A Negotiation-Based Incentive Mechanism for Efficient Transmission Expansion Planning Considering Generation Investment Equilibrium in Deregulated Environment

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ABSTRACT

The current Transmission Expansion Planning (TEP) incentive mechanisms are inadequate. They either fail to ensure revenue sufficiency or achieve socially optimal investment. The non-negligible coordination between TEP and Generation Expansion Planning (GEP) in the deregulated environment introduces more computational challenges to the TEP problem. This paper proposes a novel negotiation mechanism that enables Generation Companies (GenCos) and Load-Serving-Entities (LSEs) to negotiate TEP strategies with Transmission Companies (TransCo) directly. The negotiation process is modeled based on the Nash Bargaining theory. we explore the intertwined relationship between TEP and GEP through a bi-level, single-leader-multi-follower model. We transform the upper-level problem for better tractability and introduce a modified Proximal-Message-Passing (PMP) decentralized algorithm to achieve generation investment equilibrium at the lower level. We then utilize an iterative solving approach to coordinate the two levels. The feasibility and efficiency of this mechanism and methodologies are demonstrated using an IEEE 24-bus test system. The numerical results verify that our mechanism ensures revenue sufficiency and achieves socially optimal TEP strategies comparable to state-of-the-art mechanisms. Additionally, our mechanism maintains transmission network user privacy, aligns the benefits of TransCo with those of transmission network users, and ensures a fair allocation of TEP costs and risks. The proactive participation of market players enabled by the negotiation mechanism can promote the transformation towards new market systems by mitigating the stranded cost issue. Moreover, our decentralized algorithm effectively addresses the non-cooperative nature of GEP, and the computational efficiency analysis justifies the model's scalability and practicality.

1. Introduction

1.1. Background

Transmission Expansion Planning (TEP) has long been an essential research area in electric power system optimization. It aims to enhance transmission capacities to meet growing demands efficiently and cost-effectively (Li et al., 2022; Fuentes González et al., 2022). A wide range of TEP models has been established to improve system reliability, raise social welfare, and relieve congestion in power systems (Yin and Wang, 2022). Following the deregulation of the electric industry in recent decades, the requirements for efficient market incentives for TEP have significantly raised (Gans and King, 2000; Vogelsang, 2001). For now, TEP investors recover their investment costs through market revenues from Congestion Rents (CRs) (Papadaskalopoulos et al., 2020) or through the regulated fees (Hesamzadeh et al., 2018). These fees are calculated based on electricity market prices or the surplus of transmission network users, specifically GenCos and LSEs. However, existing cost recovery mechanisms either fail to provide sufficient revenues or achieve TEP strategies that maximize social welfare, thus highlighting the urgent need for more efficient incentive mechanisms (Vogelsang, 2020). An efficient TEP incentive mechanism should not only ensure the sustainability of TEP initiatives by providing sufficient revenue but also maximize social welfare through optimal transmission investment strategies (Hesamzadeh and Vogelsang, 2020). Meanwhile, such mechanisms must realize a fair and efficient distribution of TEP costs and benefits without compromising the privacy of transmission network users

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regarding supply cost and demand utility (Vogelsang, 2020). Consequently, the development of an incentive mechanism that encompasses these essential features is an urgent and significant issue that continues to attract considerable attention (Hesamzadeh et al., 2018; Khastieva et al., 2021). Moreover, the endogenous link between TEP and GEP is non-negligible (Gonzalez-Romero et al., 2020), necessitating the integration of coordination between TEP and GEP in TEP studies. Additionally, in a deregulated environment, GEP involves multiple GenCos, further complicating the scenario. These intricate issues increase the complexity of the coordination, necessitating the development of a more efficient modeling framework and the exploration of advanced solving techniques.

This paper proposes a novel incentive mechanism for efficient TEP that enables a Nash bargaining-based negotiation among TEP investors and transmission network users. Simultaneously, it effectively addresses the coordination between TEP and GEP via a bi-level single-leader-multi-follower structure and obtains generation investment equilibrium through a decentralized method.

1.2. Literature review

1.2.1. Incentive mechanism for efficient TEP

Several incentive mechanisms for TEP have been developed, including the Rate of Return, Competitive Procurement, Financial Transmission Right (FTR)-based, Incremental Subsidy Scheme (ISS), H-R-G-V, and Generalized-FTR-based mechanisms. These are illustrated comparatively in Table 1.

The Rate of Return mechanism, widely applied in the US following FERC 1000 (Frank, 2018), ensures that TEP investors are compensated based on an allowed rate related to their revenue requirements. Although this method has been crucial in guaranteeing sufficient revenue for TEP investors, it has been criticized for its reliance on a cost pass-through model that does not sufficiently scrutinize costs (Joskow, 2020). To address this issue, the Competitive Procurement mechanism (Joskow, 2020) was devised, promoting free entry for independent TEP investors and enhancing the transparency of TEP cost information to the regulators (CAISO, 2021; Joskow, 2020). This mechanism is superior to the Rate of Return for supplementing performance-based incentives. However, both mechanisms focus on individual project incentives rather than optimizing for system-wide social welfare (Joskow, 2020).

Considerable efforts have been made to introduce market-based mechanisms to improve efficiency. The merchant FTR-based mechanism, proposed by researchers (Hogan, 1992) and further studied (Bushnell and Stoft, 1997; Chao and Peck, 1996; Joskow and Tirole, 2005), allows TEP investors to earn market revenues from FTRs, which reflect the economic value of congestion rents. While this approach can potentially realize social-welfare-maximizing investment under specific conditions, these conditions are rarely met in reality (Papadaskalopoulos et al., 2020). [1] Another significant limitation is that the market revenue from FTR often does not cover the total TEP costs, leading to financial difficulties in implementation (Joskow, 2020).

Complementary charges apart from the market revenues have thus been initiated and developed. Among them, the Incremental Subsidy Scheme (ISS) has been introduced that relies on a subsidy design (Gans and King, 2000; Khastieva et al., 2021). Within this framework, TEP investor receives complementary charges, also called the subsidy fee, which equals the change in transmission network users' surplus between two consecutive periods, minus the previous period's market revenue. This mechanism also has the potential to achieve TEP strategies that maximize social welfare (Sappington and Sibley, 1988). However, this mechanism comes with an inherent shortcoming in the subsidy part, which requires assistance from the regulator to calculate the subsidy.[2] During this process, transmission network users must disclose private information concerning supply costs and demand utility to the regulator.[3][4] This requirement can induce barriers to the practical implementation of the mechanism (Hesamzadeh et al., 2018).

Inspired by the ISS mechanism, the H-R-G-V mechanism (Hesamzadeh et al., 2018) proposes that the TEP investor receive the entire change in transmission network users' surplus, [5] potentially leading to social-welfare-maximizing investment. Similar to the ISS, this mechanism also requires access to information on the supply costs and demand utility of transmission network users, which may pose obstacles in implementation (Biggar and Hesamzadeh, 2020).

[1] These conditions are (1) neglecting fixed investment costs and (2) assuming a radial network without a loop.

[2] What's more, the subsidy is usually neither a feasible nor a necessarily desirable policy for regulators. In particular, regulators generally do not have the power to grant subsidies.

[3] Gans and King (2000) suggest that this information (key demand utility and supply cost information) for calculating social welfare change can be readily inferred by the Independent System Operator from demand bids and generator bids for short-term generation dispatch.

[4] According to CAISO's Business Practice Manual for Transmission Expansion Planning (CAISO, 2023), the CAISO shall keep certain information confidential when its release could harm the competitiveness of wholesale markets. Under this policy, transmission network users' supply cost and demand utility are considered confidential and market-sensitive and should not be made public.

[5] This mechanism is named after its authors, M.R. Hesamzadeh, J. Rosellón, S.A. Gabriel and I. Vogelsang.

Table 1
A comparison of different incentive mechanisms for TEP

Mechanisms	Features				
	I	II	III	IV	V
Rate of Return (Frank, 2018)	yes	no	yes	no	need extra mechanism
Competitive Procurement (Joskow, 2020)	yes	no	yes	no	need extra mechanism
FTR Based (Hogan, 1992)	no	no	yes	yes	yes
ISS (Gans and King, 2000)	yes	yes	no	no	need extra mechanism
H-R-G-V (Hesamzadeh et al., 2018)	yes	yes	no	no	need extra mechanism
Generalized-FTR Based (Biggar and Hesamzadeh, 2020)	yes	yes	yes	yes	need extra mechanism
Our Proposed Mechanism	yes	yes	yes	yes	yes

(I): Guaranteeing revenue sufficiency; (II): Achieving TEP strategies that maximize social welfare; (III): Avoiding disclosing private information on supply cost and demand utility of transmission network users; (IV): Coordinating the benefits conveyed to the TEP investor and the transmission network users; (V): Realizing a reasonable distribution of costs among transmission network users;

Moreover, by handing all incremental benefits of TEP to the TEP investor, this mechanism risks leaving transmission network users at their original benefit level, potentially disincentivizing them from actions that could enhance overall welfare (Vogelsang, 2020).[6]

The generalized-FTR-based mechanism, developed by Biggar and Hesamzadeh (2020), is an innovative market-based approach for efficient TEP. Under this mechanism, a risk-neutral TEP investor signs hedge contracts with totally risk-averse GenCos and LSEs. The TEP investor then acquires generalized FTRs from the system operator, aligning its payoff with the total social welfare surplus. While this mechanism promises to guarantee revenue sufficiency and achieve social-welfare-maximizing transmission investment, it requires an extra hedging system for trading hedge contracts to address the risks associated with TEP effectively. Further research is needed to determine the practicality of this approach and its ability to be implemented effectively in the future power system (Biggar, 2022).

In summary, as specified in Table 1, existing incentive mechanisms fail to address all the necessary features for an efficient mechanism simultaneously. Thus, there is a pressing need for an efficient, comprehensive incentive mechanism for TEP that fulfills these essential criteria.

1.2.2. Practical and theoretical foundation for the negotiation-based incentive mechanism

Since TEP can relieve congestion, alter nodal prices, and affect the benefits of transmission network users. These stakeholders are strongly motivated to participate in TEP decision-making processes (Pérez-Arriaga, 2013). For instance, in China's transition from a regulated power system to a deregulated electricity market based on nodal prices, generation units in regions with a high concentration of low-cost generation face a paradigm shift. Previously, these units enjoyed stable revenues under government-regulated prices. However, after nodal price implementation, transmission line congestion can lead to lower nodal prices, reducing these GenCos' revenues and exposing them to potential stranded cost risks during the electricity market reform process (Curtin et al., 2019). These GenCos, therefore, have a strong motivation to participate in TEP decision-making to seek mutual benefits with TransCo and other market participants.

In the UK, the RPI-X regulatory mechanism, [7] designed to balance reasonable returns on investment with the promotion of efficiency and cost control, has been applied for many years (Littlechild, 2021). However, gradually, the time and cost in the regulation process required for setting the RPI-X factor has increased and has caused a great burden of regulation and confrontation (Biggar, 2022). As a possible solution to these problems, Littlechild has long advocated for direct negotiations between regulated transmission entities and their network users, with the regulator

[6] In fact, the TransCo under the H-R-G-V and ISS mechanisms can extract the full surplus from all market participants. Consider a generator who is considering investing to increase efficiency and reduce its generation costs. Under the H-R-G-V and ISS mechanisms, the generator immediately loses all the benefits of that investment in the following period. The same applies to a load when upgrading the electrical equipment in a factory. Again, TransCo will take all the increases in surplus arising from that upgrade in the following period.

[7] 'RPI' stands for the Retail Price Index, a measure of inflation; 'X' represents a factor by which the allowed prices are adjusted. Littlechild proposed the RPI-X method to limit prices to protect customers and guarantee an annual real price reduction while preserving the incentive for the regulated company to become more efficient.

acting as a backstop (Littlechild, 2012b, 2020). [8] Real-world practice has been promising (Littlechild, 2008), such as US Federal energy regulation, Oil and gas pipelines in Canada, Utilities in Alberta and Regulation, the consumer advocate in Florida, and the transmission expansion experience in Argentina (Littlechild, 2012a). However, placing this approach on a sound theoretical foundation is another outstanding issue in network regulation (Biggar, 2022).

Cooperative game theory offers a solid theoretical foundation for analyzing scenarios where participants can collaborate to achieve mutual benefits (Churkin et al., 2021). The Nash bargaining theory is an important tool in cooperative game theory. It is proven to achieve Pareto optimality and fair outcomes while effectively enhancing the economic utilities of all market players (Nash, 1950). For example, Zhou et al. (2013) models a negotiation between a renewable GenCo and a TransCo regarding a new transmission line that would permit the delivery of renewable sources to the grid. Joalland et al. (2019) adopts a negotiation process for specific transmission corridors of new transmission lines. Despite its potential, there has been very little exploration of applying Nash Bargaining theory in the design of TEP incentive mechanisms. This paper proposes a negotiation mechanism based on Nash bargaining theory that can simultaneously satisfy these five properties listed in Table 1.

1.2.3. Coordination of TEP and GEP [9]

The fundamental importance of coordination of TEP and GEP in restructured power systems has long been recognized (Roh et al., 2007, 2009), as the lack of coordination would not only underestimate the economic value of the transmission network but also depreciate the benefits brought by generation resources (Xu and Hobbs, 2019; Hesamzadeh et al., 2011; Pozo et al., 2013a, 2017; Spyrou et al., 2017; Wang et al., 2018; po Chao and Wilson, 2020). Coordination between TEP and GEP introduces multi-level modeling to reflect their interactive relationship, which increases the scale and complexity of the models (Pozo et al., 2013b; Jin and Ryan, 2014; Akbari et al., 2017; Taheri et al., 2017; Baringo and Baringo, 2018; Çelebi et al., 2021; Wogrin et al., 2021; Grimm et al., 2021). These models often employ binary (or discrete) decision variables to represent the discrete nature of transmission investments effectively. In practice, conventional thermal units' expansion variables are also discrete. However, most optimization models addressing TEP and GEP coordination use continuous variables for GEP to achieve convexity conditions necessary for complementarity reformulation to make the coordination problem tractable. To the best of our knowledge, only Pisciella et al. (2016); Pozo et al. (2017); Tohidi et al. (2017) have utilized discrete variables in both TEP and GEP, resulting in non-convex sub-problems that require complex and computationally intensive algorithms to solve. (Shivaie and Ameli, 2016a,b) address TEP and GEP coordination by a multi-level optimization model and solve it with a novel metaheuristic algorithm.

The growing integration of renewable energy and distributed energy resources further complicates the interactions between TEP and GEP, drawing intense research interest (Khastieva et al., 2019; Moradi-Sepahvand and Amraee, 2021; Pulazza et al., 2021; Tian et al., 2022). Notably, most of these studies omit specific incentive mechanisms for TEP that could maximize social welfare, typically simply assuming that the objective function is to maximize social welfare or minimize social costs.

GEP is the non-cooperative gaming outcome of multiple GenCos (Hesamzadeh et al., 2011; Tohidi et al., 2017; Gonzalez-Romero et al., 2021) in deregulated environments. Some literature has simplified this feature by modeling the GEP in a centralized manner. Some other literature acknowledges its non-cooperative nature by modeling it as individual GenCos making capacity investment decisions anticipating the outcomes of the electricity market equilibrium. These models are generally addressed using the well-established Equilibrium Problem with Equilibrium Constraints (EPEC) formulation (Jin and Ryan, 2014; Taheri et al., 2017). Although this approach is commonly used, it comes with substantial computational burdens, particularly in large-scale applications (Tohidi et al., 2018).

To mitigate these computational challenges and enhance scalability with problem size, researchers have explored the applicability of distributed algorithms for seeking generation investment equilibrium in the deregulated environment, such as the modified Benders Decomposition (Tohidi et al., 2018) and Alternating Direction Method of Multipliers (ADMM)-based algorithms (Höschle et al., 2018; Tómasson et al., 2020). For instance, Höschle et al. (2018) developed an ADMM-based algorithm to deal with the equilibrium problem without considering network

[8] Some original expression in Littlechild (2012a) is quoted here. "Contrary to initial impressions, this approach (negotiation approach) worked well: there were productive negotiations between transmission users that resulted in them commissioning needed transmission expansions, of all kinds and sizes, without undue transactions costs." "Thus, transactions costs and other potential difficulties such as conflicting interests have not generally been an obstacle to negotiating a settlement between the provider of transmission services and the users of that facility."

[9] In this section, citations are used extensively to make a connection with the comparative analysis provided in Table 2.

Table 2
The comparative literature review

Papers	I	II	III	IV
Henao et al. (2017); Joalland et al. (2019);	no	yes	no	no
Baringo and Baringo (2018); Khastieva et al. (2019); Pulazza et al. (2021); Moradi-Sepahvand and Amraee (2021); Yin and Wang (2022); Tian et al. (2022); Li et al. (2022);	yes	no	no	no
Hesamzadeh et al. (2018); Joskow (2020); Biggar and Hesamzadeh (2020); Khastieva et al. (2021) Lavrutich et al. (2023);	yes	yes	no	no
Hesamzadeh et al. (2011) Pozo et al. (2013b); Pozo et al. (2013a); Jin and Ryan (2014); Pozo et al. (2017); Akbari et al. (2017); Taheri et al. (2017); Spyrou et al. (2017); Tohidi et al. (2017); Çelebi et al. (2021); Gonzalez-Romero et al. (2021); Wogrin et al. (2021);	yes	no	yes	no
Höschle et al. (2018); Tómasson et al. (2020);	no	no	yes	yes
our paper	yes	yes	yes	yes

(I): Considering coordination between TEP and GEP; (II): Considering incentive mechanism for efficient TEP; (III): Considering the non-cooperative feature among multi GenCos; (IV): Solving the generation investment equilibrium with distributed algorithms.

constraints, which oversimplified the electricity market in the GEP model. Tómasson et al. (2020) considered a multi-area generation investment equilibrium problem and utilized the ADMM algorithm to relax the inter-area network constraints to make the problem scalable. Nonetheless, this approach requires further exploration, as they assumed each GenCo's generators are concentrated in one area, while in deregulated environments, each GenCo's generator may be dispersed across multiple areas. The Proximal Message Passing (PMP) algorithm is an extension of the exchange ADMM algorithm, which minimizing at each Gauss-Seidel pass amounts to evaluating the proximal functions relative to the specific decision vector partition (Kargarian et al., 2018). Unlike the traditional ADMM algorithm, which is sequential due to the order of multiplier updates, the PMP algorithm operates in a fully decentralized manner. It exhibits significant scalability concerning problems with network constraints.

A comparative literature review on the coordination between TEP and GEP regarding engineering and computational aspects is illustrated in Table 2. The intricate dynamics within TEP and GEP and their coordination increase the complexity of the TEP problem, necessitating the development of advanced solving techniques. Motivated by these research gaps, this paper addresses the coordination between TEP and GEP with a specific incentive mechanism for efficient TEP and a decentralized algorithm to manage the non-cooperative nature of GEP. We model the TEP and GEP decision variables with discrete ones to reflect real-world practice. The developed bi-level model and corresponding methods are scalable and applicable to large-scale problems.

1.3. Main work and contributions

This paper offers several important contributions to the field of power system planning and optimization and decision-making methods for energy systems problems, which are outlined as follows:

(1) We introduce a novel negotiation-based incentive mechanism for efficient TEP, enabling GenCos and LSEs to proactively and directly negotiate with TransCo on the TEP strategies and bargaining fees.

(2) The coordination between the TEP and GEP problems is described as a bi-level single-leader-multi-follower structure, in which the TEP problem behaves as the leader while the follower GEP problem seeks the generation investment equilibrium. The LL model accurately captures the non-cooperative feature of the GEP problem in the deregulated environment.

(3) We equivalently reformulate the non-convex TEP problem in the UL into a tractable one and devise a modified PMP decentralized algorithm to obtain the generation investment equilibrium in the LL and then utilize an iterative method to solve the bi-level model.

(4) The results verify that the proposed mechanism successfully ensures revenue sufficiency and obtains the same socially optimal TEP strategies as the state-of-the-art incentive mechanisms. It maintains the privacy of transmission network users, effectively coordinates the benefits among TransCo, GenCos, and LSEs, and achieves a fair distribution of TEP costs and risks. The proactive participation of market players enabled by the negotiation mechanism can mitigate

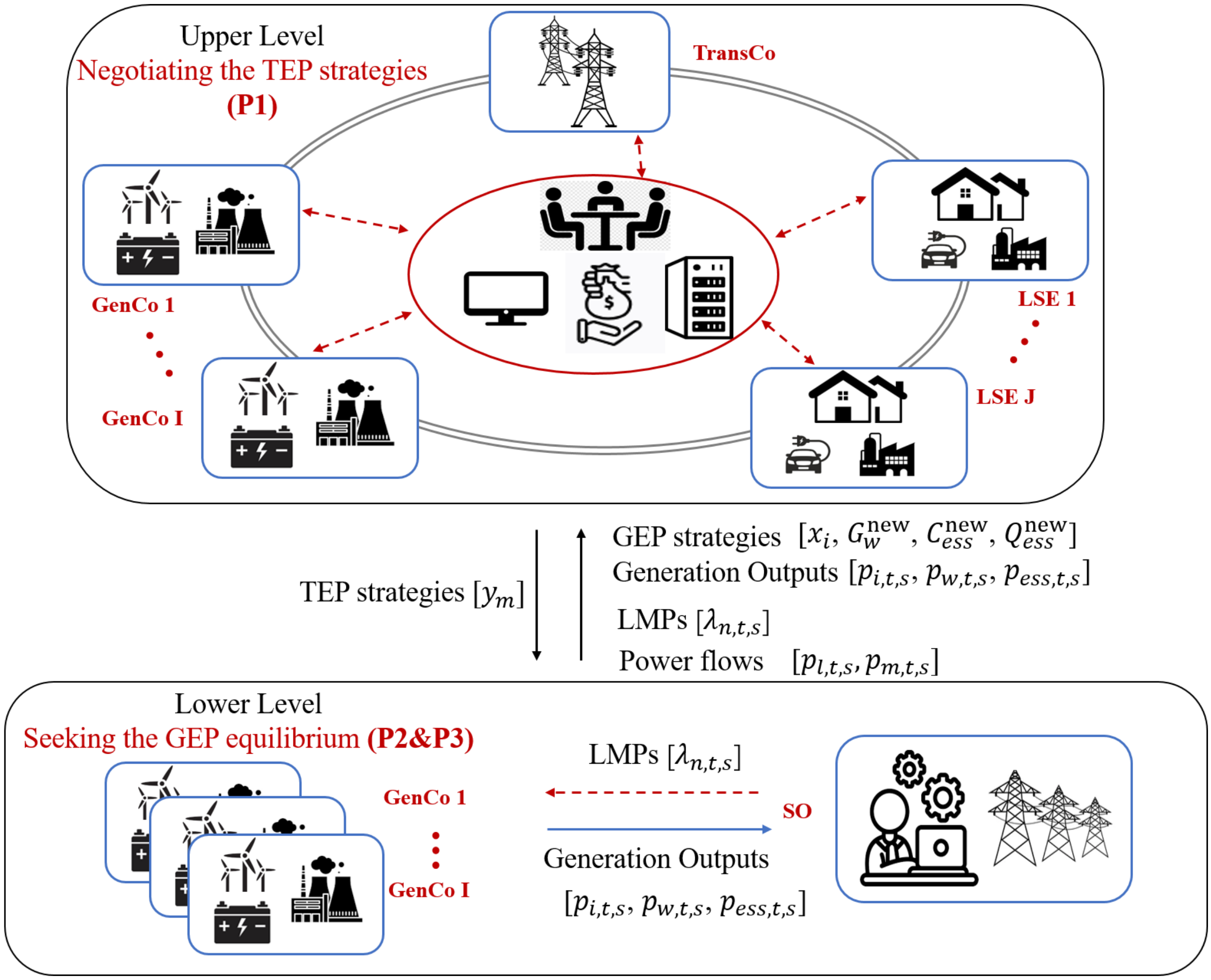


Figure 1: The framework for the proposed bi-level model for TEP and GEP

the stranded cost issue and promote the transformation toward new market systems. The developed bi-level model and corresponding methods apply to large-scale problems.

The rest of the paper is structured as follows. Section 2 details the framework for the proposed negotiation mechanism and describes the models used. Section 3 discusses the methodology employed to solve the problem. Section 4 conducts comparative studies to validate the feasibility and effectiveness of the proposed mechanism and methodologies. Section 5 provides a real-world implementation process for the mechanism, outlines policy implications, and concludes the paper.

2. Mathematical model

2.1. Problem description

This paper introduces a novel negotiation incentive mechanism for efficient TEP, allowing GenCos and LSEs to negotiate with the TransCo responsible for transmission expansion proactively. The rationale for this engagement stems from TEP's effects to alleviate congestion and alter electricity market prices, thereby impacting the utilities of GenCos and LSEs, particularly under the Locational Market Pricing (LMP) system, where prices vary across nodes. Consequently, different TEP strategies can lead to different changes in the utilities of these GenCos and LSEs, potentially increasing or decreasing their economic benefits. In this context, GenCos and LSEs are willing to participate in determining TEP strategies to enhance their utilities by influencing the LMPs at their respective nodes.

The negotiation process is modeled based on the Nash Bargaining theory, as the players negotiate to seek mutual benefits and form a cooperative game. The Nash bargaining theory is an important tool in cooperative game theory. It is proven to achieve the Pareto optimality and fair outcomes while effectively enhancing the economic utilities of all market players (Nash, 1950). Following the standard Nash bargaining theory, we assume the negotiation process among TransCo, GenCos, and LSEs is a symmetric game to simplify this problem. The implication of a symmetric game is that the market participants have equal bargaining power in deciding the optimal transmission investment, which results in an equal net benefit distribution. [10] [11]

Moreover, to effectively address the coordination between TEP and GEP, this paper establishes a bi-level single-leader-multi-follower framework, shown in Fig. 1. In this framework, the TEP, acting as the leader, influences the GEP, which, as the follower, adjusts its strategies based on the TEP decisions and provides feedback on GEP strategies, generation outputs, power flows, and LMPs. The main advantage of this model is that it assists TransCo in making optimal TEP decisions, considering the strategic behaviors of all GenCos in GEP decisions. This interaction involves four types of players: TransCo, GenCos, LSEs, and the System Operator (SO).

At the LL, the focus is on seeking the equilibrium for GEP strategies, considering the non-cooperative feature of multiple GenCos in reality. Each GenCo individually determines its expansion strategies and generation outputs to maximize utility, given the LMPs generated from the SO's problem. The SO determines these LMPs ($\lambda_{n,t,s}$) and manages the power flows ($p_{l,t,s}$, $p_{m,t,s}$) on transmission lines (Guo et al., 2021), given the outputs from each GenCo ($p_{the,t,s}$, $p_{w,t,s}$, $p_{ess,t,s}$). This non-cooperative game can be interpreted as a specific sharing problem, namely an optimal exchange, wherein the market clearing equality constraints interrelate the decision variables ($p_{the,t,s}$, $p_{w,t,s}$, $p_{ess,t,s}$) with the dual variables $\lambda_{n,t,s}$.

2.2. UL problem: negotiating the TEP strategies

This paper proposes a negotiation incentive mechanism for efficient TEP based on Nash bargaining theory. This mechanism encourages active cooperation among all stakeholders within the transmission expansion process: TransCo, GenCos, and LSEs. The model is established in this subsection, assuming TransCo, GenCos, and LSEs all participate in the negotiation. Following the standard formation of the Nash Bargaining problem, the proposed economic incentive mechanism aims to obtain the properties of Pareto efficiency and fair outcome while benefiting all involved entities (Nash, 1950).

The axiomatic theory of the bargaining game originated in two fundamental papers by Nash in 1950 and 1953 (Nash, 1950). Harsanyi directly extended Nash's axioms to the n-person case in 1958 (Harsanyi, 1959). Roth (1979) and Binmore et al. (1986) further discuss asymmetric players, where the players have unequal bargaining power. [12] The Nash bargaining theory offers a predictable framework based on known utilities and disagreement points, which helps market players formulate their negotiation strategies and anticipate the outcome (Binmore et al., 1986). One additional nice feature of the Nash bargaining theory is simplicity (Serrano, 2005), which should always be a desired feature in terms of increasing the applicability in real-world situations. Empirical evidence in support of Nash bargaining theory has been obtained from human-subject bargaining experiments (Roth, 1995). The benefits of Nash Bargaining theory are particularly well-suited for addressing the transmission investment negotiation issues discussed in this paper. However, the Nash bargaining model typically addresses static, one-time negotiations (Binmore et al., 1986). The initial disagreement points significantly influence the outcomes (Binmore, 1992).

The negotiating model for TEP solves a highly nonlinear optimization problem (**P1**) to determine the TEP strategies y_m ($m = 1, \dots, M$) and the bargaining fees π_i^{GenCo} ($i = 1, \dots, I$) and π_j^{LSE} ($j = 1, \dots, J$). The objective function (1a) is to maximize the product of the incremental utilities of TransCo, GenCos, and LSEs, which is consistent with the standard Nash Bargaining problem. The model introduces bargaining fees π_i^{GenCo} and π_j^{LSE} to redistribute participant utilities. The decision variables set is y_m, representing the TEP strategies for the Mth candidate lines.

[10] Nash institutes the idea of equality based on the risk preferences of the players. In other words, players who are risk neutral must obtain the same effective profit. Therefore, risk-neutral players, despite having unequal disagreement points, have equal bargaining power and the same net allocations. (Nagarajan and Sošić, 2008).

[11] It's important to note that while Nash Bargaining assumes equal negotiation position among participants, real-world scenarios might see differences in bargaining power. In such cases, Nash-Hasanyi's bargaining model could be employed (Chen et al., 2021; Mi et al., 2022), which accounts for the different bargaining power of each participant through specific parameters.

[12] Extending our model to asymmetric case requires further efforts involving identifying factors influencing bargaining power (e.g., the marginal contribution of participants to the cooperative alliance, risk-averse level) and selecting accurate parameters (Chen et al., 2023), and we leave it for future work.

$$
\begin{aligned}
\textbf{P1}\ \max_{y_m}\quad & \left(U_\pi + \pi_i^{\text{TransCo}} - U_\pi^0\right) \prod_{j=1}^{J} \left(U_j + \pi_j^{\text{LSE}} - U_j^0\right) \prod_{i=1}^{I} \left(U_i + \pi_i^{\text{GenCo}} - U_i^0\right) && \text{(1a)}\\
\text{subject to}\quad & U_\pi^0 = 0 && \text{(1b)}\\
& U_\pi = - \sum_{m\in M} C_m^{\text{cost}} \frac{\alpha(1+\alpha)^{yr}}{(1+\alpha)^{yr}-1} y_m, \forall m \in M && \text{(1c)}\\
& U_j^0 = \frac{1}{2}\sum_{t\in T}\sum_{l\in L} \phi_{j,l,t}^0 \omega_{l,t}^0 - \sum_{t\in T} \lambda_{j,t}^0 d_{j,t}^0, \forall j \in J && \text{(1d)}\\
& U_j = \frac{1}{2}\sum_{t\in T}\sum_{l\in L\cup M} \phi_{j,l,t} \omega_{l,t} - \sum_{t\in T} \lambda_{j,t} d_{j,t}, \forall j \in J && \text{(1e)}\\
& U_i^0 = \frac{1}{2}\sum_{t\in T}\sum_{l\in L} \phi_{i,l,t}^0 \omega_{l,t}^0 + \sum_{t\in T} \lambda_{i,t}^0 g_{i,t}^0 - \sum_{t\in T} c_i g_{i,t}^0, \forall i \in I && \text{(1f)}\\
& U_i = \frac{1}{2}\sum_{t\in T}\sum_{l\in L\cup M} \phi_{i,l,t} \omega_{l,t} + \sum_{t\in T} \lambda_{i,t} g_{i,t} - \sum_{t\in T} c_i g_{i,t}, \forall i \in I && \text{(1g)}\\
& \omega_{l,t}^0 = p_{l,t}^0 \left(-\lambda_{n\in S(l),t}^0 + \lambda_{n\in R(l),t}^0\right), \forall l \in L, t \in T && \text{(1h)}\\
& \omega_{l,t} = p_{l,t} \left(-\lambda_{n\in S(l),t} + \lambda_{n\in R(l),t}\right), \forall l \in L \cup M, t \in T && \text{(1i)}\\
& U_j + \pi_j^{\text{LSE}} - U_j^0 \geq 0, \forall j \in J && \text{(1j)}\\
& U_i + \pi_i^{\text{GenCo}} - U_i^0 \geq 0, \forall i \in I && \text{(1k)}\\
& U_\pi + \pi_j^{\text{TransCo}} - U_\pi^0 \geq 0 && \text{(1l)}\\
& \pi^{\text{TransCo}} + \sum_{j\in J} \pi_j^{\text{LSE}} + \sum_{i\in I} \pi_i^{\text{GenCo}} = 0 && \text{(1m)}
\end{aligned}
$$

Here U_π and U_π^0 are the revenue functions for TransCo before and after the TEP, as expressed in detail as (1b)-(1c). (1b) indicates that TransCo's initial revenue is set at zero. (1c) represents that the revenue of TransCo after TEP is the negative annualized TEP cost, which is calculated based on the actual TEP cost (C_m^{cost}), interest rate (α) and expected lifetime of transmission lines (yr).

Constraints (1d)-(1i) present utilities before and after TEP calculated for each LSE and GenCo and the congestion rents. The revenue functions U_j and U_i for LSEs and GenCos, respectively, are defined to include the economic effects of TEP, considering revenues from FTRs ($\frac{1}{2}\sum_{t\in T}\sum_{l\in L} \phi_{j,l,t}^0 \omega_{l,t}^0$, $\frac{1}{2}\sum_{t\in T}\sum_{l\in L\cup M} \phi_{j,l,t}\omega_{l,t}$) and electricity costs ($\sum_{t\in T} \lambda_{j,t}^0 d_{j,t}^0$, $\sum_{t\in T} \lambda_{j,t} d_{j,t}$), or revenues from FTRs ($\frac{1}{2}\sum_{t\in T}\sum_{l\in L\cup M} \phi_{i,l,t}\omega_{l,t}$, $\frac{1}{2}\sum_{t\in T}\sum_{l\in L} \phi_{i,l,t}^0 \omega_{l,t}^0$), operational costs ($\sum_{t\in T} c_i g_{i,t}^0$, $\sum_{t\in T} c_i g_{i,t}$) and sales revenues ($\sum_{t\in T} \lambda_{i,t}^0 g_{i,t}^0$, $\sum_{t\in T} \lambda_{i,t} g_{i,t}$), as shown in (1d-1e) and (1f-1g). FTRs provide GenCos and LSEs with the ability to hedge against congestion costs and gain from differences in LMPs at different nodes, as calculated in (1h) and (1i). Here, we allocate the revenues from FTR to the transmission network users based on their transmission usage rate ($\phi_{j,l,t}$, $\phi_{i,l,t}$),[13] and determines the network users' transmission usage rate according to the power flow tracing technique (Xiao et al., 2016). A detailed illustration of how power flow tracing works can be found in Appendix A.

The proposed economic incentive mechanism introduces monetary transfer that redistributes the TEP cost and investment revenue to obtain overall beneficial cooperative outcomes. Specifically, the monetary transfer here refers to the bargaining fees (π_j^{LSE}, π_i^{GenCo}). π_j^{LSE} is the bargaining fee that each LSE j pays to the TransCo. After the monetary transfer, the utility of each LSE is calculated as (1j). π_i^{GenCo} is the bargaining fee that each GenCo i pays to the TransCo. After the monetary transfer, the utility of each GenCo is calculated as (1k). The utility for the TransCo

[13] In regions such as PJM and ISO-NE, all transmission network users who pay transmission fees are eligible for Auction Revenue Rights (ARRs) based on their historical transmission usage, which entitles them to a share of the revenue generated in the annual FTR auction (ISO New England, 2018), (PJM, 2023).

after the monetary transfer equals the TransCo's revenue after the TEP (U_π) plus the sum of the bargaining fees received from LSEs and TransCos (π^{TransCo}), as illustrated in (1l).

A significant prerequisite for a successful negotiation is ensuring a sufficient revenue margin for each participant. This principle mandates that all participants involved in the negotiation process should achieve higher utility after implementing the TEP strategies. Consequently, constraints (1j)-(1l) are added to the model. Following this principle, the bargaining fee (π_j^{LSE}, π_i^{GenCo}) in a successful negotiation can be either positive or negative, depending on whether the GenCo or LSE benefits from or is adversely affected by the TEP. When the transmission network user is economically positively affected, the bargaining fee is positive, implicating paying fees to reimburse the TransCo. Conversely, when the transmission network user is economically adversely affected, the bargaining fee is negative, implicating receiving a compensating fee to encourage cooperation. The sum of the bargaining fees equals zero, guaranteeing the financial balance, as shown in (1m). The funds used to pay the compensation come from the net benefits brought by the transmission investment and require no other external funds.

2.3. LL problem: seeking the generation investment equilibrium

In a deregulated environment, each GenCo independently determines its own GEP strategies. This non-cooperative game adds complexity to the modeling and resolving the GEP problem. In the proposed LL problem, each GenCo strategically makes GEP decisions to maximize its profits (**P2**). GenCos' strategies are interconnected by market-clearing conditions (**P3**), leading to a complex generation investment problem. Moreover, we model the thermal generator's expansion decision as discrete variables, which reflects real-world practice and necessitates more complex solving techniques.

The solution concept for this LL GEP problem is defined by the Nash equilibrium, as detailed by (Myerson, 2019), where a strategy profile $\chi^* \in \chi$ is considered at Nash equilibrium if and only if $U_a(\chi^*) \geq U_a\left(\chi_a, \chi_{-a}^*\right), \forall a \in A, \forall \chi_a \in \chi$. This definition implies that within the equilibrium context, each GenCo's strategy is such that no single GenCo can enhance its utility by altering its strategy (χ_i^{GenCo}) while other GenCo's strategies remain unchanged. The constraints and bounds on GenCo's and SO's strategies demonstrate the existence of a Nash Equilibrium in the LL GEP problem.

2.3.1. Each GenCo's behavior

Each GenCo i solves the optimization problem **(P2)** to determine its optimal GEP strategy ($x_{i,the}$, $G_{i,w}^{\text{new}}$, $C_{i,ess}^{\text{new}}$, $Q_{i,ess}^{\text{new}}$) and generation outputs ($p_{i,the,t,s}$, $p_{i,w,t,s}$, $p_{i,ess,t,s}$) given the LMPs transferred from the SO's problem. The objective is to maximize its own expected utility. The subscripts (the, w, ess) denote the variables of thermal units, wind farms, and energy storage separately. Each GenCo i's decision variables set is $\chi_i^{\text{GenCo}} = \left\{p_{i,the,t,s}, p_{i,w,t,s}, p_{i,ess,t,s}, x_{i,the}, G_{i,w}^{\text{new}}, C_{i,ess}^{\text{new}}, Q_{i,ess}^{\text{new}})\right\}$.

$$\textbf{P2} \quad \max_{\chi_i^{\text{GenCo}}} \quad U_{i,the}(p_{i,the,t,s}, x_{i,the}) + U_{i,w}(p_{i,w,t,s}, G_{i,w}^{\text{new}}) + U_{i,ess}(p_{i,ess,t,s}, C_{i,ess}^{\text{new}}, Q_{i,ess}^{\text{new}}) \tag{2a}$$

subject to

$$U_{i,the}(p_{i,the,t,s}, x_{i,the}) = \sum_{s\in S}\sum_{t\in T}\sum_{the\in E\cup C} \omega_s\left(\lambda_{n\in I(the),t,s}p_{i,the,t,s} - c_{i,the}p_{i,the,t,s}\right) - \sum_{the\in C} c_{i,the}^{\text{exp}} x_{i,the} \tag{2b}$$

$$U_{i,w}(p_{i,w,t,s}, G_{i,w}^{\text{new}}) = \sum_{s\in S}\sum_{t\in T}\sum_{w\in E\cup C} \omega_s\left(\lambda_{n\in W(w),t,s}p_{i,w,t,s} - c_{i,w}p_{i,w,t,s}\right) - \sum_{w\in C}\left(c_{i,w}^{\text{exp}} G_{i,w}^{\text{new}}\right) \tag{2c}$$

$$U_{i,ess}(p_{i,ess,t,s}, C_{i,ess}^{\text{new}}, Q_{i,ess}^{\text{new}}) = \sum_{s\in S}\sum_{t\in T}\sum_{ess\in E\cup C} \omega_s\left(\lambda_{n\in E(ess),t,s}p_{i,ess,t,s} - c_{i,ess}p_{i,ess,t,s}\right) - \sum_{ess\in C} c_{i,ess}^{\text{Eexp}} C_{i,ess}^{\text{new}} - \sum_{ess\in C} c_{i,ess}^{\text{Pexp}} Q_{i,ess}^{\text{new}} \tag{2d}$$

$$G_{i,the}^{\min} \leq p_{i,the,t,s} \leq G_{i,the}^{\max}, \forall the \in E, t\in T, s\in S \tag{2e}$$

$$x_{i,the}G_{i,the}^{\min} \leq p_{i,the,t,s} \leq x_{i,the}G_{i,the}^{\max}, \forall the \in C, t\in T, s\in S \tag{2f}$$

$$0 \leq p_{i,w,t,s} \leq \alpha_{i,w,t}G_{i,w}^{\text{new}} + W_{i,w}^{\max}, \forall w \in E\cup C, t\in T, s\in S \tag{2g}$$

$$-C_{i,ess}^{\max} \leq p_{i,ess,t,s} \leq C_{i,ess}^{\max}, \forall ess \in E, t\in T, s\in S \tag{2h}$$

$$- C^{\text{new}}_{i,ess} \le p_{i,ess,t,s} \le C^{\text{new}}_{i,ess}, \forall ess \in C, t \in T, s \in S \tag{2i}$$

$$e_{i,ess,\tau,s} = e^{\text{init}}_{i,ess} + \sum_{t=1}^{\tau} p_{i,ess,t,s}, \forall ess \in E \cup C, \tau \in 1, ..., T, s \in S \tag{2j}$$

$$0 \le e_{i,ess,t,s} \le Q^{\text{new}}_{i,ess}, \forall ess \in E \cup C, t \in T, s \in S \tag{2k}$$

$$e_{i,ess,T,s} = e^{\text{init}}_{i,ess}, \forall ess \in E \cup C, s \in S \tag{2l}$$

$$0 \le G^{\text{new}}_{i,w} \le W^{\max}_{i,w}, \forall w \in C \tag{2m}$$

$$0 \le C^{\text{new}}_{i,ess} \le C^{\max}_{i,ess}, \forall ess \in C \tag{2n}$$

$$x_{i,the} \in \{0, 1\}, \forall the \in C \tag{2o}$$

In Eqs. (2b), (2c) and (2d), the expected utility ($U_{i,the}, U_{i,w}, U_{i,ess}$) is the utility per scenario weighted with each scenario's probability (ω_s). GenCo i's revenues are calculated based on the generation output ($p_{i,the,t,s}$, $p_{i,w,t,s}$, $p_{i,ess,t,s}$) multiplied by the respective LMPs ($\lambda_{n,t,s}$). The costs include GenCo i's operational cost and the GEP costs. ($c_{i,the}$, $c_{i,w}$, $c_{i,ess}$) denote each GenCo's marginal operation cost of thermal generators, wind farms, battery energy storage systems (BESS) and ($c^{\exp}_{i,the}$, $c^{\exp}_{i,w}$, $c^{\text{Eexp}}_{i,ess}$, $c^{\text{Pexp}}_{i,ess}$) denote each GenCo's GEP costs. Investments in energy storage systems are divided into two separate investments: energy capacity ($Q^{\text{new}}_{i,ess}$) and power capacity ($C^{\text{new}}_{i,ess}$). Energy capacity determines the maximum limit of the state of charge, while power capacity sets the limits on the charge and discharge rates. The first term of Eqs. (2b), (2c) and (2d) consist of each GenCo's revenues obtained selling in the spot market and operational costs; the second term is each GenCo's cost of operating the generation, and the third is each GenCo expanding the generation capacity.

The constraints (2e)-(2l) represent technical limitations for generation outputs. Eqs. (2e)(2f) indicate that for each time slot (t) and each scenario (s), the provided energy ($p_{i,the,t,s}$) must be within its minimum and maximum capacity for the exiting generator ($G^{\min}_{i,the}$, $G^{\max}_{i,the}$) and candidate generator ($x_{i,the} G^{\min}_{the}$, $x_{i,the} G^{\max}_{i,the}$). (2g) shows that the generation of wind farms ($p_{i,w,t,s}$) is limited by the available power at each time slot. Parameter ($\alpha_{i,w,t}$) is the stochastic output factor of wind farm (w) at time slot (t), ($W^{\max}_{i,w}$) is the maximum capacity of wind farm (w) and ($W^{\max}_{i,w}$) is the wind farm capacity to be invested. The BESS scheduled power ($p_{i,ess,t,s}$) can take in or deliver energy, depending on whether it is charging or discharging. (2h) and (2i) show the limit for the charging and discharging rates of BESSs. (2j) illustrates the dynamic process of the energy ($e_{i,ess,t,s}$) stored in the bank of BESSs. (2k) shows that the state of charge of BESS is restricted by the installed energy capacity of BESS ($Q^{\text{new}}_{i,ess}$). (2l) forces daily initial charge levels ($e^{\text{init}}_{i,ess}$) and terminal state ($e_{i,ess,T,s}$) in BESSs to be equal to ensure its sustainable operation. (2m) and (2n) limit that the invested capacity ($G^{\text{new}}_{i,w}$, $C^{\text{new}}_{i,ess}$) only takes positive values. (2o) denotes the thermal generator's investment decision variables ($x_{i,the}$) are discrete.

2.3.2. SO's behavior

The SO solves the optimization problem (**P3**) to determine the SO strategy, specifically power flow variables ($p_{l,t,s}, p_{m,t,s}, \theta_{n,t,s}$) and market clearing price ($\lambda_{n,t,s}$) given the generation outputs ($p_{the,t,s}$, $p_{w,t,s}$, $p_{ess,t,s}$) transferred from the GenCo's problem. The objective is to minimize the demand imbalance multiplied by the dual variables ($\lambda_{n,t,s}$), formally given by the objective function (3a). The brackets in (3a) contain the market clearing conditions for the electricity market. The power injection and withdrawal of each node are equal. Market clearing conditions are met with either the nodal power balance being guaranteed or the market clearing price ($\lambda_{n,t,s}$) being 0. The decision variables' set is $\chi^1_{\text{SO}} = \{p_{l,t,s}, p_{m,t,s}, \theta_{n,t,s}, \lambda_{n,t,s}\}$.

$$\mathbf{P3} \max_{\chi^1_{\text{SO}}} \quad \sum_{s\in S}\sum_{t\in T}\sum_{n\in N} -\omega_s \left[\begin{array}{l} \sum\limits_{the\in E\cup C|I(the)=n} p_{the,t,s} + \sum\limits_{w\in E\cup C|W(w)=n} p_{w,t,s} + \sum\limits_{ess\in E\cup C|E(ess)=n} p_{ess,t,s} \\ - \sum\limits_{l\in L|S(l)=n} p_{l,t,s} + \sum\limits_{l\in L|R(l)=n} p_{l,t,s} - \sum\limits_{m\in M|S(m)=n} p_{m,t,s} \\ + \sum\limits_{m\in M|R(m)=n} p_{m,t,s} - \sum\limits_{j\in J|J(j)=n} p_{j,t,s} \end{array} \right] \cdot \lambda_{n,t,s} \tag{3a}$$

$$\text{subject to} \quad p_{l,t,s} = \frac{100}{X_l}\left(\theta_{n\in S(l),t,s} - \theta_{n\in R(l),t,s}\right), \forall l \in L, t \in T, s \in S \tag{3b}$$

$$-F_l \leq p_{l,t,s} \leq F_l, \forall l \in L, t \in T, s \in S \tag{3c}$$

$$p_{m,t,s} - \frac{100}{X_m}\left(\theta_{n\in S(m),t,s} - \theta_{n\in R(m),t,s}\right) \leq \Xi_m\left(1 - y_m\right), \forall m \in M, t \in T, s \in S \tag{3d}$$

$$p_{m,t,s} - \frac{100}{X_m}\left(\theta_{n\in S(m),t,s} - \theta_{n\in R(m),t,s}\right) \geq -\Xi_m\left(1 - y_m\right), \forall m \in M, t \in T, s \in S \tag{3e}$$

$$-F_m \leq p_{m,t,s} \leq F_m, \forall m \in M, t \in T, s \in S \tag{3f}$$

$$-y_m \Xi_m \leq p_{m,t,s} \leq y_m \Xi_m, \forall m \in M, t \in T, s \in S \tag{3g}$$

$$\theta_{(n=\mathrm{ref}),t,s} = 0, \forall t \in T, s \in S \tag{3h}$$

$$\underline{\lambda}_{n,t,s} \leq \lambda_{n,t,s} \leq \bar{\lambda}_{n,t,s}, \forall n \in N, t \in T, s \in S \tag{3i}$$

The active power flow constraints for existing lines are formulated in (3b). 100MVA is used to convert reactance (X_l) to per unit values in the active power flow constraints. (3c) is the constraint including the upper and lower bounds (F_l) on the capacities of the existing transmission lines. Similarly, (3d)-(3g) are used for candidate lines. The active power flow constraint will only be enforced when the corresponding candidate line m is invested ($y_m = 1$). (3f) is the constraint including the upper and lower bounds (F_m) on the capacities of the candidate transmission lines. According to constraint (3g), the flow of the candidate line m is forced to zero when there is no investment in this line ($y_m = 0$). (3h) forces the reference node with zero voltage angle. The market clearing prices ($\lambda_{n,t,s}$) are limited by the price caps in (3i), here we assume a lower limit of 0 for the energy price.

3. Methodology

3.1. Reformulation of the TEP model in the UL problem

The original model **(P1)** in the UL is intractable due to its non-convex nature resulting from the product of multiple variables within the objective function.

Lemma 1 *(Reformulation of the TEP model)*: The proposed transmission investment negotiation problem **(P1)** can be reformulated into an optimal transmission investment problem that maximizes the sum of the surplus changes of the participants **(P4)** and a bargaining fees calculation subproblem **(SP4)**.

$$\textbf{P4} \qquad \max_{y_m,\Omega} \left[U_\pi - U_\pi^0\right] + \sum_{j\in J}\left[U_j - U_j^0\right] + \sum_{i\in I}\left[U_i - U_i^0\right] \tag{4a}$$

$$\text{subject to} \qquad (1b) - (1i) \tag{4b}$$

Proof: We state that the Nash bargaining solution that maximizes **(P1)** also maximizes the sum of the surplus changes of the participants from the transmission investment **(P4)**. Let us reason by contradiction (Affolabi et al., 2022). We assume that there exists an agreement (transmission investment strategy $\hat{y}_m$) that is different from the optimal solution y_m^* of the Nash bargaining problem. The TEP strategy $\hat{y}_m$ not only maximizes the sum of the surplus changes of the participants from the transmission investment **(P4)**, but also increases all market players' surplus stated in the initial Nash bargaining formulation **(P1)**. The Pareto optimality axiom of Nash bargaining states that at the bargaining solution y_m^*, no player can increase its payoff through unilateral decisions. Therefore, the assumption made earlier does not hold. Consequently, the Nash bargaining solution stated in **(P1)** is the TEP strategy y_m that maximizes **(P4)**.

After solving the optimal transmission investment problem that maximizes the sum of the surplus changes of all participants **(P4)**, the transmission investment strategy (y_m^*) and the optimal surplus of the market players can be obtained, i.e. (U_π^*, U_j^*, U_i^*). Then, the bargaining fees (π_j^{LSE}, π_i^{GenCo}) paid by each LSE and GenCo are formulated as **(SP4)**.

$$\textbf{SP4} \qquad \max_{\pi_j^{\mathrm{LSE}},\pi_i^{\mathrm{GenCo}},\pi^{\mathrm{TransCo}}} \left(U_\pi^* + \pi^{\mathrm{TransCo}} - U_\pi^0\right)\prod_{j=1}^{J}\left(U_j^* + \pi_j^{\mathrm{LSE}} - U_j^0\right)\prod_{i=1}^{I}\left(U_i^* + \pi_i^{\mathrm{GenCo}} - U_i^0\right) \tag{SP4a}$$

subject to
$$U_\pi^* + \pi^{\text{TransCo}} - U_\pi^0 \ge 0 \tag{SP4b}$$
$$U_j^* + \pi_j^{\text{LSE}} - U_j^0 \ge 0, \forall j \in J \tag{SP4c}$$
$$U_i^* + \pi_i^{\text{GenCo}} - U_i^0 \ge 0, \forall i \in I \tag{SP4d}$$
$$\pi^{\text{TransCo}} + \sum_{j\in J} \pi_j^{\text{LSE}} + \sum_{i\in I} \pi_i^{\text{GenCo}} = 0 \tag{SP4e}$$

The significant prerequisite for a successful negotiation is ensured as constraints (SP4b)-(SP4d). The bargaining fees π_j^{LSE}, π_i^{GenCo} can be computed directly after solving the optimal transmission investment problem **(P4)**, as equations (SP4f)-(SP4h), with the detailed derivation provided in Appendix B.

$$\pi_j^{\text{LSE}} = \left(U_j^* - U_j^0\right) - \frac{1}{(I+J+1)} \left\{ \left(U_\pi^* - U_\pi^0\right) + \sum_{j\in J} \left(U_j^* - U_j^0\right) + \sum_{i\in I} \left(U_i^* - U_i^0\right) \right\} \tag{SP4f}$$
$$\pi_i^{\text{GenCo}} = \left(U_i^* - U_i^0\right) - \frac{1}{(I+J+1)} \left\{ \left(U_\pi^* - U_\pi^0\right) + \sum_{j\in J} \left(U_j^* - U_j^0\right) + \sum_{i\in I} \left(U_i^* - U_i^0\right) \right\} \tag{SP4g}$$
$$\pi^{\text{TransCo}} = \left(U_\pi^* - U_\pi^0\right) - \frac{1}{(I+J+1)} \left\{ \left(U_\pi^* - U_\pi^0\right) + \sum_{j\in J} \left(U_j^* - U_j^0\right) + \sum_{i\in I} \left(U_i^* - U_i^0\right) \right\} \tag{SP4h}$$

From (SP4f)-(SP4h), we can conclude that through bargaining fees, the benefits brought and the transmission investment cost incurred are shared among the market participants. Since the transmission investment decision will only be made when the benefits exceed the cost, the net benefits are positive and the recovery of transmission investment cost is guaranteed.

$\left\{ \left(U_\pi^* - U_\pi^0\right) + \sum_{j\in J} \left(U_j^* - U_j^0\right) + \sum_{i\in I} \left(U_i^* - U_i^0\right) \right\}$ is the sum of the net benefits from the transmission investment, we can then further conclude that the bargaining fees applied to the market participants are proportional to the revenue changes of the corresponding market players, which is fair and aligns with the "beneficiary pays" principle. Charging the network cost in proportion to the benefits that the network provides to each one of its users is an efficient transmission cost allocation method (Pérez-Arriaga and Olmos, 2006). In the long term, the potential new network users, with bargaining fees duly included, will be driven to socially optimal investment according to their expected profits (Pérez-Arriaga et al., 2013).

Lemma 2 *(Socially optimal transmission investment)*: Under the proposed negotiation mechanism, the original objective function (1a) can be reformulated into (4a) and then is proved to be equivalent to the objective functions that maximize the sum of the surplus changes of the participants. When all market players participate in the transmission investment negotiation process, the sum of the surplus changes of the participants (4a) can reach the total welfare (C1). Hence, the proposed negotiation mechanism can induce TEP strategies that maximize social welfare.

Proof Lemma 1 has claimed that the original objective function (1a) can be reformulated into (4a). For proof that the reformulated objective function (4a) is equivalent to the objective functions that maximize the overall welfare surplus, see Appendix C.

Remark 1 *(Implementation theory for the Negotiation mechanism)*: To facilitate the compliance of the proposed negotiation mechanism results with the Nash bargaining solution, we shall assume the negotiation mechanism is implemented in four stages. In **stage 1**, the participants are determined, including TransCo, GenCo ($i = 1, ..., I$) and LSEs ($j = 1, ..., J$). The proposed negotiation mechanism should not deny any market players from participating and must ensure their free entry to support socially optimal outcomes. In **stage 2**, the disagreement points of the participants are determined, i.e., U_π^0, U_j^0 ($j = 1, ..., J$) and U_i^0 ($i = 1, ..., I$), which are the original surplus functions for the participants before the transmission investment. In **stage 3**, the utility functions U_π, U_j ($j = 1, ..., J$) and U_i ($i = 1, ..., I$), of the participants are optimized, which are formulated as (1c), (1e), (1g) in the proposed model and the optimal TEP strategies are obtained based on **(P4)**. In **stage 4**, the bargaining fees π_i^{GenCo} ($i = 1, ..., I$), π_j^{LSE} ($j = 1, ..., J$) are calculated based on (SP4e) and (SP4f), and this approach determines the final payoffs of the mechanism.

Remark 2 (Situations under different bargaining power): The proposed negotiation-based mechanism aims to incentive efficient transmission investment by making it possible to obtain the TEP strategies (y_m) that maximize the social welfare. The negotiation mechanism with different bargaining power (γ^{TransCo}, γ_i^{GenCo}, γ_j^{LSE}) will still induce TEP strategies that maximizes social welfare. The difference in bargaining power will only change the bargaining fees and the resulting distribution of the net benefits among the market participants. (see Appendix J for details).

Remark 3 (Discussion about the compensation fees): It's important to note that this negotiation scheme is constrained by the necessity of compensation fees or negative bargaining fees to achieve Pareto optimality. These compensation fees are essential to prevent objections from market players negatively impacted by the scheme (Coase, 1990; Littlechild, 2012a; Olmos et al., 2018). However, they might lead to efficiency loss from a broader system perspective. This efficiency loss arises from the need to shield stakeholders from the revenue losses incurred by increased market competition due to network investments (Olmos et al., 2018). In comparison, a centralized planning approach, which doesn't require compensating for individual losses, could theoretically lead to better outcomes for the entire system. Nonetheless, such centralized planning also needs to incentivize the TransCo to conduct the actual transmission investment based on either rate-of-return, RPI-X, or some kind of incentive mechanism, and these approaches often encounter significant practical challenges, including regulatory limitations and lack of stakeholder consensus, as discussed in the introduction section. The proposed negotiation mechanism strikes a balance between achieving collaborative and fair stakeholder engagement and incentivizing efficient TEP.

3.2. A decentralized modified PMP algorithm for seeking generation investment equilibrium in the LL problem

The LL problem within this framework calculates a Nash Equilibrium (NE) for the GEP problem, representing a solution to a non-cooperative game involving multiple GenCos. Drawing inspiration from the utilization of the ADMM algorithm in seeking Nash equilibrium solution (Salehisadaghiani et al., 2019), we developed a decentralized algorithm leveraging the principles of the PMP algorithm (Kraning et al., 2012), to calculate the Nash equilibrium solution for the GEP problem.

The basic idea of the devised algorithm is to work towards equilibrium by increasing or decreasing LMPs based on the unbalanced demand or supply. Due to the complex details necessary to accurately present the updates of GenCos and the SO, mathematical details concerning ***GenCo's update***, ***SO's update (power flow)*** and ***SO's update (LMP)*** are comprehensively outlined in Appendix D. Further information regarding the ***Iteration process***, ***Stopping criteria***, and ***Selection of the penalty factor value*** is provided in Appendix E. This practice keeps the main text focused on the broader conceptual framework while still providing the necessary mathematical detail in an annex for readers seeking a deeper understanding.

Note that the conventional thermal generator's expansion decisions are modeled as discrete variables. Here, we adopt the Lp-box reformulation and replace the constraints with discrete variables with an equivalent set of constraints with continuous variables, namely the intersection between the box and the (n-1) dimensional sphere (Wu and Ghanem, 2019; Ma et al., 2021). Taking an n-dimensional binary set $\{0,1\}^n$ as an example, this set can be equivalently replaced by the intersection between a box and an (n-1)-dimensional sphere (termed the Lp-box intersection) as follows:

$$x \in \{0,1\}^n \Leftrightarrow x \in [0,1]^n \cap \left\{ x : \left\| x - \frac{1}{2}1_n \right\|_p^p = \frac{n}{2^p} \right\}$$

where the sphere is centered at $\frac{1}{2}1_n$ with radius $\frac{n}{2^p}$, and $p \in N$ is a natural number and is set as 2 in this paper.

The pseudocode for the modified PMP algorithm can be found in Table 3. The iterative update steps for each GenCo and SO are set to converge toward the game's equilibrium. Since the proposed modified PMP algorithm is an extension of the exchange ADMM algorithm, all convergence results that hold for the ADMM algorithm also hold for the PMP algorithm (Boyd et al., 2010). When no GenCo or SO has the incentive to deviate from its decision, and the market clearing conditions are satisfied, an equilibrium is reached. When the optimal value for the LL generation investment equilibrium is found, $\lambda^*_{n,t,s}$ is the optimal dual variable for the market clearing conditions, which carries the physical meaning of LMPs.

3.3. Coordination of TEP in the UL and GEP in the LL

Since the mathematical models **(P4)** in the UL TEP problem and mathematical models (**P5**, **P6** & **P7**) in the LL GEP problem have a bi-level structure, they cannot be directly solved using commercial solvers. Consequently, we employ

Table 3
The pseudocode for the modified PMP algorithm

Algorithm: the decentralized algorithm for seeking generation investment equilibrium
Initialize ρ, λ, $p_{the,t,s}, p_{w,t,s}, p_{ess,t,s}, p^s_{l,t,s}, p^r_{l,t,s}, p^s_{m,t,s}, p^r_{m,t,s}$, $\theta_{n,t,s}$ and set $k = 0$
While $\|r^k\| \le \varepsilon$ & $\|s^k\| \le \varepsilon$, $k = k + 1$ do
SO Broadcasts iterates $\bar{p}^k_{n,t,s}$, $\lambda^k_{n,t,s}$ to the GenCos
(***GenCo's update***) Solve GenCos' optimization problems for updated generation output ($p^{k+1}_{the,t,s}$, $p^{k+1}_{w,t,s}$ and $p^{k+1}_{ess,t,s}$) and GEP strategies, ($x_{the}, G^{new}_{w}, C^{new}_{ess}, Q^{new}_{ess}$), see **(P5)**
(***SO's update(power flow)***) Simultaneously solve SO's optimization problems for updated power flow ($p^{s,k+1}_{l,t,s}, p^{r,k+1}_{l,t,s}$, $p^{s,k+1}_{m,t,s}, p^{r,k+1}_{m,t,s}$), see **(P6)**
SO Gathers iterates $p^{k+1}_{the,t,s}, p^{k+1}_{w,t,s}, p^{k+1}_{ess,t,s}$
(***SO's update(LMP)***) SO calculate average power imbalance ($\bar{p}^{k+1}_{n,t,s}$); update dual variables ($\lambda^{k+1}_{n,t,s}$), see **(P7)**
Calculate residual $r^{k+1}; s^{k+1}$, see **(8)** and **(9)**
End while

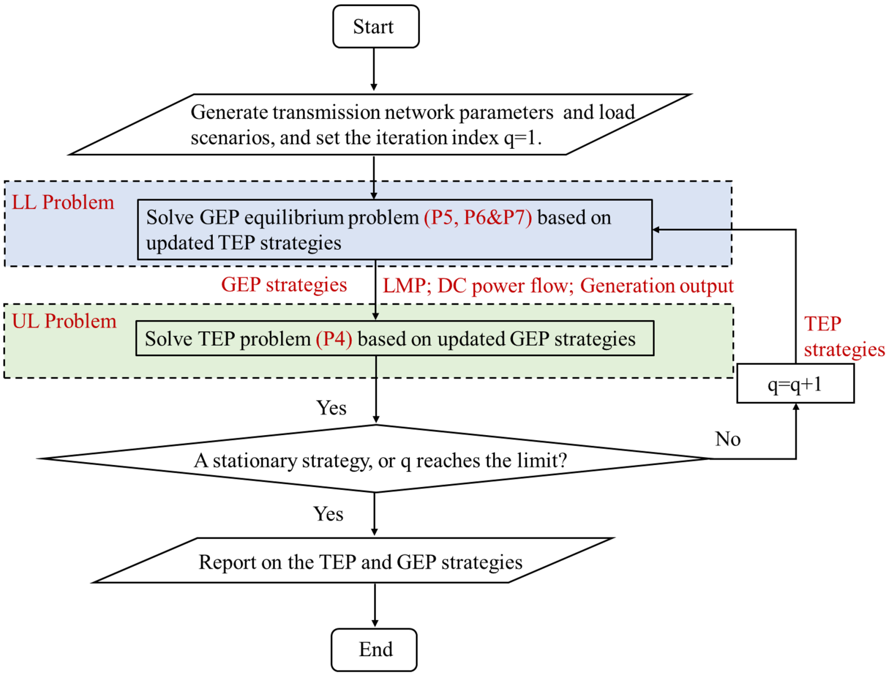
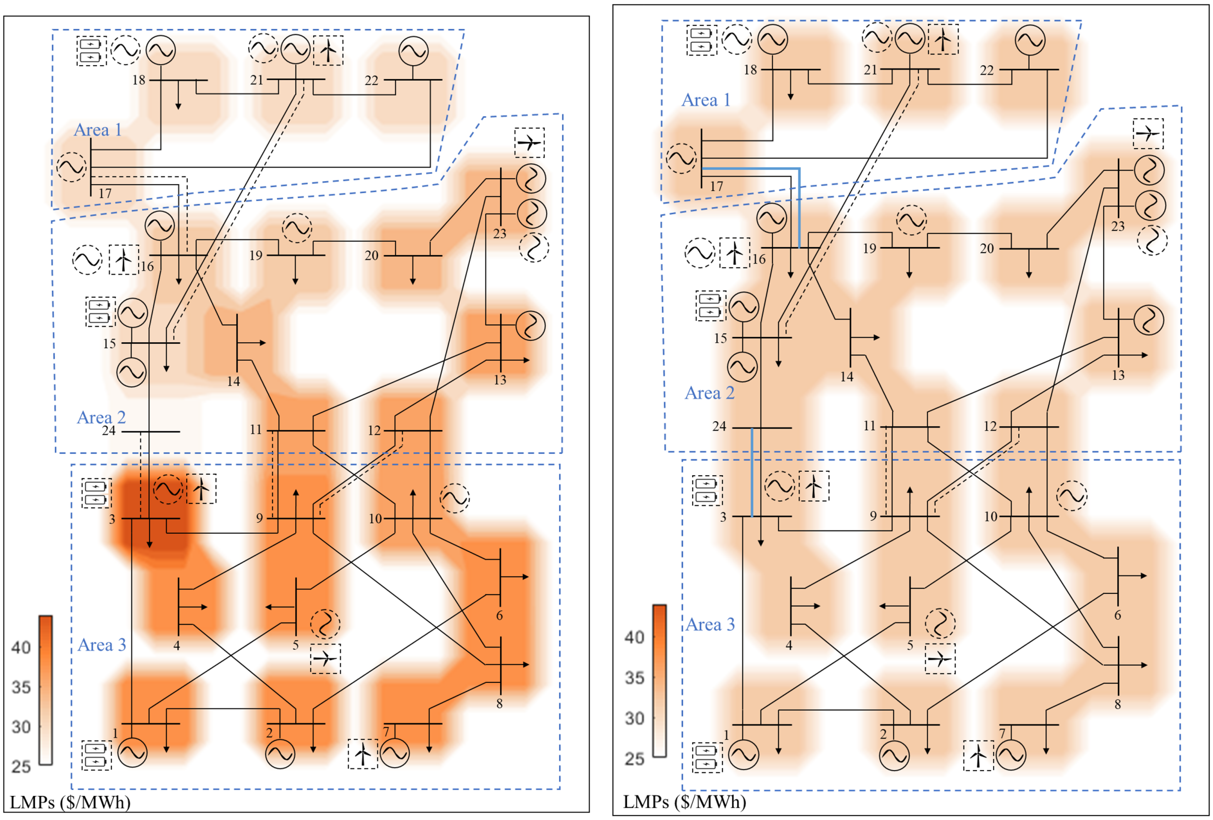


Figure 2: Flowchart of the solving methodology for the proposed bi-level model for the coordination between TEP and GEP

an iterative method utilizing a cutting plane algorithm (Wang et al., 2018; Pandzic et al., 2019). This process begins by solving the generation investment equilibrium problem (**P5**, **P6** & **P7**) to determine all GenCos' GEP strategies ($x_{a,the}, W^{new}_{a,w}, C^{new}_{a,ess}, Q^{new}_{a,ess}$) and generation outputs ($p_{a,the,t,s}, p_{a,w,t,s}, p_{a,ess,t,s}$), along with SO' strategies about the power flows ($p^s_{l,t,s}, p^r_{l,t,s}$) and corresponding LMPs ($\lambda_{n,t,s}$). Subsequently, based on the updated GEP strategies, the equivalent TEP model **(P4)** is resolved to derive the TEP strategies (y_m). These two steps are repeated until the TEP strategies converge or the iteration index exceeds the pre-defined limit.

Due to the nonlinearity and concavity of the bilevel model, the optimality and convergence of the proposed iterative approach cannot be permanently guaranteed. For instance, due to the possible occurrence of a non-existing pure NE solution, the strategies of TEP and GEP might oscillate (Wang et al., 2018). When an optimized solution cannot be found, the desired solution to the bi-level model could be selected as the one that results in maximum whole social welfare among all feasible solutions, see (10). The decision variable set is $\left\{x_{the}, G^{new}_{w}, C^{new}_{ess}, Q^{new}_{ess}, y_m\right\}$.



(a) before TEP

(b) after TEP

Figure 3: IEEE 24 bus system showing a visualization of LMPs in Case 1

$$\max \quad \sum_{s\in S}\omega_s \left[\begin{array}{r} \sum\limits_{t\in T}\sum\limits_{the\in E\cup C}\left(\lambda_{n\in I(the),t,s}-c_{the}\right)p_{the,t,s}+\sum\limits_{t\in T}\sum\limits_{w\in E\cup C}\left(\lambda_{n\in W(w),t,s}-c_w\right)p_{w,t,s} \\ +\sum\limits_{t\in T}\sum\limits_{ess\in E\cup C}\left(\lambda_{n\in E(ess),t,s}-c_{ess}\right)p_{ess,t,s}-\sum\limits_{t\in T}\sum\limits_{j\in J}\left(\lambda_{j,t,s}d_{j,t,s}\right) \end{array} \right] \\ -\sum_{the\in C}c_{the}^{\exp}x_{the}-\sum_{w\in C}c_w^{\exp}G_w^{\text{new}}-\sum_{ess\in C}c_{ess}^{\text{Eexp}}C_{ess}^{\text{new}}-\sum_{ess\in C}c_{ess}^{\text{Pexp}}Q_{ess}^{\text{new}}-\sum_{m\in M}C_m^V y_m \tag{10}$$

The complete flowchart of the solving methodology for the proposed bi-level model with the coordination of TEP and GEP is explained in detail in Fig. 2.

4. Case study

4.1. Case settings

We use the IEEE-24 bus test case for our numerical studies, enhanced by adding six wind farms located at buses 3, 5, 7, 16, 21, and 23, see Fig. 3. This figure represents existing lines and generators with solid lines while indicating candidate lines with dotted lines. The parameters for the generators, load demand profiles and distribution, and transmission line capacities are retrieved from Christos et al. (2016) and Gonzalez-Romero et al. (2021). The system is divided into three areas: Area 1, serving as the generation center, and Area 3, functioning as the load center. We set three GenCos and three LSEs within this system. Detailed information regarding the affiliation of generators to the GenCos and loads to the LSEs can be found in Tables 1 through 4 in the Data file. Additionally, Table 5 lists the parameters for five candidate transmission lines labeled T35-T39.

Table 4
Case settings

Cases	Incentive Mechanism in TEP	Participants in TEP	Models and Methods for GEP
Case 1	Proposed Negotiation Mechanism	GenCos, LSEs, TransCo	Equilibrium Solved by Modified PMP
Case 2	Proposed Negotiation Mechanism	LSEs, TransCo	Equilibrium Solved by Modified PMP
Case 3	H-R-G-V Mechanism	TransCo	Equilibrium Solved by Modified PMP
Case 4	ISS Mechanism	TransCo	Equilibrium Solved by Modified PMP
Case 5	Generalized-FTR-based Mechanism	TransCo	Equilibrium Solved by Modified PMP
Case 6	Proposed Negotiation Mechanism	GenCos, LSEs, TransCo	GEP Solved in a Centralized Manner

Table 5
Case 1 with LSEs and GenCos participating in the negotiation process

	LSE1	LSE2	LSE3	GenCo1	GenCo2	GenCo3	TransCo
Surplus Before TEP ($)	-1,158,810	-1,931,000	-2,597,853	931,462	821,213	48,826	0
Surplus After TEP ($)	-1,163,082	-1,923,053	-2,636,439	1,058,772	841,473	34,273	-2,915
Surplus Change from TEP($)	-4,272	7,947	-38,586	127,310	20,260	-14,553	-2,915
Revenue from CR Before TEP($)	19,122	36,480	40,416	50,857	45,058	103	0
Revenue from CR After TEP($)	14,153	20,454	14,672	9,019	38,458	1,801	0
Revenue Change from CR ($)	-4,969	-16,026	-25,744	-41,838	-6,600	1,698	0
Bargaining Fees ($)	9,485	8,324	64,575	-85,227	-13,415	13,098	3,159
Disagreement Point before TEP ($)	-1,139,688	-1,894,520	-2,557,437	982,319	866,271	48,929	0
Overall Utility Change ($)	244	244	244	244	244	244	244
Payoff after TEP ($)	-1,139,444	-1,894,276	-2,557,193	982,563	866,515	49,173	244

We have conducted a comparative study across six cases to evaluate the effectiveness of the proposed negotiation mechanism and methodology. The settings for each case are detailed in Table 4.

Case 1 represents the proposed negotiation mechanism, and all the GenCos and LSEs participate in negotiation with TransCo, whose model is illustrated in (P1), and reformulated in (P4).

Case 2 represents the proposed negotiation mechanism, while only LSEs participate in the negotiation with the TransCo, differing from Case 1 in the objective function. The mathematical formulations of the objective function of Case 2 and those of the following Cases 3-6 can be found in Appendix C.

Case 3 represents the H-R-G-V mechanism (Hesamzadeh et al., 2018). Case 4 represents the ISS mechanism (Khastieva et al., 2021). Case 5 represents the generalized-FTR-based mechanism (Biggar and Hesamzadeh, 2020).

Case 6 employs the proposed negotiation mechanism with all GenCos and LSEs actively negotiating with TransCo at the UL level. In the LL, the GEP problem is addressed in a centralized manner. The market clearing problem for the centralized GEP is reformulated using the Karush-Kuhn-Tucker (KKT) conditions to make the LL GEP problem tractable. For the specific formulations involved, see Appendix F and G.

The numerical results for the proposed negotiation mechanism are presented in Section 4.2. This proposed negotiation mechanism, involving all GenCos, LSEs, and TransCo (Case 1), is compared in Section 4.3 with a scenario where only LSEs and TransCo are involved. Further comparisons are made in Section 4.4.1 between the proposed negotiation mechanism (Case 1) and both the H-R-G-V mechanism (Case 3) and the ISS mechanism (Case 4). Additionally, Section 4.4.2 compares the proposed negotiation mechanism (Case 1) with the Generalized FTR mechanism (Case 5). Lastly, a comparison between the decentralized GEP (Case 1) and the centralized GEP (Case 6) is detailed in Section 4.5.

4.2. Results of the proposed negotiation incentive mechanism for efficient TEP

The detailed results for Case 1 are presented in this subsection. The negotiated outcome is a TEP strategy that calls for constructing two new transmission lines: T35 from Bus 3 to Bus 24 and T39 from Bus 16 to Bus 17, with a daily TEP cost of $2915. The impact of these new lines on the electricity market is visualized in the density plots shown in figure. 3. These plots illustrate the LMPs for time slot five before and after the TEP. After the transmission investment, the network congestion decreases, leading to an increase in LMPs at the generation centers (Area 1) and a decrease in LMPs at the load centers (Area 3).

Table 5 details the surplus and utility changes for the LSEs, GenCos, and TransCo involved in Case 1. The TEP strategy has varying impacts on surplus changes for different market participants. For instance, GenCo 1 experiences increased surplus as the new transmission lines tighten Area 1 and other areas, elevating LMPs in the generation center. Conversely, GenCo 3 sees a reduction in surplus due to the enhancement of transmission capacity with Area 1, leading to lower LMPs in the load center. Nevertheless, the overall utility changes of all LSEs and GenCos are equal to \$244, considering the sum of surplus changes from TEP, revenues from Congestion Rents (CRs), and bargaining fees. TransCo incurs a direct TEP cost of \$2,915 but gains \$3,159 from the bargaining fees, resulting in an overall utility change to \$244. It is important to note that the sum of the bargaining fees for LSEs, GenCos, and TransCo is zero, indicating a balanced budget.

The negotiation mechanism ensures an equal increase in utility for all participants, demonstrating its Pareto efficiency and fairness.[14] This is guaranteed by introducing bargaining fees to redistribute social welfare surpluses, ensuring all parties benefit from the TEP. For example, even though this TEP strategy would bring about lower LMPs and thus lower surplus for GenCo 3 (\$-14,553), a compensatory bargaining fee (\$-13,098) would be transferred to GenCo 3 to compensate for its loss and balance its total utility. As a result, by guaranteeing that all market participants' utilities would increase, the TEP strategies made under the proposed mechanism are more likely to gain support from market participants and enhance social welfare.

4.3. Comparative results considering different participants in the proposed negotiation incentive mechanism

The detailed results for Case 2 are presented in this subsection. The negotiated outcome is a TEP strategy that calls for constructing one single new transmission line: T37 from Bus 9 to Bus 12, tightening the connection between Areas 2 and 3. Table 6 details the changes in surplus and utilities for LSEs, GenCos, and TransCo, with only LSEs actively participating in the negotiation process with TransCo. Identical to the results in Case 1, participants in the TEP process enjoy the same value of increased utilities, which is \$17,176 in Case 2. However, GenCos in Case 2, not participating in the TEP negotiation process, derives benefits solely from surplus changes from TEP and revenues from CRs.

Comparing Cases 1 and 2, we observe that including more market players in the TEP negotiation process leads to constructing more transmission lines. Participation of all market players yields TEP strategies that maximize social welfare, as demonstrated in Case 1. In light of these findings, it is clear that the proposed negotiation mechanism should not deny any market players from participating and must ensure their free entry to support socially optimal outcomes.

As demonstrated in Table 6, the overall utilities of GenCos decrease when they do not participate in the TEP negotiation process. These declines in utilities motivate them to engage in the negotiation process, leading us back to Case 1. The same results apply to LSEs. These observations indicate that the proposed negotiation mechanism effectively encourages GenCos and LSEs to participate proactively while ensuring increased utilities for all involved participants. This result is crucial, as TEP directly affects the surplus for all market players, providing them with strong incentives to participate proactively in the decision-making process. For instance, when GenCos experience lower LMPs (as with GenCo 1 in the case study), they might initiate a TEP process to increase their LMPs. Similarly, when LSEs encounter higher LMPs (as with LSE 3 in this study), they could initiate a TEP process to reduce their LMPs. Notably, the negotiation mechanism ensures that no market player would be disadvantaged.

It is crucial to recognize that proactive participation by market players in deciding TEP strategies is of great significance in advancing the electricity markets. Many countries and regions are establishing (Qu et al., 2023) or refining (Weber, 2023) market mechanisms to integrate more specific spatial and temporal elements into market prices. For example, implementing the Locational Marginal Pricing (LMP) mechanism allows electricity prices to vary across nodes and time slots. However, transitioning to these new market systems may lead to the issue of stranded costs (Curtin et al., 2019) of market players, as changes in the pricing mechanism can reduce their benefits, with price differences often arising from congestion (Lin et al., 2019). The proposed negotiation mechanism provides an effective mitigation measure by enabling market players to initiate TEP initiatives that alleviate congestion and boost their benefits. Thus, in addition to providing efficient incentives for TEP, the proposed negotiation mechanism also promotes the development of electricity markets during the transitional stage.

[14] Apparently, a question comes up whether a market player would enjoy more benefits by splitting itself into multiple market players, as the increased social welfare surpluses are allocated equally among participants. It is stipulated that all market players participate in this cooperative game process with their own companies as the unit. Therefore, we will determine the ownership relationship according to the ownership structure of market participants, which means that any market participant cannot be split into two or more market participants at will. This stipulation may involve some ownership structure examination as in the market power detection (Midttun and Thomas, 1998).

Table 6
Case 2 with only LSEs participating in the negotiation process

	LSE1	LSE2	LSE3	GenCo1	GenCo2	GenCo3	TransCo
Surplus Before TEP ($)	-1,158,810	-1,931,000	-2,597,853	931,462	821,213	48,826	0
Surplus After TEP ($)	-1,124,184	-1,902,569	-2,562,677	929,742	848,657	-16,895	-1,457
Surplus Change from TEP ($)	34,626	28,431	35,176	-1,720	27,444	-65,721	-1,457
Revenue from CR Before TEP ($)	19,122	36,480	40,416	50,857	45,058	103	0
Revenue from CR After TEP($)	7,445	27,614	32,887	50,861	17,085	0	0
Revenue Change from CR ($)	-11,677	-8,866	-7,529	4	-27,973	-103	0
Bargaining Fees ($)	-5,774	-2,389	-10,470	0	0	0	17,813
Disagreement Point before TEP ($)	-1,139,688	-1,894,520	-2,557,437	982,319	866,271	48,929	0
Overall Utility Change ($)	17,176	17,176	17,176	-1,716	-529	-65,824	17,176
Payoff after TEP ($)	-1,122,512	-1,877,344	-2,540,261	980,603	865,742	-16,895	17,176

4.4. Comparative results for different TEP incentive mechanisms

The objective functions under H-R-G-V, ISS and the generalized-FTR-based mechanisms, are also equivalent to that of the social-welfare-maximizing TEP problem. Detailed proofs of this equivalence are provided in Appendix C. This alignment facilitates the development of TEP strategies that maximize social welfare. With these strategies, TransCo's revenue sufficiency can be guaranteed under all these mechanisms. We have conducted comparative studies to understand the differences between these incentive mechanisms better. These analyses highlight the implementation differences and help clarify each mechanism's implications on overall system efficiency and stakeholder benefits.

4.4.1. The proposed negotiation mechanism VS H-R-G-V and ISS mechanism

Table 7 shows the outcomes under different incentive mechanisms. In each case, the TEP strategies involve constructing two transmission lines: T35 connecting Bus 3 to Bus 24 and T39 connecting Bus 16 to Bus 17, with a daily TEP cost of $2915. Cases 3 and 4 differ from Case 1 in that in Case 1, the increases in social welfare surplus are allocated among participants, whereas in Cases 3 and 4, the surplus is allocated entirely to TransCo. This allocation demonstrates a key limitation of the H-R-G-V and ISS mechanisms, as they unintendedly devalue the contributions of transmission network users to social welfare (Biggar and Hesamzadeh, 2020). In contrast, the proposed negotiation mechanism could realize a fairer distribution of social welfare surplus, which will undoubtedly motivate GenCos and LSEs to actively contribute to enhancing the social welfare surplus. The proactive involvement of these entities is crucial for improving overall system efficiency, ensuring that all stakeholders are not only participants but also beneficiaries of the system's enhancements.

Furthermore, under the H-R-G-V and ISS mechanisms, a regulator is required to determine changes in total social welfare and calculate the complementary charges for the TransCo. This requirement necessitates access to private information about supply costs and demand utilities of GenCos and LSEs to estimate the social welfare changes resulting from TEP accurately. In contrast, the proposed negotiation mechanism fully preserves the privacy of such crucial information by enabling direct negotiations among GenCos, LSEs, and TransCo. Under the proposed negotiating mechanism, TransCo receives reimbursement through a negotiation process, and the bargaining fees calculation process can be implemented using distributed algorithms (Zheng et al., 2023), thus protecting the information privacy of transmission network users.

4.4.2. The proposed negotiation mechanism VS generalized-FTR based mechanism

Under the generalized-FTR-based mechanism, TransCo is incentivized to conduct TEP due to the expected revenue from trading hedge contracts with risk-averse GenCos and LSEs. By utilizing generalized FTRs, TransCo assumes responsibility for the risks associated with GenCos and LSEs. Risk-constrained models have been developed to allow a detailed comparison between the proposed negotiation mechanism (Case 1) and the generalized-FTR-based mechanism (Case 5), with detailed models provided in Appendix I. In the proposed negotiation mechanism, all market participants are assumed to be risk-averse and are parameterized with the same risk aversion coefficient, denoted as β.

The TEP strategies under the risk-constrained models for both mechanisms involve constructing three transmission lines: T35 connecting Bus 3 to Bus 24, T36 connecting Bus 9 to Bus 11, and T38 connecting Bus 15 to Bus 21. The daily TEP cost for these lines is $4372. A sensitivity analysis on the risk-averse coefficient (β) is conducted to understand

Table 7
the TEP strategies under different transmission incentive mechanisms

		Case 1 the proposed negotiation mechanism	Case 3 the H-R-G-V mechanism	Case 4 the ISS mechanism
T35 (from Bus 3 to Bus 24)		1	1	1
T36 (from Bus 9 to Bus 11)		0	0	0
T37 (from Bus 9 to Bus 12)		0	0	0
T38 (from Bus 15 to Bus 21)		0	0	0
T39 (from Bus 16 to Bus 17)		1	1	1
TEP Cost ($)		2,915	2,915	2,915
Congestion Rent ($)	Before TEP	192,036	192,036	192,036
	After TEP	98,557	98,557	98,557
	Changed Value	-93,479	-93,479	-93,479
LSEs' Revenue($)	Before TEP	-5,591,645	-5,687,663	-5,687,663
	After TEP	-5,590,913	-5,687,663	-5,687,663
	Changed Value	732	0	0
GenCos' Revenue($)	Before TEP	1,897,519	1,801,501	1,801,501
	After TEP	1,896,787	1,801,501	1,801,501
	Changed Value	732	0	0
Transco's Revenue($)	Before TEP	0	192,036	0
	After TEP	244	193,744	1,708
	Changed Value	244	1,708	1,708

the impact of the risk-averse attitude. The value of β ranges from 1, indicating risk neutrality, to 0, which reflects a focus on the worst-case scenario.

Figure. 4 illustrates the utilities of GenCos, LSEs, and TransCo after the TEP. The x-axis represents the assumed level of risk aversion from risk-neutral ($\beta = 1$) to highly risk-aversion ($\beta = 0.1$), and the y-axis indicates the change in utility relative to the risk-neutral case. Note that all changes in utility are negative, suggesting that utility under risk-averse conditions is lower than in risk-neutral scenarios. Under the generalized-FTR-based mechanism, since GenCos and LSEs are risk-averse, they hedge their risks through contracts, maintaining stable revenues.[15] The utility of TransCo generally declines as risk aversion increases, reaching its lowest when β is 0.3. Figure. 4(b) demonstrates a similar trend for the proposed negotiation mechanism.

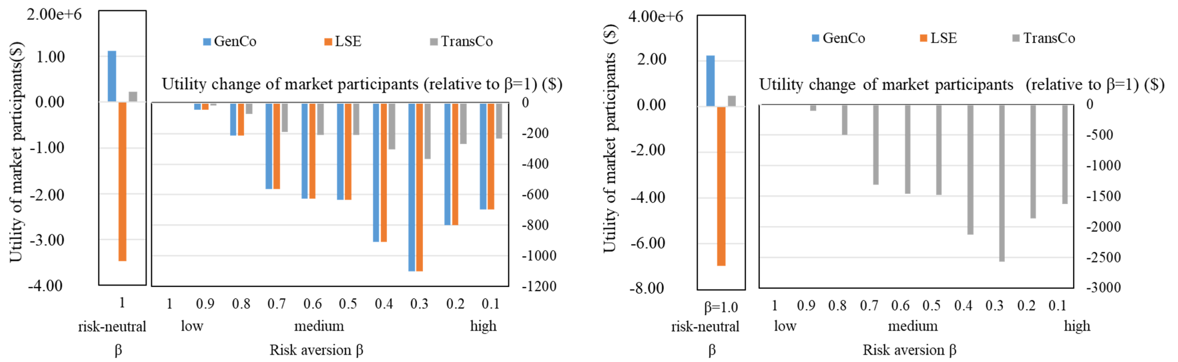
Regarding risk levels, under the generalized-FTR-based mechanism, TransCo undertakes the whole risk, as illustrated in Figure. 5(a), with the CVaR reaching $815,523 when β=0.2.[16] In contrast, under the proposed negotiation mechanism, the risk is split among market participants, with the CVaRs of GenCos, LSEs, and TransCo recorded at $349,509, $349,509, and $116,503 respectively when β=0.2, as shown in Fig. 5(b).[17] This distribution emphasizes that the proposed negotiation mechanism effectively disperses the system's intense risk among market participants rather than leaving the entire risk to one entity.

4.5. Comparative results for different GEP models

In the subsection, we conduct a comparative study of GEP strategies modeled either as the proposed non-cooperative game (Case 1) or in a centralized manner (Case 6). In the centralized approach of Case 6, the negotiated TEP strategy involves constructing two new lines: T35 connecting Bus 3 to Bus 24 and T38 connecting Bus 15 to Bus 21. The daily TEP cost for these lines is $2915, with each participant in the TEP process experiencing an equal increase in utility of $927.

Table 8 presents the detailed GEP results. In Case 1, where the model operates under a non-cooperative game approach, more thermal generators are invested mainly in the load center Area 3. This approach sees less investment in the intermittent wind farms and no investment in BESSs. Conversely, Case 6, modeled from a centralized system perspective, shows more investment in intermittent wind farms and BESSs, with only one thermal generator invested.

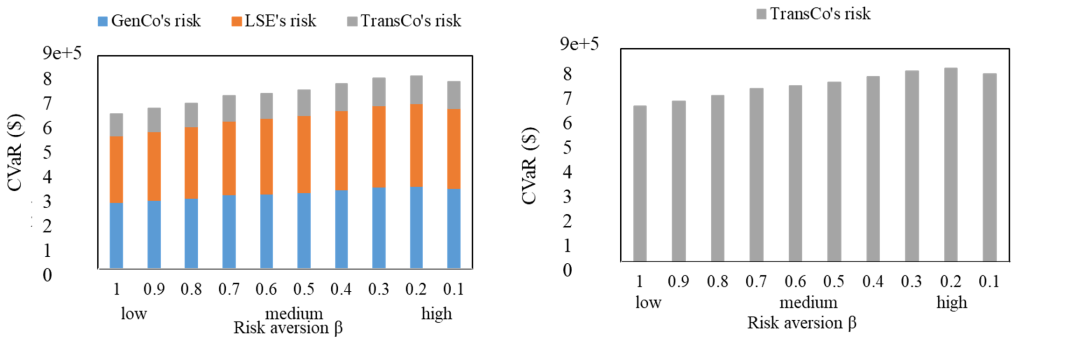
[15] GenCo and LSE's utility changes are not shown because they are unchanged relative to $\beta = 1$.
[16] GenCo and LSE's CVaRs are not shown because they are zero.
[17] Note that the entire risk for the negotiation mechanism and the generalized FTR-based mechanism is the same under the same case setting.



(a) Case 1: the proposed negotiation mechanism

(b) Case 5: the Generalized-FTR-based mechanism

Figure 4: The utilities of different market players under mechanisms with different levels of risk aversion



(a) Case 1: the proposed negotiation mechanism

(b) Case 5: the Generalized-FTR-based mechanism

Figure 5: The CVaR of different market players under mechanisms with different levels of risk aversion

This outcome reflects the centralized model's ability to handle the intermittency of wind farms more effectively and capitalize on the lower operational costs of wind energy to achieve higher utilities.

In Case 6, the GEP model approached in a centralized manner, views the system as a whole rather than from the perspective of individual GenCos by assuming that all generation resources are controlled by one single entity. This broader perspective of resources allows for more effective mitigation of the intermittency associated with wind farms and leverages the lower operational costs of wind energy to achieve higher utilities. However, the comparative results suggest that modeling the GEP problem in a centralized manner might overly favor the promotion of renewables, possibly leading to unrealistic expectations about their integration and effectiveness. Given the inherently non-cooperative nature of the GEP problem in reality, particularly within the deregulated environments, it is essential to model the GEP problem as a non-cooperative game. Although this approach introduces considerable complexities in resolving the GEP problem, it more accurately reflects the competitive dynamics of the market players and the obstacles inherent in power system planning.

4.6. Computational performance

Considering the computation time, the original UL problem **(P1)** involves nonlinear terms, which are first transformed into a mixed integer nonlinear programming (MINLP) problem **(P4)** through a series of equivalent derivations (see Appendix B for a detailed proof process). The problem can then be solved efficiently by the off-the-shelf solver Gurobi with non-convex settings. While at the LL level, the modified PMP algorithm, implemented to address the generation investment equilibrium, was executed using MATLAB on an i7-8700 desktop with 16G RAM, with Gurobi as the solver. This setup successfully resolved the generation investment equilibrium in less than 12 hours.

Table 8
Decentralized generation investment equilibrium VS GEP in a centralized manner

Portfolio		Owned by	Case 1 Decentralized GEP	Case 6 Centralized GEP
Thermal generator(MW)	Bus3	GenCo3	1	0
	Bus5	GenCo3	1	0
	Bus10	GenCo3	1	1
	Bus16	GenCo2	1	0
	Bus19	GenCo2	1	0
	Bus23	GenCo2	0	0
	Bus17	GenCo1	0	0
	Bus18	GenCo1	0	0
	Bus21	GenCo1	0	0
Wind farm(MW)	Bus3	GenCo3	0	200
	Bus5	GenCo3	0	200
	Bus7	GenCo3	0	186
	Bus16	GenCo2	200	200
	Bus21	GenCo1	200	200
	Bus23	GenCo1	200	200
BESS (MW/MWh)	Bus1	GenCo3	0	33/264
	Bus3	GenCo3	0	2/16
	Bus15	GenCo2	0	97/776
	Bus18	GenCo1	0	61/488
Gen. Invest. Cost ($*10e6)		GenCo1	53	74
		GenCo2	186	139
		GenCo3	138	174
		Total	377	387
Gen. Oper. Cost ($*10e6)		GenCo1	185	201
		GenCo2	644	473
		GenCo3	517	368
		Total	1346	1042

[18] Figure. 6 captures the evolution of the primal r^k and dual s^k residuals over the iterations. The graph presents the dual variable adaptation process and the market participants' reaction to the updated dual variables, leading to an oscillating convergence with continuously decreasing amplitudes.

To better illustrate the computational efficiency of the bi-level model, here we present the number of variables and constraints to help understand how the method's execution time or space usage grows with an increase in the network size (Li et al., 2021).

For the UL reformed TEP problem **(P4)**, the number of variables and constraints is outlined in Table 9. Considering the UL TEP strategies y_m, which are typically confined to a limited pre-selected set of candidate transmission lines M, as discussed by Zhang and Conejo (2018). The increase in the number of combination schemes of binary variables remains constrained and does not increase substantially with network size $|N|$. With network size increasing, assuming that the scheduling period refinement $|T|$ remains constant and that the number of GenCos and LSEs $|I|/|J|$ does not depend on the network scale, both the existing and candidate transmission lines $|L \cup M|$ are anticipated to increase linearly with network size. Consequently, this leads to a linear growth in the total number of continuous variables with the network size. Regarding the linear constraints, observations from the fourth row of Table 9 show that their number remains unaffected by the network size. As for the nonlinear constraints, a similar analysis suggests that their total number increases approximately linearly with the network scale.

For the LL generation investment equilibrium problem (**P5**, **P6** & **P7**), the number of variables and constraints are presented in Table 10. Note that the discrete variables are eliminated by adopting the Lp-box reformulation. As for the continuous variables, we assume that with network size $|N|$ increasing, the scheduling period $|T|$ is fixed, the number

[18] This computation time is reasonable and acceptable for these complex investment optimization problems, as reported in some articles (e.g., Khastieva et al. (2021), Tohidi et al. (2017), Pozo et al. (2017), the computation time is several hours or even longer (solution not found after three days of simulation).

Table 9
The number of variables and constraints of the UL TEP investment problem under the proposed methods

Type	Variables and constraints	Number of variables and constraints
Binary Variables	y_m	$2^{\|M\|}$
Continuous Variables	Ω, π_i, π_j, U_π, U_i, U_j	$1 + \|I\| + \|J\|$ $+1 + \|I\| + \|J\|$
Linear Constraints	Eq(4d), Eq(4e), Eq(4f), Eq(1b),	$1 + \|I\| + \|J\|$
Nonlinear Constraints	Eq(4b), Eq(4c), Eq(4g), Eq(1d), Eq(1f), Eq(1h), Eq(1i)	$\|I\| + \|J\| + 1 + \|I\| + \|J\|$ $+ \|L\| * \|T\| + \|L \cup M\| * \|T\|$

Table 10
The number of variables and constraints of the LL generation investment equilibrium problem under the proposed methods

Type	Variables and constraints	Number of variables and constraints
Binary Variables	None	0
Continuous Variables	$p_{the,t,s}$,$p_{w,t,s}$, $p_{ess,t,s}$,$p^r_{l,t,s}$,$p^s_{l,t,s}$,$p^r_{m,t,s}$, $p^s_{m,t,s}$, $\bar{p}^{k+1}_{n,t,s}$, $\theta_{n,t,s}$,$\lambda^{k+1}_{n,t,s}$, G^{new}_w, C^{new}_{ess},Q^{new}_{ess},x_{the}, r^k, s^k	$\|I\| * \|E \cup C\| * \|T\| * \|S\|$ $+2 * \|T\| * \|S\|$ $+3 * \|N\| * \|T\| * \|S\|$ $+4 * \|I\| * \|C\| + 2$
Linear Constraints	Eq(2b)-Eq(2n), Eq(5c), Eq(6b)-Eq(6c), Eq(6h)-Eq(6i), Eq(6d)-Eq(6g),Eq(6j), Eq(6k), Eq(7a)-Eq(7b), (8)-(9)	$\|I\| * \|E \cup C\| + \|I\| * \|E \cup C\| * \|T\| * \|S\|$ $+ \|E \cup C\| * \|T - 1\| * \|S\|$ $+ \|E \cup C\| * \|T\| * \|S\| + \|E \cup C\| * \|S\| + \|I\| * \|C\|$ $2 * \|T\| * \|S\| + \|T\| * \|S\|$ $+4 * \|T\| * \|S\| + \|T\| * \|S\|$ $+ \|T\| * \|S\|$ $+ \|T\| * \|S\| + 2 * \|N\| * \|T\| * \|S\| + 2$
Nonlinear Constraints	None	0

of representative scenarios $|S|$ remains limited, and the number of GenCos and LSEs $|I|/|J|$ are independent of network size. Consequently, this leads to an approximately linear increase in the number of continuous variables with the network scale. Regarding the number of linear constraints, we can apply similar reasoning and conclude that the total number of linear constraints also increases approximately linearly with the network scale. Notably, as discussed in Kraning et al. (2012), the parallel implementation of the PMP algorithm empirically scales as $O\left(N^{0.996}\right)$, indicating that the solving time is almost linear relative to the problem size.

In summary, the proposed bi-level problem with corresponding methods applies to large-scale problems due to the approximately linear increase of variables and constraints with the network scale.

5. Concluding remarks and real-world implementation

5.1. Real-world implementation

For practical implementation, crucial private information should be well protected, while other necessary information can be shared to increase the efficiency of coordination between TEP and GEP.

On the one hand, according to CAISO's Manual for TEP (CAISO, 2023), the supply cost and demand utility of transmission network users are considered confidential and market-sensitive and should not be made public. To protect the private information of transmission network users during the negotiation process, we suggest following the distributed method developed by Zheng et al. (2023). The main steps for incorporating this method into our problem can be found in Appendix H.

On the other hand, this coordination process between TEP and GEP is implemented through an extensive stakeholder engagement strategy, which depends on close collaboration with some energy agencies and efficient information sharing. Drawing insights from the CAISO 2020-2021 transmission planning process (CAISO, 2021), we identify Seven key stakeholders (Regulator, Energy Commission, Public Utilities Commission, SO, GenCos, TransCos, and LSEs) and propose a six-step core process and an implementation flowchart (as shown in Figure. 7) involving a detailed information-sharing process to facilitate efficient coordination.

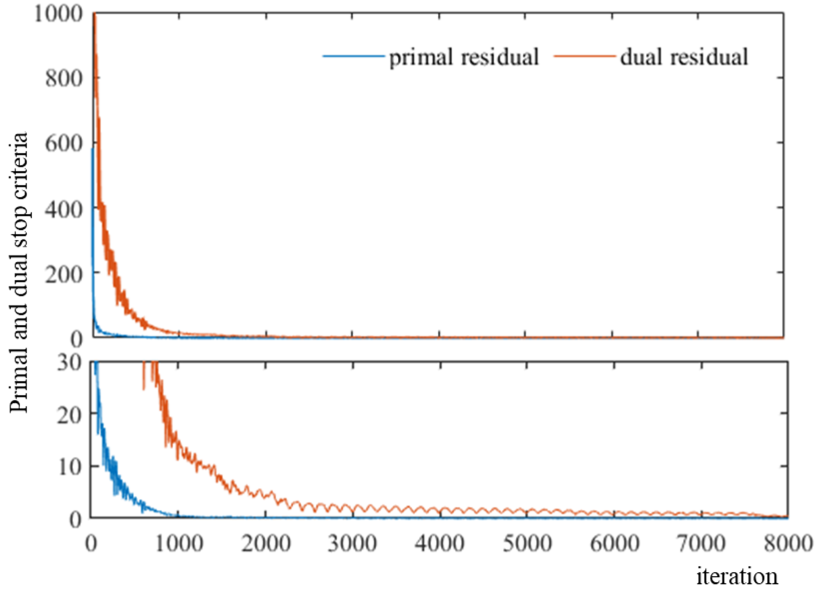


Figure 6: The convergence property of modified PMP algorithm in Case 1

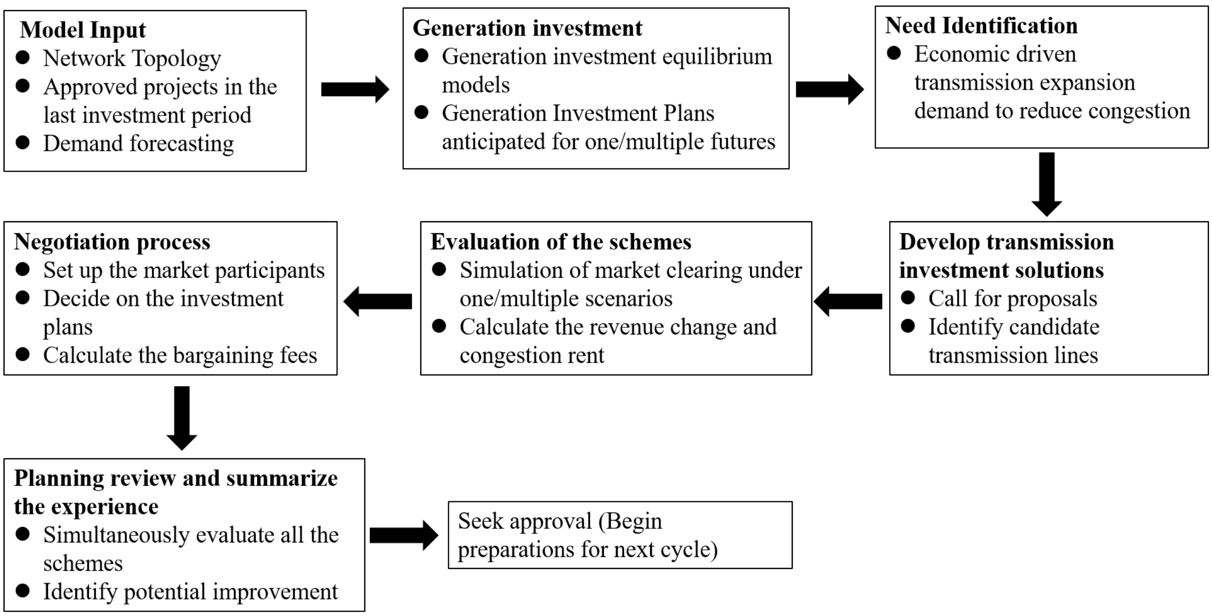


Figure 7: The process of transmission expansion planning under the proposed mechanism

(1) Stakeholder Engagement Plan: The regulator should develop a detailed plan for stakeholder engagement, including communication strategies to keep stakeholders informed about project developments and solicit feedback on project design and implementation.

(2) Demand Forecasts: The Energy Commission issues long-term energy demand forecasts through its biennial Integrated Energy Policy Report, which provides demand information for generation and transmission investments.[19]

[19] According to the WECC Information Sharing Policy (WECC, 2022), the load and resources and system adequacy planning information are not restricted and may be made publicly available.

(3) Market Data Dissemination: SO disseminates historical market clearing results and data. This information will assist GenCos, LSEs, and TransCos in making informed decisions regarding TEP and GEP of the power system.[20]

(4) Generation Investment Plans: Various GenCos conduct generation investment plans. The Public Utilities Commission monitors and evaluates these plans, ensuring regular updates and information on project progress and impacts are communicated.

(5) Annual Transmission Investment: TransCo, GenCos, and LSEs make the transmission investment decisions, which are backstopped by the SO. This process incorporates information about demand forecast and generation investment plans from the Energy Commission and Public Utilities Commission.

(6) Evaluation and Feedback. Throughout this coordination, the regulator evaluates the project, shares expected progress and impacts, solicits stakeholder feedback, facilitates negotiation, and implements necessary adjustments. The regulator is also expected to provide relevant information, such as benchmark results and comparative TEP and GEP costs, and offer access to research and advisory resources, such as capital cost analysis.

5.2. Policy implications

Based on the above discussions, this paper reaches the following policy recommendations for establishing the incentive mechanisms for efficient TEP. These recommendations aim to improve the TEP process by promoting more efficient infrastructure planning and collaborative and fair stakeholder engagement.

In most current frameworks, market participants (including GenCos and LSEs) passively pay transmission tariffs to help TEP investors cover the TEP costs through fees set by the regulator. This passive payment system raises concerns about cost reduction and extensive regulatory burdens. Our proposed negotiation mechanism allows for direct negotiations between the TransCo and transmission network users in determining TEP strategies and transmission cost allocation.

While designing more efficient incentive mechanisms for TEP, it is important to consider a broader range of properties. Current designs often emphasize revenue sufficiency and achieving socially optimal TEP strategies as key objectives. Although advanced mechanisms such as the ISS and H-R-G-V approaches effectively ensure revenue sufficiency for TEP investors and aim to maximize social welfare by attributing the overall change in social welfare to TEP investors, they may unintentionally reduce the potential contributions to the surplus of other market players. Hence, allocating TEP costs and the resulting market surplus among all beneficiaries remains critical. This issue necessitates the adoption of a fair allocation principle and implementing a process that preserves privacy. Such considerations are important to ensure that the design of incentive mechanisms for efficient TEP achieves financial goals and supports fair and confidential stakeholder engagement.

The proactive participation enabled by our proposed negotiation mechanism can implement TEP strategies as stakeholders desire, leaving them a substantial market surplus. This mechanism helps mitigate the stranded cost issue and promote the transformation towards new electricity market systems. Furthermore, encouraging more participants in the TEP process will likely increase overall social welfare. Thus, ensuring free entry into this negotiation mechanism is essential.

5.3. Conclusions

This paper proposes a novel negotiation incentive mechanism for efficient TEP, which allows transmission network users, specifically GenCos and LSEs, to negotiate directly with TransCo in determining TEP strategies and cost allocation. Utilizing Nash Bargaining Theory, this mechanism models negotiations and incorporates bargaining fees to redistribute social welfare derived from TEP among market participants fairly. The power flow tracing method allocates revenue from FTRs based on transmission usage rates. We address the efficient transmission investment challenge from a comprehensive system-wide perspective, aiming to optimize social welfare. Our approach strongly emphasizes incentives for stakeholder engagement and transmission network users' satisfaction.

We establish a bi-level single-leader-multi-follower model to consider the coordination between TEP and GEP. In this model, the TEP problem is the leader that influences the follower GEP problem, aiming to achieve the generation investment equilibrium. We model the TEP and GEP decision variables with discrete ones to reflect real-world practice. We reformulate the UL non-convex TEP problem equivalently to enhance tractability, devise a modified PMP technique to efficiently find generation investment equilibrium at the LL, and adopt an iterative method to address this bi-level model. The results indicate that,

[20]The market clearing results, which are helpful with the research and analysis, are also market-sensitive information and will be shared in an anonymous way and after a delay for a certain period.

(1) The proposed negotiation mechanism ensures revenue sufficiency and achieves socially optimal TEP strategies comparable to existing advanced incentive mechanisms. This mechanism also preserves the privacy of transmission network users, balances the interests between TransCo and transmission network users, and ensures a fair distribution of TEP costs and risks.

(2) The proposed negotiation mechanism allows GenCos and LSEs to participate in the TEP process proactively, thereby enhancing their utilities, which aids in addressing the stranded cost issue and promotes advancing toward new electricity market mechanisms at the transitional stage.

(3) The iterative method effectively coordinates TEP with GEP. The LL's Nash Equilibrium-seeking model accurately captures the non-cooperative nature of GEP issues, while the modified PMP algorithm effectively addresses generation investment equilibrium. Additionally, the computational efficiency analysis justifies the model's scalability and practicality, proving our approach is reliable for addressing the intricate transmission expansion planning problem.

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