Assessment of the impacts of distributed generation and electric vehicles as mobile sources through a nodal and zonal pricing methodology

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Abstract
Electricity is an essential asset for the economic and social development of any region. In the search for a cleaner, balanced and economical process, the industry and the electricity sector suffered several transformations over the years. Renewable energies became appealing, but electric vehicles also deserve attention, especially because they can act as source or load, with an impact on the electricity tariff. This work uses nodal and zonal pricing methodologies in a distribution system to verify the renewable micro-generation advantage to the system and to scale them through an electricity tariff system, based on a regulatory context implemented in Brazil. The used methodology enables one to assess how the distributed generators, including electric vehicles working as sources, interfere with the locational pricing in the system.

1 | INTRODUCTION

1.1 | Motivation and incitement

Electricity is an essential good and it has significant relevance to the economic development of any region. High-value energy discourages the production sector from generating jobs, and this may inhibit the income distribution in some areas.

The tariff structure must balance the shared burden of the electrical systems use. As new agents join the grid, the way energy is traded must be changed. These changes generate marginal effects on the market shares and directly interfere to shape each unit's share in the system capacity [1] and mainly signal an ideal rate for the recovery of their investments. The micro and mini generation users use electricity grids to drain their surpluses. By the principle of the balanced equation, they must take part in the allocation of costs in proportion to their use.

Technologies such as electric vehicles also need attention, as they should soon take part in this market. The adequacy of the use of electric vehicles in some countries has been studied according to [2], where the authors point out that the adequacy must be made according to the current government policies and the social acceptability of the technology.

Based on its electric mobility, electric vehicles (EV) could be categorized as a mobile charging station (MCS) or a mobile source. A MCS can give extra capacities for a fixed station charging or consumers who need extra and fast energy consumption in a place far from the charging station [3]. Besides, when EVs use renewable energy for recharging their batteries, they are an alternative to mobile source environmentally friendly. Thus, they can offer cheaper energy prices for the recharging of vehicles, laptops, and even cell phones. The electric vehicles can be seen as mobile sources and used to change the peak load hours and increase the stability of the power supply.

1.2 | Literature review

Reference [4] highlights that the renewable distributed generation throughout the system and the electric vehicles may have a high potential of benefits, mainly in economic terms. According to [5], a tariff that supports the diffusion of these technologies plays a central role. Reference [6] shows that the cost allocation system needs to be optimized, and the revenue requirement must be distributed to all contributing customers proportionally. Reference [7] indicates that the locational models based on...
marginal costs are market mechanisms that help to boost distributed energy services and they are sensitive to incentives.

The concept of tariff in this case, is not associated with the production chain, such as complementary generation by a given source, the transmission system, or sector charges, for example. It is the tariff seen by the locational side and, therefore, it is a portion of the tariff given by an allocative mechanism. This mechanism allows differentiating consumers according to the areas where they connect to the system, and should also be used to differentiate the final tariffs applied for billing the energy bill imposed on them.

According to [8], in a regulatory framework for self-consumption, in addition to energy and access costs, there are additional charges that include energy billing. These charges form the billing of consumers’ electric energy and must cover the expenses to produce the energy they consume. In [9] the author indicates that the more dynamic approach for selling electricity can generate economic savings in energy bills, but these are part of a more complex tariff in the sector.

The long run incremental cost concept may reflect the electricity grid tariff distribution and the impact of the injection or withdrawal of generation and load on each node of a radial grid. In [10] the author points out that this model can reflect the economic flows between the nodes of a distribution system. In [11–13] the authors present studies discussing the need to use the grid at the lowest possible cost, and therefore, the investments in system assets should ensure full recovery of expenses incurred by the distributors.

In [14, 15] the authors indicated that the marginal cost pricing is related to the incremental costs of the network, as well as to the costs of operation. Besides, the incremental cost is the proxy substitute for the marginal cost of expansion, since the variations in the cost of the capacity of a distribution system, annually, are quite discrete. According to [13, 16], some pricing models can be used for the distribution network to allocate costs among users, such as investment cost pricing and future cost pricing. However, the use of long-term incremental cost pricing has been presented as the most advanced model, allowing the generation of economic savings, especially in places that already use this methodology, such as in England [16].

Locational pricing was usually employed for transmission systems. Three components form this type of price: incremental losses, congestion, and investment. Methods which are based on marginal costs are better suited to situations where the system is based on bilateral transactions. The difference, however, for addressing incremental costs in locational distribution pricing, is that power injection into the buses occurs through discrete increments rather than large amounts of energy that are traded by the base generators, such as in transmission lines. Moreover, the purpose of this approach is not to maximize profits and to determine a dispatch strategy for the generators inserted in the grid, since they are small and non-dispatchable generators, such as wind turbines and photovoltaic systems.

Some changes will be necessary to adapt the conventional currently adopted metering system for the distributed generation, and the scenario proposed in this paper. Among these changes, we can mention some regulatory tools already adopted in countries, like Brazil, such as the case of data collection through geographic information systems. The main information collected by the GIS is related to the geometric layout of all circuits in the network, besides, it includes network accessors at all levels, high, medium, and low voltage. The geographic location of the users is punctuated in geographical coordinates, with latitude and longitude information. New information will have to be collected through the GIS system and they will also have to be faster and more dynamic.

In the case of the application of locational tariff and the adoption of a charging system for distributed generation and electric vehicles, it can be considered that the implementation of a smart meter suitable for the collection of information will be necessary. They should be more complete and complex to facilitate the application of the GIS and the accounting of hourly information on the generation of this equipment. There must be at least one means of communication for data traffic between the central data management system and the measurement system, the remote control and monitoring functions must also be associated with the measured quantities.

A specific means of recording information should also be considered. The adoption of new mechanisms for registering information as dynamic as locational ones that involve distributed generation, must be based on tools that regulate the flow of all information. “Power Line Communication” is already applied, which regulates the use of the distributors’ facilities for the flow of information from the unit, generation or load, to the data management centres. The information is obtained through a digital or analogue communication model.

Other channels of records should be explored in order to find a secure tool that ensures the information of all those entering this type of transaction. The data will be more voluminous and therefore, it will be necessary to invest in this type of system.

1.3 | Contribution

Considering the diversity of the current electrical system, this study aims to signal how electric vehicle’s insertion and distributed generation can modify the locational pricing of a radial distribution system and determine a way to apply a locational tariff to small generating units. Economic signalling given by locational rates based on the long-term incremental cost concept is used. Also, it is presented, through a zonal price formulation in a test system, how distributed generators can interfere in the determination of market zones, and the formulation of a new tariff design.

In countries such as Brazil, for example, the user of DG is subsidized by other users of the network. According to [17], this type of observation is relatively important, since the majority of the country’s population consists of low- and middle-income families, who are a significant part of the energy-consuming market. In the long run, these consumers will increasingly subsidize consumers with greater purchasing power and who can
bear the costs of investments in photovoltaic systems, for example. Since distribution and capacity costs are currently passed on in the same way to all users connected to the network, this can be considered a problem in a country with numerous social and economic inequalities.

The inclusion of DGs can cause changes in the behaviour of network users, which have marginal effects on market shares. Thus, these effects can interfere with the concessionaire’s power to shape user behaviour and recover their revenues. When this happens in a country with a regulatory model such as Brazil, these changes and the deficits caused by this interference are discussed and presented to the regulatory agency during the tariff review process.

Tariff reviews take place annually and incorporate this economic aspect, causing a tariff that is equivalent to the recovery of investments, and also the losses caused by DG users or referring to the increase in the prices of inputs used in the power generation process, for example. And as the tariff is applied in a unified manner by the concessionaire, it makes no distinction as to which agent or asset has caused its value to rise, since these losses or increased costs are socialized equally to all, without tariff distinction. Therefore, it can be said that these costs are passed on in the same proportion to all users.

Thus, we search to present an application of DG beyond the context of net metering, assigning them the responsibility for sharing costs in an electrical system. This cost division is based on tariffs already applied to the transmission system, but here we propose that DG’s contribution to the formation of a locational tariff should be based on the generation potential of each unit connected to the network. The goal is to create a scenario where DG and EV (Vehicle to Grid—V2G) can cooperate with the formulation of costs applied to network users as soon as they become competitive for this.

Besides, it can be considered that some regulatory measures already adopted in the country can contribute to the formulation of more flexible energy prices, such as the use of remote self-consumption for users of the DG, which establishes that the distributed generation can be positioned in a location different from the connecting point of the holder, where each kWh should be compensated [18, 19]. This type of application can favour a new energy trading methodology, and also, allows that the excess supply of a particular generator can be transported to a region with excess demand. The result of this type of situation is a scenario based on the spot market with economic dispatch based on energy bids, but subject to negotiation of restrictions between users, which would still be competitive based on a model of locational prices.

The literature, in general, does not take into consideration the role of electric vehicles in this context (as mobile charging stations or mobile sources), which is a contribution of this paper. Therefore, this paper presents the assessment of the impacts of distributed generation and electric vehicles as mobile sources through a nodal and zonal pricing methodology. Numerical results are obtained through a case study based on the IEEE 34 bus test feeder.

## 2 | METHODOLOGY

Cost allocation methods using nodal prices may encourage the rational use of energy resources within a system and flag economic signals in a simple manner [11]. Different authors in the literature have already approached methods for determining nodal prices, such as [11, 13, 20]. However, the application of electric vehicles (as mobile charging stations or mobile sources) in this context has not yet been addressed, which constitutes a contribution of this paper.

### 2.1 | Nodal prices

The nodal price ($NP$) in a distribution system is obtained as a function of the used capacity cost ($U_{j\theta}$) and the unused capacity cost ($CILP_{j\theta}$) for each active grid element, and here we are indicating that the elements are the system buses. The $NP$ value for each system agent is given as a function of two parcels as presented in Equation (1) [11], where $U_{j\theta}$ is the used capacity cost and $CILP_{j\theta}$ concerns the long-term incremental cost. Note that $j$ is the indication of the $j$ is bus and $b$ is the indication of the period.

\[
NP = U_{j\theta} + CILP_{j\theta}
\]  

The used capacity cost ($U_{j\theta}$), or parcel I, reflects whether there is an encouragement to the use of the resources provided by the grid. The unused capacity ($CILP_{j\theta}$), or parcel II, seeks to value the unused capacity at some point in the system and reflects the impact of this on the need to postpone or anticipate investments in new resources.

(i) Parcel I of the nodal price

In general, this parcel may be considered as the result of the ratio between the equivalent annual cost (EAC) and the loading level of each system element. This EAC represents the annualized cost of investing in the operation and maintenance of the active agents in the sector, and power flow is responsible for determining the used capacity of each one.

It is implicitly based on each grid asset and takes into consideration the physical assets depreciation, the financial charges, and the expected return on the invested capital. The EAC is obtained by Equation (2):

\[
EAC_j = \frac{(1 + d)^m \cdot d}{(1 + d)^m - 1} \cdot CT_j
\]

where $d$ is the capital remuneration rate, $m$ the asset lifetime, $CT_j$ the total cost, for each asset $j$.

The calculation regarding the use of an active element of the system is given by the ratio between $EAC$ and $f_j$, which is the used annual power flow capacity of the $j$. The used capacity ($U_{j\theta}$),
or parcel I, is, therefore, calculated by Equation (3):

\[ U_j = \frac{E \cdot AC_j}{f_j} = \frac{(1+d)^m \cdot d}{(1+d)^{m-1}} \cdot CT_j \]  

(3)

where \( f_j \) is the annual energy flow in the asset \( j \).

(0) Parcel II of the nodal price

Reference [21] describes that the ideal scenario would be the one where the system capacity is expanded according to the demanded load. But according to [13], this is impossible due to a system slack, which is characterized as an unused grid capacity. The unused capacity cost \((C_{ILP})\) or parcel II of the nodal price model represents precisely the cost to grid users.

The calculation, according to the maximum capacity of the system, indicates whether and when there is a need for reinforcement of the \( j \) in the grid according to Equation (4):

\[ n_j = \log\left(\frac{f_j}{f_j^{\text{max}}}\right) - \log\left(f_j\right) \]  

(4)

where \( r \) is the rate of growth of system demand; \( f_j \) is the energy flow in the asset \( j \), \( f_j^{\text{max}} \) is the maximum energy flow in the asset \( j \), and \( n_j \) is the lifetime of the active in years.

By incorporating demand growth, we will consider that the maximum value of the network operation will be reached in advance, requiring investments in the system more quickly. When addressing the generation increase in the model, it is adopted that the investments may be postponed, and thus the investments in the expansion of the system’s capacity will occur in the long term.

According to [16], a node supported by light loads will have a lower nodal loads, which will stimulate demand growth. When load growth is considered, the loads will increase, and the nodal load will increase monotonically, which will discourage new demands in these locations but will generate a stimulus for the connection of generators. Thus, it is not necessary for the model to assume the size and location of the future generation or demand, specifically. It depends on the capacity of the existing network to accommodate the generation or demand growth, providing a signal equivalent to the economic price given by a growth prospect, which will be interpreted as a sign of development.

According to [11], the future investment required for the asset duplication must be discounted from the present value of the investment. This economic analysis flags the period in which the investment must be made, considering a rate of remuneration for the capital, following the market values. The present value \( (PV) \) can be obtained as a function of time and the total cost in each active element in the grid, as in Equation (5).

\[ PV_j = \frac{CT_j}{(1+d)^n_j} \]  

(5)

where \( d \) is the compensation rate, \( n_j \) is the lifetime of the \( j \) in years, and \( CT_j \) the total cost, for each asset \( j \).

The system increment is given by \( \Delta f_j \). If a load increase occurs, the increase will be a function of \( \Delta f_{jl} \), and will be in the conventional sense of the power flow in the grid. If the increment is due to the generation increase of the DG or the insertion of a new generator, the power flow will be in the opposite direction of the element and will correspond to \( \Delta f_{jg} \).

When an increment occurs in the network, the period until investments are made, a new \( n_{jk} \) can be estimated, depending on the increment, by Equation (6):

\[ n_{jk} = \frac{\log\left(f_{j(mx)}\right) - \log\left(f_j + \Delta f_{jl}\right)}{\log(1 + r)} \]  

(6)

For the generation or load increment, the \( PV \) is given by Equation (7):

\[ PV_{jl} = \frac{CT_j}{(1+d)^{n_j}} \]  

(7)

The present value variation is given as a function of the load or generation increment in the system, according to Equation (8):

\[ \Delta PV_{jl} = PV_{jl} - PV_j \]  

(8)

where \( \Delta PV_{P_{jk}} \) is the variation in the present value of the asset.

Parcel II is defined according to Equation (9) for load increment.

\[ C_{ILP_j} = \Delta PV_{jl} \times \frac{(1+d)^m \cdot d}{(1+d)^{m-1}} \]  

(9)

where \( \Delta f_{jl} \) is the variation due to load increment.

### 2.2 Maximum system capacity

The maximum capacity used for the nodal price parcels calculation in this study is related to the system’s ability to maintain acceptable voltage levels on all buses. According to [22], problems related to voltage stability can delay system development, make it difficult to control the reactive power demand, and violate nodal voltages. Reference [20] proposes an approach considering the analysis of voltage stability and the contingencies in the system using, as a methodology, the incremental cost presented in [10]. To determine the load margin in the system, the continuation method has been employed [23].

In [24], the authors used the continuation method to analyze the reactive power market, taking into account the aspects related to voltage collapse. The results indicated that the reactive power injection in the system critical bus can improve the general reactive market.
2.3 | Continuation method

The continuation method aims to obtain a set of load flow solutions, from the base-case up to the maximum system loading. The method provides a set of results that form the bifurcation diagram, which indicates the critical point of operation of the system, as well as the critical buses that drive the system to that condition.

The interested reader is referred to [23], where the details of the continuation method are described.

2.4 | Zonal price signalling model

The incremental cost system price analysis may be obtained locally or by region. The model used in this study is based on a hierarchical cluster algorithm, which uses an objective function to determine the best offer zones by minimizing the prices within them. It weights the nodes according to their relevance to the system and their participation in the power flow of the grid.

The method for determining the zonal prices is presented in two main stages. First, the objective function formulation is introduced, and second it follows the hierarchical cluster algorithm.

2.4.1 | Variation of nodal prices in the system

The initial formulation of the problem is done by calculating the variation of prices within the system under study according to Equation (10):

\[ V = \sum_{N} \sum_{H} \left( \left( p_{n,h} - \bar{p}_{h} \right)^2 \times w_{n} \right) \]  

(10)

where \( V \) is the price variation in the system; \( n \) varies from 1 to the number of system nodes; \( h \) refers to each period in hours; \( p_{n,h} \) is the nodal price per period in the system; \( w_{n} \) the weight assigned to each node of the system.

Each node of the system is weighted according to its relevance. The offer of demand and generation level indicates the representativeness of the participation of the bus in the cost of the system as a whole [25, 26]. The weights are normalized to make their interpretation straightforward, as shown in Equations (11), (12), and (13):

\[ w_{n}^{0} = \sum_{H} \left( |q_{f_{gen,n,h}}| + |q_{d_{gen,n,h}}| \right) \]  

(11)

\[ w_{n}^{0} = \frac{\sum_{N}w_{n}^{0}}{\text{number bus}} \]  

(12)

\[ w_{n} = \frac{w_{n}^{0}}{\bar{w}_{n}} \]  

(13)

where \( q_{f_{gen,n,h}} \) is the parcel referring to the generation at the node \( n \) at the period (hours or minutes); \( q_{d_{gen,n,h}} \) is the parcel referring to the demand at the node \( n \). \( w_{n}^{0} \) is the weight referring the prices of each node; \( w_{n} \) is the normalized price.

Average prices are obtained according to Equation (14).

\[ \bar{p}_{h} = \left( \sum_{N} \left[ p_{n,h} \times w_{n} \right] \right) \times \frac{1}{\sum_{N} w_{n}} \]  

(14)

The total weight of a zone is equal to the sum of the weights of all nodes within the zone, as in Equation (15).

\[ w_{z} = \sum_{n \in N_{z}} w_{n} \]  

(15)

The average price of a specific cluster will be weighted by the average value of the nodal prices of the grouped nodes in this cluster, according to Equation (16).

\[ \bar{p}_{h,c} = \left( \sum_{n \in C} \left[ p_{n,h} \times w_{n} \right] \right) \times \frac{1}{\sum_{n \in C} w_{n}} \]  

(16)

The internal variation of a cluster is obtained by considering the average node weights and prices within this cluster, given by Equation (17).

\[ V_{\text{within}} = \sum_{C} \sum_{n \in N_{z}} \sum_{H} \left( \left( p_{n,h} - \bar{p}_{h,c} \right)^2 \times w_{n} \right) \]  

(17)

The variation between zones is calculated by the weighted deviation of the square of the time zone price of each zone, as indicated in Equation (18).

\[ V_{\text{between}} = \sum_{C} \sum_{n \in N_{z}} \left( \bar{p}_{h,c} - \bar{p}_{h} \right)^2 \times w_{n} \]  

(18)

According to [25], using a variance decomposition approach, the total price variation in the system is given by the sum of the internal change of the zone and the price variation between the zones, as in Equation (19).

\[ V_{\text{total}} = V_{\text{within}} + V_{\text{between}} \]  

(19)

2.4.2 | Pre-cluster

In pre-clustering, nodes that have similar nodal prices and meet the physical connection constraint are grouped in pairs. After the first grouping, several small zones are formed and the similarity of the nodes that form these zones is analysed. Besides, a measure of the Euclidean square distance between the nodes is calculated. All the zones that have no possibility of physical connection should remain independent.
3 | TARIFF MODEL

3.1 | Unadjusted nodal tariff

One mechanism that may signal the economic efficiency of a locational pricing model is the nodal tariff analysis. In the process of searching for a fair rate value, the incremental revenues obtained at the buses must be able to cover the total investment costs, according to a specified rate of return. Also the lifetime of system equipment, such as transformers must be considered.

The tariff must be represented as a function of line sensitivity, because of the loading or generation on the bus. This sensitivity assists the system to measure a rental fare proportional to the use of each agent. It measures sensitivity regarding the sensitivity matrix \( \beta \). The line flow sensitivity is obtained by the sensitivity matrix \( \beta \), given by the distribution system parameters, according to Equation (20):

\[
\beta = \frac{\partial F_i}{\partial P_k}
\]

where \( F_i \) is the active power flow in the line and \( P_k \) is the power injection in the bus.

The methodology used to identify the locational costs in the system, described in [10] and [11], aims to provide economic signalling that reflects a nodal model adjusted to the loading and power flow. Equation (21) yields the unadjusted nodal tariffs:

\[
\pi'_i = \sum \beta . NP_i . f p_i
\]

where \( \pi'_i \) is the unadjusted nodal tariff for the load or generation on the bus \( i \); \( \beta \) is the sensitivity matrix; \( NP_i \) is the nodal system cost in the bus \( i \); \( f p_i \) is the load weighting factor for each node.

When the unadjusted tariff is calculated for a generator positioned on a specific system node, it will be described as \( \pi'_{CG} \). Then the tariff that refers to the loads in the system, is described as \( \pi'_{L} \).

3.2 | Adjusted nodal tariff

Unadjusted fares determine unadjusted market revenues. For the calculation of the adjusted tariff, it is necessary to take into consideration the demand in the bus, the tariff-related to the marginal costs obtained for the unadjusted model, the revenues that fit the consumers, and the calculated additional parcel related to the load or extra-generation.

The cost allocation calculation is conceived in two parts: before and after adjustment. This change refers to the factor that allows one to adjust the cost recovery in the system through the nodal method and allocate them on the reference bus. According to [27], the adjustment is made through a parcel calculated via a postage stamp. As in the pro-rata and proportional division methodologies, they weight the apportionment of the total system cost between load and generation. Usually, the division is made in a proportion of 50% for generating units and 50% for consuming units.

Thus, the adjusted tariff model for a system through a locational analysis may be obtained using Equations (22) and (23):

\[
\pi'^{k}_i = \pi'_{i} + \Delta_{k}
\]

\[
\Delta_{k} = \frac{FP \times CT - \sum_{j=1}^{N} (\pi'^{k}_{j} \times P_{j})}{\sum_{j=1}^{N} (P_{j})}
\]

where \( \pi'^{k}_{i} \) is the adjusted tariff. \( \Delta_{k} \) is the adjustment portion of nodal tariffs; \( P_{j} \) refers to the maximum demand or generation in the bus or zone; \( N \) is the zone number or bus; \( CT \) is the system cost; \( FP \) is the factor of proportion for the division of cost.

This model of adjusted location tariff is already considered in the context of transmission systems, and in this study, it is applied for a locational signal for a radial distribution system. Besides, the \( FP \) in Equation (23) is weighted as follows: 70% of the cost responsibility is applied to the loads, and the other 30% are on the generation units. In Section 5.1, the application of the \( FP \) proportionally to the power injection capacity of the EV or DGs in the network is proposed.

4 | CASE STUDY

For the proposed research, some scenarios were analysed considering variations in the test system. The test system used in the study is the modified IEEE 34 bus, as shown in Figure 1. The substation is on bus 800. Note that solar generation units of 200 kW are installed in the buses 850, 842, and 852, whereas wind generation units of 600 kW are installed in the buses 850, 826, and 846.

The energy generated from photovoltaic systems is the most widespread among distributed generation systems connected to global networks. However, currently the demand for small wind turbines is also being boosted [28]. According to [29], the United States accumulated between 2013 and 2018 more than 150 MW in small wind generation, and Germany about 30.75 MW in the same period. Other countries add more than 825 MW in small wind power. In Brazil, the potential of distributed small wind plants is around 14 MW in...
5.1 | Conditions for distributed systems and electric vehicle in scenarios 2 and 3

In transmission systems generators are responsible for balancing demand and supply. In the distribution system, small generators do not have this capacity, that is, it is not possible to define that the DG equalizes this type of action. Therefore, when DG is included in a market mechanism like the one suggested in this paper, where there will be a tariff applied to it for its use of the network, this type of observation must be taken into account.

In the construction of the transmission-level locational tariff, there is the \( FP \) factor (Equation (23)) that is used in the methodology of the Regulatory Agency of Brazil, to attenuate the locational signal and optimize the dispatches at that level. Also it is used to maintain the symmetry of tariffs between generators and loads.

For the locational approach to distribution, the allocation of costs does not happen symmetrically and we suggest that to allow the cost recovery of companies, this \( FP \) factor must consider this imbalance. Therefore, this factor can be applied to the extent that the generation behavior of distributed systems varies, which will cause a change in how the apportionment of costs will affect the loads or generators.

By analysing the alternatives on energy tariffs, it is proposed that generators should be used for participation in the nodal method only when they have enough power. The tariff applied to a single user connected to the system must be able to recover all investments. Therefore, the lower the network usage, the higher the tariff applied to meet the concessionaire’s revenue. If more users are connected, this fee becomes lower because they share these costs. When the DG has a small generation potential, it will impose a tariff with a very high value so that the costs are recovered, this will cause a penalty effect and that is not the objective. To correct this effect on generation tariffs, we apply the \( FP \) variation.

As it presents a more effective behaviour in the system and it starts to use the network more significantly, the distribution of these costs becomes more balanced and maintaining the principle of a fair, neutral, and rational tariff. To promote the technology associated with these types of systems, it is indicated that the tariff will be balanced by her participation in the use of the system, the more intense this participation is, and the more apt she will be to participate in the apportionment of costs, without losing the attractiveness of this type of business.

According to the simulations carried out and the perception of how the DG should be incorporated into this type of market mechanism, when the supplied power of an access point is smaller than 380 kW, it operates under the net metering market condition. When this occurs, each kWh from this injection into the grid is a loan to the local dealership, which will repay it in the form of energy credits. When the generation potential of the microgeneration or a point with electric vehicle aggregators is less than 380 kW, it is assumed that the energy injected into the grid and the energy consumed have the same global value in the bus, and for this reason, it is suggested that the pricing model is based on net metering. When the potential is higher
than this value, it is feasible to adopt a system in which the tariff criterion is applied as the source becomes more competitive with the technological evolution or expansion of the distributed system.

Thus, in this study, it is suggested that the division between the responsibilities of recovering the total system cost is made considering the participation of renewable generation in the system given by the factor $FP$ in Equation (23), as shown in Table 1.

Then, it is proposed that the partition of the costs between the loads and the distributed generators be carried out in a staggered manner. The tariff mimics what macroeconomics models for marginal costs, i.e. small increments of energy cause a very small variation in the system. However, the parcel that they must recover from the variable costs of distribution companies becomes too large, creating an imbalance in the market. For this reason, we seek to normalize the economic operation between these agents connected at the same point or zone of the network, balancing this through an adjustment factor given in such a way that it was divided across a generation range. If the DG generation is small, the $FP$ applied to it is also small. From the moment that the generation increases, this $FP$ will also increase, until the apportionment between the loads and the generators reaches a proportional level, that is, 50% and 50%.

When this analysis is expanded to a zonal context, the difficulty of small generators in recovering the costs of operating systems through the generation rate becomes more evident and the tariff can become very high.

The first step to improve tariffs in the zones is the adoption of a proportionality model, as presented in Table 1. Considering an alternative for cost-sharing between loads and generators for the zonal configuration yields Table 2. There are two goals for this type of adoption: promoting microgeneration and creating a “feeling of fair tariff” and a “sense of well-being for everyone in the system”.

### TABLE 1 Division cost—factor $FP$

| Generation range (kW) | Load | Generation |
|-----------------------|------|------------|
| $x < 380$             | 1    | Tariff-free|
| $380 \leq x < 490$   | 0.9  | 0.1        |
| $490 \leq x < 580$   | 0.8  | 0.2        |
| $580 \leq x < 650$   | 0.7  | 0.3        |
| $x \geq 650$         | 0.5  | 0.5        |

### TABLE 2 Division cost in zones—factor $FP$

| Generation range (kW) | Load | Generation |
|-----------------------|------|------------|
| $0 \leq x < 750$     | 0.9  | 0.1        |
| $750 \leq x < 1000$  | 0.8  | 0.2        |
| $1000 \leq x < 1250$ | 0.7  | 0.3        |
| $1250 \leq x < 1500$ | 0.6  | 0.4        |
| $x \geq 1500$        | 0.5  | 0.5        |

5.2 | Assumptions considered

The adopted cost value for the test system is about US$240,000.00. It was used as the rate of return the SELIC rate (Brazilian official basic interest rate of the economy) plus the Brazil Risk of about 0.07, which are indexes applied in Brazil. A more aggressive scenario basis for the load growth of 0.05 was considered, based on the load growth from 2016 to 2017, according to data obtained from the National Electric System Operator in Brazil (ONS).

The lifetime, or functionality time, has been assumed to be the same for the entire system. For this study, the lifetime of 30 years was used. The sample period is one day, divided into intervals of 10 minutes, leading to a total of 144 tariff values obtained through nodal prices. The sample times start at midnight.

6 | RESULTS

6.1 | Scenario 1

For scenario 1, the nodal price and nodal tariffs are presented in Figures 2 and 3, respectively, for buses 850, 826, 818, 832, 842, and 840.

This tariff concerns a part of a distribution tariff to be applied to consumers at that level. Two parts make up this nodal value: the part of the system used and the part about the system’s idleness. When consumers make good use of the system, considering that every investment made for the provision of the electricity service is well-used, the energy tariff values will be lowered, indicating that there is no idleness in the bus. If users use very little the system, the nodal price may indicate that the system has been overdimensioned, and for this reason, a higher tariff is applied to these consumers in these periods.
Applying the zonal analysis, the system may be represented according to the zones delimited in Figure 4. The zones were identified using heat maps.

The zonal tariff is obtained considering the loads and generation connected in the same area. Every zone is seen as a single bus by the system, and its tariff is obtained considering the consumption, generation, and nodal prices in those areas. The location price for zones is given due to the nodal prices of the buses in the region. The tariff values are obtained considering these zonal prices, the loads that are connected in the zones, the generation systems in that zone, and the total cost of the system.

As with nodal analysis, each zone must also be able to recover the CT Equation (23) of the system. The load considered in a zone is given by the summation of the load of the buses in the zone, as well as for the generation when there are generators inserted, as suggested in scenarios 2 and 3. Figure 5 presents the value of zonal tariffs in these regions.

Similarly, buses nearest to the reference bus (bus 800), zones 1 and 2 have lower tariff values. Besides, when the system is considered in zonal form, the zonal tariff applied to bus 850, for example, is higher than the nodal tariff on the same bus. When the system is organized in zones, all buses in a zone can compensate for the high costs demanded by other buses located in the same region. This type of compensation is common in the electrical system, but the advantage in the formation of zones is the uniformity of data and ease in subsidies for distributed generation.

6.2 | Scenario 2

In scenario 2 the condition of Table 1 was applied. The nodal price and nodal tariffs are presented in Figures 6 and 7, respectively, for buses 850, 826, 818, 832, 842, and 840.

Especially on the buses 850, 826, and 842, where there is the insertion of distributed generation, it is evident the change in
nodal tariffs (by comparing Figure 3 with Figure 7). There is a reduction in the values for marginal costs on these buses in some periods.

Especially on the buses where there is the insertion of distributed generation, it is evident the change in zonal prices. There is a reduction in the values for marginal costs on these buses. Figure 8 shows the renewable generation profiles.

The use of photovoltaic and wind generation at Buses 850 reduced the costs of the nodal tariff. The nodal tariffs of the buses shown in Figure 7 are the result of the economic signalling obtained for the loads and generators distributed in these buses.

Applying the hierarchical cluster algorithm to this new system configuration, with the inclusion of renewable generation yields Figure 9. It can be noted in comparison with scenario 1 (see Figure 4) that the zones are not the same. In scenario 1 the system was divided or clusterized into six zones (Figure 5). With the inclusion of distributed generation, the buses were reorganized, and the methodology provided an outcome of four different cluster zones. For this reason, new zonal tariffs are obtained and they are presented in Figure 10. The $FP$ for the areas is considered to be 70% responsibility of the loads on the partition of costs, and 30% responsibility of distributed generators.

There are times where the renewable generation is not satisfactory to the system, thus raising the tariffs. This is due to the low representativeness of generation in some zones. When the distributed generation is too small, it proves unsatisfactory to participate in the partition of costs and ends up being penalized for not using the network in proportion to the investment made in it. In order to correct this problem, or to make the division of costs fairer in the calculation of the tariff, it is adopted the division of costs (factor $FP$) suggested in Table 2. Figure 11 is obtained by applying the PF according to Table 2.

Comparing Figure 10 and Figure 11, it turns out that this type of pricing can become more balanced when the adopted $FP$ is based on the energy potential of the source, according to Table 2.
6.3 | Scenario 3

In scenario 3, the renewable microgeneration systems work in conjunction with the V2G (Vehicle to Grid) enabled electric vehicles. The start-up of the vehicle occurs at midnight but with higher peak hour performance. The vehicles begin to operate at a 100% charge on their battery until discharging to a minimum of 30%. The number of vehicles in some buses is given in Figure 12.

For the use of V2G, the maximum number of vehicles were considered for each bus. The purpose of this limitation is not to occur high use of the system at some specific point, which could cause disturbance to the grid. Also, this is a future scenario and will take time until a high number of EVs connect to grid for this purpose, so we use a reduced analysis of what might happen on the network.

Electric vehicles enter the system during peak hours for two main reasons: it is a time when the system normally demands reinforcement, and due to logistics, allowing the owners of these machines to connect to the network after working hours.

For a vehicle to connect to the network between two system buses, a new analysis by the distributor is necessary. An alternative for this case would be the creation of a fictitious node and the calculation of nodal prices and tariffs considering this point. However, for this study, this possibility was ruled out at the moment.

Electric vehicles are included taking into consideration the division of zones according to the distributed generation, obtained in scenario 2. The objective is to reduce the zonal tariff values and to show how electric vehicles acting on V2G functionality can help the system. Figure 13 shows the nodal price and nodal tariffs with the presence of electric vehicles for buses 850 (60 V2G), 826 (8 V2G), 818 (8 V2G), 832 (60 V2G), 842 (30 V2G), and 840 (0 V2G), respectively when the vehicle is adopted.

When the electric vehicles were inserted, the marginal prices on the buses were changed. With the change in nodal prices, the zonal prices also changed. Thus, new tariffs were obtained, as shown in Figure 14. The zonal tariffs were obtained using the division of costs (factor $FP$) presented in Table 2.
Figure 15 shows the profile of the generation distributed for zones and Figure 16 shows the profile generation by electric vehicle for zones.

Electric vehicles with small energy storage capacity are not attractive for this type of action. Thus, the option would be to concentrate a more significant number of electrical vehicles. In this case, the problem lies in the need to increase the generation to a high level and to find a large number of owners willing to assist the grid.

Analysing the effects on energy tariffs, it is proposed that electric vehicles should be used only when they have enough energy storage capacity, or from a minimum generation value. As for zonal pricing, considering a set of electric vehicles as an equivalent power generator provides a better outcome for both the system and electric vehicles’ proprietors. As for the utility, a zonal contract with a set of vehicles is better managed than dealing with an electric vehicle at a time. Hence, besides providing a better pricing policy, zonal pricing also offers a possible faster negotiation framework in this new business model.

Another point observed in the study is that the inclusion of distributed generation can change the configuration of zones, and consequently, change the way prosumers will be charged.

Comparing Figure 3 with Figure 7, the mean nodal tariff on bus 850, for example, decreased by about 29% with the inclusion of distributed generation (see Figure 17). At the time when there is the highest solar utilization, around noon, the reduction in the nodal tariff is close to 32% on the same bus. Bus 832 presents an increase in the value of the nodal tariff in the interval between 10 am and 12 pm (see Figure 18), which may have occurred due to the costs that the distributed generation caused into neighbouring buses, generating compensation in other system agents.

If the distributed generation is not charged, as in net metering, it may receive some kind of cross-subsidy from the system. The application of adjusted tariffs based on nodal prices

**FIGURE 15** Profile generation distributed—scenario 3

**FIGURE 16** Generation profile of electric vehicles for zones

**FIGURE 17** Comparison of the tariff for scenarios 1 and 2 in bus 850

**FIGURE 18** Comparison of the tariff for scenarios 1 and 2 in bus 832
on these units can help to reduce these subsidies. When a user of the grid is considered as a prosumer, the higher the subsidy, the higher the parcel of cost to be shared by other consumers in the same area. Whenever the economic incentive is removed, in this case, by scaling the proportionality values of the apportionment of costs, the DG systems become held responsible for the costs imposed by the network, and this can reduce the distortion in tariffs. Figure 19 shows the portion of the load zonal tariffs and Figure 20 shows the portion of the generation zonal tariffs. The results indicate that the generation tariffs that should be applied to distributed generators are lower than the rates applied to loads zonal tariffs.

This type of application can be considered as time of use (TOU) tariffs, where tariff programming is carried out for each period. This value should reflect the average cost during these periods. As consumption and distributed generation are dynamic, thus they can be updated according to the interests of the agents.

The distributed generation is considered for the apportionment of investment and operating costs in the system, thus the nodal rate can be represented in portion related to loads tariff and the portion to the DG’s tariff.

When it is considered the electrical system divided into zones means that there is a common tariff applied to all buses that are inserted in the same region. Thus, any load that is connected to the system in one of the buses in zone 1, for example, will be cashed in according to the dynamic values obtained for the zone 1 tariff, the blue curve of Figure 19. The distributed generators connected to the system in that same bus will have a tariff to inject energy into the grid given by the blue curve of Figure 18. The two portions of tariffs together can represent the total zonal tariff applied to these regions and may have incentives according to the interest of the network administrator.

The use of electric vehicles acting as V2G in the context of locational pricing can favour the concept of mobile electric sources, with vehicles or trucks considered mobile electric stations. New businesses in the electricity sector will emerge due to the more dynamic behaviour of the distribution system. Among these new applications, electric vehicles acting as mobile sources can be highlighted. As this type of tariff addressed in this paper presents price variations depending on time and place, vehicles will be able to take advantage of this dynamic when charging or discharging their batteries.

When tariffs are most attractive in some regions, mobile charging stations (MCS) could connect to the grid at that location. In other times when the tariff is not so attractive, these MCSs can search for a region with attractive tariffs for charging their energy storage system. In the case of Figure 14, during the period between 24 PM and 4 AM, zone 3 would be more attractive for charging an MCS, because it has the lowest zone tariff. However, after 4 AM, zone 4 has better rates, mainly between 10 AM and 12 AM, so in this time range, it would be convenient for MCSs to be charged in zone 4.

Also, the locational pricing of the distribution grid can present controlled values in the market by using mobile electric sources. MCS systems can also be used to inject electric energy when and where the grid needs it more, or to consume surplus energy in a specific region at a lower price and sell it at market prices in another region.

The modality already regulated for the use of DG in Brazil, only in the context of net metering, remote self-consumption, can be used by electric vehicles in a future scenario. It is characterized by consumption in consumer units, belonging to the same holder, but located in different regions from where the generation unit is located. It is enough that they are in the same area of permission or concession.

Thus, it can be considered that in a country with natural resources as abundant as, for example, solar energy [37], electric vehicles can consume a volume of the excess energy of this type of generation at a specific point. Then, they can inject this energy at another point in the system where there is no good use of renewable resources. That is, the batteries are charged with lower-cost energy and this energy can be injected at a point where the purchase value is higher.
Fixed batteries do not allow this price dynamics, but if we consider electric vehicles from the point of view of mobile sources, a scenario of flexibility can be created for the surplus energy that photovoltaic systems can generate and ends up being “wasted” in some moments of the day.

7 CONCLUSIONS

Allocative and efficiency analysis seeks to make the system planning more transparent for all the electricity market agents, mainly, when it indicates that the generation units have the power over the zones reformulation, making clear their interference on the nodal and zonal prices in the system.

The price distribution becomes more regular when the system is presented in the form of market zones, with the distinctiveness of their user profile. If the analysis is purely nodal, the bus where the distributed generation is positioned should pick the burden and the bonus of its activity, and is limited to several operating conditions.

The alternative of using the friendly grid V2G functionality may be in the configuration of regulation capable of concentrating the most significant number of batteries in the same region. Besides, the sharing of responsibilities between the loads and the generators that use the system may occur in a balanced way. The use of the energy contained in the batteries allows the reduction of nodal prices in the bus, and also contributes to the reduction of zonal tariffs. This flexibility in space and time can be used to optimize a smart distribution system, resulting in fair tariffs for all market agents if a new smart business model is so designed. However, the lack of smart regulation can also lead to market price manipulation resulting in high spot electricity prices with benefits for a few agents on the unfair expenses over other agents.

It is possible to verify that the $FP$ factor can vary more discreetly among the possible energy bands considered for the monetization of distributed generation. Through optimization tools, such as, for example, evolutionary algorithms and the HP model, multiobjective optimization, decision support methods based on stochastic optimization techniques, and decision matrix, it is possible to find an optimal economic operation for this type of application.

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