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Coordination of Generation and Transmission Expansion Planning in a Liberalized Electricity Context - Coordination Schemes, Risk Management, and Modelling Strategies: A Review

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Abstract

After more than two decades of experience with the deregulated functioning of electricity markets, the need to coordinate generation and transmission investment decisions has been defined as a relevant problem, moreover considering the high penetration of renewables expected in the upcoming years. This lack of coordination creates risks for investors in both activities. This article reviews and classifies the most relevant works in this field in a liberalized context. We compare works on different planning approaches and the implementation of regulatory coordination schemes complementing the former to define the state of the art. Part of these works explores the role of coordination schemes in managing risks that can condition investment decisions and lead to coordination failures. We also discuss the suitability of different modelling approaches to represent the different possible planning, regulatory coordination schemes and risk measurements. Based on the review of previous works, we identify a research gap in the analysis of the combined use of planning approaches and appropriate complementary regulatory coordination schemes, including their ability to manage the most relevant risks that investors in both activities are subject to and the lack of the implementation of risk modelling strategies to assess risk aversion from stakeholders properly, especially under a proactive planning approach.

1. Introduction

The traditional centralized structure of electricity systems left both generation and transmission expansion decisions in the hands of vertically integrated utilities, allowing them to be optimized together [1]. However, with the deregulation of the industry, generation and transmission have been unbundled and joint optimization is no longer possible [2]. After more than two decades of deregulation, a number of challenges have been identified, mainly related to the impact of this deregulation process on Transmission Expansion Planning (TEP) and Generation Expansion Planning (GEP) and their coordination, as there is no longer a common expansion plan that includes expansion decisions of both types [3].

Generation and transmission are planned and operated by different entities, which can create disincentives for decisions to install new generation capacity or new transmission infrastructure [4].

Generation is controlled by private generation companies known as GENCOS, whose operation and investment decisions are driven by their aim to maximize their profits [5]. Transmission development and system (and market) operation are planned by independent entities, the System Operators (SOs) and Market Operators (MOs). Sometimes, both the SO and MO functions are performed by the same entity (which we shall call the SO). Typically, GENCOS make their investment decisions to maximize their profits, while SOs aim to maximize the welfare of the system. Conflicts of interest may arise between entities of both types, creating additional regulatory challenges.

In addition, today's need to increase the share of renewable generation integrated into the system further complicates these investment decisions because a significant portion of renewable generation is located in remote areas that are poorly connected to the rest of the system. Its power output must then be transported over long distances using transmission capacity to be built [5]; in addition, the lead time for transmission assets in this context is longer than for most of those renewable generators [6].

The interdependency between generation and transmission expansion and the uncertainty on the conditions affecting the operation of these assets increases the relevance of risks faced by generation developers and reduces the efficiency level of system development [7]. In general, the realization of investments in new generation capacity requires that the promoters have certainty about the availability of the transmission capacity that the new generation will need to use. At the same time, the system planner usually needs evidence that the new generation will be installed in order to develop the transmission capacity needed to integrate it into the system. This is known in the literature as the "chicken and egg" problem [8], [9], [10], [11].

The absence of certainty by GENCOs and the System Operator about the behavior of each other, especially regarding their intentions to pursue interdependent investments, represents a significant barrier to realizing these investments. This challenge is particularly relevant in liberalized electricity markets, where the recovery of generation investment costs is not guaranteed. GENCOs' revenues are directly impacted by market conditions, which influence marginal price behaviour. These uncertainties give rise to two main risks: counterparty risk associated with the lack of commitment by the network

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planner to undertake the transmission investments that generation ones depend on, and vice-versa (the lack of commitment by generation investors to undertake the investments that justify the undertaking of certain transmission reinforcements), and notably price risk, driven by market price volatility and the severe network congestion that the lack of coordination of generation and transmission investments can lead to. Consequently, the existence of the aforementioned risks in the GEP&TEP coordination problem emphasizes the importance of implementing risk management strategies and measures for the proper assessment of the impact that various risks associated with this coordination problem may have on the system's development.

Achieving stakeholder coordination of investments is essential to ensure long-term efficiency in the development of liberalized power systems [12]. It is, therefore, necessary to coordinate expansion planning decisions to encourage investment on both sides at the right time and in the right amounts, considering stakeholders' risk perception.

The coordination problem previously discussed is of paramount importance. However, there is a lack of a comprehensive review regarding: i) the approaches developed to drive this coordination, including planning approaches and regulatory coordination schemes, ii) the management of risks involved in the GEP&TEP coordination problem, and iii) the works on modelling the implementation of these approaches and their interaction.

The necessity to theoretically develop the main elements affecting this GEP&TEP coordination problem under a liberalized electricity framework drives the development of this work. The primary motivation of this work is to provide insights to the research community, industry stakeholders, regulators, and other interested parties in this field regarding critical elements that potentially facilitate and drive the GEP&TEP coordination. From a theoretical perspective, our purpose is to offer different possible alternatives to enhance coordination while promoting a detailed understanding of the works carried out in the literature in this area. Additionally, our aim is to identify various gaps and interesting future research elements to be considered by the different interested parties.

In the remaining sections, this article contributes a structured discussion exclusively focusing on the key elements that drive the system to solve the coordination problem between generation and transmission expansion planning in a liberalized electricity context. It delves into the interplay among these relevant elements from a theoretical perspective, including different planning approaches (with the integrated resources planning approach serving as a reference planning), complementary regulatory coordination schemes aimed at fostering system efficiency, and risk management strategies within the GEP-TEP coordination context, see Figure 1. In addition, this article analyses the relationship between the aforementioned schemes and how they have been modelled and addressed in the literature. These interconnected aspects have not previously been comprehensively analysed together, considering their mutual interactions.

2. Contributions

Given the discussion in the previous section, the main contributions of the work presented here are listed next:

i Unlike previous review papers related to the coordination between generation and transmission expansion planning, this work analyses from a theoretical point of view the alternatives available in the literature to drive the GEP&TEP coordination problem in a liberalized electricity framework, starting the discussion with the planning approach considered. Different to previous works, the planning approaches are regarded here as "primary coordination schemes" since the planning approach considered conditions the coordination framework to adopt. The integrated resources planning approach is established as a reference point for achieving full coordination; the proactive planning approach involves the provision of signals to the agents to drive the development of the system, while the reactive planning approach involves the planner reacting to the investment decisions by the GENCOs.

ii Contrary to what previous review works on this subject do, we assess the contribution of the "complementary regulatory coordination schemes" in addressing the existing challenges faced when coordinating the expansion of generation and transmission (GEP&TEP).

iii In contrast to previous review analyses, this article considers, as an additional aspect to assess within the GEP-TEP coordination problem, the impact of the level of coordination between generation and transmission expansion planning within a deregulated context on the risks perceived by agents. Depending on the planning approach, we analyse the risk exposure under each planning approach and the regulatory coordination schemes' ability to manage or reduce the risks associated with a possible lack of coordination of generation and transmission expansion. This article highlights the significance of addressing these risks and explores various modelling strategies available in the literature to tackle this issue. Prior research in this domain has predominantly focused on modelling the problem's characteristics without adequately considering the role and significance of risk.

iv This article provides a classification of the different GEP-TEP coordination modelling works, considering, in particular, the most relevant elements to achieve this coordination; these are the planning approach, the regulatory coordination schemes implemented, and the risk management strategy adopted, as well as the modelling strategies used to represent the risk exposure. Additionally, we also refer to other aspects of the modelling of the system functioning.

v This paper identifies significant gaps in the literature regarding the coordination problem between generation and transmission expansion planning, emphasizing

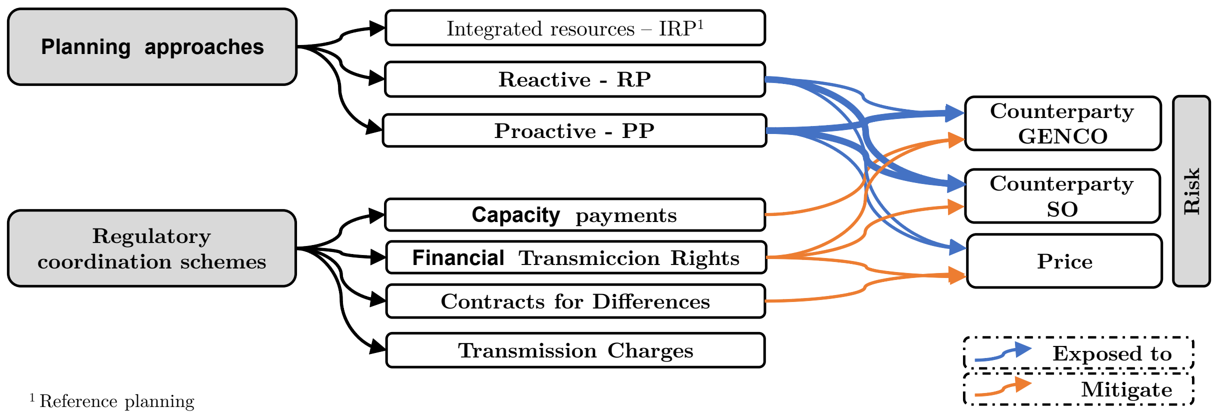

Figure 1: Key elements for driving GEP&TEP Coordination

the importance of future research on the consideration of regulatory coordination schemes for this purpose. Additionally, it highlights the need for implementing risk management tools and employing effective risk measurement strategies in this context.

3. Planning approaches as primary coordination schemes

Schemes to coordinate generation expansion planning and transmission expansion planning are of different types. First, the authorities must determine the approach they will embrace for the planning of the expansion of the system. According to the regulation in place, the possible planning approaches can be classified into Integrated-resources planning, Reactive planning and Proactive planning from the transmission planning viewpoint. The planning of the expansion of the system carried out can be combined with several possible complementary regulatory coordination schemes, which can be adapted to the specific planning approach adopted according to the objective of the regulator. These complementary coordination schemes will be discussed in a specific section. Given the uncertainty that the transmission planner may have about the connection of new generation, and the generation investments in general, this entity can follow two main strategies for network expansion planning:

- ***Reactive planning***: according to this, the transmission planner decides on the expansion of the network only once it has firm, definite information about the generation expansion plans devised by Generation Companies (GENCOs), i.e., once the transmission planer is aware of the definite investments to be undertaken by GENCOs in the next regulatory period.

- ***Proactive planning***: This concept was proposed in [13]. In this approach, the transmission planner anticipates the investments by GENCOs, and the impact on them of the transmission investment decisions, when planning the expansion of the transmission grid. Taking the foreseen generation investments into account, the planner's aim is to achieve a dynamic development of the grid that keeps pace with generation developments and, at the same time, drives them to be more efficient [7].

Together with these two approaches, which are adapted to deregulated environments, there is also the ***integrated-resources planning approach (IRP)***, which involves jointly planning the expansion of generation and transmission [14]. In this approach, a centralized decision-maker makes use of co-optimization models to optimize generation and transmission investments. This approach is only directly applicable in the traditional regulatory context, where the full electricity supply chain is in the hands of vertically integrated utilities. Consequently, in this work, this planning approach is deemed to provide a reference point corresponding to the system's optimal fully coordinated expansion, see Figure 2.

Previous studies agree to conclude that the proactive planning approach should be the preferred one. However, the existing literature does not provide a satisfactory solution to the problem of managing the differences in the construction time between generation and transmission projects, with some relevant transmission projects taking a much longer time to be deployed than generation ones [15]. This is a gap to be addressed by future research.

GEP-TEP coordination models according to the planning approach

Apart from the relevant aspects to be considered in the coordination problem, which have been previously identified, the modeller needs to define the structure, or levels, considered in this problem. The generation and transmission expansion planning models can be structured at different levels, depending on the order in which the GEP and TEP investment decisions and the market operation decisions are made. One option involves considering a single-level structure (SL), whereby all decisions are deemed to be made at the same moment, simultaneously. Alternatively, the coordination problem may be modelled using a multi-level structure (ML), whereby decisions by different types of stakeholders are made at different levels sequentially. In the

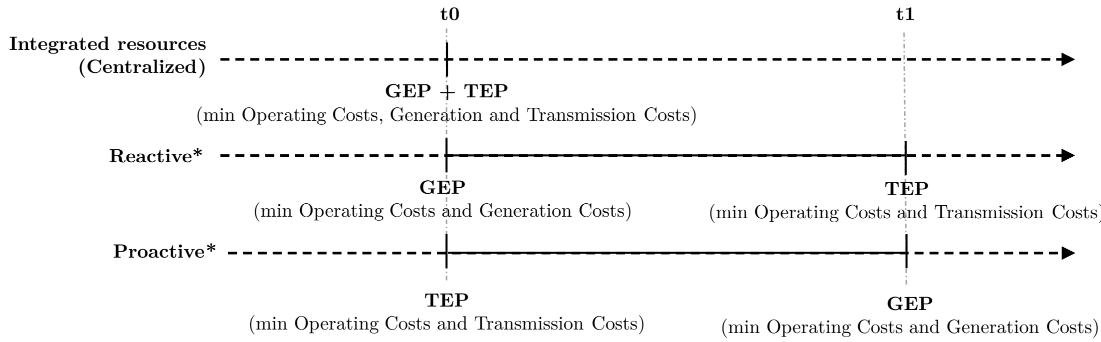

Figure 2: Decision planning approaches - Network planner's point of view

latter case, generation and transmission expansion planning decisions are commonly made first at the upper levels, while the market operation decisions are commonly made afterwards, at the lower levels, according to the planning approach implemented.

Considering the ML modelling structure, the modeller may develop bi-level mathematical programs with equilibrium constraints (MPEC), whereby there is a single optimisation problem at the upper level constrained by several simultaneous optimisation problems at the lower level. Solving this involves computing an equilibrium of the decisions made at several levels and by several actors. When the modeller aims to consider more than two decision levels, he may represent these as equilibrium problems with equilibrium constraints (EPEC), whereby there are several optimisation problems in the upper level, constrained by several optimisation problems in the lower level; nevertheless, finding an optimal solution of multilevel equilibrium problems can only be guaranteed for MPECs. For EPECs problems, there is no guarantee of the existence of an equilibrium, as explained in [15].

This section describes, in detail, how the several types of planning approaches previously analysed, and identified as primary coordination schemes, have been modelled in the relevant research works in the literature.

Integrated-resource planning (Reference planning)

Despite the fact that this approach is not suitable for deregulated systems, co-optimization models can be used in a deregulated environment to determine the potential value provided by transmission and other resources. Nevertheless, in [4], the authors propose a single-level model to evaluate the value of potential generation investments in the network expansion planning problem, particularly in the context of significant congestion affecting the transmission grid within the planning horizon. Although this model incorporates both generation and transmission costs into the objective function, it is not designed for a vertically integrated system. This model considers candidate generation investments as possible options to take into account for the TEP and aims to be a tool that can be used by the regulators to identify those generation investments whose undertaking should be encouraged; furthermore, the authors decompose the problem into sub-problems. Similarly, in [16], the authors propose a mathematical model representing an Integrated-resources planning approach to be applied in a deregulated market context. In it, the generation investments computed are deemed to represent the optimal market response to the transmission expansion plan developed instead of being part of an integrated expansion plan.

In [13], the authors make use of an integrated-resources planning approach to compare proactive and reactive planning models. They conclude that even though the integrated approach provides a more efficient overall expansion strategy, it cannot be applied in deregulated markets, and the second-best option is to implement a proactive planning approach.

The authors in [17] model the centralized generation and transmission expansion planning problem proposing the use of the Generalized Bender's Decomposition (GBD) Method and including an AC representation of the power flow derived by linearizing the AC power flow model, different to other proposals, here instead of considering DC power flow representation, they extended GDB in an AC power flow representation.

In [18], the authors propose an integrated-resource planning approach to compute the most efficient expansion strategy possible for generation and transmission planning and use this expansion strategy as a reference point to assess the efficiency of the results produced by other coordination models designed for deregulated markets. In the same way, the authors in [19] propose an integrated-resource planning approach to represent a situation where a central organization is regulated to manage the development of the generation and transmission systems simultaneously. The authors model this problem as a MINLP.

The authors in [20] consider an integrated-resources planning approach comprising three planning stages. In the first stage, investment decisions for GEP (Renewable) and TEP are made. In the second stage, contingencies are represented and their impact computed, while in the third stage, the corrective actions to implement are determined. They remark on the importance of coordinating transmission investment decisions with the deployment of ever larger amounts of renewable generation in order to avoid threatening the system's security.

In [21] the authors assume perfect coordination when following an integrated-resource planning approach. Through a probabilistic method, they formulate the occurrence of contingencies to determine the probability distribution of NSE. IN order to solve the resulting problem, they transform a MINLP problem into a MILP one. Similarly, in [22] the authors propose the application of information gap decision theory (IGDT) to formulate a MILP robust problem representing the implementation of an integrated-resource planning assuming central coordination.

The authors in [23] assume perfect coordination between decisions on generation and transmission expansion planning and propose a dynamic model to formulate this problem considering several planning horizons.

Recently, in [24], the authors consider an integrated-resource planning approach involving the iterative use of two models: a centralized expansion planning model where generation expansion, transmission expansion and generation dispatch decisions are computed; and the Cascades model to assess the risks faced by parties and update the decisions computed by the centralized model to better manage these risks.

In general, the integrated-resource planning approach is useful for producing reference expansion plans employed to assess the performance of those plans computed following other approaches.

Reactive planning

As mentioned previously, in the reactive planning approach, the transmission planner already knows which generation power plants are going to be built, when, and where. There are few studies in the literature in which reactive planning is applied.

In [13], the authors compare the outcome of implementing a proactive approach with that of implementing a reactive approach and that resulting from integrated-resource planning. They conclude that the reactive approach is likely to result in a socially suboptimal expansion of the system in the long term.

In [25], the same authors propose two models, a proactive model and an extension of the reactive planning model described in their previous study. They explicitly state in the formulation of these that the generators cannot purchase transmission rights. The reactive network expansion planning model has the same structure as the proactive planning model, with the difference that, in the former, it is assumed that the expansion of generation in one specific level is not anticipated by the network planner. Finally, they conclude that the expansion plan produced by the proactive model is never worse than that produced by the reactive model. This conclusion is based on the fact that the feasible set of planning solutions for the reactive model is a subset of the feasibility set of the proactive one, and both models have the same objective function. Consequently, the optimal solution of the proactive model cannot be worse than the one for the reactive model.

In [26], the authors propose separate mathematical models for proactive and reactive planning. In the reactive approach, the Generation companies are the leaders and regulated Transmission companies (responsible for transmission expansion planning) are the followers. The authors formulate a mixed-integer linear program model considering multiple Nash equilibria. In this approach, they consider the strategic behaviour of generation companies, which allows them to make higher profits when following the reactive approach rather than when applying the proactive one, as the transmission company could not guide generation investment decisions. They found that in the case of Proactive planning, this one prevents GENCOs from earning higher profits than those they earn for reactive planning, even when the proactive solution is more cost-efficient for the system.

In [27], the authors consider a reactive planning approach whereby, formulating a multi-level optimization problem, they develop a solution algorithm linking search-based and agent-based approaches. Even though they do not consider capacity payments, they remark how modelling additional elements such as capacity payments may result in a more accurate representation of GENCOs' behaviour.

Similarly, in [28], the authors introduced a multi-level optimization model, where capacity payments are paid by the TSO and used to encourage investments in new generation units to increase the system's reliability. An optimal expansion plan is produced by GENCOS, according to their incentives, and used by the TSO to develop a centralized transmission expansion plan under a reactive planning approach. This optimization problem is solved and tested in [29] by making use of metaheuristic methods, particularly the two-stage multi-dimensional melody search algorithm (MSA). To conclude, the authors in this work remark that the proposed method (reactive planning) provides relevant insights about the agents' behaviour that are useful for the system planners, even though this approach should not be applied in real life.

Proactive planning

This concept is first proposed in [13], where the authors introduce a proactive transmission expansion planning model considering three periods. In each period, the players (the network planner and the GENCOs) have complete information about the decisions made in the previous periods by the other players, which allows them to make efficient decisions in the following periods. The authors conclude that the proactive planning performs better than the reactive one.

This approach is extended in [25], considering different assumptions, concerning the spot market operation, among others. The authors assume in this work that the generators cannot purchase transmission rights. In [30], the authors formulate a three-level model inspired in [25]. In this case, the planner in the transmission expansion planning problem anticipates clearing equilibria, including the optimistic view by the network planner that the best EPEC (Equilibrium Problem with Equilibrium Constraint) outcome possible from a social-welfare viewpoint will come true; in [31], the same authors modify the model proposed in [30], considering demand profiles, selecting appropriate scenarios for each demand profile, and considering uncertainty in wind and hydropower output with the objective to have a more realistic representation of the system functioning. They develop a simplified formulation of this problem where the transmission planner anticipates generation expansion and market clearing. Finally, they apply the model to a real system; in [32], the same authors propose an extension of the models in [30] and [31] whereby they also consider the pessimistic view by the network expansion planner that those equilibria that are less favourable for the system interest may materialize. They propose an iterative decomposition method to solve EPEC models, concluding that the network planner can affect generation capacity investments by constructing some lines in order to mitigate market power from GENCOs.

Similar to [31], Jin and Ryan propose a three-level model in [33] and provide numerical results in [34]. This model considers an EPEC problem solved with a hybrid iterative algorithm. Within it, the authors consider price-responsive demand and strategic decisions by GENCOs. They conclude that there is no guarantee of being able to compute the optimal solution when applying the hybrid algorithm.

In [20], the authors propose a three-level model considering renewable generation to meet current renewable generation targets while coordinating GEP and TEP under contingencies and security constraints. They apply this model to a real case study, concluding that not considering security criteria in expansion planning leads to a more expensive solution. Similarly, in [35] the authors proposed a tri-level model considering equilibrium in GEP under oligopoly. This is formulated as a single problem considering a Nash equilibrium and KKT conditions. They show how the market competition developed among producers affects the expansion of the system.

In [26], the authors analyse the coordination between the expansion of the transmission grid by the planner and that of generation decided by GENCOs using a sequential-move game. The authors propose a mixed-integer bilevel linear program (MIBLP), for the implementation of the proactive planning approach.

Similarly, formulating leader/follower (Stackelberg) type games, in [19], the authors propose a two-level problem formulated as a mixed-integer nonlinear program (MINLP) to represent the proactive transmission planning scheme and compute its outcome. They compare this methodology with an IRP approach and carry out some sensitivity analyses regarding the existence of congestion in the network. The authors conclude that, in the absence of congestion, the GENCOs are dispatched according to the merit order of the existing generation plants, and investments in new generation capacity take place for the most efficient technologies in terms of operating and investment costs. On the other hand, in the presence of congestion, the existing incentives to upgrade the transmission system (mandate to maximize the social welfare in the case of a regulator vs. the incentive for the TSO to maximize its own profit) have a major impact on the expansion results.

Similarly to the previous approach, in [36], the authors propose a bi-level model representing a leader/follower type of game to compute the outcome of the proactive planning approach, where the transmission company (planner) moves first, deciding the network investments, followed by the GENCOs, deciding on the power production levels by the existing facilities and the generation investments to undertake according to the choices made previously by the transmission company.

In [37], the authors consider a proactive planning approach whereby they model market power and strategic generation expansion through the formulation of the Stackelberg-worst Nash equilibrium in a multilevel model, considering one leader (social planner) and multiple followers (GENCOs). The same authors extend their previous work in [38], proposing a numerical solution technique and applying the proposal to a 14-bus case example.

In [39], the authors also consider a bi-level model formulation as an MPEC where they compare two business models for transmission investments: i) the one based on the initiative of the Transmission System Operator (TSO); and ii) the investments promoted by Merchant investors (MI); In the upper level, transmission investments are decided according to i) and ii). Then, in the lower level, the investments promoted by wind generation operators are computed, considering their strategic behaviour. Similar to the bi-level structure proposed in [39], in [40], the authors propose a bi-level MILP formulation of the proactive planning approach, also considering storage, whereby the TSO anticipates either perfect competition or Cournot oligopoly.

Recently, in [41], authors propose a proactive planning approach using a bilevel model whereby, at the upper level, the network planner maximizes the social welfare anticipating the generation capacity expansion decisions. At the lower level, community energy projects are considered in order to promote citizen participation in energy production.

The proactive planning approach can effectively coordinate transmission and generation expansion planning. However, proactive planning alone is not able to decrease to a large enough extent the level of uncertainty that generation investors have about transmission investments, nor that of transmission planners about generation investments. Their lack of resources to manage these risks would be left largely unattended, making only use of proactive planning, which could prevent relevant investments and negatively affect the efficiency of system expansion. Stakeholders cannot effectively tackle the "chicken and egg" problem referred to above making use only of this planning approach. For this, it is necessary to encourage investments on both sides, taking into account the risk aversion strategy adopted by stakeholders in reality.

Combining the correct planning approach with the implementation of appropriate regulatory mechanisms can help to achieve this aim. According to [42], the implementation of specific incentive mechanisms as complementary regulatory coordination schemes, along with the proactive planning approach, can facilitate the growth in the amount of renewable generation deployed and its integration into the system. The next section discusses the main complementary regulatory coordination schemes that have been proposed so far.

4. Complementary Regulatory Coordination Schemes

The planning of the expansion of the system carried out can be combined with several possible complementary regulatory coordination schemes, which can be adapted to the specific planning approach adopted according to the objective of the regulator.

Implementing these complementary coordination schemes aims to increase the efficiency of the system's expansion by enhancing coordination between generation and transmission network development. Some of these complementary coordination schemes allow the generators and, to some extent; also, the consumers to internalize in their investment decisions, as well as, in some cases, in their operation ones, some additional effects, not accounted for otherwise, that the transmission grid has on the benefits and costs for the system resulting from these investment decisions. These include considering locational and temporal differentiation in energy prices, affecting capacity payments by the grid constraints, or implementing locationally differentiated transmission charges.

Other complementary schemes allow the system stakeholders involved in the expansion of the system to more efficiently manage the risks they are subject to, in some cases, creating incentives to invest in new generation (or load), or new transmission capacity. These include the capacity payment schemes but also the long-term Financial Transmission Rights (FTRs), as we will argue below.

The current need to increase the share of renewable generation integrated into the system further complicates the efficient implementation of conventional planning approaches. This is due to the fact that a relevant part of the renewable energy resources is located in remote areas weakly linked to the rest of the power system, as well as the high uncertainty existing about this generation output due to their variability and intermittency [19]. The increase in the amount of existing RES-based generation that is expected in the next years advises the implementation of complementary regulatory coordination schemes.

In addition, as far as the coordination of transmission and generation investments is concerned, the implementation of regulatory coordination schemes and public interests, coupled with market-based planning, can provide signals to the agents driving their generation investment decisions, which can be considered by regulators, SOs and other parties of the system when making transmission expansion planning decisions [43].

According to [44], the increasing growth of wholesale electricity trading increases the demand for transmission services. Network users are aware of the impact of transmission developments on their level of access to the market, including their effect on the nodal prices they earn, which are topics of high interest for them; particularly in Europe, the uneven allocation of generation technologies is leading to strong network congestion among national transmission systems. The impact of this network congestion on the system functioning clearly advises the implementation of complementary coordination schemes since there is a clear need for efficient network investment decisions and its coordination with network users' ones.

Transmission network developments have a direct benefit for the network users and the SO, or system planner, who have an incentive to cooperate to achieve the undertaking of these projects [43]. This cooperation may be triggered or facilitated through different regulatory coordination mechanisms that can act as complementary incentives or boundaries to expansion, depending on their objectives. In the absence of these complementary regulatory coordination schemes, relevant challenges to the efficient development of the grid remain to be addressed.

The authors in [45] identify two main challenges for the efficient development of the network that are difficult to address in the absence of complementary regulatory coordination schemes: the lack of commitment by the stakeholders (SO and promoter of new generation) to go ahead with the investments considered by them as potentially relevant; and the existence of asymmetric information about the benefits of certain transmission projects (due to the lack of information provided by the network planner on the costs to be faced by the GENCOs promoting new generation). This could lead to two types of inefficiencies: "investment forcing" and network "investment preempting". To illustrate these two, the authors in [45] consider a system of two nodes, one in the north with a smaller average demand and one in the south. The node in the south needs additional energy to avoid supply disruptions. This additional energy can be supplied by installing an additional generation unit in the south or an additional generation unit in the north, plus a transmission line connecting both nodes. Given these circumstances, if the SO follows a reactive planning approach, it would only react to the GENCOs' investment decisions. If the GENCO decides to build a new generation in the north (because it is cheaper than in the south), the SO will build the transmission line connecting both nodes, even if the most efficient decision for the system was to build generation only in the south. This type of inefficiency is called "investment forcing" and leads to transmission over-investments with respect to the optimal situation, where generation would only be build in the south without a need to reinforce the connection between both nodes.

On the other hand, if the most efficient option, from the system point of view, were for the GENCO to build a new generation in the north, but they decided to build it in the south, there would not be any reason for the network planner to build the link between both nodes, since the demand in the south would already be covered. This type of inefficiency is called "investment pre-empting", and normally leads to transmission under-investments with respect to the most efficient system development possible. If a proactive planning approach is followed by the network planner, those two types of inefficiencies would be partially solved since the GENCOs' behaviour could be anticipated by the network planner. However, even in this case, there would not probably be strong enough incentives for the transmission planner or the GENCO to undertake the most efficient investments.

According to [40], transmission under-investments have negative consequences for the system, such as increases in congestion costs and the level and frequency of load curtailment, which may result in increasing maintenance costs, among others. The net social costs of transmission under-investments tend to be higher than those of transmission over-investments due to the increases in consumer costs resulting from capacity shortages.

Locational Marginal Prices (LMPs) could, in theory, be used as a tool to send efficient operation signals to the market participants (generators and consumers) and to the network planner. Consequently, this tool could be used as an efficient operation coordination scheme, while the expectation of the level of LMPs could also be a guiding signal for investments. Nevertheless, in a real scenario with economies of scale and discrete investments, the net system revenues from the application of LMPs would fall short of the network development costs, which means that network-related signals conveyed through LMPs would not allow the network users to internalize the full network development costs in their investment decisions. Besides, significant uncertainty exists about the future evolution of LMPs, which may be affected, among other things, by the investment decisions in generation and transmission. This weakens the long-term signals provided through LMPs, which, as we have just argued, are also incomplete [46]. Then, long-term investment signals provided through LMPs alone would not suffice to guide efficient, coordinated generation, demand, and network investments. Additional long-term coordinating signals need to be sent.

Together with locationally differentiated energy prices, a scheme of capacity payments could be implemented to encourage the deployment and availability of additional generation capacity (or firm capacity, in general) that will be needed at certain times to supply the load envisaged. In [45], the authors show that capacity markets combined with appropriate network expansion schemes can prevent under-investments in generation capacity by avoiding the "missing money problem". However, it should be noted that capacity payments may not result in strong enough incentives for the transmission planner and the GENCOs to invest in transmission or generation capacity. Hence, some coordination problems may remain. Besides, even if capacity payments are combined with LMPs, in the absence of other signals, part of the network development costs would still not be allocated to the parties causing them. These together would undermine the efficiency of the system development.

Transmission charges should be used to make network users internalize in their investment decisions the full network development costs they are responsible for, also allowing the recovery of the network costs. In [18], the authors propose allocating transmission investment costs to the users of the transmission system according to their impact on the transmission development cost, which should influence the network users' investment decisions.

Even when the previously mentioned coordinating signals are implemented, the incentives to comply with the plans for the development of generation and transmission capacity would probably not be strong enough to provide a high enough level of certainty to the network planner and the generation companies on the evolution of generation and the transmission grid, respectively. If this certainty were high-enough, the investments by the counterpart could be considered in the development of their investment plans. Probably, the efficient way to deal with this coordination problem is through the implementation of a regulatory mechanism that reduces the level of counter-party risk perceived by the parties and encourages the undertaking of investments on both sides.

Given this, other coordination schemes should probably be implemented also to complement the aforementioned ones producing strong-enough investment incentives both on the side of the generation operator and that of the network planner. This commitment is especially relevant for the development of RES based generation to be located in remote areas where the primary energy resource is abundant.

GEP-TEP coordination models according to the Complementary Regulatory Coordination Schemes considered

In [47], the authors propose a model following an integrated-resource planning approach. This model assumes that merchant TRANSCOs and GENCOs behave competitively. Then, it is assumed that their investment decisions coincide with those centrally planned by the Independent System operator (ISO), checking security and transmission network constraints. This problem is formulated by making use of Mixed Integer Programming (MIP) to compute GENCOs' and TRANSCOs' investments, while Linear Programming is employed to solve the security and operation problem. In this context, capacity payments are applied as a coordination tool, conditioning GENCOs and TRANSCOs' investment decisions. Capacity signals are introduced as incentives for deploying generation and transmission facilities. It is assumed that the capacity payment would be contractually binding for the ISO and market players. In order to maintain the system security (if transmission network security is not met), the GENCOs and merchant TRANSCOs would be compensated by the ISO based on capacity signals, then, GENCOs would obtain revenues from energy and capacity payments and merchant TRANSCOs would obtain revenues from flowgate marginal prices and capacity payments. The authors assume that these actors are risk-neutral.

Similarly to this approach, in [48], the authors develop an optimization model which coordinates investment decisions in the monopolistic transmission and the decentralized generation activities following a proactive planning approach. In this case, the investments by Independent Power Producers (IPPs) are encouraged through the implementation of incentive payments that can be regarded as capacity payments. These aim to drive generation investments when needed by the system to safeguard security. These incentive mechanisms are implemented within the context of the coordinated planning performed by a central entity (state-owned transmission company). Generation investments which contribute to the socially optimal system expansion might be delayed by IPPs. For instance, those IPPs that aim to safeguard security during on-peak demand periods might require receiving extra incentives because of the fact that they remain largely idle during off-peak periods. Accordingly, IPP could determine its incentive requirements. Then, those would be implemented as payments, which are fine-tuned iteratively in the centralized planning problem until the reliability levels required are reached.

The authors in [49] assess the implementation of capacity payments represented in a single-level MILP problem which can be seen as a two-stage problem. In it, the objective function considers the minimization of investment and operational costs. Capacity payments are considered in the objective function as being related to investment decisions. Possibly, additional ones could be implemented in the form of Feed in Tariffs considered in that part of the objective function referring to the operational costs. Capacity payments are used to increase generation capacity additions in the form of renewable generation.

In the same way, in [50], the authors consider the implementation of capacity payments in order to encourage generation investments. They propose an iterative method to solve a tri-level optimization model to coordinate investment decisions. In a first step, LMPs are computed together with the system operation. Then, GENCOs plan their investments, considering the LMPs computed in the previous step, and the existing transmission network, as resulting from the previous iteration, while the SO checks security constraints. In the third step, if there is any violation of the security constraints and network reliability requirements, the system operator applies capacity payments to drive generation capacity investments that can increase network reliability. Finally, the SO, considering the resulting generation plan, computes the transmission expansion plan, following a reactive planning approach.

In [18], the authors propose an iterative algorithm for the computation of system expansion based on a Reactive planning approach. They develop and propose a model which computes the equilibrium between transmission and generation expansion planning investments, using transmission charges as a coordination tool. These charges are deemed proportional to the marginal impact of generation investments on transmission investment costs, with the aim of influencing GENCOs' investment decisions. This iterative model treats generation expansion planning and centralized transmission expansion planning separately, computing the former as being only influenced by the transmission charges and the latter being computed considering the generation expansion planning results, following a reactive planning approach. The results of each problem (generation and transmission expansion) are fed iteratively into the other one until convergence is achieved and stable values for the transmission charges applied are determined.

As mentioned before, few studies in the literature have considered and modelled the use of complementary regulatory coordination schemes for generation and transmission expansion planning; within the literature, no work have consider before the modelling of the implementation of a regulatory mechanism aimed at deploying strong enough incentives to achieve a sort of commitment by the transmission planner and the generation companies to go ahead with their investments under a proactive planning approach. In order to facilitate the undertaking of generation and transmission investments at the right time, deploying instruments that allow risk-averse generation investors and transmission companies to effectively and efficiently manage the risks they perceive is of paramount importance. This is a gap to be addressed by future research.

5. Risk management in the GEP-TEP coordination problem

Risk is considered in the literature as the hazard exposure caused by the uncertainty that market participants, and other system stakeholders, face [51], and risk management refers to the process to identify, control and measure the risk [52]. In liberalized electricity markets, risks can be analysed from different perspectives, including that of System operators, Generation companies, and consumers, among others. In general, decision-makers are risk averse [53].

Depending on the viewpoint adopted, several risks can be considered; in the generation and transmission expansion planning problem, generation and transmission are planned and operated by different entities. A lack of coordination between the decisions made by the utilities and the central planner may discourage them from undertaking some socially efficient investments [4].

Generation is owned by private companies known as GENCOS, whose operational and investment decisions are driven by the objective of maximising their profits [5]. The expansion of the transmission system and the system (and market) operation are planned by independent entities, the System Operators (SOs) and Market Operators (MOs). Sometimes, both the SO and MO functions are carried out by the same entity (which we shall call the SO). Normally, SOs aim to maximise the welfare of the system.

The lack of trust between the GENCOS and the SO regarding their intention to undertake certain investments whose benefits are interdependent may end up preventing these and other socially efficient ones from happening. This becomes evident when considering that, in the liberalized electricity context, the cost recovery of generation investments is not guaranteed since GENCOS' incomes depend on market conditions that directly influence the marginal price behaviour. Those types of uncertainties can lead to a counterparty risk caused by the lack of coordination among the stakeholders' decisions and a market risk, particularly

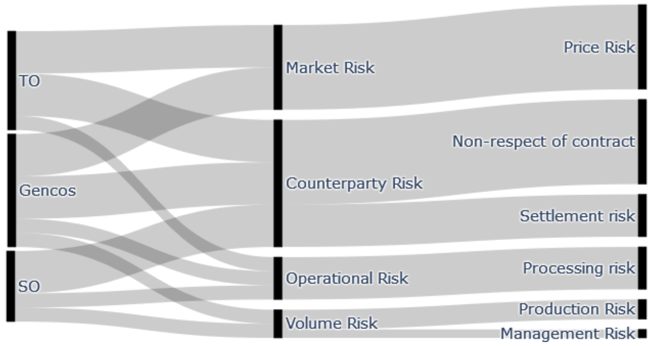

Figure 3: Stakeholders risks - Generation and Transmission Expansion Planning

price risk, caused by the market price volatility and the effect of this on GENCO's market profits.

Counterparty risks concern the risk that a counterparty (in this case, the GENCOs whose investments should be coordinated with the transmission ones) does not fulfil his contractual obligations (in this case, the plans GENCOs have published about the construction of new generation capacity). This may prevent or delay the construction of the transmission capacity promoted by the network planner and to be used by the new generation to be installed, which, in turn, creates relevant counterparty risks faced by the GENCOs. When network investments are merchant, i.e. they are promoted and made by private entrepreneurs aiming to maximize their profits out of the commercial exploitation of the corresponding transmission assets, the merchant network promoters and owners are not only subject to counterparty risk, but also to price risks related to the uncertainty existing about the market value of the transmission capacity they build, and, therefore, their market revenues.

Besides the uncertainty existing about the prices that GENCOs are subject to, the lack of information by the network planner on the costs to be faced by the GENCO's promoting new generation, caused by the existence of asymmetric information [45] about the system benefits and costs associated with the generation and transmission investments, can cause additional counterparty risks faced by the network planners related to the uncertainty about the potential inability of GENCOs to fulfil their contractual obligations [54].

The different types of risks that may exist can be summarized in figure 3. All these different risks can be measured, for instance, through indicators like the Value at Risk (VaR), which, probably, is the most popular instrument to measure risks. VaR can be computed making use of different techniques, such as historical data methods, historical simulation approaches, analytical methods and monte carlo simulation [51]-[55].

Among the coordination planning schemes discussed here, under a centralized planning scheme, which is applied in a traditional, fully regulated context featuring vertically integrated utilities, there is complete avoidance of counterparty and price risks. In this context, investments are guaranteed the recovery of costs incurred plus a reasonable rate of return. Additionally, generation and transmission investments are perfectly coordinated from a social point of view, which helps prevent idle investments. Moreover, network congestion is limited to reasonable and efficient levels in this context.

Under reactive planning, transmission investments adapt to the generation ones being decided previously. Then, the counterparty risk that generation and transmission investments are subject to is largely reduced since transmission investments only react to already decided generation ones, and generation investors have the guarantee that the development of the grid will adapt, to the extent possible, to the needs of the newly built generation. Similarly, the network planner aims to maintain the level of congestion in the grid within efficient limits under this planning approach. However, for this to be achievable, the network planner needs access to the necessary funds for identified network reinforcements and obtaining permits in a reasonable time frame. Therefore, in practical terms, generation investments may still face some non-negligible risks, even with the implementation of reactive planning.

Under proactive planning, the counterparty risk faced by the transmission planner is larger, while that faced by generation investors is lower, given that they know in advance which transmission investments are to be undertaken. On the other hand, the price risks faced by generation investors associated with the existence of relevant network congestion are large, given the high chances that generation investments, being decided in a decentralized manner, do not adapt to the development of the grid.

Especially in the context of the application of proactive planning, but also when reactive planning is applied, complementary regulatory coordination schemes can play a relevant role in managing the resulting risks associated with a lack of coordination of investments.

In the literature, several works focus on identifying mechanisms to manage price risks or counterparty risks. For instance, Contracts for Differences (CfD) could be used to manage these risks. CfD instruments are forward electricity contracts that ensure revenue stability for renewable generators by mitigating their exposure to spot prices. These instruments are typically entered into by a renewable generator and a counterparty offtaker who purchases electricity from the same pool in which the generator sells its electricity [56]. This mechanism can be used to manage the price risk caused by the uncertainty existing about the spot market price. However, it is not well suited to manage the price risk caused by network congestion. Furthermore, this mechanism is not able to coordinate generation and transmission expansion planning decisions.

Another risk-hedging instrument is Capacity payments. This instrument can mitigate, to some extent, the counterparty risk faced by the SO, since it is able to encourage the deployment and availability of additional generation capacity (or firm capacity, in general) that will be needed at certain times to supply the load envisaged. In [45], the authors show that capacity markets coordinated with network investments can prevent under-investments in generation capacity by

Table 1
Characteristics of mechanisms to manage risks in GEP&TEP coordination problem

Mechanism	Potential risk to mitigate	Characteristics
CP	Counterparty (partially)	• Provide economic incentives for generation investors • Do not provide incentives for the transmission planner.
FTRs	Market (Price) - Counterparty	• Able to manage price risk caused by network congestion. • Could manage counterparty risk. • Not suitable for managing price risk associated with the uncertainty about the electricity price in the reference node.
CfD	Market (Price)	• Ensure revenue stability for renewable generation. • Mitigate exposure to spot prices. • Not suitable for managing price risk caused by network congestion.

avoiding the "missing money problem". However, while capacity payments provide some relevant, though incomplete, economic incentives for generation investors to deploy the corresponding generation capacity, they do not provide similar incentives for the transmission planner to undertake the planned transmission investments, though these instruments partly reduce the counterparty risk this planner faces. Besides, capacity payments are not suitable for managing the price risks that GENCOs and merchant transmission promoters are subject to.

Financial Transmission Rights (FTRs) are a relevant risk hedging instrument potentially complementing some of the previous ones. The basic format for these rights is the point-to-point one. FTRs of this type provide their owner with the right, or obligation, to earn the congestion rents produced by the transmission grid between the injection and withdrawal nodes defined in these contracts, in return for the payment of the price set for these rights in the corresponding auction [57]. Congestion rents are the net revenues collected by the SO out of the system dispatch that are caused by congestion and losses when locationally differentiated prices are in place. They result from the fact that, under these prices, payments made by consumers are larger than those received by generators. In contrast with physical transmission rights, financial rights do not affect the dispatch of the system.

Up till now, FTRs have been successfully implemented in different power markets such as New York, PJM and New England, among others [58], and have been considered in the literature mostly as an efficient tool to hedge the risk of market agents associated with the uncertainty existing about the price of accessing the transmission capacity they need to use in the short term [57]. But long-term FTRs also create incentives for transmission planners to promote the transmission investments to be used by the new generation covered by these rights [59], creating incentives to undertake the transmission and generation investments leading these stakeholders to engage in the corresponding transmission contracts. Not undertaking these investments would leave the transmission planner subject to the risk of not having enough market revenues to pay the network users having acquired these rights, while generation investors' market revenues would depend on the level of congestion eventually existing in the grid. Then, acquiring LT FTRS would potentially limit the counterparty risks that both types of stakeholders are subject to. Additionally, the market risk that the generation and transmission assets covered by LT FTRs are subject to, related to the existence of congestion in the grid, would be largely limited, though, in the case of generation assets, investors may need to combine LT-FTRs with other products, largely CfDs, to achieve a full hedge against price risk.

However, the implementation of FTRs as a long-term financial mechanism for coordinating generation and transmission expansion planning in a liberalized electricity market environment has not been analysed in detail. The ability of this instrument to manage the perception that the relevant stakeholders in the system expansion have of the long-term risks they are subject to, trying to drive a socially optimal expansion of the system, has not been investigated either.

5.1. Risk Measurements & Modelling strategies

Uncertainty implies the existence of risks, and the risk profile of a decision-maker depends on the decision-maker's perspective [60]. Risks can be measured and modelled in different ways according to the literature [61]-[52]; here, we summarize the most representative risk measurements and modelling strategies that exist, and we discuss their use in the problem of coordinating the generation and transmission expansion. Risk measurement strategies refer to specific approaches devised to measure or assess the risk, while the term modelling strategies refer to the alternatives to represent the existing risks within the system representation approach adopted, see Figure 4.

VaR-CVaR: Value at Risk (VaR) and Conditional value at risk (CVaR) are natural risk measurement tools highly implemented in literature [60]. By definition, given a level of confidence, VaR corresponds to the value of the maximum loss for that confidence level, and CVaR is the expected loss value of the tail VaR [62]. VaR and CVaR can be computed using different methods, including historical, analytical and the implementation of Montecarlo simulation [52]. Models applied to solve GEP-TEP coordination problems lack the implementation of this measurement. Only in [20] do the authors consider the implementation of CVaR, see Table2.

Real-options valuation (ROV): Real options are employed to analyse the dynamics of specific decisions in order to provide guidance to the decision-maker under uncertainty [63], particularly on investment decisions when time flexibility exists in management actions. ROV allows the decision makers to consider the value of waiting as part of the decision investment process [61]. ROV can be carried out, for instance, by making use of dynamic programming [64], Monte Carlo simulation or lattice-based models [65]. Models aimed at coordinating generation and transmission expansion planning do not include ROV to face uncertainty. However, this tool has been used and analysed separately for generation expansion planning and transmission expansion planning, as in [65] and [63], respectively.

Monte-Carlo simulation: Monte-Carlo simulation is a quantitative method, based on the creation of random scenarios (random sampling), that provides statistical information in order to assess the performance of decisions or to assess the performance of risk analysis [66]. Monte Carlo simulation can be used in risk management as a risk estimation method, for instance, to compute the VaR or ROV. In Generation and transmission expansion planning, it has been implemented in studies such as [20].

Optimisation methods: Optimization techniques have been widely used when considering uncertainty. Developing an optimization problem involves mathematically formulating it, including an objective function, typically with an economic objective, a set of decision variables and a set of constraints [67]. The inclusion of stochasticity in the optimization model formulation helps to represent in a more realistic way the behaviour of the system. Risk can be considered, for instance, through the inclusion of risk-constrained strategies to manage uncertainties. Optimization methods can also be combined with real options, Information Gap decision theory or CVaR, as proposed in [68], and discussed in [69]. Few studies in the literature combine these tools in the generation and transmission expansion planning problem. The authors in [53] consider CVaR in the formulation of a two-stage optimization problem representing risk affecting Transmission and Generation costs. The authors in [28]-[29] consider a risk-constrained strategy to manage uncertainties related to the market price and demand through the implementation of information gap decision theory IGDT. The authors in [70] consider some relevant risks by introducing a term in the objective function of an optimization model whereby they aim to minimize the standard deviation of the variable affected by these risks multiplied by a parameter chosen by the decision maker to represent the importance of the risk measurement.

Decision analysis (DA): considers the perspective of the decision-maker for different situations that different probabilities are assigned to, and according to their preferences, the effect or reaction that these situations may cause [52]. Concerning risks, in Multi-criteria Decision analysis, there is a particular method named multi-attribute utility theory (MAUT) that considers risk attitudes in order to create utility functions. Even when the application of these methods has increased, they have not been applied in GEP-TEP coordination problems [71].

Information-Gap Decision Theory (IGDT): is a quantitative method based on the idea of making decisions being subject to a significant lack of information [72]. This method is commonly used to achieve the maximum welfare of the system under different sets of conditions, including those related to risk materialization [73]. Few studies have focused on the coordination of generation and transmission expansion planning, considering this method as a risk modelling strategy. Authors in [28]-[29] implement information gap decision theory IGDT to make robust decisions in the presence of uncertainties [72].

GEP-TEP coordination models considering Risk Measurements and modelling strategies

Risk modelling strategies have been applied in many areas. However, few works address the modelling of the GEP-TEP coordination problem; few models include those types of analysis. Authors in [28]-[29] consider a risk-constrained strategy to manage uncertainty related to the evolution of price and demand through the implementation of information gap decision theory IGDT, which is employed to make robust decisions to face uncertainties [72].

Authors in [20] model a GEP-TEP problem as a single-level optimization problem, considering two stages to manage contingencies affecting the system security. They consider the computation of the CVAR, including the impact on it of the loss of load incurred, as a post-processing tool, by making use of Montecarlo simulation. Similarly, in [74], the authors formulate a risk-based dynamic GEP-TEP problem where they consider the risk associated with the occurrence of each contingency in order to obtain a planning solution that avoids failures in cascade. They model this risk considering the probability and consequence of each contingency and compute a load-shedding penalty cost by implementing risk indexes that compute the value of loss of load.

In [24], the authors propose a risk-informed approach to consider the risk of systemic failures through an iterative interplay of two models: i) the centralized investment model,

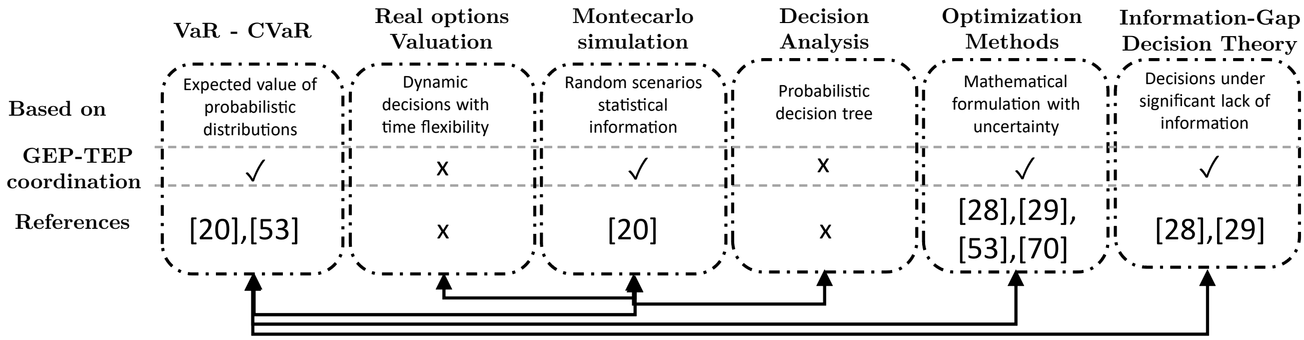

Figure 4: Risk modelling strategies - Interactions. Arrows at the bottom connect boxes for techniques that have been implemented together.

where generation and transmission expansion, as well as generation dispatch decisions, are computed, and ii) the Cascades model, used for updating the decisions made in the centralized model and carry out the risk assessment by comparing risk curves for specific years computed making use of the Wasserstein distance.

Few studies in the literature consider the implementation of risk measurement tools or risk modelling strategies to assess the risk incurred in the problem of coordinating the generation and the transmission expansion planning, see Table 2. Moreover, no previous work has explored the consideration of this measurement in order to assess the implementation of regulatory coordination schemes. Therefore, this is a gap to be filled in by future research.

6. Additional aspects to be considered for the classification of the coordination between generation and transmission expansion planning models.

In addition to the different planning approaches, complementary coordination schemes and risk measurements, the following elements must be taken into account when analysing the coordination of generation and transmission expansion planning from the modelling perspective:

Uncertainty (UN): the impossibility of describing exactly the state or level of a specific variable in the future. This condition depends on the nature of the variable and can be considered as short or long-run uncertainty [75]. For instance, the level of economic growth and future regulatory developments are common uncertainties considered in the long run, while the demand behaviour, the amount of renewable resources available and the existing weather conditions are uncertainties to be potentially considered in the short run. Stochasticity and probabilistic events are intrinsically related to this unpredictable behaviour of certain variables, which is commonly modelled through probabilistic methods, stochastic programming and robust optimization. The consideration of uncertainty in the model implies carrying out a better representation of reality, moreover when considering risk management (due to their interrelationship, this aspect is next to Risk Modelling in Table 2 and leads to a more robust planning [76].

Level Structure (LS) or Stages Structure (SS): The level structure considered for the problem should adapt to represent different actors or different decisions in competitive games [77]. On the contrary, the stage structure refers to the several stages taken in cooperative games. Stages are represented inside a level structure. For instance, a centralized investment and operational problem can be modelled on a single level while considering different stages to represent the details of the operation. Thus, one can make use of benders decomposition in a two-stage approach, or consider an additional stage to check the reliability of the system. Then, the problems represented may be differentiated as single-level (Sl), or multi-level (Ml), and single-stage (Ss), or multi-stage (Ms).

Solution Technique : Refers to the technique implemented to solve the optimization model; typically, these are addressed through solution techniques, which are either exact or non-exact. In general, exact techniques guarantee convergence and optimality, while non-exact techniques encompass heuristics or metaheuristics, generally offering good solutions in a reasonable time without ensuring optimality. Additional options include the consideration of iterative methods or algorithms explicitly designed to solve particular problems.

Case Study : A case study encompasses either the realistic or theoretical case considered to test the model; in general, the size of the cases provides information regarding the scalability of the proposed model.

Other relevant aspects of the functioning of the system: The system's representation in modelling can incorporate a range of details, and this work introduces some additional relevant aspects not directly linked to GEP&TEP coordination. These include *Transmission Network Representation (TNR)*, offering different models like DC load-flow for expansion planning, which excludes reactive power flows and node voltage magnitudes. Though more realistic in representing network flows and their operational impact, the AC load flow model is nonlinear. Alternatively, the generalized network flow model (GF) provides a simpler representation focusing solely on nodal power flow balance, neglecting the 2nd Kirchoff law. *Market Power (MP)* involves an anti-competitive practice where market participants, particularly generators, strategically adjust their behaviour to influence market prices for their profit or others'. This strategic behaviour is often modelled using game theory and algorithms like Cournot, Bertrand, and Stackelberg supply function equilibria (SFE) [78]. *Demand Elasticity (DE)* addresses demand response to market prices, which can generally be elastic or inelastic in models. Various types of elasticity can be considered, including income elasticity, own-price elasticity, elasticity of substitution, and cross-price elasticity [79].

7. Classification of GEP-TEP coordination modelling works

In this section, we classify the most relevant expansion planning studies according to the primary coordination schemes, the complementary regulatory coordination schemes, and the risk measures considered in them, see Table 2. This classification is carried out considering the relevant aspects, or features, of a planning approach, as previously described. Previous reviews of this topic do not consider the use of complementary regulatory coordination schemes affecting investment decisions. What is more, they do not consider the risk measurements and the corresponding risk modelling strategies applied in each work, which is a relevant aspect to classify and assess the corresponding works [75], [80], [15],[81].

8. Discussion

Generation and Transmission expansion planning is a problem of high interest to the academic community and has been modelled by different authors, see Table 2. Nowadays, with the high penetration of renewable generation and the necessity to adapt the system to this new generation, there is a growing need to coordinate efficiently the expansion of generation and transmission. This paper reviews the possible coordination approaches, including, for the first time, the application of Regulatory coordination schemes to drive the development of generation and transmission, as well as the application of risk measurement strategies within the coordination schemes.

The works classified in this article consider the planning approach; in particular, under a proactive planning approach, as explained in section 3, the transmission planner anticipates the investments by GENCOs based on some preliminary information about them. However, this preliminary information, most of the time, is just the expected behaviour of the GENCO, estimated according to historical data or assumptions made regarding new developments that, in theory, would be taking place in the future. However, an appropriate proactive planning approach application needs to consider the possible implementation of regulatory instruments that increase the coordination of investment decisions. Typically, the works based on proactive planning reviewed do not consider the use of regulatory coordination schemes. Through these tools, the TSO can send signals to the agents, which GENCOs respond to. Then, anticipating the reaction of agents to these signals, the TSO can have more solid information about the likely GENCO's behaviour, which should allow the former to define more realistic scenarios about this behaviour when following a proactive planning approach.

Under a reactive planning approach, the TSO knows which generation projects are going to be built when making the transmission investment decisions, but he cannot condition or drive, these decisions by having made an implemented in advance the development of the network occurring in the corresponding period.

The combination of any of these two main planning approaches with some regulatory coordination instruments providing both generation investors and network planners with incentives to undertake certain investments is providing both sides with a higher level of certainty about the investments their counterpart will undertake, which limits the counter-party risk they face. Note that in the integrated resource planning approach, the coordination between the generation and transmission investments is inherent to the planning scheme.

In general, both TSOs and GENCOs are highly exposed to risk in a deregulated context. In this context, the assessment of risks and management of them by the stakeholders is a valuable element when they plan the investments to undertake. This is becoming even more relevant due to the growing penetration of RES-based generation expected in the coming years. However, the works in the literature considering a proactive planning approach do not consider risk measurements and modelling strategies, while few works following a reactive planning approach consider the use of measurements and modelling of risks, see Table 2.

Thus, few previous works have explored the implementation of regulatory coordination schemes and risk measurement tools when considering and modelling the use of a proactive planning approach. Other elements, such as the existence and exercise of market power or the demand elasticity, have been considered by some authors when analysing the implementation of any of the different planning approaches.

There is a preference, within the academia and the industry, to make use of bi-level problems to represent the coordination of generation and investment decisions in a deregulated context, both under a proactive and a reactive approach. Even when bi-level problems are complex, they are less difficult to solve than multilevel ones. Single-level problems are most commonly used to represent integrated planning approaches, typically considering a MILP formulation, which is easy to solve, making use of commercial solvers.

Future challenges in this field involve modelling the planning problem considering the implementation of risk management tools and the appropriate risk measurements and modelling representation, as well as the use of regulatory coordination schemes to achieve a more efficient and tightly coordinated expansion of the system resources, those future challenges to be addressed are discussed in the conclusions section.

Table 2
Review of the modelling of the schemes to coordinate generation and transmission expansion planning

Ref	PY	PA	CRCS	RM	Uncertainty	LS-SS	Solution Technique	Case Study	Other Aspects
[47]	2007	IRP	yes (CP)	no	no	ML(3)	Iterative algorithm using Benders decomposition	Two-bus - Modified IEEE 30-bus system	TNR(DC)
[49]	2019	IRP	yes (CP)	no	no	SL-MS(2)	MILP solved with CPLEX	24-node example (IEEE RTS-24)	TNR(DC)
[70]	2007	IRP	no	yes (OM)	yes (Demand, capacity of lines, capacity factor of generation units)	SL-MS(2)	Benders decomposition	6-Node System - 21-Node System	TNR(DC)
[20]	2016	IRP	no	yes (CVaR)	yes (Demand, Renewable generation)	SL-MS(2)	Xpress-MP	(3e+2c)-Bus System - Main Chilean Power System	TNR(DC)
[53]	2017	IRP	no	yes (CVaR)	yes (Demand, cost changes, Renewable Portfolio Standards (RPS) policies)	SL-MS(2)	MILP	WECC 240-bus system	TNR(DC)
[74]	2020	IRP	no	yes (OM)	yes	SL	MISOCP, solved with CPLEX	IEEE 24-bus system	TNR(DC)
[24]	2023	IRP	no	yes (WD)	yes (system failures)	SL-MS(2)	Iterative procedure	Central European power system	TNR(DC)
[4]	2008	IRP	no	no	no	SL	Benders decomposition	4-bus system - Turkish power system	TNR(DC)
[16]	2014	IRP	no	no	yes (economic, policy)	SL	Deterministic, heuristics	240-bus	TNR(DC)
[21]	2014	IRP	no	no	yes (behaviour of the system components, contingencies)	SL	MINLP converted in MILP, solved with CPLEX	6-Bus test system, IEEE 24-Bus, IEEE 118-Bus, 15-Unit Test System	TNR(DC)
[17]	2015	IRP	no	no	no	SL-MS(2)	Iterative algorithm using GBD	6-bus Garver test case, IEEE 30-bus system	TNR(AC)
[18]	2017	IRP	no	no	no	SL	MILP solved with CPLEX	IEEE-RTS96	TNR(DC),DE
[22]	2020	IRP	no	no	yes	SL	MILP solved with CPLEX	6-bus Garver test case, IEEE 30 bus test system, IEEE 118 bus test system	TNR(DC)
[28]-[29]	2015	RP	yes (CP)	yes (IGDT)	yes (Demand, Price)	ML(4)	Multidimentional Melody Search(MSA) Metaheuristic	46-bus south Brazilian electric power grid, IEEE 118-bus test system	TNR(DC),MP
[48]	2010	PP	yes (CP)	no	yes (Load growth, electricity prices)	ML(3)	Iterative solution method	Two-bus and the IEEE 30-bus systems	TNR(DC)
[50]	2013	RP	yes (CP)	no	yes (load and bid prices of the generating units)	ML(3)	Iterative solution method	The modified IEEE 30-bus system	TNR(DC)
[18]	2017	RP	yes (TC)	no	no	SL	Iterative algorithm	IEEE-RTS96	TNR(DC),DE
[27]	2010	RP	no	no	yes (Demand levels, forced outages of generation and transmission systems, future policy and regulation and economic inflation)	ML(3)	Algorithm linking search-based and the agent-based approaches	Five.bus test system	TNR(DC),MP
[26]	2017	RP	no	no	yes (Wind)	ML(2)	Moore-Bard algorithm	The Modified IEEE-RTS96 The Modified IEEE 118-bus Test System	TNR(GF)
[25]	2007	RP	no	no	yes (Network topology, market operation)	ML	sequential quadratic programming algorithm	32-bus representation Chilean case	TNR(DC),DE,MP

Ref: Reference number, PY: Publication Year, PA: Planning Approach (IRP: Integrated Resources Planning RPA: Reactive Planning Approach, RP: Reactive Planning, PP: Proactive planning), CRCS: Complementary Regulatory Coordination Scheme (TC: Transmission charges, CP: Capacity payments), RM: Ris Measurement/Modelling strategy, LS-SS: Level Structure or stages structure (SL: Single-Level, ML: Multi-Level, Ss; Single-stage, Ms: Multi-stage),MP: Market power, DE: Demand elasticity, TNR: Transmission network representation (DC: DC flow model, AC:AC flow model, GF Generalized network flow model). : Includes both CRCS & RM, : Includes CRCS, : Includes RM

Continuation of Table 2

Ref	PY	**PA**	**CRCS**	**RM**	Uncertainty	LS-SS	Solution Technique	Case Study	Other Aspects
[13]	2006	PP	no	no	yes (network, demand, generation)	ML(3)	sequential quadratic programming algorithm	30-bus/3-zone	TNR(DC),DE,MP
[25]	2007	PP	no	no	yes (network topology, spot market operation)	ML(3)	sequential quadratic programming algorithm	32 buses – Chilean power network	TNR(DC),DE,MP
[37]	2011	PP	no	no	no	ML(2)	MILP solved with CPLEX	3-node example	TNR(DC),MP
[38]	2011	PP	no	no	no	ML(2)	Algorithm including meta-heuristic(IPGA)	modified IEEE 14-Bus example	TNR(DC),MP
[30]	2012	PP	no	no	no	ML(3)	MIP solved with CPLEX	3-node example and a 4-node example	TNR(DC),MP
[39]	2013	PP	no	no	no	ML(2)	MILP and MIQPs solved with Gurobi	Three node network example	TNR(DC),MP
[19]	2013	PP	no	no	no	ML(2)	MILP and MINLP solved with CPLEX	three node network and 21 nodes network	TNR(DC),DE
[31]	2013	PP	no	no	yes (Demand and, wind and hydropower)	ML(3)	MILP solved with CPLEX	Main Chilean power network	TNR(DC),MP
[33]	2014	PP	no	no	no	ML(3)	Diagonalization method (DM) and complementarity problem reformulation (CP)	Modified IEEE 30-bus system, IEEE 118-bus system	TNR(DC),DE,MP
[36]	2014	PP	no	no	no	ML(2)	Progressive penalization algorithm based on (k-th best algorithms)	6-bus Garver test case	TNR(DC)
[32]	2017	PP	no	no	no	ML(3)	Algorithm based on a column-and-row generation algorithm and a disjunctive cutting plane algorithm	24-node example (IEEE RTS-24)	TNR(DC),MP
[35]	2017	PP	no	no	no	ML(3)	MILP solved with commercial solvers	Modified IEEE 14-Bus test system	TNR(DC),DE
[26]	2017	PP	no	no	yes (Wind)	ML(2)	two heuristic versions of Moore-Bard algorithm	The Modified IEEE-RTS96, The Modified IEEE 118-bus Test System	TNR(GF)
[40]	2019	PP	no	no	no	ML(2)	MILP solved with GUROBI	4-bus system example	TNR(DC),DE,MP
[41]	2022	PP	no	no	no	ML(2)	MILP solved with Gurobi	3-bus example	TNR(DC),MP

Ref: Reference number, PY: Publication Year, PA: Planning Approach (IRP: Integrated Resources Planning RPA: Reactive Planning Approach, RP: Reactive Planning, PP: Proactive planning), CRCS: Complementary Regulatory Coordination Scheme (TC: Transmission charges, CP: Capacity payments), RM: Ris Measurement/Modelling strategy, LS-SS: Level Structure or stages structure (SL: Single-Level, ML: Multi-Level, Ss; Single-stage, Ms: Multi-stage),MP: Market power, DE: Demand elasticity, TNR: Transmission network representation (DC: DC flow model, AC:AC flow model, GF Generalized network flow model). : Includes both CRCS & RM, : Includes CRCS, : Includes RM

9. Conclusions

This article reviews several previously proposed or implemented approaches to coordinate the planning of generation and transmission expansion. It begins by discussing the implementation of these approaches, followed by an analysis of their modelling. Lastly, it examines works that analyze the impact of GEP/TEP coordination on the risks perceived by agents and the coordination schemes that can be adopted to mitigate these risks. The discussion encompasses approaches devised to model this risk impact and its management, including their features and merits.

The literature considers two main general planning approaches to tackle the generation and transmission expansion coordination problem in deregulated systems: the Reactive Planning approach and the Proactive Planning approach. Additionally, in this context, conducting Integrated Resource Planning, even when not directly implementable, is useful to set a reference point for the level of coordination that can potentially be achieved.

Within existing general planning approaches in a deregulated context, the integrated resource planning approach is typically regarded as producing the reference coordinated expansion plan used to evaluate the performance of other planning approaches. Achieving perfect coordination in a deregulated context involves making relevant simplifying assumptions about the agents' behaviour, including their access to complete information and competitive bidding. Modelling this planning approach generally entails significantly less complexity and computational burden than other planning approaches. This approach facilitates the assessment of the impact of different regulatory schemes on the efficiency of the functioning of the system in the aforementioned idealized context.

The reactive planning approach, corresponding to the traditional method in a deregulated context, has been implemented in a wide variety of countries. It aims to reduce the risk perceived by the generation stakeholders. However, this conservative approach can lead to inefficiencies in the system's expansion since, being the planner only reactive to the investment decisions made by generation investors, the former cannot influence these decisions by deciding in advance how the network will expand. This approach has been used by some researchers assessing the performance of some complementary regulatory schemes, like capacity payments and transmission charges.

The research community has shown a greater interest in proactive planning compared to reactive planning, recognizing the potential for increased efficiency in the system expansion resulting from the implementation of the former approach. However, most literature exploring proactive planning has not considered the implementation of regulatory coordination schemes alongside it. Additionally, these studies often assume market participants to be risk-neutral, which is not reflective of reality. Through analysis of the relevant literature, we have confirmed the importance of implementing complementary regulatory coordination schemes to ensure that investment decisions by transmission planners and generation companies are influenced by each other's needs.

When exploring the coordination of the expansion of generation and transmission, it is very relevant to consider the existing conditions challenging the coordination of generation and transmission investments. These include i) the increasing difference between the construction time of generation and transmission facilities; ii) the risk aversion of stakeholders preventing them from carrying out certain investments due to the lack of commitment by their counterparty to undertake the investments the former would need; iii) the lack of information available to the system stakeholders and, therefore, the existing uncertainty, about the market conditions that the assets they build will be subject to, due to the deregulated nature of some activities in the electricity sector.

The problem of a lack of commitment between GENCOs and the transmission planner regarding their investment decisions in order to coordinate them remains, which results in some efficiency losses. The implementation of one, or several, regulatory coordination schemes addressing the lack of mutual commitment by providing strong incentives to undertaking the planned generation and transmission expansion investments remains a necessity to achieve a highly efficient system expansion; however, few studies in the literature consider the implementation of regulatory mechanisms like transmission charges or capacity payments as coordination tools.

The use of complementary regulatory coordination schemes in combination with the aforementioned planning approaches aims to increase the efficiency of the system expansion through some signals facilitating the coordination of investment decisions by generators and the network planner, and some of them could act as risk management tools in this coordination context.

According to the literature, there is no evidence of a perfect risk hedging instrument that allows complete GEP&TEP coordination. However, the combination of regulatory coordination schemes that can manage separately different types of risks, such as FTRs combined with other mechanisms able to hedge particular risks, such as CfDs, could potentially help the stakeholders manage the most relevant risks arising in the GEP&TEP coordination problem, such as the counterparty and price risks.

The implementation of complementary regulatory coordination schemes has been considered either under a reactive planning approach or under integrated resource planning. Generally, those coordination models that consider the implementation of regulatory coordination schemes do not consider the modelling of the risk perceived by the stakeholders. Our research has revealed the lack of previous modelling works considering the risk perception that the system stakeholders have when analysing the implementation of this type of coordination schemes in real-life electricity systems, in particular when considering a proactive planning approach.

The investment decisions made by different actors are directly affected by their perception of the risks these investments are subject to. In fact, the consideration of uncertainty has been identified by many authors as a critical element to be considered in this problem. This advices representing the impact of the risks perceived by agents on the value they place on the investments they undertake when analysing the implementation of specific coordination schemes. Then, the ability of these coordination schemes to manage the relevant risks related to a lack of coordination could also be assessed. Considering the impact of risk on the generation and transmission investments requires making use of appropriate measures of risk.

The options devised to explore the GEP-TEP coordination problem representing it have been classified according to their features, regarding the overall planning approach they follow, the type of complementary regulatory coordination schemes they include, and the risk measurement and risk modelling strategy they consider. The review carried out reveals that most of the approaches proposed in the literature lack the use of complementary regulatory coordination schemes, as well as proper risk representation and risk modelling strategies.

Gaps and future research

According to the conclusions previously discussed, here we summarize the main relevant elements on this topic to be further investigated by future research works.

i *Risk Analysis in GEP&TEP Coordination*: The consideration of risk in researching the GEP&TEP coordination problem is crucial, as agents' investment decisions are heavily influenced by their perception of associated risks. However, few studies in the literature conduct a risk analysis in this context. Future research efforts should focus on assessing the impact of uncertainty caused by the lack of coordination on the stakeholders' investment decisions and the system's welfare. This requires using appropriate measures to represent the risks associated with the lack of GEP&TEP coordination, an aspect neglected in most works.

ii *Use of Regulatory Coordination Schemes*: Driving research on the use of regulatory coordination schemes is essential for addressing the lack of mutual commitment in the GEP&TEP coordination problem. This is necessary to provide strong incentives to stakeholders for undertaking planned generation and transmission expansion investments.

iii *Realistic Risk Representation in Proactive Planning Approach*: While the proactive planning approach is favoured in the literature, it is often considered risk-neutral, leading to its unrealistic representation within the context of the GEP&TEP coordination problem. Future research should address this gap by incorporating realistic risk considerations into the proactive planning approach.

iv *Interrelationship Between Critical Elements*: In future research, exploring the main interactions among the various elements affecting the coordination of generation and transmission investment decisions is crucial. Understanding how the choice of a planning framework influences the selection of complementary regulatory coordination instruments to implement, especially considering the impact of risks on agents' investment decisions, is essential. This exploration will provide valuable insights into how different elements interact and influence each other, ultimately contributing to more effective and efficient decision-making in the coordination of generation and transmission investments.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work, the authors used ChatGPT-3.5 in order to avoid grammatical errors and typos, improving readability and language. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

CRediT authorship contribution statement

Stefanía Gómez: Investigation, Conceptualization, Methodology, Formal analysis, Writing - Original Draft . **Luis Olmos:** Supervision, Conceptualization, Methodology, Formal analysis, Writing - Review & Editing, Validation.

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