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# Novel Dynamic Framework to Form Transmission Tariffs with Suitable Economic Signals

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A B S T R A C T

The energy transition intensifies the limitations verified on transmission cost allocation (TCA) methods traditionally employed. Two methodological limitations common to them can be identified: 1) lack of coordination between transmission pricing and load evolution and 2) lack of signals to guide the growth in generation capacity. This work presents a novel dynamic framework to form transmission tariffs capturing two important aspects: the load evolution at each bus and the optimal generation necessary to minimize the transmission loss. The framework overcomes the identified limitations and provides suitable tariff adjustments that reflect the responsibility of each user on network investment. A dynamic tariff-load balance is induced and generators who contribute to loss minimization are rewarded. So, effective signals for the generation capacity expansion are obtained. Also, the tariff formation is integrated with the reconfiguration of responsive distribution networks (DNs). Thus, this work proposes a new structure in terms of tariff integration and operational coordination in accordance with modern rate designs and recent energy security concerns.

*Keywords:* Transmission cost allocation (TCA); energy transition; integration; distribution networks (DNs); generation capacity; suitable signals

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## 1. Introduction

This work presents a novel dynamic framework to form transmission network use of system (TNUoS) tariffs with suitable economic signals and analyses its performance through an integrated structure with feedback between tariffs and agents of electricity consumption and generation. The TNUoS tariff is formed by the dynamic framework in a process composed by different stages. During the tariff formation process, coordinated adjustments are made by the framework in the original tariffs produced by any transmission cost allocation (TCA) method. Two aspects are considered in these adjustments: the load evolution at each distinct bus of the system and the optimal generation necessary to minimize the transmission loss. Both aspects are innovative and direct contributions to the power sector, as they are attributes not verified on traditional TCA methods.

In terms of consumption, adjustments are made by the framework to rise the final TNUoS tariff at buses with load growth and to reduce it at those buses with load decrease. Thus, a flexibility incentive with suitable signal is introduced in the tariff and a coordinated tariff-load balance is induced automatically. So, considering responsive agents of consumption, who seek the lowest tariffs to minimize their costs, the framework incentivizes the load growth throughout a greater number of buses, promoting a more distributed growth. In relation to generation, the framework rewards generators that contribute to minimize the transmission loss, through the calculation of benefits that work as discounts in their TNUoS tariffs. So, an appropriate economic signal is provided to generators, since these benefits are naturally incorporated into their fixed costs. Therefore, the framework induces the generation capacity expansion at locations that contribute to the loss reduction, granting a systemic benefit for all transmission users.

This work also integrates the tariff formation process with the reconfiguration of responsive distribution networks (DNs) that considers transmission economic signals. The reconfiguration minimizes the global cost paid by distribution utilities and guarantees the loading growth into the DNs without operational violations. The paper is organized as follows. Section 2 analysis the impact of the energy transition on traditional TCA methods. Section 3 presents the integrated structure developed in the work. Section 4 exhibits the application results obtained. Finally, Section 5 brings the main conclusions.

## 2. Transmission Pricing in the Face of the Energy Transition

Electric power systems are undergoing an energy transition process that shifts the power sector paradigm. Decarbonisation goals have been at the centre of discussions about reforms in electricity markets around the world [1]. We observe that integration and interconnection are evident aspects that are being intensified with the energy transition [2]. So, the current rate designs that prioritize volumetric tariffs ($/Wh), in detriment of capacity tariffs ($/W), are compelled to be updated. In modern rate designs, consensus today is that capacity tariffs must acquire greater weight in electricity bills [3]. The discussion focuses mainly on two aspects: what percentages are appropriate for this weight, and which methodologies are suitable for providing efficient capacity tariffs. Intermittent renewable technologies create flexibility challenges due to their high variability in electricity production, combined with their low predictability and controllability. As they produce electricity at almost zero marginal cost, their larger presence forces reforms on electricity markets [4]. Thus, regulation must provide economic incentives for individual users, allowing them to make their own decisions in a decentralized way, but moving the system towards better operational security conditions.

### *2.1. Transmission Cost Allocation Methods*

The novel dynamic framework is not a new TCA method. In turn, the dynamic framework is a supplementary scheme composed of different phases, which employs any TCA method in one of its phases. The framework meets the three practical requirements necessary for modern TCA algorithms [5]: implementation of effective costs and benefits (clear perception by the agents), provision of individual signals (to avoid cost socialization and cross-subsidies), and fulfilment of general regulatory basis (economic efficiency, fairness, and transparency). Thus, the framework presented in this work increases the economic efficiency of TNUoS tariffs, overcoming methodological limitations verified on traditional TCA methods. In this way, the total transmission cost (TTC) is allocated more fairly, providing individual economic signals that induce better agent behaviours.

Different strategies can be employed for TCA, as long as the TTC is fully recovered from the set of users. Thus, we can subdivide TCA methods into six different categories: elementary, power flow based, incremental cost based, marginal cost based, alternative, and innovative. Elementary methods are those whose simplified design gave rise to the TCA [6]. In practice, these methods still form the regulatory basis utilized in most of the world, being constituted by three main methods: Postage Stamp, Contract Path, and MW-Mile. The methods based on power flow examine the amount of power transacted and the electrical distance between the points of generation and consumption [7, 8]. In methods based on incremental cost, users pay the full cost of new installations required by transactions [9, 10]. It means that charges are evaluated taking into account the new costs caused by them. Methods based on marginal cost are characterized by emphasizing the differences among nodal prices that arise due to transmission restrictions in the network [11, 12]. Alternative methods are composed of different strategies developed from other categories, with the alteration of some of their main characteristics [13, 14]. Finally, innovative methods refer to procedures with a high degree of innovation in the proposing strategies [15, 16].

To show the generic character of the dynamic framework, two TCA methods are employed in this work: Equivalent Bilateral Exchange (EBE) [17, 18] and Nodal [18, 19]. The EBE method is based on a principle of equivalent and bilateral exchanges, which states that once the laws of Kirchhoff are satisfied by a power flow solution, each load is supplied by a generation fraction, uniformly divided across all generators. Similarly, each generator supplies a load fraction, divided across all loads also in a uniform manner. The EBE method has an approach that adheres to the four high level principles that guide the TCA praxis [6]: costs must be allocated in proportion to benefits, transmission charges should not depend on commercial transactions, transmission charges should be established ex-ante (the most distant of actual applications), and the format of transmission tariffs matters (the capacity format is indicated). The EBE method is independent from the choice of the slack bus and recognizes the counter-flows. Furthermore, the percentage of TTC to be recovered along with generation and load does not need to be specified before the method running and its equations are clear, which makes the method suitable for many applications. Therefore, this is the first TCA method employed by the dynamic framework.

The second method employed by the dynamic framework is the Nodal method. This method is formulated with the aim of quantifying two distinct aspects: the incremental cost of additional network capacity and the user contribution to investments in the existing network. A sensitivity matrix that provides the flow changes associated with the power injections is calculated and the TNUoS tariff is then formed by two parts. The first corresponds to a uniform stamp (identical to Postage Stamp method), which is corrected by the second part that introduces a location signal. Nodal constitutes the method currently employed in Brazil and it is very similar to the method presently adopted by Great Britain. The Brazilian regulatory agency in its reform agenda concluded that the Nodal method needs to be improved [20]. The main concern refers to the economic efficiency provided by its locational signals. Thus, the agency started a project to define a new TCA method that will be applied in the Brazilian system. Dissatisfaction with the locational signals provided by the TCA method to generation has raised concerns in Scotland, forcing regulators to discuss feasible alternatives of improvement [21]. Thus, Nodal is the second TCA method employed by the dynamic framework, with equal shares of the TTC recovery between generation and load (50% - 50%), identical to the current Brazilian proportion. Therefore, a direct contribution to the Brazilian regulatory agency and an indirect one to the British regulatory agency are granted by the framework with the Nodal method employment, since the economic efficiency of their locational signals are increased.

### *2.2. Methodological Limitations Intensified by the Energy Transition*

Although distinct TCA methods have been traditionally employed around the world, two methodological limitations, intensified by the energy transition, can be identified [5]: 1) lack of coordination between transmission pricing and load evolution and 2) lack of signals to guide the growth in generation capacity throughout the transmission system.

#### *2.2.1. Limitation 1: Lack of Coordination between Transmission Pricing and Load Evolution*

Traditional TCA methods form the TNUoS tariff based on equations that utilize only information from the present as input. The load evolution over time is not captured by them. This limitation occurs since these methods were developed under the old paradigm of passive consumers. Thus, they reveal to be inefficient in the energy transition context with active users who respond to tariff signals. From a uniform tariff, some traditional methods evolved in distinct approaches that seek to justify locational signals established on different assumptions. As each method guarantees the full TTC recovery and distinct assumptions are accepted, different TCA methods are currently employed. So, when the load grows at a bus, its tariff does not necessarily rise, which is desirable to induce the load growth at other buses. Similarly, it is desirable that buses with load decrease have their tariffs reduced to recompense these users, as a flexibility resource, besides inducing the load growth at these locations. Only in this way, a coordinated and dynamic balance can be achieved, in terms of transmission pricing and load evolution.

#### *2.2.2. Limitation 2: Lack of Signals to Guide the Growth in Generation Capacity Throughout the Transmission System*

Another limitation verified is the lack of signals to guide the growth in generation capacity throughout the transmission system. With the replace of polluting sources, which are concentrated and close to the consumption centres, to intermittent renewable sources that are decentralized and dependent on climatic conditions, the need for suitable generation signals boosts. Moreover, with the energy transition, the load evolution and the generation behaviour are becoming faster and more unpredictable. So, two questions have become relevant. Which locations are the most suitable to expand the generation capacity? And how can new resources of generation be induced to such locations? In this sense, we can observe that traditional TCA methods employ basic procedures to determine the generation dispatch responsible for the power flow information. Thus, these methods provide a TNUoS tariff for generators without efficient signals. We believe that tariff signals need to guide the generation capacity expansion to locations that are contributory to improve the system operational conditions. The optimal generation dispatch necessary to minimize the transmission loss must be captured. Thus, the generators that contribute to the loss reduction are rewarded, through discounts on their tariffs, providing an overall gain for all users. In this way, naturally generation gets close to load, which also contributes to avoid the transmission congestion in a long-term prospect.

## 3. Integrated Structure with the Feedback between Transmission Tariffs and Agents of Electricity Consumption and Generation

The integrated structure developed in this work to analyse the feedback between transmission tariffs and responses from agents of electricity consumption and generation is composed of four interconnected parts. They can be nominated as: dynamic framework to form the transmission tariffs, agents of electricity consumption, agents of electricity generation, and power flow procedure. The framework is an original development and constitutes the main contribution of the work. The agents of consumption are subdivided into: unresponsive loads, responsive loads, and responsive DNs. In this study, the agents of generation are solely responsive generators, to allow the analysis of generation capacity expansion in response to transmission tariffs. Finally, the power flow procedure adopted in the work is subdivided in: power flow and optimal power flow (OPF). They provide the required information for the TNUoS tariff formation by the framework. Fig. 1 shows the general arrangement of the integrated structure.

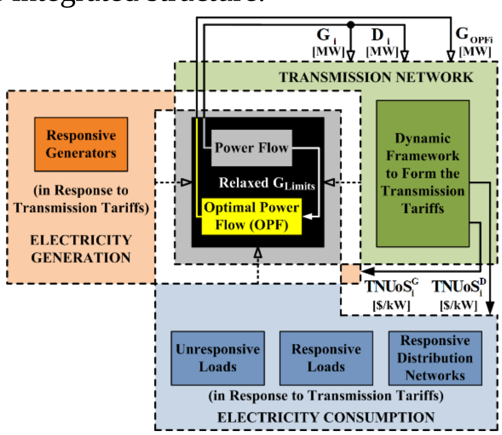


Fig. 1. General arrangement of the integrated structure.

The dynamic framework forms transmission tariffs for load demand ($TNUoS_i^D$) and generation ($TNUoS_i^G$). The TNUoS tariff is utilized by responsive loads, responsive DNs and responsive generators aiming to reduce their transmission cost. The power flow procedure utilizes information from transmission network and electricity consumption and generation, performing a dispatch and also an optimal dispatch to minimize the transmission loss. Thus, new values of generation ($G_i$), consumption ($D_i$), and optimal generation ($G_{OPFi}$) from each bus are provided for the framework that updates the transmission tariffs in a dynamic process.

### *3.1. Dynamic Framework to Form the Transmission Tariffs*

Different approaches can be applied to determine how transmission investors will recover their costs [6]. The definition of specific criteria to form the TTC is outside the scope of this work, which focuses on the TTC allocation across the buses. Similarly to [18], the TTC value, in \$, employed is based on the reactance value and is given by:

$$TTC = 10^6 . \sum_{k=1}^{N_L} x_k \, , \tag{1}$$

where $N_L$ is the total number of transmission lines and $x_k$ is the reactance of the line *k*.

Initially, the dynamic framework calculates a coupling factor ($F$) between the load evolution and the present state of the power system. This factor is obtained from:

$$F = \frac{\left( \sum_{i=1}^{N_D} \left| D_i^t - D_i^{t-1} \right| \right) . W_F}{\left( G_{TOTAL}^t + D_{TOTAL}^t \right) . N_{GD}} \, , \tag{2}$$

where $N_D$ is the total number of loads, $D_i^t$ is the load demand on bus *i* at the instant of time *t*, $D_i^{t-1}$ is the load demand on bus *i* at the previous instant, $W_F$ is the coupling factor weight, $G_{TOTAL}^t$ is the total generation at time *t*, $D_{TOTAL}^t$ is the total load demand at time *t*, and $N_{GD}$ is the total number of generators and loads. Then, the system costs are calculated, subdivided into evolution cost ($C_E^{TOTAL}$) and present cost ($C_P^{TOTAL}$):

$$C_E^{TOTAL} = (TTC).(F) \, , \tag{3}$$

$$C_P^{TOTAL} = (TTC).(1 - F) \, , \tag{4}$$

where $$C_E^{TOTAL} + C_P^{TOTAL} = (TTC).(F) + (TTC).(1-F) = TTC.(F + 1 - F) = TTC. \tag{5}$$

The evolution cost only exists if the coupling factor is not null. Moreover, the sum of the two costs guarantees the full TTC recovery for any $F$. The value of $F$ changes every instant of time, since it is composed of non-controllable variables that are modified over time, especially the individual load demands. $W_F$ is a nonnegative value ($W_F \geq 0$) that can amplify $F$ ($W_F > 1$); attenuate $F$ ($0 < W_F < 1$); or even cancel $F$ ($W_F = 0$), inactivating the dynamic framework with a null evolution cost.

Afterwards, the present cost ($C_P^{TOTAL}$) is allocated to each system bus ($C_{Pi}$). For this allocation, any TCA method can be employed. In this work, we employ two traditional methods: EBE [17, 18] and Nodal [18, 19].

Hereafter, the cost-benefit of the evolution ($C_{Bi}^{EX-ANTE}$) is calculated from:

$$C_{Bi}^{EX-ANTE} = \left[ \frac{C_E^{TOTAL}}{\sum_{i=1}^{N_D} \left| D_i^t - D_i^{t-1} \right|} \right] . \left( D_i^t - D_i^{t-1} \right) . \tag{6}$$

This cost-benefit does not guarantee the full TTC recovery. Therefore, the evolution cost associated with each load of the system is calculated ($C_{Ei}^{D}$), containing the additional portion necessary for the full recovery. It is given by:

$$C_{Ei}^{D} = C_{Bi}^{EX-ANTE} + \frac{\left(C_{E}^{TOTAL} - \sum_{i=1}^{N_D} C_{Bi}^{EX-ANTE}\right).N_D.D_i^t}{N_{GD}.D_{TOTAL}^{t}}. \tag{7}$$

With the values of the necessary costs ($C_{Pi}$, $C_{Ei}^{D}$), the final TNUoS tariff associated with the load *i* at the instant of time *t* ($TNUoS_i^D$) is then calculated from:

$$TNUoS_i^D = \frac{C_{Pi} + C_{Ei}^{D}}{D_i^t}. \tag{8}$$

Regarding the generators, the evolution cost associated with generation ($C_E^G$) is:

$$C_E^G = \frac{C_{E}^{TOTAL} - \sum_{i=1}^{N_D} C_{Bi}^{EX-ANTE}}{N_{GD}}. \tag{9}$$

The value resulting from this calculation is isonomic in terms of impact for generators. Thus, to consider the contribution of each generator to transmission loss minimization, an individual benefit associated with the minimization ($B_{Ei}^{G}$) is calculated from:

$$B_{Ei}^{G} = C_E^G.\left[\frac{\left(G_{OPFi}^{t} - G_i^t\right)/B_{BASE}}{\left(1 + M_{DIF}^{G}\right)^{A_B}}\right], \tag{10}$$

where $$M_{DIF}^{G} = \sqrt{\frac{\sum_{i=1}^{N_G}\left(\frac{\left|G_{OPFi}^{t} - G_i^t\right|}{\left|G_{OPF}^{t} - G^t\right|_{MIN}} - \frac{\sum_{i=1}^{N_G}\frac{\left|G_{OPFi}^{t} - G_i^t\right|}{\left|G_{OPF}^{t} - G^t\right|_{MIN}}}{N_G}\right)^2}{N_G}}, \tag{11}$$

$G_{OPFi}^{t}$ and $G_i^t$ are the optimal generation and the verified generation on bus *i* at the instant of time *t* respectively, $B_{BASE}$ is the base of the benefit, in MW, $M_{DIF}^{G}$ is the monitoring variable of generation capacity, $A_B$ is the attenuator of the benefit, $N_G$ is the total number of generators, $\left|G_{OPFi}^{t} - G_i^t\right|$ is the absolute difference between the optimal and the verified generation for each generator, and $\left|G_{OPF}^{t} - G^t\right|_{MIN}$ is the minimum absolute difference across all generators.

This benefit inserts individuality to the evolution cost associated with generation, since the contribution of each generator in transmission loss minimization is apprehended by the benefit. The base is a positive value less than or equal to one (0 < $B_{BASE}$ ≤ 1). Its default value is one ($B_{BASE}$ = 1), but the value can be decreased to amplify the benefit. The monitoring variable ($M_{DIF}^{G}$) allows to quantify, through a global measure, the quality of the system generation capacity in terms of the difference between: the optimal generation to transmission loss minimization and the generation actually verified. This variable provides a measure of the uniformity level in relation to the mentioned difference. Finally, the attenuator is a nonnegative value ($A_B$ ≥ 0) that can provide the maximum benefit ($A_B$ = 0), as well as progressively attenuate the benefit ( $A_B$ > 0).

Afterwards, the difference between the evolution cost associated with the whole generation and the benefit associated with each generator ( $C^G_{EX-ANTEi}$ ) is calculated from:

$$C^G_{EX-ANTEi} = C^G_E - B^G_{Ei}. \tag{12}$$

This difference, configured as a general cost discounted by an individual benefit, does not guarantee the full TTC recovery. Therefore, the evolution cost associated with each generator of the system ( $C^G_{Ei}$ ), containing the additional portion for the full recovery, is given by:

$$C^G_{Ei} = C^G_{EX-ANTEi} + \left( \frac{C^G_E .N_G - \sum_{i=1}^{N_G} C^G_{EX-ANTEi}}{G^t_{TOTAL}} \right) .G^t_i . \tag{13}$$

Obtained the individual values of the required costs ( $C_{Pi}$ , $C^G_{Ei}$ ), the final TNUoS tariff associated with the generator *i* at the instant of time *t* ( $TNUoS^G_i$ ) is then calculated from:

$$TNUoS^G_i = \frac{C_{Pi} + C^G_{Ei}}{G^t_i}. \tag{14}$$

The coupling factor weight $W_F$ is an adjustment parameter of $C^{TOTAL}_E$ , since the other variables ( $TTC$ , $D^t_i$ , $D^{t-1}_i$ , $G^t_{TOTAL}$ , $D^t_{TOTAL}$ , and $N_{GD}$ ) are non-controllable. In other words, such variables reflect the transmission cost formation and the behaviour of consumption and generation, which is outside the scope of cost allocation, focus of this work. Therefore, $W_F$ represents a control variable of $F$ and, consequently, of $C^{TOTAL}_E$ , allowing the tuning of the tariff adjustments made by the framework. The value of $W_F$ must be as greater as the dispersion of the original tariffs provided by the pure TCA method is in order to become more intense the adjustments. Thus, if a fixed value for $W_F$ is adopted over time, the load tariff adjustments will have an uncontrollable intensity, as the other variables will naturally change. On the other hand, if a flexible value is utilized for $W_F$ , the adjustments will have a controllable intensity, as $W_F$ can be tuned, depending on the non-controllable variable behaviours.

In the work, a flexible value for $W_F$ is employed, so that $F$ is amplified ( $W_F$ > 1). Thus, $C^{TOTAL}_E$ is increased, and the tariff adjustments are intensified. For the tuning of $W_F$ , maximum and minimum load tariff limits are adopted. The upper limit corresponds to 150% of the maximum tariff obtained with $W_F$ = 0 (framework inactivated) and the lower limit corresponds to 50% of the minimum tariff with $W_F$ = 0. It means that $TNUoS^D_{MIN} \leq TNUoS^D_i \leq TNUoS^D_{MAX}$ where $TNUoS^D_{MIN} = 0.5.TNUoS^{D(W_F=0)}_{MIN}$ and $TNUoS^D_{MAX} = 1.5.TNUoS^{D(W_F=0)}_{MAX}$ . So $W_F$ must contain a value such that all load tariffs obtained with the framework are contained within this range. Thus, the intensity of tariff adjustments is tuned at each instant of time, based on these percentages. If broader limits were adopted, such as 180% and 20%, the adjustments would become more intense, but the original tariff characteristics of the pure TCA method would be less preserved. In opposite way, limits like 120% and 80% would make adjustments less intense. Therefore, the intermediate value of 150% and 50% was adopted. However, regardless of the $W_F$ value, the framework characteristics of full TTC recovery, as well as individual, proportional, and coordinated tariff adjustments across the different load buses, are preserved.

In relation to the base of the benefit $B_{BASE}$ and to the attenuator of the benefit $A_B$, in this work, $B_{BASE}$ is kept with the value 1 (default) and the smallest possible values are adopted for $A_B$, so that the individual benefits calculated by the framework ($B_{Ei}^G$) have the maximum impact possible on the tariff adjustments. The value of $A_B$ is tuned in order to keep the generation tariffs within the established percentage range. This range corresponds to 150% of the maximum generation tariff obtained with $W_F$ = 0 and to 50% of the minimum generation tariff with $W_F$ = 0. That is, $TNUoS_{MIN}^G \leq TNUoS_i^G \leq TNUoS_{MAX}^G$ where $TNUoS_{MIN}^G = 0.5.TNUoS_{MIN}^{G(W_F=0)}$ and $TNUoS_{MAX}^G = 1.5.TNUoS_{MAX}^{G(W_F=0)}$. Therefore, a percentage range identical to the utilized for load tariffs is adopted for generation tariffs. At each instant of time, $A_B$ is then tuned to control the adjustments, keeping the generation tariffs provided by the framework within this range.

We can verify that $B_{BASE}$ represents a control variable with an opposite effect to $A_B$. The individual benefits ($B_{Ei}^G$) are amplified by $B_{BASE}$, when values lower than the default 1 (maximum value) are adopted. On the other side, $A_B$ progressively attenuates $B_{Ei}^G$, when values greater than 0 (minimum value) are incrementally employed. We can also notice that the other variables associated with $B_{Ei}^G$ ($C_E^G$, $G_{OPFi}^t$, $G_i^t$, and $N_G$) are non-controllable. The variable $C_E^G$ is coupled to $C_E^{TOTAL}$ and, consequently, to $F$ and to $W_F$. Thus, $B_{BASE}$ and $A_B$ are fundamental for controlling the generation tariff adjustments, since the $W_F$ increase will lead to a proportional rise of $C_E^G$. In this way, $B_{BASE}$ and $A_B$ work as control variables that allow the decoupling between the adjustments for load tariffs and for generation tariffs. It is worth highlighting that whatever the values of $B_{BASE}$ and $A_B$, the framework guarantees the full TTC recovery and also the provision of individual, proportional and coordinated adjustments across the distinct generation buses of the system. Therefore, this attribute, added to the analogous aspect of $W_F$ for load buses, provides a very generic and robust character to the framework.

Besides ensuring the full TTC recovery for any configuration, the framework guarantees the overall TCA regulatory basis. Economic efficiency: costs and benefits proportional to the intensity with which each agent demands or relieves the system. Fairness: since individual and coordinated adjustments are provided based on the behaviour of each agent in the system. And transparency: due to the deterministic modelling with straight equations that do not introduce uncertainty into the calculations as there are no associated predictions and estimates. The framework can be separated into four phases: Definition of System Costs (Phase A), Allocation of the Present Cost (Phase B), Formation of the Load TNUoS Tariff (Phase C), and Formation of the Generation TNUoS Tariff (Phase D), which are illustrated in Fig. 2.

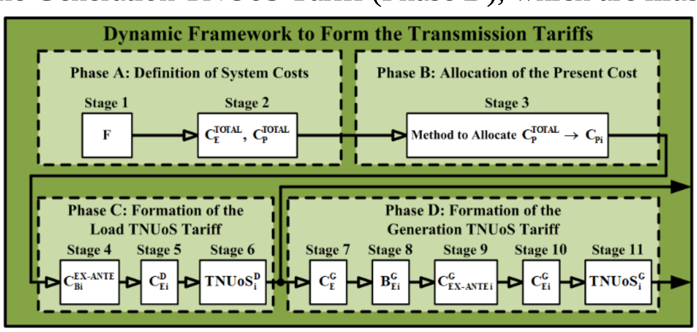

Fig. 2. Flowchart with the dynamic framework.

In turn, each phase can be subdivided into different stages:

- Phase A: Coupling Factor (Stage 1) - Equation (2), System Costs (Stage 2) - Equations (3) and (4);
- Phase B: Present Cost for Each System Bus (Stage 3);
- Phase C: Cost-Benefit of the Evolution (Stage 4) - Equation (6), Evolution Cost for Load (Stage 5) - Equation (7), Final Load Tariff (Stage 6) - Equation (8);
- Phase D: Evolution Cost for Generation (Stage 7) - Equation (9), Benefit for Loss Minimization (Stage 8) - Equation (10), Difference between Cost and Benefit (Stage 9) - Equation (12), Cost of the Evolution Considering the Benefit (Stage 10) - Equation (13), Final Generation Tariff (Stage 11) - Equation (14).

The algorithms of all stages that compose the dynamic framework, as well as the traditional TCA methods employed in Phase B, were developed on Matlab platform.

### *3.2. Responsive Distribution Networks Employed*

The responsive DNs employed in this work are sensitive to the TNUoS tariff and their configurations are determined by an optimization model that considers three costs in their objective function: cost for using the transmission network, cost of electricity losses into the DN, and cost of operation and maintenance of the border substations (SSs) [22]. The model considers as constraints: voltage limits at distribution nodes, current limits into distribution branches, and maximum SS capacities. So, the minimum cost configuration is determined by the model through a heuristic algorithm composed of two stages: the construction search phase and the local search phase [23]. Thus, the loading at each border SS is modified through the action of switching devices along the feeders.

Modern DNs with control devices and models that minimize costs will allocate load at border SSs with lower TNUoS tariffs in the future, although currently most distribution utilities do not undertake this. It occurs due to the lack of regulatory incentives nowadays, which allows the utilities to pass the transmission cost to their final customers in an integral and uniform way. However, with the DN modernization due to the energy transition, the feasibility of DNs that respond to economic signals and minimize their global costs is being gradually increased. Also, the growing importance of capacity tariffs and regulatory directions pointed out recently by the world literature indicate that this scenario is already being considered by regulators [1, 24]. Thus, economic incentives for distribution utilities to reduce their transmission cost will be naturally introduced, which promotes a better use of power system resources, postpones reinforcements, and so decreases the overall cost paid by users.

### *3.3. Power Flow Procedure Adopted*

The power flow procedure adopted in the work is composed of two stages: simple power flow and OPF to transmission loss minimization. Both stages are obtained with the computational package Matpower 7.0, a consolidated tool that runs on Matlab and offers performance and robustness in power system simulation [25]. To determine the system dispatch, providing the framework information, an alternating current (AC) power flow is performed. The method of Newton with polar representation is utilized, since this is the default method of the package. Additionally, an OPF to minimize the transmission loss is executed to provide the optimal generation required by the Stage 8 in the dynamic framework. To execute the OPF, it is needed to assign positive, constant, and equal marginal costs for all generators with the function MIPS (Matpower Interior Point Solver), the default function. Since generation must equal demand plus losses, if demand is constant, loss is minimized by minimizing overall generation. With equal costs for generators, the default objective of minimizing the total cost is equivalent to minimize the total generation, which is equivalent to transmission loss minimization. The electrical characteristics of the transmission network used to obtain the AC power flow, in terms of bus data and branch data, are kept the same. Only the generation limits are relaxed to allow an effective OPF execution. The established limits of active and reactive generation are systemic with equal values for all generators.

The maximum active generation limit established corresponds to 150% of the average active generation verified in the system ($G^{MW}_{MAXIMUM} = 1.5.G^{AVERAGE}_{VERIFIED}$). If the resulting optimal value at any bus is equal to the established maximum limit and if this value is smaller than the generation verified at this bus ($G^{MW}_{OPF} = G^{MW}_{MAXIMUM} < G^{MW}_{VERIFIED}$), then the maximum limit must be increased in steps of 5% (155%, 160%, and so on). This is performed until every optimal generation below the verified generation ($G^{MW}_{OPF} < G^{MW}_{VERIFIED}$) is also below the established maximum limit ($G^{MW}_{OPF} < G^{MW}_{MAXIMUM}$). The guarantee of this condition is important to ensure that no generator is financially harmed due to the calculation of a benefit (Stage 8) restricted by the maximum limit. The minimum active generation limit established corresponds to 50% of the minimum active generation verified in the system ($G^{MW}_{MINIMUM} = 0.5.G^{MINIMUM}_{VERIFIED}$). Thus, the executed OPF guarantees a dispatch with minimum transmission loss and provides optimal values of generation, with the respect for all electrical constraints of the original network.

## 4. Application Results

The flowchart with the simulation scheme, which unifies the interconnected parts that compose the integrated structure developed in this work, is illustrated in Fig. 3.

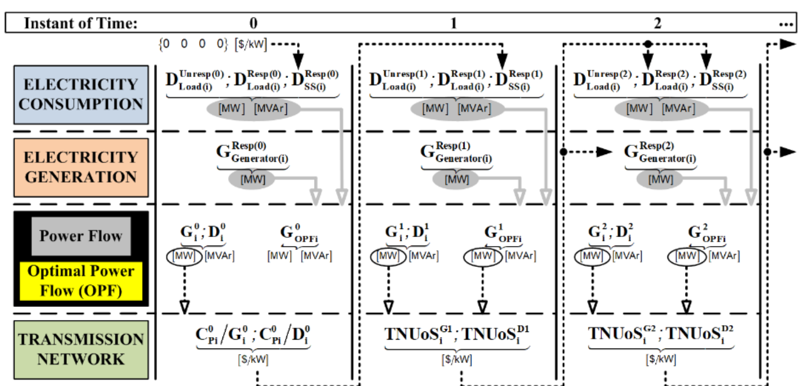


Fig. 3. Flowchart with the simulation scheme.

At the beginning of the instant 0, the loading at border SSs ($D^{Resp(0)}_{SS(i)}$), which connect the responsive DNs to the transmission network, is determined employing null TNUoS tariffs. Active and reactive power from these border SSs, as well as from responsive loads ($D^{Resp(0)}_{Load(i)}$) and from unresponsive loads ($D^{Unresp(0)}_{Load(i)}$), are needed to perform the AC power flow. The specified values of active power from responsive generators ($G^{Resp(0)}_{Generator(i)}$) are also needed. TNUoS tariffs are calculated by a traditional TCA method ($C^0_{Pi}/G^0_i$ and $C^0_{Pi}/D^0_i$), since the dynamic framework requires the previous instant to form the tariffs. Thus, the optimal generation, obtained with OPF, is not utilized at this instant 0. At the instant 1, the responsive DNs employ TNUoS tariffs calculated at instant 0 for their reconfiguration. In addition to the AC power flow, the optimal generation is now utilized for the TNUoS tariff formation by the dynamic framework ($TNUoS_i^{G1}$ and $TNUoS_i^{D1}$). From the instant 2, the total system load is progressively increased. Thus, TNUoS tariffs calculated at the previous instant are employed by responsive DNs and responsive loads. Responsive generators also react to these tariffs, expanding their generation capacity to counterbalance the system load growth.

### *4.1. Power System Test Case*

The power system test case contains 40 buses and 54 transmission lines and its single-line diagram is shown in Fig. 4. This test case is derived from a system with 24 buses and 38 lines in peak load condition, whose original data may be obtained in [26].

Eight buses and eight lines were added to the original system, as the dynamic framework needs to identify the power injection type: load demand or generation. The added lines contain null resistance. The reactance ($x$) and susceptance ($b$) values, in p.u., are equal to half of the lowest adjacent values to the original bus where the new load bus is connected (from 25 to 32): $x_{1\text{-}25} = 0.0070$, $b_{1\text{-}25} = 0.0115$, $x_{2\text{-}26} = 0.0070$, $b_{2\text{-}26} = 0.0170$, $x_{7\text{-}27} = 0.0305$, $b_{7\text{-}27} = 0.0085$, $x_{13\text{-}28} = 0.0240$, $b_{13\text{-}28} = 0.0500$, $x_{14\text{-}29} = 0.0210$, $b_{14\text{-}29} = 0.0410$, $x_{15\text{-}30} = 0.0085$, $b_{15\text{-}30} = 0.0180$, $x_{16\text{-}31} = 0.0085$, $b_{16\text{-}31} = 0.0180$, $x_{18\text{-}32} = 0.0070$, $b_{18\text{-}32} = 0.0150$.

Additionally, eight buses and eight lines were added to represent the border SSs that connect two responsive DNs: DN A (Buses: 33, 34, 35, 36) and DN B (Buses: 37, 38, 39, 40). These lines possess null resistance and null susceptance. However, the reactance ($x$) value, in p.u., is equal to one eighth of the lowest adjacent value to the original bus where the SS is connected. Thus, for the responsive DN A, we have: $x_{5\text{-}33} = 0.0106$, $x_{6\text{-}34} = 0.0076$, $x_{8\text{-}35} = 0.0076$, $x_{10\text{-}36} = 0.0076$. Also, the responsive DN B has: $x_{4\text{-}37} = 0.0130$, $x_{4\text{-}38} = 0.0130$, $x_{9\text{-}39} = 0.0105$, $x_{9\text{-}40} = 0.0105$. The TTC value, obtained from Equation (1), is $ 2,965,900.

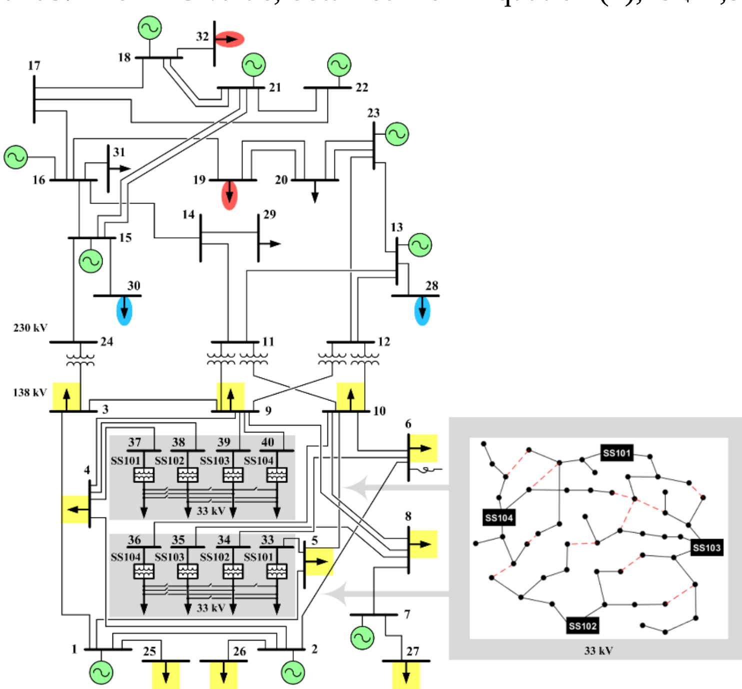


Fig. 4. Single-line diagram with the power system test case.

At $t = 0$, the responsive DNs (in gray) start with a load factor of 0.4, where SS101: 18.43 MW and 3.93 MVAr, SS102: 18.57 MW and 3.96 MVAr, SS103: 20.52 MW and 4.39 MVAr, SS104: 21.19 MW and 4.61 MVAr. The initial configuration of both responsive DNs is the same and is exhibited in Fig. 4 (null TNUoS tariffs). Loads at buses to which the border SSs are connected are reduced. Thus, the bus-SS set preserves the original system load and an active power flow, identical to the original data obtained in [26], is achieved. At $t = 1$, the responsive DNs are reconfigured, but the load factor of 0.4 is maintained.

From $t = 2$, the original total load (2850 MW and 580 MVAr) is progressively increased so that the economic signals provided by the TNUoS tariffs can be evaluated. The two responsive DNs have their load factor increased in steps of 0.1, reaching a value of 1.0 at the end of the period ($t = 7$). Furthermore, from $t = 2$, three other sets have their original values modified: responsive loads, unresponsive loads, and responsive generators. Ten responsive loads (in yellow), Buses 3, 4, 5, 6, 8, 9, 10, 25, 26, and 27, form a set that grows your total load by 6% each instant. This growth is subdivided across the responsive loads, inversely proportional to their TNUoS tariffs. Buses with the lowest tariffs receive the highest load growths in the following proportion: $1^{st}$ (cheapest) - 22%, $2^{nd}$ - 18%, $3^{rd}$ - 15%, $4^{th}$ - 13%, $5^{th}$ - 11%, $6^{th}$ - 9%, $7^{th}$ - 7%, $8^{th}$ - 5%, $9^{th}$ - 0%, $10^{th}$ (most expensive) - 0%. This division guarantees satisfactory operational conditions in the final simulation instants, when the system load is significantly increased. Four unresponsive loads have their loading changed regardless of their TNUoS tariff values. The Buses 28 and 30 (in blue) increases their loading by 6% every instant. On the other hand, the Buses 19 and 32 (in red) decreases their loading by 24% each instant. This allows the direct analysis of tariffs obtained with the action of the dynamic framework and without its action (framework inactivated). Finally, all ten generators (in green), Buses 1, 2, 7, 13 (slack), 15, 16, 18, 21, 22, and 23, are responsive. They counterbalance the system load growth, increasing their generation capacity. The increases are inversely proportional to the TNUoS tariffs with the proportion: $1^{st}$ (cheapest) - 19%, $2^{nd}$ - 17%, $3^{rd}$ - 15%, $4^{th}$ - 13%, $5^{th}$ - 11%, $6^{th}$ - 9%, $7^{th}$ - 7%, $8^{th}$ - 5%, $9^{th}$ - 3%, $10^{th}$ (most expensive) - 1%. If the increases occurred in a smaller number of generators, the operational conditions of the system would be degraded, which would restrict the set of simulations.

### *4.2. EBE Method*

In the following, an overview of the tariffs obtained with the pure EBE method is presented. Afterwards, the dynamic framework is activated and the results obtained are detailed. Finally, an analysis related to power flows and the transmission loss is shown.

#### *4.2.1. Tariff Overview with Pure EBE Method (without the Framework)*

Fig. 5 illustrates the TNUoS tariffs obtained with the pure EBE method for the four sets: all responsive generators, unresponsive loads, responsive loads, and responsive DNs.

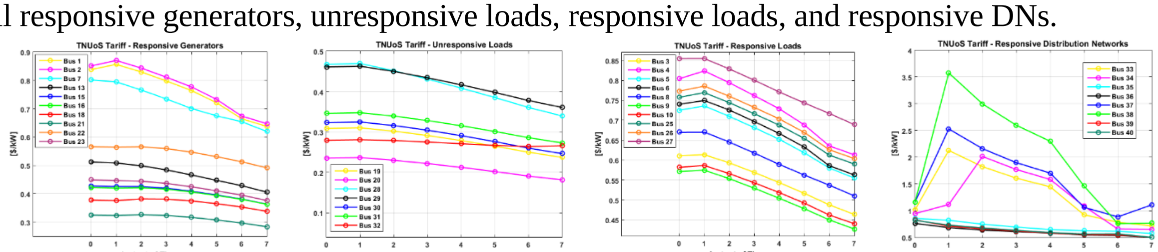


Fig. 5. TNUoS tariffs obtained with the pure EBE method: the four sets of agents.

For all responsive generators and responsive loads, the tariff order is kept over time, although the powers change their order. For the unresponsive loads, Bus 28 displays a large tariff reduction, despite this bus exhibits a load growth. And Bus 32 has the smallest tariff reduction, although it presents the greatest load decrease. About the responsive DNs, Buses 33, 34, 37, and 38 show a volatile behaviour, with high tariffs at the beginning. It is a method characteristic: with low loads, its tariffs get high values. Thus, the economic signals provided by the pure EBE method reveal to be inefficient, which makes evident the limitations 1 and 2.

#### *4.2.2. Dynamic Framework with EBE Method in Phase B*

Fig. 6 shows the power generation and the TNUoS tariff for all responsive generators.

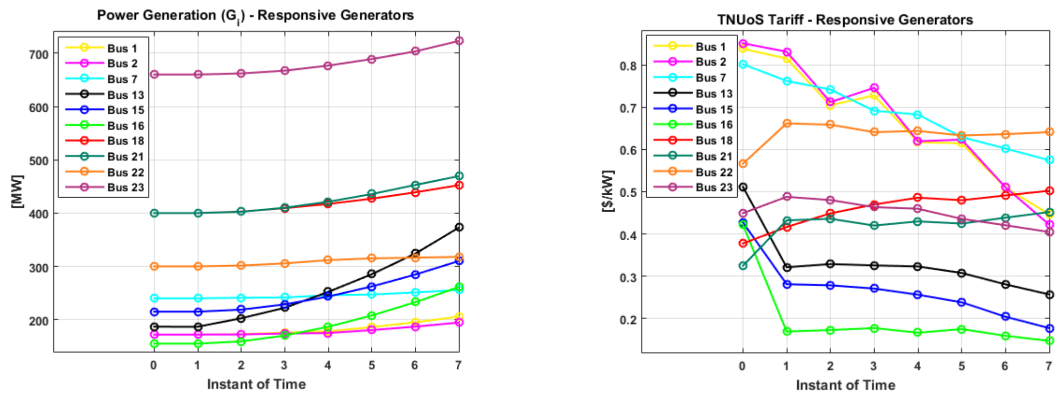


Fig. 6. Responsive generators: power generation ( $G_i$ ) and TNUoS tariff.

It is verified a significant reduction of the tariffs at Buses 1 and 2 and a less substantial reduction of the tariff at Bus 7. The tariffs at Buses 13, 15, and 16 also decrease with considerable intensity already at $t$ = 1. It occurs because the difference between the optimal and the verified generation for these six buses is positive during the whole period, which produces positive benefits and, consequently, tariff discounts. Contrarily, the generators at Buses 18, 21, 22, and 23 have negative benefits and thus tariff rises. The largest generation growths occur at buses with the lowest tariffs, as expected, where Bus 13 is the slack. The power demand and the TNUoS tariff for the unresponsive loads are illustrated in Fig. 7.

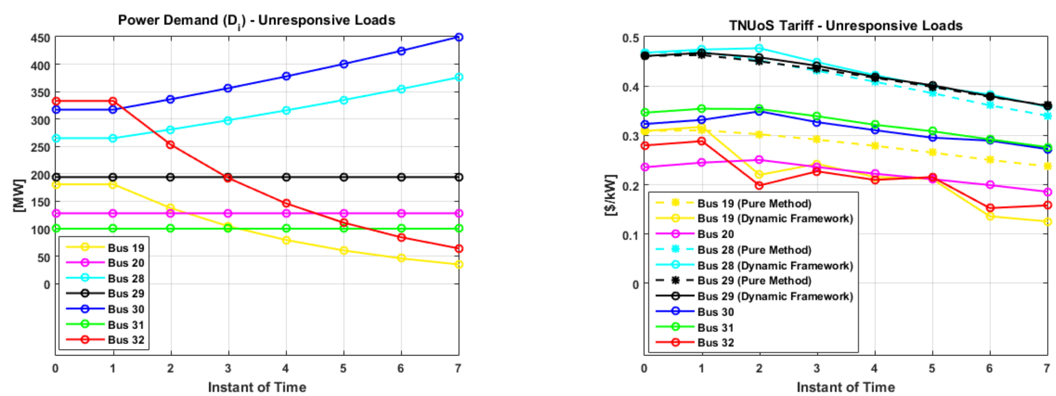


Fig. 7. Unresponsive loads: power demand ( $D_i$ ) and TNUoS tariff.

Buses 19 and 32, whose loads decrease, have their tariffs considerably reduced by the framework. In the end, these buses get to have the lowest loads and also the lowest tariffs. For comparison, the tariff at Bus 19 is also shown with the pure EBE method, which makes clear the role of the framework in reducing the tariff. Tariffs at Buses 28 and 30, whose loads grow smoothly, rise also smoothly in relation to the pure method. This gets clear when the tariffs at Bus 28, without and with the framework, are compared. The buses whose loads keep their values, Buses 20, 29, and 31, have little tariff changes, as exposed by the tariffs at Bus 29. Fig. 8 shows the power demand and the TNUoS tariff obtained for the responsive loads.

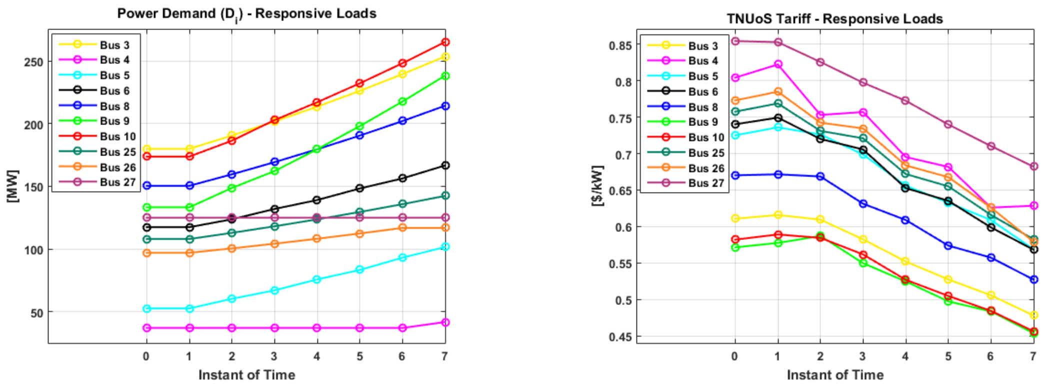


Fig. 8. Responsive loads: power demand ( $D_i$ ) and TNUoS tariff.

As expected, the load intensities are inversely proportional to the tariff values: higher loads occur on the cheaper buses. Bus 5 and 6 alternate their tariff positions at each instant. Also, there is alternation of positions at some instants between the buses: 9 and 10, 4 and 26, 25 and 26. As the load variations are small, in relation to their nominal loads, the tariff changes are also small. However, they are enough for the alternation of positions across tariffs with close values, which stimulates a more distributed load growth in the system. The power demand and the TNUoS tariff for the responsive DNs are exhibited in Fig. 9.

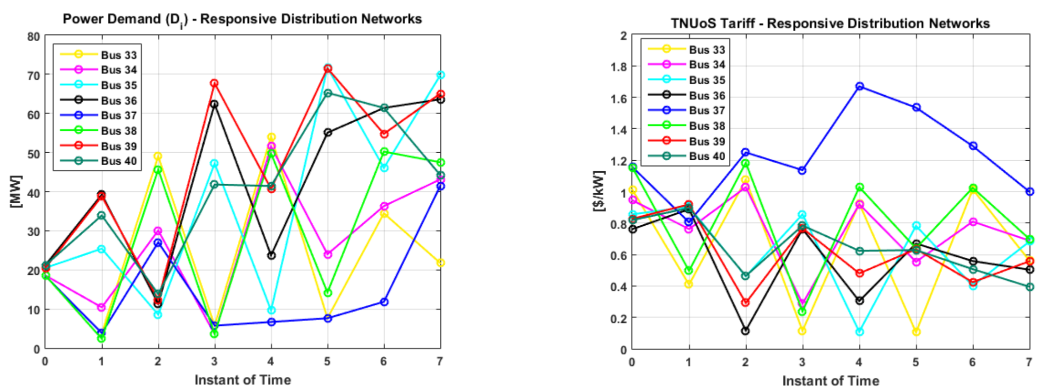


Fig. 9. Responsive DNs: power demand ( $D_i$ ) and TNUoS tariff.

A dynamic tariff-load balance over the period is obtained. When the load at the bus (border SS) grows, its tariff value also rises. And when such load decreases, its respective tariff also reduces. As the DN reconfiguration prioritizes the loading at SSs with lower tariffs, to minimize their internal costs, a dynamic balance is obtained. Bus 37, which initially has the highest tariff, is the last SS to have its loading substantially increased. Its low load makes that the present cost allocated by the EBE method (Phase B of the framework) produces a high tariff. Finally, the responsive DNs do not present operational violations, which shows the effectiveness of the configurations obtained. Table 1 exhibits the tariff limits adopted by the framework to tune its adjustment parameters and the monitoring variable outcomes.

**TABLE 1**
**Limits Adopted, Adjustment Parameters, and Monitoring Variable with EBE Method in Phase B**

| **Limits and Parameters:** | **Instant of Time (*t*):** 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| $TNUoS_{MAX}^{D}$ [$/kW] | 5.3669 | 1.6398 | 3.8958 | 2.5115 | 2.3100 | 1.7787 | 1.1860 |
| $TNUoS_{MIN}^{D}$ [$/kW] | 0.1183 | 0.1139 | 0.1109 | 0.1054 | 0.1013 | 0.0960 | 0.0911 |
| $W_F$ | 30.0 | 21.3 | 13.5 | 16.1 | 14.6 | 30.0 | 30.0 |
| $TNUoS_{MAX}^{G}$ [$/kW] | 1.3056 | 1.1979 | 1.2141 | 1.1046 | 1.0944 | 1.0071 | 0.9476 |
| $TNUoS_{MIN}^{G}$ [$/kW] | 0.1616 | 0.1641 | 0.1617 | 0.1591 | 0.1540 | 0.1489 | 0.1429 |
| $A_B$ | 1.8 | 2.8 | 2.8 | 2.6 | 2.1 | 1.9 | 1.1 |
| $M_{DIF}^{G}$ | 2.5421 | 2.2228 | 1.8749 | 1.8191 | 2.2137 | 2.3527 | 4.0335 |

At $t = 1$, the framework starts with the coupling factor weight equal to 30.0 and the load tariff limits are satisfied. In order to meet the generation tariff limits, the attenuator of the benefit needs to start with a value of 1.8. From $t = 2$ to $t = 5$, the weight is reduced and the attenuator is increased to fulfil the tariff limits. At $t = 6$, the weight reaches the original value of 30.0 as the growth in DN loading allows greater acting of the framework in load tariff adjustments. The attenuator reaches its minimum value of 1.1 at $t = 7$ because, as generators respond to TNUoS tariffs, the generation difference (optimal and verified) at Bus 16, which has the lowest tariff, decreases (lower benefit), thus allowing greater framework acting. The monitoring variable shows little variations up to $t = 6$ and huge elevation at $t = 7$. This is governed by the minimum absolute difference between the optimal and the verified generation (Bus 7). At $t = 7$, this difference declines, while the larger differences (Buses 18 and 21) rise. Thus, the measure dispersion increases (lower uniformity), which is reflected by the variable.

### *4.2.3. Transmission Flows and Loss: EBE Comparative Analysis*

Fig. 10 presents a comparative analysis between the results obtained with the pure EBE method (framework inactivated) and with the dynamic framework activated, in relation to the total transmission loss and to the power flow from areas whose OPF indicates generation decline in order to reduce the transmission loss (Buses 18, 21, 22, and 23).

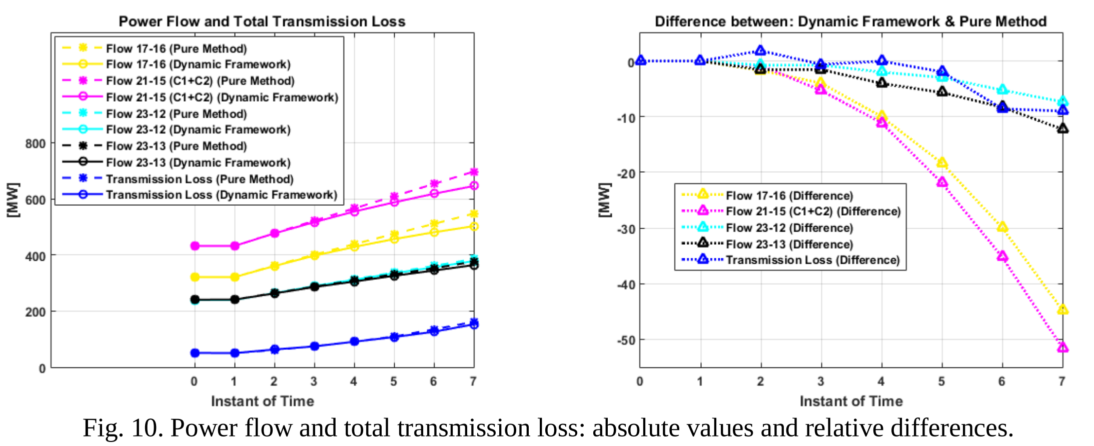

Fig. 10. Power flow and total transmission loss: absolute values and relative differences.

With the dynamic framework, flows from areas that do not contribute to minimize the transmission loss, Flow 17-16, Flow 21-15 (Circuit 1 + Circuit 2), Flow 23-12, and Flow 23-13, are decreased as well as the total transmission loss. This gets more evident when we analyze the relative differences regarding the dynamic framework and the pure method. When the system loading is intensified, from $t = 5$, the decreases become higher. This fact shows the framework effectiveness in providing suitable signals for generators. With the framework inactivated, the generation tariff order is kept the same over the whole period, which reveals that the tariff signals provided only by the EBE method do not conduct properly the generation capacity expansion. In this sense, the dynamic framework provides a relevant contribution, capturing the system evolution and indicating suitable locations for the expansion, which decreases the intensity of distant flows and thus reduces the total transmission loss.

### *4.3. Nodal Method*

An overview of the tariffs obtained with the pure Nodal method is exposed in the following. After, the results with the activation of the dynamic framework are detailed. Lastly, an analysis associated with power flows and with the transmission loss is illustrated.

#### *4.3.1. Tariff Overview with Pure Nodal Method (without the Framework)*

Fig. 11 shows the TNUoS tariffs with the pure Nodal method for the four sets: all responsive generators, unresponsive loads, responsive loads, and responsive DNs.

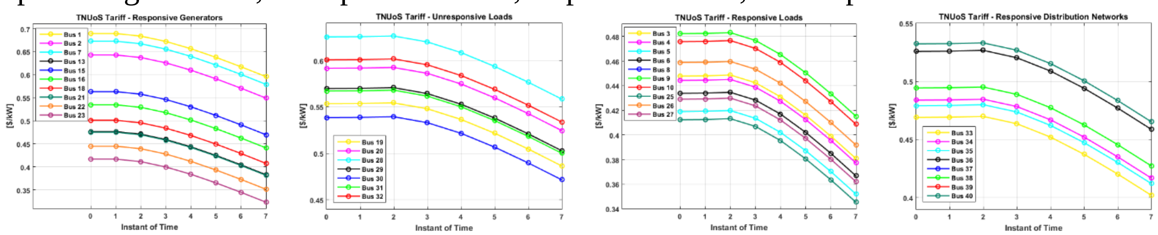

Fig. 11. TNUoS tariffs obtained with the pure Nodal method: the four sets of agents.

For the four sets, the tariff order remains unchanged during the whole period as we can verify, although the power positions change in all sets over time. Thus, this overview shows the total lack of economic efficiency provided by the pure Nodal method, limitations 1 and 2, since the tariffs formed by the method do not respond to generation and load variations.

#### *4.3.2. Dynamic Framework with Nodal Method in Phase B*

Fig. 12 exhibits the power generation and the TNUoS tariff for all responsive generators.

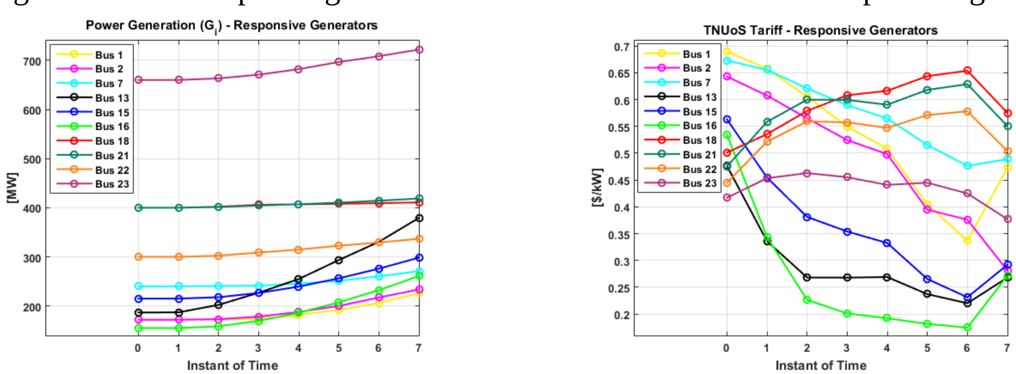

Fig. 12. Responsive generators: power generation ($G_i$) and TNUoS tariff.

The difference between the optimal and the verified generation at Buses 1, 2, 7, 13, 15, and 16 is positive over the whole period, which produces positive benefits and thus tariff discounts. Up to $t = 6$, a significant reduction of the tariffs at Buses 1, 2, 13, 15, and 16 is verified. A less expressive reduction is noticed at Bus 7. The generators at Buses 18, 21, 22, and 23 present negative benefits along the period. The tariffs at Buses 18, 21, and 22 rise significantly until $t = 6$. A less expressive rise is verified at Bus 23. From $t = 6$ to $t = 7$, the tariffs at Buses 1, 7, 13, 15, and 16 rise and the tariff at Bus 2 reduces. It occurs because, although these buses have positive benefits, the difference between the optimal and the verified generation only grows at Bus 2. The tariffs at Buses 18, 21, 22, and 23, with negative benefits, are also reduced because such difference gets less negative at these buses. The largest generation growths occur at buses with the lowest tariffs, as awaited (Bus 13: slack). The power demand and the TNUoS tariff for the unresponsive loads are illustrated in Fig. 13.

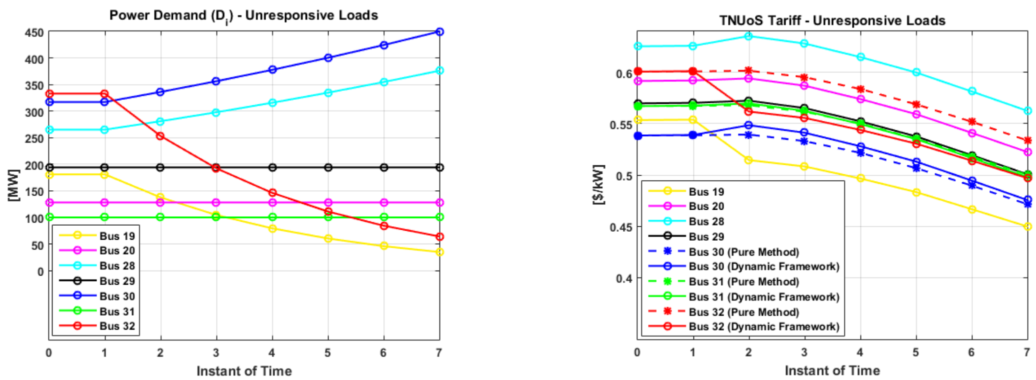

Fig. 13. Unresponsive loads: power demand ( $D_i$ ) and TNUoS tariff.

Buses 19 and 32, whose loads decrease, have their tariffs reduced by the framework. For comparison, the tariff at Bus 32 with the pure Nodal method is shown, which makes clear the action of the framework in the tariff reduction. The tariffs at Buses 28 and 30, whose loads grow smoothly, also rise smoothly, which can be verified comparing the tariffs at Bus 30 with the pure method and with the framework activated. Buses 20, 29, and 31, with constant loads, have their tariffs little modified, as shown by the Bus 31 that allows such verification. Fig. 14 shows the power demand and the TNUoS tariff obtained for the responsive loads.

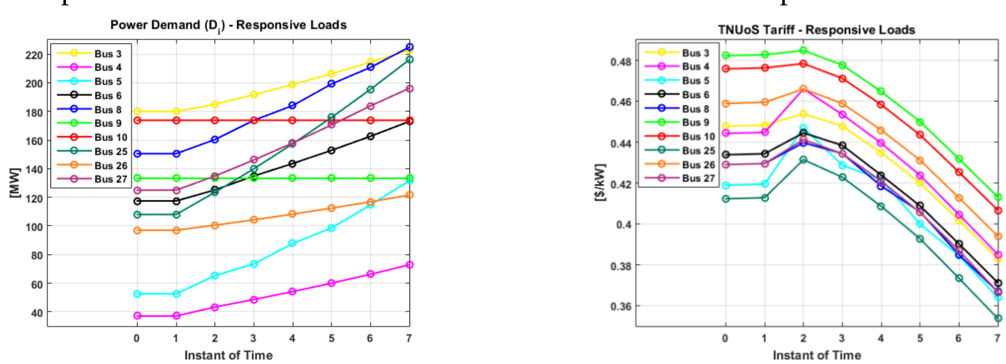

Fig. 14. Responsive loads: power demand ( $D_i$ ) and TNUoS tariff.

The load intensities are inversely proportional to the tariff values, as expected. The largest load growth occurs at Bus 25, while the loads at Buses 9 and 10 are unchanged. Buses 9 (highest), 10, 25 (lowest), and 26 maintain their tariff positions over the whole period. The other buses alternate their tariff positions at distinct instants of time. As the tariffs with the employment of Nodal method in Phase B of the framework have closer values, compared to the employment of EBE method, the tariff positions change more often. That is, with Nodal in Phase B, the tariff adjustments undertaken by the framework have a greater final effect. Thus, the stimulus for the agents of consumption to grow their demand in a more distributed manner is better perceived by the loads. The power demand and the TNUoS tariff for the responsive DNs are exhibited in Fig. 15.

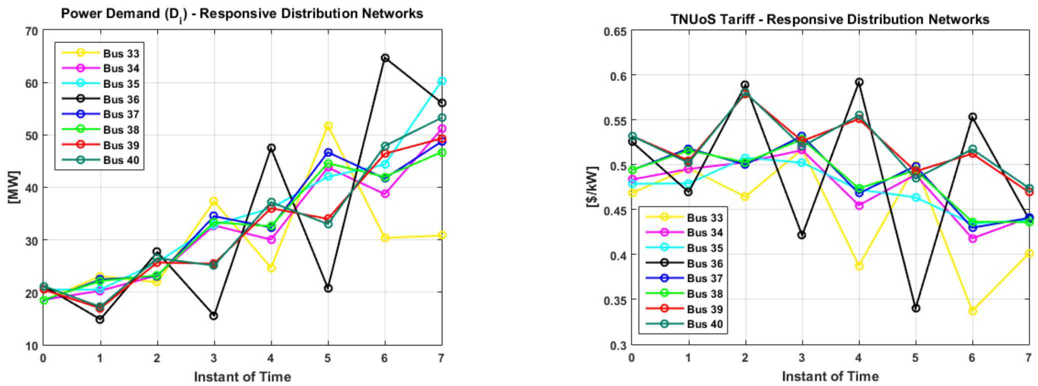


Fig. 15. Responsive DNs: power demand ( $D_i$ ) and TNUoS tariff.

A dynamic tariff-load balance over the period is obtained: when the SS loading grows, its tariff also rises; and when the SS loading decreases, its tariff also reduces. As the loading of the cheapest SSs is privileged, a balance is then reached. It can be noticed that the tariff adjustments made by the framework are proportional to the load variation magnitudes and coordinated across the different buses. The responsive DNs do not have operational violations, which confirms the reconfiguration effectiveness. Table 2 illustrates the tariff limits adopted by the framework to tune its adjustment parameters and the monitoring variable outcomes.

**TABLE 2**
**Limits Adopted, Adjustment Parameters, and Monitoring Variable with Nodal Method in Phase B**

| Limits and Parameters: | Instant of Time ($t$): 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| $TNUoS^D_{MAX}$ [$/kW] | 0.9384 | 0.9390 | 0.9302 | 0.9122 | 0.8908 | 0.8641 | 0.8372 |
| $TNUoS^D_{MIN}$ [$/kW] | 0.2062 | 0.2064 | 0.2035 | 0.1975 | 0.1904 | 0.1815 | 0.1726 |
| $W_F$ | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 |
| $TNUoS^G_{MAX}$ [$/kW] | 1.0344 | 1.0262 | 1.0079 | 0.9832 | 0.9531 | 0.9213 | 0.8871 |
| $TNUoS^G_{MIN}$ [$/kW] | 0.2085 | 0.2057 | 0.1996 | 0.1914 | 0.1814 | 0.1708 | 0.1593 |
| $A_B$ | 0.0 | 1.9 | 2.0 | 1.7 | 1.4 | 0.8 | 0.0 |
| $M^G_{DIF}$ | 2.6901 | 1.4562 | 1.0476 | 0.9671 | 0.7619 | 0.7267 | 0.8402 |

At $t$ = 0, the set of tariffs obtained with the Nodal method has a standard deviation of 0.0732. For this instant, the EBE method, previously employed for allocating the present cost, presented a standard deviation of 0.2452. Thus, as 30.0 was utilized for $W_F$ at $t$ = 0 with EBE method, the initial value of 9.0 for $W_F$ is now used with Nodal method, where 0.0732/0.2452 ≈ 9.0/30.0. During the whole period, a weight of 9.0 is used because the load tariff limits are satisfied with such value. To meet the generation tariff limits, the attenuator needs to be greater than zero between $t$ = 2 and $t$ = 6. At $t$ = 7, the attenuator reaches its initial null value, since the generation difference (optimal and verified) at Bus 16 decreases considerably, reducing your benefit, and rising your tariff. Thus, the framework can employ the maximum calculated benefits, providing a relevant tariff discount to Bus 2, which has the highest benefit. The monitoring variable gradually decreases its value until $t$ = 6. At $t$ = 7, its value grows, since the minimum absolute difference between the optimal and the verified generation, at Bus 7, declines. This minimum difference was gradually being increased, which contributed to reducing the dispersion of measures. Thus, at $t = 7$, the dispersion increases (lower uniformity) and the variable reflects this increase.

#### *4.3.3. Transmission Flows and Loss: Nodal Comparative Analysis*

Fig. 16 shows the analysis of the total transmission loss and the power flow from areas whose OPF indicates generation decline (Buses 18, 21, 22, and 23), considering the pure Nodal method (framework inactivated) and the dynamic framework activated.

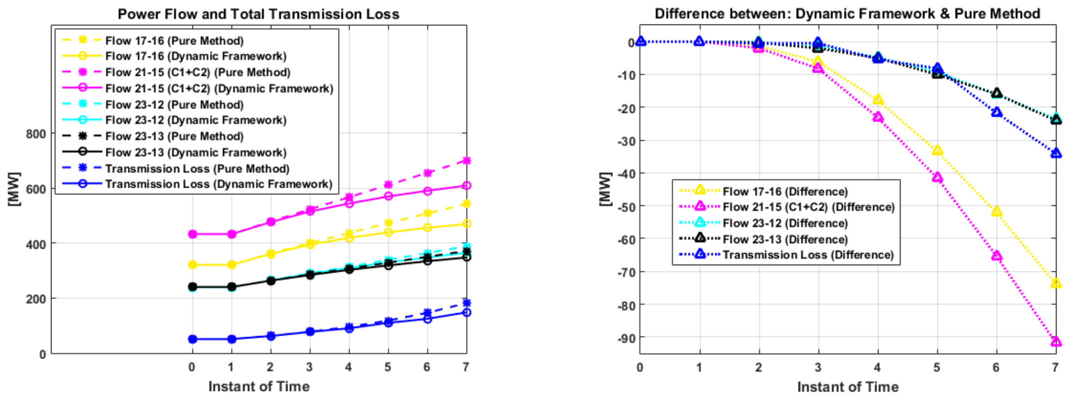


Fig. 16. Power flow and total transmission loss: absolute values and relative differences.

With the action of the dynamic framework, it is verified a decrease in flows from areas that do not contribute to minimize the transmission loss, 17-16, 21-15 (C1+C2), 23-12, and 23-13. Total transmission loss is also decreased. It is shown that when the system loading is intensified, the decreases become higher. This behavior confirms the effectiveness of the tariff signals provided by the framework for generators. When compared to the employment of EBE method in Phase B of the framework, it is noticed that Nodal provides more effective results. The flows and the transmission loss are reduced more intensely, as the generation tariffs have lower dispersion with the Nodal method. Thus, higher benefits may be utilized, more relevant tariff discounts may be provided, and then a more suitable generation capacity expansion may be obtained. Finally, it is worth to mention that, with the framework inactivated, the generation tariff positions are kept the same for the whole period with pure EBE and Nodal methods, which shows the inability of traditional TCA methods to provide useful signals for generators. This fact highlights the contribution of the work, since suitable signals that guide properly the generation capacity expansion are guaranteed by the framework.

## 5. Conclusions

The novel dynamic framework presented in this work forms TNUoS tariffs that reflect the responsibility of each user in network investment considering the system evolution. The framework has generic modelling that allows its application with any TCA method. It also reveals to be robust and flexible due to parameters that allow its tuning in the face of distinct power systems, cost structures, and regulatory policies. The load evolution at each bus is captured and coordinated adjustments, proportional to each load variation, are made. The optimal generation, to minimize the transmission loss, is also captured and adjustments are performed in accordance with each generator contribution to such minimization. As well, the quality of the system generation capacity can be monitored through a global variable that quantifies the difference between the optimal generation and the generation actually verified. The work also integrates the formation process of TNUoS tariffs with the reconfiguration of responsive DNs that aim to minimize their global cost considering the transmission cost.

From the application results previously exposed, important findings can be extracted in relation to the framework action. The load dynamic efficiency is increased, as the load tariffs respond to consumption variations across the system. So, active customers are incentivized to grow their consumption throughout a greater number of buses, which stimulates a more distributed load growth. Generation gets close to load, as the generation tariffs at buses that contribute to transmission loss minimization receive a discount, incentivizing that responsive generators grow their capacity at these locations. Thus, power flows from areas whose OPF indicates the reduction of generation are decreased and, consequently, the total transmission loss is reduced as well. So, effective signals for the generation capacity expansion are obtained. Finally, the integration between TNUoS tariffs and responsive DNs produces a dynamic tariff-load balance, which guarantees a rise of fairness across the segments.

Such findings show the effectiveness of the contributions provided by the novel dynamic framework. Currently, regulatory improvements are being sought to the obtaining of efficient economic signals and, therefore, the dynamic framework reveals to be apt to contribute in this aim, launching new possibilities of tariff integration and operational coordination.

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