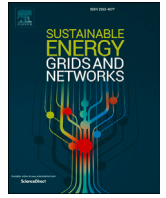




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Transmission cost allocation: Equilibrium analysis of cost efficiency and environmental tradeoffs

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HIGHLIGHTS

- A novel Gauss–Seidel framework models complex and nonlinear network tariffs to compute long-term market equilibria, overcoming the limitations of linear bi-level models.
- Our results show the varying impacts of network tariff schemes on long-term investments in thermal-dominated versus low-carbon power systems, and their implications for cost efficiency and CO₂ emissions.
- Departing from conventional theory, the postage stamp scheme may create inefficiencies in low-carbon power systems.
- The beneficiaries-pay scheme delivers significant environmental benefits at a modest social cost, providing a practical policy alternative.

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ABSTRACT

In the shift towards decarbonization, it's crucial to understand how different transmission cost allocation schemes affect investment incentives. In practice, these schemes aim not just for economic efficiency but also fairness, and, in the decarbonization context, these can also support policy objectives that aim at renewable integration and reductions in CO₂ emissions. This study introduces a market equilibrium model and solution approach that can be used to analyze how different network tariff schemes influence investments in generation, energy storage, and transmission. Assuming a competitive market, the model quantifies the long-term effects of network tariffs on investment decisions through an iterative Gauss–Seidel process, achieving market equilibrium. This process ensures transmission costs are fully covered by congestion rents and network tariffs and that generators recover all costs through energy sales. Evaluating outcomes under five network tariff schemes through illustrative and real-world case studies, our findings show the varying impacts of network tariffs on investments in both thermal and low-carbon power systems, and their implications for cost efficiency and CO₂ emissions.

1. Introduction

To achieve carbon neutrality, integrating substantial volumes of renewable electricity, mainly from solar and wind, is crucial to replace generation from carbon-intensive sources and meet the rising demand driven by the electrification of transport and heating systems. This transition mandates significant investments in transmission infrastructure to enable the delivery of electricity from remote production

sites to consumers. The *New Energy Outlook 2023: Grids* report from BloombergNEF underscores this need, estimating that attaining global net zero emissions by 2050 will demand an investment of US\$21 trillion in power grids, which accounts for both transmission and distribution networks [1]. This figure represents nearly 20 % of the global gross domestic product in 2023, highlighting the costly nature of grid development. Given the critical importance associated with power transmission

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Nomenclature

Sets

G	Set of all generators (including energy storage plants).
G^C	Set of conventional generators.
G^R	Set of renewable generators.
G^S	Set of energy storage plants.
G_n	Set of generators connected to bus n .
\mathcal{L}	Set of transmission lines.
\mathcal{N}	Set of buses.
\mathcal{T}	Set of periods (hours).

Parameters

τ_g	Annual network charge per MW allocated to generator g [\$/MW].
$\pi_g^{op.G}$	Operational variable cost of generator g [\$/MWh].
$\varepsilon_g^{ec.G}$	Carbon emission coefficient of generator g [tCO_2 /MWh].
σ	Carbon tax [\$/ tCO_2].
$\pi_g^{inv.G}$	Investment cost of generator g (annualized) [\$/MW].
$\pi_l^{var.T}$	Investment (variable) cost of transmission line l (annualized) [\$/MW].
$\pi_l^{fix.T}$	Investment (fixed) cost of transmission line l (annualized) [\$] or [\$/km].

x_l	Reactance of line l [Ω].
$D_{n,t}$	Demand at bus n in hour t [MW].
$\alpha_{g,t}^R$	Normalized profile of available natural resource of the renewable generator g , in hour t [pu].
d_s	Energy capacity of energy storage plant s measured in hours at full power capacity [h].
η_s^-	Discharge efficiency of energy storage plant s [pu].
η_s^+	Charge efficiency of energy storage plant s [pu].
M	Sufficiently large positive constant (Big M).

Decision variables

$P_{g,t}$	Power output of generator g , in hour t [MW].
$P_{s,t}^-$	Discharge power of energy storage plant s , in hour t [MW].
$P_{s,t}^+$	Charge power of energy storage plant s , in hour t [MW].
$E_{s,t}$	Energy stored in energy storage plant s , in hour t [MWh].
\bar{P}_g	Capacity of generator g [MW].
\bar{P}_s	Capacity of energy storage plant s [MW].
$f_{l,t}$	Power flow of line l , in hour t [MW].
$\delta_{n,t}$	Voltage angle in bus n , in hour t [rad].
\bar{F}_l	Capacity of line l [MW].
B_l	Binary variable associated with the decision of whether (or not) to install line l {0, 1}.

networks, it is essential that regulatory frameworks are designed to guide this evolution efficiently.

In restructured markets, efficient transmission development, marked by economies of scale and discrete investment alternatives, requires centralized planning by regulated entities. Unlike generation, where market signals suffice, transmission projects depend on tariffs for capital cost recovery. This is because congestion rents, derived from Locational Marginal Prices (LMPs), only cover a fraction of the total cost of efficient transmission investments [2]. Costs that can not be recovered through market signals are known as residual costs of transmission infrastructure.

Currently, there is no consensus on the optimal tariff design for recovering transmission costs that would support the most efficient development of transmission infrastructure. Specifically, the industry lacks a universally accepted method for allocating the costs of new transmission lines between electricity generators and consumers. This lack of consensus is reflected in the wide array of transmission cost-recovery mechanisms seen in electricity markets worldwide.

For example, in the U.S., the majority of regulated charges aimed at supporting transmission investments by electric utilities are typically allocated to the load. For transmission upgrades beyond the scope of existing rate structures, FERC Order 890 and Order 1000 outline principles intended to ensure that cost allocations are in line with the benefits received. Nevertheless, these guidelines do not predetermine the specific outcomes within each of the country's 15 transmission planning regions. Notably, FERC Order 1000 introduces a flexible principle, permitting regions to adopt varied cost allocation methods tailored to different categories of transmission projects, such as those focused on reliability, economic efficiency, or public policy objectives [3,4].

In Europe, Germany, Italy, and the Netherlands employ transmission tariffs that assign 100 % of the costs to the load. Conversely, countries such as Great Britain, Norway, Ireland, and Sweden share a portion of transmission costs with generators, applying tariffs that differ based on locations within the network. A notable example is the electricity market in Great Britain, which operates on a single-zone price for electricity rather than LMPs. Despite this, locational transmission tariffs can vary significantly, with differences exceeding €15 per MWh between regions [5].

This absence of a unified approach to transmission cost allocation is further highlighted by significant shifts in transmission pricing schemes within specific markets over time. In Chile for instance, since the restructuring of its power system in 1982, over four decades have witnessed the country undergoing two major reforms and experimenting with three distinct regulatory frameworks for transmission planning and pricing. Initially, the system allowed for bilateral negotiations between transmission companies and grid users, enabling parties to directly negotiate transmission charges. However, by 2004, this model was revised due to emerging challenges such as insufficient transmission investment, the growing complexity of negotiations among interested parties, and free rider problems [6]. The 2004 reform introduced a shift towards centralized planning of transmission investments, adopting a cost-recovery mechanism that allocated 20 % of transmission costs to customers and 80 % to generators. Under this scheme, generators contributed to transmission costs through a tolling method that assessed the marginal impact of each generation unit on the system's power lines. A further reform in 2016, aimed at facilitating the development of transmission infrastructure to integrate renewables through simplifying the transmission planning and pricing processes. The reform maintained the central planning approach but transitioned to a postage-stamp cost allocation method, assigning 100 % of transmission costs to the load [7].

The worldwide variation in transmission cost allocation mechanisms used in the industry mirrors a wider discussion evident in the academic literature on this subject, marked by a tension between two seemingly conflicting goals: economic efficiency and fairness.

Ramsey pricing is central to the economic theory supporting transmission pricing mechanisms that allocate all residual capital costs to demand. This principle indicates that in scenarios where fixed costs exceed the revenues from marginal cost pricing, such as congestion rents, maximizing social welfare requires pricing adjustments above marginal costs targeted at market participants with the lowest sensitivity to price changes, traditionally consumers over generators [8]. Applying a uniform postage-stamp rate to all consumers serves as a practical application of this principle, as seen in the regulated transmission investments in the US, as well as in electricity markets in Germany, Italy, the Netherlands, and Chile. In nodal markets, such a

strategy helps to maintain undistorted incentives (LMPs) for the optimal siting of new generators [9–11]. Yet, the ability of this approach to drive efficient market outcomes depends on the assumption that the siting choices of new generation facilities have no impact on transmission investment plans [12], an assumption that may not hold in all instances [13].

Fairness represents another key objective among the myriad transmission cost allocation mechanisms discussed in academic literature [14–18]. Specifically, it's been argued that the beneficiaries-pay principle –conceptualized in FERC Order 890 and Order 1000 in the U.S.– leads to equitable cost distributions by enabling market participants to voluntarily contribute to transmission investments, thereby preserving the integrity of efficient market signals [19,20]. However, efforts to achieve this fairness principle have faced criticism due to the challenges in accurately identifying all beneficiaries of new transmission projects and concerns that the resulting allocation of transmission costs may distort investment signals for generators [21,22].

As highlighted by both theoretical and empirical studies on transmission planning and pricing, the method of transmission cost allocation represents a critical regulatory issue, as it has a considerable impact on future investment decisions concerning both transmission infrastructure and power generation facilities. However, what appears to be less explored in academic research is not the variety of cost allocation mechanisms per se, but rather tools to understand how these mechanisms effectively affect investment incentives.

Some of the existing studies that evaluate different transmission tariff schemes do so after investment decisions in transmission and generation assets have already been made [23]. Meanwhile, limited studies incorporate the network tariff into generation and transmission planning by relying on complex bi-level or multi-level equilibrium models [24–27]. However, a distinctive feature of these multi-level approaches is that the network tariff structure must be adopted linearly for their resolution. This presents a significant difficulty in the application of the actual network tariff schemes, which are often based on complex and non-linear mathematical formulations or algorithms.

Notwithstanding the advances in research previously referenced, existing studies have not yet integrated the various network tariff schemes developed in the literature into generation and transmission investment decisions. Thus, the actual effects of network tariff schemes on long-term market development have not yet been quantified and demonstrated in terms of cost efficiency and CO₂ emissions. The latter is becoming more pressing in the context of decarbonization. In this context, the present work proposes a new model and solution approach to incorporate the actual network tariff schemes into future generation, energy storage, and transmission investment decisions, and to examine the long-term market equilibrium under those network tariffs for transmission cost recovery. This solution approach is based on the iterative Gauss–Seidel method, which allows for dealing with the non-linearities of complex mathematical formulations or algorithms of various network tariff schemes. This iterative method calculates, outside the optimization process, the network tariff assigned to generation and energy storage based on the different network tariff schemes, and then iterates successively until the transmission costs are fully recovered. We assume that these schemes are determined and applied by a regulatory body, following a socially optimal transmission expansion strategy devised by a central planner that takes into account generators' responses to transmission investments and the transmission tariff employed for cost recovery. We use illustrative test cases to explore how generation investors, including those in energy storage, react to different tariff schemes. Specifically, we contrast the investment behaviors in purely thermal systems against those in low-carbon systems. Additionally, we assess the implications of these tariff schemes on the long-term market equilibrium within the Chilean electricity market, exploring trade-offs between economic efficiency and CO₂ emissions reductions under different cost allocation mechanisms.

Overall, the main contributions of this work are listed as follows:

- To present a mathematical methodology to integrate five actual tariff schemes into future generation and energy storage investments, ensuring full recovery of transmission investment costs through complex and non-linear formulations or algorithms for the network tariff calculation.
- To contrast the effects of the five tariff schemes on investment behavior in pure thermal versus low-carbon systems through illustrative case studies.
- To assess the real impact of the five tariff schemes on the long-term equilibrium of the Chilean electricity market in terms of cost efficiency and CO₂ emissions.

We structure the rest of the paper as follows. Section 2 describes the mathematical methodology proposed to study the different effects of tariff schemes on long-run equilibrium. In Sections 3 and 4, we present the case studies, their results and discussion, respectively. Finally, in Section 5, we conclude.

2. Methodology

2.1. Market equilibrium

We propose a long-term market equilibrium model to study the impacts of various network tariff schemes on future generation (including energy storage plants) and transmission investments. The agents represented in the market equilibrium model are:

- A central transmission planner that minimizes the cost of network investments and operations.
- A set of investors deciding on new generation capacities (and energy storage capacities) in a perfectly competitive market.
- A system operator deciding on generation dispatches at minimum cost.
- A regulatory authority in charge of recovering the residual network cost (i.e., network investment costs minus congestion revenues) by applying a network charge on generation (including energy storage plants) and demand.

Our model contains two important assumptions. First, we assume a perfectly competitive market, where generators are modeled as price takers (i.e., they do not behave strategically); and secondly, we assume inelastic demands. Note that these assumptions are reasonable for studying the impacts of tariffs on long-term investments and are commonly used in the literature. Under these assumptions, we can solve this equilibrium problem through an iterative, Gauss–Seidel process by updating the value of the network charge, like that proposed in [28,29], where, in each iteration, a minimization problem is solved. This minimization problem corresponds to the co-optimization of the generation (including energy storage plants) and transmission expansions. In each iteration, we (re)calculate the network charge that each generator and energy storage plant should pay (given the transmission investments), and include them within the investment cost of generation and energy storage considered in the co-optimization problem for the next iteration (see Fig. 1).

Importantly, the iterative Gauss–Seidel method is employed because of its ability to integrate various network tariff schemes based on complex mathematical formulations or algorithms, resolving non-linearities in the long-term market equilibrium subject to the actual network charges, and thus overcoming the need to use linear approximations of network tariffs applied in multi-level equilibrium models.

Hence, when this model converges, we can demonstrate that the ultimate generation-transmission expansion plan is fully consistent with the network charge, which is included as generation investment costs in the iterative minimization problem. Furthermore, as we use linear programming in the iterations (from iteration 2 onwards), the strong duality property is met [30], meaning that LMPs and revenues of generators can

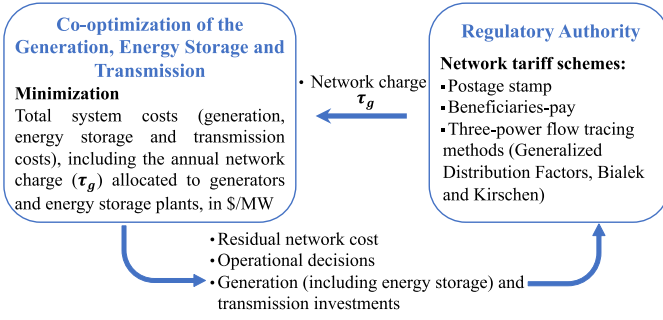


Fig. 1. Long-term market equilibrium model under network tariff schemes.

exactly cover their investment and operational costs, including the network charge (internalized within the investment costs of the generators and energy storage facilities in the model), and leaving zero profit for market participants in the long-term (consistent with the competitive equilibrium assumption).

Next, we present the problem formulation and describe the algorithm used to solve it.

2.1.1. The co-optimization of generation, energy storage, and transmission infrastructure

The co-optimization problem below aims to determine the optimal power system expansion plan, ensuring that the total cost of investment and operation (including costs of CO₂ emissions) is minimized 1. Note that each transmission line has a binary decision variable, B_l , which represents whether the line is constructed (used to calculate the fixed cost); and a continuous decision variable, \bar{F}_l , which represents its capacity (used to calculate the variable cost). The formulation of this mixed integer linear programming (MILP) problem is:

$$\text{Minimize } \sum_{t \in T} \sum_{g \in G^C} (\pi_g^{op.G} + \varepsilon_g^{ec.G} \cdot \sigma) P_{g,t} + \sum_{g \in G} \pi_g^{inv.G} \bar{P}_g + \sum_{l \in \mathcal{L}} (\pi_l^{var.T} \bar{F}_l + \pi_l^{fix.T} B_l) \quad (1)$$

subject to:

$$\sum_{g \in G_n \setminus \{G^S\}} P_{g,t} + \sum_{s \in G_n^S} P_{s,t}^+ + \sum_{l \in \mathcal{L} | r(l)=n} f_{l,t} - \sum_{l \in \mathcal{L} | f(l)=n} f_{l,t} = D_{n,t} + \sum_{s \in G_n^S} P_{s,t}^+ : (\lambda_{n,t}); \quad \forall n \in \mathcal{N}, \forall t \in T \quad (2)$$

$$0 \leq P_{g,t} \leq \bar{P}_g; \quad \forall g \in G^C, \forall t \in T \quad (3)$$

$$0 \leq P_{g,t} \leq \bar{P}_g^R; \quad \forall g \in G^R, \forall t \in T \quad (4)$$

$$-\bar{P}_s \leq P_{s,t}^- - P_{s,t}^+ \leq \bar{P}_s; \quad \forall s \in G^S, \forall t \in T \quad (5)$$

$$E_{s,t} = E_{s,t-1} - P_{s,t}^- / \eta_s^- + P_{s,t}^+ \eta_s^+; \quad \forall s \in G^S, \forall t \in T \quad (6)$$

$$0 \leq E_{s,t} \leq \bar{P}_s d_s; \quad \forall s \in G^S, \forall t \in T \quad (7)$$

$$-M(1 - B_l) + \frac{\Delta_{fr(l),t} - \Delta_{to(l),t}}{x_l} \leq f_{l,t} \leq \frac{\Delta_{fr(l),t} - \Delta_{to(l),t}}{x_l} + M(1 - B_l); \quad \forall l \in \mathcal{L}, \forall t \in T \quad (8)$$

$$-\bar{F}_l \leq f_{l,t} \leq \bar{F}_l; \quad \forall l \in \mathcal{L}, \forall t \in T \quad (9)$$

$$\bar{F}_l \leq M B_l; \quad \forall l \in \mathcal{L} \quad (10)$$

$$B_l \in \{0, 1\}; \quad \forall l \in \mathcal{L} \quad (11)$$

Eq. (2) is the power balance equation, where $\lambda_{n,t}$ refers to the LMP at bus n at time/hour t . Eqs. (3) and (4) ensure that power dispatches respect the maximum capacity of the generators, considering the limitations of the available renewable resources. Eqs. (5)–(7) model the energy storage plants recognizing power and energy-related decisions. Eqs. (8)

and (9) model the DC power flows and the line ratings. Note that, as the model can plan new transmission lines, a Big-M formulation is applied in Eq. (8). Finally, Eq. (10) captures that investments in lines feature a binary component associated with the decision of whether (or not) to install a line. Note that, in Eq. (1), the transmission cost is divided into a variable cost component and a fixed (or binary) cost component.

It is important to mention that the solution to the optimization problem above will exhibit the following fundamental characteristics [31]:

- Revenues collected through LMPs will exactly recover the total cost of generation, meaning that every generator will exactly recover its investment and operational costs by selling its energy at a price equal to $\lambda_{n,t}$.¹
- Revenues collected through LMP differentials (the so-called congestion rents/revenues) will exactly recover the variable cost component of the transmission investment (denoted as $\sum_{l \in \mathcal{L}} \pi_l^{var.T} \bar{F}_l$).

Remarkably, both above-described features are fundamental for the proposed market equilibrium model to work. The first feature is that, in a perfectly competitive market, generation and energy storage firms can adequately internalize their investment and operating costs by increasing LMPs to cover all their costs associated with generation. The second feature is mainly due to the variable component of each transmission line being properly internalized within the marginal cost of supplying demand from an end bus, thus leading to an LMP decoupling between both ends of the line that only recovers the variable cost of transmission investment. This means that the fixed cost of transmission investment (denoted as $\sum_{l \in \mathcal{L}} \pi_l^{fix.T} B_l$) will not be recovered, leaving a residual network cost that has to be remunerated somehow [32].

Due to this residual network cost (i.e., the part of the network investment cost that cannot be recovered through LMPs), the regulator must design mechanisms for charging market participants and thus adequately remunerating transmission networks. Note that, in a market environment, these charges will necessarily change the optimal decision obtained by Eqs. (1)–(11) since, at the optimal point, generators and energy storage facilities do not perceive sufficient revenues to pay network charges. Hence, generators and energy storage plants must move away from the optimal point to generate extra profits to pay network charges. In our approach, this is modeled through the following iterative process.

2.1.2. The Gauss–Seidel iterations

After solving the MILP problems (1)–(11), called iteration 1, we determine the annual network charges per MW and allocate them among market participants (generators and energy storage facilities). These annual network charges τ_g in terms of \$/MW are determined as the fraction of the annual network payment ω_g and installed capacity \bar{P}_g of each generator and energy storage plant. Importantly, we calculate the annual network payment ω_g for each generator and energy storage plant regarding different tariff schemes (the representation of each network tariff scheme will be detailed in the next subsection).² Note that although the network charge in the model is reduced to a capacity payment, it effectively captures both capacity and energy payment components. This is possible because ω_g is computed after system investments and operations have been determined, allowing the transmission cost allocated to each generator and energy storage plant to be expressed in terms of \$/MW by dividing the allocated cost by the capacity of the generator or energy storage facility.

¹ Importantly, since we assume that the system operation is linear, the proposed optimization problem does not present fixed cost recovery issues in the operation of generation, hence, no uplift payments are necessary.

² Of utmost importance, the given tariff regime can be either represented through a set of algebraic equations or a more complex mechanism. As we use a Gauss–Seidel iterative algorithm, our model is robust to an array of tariff mechanisms.

After determining and allocating the annual network charges per MW τ_g to each market participant g , we solve the following linear problem (from iteration 2 onwards):

$$\begin{aligned} \text{Minimize } & \sum_{t \in T} \sum_{g \in G^C} (\pi_g^{op.G} + \varepsilon_g^{ec.G} \cdot \sigma) P_{g,t} + \sum_{g \in G} (\pi_g^{inv.G} + \tau_g) \bar{P}_g \\ & + \sum_{l \in \mathcal{L}} \pi_l^{var.T} \bar{F}_l \end{aligned} \quad (12)$$

subject to: constraints (2)–(10)

Note that Eq. (12) differs from 1 in a single fundamental point: in 12, the fixed cost of transmission investment is represented through τ_g . In turn, in Eq. (12), τ_g can modify generation and energy storage investments, which may also modify transmission investments marginally (affecting only its variable cost, as Eq. (11) is replaced by a set of constraints that fix the binary variables B_l equal to the solution of the first problems (1)–(11)). If we iteratively run (12) by recalculating τ_g according to the latest transmission plan available, we will eventually converge to the solution of the market equilibrium problem. Importantly, the convergence of this iterative Gauss–Seidel process is not guaranteed. For convergence, the process of updating the network charge value τ_g should satisfy the Lipschitz continuity condition and preserve the contraction property, as stated in [28]. In our case studies, these properties are not always satisfied. Nevertheless, the Gauss–Seidel process converges for a wide range of parameters that are sufficient to demonstrate tariff schemes’ impacts on long-term market equilibrium. Remarkably, the Gauss–Seidel iterative algorithm may encounter convergence issues when applied in large-scale case studies, due to the increase in the number of market participants, which leads to a significant increase in the number of decision variables related to operation and investment.

It is important to highlight that a strategy has been employed to verify the equilibria reached using the iterative Gauss–Seidel method, establishing different starting points for the network charge in the first iteration. The results obtained show that the equilibria found are consistent across all the starting points explored, thereby ruling out the existence of multiple equilibria. This finding validates the stability and uniqueness of the equilibria obtained in our case studies analyzed.

In summary, the iterative process of the Gauss–Seidel algorithm used to solve the proposed market equilibrium problem subject to different network tariff schemes is outlined in Fig. 2:

2.2. Network tariff schemes

Given that the solution of MILP problems (1)–(11) leaves a residual network cost equal to the fixed cost of transmission investment to be recovered through the application of regulated tariffs, we study five different network tariff schemes. These are the postage stamp [33], the beneficiaries-pay [19], and three variants of the power flow tracing method (following the pioneering work by Rudnick [34], Bialek [35], and Kirschen and Strbac [36]).

The proportion of the transmission cost that is allocated by the above-mentioned tariff schemes should be equal to the residual network cost (denoted as $\sum_{l \in \mathcal{L}} RC_l$). Following practices in the real world, we first define a proportion of the residual network cost to be paid by generation (denoted as allocation factor γ^G) and a proportion to be paid by demand ($1 - \gamma^G$). As demand is inelastic, transmission payments will not impact its levels, and this is in opposition to generation, where investment decisions will change due to network payments. Remarkably, as energy storage plants also withdraw power from the network, their investment decisions may be affected by the proportion of network payments allocated to demand.

The formulation of each network tariff scheme is presented as follows:

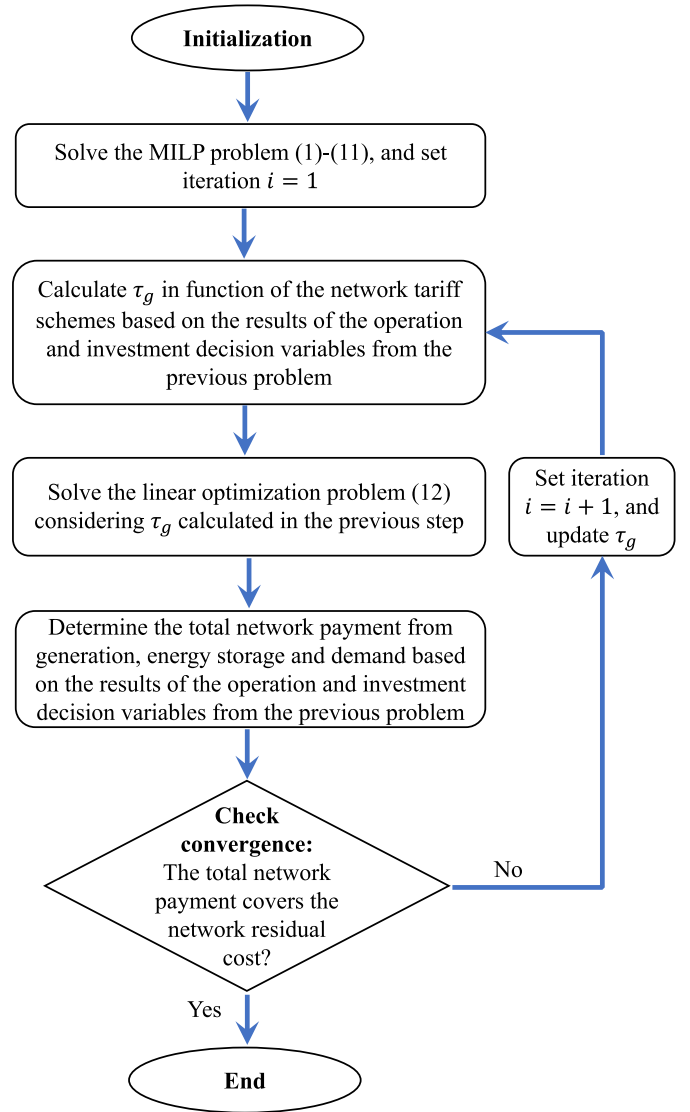


Fig. 2. Flowchart of the Gauss–Seidel iterative algorithm.

- (i) **Postage stamp scheme** defines a uniform and non-discriminatory annual network payment ω_g based on a pro-rata of the installed capacity of each generator and energy storage plant, as follows:

$$\omega_g = \frac{\gamma^G \cdot \sum_{l \in \mathcal{L}} RC_l}{\sum_{g \in G} \bar{P}_g} \cdot \bar{P}_g; \forall g \in G \quad (13)$$

where RC_l is the residual cost of transmission line l and \bar{P}_g is the installed capacity of generator g . Note that residual network cost ($\sum_{l \in \mathcal{L}} RC_l$) is equal to fixed cost component of transmission investment ($\sum_{l \in \mathcal{L}} \pi_l^{fix.T} B_l$).

- (ii) **Beneficiaries-pay scheme** calculates an annual network payment ω_g per generator and energy storage plant proportional to the economic benefit captured by them from the transmission investment plan, as follows:

$$\omega_g = \gamma^G \cdot \beta_g \cdot \sum_{l \in \mathcal{L}} RC_l; \forall g \in G \quad (14)$$

where β_g is the fraction of the total economic benefit that each generator g or energy storage plant s perceives for the transmission

investment plan. The determination of these economic benefits for generators and energy storage facilities is based on the following algorithmic process:

Step 1 Determine the income of each generator (I_g) with the results obtained from the simulation of the system operation with and without all transmission lines invested, as follows:

$$I_g = \sum_{i \in \mathcal{T}} (\lambda_{n(g),i} - \pi_g^{op,G}) \cdot P_{g,i}; \forall g \in G \setminus \{G^S\} \quad (15)$$

Note that Eq. (15) is applied for all generators, except for energy storage plants. This is because the income of an energy storage plant as a generator must be affected by the withdrawal payments it makes as a load. Therefore, the net income of each energy storage plant (I_s) is determined by the following equation:

$$I_s = \sum_{i \in \mathcal{T}} \lambda_{n(s),i} \cdot (P_{s,i}^- - P_{s,i}^+); \forall s \in G^S \quad (16)$$

Step 2 Calculate the net economic benefits of each generator and energy storage plant (ΔB_g) using their respective incomes with and without transmission lines, as follows:

$$\Delta B_g = I_g^{with.Tx} - I_g^{without.Tx}; \forall g \in G \quad (17)$$

where $I_g^{with.Tx}$ is the income of generator g or energy storage plant s with transmission lines, and $I_g^{without.Tx}$ is the income of generator g or energy storage plant s without transmission lines. Note that both incomes (with and without transmission lines) are calculated based on Eqs. (15) and (16).

Step 3 Exclude negative net benefits because they are equivalent to economic losses resulting from the construction of the transmission lines.

$$\Delta B_g = \begin{cases} 0 & ; \text{if } \Delta B_g < 0 \\ \Delta B_g & ; \text{otherwise} \end{cases}; \forall g \in G \quad (18)$$

Step 4 Determine the percentages of the economic benefits for each generator and energy storage plant (β_g), as follows:

$$\beta_g = \frac{\Delta B_g}{\sum_{g \in G} \Delta B_g}; \forall g \in G \quad (19)$$

Note that the beneficiaries-pay scheme is the benchmark for fairness as explained in the introduction.

(iii) **Three-power flow tracing methods** determine an annual network payment according to the usage of the transmission network by each generator, as follows:

$$\omega_g = \gamma^G \cdot \sum_{i \in \mathcal{T}} \sum_{l \in \mathcal{L}} \varphi_{l,g,t} \cdot \frac{RC_l}{|\mathcal{T}|}; \forall g \in G \setminus \{G^S\} \quad (20)$$

where $|\mathcal{T}|$ is the number of hours, and $\varphi_{l,g,t}$ corresponds to the network usage factor of generator g over line l , in hour t , by injecting power.

Importantly, Eq. (20) is applied to all generators, except for energy storage plants. This is because energy storage plants must consider the payment that they make for their use of the network when injecting and withdrawing power, as follows:

$$\omega_s = \gamma^G \cdot \sum_{i \in \mathcal{T}} \sum_{l \in \mathcal{L}} \varphi_{l,s,t} \cdot \frac{RC_l}{|\mathcal{T}|} + (1 - \gamma^G) \cdot \sum_{i \in \mathcal{T}} \sum_{l \in \mathcal{L}} \phi_{l,s,t} \cdot \frac{RC_l}{|\mathcal{T}|}; \forall s \in G^S \quad (21)$$

where $\phi_{l,s,t}$ is the network usage factor of energy storage plant s over line l , in hour t , when withdrawing power from the network.

Notice that all network usage factors for both injection and withdrawal can change depending on the variant of the applied power flow tracing method (Generalized Distribution Factors, Bialek, or Kirschen). Each power flow tracing method relies on a different algorithmic process to determine network usage factors.

In summary, as demonstrated above, the postage stamp scheme is characterized by the allocation of a network charge indiscriminately (i.e., to all generators and energy storage facilities) and uniformly (i.e., irrespective of the location of the generators and energy storage facilities in the system). Conversely, the beneficiaries-pay scheme allocates a network charge to generators and energy storage plants that benefit from constructing or expanding of the transmission asset (i.e., based on a principle of fairness). The amount of the network charge assigned to a generator and energy storage plant is proportionally dependent on the economic benefit captured from the transmission investment plan. In contrast, the power flow tracing methods (Generalized Distribution Factors, Bialek, and Kirschen) allocate a network charge to generators and energy storage facilities that utilize the transmission. The magnitude of the network charge allocated to a generator and energy storage plant is proportionally dependent on the use of the transmission asset.

In both the beneficiaries-pay and power flow tracing methods, the amount of network charge is subject to the location of the generators and energy storage facilities in the system (i.e., generators or energy storage plants located further away from the load center benefit from and use more of the transmission asset). Consequently, both network tariff schemes can be regarded as a locational pricing system. Notice that the beneficiaries-pay and power flow tracing methods result in a distinct network charge, given that the energy storage plants' and generators' profit ratio does not equal their transmission usage ratio. Furthermore, in the case of the power flow tracing methods, energy storage facilities receive a network charge in addition to the charge incurred when they inject generation into the system because they utilize the transmission also when they behave as load. In the case of the beneficiaries-pay scheme, energy storage facilities are subject to a single network charge, as the net economic benefit is calculated as a plant (i.e., incomes as generator minus expenses as load).

Finally, we want to emphasize that, due to space limitations, the full formulation of the calculated five network tariff schemes has been omitted. Nevertheless, the interested reader can find the detailed formulation of these mentioned tariff schemes in the following specific works, on which, we base our calculations:

- Postage stamp scheme demonstrated in [33].
- Beneficiaries-pay scheme proposed in [19].
- The generalized distribution factors (GGDF and GLDF) proposed by Rudnick et al. [34].
- The topological distribution factors presented by J. Bialek [35], known as Bialek method
- The contributions-based factors proposed by Kirschen and Strbac [36], known as Kirschen method.

3. Illustrative case study

3.1. Description

In this case study we illustrate an application of the proposed methodology and demonstrate the potential long-term impacts of network tariff schemes on market equilibrium. We applied the proposed solution framework to a 2-bus power system presented in Fig. 3 and considered different network tariff schemes.

To analyze the impact of the five network tariff schemes in the context of both a thermal-dominated and low-carbon electricity system, we implemented two case studies:

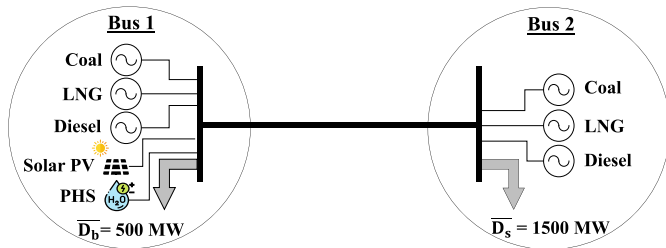


Fig. 3. 2-bus power system.

- **Case A:** This case focuses on modeling the long-term market equilibrium by applying the tariff schemes to six thermal generation investments located in bus 1 and 2 (see generation costs in Table 1). For the transmission line, we set a variable investment cost of 4 \$/MW and a fixed investment cost of 95 k\$.
- **Case B:** This case centers on modeling the long-term market equilibrium applying the tariff schemes on a low-carbon electricity system where new investments in solar photovoltaic (PV) power plant and pumped hydro storage (PHS) power plant are included in bus 1, in addition to thermal generation investments defined in Case A (see generation costs in Table 1). For the transmission line, we define a variable investment cost of 4 \$/MW and a fixed investment cost of 200 k\$.

Importantly, in Case A, the goal is to replicate some of the most fundamental results in transmission tariff theory, while in Case B, the aim is to gain new insights into the transmission tariff applied in a low-carbon power system.

For both cases, we model generation and transmission investments assuming that, originally, there are no power plants and transmission infrastructure (greenfield approach). Therefore, under the assumption of a perfectly competitive market, all generators perceive zero profits in equilibrium. Also, we do not consider a carbon tax (i.e., the carbon tax is zero). In addition, for simplicity, we employ one representative day to model annual operation and investment decisions, assuming that days are the same throughout the year, thus ignoring weekly and seasonal variations. This simplification in the model is reasonable as a first instance to demonstrate the applicability of the proposed methodology and illustrate the main effects of different network tariff schemes on the investment decisions of market participants. Notice that this illustrative case study tends to omit certain data and variables to simplify the analysis, resulting in a lack of representation of all possible scenarios and multi-stakeholder interactions that can arise in a more complex and real context. Nevertheless, in the following section, we will demonstrate the scalability of the proposed approach in a larger, real-world instance to capture the full range of data and variables.

In this illustrative case study, we evaluate the impact of network tariffs on generation investment decisions considering two extreme scenarios. In one scenario we assume that all network costs are allocated to price-insensitive customers (i.e., 0 % of network costs are allocated to generators). In the other scenario, we assume that all network costs

are allocated to generators (i.e., 100 % of network costs are allocated to generators).

3.2. Results and discussion

Fig. 4 illustrates the generation investment decisions subject to the network tariff schemes with an allocation factor (γ^G) equal to 0 % and 100 % in a power system with only dispatchable thermal units (Case A). On the other hand, Fig. 5 shows the generation investment decisions subject to the network tariff schemes with an allocation factor (γ^G) equal to 0 % and 100 % in a low-carbon power system (Case B). Note that, for cases A and B, the power flow tracing methods (i.e., Generalized Distribution Factors, Bialek, and Kirschen) result in identical network charges for generators and energy storage facilities because, in a 2-bus power system, the network usage factors of generators and energy storage plants across these methods are the same. Thus, we present the results for the Generalized Distribution Factors, Bialek, and Kirschen methods as a single tariff scheme called the power flow tracing method.

Remarkably, in cases A and B, all network tariff schemes with an allocation factor equal to 0 % converge to the same market equilibrium. In case A, this outcome is mainly attributed to the allocation of the entire network charge to demand, which is inelastic in all network tariff schemes (see Fig. 4). Whereas in case B, particularly in the power flow tracing method, this outcome occurs because the network charge allocated to the energy storage plant as load is not high enough to change investment decisions (see Fig. 5).

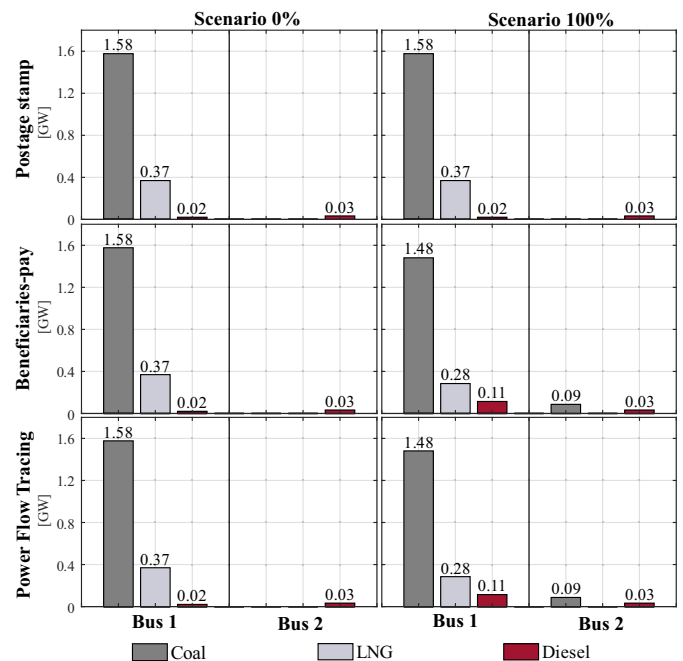


Fig. 4. Generation investment strategies under network tariff schemes in a thermal-dominated electricity system (Case A).

Table 1
Generation and energy storage input data for cases A and B.

Technology	Bus 1		Bus 2	
	Investment cost [\$/MW]	Operational cost [\$/MWh]	Investment cost [\$/MW]	Operational cost [\$/MWh]
Coal	300	60	300	66
LNG	60	100	60	110
Diesel	20	120	20	132
Solar PV	235	0	-	-
PHS	320	0	-	-

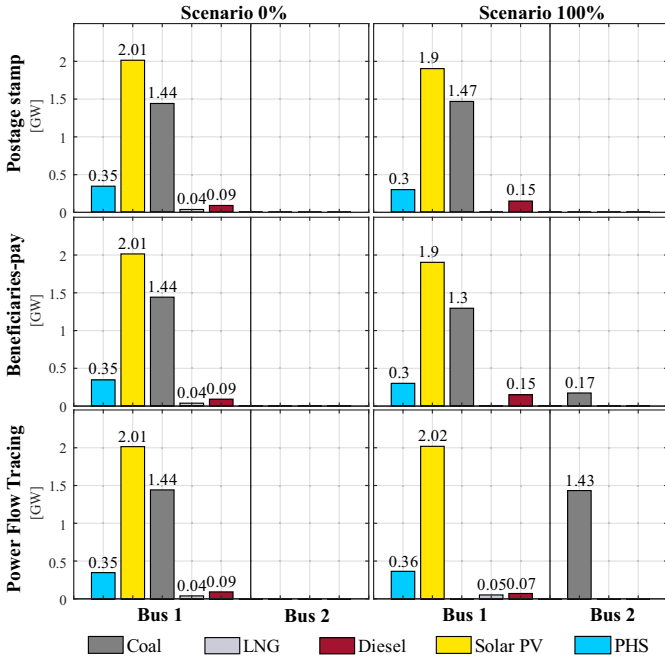


Fig. 5. Generation and energy storage investment strategies under network tariff schemes in a low-carbon electricity system (Case B).

Fig. 4 demonstrates that larger network tariffs paid by generators in a thermal-dominated power system do not affect their investment decisions, provided that the used tariff scheme follows the postage stamp method. This is because all investors in thermal generation face an increase in their investment costs in proportion to the allocated network charge, which is recovered in peak load periods (where LMPs can be increased up to the point necessary to recover all costs). This example demonstrates that the postage stamp scheme does not distort investment decisions. Furthermore, we can prove that this is always the case in a pure thermal power system in line with [10]. However, in a low-carbon electricity system, our results show that the postage stamp scheme can yield inefficient generation investment decisions (see Fig. 5). Specifically, when subject to uniform network tariffs, investors in renewable generation are incentivized to reduce capacity investments in order to increase energy prices during periods of renewable availability, thus ensuring cost recovery. In contrast to thermal units that can all benefit from increased prices during peak demand hours, renewable generators may not be operational during those hours due to resource intermittency and therefore cannot benefit equally.

These findings are theoretically significant, as they challenge the conventional assumption, supported in the thermal-dominated context (e.g., [10]), that postage stamp tariffs do not introduce substantial inefficiencies. Our analysis reveals that, in low-carbon systems, such tariffs can distort long-term investment decisions even when investors receive accurate short-term locational signals through LMPs.

4. Chilean system case study

4.1. Description

This case study aims to demonstrate and evaluate the effects of network tariff schemes on the long-term development of a real power system. Through this real-world case, we seek to capture the full diversity of data in the generation and demand profiles and decision variables since the cases presented in the previous section are only illustrative.

We use a 9-bus system representation of the Chilean National Interconnected System (NIS) based on [37]. In the NIS, generation and energy storage firms are subject to the five network tariff schemes previously introduced with different allocation factors (γ^G), covering the range from 0 % to 100 %, in incremental steps of 25 %.

For long-term system planning, we run our model in a greenfield fashion (ignoring existing generation and transmission capacities). In Table 2, we show the input data for the candidate generation and energy storage technologies following the values reported by the National Energy Commission [38].

For PHS technology, we set a roundtrip efficiency of 75 % and a maximum capacity to store energy equal to 12 hours of operation at full power output. For transmission lines, we use a variable investment cost of 74.59 \$/MW-km per year and a fixed investment cost of 1000 k\$/km per year. Regarding demand, we use hourly real load profiles of 2017, which we scale to 137 TWh according to the Chilean Ministry of Energy’s projection for the target year 2030. In addition, we set a carbon tax equal to 25 \$/tCO₂ based on [39] since generation planning should be consistent with possible investment scenarios in the target year. Finally, we use normalized hourly profiles per bus.

4.2. Results and discussion

Table 3 presents the results of the different long-term market equilibria under the proposed five network tariff schemes, where total costs (or social costs) and carbon emissions are shown and compared. Importantly, given the inelasticity of demand, the network tariff schemes such as postage stamp and beneficiaries-pay with an allocation factor (γ^G) equal to 0 % correspond to the most cost-effective equilibrium in terms of the social cost. In fact, this equilibrium point coincides with the solution of the central planning problem (iteration 1), as from iteration 2 onward, the solution remains unchanged (consumers are assumed to be inelastic). However, the network tariff schemes based on power flow tracing methods (Generalized Distribution Factors, Bialek, and Kirschen) converge to a market equilibrium that is less cost-effective. This is mainly because energy storage plants are also subject to an annual network charge when withdrawing power from the transmission network in these power flow tracing methods. Therefore, investors in energy storage plants react to the presence of a network charge fully allocated to demand, thus changing the optimal generation mix and distorting the socially optimal equilibrium, as shown in Table 3 (see scenario 0 % of the power flow tracing methods).

The results in Table 3 show that, as the network charge allocation to generation rises, the social cost of the system increases for all network tariff schemes (albeit at different levels). One of the most remarkable

Table 2
Generation and energy storage input data in the Chilean electricity market.

Technology	Operational cost [\$/MWh]	Investment cost [\$/kW]	Lifespan [years]	Emission coefficient [tCO ₂ /MWh]
Coal	33	3000	35	0.95
LNG	88	1090	30	0.44
Diesel	219	687	30	0.78
Run-of-river	0	4000	45	0
Reservoir	0	3500	45	0
Wind	0	1200	25	0
PHS	0	1180	30	0
Solar PV	0	970	25	0

Table 3
Long-term market equilibrium under five tariff schemes.

Scenario of allocation factor (γ^G)		0 %	25 %	50 %	75 %	100 %
Postage stamp	Social cost [M\$]	13330	13359	13439	13686	14666
	Emissions [MtCO ₂]	25.95	36.13	31.49	44.91	104.85
Beneficiaries-pay	Social cost [M\$]	13330	13481	13711	13971	14055
	Emissions [MtCO ₂]	25.95	36.93	38.19	15.63	15.97
GGDF/GLDF	Social cost [M\$]	13334	13406	13483	13637	14016
	Emissions [MtCO ₂]	28.30	32.62	37.99	42.42	43.27
Bialek method	Social cost [M\$]	13334	13430	13554	13596	14024
	Emissions [MtCO ₂]	28.30	32.03	30.98	40.07	42.67
Kirschen method	Social cost [M\$]	13334	13415	13541	13803	13884
	Emissions [MtCO ₂]	28.30	31.74	33.54	33.84	37.47

results corresponds to the long-term market equilibrium under the scenario 100 % postage stamp. Our results show that a postage stamp with a high-cost allocation to generation may significantly reduce the market's economic efficiency and increase CO₂ emissions. In terms of economic efficiency, this result contradicts what classical economic theory reports concerning the postage stamp, which states that applying a uniform and non-discriminatory network tariff would avoid distorting efficient market signals [9–11]. As explained earlier, based on the 2-bus system, this economic inefficiency caused by the postage stamp is justified because of the penetration of renewables. In fact, renewable generators that do not participate during peak hours (when LMPs can be increased to recover fixed costs) have to install less capacity to raise LMPs and thus increase revenues to pay network charges. In turn, the decreased renewable generation capacity installed is replaced by more carbon-intensive generation, thus leading to higher energy prices and increased levels of CO₂ emissions.

The results associated with the network tariff schemes such as the beneficiaries-pay (which is the benchmark for fairness) and the power flow tracing methods (Generalized Distribution Factors, Bialek, and Kirschen) also show that social costs increase with the amount of cost allocated to generation. Nevertheless, these cost increases are smaller than those under the postage stamp scheme. Interestingly, although the cost-efficiency of all network tariff schemes decreases for increased cost allocations to generation, the CO₂ emission performances do not follow this pattern. We find that specific locational network tariff schemes with a high residual cost allocation to generation can deliver a low-carbon market equilibrium (see the scenario 75 % and 100 % of the beneficiaries-pay and the scenario 100 % of the power flow tracing methods). The low-carbon market equilibria resulting from locational network tariffs can be explained by the fact that generation investors position themselves at strategic points in the system where market prices remain attractive and there is still considerable availability of natural

resources (such as solar or wind energy). This favours investment in renewable technologies over those that are carbon-intensive. Interestingly, the beneficiaries-pay scheme not only ensures fairness (by definition) but also results in a low level of CO₂ emissions at a modest additional cost, making it a potentially attractive alternative in practice.

Finally, Table 4 shows the payments made by demand for the electricity supply (separated into an energy and transmission component) under the five network tariff schemes evaluated.

According to Table 4, demand ends up paying more for electricity supply in the scenarios where it is allocated lower network charges (e.g., where 75 % and 100 % of network costs are allocated to generation). Hence, our results demonstrate that demand should assume a more significant proportion of the network charges since this supports a more efficient system expansion. On the contrary, the distortion introduced by more considerable network charges to generation may result in a higher system cost ultimately paid by demand.

Notice that not all network tariff schemes lead to cost-effective market equilibrium under a full allocation of the network charge to demand. The results in Table 4 demonstrate that inelastic consumers end up paying more for electricity supply under the network tariff schemes based on power flow tracing methods than they do under the postage stamp and beneficiaries-pay schemes (see scenario 0 % of the power flow tracing methods). This is because, under the power flow tracing methods, energy storage facilities are subject to a network charge when withdrawing power from the transmission network, which distorts LMPs and thus increases the energy payments of inelastic consumers. Importantly, under the power flow tracing methods, as the integration of energy storage plants increases in the power system, the market equilibrium becomes less cost-effective. As a result, the payments of inelastic consumers for electricity supply will become progressively more significant.

Table 4
Demand payments (in M\$) for the electricity services.

Scenario of allocation factor (γ^G)		0 %	25 %	50 %	75 %	100 %
Postage stamp	Network charge	1847	1385	924	462	0
	Energy charge	11483	11974	12515	13224	14666
	Full payment	13330	13359	13439	13686	14666
Beneficiaries-pay	Network charge	1847	1385	924	462	0
	Energy charge	11483	12096	12787	13509	14055
	Full payment	13330	13481	13711	13971	14055
JGGDF/GLDF	Network charge	1847	1385	924	462	0
	Energy charge	11487	12021	12559	13175	14016
	Full payment	13334	13406	13483	13637	14016
Bialek method	Network charge	1847	1385	924	462	0
	Energy charge	11487	12045	12630	13134	14024
	Full payment	13334	13430	13554	13596	14024
Kirschen method	Network charge	1847	1385	924	462	0
	Energy charge	11487	12030	12617	13341	13884
	Full payment	13334	13415	13541	13803	13884

5. Conclusions and future work

This paper introduces a novel computational framework based on the Gauss–Seidel iterative method, which allows for the analysis of long-term market equilibria under complex and nonlinear formulations of five representative transmission tariff schemes. Unlike conventional bi-level models, which typically rely on linear equations and simplified tariff representations, our approach provides greater modelling flexibility and computational efficiency, features that are particularly valuable for accurately capturing the dynamics of low-carbon power systems. We apply this model to assess the long-term economic and environmental performance of various network tariff schemes.

Our findings reveal that, contrary to the principles of classical transmission cost allocation theory, largely developed in the context of thermal-dominated systems, the application of uniform and non-discriminatory tariffs (on top of LMPs in the short-term spot market), such as the postage stamp scheme, to generation may induce inefficient and more carbon-intensive long-term equilibria. This outcome is particularly relevant in the context of power systems undergoing rapid decarbonization, where such tariff designs can distort investment signals and undermine environmental goals.

Among the alternatives explored, the beneficiaries-pay scheme stands out as a promising option. It offers meaningful environmental benefits with only a modest increase in overall social cost. As such, it emerges as a viable and potentially more sustainable cost allocation mechanism in practice, especially when environmental performance is considered alongside economic efficiency.

Future research will extend this framework by incorporating demand elasticity, enabling a more comprehensive assessment of how tariff design interacts with both supply- and demand-side dynamics in shaping long-term equilibria.

CRedit authorship contribution statement

Ricardo Haro: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Rodrigo Moreno:** Writing – review & editing, Writing – original draft, Validation, Supervision, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Conceptualization. **Francisco D. Muñoz:** Writing – review & editing, Writing – original draft, Validation, Resources, Methodology, Investigation, Formal analysis, Conceptualization. **Dimitrios Papadaskalopoulos:** Writing – review & editing, Validation, Resources, Investigation, Formal analysis, Conceptualization. **Yijun Li:** Validation, Resources, Research, Formal Analysis, Conceptualization. **Goran Strbac:** Validation, Resources, Investigation, Formal analysis, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Data will be made available upon request.

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