Distribution Network Tariffs and Distributed Generation: Need for an Innovative Methodology to Face New Challenges. Application to a Case Study

by

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Abstract

The electricity sector is undergoing massive changes, due to the liberalization process and the changes occurred in the regulatory regimes in many countries. In particular, the distribution sector is facing the challenges related to the integration of an increasing amount of distributed generation (DG) in the distribution grids, which is likely to affect the planning and operation of the grids themselves and, consequently, to cause additional costs and benefits for the different network users.

This paper investigates the broad range of issues arising within the rate design process due to DG integration, especially in terms of cost allocation and connected risk of cross subsidization of some customer categories by other ones.

The simulations indicate, on one hand, that, when net metering is adopted and volumetric tariffs utilized, cross subsidization of customers with self generation by the customers without it is likely to arise; on the other hand, separate volumetric tariffs to be applied to producers and consumers are proposed, in order for the network costs to be allocated on a cost-causality basis and, in this way, neutralize such risk for cross subsidization.

Introduction

In several countries, the amount of distributed generation (DG) [1] in the distribution networks has been considerably increasing in the last years, mainly due to the energy targets set at national and international level. Thusly, the distribution sector needs to cope with the challenges arising from the integration of an increasing amount of DG in the grids, which is likely to affect the network planning and operation and, consequently, to cause increased or lower network costs if compared to the traditional passive network scenario [2].

The main available tools to pursue an efficient integration of the DG in the electricity systems are, on one hand, the *economic regulation of the Distribution System Operators* (DSOs) and, on the other hand, *network tariffs for grid users*. These two represent complementary aspects of distribution regulation; the latter represents the focus of this paper.

The distribution tariff design, also known as *rate design*, consists, at a first stage, in the *determination of the total allowed revenue* for the distribution business and, at as second stage, in the allocation of that revenue among the users of the distribution network, i.e. in the *decision on the tariff structure* to be adopted. This paper focuses on the second stage of the process [3]. Some studies can be found in the literature about the guiding principles of tariff design and the traditional methodologies followed so far. Not much, however, has been studied on the new challenges that the DG poses within tariff design, such as a need for new cost allocation methodologies in order for consumers and DG owners to share the total cost of the distribution activity, taking into account the additional costs and benefits caused by the DG itself. In fact, either DG owners are still exempt from paying distribution tariffs or load-tailored schemes are applied to the DG.

The main aim of the method proposed in this paper is to show how some tariff structures can, in fact, increase the cross subsidization phenomena, the more the higher the level of PV penetration in the grids, and to quantify such cross subsidization. A proposal for a cost causation-based methodology is finally drawn, and its practical applicability and the several issues connected to it discussed.

1 General issues concerning tariffs

1.1 Tariff definitions and components

The distribution tariff, also known as *Distribution Use of System (DUoS) charge*, represents the grid-related component of a so-called access or comprehensive tariff, which includes the cost for the energy and for any enforced renewable support scheme, fees and the so-called retailing costs. The DUoS charge is meant to cover the recurrent operating and capital costs for network maintenance and expansion [4] and is paid by the network users periodically. Its main structural elements typically are [5]:

- A *fixed charge* (€/period): it is an invariant fee, meant to cover the infrastructure supply and delivery costs regardless of the customer’s consumption.
- A *volumetric charge* (€/kWh/period): it is proportional to the energy consumed by each customer, and it is meant to cover the variable network costs connected to the energy transport; it may fluctuate by time of the day within the considered period.
- A *capacity charge* (€/kW/period): it is collected on the maximum power used during a specific time range, regardless of the duration or frequency of that level of consumption. It is meant to cover the fixed costs of the infrastructure shared with other customers, in proportion to the capacity each of them requires.

A high degree of flexibility characterizes tariff design: volumetric or capacity charges, as well as combinations of them, can be adopted, and the DG may have to pay network charges or not, depending on the different regulations [4].

1.2 Tariffs design principles

The fundamental principles rate design lies upon are considered to be:

- *Universal access* to electricity, to be guaranteed to all network users;
- *Complete cost recovery* of the accredited costs for the distribution companies;
- *Additivity* of components, whose sum has to add up to the total revenue requirement;
- *Productive efficiency*, i.e. network services being provided to the network users at the lowest cost possible;
- *Allocative efficiency*, i.e. customers being charged according to how much they value the service they receive;
- *Cost-causality*, i.e. tariffs accurately reflecting the contribution from each network user to the network costs and to allocate them to the users accordingly;
- *Equity*, i.e charging, through tariffs, each consumer the same amount for using the same good or service, independently of the way the electricity is used and of the customer’s characteristics.
- *Transparency*, i.e. the adopted methodology and the results of the tariff allocation being available to all network users;
- *Simplicity*, i.e. the adopted methodology and the results of the tariff allocation being as easy as possible to understand;

- *Stability*, i.e. tariffs which are stable in the short-term and gradually change in the long-term, so to reduce regulatory uncertainty.

Some of these principles might be conflicting with each other. For instance, simplicity and cost-causality are very difficult to achieve at the same time, as well as economic efficiency and sustainability; therefore, rate design needs to prioritize some of the principles over others. Which weight to assign to each principle, however, depends on several factors. For example, the unbundling of the different activities in the last years has already shifted the tariffs' focus from the sustainability of the electrical companies to other principles like efficiency, additivity and transparency [6].

1.3 New challenges arising from DG integration within rate design

Several issues inherent with tariff design depend on the inherent, and peculiar, characteristics of electricity networks themselves. In fact, due to the shared nature of the grids, the cost of providing a service to one user depends on the services being provided to other users, as well as on how the users are utilizing the system [4]. The choice of what network to build, which connections to enable and what quality of service to provide turns out to be challenging; additionally, due to the long life of the network assets and their immovability, often the Regulator has to take, on behalf of network users, decisions that will impact them in the future. From a tariff standpoint, this translates into the following questions: how to share the burden of paying for the network? Can network users be charged according to the benefits they receive from the system or according to the costs they impose on it [4]? For instance, all network users usually benefit from reliability-related network reinforcements, but it is hard to determine how much each user should be charged for such costs [4].

The increasing integration of DG in distribution grids is posing several challenges in terms of network planning and operation; moreover, additional costs or benefits caused by the DG to the system might arise as well [2]. The aspects of the distribution business on which the DG has a potential impact in terms of additional costs can be summarized as follows:

- Initial network investments might be needed to accommodate the power injected by the DG [7]. They represent a capital cost and include circuits and substations upgrade in rural networks, and switchboards replacement in urban networks [8].
- Changes in *distribution operation and maintenance costs* can occur, in terms of losses modification, a need for more sophisticated voltage control schemes and for more complex protection devices, new voltage quality problems, maintenance of reliability of supply in case of DG failures [7].
- Changes in the *long-term network planning*.

However, the actual impact of the DG integration seems to vary depending on [9]: the DG penetration and concentration levels, network characteristics and dynamics of the distribution networks (e.g. electricity demand growth and need for network asset replacement), the type of network management and DG generation technology/profile.

In general, the structure of the network tariffs determines the way network costs are distributed among the different network users. The structure of the tariffs also defines how the potential additional costs and benefits due to a high presence of the DG in the grid are re-distributed among those users. Some experiences showing the importance of these issues already exist: in [10], for instance, it is stated that the incorrect pricing of DG power has already caused an increase in costs for the customers with no DG in several States in the USA.

The main challenges tariff design is now facing in presence of DG can be identified in:

- **DG exemption from distribution tariffs**: Despite the potential impact of the DG on network costs [2], still in most of the countries only consumers, and not DG owners, pay for the DUoS charges. This is, in some cases, the result of a policy attempt to acknowledge the potential benefits caused by the DG to the system, e.g. the reduction of network usage and losses.

- **Load-tailored schemes applied to DG**: this approach seems to be even more detrimental than the DG exemption from DUoS charges [11]. The most relevant example is represented by the *combination of volumetric tariffs with net metering*: on one hand, most of the direct network costs depend on peak demand and they are, therefore, not much dependent on the energy delivered; on the other hand, currently in the majority of the EU countries network tariffs for households and small businesses are almost completely based on the volume of the energy absorbed by the customers [12]. According to [12], about 50 to 70% of the allowed DSOs' revenues in EU countries are recovered through volumetric charges, despite the fact that electricity grids are characterized by high fixed costs and low variable costs [13]. In general, this kind of tariffs, in fact, is meant to send signals to the consumers to reduce their own consumption, but, at the same time, it entails a risk for non recovery of the costs arising from consumption at peak times [12]; this contradicts the *cost recovery* principle. When a considerable amount of DG is connected to the grids and a net metering approach adopted, the risk for non recovery of costs for the DSOs becomes even bigger, due to a potential reduction in the net energy absorbed by the customers. This risk is particularly marked when old meters are adopted; as a matter of fact, they usually provide the accumulated net consumption over a long period of time, e.g. one or two months; in this way, the energy absorbed by the load during the morning and evening peaks, as well as the one injected into the grid during mid-day hours, e.g. for rooftop solar PV (photovoltaic), is for instance neglected [3]. A risk for cross-subsidization of network users with self-production (or *prosumers*) by the ones without self-production (in other words, the so-called *free riding* by the latter) may arise as well [3], meaning that certain categories of customers are charged lower tariffs than others for similar network services [4].This represents a clear violation of both *cost-causality* and *equity* principles [12], [10]. Moreover, net metering not only shifts to other customers a portion of the DG customers' allocated share of fixed costs for the grid services, but it also increases the variable energy costs for the distributors to serve the other customers [10]. An increasingly important issue to be addressed is, therefore, how to treat the *prosumers* from a tariff point of view. Furthermore, when net metering is adopted, the application of differentiated tariffs between withdrawn and supplied energy is not feasible; this implies that the DG may receive the retail rate for the energy supplied to the grid, even though the charges include costs incurred at higher voltage levels. In this way, no compensation rate for the DG energy can be set to take into account that it is likely to off-set the use of higher voltage levels.

2 Method

The methodology proposed in this paper can be structured into three main steps, namely: the network cost calculation, the tariff determination and the assessment of the tariff performance, based on a specific criterion. Each step is described in each of the following subsections.

2.1 Network costs calculation

The initial step of the proposed method consists in a calculation of the costs to be split among the network users through the tariffs. In order to compute such costs, the so-called Reference Network Models (RNMs) are used [14]. A RNM is a large-scale distribution network planning tool that can be used either for planning distribution networks from the scratch, by considering the interconnections with existent substations as well as supply points together with DG connections (so-called *greenfield* planning model) or incrementally from an existing grid, so to obtain the required reinforcements and new facilities to connect the expected new loads and DG connections (so-called *brownfield* planning model). The simultaneous planning of low voltage (LV), medium voltage (MV) and high voltage (HV) networks makes use of simultaneity factors, and the layout of cables in urban areas takes into account the street map generated by the model itself, so that the feasibility of planning decisions is evaluated not only from an electrical, but also from a physical point of view.

On one hand, the inputs required by the *greenfield* model are: the location and demand of contracted HV/MV/LV customers, as well as the location and installed capacity of DG and of transmission substations. On the other hand, the inputs to the *brownfield* model include the capacity and location of the HV/MV substations and MV/LV transformers and the layout and electrical data of the existing lines as well.

The cost information provided as an output by the RNMs are split into the costs for network investment, for preventive and corrective maintenance, for energy losses and for investments in protection devices. Only network costs are considered to be of interest from the tariff standpoint in this application, under the assumption that energy losses represent an *energy-only* cost, therefore not included in the network component of the tariffs. Thus, the expression *total network costs* used in the following of this paper refers to the totality of costs listed except for energy losses ones.

2.2 Tariffs determination

As a preliminary step towards the tariffs setting, it is essential to know what kind of metering system is available for the case study to be analyzed, as it determines the kind of information about the users' consumption and profiles available to the actor in charge of the rate design task, i.e. the Regulator or the DSO, depending on the different countries.

Two different metering approaches are hereby considered: a *net metering* one, performed by only one meter for consumed and injected energy, which are, furthermore, assumed to be *yearly* netted at each node, and a *two meters* arrangement, where produced and consumed energies are separately metered at each load point. A pure *volumetric tariff*, with no capacity component, is assumed to be adopted in both cases.

2.2.1 Tariff calculation with only one meter and net metering applied

When only one meter is used for measuring consumed and injected energy at each node, and the total energy absorbed is netted on a yearly basis, a unique volumetric tariff for all network users is computed, according to Eq. (1):

$$Unit\ volumetric\ tariff_i = \frac{Total\ annual\ network\ cost_i}{Aggregated\ annual\ net\ energy_i} \quad (1)$$

Where *i=1:n* represents the scenarios of PV penetration analyzed; $Total\ annual\ network\ cost_i$ is the annual total network cost, including the *greenfied* and *brownfield* network costs but excluding from both the cost for losses; $Aggregated\ annual\ net\ energy_i$ represents the aggregated yearly energy of all the nodes constituting the network in the *brownfield* model. $Unit\ volumetric\ tariff_i$ is expressed in USD/kWh of consumed energy.

2.2.2 Tariff calculation with two separate meters

In the case of two different meters installed to measure consumption and production at each node of the grid, two different tariffs are calculated to be applied to consumed and injected energy, under the assumption that the DG units are charged a DUoS fee just like loads.

The two volumetric fees are calculated in such a way to reflect the network costs caused by the loads, on one hand, and by the DG systems, on the other hand, i.e. assigning a very big weight to the *cost causality* principle. Therefore, the total network costs for the corresponding scenario are first split into their *DG- driven* and *load-driven* components, according to Eq. (2) and (3):

$$Load\_driven\ network\ costs_i = Total\ annual\ network\ cost_1 \qquad (2)$$

$$DG\_driven\ network\ costs_i = Total\ annual\ network\ cost_i - Total\ annual\ network\ cost_1 \qquad (3)$$

Eq. (2) and (3) lie upon the assumption of a fixed load increase in the *brownfield* model with respect to the g*reenfield* one for each scenario *i;* this implies that $DG\_driven\ network\ costs_i$ are represented by the total annual cost for the correspondent scenario from which the annual network costs in scenario 1, completely attributable to loads, have been deducted. An additional underlying assumption is here represented by the hypothesis that the very little DG penetration in scenario 1, if any, is neglected from the network cost allocation standpoint, thus assuming the totality of such costs has a load-driven nature.

A calculation of the load- and DG-volumetric tariffs, according to Eq. (4) and (5), follows:

$$Load\ unit\ volumetric\ tariff_i = \frac{Load\_driven\ network\ cost_i}{Aggregated\ annual\ load\ energy_i} \qquad (4)$$

$$DG\ unit\ volumetric\ tariff_i = \frac{DG\_driven\ network\ cost_i}{Aggregated\ annual\ DG\ energy_i} \qquad (5)$$

Where $Aggregated\ annual\ load\ energy_i$ and $Aggregated\ annual\ DG\ energy_i$ represent the yearly energy consumed by the loads and the yearly energy injected by DG systems, aggregated by load and DG connection points, respectively.

2.3 Tariff performance assessment

In order to assess the performance of any enforced tariff design, it is first necessary to establish a criterion to evaluate the tariffs against. In this case, the *cross subsidization rate* has been chosen for this purpose; in fact, the aim of this analysis is to show how the combination of a net metering arrangement with pure volumetric tariffs can actually cause cross subsidization issue of some customers by others, especially in situations of high DG penetration. The cross subsidization rate is directly related to the cost causality principle, of which it represents a good indicator. Consequently, a comparison of the combined net metering-volumetric tariff situation with an ideal one, where tariffs are set based on a strict cost causality principle, is used to suggest a way to go for future tariff design. The several challenges connected to this ideal setting need to be discussed and taken into account, though.

In order to calculate the *cross subsidization rate,* a first distinction is made between so-called *pure load-nodes,* where no DG system is connected, and so-called *prosumer-nodes,* where PV systems are present. Therefore, the total annual payments by the pure load- and prosumer-nodes, based on the calculated tariffs, are computed according to Eq. (6), (7), (8) and (9):

Net metering case:

$$Pure\ load\ payment\_NET_i = Unit\ volumetric\ tariff_i \cdot Aggregated\ annual\ pure\ load\ energy_i \quad (6)$$

$$Prosumer\ payment\_NET_i = Unit\ volumetric\ tariff_i \cdot Aggregated\ annual\ prosumer\ energy_i \quad (7)$$

Where $Aggregated\ annual\ pure\ load\ energy_i$ and $Aggregated\ annual\ prosumer\ energy_i$ represent the yearly aggregated net energy of the pure load nodes and of the prosumer nodes, respectively.

Two meters case:

$$Pure\ load\ payment\_TWO_i = Load\ volumetric\ tariff_i \cdot Aggregated\ annual\ pure\ load\ energy_i \quad (8)$$

$$Prosumer\ payment\_TWO_i = Load\ volumetric\ tariff_i \cdot Aggregated\ annual\ prosumer\ load\ energy_i + DG\ unit\ volumetric\ tariff_i \cdot Aggregated\ annual\ DG\ energy_i \quad (9)$$

Where $Aggregated\ annual\ pure\ load\ energy_i$ represents the yearly aggregated net energy of the pure load nodes and $Aggregated\ annual\ prosumer\ load\ energy_i$ is the yearly aggregated net energy of the pure load nodes.

Since the number of prosumer nodes increases with the increase of PV penetration in the grid, and the number of pure load nodes decreases accordingly, the different annual payments need to be normalized by the share of costs attributable to pure load and prosumers nodes, calculated by using Eq. (10), (11) and (12):

$$Pure\ load\ cost\ share_i = Total\ annual\ network\ cost_i \cdot Aggregated\ annual\ pure\ load\ energy_i \quad (10)$$

$$Prosumer\ load\ cost\ share_i = Total\ annual\ network\ cost_i - Pure\ load\ cost\ share_i \quad (11)$$

$$Prosumer\ total\ cost\ share_i = Prosumer\ load\ cost\ share_i + DG\_driven\ network\ cost_i \quad (12)$$

The normalization is carried out as follows:

Net metering case:

$$Pure\ load\ payment\_NET\_norm_i = \frac{Pure\ load\ payment\_NET_i}{Pure\ load\ cost\ share_i} \quad (13)$$

$$Prosumer\ payment\_NET\_norm_i = \frac{Prosumer\ load\ payment\_NET_i}{Prosumer\ total\ cost\ share_i} \quad (14)$$

Two meters case:

$$Pure\ load\ payment\_TWO\_norm_i = \frac{Pure\ load\ payment\_TWO_i}{Pure\ load\ cost\ share_i} \quad (15)$$

$$Prosumer\ payment\_TWO\_norm_i = \frac{Prosumer\ payment\_TWO_i}{Prosumer\ total\ cost\ share_i} \quad (16)$$

The *cross subsidization rate* is, finally, computed as in Eq. (17) and (18), and expressed in p.u.

Net metering case:

$$Unitary\ cross\ subsidization\_NET_i = Pure\ load\ payment\_NET\_norm_i - Prosumer\ payment\_NET\_norm_i \quad (17)$$

Two meters case:

$$Unitary\ cross\ subsidization\ \_TWO_i = Pure\ load\ payment\_TWO\_norm_i - Prosumer\ payment\_TWO\_norm_i \quad (18)$$

3 Case study description

A fictitious network from Denver (Colorado, USA) has been used for performing the different simulations according to the described methodology. The network is characterized by the following load and PV data:

	LV	MV	HV
Load power density (kW/km^2)	900	600	100
Load energy density (MWh/km^2/year)	3153.6	3153.6	700.8
Load point average power (kW)	15	200	5000
Load average energy (kWh/year)	3153600	3153600	700800
Load average power factor (p.u.)	1	1	1
Industrial profile share	0,8	0,8	0,8
Commercial profile share	0,15	0,15	0,15
Residential profile share	0,05	0,05	0,05
Initial PV power density (kW/km^2)	0	0	0
Initial PV energy density (kWh/km^2/year)	0	0	0
PV average power (kW)	15	200	5000
PV average capacity factor (p.u.)	0,24	0,25	0,26
PV average power factor (p.u.)	1	1	1
Voltage (kV)	0,24	12	33

Table 1. Characteristics of the Network adopted for the case study.

The analyses have been performed for *i*=8 different scenarios of PV penetration. Each scenario is characterized by a different number of nodes with a PV system installed, that increases with the PV penetration itself. This translates into different values of the maximum ratios between the hourly PV production and load consumption and between the aggregated energy injected by the PV units and the aggregated energy consumed by the load over one year, respectively. Those two figures are listed in Table 2 for each scenario. Note that the load capacity is assumed to increase by 2% in the *brownfield* case if compared to the *greenfield* one in every scenario; this increase is meant to reflect a realistic load growth, but is kept constant over the different scenarios according to the main objective of computing the incremental costs due to DG in each scenario.

Scenarios	Maximum hourly PV production (as a share of hourly load)	Aggregated PV energy (as a share of aggregated load energy)
1	0.0012	$3.267 \cdot 10^{-4}$
2	0.1681	0.0453
3	0.3667	0.0993
4	0.5415	0.1475
5	0.7081	0.1927
6	0.9189	0.2492
7	1.0908	0.2962
8	1.2572	0.3409

Table 2. Scenarios of PV penetration.

4 Results discussion

The simulations have been carried out for the two cases of *net metering* and *separate metering* for consumption and production at each node of the grid. The annual total network costs and their shares attributable to the different network users' categories do not vary depending on the metering system and tariff design applied. As Fig. 1 shows, while the load-driven share of total costs keeps constant over the different scenarios, the PV-driven share increases with the PV penetration. The pure-load and prosumer-load cost shares turn out to decrease and increase with increasing PV, respectively: this is due to that an increasing number of nodes pass from being pure load- to prosumer nodes with a PV increase in the grid.

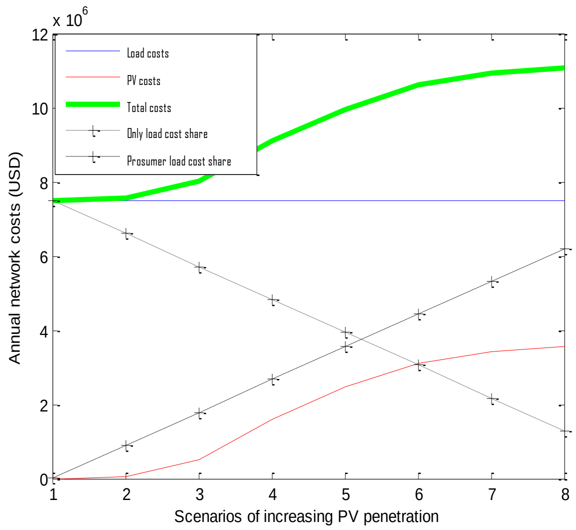

Fig. 1. Annual network costs for scenarios of increasing PV penetration.

The results for the two cases are shown and discussed in the following.

4.1.1 Results for the net metering case

As shown in Fig. 2, the volumetric tariff increases with the increase of PV penetration, as it reflects the already observed increase in total network costs. The unit value of the tariff in Scenario 8 turns out to be more than the double than the one in Scenario 1.

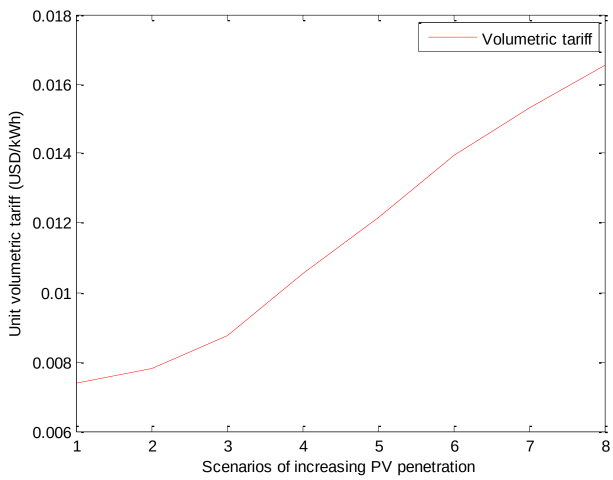

Fig. 2. Unit volumetric tariff for net metering case and for scenarios of increasing PV penetration.

However, the general figures in Fig. 2 do not say much about how this tariff increase is split between the two network users' categories hereby considered, i.e. pure load and prosumer-customers. With this respect, Fig. 3 pictures the total payments by pure load- and by prosumer-customers, normailized by their respective share of the total costs. The former turn out to increase with the scenarios, while the latter decreases; this result reflects the effect of combining net metering (especially on such a long period as one year) with pure volumetric tariff, i.e. the customers with no self generation absorbing most of the cost increase due to the PV installation, while the prosumers enjoying a sort of *free riding* situation, as they are actually charged only for the net energy they consume, which does not reflect the costs they are causing to the system.

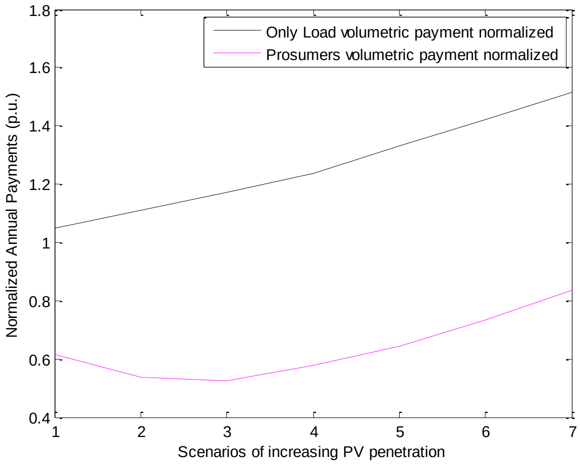

Fig. 3. Normalized annual payments by pure load- and prosumer-customers for net metering case and for scenarios of increasing PV penetration (scenario 1 excluded).

The computation of the *cross subsidization rate*, presented in Fig. 4, confirms the previous result: while the ideal rate, under a perfect cost causality-based allocation methodology, would be 0 in each scenario, the real one increases from 0.43 up to 0.67 from scenario 2 to scenario 8.

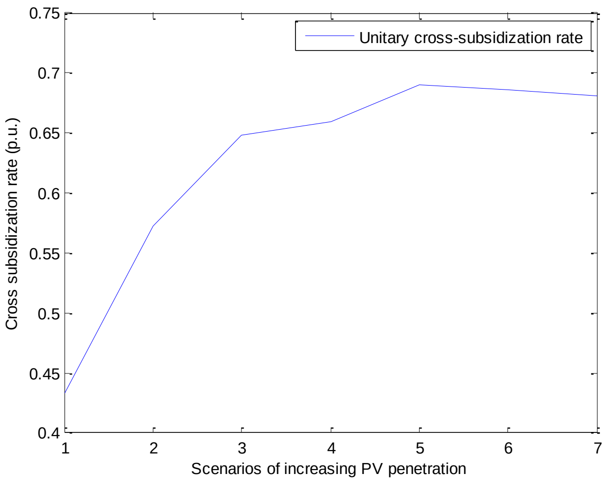

Fig. 4. Cross subsidization rate for net metering case and for scenarios of increasing PV penetration (scenario 1 excluded).

The *cross subsidization rate* increase is quite dramatic in the first two scenarios, while it grows more slowly afterwards, and it actually decreases slightly in the last two scenarios. This can be explained by the fact that network costs tend to increase more when a network needs to adapt to PV almost from the scratch, than in a network with an already considerable amount of PV installed.

4.1.2 Results for the two separate meters case

The tariff calculation in this second case leads to completely different results: two different tariffs are computed for loads and PV systems and, while the tariff for loads stays constant over the PV scenarios, reflecting the load-driven cost trend, the one for PV increases; its increase resembles somehow the shape already seen of *cross subsidization rate* for the net metering case, allegedly for the same reasons explained in that case.

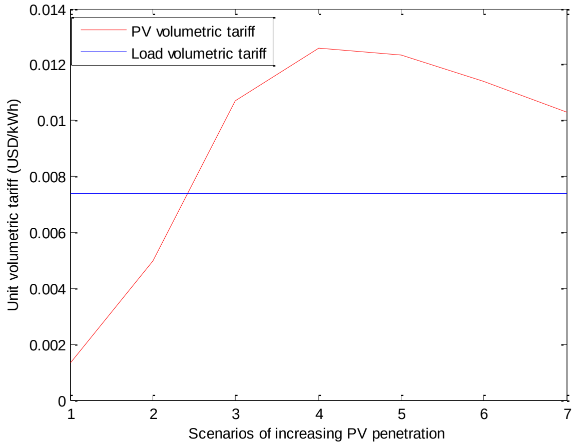

Fig. 5. Unit volumetric tariffs for loads and PV for two meters case and for scenarios of increasing PV penetration (scenario 1 excluded).

The total payments by pure load- and by prosumer-customers, normailized by their respective share of total costs, are both equal to 1, as in Fig. 6.

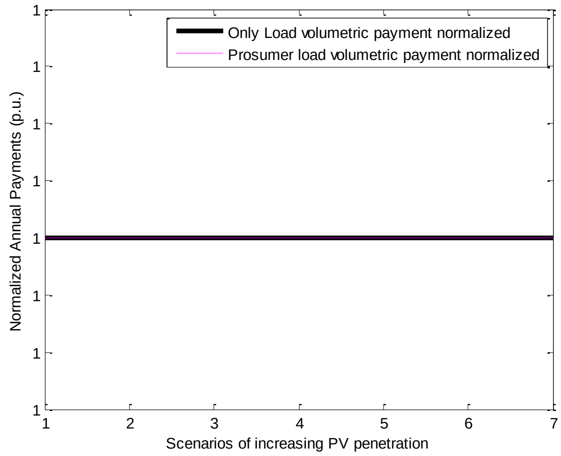

Fig. 6. Normalized annual payments by pure load- and prosumer-customers for two meters case and for scenarios of increasing PV penetration (scenario 1 excluded).

This implies the *cross subsidization rate* to be equal to 0 in all the scenarios, proving the total *cost reflectivity* of the proposed tariff arrangement.

However, the application of proposed separated tariffs for DG and loads is not exempt from difficulties and challenges. First, the tariffs, according to the proposed methodology, are computed ex-post, but this is not the case in reality in most of the countries, where they are actually calculated ex-ante. Second, the *greenfield* model, as it was used in the simulations, is characterized by almost no DG penetration; this may be not the case in several real situations, where there is some DG already installed in the grids when a new tariff methodology starts to be used, and it can be quite challenges in this case to split the costs among DG and load already at that stage. Third, the worst case scenario of load-DG simultaneity used as input to the RNM was based on the assumption that the worst case situation for which the network needs to be planned occurs during the same hour of the year for each load category; this hypothesis is not very realistic, and might have affected the cost calculation done.

5 Conclusion

The amount of distributed generation (DG) in the distribution grids has been considerably increasing in the last years, thus creating new challenges for the distribution sector to cope with, regarding e.g. the network planning and operation. Along with the technical challenges in those areas, additional or lower network costs might arise, if compared with no DG integration scenario, depending on the DG penetration and concentration levels, network characteristics and dynamics of the distribution networks, the type of network management and DG generation technology/profile. Therefore, an increasingly urgent question is: who is going to pay for those additional DG-driven costs/benefits? How can they be allocated to the different network users in a way which is as much as possible cost reflective? Network tariffs are the main tool to allocated network costs and they need, therefore, to be revised, in order to adapt to the new challenges arising.

A methodology has been proposed in this paper to evaluate how different tariff structures have different consequences on the network users in terms of cross subsidization of some customers' groups by others, the more the higher the level of PV penetration in the grids. A proposal for a cost causation-based methodology has been finally drawn, and its practical applicability discussed.

The method has been applied to a case study. The simulations show that, on one hand, when net metering is adopted and volumetric tariffs utilized, cross subsidization of customers with self generation by the customers without it is likely to arise; on the other hand, separate volumetric tariffs to be applied to producers and consumers allocated network costs on a cost-causality basis and, in this way, neutralize such risk for cross subsidization.

Future work should include an extension of the analysis performed to analyze network tariff with a capacity component, and different volumetric-capacity ratios; moreover, clusters for different load and DG categories need to be obtained as a further step of the loads-DG clustering from a tariffs standpoint, in order to make the model more applicable in reality

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