Comparative Analysis of Distribution Network Cost Allocation Alternatives

Rodrigo D. Guarizi, Roberto C. Lotero, *Member, IEEE*, João Bosco A. London, Jr.

***Abstract*— This paper presents a comparative study among methods of allocation of fixed costs in Distribution Networks (DNs). The application of these methods allows obtaining distribution use-of-system charges. Three pricing mechanisms composed of two part tariffs are evaluated. In the three mechanisms, the first part is obtained by the Long Run Incremental Cost (LRIC) method. The second one is determined by the following methods: Postage Stamp (PS), MW-Mile (MWM) or Ramsey-Boiteux (RB). The characterization and comparison of each method are performed from the point of view of regulatory principles that define guidelines on network pricing. The results allow identifying the adherence of the methods in compliance with the regulatory principles. Conflicting character between different principles is observed. The methods are tested and validated in the IEEE13-node distribution network. A study along these lines points to the proposition of new alternatives in pricing the use of DNs in the face of the growth of Distributed Energy Resources.**

***Index Terms*— allocation of fixed costs, distribution use-of-system charges, regulatory principles, network pricing**

I. Introduction

TECHNOLOGICAL evolution, cost reduction due to the increase in scale, and the opening of the electricity market enabled the significant growth of Distributed Energy Resources (DERs) [1], [2]. It has been causing an unprecedented transformation in electricity distribution network (DN) against a backdrop of falling revenue and the transfer of costs from customers who adopt DERs to those who do not, placing the need at the center of the discussions of reform in the distribution service pricing process [1], [3].

This pricing process is the mechanism for differentiating tariffs charged for the use of the DN infrastructure to different types of users in the concession area. The tariff must allow the DNs operators to recover the costs involved in providing the service, contributing to its economic and financial balance both in the short and in the long term [4]. The need to consider DERs in this process creates new challenges and concerns about how to reform existing models, ranging from small changes in the prevailing tariff structure and net metering rules, to more significant structural changes that address each type of customer individually [5].

Several studies in the literature have addressed the problem of cost allocation in DNs. Most methods derive from those proposed for pricing the use of transmission systems and can be divided into average cost methods [6], [7] and short- [8], [9] and long-run [10], [11] marginal or incremental cost methods.

The Postage Stamp (PS) [6], [7], Average Participations (AP) [12], [13], and MW-Mile (MWM) and its variants [14], [15] stand out among the average cost methods. These methods stand out for their simplicity of implementation and for providing stable tariffs over a given period. The PS method allocates costs equally among system users, regardless of location and form of use. The MWM and its variants depend on the power flow and the distance between generator injection and loading points, providing a locational signal, but they do not adequately recover the costs involved in providing the service [16], [17]. The AP method, on the other hand, is characterized by simplicity and good locational signaling, but it has the problem of tariff volatility [7].

The short-run marginal/incremental cost methods present a problem with tariff volatility and the fact that the obtained revenue does not allow for the recovery of the cost of investments made in the expansion or reinforcement of the system. On the other hand, long-run marginal/incremental methods seek to reflect the network expansion cost variation, necessary to meet a marginal [7] or incremental [11], [18] increase in the generation capacity or demand in each system node. The great advantage of these methods is the locational signaling, but the methods are complex depending on the problem size, in addition to not allowing the recovery of the total costs incurred in providing the transport service [19].

More recent studies have sought to overcome the problems of volatility, lack of locational signaling, presence of cross-subsidies, and non-recovery of company costs by combining two or more cost allocation techniques. In [20], the allocation of costs in DNs is compared using two methods composed of two parts. The first part is the result of an optimal power flow solution, that is, the Short-Run Marginal Cost (SRMC) is obtained, and the second part is determined by PS or AP.

Following the same line, [21] determines the first part as in [20] and the second part using the PS method, considering the contribution of network users in the period of greatest loading of the system feeders. In [19], an improvement of the previous study is proposed using a third part obtained through the Ram-

Submission date: 02/01/2023. Acknowledgement to the Federal University of Latin American Integration for enabling the doctorate studies and the National Council for Scientific and Technological Development – CNPq (granting number 308297/2018-0).

R. D. Guarizi, São Carlos School of Engineering, University of São Paulo (USP), São Carlos, SP, Brazil. Federal University of Latin American Integration (UNILA), Foz do Iguaçu, PR, Brazil, rodrigodg@usp.br, rodrigo.guarizi@unila.edu.br.

R. C. Lotero. Western Paraná State University (UNIOESTE), Foz do Iguaçu, PR, Brazil, roberto.lotero@unioeste.br.

J. B. A. London Jr. São Carlos School of Engineering, University of São Paulo (USP), São Carlos, SP, jbalj@sc.usp.br.

sey-Boiteux (RB) method to allocate the residual cost not covered by the first two parts. The methods used in previous studies can provide locational signaling to system users during peak periods and allow recovery of the company's total costs. In [16], [17], the AP, SRMC, and MWM methods, adapted to DNs, are used together to allocate fixed costs (operational, maintenance, and investment); network usage costs; and loss costs.

The common characteristic among the most recent studies is to allocate costs using a combination of more than one method, aiming to overcome the disadvantages of one method with the advantages of the other [16], [17], [19]–[21]. However, the literature still lacks comparative studies between the cost allocation methods in DNs. A study on this topic allows decision-makers, both distribution utilities and regulatory agencies, to identify new alternatives for pricing the use of DNs, considering the significant changes that have been taking place in these networks.

Therefore, this study aimed to carry out a comparative analysis between three alternatives for cost allocation in DNs based on the combination of methods already existing in the literature. Thus, the main contribution of this study lies in the characterization of each proposed pricing alternative in the light of regulatory principles, an aspect little explored in the literature. Cost allocation is performed by combining two parts, obtained by different methods aiming to meet the regulatory principles more effectively, which is also a contribution of this study. Another contribution consists of the adaptation of the RB method to be used associated with the Long-Run Incremental Cost (LRIC) method in DNs. Finally, the comparative analysis between the Nodal Prices (NPs) obtained by the different methods, identifying the advantages and disadvantages of each one, is also a contribution of this study.

This paper is organized as follows: Section 2 presents an overview of the principles that guide the proposition of methods for cost allocation in DNs, as well as the methods used in the study; Section 3 contains the tests performed and discussion of the results; finally, Section 4 presents the final considerations.

II. Cost allocation in distribution systems

Distribution use-of-system charges should allow for the recovery of costs efficiently incurred by companies providing the service, while encouraging the efficient use of the system, postponing the need for network expansion [11]. It can be achieved through the proper design of the tariff structure and the establishment of tariff values close to the actual value of service [4].

An important characteristic in the pricing process is the economic signal provided to network users, to which they can react. This economic signal must include the efficient allocation of costs that each user imposes on the system. In other words, it must be efficient and aligned with the level of use of the network, that is, the tariff must provide an incentive to use available resources if the network is underutilized, and an opposite incentive must be created if the level of use is high and there is an expected growth in demand [19].

The mentioned characteristics, among others, are part of the regulatory principles that guide the development of cost allocation methods in DNs, being grouped into three categories (Fig. 1) [19], [22]–[24].

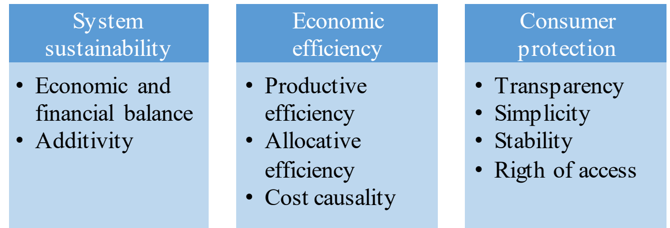


Fig. 1. Regulatory Principles

The economic and financial balance and additivity are related to the revenue required by the distribution utility to recover the costs incurred in providing the service, which is limited to the revenue allowed by the regulatory agency when establishing regulated tariffs. Efficient cost recovery includes return on investments.

The economic efficiency principles aim to provide economic signals to distribution utilities and consumers to maximize social welfare in the short and long term. Productive efficiency establishes that the service must be provided at the lowest possible cost, encouraging investment and coordination. Allocative efficiency aims to encourage users to use the network efficiently, reducing peak demand to postpone investments. Causality or reflectivity of costs aims to charge system users according to the contribution of each one in loading the network or by the costs imposed on the system so that electricity reaches them.

Finally, consumer protection requires transparent tariff rules, simple to understand and stable in the short term, treating similar consumers equally (or non-discriminatorily) and guaranteeing universal access to the system and continuous use of electricity.

In practice, comprehensive compliance with all principles is not possible, as there are some that conflict with each other, and it is necessary to find a compromise solution that meets at least three of them [23]: recovery of total costs, equity, and transparency.

In this context, this study analyzed three cost allocation alternatives in DNs. Costs are allocated via NPs formed using two parts (Fig. 2). Part I (PI) is obtained using the LRIC method, which considers the idle capacity of the network and signals the impact on the anticipation or postponement of necessary investments in the system [11]. Part II (PII) is determined using one of the following three methods: Postage Stamp [7], or MW-Mile [25], or Ramsey-Boiteux [26].

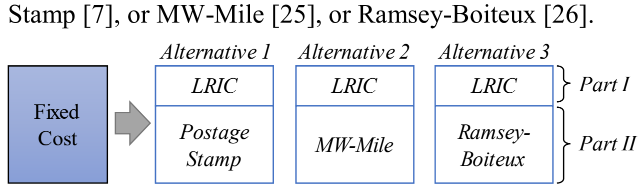


Fig. 2. Cost allocation alternatives

The mathematical formulation of methods used in this study is described below.

A. Long-Run Incremental Cost

The LRIC method determines an incremental nodal cost resulting from the addition of a demand unit on the network nodes [11]. The LRIC general equation for a network operating radially is given by:

$$LRIC_i = \frac{\sum_{j \in z_i} \Delta CI_j}{\Delta P_i} \quad i = 1, 2, \ldots, k \tag{1}$$

Where k is the total number of nodes in the feeder, $LRIC_i$ is the Long-Run Incremental Cost obtained for node i, j is a circuit or branch located between two nodes, z_i is the set of circuits or branches upstream from node i to the supply point (substation), ΔP_i represents the increment in demand at node i, and ΔCI_j is the increment in the cost of branch j caused by ΔP_i.

The LRIC method is based on the network idle capacity, determining the incremental cost in each node resulting from the addition of a demand unit in that node of the network. Therefore, initially, the time in years for each branch of the network to be operating at its maximum capacity f_j^{max} needs to be estimated through

$$f_j^{max} = f_j (1 + r)^{n_j} \quad \forall j \tag{2}$$

Where f_j is the current loading of branch j, r is the system demand growth rate, and n_j is the time horizon for branch j to reach f_j^{max}. Isolating n_j gives:

$$n_j = \frac{log\left(f_j^{max}\right) - log(f_j)}{log(1+r)} \quad \forall j \tag{3}$$

The method assumes that the capacity of asset j is doubled when the loading reaches f_j^{max} in n_j years. The total cost incurred by duplicating the asset must be discounted to its present value, using a discount rate d for the invested capital, as follows:

$$PV_j = \frac{CT_j}{(1+d)^{n_j}} \quad \forall j \tag{4}$$

In this study, CT_j represents the total fixed cost of each asset j in the system, which includes the investment cost and the non-variable costs of operation and maintenance of the asset [26]. In other words, CT_j represents the cost to provide the infrastructure necessary for the transport of electricity and its recovery is essential for the economic and financial balance of companies.

The next step consists of increasing the demand of node i in ΔPi, causing a variation Δf_j in the loading of each branch j of the set z_i of the networ. This process is executed for all nodes i in the DN. Next, the new time horizon is determined for the branches upstream of i to reach the maximum capacity by:

$$n_j^{novo} = \frac{log(f_j^{max}) - log(f_j + \Delta f_j)}{log(1+r)} \quad \forall j \in z_i \tag{5}$$

Then, the new present value of the investment is calculated through:

$$VP_j^{novo} = \frac{CT_j}{(1+d)^{n_j^{novo}}} \quad \forall j \in z_i \tag{6}$$

Therefore, the variation in the present value of the total cost in branch j can be obtained due to the increment ΔP_i, as follows:

$$\Delta VP_j = VP_j^{novo} - VP_j \quad \forall j \in z_i \tag{7}$$

The present value of the incremental cost of anticipating investment in branch j resulting from the incremental increase in demand in node i results from it. The time horizon n_j^{new} is lower than n_j with the reduction of idle capacity in branches, caused by ΔP_i. Thus, the present value PV_j^{new} will result in a value higher than PV_j. Then, ΔPV_j is annualized, according to

$$\Delta CI_j = \Delta VP_j \times \frac{(1+d)^{m_j}.d}{(1+d)^{m_j}-1} \quad \forall j \in z_i \tag{8}$$

The term that multiplies ΔPV_j is the corresponding Annuity Factor (AF_j), which considers the lifespan of the respective asset (m_j) and the discount rate d on invested capital, considered adequate for investments in DSs [11]. Lastly, LRIC, in \$/kW/year for the node i, is obtained through (1) [11].

The nodal revenue is obtained through the product between $LRIC_i$ and the demand i. Therefore, the total revenue (R_{LRIC}) results from the sum of the nodal revenues, according to:

$$LRIC_i = D_i \times LRIC_i \quad i = 1, 2, \ldots, n \tag{9}$$

$$R_{LRIC} = \sum_{i=1}^{k} LRIC_i \tag{10}$$

The revenue obtained by this incremental method is not sufficient to cover the total costs incurred by companies operating in a business characterized by economies of scale. Therefore, a reconciliation process between the revenue that guarantees the company's economic and financial balance and the revenue obtained by the previous method needs to be performed. Thus, the remaining revenue (R_{REM}) is obtained as follows:

$$R_{REM} = R_{EXP} - R_{LRIC} \tag{11}$$

The expected annual revenue (R_{EXP}) by the distribution utility is obtained as follows:

$$R_{EXP} = \sum_{j=1}^{u} EAC_j \tag{12}$$

Where EAC_j represents the Equivalent Annual Cost of each asset j in the system and is obtained through:

$$EAC_j = \frac{(1+d)^m.d}{(1+d)^m - 1} \times CT_j \quad \forall j \tag{13}$$

The methods used to allocate costs not recovered with the *LRIC* method and which are part of the remaining revenue are shown below.

B. Postage Stamp

The PS method establishes a single tariff for all users of the system, regardless of their location and use-of-system degree. Therefore, the single tariff for all system users is given by:

$$PS = \frac{R_{REM}}{D_{total}} \tag{14}$$

Where D_{total} represents the aggregate demand of the system. The nodal revenue RPS_i and remaining revenue R_{REM} are obtained for k nodes, respectively, through:

$$RPS_i = D_i \times PS \;\; i = 1, 2, \ldots, k \tag{15}$$

$$R_{REM} = \sum_{i=1}^{k} RPS_i \tag{16}$$

C. MW-Mile

This method is widely used for fixed cost allocation in transmission networks based on the extent-of-use philosophy, being necessary to know the cost and the demand of each branch of the network [25], [27]. In the present study, the remaining revenue is allocated according to the used capacity of the elements of the DN, as follows:

$$MWM_i = \sum_{j \in z_i} \frac{EAC_{REMj}}{f_j} \quad \forall j \in z_i \tag{17}$$

Where MWM_i is the tariff at node I and EAC_{REMj} is the remaining Equivalent Annual Cost of branch j. The latter is obtained as follows:

$$EAC_{REMj} = EAC_j \times \left(1 - \frac{R_{LRIC}}{R_{EXP}}\right) \quad \forall j \tag{18}$$

Finally, the nodal revenue and the total revenue are obtained as follows:

$$RMWM_i = D_i \times MWM_i \quad i = 1, 2, \ldots, k \tag{19}$$

$$R_{REM} = \sum_{i=1}^{k} RMWM_i \tag{20}$$

D. Ramsey-Boiteux Price

The RB method is formulated by a social welfare maximization problem subject to the distribution utility's economic and financial balance constraint [28]. The result of the social welfare maximization problem is presented by (21), adding the consumer's surplus to that of the producer, subject to the producer's profit constraint [26], [29].

$$\frac{\rho_i - CM_i}{\rho_i} = -\frac{\lambda}{1+\lambda}\frac{1}{\varepsilon_i} \quad \forall i \tag{21}$$

Where sub-index i refers to a group or class of consumers, ρ_i is the RB tariff for group i (\$/kWh), MC_i is the marginal cost for group i (\$/kWh), λ is the Lagrange multiplier from the maximization problem, and ε_i is the price elasticity of demand associated with group i. By isolating ρ_i, we obtain:

$$\rho_i = \frac{MC_i}{1+\frac{R}{\varepsilon_i}} \quad \forall i \tag{22}$$

Where the term $\lambda/(1+\lambda)$, called R, is the Ramsey number.

The RB method was used with some adaptations in the present study. The aim is to allocate the difference between the total cost and *LRIC* between users located at different nodes of the network, resulting in:

$$\rho_i = \frac{LRIC_i}{1+\frac{R}{\varepsilon_i}} \quad \forall i \tag{23}$$

Where sub-index i represents node i of the network, ρ_i is the RB price at node i, and ε_i is the price elasticity of demand at node i.

The following equality must be met to cover the distribution company's total costs:

$$\sum_{i=1}^{k} \rho_i \times D_i = R_{EXP} \tag{24}$$

Replacing (1) in (2), we have:

$$\sum_{i=1}^{k} \left[\left(\frac{LRIC_i}{1+\frac{R}{E_i}}\right) \times D_i\right] - R_{EXP} = 0 \tag{25}$$

Equation (25) can be solved for the Ramsey number R using some numerical method [26], [30]. In the present study, the *vpasolve* function of the *Matlab* software was used. If the system has k nodes, whose elasticities differ from each other, k R's will be obtained as a solution. However, the Ramsey number must be the same between different consumer groups [28]. Thus, according to [26], [30], the criterion adopted for choosing R is the one that minimizes the deviation between ρ_i and $LRIC_i$:

$$\Delta_{min} = min\left\{\sqrt{\sum_{i=1}^{k}(\rho_i - LRIC_i)^2}\right\} \tag{26}$$

III. Tests and Results

A single-phase equivalent of the IEEE13-node test feeder [31] was used to perform the tests (Fig. 3). Node 0 (zero) represents the substation (SB) of the feeder that supplies a total demand of 1,866.67 kW, i.e., the maximum feeder loading. The loadings distributed in branch 1–5 were concentrated in fictitious node 2. The base voltage used is 4.16 kV and the lifespan adopted for all network elements is 40 years, during which a total fixed cost of \$1,200,000 must be recovered, resulting in an investor's expected annual income of \$90,010.97, earned through (12).

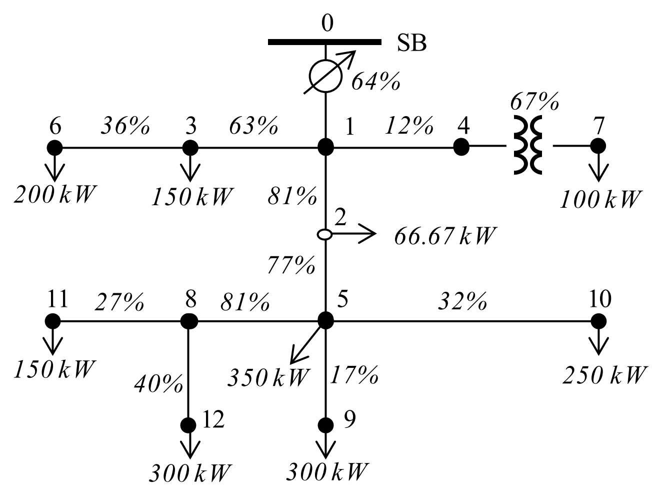


Fig. 3. IEEE 13 Test Feeder Topology with the demand of each node and the percentage loading of each branch relative to the corresponding maximum capacity

The power flow analisys is used to determine the used capacity of branches, according to the model presented in [32].

Table Ishows complementary data from the test feeder. The first and second columns define the system branches, the third column shows the total costs of each branch, the fourth the maximum capacity of each branch, and the fifth column shows the peak demands in each "to" node.

TABLE I
IEEE13-NODE SYSTEM DATA

from	to	Cost (\$)	P_{max} (kW)	*D* (kW)
0	1	521,602.47	2,900.00	0.00
1	2	157,676.59	1,753.30	66.67
1	3	24,839.46	552.41	150.00
1	4	36,719.21	816.60	0.00
2	5	157,676.59	1,753.30	350.00
3	6	14,903.68	552.41	200.00

4	7	10,000.00	150.00	100.00
5	8	14,903.68	552.41	0.00
5	9	157,676.59	1,753.30	300.00
5	10	35,531.23	790.18	250.00
8	11	14,903.68	552.41	150.00
8	12	53,566.84	744.55	300.00
Total		**1,200,000.00**	**12,870.87**	**1,866.67**

Fig. 4 shows the results using the LRIC method. Nodes without demand are not considered, as they do not generate revenue. LRIC increases as the distance from the node to the SB or loading of the upstream branches of the network increases. Nodes 3, 6, and 7, which are close to SB, have the lowest LRICs. The opposite occurs with nodes 9 and 10. Nodes 11 and 12 are more distant and share circuit 5–8 with 81% of the used capacity, implying higher LRIC values.

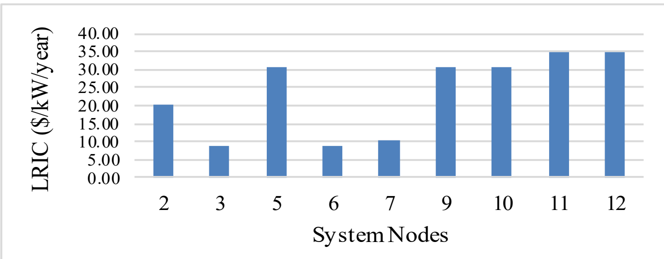


Fig. 4. Long-Run Incremental Cost

$LRIC_2$ is larger than $LRIC_6$ even with node 2 being closer to SB because consumers connected to this node use branch 1–2, which is close to its capacity limit. Thus, the installation of an additional power unit at this point increases the need to reinforce the system. Additionally, the revenue obtained with this method is $48,739.48, representing approximately 54% of the total costs, requiring an adjustment part.

Fig. 5 shows the result of applying the methods to obtain Part II. The PS method results in the same tariff for all nodes, neither providing a locational signal nor reflecting costs related to the level of use of the system. In this case, the revenue of $41,271.49 is obtained, which results in the annual revenue expected by the distribution utility R_{EXP} of $90,010.97 when added to R_{LRIC}.

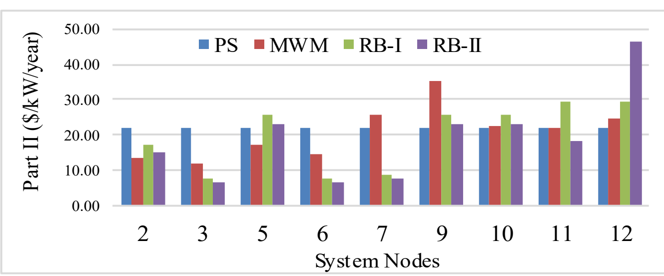


Fig. 5. Comparison of Part II

According to (17), the tariff obtained by the MWM method will depend on the ratio between the remaining EAC_j and the load flow f_j of each element in the network. Table II shows the MWM tariff composition obtained for the nodes 7, 9, 11 and 12. The highest tariffs are MWM_7 and MWM_9 (Fig. 5 and Table II). It is due to the low use of circuits 1–4 (12%) and 5–9 (17%), highlighting the economy of scale that characterizes energy distribution.

TABLE II
TARIFF COMPOSITION OF THE MWM METHOD

	MWM – Branches used ($/kW/year)									
Node	**0-1**	**1-2**	**1-4**	**2-5**	**4-7**	**5-8**	**5-9**	**8-11**	**8-12**	**Total**
7	9.61	-	12.63	-	3.44	-	-	-	-	**25.68**
9	9.61	3.83	-	4.02	-	-	18.08	-	-	**35.53**
11	9.61	3.83	-	4.02	-	1.14	-	3.42	-	**22.01**
12	9.61	3.83	-	4.02	-	1.14	-	-	6.14	**24.74**

According to (18), the EAC_{REM} of the 0–1 branch reaches $17,939.42, consisting of the largest cost to be recovered. This branch is shared among all system users and has 64% of the loading, and the allocation of this cost will influence the MWM tariff of all nodes, especially those farthest from the SB, such as 11 and 12. The revenue resulting from the MWM method is equal to that obtained in the PS method.

Typical elasticity values found in [28], [33] were considered to obtain RB prices. RB prices were obtained for two cases to show the elasticity effect. Fig. 5 shows both cases, that is, *RB-I* and *RB-II*, which result from the difference between ρ_i and $LRIC_i$. The first case considers the elasticity equal to −0.4 for all nodes. The second case preserves the elasticity of the previous case, except for nodes 11 and 12, with values of −0.5 and −0.3, respectively, being chosen because they are further away from SB, sharing several network assets.

The obtained RB_i-*I* prices are equivalent to 85% of LRIC at each node, resulting in the same LRIC nodal price profile. The R number obtained for this case was 0.1834. On the other hand, RB_i-*II* prices are equivalent to 75% of LRIC at nodes 2 to 10, 52% of $LRIC_{11}$ and 133% of $LRIC_{12}$. The R number obtained for this case was 0.1710. In this case, the price variation at node 12 was expected to be higher compared to the other nodes, as it has the lowest elasticity, and a lower price variation at node 11 because it has the highest elasticity. Fig. 5 compares *RB-I* and *RB-II* and shows a 12% decrease in tariffs from nodes 2 to 10, 39% at node 11, and an increase of 56% at node 12. These variations confirm the RB rule, in which costs are allocated inversely proportional to elasticity, maintaining the equilibrium relationship defined by (24).

Fig. 6 shows the NPs resulting from the sum of Parts I and II. The highest tariff was $81.35/kW/year for node 12, whereas the lowest tariff reached $15.40/kW/year for node 6, both from the *LRIC+RB-II* method. In this case, it results in the highest nodal price of the system, as the RB method allocates costs inversely proportional to elasticity, with node 12 having the lowest elasticity and the highest LRIC.

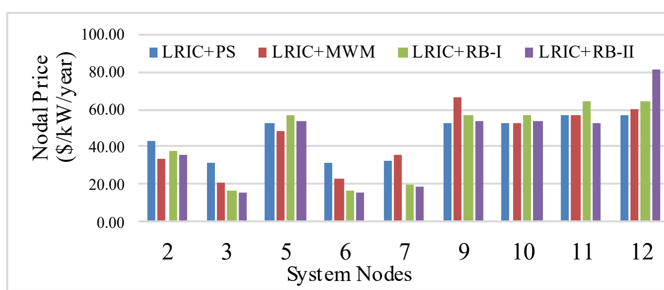


Fig. 6. Nodal Price

The lowest tariffs are found at nodes 3, 6, and 7, obtained by the RB method and influenced by the low network usage.

On the other hand, the loading of upstream branches will increase if demand increases at these nodes, implying higher LRIC values and higher nodal prices. Also, the highest tariffs result from the PS method at the nodes closest to the SB, which distorts the locational incentive relative to other methods.

Nodes 2 and 5 present higher tariffs compared to nodes 3, 6, and 7 despite being close to the SB. It is due to the high loading of circuits 1–2 and 2–5 with 81% and 77%, respectively. The highest tariffs were obtained for nodes 9, 10, 11, and 12. The highest tariff at node 9 is obtained by the LRIC+MWM alternative, influenced by the low utilization of the 5–9 branch, with 17% of loading. In this case, the tariff signals to the distribution utility a certain underutilization of the network, as occur with the higher tariff for node 7 due to the low use of circuit 1–4 (12%).

Table III shows the nodal and total revenue from the application of pricing alternatives. The used methods can reconcile the distribution utiliy´s revenue considering the scenario used to determine NPs.

TABLE III
NODAL REVENUE

Node	LRIC+PS ($/year)	LRIC +MWM ($/year)	LRIC +RB-I ($/year)	LRIC +RB-II ($/year)
2	2,839.88	2,261.76	2,522.37	2,385.39
3	4,633.02	3,124.25	2,431.40	2,299.37
5	18,441.47	16,812.45	19,766.20	18,692.81
6	6,185.06	4,685.96	3,256.10	3,079.28
7	3,258.08	3,614.96	1,933.79	1,828.78
9	15,807.47	19,834.12	16,943.37	16,023.28
10	13,179.80	13,238.24	14,132.24	13,364.80
11	8,537.11	8,522.40	9,641.38	7,933.38
12	17,129.09	17,916.83	19,384.11	24,403.88
TOTAL	**90,010.97**	**90,010.97**	**90,010.97**	**90,010.97**

A. Analysis of methods in the light of regulatory principles

As seen in the previous section, the sustainability principle is met in the three pricing alternatives when combining two cost allocation techniques. This can be seen in Table III.

The LRIC method adheres to the allocative efficiency principle because it provides locational signaling and considers the network usage level by users connected to a given node. Fig. 3 and 5 show that the higher the distance from the supply point (SB) to a node, the higher the number of elements used by the agent and the higher the cost allocated to it. Moreover, an increase in the degree of use leads to a decrease in the available capacity, increasing the cost allocated to agents, signaling the need to expand the system. Thus, the LRIC method also seeks to meet the principle of cost causality.

On the other hand, the PS method has the advantage of meeting the simplicity principle due to its ease of understanding and implementation. For this reason, it is widely adopted by regulators in several countries around the world as a complement to ensure adequate remuneration for the electricity grid. However, it defines an equal tariff for all system users, thus characterizing a cross-subsidy and not meeting the allocative efficiency principle. Under these conditions, users who settle in more distant regions are subsidized by those located closer to the supply point, particularly benefiting consumers who have high peak demand installed at the end of the feeders. This situation is shown in Fig. 5, which compares PS_2 and PS_{12}.

The MWM method also provides locational signaling, as the higher the number of elements used by the agent, the higher the cost allocated to it, seeking to meet the cost causality principle. However, the increase in the use of the network leads to a lower nodal tariff for the agent that uses a certain set of z_i elements, encouraging the use of the idle capacity of the resources available in the system. As shown in Table III, this part seeks to overcome the distortion caused by Part I, that is, meet the system sustainability principles.

The RB method preserves the concessionaire's economic and financial sustainability by considering an adjustment factor relative to the marginal cost, enabling the recovery of fixed costs. On the other hand, it violates the equity principle, as it penalizes consumers with less elasticity. It can be observed in $RB\text{-}II_{12}$ (Fig. 5) and NP_{12} (Fig. 6). The present study considered known elasticity values. However, according to [34], the RB method presents some implementation complexity due to the lack of information about the elasticities applicable to different consumer groups. The highest difficulty is related to the fact that elasticity has a short and long-term temporal character and depends on factors such as temperature and per capita income, among others [28]. These characteristics imply non-compliance with consumer protection principles.

Analyzing the tariff stability regarding the PNs shown in Fig. 6 is important [35]. Understanding this analysis implies assuming that the methods have two determining characteristics in the use of the network for each node: i) they are dependent on the network and, ii) on the magnitude of the nodal demand [7]. An individual analysis of the methods would lead to the conclusion that the PS method does not depend on the network [7], but the objective is to analyze the tariff resulting from the sum of Parts I and II.

Thus, the dependence of the network on each pricing alternative can be observed in the different values obtained for each node in the system. The tariffs for all agents are desirable to be included in the lowest possible range of values. In short, the lower the range of tariff values, the less dependence on the network and the higher the stability. It means that the tariff volatility will be lower in a given period.

Table IV shows the maximum and minimum values of tariffs and the standard deviation, mean, and volatility of each method, obtained by the ratio between the standard deviation and the mean of tariffs. LRIC+PS has the lowest volatility among the tested methods, followed by LRIC+MWM. The LRIC+RB method has less stability among the analyzed methods, especially if the influence of elasticity is considered, as is the case of LRIC+RB-II. The conflict between the principles of simplicity and tariff stability between the PS and RB methods is evident even in a small test system.

TABLE IV
ANALYSIS OF NODE PRICE STABILITY

	LRIC +PS ($/kW/ year)	LRIC +MWM ($/kW/ year)	LRIC+RB-I ($/kW/ year)	LRIC+RB-II ($/kW/ year)
Maximum	57.10	66.11	64.61	81.35
Minimum	30.89	20.83	16.21	15.33
Standard deviation	11.30	16.28	20.87	22.58
Mean	45.46	44.22	43.11	42.15
Volatility (%)	24.86	36.81	48.40	53.57

The additivity principle means that final tariffs must reflect the sum of all cost items applicable to each consumer group. As a result, the revenue collected from consumers must be at least equal to the revenue required by the distribution utility, meeting the principle of economic and financial balance of the company. According to the results shown in Table III, the methods used can reconcile the distribution utility´s revenue.

IV. CONCLUSION

This paper presented a comparative study of three pricing alternatives for the electricity distribution service. Each of the alternatives combines two cost allocation methods, and all the alternatives allowed obtaining NPs that ensure the recovery of the distribution utility´s fixed costs. In the three alternatives, Part I was obtained through LRIC, which provides locational economic signaling, as well as signaling of the utilization level of network assets, but it does not cover the distribution utility´s fixed costs. On the other hand, Part II is obtained by one of the following methods: PS, or MWM, or RB.

NPs resulting from the three cost allocation alternatives can preserve the locational signal while signaling the network usage level. Therefore, the combination of the two methods allowed compliance with more than one regulatory principle. The obtained results showed that the deficiencies of Part I can be compensated by the benefits of Part II. In this context, consumer protection principles can be better served by the LRIC+PS alternative, while the LRIC+RB alternative shows less stability in tariffs, followed by the LRIC+MWM method.

The development of this study allowed us to observe the conflicting nature of meeting more than one regulatory principle. For instance, discriminating tariffs according to the cost causality can be efficient, but it can limit universal access to the system.

However, the results considered a specific scenario of network loading in a one-year period, with variables considered deterministic and based on expected values. Further studies must be carried out to include the uncertainties arising from the growth of DERs in DNs. In this sense, the deterministic parameters that allow determining NPs, such as demand and generation level at the system nodes, elasticity, demand growth rate, or discount rate on invested capital can be adressed as uncertainties. Another aspect that should be explored is the multi-objective modeling of the problem, given the conflicting nature of regulatory principles.

REFERENCES

[1] C. Cambini and G. Soroush, “Designing grid tariffs in the presence of distributed generation,” *Util. Policy*, vol. 61, no. November, p. 100979, Dec. 2019.

[2] C. Schick, N. Klempp, and K. Hufendiek, “Impact of network charge design in an energy system with large penetration of renewables and high prosumer shares,” *Energies*, vol. 14, no. 21, 2021.

[3] R. Athawale and F. A. Felder, “Electric utility death spiral: Revisited in the context of tariff design,” *Electr. J.*, vol. 35, no. 1, p. 107062, 2022.

[4] F. Li *et al.*, “Distribution Pricing: Are We Ready for the Smart Grid?,” *IEEE Power Energy Mag.*, vol. 13, no. 4, pp. 76–86, Jul. 2015.

[5] V. A. Martins, D. A. C. Branco, and M. C. M. Hallack, “Economic Effects of Micro-and Mini-Distributed Photovoltaic Generation for the Brazilian Distribution System,” *Energies*, vol. 15, no. 3, pp. 1–25, 2022.

[6] D. Shirmohammadi, X. V. Filho, B. Gorenstin, and M. V. P. Pereira, “Some fundamental, technical concepts about cost based transmission pricing,” *IEEE Trans. Power Syst.*, vol. 11, no. 2, pp. 1002–1008, May 1996.

[7] D. A. Lima, A. Padilha-Feltrin, and J. Contreras, “An overview on network cost allocation methods,” *Electr. Power Syst. Res.*, vol. 79, no. 5, pp. 750–758, May 2009.

[8] Yikui Liu, Jie Li, Lei Wu, and Qingzhen Liu, “Ex-post real-time distribution LMP based on state estimation,” in *2016 IEEE Power and Energy Society General Meeting (PESGM)*, Jul. 2016, vol. 2016-Novem, pp. 1–5.

[9] L. Bai, J. Wang, C. Wang, C. Chen, and F. F. Li, “Distribution Locational Marginal Pricing (DLMP) for Congestion Management and Voltage Support,” *IEEE Trans. Power Syst.*, vol. 8950, no. c, pp. 1–1, 2017.

[10] C. Gu and F. Li, “Long-Run Marginal Cost Pricing Based on Analytical Method for Revenue Reconciliation,” *IEEE Trans. Power Syst.*, vol. 26, no. 1, pp. 103–110, Feb. 2011.

[11] F. Li and D. L. Tolley, “Long-Run Incremental Cost Pricing Based on Unused Capacity,” *IEEE Trans. Power Syst.*, vol. 22, no. 4, pp. 1683–1689, Nov. 2007.

[12] J. Bialek, “Topological generation and load distribution factors for supplement charge allocation in transmission open access,” *IEEE Trans. Power Syst.*, vol. 12, no. 3, pp. 1185–1193, 1997.

[13] D. Kirschen, R. Allan, and G. Strbac, “Contributions of individual generators to loads and flows,” *IEEE Trans. Power Syst.*, vol. 12, no. 1, pp. 52–60, 1997.

[14] J. W. M. Lima, “Allocation of transmission fixed charges: an overview,” *IEEE Trans. Power Syst.*, vol. 11, no. 3, pp. 1409–1418, 1996.

[15] G. A. Orfanos, G. T. Tziasiou, P. S. Georgilakis, and N. D. Hatziargyriou, “Evaluation of transmission pricing methodologies for pool based electricity markets,” in *2011 IEEE Trondheim PowerTech*, Jun. 2011, vol. 218903, pp. 1–8.

[16] T. Soares, M. Cruz, and M. Matos, “Cost Allocation of Distribution Networks in the Distributed Energy Resources Era,” in *2019 International Conference on Smart Energy Systems and Technologies (SEST)*, Sep. 2019, pp. 1–6.

[17] T. Soares, F. Pereira, H. Morais, and Z. Vale, “Cost allocation model for distribution networks considering high penetration of distributed energy resources,” *Electr. Power Syst. Res.*, vol. 124, pp. 120–132, Jul. 2015.

[18] C. Gu and F. Li, “New development in distribution network pricing for revenue recovery in the Great Britain,” in *2011 IEEE Power and Energy Society General Meeting*, Jul. 2011, pp. 1–5.

[19] I. Abdelmotteleb, T. Gómez, J. P. Chaves Ávila, and J. Reneses, "Designing efficient distribution network charges in the context of active customers," *Appl. Energy*, vol. 210, no. May 2017, pp. 815–826, Jan. 2018.

[20] I. Abdelmotteleb, T. G. S. Roman, and J. Reneses, "Distribution network cost allocation using a locational and temporal cost reflective methodology," in *2016 Power Systems Computation Conference (PSCC)*, Jun. 2016, pp. 1–7.

[21] I. Abdelmotteleb, T. Gómez, and J. Reneses, "Evaluation Methodology for Tariff Design under Escalating Penetrations of Distributed Energy Resources," *Energies*, vol. 10, no. 6, p. 778, Jun. 2017.

[22] M. Nijhuis, M. Gibescu, and J. F. G. Cobben, "Analysis of reflectivity & predictability of electricity network tariff structures for household consumers," *Energy Policy*, vol. 109, no. January, pp. 631–641, Oct. 2017.

[23] A. Picciariello, J. Reneses, P. Frias, and L. Söder, "Distributed generation and distribution pricing: Why do we need new tariff design methodologies?," *Electr. Power Syst. Res.*, vol. 119, pp. 370–376, Feb. 2015.

[24] M. P. Rodríguez Ortega, J. I. Pérez-Arriaga, J. R. Abbad, and J. P. González, "Distribution network tariffs: A closed question?," *Energy Policy*, vol. 36, no. 5, pp. 1712–1725.

[25] C. T. Mancera and A. C. Monroy, "Pricing of distribution networks with distributed generation: Application of nodal pricing," in *2011 IEEE PES CONFERENCE ON INNOVATIVE SMART GRID TECHNOLOGIES LATIN AMERICA (ISGT LA)*, Oct. 2011, pp. 1–7.

[26] M. Ghayeni and R. Ghazi, "Transmission network cost allocation with nodal pricing approach based on Ramsey pricing concept," *IET Gener. Transm. Distrib.*, vol. 5, no. 3, p. 384, 2011.

[27] P. M. Sotkiewicz and J. M. Vignolo, "Allocation of Fixed Costs in Distribution Networks With Distributed Generation," *IEEE Trans. Power Syst.*, vol. 21, no. 2, pp. 639–652, May 2006.

[28] B. Lin and Y. Wang, "Analyzing the elasticity and subsidy to reform the residential electricity tariffs in China," *Int. Rev. Econ. Financ.*, vol. 67, no. July 2019, pp. 189–206, 2020.

[29] G. Rothwell and T. Gómez, *Electricity Economics: Regulation and Deregulation*, 1st ed. EUA: John Wiley & Sons, 2003.

[30] L. Qiao, L. Zhang, and H. Gao, "Distribution Network Cost Allocation Based on Nodal Price," in *2018 IEEE Innovative Smart Grid Technologies - Asia (ISGT Asia)*, May 2018, pp. 587–592.

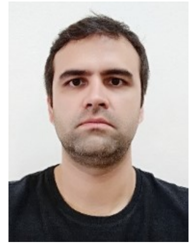
[31] W. H. Kersting, "Radial distribution test feeders," in *2001 IEEE Power Engineering Society Winter Meeting. Conference Proceedings (Cat. No.01CH37194)*, 2001, vol. 2, no. C, pp. 908–912.

[32] D. Shirmohammadi and H. W. Hong, "Reconfiguration of electric distribution networks for resistive line losses reduction," *IEEE Trans. Power Deliv.*, vol. 4, no. 2, pp. 1492–1498, Apr. 1989.

[33] P. E. Steele Santos, J. W. Marangon Lima, R. C. Leme, and T. G. Leite Ferreira, "Distribution charges for consumers and microgeneration considering load elasticity sensitivity," *Energy Econ.*, vol. 34, no. 2, pp. 468–475, Mar. 2012.

[34] N. Li, R. A. Hakvoort, and Z. Lukszo, "Cost allocation in integrated community energy systems - A review," *Renew. Sustain. Energy Rev.*, vol. 144, p. 111001, Jul. 2021.

[35] H. A. Gil, F. D. Galiana, and A. J. Conejo, "Multiarea Transmission Network Cost Allocation," *IEEE Trans. Power Syst.*, vol. 20, no. 3, pp. 1293–1301, Aug. 2005.



Rodrigo D. Guarizi. Ph.D. student in Electrical Engineering at the São Carlos School of Engineering (EESC) of the University of São Paulo (USP). He obtained a degree in Electrical Engineering from the Western Paraná State University (UNIOESTE) in 2011 and a master's degree in Electrical and Computer Engineering from the same university in 2014. He has been an Assistant Professor at the Federal University of Latin American Integration (UNILA) since 2015. His main area of expertise is regulation and energy markets.

Roberto C. Lotero (M'08). He obtained an electromechanical engineer degree from the Universidad Tecnológica Nacional, Argentina, in 1991, a master's degree in Electrical Engineering from the Federal University of Santa Maria, Brazil, in 1993, and a doctorate from the Federal University of Santa Catarina, Brazil, in 1999. He is currently an Associate Lecturer at the Western Paraná State University (UNIOESTE), Brazil. He works mainly on the following topics: planning of distribution systems, micro-grids, and electricity markets.

João Bosco A. London Jr. Graduated in Electrical Engineering (EE) from the Federal University of Mato Grosso (1993), Master's in EE from the São Carlos School of Engineering (EESC) of the University of São Paulo (USP) (1997), and Ph.D. in EE from the Polytechnic School of USP (2000). He held two post-doctoral fellowships abroad, the first at Virginia Tech USA (11/2002 to 03/2003) and the second at INESC TEC/ Portugal (08/2018 to 01/2019). He is currently an Associate Lecturer at EESC-USP. His main areas of interest are real-time modeling of electrical power systems and network reconfiguration to address problems in distribution systems.