time step varies greatly between supplier, country, and metering scheme. Traditional allocation of network charges is computed in the order of months while the alternative and proposed methods can be studied given the technical specifications of the smart metering device. To perform a robust analysis of the problem a 5-minute time step was selected, this allows for enough granularity without becoming an unnecessary computational burden. The test networks and case study are modelled using OpenDSS and the COM interface with Matlab through an AC power flow simulation. Details on electricity demand and generation profiles are given in this subsection, these are used to simulate energy flows required as input for the economic study.

1) Demand Profile: The test networks and case study include peak load information, but detailed demand profiles are not available. The CREST demand model [24] was selected to fill the gap, it is an open-source high-resolution stochastic domestic electricity demand model. This model has been validated using real utility data from the United Kingdom, and it has been used in numerous distribution system studies. The active power demand data simulated corresponds to the peak load and it is complemented by reactive power demand that matches the power factor in the documentation. No load-voltage dependency considerations are made for the test networks, while the case study modelling follows constant-impedance, constant-current and constant-power (ZIP) curves available in the documentation. The demand is modelled depending on the peak load and the amount of customers associated to the node when known, this corresponds to a year-long simulation of demand with 5 minute resolution equivalent to a leap year analogous to 2020.

2) Generation Profile: For the purpose of this study, a purely photovoltaic (PV) generation profile is suggested. This profile includes seasonal and weather variations for the geographical location of the case study and it was simulated using the respective functionality of the CREST model. For simplicity, all generators were modelled with a constant power factor equal to one, and as a result, each time step presents a generation multiplier that will be applied to the installed capacity determined by the allocation method selected in each iteration of the study. It is assumed that the topology is enclosed geographically, therefor the multiplier applies equally for every generation unit.

III. VALIDATION

The validation process aims to cover different foreseeable scenarios in future distribution networks. This section presents the details of the studied topologies, together with the price schemes and trading environments to perform the economic balancing necessary to test the proposed methodology of assignment of use of network charges.

A. Studied Topologies

- **Test Network 1**. The modified version of the IEEE 33-bus radial feeder consisting of 32 branches and 33 nodes is used in a variety of distribution network studies across the literature. The bus and branch data, paired with base loads for each bus can be found in [25]. The documentation includes a synchronous generator that represents the point of connection feeding the system. For the purpose of this study, the point of connection will be modelled as the supplier and the remaining 32 nodes are distribution transformers that represent individual participant nodes.
- **Test Network 2**. The IEEE 123-bus network includes 91 loaded nodes that can be modelled as participants. It represents an additional level of complexity considering the larger number of connections. While there are multiple possibilities for reconfiguration and meshed operation, the standard configuration was used for the purpose of this study.
- **Case Study**. A typical urban Irish medium voltage feeder was selected as case study. It has four single-phase loaded buses and 17 three-phase loaded buses for a total of 52 potential single-phase participant nodes. There are no voltage or line-loading problems at a peak load of 1713.6 kW and 589.1 kVAr in this feeder with a total of 6.16 km of lines operating at 10 kV.

B. Price Schemes Offered by Suppliers

To understand the economic implications of DER developments in distribution networks, it is important to capture different pricing schemes for purchase and sale of electricity. For the purpose of this study, the authors considered combinations of the following price schemes.

1) Energy Purchase: Traditionally, individual users are billed their energy balance over a relatively long period (i.e., in the order of months) using a flat tariff that captures generation, transmission, distribution and commercialisation costs. There is no negotiation process because the supplier unilaterally calculates these costs as result of price signals from the wholesale market, the grid operator and regulator. This scheme is still used by the majority of suppliers worldwide [26]. Nonetheless, with the need to flatten the demand curve and displace energy demand away from peak consumption times, and with the roll out of smart metering schemes that allow energy quantification on smaller time steps (i.e., in the order of minutes or hours), suppliers have developed more dynamic tariffs, the most popular one currently in use is the time-of-use tariff (ToU), that consists of a step function assigning different prices for the purchase of energy depending on the time of the day when the purchase occurs.

2) Energy Selling: At the beginning of the energy transition, small scale DER installed by individual users was conceived for self-consumption combined with in-site energy storage, therefore the supplier did not initially pay for energy fed to the grid, this means that users were only billed for energy consumed. With the introduction of energy policy aiming to increase the share of small scale DER installations, regulators around the world gradually introduced a monetary incentive for energy fed to the grid, this is known as feed-in-tariff (FiT).

The specific prices used for this study correspond to those in [27]. Other price schemes are under consideration by suppliers and the research community, including smart contracts and aggregators [28], [29], however these are still at an early stage and will not be considered for the present study.

C. Local Trading Environments

It is not only the prices offered by the supplier that define how the economic balancing will be conducted, different policy frameworks are expected to allow or restrict local trading to a certain degree. The following trading environments were selected for study in this manuscript:

1) **Only the supplier is able to sell energy to participants**. In this trading environment, no policy has been developed to pay incentives for energy fed to the grid. The supplier offers a FiT equal to zero regardless of the price scheme for purchase of electricity.
2) **Only the supplier is able to trade (sell and purchase) with participants**. For this environment, policy has already introduced a FiT, every energy unit fed to the grid will be paid to the participant node at this price, trading between participants is not allowed.
3) **Local trading is allowed clearing the market with the shortest electrical distance**. A hypothetical trading scenario in which participant nodes are allowed to buy and sell electricity to a participant other than the supplier. There is no decision making process, the market is cleared prioritising trades with the shortest electrical distance criteria similar to the one presented in [30].
4) **Local trading is allowed using a zero-intelligence continuous double auction algorithm (ZI-CDA)**. Participant nodes submit their orders (either bid or offer) during each trading slot. All the arriving bids and offers received are accumulated in the order book, ordered according to their prices [27], and matched until the market is cleared. Partial or unmatched orders are assumed to be fulfilled with the supplier at the pre-defined rates (i.e. FiT, Flat or ToU). In this paper, Zero-Intelligence agents are adopted: a participant node simply bids in the CDA market using random prices within a budget constraint, this prevents participants from trading at a loss. A ZI-CDA marketplace can sustain a high level of efficiency [31].

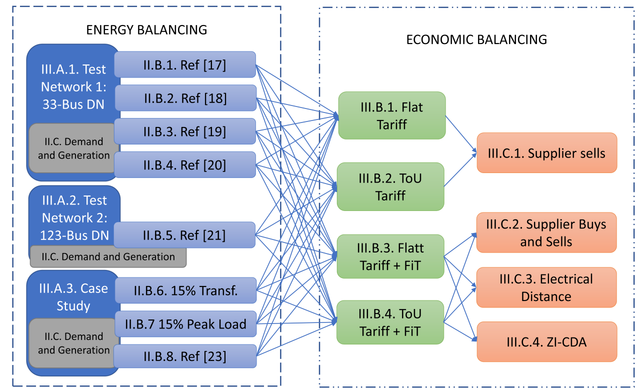

Fig. 3. Overview of the simulated scenarios. index corresponds to subsection in text.

D. Considerations and Limitations

An overview of the scenarios proposed for the validation process is presented in Fig. 3, a total of 48 independent year-long simulations were performed to offer a robust analysis of the problem. Nonetheless, a number of potential scenarios are left out of scope to simplify the problem:

- PV installations have sustained periods of unavailability where no local trading occurs. During these, power and revenue flows depend only on the demand. Therefore, effects of the proposed methodology are expected to be greater with other generation technologies with shorter/fewer periods of unavailability.
- Flexibility resources (e.g., energy storage, etc.) are not included in this study.
- Electrification of heat and transport is not considered in this work.
- For the purpose of this study, users represent MV/LV transformers and the values for energy bids and offers represent aggregated values of several behind-the-meter PV installations and non-flexible loads, this means that energy balancing does not follow dispatch rules.
- It is assumed in this study that participant nodes do not respond to price signals (i.e., there is no demand response capabilities), this simplification reduces noise when comparing different trading environments and DER allocations from a use of network charges perspective.
- A different allocation of DER results in different energy and revenue flows, therefore a systematic study of various allocation methods is required to further explore economic implications of high penetration.
- While there are certain countries and regulatory frameworks that allow for network charges to be paid in part through standing charges, these will not be considered for this study. This is possible in distribution networks where users are homogeneous (i.e., residential and commercial mostly), as standing charges are equivalent for all participants and can be seen as an offset of the variable charges calculated in this work.
- Deregulated market structures require the simultaneous evaluation of different trading schemes and trading

environments for participants in the same network. This increases exponentially the complexity of the problem and restricts the interpretability of the results. For these reasons, deregulation was not considered in this study.

The proposed simulated scenarios were selected to cover a range of foreseeable occurrences in terms of topology, DER penetration and distributions, price schemes and trading environments. The objective is threefold: first, to offer a robust validation process for the proposed methodology (i.e., determining if under different circumstances the revenue based allocation has a better performance for social welfare than the traditional and alternative allocations). Second, to identify patterns amongst different scenarios to formulate conclusions on preferred DER allocation methods, price schemes and trading environments. Third, to contribute to the literature on technical-economic simulation of distribution networks, as the results from this work may be useful for future research and applications.

IV. Results

This section presents the results of the study. First, the proposed methodology is studied in detail using one of the scenarios proposed. Second, the results of all the simulations for the test networks and case study are presented. At last, an analysis of the results is performed to identify key benefits of certain DER allocation methods, price schemes and trading environments.

A. Detailed Results

For this subsection, the following scenario was selected. Given the demand and PV generation profiles, test network 1 was equiped with the DER allocation proposed in [17], and the yearly QSTS simulation was performed to obtain an energy balance (i.e., for each time step, the energy excess or requirement of every participant node). Using the price scheme that includes supplier prices ToU and FiT, combined with the trading environment that allows local trading clearing the market with the shortest electrical distance, the economic balancing was performed. Ultimately, considering the proposed mechanism for the assignment of use of network charges, each participant was charged fees corresponding to the addition of technical losses, operation, investment and maintenance costs. The assignment is then compared to the traditional and alternative mechanisms to assign use of network charges. Fig. 4 presents the total values of the year that follow the sequence presented before. As seen in Fig. 4, the proposed assignment is reducing the use of network charges for some participant nodes and increasing them for others, at this stage it is not possible to draw conclusions on the reasons for these changes. As an example, participant node 6 has a reduction in use of network charges while participant 24 sees an increase, despite both having DER installed. Similarly participant 8 has a reduction, while participant node 16 presents an increase, despite them not having generation capabilities.

B. All Simulation Results

To gain a better understanding on the impact that high penetration of DER might have in the assignment of use of network

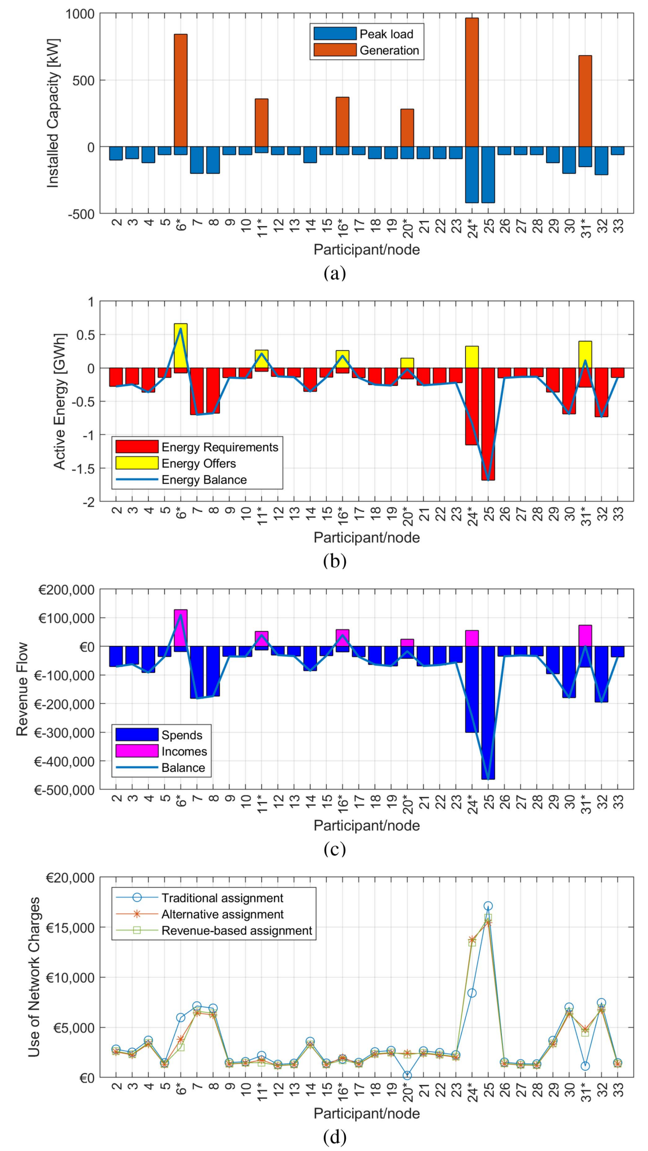

Fig. 4. Detailed results for DER allocation method [17] considering ToU and electrical distance over the course of the studied year. (*) Participant nodes with DER. (a) Installed DER and peak load, (b) energy balance resulting from PF simulations, (c) economic balance, and (d) assignments of charges.

charges, all the values obtained were included in a scatter plot as function of the ratio between the DER installed capacity and peak load of the participant node, this can be seen in Fig. 5. It was discovered that for the simulated scenarios, there are four generation to load zones connected to an increase or reduction of charges compared to the traditional assignment.

- Participants with a generation to load ratio lower than 1 (i.e., participant nodes that have less DER installed compared to the peak load) always present a reduction in network charges.
- Those with a generation to load ratio between 1 and 5 (i.e., participant nodes with similar DER compared to their peak load) always present an increase in use of network charges. This can be seen specifically in the enlarged portion of Fig. 5.

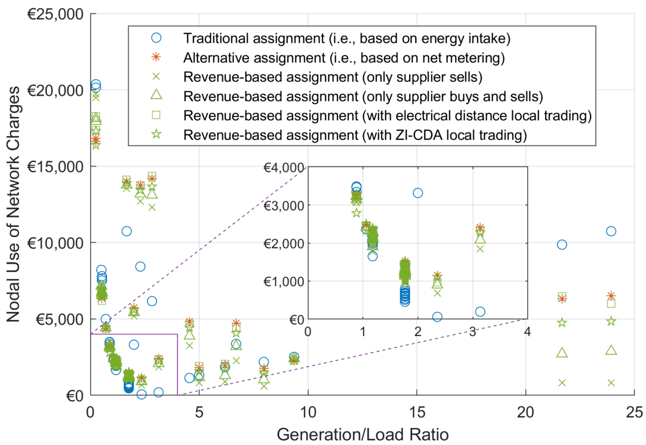

Fig. 5. Scatter plot of use of network charges for participant nodes with different generation-to-load ratio in the test network using and all DER allocations [17]–[20]. ToU price scheme.

- Participants with a ratio between 5 and 7.5 may present an increase or decrease in charges depending on the trading environment.
- Ultimately, those with a ratio higher than 7.5 (i.e., participant nodes that have a very large DER installed compared to their peak load), always present a reduction of charges.

These ratios are linked to different levels of self-consumption for PV installations, and self-consumption levels are indirectly associated to congestion (i.e., if local consumption is intensive, congestion and losses are reduced as discussed in [20]). It is important to note that the generation to load ratio of installed capacity serves only as an indicator: actual self-consumption is linked to instantaneous generation and load states. Therefore, it is hypothesised that reductions and increases in use of network charges assigned through the proposed methodology may be linked to levels of self-consumption for two reasons: congestion and loss reduction.

1) Test Network 1 Results: To identify patterns it is useful to have an overview of all the simulations performed. Given all price schemes, DER allocation methods and trading environments studied, a comparison of traditional, alternative, and proposed assignment of use of network charges for all participants in the test network can be found in Fig. 6. Each sub-figure includes first, the traditional use of network charges for each participant using different price schemes (i.e., flat tariffs and ToU tariffs), and second, the increase or decrease in use of network charges using the alternative and proposed method. Additionally, to test the connection between self-consumption and charges increase/decrease discussed in the previous paragraph, Fig. 6 presents the percentage of energy used in the node that came from self-consumption. It is important to clarify that in every figure given the same price scheme, the global charges are the same (i.e., none of the charge allocation methodologies modify the charges, only the way they are distributed among participants).

It was discovered that the price scheme has a global impact on how the use of network charges are calculated, therefore in the overall charges too: while the distribution of network charges does not change, the global charges increased between 2.0% and 7.2% for this test network using ToU tariffs as price scheme. The increase is relatively small, but it suggests that it is in the interest of the supplier to adopt dynamic tariffs, as these would increase their income from use of network charges while becoming an additional incentive for participants to shift their consumption to less congested time-steps.

For this test network, the largest decrease in use of network charges when compared to the traditional assignment corresponds to € 9,912, it happened for participant node 6, when the allocation in [18] is used, paired with the ToU price scheme and no local trading is allowed. The largest increase in charges happened to participant node 24, also using [18], ToU price scheme, and the electrical distance trading environment, this increase corresponded to € 8,179. This shows how significant use of network charges can be unfairly assigned to a participant node that is not using the grid as much as others.

Results in Fig. 6 support the hypothesis formulated before: there appears to be a connection between self-consumption and changes in the assignment of charges. For all the scenarios studied in test network 1, nodes that have a larger self-consumption rate relative to others benefit from a decrease in network charges, while lower self-consumption rates end in increased charges.

It is visible especially in Figs. 6(a), 6(b), and 6(c) that participant nodes without generation capabilities are seeing very small (close to zero) changes in network charges, leaving them unaffected. Additionally, when the values for each plot for change in use of network charges are added the resulting change is zero, this means that as discussed previously the change of network charges does not affect the supplier. These results suggest that the proposed methodology exclusively targets users that are making a more (or less) intensive use of the network.

It is important to note that both the alternative and proposed allocation of network charges methodologies represent an improvement from the traditional method. Participants with generation capabilities see a change in network charges, the direction of which depends on whether this resource is mostly used locally or is fed to the grid. However, the proposed methodology is preferred as it not only captures energy fed to the grid, but under which operational circumstance it was fed (i.e., charges are indirectly connected to congestion).

The allocation method [20] presents a higher degree of node participation (i.e., all participants have DER capabilities), this results in smaller changes in the magnitude of network charges compared to the other resource distributions (e.g., those in Refs. [17]–[19]). Nonetheless, the same connection between self-consumption and change in charges is visible. Notably, the energy generated by nodes 24 and 25 in Fig. 6(d) goes exclusively to self-consumption, and this results in the largest reduction in network charges for the scenario. At last, while it is noticeable that different trading environments result in different magnitudes of increase or reduction, there is not enough evidence to conclude which are preferred.

2) Test Network 2 Results: For the largest test network, the change in global charges was 1.8% using the time of use tariff. This network has more participant nodes, but only five of them have DER capabilities. Results of the simulation for the IEEE

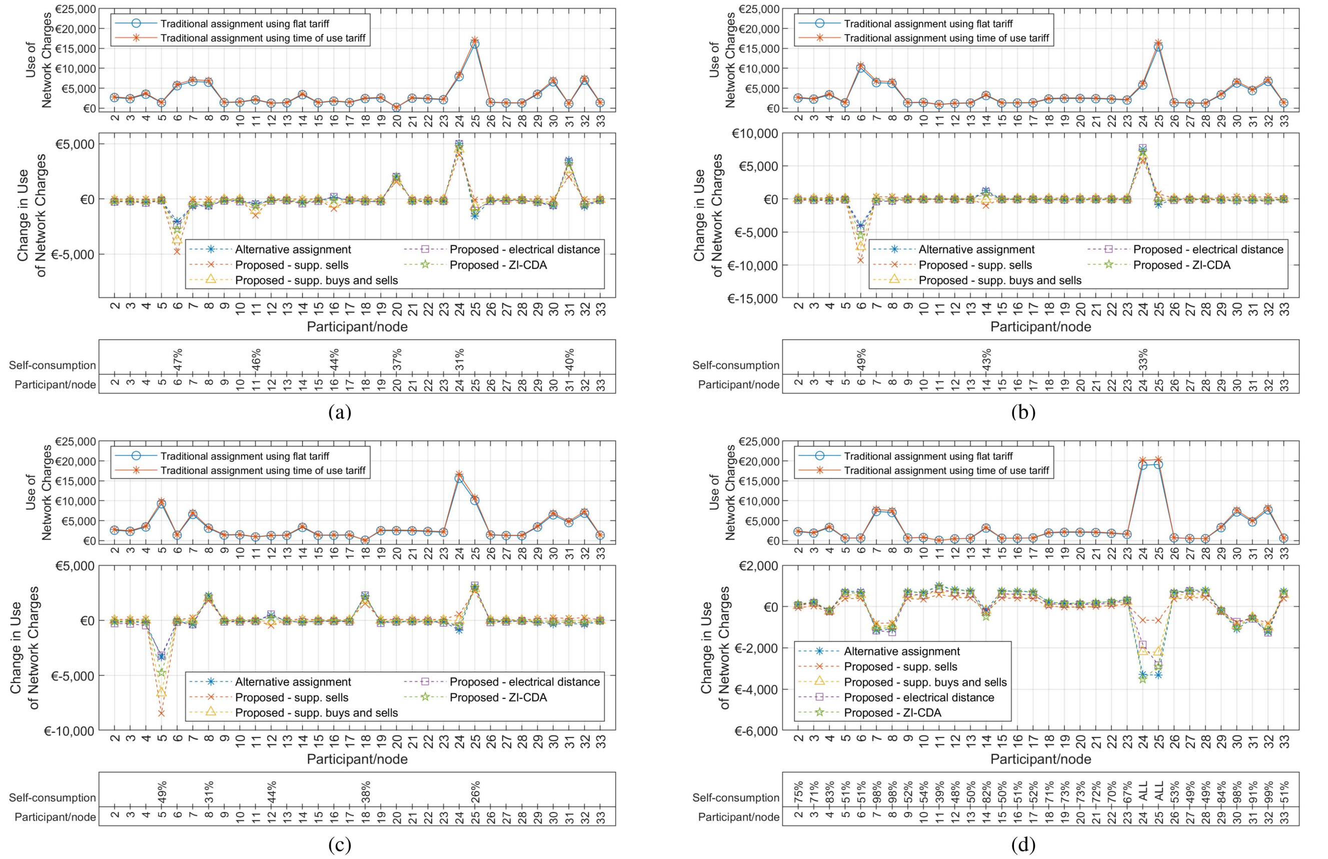

Fig. 6. Change in use of network charges assigned to participant nodes in the IEEE 33-bus network using DER allocations in (a) Ref. [17], (b) Ref. [18], (c) Ref. [19], and (d) Ref. [20].

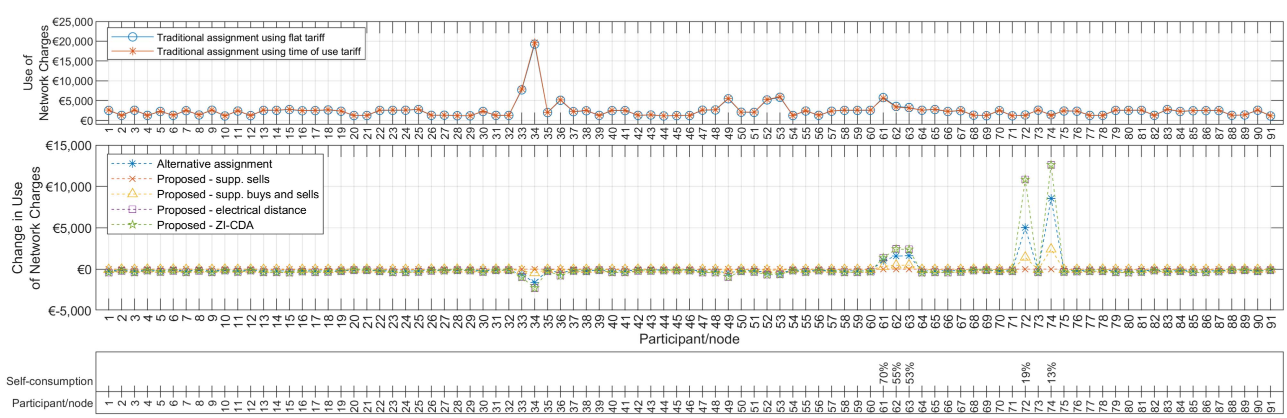

Fig. 7. Change in use of network charges assigned to participant nodes in the IEEE 123-bus network using DER allocations in [21].

123-bus network are registered in Fig. 7. Responding to the identification of higher relative revenues, a significant increase in network charges is seen by participant nodes 72 and 74, this is associated to their smaller self-consumption rates: since most of the energy generated is fed to the grid, these users are assigned larger network charges. In contrast, participant nodes 61, 62, and 63 see a relatively small increase because most of the energy they generate is used in self-consumption.

For this network and allocation of DER, a benefit in the form of network charges reduction is seen by all non-DER participants. Participant node 34 has a large amount of traditional use of network charges assigned to it, and these are greatly reduced thanks to the application of the proposed methodology. This is explained in two ways: first, when local trading is enabled, DER participants are offering a cheaper price of electricity compared to the supplier, which ends up in a less intensive flow of revenue for non-DER participants. Second, the more intensive use of the grid (measured through the revenue increase) that DER participants have, represents an immediate reduction in network charges for the rest of the participants.

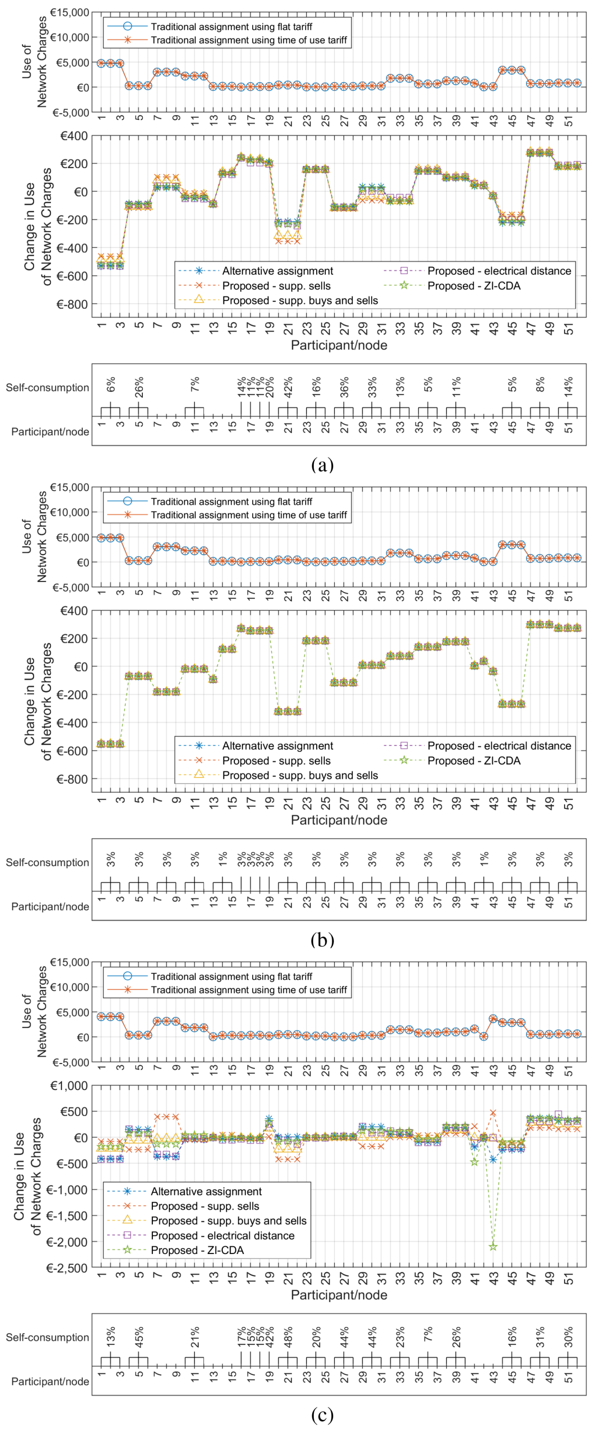

Fig. 8. Change in use of network charges assigned to participant nodes in the case study using (a) 15% transformer allocation rule, (b) 15% peak load allocation rule, and (c) the Irish supplier allocation rules in [23].

3) Case Study Results: Results for scenarios with all price schemes, DER allocation methods and trading environments for the Irish MV feeder are presented in Fig. 8. As it occurred with the test networks, the global charges for the case study increased between 0.9% and 4.9% when time of use tariff is used, again suggesting that suppliers benefit from dynamic tariffs. The largest increase and decrease in charges happened for node 43 using the Irish supplier allocation rules in [23], corresponding respectively to € 475 and € 2,100.

TABLE II
LOSSES AND CHARGES FOR EACH DER ALLOCATION METHOD TEST NETWORK - IEEE 33-BUS RADIAL DISTRIBUTION NETWORK

DER allocation method	Yearly Losses [kWh]	Price Scheme	Calculated Charges
Ref. [17]	205,741	Flat tariff	€ 103,616
		Time of use	€ 110,178
Ref. [18]	214,850	Flat tariff	€ 105,990
		Time of use	€ 112,977
Ref. [19]	215,857	Flat tariff	€ 106,252
		Time of use	€ 113,295
Ref. [20]	210,955	Flat tariff	€ 104,975
		Time of use	€ 111,779

Results for the case study do not support the hypothesis on self-consumption being the sole factor for changes in network charges (e.g., in Fig. 8(a) node 45 has the smallest self-consumption rate and still benefits from a reduction in network charges). This initially is attributed to the topological complexity of real networks, and further investigation is required. It is hypothesised that changes in network charges are connected to more than one factor (i.e., not only self-consumption rates). Nonetheless, it is still possible to test individually that the proposed methodology is correctly identifying which users should assume larger charges. It was verified that node 45 mentioned before presents an overall reduction in imported energy and exported energy, which translates in less intensive use of the grid and subsequently assigned network charges. This was verified by brute force for every node and no exceptions were found.

When generation resource is allocated following the 15% transformer rating rule of thumb, every participant across different price schemes and trading environment had an proportional increase or decrease in grid usage. This is reflected in the fact that changes in use of network charges in Fig. 8(b) are homogeneous regardless of trading environment, price scheme, and charge assignment method.

For this particular DER allocation method, network charges change is the result of net metering, which in turn would make the proposed methodology unnecessary. The alternative methodology (i.e., net metering) would be preferred if this rule of thumb is applied.

C. Effect of Losses in Use of Network Charges Calculations

It was mentioned before that network charges are assigned based on technical losses, operation, investment and maintenance costs. The techno-economic analysis performed in this study allows to investigate on an important part of the variable portion of network charges: losses. Table II presents an overview of the allocation methods, and corresponding losses over the studied year for the test network.

Lower yearly losses are present for allocation methods in Refs. [17] and [20]. Since losses are included in the network charges, results in Table II for calculated charges were as expected: these methods have fewer charges to settle. The two DER allocation methods cited before are preferred from a network charges point of view. As it was previously hypothesised in [20], this may be explained because these two methods have the highest participation and self-consumption rates as seen in Table I.

V. Conclusion

This paper offers a novel method for the assignment of use of network charges in distribution networks that is based on participant revenue. The approach is in principle scalable to the transmission and lower voltage levels. Extensive simulation work was performed including multiple DER allocations, price schemes and local trading rules. This paper presents an initial step in the simultaneous simulation of economic and technical constraints of power systems.

It was discovered through simulation work that the price scheme selected has a very small impact on the assignment of network charges. However as the way the charges are calculated varies with the price scheme, the total perceived by the supplier changes. Results suggest that the supplier receives more charges using the ToU price scheme, this is because the majority of losses occur in peak consumption times, during time steps that correspond with a more expensive energy price compared to flat tariff. Suppliers are recommended to adopt dynamic tariffs as their income product of use of network charges calculation is expected to increase.

Using the proposed methodology does not increase or decrease the amount received by the supplier for network charges, it does not affect the network charges assigned to participant without DER capabilities either. However the assignment to participants with DER changes significantly: the revenue based assignment of use of network charges has the potential to significantly increase or decrease how much must be paid by these participant nodes. The method calculates the charges based on the economic benefit each user is taking from the grid, therefore it is considered more fair for participants without affecting the interests of the supplier.

Results suggest that the application of the proposed methodology benefits with charges reduction those participant nodes that present a higher generation to load ratio (corresponding to higher self-consumption rates in the case of PV generation). In contrast, participant nodes that have low generation to load ratio see an increase of charges assigned to them. This redistribution of use of network charges is responding to a correct identification of those users that are receiving more revenue thus using the grid the most. Given the zero-marginal cost nature of renewable energy, the benefit received by participants from DER installations is expected to be greater than any potential network charges incurred. However, the prosumer is always able to decide not to export electricity to avoid an increase in network charges if this is within its interest. This can be done either by changing its consumption patterns or through energy storage.

It was found that while net metering as criteria to assign charges is an improvement from the traditional assignment, it is preferred to use revenue, as for the latter, congestion is considered indirectly (i.e., users with intensive use of the grid in moments of congestion are assigned a larger portion of the charges).

The connection between self-consumption, losses and network charges was explored. Results partially support the hypothesis that higher self-consumption rates lead to a decrease in losses and a less intensive use of the grid, which in turn reduces network charges for participants.

This study was conducted using zero-constraint DER allocation methods. However, some grids may present congestion issues during certain time steps in the future. The proposed methodology is applicable to congestion cases and in theory contributes to its reduction via increased charges, but it does not represent a solution to congestion.

It will be possible for future work to further assess the validity of the proposed methodology given additional technologies, pricing schemes, and market structures. A special mention is made for the case of deregulation in electricity markets, as the simultaneous occurrence of different pricing schemes coming from different suppliers provides an interesting research opportunity.

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