# Analysis of the impact of FTRs on the Generation and Transmission expansion planning and its coordination

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# Abstract

After more than two decades of experience with the deregulated functioning of electricity markets, several challenges have emerged for the development of power systems, among others, the need to coordinate generation and transmission investment decisions, moreover considering the high penetration of renewable generation expected in the upcoming years, which creates an additional problem associated with the risks for investors in both activities. Therefore, this thesis analyses the impact of FTRs on the expansion of the system and their use as a potential tool to coordinate generation and transmission expansion planning in a liberalized electricity environment and to hedge the market price risk caused by network congestion faced by generation investors in remote areas.

This document includes a review and classification of the most relevant works in this field to identify a research gap in the analysis of the combined use of planning approaches and appropriate complementary regulatory coordination schemes, including their use to manage the most relevant risks that investors in both activities are subject to and the lack of implementation of risk modeling strategies to assess the effects of the risk aversion of stakeholders properly. Given the research objective defined, this thesis work focuses on assessing the impact on the efficiency of the system's expansion of the implementation of Long-Term Financial Transmission Rights as a tool to hedge the market price risk caused by network congestion faced by generation investors in remote areas. Together with this, the relevance of implementing FTRs as a coordination tool is assessed, assuming that generation investors in remote areas are strategic and risk-averse.

Based on the computed results, it is possible to conclude that the availability of FTRs to manage the price risk perceived by risk-averse generation companies in remote areas should trigger a relevant increase in the system's social welfare and could also lead to relevant changes in the generation and transmission socially optimal investment decisions, involving additional generation investments in remote areas, particularly in the North Sea within the European system. In addition, FTRs are shown to contribute to partially solving the coordination problem by providing significant welfare-enhancing coordination incentives to investors.

# Acknowledgements

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# Contents

# Notation

## Indexes

| | |
|---|---|
| $w$ | Scenarios $\in w$ |
| $\hat{w}$ | Worst case scenario |
| $wp$ | Scenarios when computing the perfectly coordinated system expansion, as if a central planner computed this $\in w$ |
| $wcp$ | Scenarios considered by generation companies $\in w$ |
| $p$ | Period (hours) |
| $nd$ | Node (bus) |
| $ni$ | Initial node $\in nd$ |
| $nf$ | Final node $\in nd$ |
| $c$ | Circuit |
| $(ni, nf, c)$ | Line (initial node, final node, circuit) |
| $g$ | Existing committed and candidate generation unit |
| $ge$ | Existing generation unit |
| $gc$ | Candidate generation unit |
| $la$ | Existing and candidate lines for circuit $c$ between nodes $ni$ and $nf$ |
| $lc$ | Candidate lines for circuit $c$ between nodes $ni$ and $nf$ |
| $le$ | Existing lines for circuit $c$ between nodes $ni$ and $nf$ |
| $ll$ | Existing and candidate lines with a loss factor |
| $cp$ | Company |
| $gcp$ | Existing and candidate generation unit $g$ of company $cp$ |
| $gccp$ | Candidate generation unit $gc$ of company $cp$ |
| $gcncp$ | Candidate generation unit $gc$ different from $gccp$ |
| $gnd$ | Connection node of a unit $g$ at a node $nd$ |
| $ftrnd$ | FTRs connection node of a candidate generation unit $gc$ |
| $grf$ | FTRs reference node of a candidate generation unit $gc$ |

## Parameters

| | |
|---|---|
| $PR^w$ | Probability of occurrence of each scenario w. $PR^w \in [0, 1]$ |
| $DU_p$ | Duration [h] |
| $MP_g$ | Maximum output of unit $g$ [GW] |
| $MinP_g$ | Minimum output of unit $g$ [GW] |
| $X_{(ni,nf,c)}$ | Line reactance [p.u.] |
| $L_{(ni,nf,c)}$ | Loss factor [p.u] |

| | |
|---|---|
| $TTC_{(ni,nf,c)}$ | Total transmission capacity of circuit $c$ between two nodes $ni$ and $nf$ [GW] |
| $D_{nd}$ | Hourly load by node $nd$ [GW] |
| $Sb$ | Base power [GW] |
| $FCT_{(ni,nf,c)}$ | Annualized Fixed investment cost of a transmission line [$M\$$] |
| $FCG_{gc}$ | Fixed investment generation cost [$M\$/MW$] |
| $VC_g$ | Variable cost [$M\$/GWh$] |
| $CENS$ | Energy non-served cost [$M\$/GWh$] |
| $CO_{2g}$ | Cost associated to $CO_2$ emissions [$\$/tCO_2$] |
| $MF_{(ni,nf,c)}$ | Maximum flow over a line used in the DC power flow constraint (Disjunctive formulation) |
| $vMF_{(ni,nf,c)}$ | Maximum flow over a line used in the DC power flow constraint for the virtual flows (Disjunctive formulation) |
| $\beta_{cp}$ | Trade off between the expected system cost and the risk by company $cp$ |
| $\alpha$ | Confidence level (CVaR) $\in [0,1]$ |

## Variables

### Binary

| | |
|---|---|
| $it_{(ni,nf,c)}$ | TEP installation binary decision for each circuit c between each two nodes, $ni$ and $nf$. $it_{(ni,nf,c)} \in 0-1$ |
| $ig_{gc}$ | GEP investment decision for candidate generators gc. $ig_g c \in 0-1$ |

### Positive

| | |
|---|---|
| $tf$ | Total system fixed cost [M$] |
| $tv$ | Total system variable cost [M$] |
| $te$ | Total system emission cost [M$] |
| $tr$ | Total system ENS cost [M$] |
| $gp^w_{(p,g)}$ | Production of the unit $g$ in the period $p$ [GW] |
| $e^w_{(p,nd)}$ | Energy non-served in node $nd$ in period $p$, scenario $w$ [GW] |
| $ftr_{(p,gc)}$ | Capacity of the FTRs contracted by generator $gc \in gccp$, in period $p$ [GW] |
| $\eta^w_{cp}$ | Auxiliary variable computed by deducting the profits of company $cp$ for scenario $w$ from the VaR. |
| $cftr_{gccp}$ | FTR cost associated with the generator $gc$ of company $cp$ |

### Free

| | |
|---|---|
| $tc$ | Total system cost [M$] |
| $f^w_{(ni,nf,c)}$ | Flow over circuit $c$ between nodes $ni$ and $nf$ in scenario $w$ [GW] |
| $\theta^w_{nd}$ | Voltage angle for node $nd$ in scenario $w$ [rad] |
| $vf^w_{(ni,nf,cc)}$ | Virtual flow over circuit $c$ between nodes $ni$ and $nf$ (FTR Max Power) in scenario $w$ [GW] |
| $l^w_{(p,ni,nf,c)}$ | Losses over circuit $c$ between nodes $ni$ and $nf$ in period $p$, for scenario $w$. |
| $v\theta^w_{nd}$ | Virtual voltage angle for node $nd$ (FTR Max Power) in scenario $w$ [rad] |

| | |
|---|---|
| $\lambda^{w}_{(p,nd)}$ | Dual variable of the constraint: Balance between generation and demand. |
| $\phi_{cp}$ | Auxiliary variable that computes the VaR |
| $cvar_{cp}$ | Conditional Value at Risk of company $cp$ [M$] |
| $gpr^{w}_{cp}$ | Generation profit for company $cp$ in scenario $w$ [M$] |
| $gbf^{w}_{cp}$ | Generation operation benefits for company $cp$ in scenario $w$ [M$] |
| $gpr_{cp}$ | Total generation profits for company $cp$ [M$]. |

# Chapter 1

# Introduction and Motivation

After the deregulation of the electricity industry, the generation and transmission activities have been unbundled, leading to the inability to jointly optimize investments of both types, which was possible within vertically integrated structures [1]. This deregulation process has impacted significant regions of Europe and America, resulting in new challenges for achieving a satisfactory development of the power system, especially regarding the coordination of Transmission Expansion Planning (TEP) decisions and Generation Expansion Planning (GEP) [2], and the management of the risk associated with the uncertainty of the revenues from the market of generation investments, which results in uncertain profitability for these investments. In a liberalized electricity market context, the revenues of generation plants depend on the market conditions that influence the marginal price behavior. This leads to relevant uncertainty regarding the profits of generation investors. Besides, a lack of coordination among utilities and the central planner may negatively affect the revenues of new generation assets, or the increase in the social benefit produced by new transmission ones, thus discouraging the generation investors and the network planner from undertaking some socially efficient investments [3]. Generation is owned by private companies known as GENCOS, which make operational and investment decisions with the aim to maximize their profits [4]. The expansion of the transmission system and the system operation are often planned by independent entities, the System Operators and Market Operators, though, sometimes, both functions are carried out by the same entity, referred to as the SO. SOs are heavily regulated entities that typically aim to maximize the system welfare. The lack of certainty by GENCOS and the SO regarding their intention to undertake mutually beneficial investments may prevent their realization, along with other socially efficient investments, impacting the efficiency of the system development; therefore, the coordination of the investments by the stakeholders (GENCOS and SO) is a major requisite for ensuring the long-term efficiency in the development of liberalised power systems [5].

The necessity to increase the share of renewable generation is causing a significant fraction of new generation deployment to be affected by these problems. A notable portion of the most promising renewable generation to be installed is located in remote areas weakly connected to the main power grid. Then, their power output must traverse lengthy distances through transmission corridors, which, if not reinforced, may become heavily congested [4]. As a result, this generation faces large market risk that it cannot properly manage without suitable hedging instruments. Not giving them the option to use these instruments may probably decrease the level of efficiency of the system development [6]. Achieving the coordination of the investments by the stakeholders and providing them with tools to manage their (market) risks regarding these investments, possibly associated with the occurrence of network congestion, are major requisites for ensuring long-term efficiency in the development of liberalized power systems [5]. First, the uncertainty about the profitability of investments faced by generation companies associated with the long-term uncertainty on their revenues from the sale of electricity can prevent them from carrying out relevant projects. The long-term revenue uncertainty of generation investments is caused by the large variability of the average price earned by these across the scenarios that can unfold in the future, which is partly due to the congestion that may occur in the network. Second, realizing new generation capacity investments requires promoters to have certainty about the availability of the transmission capacity needed and the conditions (price) of access to this capacity. Simultaneously, the system planner requires evidence of the future installation of new generation to develop the transmission capacity to integrate it into the grid; this is known in the literature as the “chicken and egg” problem. Therefore, it is necessary to achieve some coordination of expansion planning decisions to encourage investments on both sides at the right time and in the appropriate amounts. Considering the implementation of mechanisms that drive the coordinated system development while allowing GENCOs to manage the price risk associated with network congestion is highly advisable. Both problems to be addressed are more prominent for renewable generation. Typically, conventional generation is installed in areas that are strongly connected to the rest of the system. This does not occur for large renewable generation developments, since primary renewable generation resources are typically concentrated in remote areas with highly volatile prices whose connection to the rest of the system needs to be reinforced [7].

The development of relevant network congestion associated with the installation of new generation in specific areas emphasizes the necessity of implementing signals that coordinate investment decisions by the corresponding investors and the network planner. Moreover, precisely predicting the pattern of congestion long before the system’s operation, at the time when there is the need to decide the investments to undertake and ensure effective grid access for them, can be difficult for the system stakeholders, including generation developers and the grid planner. This is because the pattern of network congestion depends on several factors, like the investment decisions made by the rest of system stakeholders, that are out of the control of both each generation investor and the network planner.

The uncertainty about the pattern of congestion makes the benefits produced by generation investments, as well as the social benefits produced by transmission investments, highly uncertain; this substantially decreases the attractiveness of these generation investments, possibly preventing promoters from undertaking investments that are beneficial for the system. Thus, there is a need for instruments that coordinate the generation investment decisions with those of the network planner and allow the stakeholders to effectively manage the risk associated with the volatility across scenarios of their market revenues and the uncertainty about them.

This thesis project investigates two main issues:

- The use of Long-Term Financial Transmission Rights (LT FTRs) by GENCOs and the transmission planner to manage the risk associated with the long-term uncertainty about the electricity price differences between the areas where new generation is to be installed and those areas where main load centers are located, and
- The capacity of FTRs to drive the coordination of the generation and transmission investment decisions in a deregulated context.

This document has been structured so that it, first, includes a review and classification of the most relevant works focusing on the coordination of the generation and the transmission expansion planning, as well as those works focused on the management of the risks faced by the stakeholders in the GEP-TEP coordination problem. This is provided in chapter 2. The interactions existing between both problems are considered here. This aims to contribute, in a structured way, to the discussion of the different types of planning approaches and existing complementary regulatory coordination schemes that can be implemented to increase the efficiency of the development of the system. Within this, the properties of the existing regulatory mechanisms to hedge different types of risks present in the GEP-TEP problem are discussed. In addition, an analysis of the relationship existing between the aforementioned schemes and how they have been modelled is also carried out within the literature review section. Based on the review of previous works, within chapter 2 some relevant research gaps are identified in the analysis of the combined use of planning approaches and appropriate complementary regulatory coordination schemes able to manage relevant risks faced by the stakeholders in order to achieve two main goals: 1) an effective and efficient coordination of the investments in generation and transmission projects; and 2) the efficient management by the investors in both activities of the most relevant risks that they are subject to. As argued in the review, this requires using appropriate risk modelling strategies to represent the risk aversion profile of the stakeholders.

Subsequently, chapter 3 provides an analysis of the use of Long-Term Financial Transmission Rights (LT FTRs) by GENCOs and the transmission planner to manage the risk associated with the long-term uncertainty existing about the electricity price differences between the areas where new generation is to be installed and those areas where main load centers are located. This chapter analyses the impact of the use of LT FTRs on the socially optimal, fully coordinated, expansion of the system and its social welfare. In other words, this analysis is carried out in a context where the coordination of generation and transmission decisions is assumed to be socially optimal.

Afterwards, chapter 4 provides an analysis of the ability of LT FTRs, used by GENCOS and the transmission planner, to drive the coordination of the generation and transmission investment decisions in a deregulated context, as well as the ability of these rights to allow GENCOs to manage the network-related market (price) risk they face associated with price volatility caused by network congestion.

Finally, in chapter 5 provides conclusions and future research insights.

## List of publications

In this section different publications associated with this thesis are listed. The first publication comprises the developments associated with chapter 2, and the second one with those in chapter 3.

1. Gómez, S., Olmos, L., Coordination of generation and transmission expansion planning in a liberalized electricity context — coordination schemes, risk management, and modelling strategies: a review. Sustainable Energy Technologies and Assessments. Vol. 64, pp. 103731-1 - 103731-16, Abril 2024.

2. Gómez, S., Olmos, L., Ramos, A., Rivier, M., A bi-level framework to analyse the alternative use of FTRs as a long-term risk hedging instrument. Application to a European case study. Applied Energy.

# Chapter 2

# Literature Review, Research Questions and Contributions

## 2.1 Definition of the scope of the research field to explore

Due to the traditional fully regulated, centralized, structure of electricity systems, both generation and transmission expansion decisions had traditionally been left in the hands of vertically integrated utilities optimizing together investments of both types [8]. However, with the deregulation of the industry, generation and transmission have become unbundled, and the joint optimization of their expansion is no longer possible [1], since a common expansion plan that includes expansion decisions of both types is no longer determined [2]. After more than two decades since deregulation took place, relevant aspects of the efficiency of Transmission Expansion Planning (TEP) and Generation Expansion Planning (GEP) and their level of coordination are still to be assessed.

Generation and transmission are planned and operated by different entities, which can create disincentives to install new generation capacity or new transmission infrastructure [3].

In those systems where the electricity sector has gone through a liberalization process (most in the developed world), generation is controlled by private generation companies known as GENCOS, whose operation and investment decisions are driven by their aim to maximize their profits [4]. 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 between the interests of entities of both types, and a lack of coordination of the decisions they make, may result in losses in the efficiency of the development of the system, creating additional regulatory challenges.

In addition, today's need to increase the amount of RES-based generation integrated into the system further complicates these investment decisions because a significant portion of this 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 [4]; in addition, the lead time for transmission investments in this context is longer than that for investments in most of the RES-based generators [9].

The interdependency between generation and transmission expansion and the uncertainty on the conditions affecting the operation of these assets increases the relevance of the risks faced by generation developers and reduces the efficiency of the system development [6]. 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 requires some 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 [10], [11], [12], [13].

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 by the regulation. GENCOs' revenues are directly impacted by market conditions, which influence the level of electricity prices. These uncertainties give rise to two main risks: counterparty risk associated with the lack of commitment by the network 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 the volatility of the market price, which, in the case of remote areas where large amounts of RES-based generation is to be installed, is largely due to the severe network congestion that the lack of coordination of generation and transmission investments can lead to. 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 the various risks associated with this coordination problem may have on the system's development.

Achieving the coordination of investments at stakeholder level is essential to ensure the long-term efficiency in the development of liberalized power systems [5]. It is, therefore, necessary to coordinate the expansion planning decisions made by GENCOs and system planners by encouraging them to undertake efficient investments that are interdependent at the right time and in the right amounts, considering the stakeholders' risk perception.

Understanding the GEP&TEP problem and its coordination is of paramount importance. However, there is a lack of a comprehensive review of previous works focusing on: i) the management of those risks involved in the GEP&TEP problem and its coordination; ii) the approaches developed to drive this coordination, including both the planning approaches and regulatory coordination schemes that can be put in place with this aim; and iii) modelling the implementation of these approaches and their interaction.

The primary motivation of the review work discussed in this chapter is to provide the research community, industry stakeholders, regulators, and other interested parties in this field with relevant insights into the previous works on the implementation of specific critical instruments and planning solutions that could, potentially, facilitate the understanding of the GEP&TEP problem and its coordination in order to drive the latter in the right direction considering the existence of the risks perceived by different actors. From a theoretical perspective, the purpose of the review here is to identify the different possible options to increase the level risk hedging available to the stakeholders and, accordingly, the level of coordination of GEP and TEP (including the role of FTRs in doing so), while achieving a detailed understanding of the works carried out in the literature in this area. Additionally, our aim is to identify relevant gaps and research questions that entities active in this research field could focus on.

In the remaining sections of this chapter, we provide a structured discussion focusing on the

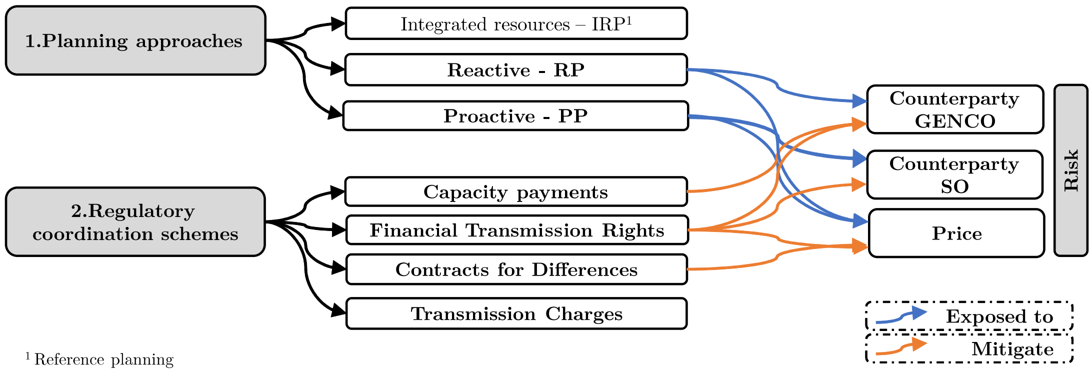


Figure 2.1: Key elements affecting GEP&TEP problem and its Coordination

key elements that impact the expansion of generation and transmission expansion planning and its coordination in a liberalized electricity market context. We delve into the interplay among these relevant elements from a theoretical perspective, considering different planning approaches, existing complementary regulatory coordination schemes aimed at fostering the system efficiency, including the use of FTRs as a coordination scheme, and risk management strategies considered within the GEP-TEP problem and its coordination, see Figure 2.1. In addition, this chapter analyses the relationship between the features of the aforementioned schemes and how they have been modelled and assessed in the literature. These interconnected aspects have not been previously analysed comprehensively altogether, considering their mutual interactions.

## 2.2 Planning approaches in the GEP-TEP problem

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 that could act as primary coordination schemes 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 planner is aware of the definite investments to be undertaken by GENCOs in the next regulatory period, this approach is the most common considered in real-life power systems.

- ***Proactive planning***: This concept was proposed in [14]. In this approach, the transmission planner anticipates the investments by GENCOs, and the impact on them of the transmission

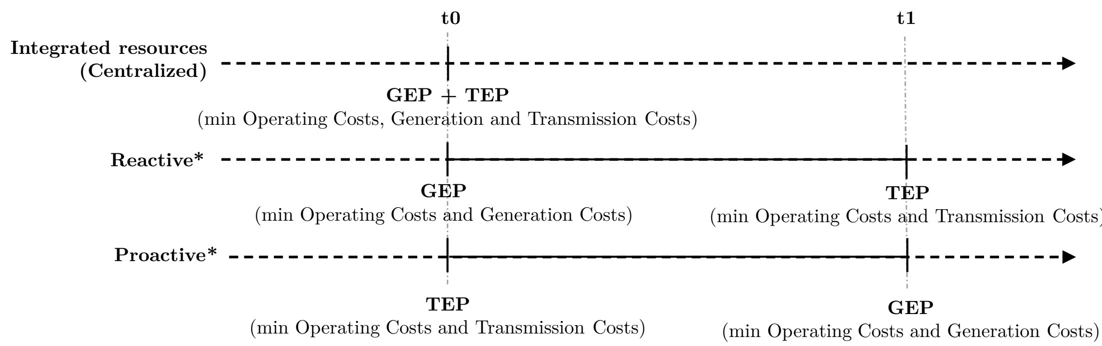


Figure 2.2: Decision planning approaches - Network planner's point of view

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 [6].

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 [15]. 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 2.2.

Previous studies agree to conclude that the reactive planning approach has been widely implemented and is a more realistic planning approach, while the proactive planning approach is mainly studied in the academic literature. 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 [16]. This is a gap to be addressed by future research.

## GEP-TEP models according to the planning approach

Apart from the relevant aspects to be considered in the GEP&TEP problem and its coordination, 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 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, they 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 [16].

This section describes, in detail, how the several types of planning approaches previously analysed, and identified as possible 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 [3], 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 [17], 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 [14], 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.

The authors in [18] 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. Unlike other proposals, in that one, instead of considering the DC power flow representation, the authors extend GDB in an AC power flow representation.

In [19], 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 [20] 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 [21] 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 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 [22], 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 [23] 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 [24] 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 [25], 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 waits for generation investment decisions to be made so that, when planning the expansion of the grid, it already knows which generation power plants are going to be built, when, and where. Even though it is the most widely implemented planning approach in real systems, there are few studies in the literature in which reactive planning is applied.

In [14], 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 [26], 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 [27], the authors propose separate mathematical models for proactive and reactive planning. In the reactive approach, the Generation companies are the leaders and the 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 find that in the case of Proactive planning, GENCOs are prevented from earning higher profits than those they earn under a reactive planning approach, even when the proactive solution is more cost-efficient for the system.

In [28], 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 [29], the authors introduce 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 [30] 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.

The reactive planning approach alone cannot effectively coordinate transmission and generation expansion planning. It is necessary to consider the risk aversion of stakeholders, which advises introducing risk hedging instruments from both sides (GET and TEP) in order to protect them against different risks that can prevent them from carrying out potentially beneficial investments. Therefore, implementing reactive planning in combination with a proper regulatory incentive or coordination scheme could facilitate this coordination. However, this has not been studied yet in the literature and is, therefore, considered a research gap to be filled in.

#### Proactive planning

This concept is first proposed in [14], 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.

This approach is extended in [26], considering different assumptions, concerning the spot market operation, among others. The authors assume in this work that the generators cannot purchase transmission rights. In [31], the authors formulate a three-level model inspired in [26]. 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 [32], the same authors modify the model proposed in [31] 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 [33], the same authors propose an extension of the models in [31] and [32] 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 [32], Jin and Ryan propose a three-level model in [34] and provide numerical results in [35]. 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 [21], 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 [36] 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 [27], 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 [20], 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 maximise the social welfare in the case of a regulator vs. the incentive for the TSO to maximise its own profit) have a major impact on the expansion results.

Similarly to the previous approach, in [37], 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 [38], 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 [39], proposing a numerical solution technique and applying the proposal to a 14-bus case example.

In [40], 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 [40], in [41], 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 [42], 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.

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.

The next section discusses the main complementary regulatory coordination schemes that have been proposed so far.

## 2.3 Existing 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.

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 [20]. 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 [7], 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 [44] 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 [44] 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 locally. 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 [41], 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 has just been argued, are also incomplete [45]. 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 [44], 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"[1]. 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 [19], 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 counterparty 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.

[1] In competitive electricity markets, prices for energy may not reflect the value of investment in customers' perception of the electric service [46]

### GEP-TEP 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 optimisation model which coordinates investment decisions in the monopolistic transmission and the decentralised 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 minimisation 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 [19], the authors propose an iterative algorithm for the computation of the system expansion based on a Reactive planning approach. They develop and propose a model that 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 centralised transmission expansion planning separately, computing the former as being 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 has considered 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 reactive or proactive planning approach. In order to facilitate the undertaking of socially beneficial 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.

## 2.4 Risks in the GEP-TEP 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 [3].

Generation is owned by private companies known as GENCOS, whose operational and investment decisions are driven by the objective of maximising their profits [4]. 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 (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 price risk, caused by the market price volatility and the effect of this on GENCO's market profits.

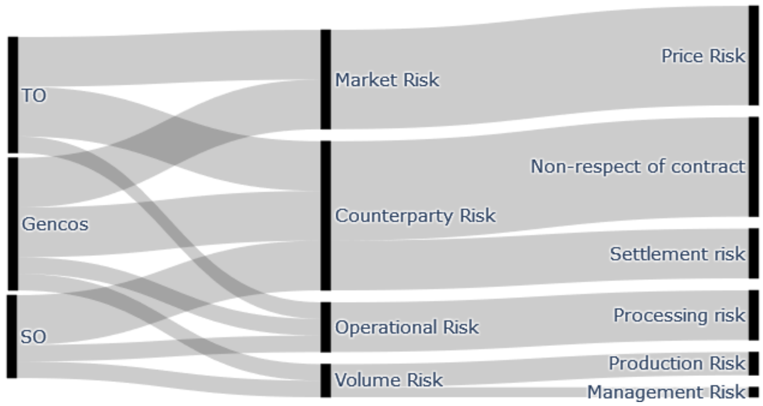


Figure 2.3: Stakeholders risks - Generation and Transmission Expansion Planning

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 [44] 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].

Apart from the main risks in this problem mentioned above, there are additional relevant risks such as volume risk, which is associated with uncertainty regarding the amount of energy involved. For generation, this risk relates to the uncertainty in the energy demanded, or the ability to produce or deliver energy. For transmission owners, volume risk is linked to uncertainty in the energy flows or the available transmission capacity. Another relevant type of risk is operational risk, which arises from potential failures in the operation of assets, caused by human errors, maintenance issues, technical malfunctions, or other unforeseen events.

The different types of risks that may exist can be summarized in Figure 2.3. 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 previously discussed, 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.

Both in the context of the application of proactive planning and reactive planning, complementary regulatory coordination schemes can play a relevant role in managing the resulting risks associated with a lack of coordination of investments.

## 2.5 Risk management in the GEP-TEP problem

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 (CP)**, or more generally named Capacity Remuneration Mechanism (CRM). 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 [44], the authors show that capacity markets coordinated with network investments can prevent under-investments in generation capacity by 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

Table 2.1: Characteristics of mechanisms to manage risks in GEP&TEP coordination problem

| **Mechanism** | **Potential risk to mitigate** | **Characteristics** |
|---|---|---|
| CRM (CP) | Counterparty (partially) | • Provide economic incentives for generation investors<br>• Do not provide incentives for the transmission planner. |
| FTRs | Market (Price) - Counterparty | • Able to manage price risk caused by network congestion.<br>• Could manage counterparty risk.<br>• 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.<br>• Mitigate exposure to spot prices.<br>• Not suitable for managing price risk caused by network congestion. |

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, but, instead, only to limit these for generation investments. Exists other mechanisms, that are not analysed here in detail since are less general such as coalitions of generators and merchant network owner, that involve the generator building the necessary transmission infrastructure to access a stable-price as a result of this coalition, however this is mainly implemented when the network owner is merchant, as mentioned, however, in most of the systems, network investments are regulated, therefore the implementation of this kind of mechanisms could be limited.

**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 for the purchase of energy are larger than those received by generators for the sale of it.

In order to explain this better, consider the 2-node case shown in Figure 2.4, where $P_g$ correspond to power generation and $P_d$ correspond to power demand, and $\overline{\phi_l}$ represents the maximum flow of the NG-ND line. The prices shown in the figure correspond to the average case where G1 produces 50 units of energy. Now, consider that generator G* is risk averse. Taking into account that it is

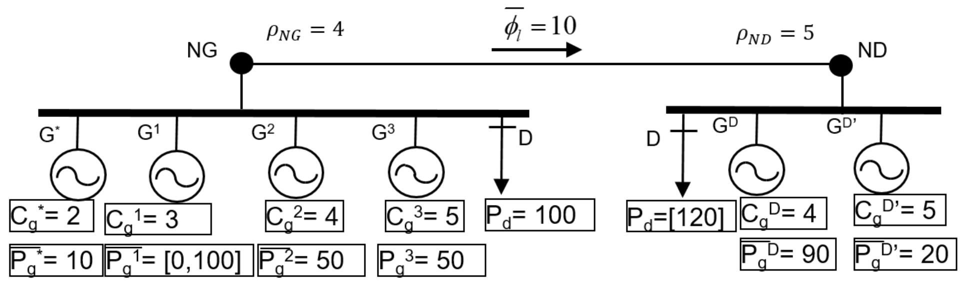


Figure 2.4: -node numerical example FTRs

subject to price risk associated with the uncertain level of electricity production by G1, it decides to follow the strategy outlined next: G* signs an FTR contract with the Network owner (N) for a Quantity: Q=10; Price: 1; Injection and withdrawal nodes: NG and ND, respectively.

Considering this strategy from G*, in an unfavourable scenario where G1 output is 100, then $\rho_{ND} = 5$ and $\rho_{NG} = 3$, the corresponding transfers of funds in the cases with and without FTRs for the amount of energy negotiated under the FTR contract are provided in Table 2.2

Table 2.2: funds considering a FTRs contract for the FTRs 2 node example.

| **Energy Market** | **FTRs contrat** | **Outcome with FTRs** | **Outcome without FTRs** |
|---|---|---|---|
| G* earns 3Q=30 | G* pays Q=10 to N | G* earns 3Q+2Q-Q=4Q=40 | G* earns 3Q=30 |
| N earns (5-3)Q=20 | N pays (5-3)Q=20 | G*'s profits = 4Q-2Q=20 | G*'s profits = 3Q-2Q=10 |
| | | N earns Q=10 | N earns 2Q=20 |

Please note that FTRs contract protect G* from low prices at his node, and set his profits to the expected ones, also note that in this particular case (unfavourable conditions for G*) signing an FTRs contract results in lower revenues for N. However, if $\rho_{NG} = \rho_{ND} = 5$ revenues for N would be higher in the case with FTRs than in the case without FTRs. In General FTR contracts stabilize G* ad N revenues.

Up till now, FTRs 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]. However, 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 [58], 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 (merchant) 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.

Therefore, in generation and transmission expansion planning, considering regulated network investments, LT FTRs can be potentially used to manage two types of risk:

- **Price risk due to network congestion**: GENCOs that purchase LT FTRs for their plant outputs can sell energy at the price of a reference node, typically a major load centre with more stable prices than those at the nodes where their assets are located. LT FTRs help manage the uncertainty of prices at a specific node caused by congestion. However, FTRs do not hedge against the price uncertainty at the reference node itself. Thus, this reference node should have stable prices, or alternatively, LT FTRs should be combined with other instruments (e.g., CfDs) to manage price risk at the reference node [59].
- **Counterparty risk for generation investors and the system operator (SO)**: When stakeholders contract LT FTRs, these create a financial incentive to undertake generation and transmission investments. LT FTRs mitigate the price risk for generation investors by stabilizing the revenues of the generation assets covered by them, while, for regulated network investments, these rights serve as a financing tool and, in the case of merchant investments, also stabilize their market revenues. However, once LT FTRs are contracted, if the new generation and transmission assets covered by these LT FTRs are not built, the corresponding generation investors will perceive the congestion rents produced by these rights as an uncertain net revenue stream, while the network owner will be subject to an additional risk associated with the possibility of the congestion produced by the existing network not being sufficient to cover the payments owed to FTR holders. Thus, once LT FTRs are contracted, network planners can be confident that generation investors are motivated to complete the envisaged new generation projects, which justify the associated planned network expansions. Similarly, GENCOs are aware that the network owner is incentivized to carry out the necessary network expansions to accommodate the new generation capacity they plan to build.

Here, it is important to consider that the price risk due to the network congestion cannot be mitigated by generators except through long-term FTRs. Furthermore, in the case of generation located in remote areas, the negotiation of power purchase agreements or other types of contracts referred to their area or connection node would probably be subject to conditions of low liquidity and, therefore, to a price that is likely not to be representative of the expected value of that energy. Therefore it is relevant to be focus in the analysis of FTRs in the GEP&TEP problem and its coordination.

However, the impact of the implementation of FTRs as a long-term financial mechanism for coordinating generation and transmission expansion planning in a liberalized electricity market environment, and its ability to allow the different stakeholders to manage the risks they are subject to in this context and in particular those risks that are difficult to manage properly in any other way, have not been analysed yet, therefore, it is important to analyse this instrument in this context.

### 2.5.1 Risk Measurements & Modelling strategies

Uncertainty implies the existence of risks, and the risk profile of a decision-maker depends on its own perspective [60]. Risks can be measured and modelled in different ways according to the literature [61]-[52]; here, a summary of the most representative risk measurements and modelling strategies that exist is given, and a discussion on their use in the problem of coordinating the generation and transmission expansion is provided. 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 2.5.

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 [21] do the authors consider the implementation of CVaR, see Table 2.3.

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 [21].

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 [29]-[30] 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.

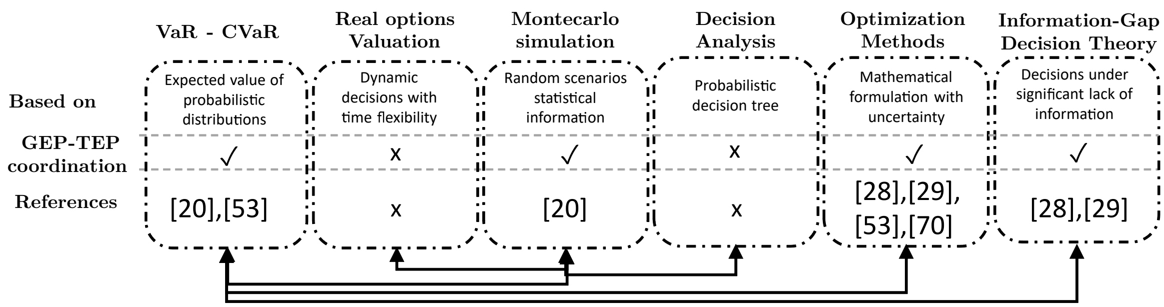


Figure 2.5: Risk modelling strategies - Interactions. Arrows at the bottom connect boxes for techniques that have been implemented together.

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 [29]-[30] implement information gap decision theory IGDT to make robust decisions in the presence of uncertainties [72].

### GEP-TEP models considering Risk Measurements and modelling strategies

Risk modelling strategies have been applied in many areas. However, few of these works address the modelling of the GEP-TEP coordination problem; few models include those types of analysis. Authors in [29]-[30] 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 [21] 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 [25], 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, 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 2.3. Moreover, no previous work has explored the consideration of these measurements in order to assess the implementation of regulatory coordination schemes. Therefore, this is a gap to be filled in by research.

## 2.6 FTRs in the GEP-TEP problem

As mentioned previously in section 2.5, FTRs have been considered as an efficient tool to hedge the risk of market agents related to the price of accessing the transmission capacity in the short term.

Some previous works have focused on exploring the use of FTRs to drive the expansion of the system. Thus, the authors in [75] analyse, from a theoretical point of view, the importance and necessity of introducing long-term financial transmission contracts for new generation facilities in the US markets since, without this instrument, cost recovery in the long term for these facilities may not be guaranteed. In [76], the authors analyse the impact of implementing LT FTRs on transmission investments. They model Hogan's proposal for the allocation of FTRs as a bi-level problem, concluding that the simultaneous feasibility of these rights can be guaranteed before and after expansion. Authors in [77] assess the impact of the implementation of FTRs on the transmission expansion, providing network users with perfect congestion hedges for long-term transactions that are feasible under the simultaneous feasibility test. They develop a system dynamic model for this, concluding that implementing FTRs in combination with transmission expansion investments is perfectly feasible.

The authors in [75] identify and discuss potential barriers to implementing LT FTRs successfully. These include i) the uncertainty existing about the ability of the planner to implement the planned upgrades and decommissioning of facilities in the transmission network; ii) the unpredictability of congestion prices, limiting the ability of generation and transmission owners to agree on a price for these FTRs; iii) the creditworthiness of market participants; and iv) the limits to the capacity of FTRs to effectively hedge the price risk that the stakeholders are subject to. As explained theoretically in [75], the first three barriers are intrinsic to the LMP markets, while the fourth can be addressed by providing additional instruments like CfDs that, when combined with FTRs, provide a complete hedge against the price risk.

FTRs have been successfully implemented in different power markets such as New York, PJM and New England, among others [78]. In Europe, even when LMPs (Locational Marginal Prices) have not been implemented, a set of bidding, or price, zones have been defined. The electricity price of these zones in the Day-Ahead market may differ from one another, reflecting congestion existing in the grid. FTRs are used in Europe to allow network users to protect themselves from the risk associated with the volatility of the price differences existing among countries/areas [79], i.e. the price to be paid by these network users to access the transmission grid when trading their energy in other price (bidding) zones than that where they are located.

In addition, organisations such as ACER (Agency for the Cooperation of Energy Regulators) and CEER (Council of European Energy Regulators) have discussed the potential use of Long-Term Financial Transmission Rights (LT FTRs) as a tool to enhance the efficiency of the European electricity market and to provide market participants with better risk management capabilities, see [80].

Also, the discussion associated with moving the European Market to Nodal Pricing is still open. According to the literature, several studies have analysed this possibility and have even recommended the implementation of nodal prices in Europe [81], [82], [83]; therefore, the analysis of mechanisms that could also work in that framework is even more relevant.

To the best of current knowledge and considering the capabilities of LT-FTRs as a risk heading instrument, as mentioned in section 2.5, no previous work has explored the impact on the system expansion, concerning both generation and transmission investments, of the use of FTRs as a long-term risk hedging instrument (LT-FTRs) and therefore its potential as a coordination instrument, allowing the generation investors to effectively manage the risk they face associated with the uncertainty in the price the generation they plan to build will have to pay to access the grid. By allowing generation investors to effectively and efficiently manage this risk, LT-FTRs can be expected to achieve an increase in the system welfare.

The use of FTRs should, then, lead to a more efficient system expansion, coupling the construction of baseload plants and the associated transmission investments, while providing some certainty to stakeholders about achieving revenue adequacy. Therefore, the pertinence of implementing FTRs as a coordination tool is a topic that is considered a gap in the literature.

### 2.6.1 Types of FTRs, Revenue Adequacy and Allocation Rules

Different types of FTRs are discussed in the literature, as explained in [84]; the most common, basic format of FTRs considered is that of point-to-point financial transmission rights, where FTRs provide the 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. In contrast with physical transmission rights, which is a mechanism that provides the owner with the right or obligation to physically use the transmission capacity between points of injection and withdrawal defined, and that can affect the dispatch of the system, this financial mechanism (FTRs) does not affect the dispatch of the system.

In the case of point-to-point obligations, the main purpose of FTRs is to provide a perfect hedge against variable transmission costs faced by these rights owners, since, whatever the sign of the price difference between the withdrawal and injection nodes in the right, the corresponding payment must be made. This renders a payment obligation under the FTRs that complements the local price applied on the right holder as a result of the spot market, provided this stakeholder is physically producing or consuming an amount of energy corresponding to the amount of FTRs contracted, to result in a net price applied on this stakeholder that matches the price resulting from the market on the other end node considered in the FTRs it has acquired. By contrast, in the case of a point-to-point option, carrying out the payment corresponding to the price difference between the two end nodes defined in the right is not required.

Another FTR type is the flowgate financial transmission rights which is a contract that entails the right holder to earn the shadow price of the associated network constraint in the actual dispatch for a quantity of the product being constrained equal to the amount of FTRs contracted. The FTRs of this type can also be defined as obligations or options, since the shadow price of the associated constraint, for the direction of the energy flow defined in the contract, can also be positive or negative.

More recently, the authors in [85] introduce a new type (format) of FTRs that is suited for renewable generation in particular, and is named generalized FTRs (G-FTRs). These rights comprise Cap or Floor contracts combined to build a portfolio that provides a perfect hedge for a generator or load with a fixed supply or demand curve.

The size and sign of the payments resulting from the FTRs depend on the clearing of the spot market but, provided the total amount of transmission capacity that the rights traded refer to do not exceed that existing in the grid, these rights are revenue adequate by definition, which involves that the System Operator is able to fulfill the payment obligations resulting from all the rights issued making use of the congestion rents produced by the grid in the market. The revenue adequacy condition just stated applies to, either the net amount of transmission capacity that all the rights together refer to, or to the total amount of capacity corresponding to those rights that refer to a flow of energy in each direction, depending on whether the rights are defined as obligations or options, respectively. Typically, the revenue adequacy of the FTRs issued is ensured through the simultaneous feasibility test [86]. However, even if revenue adequacy does not hold strictly speaking, the deficits of congestion rents produced in certain periods could be transferred to others to ensure the ability of the system to fulfill the corresponding payment obligations.

FTRs of different types can be allocated through different mechanisms and sets of rules; the most common and transparent of them are auctions, a bid-based mechanism where participants submit bids for FTRs with a quantity-price format that are considered together in the auction process, a centralised one, to determine and implement the FTRs allocation that maximises the social welfare.

Despite the different formats previously exposed in literature, none of them have been analysed in the context of the GEP-TEP problem and its coordination. Therefore, the assessment of at least the basic format of FTRs and their allocation in this context remains a gap in the literature.

## 2.7 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 [87]. 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 2.3 and leads to a more robust planning [88].

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 [89]. 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) [90]. *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 [91].

## 2.8 Classification of GEP-TEP coordination modelling works

In this section, the most relevant expansion planning studies are classified according to the planning approaches as primary coordination schemes, the complementary regulatory coordination schemes, and the risk measures considered in them, see Table 2.3. 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 [87], [92], [16], [93].

Table 2.3: 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) |
| [21] | 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) |
| [25] | 2023 | IRP | no | yes (WD) | yes (system failures) | SL-MS(2) | Iterative procedure | Central European power system | TNR(DC) |
| [3] | 2008 | IRP | no | no | no | SL | Benders decomposition | 4-bus system - Turkish power system | TNR(DC) |
| [17] | 2014 | IRP | no | no | yes (economic, policy) | SL | Deterministic, heuristics | 240-bus | TNR(DC) |
| [22] | 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) |
| [18] | 2015 | IRP | no | no | no | SL-MS(2) | Iterative algorithm using GBD | 6-bus Garver test case, IEEE 30-bus system | TNR(AC) |
| [19] | 2017 | IRP | no | no | no | SL | MILP solved with CPLEX | IEEE-RTS96 | TNR(DC),DE |
| [23] | 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) |
| [29]-[30] | 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) |
| [19] | 2017 | RP | yes (TC) | no | no | SL | Iterative algorithm | IEEE-RTS96 | TNR(DC),DE |
| [28] | 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 |
| [27] | 2017 | RP | no | no | yes (Wind) | ML(2) | Moore-Bard algorithm | The Modified IEEE-RTS96 The Modified IEEE 118-bus Test System | TNR(GF) |
| [26] | 2007 | RP | no | no | yes (Network topology, market operation) | ML | sequential quadratic programming algorithm | 32-bus representation Chilean case | TNR(DC),DE,MP |

**Continuation of Table 2.3**

| Ref | PY | **PA** | **CRCS** | **RM** | Uncertainty | LS-SS | Solution Technique | Case Study | Other Aspects |
|---|---|---|---|---|---|---|---|---|---|
| [14] | 2006 | PP | no | no | yes (network, demand, generation) | ML(3) | sequential quadratic programming algorithm | 30-bus/3-zone | TNR(DC),DE,MP |
| [26] | 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 |
| [38] | 2011 | PP | no | no | no | ML(2) | MILP solved with CPLEX | 3-node example | TNR(DC),MP |
| [39] | 2011 | PP | no | no | no | ML(2) | Algorithm including meta-heuristic(IPGA) | modified IEEE 14-Bus example | TNR(DC),MP |
| [31] | 2012 | PP | no | no | no | ML(3) | MIP solved with CPLEX | 3-node example and a 4-node example | TNR(DC),MP |
| [40] | 2013 | PP | no | no | no | ML(2) | MILP and MIQPs solved with Gurobi | Three node network example | TNR(DC),MP |
| [20] | 2013 | PP | no | no | no | ML(2) | MILP and MINLP solved with CPLEX | three node network and 21 nodes network | TNR(DC),DE |
| [32] | 2013 | PP | no | no | yes (Demand and, wind and hydropower) | ML(3) | MILP solved with CPLEX | Main Chilean power network | TNR(DC),MP |
| [34] | 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 |
| [37] | 2014 | PP | no | no | no | ML(2) | Progressive penalization algorithm based on (k-th best algorithms) | 6-bus Garver test case | TNR(DC) |
| [33] | 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 |
| [36] | 2017 | PP | no | no | no | ML(3) | MILP solved with commercial solvers | Modified IEEE 14-Bus test system | TNR(DC),DE |
| [27] | 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) |
| [41] | 2019 | PP | no | no | no | ML(2) | MILP solved with GUROBI | 4-bus system example | TNR(DC),DE,MP |
| [42] | 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

## 2.9 Discussion

Generation and Transmission expansion planning and their coordination is a problem of high interest for the academic community and has been modelled in different works, see Table 2.3. 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 chapter provides a review of 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 are classified in this chapter considering the planning approach; in particular, under a proactive planning approach, as explained in section 2.2, the transmission planner anticipates the investments by GENCOs based on some preliminary information obtained about their behavior. However, this preliminary information, most times, concerns just the expected behaviour of the GENCOs, estimated according to historical data or assumptions made regarding the new generation 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 it cannot condition, or drive, these decisions by having determined and implemented in advance the development of the network occurring in the corresponding period. Typically, the works based on reactive planning reviewed do not consider the use of regulatory coordination schemes able to manage the counterparty risk that investments by GENCOs are subject to; some works have analysed the use of capacity payments or transmission charges under this approach, though not the use of other regulatory schemes addressing additional relevant types of market and other risks, and few of them have included the consideration of risk measurement tools. see Table 2.3

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.

Thus, in general, few previous works have explored the implementation of regulatory coordination schemes and risk measurement tools when considering and modelling the GEP and TEP problem; and non of these works have considered the use of regulatory coordination schemes that provide hedging against the counterparty risk and the market price risk resulting from the uncertainty existing about the cost of accessing the grid capacity. Thus, none of these works have measured the impact on the efficiency of the system development and operation of appropriately managing these risks through regulatory coordination schemes such as LT-FTRs. 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 broad planning approaches discussed.

There is a preference, within academia and the industry, to make use of bi-level problems to represent the coordination of generation and transmission 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 minimizing total costs, are most commonly used to represent integrated planning approaches, typically considering a MILP formulation, which is easy to solve making use of commercial solvers.

Challenges in this field include modelling the planning problem considering the management of relevant risks, based on the use of appropriate risk measurements, through the implementation of appropriate regulatory coordination schemes to achieve a more efficient and tightly coordinated expansion of the system resources; those challenges are aimed to be addressed in the following chapters of this document.

## 2.10 Final Remarks

This chapter 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 analyse the impact on GEP&TEP coordination of the risks perceived by agents and the coordination schemes that can be adopted to effectively manage these risks. This 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. Considering this approach facilitates the assessment of the impact of different regulatory schemes on the efficiency of the functioning of the system in the aforementioned idealised context.

The reactive planning approach, corresponding to that traditionally implemented in a deregulated context, has been employed in a wide variety of countries. This approach has been used by some researchers when assessing the performance of some complementary regulatory schemes, like capacity payments and transmission charges. However, those works have not considered the implementation or regulatory schemes that tackle counterparty risk or the market risk associated with the uncertainty about the price of accessing the grid capacity. In addition, none of these works has analysed or measured the impact on system development of managing these risks through the corresponding regulatory scheme.

The research community has shown interest in proactive planning, recognizing the potential for increased efficiency in the system expansion resulting from applying it. 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 the analysis of the relevant literature, this work confirms 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 and that these investments are shielded from relevant risks potentially affecting them negatively.

When exploring the coordination of the expansion of generation and transmission, it is very relevant to consider the existing conditions challenging this coordination. 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 about the system evolution 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, resulting in some efficiency losses. The implementation of one, or several, regulatory coordination schemes addressing the lack of mutual commitment by providing strong incentives for 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. In addition, Financial Transmission Rights have not been analyzed in this context as a regulatory coordination mechanism.

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, most importantly, in the case of some schemes like LT-FTRs, by allowing the concerned stakeholders to manage relevant risks their investments are subject to in this 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 be used to manage separately different types of risks, such as FTRs combined with other mechanisms like CfDs, could potentially help the stakeholders manage the most relevant risks arising in the GEP&TEP problem, such as the counterparty and price risks.

This 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.

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 or other uncertainty sources could also be assessed. Considering the impact of risks on the generation and transmission investments requires making use of appropriate measures of risk.

## 2.11 Definition of the research gaps to fill in within the state of the art

Based on the discussion in previous sections, the main relevant gaps on this topic that are further investigated in this research work are provided.

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 the associated risks. However, few studies in the literature conduct a risk analysis in this context. This research work focuses on assessing the impact on the system development and welfare of the uncertainty associated with the price of accessing the transmission grid capacity and the possible lack of coordination of the stakeholders' investment decisions. This requires using appropriate measures to represent the risks associated with the occurrence of grid congestion and the severity of it, as well as 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 and simultaneously mitigate their exposure to different risks, including the Market risk (Price), and the Counterparty risk. Therefore, the consideration of regulatory schemes such as LT-FTRs is crucial.

iii *Realistic Risk Representation in the Reactive Planning Approach*: While the proactive planning approach is favoured in the literature, the Reactive planning approach is the most widely implemented in real systems. Both of them are often considered risk-neutral, leading to their unrealistic representation within the context of the GEP&TEP coordination problem. This research addresses this gap by incorporating realistic risk considerations into the representation of the reactive planning approach.

iv *Analysis of the impact that different risks faced by Generation investors have on the generation expansion under different Planning Approaches*: Assessment of the value that generation investors assign to, mitigating the risks they face —largely the price risk resulting from network congestion— and the corresponding need to consider risk-hedging instruments like Financial Transmission Rights (FTRs) under different planning approaches, the integrated planning approach representing perfect coordination and the reactive planning approach. This has not yet been addressed in the literature within this context and remains an open research need.

v *Interrelationship Between Critical Elements*: Exploring some main interactions among the various elements affecting the coordination of generation and transmission investment decisions, which is crucial. The aim is to contribute to understand how the choice of a planning framework influences the selection of the complementary regulatory coordination instruments to implement, especially considering the impact of risks on agents' investment decisions. This is essential. This exploration provides 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.

## 2.12 Research questions and contributions

Given the previous discussion, the main **research questions** of this work are the following:

**Rq1** What would be the impact of implementing LT-FTRs on the investment decisions made by risk-averse generation and transmission investors, and the impact on risk perception by GENCOs, assuming perfect coordination among them from a social point of view?

**Rq2** What would be the impact of the use of these rights on the social welfare of the system, the net value that generators obtain from their investments, and the nodal prices in the system, assuming these are implemented, given the risk profile of stakeholders, who would value positively the stabilisation of their market revenues?

**Rq3** What would be the impact of implementing LT-FTRs on the investment decisions made by risk-averse generation and transmission investors and their coordination, and the impact on risk perception by GENCOs in a liberalised electricity context under a reactive planning approach?

**Rq4** What would be the impact of implementing LT-FTRs on the social welfare of the system, the net value that generators obtain from their investments, and the nodal prices in the system, assuming these are implemented, considering risk-averse generation (strategic) and transmission investors in a liberalised electricity context under a reactive planning approach?

Accordingly, the main **contributions** of this work are listed below:

i Assessment of the impact that the implementation of LT-FTRs over the transmission capacity required to access remote areas would have on the expansion of the system, the risk perception by GENCOs, the associated social system welfare and nodal prices, in a context where perfect coordination between generation and transmission investment decisions, from a social point of view, takes place, and both transmission investors and generation investors in remote areas are deemed to be risk-averse.

ii Development of a bi-level optimization expansion planning model, under an Integrated Resources Planning Approach, with the purpose of maximizing the social welfare of the system through the optimization of the upper level problem objective function, comprising the system costs and considering the value for risk averse GENCOs in remote areas of hedging through the use of LT-FTRs the network price risk they are subject to, modelling the CVaR of the profits of the set of generation investments by GENCOs in remote areas in a context of perfect coordination.

iii Assessment of the effect on the expansion of generation and transmission in the system, its coordination, the risk perception by GENCOs, the associated social welfare and nodal prices, of the use of LT-FTRs by risk-averse, profit-maximising, generation investors in remote areas and the transmission planner in order to drive the development of remote generation.

iv Formulation of a bilevel optimization expansion planning problem to assess how the option for generation investors in remote areas to contract LT-FTRs in order to manage the risk associated with the uncertainty about the price to pay to access the transmission grid they are subject to, would affect the development of the system, the risk perception by GENCOs in remote areas and the social welfare, as well as the nodal prices, considering a reactive planning approach and strategic, risk-averse, generation investors in remote areas, a risk-averse network planner, and competitive generation being developed in the rest of the system. This allows us to determine the effect that LT-FTRs have on the coordination of these generation investments and the associated transmission ones.

# Chapter 3

# Analysis of FTRs as a potential long-term risk hedging instrument. Application in a context of socially efficient coordination

This chapter investigates the use of LT FTRs by GENCOs to manage the risk associated with the existing long-term uncertainty about the electricity price differences between the areas where new generation is to be installed and those areas where some main load centres are located. The transmission planner is deemed to seek to achieve revenue adequacy for the LT FTRs issued when deciding on the network reinforcements to undertake. Therefore, the analysis here is limited to the use of FTRs to manage the price risk faced by GENCOs caused by network congestion (other risks such as counterparty risks or operational risks are not considered here). The value that hedging their market price risk has for generation investors in remote areas is computed through the CVaR of the profits made by the set of generation investments undertaken by each of these investors. It is assumed that the socially most efficient coordination of the generation and transmission investments takes place, to determine the best possible optimum that the use of LT FTRs could lead the system to if coordination failures do not occur. Therefore, the role of LT FTRs as an investment coordination tool is not explored here. In this context, the analysis is focused on the impact of the use of LT FTRs on the expansion of the system and its social welfare. The methodology developed to analyse this use of LT FTRs is applied to a Schematic European case study.

Please note that in Europe, even when LMPs (Locational Marginal Prices) have not been implemented, a set of bidding, or price, zones has been defined. The electricity price of these zones in the Day-Ahead market may differ from one another, reflecting congestion existing in the grid. FTRs are currently used for agents to be able to hedge price differences among these zones. Notice that the approach proposed in this chapter to assess the use of LT FTRs could be applied in any kind of market where their contracting by generators is deemed possible, which is an option that could make sense in different contexts, like the European one; however, this work does not provide a regulatory framework to implement FTRs as a whole.

In this chapter, the aim is to answer two main research questions, the ones corresponding to Rq1 and Rq2 stated in chapter 2.

Accordingly, the focus of this chapter is on the following aspects:

i. Assessment of the impact that the implementation of LT FTRs, for the transmission capacity required to access remote areas, would have on the expansion of the system, risk perception by risk-averse GENCOs and the associated social system welfare in a context where perfect coordination between generation and transmission investment decisions, from a social point of view, takes place, and both transmission investors and generation investors in remote areas are deemed to be risk-averse.

ii. Development of a bi-level optimization expansion planning model, considering the use of FTRs, which is adapted to represent the context explored here and described in (i). This model aims to analyse the impact of FTRs, on the social welfare of the system and nodal prices considering that stabilising the market revenues for generation investors in remote areas by hedging their price risk, represents value for the system as a whole, by providing the system the possibility to count on efficient generation that in other conditions wouldnt be feasible. The perception of risk for these investors is computed through the CVaR of the profits made by GENCOs in remote areas. These are areas whose price is deemed to be much more volatile and unpredictable than that of the bulk system where the reference node considered in LT FTRs is located. Transmission investors, being risk-averse, are only willing to sell to generation investors those socially efficient LT FTRs for which the revenue adequacy condition holds. This involves imposing the condition that the flows created by all transactions supported by FTRs should be simultaneously feasible, which may require the construction of specific network reinforcements.

iii. Exploring, in the context set out here, the impact of the implementation of LT FTRs on the expansion of the system, risk perception by GENCOs in remote areas and the social welfare of the system for a realistic case study representing the Western European system in a schematic way.

## 3.1 Conceptual definition and discussion of the problem addressed: LT FTRs and Risk

The literature review conducted in chapter 2 has allowed us to conclude that, within those models developed so far to compute the generation and transmission expansion planning considering the use of some coordinating schemes or instruments, none takes into account the impact of these schemes or instruments on the level of the relevant risks faced by the stakeholders (computed making use of appropriate risk measurement tools) to determine the expansion of the system and the level of use of these instruments, see [47], [48], [50], [19]. No previous work has explored the consideration of risk measurement tools to assess the potential impact of regulatory coordination schemes on the expansion of the system under an integrated-resource planning approach. This is a gap in the literature that is partly filled in this section for what concerns the implementation of LT FTRs, in an idealized context characterized by achieving a socially efficient coordination of the generation and transmission investments, as discussed next.

While FTRs may help manage both the price and the counterparty risks that may be faced by GENCOs, network planners and network investors, as mentioned in section 2.5, this study focuses solely on using FTRs to manage the price risk faced by GENCOs when network investments are promoted by the SO, as is typical in most systems. Other risks, such as the counterparty risks for GENCOs, network planners, and investors, the price risk for merchant network investors, the operational risks for GENCOs and the SO (due to technical failures or internal procedures), and the volume risk faced by GENCOs due to the uncertainty existing about the production levels of their new plants, are not analysed here.

To the best of current knowledge, no previous work has explored the impact on the system expansion, concerning both generation and transmission investments, of the use of FTRs as a long-term risk hedging instrument (LT-FTRs) allowing the generation investors to effectively manage the risk they face associated with the uncertainty in the price the generation they plan to build will have to pay to access the grid. By allowing generation investors to effectively and efficiently manage this risk, LT-FTRs can be expected to achieve an increase in the system welfare. The use of FTRs should, then, lead to a more efficient system expansion, coupling the construction of baseload plants and the associated transmission investments, while providing some certainty to stakeholders about achieving revenue adequacy. Therefore, the pertinence of implementing FTRs as a coordination tool is a topic of interest that we address in chapter 4.

## 3.2 Proposed Mathematical Formulation

In order to explore the impact on the development of the system of the implementation of LT FTRs as a mechanism to hedge the market price risk of GENCOs, while also accounting for the risk-averse behaviour of the TSO selling these rights, the proposal is for the use of a bi-level expansion planning model whose formulation is described in this section. This aims to assess the impact of LT FTRs on the generation and transmission expansion planning decisions, risk perception from risk averse GENCOs in remote areas in a context where perfect coordination between generation and transmission investment decisions, from a social point of view, is deemed to take place.

It is important to note that, even if the agents in the system were deemed to behave strategically, contracting FTRs should allow these agents to increase the value that the investments they undertake have for them. Thus, the use of FTRs should increase the social benefit resulting from a given set of investments and, in addition, provides additional incentives for investors to undertake generation projects that they might deem unprofitable in the absence of FTRs.

Accordingly, the resulting planning and operation of this model aims to maximise the social welfare of the system through the optimization of the upper level objective function, comprising the system costs and considering the value that hedging the price risk from risk averse GENCOs in remote areas through the implementation of FTRs, have on the system, considering that being able to reduce the risk perception from those agents, could increase the availability of efficient generation investments to be deployed. Here, it is important to take into account that the variation in total system costs captures the variation in the net social welfare for inelastic demand, and considering the Energy non Served cost (ENS), provided that the increase in the value of generation investments for the corresponding investors is also included.

Assuming the perfect coordination of the long-term decisions made by the generation investors and the network planner from a social point of view, the solution of the expansion planning problem, representing the decisions separately made by generation investors and transmission expansion planners, can be computed as that determined by central planning authorities looking after the interest of the whole system, and, thus, aiming to maximise the aggregate value that generation and transmission investments have for all the system stakeholders. This involves considering both, the impact that the risk aversion profile of GENCOS has on the value that the economic benefits produced by the generation plants they deploy have for these companies, given the probability distribution of these benefits, as well as the impact of the investment decisions on the system operation resulting from the centralized dispatch.

Both investment and operation decisions are modelled as being made by social welfare maximising planning authorities, though in different timeframes. First, the investment decisions are made in the long-term, considering or not the option to contract FTRs to manage the price risk of generation investors. Then, the operation decisions are computed. This is the same decision-making process generally occurring in real-life expansion planning.

The reader should notice that this work represents the impact of the long-term planning and operation decisions on the welfare of the system as the impact of these decisions on the aggregated value that the whole set of agents of the system gives to the benefits they receive; therefore, this impact includes two main components:

- The impact of the decision variables on the expected profit of the system agents. This impact, in aggregate terms for all the agents in the system, and when the cost of energy non-served (ENS), associated with the non-supply of a certain amount of energy demanded by consumers, is considered as part of the system costs, coincides with the impact of the planning decisions on the system costs. This impact on system costs is determined according to the formulation outlined below.

- Given that, in the context analysed here, part of the agents is risk averse, it is also necessary to consider the impact that the operation and long-term planning decisions have on the effect that the risk profile of those agents has on the value that they assign to the benefits produced by those assets in which they invest (the new generation plants in remote areas), given the probability distribution of these benefits.

These two components of the system welfare impact of decision variables are considered within the objective function of the upper level problem formulated.

Please also notice that the main sources of risk considered here are, first, the uncertainty associated with the evolution of grid access prices for generators located in areas with particularly volatile prices, such as remote regions. This risk can only be mitigated by all parties—generators, demand, and the entity offering risk management products— through long-term transmission rights issued and allocated according to a strategy such as the one proposed. Furthermore, in the case of generation located in remote areas, the negotiation of power purchase agreements referred to their area or connection node would probably be subject to conditions of low liquidity and, therefore, to a price that is likely not to be representative of the expected value of that energy. Second, the system planner risk relates to the risk of the revenues from congestion rents resulting from the operation of the system not being large enough to pay the amounts owed to the FTR holders. Typically, the condition enforced to achieve a reasonable level of certainty that congestion rents are sufficient to pay the right holders involves that the existing and newly built capacity in the network is sufficient to host the virtual-flows resulting from the undertaking of transactions corresponding to the rights contracted. This is what is called the FTR simultaneous feasibility test.

Accordingly, it is important to take into account that this formulation is not only considering the aversion of the generation companies in remote areas to the price risk caused by network congestion, modelled in this case through the consideration in the UL problem objective function of the CVaR of the profits made by these companies from the generation they deploy in this areas. The problem formulation proposed also represents the system planner's aversion to the risk of not being able to pay the FTR holders the amounts owed to them from the congestion rents produced by the grid in the dispatch. This is modeled through the enforcement of the FTRs simultaneous feasibility constraints.

Bi-level (or multilevel) models can be employed to represent decisions made by different actors in different levels or the different types of decisions made by the same actors in the different levels [16]. The latter is the case here.

The consideration of two decision making levels in the problem formulated here is motivated by the need to explicitly represent the impact, on the expansion of the system, of the price risk faced by generation investors in remote areas associated with the occurrence of congestion on the network connecting these areas to the rest of the system. This has two main implications leading to the separate modelling of the long-term decision-making problem, addressing expansion planning and FTR contracting, and the short-term problem, concerning the representation of the system operation:

- If the system operation were computed in the same problem as the optimal system expansion and amount of FTRs to be contracted, the operation decisions would not only be computed with the aim to minimise the system operation costs (including NSE and emission ones), which is the only objective to be pursued by the system operation. If this were the case, operation decisions would be made with the additional aim of optimizing the impact of the price risk perceived by risk-averse investors in generation in remote areas on the overall value that they assign to these investments. Within the proposed formulation of the problem addressed, this impact is included in the objective function of the long-term planning problem in order to accurately assess the impact of the use of LT-FTRs on the overall system welfare, to be maximised when assuming the perfect coordination of these decisions. Note that the impact of the price-risk on the value assigned by risk-averse investors to their generation investments is expressed in terms of the CVaR of these investments for the investors, which is a term expressed in terms of the system operation variables related to the system conditions in the remote areas considered. This would lead to system operation variables not reflecting the real system operation.

- Explicitly considering the short-term energy prices in the long-term planning problem formulation is necessary in order to consider the market profits of new generation in remote areas when computing the CVaR of these investments for their promoters, as stated above. This is only possible when representing the system operation resulting in these energy prices in a separate problem. Formulating the optimality constraints of the operation problem and enforcing these within the overall problem to solve is a possible way to achieve this.

Given the two-level problem formulation developed, the long-term planning decisions on generation and transmission investments and FTRs contracting are made within the upper level problem and the operation decisions within the lower level one.

The assumptions made in developing the proposed problem formulation follows:

- Network investments are regulated

- Perfect (socially optimal) coordination takes place among generation and transmission investment decisions.
- Generation investors are risk-averse (they are subject to market price risk). The impact of this risk on the value they assign to their profits is modelled through the CVaR of these profits.
- Only the uncertainty GENCOs face in remote areas is worth being represented. The rest of GENCOs are deemed to have certainty about the market conditions affecting their investments.
- Demand is considered inelastic, while storage is not considered. Considering these two additional sources of flexibility could potentially affect the results and conclusions of the study.
- Transmission investors are risk averse (risk associated with the price earned for the sale of FTRs). Their strategy to protect themselves from this risk is represented by the enforcement of FTRs simultaneous feasibility constraints. Note that this risk is not managed using sophisticated risk measurement tools, as in the case of GENCOs.
- The counterparty risk faced by the SO associated with the uncertainty about the generation investments to be carried out by the GENCOs is not considered in this formulation, since perfect coordination of investment decisions is assumed.
- The counterparty risk faced by GENCOs due to the uncertainty these companies may have about the network investments to be carried out by the SO to integrate the new power plants the former build is not considered here either, since perfect coordination of investment decisions is assumed.
- The cost of energy non-served (ENS), associated with the non-supply of a certain amount of energy demanded by consumers, is considered as part of the system costs minimised within the planning problem formulated. Under this condition, the impact of the planning decisions on the system welfare coincides with that on the system costs.

The results computed by solving this problem include: i) the socially optimal generation and transmission expansion planning decisions; ii) the impact that the implementation of FTRs have on the social welfare corresponding to this expansion and the resulting system operation; as well as iii) the amount of LT FTRs defined between each remote area and the system reference node to be sold by the network owner to the generation companies in this remote area.

### 3.2.1 Discussion of uncertainty modeling in the formulation

Two sources of uncertainty are considered in the problem formulation:

i) the exogenous uncertainty, corresponding to external factors that are not inherent to the investment and operation decisions made by the stakeholders here represented. It is assumed that all the stakeholders here considered make the same representation of the exogenous uncertainty, i.e. they consider the same set of exogenous scenarios; and
ii) the endogenous uncertainty that each stakeholder in the system may have about the investment strategy followed by the rest of stakeholders. Given that only the effect on the system development of the uncertainty faced by the GENCOs in the remote areas is represented here, for simplicity reasons, it is assumed that the endogenous uncertainty faced by each GENCO in a remote area only concerns the strategy followed by the rest of GENCOs in this area. The rest of stakeholders in the system (GENCOs that are not investing in remote areas and the network planner) are expected to make decisions that are socially optimal.

Given that the uncertainty of type i) is exogeneous to the system expansion and operation, this uncertainty must be considered when making any type of decision here represented. However, the uncertainty of type ii) must not be considered when computing the socially efficient expansion and operation of the system, neither the socially efficient amount of FTRs to be contracted, given that the expansion, operation, and risk hedging decisions are deemed to be socially efficient, which involves that all these are 100% coordinated from a social point of view. Uncertainty of type ii) must only be considered when computing the value that risk-averse GENCOs assign to the benefits produced by the plants they deploy according to the probability distribution of the benefits produced by these plants. Then, the risk-averse GENCOs, when determining the probability distribution of their profits, should consider a set of scenarios corresponding to the representation of both the uncertainty of type i) and that of type ii). Therefore, there are two sets of operation scenarios to be considered:

- Scenarios *wcp* (company's scenarios), considered by the GENCOs in remote areas when computing the probability distribution of the profits of their new power plants in order to compute the effect of uncertainty on the value that these plants have for the investors; and
- Scenarios *wp* (planner's scenarios), considered when computing the socially optimal expansion of the system and risk hedging strategies.

Scenarios *wcp* are defined considering the uncertainty of type i) and ii). Note that the scenarios *wcp* are specific to each GENCO in the remote areas. Therefore, there are as many sets of operation scenarios *wcp* as GENCOs in remote areas. Scenarios *wp* are defined considering only the uncertainty of type i). Note that, when there is a single risk-averse GENCO (a single one for all the remote areas considered), this GENCO assumes that the behaviour of the rest of the system stakeholders, also the rest of GENCOs, is the socially efficient one, given the commonly shared exogenous uncertainty existing about the development of the system (uncertainty of type i)). Then, for this single risk-averse GENCO, the uncertainty of type ii) does not exist. He is only subject to uncertainty of type i). Thus, in this case, there is only one type of operation scenarios to consider.

Note that, in this context, the implementation of risk management strategies based on the use of risk metrics like the VaR, or the CVaR, allow these stakeholders to manage risks according to the value that their costs and revenues have for them due to the probability of occurrence of these costs and revenues. The VaR and the CVaR are the natural risk metrics that are most widely employed in the literature to quantitively assess the impact of risks and manage them [51]. Taking the CVaR as the risk assessment tool to consider allows us to determine the impact of LT-FTRs on the average benefits that remote generation investors would obtain over the whole set of most unfavourable scenarios, capturing a larger amount of information about the LT-FTRs impact on the probability distribution of these benefits than just the impact of FTRs on the upper limit of the tail of this distribution, as could be done employing the VaR as a risk assessment tool. The CVaR provides a more comprehensive representation of the behaviour of these benefits in unfavourable conditions than other risk measures. Therefore, the CVaR offers a broader perspective of the impact that contracting FTRs would have on the benefits of generation investors in remote areas in the most unfavourable scenarios for them.

### 3.2.2 Discussion of the representation made of the interactions between the upper and the lower level problems

This formulation represents the planning decisions made at two hierarchy levels. Generation and transmission investment decisions, those on the number of FTRs to be contracted by the GENCOs and the network owner, as well as the operation decisions resulting from the aforementioned, perfectly coordinated and socially efficient investment decisions, are made in the upper level problem considering the operation scenarios defined to represent only uncertainty of type i).

The operation decisions made in each of the lower level subproblems are computed seeking to minimise the system operation costs over the set of scenarios *wcp* considered by the corresponding GENCO in a remote area. In the resulting bi-level problem, the nodal marginal prices resulting from the operation computed in the lower level subproblems are considered in the upper level problem objective function within the expression of the CVaR of the profits produced by the generation investments for the corresponding GENCOs. Note that the nodal prices can be computed as the dual variables of the corresponding energy balance constraints. These dual variables are explicitly represented within the expression of the KKT optimality conditions of the lower level problems, employed when formulating the problem at hand as a Mathematical Program with Equilibrium Constraints (MPEC), see Figure 3.1.

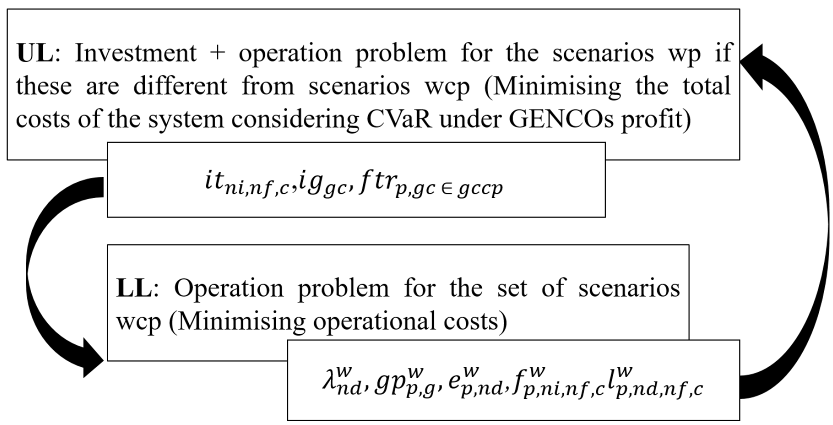


Figure 3.1: Interaction between problems - IRP

Note that, within each lower level problem, the computation of the system operation decisions for each of the scenarios defined is carried out to determine the probability distribution of the benefits of the corresponding GENCO's power plants according to this GENCO. These are the sets of scenarios separately defined by this GENCO considering the uncertainty of types i) and ii) it perceives. The operation scenarios considered within each lower level problem are characterized in terms of the amount and type of the rest of new generation being deployed in the corresponding remote area. These scenarios are defined in terms of some uncertain parameters whose realizations are specific to this lower level problem. If there is only one GENCO in the remote areas and, therefore, there is no uncertainty of type ii), the operation scenarios considered and operation decisions made in the single lower level problem defined are also the ones computed in the upper level problem.

### 3.2.3 Formulation of the upper level (UL) - Investment Problem

**Objective Function**

This considers the minimisation of the total costs of the system, including the fixed, variable, emission and ENS costs, less a term representing the effect that the risk perception by GENCOs about their profits (*gpr*), has on the value the GENCOs assign to these profits. This last term is represented in terms of the CVaR of the corresponding profits. The changes taking place in the total system costs here coincide with those changes affecting the aggregate benefits of all the stakeholders in the system. The CVaR term within the objective function represents the extra value that GENCOs in remote areas assign to their benefits in the worst scenarios possible identified by them. Then, the changes taking place in the objective function can be deemed to coincide with those taking place in the overall social welfare, defined as the overall value assigned by all the system stakeholders to the benefits they perceive.

By including this term in the objective function, the solution that maximises the objective function is the same as the one that maximises social welfare, including the impact on the value of generation investments for their investors, as just discussed.

It is important to take into account that the variation in total system costs captures the variation in the net social welfare for inelastic demand, and considering the Energy non Served cost (ENS), provided that the increase in the value of generation investments for the corresponding investors, associated with the reduction in the volatility of the returns on these investments (and, consequently, the returns in the most unfavorable scenarios), is also included.

Consequently, the impact of the use of LT-FTRs on the overall system welfare, can be computed as the difference between the value of the objective function of the upper level problem for the optimum solution when considering the existence of LT-FTRs, and the value of this objective function at the optimum when LT-FTRs are deemed not to be available.

Also the impact on the system expansion can be computed as the difference between the optimal values of the investment decision variables in the upper level problem computed when considering LT-FTRs and the optimal values of these variables computed not considering the existence of these rights. Both several of the terms of the objective function of this problem and the problem constraints are expressed in term of these investment decision variables.

Note that the CVaR term defined for each GENCO is deducted from the term representing the overall system costs comprising also the objective function. Therefore, the aim is to maximise this CVaR term, which is proportional to the expected value of the corresponding GENCO's profits over the set of worst-case scenarios from the GENCO's point of view (those scenarios for which these profits are below the $(1-\alpha)$ quantile of their probability distribution), while, at the same time, minimising the aggregate value of the system costs over the whole set of scenarios considered.

The proportionality factor weighting in the CVaR of the GENCO's profits within the objective function, $\beta_{cp}$, represents the risk profile of this GENCO. Accordingly, $\beta_{cp} = 0$ implies risk neutrality and therefore no impact of the CVaR, leading to the classical objective function of cost minimisation, leading to the fully centralised formulation.

See below the discussion on the impact of risk on the value that GENCOs assign to their profits over the several scenarios considered. Then, a decrease in the GENCO's expected profits in the worst-case scenarios results in an increase (worsening of the value) of the objective function to minimise, while an increase in the CVaR of the GENCO's profits results in a decrease (improvement of the value) of the objective function. This objective function may adopt positive or negative values depending on the level of the expected profits of the GENCO (typically positive) and the expected value of these profits over the worst-case scenarios, which may be positive or negative.

$$\text{Minimise} \quad OF = tf + tv + tr + te - \sum_{cp} \beta_{cp} cvar_{cp} \tag{3.2.1}$$

Below, each of the terms in 3.2.1 are discussed separately. Please note that equations 3.2.6, 3.2.7 and 3.2.8 are necessary for the computation of the CVaR of the benefits of the GENCOs in remote areas.

**Total fixed costs**

The sum of fixed costs for all candidate transmission lines ($it_{lc}$) and all candidate generation units ($ig_{gc}$) that are installed.

$$tf = \sum_{lc} FCT_{lc} it_{lc} + \sum_{gc} FCG_{gc} ig_{gc} \tag{3.2.2}$$

**Total variable costs**

Sum of the variable costs for the generation units, multiplied by its power output ($gp^{wp}_{p,g}$) in the several scenarios $wp$ and periods $p$ weighted with the probability of occurrence of the corresponding scenarios.

$$tv = \sum_{wp,p,g} PR^{wp} VC_g DU_p gp^{wp}_{p,g} \tag{3.2.3}$$

**Total reliability costs**

Sum of the ENS costs, multiplied by the ENS ($e^{wp}_{p,nd}$) in the several scenarios $wp$ and periods $p$ weighted with the probability of occurrence of the corresponding scenarios.

$$tr = \sum_{wp,p,nd} PR^{wp} CENS DU_p e^{wp}_{p,nd} \tag{3.2.4}$$

**Total emission costs**

Sum of the $CO_2$ costs multiplied by the power output of generators ($gp^{wp}_{p,g}$) in the several scenarios $wp$ and periods $p$ weighted with the probability of occurrence of the corresponding scenarios.

$$te = \sum_{wp,p,g} PR^{wp} CO_{2g} DU_p gp^{wp}_{p,g} \tag{3.2.5}$$

**Impact of the risk considered on the value of profits for GENCOs**

This term depends on the conditional value at risk of profits for investors, CVaR, which is given a weight, $\beta_{cp}$, depending on the risk profile of GENCOs. The CVaR formulation was proposed in [68] by Rockafellar. The CVaR is defined as the expected value of the generation company's profits $gpr^{wcp}_{cp}$, whenever these profits are smaller than the $(1-\alpha)$ quantile of the profit distribution over scenarios. The auxiliary variable $\eta_w$is nonnegative and is bounded by constraint 3.2.7, which is formulated in terms of the Value at Risk (VaR) of the company's profits for this confidence level, $\phi$, and the generation company's profits for scenario $w$, $gpr^{wcp}_{cp}$, deducting the latter from the VaR.

The reader should notice that minimising the objective function, where the impact of risk on the value of profits for companies is deducted from the system costs, and enforcing constraints 3.2.6 and 3.2.7 to compute the impact of risks on the value of these profits for companies, leads the optimal value of $\phi$, for a given confidence level $\alpha$, to be the maximum generation company's profit value such that the probability of the company's profits being lower than this value is less than or equal to $(1-\alpha)$, i.e. the formulation adopted leads the optimal value of $\phi$ to be equal to the VaR, as discussed in [69].

$$cvar_{cp} = \phi_{cp} - \frac{1}{(1-\alpha)} \sum_{w} PR^{wcp} \eta_{cp}^{wcp} \qquad \forall \quad cp \qquad (3.2.6)$$

$$\phi_{cp} - gpr_{cp}^{wcp} \leq \eta_{cp}^{wcp} \qquad \forall \quad wcp, cp \qquad (3.2.7)$$

GENCO's Profits $gpr_{cp}^{wcp}$ computed in 3.2.8 (including the FTR benefits and costs): Each company cp's profits are the sum of several terms computed per scenario. The first term represents the revenues of the company provided by the FTRs acquired, computed as the difference between the LMP at the reference node ($\lambda_{p,grf}^{wcp}$) and the LMP at the connection node ($\lambda_{p,gnd}^{wcp}$) multiplied by the amount of capacity contracted through the FTRs ($ftr_{p,gc}$). The second term represents the revenues from the sale of energy, computed as the production level of the corresponding generators multiplied by the LMP in their connection nodes. The third term represents the variable costs associated with the electricity production. The fourth term represents the generation investment costs associated with new installed generation capacity. Finally, the last term represents the cost of the FTRs acquired. Notice that the expression of each GENCO's profits includes a bilinear term where the variables $ftr_{p,gc}^{wcp}$ and $\lambda_{p,nd}^{wcp}$ are multiplied.

$$\begin{aligned} gpr_{cp}^{wcp} = & \sum_{p,nd,gc \in gccp} (\lambda_{p,grf}^{wcp} - \lambda_{p,ftrnd}^{wcp}) DU_p ftr_{p,gc} + \sum_{p,nd,g \in gcp} \lambda_{p,nd}^{wcp} DU_p gp_{p,g}^{wcp} \\ & - \sum_{p,g \in gcp} VC_{gcp} DU_p gp_{p,g}^{wcp} - \sum_{gc \in gccp} FCG_{gc} ig_{gc} - \sum_{gc \in gccp} cftr_{gc} \quad \forall \quad wcp, cp \end{aligned} \qquad (3.2.8)$$

**FTRs Cost**

The FTRs cost is the expected value of the differences in the nodal prices between the reference node and the connection node in these FTRs ($\lambda_{p,grf}^{wcp} - \lambda_{p,gnd}^{wcp}$) multiplied by the amount of capacity contracted through these FTRs ($ftr_{p,gc}$), considering the probability of all $wcp$ scenarios.

$$cftr_{gc} = \sum_{wcp} PR^{wcp} \sum_{p,nd} (\lambda_{p,grf}^{wcp} - \lambda_{p,gnd}^{wcp}) DU_p ftr_{p,gc} \quad \forall \quad gc \in gccp \qquad (3.2.9)$$

Considering bilinear elements in the computation of the generation company's profits can cause numerical issues. To deal with this problem, these bilinear elements are linearized.

**Bilinear terms linearization**

The procedure proposed in [94] was followed to linearize the bilinear elements $\lambda_{p,grf}^{wcp} ftr_{p,gc}$, and $\lambda_{p,nd}^{wcp} gp_{p,g}^{wcp}$. First it is necessary to approximate the continuous decision values $ftr_{p,gccp}$ and $gp_{p,g}^{wcp}$ by M discrete values, where $M = 2^k$ and $k$ is non-negative. Consider $\left[\underline{FTR}_{p,gc}, \overline{FTR}_{p,gc}\right] = \left[0, \overline{FTR}_{gc}\right]$, $\left[\underline{gp}_{p,g}^{wcp}, \overline{gp}_{p,g}^{wcp}\right] = [0, MP_{gc}]$ and $\left[\underline{\lambda}_{p,nd}^{wcp}, \overline{\lambda}_{p,nd}^{wcp}\right] = [0, CENS]$, then the discrete approximation is formulated through binary expansion, as follows:

$$ftr_{p,gc} = \underline{FTR}_{p,gc} + \Delta 1_{p,gc} \sum_{k} 2^k u_{p,gc,k} \quad \forall \quad p, gc \in gccp \qquad (3.2.10)$$

Where:

$$\Delta 1_{p,gc} = \frac{\overline{FTR}_{p,gc} - \underline{FTR}_{p,gc}}{M} \quad \forall \quad p, gc \in gccp$$
$$u_{p,gc,k} \in (0,1) \quad \forall \quad p, k, gc \in gccp$$

Multiplying both sides of 3.2.10 by $\lambda^{wcp}_{p,nd}$, and adding a new variable $z^{w}_{p,gccp,nd,k} = u_{p,gccp,k}\lambda^{wcp}_{p,nd}$ we obtain equation 3.2.11.

$$\lambda^{wcp}_{p,nd} ftr_{p,gc} = \lambda^{wcp}_{p,nd}\underline{FTR}_{p,gc} + \Delta 1^{wcp}_{p,gc} \sum_k 2^k z^{wcp}_{p,gc,nd,k} \; \forall \; wcp, p, gc \in gccp \tag{3.2.11}$$

Since the term $u_{p,gc,k}\lambda^{wcp}_{p,nd}$ is the multiplication of a continuous and an integer variable, it can be linearized by equations 3.2.12 and 3.2.13 :

$$0 \le \lambda^{wcp}_{p,nd} - z^{wcp}_{p,gc,nd,k} \le \overline{\lambda}^{wcp}_{p,nd}\left(1 - u_{p,gc,k}\right) \quad \forall \quad wcp, p, nd, k, gc \in gccp \tag{3.2.12}$$
$$0 \le z^{wcp}_{p,gc,nd,k} \le \overline{\lambda}^{wcp}_{p,nd} u_{p,gc,k} \quad \forall \quad wcp, p, nd, k, gc \in gccp \tag{3.2.13}$$

Similarly, the same procedure is applied in order to linearize the therm $\lambda^{wcp}_{p,nd} gp^{wcp}_{p,g}$ as follows:

$$gp^{wcp}_{p,g} = \underline{gp}^{wcp}_{p,g} + \Delta 2^{wcp}_{p,g} \sum_k 2^k v^{wcp}_{p,g,k} \quad \forall \quad wcp, p, g \in gcp \tag{3.2.14}$$

Where:

$$\Delta 2^{wcp}_{p,g} = \frac{\overline{gp}^{wcp}_{p,g} - \underline{gp}^{wcp}_{p,g}}{M} \quad \forall \quad wcp, p, g \in gcp$$
$$v^{wcp}_{p,g,k} \in (0,1) \quad \forall \quad wcp, p, g \in gcp$$

Multiplying both sides of 3.2.14 by $\lambda^{wcp}_{p,nd}$, and adding a new variable $x^{wcp}_{p,g,nd,k} = v^{wcp}_{p,g,k}\lambda^{wcp}_{p,nd}$, we obtain equation 3.2.15

$$\lambda^{wcp}_{p,nd} gp^{wcp}_{p,g} = \lambda^{wcp}_{p,nd}\underline{gp}^{wcp}_{p,g} + \Delta^{wcp}_{2p,g} \sum_k 2^k x^{wcp}_{p,g,nd,k} \quad \forall \quad wcp, p, nd, g \in gcp \tag{3.2.15}$$

Since the term $v^{wcp}_{p,g,k}\lambda^{wcp}_{p,nd}$ is the multiplication of a continuous and an integer variable, it can be linearized by equations 3.2.16 and 3.2.17:

$$0 \le \lambda^{wcp}_{p,nd} - x^{wcp}_{p,g,nd,k} \le \overline{\lambda}^{wcp}_{p,nd}\left(1 - v^{wcp}_{p,gcp,k}\right) \quad \forall \quad wcp, p, g \in gcp \tag{3.2.16}$$
$$0 \le x^{wcp}_{p,g,nd,k} \le \overline{\lambda}^{wcp}_{p,nd} v^{wcp}_{p,g,k} \quad \forall \quad wcp, p, g \in gcp \tag{3.2.17}$$

**Constraints**

**FTRs - Feasibility equations**

Here, the constraints enforced to make the FTRs allocated simultaneously feasible are provided. as mentioned in the introduction of section 3.2, those constraints are included in order to hedge the risk associated to the possible insufficient congestion rent revenue from the operation to pay the amounts owed to the rights holders, therefore this is a condition usually imposed with the aim of making the congestion rents produced by the grid in the system operation large enough to pay the owners of FTRs the amounts owed to them. This formulation includes the representation of the equilibrium between the number of FTRs to be allocated and the virtual flows ($vf$), this equilibrium is reached through the implementation of the Balance FTRs feseability constraint which is an equality constraint that couples the FTRs and the virtual flows, those virtual flows respect the transfer capacity ($TTC_{ni,nf,c}$) of lines and the DC load flow constraints respecting the same laws as the physical flows in order to issue a set of FTRs that is compatible with the network capacity. According to [95] *"the simultaneous feasibility test must be run to ensure that the transmission system can support the set of issued FTRs. If the set of FTRs is simultaneously feasible, then there is some reasonable amount of certainty that the network is revenue adequate to pay the owners of FTRs the amounts owed to them"*

**Virtual flows constraints (transfer capacity of candidate lines)**: For each candidate line, the relationship between the virtual flow ($vf$) across a circuit between two nodes and the transfer capacity for the line that links these nodes depends on the variable $it_{(ni,nf,c)}$. If the decision is not to install the line, the flow will be zero, while if the decision is to install the line, the virtual flow could not be higher than the total transmission capacity ($TTC_{ni,nf,c}$) of the circuit built.

$$\frac{vf^{wcp}_{p,ni,nf,c}}{TTC_{ni,nf,c}} \geq it_{ni,nf,c} \quad \forall \quad wcp, p, (ni, nf, c) \in lc \tag{3.2.18}$$

$$\frac{vf^{wcp}_{p,ni,nf,c}}{TTC_{ni,nf,c}} \leq it_{y,ni,nf,c} \quad \forall \quad wcp, p, (ni, nf, c) \in lc \tag{3.2.19}$$

**DC load virtual-flow constraints (for existing and candidate lines)**: Represents the virtual flow through the line between two nodes, using a DC formulation for AC lines (as when modeling physical flows). For the candidate lines, the virtual voltage angle difference between both ends of these lines should only be constrained by the virtual flow equation linking node voltages and the virtual flow when the line is installed.

$$\frac{vf^{wcp}_{p,ni,nf,c}}{vMF_{ni,nf,c}} \geq [v\theta^{wcp}_{p,ni} - v\theta^{wcp}_{p,nf}]\frac{Sb}{X_{ni,nf,c}vMF_{ni,nf,c}} - 1 + it_{ni,nf,c} \quad \forall \quad wcp, p, (ni, nf, c) \in lc \tag{3.2.20}$$

$$\frac{vf^{wcp}_{p,ni,nf,c}}{vMF_{ni,nf,c}} \leq [v\theta^{wcp}_{p,ni} - v\theta^{wcp}_{p,nf}]\frac{Sb}{X_{ni,nf,c}vMF_{ni,nf,c}} + 1 - it_{ni,nf,c} \quad \forall \quad wcp, p, (ni, nf, c) \in lc \tag{3.2.21}$$

$$vf^{wcp}_{p,ni,nf,c} = [v\theta^{wcp}_{p,ni} - v\theta^{wcp}_{p,nf}]\frac{Sb}{X_{ni,nf,c}} \quad \forall \quad wcp, p, (ni, nf, c) \in le \tag{3.2.22}$$

**FTRs Balance constraints**:

For each scenario, each period and each node, the amount of FTRs contracted having this node as the reference one $ftrndrf$(incoming FTRs) less the amount of FTRs contracted having this node as the injection one $ftrnd$ (outgoing FTRs) should be equal to the difference between the incoming virtual flows into the node $vf^{wcp}_{p,ni,nd,c}$ and the outgoing virtual flows from this node $vf^{wcp}_{p,nd,nf,c}$ (please consider that $ftrndrf$ and $rfrnd$ are mutually exclusive sets).

$$\sum_{ni \in la(ni,nd,c)} vf^{wcp}_{p,ni,nd,c} - \sum_{nf \in la(nd,nf,c)} vf^{wcp}_{p,nd,nf,c} = \sum_{gc \in ftrndrf} ftr_{p,gc} - \sum_{gc \in ftrnd} ftr_{p,gc} \ \forall \ wcp, p, nd \tag{3.2.23}$$

**Bounds for the transfer capacity in existing lines:** For each existing line, the virtual flow is bounded by the total transfer capacity of the line.

$$-TTC_{ni,nf,c} \leq vf^{wcp}_{p,ni,nf,c} \leq TTC_{ni,nf,c} \quad \forall \quad p, wcp, le_{ni,nf,c} \tag{3.2.24}$$

**Bounds for the FTR contracted capacity**:

For each candidate generation unit, the FTR contracted capacity is bounded by its maximum generation output.

$$ftr_{p,gc} \leq MCI^{wcp}_{p,gc} ig_{gc} \quad \forall \quad wcp, p, gc \in gccp \tag{3.2.25}$$

**Operation constraints**

These correspond to the operation constraints considered when computing the perfectly coordinated expansion of the system and the set of FTRs to be assigned to generation investors in remote areas as if all these decisions were made by a central planner. Therefore, these constraints must be defined for the set of scenarios *wp*. Leaving aside the set of scenarios for which they are defined, the operation constraints to be enforced here coincide with those represented in the lower-level problem. Thus, they are not formulated here to be more concise. These are constraints 3.2.27 - 3.2.39 defined over the scenario set *wp*. If scenarios *wp* coincide with scenarios *wcp*, these constraints must be neglected and only the operation constraints from the LL problem will be considered.

### 3.2.4 Formulation of the lower level (LL) - Operation problem

The LL problem is solely considered for the computation of the operation of the system and prices taken into account by the generation investors in remote areas when computing the probability distribution of their benefits and the value they assign to these benefits. In other words, the LL problem, as a whole, is defined only over scenarios *wcp*. However, the operation constraints are also defined over scenarios *wp* when computing the expansion of the system and the FTRs to be assigned in the UL problem. Thus, while the objective function here is only formulated over the scenarios *wcp* considered by the generation investors, the LL problem constraints are defined over a generic set of scenarios *w* that should coincide with scenarios *wcp* when solving the LL problem, and with scenarios *wp* when these constraints are included in the UL problem.

Please note that if scenarios *wcp* do not exist, then the CVaR Term in the UL problem and those operation constraints in the LL problem should be neglected, resulting in the classical fully centralised problem.

#### Objective function

The objective function to minimise in this problem represents the operation costs, including the variable costs, reliability costs and emission costs.

$$\text{Minimise} \quad \sum_{wcp,p,g} PR^{wcp} SVC_g gp^{wcp}_{p,g} + \sum_{wcp,p,nd} PR^{wcp} CENSe^{wcp}_{p,nd} + \sum_{wcp,p,g} PR^{wcp} CO2_g gp^{wcp}_{p,g} \tag{3.2.26}$$

**Constraints**

Dual variables of each set of equations appear after colons.

**Flow constraint (for candidate lines)**

For each candidate line, the relationship between the flow $f^w_{p,ni,nf,c}$ across a circuit between two nodes and the transfer capacity for the line that links these nodes depends on the variable $it_{(ni,nf,c)}$. If the decision is not to install the line, the flow will be zero, while if the decision is to install the line, the flow could not be higher than the total transmission capacity of the circuit built.

$$\frac{f^w_{p,ni,nf,c}}{TTC_{ni,nf,c}} \geq -it_{ni,nf,c} : \underline{\gamma}^w_{p,ni,nf,c} \qquad \forall \quad w,p,(ni,nf,c) \in lc \tag{3.2.27}$$

$$\frac{f^w_{p,ni,nf,c}}{TTC_{ni,nf,c}} \leq it_{ni,nf,c} : \overline{\gamma}^w_{p,ni,nf,c} \qquad \forall \quad w,p,(ni,nf,c) \in lc \tag{3.2.28}$$

**DC power flow constraints (for existing and candidate lines)**

Represents the flow through the line between two nodes, using a DC formulation for AC lines (only changes in the voltage angles are considered). For the candidate lines, the voltage angle difference between both ends of these lines should only be constrained by the flow equation linking node voltages and the flow when the line is installed.

$$\frac{f^w_{p,ni,nf,c}}{MF_{ni,nf,c}} \geq [\theta^w_{p,ni} - \theta^w_{p,nf}]\frac{Sb}{X_{ni,nf,c}MF_{ni,nf,c}} - 1 + it_{ni,nf,cc} : \underline{\tau}^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{3.2.29}$$

$$\frac{f^w_{p,ni,nf,c}}{MF_{ni,nf,c}} \leq [\theta^w_{p,ni} - \theta^w_{p,nf}]\frac{Sb}{X_{ni,nf,c}MF_{ni,nf,c}} + 1 - it_{ni,nf,c} : \overline{\tau}^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{3.2.30}$$

$$f^w_{p,ni,nf,c} = [\theta^w_{p,ni} - \theta^w_{p,nf}]\frac{Sb}{X_{ni,nf,c}} : \phi^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in le \tag{3.2.31}$$

**Bound for Theta angle**

$$-\frac{\pi}{2} \leq \theta^w_{p,nd} \leq \frac{\pi}{2} : \underline{\varphi}^w_{p,nd}, \overline{\varphi}^w_{p,nd} \quad \forall \quad w,p,nd \tag{3.2.32}$$

**Bounds for transfer capacity in existing lines** For each existing line, the flow is bounded by the total transfer capacity of the line.

$$-TTC_{ni,nf,c} \leq f^w_{p,ni,nf,c} \leq TTC_{ni,nf,c} : \underline{\phi}^w_{p,ni,nf,c}, \overline{\phi}^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in le \tag{3.2.33}$$

**Ohmic losses as a function of the flow**

$$-\frac{L_{ni,nf,c}}{2} f^w_{p,ni,nf,c} \leq l^w_{p,ni,nf,c} \geq \frac{L_{ni,nf,c}}{2} f^w_{p,ni,nf,c} : \underline{\mu}^w_{p,ni,nf,c}, \overline{\mu}^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{3.2.34}$$

**Bounds for losses**

$$0 \leq l^w_{p,ni,nf,c} \leq \frac{L_{ni,nf,c}}{2} TTC_{ni,nf,c} : \underline{\delta}^w_{p,ni,nf,c}, \overline{\delta}^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{3.2.35}$$

**Bounds of production related to Installed Generation Capacity** For each generation unit, the production should be limited by the maximum production capacity corresponding to this unit.

$$0 \leq gp^w_{p,gc} \leq ig_{gc} MP_{gc} \colon \underline{\rho}^w_{p,gc}, \overline{\rho}^w_{p,gc} \quad \forall \quad w,p,gc \tag{3.2.36}$$

$$0 \leq gp^w_{p,ge} \leq MP_{ge} \colon \underline{\omega}^w_{p,g}, \overline{\omega}^w_{p,g} \quad \forall \quad w,p,ge \tag{3.2.37}$$

**Bounds for ENS**

$$0 \leq e^w_{p,nd} \leq D_{nd} : \underline{\zeta}^w_{p,nd}, \overline{\zeta}^w_{p,gc} \quad \forall \quad w,p,nd \tag{3.2.38}$$

**Balance between generation and demand**

For each scenario, each period and each node, the sum of all the generation by the units $gp^w_{p,g}$ in this node, and the ENS $e^w_{p,nd}$ in that node, should be equal to the demand $D_{nd}$ plus the net amount of power flowing out of the node, considering losses. The dual variable of this constraint, $\lambda^w_{p,nd}$, corresponds to the Locational Marginal Price (nodal price).

$$\sum_{g \in gnd} gp^w_{p,g} + e^w_{p,nd} = D_{nd} + \sum_{nf \in la(nd,nf,c)} f^w_{p,nd,nf,c} - \sum_{ni \in la(ni,nd,c)} f^w_{p,ni,nd,c}$$
$$+ \sum_{nf \in ll(nd,nf,c)} l^w_{p,nd,nf,c} + \sum_{ni \in ll(ni,nd,c)} l^w_{p,ni,nd,c} \colon \lambda^w_{p,nd} \quad \forall \quad w,p,nd \tag{3.2.39}$$

### KKT conditions of the lower level (LL) - Operation problem

Equations 3.2.40, 3.2.41, 3.2.42, 3.2.43, 3.2.44, correspond to the derivative of the lagrangian function with respect to the variables $f^w_{p,nd,nf,c}, gp^w_{p,g}, \Theta^w_{p,nd},\ e^w_{p,nd}$ and $l^w_{p,ni,nf,c}$ respectively, finally, equations 3.2.45 and 3.2.46 corresponds to the equality constraints of the operation problem.

$$-\underline{\Upsilon}^w_{p,ni,nf,c \in lc(ni,nf,c)} + \overline{\Upsilon}^w_{p,ni,nf,c \in lc(ni,nf,c)} - \underline{\tau}^w_{p,ni,nf,c \in lc(ni,nf,c)} + \overline{\tau}^w_{p,ni,nf,c \in lc(ni,nf,c)}$$
$$-\underline{\phi}^w_{p,ni,nf,c \in le(ni,nf,c)} + \overline{\phi}^w_{p,ni,nf,c \in le(ni,nf,c)} - \phi^w_{p,ni,nf,c\ \in le(ni,nf,c)} - \frac{L_{ni,nf,c}}{2} \underline{\mu}^w_{p,ni,nf,c \in ll(ni,nf,c)}$$
$$+\frac{L_{ni,nf,c}}{2} \overline{\mu}^w_{p,ni,nf,c \in ll\{ni,nf,c)} + \lambda^w_{p,ni \in la} - \lambda^w_{p,nf \in la} = 0 \colon f^w_{p,nd,nf,c}$$
$$\forall \quad w,p,(ni,nf,c) \in la \tag{3.2.40}$$

$$PR^w SVC_g + PR^w CO_{2g} - \lambda^w_{p,nd} - \underline{\rho}^w_{p,gc} + \overline{\rho}^w_{p,gc} - \underline{\omega}^w_{p,g} + \overline{\omega}^w_{p,g} = 0 \colon gp^w_{p,g}$$
$$\forall \quad w,p,g,nd \in gnd \tag{3.2.41}$$

$$\sum_{nf \in le(nd,nf,c)} \frac{Sb}{X_{nd,nf,c}} \phi_{p,nd,nf,c} - \sum_{ni \in le(ni,nd,c)} \frac{Sb}{X_{ni,nd,c}} \phi_{p,ni,nd,c} - \sum_{nf \in lc(nd,nf,c)} \frac{Sb}{X_{nd,nf}} \overline{\tau}_{p,nd,nf,c}$$
$$- \sum_{ni \in lc(ni,nd,c)} \frac{Sb}{X_{ni,nd,c}} \underline{\tau}_{p,ni,nd,c} + \sum_{ni\ \in lc(ni,nd,c)} \frac{Sb}{X_{ni,nd,c}} \overline{\tau}_{p,ni,nd,c} + \sum_{nf \in lc(nd,nf,c)} \frac{Sb}{X_{nd,nf,c}} \underline{\tau}_{p,nd,nf,c}$$
$$-\underline{\varphi}^w_{p,nd} + \overline{\varphi}^w_{p,nd} = 0 \colon \Theta^w_{p,nd} \quad \forall \quad w,p,nd \tag{3.2.42}$$

$$PR^wCENS - \lambda^w_{p,nd} + \overline{\zeta}^w_{p,nd} - \underline{\zeta}^w_{p,nd} = 0\colon e^w_{p,nd} \quad \forall \quad w,p,nd \tag{3.2.43}$$

$$\lambda^w_{p,ni\in ll} + \lambda^w_{p,nf\in ll} - \underline{\mu}^w_{p,ni,nf,c} - \overline{\mu}_{p,ni,nf,c} = 0\colon l^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{3.2.44}$$

$$-f^w_{p,ni,nf,c} + \left[\Theta^w_{p,ni} - \Theta^w_{p,nf}\right] \frac{Sb}{X_{ni,nf,c}} = 0 \quad \forall \quad w,p,(ni,nf,c) \in le \tag{3.2.45}$$

$$D_{nd} - \sum_{gnd} gp^w_{p,g} - e^w_{p,nd} + \sum_{nf\in la(nd,nf,c)} f^w_{p,nd,nf,c} - \sum_{ni\in la(ni,nd,c)} f^w_{p,ni,nd,c} + \sum_{nf\in ll(nd,nf,c)} l^w_{p,nd,nf,c} + \sum_{ni\in ll(ni,nd,c)} l^w_{p,ni,nd,c} = 0 \quad \forall \quad w,p,nd \tag{3.2.46}$$

**Complementarity Conditions**

Complementarity conditions of the LL problem are provided in this section, linearization of the corresponding operation constraints are provided in Appendix A

$$0 \le \left(f^w_{p,ni,nf,c} - \left[\Theta^w_{p,ni} - \Theta^w_{p,nf}\right] \frac{Sb}{X_{ni,nf,c}} + MF_{ni,nf,c}\left(1 - it_{ni,nf,c}\right)\right) \perp \underline{\tau}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{3.2.47}$$

$$0 \le \left(-f^w_{p,ni,nf,c} + \left[\Theta^w_{p,ni} - \Theta^w_{p,nf}\right] \frac{Sb}{pX_{ni,nf,c}} + MF_{ni,nf,c}\left(1 - it_{ni,nf,c}\right)\right) \perp \overline{\tau}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{3.2.48}$$

$$0 \le \left(f^w_{p,ni,nf,c} + TTC_{ni,nf,c} it_{ni,nf,c}\right) \perp \underline{\Upsilon}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{3.2.49}$$

$$0 \le \left(-f^w_{p,ni,nf,c} + TTC_{ni,nf,c} it_{ni,nf,c}\right) \perp \overline{\Upsilon}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{3.2.50}$$

$$0 \le \left(f^w_{p,ni,nf,c} + TTC_{ni,nf,c}\right) \perp \underline{\phi}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in le \tag{3.2.51}$$

$$0 \le \left(-f^w_{p,ni,nf,c} + TTC_{ni,nf,c}\right) \perp \overline{\phi}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in le \tag{3.2.52}$$

$$0 \le \left(-gp^w_{p,gc} + MP_{gc}\mathrm{i}g_{gc}\right) \perp \overline{\rho}_{p,gc} \ge 0 \quad \forall \quad w,p,gc \in gnd \tag{3.2.53}$$

$$0 \le \left(gp^w_{p,gc}\right) \perp \underline{\rho}_{p,gc} \ge 0 \quad \forall \quad w,p,gc \in gnd \tag{3.2.54}$$

$$0 \le \left(-gp^w_{p,g} + MP\right) \perp \overline{\omega}_{p,g} \ge 0 \quad \forall \quad w,p,g \in ge \tag{3.2.55}$$

$$0 \le \left(gp^w_{p,g}\right) \perp \underline{\omega}_{p,g} \ge 0 \quad \forall \quad w,p,g \in ge \tag{3.2.56}$$

$$0 \le \left(D_{nd} - \mathrm{e}^w_{p,nd}\right) \perp \overline{\zeta}_{p,nd} \ge 0 \quad \forall \quad w,p,nd \tag{3.2.57}$$

$$0 \le \left(\mathrm{e}^w_{p,nd}\right) \perp \underline{\zeta}_{p,nd} \ge 0 \quad \forall \quad w,p,nd \tag{3.2.58}$$

$$0 \le \left(0.5L_{ni,nf,c} f^w_{p,ni,nf,c} + l^w_{p,ni,nf,c}\right) \perp \underline{\mu}_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{3.2.59}$$

$$0 \le \left(l^w_{p,ni,nf,c} - 0.5L_{ni,nf,c} f^w_{p,ni,nf,c}\right) \perp \overline{\mu}_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{3.2.60}$$

$$0 \le \left(l^w_{p,ni,nf,c} - 0.5L_{ni,nf,c} TTC_{ni,nf,c}\right) \perp \underline{\delta}_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{3.2.61}$$

$$0 \le \left(0.5L_{ni,nf,c} TTC_{ni,nf,c} - l^w_{p,ni,nf,c}\right) \perp \overline{\delta}_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{3.2.62}$$

$$0 \leq \left(\theta^{w}_{p,nd} + \frac{\pi}{2}\right) \quad \perp \quad \underline{\varphi}_{p,nd} \geq 0 \qquad \forall \quad w, p, nd \tag{3.2.63}$$

$$0 \leq \left(\frac{\pi}{2} - \theta^{w}_{p,nd}\right) \quad \perp \quad \overline{\varphi}_{p,nd} \geq 0 \qquad \forall \quad w, p, nd \tag{3.2.64}$$

### 3.2.5 Solving strategy

As mentioned above, the problem at hand, formulated as a bi-level problem, is transformed into an MPEC by deriving the KKT optimality conditions of the operation problem (LL) and integrating these into the expansion planning problem (UL). The KKT conditions of the LL operation problem are derived in Appendix A. Therefore, the overall optimization problem to be solved can be represented in a single level according to the following MILP formulation where complementarity constraints have been linearized making use of the BigM formulation and M values have been tuned following the algorithm proposed in [96].

**Upper level** Eq [(4.3.9 - 3.2.25)]
**Lower level** (KKTs)

Operation see Eq [(3.2.40 - 3.2.46)].
Linearised complementarity constraints Eq [(A.0.1 - A.0.36)], see Appendix A.

This model has been implemented in Python using Pyomo, and computations were performed on a computer equipped with an Intel® Core™ i7-8700 CPU and 32 GB of RAM.

## 3.3 Case Studies and Results

### 3.3.1 Illustrative 2-node example

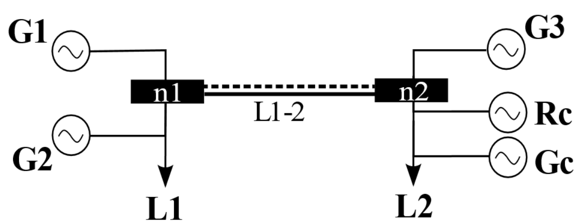


Figure 3.2: Illustrative 2-node example

Consider the simplified 2-node system in Figure 3.2, where there is an existing line L1-2 whose capacity is 35 MW and a candidate line L1-2 from node 1 to node 2 whose capacity is 70 MW and whose investment cost is 14.7 [M€]. Within this system are three existing generators, G1, G2, and G3, and two candidate generators, Rc and Gc, both in node 2. The generation capacity and variable production cost for each generator are summarized in Table 3.1. The annualized investment costs for Rc and Gc are 30.4[M€/year] and 27.4[M€/year], respectively.

Candidate generator, Rc is risk averse. When representing the risk profile, parameter $\alpha$ has been set to 0.75. This means that the scenarios considered by the corresponding investors when aiming to

Table 3.1: Generators features. Illustrative 2-node example

| Gen | Node | Capacity [MW] | VarCost [€/MWh] |
|---|---|---|---|
| G1 | n1 | 40 | 80 |
| G2 | n1 | 40 | 70 |
| G3 | n2 | 40 | 50 |
| Gc | n2 | 200 | 3 |
| Rc | n2 | 180 | 0 |

maximise their lowest possible benefits concern those scenarios leading to the worst possible outcome for these generators in economic terms and whose accumulated probability of occurrence is 0.25.

Generator Rc faces some relevant risk related to the uncertainty about the future price evolution at his node, i.e. the one it earns for the electricity it produces. On the other hand, Gc, if built, is not facing any relevant risk since it is assumed that Gc earns high-enough predefined revenues secured by its promoter in a long-term generation capacity auction it wins.

The uncertainty perceived by generator Rc about the future system evolution and the benefits it will make is represented through five equiprobable scenarios. In this case, the only parameter represented as uncertain is the future demand. The distribution of the demand among the nodes for each of the scenarios considered by generator Rc when determining the probability distribution of its profits is summarized in Table 3.2.

Contracting FTRs is an option open for generators to manage the risk associated with uncertainty about the price of the node where they are located. FTRs are defined by taking node ‘n1’ as the reference node given the generation features available and to be deployed in each node, the price of ‘n1’ is expected to be more stable than that of ‘n2’. Acquiring FTRs provides the owners the right to earn the congestion rents produced by the grid between the node where they are located and node ‘n1’.

Table 3.2: Demand behaviour [MW]

| Sc | n1 | n2 | TotalDem |
|---|---|---|---|
| 1 | 100 | 170 | 270 |
| 2 | 105 | 150 | 255 |
| 3 | 130 | 130 | 260 |
| 4 | 110 | 110 | 220 |
| 5 | 120 | 90 | 210 |

In this Case Study, generation and transmission investments are discrete and involve relatively large capacity additions, as long as generator Rc is installed, the development of the rest of the system and its operation are not affected by Rc’s decision to contract FTRs and the amount of them that Rc contracts. As mentioned before, the price paid by generator Rc for the contracted FTRs is deemed to be equal to the expected difference in prices between the connection and reference nodes defined in the FTR contract. Thus, the price paid for the FTRs equals the expected revenues provided by these FTRs as a result of the network-constrained market clearing.

Given that the price in the reference node is more stable than that in node 'n2', FTRs would allow generator Rc to increase its net market revenues in the most unfavourable scenarios, i.e. those where the price in its connection node, n2, is lowest. Then, by contracting FTRs, Rc stabilises its revenues. Given that generator Rc is risk-averse, increasing its market revenues in the most unfavourable conditions and stabilising its revenues while not modifying its expected profits has an added value for this generator. As a consequence, while the investor for generator Gc should not be interested in acquiring FTRs, generator Rc could find buying FTRs attractive.

The change in the expected aggregated net benefits made by agents has been computed as the corresponding change in the expected total system costs since both should coincide. The impact of the market risk faced by the investor for generator Rc, which is the single investment by a risk-averse investor deemed to be subject to relevant risks, on the value this investor puts on the market benefits of generator Rc has been modelled as an additional term in the objective function expressed in terms of the CVaR of the probability distribution of generator Rc's profits determined by the investor for this generator. The latter is affected by the amount of FTRs contracted.

### Results

Provided that generator Rc is built, the rest of the investment decisions made in this Case Study involve building candidate line L1-2, not building generator Gc, and having generator Rc contracting an amount of 105 M units of FTRs; note that this value is conditioned by the need to enforce the FTRs feasibility constraints imposed to guarantee the SO revenue adequacy. The production of each generator per scenario, if Rc is installed, is provided in Table 3.3. The locational marginal prices for each node and scenario resulting from these investment decisions are shown in Table 3.4. Considering n1 as the reference node, this table shows the price difference between the reference node and the connection node of candidate generator Rc (node n2) in its last column. The system's operation and the resulting prices vary across the scenarios considered. In scenarios 1 and 2, where there is no congestion, G2 is the price setter at both nodes, resulting in a price difference of 0. However, in the presence of congestion, in scenarios 3 and 4, G2 sets the price at node n1, while G3 sets the price at node n2, leading to a price difference of 20 between the two. Finally, in scenario 5, where the congestion is more relevant, G2 is the price setter at node n1 and Rc is the one at node n2, resulting in a significant price difference of 70 between the two nodes. Therefore, scenario 5 represents the worst-case scenario from Rc's perspective.

Table 3.3: Generation output results over the set of scenarios considered and for all units [MW] ($gp^{w}_{p,g}$)

| Sc | G1 | G2 | G3 | Rc | Gc |
|---|---|---|---|---|---|
| 1 | 0 | 30 | 40 | 200 | 0 |
| 2 | 0 | 15 | 40 | 200 | 0 |
| 3 | 0 | 25 | 35 | 200 | 0 |
| 4 | 0 | 5 | 15 | 200 | 0 |
| 5 | 0 | 15 | 0 | 195 | 0 |

Table 3.4: Nodal price behaviour [€/MWh]

| Sc | n1 | n2 | PriceDiff |
|---|---|---|---|
| 1 | 70 | 70 | 0 |
| 2 | 70 | 70 | 0 |
| 3 | 70 | 50 | 20 |
| 4 | 70 | 50 | 20 |
| 5 | 70 | 0 | 70 |

The annual generator Rc's market income, the congestion rents produced by the FTRs acquired by this generator, and, as a result of these and the costs incurred, the net annual benefits obtained by generator Rc, both when FTRs are available to be contracted and when they are not, are provided per scenario in Table 3.5. Please remember that profits made by each generator are considered when computing the impact of FTRs on the system welfare.

Table 3.5: Annual revenues and profits of generator Rc if installed[M€]

| sc | Income (Market) | Income (FTRs) | $gpr_{cp}^{w}$ with FTRs | $gpr_{cp}^{w}$ without FTRs (forcing $ig_{Rc} = 1$) |
|---|---|---|---|---|
| 1 | 122.64 | 0 | 72.02 | 92.24 |
| 2 | 122.64 | 0 | 72.02 | 92.24 |
| 3 | 87.6 | 18.37 | 55.36 | 57.2 |
| 4 | 87.6 | 18.37 | 55.36 | 57.2 |
| 5 | 0 | 64.31 | 13.7 | -30.4 |

According to Table 3.5, the expected value of the generator Rc's profits when contracting FTRs and its expected value when not contracting FTRs, over all the scenarios, amount to 53.7[M€]. However, FTRs allow this generator to stabilise its income and profits. Even under unfavourable conditions, the net profits of generator Rc are positive when contracting FTRs since, also in the corresponding scenario, this generator is earning the stable, higher price of the node where the main load centre is located. Thus, in scenario Sc05, not contracting FTRs, the resulting generator Rc's profit is negative, while acquiring FTRs generator Rc makes a positive profit.

Table 3.6 provides the main results for this case study, in particular, row 1 on the value of the objective function of the UL problem is employed to compute the impact of LT-FTRs on the system welfare, while rows 6 and 7, are showing the investment decisions by the stakeholders. As shown in Table 3.6, when contracting FTRs is allowed, and investors are risk averse, it is socially optimal to build generator Rc and not generator Gc and to have Rc contracting 105 units of FTRs.

Note that, due to the simultaneous feasibility condition applied to the full set of FTRs issued, contracting FTRs requires building line LN1-2. This condition applies because the SO, being fully regulated, is strongly risk averse and is not willing to run the risk of the congestion rents it is earning in the dispatch not being large enough to pay the FTRs owners the amounts owed to them. On the other hand, when FTRs are not considered an option while investors are deemed risk averse, building generator Gc, instead of generator Rc is socially optimal, as resulting from the perfect coordination of stakeholders' decisions, even when Gc's operational costs are higher than those of Rc. When generation investors are risk-neutral, investing in generator Rc is socially optimal. Note that non-risk averse results have been obtained solving a single-level optimization problem since, when GENCOs are deemed to be risk-neutral, the CVaR term in the objective function of the upper level problem is disregarded as explained in section 3.2.3. Then, the problem addressed becomes the classical centralised, generation and transmission expansion planning problem, which can be formulated as a single level problem. Note that this is the case resulting in the lowest possible system costs and is therefore considered the benchmark case.

The investment plus operation costs incurred at the system level when generator Rc is installed, either because investors are risk averse and FTRs are available to be contracted, or the investment in generator Rc is forced to take place, or because investors are deemed to be risk neutral, amount to 53.8 [M€]. These costs amount to 66 [M€] when investors are risk-averse and cannot acquire FTRs.

The impact of uncertainty on the value placed by the investor of generator Rc on this generator's

Table 3.6: Amounts of costs of different types incurred when generation investors are risk averse and i) FTRs can be contracted; ii) FTRs cannot be contracted, and the investment in generator Rc is forced; iii) FTRs cannot be contracted and socially optimal investment decisions are made by all investors; and iv) investors are risk-neutral – 2-node example.

| | **Risk** | | | **Non-risk averse** |
|---|---|---|---|---|
| | **with FTRs** | **without FTRs (forcing $ig_{Rc} = 1$)** | **without FTRs** | |
| 1 ObjectiveFunction [M€] | 31.8 | 66.7 | 66.0 | 53.8 |
| 2 Inv+Op Cost[M€] | 53.8 | 53.8 | 66.0 | 53.8 |
| 3 FTRCost[M€] | 20.2 | - | - | NA |
| 4 Impact of risks on value of generators Rc's profits for its investor [M€] | 22 | -12.9 | - | NA |
| 5 FTR[M] | 105 | - | - | NA |
| 6 $ig_{Rc}$ | 1 | 1 | 0 | 1 |
| 7 $ig_{Gc}$ | 0 | 0 | 1 | 0 |

profits when this investor is risk averse is 22 [M€] when FTRs can be contracted, and -12.9 [M€] when they cannot be contracted, and the investment in generator Rc is forced. As a result, one can conclude that building generator Rc, instead of Gc, and investing in line LN1-2 is socially optimal in any case. Furthermore, this leads to a decrease in the expected overall system costs since generator Rc is more efficient than generator Gc. However, if investors are risk averse, the most efficient system expansion only occurs when FTRs can be contracted. The reader should note that here it has not been checked whether this investment strategy is optimal from the point of view of generator Rc, who should be willing to maximise its own profits.

### 3.3.2 Representative European case study

In this case study the Western European electricity system is considered, as depicted in Figure 3.3. The use of FTRs as a mechanism for risk-averse GENCOs to hedge the long-term price risk their generation investments are subject to due to the possible occurrence of network congestion, is assessed. The network within each country is represented as a single node connected to the neighbouring countries. The network model comprises 24 nodes: 20 corresponding to individual European countries, one node representing the Baltic area (LT, LV, and EE), another node representing Southeast Europe (BA, ME, RS, RO, BG, MK, GR) and two additional nodes representing remote areas where renewable generation can be deployed. One of these areas is located in the North of Africa (NA), and the other in the North Sea (NS). Links in grey within the system schematic representation in Figure 3.3 correspond to equivalent corridors representing several connections among the corresponding system areas. The features of these equivalent corridors have been determined following the Ward equivalent approach. Within this case study, the aim is to determine the system's expansion in the 2030-time horizon.

The network data have been derived considering the dataset for net transfer capacities among national systems published in the transparency platform of ENTSO-E, available in [97], and the technical information on the features of network elements within the PYPSA dataset described

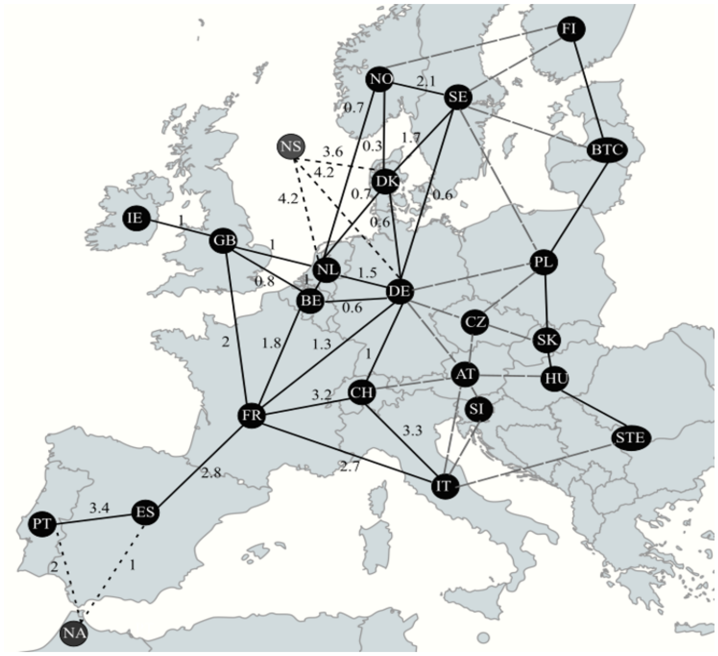


Figure 3.3: Equivalent European network considered in the 2030-time horizon -Existing network and candidate lines considered in remote areas [GW]

fully in [98] for overhead AC lines. For HVDC lines, the data considered are available in [99]. Generation and Demand data have been drawn from MAF2019 and MAF2020 datasets and the solar and wind generation profiles. Information on these is available in [100]. The operation and generation investment costs considered are those available in [101] and [102] respectively. A 5% discount rate has been considered. The network investment costs considered are those available in [103] and [104]-[105] for Europe and Africa, respectively. The network configuration in the NS remote area and the options for the potential development of this grid, including the potential connections between the network in this area and the neighbouring countries, have been drawn from the scenario 2030 data set available within the North Sea Wind Power Hub (NSWPH) [106]. Demand data for the North of Africa have been drawn from [107], while the generation capacities, the generation investment costs and the variable production costs have been drawn from [108]. Investment costs have been taken from [109] for the North Sea, considering economies of scale. $CO_2$ prices have been drawn from the report in [110]; specifically, a value of 128 €$/tCO_2$ has been considered, corresponding to the gradual development scenario by 2030 in the analyses reported.

In total, 35 candidate generators, 67 existing generators, 47 existing lines and 14 candidate lines have been considered. Table 3.7 summarizes the annual demand data considered per country and Table 3.8 summarizes the existing and candidate generation capacity considered per technology Additional details on the data considered can be requested from the authors.

For the sake of simplicity, generation investment decisions have been deemed to be continuous, in line with the scalability of relevant generation investment projects in different countries, particularly renewable generation, and just six time periods have been selected, making use of the k-medoids clustering technique, to represent the operation of the system throughout the target year. Note that the operation periods to consider have been chosen taking separately the demand, solar power production, and wind power production within each region as classification variables. Using these classification variables, it is possible to select, for their consideration in the problem, all the main types of representative periods to take into account: i) those when the power generation to be deployed by the risk-averse investor is producing energy and there is relevant congestion on the interconnection between the remote areas and the rest of the system (probably, the worst case ones from the point of view of Gencos in these areas, in the absence of FTRs); ii) those when this generation is also producing energy but the aforementioned interconnection is not congested, and; iii) those when the generation built by the targeted investor is not producing energy. To determine the appropriate number of representative hours to consider, the elbow method has been implemented trying to strike an optimal trade-off between the level of detail considered in the representation of the system operation and the computational burden of the problem. Following this approach is possible because there is no consideration of inter-temporal constraints in the problem formulated. The reader should note that the number of operation snapshots considered must be balanced with the number of scenarios taken into account.

Table 3.7: Annual Demand Considered per country [TWh]

| **PT** | **ES** | **FR** | **GB** | **BE** | **DE** | **CH** | **IT** | **NL** | **DK** | **SE** | **IE** | **NO** | **NA** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 58 | 266 | 488 | 240 | 92 | 492 | 82 | 305 | 91 | 26 | 128 | 51 | 181 | 58 |

Table 3.8: Existing and candidate Generation capacity per technology [MW].

| | **Solar** | **Wind** | **Hydro** | **Gas** | **Nuclear** | **Others** |
|---|---|---|---|---|---|---|
| Existing | 137,075 | 197,203 | 117,478 | 135,797 | 80,056 | 20,081 |
| Candidate | 160,666 | 110,079 | 36,767 | - | 365 | - |

In addition, the $\alpha$ and $\beta_{cp}$ parameters, considered when modelling the impact of uncertainty on the value of investments for GENCOs in remote areas are assigned a value of 80%. This is a reference value commonly used in the literature for these parameters [69] and corresponds to the standard risk profile of investors in this type of generation assets. The reference node considered for the definition of FTRs is the one corresponding to Germany (DE). This is deemed to be strongly connected to the rest of the system and have stable enough prices.

Given that, in this case study, as will be shown in the results section, only one GENCO, located in the NS area, is deemed to be subject to a relevant level of risk concerning the level of its profits, and is therefore represented as risk averse, then, only the CVaR of this GENCO is computed in this case study. Accordingly, the higher the level of risk aversion by this GENCO, the more conservative the investment strategy it would opt for, and the more relevant the role played by LT FTRs could be.

As discussed in 3.2.1, the uncertainty represented is of two types: external or exogenous uncertainty, reflecting external factors not to be determined within the problem, and internal, or endogenous, uncertainty corresponding to the uncertainty each stakeholder has about the investment strategy to be followed by the rest of stakeholders.

In this case study, assuming each GENCO within a remote area deems the behaviour of the GENCOs in the rest of areas in the system competitive, i.e social-welfare maximising, this GENCO may still have some uncertainty about the investment decisions made by the rest of GENCOs in his area. For simplicity reasons, the GENCOs in the rest of the system, whose investments are also being computed within the problem formulated, are deemed to perceive as certain and predictable those conditions that could affect the profitability of their investments. Therefore, the value they assign to their investments is deemed not to be affected by uncertainty and the management made of it. However, in principle, the GENCOs in remote areas are deemed to perceive both endogenous uncertainty and exogenous uncertainty affecting the revenues and profits of their investments. This is why they are potentially interested in acquiring FTRs to hedge the corresponding risk.

Exogenous uncertainty is to be considered both:

- when planning the expansion of the system, assuming socially perfect coordination among the stakeholders' decisions, and
- when determining the value that GENCOs in remote areas, whose investment decisions are being computed, put on the investments they undertake.

Here it is assumed that there is a single GENCO considering the deployment of generation in each remote area. Therefore, the endogenous uncertainty perceived by GENCOs in remote areas is neglected. Only exogenous uncertainty is deemed to exist.

In general, the set of scenarios considered when representing the uncertainty faced by GENCOs in remote areas when computing the value of their investments, *wcp* in the formulation, should be different from the set of scenarios considered to represent the uncertainty affecting the computation of the perfectly coordinated expansion of the system, based on the simplifying assumptions adopted in this work. The latter scenarios should only reflect exogenous uncertainty and are denoted as *wp* in the formulation. However, since endogenous uncertainty is not considered, thus, the scenarios *wcp* coincide with the scenarios *wp*. Table 3.9 summarises the main assumptions made associated with the modelling of risk considered in the formulation:

Table 3.9: Main assumptions associated with modelling of risk

| |
|---|
| $\alpha = 0.8$ |
| $\beta_{cp} = 0.8$ |
| $ig_{gc} \in [0, 1]$ |
| $wcp = wp$ |

Exogenous uncertainty has been defined as the amount of generation deployed within each remote area, besides that deployed by the GENCOs whose investment decisions are being computed. This additional generation investment within remote areas, not determined endogenously in this problem, corresponds to RES-based generation capacity procured by national authorities within the countries in the region through support schemes like generation auctions, where winners are guaranteed remuneration for these investments. Then, this additional generation is not interested in FTRs, as they do not perceive uncertainty about the revenues they will make.

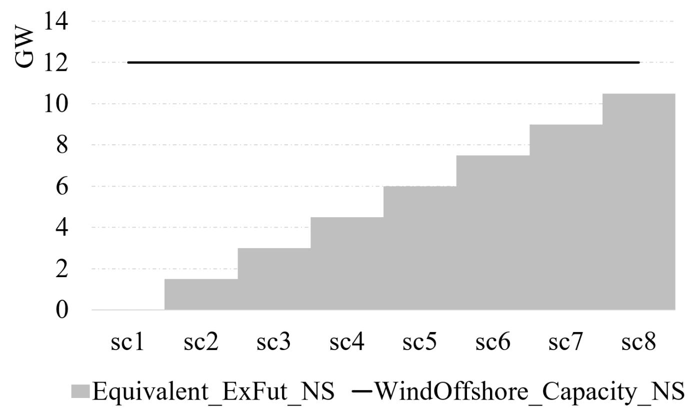


Figure 3.4: Uncertainty scenarios considered in the NS area

The set of scenarios *wp*, being the same as *wcp*, are defined in terms of the amount of RES generation capacity deployed within a remote area that is decided exogenously.

The amounts of additional, exogenously determined, generation (Offshore Wind) deployed in the North Sea (NS) within the representative scenarios considered for this are depicted in Figure 3.4 under the name "Equivalent EXFut NS". This figure also represents the maximum overall amount of generation capacity that can exist in this area (12,000 MW). This is depicted under the name "WindOffshore Capacity NS".

The amount and type of this additional generation, can affect the electricity prices in these areas and, the market revenues of the GENCOs whose investment decisions are made. This new generation would compete with GENCOs' generation to access the interconnection capacity between these areas and the rest of the system. The smaller the amount of additional generation capacity of this type deployed, the more favourable the corresponding scenario is for the GENCO in the corresponding area whose investments, potentially conditioned by the acquisition of FTRs, are being computed.

### Results

Here, the computed results on the expansion of the system are provided, the resulting operation, and the objective function, both for the situation where long-term FTRs are made available for the generation investors in the remote areas to contract them, and for that situation where FTRs are not made available. In the former situation, the amount of FTRs to be contracted is also computed. These results are computed assuming perfect coordination of the investment decisions made by the stakeholders, as explained above.

Nodes NA (North Africa) and NS (North Sea) are the nodes representing the remote areas weakly connected to the rest of the system where new generation can be potentially interested in acquiring FTRs. Based on the computed results, considering the offshore wind renewable potential in the NS, the potential of RES-based generation in the NA, the distribution of primary RES-based energy resources within Europe, and the network cost required to integrate the generation deployed in each of the two areas into the European electricity system, deploying off-shore wind generation in the NS make sense, while the deployment of generation capacity in the NA to supply the European

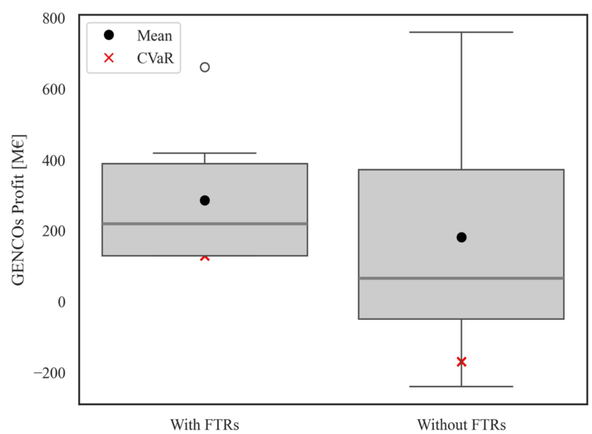


Figure 3.5: Boxplot - Profit of the GENCO in the NS both considering FTRs and not considering FTRs when this GENCO is deemed to be risk-averse

demand is not cost-efficient. The latter result is partly due to the similarities between the features of the potential new solar generation in the North of Africa and those in Southern Europe. Given the higher network integration costs of the former, the model determines it is more efficient to deploy solar generation capacity in the south of Europe and not in Africa until the potential of the former has been exhausted. The deployment of part of that offshore wind generation in the NS deemed to be cost-efficient is, nevertheless, contingent on the acquisition of LT FTRs by this generation, providing it with a price risk hedge. As shown in Table 3.10, when the GENCO in the NS area is deemed risk averse, the level of the socially optimal NS generation investments in the case where FTRs can be contracted is 69% of the overall maximum generation capacity that can be installed while, when FTRs cannot be contracted, the level of these investments is only 56%.

By acquiring LT FTRs, the GENCO located in this area manages to increase the CVaR of the market benefits it would make out of its investments in this area. Then, some of these investments are made socially profitable when considering the effect of uncertainty on the value that the GENCO puts on them. Making FTRs available can facilitate a risk-averse GENCO to undertake additional generation investments within the North Sea that are socially efficient when assuming that generation companies behave competitively and their investments are perfectly coordinated with the transmission ones planned. This is because FTRs are found to allow this GENCO to effectively manage the price risk it perceives associated with these investments. Given the expansion planning results, the focus of the next discussion is on the results for the NS remote area.

The results computed are shown for the target year and the representative scenarios. The impact of contracting LT-FTRs on the set of investments to undertake depends on some of the framework conditions applied in the system. Notably, in order for the FTRs to trigger additional investments in the NS area, contracting FTRs should make the expected net social value created by these additional NS generation investments larger than the expected net social value created by some generation that is installed in other areas more tightly connected to the rest of the system in the case where FTRs are not available. Contracting FTRs increases the value created by additional NS generation due to the increase in the stability of this generation's profits across scenarios rendered by FTRs.

According to Figure 3.5 and Table 3.10, the CVaR of the profits of the GENCO in the NS area when FTRs are not available is negative and significant (-169 [M€]). On the other hand, when the GENCO can contract FTRs, the CVaR of the profits of these investments becomes positive and large (129 [M€]). This means that contracting FTRs allows the GENCO to significantly increase the value of the profits it makes from the new generation it builds in the NS area in those the scenarios considered that are most unfavourable for this GENCO. Also, as shown in Figure 3.5, the variability across scenarios of the profits made by this new NS generation when contracting FTRs is much smaller than the variability of these profits when not contracting FTRs.

Table 3.10: Amounts of costs of different types incurred when considering the GENCO in the NS as risk averse – Representative European Case Study.

| | | **Risk averse** | |
|---|---|---|---|
| | | **with FTRs** | **without FTRs** |
| 1 | Generation Investment Cost in NS [M€] | 1,518 | 1,242 |
| 2 | Network Investment Cost in NS [M€] | 191 | 191 |
| 3 | Generation Investment Cost Rest of Europe [M€] | 31,444 | 30,282 |
| 4 | Network Investment Cost Rest of Europe [M€] | 235 | 188 |
| 5 | Total Investment Cost [M€] | 33,388 | 31,903 |
| 6 | Operational Cost [M€] | 30,607 | 31,276 |
| 7 | Emissions Cost [M€] | 19,250 | 19,864 |
| 8 | Inv + Total Oper. Cost [M€] | 83,245 | 83,043 |
| 9 | CVaR [M€] | 129 | -169 |
| 10 | ObjectiveFunction [M€] | 83,142 | 83,178 |
| 11 | Cost of buying FTRs ($cftr$) [M€] | 629 | - |
| 12 | Amount of gener. in the NS as a fraction of gener. potential: $ig_{NS}$ [%] | 69 | 56 |

Table 3.10 provides some relevant results associated with the research questions analysed in this chapter. In particular, row 12 shows the amount of generation built within the remote area affected by the implementation of LT-FTRs, both in the case where these rights are made available and when they are not. This is most relevant when assessing the impact of these rights on the system development. Row 10 shows the value of the objective function of the UL problem both when implementing and when not implementing FTRs. The difference between the value of UL problem objective function in these two cases is the impact of LT-FTRs on the system welfare.

As shown in Table 3.10, if the GENCO in the NS area is risk-averse, the expected net social welfare of the system resulting from its planned expansion is more extensive when this GENCO can contract FTRs than when it cannot. On the other hand, the total costs incurred (investment plus overall operation costs) when FTRs can be contracted are higher than those incurred when FTRs cannot be contracted. As mentioned, contracting FTRs allows the risk-averse generation to be installed in the NS area to significantly increase the value it puts on its market profits by significantly increasing these profits in the worst-case scenarios. However, being able to contract a certain amount of FTRs requires making these simultaneously feasible.

It is also essential to consider that investments in generation in the NS area and investments in transmission capacity in the system are deemed continuous, except those investments focused on reinforcing the direct interconnectors between the NS area and the neighbouring nodes. Given this,

Table 3.11: Amounts of costs of different types incurred when considering the GENCO in the NS as risk averse – Representative European Case Study.

| | | **Non-risk averse** |
|---|---|---|
| 1 | Generation Investment Cost NS [M€] | 2,031 |
| 2 | Network Investment Cost NS [M€] | 191 |
| 3 | Generation Investment Cost Rest of Europe [M€] | 29,785 |
| 4 | Network Investment Cost Rest of Europe [M€] | 188 |
| 5 | Investment Cost [M€] | 32,195 |
| 6 | Operational Cost [M€] | 30,950 |
| 7 | Emissions Cost [M€] | 19,561 |
| 8 | Inv + Total Oper. Cost [M€] | 82,706 |
| 9 | Amount of gener. in the NS as a fraction of gener. potential: $ig_{NS}$ [%] | 91 |
| 10 | Postprocessing CVaR result [M€] | -1,513 |

making feasible the socially optimal amount of FTRs to be issued (maximising the overall value that market agents put on the profits they make) involves building more transmission capacity aimed at increasing the transfer capacity between the NS area and the reference node than what is optimal from the point of view of the minimisation of the expected system costs (the average costs over all the scenarios considered).

Note that, as shown in Table 3.10, the additional amount of transmission capacity built in the case where FTRs are available beyond that built in the case where FTRs are not available does not concern the direct interconnectors between the NS area and the neighbouring nodes (these correspond to discrete investment decisions), but other transmission lines whose reinforcement, for many of them, is required to achieve an increase in the transfer capacity between the NS area and the reference node, given that FTRs are defined between these two nodes. Thus, in this Case Study, the ability to contract FTRs triggers additional generation investments in the NS area and transmission investments in the vicinity of the NS area, which, altogether, with the FTRs contracted, lead to an increase in the expected social welfare, representing the aggregated value that agents in the system, generators and consumers, put on the profits they make, but also an increase in the overall expected system costs across all the scenarios considered.

Table 3.11 provides results for the case where the GENCO in the NS area is non-risk averse or risk-neutral. In this case, the term associated with the CVaR is not included in the objective function to optimize, then, those differences in the objective function caused by the implementation of FTRs, represents both the decrease in the expected social welfare and increase in the expected system costs resulting from the system expansion since in this case, the increase in the social welfare coincides with the decrease in the total system costs (expansion plus operation), becoming the classical centralised, generation and transmission expansion planning problem, which can be formulated as a single-level minimising costs problem and considered a benchmark, as explained in subsection 3.2.3.

As a post-processing result, the CVaR level is computed for the investments undertaken in the NS area. According to the formulation proposed, this CVaR level is proportional to the impact that the risk that the market revenues of the GENCO in the NS area are subject to, would have on

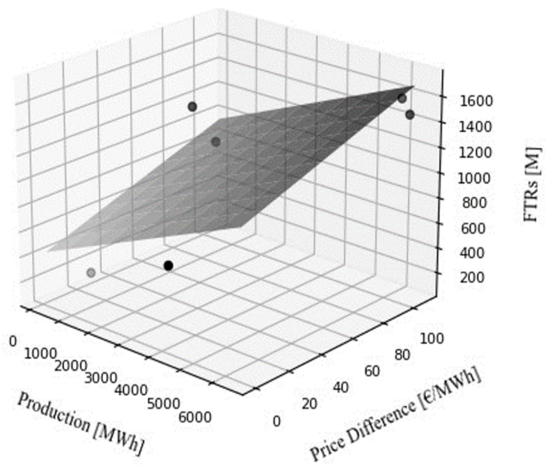


Figure 3.6: Impact of the price difference between the NS area and the reference node on the amount of additional generation deployed in this area, its production, and the amount of FTRs contracted

the value assigned by a risk-averse GENCO to the socially efficient investments undertaken by a risk-neutral GENCO. The value of the CVaR for the generation built by a risk-neutral GENCO was computed assuming the risk profile of the risk-averse GENCO considered in the previous cases is extremely negative, amounting to -1,513 [M€]. This reflects the high market risk that the generation built by a risk-neutral GENCO in the NS is subject to. The investments by this GENCO amount to 91% of the maximum amount of investments possible in the remote area.

As explained in subsection 3.2.3, the CVaR term is considered with a negative sign in the objective function of the upper level (minimisation) problem and, therefore, is being maximised. This term is not bounded, or limited, by any constraint specifically. However, within this case study, the CVaR, representing the expected value of the GENCO's profits in the worst-case scenarios, has a negative value in the case where FTRs are not available. Therefore, the absolute value of the CVaR term should be minimised, as long as it is negative, while it should be maximised when becoming positive due to the implementation of FTRs.

The results and discussion provided below are focused the assessment of how the use of FTRs impacts the investment decisions made by risk-averse generation companies. Figure 3.6 shows, for the case where FTRs are available to be contracted and the GENCO in the NS area is risk averse, and across the operation hours, or operation situations, considered to represent the operation of the system throughout the year, the relationship that exists among the price difference between the reference node defined and the NS area, the amount of FTRs contracted by the GENCO in the NS area, and the amount of electricity production in this area. The surface there represented illustrates how the larger the difference in prices between the NS area and continental Europe (reference node) is in an operation snapshot, the larger the amount of FTRs contracted by the generation in the NS is, and the larger the amount of new generation deployed there and its production also is.

Table 3.12 provides the amount of renewable generation built in the NS and the rest of Europe in the three different cases considered: the case with risk-averse investors in generation in the NS area and the possibility to contract FTRs; that with risk-averse investors in the NS area but where they

Table 3.12: Size of the investments in renewable generation taking place in each of the three cases considered for the risk profile of the GENCO in the NS and the availability of LT FTRs [MW]

| | | **Solar** | **Wind** | **Hydro** |
|---|---|---|---|---|
| Risk-averse Without FTRs [MW] | North Sea | | 6,750 | |
| | Rest of Europe | 69,137 | 49,538 | 25,618 |
| Risk-averse With FTRs [MW] | North Sea | | 8,250 | |
| | Rest of Europe | 70,411 | 50,246 | 28,456 |
| Non-risk averse [MW] | North Sea | | 11,039 | |
| | Rest of Europe | 70,985 | 48,031 | 24,671 |

cannot contract FTRs, and; that where the investors in generation in the NS area are risk-neutral. The difference between the results shown for the two first cases explored corresponds to the impact of LT-FTRs on the development of clean generation in Europe, which is the main issue to be addressed related to Rq1. According to the results, when considering risk-averse investors in the NS area, contracting FTRs triggers significant additional investments in renewable generation, specifically in wind generation, in the NS area. Renewable generation investments in the NS area amount to 8,250 MW of capacity in the case with FTRs, while these are only 6,750 MW of capacity when FTRs cannot be contracted. This represents an increase of 22.2% in the magnitude of these investments.

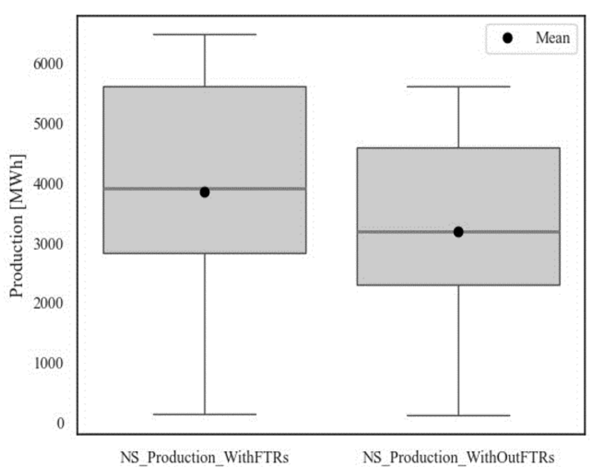


Figure 3.7: North Sea Power Production with FTRs vs without FTRs - Boxplot format

When not being able to contract FTRs, due to the significant price risk offshore wind generation in the NS area is subject to, it is socially optimal, according to the decisions made by perfectly coordinated generation and transmission investors, to make use of more thermal generation in the rest of Europe instead of wind generation in the NS area, even though the expected operational costs incurred are larger than those incurred by wind generation in the NS area (due to the especially favourable conditions that exist for the production of electricity from wind in this area). Making use of gas-fired generation instead of wind (see Figure 3.8) results in higher electricity prices in Europe, including the reference node, when the production of RES-based generation is low overall in Europe. In some of these situations, the production of wind generation in the NS area will not be negligible, given the higher quality of the primary energy resource there, but it will not be large enough to create congestion on the corridors linking this NS area to continental Europe. The latter is relevant since, in the absence of FTRs, congestion occurring on the connection between the NS area and the rest of Europe prevents wind generation in the NS from accessing the electricity prices existing in the reference node and Europe in general. In the later operation situations considered, making use of gas-fired generation instead of RES-based generation would result in higher electricity prices being earned by risk-averse wind generation in the NS not having contracted FTRs (because these are not available), both in the most favourable and the most unfavourable scenarios. Then, this investment strategy could increase the CVaR of those wind generation investments undertaken by risk-averse investors in the NS and result especially attractive for that generation in the NS not having been able to contract FTRs, see Figure 3.7 and Figure 3.8.

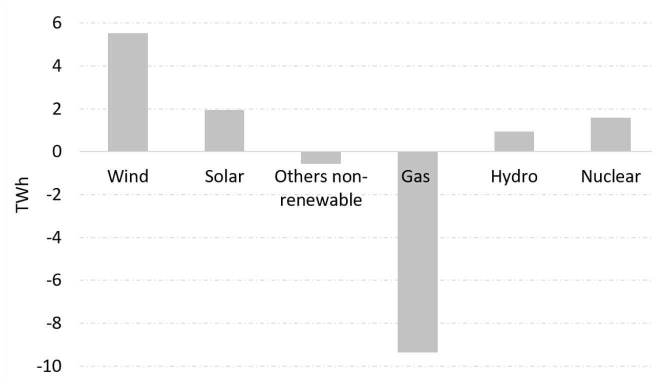


Figure 3.8: Differences in the annual electricity production by technology in Europe, when investors in generation in the NS are risk-averse, between the cases where FTRs can and cannot be contracted.

On the other hand, where risk-averse investors in the NS can contract FTRs, additional investments in renewable generation take place in Europe and accordingly, more production of solar, hydro and wind instead of other technologies like gas-fired generation. Note that, when being able to contract FTRs, wind generation built by risk-averse investors in the NS can have access to electricity prices in the reference node (representing European prices) in all kinds of operation situations, both when congestion on the NS-Europe interconnectors occurs and when it does not. Given the relevant correlation between offshore and onshore wind generation in the area, in most of the operation situations when wind generation in the NS is producing relevant amounts of power, the overall RES-based generation output in this part of Europe will also be significant, and electricity prices in Europe will be low. Then, investing in hydro generation in Europe, results in the price curve in the Reference node being smoothed and, therefore, prices increasing in low-price hours. Consequently, investing in additional hydro generation when risk-averse investors in the NS area can contract FTRs allows the generation built by these investors to get access to higher prices in most of the operation situations where it is producing energy, also in the most unfavourable scenarios for this generation, and, therefore, results in an increase of the CVaR of these NS wind generation investments, see Table 3.12 and Figure 3.8.

When NS generation investors are deemed risk-neutral, wind generation investments in the NS area are largest. This generation is subject to significant variability across scenarios in the electricity price it earns. However, investors building this generation being risk-neutral, these investments are not constrained by the associated price risk and the possible measures to be taken to manage this risk, i.e. the contracting of FTRs and the construction of an additional amount of transmission capacity built to make the FTRs issued feasible. Wind generation investments in the area amount 91% of the wind generation potential. Besides, investments in wind generation in the surrounding area, whose output is highly correlated with that of generation in the NS, decrease. Given this decrease, there is room to increase investments in other complementary, RES-based generation, essentially solar.

Lastly, when NS wind generation investors are risk-neutral, there is no incentive to further increase investments in hydro generation in Europe, at the expense of those investments in other less flexible generation, in order to increase the prices earned by NS wind generation in the most unfavourable scenarios for NS wind generation, which are those where wind generation and RES based generation, in general, is most abundant in Europe. Then, investments in hydro generation are smaller in this case than in those where NS generation investors are risk-averse, see Table 3.12 and Figure 3.8.

Table 3.13: Metrics for differences between the prices weighted by demand in the case with FTRs and the case without FTRs, in those nodes interconnected with the remote area (NS) [€/MWh].

| | **DK** | **NL** | **DE** |
|---|---|---|---|
| Avg | -0.207 | -0.069 | - |
| Max | 0.362 | 0.014 | - |
| Min | -0.655 | -0.320 | - |

Table 3.13 provides relevant metrics associated with the price differences weighted by demand between the case with FTRs and the case without FTRs for those nodes that are directly connected to node NS. It is important to note that the investments and operation resulting when considering FTRs available, lead to lower prices in those nodes directly connected to the North sea compared to the case where FTRs are not available. This implies that the availability of FTRs results in better supply conditions for final users in those areas.

## 3.4 Final Remarks

This chapter explores the use of LT FTRs by risk-averse GENCOs to hedge the price risk they face caused by network congestion, assuming that decisions by the agents are competitive and perfectly coordinated from a social point of view. The approach proposed to address this problem involves developing a bi-level optimisation model. In this model, the expansion of the system and the amount of FTRs to be contracted are computed in the upper level problem, and the operation of the system for the scenarios representing the uncertainty faced by risk-averse GENCOs is computed in the lower level problem. The impact of uncertainty on the value placed by those companies on their investments is represented by considering the CVaR of the profits made by GENCOs in the most unfavourable scenarios. Besides, the strategy adopted by the network owners and the system planner to avoid running the risk of the congestion rents resulting from the system operation not being large enough to afford the payments to LT FTRs owners involves enforcing the simultaneous feasibility of all the FTRs issued.

This model is employed to determine the relevance and specific impact of the consideration of LT-FTRs in two case studies: 1) a 2-node illustrative one and 2) a European one in the 2030 timeframe where uncertainty about the future price to be earned is deemed to potentially affect the RES-based generation to be deployed in remote areas weakly linked to the rest of the system, as in the North Sea. Both case studies show that when there is perfect coordination among the investment decisions made by transmission planners and GENCOs and the latter behave competitively, the availability of LT-FTRs enables GENCOs to effectively manage the price risk that generation investments in specific areas, like remote ones, are subject to. This allows GENCOs to stabilize their revenues across the scenarios considered.

In both case studies, results show lower values of the CVaR of the profits made by generation investments in remote areas when FTRs are not available than when contracting FTRs is possible; this means that the acquisition of FTRs by generators impacts the CVaR computed, i.e. on the expected value of the generation profits for the worst-case scenarios, reducing the variability of the profits made across scenarios. The reader should note that considering risk-averse investors and the availability of LT FTRs to be contracted does not force additional socially efficient investments in the system. Thus, making LT FTRs available could result, or not, in the deployment of additional socially efficient RES-based generation capacity that, otherwise, would not be profitable.

However, in both case studies, the results show increases in the size of remote, cost-efficient generation investments that are triggered by the use of LT FTRs. In other words, contracting FTRs results in more significant investments in efficient renewable generation in remote areas. These changes are particularly relevant for the European case study in the North Sea. Assuming perfect coordination among the investment decisions by stakeholders, the investments planned, and the FTRs allocated are optimal from the social point of view.

Considering risk aversion by the generation investors in remote areas, allocating FTRs to them was optimal in both case studies. This implies that taking into account the value that investors place on the investments they undertake, the availability of LT FTRs increases the social welfare resulting from the development of the system, which is maximised in the expansion planning and FTR allocation problem formulated. However, this is not always accompanied by a decrease in the total system costs incurred when allowing agents to contract FTRs. Thus, for example, due to the need to make FTRs feasible, the issuance of LT FTRs may trigger additional investments in transmission capacity that are not justified from the point of view of minimising the system costs.

The reader should also note that if investors were risk-neutral, issuing LT FTRs should not affect the development of the system. Assuming that agents behave rationally, the price to be paid by GENCOs for the LT FTRs they acquire is deemed to coincide with the congestion rents corresponding to these LT FTRs in the dispatch. Consequently, when uncertainty exists, the price paid for these rights should amount to the expected congestion rents in the dispatch these rights would allow their owner to earn across all the possible scenarios that could develop. Then, LT-FTRs should not affect the value that risk-neutral GENCOs place on the investments they undertake, since, for these GENCOs, the stabilisation across scenarios of the revenues and profits produced by their investments that can be achieved by contracting LT FTRs has no value. Given that LT-FTRs issued should not affect the value of investments for risk-neutral GENCOs, these rights should not affect the system's expansion either when all the investors are of this type.

# Chapter 4

# Assessment of FTRs as a long-term risk hedging instrument and a driver of coordination within the Generation and Transmission expansion planning

As mentioned in section 2.6, LT FTRs are also a long-term financial mechanism for allowing generation investors to manage the long-term risk they face associated with the volatility and unpredictability of the price they will have to pay to access the grid capacity needed to trade their energy in large demand centers and increasing the level of coordination of the generation and transmission expansion planning in a liberalised electricity environment. Contrary to what occurs for other regulatory instruments driving investments, see section 2.3, the implementation of LT FTRs does not involve the system authorities determining ex-ante the amount of generation or transmission capacity to be installed, its location, or the price to be applied to these rights. LT FTRs make a novel investment driving and coordination tool for generation and transmission expansion planning that can encourage both generation and transmission investments by reducing the price risk perceived by the generation companies associated with their investments, which should trigger additional ones, and by providing more confidence to the SO that the generation investments that are triggering the network expansion decisions will be actually undertaken.

This chapter provides at first a conceptual definition of the use of LT-FTRs in the context of GEP&TEP coordination, then this chapter investigates the ability of the use by GENCOs of Long-Term Financial Transmission Rights (FTRs) to manage the network related market risk they face and the ability of these rights to increase the level of coordination between the investments undertaken by these stakeholders and those by the transmission planner, through the implementation of a bi-level optimization model representing stakeholder's interactions. In a context assuming a planning approach where generation investors in remote areas are strategic and risk-averse. For this, a stylised case study is considered where the development of generation in remote areas, like the

North Sea, has significant potential.

In this chapter, the aim is to answer two main research questions, the ones corresponding to **Rq3** and **Rq4** stated in section 2.12.

Accordingly, the focus of this chapter is on the following aspects:

- Formulation of a bilevel optimisation expansion planning problem under a Reactive Planning approach, in order to asess the use of LT FTRs by risk-averse generation investors in remote areas and the impact of those LT-FTRs on the coordination of those generation investments and the associated transmission investments.
- Computation of the effect, on the expansion of the system and the resulting costs, of implementing LT FTRs to drive the development of remote generation in a stylized case study within the European context, considering for this the formulation of the expansion planning problem here developed and a schematic representation of this system.

## 4.1 Conceptual definition and discussion of the problem addressed: LT-FTRs and GEP-TEP Coordination

As mentioned previously, risk hedging capabilities of Long-term FTRs, create incentives for transmission planners to promote the transmission investments to be used by the new generation covered by these rights [58], creating stimulus to undertake the transmission and generation investments, leading these stakeholders to engage in the corresponding transmission contracts.

As discussed in subsection 2.6.1, FTRs of different types can be allocated through different rules; however, for the sake of simplicity, the analysis carried out in this chapter is focused on the case of point-to-point FTRs defined as obligations that are allocated, in the long-term, through a centralized auction being run by the SO and network planner together with the network expansion planning process. However, other formats of FTRs previously mentioned in subsection 2.6.1 and allocation processes, including the reallocation of these in secondary markets, could have been considered, making the formulation of the problem addressed and its solution largely more complex.

Figure 4.1 shows the timeline for the allocation of LT-FTRs and the development and operation of the system throughout the period that these contracts refer to. First, the allocation of contracts takes place. Right after this, the FTR contracts are signed. Then, the generation and transmission developments that the FTRs refer to are deployed, here, the planning horizons for GEP and TEP are not separately defined, since a single long-term planning horizon in which both take place is considered, however this is a topic of interest for future research. Finally, once these developments have been implemented, the operation period defined in these contracts starts and those payments corresponding to the congestion rents produced by the transmission capacity contracted are made, according to the market clearing, until the end of the contract period.

Long term Financial Transmission Rights as a coordination mechanism can be analysed from different perspectives according to the stakeholders. In order to illustrate how this mechanism could work, please consider the case of a renewable generator located in a remote area weakly linked to the rest of the system.

This generator would like to sell its power output at the price of large consumption centres in the system, but, for this, the energy it produces would need to be transported over long distances, making use of congested transmission capacity. There is large uncertainty about the price this generator would have to pay to access the required transmission capacity and, therefore, also about

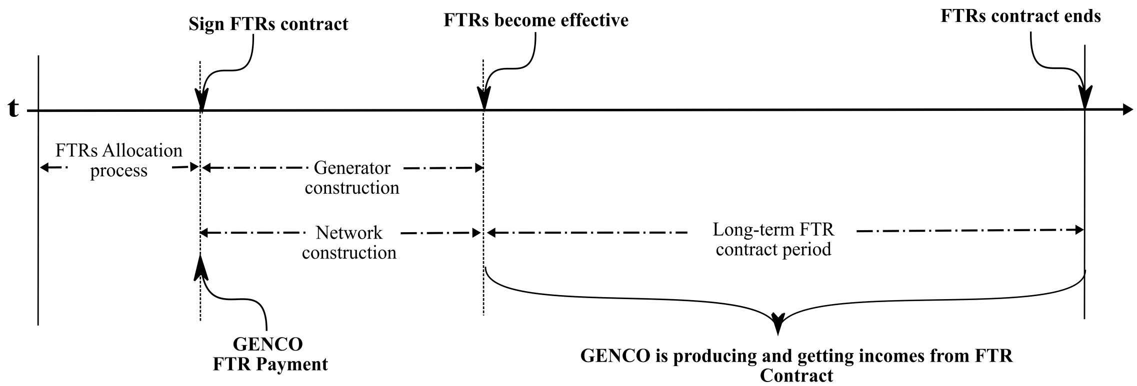


Figure 4.1: Timeline FTRs contract

the revenues that the network owner would make over this transmission capacity. However, if the GENCO and the transmission owner sign an FTR over this capacity, the GENCO would be provided with the right, or obligation, to sell his energy at the price of the withdrawal node in the contract, which should normally be chosen to be a reference node in the system (main load centre with an attractive price to sell energy), while the network owner would be provided with some funds, those from the sale of the FTR, that it could use to build the transmission capacity that the contract refers to, thus making sure that his revenues from the dispatch (the congestion rents resulting from it) suffice to pay the owner of the FTR the agreed amount (that part of the congestion rents in the dispatch corresponding to the contracted transmission capacity). Notice that not building the transmission capacity backing the FTR would put at risk the network owner financially speaking since the revenue adequacy criterion just mentioned would not be met for the FTRs sold. When introducing this mechanism, the stakeholders involved would have some benefits, which are described below for GENCOs, the Network owner and the system.

### Advantages for GENCOs

GENCO will be able to sell its energy at the price of a reference node (main load centre with a more stable, price to sell energy), reducing the risk from price volatility due to network congestion.

- As a consequence, it can reduce CAPEX of new GENCO's investments by facilitating and cheapening the financing.

Create economic incentives for the Network Owner to go ahead with the network investments required to evacuate the production of the new GENCO's investments:

- Both if the network owner builds the new capacity that FTR refers to, and if it does not build it, the generation company buying FTRs will be provided with the corresponding congestion rents. Not building the corresponding transmission capacity would not allow the network owner to earn these rents from the system operation and would put the network owner at risk of not being able to afford the payments owed to FTR holders.

**Advantages for the Network owner**

- The network owner would be provided with some funds, those from the sale of the FTR, that it could use to build the transmission capacity that the contracts refer to. Advantages for the SO, representing the System

  **Advantages for the SO, representing the System**

- The SO can maximise the social efficiency of the expansion of the grid and the FTRs sold taking into account the effect that these have on the decisions by the generation investors on the generation to build, largely including RES based generation, and the offers for FTRs to submit.

- Limit relevant practical adverse effects of the market and counterparty risk that the stakeholders are naturally subject to, resulting in decreases in the social efficiency of the expansion. These adverse effects are related to the stakeholders' risk aversion, the lack of information, and the lack of commitment by these stakeholders.

- Socially beneficial generation and transmission capacity that would not have been installed in the absence of FTRs should become possible under this scheme.

- Contracting an FTR provides the GENCO with incentives to build the generation capacity to be integrated into the system through the transmission capacity backed by this FTR. This creates some economic incentives (that could possibly be seen as a not binding, economically driven commitment) for the GENCO to go ahead with the new generation investments that are the ones that are justifying the considered network expansion (investment in network facilities integrating the new generation).

- If the GENCO does not build this generation capacity, it would run the risk that the FTRs it has already paid for produce some congestion rents not covering his FTR purchase expenses.

This chapter addresses the impact of the implementation of FTRs on the GEP-TEP coordination, considering a reactive planning approach, which is the most widely implemented planning approach, even though the proactive planning approach is the preferred one in the literature.

## 4.2 Representation of Interactions between the problems considered

To assess the implementation of FTRs as a coordination mechanism for investment decisions, a bi-level model is proposed in this section, which aims to coordinate generation and transmission expansion planning decisions, considering a reactive planning approach in which FTRs are included as a mechanism for both sides to couple (coordinate) the investment decisions. Solving the bi-level problem here formulated, provides the computation of what would be the expansion of the system, corresponding to the generation and transmission investment decisions made by the corresponding stakeholders, the amount of FTRs contracted and the offer that GENCOs would make for these, according to the rational incentives for them considering these investors as strategic, profit maximizing, players in the long-term and resulting from the implementation of the reactive coordination framework here explored.

The reader should note that the main sources of risk considered here are, first, the uncertainty associated with the evolution of grid access prices for generators located in areas with largely volatile prices, such as remote regions. This risk cannot be properly managed by all the parties involved—generators, demand, and the entity offering risk management products— except through long-term transmission rights issued and allocated according to a strategy such as the one proposed. Furthermore, in the case of generation located in remote areas, the negotiation of power purchase agreements in their area or connection node would typically be subject to conditions of low liquidity and, therefore, to a price that is likely not to be representative of the expected value of that energy. Second, the system planner risk relates to the risk of the revenues from congestion rents resulting from the operation of the system not being large enough to pay the amounts owed to the FTR holders. Typically, the condition enforced to achieve a reasonable level of certainty that congestion rents are sufficient to pay the right holders involves that the existing and newly built capacity in the network is sufficient to host the virtual-flows resulting from the undertaking of transactions corresponding to the rights contracted. Third, both the generators and the TSO, or the system planner, are subject to a counterparty risk associated with the lack of coordination between the investments undertaken by these parties. This risk can be mitigated through the economic incentives that the FTR contract provides to both generation investors and the network planner to carry out the planned investments.

Accordingly, here, the aversion of the companies deploying generation in remote areas to the price risk caused by network congestion is modelled through the explicit consideration of these GENCO's market benefits in the worst-case scenario within the objective function these companies aim to maximize. Apart from this, the system planner's aversion to the risk of not being able to pay the amounts owed to FTR holders from the congestion rents produced by the grid in the system operation is modelled here through the enforcement of the FTRs simultaneous feasibility constraints. Finally, as already mentioned, the transmission contracts signed by the generation investors and the transmission planner/SO create some economic incentives for the undertaking of the investments planned by both parties related to the use of the transmission capacity supporting these transmission contracts. These incentives mitigate the counterparty risk faced by both parties associated with the other not undertaking these investments. In any case, given that the general scheme for the coordination of generation and transmission investments considered in these analyses is a reactive one, the network planner should have some reasonable level of certainty about the undertaking of the generation investments concerned. The generation companies aim to create some incentives for the planner to undertake the corresponding transmission investments through the acquisition of FTRs over this transmission capacity. Thus, the former make an offer for these rights that they deem to be sufficiently attractive for the transmission planner to accept it.

This chapter is based on the one explained in chapter 3 where has been discussed and assessed the impact of the use of LT-FTRs on the socially optimal expansion of the system and the associated costs considering the investors in generation in remote areas contracting FTRs as stakeholders behaving competitively and socially optimal coordination taking place among investment decisions made by these and other agents, analysing risk-heading capabilities of LT-FTRs [111].

The optimisation problem formulated considers a reactive planning approach where decisions are made in two levels:

i) an Upper Level, where strategic GENCO in a remote area decides on the generation investments to be carried out and, at the same time, on the offer that they should make for the FTRs backing these investments, in order to maximise their own profits

ii) a Lower Level where, assuming that market agents in the rest of the system (that part excluding the remote areas where new generation may be deployed possibly acquiring FTRs) behave competitively when making their investment decisions, and all the market agents behave competitively in the dispatch, the following decisions are made, representing the corresponding decision making process as a social welfare maximizing one:

a. the expansion of the rest of the system, including both the generation and transmission expansion,
b. the amount of FTRs to be sold to strategic generation investors in remote areas, and
c. the system operation (dispatch).

Note that, following this social-welfare-maximizing perspective, the SO is deemed to consider as a cost for the system the congestion revenues to be paid to the strategic generators acquiring FTRs and as revenue for the system the income that the system would obtain from selling these FTRs at a price equal to the offer made for these FTRs by these strategic generators. Following this approach, the SO is able to compute the allocation of FTRs, the investments in transmission to be made, and the competitive system dispatch, while the investments in non-strategic generation (that not located in remote areas), being made by agents behaving competitively, are determined as those resulting in the minimisation of the total system costs.

Also note that the upper level is formulated for a single company *cp*, however, the formulation proposed could be naturally extended and complicated by considering multiple companies in the upper-level problem competing among them.

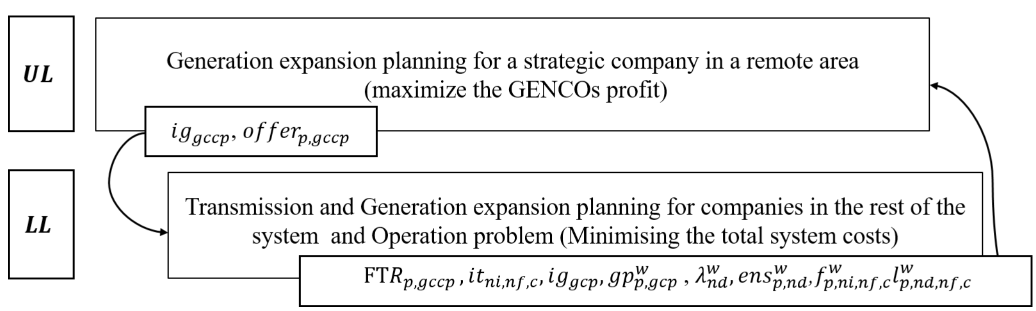


Figure 4.2: Interaction between problems - RP

See in Figure 4.2 a schematic representation of the decision making process being modelled. Next, the formulation of the problem in each of the decision making levels considered is discussed in detail.

## 4.3 Proposed Mathematical Formulation

### 4.3.1 Formulation of the upper level (UL) - Generation expansion planning for strategic GENCOs in remote Areas

**Objective Function**

Maximize the Genco's profit, see Equation 4.3.1. The components of these profits are discussed below.

$$\text{Maximise} \quad gpr_{cp} \tag{4.3.1}$$

**Constraints**

**Company Generation Profits (including FTR benefits and costs)**:

The Genco's profits to maximise include the expected value of the market benefits, i.e. those corresponding to a long-term scenario w representing all those that may unfold, the market benefits of this Genco in the worst-case long-term scenario $\hat{w}$ weighted with a constant $\beta$ representing the relative importance that this GENCO assign to the revenues in the worst-case scenario (directly associated with their risk profile), the costs associated with their generation investment decisions, and those prospective costs associated with the purchase of LT FTRs at a price equal to the offer made for these rights (cost equals the offer made for the FTRs multiplied by the FTRs that the Genco is allocated). The reader should notice that the FTRs are allocated by the SO in the lower level.

Note also that all those revenues and costs that are associated with the system operation are computed considering the duration $DU_p$ of the several periods of time $p$ that the target year is deemed to be divided into.

$$grp_{cp} = \sum_{w} gbf_{cp}^{w} + \beta gbf_{cp}^{\hat{w}} - \sum_{gccp} FCG_{gccp} ig_{gccp} - \sum_{p,gccp} DU_p offer_{p,gccp} ftr_{p,gccp} \quad \forall \quad cp \tag{4.3.2}$$

The market benefits of the strategic Genco in any scenario $w$, considering already those revenues corresponding to the congestion rents produced by the set of FTRs acquired, are computed, for all the operation hours in the target year, as the sum of i) these congestion rents, determined as the difference between the LMPs at the reference and the new generation connection nodes, multiplied by the amount (capacity) of the FTRs contracted (this correspond to the revenues of the Genco associated with the acquisition of FTRs), ii) the revenues from the direct sale of the energy produced at the local nodal price, determined as the energy production level multiplied by the LMP in the generation connection node, less iii) the variable costs incurred associated with the production of this energy.

It is very important to note also that, according to the objective function considered in the LL, the dual variable of the demand constraint $\lambda_{p,nd}^{w}$ internalizes the duration $DU_p$ and probability $PR^w$, therefore, when computing benefits and costs, this variable does not need to be multiplied by $DU_p$ and $PR^w$, different to the rest of the terms considered.

$$gbf_{cp}^{w} = \sum_{p,nd,gccp} \left(\lambda_{p,grf}^{w} - \lambda_{p,ftrnd}^{w}\right) ftr_{p,gccp} + \sum_{p,nd,gcp} \lambda_{p,nd}^{w} gp_{p,gcp}^{w} - \sum_{p,gcp} PR^{w} DU_p VC_{gcp} gp_{p,gcp}^{w}$$

$$\forall \quad w, cp \tag{4.3.3}$$

$$offer_{p,gccp} \geq 0 \quad \forall \quad gccp \tag{4.3.4}$$

**Bilinear terms linearization**

The reader should note that Gencos profit computation includes nonlinear terms; therefore, the procedure proposed in [94] was followed to linearise the bilinear elements $\lambda^{w}_{p,grf} ftr_{p,gccp}$, $\lambda^{w}_{p,nd} gp^{w}_{p,g}$ and $offer_{p,gccp} ftr_{p,gccp}$. The first two terms are linearized following the procedure explained in section 3.2.3, and for the linearization of the last term it is necessary to approximate the continuous decision values $ftr_{p,gccp}$ by M discrete values, where $M = \mathbf{2}^k$ and $k$ is non-negative. Consider $\left[\underline{FTR}_{p,gccp}, \overline{FTR}_{p,gccp}\right] = \left[0, \overline{FTR}_{gccp}\right]$, and $\left[\underline{offer}_{p,gccp}, \overline{offer}_{p,gccp}\right] = [0, CENS]$, then the discrete approximation is formulated through binary expansion, as follows:

$$ftr_{p,gccp} = \underline{FTR}_{p,gccp} + \Delta 1_{p,gccp} \sum_{k} 2^k u_{p,gccp,k} \quad \forall \quad p, gccp \tag{4.3.5}$$

Where:

$$\Delta 1_{p,gccp} = \frac{\overline{FTR}_{p,gccp} - \underline{FTR}_{p,gccp}}{M} \quad \forall \quad p, gccp$$
$$u_{p,gccp,k} \in (0,1) \quad \forall \quad p, k, gccp$$

Multiplying both sides of 4.3.5 by $offer_{p,gccp}$, and adding a new variable $y_{p,gccp,k} = u_{p,gccp,k} offer_{p,gccp}$ we obtain equation 4.3.6.

$$offer_{p,gccp} ftr_{p,gccp} = offer_{p,gccp} \underline{FTR}_{p,gccp} + \Delta 1^{w}_{p,gccp} \sum_{k} 2^k y^{w}_{p,gccp,nd,k} \quad \forall \quad w, p, gccp \tag{4.3.6}$$

Since the term $u_{p,gccp,k} offer_{p,gccp}$ is the multiplication of a continuous and an integer variable, it can be linearized by equations 4.3.7 and 4.3.7:

$$0 \leq offer_{p,gccp} - y_{p,gccp,k} \leq \overline{offer}_{p,gccp} (1 - u_{p,gccp,k}) \quad \forall \quad p, k, gccp \tag{4.3.7}$$

$$0 \leq y_{p,gccp,k} \leq \overline{offer}_{p,gccp} u_{p,gccp,k} \quad \forall \quad p, nd, k, gccp \tag{4.3.8}$$

### 4.3.2 Formulation of the lower level (LL) - Investment and Operation Problem (system planner)

**Objective Function**

**Total costs**

The planning decisions resulting from maximising the welfare of the system are here computed as those resulting from minimising the total costs of the system, including the fixed, variable and ENS costs, being part of these the costs and benefits for the system associated with the sale of FTRs, which have already been discussed above, see Equation 4.3.9. As aforementioned, the SO is deemed to consider as a cost for the system the congestion revenues to be paid to the strategic generators acquiring FTRs and as a revenue for the system the income that the system would obtain from selling these FTRs at a price equal to the offer made for these FTRs by the strategic generators.

The assumption that the system planning resulting from maximising the social welfare is the same as that resulting from minimising the system costs is valid because the demand is here deemed to be inelastic and the cost of not serving part of it is considered as ENS costs.

$$\text{Minimise} \quad OF = tf + tv + tr + te + cftr_{gc} - \sum_{p,gccp} DU_p offer_{gccp} ftr_{p,gccp} \tag{4.3.9}$$

Below, each of the terms in 4.3.9 are discussed separately.

**Total fixed costs**
These are deemed to correspond to the sum of the investment costs for all candidate transmission lines and all candidate generation units that are installed. The cost for those already existing is deemed a sunk cost not to be included in the objective function, see Equation 4.3.10.

$$tf = \sum_{lc} FCT_{lc} it_{lc} + \sum_{gc} FCG_{gc} ig_{gc} \tag{4.3.10}$$

**Total variable costs**
Sum of the variable costs incurred by all the generation units in the scenarios $w$ and periods $p$, see Equation 4.3.11.

$$tv = \sum_{w,p,g} PR^w VC_g DU_p gp^w_{p,g} \tag{4.3.11}$$

**Total reliability costs**
Sum of the ENS costs for demand that is not served in the several scenarios $w$ and periods $p$ weighted with the probability of occurrence of the corresponding scenarios, see Equation 4.3.12.

$$tr = \sum_{w,p,nd} PR^w CENS DU_p e^w_{p,nd} \tag{4.3.12}$$

**Total emission costs**
Sum of the $CO_2$ costs in the several scenarios $w$ and periods $p$ weighted with the probability of occurrence of the corresponding scenarios, see Equation 4.3.13.

$$te = \sum_{w,p,g} PR^w CO_{2g} DU_p gp^w_{p,g} \tag{4.3.13}$$

**FTRs Cost**
The FTRs cost for the system associated with the congestion rents to be paid to the FTR owners (strategic GenCo) having acquired them, which are computed as the expected value of the differences in the nodal prices between the reference node and the connection node multiplied by the amount of capacity contracted through these FTRs, considering the probability of all $w$ scenarios.

$$cftr_{gc} = \sum_{w,p,nd} (\lambda^w_{p,grf} - \lambda^w_{p,gnd}) ftr_{p,gc} \quad \forall \quad gc \in gccp \tag{4.3.14}$$

### Constraints

Next, the constraints in this problem are discussed. For each constraint, the dual variable of each set of equations appears after the colon.

**FTRs - Feasibility equations** Here, the constraints enforced to make the FTRs allocated simultaneously feasible are provided. as mentioned in the introduction of section 3.2, those constraints are included in order to hedge the risk associated to the possible insufficient congestion rent revenue from the operation to pay the amounts owed to the rights holders, therefore this is a condition usually imposed with the aim of making the congestion rents produced by the grid in the system operation large enough to pay the owners of FTRs the amounts owed to them. This formulation includes the representation of the equilibrium between the number of FTRs to be allocated and the virtual flows ($vf$), this equilibrium is reached through the implementation of the Balance FTRs feseability constraint which is an equality constraint that couples the FTRs and the virtual flows, those virtual flows respect the transfer capacity ($TTC_{ni,nf,c}$) of lines and the DC load flow constraints respecting the same laws as the physical flows in order to issue a set of FTRs that is compatible with the network capacity. According to [95] *"the simultaneous feasibility test must be run to ensure that the transmission system can support the set of issued FTRs. If the set of FTRs is simultaneously feasible, then there is some reasonable amount of certainty that the network is revenue adequate to pay the owners of FTRs the amounts owed to them"*

**Virtual flows constraints (transfer capacity of candidate lines)**: For each candidate line, the relationship between the virtual flow ($vf$) across a circuit between two nodes and the transfer capacity for the line that links these nodes depends on the variable $it_{(ni,nf,c)}$. If the decision is not to install the line, the flow will be zero, while if the decision is to install the line, the virtual flow could not be higher than the total transmission capacity ($TTC_{ni,nf,c}$) of the circuit built.

$$\frac{vf^w_{p,ni,nf,c}}{TTC_{ni,nf,c}} \geq it_{ni,nf,c} \quad \forall \quad w,p,lc_{ni,nf,c} \tag{4.3.15}$$

$$\frac{vf^w_{p,ni,nf,c}}{TTC_{ni,nf,c}} \leq it_{y,ni,nf,c} \quad \forall \quad w,p,lc_{ni,nf,c} \tag{4.3.16}$$

**DC load virtual flow constraints (for existing and candidate lines)**: Represents the virtual flow through the line between two nodes, using a DC formulation for AC lines (as when modeling physical flows). For the candidate lines, the virtual voltage angle difference between both ends of these lines should only be constrained by the virtual flow equation linking node voltages and the virtual flow when the line is installed.

$$\frac{vf^w_{p,ni,nf,c}}{vMF_{ni,nf,c}} \geq [v\theta^w_{p,ni} - v\theta^w_{p,nf}]\frac{Sb}{X_{ni,nf,c}vMF_{ni,nf,c}} - 1 + it_{ni,nf,c} \quad \forall \quad w,p,lc_{ni,nf,c} \tag{4.3.17}$$

$$\frac{vf^w_{p,ni,nf,c}}{vMF_{ni,nf,c}} \leq [v\theta^w_{p,ni} - v\theta^w_{p,nf}]\frac{Sb}{X_{ni,nf,c}vMF_{ni,nf,c}} + 1 - it_{ni,nf,c} \quad \forall \quad w,p,lc_{ni,nf,c} \tag{4.3.18}$$

$$vf^w_{p,ni,nf,c} = [v\theta^w_{p,ni} - v\theta^w_{p,nf}]\frac{Sb}{X_{ni,nf,cc}} \quad \forall \quad w,p,le_{ni,nf,c} \tag{4.3.19}$$

**FTRs Balance constraints**:

For each scenario, each period and each node, the amount of FTRs contracted having this node as the reference one $ftrndrf$(incoming FTRs) less the amount of FTRs contracted having this node as the injection one $ftrnd$ (outgoing FTRs) should be equal to the difference between the incoming virtual flows into the node $vf^{wcp}_{p,ni,nd,c}$ and the outgoing virtual flows from this node $vf^{wcp}_{p,nd,nf,c}$ (please consider that $ftrndrf$ and $rfrnd$ are mutually exclusive sets).

$$\sum_{ni \in la(ni,nd,c)} vf^{w}_{p,ni,nd,c} - \sum_{nf \in la(nd,nf,c)} vf^{w}_{p,nd,nf,c} = \sum_{gc \in ftrndrf} ftr_{p,gc} - \sum_{gc \in ftrnd} ftr_{p,gc} \quad \forall \quad w,p,nd \tag{4.3.20}$$

**Bounds for the transfer capacity in existing lines:** For each existing line, the virtual flow is bounded by the total transfer capacity of the line.

$$-TTC_{ni,nf,c} \leq vf^{w}_{p,ni,nf,c} \leq TTC_{ni,nf,c} \quad \forall \quad p,w,(ni,nf,c) \in le \tag{4.3.21}$$

**Bounds for the FTR contracted capacity**:

For each candidate generation unit, the FTR contracted capacity is bounded by its maximum generation output.

$$ftr_{p,gc} \leq MCI^{w}_{p,gc} ig_{gc} \quad \forall \quad w,p,gc \in gccp \tag{4.3.22}$$

**Operation constraints equations**

Dual variables of each set of equations appear after colons.

**Flow constraint (for candidate lines)**

For each candidate line, the relationship between the flow across a circuit between two nodes and the transfer capacity for the line that links these nodes depends on the variable $it_{(ni,nf,c)}$. If the decision is not to install the line, the flow will be zero, while if the decision is to install the line, the flow could not be higher than the total transmission capacity of the circuit built.

$$\frac{f^{w}_{p,ni,nf,c}}{TTC_{ni,nf,c}} \geq -it_{ni,nf,c} : \underline{\gamma}^{w}_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{4.3.23}$$

$$\frac{f^{w}_{p,ni,nf,c}}{TTC_{ni,nf,c}} \leq it_{ni,nf,c} : \overline{\gamma}^{w}_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{4.3.24}$$

**DC power flow constraints (for existing and candidate lines)**

Represents the flow through the line between two nodes, using a DC formulation for AC lines (only changes in the voltage angles are considered). For the candidate lines, the voltage angle difference between both ends of these lines should only be constrained by the flow equation linking node voltages and the flow when these lines are installed.

$$\frac{f^{w}_{p,ni,nf,c}}{MF_{ni,nf,c}} \geq [\theta^{w}_{p,ni} - \theta^{w}_{p,nf}] \frac{Sb}{X_{ni,nf,c} MF_{ni,nf,c}} - 1 + it_{ni,nf,cc} : \underline{\tau}^{w}_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{4.3.25}$$

$$\frac{f^{w}_{p,ni,nf,c}}{MF_{ni,nf,c}} \leq [\theta^{w}_{p,ni} - \theta^{w}_{p,nf}] \frac{Sb}{X_{ni,nf,c} MF_{ni,nf,c}} + 1 - it_{ni,nf,c} : \overline{\tau}^{w}_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{4.3.26}$$

$$f^w_{p,ni,nf,c} = [\theta^w_{p,ni} - \theta^w_{p,nf}]\frac{Sb}{X_{ni,nf,c}} : \phi^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in le \tag{4.3.27}$$

**Bound for Theta angle**

$$-\frac{\pi}{2} \leq \theta^w_{p,nd} \leq \frac{\pi}{2} : \underline{\varphi}^w_{p,nd}, \overline{\varphi}^w_{p,nd} \quad \forall \quad w,p,nd \tag{4.3.28}$$

**Bounds for transfer capacity in existing lines** For each existing line, the flow is bounded by the total transfer capacity of the line.

$$-TTC_{ni,nf,c} \leq f^w_{p,ni,nf,c} \leq TTC_{ni,nf,c} : \underline{\phi}^w_{p,ni,nf,c}, \overline{\phi}^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in le \tag{4.3.29}$$

**Ohmic losses as a function of the flow**

$$-\frac{L_{ni,nf,c}}{2} f^w_{p,ni,nf,c} \leq l^w_{p,ni,nf,c} \geq \frac{L_{ni,nf,c}}{2} f^w_{p,ni,nf,c} : \underline{\mu}^w_{p,ni,nf,c}, \overline{\mu}^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{4.3.30}$$

**Bounds for losses**

$$0 \leq l^w_{p,ni,nf,c} \leq \frac{L_{ni,nf,c}}{2} TTC_{ni,nf,c} : \underline{\delta}^w_{p,ni,nf,c}, \overline{\delta}^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{4.3.31}$$

**Bounds of production related to Installed Generation Capacity** For each generation unit, the production should be limited by the maximum production capacity corresponding to this unit.

$$0 \leq gp^w_{p,gc} \leq ig_{gc} MP_{gc} : \underline{\rho}^w_{p,gc}, \overline{\rho}^w_{p,gc} \quad \forall \quad w,p,gc \tag{4.3.32}$$

$$0 \leq gp^w_{p,ge} \leq MP_{ge} : \underline{\omega}^w_{p,g}, \overline{\omega}^w_{p,g} \quad \forall \quad w,p,ge \tag{4.3.33}$$

**Bounds for ENS**

$$0 \leq e^w_{p,nd} \leq D_{nd} : \underline{\zeta}^w_{p,nd}, \overline{\zeta}^w_{p,gc} \quad \forall \quad w,p,nd \tag{4.3.34}$$

**Balance between generation and demand**

For each scenario, each period and each node, the sum of all the generation by the units $gp^w_{p,g}$ in this node, and the ENS $e^w_{p,nd}$ in that node, should be equal to the demand $D_{nd}$ plus the net amount of power flowing out of the node, considering losses. The dual variable of this constraint, $\lambda^w_{p,nd}$, according to the objective function considered, internalises the duration $DU_p$ and probability $PR^w$, therefore, here the Locational Marginal Price (nodal price) $= \frac{\lambda^w_{p,nd}}{DU_p PR^w}$.

$$\sum_{g \in gnd} gp^w_{p,g} + e^w_{p,nd} = D_{nd} + \sum_{nf \in la(nd,nf,c)} f^w_{p,nd,nf,c} - \sum_{ni \in la(ni,nd,c)} f^w_{p,ni,nd,c} + \sum_{nf \in ll(nd,nf,c)} l^w_{p,nd,nf,c} + \sum_{ni \in ll(ni,nd,c)} l^w_{p,ni,nd,c} : \lambda^w_{p,nd} \quad \forall \quad w,p,nd \tag{4.3.35}$$

**KKT conditions of the lower level (LL) - Operation problem**

**FTRs - Feasibility** 4.3.36 - 4.3.38, correspond to the derivative of the lagrangian function with respect to the variables $vf^{w}_{p,nd,nf,c}, ftr_{p,gccp}$, and $v\Theta^{w}_{p,nd}$ respectively. Finally, equations 4.3.39 and 4.3.40 correspond to the equality constraint associated with virtual flows and FTRs balance, respectively.

$$\begin{aligned}
&-\underline{v\Upsilon}^{w}_{p,ni,nf,c\ \in lc(ni,nf,c)}+\overline{v\Upsilon}^{w}_{p,ni,nf,c\ \in lc(ni,nf,c)}-\underline{v\tau}^{w}_{p,ni,nf,c\ \in lc(ni,nf,c)}+\overline{v\tau}^{w}_{p,ni,nf,c\ \in lc(ni,nf,c)}\\
&\quad-\underline{v\phi}^{w}_{p,ni,nf,c\ \in le(ni,nf,c)}+\overline{v\phi}^{w}_{p,ni,nf,c\ \in le(ni,nf,c)}-v\phi^{w}_{p,ni,nf,c\ \in le(ni,nf,c)}+\Psi^{w}_{p,nf}\\
&\qquad-\Psi^{w}_{p,ni}=0\colon vf^{w}_{p,nd,nf,c}\quad\forall\quad w,p,(ni,nf,c)\in la
\end{aligned}\tag{4.3.36}$$

$$\begin{aligned}
&-offer_{p,gccp}DU+\sum_{w}\left(\lambda^{w}_{p,ftrndrf}-\lambda^{w}_{p,ftrnd}\right)-\underline{\kappa}^{w}_{p,gccp}+\sum_{w}\overline{\kappa}^{w}_{p,gccp}\\
&\quad+\sum_{w}\left(\Psi^{w}_{p,ftrndrf}-\Psi^{w}_{p,ftrnd\in(gnd)}\right)=0\colon ftr_{p,gccp}\quad\forall\quad p,gccp
\end{aligned}\tag{4.3.37}$$

$$\begin{aligned}
&\sum_{nf\in le(nd,nf,c)}\frac{Sb}{X_{nd,nf,c}}v\phi_{p,nd,nf,c}-\sum_{ni\in le(ni,nd,c)}\frac{Sb}{X_{ni,nd,c}}v\phi_{p,ni,nd,c}-\sum_{nf\in lc(nd,nf,c)}\frac{Sb}{X_{nd,nf}}\overline{v\tau}_{p,nd,nf,c}\\
&-\sum_{ni\in lc(ni,nd,c)}\frac{Sb}{X_{ni,nd,c}}v\underline{\tau}_{p,ni,nd,c}+\sum_{ni\ \in lc(ni,nd,c)}\frac{Sb}{X_{ni,nd,c}}v\overline{\tau}_{p,ni,nd,c}+\sum_{nf\in lc(nd,nf,c)}\frac{Sb}{X_{nd,nf,c}}\underline{v\tau}_{p,nd,nf,c}\\
&\qquad-\underline{v\varphi}^{w}_{p,nd}+\overline{v\varphi}^{w}_{p,nd}=0\colon v\Theta^{w}_{p,nd}\quad\forall\quad w,p,nd
\end{aligned}\tag{4.3.38}$$

$$-vf^{w}_{p,ni,nf,c}+\left[v\Theta^{w}_{p,ni}-v\Theta^{w}_{p,nf}\right]\frac{Sb}{X_{ni,nf,c}}=0\quad\forall\quad w,p,(ni,nf,c)\in le\tag{4.3.39}$$

$$\sum_{ni\in la(ni,nd,c)}vf^{w}_{p,ni,nd,c}-\sum_{nf\in la(nd,nf,c)}vf^{w}_{p,nd,nf,c}=\sum_{gc\in ftrndrf}ftr_{p,gc}-\sum_{gc\in ftrnd}ftr_{p,gc}\quad\forall\quad w,p,nd\tag{4.3.40}$$

**Complementarity conditions** Non-linear complementarity conditions from FTRs feasibility constraints are provided from Equation 4.3.41 to Equation 4.3.51

$$0\leq\left(vf^{w}_{p,ni,nf,c}-\left[v\Theta^{w}_{p,ni}-v\Theta^{w}_{p,nf}\right]\frac{Sb}{X_{ni,nf,c}}+MF_{ni,nf,c}\left(1-it_{ni,nf,c}\right)\right)\perp\underline{v\tau}^{w}_{p,ni,nf,c}\geq 0\tag{4.3.41}$$

$$\forall\quad w,p,(ni,nf,c)\in lc\tag{4.3.42}$$

$$\begin{aligned}
&0\leq\left(-vf^{w}_{p,ni,nf,c}+\left[v\Theta^{w}_{p,ni}-v\Theta^{w}_{p,nf}\right]\frac{Sb}{pX_{ni,nf,c}}+MF_{ni,nf,c}\left(1-it_{ni,nf,c}\right)\right)\perp\overline{v\tau}^{w}_{p,ni,nf,c}\geq 0\\
&\qquad\forall\quad w,p,(ni,nf,c)\in lc
\end{aligned}\tag{4.3.43}$$

$$0 \leq \left(vf^{w}_{p,ni,nf,c} + TTC_{ni,nf,c} it_{ni,nf,c}\right) \quad \perp \quad \underline{v\Upsilon}^{w}_{p,ni,nf,c} \geq 0 \qquad \forall \quad w, p, (ni, nf, c) \in lc \quad (4.3.44)$$

$$0 \leq \left(-vf^{w}_{p,nd,nf,c} + TTC_{ni,nf,c} it_{ni,nf,c}\right) \quad \perp \quad \overline{v\Upsilon}^{w}_{p,ni,nf,c} \geq 0 \qquad \forall \quad w, p, (ni, nf, c) \in lc \quad (4.3.45)$$

$$0 \leq \left(vf^{w}_{p,ni,nf,c} + TTC_{ni,nf,c}\right) \quad \perp \quad \underline{v\phi}^{w}_{p,ni,nf,c} \geq 0 \qquad \forall \quad w, p, (ni, nf, c) \in le \quad (4.3.46)$$

$$0 \leq \left(-vf^{w}_{p,ni,nf,c} + TTC_{ni,nf,c}\right) \quad \perp \quad \overline{v\phi}^{w}_{p,ni,nf,c} \geq 0 \qquad \forall \quad w, p, (ni, nf, c) \in le \quad (4.3.47)$$

$$0 \leq \left(-ftr_{p,gccp} + MP_{gccp} icg_{gccp}\right) \quad \perp \quad \overline{\kappa}^{w}_{p,gccp} \geq 0 \qquad \forall \quad w, p, gccp \quad (4.3.48)$$

$$0 \leq \left(ftr_{p,gccp}\right) \quad \perp \quad \underline{\kappa}_{p,gccp} \geq 0 \qquad \forall \quad w, p, gccp \quad (4.3.49)$$

$$0 \leq \left(v\theta^{w}_{p,nd} + \frac{\pi}{2}\right) \quad \perp \quad \underline{v\varphi}_{p,nd} \geq 0 \qquad \forall \quad w, p, nd \quad (4.3.50)$$

$$0 \leq \left(\frac{\pi}{2} - v\theta^{w}_{p,nd}\right) \quad \perp \quad \overline{v\varphi}_{p,nd} \geq 0 \qquad \forall \quad w, p, nd \quad (4.3.51)$$

**Investment and Operation** 4.3.52-4.3.58, correspond to the derivative of the lagrangian function with respect to the variables $f^{w}_{p,nd,nf,c}, gp^{w}_{p,g}, it_{(ni,nf,c)}, ig_{gc}, \Theta^{w}_{p,nd}, ens^{w}_{p,nd}$ and $l^{w}_{p,ni,nf,c}$ respectively. Finally, equations 4.3.59 4.3.60 correspond to the equality constraints associated with flows and balance constraints, respectively.

$$\begin{aligned}
&-\underline{\Upsilon}^{w}_{p,ni,nf,c\ \in lc(ni,nf,c)} + \overline{\Upsilon}^{w}_{p,ni,nf,c\in lc(ni,nf,c)} - \underline{\tau}^{w}_{p,ni,nf,c\in lc(ni,nf,c)} + \overline{\tau}^{w}_{p,ni,nf,c\in lc(ni,nf,c)} \\
&-\underline{\phi}^{w}_{p,ni,nf,c\in le(ni,nf,c)} + \overline{\phi}^{w}_{p,ni,nf,c\in le(ni,nf,c)} - \phi^{w}_{p,ni,nf,c\ \in le(ni,nf,c)} - \frac{L_{ni,nf,c}}{2}\underline{\mu}^{w}_{p,ni,nf,c\in ll(ni,nf,c)} \\
&\qquad + \frac{L_{ni,nf,c}}{2}\overline{\mu}^{w}_{p,ni,nf,c\in ll\{ni,nf,c)} + \lambda^{w}_{p,ni\in la} - \lambda^{w}_{p,nf\in la} = 0 \\
&\qquad : f^{w}_{p,nd,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in la \qquad (4.3.52)
\end{aligned}$$

$$\begin{aligned}
&PR^{w} VC_{g} DU_{p} + PR^{w} CO2_{g} DU_{p} - \lambda^{w}_{p,nd\in(gnd)} - \underline{\rho}^{w}_{p,gc} + \overline{\rho}^{w}_{p,gc} - \underline{\omega}^{w}_{p,g} + \overline{\omega}^{w}_{p,g} = 0 \\
&\qquad : gp^{w}_{p,g} \quad \forall \quad w, p, g, nd \in gnd \qquad (4.3.53)
\end{aligned}$$

$$\begin{aligned}
&FCT_{lc} + PR^{w} CO2_{g} DU_{p} - \lambda^{w}_{p,nd\in(gnd)} - \underline{\rho}^{w}_{p,gc} + \overline{\rho}^{w}_{p,gc} - \underline{\omega}^{w}_{p,g} + \overline{\omega}^{w}_{p,g} = 0 \\
&\qquad : it_{(ni,nf,c)} \quad \forall \quad (ni, nf, c) \in lc \qquad (4.3.54)
\end{aligned}$$

$$\begin{aligned}
&FCG_{gc} + PR^{w} CO2_{g} DU_{p} - \lambda^{w}_{p,nd\in(gnd)} - \underline{\rho}^{w}_{p,gc} + \overline{\rho}^{w}_{p,gc} - \underline{\omega}^{w}_{p,g} + \overline{\omega}^{w}_{p,g} = 0 \\
&\qquad : ig_{gc} \quad \forall \quad gc \in gcncp \qquad (4.3.55)
\end{aligned}$$

$$\begin{aligned}
&\sum_{nf\in le(nd,nf,c)} \frac{Sb}{X_{nd,nf,c}} \phi_{p,nd,nf,c} - \sum_{ni\in le(ni,nd,c)} \frac{Sb}{X_{ni,nd,c}} \phi_{p,ni,nd,c} - \sum_{nf\in lc(nd,nf,c)} \frac{Sb}{X_{nd,nf}} \overline{\tau}_{p,nd,nf,c} \\
&- \sum_{ni\in lc(ni,nd,c)} \frac{Sb}{X_{ni,nd,c}} \underline{\tau}_{p,ni,nd,c} + \sum_{ni\in lc(ni,nd,c)} \frac{Sb}{X_{ni,nd,c}} \overline{\tau}_{p,ni,nd,c} + \sum_{nf\in lc(nd,nf,c)} \frac{Sb}{X_{nd,nf,c}} \underline{\tau}_{p,nd,nf,c} \\
&\qquad -\underline{\varphi}^{w}_{p,nd} + \overline{\varphi}^{w}_{p,nd} = 0 \colon \Theta^{w}_{p,nd} \quad \forall \quad w, p, nd \qquad (4.3.56)
\end{aligned}$$

$$PR^{w} CENS - \lambda^{w}_{p,nd} + \overline{\gamma}^{w}_{p,nd} - \underline{\gamma}^{w}_{p,nd} = 0 \colon ens^{w}_{p,nd} \quad \forall \qquad w, p, nd \qquad (4.3.57)$$

$$\lambda^w_{p,ni\in ll} + \lambda^w_{p,nf\in ll} - \underline{\mu}^w_{p,ni,nf,c} - \overline{\mu}_{p,ni,nf,c} = 0 \colon l^w_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{4.3.58}$$

$$-f^w_{p,ni,nf,c} + \left[\Theta^w_{p,ni} - \Theta^w_{p,nf}\right] \frac{Sb}{X_{ni,nf,c}} = 0 \quad \forall \quad w,p,(ni,nf,c) \in le \tag{4.3.59}$$

$$D_{nd} - \sum_{gnd} gp^w_{p,g} - e^w_{p,nd} + \sum_{nf\in la(nd,nf,c)} f^w_{p,nd,nf,c} - \sum_{ni\in la(ni,nd,c)} f^w_{p,ni,nd,c} + \sum_{nf\in ll(nd,nf,c)} l^w_{p,nd,nf,c} + \sum_{ni\in ll(ni,nd,c)} l^w_{p,ni,nd,c} = 0 \quad \forall \quad w,p,nd \tag{4.3.60}$$

**Complementarity conditions**

Non-linear complementarity conditions from investment and operation constraints are provided from Equation 4.3.61 to Equation 4.3.79

$$0 \le \left( f^w_{p,ni,nf,c} - \left[\Theta^w_{p,ni} - \Theta^w_{p,nf}\right] \frac{Sb}{X_{ni,nf,c}} + MF_{ni,nf,c}\left(1 - it_{ni,nf,c}\right) \right) \perp \underline{\tau}^w_{p,ni,nf,c} \ge 0 \tag{4.3.61}$$

$$\forall \quad w,p,(ni,nf,c) \in lc \tag{4.3.62}$$

$$0 \le \left( -f^w_{p,ni,nf,c} + \left[\Theta^w_{p,ni} - \Theta^w_{p,nf}\right] \frac{Sb}{pX_{ni,nf,c}} + MF_{ni,nf,c}\left(1 - it_{ni,nf,c}\right) \right) \perp \overline{\tau}^w_{p,ni,nf,c} \ge 0$$

$$\forall \quad w,p,(ni,nf,c) \in lc \tag{4.3.63}$$

$$0 \le \left(f^w_{p,ni,nf,c} + TTC_{ni,nf,c} ict_{ni,nf,c}\right) \perp \underline{\Upsilon}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{4.3.64}$$

$$0 \le \left(-f^w_{p,nd,nf,c} + TTC_{ni,nf,c} ict_{ni,nf,c}\right) \perp \overline{\Upsilon}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in lc \tag{4.3.65}$$

$$0 \le \left(f^w_{p,ni,nf,c} + TTC_{ni,nf,c}\right) \perp \underline{\phi}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in le \tag{4.3.66}$$

$$0 \le \left(-f^w_{p,ni,nf,c} + TTC_{ni,nf,c}\right) \perp \overline{\phi}^w_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in le \tag{4.3.67}$$

$$0 \le \left(-gp^w_{p,gc} + MP_{gc} \mathrm{ig}_{gc}\right) \perp \overline{\rho}_{p,gc} \ge 0 \quad \forall \quad w,p,gc \in gnd \tag{4.3.68}$$

$$0 \le \left(gp^w_{p,gc}\right) \perp \underline{\rho}_{p,gc} \ge 0 \quad \forall \quad w,p,gc \in gnd \tag{4.3.69}$$

$$0 \le \left(-gp^w_{p,g} + MP\right) \perp \overline{\omega}_{p,g} \ge 0 \quad \forall \quad w,p,ge \tag{4.3.70}$$

$$0 \le \left(gp^w_{p,g}\right) \perp \underline{\omega}_{p,g} \ge 0 \quad \forall \quad w,p,ge \tag{4.3.71}$$

$$0 \le \left(D_{nd} - \mathrm{ens}^w_{p,nd}\right) \perp \overline{\gamma}_{p,nd} \ge 0 \quad \forall \quad w,p,nd \tag{4.3.72}$$

$$0 \le \mathrm{ens}^w_{p,nd} \perp \underline{\gamma}_{p,nd} \ge 0 \quad \forall \quad w,p,nd \tag{4.3.73}$$

$$0 \le \left(0.5L_{ni,nf,c}\; f^w_{p,ni,nf,c} + l^w_{p,ni,nf,c}\right) \perp \underline{\mu}_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{4.3.74}$$

$$0 \le \left(l^w_{p,ni,nf,c} - 0.5L_{ni,nf,c}\; f^w_{p,ni,nf,c}\right) \perp \overline{\mu}_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{4.3.75}$$

$$0 \le \left(l^w_{p,ni,nf,c} - 0.5L_{ni,nf,c}\; TTC_{ni,nf,c}\right) \perp \underline{\delta}_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{4.3.76}$$

$$0 \le \left(0.5L_{ni,nf,c}\; TTC_{ni,nf,c} - l^w_{p,ni,nf,c}\right) \perp \overline{\delta}_{p,ni,nf,c} \ge 0 \quad \forall \quad w,p,(ni,nf,c) \in ll \tag{4.3.77}$$

$$0 \le \left(\theta^w_{p,nd} + \frac{\pi}{2}\right) \perp \underline{\varphi}_{p,nd} \ge 0 \quad \forall \quad w,p,nd \tag{4.3.78}$$

$$0 \le \left(\frac{\pi}{2} - \theta^w_{p,nd}\right) \perp \overline{\varphi}_{p,nd} \ge 0 \quad \forall \quad w,p,nd \tag{4.3.79}$$

### 4.3.3 Solving strategy

As mentioned above, the problem at hand, formulated as a bi-level problem, is transformed into an MPEC by deriving the KKT optimality conditions of the Lower Level problem (LL) and integrating these into the Upper Level problem (UL). The linearization of the KKT complementarity conditions of the LL operation problem are provided in Appendix A. Therefore, the overall optimization problem to be solved can be represented in a single level according to the following MILP formulation where complementarity constraints have been linearized making use of the BigM formulation and M values have been tuned following the algorithm proposed in [96].

**Upper level** Eq [(4.3.1 - 4.3.22)]
**Lower level** (KKTs)
FTRs Feasibility see Eq [(4.3.36 - 4.3.40)].
- Linearised complementarity conditions Eq [(A.0.37 - A.0.56)], see Appendix A.
Investment and Operation see Eq [(4.3.52 - 4.3.60)].
- Linearised complementarity conditions Eq [(A.0.1 - A.0.36)], see Appendix A.

This model has been implemented in Python using Pyomo, and computations have been performed on a computer equipped with an Intel® Core™ i7-8700 CPU and 32 GB of RAM.

## 4.4 Case Study and Results

### 4.4.1 Stylized 2-node case

As a stylized case study, we consider a simplified representation of the Western European electricity system, as depicted in Figure 4.3. As aforementioned, this case study illustrates the use of FTRs as a coordination mechanism for transmission and generation investments, focusing on a risk-averse GENCO located in a remote area that aim to hedge the long-term price risk their generation investments are subject to due to the possible occurrence of network congestion.

The system depicted in Figure 3 comprises two nodes, one node representing the North Sea remote area where renewable generation can be deployed in the North Sea (labelled 'NS'), a part of the European power system that can be deemed a remote area where significant amounts of renewable generation can be deployed, and the other node corresponding to an aggregate representation of that part of the European system that can be effectively accessed by the generation in the NS to supply the load located there (labelled 'RE'). The reader should note that the generation represented within RE corresponds to that generation located within the rest of Europe that can effectively compete with the generation in node NS to supply some load in the European system. In other words, energy resources, generation and demand, located in areas that are not part of the potentially relevant market for generation in node NS, due to network congestion, has been excluded from the analysis. Here, the aim is to explore the effect of LT-FTRs on the system's expansion in the 2030-time horizon.

Generation and Demand data in node RE, including the solar and wind generation profiles, have been drawn from MAF2019 and MAF2020 datasets. Information on these is available in [100]. The operation and investment costs considered for generation are those available in [101] and [102] for node RE, and those available in [109] for node NS, respectively. A 5% of discount rate was considered to annualize the investment costs. The network investment costs considered are those


Figure 4.3: Stylized 2-node Case

available in [103]. 128 €/tCO2 has been considered for the CO2 price [110], which corresponds to the gradual development scenario by 2030.

The data set for the scenario 2030 available within the North Sea Wind Power Hub (NSWPH) [106] has been used to draw the network configuration in the remote area. In total, eight existing generators, and three candidate generators have been considered within node RE. Table 4.1 provides the existing and candidate generators, which correspond to generation aggregated per technology type.

Table 4.1: Existing and candidate Generation capacity per technology [MW]. Stylized 2-node example.

| | **Solar** | **Wind** | **Hydro** | **Gas** | **Nuclear** | **Others** |
|---|---|---|---|---|---|---|
| Existing | 86,182 | 105,615 | 55,820 | 44,625 | 68,099 | 21,690 |
| Candidate | 55,545 | 37,952 | 5,356 | - | - | - |

Regarding the representation of the behaviour of strategic agents, $\beta_{\mathbf{cp}}$ parameter is assigned a value of 80%, considered when modelling the impact of uncertainty for GENCOs in remote areas. This is a value typically used in literature [69]. The reference node considered for the definition of FTRs is the one corresponding to the Rest of Europe (RE), node that represents the rest of the system and is considered to have stable enough prices.

For simplicity, generation and transmission investment decisions have been deemed to be continuous, aligning with the scalability of generation projects, in particular renewable generation in the NS. To represent the system's operation throughout the target year, only six time periods have been selected using k-medoids clustering technique. These operation periods have been chosen as representatives of the clusters of operation snapshots defined considering separately the demand, solar power production, and wind power production. To determine the appropriate number of representative hours, the elbow method was applied to strike a balance between the level of detail considered in the representation of the system operation and the computational burden of the resulting problem. This approach is feasible because the problem formulation does not impose inter-temporal constraints relateed to the energy resources management, such as storage, linking the operation in several periods. This involves computing ex-ante some operation profile for period-coupling resources, like storage, and taking into account the net power output of these in each operation situation.

In this case study, only one GENCO '*Wind_New_NS*' featuring a generation capacity of up to 12,000 MW, and located in node NS, is deemed to be subject to a relevant level of risk affecting its market profits, and is therefore represented here as risk averse. In this case, the higher the level of risk aversion by this GENCO, the more conservative the investment strategy it would opt for, and the more relevant the role played by LT FTRs could be. In addition, a non-risk averse GENCO featuring a capacity of 4000 MW is deemed to be existing by 2030 in node NS. Accordingly, the candidate network linking node NS to the rest of the system has an overall capacity of 16,000MW as shown in Figure 4.3.

Here, it is assumed that the risk-averse GENCO within the remote area deems the long-term behaviour of the GENCOs in the rest of the system as competitive, i.e the social-welfare maximising one, which is in line with the actual behavior of these other companies, according to the assumptions. Still, this risk-averse GENCO is deemed to face some uncertainty about the evolution of the demand in this area and the rest of Europe, which may affect congestion between node NS and node RE. Therefore, the risk averse GENCO in the remote area is deemed to perceive some uncertainty affecting the revenues, costs, and therefore the profits of its investments. This uncertainty is deemed to affect the evolution of demand in nodes NS and RE in the relevant planning timeframe. The need to manage this uncertainty is potentially driving this Genco to acquire FTRs to hedge risk associated with the price differences between node NS, where its new generation is to be connected, and node RE, whose prices are deemed significantly more stable and predictable.

The uncertainty perceived by generator '*Wind_New_NS*' about the future system evolution and the market benefits it will make is represented, in a simplified manner, through the consideration of two scenarios, medium scenario, whose output and corresponding market revenues and benefits for the strategic generator are deemed representative of moderate conditions, and a low or worst-case scenario, representative of those where GenCos benefits from its investments would plummet. Note that the only parameter here represented as uncertain, characterising each scenario, is the future demand. Here it is important to take into account that the demand behavior in the North Sea is highly uncertain due to several factors, such as the uncertainty affecting the geographical location and the amount of hydrogen production in the future. Therefore, demand is considered here as a relevant element of uncertainty for GENCOs located in the remote area. The higher the demand within a scenario in the node NS, the connection node for this Genco's investments, the more favorable the scenario for this Genco is. Consequently, the worst-case scenario is represented here as a scenario where demand in node NS is lower than in the medium scenario considered and where demand in the reference node (RE) is larger than in the medium scenario. The probability of occurrence of the medium scenario (sc01) is 0.8, while that of the worst-case scenario (sc02) for this Genco is 0.2.

Scenario sc01 has been defined considering an evolution of the mainland system in Europe in 2030 corresponding to that in MAF2020 and an evolution of the system in the North Sea (node NS) based on two elements i) moderate electrification of fuel oil and gas platforms resulting on 2 GW of load and ii) moderate hydrogen production from the output of wind offshore resulting in 2 GW extra of load.

Regarding platform electrification, regional studies and pilot initiatives suggest that by 2030, around 50 fuel-oil and gas platforms could be electrified [112]. Assuming an average load of 40 MW per platform [113], this results in an estimated demand in node NS of approximately 2 GW. Offshore wind developments in NS should allow these platforms to replace their on-site gas-fired generation with the former. Meanwhile, green hydrogen production is expected to emerge as a key component of the North Sea's energy transition, leveraging its expected vast offshore wind developments.

Initiatives such as AquaVentus and NortH2 illustrate the planned deployment of GW-scale offshore electrolysis capacity in the North Sea by 2030. AquaVentus aims for a modular development targeting up to 10 GW of capacity by 2035, with early phases involving approximately units totalling 1 GW capacity. Meanwhile, NortH2 plans to reach 1 GW of capacity by 2027 and expand up to 4 GW by 2030, making large-scale offshore green hydrogen production a tangible goal. Considering these roadmaps and early-stage projects, assuming 2 GW of offshore electrolysis demand in node NS by 2030 is consistent with current regional strategies and market developments, see [114]. Altogether, this 2 GW + 2 GW split makes an estimate of the North Sea's total electricity demand by 2030 in the medium scenario.

By contrast, the worst-case scenario for the Genco deploying generation in node NS, sc02, is a scenario considering higher demand across continental Europe and zero demand at the North Sea.

It is reasonable to assume that the demand projected for node NS in the medium scenario is relocated in scenario sc02 to the rest of Europe. What is more, in a worst-case scenario, one could assume the new electricity demand developments taking place at continental level, in this case located in the continental plato, to be larger, as corresponding to a high-demand scenario, triggered by both the reallocation of North Sea energy functions and an accelerated rollout of electrification and hydrogen production across the continent [114]. This assumption is plausible, given the larger scale, stronger infrastructure, and higher renewable integration capacity of the continental power system. Thus, shifting future electricity demand increases to continental Europe could increase the energy demand growth potential. Note that those additional demand developments in mainland Europe in scenario sc02, which are here deemed to amount to 8 GW of capacity, could result in electricity price increases.

The distribution of the demand between the two nodes comprising the relevant regional market area represented for the two scenarios considered by the strategin GENCO in NS when determining the probability distribution of its profits is summarised in Table 4.2.

Table 4.2: Demand behaviour. Stylized 2-node example.

| | | **RE** | **NS** |
|---|---|---|---|
| Sc01 | Peak Demand [MW] | 209,198 | 3,734 |
| | Energy [GWh] | 1,602,742 | 25,726 |
| Sc02 | Peak Demand [MW] | 216,484 | |
| | Energy [GWh] | 1,654,195 | |

Generators have the option of contracting FTRs to manage the risk associated with the uncertainty they face about the price of the node where they are located. Here, FTRs are defined taking node RE as the reference node of the right, and node NS as the intake node. Given the features of generation and demand available and to be deployed in each node, the price of node RE is expected to be more higher and more stable than that of node NS.

Then, by contracting FTRs, generation '*Wind_New_NS*' should be able to stabilise its revenues and profits. As a consequence, the Genco developing generation '*Wind_New_NS*' could find buying FTRs attractive.

**Results**

Here the results computed on the expansion of the system, the resulting operation, and the objective function are provided, both for the case where long-term FTRs are made accessible to the generation investors in the remote area to contract them, and for the case where FTRs are not made available. In the former situation, we also compute the amount of FTRs to be contracted. These results are computed assuming strategic behaviour from GENCOs and a lack of coordination of the generation and transmission investment decisions made by the stakeholders.

According to the results computed, deploying off-shore wind generation in the NS turns out to be cost efficient, given the abundant offshore wind renewable potential in the NS, the distribution of primary renewable energy resources across Europe, and the network costs associated with integrating the generation deployed in the European electricity system. The deployment of part of that offshore wind generation in the NS is deemed to be cost-efficient; however, its deployment is contingent on acquiring LT FTRs by this generation, providing it with a price risk hedge.

As shown in Table 4, when the GENCO in the NS area is deemed risk averse, the level of the socially optimal NS generation investments in the case where FTRs can be contracted is 98% of the maximum amount of generation capacity that can be installed while, when FTRs cannot be contracted, the level of these investments drops to only 86% of the potential maximum amount. Accordingly, in the presence of FTRs, the level of transmission investments is 87% of the maximum amount deemed possible, while, when FTRs cannot be contracted, the level of transmission investments reaches only 78% of this maximum amount. Then, making FTRs available increases both investments in generation and transmission, coordinating them, see rows 11 and 12.

By acquiring LT FTRs, the GENCO located in node NS manages to increase the profits it would make out of its investments in this area. Then, some of these generation investments become profitable for this GENCO due to the availability of LT FTRs for it to contract. Then, making FTRs available would lead a risk-averse GENCO to undertake additional generation investments within the North Sea that are socially efficient. This is because FTRs are found to allow this GENCO to effectively manage the market price risk it perceives associated with these investments.

The results computed are shown here for the target year and the two cases being compared (with and without LT-FTRs available). Besides, some results, like the benefits made by the GENCO in node NS, are provided for each of the 2 scenarios considered. The impact of contracting LT-FTRs on the set of investments undertaken depends on some of the framework conditions defined for the system considered. Notably, the amount of additional investments in the NS area triggered by the availability of LT-FTRs largely depends on the difference between the amounts of congestion rents produced by LT-FTRs in both scenarios and the relative value assigned by the GENCO to its benefits in the worst case scenario compared to those in the medium scenario. Contracting LT-FTRs increases the value obtained by the GENCO from investing in additional NS generation due to the increase in the stability of this generation's profits across scenarios rendered by FTRs. Besides, the larger the expected net social value created by these additional NS generation investments is compared to the expected net social value created by the generation that is installed in other areas more tightly connected to the rest of the system, the larger the amount of transmission capacity the network planner is willing to build to integrate additional remote generation and the more inclined it is to accept an offer for LT-FTRs made by the GENCO in the NS.

Table 4.3: Benefits obtained by the GENCO in the two scenarios considered both when LT-FTRs are available and when they are not and difference between the benefits it obtains in both scenarios in each of the two cases. Stylised 2-node example.

| **Benefits [M€]** | **with FTRs** | **without FTRs** |
|---|---|---|
| Sc01 | 3,009 | 3,235 |
| Sc02 | 1,090 | 723 |
| Difference | 1,919 | 2,513 |

Table 4.4 shows that the GENCO's profits (including the weighted benefits in the NS area for the two scenarios considered and additional terms as fixed costs and the offer made by the FTRs see Equation 4.3.2) when FTRs are not available are lower than its profits when GENCO can contract FTRs. As shown in Table 4.3, contracting FTRs allows GENCO to significantly increase the benefits it makes from the new generation it builds in the NS area in the worst-case scenario considered, while these benefits are lower in the medium scenario (Sc01) when contracting FTRs. This is due to the fact that, being able to contract FTRs to increase its benefits in the worst-case scenario, the optimal amount of generation to be developed from its point of view becomes larger than the optimal one according to the expected profits alone. It is also relevant to note that contracting FTRs encourages the relevant stakeholders, GENCO and transmission planner, to coordinate their investments, since, once FTRs are contracted, they create incentives for the stakeholders to build the generation and transmission capacity leading to the energy exchanges supported by these products. As shown also in Table 4.3, the variability across scenarios of the benefits made by this new NS generation when contracting FTRs is significantly smaller than the variability of these when not contracting FTRs.

If the GENCO in the NS area is risk-averse, the expected net social welfare of the system resulting from its planned investments is larger when this GENCO can contract FTRs than when it cannot. Accordingly, the total costs incurred by the system (investment plus overall operation costs) when FTRs can be contracted are lower than those incurred when FTRs cannot be contracted, see row 6 from Table 4.4.

Thus, in this Case Study, the ability to contract FTRs triggers additional generation and transmission investments in the NS area, which, altogether, with the FTRs contracted, lead to an increase in the GENCO's profit and the expected social welfare, showing the potential of FTRs to trigger additional investments by the several stakeholders that, altogether, are socially efficient and are largely coordinated in an efficient manner.

Please note the close similarity between the magnitude of the offer issued by the GENCO in the NS node for the FTRs it contracts (row 8) and the congestion rents produced by these FTRs (row 9). This alignment indicates that the mathematical formulation considered (not constraining the price offered for LT-FTRs) is, in this case, resulting in a price to be offered by the GENCO for the LT-FTRs it aims to contract, in order for this offer to be accepted by the network planner, that is close to the market value of the corresponding FTRs (and even a bit larger). Probably, this is due to the fact that the system planner faces a cost when selling transmission rights associated with

Table 4.4: Main results computed when considering the GENCO in the NS as risk averse, and non-risk averse – Stylized 2-node example.

| | | **Risk averse** | | **Non-risk averse** |
|---|---|---|---|---|
| | | **with FTRs** | **without FTRs** | |
| 1 | Generation Investment Cost [M€] | 16,316 | 16,372 | 16,303 |
| 2 | Network Investment Cost [M€] | 354 | 321 | 358 |
| 3 | Total Investment Cost [M€] | 16,671 | 16,693 | 16,662 |
| 4 | Operational Cost [M€] | 11,775 | 11,783 | 11,778 |
| 5 | Emissions Cost [M€] | 3,721 | 3,738 | 3,721 |
| 6 | Inv + Total Oper. Cost [M€] | 32,167 | 32,214 | 32,161 |
| 7 | FTRs allocated [M] | 10,240 | - | - |
| 8 | Offer made for all FTRs [€] | 262,157,841 | - | - |
| 9 | Congestion Rents (vFTRCost) [€] | 262,157,738 | -169 | - |
| 10 | GENCOs Profit [M€] | 5,744 | 4,479 | - |
| 11 | Amount of gener. in the NS as a fraction of gener. potential: $ig_{NS}$ [%] | 98 | 86 | 100 |
| 12 | Amount of gener. in the NS as a fraction of gener. potential: $it_{NS}$ [%] | 87 | 78 | 88 |

the congestion rents they are expected to produce, which should be handed over to the GENCO having acquired these rights. However, in reality, the planning authority might renounce to recover from the sale of FTRs the full amount to be transferred to FTR owners in the form of congestion rents if the decision to deploy additional remote generation that is highly beneficial for the system is contingent on the acquisition of these rights by the GENCO and there is no competition for the acquisition of LT-FTRs among network users.

Last column of Table 4.4 provides results for the case where the GENCO in the NS node is risk-neutral and it is not behaving strategically. In this case, the problem aimed at computing the development of the system becomes the classical centralised, generation and transmission expansion planning problem, which can be formulated as a single-level problem and considered a benchmark.

When comparing the results in Table 4.4 to those for this benchmark, it becomes evident that the consideration of Financial Transmission Rights (FTRs) corresponding to the new capacity connecting node NS to the rest of the system leads to expansion decisions by stakeholders that resemble more closely those of the fully centralized planning of the expansion than those decisions made by stakeholders when FTRs are not available.

Table 4.5 provides the amount of renewable generation built in node NS and the rest of Europe in the three different cases considered: the case where investors in generation in the NS area are risk-averse and they have the possibility to contract LT-FTRs; that where investors in generation in the NS area are risk-averse but they cannot contract FTRs, and; that corresponding to the benchmark case, where investors in generation in the NS area are risk-neutral and not strategic.

According to the results in Table 4.5, when considering risk-averse investors in the NS area, contracting FTRs triggers significant additional investments in renewable wind generation in the NS area. Renewable generation investments in the NS area amount to 11,760 MW of capacity in the case where FTRs are available, while these amount to 10,320 MW of capacity when FTRs cannot

Table 4.5: Results – Investments in renewable generation in the three cases considered [MW].

| | | Solar | Wind |
|---|---|---|---|
| Risk-averse Without FTRs [MW] | North Sea | | 6,750 |
| | Rest of Europe | 69,137 | 49,538 |
| Risk-averse With FTRs [MW] | North Sea | | 8,250 |
| | Rest of Europe | 70,411 | 50,246 |
| Non-risk averse [MW] | North Sea | | 11,039 |
| | Rest of Europe | 70,985 | 48,031 |

be contracted. This represents an increase of 14% in the magnitude of these investments.

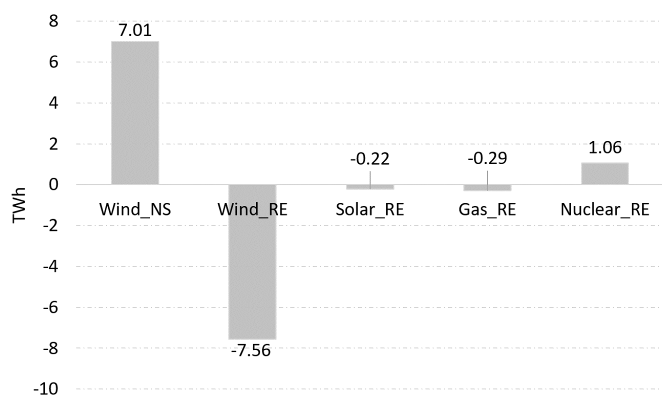


Figure 4.4: Differences in the annual electricity production by technology in Europe, when investors in generation in the NS area are risk-averse, between the cases where FTRs can and cannot be contracted – Stylized 2-node example.

When not being able to contract FTRs, due to the significant price risk offshore wind generation in the NS area is subject to, investors in these area decide to deploy a lower amount of RES-based generation (wind generation) there, being this replaced by larger amounts of electricity being produced by thermal generation already available in the rest of Europe and by production from additional RES-based generation (both solar and wind) being deployed in the rest of Europe (node RE), despite the especially favourable conditions that exist for the production of electricity from wind in the node NS, see Table 4.5 and Figure 4.4. When FTRs are not available, this reallocation of generation occurs even though the expected overall costs (including the investment and variable ones) incurred by additional thermal and RES-based generation in node RE are larger than those incurred by wind generation in the NS area.

When NS generation investors are deemed risk-neutral and non-strategic, a case equivalent in its turnout to that resulting from the centralized system expansion planning, wind generation investments in the NS area reach their maximum potential and network investments reach 88% of their maximum considered, see the last column of Table 4.4 and Table 4.5. This indicating that, from the system welfare perspective, fully utilizing wind generation in the NS is economically beneficial.

Table 4.6: Metrics for differences between the prices weighted by demand in the case with FTRs and the case without FTRs, in nodes NS and RE [€/MWh].

| | **NS** | **RE** |
|---|---|---|
| Avg | -0.174 | -0.216 |
| Max | 0 | 0 |
| Min | -1.041 | -1.299 |

Table 4.6 provides relevant metrics associated with the price differences weighted by demand between the case with FTRs and the case without FTRs for nodes NS and RE. It is important to note that the investments and the operation resulting from considering FTRs available lead to lower prices in both nodes compared to the case where FTRs are not available. This implies that the availability of FTRs results in better supply conditions for final users in those areas.

## 4.5 Final Remarks

This chapter explores the use of LT FTRs by a strategic risk-averse GENCO to hedge the price risk they face caused by network congestion and coordinate GEP and TEP investment decisions, assuming that these decisions are competitive, except for the investment decisions by the GENCO contracting LT-FTRs, and that the investments decisions by the strategic GENCO and the network planner are imperfectly coordinated. The proposed approach to address this problem involves formulating and solving a bilevel optimisation problem. Within this model, in the Higher-Level problem, the risk-averse GENCO that is interested in acquiring FTRs (located in a remote area) determines its investment strategy and the bid for FTRs to be submitted to the network planner with the aim of maximising its profits. When computing the profits, it considers the revenues it would make associated with the purchase of the FTRs, and the costs it would incur to purchase these rights according to the bid made for it and submitted, which is deemed to be the necessary one to acquire these FTRs. In the Lower-Level problem the expansion of the system (excluding that of the remote generation owned by the GENCO whose strategy is decided in the upper level problem) and the operation of the system, as well as the amount of FTRs to be allocated to the GENCOs interested in them are computed by the system planner, according to the bids for FTRs made by the GENCOs and the costs associated with the congestion rents to be paid to the rights holders.

Besides, the fact that the network owners and the system planner aim to avoid running the risk of the congestion rents resulting from the dispatch not being large enough to afford the payments to the LT FTRs owners involves enforcing the simultaneous feasibility of all the FTRs issued. The solving strategy considered for this problem involves formulating the KKT optimality conditions of the lower problem to formulate the two-level problem as a single-level one and linearizing this.

The resulting problem statement, formulation and solving stategy are employed to determine the relevance and specific impact on the system development and social welfare of the consideration of LT-FTRs in a stylized European case study in the 2030 timeframe where uncertainty about the future price to be earned by new remote wind generation to be located in the North Sea is deemed to potentially affect the amount of this generation to be deployed. Uncertainty in this case study is represented by considering long-term scenarios on the evolution of local electricity demand in the North Sea.

LT-FTRs allow the GENCO in the North Sea to stabilise its revenues across the demand scenarios considered by allowing these GENCOs to effectively manage the transmission price risk they are subject to. This results in an increase in the value placed by these GENCOs on the investments they undertake. At the same time, LT-FTRs provide financial incentives to these GENCOs and the network planner to build the generation and transmission capacity backed by the FTRs contracted, thus increasing the level of coordination of their investment decisions. These coordination incentives could be seen as a financial commitment affecting these stakeholders to carry out the investments that are supported by the LT-FTRs contracted. In other words, LT-FTRs provide the buying and selling sides involved in these contracts more certainty about their counterparty investment decisions.

Consequently, despite the fact that generation investors are not able to capture the whole social value of the generation developments they undertake, and the fact that the availability of LT-FTRs to be contracted is not forcing additional investments in the system, we have found out that the use of LT-FTRs triggers additional, coordinated, socially-efficient, generation and network investments in the North Sea, resulting in an increase in the concerned GENCOs profits and the social welfare resulting from the development of the system.

According to results computed, there is a close similarity between the magnitude of the bid for FTRs issued by the GENCO in the North Sea and the congestion rents produced by these FTRs. This alignment indicates that, in this case, the price to be offered by this GENCO for the LT-FTRs it aims to contract, in order for this offer to be accepted by the network planner, should be close to the market value of the corresponding FTRs (and even a bit larger).

Finally, it is crucial to emphasize that the influence of LT-FTRs on the investments made depends on the framework conditions within the system, in particular those uncertainty factors that affect the electricity price at the node where remote generation is intended to be deployed.

# Chapter 5

# Conclusions and Future Research

This work assesses the implementation of LT-FTRs in the context of Generation and Transmission expansion planning and its coordination.

Initially, in chapter 2, several works are reviewed in this context and classified according to their modelling features, taking into account different elements such as the planning approach, the coordination mechanisms and risk measurements considered in them.

This review has shown that investment decisions made by different actors are directly affected by their perception of the risks to which these investments are exposed. Considering the impact of risk on generation and transmission investments requires the use of appropriate risk measures. Accordingly, implementing one or more regulatory coordination schemes that allows them to manage the various risks faced by stakeholders, such as the transmission capacity price risk and the lack of mutual commitment, and that provide strong incentives to carry out the planned generation and transmission expansion, is essential for achieving an efficient system expansion.

According to the literature, there is no single perfect risk-hedging instrument that enables a fully efficient and coordinated expansion of generation and transmission. Nevertheless, combining different regulatory mechanisms, for instance, using LT-FTRs together with other instruments such as CfDs, could help interested parties manage the most relevant risks, namely counterparty and price risks, in the GEP&TEP coordination problem.

As mentioned in chapter 2, it is also important to consider different factors that affect GEP&TEP coordination, including, (i) the different construction times for generation and transmission facilities; (ii) the risk aversion of parties caused by their counterparty's lack of commitment to invest; (iii) the uncertainty stakeholders face due to limited information about future market conditions affecting their assets.

The review carried out has shown the importance of implementing complementary regulatory coordination schemes that comprehensively address the diverse risks that stakeholders are exposed to, thereby ensuring that investment decisions by transmission planners and generation companies are influenced by each other's needs and effectively aligned.

Subsequently, chapter 3 explores the use of LT FTRs by risk-averse GENCOs to hedge the price risk resulting from network congestion, assuming that agents' decisions are perfectly coordinated from a social perspective. Accordingly, chapter 3 proposes a bi-level optimisation model, in which the upper level computes the system expansion and quantity of FTRs to be contracted, through the minimisation ot he total system costs considering the value for risk averse GENCOs in remote areas of hedging through the use of LT-FTRs and the lower level computes the operation of the system under uncertainty faced by risk-averse GENCOs. In this formulation the variation in total system costs captures the variation in the net social welfare for inelastic demand, and considering the Energy non Served cost (ENS), provided that the increase in the value of generation investments for the corresponding investors, associated with the reduction in the volatility of their profits, is also included. The impact of uncertainty on GENCOs investments is represented by considering the Conditional Value at Risk (CVaR) of the profits made by risk averse GENCOs in the most unfavourable scenarios. GENCOs in the rest of the system are considered to be risk neutral.

Based on the computed results, it can be concluded that the CVaR of profits from generation investments in remote areas is lower when FTRs are not available than when generators can contract FTRs. This indicates that FTRs have a positive impact on the expected value of generation profits in worst-case scenarios, by reducing the variability of profits across scenarios. In addition, the use of LT FTRs in this context increases the size of remote, cost-efficient generation investments in remote areas, providing solution to Rq1.

Considering perfect coordination among the generation and transmission investment decisions, the investments planned, and the FTRs allocated are optimal from the social perspective, increasing the welfare of the system. Moreover, final consumers in the area of analysis could benefit from the efficient generation investments carried out in the presence of FTRs by getting lower prices in the case where FTRs are made available than in the case without FTRs, providing solution to Rq2.

Then chapter 4 provides a bi-level model with the aim to assess the impact of LT-FTRs on the coordinated generation and transmission expansion planning decisions, considering a reactive planning approach, computing in the upper level the maximisation of risk averse GENCO's profits in the remote area, and in the lower level the expansion and operation on the rest of the system considering that GENCOs in the rest of the system are risk neutral, computing, among others, the amount of FTRs to be allocated and the offers to be made by strategic risk-averse generation investors for these LT-FTRs, showing the ability of LT-FTRs to trigger additional investments in generation and transmission capacity in remote areas, with respect to the case where FTRs cannot be acquired.

Considering the reactive planning context, LT-FTRs allow the GENCO in the North Sea to stabilise its profits providing higher profits in the case where FTRs are available in comparison when FTRs are not available by allowing these GENCOs to effectively manage the transmission price risk they are subject to. This results in an increase in the value placed by these GENCOs on the investments they undertake, resulting in higher investments in the case where FTRs are available, providing answer to Rq3. At the same time, LT-FTRs provide financial incentives to these GENCOs and the network planner to build the generation and transmission capacity backed by the FTRs contracted, thus increasing the level of coordination of their investment decisions and reducing their corresponding counterparty risk. Those coordinated investments resulting from the consideration of FTRs, leads to an increase of the the social welfare of the system. Moreover, final consumers in the area of analysis could benefit from the efficient generation investments carried out in the presence of FTRs by getting lower prices in the case where FTRs are made available than in the case without FTRs, providing answer to Rq4.

Regarding the offer made by a risk-averse Genco for LT-FTRs, the results obtained show that, in the context being modelled, there is a close relationship between the magnitude of the bid for FTRs issued by the GENCO in the North Sea and the congestion rents expected to be produced by these FTRs. This indicates that, in order to be accepted by the network planner, this offer should be close to the market value of the corresponding FTRs.

In general, considering the value that investors assign to their investments, the results obtained show that the availability of LT FTRs should probably enhance the social welfare achieved through system development.

Moreover, LT-FTRs should not affect the investment decisions of risk-neutral GENCOs, since the stabilisation across scenarios of the revenues and profits produced by their investments that can be achieved by contracting LT FTRs has no value for them.

In those cases where FTRs are not available, typically there are lower amounts of cost efficient investments in renewable generation in the area of analysis. This missing generation is replaced with more expensive generation in the rest of the system.

Comparing the results obtained in both models, considering perfect coordination and the reactive planning context, it is possible to conclude that the availability of FTRs enhance the social welfare achieved through system development, results also shows that the use of LT FTRs increases the size of remote, cost-efficient generation investments in remote areas, and in the reactive planning context LT-FTRs triggers additional, coordinated, socially-efficient, generation and network investments in the North Sea. The differences in the results obtained in both models are associated with the differences in the case studies considered and differences in the mathematical representations used in each model.

Finally, it is essential to state that the impact of LT-FTRs on the set of investments undertaken depends on some of the framework conditions applying in the system, notably those related to the uncertainty factors affecting the electricity price at the node or area where remote generation is to be deployed. The relevant uncertainty factors here incude i) the uncertainty about the future development of the local or global demand; ii) the uncertainty about the amount of investments in transmission capacity connecting this area to the rest of the system that will be undertaken; or iii) the uncertainty about the new, additional, generation developments in this remote node or area. All these factors are somehow related and can affect the pattern of grid congestion and its severity across the scenarios defined. These factors are critical when considering the deployment of generation in remote areas weakly linked to the rest of the system. The fact that relevant uncertainty related to the occurrence and severity of congestion exists drives the usefulness of contracting LT FTRs. In situations where, either relevant congestion does not condition the profitability of investments, or relevant uncertainty about the occurrence of this congestion does not exist, the impact of contracting LT FTRs on the efficiency of the system's development would be limited.

It is also important to take into account that there are still relevant aspects of the impact of the use of LT-FTRs on the system that remain unexplored and could be addressed by future research to complement the work discussed in this document.

Some of these are listed next:

i. The impact of the use of LT-FTRs as a potential coordination mechanism for the GEP&TEP problem, could be analyzed under a Proactive Planning Approach. Despite the fact that this Proactive approach is less realistic than the Reactive one, it is an approach that has recently gained relevance in the literature and is deemed to be, theoretically speaking, more efficient.

ii. Considering alternative FTR formats, potentially more complicated ones such as Generalised FTRs (G-FTRs) proposed in [85] and particularly interesting for Renewable generation, could be interesting when analysing the impact of those FTRs in the GEP&TEP and its coordination.

iii. Analyse the combination of LT-FTRs with additional risk heading instruments, such as CfD, could be interesting in order to assess what their joint impact on the expansion of the system and the coordination of GEP and TEP would be. As aforementioned, this would be relevant when the price of the node or area taken as a reference for the definition of LT-FTRs is not stable enough.

iv. When analysing the impact of LT-FTRs on the GEP&TEP coordination, it would be interesting to consider several strategic companies willing to acquire LT-FTRs for the generation they deploy in remote areas. The decisions of these companies would all be computed in the upper-level problem. This would allow one to determine the possible changes in the LT-FTR bidding behavior and expansion decisions by these generation companies that could result from the strategy they follow.

v. Considering the further complexity in the representation of the expansion of the system resulting from considering different, specific, planning horizons for GEP and TEP.

vi. Further complications in the representation of the operation of the system, like the computation of optimal operation of storage endogenously within the problem addressed, could be considered in order to provide a more realistic representation of the operation.

vii. Explore approaches not guaranteeing optimality, such as heuristic or metaheuristics, to solve the bi-level problem addressed, which could allow one to consider further complications in the representation of the system functioning and LT-FTRs in this problem.

# Appendix A

# Linearized Complementarity Conditions

Using the big M formulation, in this section the complementarity conditions are linearized. $\overline{Mdual}$, $\underline{Mdual}$ refer to the big M parameters corresponding to each dual variable for upper and lower bounds, respectively. Big M parameters were computed making use of the algorithm proposed in [96], corresponding to the modified regularization method. $\overline{Ydual}, \underline{Ydual}$ refer to binary variables corresponding to each dual variable for the upper and lower bounds, respectively.

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$$0 \leq f^{w}_{p,ni,nf,c} + TTC_{ni,nf,c} it_{ni,nf,c} \leq \underline{M\Upsilon Y\Upsilon}^{w}_{p,ni,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in lc \tag{A.0.1}$$

$$0 \leq \underline{\Upsilon}^{w}_{p,nd,nf,c} \leq \underline{M\Upsilon}\left(1 - \underline{Y\Upsilon}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in lc \tag{A.0.2}$$

$$0 \leq -f^{w}_{p,nd,nf,c} + TTC_{ni,nf,c} it_{ni,nf,c} \leq \overline{M\Upsilon Y\Upsilon}^{w}_{p,ni,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in lc \tag{A.0.3}$$

$$0 \leq \overline{\Upsilon}^{w}_{p,nd,nf,c} \leq \overline{M\Upsilon}\left(1 - \overline{Y\Upsilon}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in lc \tag{A.0.4}$$

$$0 \leq f^{w}_{p,ni,nf,c} - \left[\Theta^{w}_{p,ni} - \Theta^{w}_{p,nf}\right] \frac{Sb}{X_{ni,nf,c}} + MF_{ni,nf,c}\left(1 - it_{ni,nf,c}\right) \leq \underline{M\tau Y\tau}^{w}_{p,ni,nf,c}$$
$$\forall \quad w, p, (ni, nf, c) \in lc \tag{A.0.5}$$

$$0 \leq \underline{\tau}^{w}_{p,nd,nf,c} \leq \underline{M\tau}\left(1 - \underline{Y\tau}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in lc \tag{A.0.6}$$

$$0 \leq -f^{w}_{p,ni,nf,c} + \left[\Theta^{w}_{p,ni} - \Theta^{w}_{p,nf}\right] \frac{Sb}{pX_{ni,nf,c}} + MF_{ni,nf,c}\left(1 - it_{ni,nf,c}\right) \leq \overline{M\tau Y\tau}_{p,ni,nf,c}$$
$$\forall \quad w, p, (ni, nf, c) \in lc \tag{A.0.7}$$

$$0 \leq \overline{\tau}^{w}_{p,ni,nf} \leq \overline{M\tau}\left(1 - \overline{Y\tau}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in lc \tag{A.0.8}$$

$$0 \leq f^{w}_{p,ni,nf,c} + TTC_{ni,nf,c} \leq \underline{M\phi Y\phi}^{w}_{p,ni,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in le \tag{A.0.9}$$

$$0 \le \underline{\phi}^w_{p,ni,nf,c} \le \underline{M\phi}\left(1 - \underline{Y\phi}^w_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in le \tag{A.0.10}$$

$$0 \le -f^w_{p,ni,nf,c} + TTC_{ni,nf,c} \le \overline{M\phi Y\phi}^w_{p,ni,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in le \tag{A.0.11}$$

$$0 \le \overline{\phi}^w_{p,ni,nf,c} \le \overline{M\phi}\left(1 - \overline{Y\phi}^w_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in le \tag{A.0.12}$$

$$0 \le -gp^w_{p,gc} + MP_{gc}\mathrm{ig}_{gc} \le \overline{M\rho Y\rho}^w_{p,gc} \quad \forall \quad w, p, gc \in gnd \tag{A.0.13}$$

$$0 \le \overline{\rho}^w_{p,gc} \le \overline{M\rho}\left(1 - \overline{Y\rho}^w_{p,gc}\right) \quad \forall \quad w, p, gc \in gnd \tag{A.0.14}$$

$$0 \le \left(gp^w_{p,gc}\right) \le \underline{M\rho Y\rho}^w_{p,gc} \quad \forall \quad w, p, gc \in gnd \tag{A.0.15}$$

$$0 \le \underline{\rho}^w_{p,gc} \le \underline{M\rho}\left(1 - \underline{Y\rho}^w_{p,gc}\right) \quad \forall \quad w, p, gc \in gnd \tag{A.0.16}$$

$$0 \le -gp^w_{p,g} + MP \le \overline{M\omega Y\omega}^w_{p,g} \quad \forall \quad w, p, g \tag{A.0.17}$$

$$0 \le \overline{\omega}_{p,g} \le \overline{M\omega}\left(1 - \overline{Y\omega}^w_{p,g}\right) \quad \forall \quad w, p, g \tag{A.0.18}$$

$$0 \le (gp^w_{p,g}) \le \underline{M\omega Y\omega}^w_{p,g} \quad \forall \quad w, p, g \tag{A.0.19}$$

$$0 \le \underline{\omega}_{p,g} \le \underline{M\omega}\left(1 - \underline{Y\omega}^w_{p,g}\right) \quad \forall \quad w, p, g \tag{A.0.20}$$

$$0 \le \ \mathrm{e}^w_{p,nd} \le \ \underline{M\gamma Y\gamma}^w_{p,nd} \quad \forall \quad w, p, nd \tag{A.0.21}$$

$$0 \le \underline{\gamma}_{p,nd} \le \underline{M\gamma}\left(1 - \underline{Y\gamma}_{p,nd}\right) \quad \forall \quad w, p, nd \tag{A.0.22}$$

$$0 \le \mathrm{D}_{nd} \ - \ \mathrm{e}^w_{p,nd} \le \overline{M\zeta Y\zeta}^w_{p,nd} \quad \forall \quad w, p, nd \tag{A.0.23}$$

$$0 \le \overline{\zeta}^w_{p,g} \le \overline{M\zeta}\left(1 - \overline{Y\zeta}^w_{p,g}\right) \quad \forall \quad w, p, nd \tag{A.0.24}$$

$$0 \le 0.5L_{ni,nf,c}f^w_{p,ni,nf,c} + l^w_{p,ni,nf,c} \le \underline{M\mu Y\mu}^w_{p,ni,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in ll \tag{A.0.25}$$

$$0 \le \underline{\mu}^w_{p,ni,nf,c} \le \underline{M\mu}\left(1 - \underline{Y\mu}^w_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in ll \tag{A.0.26}$$

$$0 \le l^w_{p,ni,nf,c} - 0.5L_{ni,nf,c} \ f^w_{p,ni,nf,c} \le \overline{M\mu Y\mu}^w_{p,ni,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in ll \tag{A.0.27}$$

$$0 \le \overline{\mu}^w_{p,ni,nf,c} \le \overline{M\mu}\left(1 - \overline{Y\mu}^w_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in ll \tag{A.0.28}$$

$$0 \le l^w_{p,ni,nf,c} - 0.5L_{ni,nf,c} \ TTC_{ni,nf,c} \le \underline{M\delta Y\delta}^w_{p,ni,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in ll \tag{A.0.29}$$

$$0 \le \underline{\delta}^w_{p,ni,nf,c} \le \underline{M\delta}\left(1 - \underline{Y\delta}^w_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in ll \tag{A.0.30}$$

$$0 \le 0.5L_{ni,nf,c}TTC_{ni,nf,c} - l^w_{p,ni,nf,c} \le \overline{M\delta Y\delta}^w_{p,ni,nf,c} \quad \forall \quad w, p, (ni, nf, c) \in ll \tag{A.0.31}$$

$$0 \le \overline{\delta}^w_{p,ni,nf,c} \le \overline{M\delta}\left(1 - \overline{Y\delta}^w_{p,ni,nf,c}\right) \quad \forall \quad w, p, (ni, nf, c) \in ll \tag{A.0.32}$$

$$0 \le \theta^w_{p,nd} + \frac{\pi}{2} \le \underline{M\varphi Y\varphi}^w_{p,nd} \quad \forall \quad w, p, nd \tag{A.0.33}$$

$$0 \leq \underline{\varphi}_{p,nd} \leq \underline{M\varphi}\left(1-\underline{Y\varphi}^{w}_{p,nd}\right) \quad \forall \quad w,p,nd \tag{A.0.34}$$

$$0 \leq \frac{\pi}{2}-\theta^{w}_{p,nd} \leq \overline{M\varphi Y\varphi}^{w}_{p,nd} \quad \forall \quad w,p,nd \tag{A.0.35}$$

$$0 \leq \overline{\varphi}_{p,nd} \leq \overline{M\varphi}\left(1-\overline{Y\varphi}^{w}_{p,nd}\right) \quad \forall \quad w,p,nd \tag{A.0.36}$$

**FTRs Feasibility**

$$0 \leq \mathrm{vf}^{w}_{p,ni,nf,c}+TTC_{ni,nf,c}it_{ni,nf,c} \leq \underline{Mv\Upsilon Yv\Upsilon}^{w}_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c)\in lc \tag{A.0.37}$$

$$0 \leq \underline{v\Upsilon}^{w}_{p,nd,nf,c} \leq \underline{Mv\Upsilon}\left(1-\underline{Yv\Upsilon}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w,p,(ni,nf,c)\in lc \tag{A.0.38}$$

$$0 \leq -vf^{w}_{p,nd,nf,c}+TTC_{ni,nf,c}it_{ni,nf,c} \leq \overline{M\Upsilon Y\Upsilon}^{w}_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c)\in lc \tag{A.0.39}$$

$$0 \leq \overline{\Upsilon}^{w}_{p,nd,nf,c} \leq \overline{M\Upsilon}\left(1-\overline{Y\Upsilon}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w,p,(ni,nf,c)\in lc \tag{A.0.40}$$

$$0 \leq vf^{w}_{p,ni,nf,c}-\left[v\Theta^{w}_{p,ni}-v\Theta^{w}_{p,nf}\right]\frac{Sb}{X_{ni,nf,c}}+MF_{ni,nf,c}\left(1-it_{ni,nf,c}\right) \leq \underline{Mv\tau Yv\tau}^{w}_{p,ni,nf,c}$$
$$\forall \quad w,p,(ni,nf,c)\in lc \tag{A.0.41}$$

$$0 \leq \underline{v\tau}^{w}_{p,nd,nf,c} \leq \underline{Mv\tau}\left(1-\underline{Yv\tau}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w,p,(ni,nf,c)\in lc \tag{A.0.42}$$

$$0 \leq -vf^{w}_{p,ni,nf,c}+\left[v\Theta^{w}_{p,ni}-v\Theta^{w}_{p,nf}\right]\frac{Sb}{pX_{ni,nf,c}}+MF_{ni,nf,c}\left(1-it_{ni,nf,c}\right) \leq \overline{Mv\tau Yv\tau}_{p,ni,nf,c}$$
$$\forall \quad w,p,(ni,nf,c)\in lc \tag{A.0.43}$$

$$0 \leq \overline{v\tau}^{w}_{p,ni,nf} \leq \overline{Mv\tau}\left(1-\overline{Yv\tau}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w,p,(ni,nf,c)\in lc \tag{A.0.44}$$

$$0 \leq vf^{w}_{p,ni,nf,c}+TTC_{ni,nf,c} \leq \underline{Mv\phi Yv\phi}^{w}_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c)\in le \tag{A.0.45}$$

$$0 \leq \underline{v\phi}^{w}_{p,ni,nf,c} \leq \underline{Mv\phi}\left(1-\underline{Yv\phi}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w,p,(ni,nf,c)\in le \tag{A.0.46}$$

$$0 \leq -vf^{w}_{p,ni,nf,c}+TTC_{ni,nf,c} \leq \overline{Mv\phi Yv\phi}^{w}_{p,ni,nf,c} \quad \forall \quad w,p,(ni,nf,c)\in le \tag{A.0.47}$$

$$0 \leq \overline{v\phi}^{w}_{p,ni,nf,c} \leq \overline{Mv\phi}\left(1-\overline{Yv\phi}^{w}_{p,ni,nf,c}\right) \quad \forall \quad w,p,(ni,nf,c)\in le \tag{A.0.48}$$

$$0 \leq -\mathrm{ftr}_{p,gc}+MCI^{w}_{p,gc}icg_{gc} \leq \overline{M\kappa Y\kappa}^{w}_{p,gc} \quad \forall \quad w,p,gc\in gccp \tag{A.0.49}$$

$$0 \leq \overline{\kappa}^{w}_{p,gc} \leq \overline{M\kappa}\left(1-\overline{Y\kappa}^{w}_{p,gc}\right) \quad \forall \quad w,p,gc\in gccp \tag{A.0.50}$$

$$0 \leq \mathrm{ftr}_{p,gccp} \leq \underline{M\kappa Y\kappa}^{w}_{p,gc} \quad \forall \quad w,p,gc\in gccp \tag{A.0.51}$$

$$0 \leq \underline{\kappa}^{w}_{p,gc} \leq \underline{M\kappa}\left(1-\underline{Y\kappa}^{w}_{p,gc}\right) \quad \forall \quad w,p,gc\in gccp \tag{A.0.52}$$

$$0 \leq v\theta^{w}_{p,nd}+\frac{\pi}{2} \leq \underline{Mv\varphi Yv\varphi}^{w}_{p,nd} \quad \forall \quad w,p,nd \tag{A.0.53}$$

$$0 \leq \underline{v\varphi}_{p,nd} \leq \underline{Mv\varphi}\left(1-\underline{Yv\varphi}^{w}_{p,nd}\right) \quad \forall \quad w,p,nd \tag{A.0.54}$$

$$0 \leq \frac{\pi}{2}-v\theta^{w}_{p,nd} \leq \overline{Mv\varphi Yv\varphi}^{w}_{p,nd} \quad \forall \quad w,p,nd \tag{A.0.55}$$

$$0 \leq \overline{v\varphi}_{p,nd} \leq \overline{Mv\varphi}\left(1-\overline{Yv\varphi}^{w}_{p,nd}\right) \quad \forall \quad w,p,nd \tag{A.0.56}$$

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