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A Bi-level framework to analyse the alternative use of FTRs as a long-term risk hedging instrument. Application to a European case study

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Abstract

A large portion of the Renewable Energy Sources generation investments occurs in remote areas, which are normally weakly connected to the rest of the system. Hence, relevant congestion occurs in the network linking these areas to the main load centres, where prices tend to be more stable. Congestion drives significant changes in the electricity price in remote areas that are difficult to predict. As a result, investors in remote areas face relevant long-term market price risk, which may prevent them from undertaking some socially beneficial generation investments. We address two main research questions. We investigate how Long-Term Financial Transmission Rights (LT-FTRs) affect the investment decisions made by risk-averse generation and transmission investors under perfect coordination. Together with this, we aim to determine what effect the use of LT-FTRs would have on the social welfare, considering the stakeholders' risk profiles and, related to this, the value that the stabilization of their revenues would have for them. In providing an answer to these questions, we, for the first time, determine the impact of the implementation of LT-FTRs on the efficiency of the system's expansion, considering the use of these rights as a tool to hedge the market price risk caused by network congestion that generation investors in remote areas are subject to. In doing so, we represent the effect of the market price risk on the generation investors' profits through the Conditional Value at Risk of these profits, considering the uncertainty factors affecting the price earned by the corresponding generators. The computation of the socially optimal expansion of the system, representing the ideal situation where the coordination of generation and transmission investments is socially efficient, is formulated, both considering LT-FTRs and not considering these, as a bi-level optimization problem. In the upper level of this problem, we represent the investment decisions that are made in the long-term, including, in the corresponding case, the contracting of FTRs to manage the price risk of generation investors, while the operation decisions are represented within the lower level of the problem. Finally, this problem is converted into an MPEC making use of the Karush-Kuhn-Tucker conditions. Finally, we explore the use of LT-FTRs in the European power system as a representative case study where the development of renewable generation in remote areas, such as the North Sea, has significant potential. Based on the results computed, we conclude that the availability of LT-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, potentially, in the transmission socially optimal investment decisions, involving additional generation investments in remote areas, particularly in the North Sea within the European system.

Keywords: FTRs, generation expansion planning, transmission expansion planning, risk management.

I. 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 the investment decisions made in both, as was possible within the vertically integrated structures **[1]**. This deregulation process has impacted significant regions of Europe and America, presenting various challenges for developing the power system, especially regarding the coordination of Transmission Expansion Planning (TEP) decisions and Generation Expansion Planning (GEP) ones **[2]**, involving the management of the risk associated with the uncertainty of the market revenues of the generation investments, which results in the profitability for these investments being uncertain.

In a liberalized electricity context, the revenues of generation plants depend on the market conditions that influence the marginal price behaviour. This leads to relevant uncertainty regarding the profits of generation investors. Besides, a lack of coordination among utilities and the central planner may discourage them 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 maximise 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, which aim to maximise the welfare of the system. The fact that GENCOs and the SO are uncertain about the intention of their counterparty to undertake mutually beneficial investments may prevent their realization, along with that of other socially efficient investments, impacting the efficiency of the system development.

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 a large market risk that cannot be properly managed without suitable hedging instruments, which decreases the level of efficiency of system development **[5]**. 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 to ensuring long-term efficiency in the development of liberalized power systems **[6]**.

The uncertainty about the profitability of investments faced by generation companies associated with the long-term uncertainty about their revenues from the sale of electricity can prevent these companies 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, as well as that of the amount of energy that they can inject in the grid, across the scenarios that can unfold in the future. In the case of new generation to be located in remote areas, this is largely due to the congestion that may occur in the network, which may be due to the variability of the system conditions and the uncertainty about their probability of occurrence, or to the lack of investments in transmission capacity to be used by new generation projects. At the same time, the system planner requires evidence of the future installation of new generation to develop the transmission capacity to integrate it into the grid; this lack of trust in the counterparty's investment decisions is known in the literature as the "chicken and egg" problem and reflects the existence of counterparty risk for both types of stakeholders. 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 weakly linked to the rest of the system, where prices tend to be highly volatile **[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 affecting the operation conditions in these areas long before the system's operation, when there is the need to decide the investments to undertake and ensure effective grid access for them, can be challenging for the system stakeholders, including generation developers and the grid planner. This is because the pattern of this 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.

Long-term Financial Transmission Rights (LT FTRs) represent a potentially efficient instrument to facilitate the coordination of generation and transmission investment decisions and manage both the price risk caused by network congestion and the counterparty risk that may be faced by GENCOs, network planners and network investors. Consequently, these rights could be an efficient instrument to promote socially efficient generation investments in remote areas and those network investments required to integrate this generation into the grid.

We now briefly illustrate the use of LT FTRs referring to the interconnection capacity between a remote area and the rest of the system. Consider a renewable generator to be located in this area, which is weakly connected to the rest of the system. This generator aims to sell the energy it produces at the price of major consumption centres, but this energy may need to be transmitted over long, congested lines. However, there is uncertainty about the cost of accessing this transmission capacity and the revenues the network owner will earn from it. If this generator acquires LT FTRs from the transmission owner, it gains the right (or obligation) to sell its energy in the period covered by the LT FTRs acquired at the price of the reference node in the system specified in this transmission contract. This price should be much more stable than that of the remote area where the generator is located. The transmission owner, in turn, receives funds from these FTRs sale, which can be used to build the transmission capacity required to host the flows corresponding to the realization of the transactions backed by the FTRs. This ensures that congestion rents from the dispatch will be sufficient to pay the FTR holder. Failing to build this transmission capacity would expose the network owner to financial risk, as the revenue adequacy criterion for the FTRs issued would not be met.

This article 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, here we only explore 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. We assume 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, we analyse 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 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 we propose in this article 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.

Summarizing, in this work, we aim to answer two research questions. The first one focuses on the impact of the use of LT FTRs, in the aforementioned context, on the expansion of the system. The second one focuses on the impact of LT FTRs on the welfare of the system in this context. The reader should note that computing the system expansion following any approach easily allows one to determine the associated costs and benefits considered for the system stakeholders and, therefore, the associated social welfare. Therefore, any work addressing the first research question should also be able to address the second one, which is, nevertheless, a separate question. We consider the typical risk profile of GENCOs, who would value positively the stabilization of their market revenues; these are topics that have not been discussed and modelled yet in the literature, as we show below.

II. State of the Art Review

In this section, we provide a review of those works focused on the management of the risks associated with the generation and transmission investments and the coordination of these investments. First, we discuss the relevant risks that are considered in this work faced by each of the main stakeholders, considered separately, associated with their generation and transmission investments, as well as the alternatives provided in the literature to assess the relevant risks in this context. Then, we discuss the modelling strategies adopted so far to investigate the computation of planning decisions in power systems, also considering the relevant risks and their influence on the abovementioned decisions, but not the implementation of complementary coordination schemes. Afterwards, we discuss the importance of implementing regulatory coordination schemes to address the relevant coordination failures in the expansion planning process and manage some relevant risks faced by the stakeholders in this process. Considering this, we review the coordinating schemes that have been explored and modelled in the literature under an integrated-resources planning approach. Finally, we identify the potentially relevant risks that LT FTRs can hedge in this context and how this mechanism has been considered in the literature until now. For each of the aspects of the problem at hand for which the relevant existing works are reviewed, we pinpoint the relevant gaps filled in by our work.

In electricity markets, risk is defined as the potential danger stemming from market participants' uncertainty **[8]**. In generation and transmission expansion planning, GENCOs, the transmission owners (TO) and the SO are exposed to uncertainties that lead to different types of risks to which they are subject. In particular, the uncertainty about the future level of the energy prices to be earned by GENCOs, especially for those generation assets located in remote areas, leads them to be subject to significant levels of Market (price) risk. This, in turn, may affect the ability of GENCOs to recover their investment costs, potentially influencing their decision to proceed with their investment initiatives, even when they have requested access to the grid for the corresponding generation assets.

In other words, the price risk that impacts investments in generation in remote regions can increase the counterparty risk faced by the network planner, usually the SO, regarding the development of the regulated network investments it identifies as being relevant for the system. The SO counterparty risk arises from the possibility that the counterparty (GENCOs whose investments must be aligned with transmission investments) may not meet their contractual obligations, particularly regarding the plans they have published for the construction of new-generation capacity, this due to the lack of coordination between the stakeholders. The counterparty risk faced by the SO may deter this entity from pursuing the development of the transmission capacity that would be used by the new generation facilities, which, in turn, introduces significant counterparty risks faced by GENCOs **[9]**.

When private entrepreneurs undertake network investments with the objective of maximising their profits from commercially exploiting the associated transmission assets, the promoter and owner face counterparty risk and price risks due to the existing uncertainty about the market value of the transmission capacity they develop and, consequently, their potential market income. This price risk increases the probability that the private entrepreneurs (merchant investors) eventually do not undertake the network investments they are promoting, which, in turn, increases the counterparty risk faced by GENCOs seeking investments in new generation capacity, especially those to take place in remote areas **[10]**.

Investment decisions and their irreversible nature lead the system stakeholders to be subject to relevant risks that can be quantitatively assessed through the use of different techniques such as VaR, CVaR, Real-options valuation, Monte-Carlo simulation, Decision analysis, Information-Gap Decision Theory or Optimization techniques, according to the literature **[11]-[12]**. In addition, the consideration of smart options through the quantitative valuation of the Option Value of transmission and generation investments could allow planners and investors to manage the risk of over-investing amid uncertainty **[13]**. In particular, the implementation of risk management strategies based on the use of risk metrics like the Value at Risk (VaR), or the Conditional value at risk (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 [8]. However, few studies in the literature consider the implementation of risk measurement tools or risk modelling strategies to assess the risks incurred in the problem of planning the expansion of generation and transmission.

The generation and the transmission expansion planning can be modelled considering that the planning and operation decisions are made in one or several decision making levels, in the latter case typically reflecting the order in which the GEP and TEP investment decisions, and the market operation decisions are made. One first option involves considering a single-level structure (SL), whereby all decisions are deemed to be made in the same moment, simultaneously. Alternatively, the coordination problem may be modelled using a multi-level structure (ML), whereby decisions are made in different moments, or sequentially. In the latter case, generation and transmission expansion planning decisions are commonly made first, and represented within the upper levels, while the market operation decisions are commonly made afterwards, in the lower levels, according to the planning approach implemented.

When employing a ML modelling structure, the modeller may develop bi-level optimization models, where the two different levels can represent the decisions made by different actors, like when following a reactive planning approach (Transmission planner reacts to GENCOs behaviour) or a proactive planning approach (Transmission planner anticipates de behaviour of GENCOs), as explored in [14]; alternatively, the two or more levels can represent the different types of decisions made by the same actors [15], like in the work discussed here, which follows an integrated-resources planning approach assuming the socially perfect coordination occurs among planning decisions.

There are few works in the literature that consider the existing risks in the modelling of the GEP-TEP expansion planning problem. In particular, the authors in **[16]** model a GEP-TEP problem as single level optimization problem, considering an additional stage to manage contingencies affecting the system security. They compute the CVaR of the total system costs including the impact on it of the loss of load incurred, as a post-processing tool, by making use of Montecarlo simulation. Similarly, in **[17]** the authors model 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 consider the probability and consequences of each contingency and, based on these, compute a load-shedding penalty cost involving the use of risk indexes that take into account the value of the loss of load. In **[18]** 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. So far, ML problems have not been formulated, when adopting a centralized, or fully coordinated, planning approach, to represent the impact of risks on the value that some, or all, the agents in the system assign to the market benefits they obtain, as we do in our work.

System expansion planning can be combined with the application of possible signals or regulatory mechanisms that can drive the coordination of the GEP and TEP and/or manage the stakeholders' risk perception related to the effect of the grid on the system functioning. These mechanisms can be finetuned according to the objectives of the regulator. The authors in **[10]** have identified the lack of commitment and asymmetric information as relevant challenges to achieving a coordinated development of the network and the generation. These challenges are difficult to address in the absence of complementary regulatory coordination and risk management tools. These mechanisms achieve an increase in the level of efficiency of the expansion of the system, typically by increasing the level of coordination among the expansion planning decisions made by system stakeholders and/or by enabling stakeholders to effectively manage the risks they are subject to. Not addressing these challenges satisfactorily could lead to several undesirable situations: i) network "investment forcing", which results in transmission over-investment with respect to the optimal situation; ii) network and generation "investment preempting", which leads to underinvesting in generation and/or transmission assets whose deployment would be beneficial for the system **[19]**; and iii) generation investment misalignment with the system needs, resulting in the undertaking of some generation investments that have a lower social value than other investments that are not undertaken.

Relevant coordination mechanisms include considering locational and temporal differentiation in energy prices, affecting capacity payments by the grid constraints **[10]**, or implementing locationally differentiated transmission charges **[20]**.

As investigated by several authors, some coordination mechanisms can be used to manage the price risk that stakeholders are subject to. This is the case of the Contracts for Differences (CfD); these are forward electricity contracts that increase the stability of the income of renewable generators or other stakeholders by mitigating their level of exposure to spot price risks. These instruments are agreements entered into by a renewable generator (or other electricity producers) and a counterparty, who buys electricity on the same market where this generator sells its electricity **[21]**. CfD are able to manage the price risk resulting from the uncertainty surrounding the spot market price. Nevertheless, these contracts are unable to protect agents from the price risk resulting from network congestion.

Capacity payments have the potential to stabilize the long-term revenues made by generation associated with their contribution to the supply of load in the most stressful system conditions. If not implemented, the generation would need to rely on being able to earn high enough prices in these stressful conditions to obtain large enough overall revenues to profit from their investments, see **[19]**. However, capacity payments do not target the specific price risk faced by generators associated with potential network congestion, depressing the electricity price they earn in different types of operation situations.

Within those previous works investigating the implementation of the aforementioned coordinating signals/schemes to guide the development of the system, no work determines the impact of the use of these instruments on the level of the relevant risks perceived by the system stakeholders and explicitly considers this impact in making expansion planning decisions. What is more, few of these works consider the implementation of regulatory coordination schemes under an integrated-resources planning approach. In **[10]**, the authors develop a model following an integrated-resource**s** planning approach. This model assumes that TSOs 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 constrains. This problem is formulated 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 investing in additional generation and transmission facilities. It is assumed that the capacity payment would be contractually binding between the ISO and market players. The ISO would compensate GENCOs and TRANSCOs for maintaining the system security based on the capacity signals. Accordingly, GENCOs obtain their revenues from energy and capacity payments and TRANSCOs obtain their revenues from flow and capacity payments. Similarly to this approach, in [20], the authors develop an optimization model which coordinates investment decisions in the monopolistic transmission and the decentralized generation activities. 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. The expansion of both generation and transmission is deemed to be planned in a coordinated way by a central entity, which is assumed to be a state-owned transmission company. However, generation investments that are included within the optimal system expansion plan to safeguard security during on-peak demand periods might be delayed by the relevant IPPs because the revenues of these generation assets in off-peak periods are deemed insufficient. These IPPs may require higher incentive payments, determined by solving a separate problem, to proceed with these investments. The incentive requirements determined by IPPs are deemed payments taken as an input in the centralized planning problem. Both problems are solved in an iterative process until reliability requirements is satisfied.

As already mentioned, the literature review conducted 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 **[10]**, **[20]**, **[22]**, **[23]**. 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 by our work for what concerns the implementation of a specific coordination scheme, the LT FTRs, in an idealized context characterized by achieving a socially efficient coordination of the generation and transmission investments, as we shall discuss next.

Apart from the regulatory mechanisms previously described and modelled in the literature, Transmission Rights can also be employed to manage the long-term price risk faced by certain generation investors that is caused by network congestion while, at the same time, driving the coordination of GEP and TEP. Transmission Rights can be framed as point-to-point financial transmission rights (FTRs). These grant their holders the right, or obligation, to receive congestion rents generated by the transmission grid between the specific injection and withdrawal nodes. In exchange for these entitlements, holders pay the price established for these rights in the relevant auction or as agreed upon bilaterally with the issuing party. FTRs have primarily been regarded in the literature as a tool to cover the risk faced by market agents associated with the price of accessing the network capacity that they need to use in the short term and have been effectively implemented in various power markets such as New England, PJM and New York, among others **[27]**.

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 **[28]**, 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 [29]**.**

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 [9].
- 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.

While FTRs may help manage both the price and the counterparty risks that may be faced by GENCOs, network planners and network investors, 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.

Some previous works have focused on exploring the use of FTRs to drive the expansion of the system. Thus, the authors in **[30]** 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 **[31]**, 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 **[32]** 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 **[30]** 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 **[30]**, 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.

To our 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. Accordingly, in this work, we aim to answer two research questions, the first one related to the impact of the potential use of FTRs on the expansion of the system, and the second one related to the impact of FTRs on the welfare of the system, considering the risk profile of GENCOs, who would value positively the stabilization of their market revenues. These are topics that have not been discussed and modelled yet in the literature.

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 should be addressed by future research.

III. Research questions and Contributions

Given the discussion in the previous sections, in this paper, we assess how the use of LT FTRs would affect the expansion of the system and its efficiency from a social point of view, unlike other previous related works. The main research questions answered 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 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, given the risk profile of stakeholders, who would value positively the stabilization of their market revenues?

The main contributions of this work here are listed below:

(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 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 maximise the social welfare of the system while representing the value of stabilising their market revenues for generation investors in remote areas, preventing them from incurring relevant losses in the worst-case scenarios. The value that hedging their market price risk has for these investors is computed through the CVaR of the profits made by the set of generation investments undertaken by each investor 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 and the social welfare of the system for a realistic case study representing the Western European system in a schematic way.

IV. 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 or TransCos selling these rights, we propose 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 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. LT FTRs are not merely risk management tools but also facilitate investment coordination. As mentioned when reviewing previous works on the use of FTRs, once contracted, LT FTRs provide incentives both for network planners and generation companies to undertake the transmission and generation investments hedged by these rights. If these investments are not carried out, FTR sellers face the risk of not being able to pay FTR holders the congestion rents produced by their rights out of the congestion rents produced by the grid in the market. Similarly, if LT FTR holders do not build the generation assets hedged by these rights, they become an additional source of uncertainty affecting these agents' market revenues, rather than a revenue stabilizer. The extra investing incentives produced by LT FTRs could prompt strategic generation investors to undertake system-beneficial investments that, in the absence of these FTRs, they could avoid in order to exercise market power. The impact of the strategic behaviour of agents on the system development in this context is a very relevant topic to be investigated in the future.

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 in this work we are representing 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. We are determining this impact on system costs according to the formulation outlined below.
- Given that, in the context analysed here, part of the agents is risk averse, we also need 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.

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 **[15]**. 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. In 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 from the long-term planning one. 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 follow**:**

- 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.
- In our problem setting, 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 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.

A. Notation

Indexes

w	All scenarios
wp	Scenarios when computing the perfectly coordinated system expansion, as if a central planner computed this
wcp	Scenarios considered by generation companies
p	Period (hours)
nd, ni, nf	Node (bus)
c	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
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$/GWh]
CO_{2_g}	Cost associated to CO_2 emissions [$/t$CO_2$]
$MF_{ni,nf,c}$	Maximum flow over a line used in the DC power flow constraint (Disjunctive formulation)
v$MF_{ni,nf,c}$	Maximum flow over a line used in the DC power flow constraint for the virtual flows (Disjunctive formulation)
β_{cp}	Trade off between the expected system cost and the risk by company cp
α	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. $ig_{gc} \in \{0\text{-}1\}$

- *Positive*

tf	Total system fixed cost [M$]
tv	Total system variable cost [M$]
te	Total system emission cost [M$]
tr	Total system ENS cost [M$]
$gp_{p,g}^{w}$	Production of the unit g in the period p [GW]
$e_{p,nd}^{w}$	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]
η_{cp}^{w}	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$]
$f_{ni,nf,c}^{w}$	Flow over circuit c between nodes ni and nf in scenario w [GW]
θ_{nd}^{w}	Voltage angle for node nd in scenario w [rad]
$vf_{ni,nf,cc}^{w}$	Virtual flow over circuit c between nodes ni and nf (FTR Max Power) in scenario w [GW]
$l_{p,ni,nf,c}^{w}$	Losses over circuit c between nodes ni and nf in period p, for scenario w.
$v\theta_{nd}^{w}$	Virtual voltage angle for node nd (FTR Max Power) in scenario w [rad]
$\lambda_{p,nd}^{w}$	Local Marginal Price for node nd in period p in scenario w [$/MWh]
φ_{cp}	Auxiliary variable that computes the VaR
$cvar_{cp}$	Conditional Value at Risk of company cp [M$]
gpr_{cp}^{w}	Total generation operation profit, including FTR benefits for company cp in scenario w [M$]

B. *Discussion of uncertainty modelling in the formulation*

We consider two sources of uncertainty in our 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. We assume 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 here we are only representing the effect on the system development of the uncertainty faced by the GENCOs in the remote areas, for simplicity reasons, we are assuming 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 $\boldsymbol{wcp}$, 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 $\boldsymbol{wp}$, considered when computing the socially optimal expansion of the system and risk hedging strategies.

Scenarios $\boldsymbol{wcp}$ are defined considering the uncertainty of type i) and ii). Note that the scenarios $\boldsymbol{wcp}$ are specific to each GENCO in the remote areas. Therefore, there are as many sets of operation scenarios $\boldsymbol{wcp}$ as GENCOs in remote areas. Scenarios $\boldsymbol{wp}$ 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 [8]. 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.

C. 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 within two subproblems. 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 2.

Note that, within each lower level problem, we compute the system operation decisions for each of the scenarios defined 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) he 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.

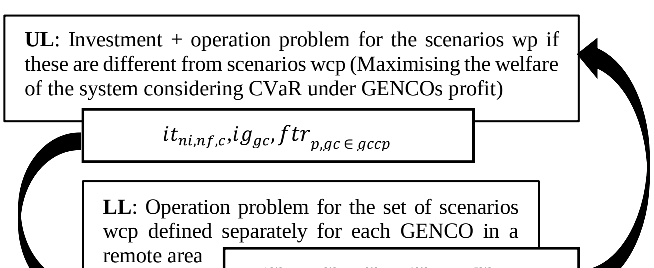

Figure 1. Interactions between problems

D. Formulation of the upper level (UL) - Investment Problem

D.1 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 ($\boldsymbol{gpr}$), 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 represented 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. Consequently, the impact of the use of LT-FTRs on the overall system welfare, which is the piece of information required to answer **Rq2**, 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.

The piece of information needed to answer **Rq1** is 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 of the objective function defined for each GENCO is deducted from the term representing the overall system costs comprising also the objective function. Therefore, we aim 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, $\boldsymbol{\beta_{cp}}$, represents the risk profile of this GENCO. 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.

$$OF = tf + tv + tr + te - \sum_{cp} \beta_{cp} cvar_{cp} \quad (1)$$

Below, we discuss separately each of the terms in **(1).** Please note that computing the changes in the social welfare resulting from implementing LT-FTRs requires computing the value of the whole objective function both when LT-FTRs are deemed to exist and when they are deemed no to exist. Then, all the term of the objective function are relevant to providing an answer to **Rq2**. The system investment variables, whose changes due to the implementation of LT-FTRS we need to compute to provide an answer to **Rq1**, are considered both in those terms of the objective function representing the system investment costs and, within the CVaR term of this function, in the term of the expression of the profits of the GENCOs in remote areas representing the cost of the generation investments carried out by these firms. Equations **(6)**,**(7)** and **(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 and all candidate generation units that are installed.

$$tf = \sum_{lc} FCT_{lc}\, it_{lc} + \sum_{gc} FCG_{gc}\, ig_{gc} \quad (2)$$

Total variable costs

Sum of the variable costs for the generation units in the several scenarios $\boldsymbol{wp}$ and periods $\boldsymbol{p}$.

$$tv = \sum_{wp,p,g} PR^{wp} VC_g DU_p\, gp_{p,g}^{wp} \quad (3)$$

Total reliability costs

Sum of the ENS costs in the several scenarios $\boldsymbol{wp}$ and periods $\boldsymbol{p}$ weighted with the probability of occurrence of the corresponding scenarios.

$$tr = \sum_{wp,p,nd} PR^{wp} CENSDU_p e_{p,nd}^{wp} \quad (4)$$

Total emission costs

Sum of the $\boldsymbol{CO_2}$ costs in the several scenarios $\boldsymbol{wp}$ and periods $\boldsymbol{p}$ weighted with the probability of occurrence of the corresponding scenarios.

$$te = \sum_{wp,p,g} PR^{wp} CO_{2_g} DU_p\, gp_{p,g}^{wp} \quad (5)$$

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, $\boldsymbol{\beta_{cp}}$, depending on the risk profile of GENCOs. The CVaR formulation was proposed in **[26]** by Rockafellar. The CVaR is defined as the expected value of the generation company's profits, whenever these profits are smaller than the $(1-\alpha)$ quantile of the profit distribution over scenarios. The auxiliary variable $\boldsymbol{\eta_w}$ is nonnegative and is bounded by constraint (7), which is formulated in terms of the Value at Risk (VaR) of the company's profits for this confidence level, ($\boldsymbol{\varphi}$), and the generation company's profits for scenario $\boldsymbol{w}$, $\boldsymbol{gpr_{cp}^{w}}$, 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 (6) and (7) to compute the impact of risks on the value of these profits for companies, leads the optimal value of $\boldsymbol{\varphi}$, for a given confidence level $\boldsymbol{\alpha}$, 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 $\boldsymbol{\varphi}$ to be equal to the VaR, as discussed in **[33]**.

$$cvar_{cp} = \varphi_{cp} - \frac{1}{1-\alpha} \sum_{w} PR^{wcp} \eta_{cp}^{wcp}\ \forall cp \quad (6)$$

$$\varphi_{cp} - gpr_{cp}^{wcp} \leq \eta_{cp}^{wcp}\ \forall\, wcp, cp \quad (7)$$

<u>GENCO's Profits (including the FTR benefits and costs):</u>

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 ($\boldsymbol{\lambda_{p,grf}^{wcp}}$) and the LMP at the connection node ($\boldsymbol{\lambda_{p,gnd}^{wcp}}$) multiplied by the amount of capacity contracted through the FTRs ($\boldsymbol{ftr_{p,gc}}$). 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 within which the variables $\boldsymbol{ftr_{p,gc}^{wcp}}$ and $\boldsymbol{\lambda_{p,nd}^{wcp}}$ are multiplied. This term is also part of the objective function.

$$\begin{aligned} \mathrm{GPR}_{cp}^{wcp} = & \sum_{p,nd,gc\in gccp} \left(\lambda_{p,grf}^{wcp} - \lambda_{p,ftrnd}^{wcp}\right) DU_p ftr_{p,gc} \\ & + \sum_{p,nd,g\in gcp} \lambda_{p,nd}^{wcp} DU_p gp_{p,g}^{wcp} \\ & - \sum_{p,g\in gcp} VC_{gcp} DU_p gp_{p,g}^{wcp} - \sum_{gc\in gccp} FCG_{gc} ig_{gc} \\ & - \sum_{gc\in gccp} cftr_{gc}\ \forall\, \mathrm{wcp, cp} \end{aligned} \quad (8)$$

<u>FTRs Cost</u>

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 multiplied by the amount of capacity contracted through these FTRs, considering the probability of all '$\boldsymbol{wcp}$' scenarios.

$$\mathrm{CFTR_{gc}} = \sum_{\substack{\mathrm{wcp} \\ \in\, \mathrm{gccp}}} \mathrm{PR^{wcp}} \sum_{\mathrm{p,nd}} \left(\lambda_{\mathrm{p,grf}}^{\mathrm{wcp}} - \lambda_{\mathrm{p,gnd}}^{\mathrm{wcp}}\right) DUp\ \mathrm{ftr_{p,gc}}\ \forall\ \mathrm{gc} \quad (9)$$

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, as explained in annex A.

D.2 Constraints

FTRs - Feasibility equations

To guarantee the simultaneous feasibility of the FTRs, an additional flow variable is considered to model virtual flows corresponding to the amount of transmission capacity contacted through all the FTRs issued. The virtual flows $\boldsymbol{vf}$ corresponding to the FTRs contracted should be compatible with the network capacity and are computed according to the same laws as the physical flows.

Virtual flows constraints (transfer capacity of candidate lines):

$$\frac{vf_{p,ni,nf,c}^{wcp}}{TTC_{ni,nf,c}} \geq -it_{ni,nf,c} \; \forall \, wcp, p, lc_{ni,nf,c} \tag{10}$$

$$\frac{vf_{p,ni,nf,c}^{wcp}}{TTC_{ni,nf,c}} \leq it_{y,ni,nf,c} \; \forall \, wcp, p, lc_{ni,nf,c} \tag{11}$$

DC load flow constraints (for existing and candidate lines):

$$\frac{vf_{p,ni,nf,c}^{wcp}}{vMF_{ni,nf,c}} \geq \left[v\Theta_{p,ni}^{wcp} - v\Theta_{p,nf}^{wcp}\right]\frac{Sb}{X_{ni,nf,c} v\mathrm{MF}_{ni,nf,c}} - 1 + it_{ni,nf,c} \; \forall \, \mathrm{wcp}, \mathrm{p}, \mathrm{lc}_{ni,nf,c} \tag{12}$$

$$\frac{vf_{p,ni,nf,c}^{wcp}}{vMF_{ni,nf,c}} \leq \left[v\Theta_{\mathrm{p,ni}}^{\mathrm{wcp}} - v\Theta_{\mathrm{p,nf}}^{\mathrm{wcp}}\right]\frac{Sb}{X_{ni,nf,c} vMF_{ni,nf,c}} + 1 - \mathrm{it}_{ni,nf,c} \; \forall \, \mathrm{w}, \mathrm{p}, \mathrm{lc}_{ni,nf,c} \tag{13}$$

$$vf_{p,ni,nf,c}^{wcp} = \left[v\Theta_{p,ni}^{wcp} - v\Theta_{p,nf}^{wcp}\right]\frac{Sb}{X_{ni,nf,cc}} \; \forall \, wcp, p, le_{ni,nf,cc} \tag{14}$$

Balance constraints:

For each scenario, each period and each node, the amount of FTRs contracted having this node as the reference one (incoming FTRs) less the amount of FTRs contracted having this node as the injection one (outgoing FTRs) should be equal to the difference between the incoming virtual flows into the node and the outgoing virtual flows from this node ($\boldsymbol{ftrndrf}$ and $\boldsymbol{rfrnd}$ are mutually exclusive sets).

$$\sum_{la_{ni,nd,c}} vf_{p,ni,nd,c}^{wcp} - \sum_{la_{nd,nf,c}} vf_{p,nd,nf,c}^{wcp} = \sum_{gc \in ftrndrf} ftr_{p,gc} - \sum_{gc \in ftrnd} ftr_{p,gc} \; \forall \, \mathrm{wcp}, \mathrm{p}, \mathrm{nd} \tag{15}$$

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.

$$-TTC_{ni,nf,c} \leq vf_{p,ni,nf,c}^{wcp} \leq TTC_{ni,nf,c} \;\; \forall p, wcp, le_{ni,nf,c} \tag{16}$$

Bounds for the FTR contracted capacity:

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

$$ftr_{p,gc} \leq MCI_{p,gc}^{wcp} ig_{gc} \; \forall \, \mathrm{wcp}, \mathrm{p}, gc \in gccp \tag{17}$$

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 '$\boldsymbol{wp}$'. 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 (30)-(40) defined over the scenario set '$\boldsymbol{wp}$'.

E. 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 '$\boldsymbol{wcp}$'. However, the operation constraints are also defined over scenarios '$\boldsymbol{wp}$' 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 '$\boldsymbol{wcp}$' considered by the generation investors, the LL problem constraints are defined over a generic set of scenarios '$\boldsymbol{w}$' that should coincide with scenarios '$\boldsymbol{wcp}$' when solving the LL problem, and with scenarios '$\boldsymbol{wp}$' when these constraints are included in the UL problem. Obviously, solving the LL problem is need both to provide an answer to **Rq1** and **Rq2**. However, the variables computed within this problem do not include the investment ones characterizing the expansion of the system, needed to provide an answer to **Rq1**. However, the CVaR of the benefits of risk-averse generation investors computed to determine the changes in the system welfare resulting from the implementation of LT-FTRs, i.e. the answer to **Rq2**, is expressed in terms of the operation variables over scenarios '$\boldsymbol{wcp}$' computed within the LL problem.

E.1 Objective function

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

$$\min \sum_{wcp,p,g} PR^{wcp} SVC_g \, gp_{p,g}^{wcp} + \sum_{wcp,p,nd} PR^{wcp} CENS \, e_{p,nd}^{wcp} + \sum_{wcp,p,g} PR^{wcp} CO2_g \, gp_{p,g}^{wcp} \tag{18}$$

E.2 Constraints

Dual variables of each set of equations appear after colons

Flow constraint (transfer capacity of 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 $\boldsymbol{it_{ni,nf,c}}$. 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.

$$\frac{f^{w}_{p,ni,nf,c}}{TTC_{ni,nf,c}} \geq -it_{ni,nf,c} \;\; : \underline{\Upsilon}^{w}_{p,ni,nf,c} \;\forall\; w, p, lc_{ni,nf,c} \tag{19}$$

$$\frac{f^{w}_{p,ni,nf,c}}{TTC_{ni,nf,c}} \leq it_{ni,nf,c} \;\; : \overline{\Upsilon}^{w}_{p,ni,nf,c} \forall \;\; w, p, lc_{ni,nf,c} \tag{20}$$

<u>**DC power flow constraints (for existing and candidate lines)**</u>

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.

$$\frac{f^{w}_{p,ni,nf,c}}{MF_{ni,nf,c}} \geq \left[\Theta^{w}_{p,ni} - \Theta^{w}_{p,nf}\right] \frac{Sb}{X_{ni,nf,c} MF_{ni,nf,c}} - 1 + it_{ni,nf,cc} \; : \underline{\tau}^{w}_{p,ni,nf,c} \forall\, w, p, lc_{ni,nf,c} \tag{21}$$

$$\frac{f^{w}_{p,ni,nf,c}}{MF_{ni,nf,c}} \leq \left[\Theta^{w}_{p,ni} - \Theta^{w}_{p,nf}\right] \frac{Sb}{X_{ni,nf,c} MF_{ni,nf,c}} + 1 - it_{ni,nf,c} \; : \overline{\tau}^{w}_{p,ni,nf,c} \forall\, w, p, lc_{ni,nf,c} \tag{22}$$

$$f^{w}_{p,ni,nf,c} = \left[\Theta^{w}_{p,ni} - \Theta^{w}_{p,nf}\right] \frac{Sb}{X_{ni,nf,c}} : \phi^{w}_{p,ni,nf,c} \;\forall\, w, p, le_{ni,nf,c} \tag{23}$$

<u>Bound for Theta angle</u>

$$-\frac{\pi}{2} \;\leq\; \theta^{w}_{p,nd} \leq \frac{\pi}{2} \;:\; \underline{\varphi}^{w}_{p,nd}, \overline{\varphi}^{w}_{p,nd} \;\; \forall\, w, p, nd \tag{24}$$

<u>Bounds for transfer capacity in existing lines:</u>

For each existing line, the flow is bounded by the total transfer capacity of the line.

$$-TTC_{ni,nf,c} \;\leq\; f^{w}_{p,ni,nf,c} \leq TTC_{ni,nf,c} \;:\; \underline{\phi}^{w}_{p,ni,nf,c}, \overline{\phi}^{w}_{p,ni,nf,c} \;\; \forall\, w, p, le_{ni,nf,c} \tag{25}$$

<u>Ohmic losses as a function of the flow</u>

$$-\frac{L_{ni,nf,c}}{2} f^{w}_{p,ni,nf,c} \;\leq\; l^{w}_{p,ni,nf,c} \geq \frac{L_{ni,nf,c}}{2} f^{w}_{p,ni,nf,c} \;:\; \underline{\mu}^{w}_{p,ni,nf,c}, \overline{\mu}^{w}_{p,ni,nf,c} \;\; \forall w, p, ll_{ni,nf,c} \tag{26}$$

<u>Bounds for losses</u>

$$0 \;\leq\; l^{w}_{p,ni,nf,c} \leq \frac{L_{ni,nf,c}}{2} TTC_{ni,nf,c} \;:\; \underline{\delta}^{w}_{p,ni,nf,c}, \overline{\delta}^{w}_{p,ni,nf,c} \;\; \forall w, p, ll_{ni,nf,c} \tag{27}$$

<u>Bounds of production related to Installed Generation Capacity</u>

For each generation unit, the production should be limited by the maximum production capacity corresponding to this unit.

$$0 \leq\; gp^{w}_{p,gc} \leq ig_{gc} MP_{gc} : \underline{\rho}^{w}_{p,gc}, \overline{\rho}^{w}_{p,gc} \;\forall\, w, p, gc \tag{28}$$

$$0 \leq gp^{w}_{p,ge} \leq MP_{ge} : \underline{\omega}^{w}_{p,g}, \overline{\omega}^{w}_{p,g} \;\forall\; w,p,ge \tag{29}$$

<u>Bounds for ENS</u>

$$0 \leq e^{w}_{p,nd} \leq D_{nd} \!: \underline{\zeta}^{w}_{p,nd}, \overline{\zeta}^{w}_{p,gc} \;\forall\, w, p, nd \tag{30}$$

<u>Balance between generation and demand</u>

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

$$\begin{aligned} \sum_{g \in gnd} gp^{w}_{p,g} + e^{w}_{p,nd} &= D_{nd} + \sum_{nf,c \,\in\, la} f^{w}_{p,nd,nf,c} - \sum_{ni,c \,\in\, la} f^{w}_{p,ni,nd,c} \\ &+ \sum_{nf,c \,\in\, ll} l^{w}_{p,nd,nf,c} + \sum_{ni,c \,\in\, ll} l^{w}_{p,ni,nd,c} : \lambda^{w}_{p,nd} \;\forall\, w, p, nd \end{aligned} \tag{31}$$

F. 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 Annex B.

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 **[34] (**see **Annex B)**.

Upper level → Eq [(1 - (17]
Lower level (KKTs) (See Annex B) → Eq [(42)-(48)] (KKTs without complementarity constraints) - Eq [(60)-(73)] (linearized complementarity constraints)

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.

G. Discussion on the computation of the most appropriate set of investment strategies by the system stakeholders

Assuming perfect coordination among the investment decisions made by the GENCOs and the transmission expansion planner, the investment decisions computed are those to be made by the aforementioned stakeholders in order to maximise the overall value that all the market players as a whole place on the investments undertaken, i.e. the social value of these investments considering the impact of FTRs. Then, in principle, a single set of decisions by the system stakeholders, including the market players and the network planner, resulting in a single set of CVaR values of their investments for GENCOs, is computed. As explained in section D.1, the CVaR term in the objective function, to be maximised, is proportional to the expected value of the corresponding GENCO's profits over the set of worst-case scenarios from its point of view (according to their probability distribution). Together with this, we aim to minimise the expected value of the system costs over the whole set of scenarios '$\boldsymbol{wp}$' considered. The proportionality factor weighting in the CVaR of the GENCO's profits, $\boldsymbol{\beta_{cp}}$, represents the risk profile of this GENCO. Accordingly, the CVaR is computed for each GENCO considered. In other words, the CVaR of the benefits earned by each risk-averse GENCO considering the acquisition of FTRs should be separately accounted for in the objective function, since the impact of contracting FTRs is different for each of these GENCOs.

However, the specific features considered for the function representing the costs incurred and profits made by the abovementioned GENCOs over the sets of long-term scenarios taken into account may result in the objective function of the expansion planning problem being quite flat for a relatively wide range of decision strategies (sets of investment decisions and FTRs allocations to be made by the system stakeholders).

In this case, computing, through a structured sensitivity analysis, a set of frontiers, or a number of sets of investment decisions by the stakeholders, and ranking these investment strategies according to some criterion, would be sensible. These sets of strategies should be computed varying certain relevant framework conditions of the problem formulated within a sensible range defined for them. The framework conditions to be varied within this sensitivity analysis could be the values of the set of ($\boldsymbol{\beta_{cp}}$) parameters considered for the several GENCOs considered, given the high level of uncertainty existing about the specific risk profile of these agents. Afterwards, the sets of strategies generated in this way could be ranked according to the minimum CVaR value computed for any of the GENCOs for each of these sets. Our objective should probably be maximising the minimum CVaR value computed across all the GENCOs, given the high level of uncertainty existing about the specific risk profile of each GENCO.

V. CASE STUDIES

A. *Illustrative 2-node example*

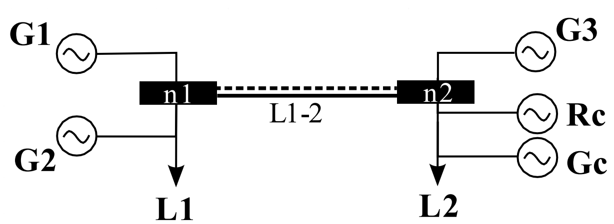

Figure 2. Illustrative 2-node example

Consider the simplified 2-node system in Figure 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 1. The annualized investment costs for Rc and Gc are 30.4[M€/year] and 27.4[M€/year], respectively.

Candidate generators, Rc and Gc, are risk averse. When representing their risk profile, parameter α has been set to 0.75. This means that the scenarios considered by the corresponding investors when aiming to 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 we are assuming that Gc earns high-enough predefined revenues secured by its promoter in a long-term generation capacity auction he 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 2.

Table 1. Generators features. Illustrative 2-node example

Gen	Node	Capacity [MW]	VarCost [€/MWh]
G 1	n1	40	80
G 2	n1	40	70
G 3	n2	40	50
Gc	n2	200	3
Rc	n2	180	0

Table 2. Demand behaviour [MW]

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

Table 3. 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

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 network users, generators and demands, the right to earn the congestion rents produced by the grid between the node where they are located and node ‘n1’.

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 in section V, 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 stabilize its revenues. Given that generator Rc is risk-averse, increasing its market revenues in the most unfavourable conditions and stabilizing 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 benefits determined by the investor for this generator. The latter is affected by the amount of FTRs contracted.

A.1 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 4. The locational marginal prices for each node and scenario resulting from these investment decisions are shown in Table 3. 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.

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 6. These results are associated with Rq2, since the overall profits made by each generator are considering when computing the impact of FTRs on the system welfare. According to Table 6, the expected value of the generator Rc's profits when contracting FTRs over all the scenarios and its expected value when not contracting FTRs over all the scenarios amount to 53.7[M€]. However, FTRs allow this generator to stabilize 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 4. Generation output results over the set of scenarios considered and for all units [MW] ($gp_{p,g}^{w}$)

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 5 provides the main results associated with the research questions defined in our work. In particular, the first 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, to the answer to **Rq2,** while rows 6 and 7, showing the investment decisions by the stakeholders, provide and answer to **Rq1**. As shown in Table 5, 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 $\mathbf{Gc's}$ operational costs are higher than those of Rc. When generation investors are risk-neutral, investing in generator **Rc** is socially optimal, as computed by the model. 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. 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.

Table 5. Social welfare components and investment decisions made to maximise social welfare 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) when investors are risk-neutral – Illustrative example.

		Risk Averse			**Non-risk averse**
		with FTRs	**without FTRs (forcing $ig_{\mathrm{Rc}} = 1$)**	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

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 <u>forced</u> 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.

Table 6. Annual revenues and profits of generator Rc if installed[M€]

Sc	Income (Market)	Income (FTRs)	gpr_{cp}^{w} with FTR	gpr_{cp}^{w} without FTR (forcing $ig_{\mathrm{Rc}} = 1$)
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

The impact of uncertainty on the value placed by the investor of generator Rc on this generator's 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 we have not checked whether this investment strategy is optimal from the point of view of generator Rc, who should be willing to maximise its profits. This is left for future research.

B. Representative European case study

In this case study, we consider the Western European electricity system, as depicted in Figure 3. We assess, 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.

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 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, we aim to determine the system's expansion in the 2030-time horizon.

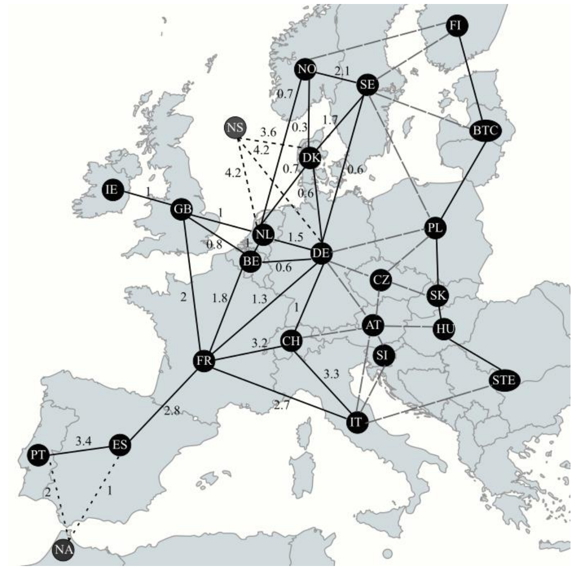

Figure 3. Equivalent European network considered in the 2030-time horizon - Existing network and candidate lines considered in remote areas [GW]

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 **[35]**, and the technical information on the features of network elements within the PYPSA dataset described fully in **[36]** for overhead AC lines. For HVDC lines, the data considered are available in **[37]**. 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 **[38]**. The operation and generation investment costs considered are those available in **[39]**. We have considered a 5% discount rate. The network investment costs considered are those available in **[40]** and **[41]-[42]** 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) **[43]**. Demand data for the North of Africa have been drawn from **[44]**, while the generation capacities, the generation investment costs[1] and the variable production costs have been drawn from **[45]**. Investment costs have been taken from **[46]** for the North Sea, considering economies of scale. $\boldsymbol{CO_2}$ prices have been drawn from the report in **[47]**; specifically, a value of 128 €/t$\boldsymbol{CO_2}$ 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 *7*** summarizes the annual demand data considered per country and **Table *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

[1] Overnight investment cost includes IDC (interest during construction)

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, we are able 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, we have applied the elbow method 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 we have not considered 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 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 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 $\boldsymbol{\alpha}$ and $\boldsymbol{\beta_{cp}}$ 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 **[33]** 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.

As discussed in section IV.G, given that, in this case study, as we will see 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. Consequently, within this case study, there is no need to select a set of strategies achieving an appropriate balance of the level of market risk born by the GENCOs. 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. As discussed in section IV.B, 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.

Note that this is in line with the fact that the electricity prices in the main continental plateau, are largely more stable than those in the NS area and any area in the Plato is far more deeply integrated into the bulk of the system than the NS area. **Table *9*** summarizes the main assumptions made associated with the modelling of risk considered in the formulation:

Table 9. Main assumptions associated with modelling of risk

$\boldsymbol{\alpha}$=0.8
$\boldsymbol{\beta_{cp}}$=0.8
$\boldsymbol{ig_{gc}} \in [\mathbf{0}, \mathbf{1}]$
$\boldsymbol{wcp}$=**wp**

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 we are also computing, put on the investments they undertake.

Here we assume 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, '$\boldsymbol{wcp}$' 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 our work. The latter scenarios should only reflect exogenous uncertainty and are denoted as '$\boldsymbol{wp}$' in the formulation.

However, since endogenous uncertainty is not considered, thus, the scenarios ‘$\boldsymbol{wcp}$’ coincide with the scenarios ‘$\boldsymbol{wp}$’.

We have defined exogenous uncertainty as the amount of generation deployed within each remote area, besides that deployed by the GENCOs whose investment decisions we are computing. This additional generation investment within remote areas, not determined endogenously in our 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.

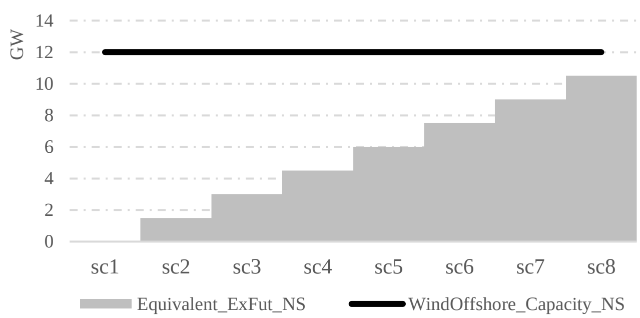

Figure 4. Uncertainty scenarios considered in the NS area

The set of scenarios ‘$\boldsymbol{wp}$’, being the same as ‘$\boldsymbol{wcp}$’, 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 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, we are computing.

B.1 Results

Here we provide the results we have computed on the expansion of the system, the resulting operation, and the overall system welfare, 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, we also compute the amount of FTRs to be contracted. 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 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 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, we focus our discussion next 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 5 and Table 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 he makes from the new generation he builds in the NS area in those of the scenarios considered that are most unfavourable for this GENCO. Also, as shown in Figure 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.

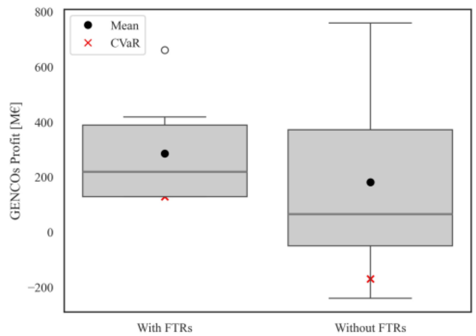

Figure 5. Boxplot - Profit of the GENCO in the NS both considering FTRs and not considering FTRs when this GENCO is deemed to be risk-averse

Table 10 provides some relevant results associated with the research questions defined in our work. In particular, row 12 shows the amount of generation built within the remote area affected by the implementation of LT-FTRs, the NS, 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, according to **Rq1.** 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, i.e. the answer to **Rq2**.

As shown in Table 10, if the GENCO in the NS area is risk-averse, the expected net social welfare of the system resulting from its planned expansion (deemed to change in line with the value of the objective function considered in the problem but with the opposite sign) is more extensive when this GENCO can contract FTRs than when he 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, 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).

Table 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 (vFTRCost) [M€]	629	-
12	Amount of gener. in the NS as a fraction of gener. potential: ig_{NS} [%]	69	56

Note that, as shown in Table 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 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, which, then, 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 problem and considered a benchmark.

Table 11. Amounts of costs of different types incurred when considering the GENCO in the NS as non-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

		Non-risk averse
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	Post-processing CVaR result [M€]	-1,513

As a post-processing result, we have computed the CVaR level 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 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 section IV.D, 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.

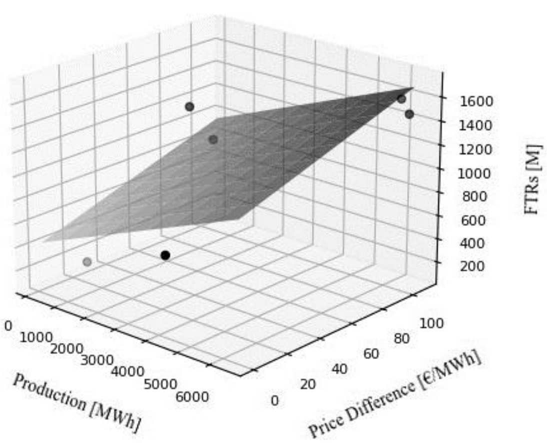

Figure 6. Impact of the price difference between the NS area and the reference node on the amount of additional generation deployed in this area, its production, and the amount of FTRs contracted

The results and discussion provide below are focused on Rq1, since, next, we are assessing how the use of FTRs impacts the investment decisions made by risk-averse generation companies. Figure 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 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

Table 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 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 in Table 12, 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. 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 deploy more thermal generation in the rest of Europe instead of wind generation in the NS area, even though the expected overall costs (including the investment and variable ones) incurred by this thermal generation 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). Investing in gas-fired generation instead of solar and wind 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 either (given that the production of offshore and onshore wind generation exhibits some correlation). 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, investing in gas-fired generation instead of additional 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 no made 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 7 and **Figure 8**. The results here provided are, again, largely associated with **Rq1**.

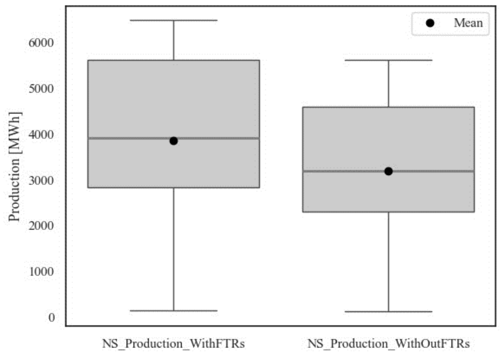

Figure 7. North Sea Power Production with FTRs vs without FTRs - Boxplot format

On the other hand, where risk-averse investors in the NS can contract FTRs, additional investments in hydro generation take place in Europe instead of those in 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 instead of other types of generation, being hydro generation flexible in its use, results in the price curve in the Reference node being smoothened 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 12 and **Figure 8**.

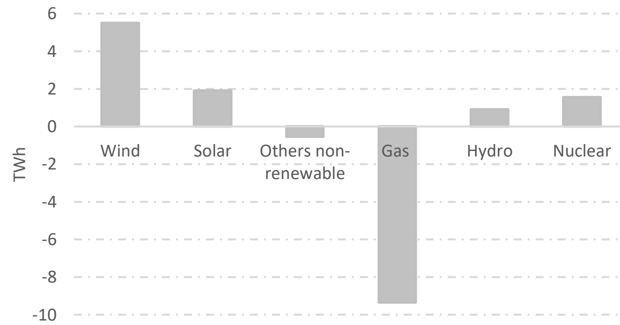

Figure 8. Differences in the annual electricity production by technology in Europe, when investors in generation in the NS area are risk-averse, between the cases where FTRs can and cannot be contracted.

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, being investors building this generation 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, expensive amount of transmission capacity built to make the FTRs issued feasible.

Wind generation investments in the area amount to almost 91% of the wind generation potential in the area. Besides, investments in on-shore 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 12 and **Figure 8**.

VI. CONCLUSIONS AND FUTURE RESEARCH

We explore 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. Our approach to address this problem involves developing a bi-level optimization 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 problems (one per GENCO). 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. We find in both case studies 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 is not forcing 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 we formulate. 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.

It is essential to state that the impact of LT-FTRs on the set of investments to undertake 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, such as i) the uncertainty about the new, additional, generation developments in this remote node or area; 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 future development of the local or global demand. 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 talking about the deployment of generation in remote areas weakly linked to the rest of the system. The fact that relevant uncertainty related to the occurrence of congestion exists drives the usefulness of contracting LT FTRs. In situations where, 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.

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 stabilization 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.

In this work, we have assessed the benefits of LT-FTRs implementation for risk management in the long term, and the resulting impact of this on the expansion of the system. This is a topic that had not been previously discussed and modelled in the literature. Due to this, there are still relevant aspects of the impact of the use of these rights on the system that remain unexplored and could be addressed by future research in order to complement the work discussed here. Some of these are listed next:

i) The impact of the use of FTRs on the system functioning and welfare could be analysed considering that investment decisions by the system stakeholders are not perfectly coordinated. Then, the role of LT-FTRs as instruments to coordinate the investment decisions made by the generation companies and transmission planners should be considered. This could be done for two different settings:
    a. either assuming that agents behave competitively, or
    b. assuming that they behave strategically though their decisions are potentially bounded by supervision by the regulatory authorities. This could be a more realistic setting, since private stakeholders like GENCOs have a natural incentive to maximise their own profits.
ii) Additional tools, such as machine learning techniques, could be employed to assess, from a different perspective, the impact of LT-FTRs on the expansion of the system, its efficiency, and the risk perception by agents.

iii) The granularity of network investments, especially on the interconnections between the remote areas and the rest of the system, could be refined, considering both strategic and incremental investment options, to explore the impact of economies of scale affecting these investments on the impact of LT-FTRs on the network, and potentially also generation, development, see [49].

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

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

Credit authorship contribution statement

Stefanía Gómez: Investigation, Conceptualization, Methodology, Software, Formal analysis, Writing - Original Draft. **Luis Olmos:** Supervision, Conceptualization, Methodology, Formal analysis, Writing - Review & Editing, Validation. **Andrés Ramos:** Supervision, Conceptualization, Methodology. **Michel Rivier Abbad:** Supervision, Conceptualization, Methodology.

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ANNEX A

Bilinear terms linearization

The procedure proposed in **[48]** was followed to linearize the bilinear elements $\boldsymbol{\lambda_{p,grf}^{wcp} ftr_{p,gc}^{wcp}}$, and $\boldsymbol{\lambda_{p,nd}^{wcp} gp_{p,g}^{wcp}}$. First it is necessary to approximate the continuous decision values $\boldsymbol{ftr_{p,gc}^{wcp}}$ and $\boldsymbol{gp_{p,g}^{wcp}}$ by M discrete values, where $\boldsymbol{M = 2^k}$ and k is non-negative. Consider $\left[\underline{\mathbf{FTR}}_{p,gc}, \overline{\boldsymbol{FTR}}_{p,gc}\right]$ = [0, $\boldsymbol{MCI_{gc}}$], $\left[\underline{\mathbf{gp}}_{p,g}^{wcp}, \overline{\boldsymbol{gp}}_{p,g}^{wcp}\right]$= [0, $\boldsymbol{MCI_{gc}}$], and $\left[\underline{\boldsymbol{\lambda}}_{p,nd}^{wcp}, \bar{\boldsymbol{\lambda}}_{p,nd}^{wcp}\right]$ = [0, $\boldsymbol{CENS}$], then the discrete approximation is formulated through binary expansion, as follows:

$$ftr_{p,gc} = \underline{\mathrm{FT}R}_{p,gc} + \Delta 1_{p,gc \sum_k 2^k u_{p,gc,k}} \ \forall \ \mathrm{p, gc} \ \in gccp \tag{32}$$

Where:

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

Multiplying both sides of **(32)** by $\boldsymbol{\lambda_{\mathrm{p,nd}}^{\mathrm{wcp}}}$, and adding a new variable $\boldsymbol{z_{p,gccp,nd,k}^{w} = u_{p,gccp,k} \lambda_{\mathrm{p,nd}}^{\mathrm{wcp}}}$ we obtain equation **(33**.

$$\lambda_{\mathrm{p,nd}}^{\mathrm{wcp}} ftr_{p,gc} = \lambda_{\mathrm{p,nd}}^{\mathrm{wcp}} \underline{\mathrm{FT}R}_{p,gc} + \Delta 1_{p,gc}^{wcp} \sum_k 2^k z_{p,gc,nd,k}^{wcp} \ \forall \ wcp, p, gc \in gccp \tag{33}$$

Since the term $\boldsymbol{u_{p,gc,k} \lambda_{\mathrm{p,nd}}^{\mathrm{wcp}}}$ is the multiplication of a continuous and an integer variable, it can be linearized by equations **(34)** and **(35)** :

$$0 \le \lambda_{\mathrm{p,nd}}^{\mathrm{wcp}} - z_{p,gc,nd,k}^{wcp} \le \bar{\lambda}_{\mathrm{p,nd}}^{\mathrm{wcp}} \left(1 - u_{p,gc,k}\right) \ \forall \ wcp, p, nd, k, gc \in gccp \tag{34}$$

$$0 \le z_{p,gc,nd,k}^{wcp} \le \bar{\lambda}_{\mathrm{p,nd}}^{\mathrm{wcp}} u_{p,gc,k} \ \forall \ wcp, p, nd, k, gc \in gccp \tag{35}$$

The same procedure is applied to $\boldsymbol{\lambda_{p,nd}^{wcp} gp_{p,g}^{wcp}}$ as follows:

$$gp_{p,g}^{wcp} = \underline{\mathrm{gp}}_{p,g}^{wcp} + \Delta 2_{p,g}^{wcp} \sum_k 2^k v_{p,g,k}^{wcp} \ \forall \ wcp, p, g \ \in gcp \tag{36}$$

Where:

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

Multiplying both sides of **(36)** by $\boldsymbol{\lambda_{\mathrm{p,nd}}^{\mathrm{wcp}}}$, and adding a new variable $\boldsymbol{x_{p,g,nd,k}^{wcp} = v_{p,g,k}^{wcp} \lambda_{\mathrm{p,nd}}^{\mathrm{wcp}}}$, we obtain equation **(37)**

$$\lambda_{\mathrm{p,nd}}^{\mathrm{wcp}} gp_{p,g}^{wcp} = \lambda_{\mathrm{p,nd}}^{\mathrm{wcp}} \underline{gp}_{p,g}^{wcp} + \Delta_{2p,g}^{wcp} \sum_k 2^k x_{p,g,nd,k}^{wcp} \ \forall \ wcp, p, nd, g \in gcp \tag{37}$$

Since the term $\boldsymbol{v_{p,g,k}^{wcp} \lambda_{\mathrm{p,nd}}^{\mathrm{wcp}}}$ is the multiplication of a continuous and an integer variable, it can be linearized by equations **(38)** and **(39)**:

$$0 \le \lambda_{\mathrm{p,nd}}^{\mathrm{wcp}} - x_{p,g,nd,k}^{wcp} \le \bar{\lambda}_{\mathrm{p,nd}}^{\mathrm{wcp}} \left(1 - v_{p,gcp,k}^{wcp}\right) \ \forall \ wcp, p, g \ \in gcp \tag{38}$$

$$0 \le x_{p,g,nd,k}^{wcp} \le \bar{\lambda}_{\mathrm{p,nd}}^{\mathrm{wcp}} v_{p,g,k}^{wcp} \ \forall \ wcp, p, g \ \in gcp \tag{39}$$

Finally, the term $\mathbf{GP}\boldsymbol{R_{cp}^{wcp}}$ is reformulated as follows:

$$\begin{aligned} gpr_{cp}^{wcp} = & \sum_{p,nd,gc \in gccp} \Delta 1_{p,gc}^{wcp} \sum_k 2^k \left(z_{p,gc,grf,k}^{wcp} - z_{p,gc,ftrnd,k}^{wcp}\right) + \sum_{p,nd,g \in gcp} \Delta 2_{p,g}^{wcp} \sum_k 2^k x_{p,g,nd,k}^{wcp} \\ & - \sum_{p,g \in gcp} VC_g \mathrm{gp}_{p,g}^{wcp} - \sum_{gc \in gccp} FCG_{gc} ig_{gc} \\ & - \sum_{gc \in gccp} cftr_{gc} \ \forall \ \mathrm{wcp, cp} \end{aligned} \tag{40}$$

$$\mathrm{cftr_{gc}} = \sum_{\mathrm{wcp}} \mathrm{PR^{wcp}} \Delta 1_{p,gc}^{wcp} \sum_k 2^k (z_{p,gc,grf,k}^{wcp} - z_{p,gc,gnd,k}^{wcp}) \ \forall \ \mathrm{gc} \ \in \mathrm{gccp} \tag{41}$$

Notice that the reformulation of the problem considering this linearization should include equations**(32)**, **(34)**, **(35)**, **(36)**, **(38)** and **(39)** as additional constraints.

ANNEX B

KKT conditions of the operation problem (LL)

Equations **(42)**, **(43)**, **(44)**, **(45)**, **(46)**, correspond to the derivative of the lagrangian function with respect to the variables $\boldsymbol{f_{p,nd,nf,c}^{w}}$, $\boldsymbol{gp_{p,g}^{w}}$, $\boldsymbol{\Theta_{p,nd}^{w}}$, $\boldsymbol{e_{p,nd}^{w}}$ and $\boldsymbol{l_{p,ni,nf,c}^{w}}$

respectively, finally, equations (47) and (48) corresponds to the equality constraints of the operation problem.

$$-\underline{\Upsilon}^{w}_{p,ni,nf,c\in lc(ni,nf,c)}+\overline{\Upsilon}^{w}_{p,ni,nf,c\in lc(ni,nf,c)}-\underline{\tau}^{w}_{p,ni,nf,c\in lc(ni,nf,c)}+\overline{\tau}^{w}_{p,ni,nf,c\in lc(ni,nf,c)}-\underline{\phi}^{w}_{p,ni,nf,c\in le(ni,nf,c)}+\overline{\phi}^{w}_{p,ni,nf,c\in le(ni,nf,c)}-\phi^{w}_{p,ni,nf,c\in le(ni,nf,c)}-\frac{L_{ni,nf,c}}{2}\underline{\mu}^{w}_{p,ni,nf,c\in ll(ni,nf,c)}+\frac{L_{ni,nf,c}}{2}\overline{\mu}^{w}_{p,ni,nf,c\in ll\{ni,nf,c)}+\lambda^{w}_{p,ni\in la}-\lambda^{w}_{p,nf\in la}=0 \quad : f^{w}_{p,nd,nf,c}\ \forall w,p,ni,nf,c\ \in la \tag{42}$$

$$\mathrm{PR^{w}SVC_{g}}+\mathrm{PR^{w}CO_{2}}_{\mathrm{g}}-\lambda^{\mathrm{w}}_{\mathrm{p,nd\in(gnd)}}-\underline{\rho}^{\mathrm{w}}_{\mathrm{p,gc}}+\overline{\rho}^{\mathrm{w}}_{\mathrm{p,gc}}-\underline{\omega}^{\mathrm{w}}_{\mathrm{p,g}}+\overline{\omega}^{\mathrm{w}}_{\mathrm{p,g}}=0 \quad : gp^{w}_{p,g}\ \forall w,p,g,nd\ \in gnd \tag{43}$$

$$\sum_{nf\in le(nd,nf,c)}\frac{Sb}{X_{nd,nf,c}}\phi_{p,nd,nf,c}-\sum_{ni\in le(ni,nd,c)}\frac{Sb}{X_{ni,nd,c}}\phi_{p,ni,nd,c}-\sum_{nf\in lc(nd,nf,c)}\frac{Sb}{X_{nd,nf}}\overline{\tau}_{p,nd,nf,c}-\sum_{ni\in lc(ni,nd,c)}\frac{Sb}{X_{ni,nd,c}}\underline{\tau}_{p,ni,nd,c}+\sum_{ni\in lc(ni,nd,c)}\frac{Sb}{X_{ni,nd,c}}\overline{\tau}_{p,ni,nd,c}+\sum_{nf\in lc(nd,nf,c)}\frac{Sb}{X_{nd,nf,c}}\underline{\tau}_{p,nd,nf,c}-\underline{\varphi}^{w}_{p,nd}+\overline{\varphi}^{w}_{p,nd}=0 \quad : \Theta^{w}_{p,nd}\ \forall w,p,nd \tag{44}$$

$$\mathrm{P}R^{w}\mathrm{CENS}-\lambda^{w}_{p,nd}+\overline{\zeta}^{w}_{p,nd}-\underline{\zeta}^{w}_{p,nd}=0 : e^{w}_{p,nd}\ \forall w,\mathrm{p,nd} \tag{45}$$

$$\lambda^{w}_{p,ni\in ll}+\lambda^{w}_{p,nf\in ll}-\underline{\mu}^{w}_{p,ni,nf,c}-\overline{\mu}_{p,ni,nf,c}=0 \quad : l^{w}_{p,ni,nf,c}\ \forall w,p,ni,nf,c\ \in ll \tag{46}$$

$$-f^{w}_{p,ni,nf,c}+\left[\Theta^{w}_{p,ni}-\Theta^{w}_{p,nf}\right]\frac{Sb}{X_{ni,nf,c}}=0 \quad \forall w,p,le_{ni,nf,c} \tag{47}$$

$$D_{nd}+\sum_{la}f^{w}_{p,nd,nf,c}-\sum_{la}f^{w}_{p,ni,nd,c}-\sum_{gnd}gp^{w}_{p,g}-e^{w}_{p,nd}=0 \quad \forall w,p,nd \tag{48}$$

Complementarity conditions

$$0\le\left(f^{w}_{p,ni,nf,c}+TTC_{ni,nf,c}it_{ni,nf,c}\right)\perp\underline{\Upsilon}^{w}_{p,ni,nf,c}\ge0 \quad \forall(ni,nf,c)\in lc,\ \forall w,p \tag{49}$$

$$0\le\left(-f^{w}_{p,ni,nf,c}+TTC_{ni,nf,c}it_{ni,nf,c}\right)\perp\overline{\Upsilon}^{w}_{p,ni,nf,c}\ge0 \quad \forall(ni,nf,c)\in lc,\ \forall w,p \tag{50}$$

$$0\le\left(\mathrm{f}^{\mathrm{w}}_{\mathrm{p,ni,nf,c}}-\left[\Theta^{w}_{p,ni}-\Theta^{w}_{p,nf}\right]\frac{Sb}{X_{ni,nf,c}}+MF_{ni,nf,c}\left(1-it_{ni,nf,c}\right)\right)\perp\underline{\tau}^{w}_{p,ni,nf,c}\ge0 \quad \forall(ni,nf,c)\in lc,\ \forall w,p \tag{51}$$

$$0\le\left(-f^{w}_{p,ni,nf,c}+\left[\Theta^{w}_{p,ni}-\Theta^{w}_{p,nf}\right]\frac{Sb}{pX_{ni,nf,c}}+MF_{ni,nf,c}\left(1-it_{ni,nf,c}\right)\right)\perp\overline{\tau}^{w}_{p,ni,nf,c}\ge0 \quad \forall(ni,nf,c)\in lc,\ \forall w,p \tag{52}$$

$$0\le\left(f^{w}_{p,ni,nf,c}+TTC_{ni,nf,c}\right)\perp\underline{\phi}^{w}_{p,ni,nf,c}\ge0 \qquad 0\le\left(-f^{w}_{p,ni,nf,c}+TTC_{ni,nf,c}\right)\perp\overline{\phi}^{w}_{p,ni,nf,c}\ge0 \quad \forall(ni,nf,c)\in le,\ \forall w,p \tag{53}$$

$$0\le\left(-gp^{w}_{p,gc}+MP_{gc}ig_{gc}\right)\perp\ \overline{\rho}_{p,gc}\ge0 \qquad 0\le\left(gp^{w}_{p,gc}\right)\perp\underline{\rho}_{p,gc}\ge0 \quad \forall gc\in gnd,\ \forall w,p \tag{54}$$

$$0\le\left(-gp^{w}_{p,g}+MP\right)\perp\overline{\omega}_{p,g}\ge0 \qquad 0\le\left(gp^{w}_{p,g}\right)\perp\underline{\omega}_{p,g}\ge0 \quad \forall ge,\ \forall w,p \tag{55}$$

$$0\le\left(\mathrm{D_{nd}}-\mathrm{e}^{w}_{p,nd}\right)\perp\ \overline{\zeta}_{p,nd}\ge0 \qquad 0\le\mathrm{e}^{w}_{p,nd}\ \perp\underline{\zeta}_{p,nd}\ge0 \quad \forall nd,\ \forall w,p \tag{56}$$

$$0\le\left(0.5\mathrm{L_{ni,nf,c}}\,f^{w}_{p,ni,nf,c}+l^{w}_{p,ni,nf,c}\right)\perp\underline{\mu}_{p,ni,nf,c}\ge0 \qquad 0\le\left(l^{w}_{p,ni,nf,c}-0.5\mathrm{L_{ni,nf,c}}\,f^{w}_{p,ni,nf,c}\right)\perp\ \overline{\mu}_{p,ni,nf,c}\ge0 \quad \forall ni,nf,c\ \in ll,\ \forall w,p \tag{57}$$

$$0\le\left(\mathrm{l^{w}_{p,ni,nf,c}}-0.5\mathrm{L_{ni,nf,c}\ TTC_{ni,nf,c}}\right)\perp\underline{\delta}_{\mathrm{p,ni,nf,c}}\ge0 \qquad 0\le\left(0.5\mathrm{L_{ni,nf,c}}\ \mathrm{TT}C_{ni,nf,c}-l^{w}_{p,ni,nf,c}\right)\perp\ \overline{\delta}_{p,ni,nf,c}\ge0 \quad \forall ni,nf,c\ \in ll,\ \forall w,p \tag{58}$$

$$0\le\left(\theta^{w}_{p,nd}+\frac{\pi}{2}\right)\perp\underline{\varphi}_{p,nd}\ge0 \qquad 0\le\left(\frac{\pi}{2}-\theta^{w}_{p,nd}\right)\perp\ \overline{\varphi}_{p,nd}\ge0 \quad \forall\ \mathrm{nd},\ \forall w,p \tag{59}$$

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 [34], 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.

$$0\le\ \mathrm{f^{w}_{p,ni,nf,c}}+\mathrm{TTC_{ni,nf,c}it_{ni,nf,c}}\le\underline{M\Upsilon}\cdot\underline{Y\Upsilon}^{w}_{\mathrm{p,ni,nf,c}} \qquad 0\le\underline{\Upsilon}^{w}_{p,nd,nf,c}\le\underline{M\Upsilon}\left(1-\underline{Y\Upsilon}^{w}_{p,ni,nf,c}\right) \quad \forall(ni,nf,c)\in lc,\ \forall w,p \tag{60}$$

$$0\le-f^{w}_{p,nd,nf,c}+TTC_{ni,nf,c}it_{ni,nf,c}\le\overline{M\zeta}\cdot\overline{Y\zeta}^{w}_{p,ni,nf,c} \qquad 0\le\overline{\zeta}^{\mathrm{w}}_{\mathrm{p,nd,nf,c}}\le\overline{M\zeta}\left(1-\overline{Y\zeta}^{\mathrm{w}}_{\mathrm{p,ni,nf,c}}\right) \quad \forall(ni,nf,c)\in lc,\ \forall w,p \tag{61}$$

$$0\le f^{w}_{p,ni,nf,c}-\left[\Theta^{w}_{p,ni}-\Theta^{w}_{p,nf}\right]\frac{Sb}{X_{ni,nf,c}}+MF_{ni,nf,c}\left(1-it_{ni,nf,c}\right)\le\underline{M\tau}\cdot\underline{Y\tau}^{w}_{p,ni,nf,c} \qquad 0\le\underline{\tau}^{w}_{p,nd,nf,c}\le\underline{M\tau}\left(1-\underline{Y\tau}^{w}_{p,ni,nf,c}\right) \quad \forall(ni,nf,c)\in lc,\ \forall w,p \tag{62}$$

$$0\le-f^{w}_{p,ni,nf,c}+\left[\Theta^{w}_{p,ni}-\Theta^{w}_{p,nf}\right]\frac{Sb}{pX_{ni,nf,c}}+MF_{ni,nf,c}\left(1-it_{ni,nf,c}\right)\le\overline{M\tau}\cdot\overline{Y\tau}_{p,ni,nf,c} \qquad 0\le\overline{\tau}^{w}_{p,ni,nf}\le\overline{M\tau}\left(1-\overline{Y\tau}^{w}_{p,ni,nf,c}\right) \quad \forall(ni,nf,c)\in lc,\ \forall w,p \tag{63}$$

$$0\le f^{w}_{p,ni,nf,c}+TTC_{ni,nf,c}\le\underline{M\phi}\cdot\underline{Y\phi}^{w}_{p,ni,nf,c} \qquad 0\le\underline{\phi}^{w}_{p,ni,nf,c}\le\underline{M\phi}\left(1-\underline{Y\phi}^{w}_{p,ni,nf,c}\right) \qquad 0\le-f^{w}_{p,ni,nf,c}+TTC_{ni,nf,c}\le\overline{M\phi}\cdot\overline{Y\phi}^{w}_{p,ni,nf,c} \qquad 0\le\overline{\phi}^{w}_{p,ni,nf,c}\le\overline{M\phi}\left(1-\overline{Y\phi}^{w}_{p,ni,nf,c}\right) \quad \forall(ni,nf,c)\in le,\ \forall w,p \tag{64}$$

$$\begin{aligned} &0 \le -gp^{w}_{p,gc} + MP_{gc} ig_{gc} \le \overline{M\rho} \cdot \overline{Y\rho}^{w}_{p,gc} \\ &0 \le \bar{\rho}^{w}_{p,gc} \le \overline{M\rho}\left(1 - \overline{Y\rho}^{w}_{p,gc}\right) \\ &0 \le \left(gp^{w}_{p,gc}\right) \le \underline{M\rho} \cdot \underline{Y\rho}^{w}_{p,gc} \\ &0 \le \underline{\rho}^{w}_{p,gc} \le \underline{M\rho}\left(1 - \underline{Y\rho}^{w}_{p,gc}\right) \end{aligned} \quad \begin{aligned} &\forall gc \in gnd, \\ &\forall\, w, p \end{aligned} \qquad (65)$$

$$\begin{aligned} &0 \le -gp^{w}_{p,g} + MP \le \overline{M\omega} \cdot \overline{Y\omega}^{w}_{p,g} \\ &0 \le \overline{\omega}_{p,g} \le \overline{M\omega}\left(1 - \overline{Y\omega}^{w}_{p,g}\right) \\ &0 \le (gp^{w}_{p,g}) \le \underline{M\omega} \cdot \underline{Y\omega}^{w}_{p,g} \\ &0 \le \underline{\omega}_{p,g} \le \underline{M\omega}\left(1 - \underline{Y\omega}^{w}_{p,g}\right) \end{aligned} \quad \begin{aligned} &\forall g \\ &\forall\, w, p \end{aligned} \qquad (66)$$

$$\begin{aligned} &0 \le \mathrm{e}^{w}_{p,nd} \le \underline{M\gamma} \cdot \underline{Y\gamma}^{w}_{p,nd} \\ &0 \le \underline{\gamma}_{p,nd} \le \underline{M\gamma}\left(1 - \underline{Y\gamma}_{p,nd}\right) \end{aligned} \quad \begin{aligned} &\forall nd, \\ &\forall\, w, p \end{aligned} \qquad (67)$$

$$\begin{aligned} &0 \le \mathrm{D_{nd}} - \mathrm{e^{w}_{p,nd}} \le \overline{\mathrm{M}\zeta} \cdot \overline{\mathrm{Y}\zeta}^{\mathrm{w}}_{\mathrm{p,nd}} \\ &0 \le \bar{\zeta}^{\mathrm{w}}_{p,g} \le \overline{M\zeta}\left(1 - \overline{Y\zeta}^{w}_{p,g}\right) \end{aligned} \quad \begin{aligned} &\forall nd, \\ &\forall\, w, p \end{aligned} \qquad (68)$$

$$\begin{aligned} &0 \le 0.5\mathrm{L_{ni,nf,c}}\, f^{w}_{p,ni,nf,c} + l^{w}_{p,ni,nf,c} \\ &\quad \le \underline{M\mu} \cdot \underline{Y\mu}^{w}_{p,ni,nf,c} \\ &0 \le \underline{\mu}^{\mathrm{w}}_{p,ni,nf,c} \le \underline{M\mu}\left(1 - \underline{Y\mu}^{w}_{p,ni,nf,c}\right) \end{aligned} \quad \begin{aligned} &\forall ni, nf, c \\ &\qquad \in ll \\ &\forall\, w, p \end{aligned} \qquad (69)$$

$$\begin{aligned} &0 \le l^{w}_{p,ni,nf,c} - 0.5\mathrm{L_{ni,nf,c}}\, f^{w}_{p,ni,nf,c} \\ &\quad \le \overline{M\mu} \cdot \overline{Y\mu}^{w}_{p,ni,nf,c} \\ &0 \le \bar{\mu}^{\mathrm{w}}_{p,ni,nf,c} \le \overline{M\mu}\left(1 - \overline{Y\mu}^{w}_{p,ni,nf,c}\right) \end{aligned} \quad \begin{aligned} &\forall ni, nf, c \\ &\qquad \in \mathrm{ll} \\ &\forall\, w, p \end{aligned} \qquad (70)$$

$$\begin{aligned} &0 \le \mathrm{l^{w}_{p,ni,nf,c}} - 0.5\mathrm{L_{ni,nf,c}}\, \mathrm{TTC_{ni,nf,c}} \\ &\quad \le \underline{M\delta} \cdot \underline{Y\delta}^{w}_{p,ni,nf,c} \\ &0 \le \underline{\delta}^{\mathrm{w}}_{p,ni,nf,c} \le \underline{M\delta}\left(1 - \underline{Y\delta}^{w}_{p,ni,nf,c}\right) \end{aligned} \quad \begin{aligned} &\forall ni, nf, c \\ &\qquad \in ll \\ &\forall\, w, p \end{aligned} \qquad (71)$$

$$\begin{aligned} &0 \le 0.5\mathrm{L_{ni,nf,c}}\, \mathrm{TT}C_{ni,nf,c} - l^{w}_{p,ni,nf,c} \\ &\quad \le \overline{M\delta} \cdot \overline{Y\delta}^{w}_{p,ni,nf,c} \\ &0 \le \bar{\delta}^{\mathrm{w}}_{p,ni,nf,c} \le \overline{M\delta}\left(1 - \overline{Y\delta}^{w}_{p,ni,nf,c}\right) \end{aligned} \quad \begin{aligned} &\forall ni, nf, c \\ &\qquad \in ll \\ &\forall\, w, p \end{aligned} \qquad (72)$$

$$\begin{aligned} &0 \le \theta^{w}_{p,nd} + \frac{\pi}{2} \le \underline{M\varphi} \cdot \underline{Y\varphi}^{w}_{p,nd} \\ &0 \le \underline{\varphi}_{p,nd} \le \underline{M\varphi}\left(1 - \underline{Y\varphi}^{w}_{p,nd}\right) \\ &0 \le \frac{\pi}{2} - \theta^{w}_{p,nd} \le \overline{M\varphi} \cdot \overline{Y\varphi}^{w}_{p,nd} \\ &0 \le \overline{\varphi}_{p,nd} \le \overline{M\varphi}\left(1 - \overline{Y\varphi}^{w}_{p,nd}\right) \end{aligned} \quad \begin{aligned} &\forall nd, \\ &\forall\, \mathrm{w,p} \end{aligned} \qquad (73)$$