Transmission and interconnection planning in power systems: Contributions to investment under uncertainty and cross-border cost allocation

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Abstract

Electricity transmission network investments are playing a key role in the integration process of power systems in the European Union. Given the magnitude of investment costs, their irreversibility, and their impact in the overall development of a region, accounting for the role of uncertainties as well as the involvement of multiple parties in the decision process allows for improved and more robust investment decisions.

Even though the creation of this internal energy market requires attention to flexibility and strategic decision-making, existing literature and practitioners have not given proper attention to these topics.

Using portfolios of real options, we present two stochastic mixed integer linear programming models for transmission network expansion planning. We study the importance of explicitly addressing uncertainties, the option to postpone decisions and other sources of flexibility in the design of transmission networks. In a case study based on the Azores archipelago we show how renewables penetration can increase by introducing contingency planning into the decision process considering generation capacity uncertainty.

We also present a two-party Nash-Coase bargaining transmission capacity investment model. We illustrate optimal fair share cost allocation policies with a case study based on the Iberian market.

Lastly, we develop a new model that considers both interconnection expansion planning under uncertainty and cross-border cost allocation based on portfolios of real options and Nash-Coase bargaining. The model is illustrated using Iberian transmission and market data.

Resumo

Os investimentos em redes de transmissão de electricidade desempenham um papel fundamental no processo de integração dos sistemas energéticos da União Europeia. Dada a magnitude dos custos de investimento, a sua irreversibilidade e o seu impacto no desenvolvimento global de uma região, considerar a existência de incertezas e o envolvimento de múltiplos decisores permite que as decisões sejam melhores e mais robustas.

Embora a criação deste mercado de energia interno requeira atenção à tomada de decisões flexiveis e estratégicas, a literatura existente e os profissionais não prestaram ainda a devida atenção a estes temas.

Utilizando portfólios de opções reais, apresentamos dois modelos de programação linear inteira mista estocásticos para o planeamento da expansão das redes de transmissão. Estudamos a importância de incorporar incertezas explicitamente, a opção de adiar decisões e outras fontes de flexibilidade no desenho de redes de transmissão. Num caso de estudo baseado no arquipélago dos Açores mostramos como a penetração de energias renováveis pode aumentar, ao introduzir um plano contingente no processo de decisão, considerando a incerteza da capacidade de geração.

Apresentamos também um modelo de investimento de em capacidade de transmissão com negociação de Nash-Coase para dois agentes. Ilustramos políticas ideais para uma alocação dos custos justa num caso de estudo baseado no mercado Ibérico.

Por último, desenvolvemos um novo modelo que considera quer o planeamento da expansão de interconexões em contexto de incerteza como a alocação de custos entre fronteiras baseado em portfólios de opções reais e negociações de Nash-Coase. O modelo é ilustrado usando dados de transmissão e mercado Ibéricos.

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Chapter 1

Introduction

1.1 Context and motivation

Power systems in the European Union (EU) have been undergoing a series of changes as part of a unification process into a single pan-European infrastructure. Transmission network investments play a key role in this process, in a setting where uncertainty and the existence of multiple parties greatly increase the complexity of decisions. Therefore, attention must be given to aspects such as the option value of flexibility and the strategic value resulting from the reaction to other parties.

In this section, we summarize the main energy sector developments that have been taking place in the EU, laying out the context that motivates our research in electricity transmission network investment. Specifically, we set our focus on the transposition of the Real Options methodology from Finance literature, accounting for the impact of key uncertain parameters in long term decisions, such as the evolution of demand and electricity generation capacity. We also consider cross-border cost allocation when different transmission investors must share investment responsibilities.

Given the potential benefit to social welfare in the EU, European electricity markets are being integrated in a Europe-wide Power Exchange (PX), allowing electricity to be transferred between Member States. The improvement of the conditions for free trade, by itself, justifies the expansion of interconnections. Moreover, increasing environmental concerns have led to the presence of a higher share of renewable energy sources (RES) in the generation pool, resulting in additional pressure on interconnecting transmission lines. In fact, because RES use volatile natural resources, such as wind or solar energy, and electricity is mostly non-storable, the maximization of environmental benefits often will require the delivery of electricity obtained from these sources to more distant areas, in particular to areas in adjacent Member States. In order to alleviate congestion, this increase in interconnection demand requires expansion investments, in both transmission network capacity within Member States and cross-border interconnections between Member States.

Since the 1990s, the EU has taken consecutive steps to develop the new paradigm for the European power system, named Internal Energy Market. It aims to improve economic and social cohesion throughout the EU Member States, mostly in least-favoured regions, reducing the living condition gap respective to other regions[1]. By improving cross-border power transfers among Member States, the optimization of resource allocation is facilitated. This leads to a reduction in investment costs of transmission and generation infrastructure while improving security and quality of supply. Ultimately, electricity costs for consumers decrease while diminishing our environmental impact. In turn, the economic integration of the Common Market improves as this pan-European pooling of resources increases market pressure on generation companies (GENCOs). Competition is reinforced among them[2] benefiting the long-term increase of social welfare in the EU. Implementing this vision goes well beyond the electricity sector, in fact, these intended changes are aligned with the EU principle that the free movement of goods is a right of European citizens.

Historically, independent electricity markets existed in each Member State. In order to initiate the restructuring process, an important early step was given in 1996 with the passing of the First Directive concerning common rules for the internal market in electricity[3]. The focus of this first stage of development of the European Internal Energy Market intended for competition to be introduced in industries that used to be dominated by vertically integrated and state-owned companies. It aimed at the identification of individual areas that could be improved with the introduction of competition, and then on requiring these vertically integrated companies to be unbundled into

[1]Council of the European Communities, Council Directive of 29 October 1990 on the transit of electricity through transmission grids (90/547/EEC), http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A31990L0547 (Last accessed in 09/09/2017)

[2]European Commission, Commission Working Document on Internal Energy Market, COM (88) 238, 2 May 1988, http://eur-lex.europa.eu/procedure/EN/107212 (Last accessed in 09/09/2017)

[3]European Parliament and the Council of the European Union, Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity, http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A31996L0092 (Last accessed in 09/09/2017)

distinct businesses. In its reorganization, the electricity sector was divided in GENCOs, to develop and exploit generation capacity, Transmission System Operators (TSOs), to operate and maintain the transmission system and its interconnectors, and Distribution System Operators (DSOs), to connect customers to the network.

The First Directive clearly distinguished between GENCOs, on one hand, and TSOs and DSOs, on the other. Whereas the construction of new generation capacity was required to be authorized based on objective, transparent and non-discriminatory criteria, which enabled the presence of multiple companies, Member States were required to designate a single TSO and a single DSO. Thus, monopolies were retained in the transmission and the distribution businesses. TSOs and DSOs became single entities operating in their respective regions, under strict regulations to enforce their exclusivity. Even in countries with more than one operator, such as Germany or Great Britain, each was assigned a distinct sub-region. In contrast, GENCOs could own multiple generators, which allowed them to adjust their capacities and be submitted to free market conditions. In opposition to single TSO or DSO companies acting as monopolists, as new GENCOs emerge, the generation business comes under increased competition, its market power is reduced, leading to lower consumer prices and increased social welfare.

Considering the low interconnection capacity, the European Council defined in 2002 a target for interconnection capacity for all member states[4]. With this new ruling, new interconnection investments should be exercised to sustain cross-border trade guaranteeing at least 10% of production capacity existing in 2005.

In 2003, with the passing of a Second Directive concerning common rules for the internal market in electricity[5], independent regulatory authorities were established by each Member State. Among other responsibilities, these entities should define rules to allow cross-border power flow in interconnection transmission lines, together with congestion management, and the responsibility of fostering further investments in their capacity. As for the development of new interconnection capacity, Member States could also require TSOs to comply with minimum standards. An impor-

[4]Presidency of the European Council, Presidency Conclusions of the Barcelona European Council (March 2002), http://ec.europa.eu/invest-in-research/pdf/download_en/barcelona_european_council.pdf (Last accessed in 09/09/2017)

[5]European Parliament and the Council of the European Union, Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC, http://eur-lex.europa.eu/eli/dir/2003/54/oj (Last accessed in 09/09/2017)

tant driver for this ruling is security of supply. One of the main responsibilities assigned to TSOs is the requirement to provide adequate system capacity and reliability.

It was possible for two neighbouring networks to have significant price differentials thus justifying the need for interconnections and cross-border trade. However, as no rules were defined for interconnection investment coordination between TSOs of distinct Member States, these price differentials could not be mitigated. With the enforcement of market based mechanisms for congestion management, a significant step was given to facilitate efficient cross-border trade and provide TSOs with correct market signals[6] [7] by which to plan further cross-border transmission expansions. Overall, this directive was not able to provide sufficient incentives for the required interconnection investments to take place[8], and constraints in interconnection capacity continued to restrict trade between Member States. Therefore, the integration of electricity markets and building of the Internal Energy Market was compromised.

Concurrently, in a deliberate move, the EU sought the promotion of environmental protection with the creation of incentives that could entice the investment in RES technologies. With a Third Directive concerning common rules for the internal market in electricity[9], Member States were allowed to require market clearing discrimination in favour of RES and combined heat and power producers. As RES technologies have significantly higher output variability, mostly due to uncontrollable weather conditions, the transmission system became less predictable. In this context, the relevance of short-term cross-border power transfers is an additional concern facing transmission and interconnection planning. To the already important role of cross-border interconnections in addressing regional long-term generation imbalances, now TSOs had to consider the variability of the preferred generation technologies.

[6]European Parliament and the Council of the European Union, Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity, http://eur-lex.europa.eu/legal-content/en/ALL/?uri=CELEX:32003R1228 (Last accessed in 09/09/2017)

[7]Commission of the European Communities, Commission Decision of 9 November 2006 amending the Annex to Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity, http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32006D0770 (Last accessed in 09/09/2017)

[8]European Commission, DG Competition report on energy sector inquiry (SEC(2006)1724, 10 January 2007), http://ec.europa.eu/competition/sectors/energy/2005_inquiry/index_en.html (Last accessed in 09/09/2017)

[9]European Parliament and the Council of the European Union, Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, Article 12(a), http://eur-lex.europa.eu/legal-content/en/ALL/?uri=celex%3A32009L0072 (Last accessed in 09/09/2017)

TSOs must not merely adapt transmission systems to the regulatory changes that a new vision for the energy industry entails. They must also consider the economic conditions in which they develop, maintain, and operate secure, reliable and efficient systems. Due to the long lifetimes of transmission networks, the planning of transmission expansions must consider the corresponding uncertain contexts as good decisions require robustness against all possible unfoldings of events. For this reason, demand evolution, and other uncertain financial data, such as generation costs, discount rates and investment costs, together with the possibility that system components might become unavailable (Blanco and Olsina, 2011), should be explicitly brought into the analyses.

Recently, the Price Coupling of Regions (PCR) initiative was launched by seven European Power Exchanges with the objective of devising a single price coupling solution to obtain electricity prices and manage cross border capacity in Europe[10]. In February 2014, the North West Day Ahead Project (NWE DA Project), a day ahead market coupling implementation pilot that accounts for more than 75% of the total electricity consumption of Europe, was launched[11]. Supported by ENTSO-E, the European Network of Transmission System Operators for Electricity, this project coordinated TSOs and PXs of Austria, Belgium, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland and Sweden.

Only a few months later, in May 2014, a new step in the integration of European Electricity Markets was given, when the day-ahead market coupling was extended to Portugal and Spain through the French-Spanish border[12]. More recently, in February 2015, Italy and Slovenia also joined the Multi-Regional Coupling effort leading it to represent 85% of total European power consumption [13]. Switzerland is currently in negotiations and Greece is also set to be integrated[14].

[10]REN, Energy prices of European wholesale market are standardised, https://www.ren.pt/en-GB/media/comunicados/detalhe/energy_prices_of_european_wholesale_market_are_standardised/ (Last accessed in 09/09/2017)

[11]ENTSO-E, Go-live of NWx E Project a Major Step towards an Integrated European Electricity Market https://www.entsoe.eu/news-events/announcements/announcements-archive/Pages/News/Go-live-of-NWE-Project-a-Major-Step-towards-an-Integrated-European-Electricity-Market.aspx, (Last accessed in 09/09/2017)

[12]ENTSO-E, South-Western and North-Western Europe Market Coupling Project Go-Live, https://www.entsoe.eu/news-events/announcements/announcements-archive/Pages/News/SWE-NWE-Market-Coupling-Go-Live.aspx (Last accessed in 09/09/2017)

[13]EPEXSPOT, A major step towards market integrationhttp://www.epexspot.com/en/market-coupling/another_step_towards_market_intergration, (Last accessed in 09/09/2017)

[14]EPEXSPOT, Italian borders market coupling to launch on 24 February 2015 http://www.epexspot.com/en/press-media/press/details/Press/show_detail/30385, (Last accessed in 09/09/2017)

As of today, there are still cross-border bottlenecks that restrict trade in the EU. The most significant are in four regions whose interconnection capacity with mainland Europe is significantly insufficient: the Baltic States, the Iberian peninsula, Italy, and Great Britain and Ireland. Remarkably, all of these "electric peninsulas" have high RES development potential. Nevertheless, the exploitation of this renewable potential will keep being constrained if interconnection capacity is not at least doubled in some of these regions, or increased up to 10 times, as in the case of the Iberian peninsula-mainland Europe connection (ENTSO-E, 2014). By itself, this fact suggests the need for further cross-border cooperation. Other important challenges are improving interconnections between Nordic countries with mainland Europe, interconnections between Poland and Germany, the Czech Republic and Slovakia, reinforcement of South-Eastern Europe with Central Europe as well as within the Balkan peninsula (ENTSO-E, 2016).

Roadmap 2050 is a project developed by the European Climate Foundation that serves as a guide to the energy sector focused on the decarbonization of the power sector, reducing carbon emissions by at least 80% below 1990 levels by 2050. Beyond the development of the internal electricity market, ambitious goals such as those outlined in Roadmap 2050 suggest that an integrated European approach for power system development is necessary improve resource sharing between Member States thus avoiding a 12% increase in transmission costs and a 18% in operating costs by 2030[15].

Traditional methods of valuation and decision-making assume stable environments, in which costs and benefits can be well specified. Nevertheless, investment plans in many important contexts, are subject to uncertainties and multiple agents acting according to their own interests. influence each other. In this context, decisions of a player influence the reactions of other player, and current and future investment decisions interact significantly. To improve the quality of investment decisions, the value of postponement and operational flexibility and the strategic value of reacting to other parties involved should be explicitly considered (Smit and Trigeorgis, 2004). In the specific case of as transmission and interconnection planning in power systems, uncertainty in key decision parameters must be considered, given the magnitude of the investment costs, as well as the irreversibility of the investments, and their impact in the overall development of a region.

Moreover, the fact that cross-border interconnections have an impact on at least two neigh-

[15] `http://www.roadmap2050.eu/`

bouring economies requires a fair share method to assign the responsibilities for investment costs, and to enable strategic coordination of TSOs. A source of this strategic value is the interaction between TSOs and market agents, GENCOs and consumer companies, as the TSOs must preempt electricity dispatch in both volumes, prices and network congestion. A further source of value is the cooperation required between neighbouring TSOs in realizing both the cross-border and the internal investments required to optimize social welfare. The topics of flexible and strategic decision-making are quite relevant for the integration process. Still, these are not currently receiving appropriate attention from the literature.

1.2 Research questions

The research outlined in this thesis addresses transmission system expansion issues relevant to the development of the European electricity market, as well as other regions considering market-coupling. Our work bridges three topics in transmission networks: transmission network expansion planning (TNEP), uncertainty, and the existence of multiple players under cooperation. Considering TNEP as a starting point, we look at the impact of uncertainty on investment decisions in the development of these infrastructures, and examine how two independent decision makers with conjoined transmission networks can reach agreements for the expansion of interconnections.

The key research questions addressed in the scope of this dissertation are the following:

1. **Expansion under uncertainty** What is the impact of uncertain parameters evolving in time, and the value of postponement and other sources of operational flexibility, in transmission network expansion planning?

2. **Cross-border cost allocation** What is the level of investment, and what is a fair share allocation of costs, in the expansion of an interconnection between two regions, when they cooperate to establish a voluntary agreement?

3. **Cross-border cost allocation under uncertainty** What is the impact of uncertainty and transmission network configuration on the level of investment, and the fair share allocation of costs, in the expansion of the interconnections between two regions, when they cooperate to establish a voluntary agreement?

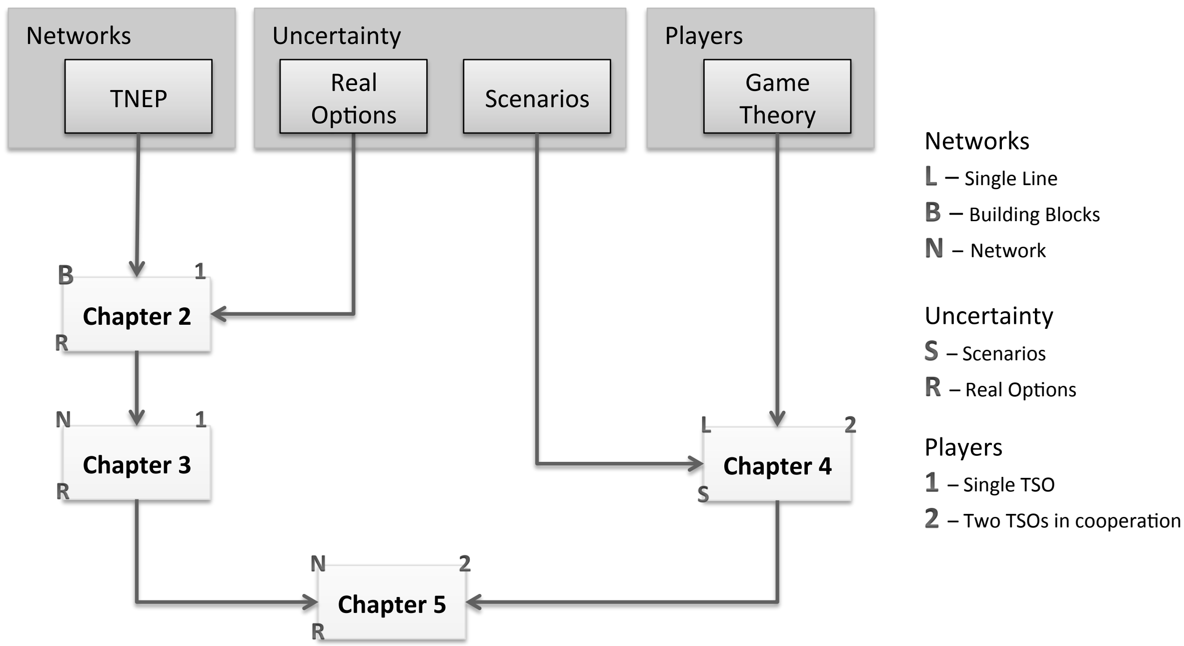

Figure 1.1: Thesis structure representing the relationships between the four studies of the thesis.

Our contributions to address these research questions are presented in four studies. The first research question is explored within our first two studies, Chapters 2 and 3. In a parallel line of research, we answer the second research question in a third study presented in Chapter 4. Lastly, for the third research question, a final study encapsulating both lines of research is included as Chapter 5. Figure 1.1 presents the relationships between the multiple parts of the thesis.

1.3 Thesis overview

In Chapter 2, we present, to the best of our knowledge, the first multi-stage transmission network expansion planning model under uncertainty where the multiple transmission line expansion possibilities are formulated as a portfolio of real options. We consider long-term uncertainty in electricity demand and study its impact in power transmission expansion planning, and the value of postponement and other sources of flexibility to address it. Specifically, in this study we introduce the overall framework used to integrate uncertainty and contingency into transmission planning, and apply it to study basic network building blocks (Delgado and Claro, 2013).

In Chapter 3, we expand the previous chapter with a more sophisticated modelling of uncertainties which also allows for a larger number of uncertain parameters, and a case study of the role of transmission expansion to improve renewable penetration in the Azores archipelago, taking advantage of the fact that some islands have a renewable power capacity surplus that could be made available to islands with a renewable capacity deficit.

In Chapter 4, we propose a new optimization model for two TSOs that must cooperatively decide on the investment in transmission capacity for a single interconnection line. This is achieved using Nash-Coase bargaining, with investment cost sharing as the key enabler. Flows between regions are obtained considering supply and demand curves, and a case application is developed for characteristic scenarios based on 2013 Iberian data.

In Chapter 5, we combine an improved transmission network expansion planning model, where electricity markets are also accounted for, with interconnection cross-border cost allocation using Nash-Coase bargaining under uncertainty modelled using Portfolios of Real Options. In this study, we revisit the Iberian case, considering a simplified transmission network, to study the impact of uncertainty and the value of postponement and other sources of flexibility on transmission investment sharing.

In Chapter 6, we provide a discussion of all major findings and future work.

Chapter 2

Capacity expansion in transmission networks using portfolios of real options

We adopt in this paper a perspective of portfolios of real options, to propose a mixed integer linear programming model for multistage transmission network expansion planning. The model is then used to analyze three fundamental network building blocks - an independent design, a radial design, and a meshed design - seeking to develop network design insights, in particular regarding the joint value of postponement and other sources of operational flexibility. The results clearly point to the importance of explicitly incorporating uncertainty, adopting a multistage perspective, and addressing complex interactions between different sources of flexibility, in the design of transmission networks.

2.1 Introduction

Energy network infrastructures, such as power or natural gas transmission networks, are long-term technology investments that play a critical supporting role for contemporary societies. Although this role should desirably be fulfilled in a stable manner, these network infrastructures are de-

This chapter was published as Loureiro et al. (2015)

signed, implemented and operated in a very complex and volatile industry context (Bhattacharya and Kojima, 2012). Furthermore, the challenges associated with the large uncertainties in the operating conditions that they will face throughout their long lifetimes (Merrill and Wood, 1991), are intensified by the fact that the financial values involved are extremely high, and the investments are irreversible (Felder, 1996).

In the specific case of the power transmission grid, uncertainty requires that planners carefully consider the trade-offs between incurring unnecessary capacity costs, in the case of overinvestment, and the inability to meet demand or to source from the cheapest power supplies, in the case of underinvestment (Cedeño and Arora, 2011).

An appropriate generic framework to conceptualize this type of investments is the capacity portfolio, i.e., a processing network with interdependent resource capacity decisions. Van Mieghem (2003) suggests this framework in his review of the literature on strategic capacity management, and stresses four important features of this type of investments: three highlighted by Dixit and Pindyck (1994) - irreversibility, uncertainty, and flexibility; and one added by the author - multidimensionality.

Felder (1996) suggested the use of options theory to address these features in electricity resource planning, but pointed to three difficulties in its application: (i) how to model the random process that determines the underlying asset's value; (ii) how to determine all options a particular project may eliminate and create; and (iii) how to combine the various options for a given project. The latter two are clearly related to the issue of multidimensionality.

To address this set of challenges in Transmission Network Expansion Planning (TNEP), we adopt in this paper a perspective of portfolios of real options, i.e., "combinations of multiple risky assets and multiple real options written on these assets subject to constraints" (Brosch, 2008). In this application, the multiple risky assets are the new transmission lines, and the constraints are the technical limitations that result from network configuration, power flow and losses. The multiple real options, however, are much more diverse and even difficult to itemize, and include not only the most immediate call options on demand above capacity (Birge, 2000) or options to delay (Dixit and Pindyck, 1994), but also several other operational sources of flexibility, such as switching options arising from multiple sourcing, component commonality or resource redundancy (Van Mieghem, 2003). To implement this application, we extend to a multi-period setting the mixed integer linear programming (MILP) model for TNEP under demand uncertainty of Delgado and Claro (2013). We contribute in this manner to advance the research on TNEP, which has directed its attention mainly to deterministic contexts or, if considering uncertainty, has either focused on one-stage or two-stage recourse versions of the problem, or neglected the value of flexibility and the interactions between options in approaches for multi-period settings.

In order to validate its applicability, and to search for network design insights, we use the model to study numerically three network building blocks: an independent network, a radial network, and a meshed network. Similarly to the study of Delgado and Claro (2013), this work is also inspired by the analysis of risk mitigation in newsvendor networks of Van Mieghem (2007). We study how uncertainty and demand correlation, together with network structure, change capacity investments, but go beyond those studies by extending the analysis to a multi-period setting.

The paper is organized as follows: Section 2 reviews previous research; Section 3 describes the mathematical programming formulation; Section 4 presents the case studies, the results of the numerical studies and their discussion; Section 5 contains conclusions and future work perspectives.

2.2 Literature review

TNEP involves making decisions on network capacity, i.e., where, when, how many, and what types of lines to construct, considering the contingent power flow (Latorre et al., 2003). Although the generic problem is multiobjective, an economic criterion is usually considered in the literature, with costs related to both capacity investment and power flow (Foroud et al., 2010; Maghouli et al., 2011). The generic problem is also stochastic, but is usually addressed assuming a deterministic context (Buygi et al., 2003).

A common simplification in computational models for TNEP is (direct current) power flow linearization, but the resulting formulations are still combinatorial, nonlinear and nonconvex (Latorre et al., 2003). The computational challenges of the problem have often led researchers to address it with metaheuristic approaches (da Silva et al., 2011). Alguacil et al. (2003) briefly review the work on exact and combined optimization-based approaches to TNEP.

Buygi et al. (2003) reviewed the scarce literature on TNEP under uncertainty, and identified four categories of probabilistic approaches: probabilistic load flow, probabilistic reliability criteria and scenario techniques, which are one-stage approaches, and decision analysis, a multi-stage approach whose application to complex settings such as networks becomes impractical and inefficient. Bustamante-Cedeño and Arora (2008) also review the very scarce literature on TNEP under uncertainty, describing one-stage or two-stage recourse approaches.

A distinction that is critical to our work is related to the static or dynamic nature of the settings for the problem (Latorre et al., 2003). We focus on dynamic settings, which have been addressed with multi-stage models, but mostly assuming deterministic conditions (Aguado et al., 2012).

Recent references for multi-stage deterministic settings are Rocha and Saraiva (2012), who apply discrete evolutionary particle swarm optimization to a nonlinear formulation, and Zhang et al. (2012), who propose a MILP formulation which includes linearized losses and generator costs, and security considerations.

Vasquez and Olsina (2007) apply real options valuation to a small set of transmission expansion strategies for a single corridor in a two-period setting, to highlight the value of flexibility. Chamorro et al. (2012) propose an optimization simulation model also for a single corridor, which can be used to assess specific expansion strategies. These two approaches however do not directly provide suggestions regarding the network capacity decisions laid out above. Maghouli et al. (2011) present a nonlinear multi-stage model with uncertainty incorporated through the use of scenarios, and three objectives: the expected net present value of total social costs, the maximum adjustment cost across the scenarios, and the maximum regret. The model however is not entirely dynamic, due to the fact that investment decisions in a specific state of nature are not contingent on its specific and unique past uncertainty and decision path. In the same line, Akbari et al. (2012) propose a stochastic multi-objective mathematical programming model, Liu et al. (2012) present a nonlinear multistage model with scenarios and two objectives - the expected lifecycle cost, and the conditional value-at-risk (Rockafellar and Uryasev, 2002) of social welfare - and Aguado et al. (2012) propose a MILP model with scenarios and maximization of social welfare as the objective.

Similarly to Delgado and Claro (2013), our work is also inspired by mathematical programming approaches to capacity investment under uncertainty in industrial networks (Ahmed et al., 2003; Claro and Sousa, 2012) and studies of newsvendor network models (Tomlin and Wang, 2005; Van Mieghem, 2007).

Portfolio approaches have been applied to other areas of energy planning. Bhattacharya and Kojima (2012) use portfolio optimization to illustrate the relative importance of renewable energy in electricity supply. Fuss et al. (2012) integrate a real options approach with portfolio optimization for a similar application. However, these approaches do not explicitly model time concerns or more complex technical interactions between the components of the portfolio. Huang and Wu (2008) also use portfolio risk analysis to plan electricity supply, considering time, but not an options perspective. The stochastic optimization methodology suggested by Svensson et al. (2009b), and applied by Svensson et al. (2009a) to investments in a pulp mill, is very close to our approach. We extend this type of analysis method to explicitly focus on network sources of flexibility and uncertainty.

2.3 Mathematical programming model

2.3.1 Notation for the transmission network

The transmission network comprises a set of buses $\mathcal{B}$, including a subset $\mathcal{B}_S$ of buses with power supply, a subset $\mathcal{B}_D$ of buses with power demand, and another subset of buses with neither supply nor demand.

The set of corridors $\mathcal{C}$ consists of all possible pairs of buses, except for identical pairs, with $\mathcal{C}_A \subseteq \mathcal{C}$ being the subset of corridors where expansion is allowed. Using a set $\mathcal{K}$ to distinguish between lines in a single corridor, $\mathcal{X} = \mathcal{C}_{\mathcal{A}} \times \mathcal{K}$ denotes the set of all lines in all corridors in the network, considering the two possible flow directions for each line. As a simpler notation for lines, we use the tuple $x = \{i, j, k\} \in \mathcal{X}$ to represent starting bus i, end bus j, and line k, and $y(x) = \{j, i, k\} \in \mathcal{X}$ for the opposite direction. $\mathcal{X}_i$ is the set of lines connected to bus i as a starting bus.

2.3.2 Binomial tree

We focus our treatment of uncertainty on demand, considered in many circumstances to be the key uncertainty in transmission network design. We model the evolution of the demand in bus i,

D_i, as a geometric Brownian motion (Marathe and Ryan, 2005), with μ_i as the trend, and σ_i as the standard deviation:

$$dD_i = \mu_i D_i dt + \sigma_i D_i dW_i, \quad i \in \mathcal{B}_D.$$

The joint evolution of demands, characterized with a correlation coefficients matrix ρ, is modeled with a binomial tree, following Cox et al. (1979), and considering path-dependency (Figure 2.1). For each demand, at each node, we consider up and down moves, so that with U demands, 2^U nodes immediately follow each node in the tree, leading to a set of nodes $\mathcal{N}$ with size

$$|\mathcal{N}| = \sum_{i=0}^{n} (2^U)^i.$$

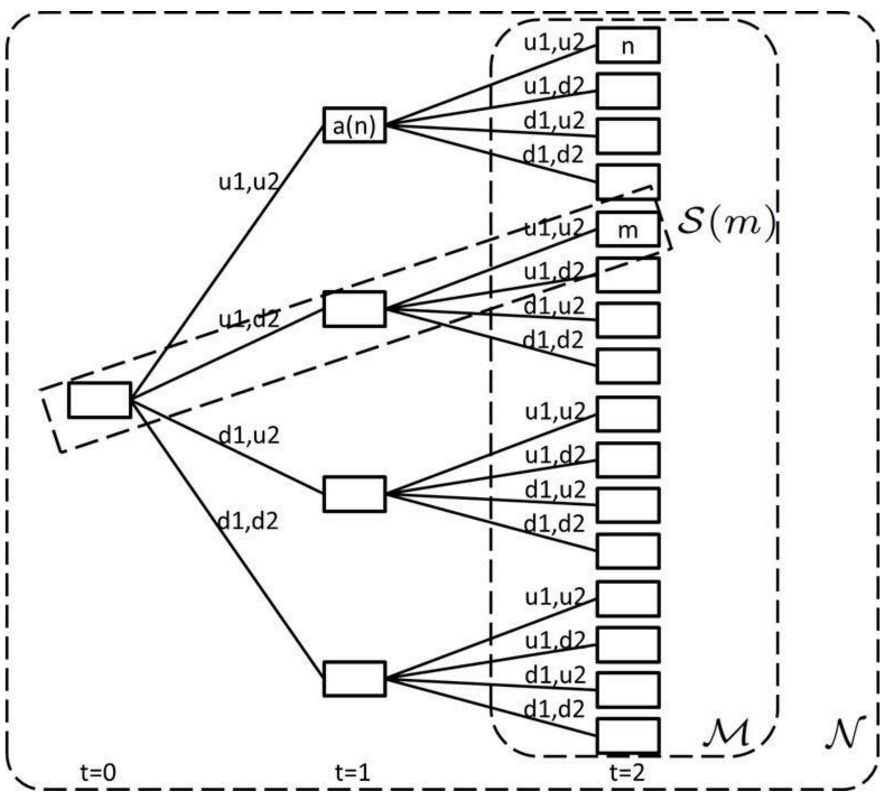

Figure 2.1: Path-dependent binomial tree for two underlying demands.

A scenario $\mathcal{S}(m) \in \mathcal{N}$ is a path in the tree, from the root node (node 0) to a terminal node m. The probability $Prob(m)$ of each scenario is computed by the joint probability of all nodes in its corresponding path. The node that precedes node n is denoted $a(n)$, and the time stage for a node n is indicated by $t(n)$, with zero as the time stage for the root node.

We then follow Brosch (2008) to obtain the up and down factors and the node probabilities:

$$u_i = e^{\mu_i \Delta t + \sigma_i \sqrt{\Delta t}}$$
$$d_i = e^{\mu_i \Delta t - \sigma_i \sqrt{\Delta t}}$$

$$\begin{aligned} p1 &= \frac{1}{4}\left[1 + \rho_{1,2}\right], \quad u_1, u_2 \\ p2 &= \frac{1}{4}\left[1 - \rho_{1,2}\right], \quad u_1, d_2 \\ p3 &= \frac{1}{4}\left[1 - \rho_{1,2}\right], \quad d_1, u_2 \\ p4 &= \frac{1}{4}\left[1 + \rho_{1,2}\right], \quad d_1, d_2. \end{aligned}$$

2.3.3 Objective

Our objective is to maximize the expanded net present value of the investment and operation of the network, i.e., the expectation of the present value of all net cash-flows in all the scenarios:

$$max \sum_{m \in \mathcal{M}} Prob(m) \left[\sum_{n \in \mathcal{S}(m)} \left[\frac{CF_n - I_n}{(1+r)^{t(n)\Delta t}} \right] + \frac{CF_m(1+g)}{(r-g)(1+r)^{t(m)\Delta t}} \right]. \quad (2.1)$$

The net cash-flow at a node n is obtained by subtracting the investment I_n from the operational cash-flow CF_n. Under risk-neutrality, the net cash flows are discounted using a fixed risk-free interest rate r and considering a time interval between stages Δt and the node's time stage $t(n)$. To account for the future exploration of the network, we also add a perpetuity component to each terminal node m, with a constant growth rate g.

The operational cash-flow in node n is expressed as

$$CF_n = \sum_{i \in \mathcal{B}_D} [(D_{i,n} - \Gamma_{i,n})\delta_i - \Gamma_{i,n}\gamma_i] - \sum_{i \in \mathcal{B}_S} E_{i,n} c_i \quad , n \in \mathcal{N}. \quad (2.2)$$

The revenues are obtained by the product of the price δ_i and the satisfied demand, i.e., the difference between the demand $D_{i,n}$ and the load curtailment $\Gamma_{i,n}$, in all demand buses. The costs are the opportunity costs of load curtailment, with a unit cost of γ_i, and the energy ($E_{i,n}$) costs, with a unit cost of c_i. We consider fixed prices and costs. These cash flows can be seen as a gain in social welfare that justifies the transmission system operator's investment in the expansion of the network.

Considering binary investment decision variables $\omega_{x,n}$, which take value 1 if line x is built in node n, the investment cost in node n, I_n, is the sum of the costs C_x of all the new lines:

$$I_n = \sum_{x \in \mathcal{X}} C_x \omega_{x,n} \qquad , \forall n \in \mathcal{N} \tag{2.3}$$

$$\omega_{x,n} = \{0, 1\} \qquad , \forall n \in \mathcal{N}, x \in \mathcal{X}. \tag{2.4}$$

2.3.4 Transmission network expansion planning constraints

We follow closely Alguacil et al. (2003) to develop the part of our model related to Transmission Network Expansion Planning. Using binary variables $\Omega_{x,n}$ that take a value of 1 if line x has been built in node n or previously, the current network configuration at a node n is given by considering for each line x the sum of previous and current investments:

$$\Omega_{x,n} = \Omega_{x,a(n)} + \omega_{x,n} \qquad , \forall n > 0 \in \mathcal{N}, x \in \mathcal{X} \tag{2.5}$$

$$\Omega_{x,0} = \omega_{x,0} \qquad , \forall x \in \mathcal{X} \tag{2.6}$$

$$\Omega_{x,n} = \{0, 1\} \qquad , \forall n \in \mathcal{N}, x \in \mathcal{X}. \tag{2.7}$$

Given a certain network configuration, the flows are then modeled through the following set of constraints:

$$E_{i,n} - (D_{i,n} - \Gamma_{i,n}) - \sum_{x \in \mathcal{X}_i} \left[f_{x,n} + \frac{1}{2} h_{x,n} \right] = 0 \qquad , \forall n \in \mathcal{N}, \quad i \in \mathcal{B} \tag{2.8}$$

$$f_{x,n} = -f_{y(x),n} \qquad , \forall n \in \mathcal{N}, \quad x \in \mathcal{X} \tag{2.9}$$

$$h_{x,n} = h_{y(x),n} \quad ,\forall n \in \mathcal{N}, \quad x \in \mathcal{X} \tag{2.10}$$

$$0 \leq E_{i,n} \leq E_i^{max} \quad ,\forall n \in \mathcal{N}, \quad i \in \mathcal{B}_S \tag{2.11}$$

$$0 \leq \Gamma_{i,n} \leq D_{i,n} \quad ,\forall n \in \mathcal{N}, \quad i \in \mathcal{B}_D \tag{2.12}$$

$$0 \leq h_{x,n} \leq F_x^{max}\Omega_{x,n} \quad ,\forall n \in \mathcal{N}, \quad x \in \mathcal{X} \tag{2.13}$$

$$f_{x,n} + \frac{1}{2}h_{x,n} \leq F_x^{max}\Omega_{x,n} \quad ,\forall n \in \mathcal{N}, \quad x \in \mathcal{X} \tag{2.14}$$

$$- f_{x,n} + \frac{1}{2}h_{x,n} \leq F_x^{max}\Omega_{x,n} \quad ,\forall n \in \mathcal{N}, \quad x \in \mathcal{X} \tag{2.15}$$

$$- (1-\Omega_{x,n})M^* \leq \frac{f_{x,n}}{B_x} + (\theta^+_{i,j,n} - \theta^-_{i,j,n}) \leq (1-\Omega_{x,n})M^* \quad ,\forall n \in \mathcal{N}, \quad x = \{i,j,k\} \in \mathcal{X}. \tag{2.16}$$

Constraints 2.8 are the power balance constraints, for every bus i and node n, which consider generation $E_{i,n}$, demand $D_{i,n}$, curtailment $\Gamma_{i,n}$, flows to and from other buses $f_{x,n}$, and losses $h_{x,n}$. Constraints 2.9 and 2.10 establish the relationship between the flows and losses in any line for a specific direction and its opposite. Constraints 2.11 are generation capacity constraints with limits E_i^{max}, and the natural limits for load curtailment are included through constraints 2.12. The transmission capacity constraints for each line, in each node, are established in constraint 2.13 for the total losses, and constraints 2.14 and 2.15 for the real power injection in the line, considering transmission capacities F_x^{max}.

Constraints 2.16 define, for each line and node, the lossless flow. If the line does not exist, they are non-binding, with a sufficiently large positive constant M^*. In the case that it does exist, the values of the lossless flows are obtained from these constraints, involving the angle difference for the corridor $\theta^+_{i,j,n} - \theta^-_{i,j,n}$ and the susceptance B_x, and considering in this way the linearization of the sine function and the product of investment and flow variables (Alguacil et al., 2003).

A final set of constraints computes and linearizes losses:

$$0 \leq -\frac{h_{x,n}}{G_x} + \sum_{\ell=1}^{L} \alpha_{i,j}(\ell)\theta_{i,j,n}(\ell) \leq (1-\Omega_{x,n})M^{**} \quad ,\forall n \in \mathcal{N}, \quad x = \{i,j,k\} \in \mathcal{X} \tag{2.17}$$

$$\sum_{\ell=1}^{L} \theta_{i,j,n}(\ell) = \theta^+_{i,j,n} + \theta^-_{i,j,n} \quad ,\forall n \in \mathcal{N}, \quad (i,j) \in \mathcal{C}_A \tag{2.18}$$

$$\theta_{i,n} - \theta_{j,n} = \theta^+_{i,j,n} - \theta^-_{i,j,n} \quad ,\forall n \in \mathcal{N}, \quad (i,j) \in \mathcal{C}_A \tag{2.19}$$

$$0 \leq \theta_{i,j,n}(\ell) \leq a_{i,j} + (1 - \Omega_{x,n})M^* \qquad , \forall n \in \mathcal{N}, \quad x = \{i,j,k\} \in \mathcal{X}, \quad \ell \in 1, ..., L \tag{2.20}$$

$$\theta^+_{i,j,n} \geq 0 \qquad , \forall n \in \mathcal{N}, \quad (i,j) \in \mathcal{C}_A \tag{2.21}$$

$$\theta^-_{i,j,n} \geq 0 \qquad , \forall n \in \mathcal{N}, \quad (i,j) \in \mathcal{C}_A \tag{2.22}$$

$$\theta^{ref} = 0. \tag{2.23}$$

Constraints 2.17 define the linear approximations of line losses, considering a sufficiently large positive constant M^{**}, conductance G_x, and L piecewise linear blocks, each block ℓ having a slope $\alpha_{i,j}(\ell)$ and angle block $\theta_{i,j,n}(\ell)$.

The absolute values of angle differences for each corridor are determined in constraints 2.18, and the differences between the angles at each bus, $\theta_{i,n}$ and $\theta_{j,n}$, in constraints 2.19. Constraints 2.20 establish lower and upper ($a_{i,j}$) limits for the contribution of each angle block to the total angle difference, for each line and node.

2.4 Case studies

2.4.1 Network building blocks

We apply the model presented in the previous section to three case studies of building blocks for networks, which feature fundamental themes for network design under uncertainty (Delgado and Claro, 2013): an independent network, a radial network, and a meshed network. These building blocks are presented in Figure 2.2, with nodes representing buses and arcs representing corridors. D1 and D2 are the demand buses, and S is the supply bus. The figure also includes the index for the buses, with values $1-4$. Each corridor is denoted by the pair of index values of the buses that it connects.

The independent network is the base case, featuring two corridors that are independent in operational terms. The radial design includes a shared corridor upstream from the two dedicated corridors, introducing two forms of operational flexibility (Van Mieghem, 2007): demand-pooling due to compensating fluctuations of the two demands, and the option to prioritize the demand with higher margin. The meshed design also includes a shared corridor, but downstream from the ded-

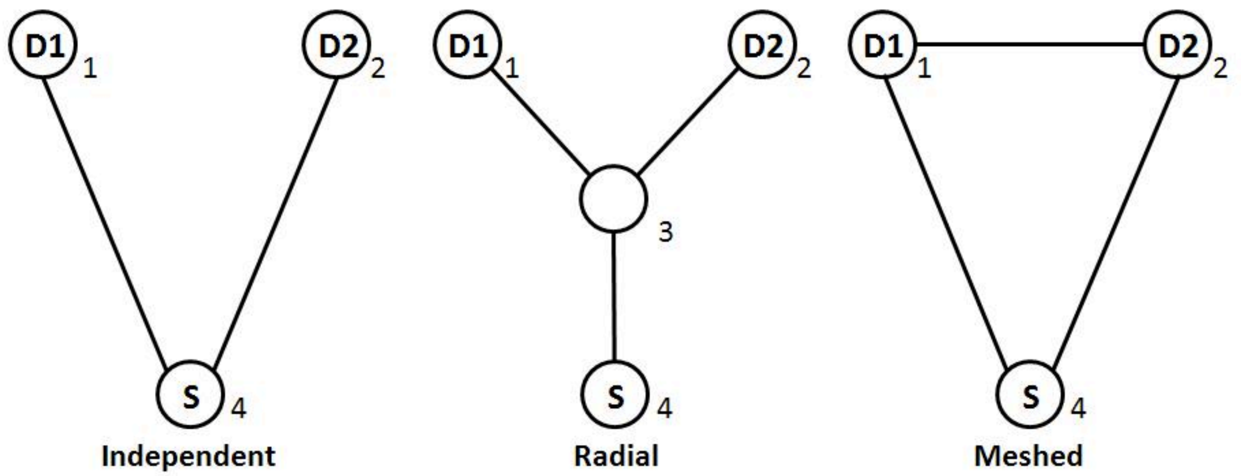

Figure 2.2: Network building blocks.

icated corridors, connecting the two demand buses, and resulting in a very versatile configuration: its optimization can yield an actual meshed network (with the shared resource providing flexibility benefits), an independent network (in case of no investment in the shared corridor), or a radial network (in case of no investment in one of the dedicated corridors).

In both radial and meshed designs, power flow in the shared corridors will have as a downside increased losses, as the total transmission distance from the supply bus to the demand bus will be higher. We consider constant lengths for the corridors between supply and demand buses across the network building blocks: 500 km for corridors $(1,4)$ and $(2,4)$, and 200 km for corridor $(1,2)$. Equal lengths for corridors $(1,4)$ and $(2,4)$ allow for symmetric results, and a lower length for corridor $(1,2)$ allows for additional value for the meshed design (Van Mieghem, 2007).

In the case of the radial design, we consider the independent design as a particular extreme case where the length of the upstream corridor is null, as well as three possible lengths for the upstream corridor $(3,4)$: 150, 300 and 450 km. In these three possibilities, corridors $(1,3)$ and $(2,3)$ will feature lengths of 355, 215 and 110 km, respectively. These alternative positions for the intermediate bus force the radial design to be at least as good as the independent design.

The upper limit on each angle block is $\pi/32$, and the slope for block of angles l is $(2l-1)\,\pi/32$. The capacity for all the lines is set at 1.0 p.u.. The resistance and the reactance for the lines in the dedicated corridors are 0.036 p.u. and 0.258 p.u., respectively. For the lines in the other corridors, the values of resistance and reactance are proportional to their lengths. The financial margins in both demands are equal, and are approximately 33% higher than the annual perpetuity for the investments in the independent corridors. The curtailment costs are also equal and set very high at a value approximately 33 times higher than the annual perpetuity for the investments in the independent corridors.

2.4.2 Scenario tree

The binomial tree has two time steps, and reflects a long-term planning schedule, with a Δt of 5 years. We define both μ_1 and μ_2 as 5%, the discount rate as 5%, and for the perpetuity we assume a 0% growth rate. The initial values for both demands are 1.0 p.u.. The standard deviations for both demands are also equal, and are described as proportions of the expected value, with four different levels considered: 0.00, 0.10, 0.20, and 0.30. It should be stressed that the 0.00 standard deviation case corresponds to a deterministic scenario. We also consider five levels for their correlation coefficient: $-1.0, -0.5, 0.0, +0.5$ and $+1.0$.

Figures 2.3 to 2.6 present, in a tabular format, data in scenario trees. The structures of the scenario trees considered in all these figures are the same as the structure presented in Figure 2.1. The table cells will hold different data, according to the figure, but in all figures the cell to the left contains the data for the root node of the scenario tree, the four middle cells for the four nodes in time stage 1, and the final 16 cells for the 16 nodes in time stage 2. The four cells immediately to the right of a cell correspond to the four children nodes of a node in the scenario tree, and the evolution of the uncertain parameters in the table follows exactly the evolution depicted in Figure 2.1.

Figure 2.3 presents the conditional probabilities for the nodes of the scenario tree, for the five distinct levels of the demand correlation coefficient, and Figure 2.4 shows the two demands in the nodes of the scenario tree, for different levels of standard deviation.

2.4.3 Results and discussion

To highlight the impact of operational flexibility and the intrinsic value of the network design, we present a first set of results for the case of no postponement flexibility, i.e., when all investments must occur at time stage 0.

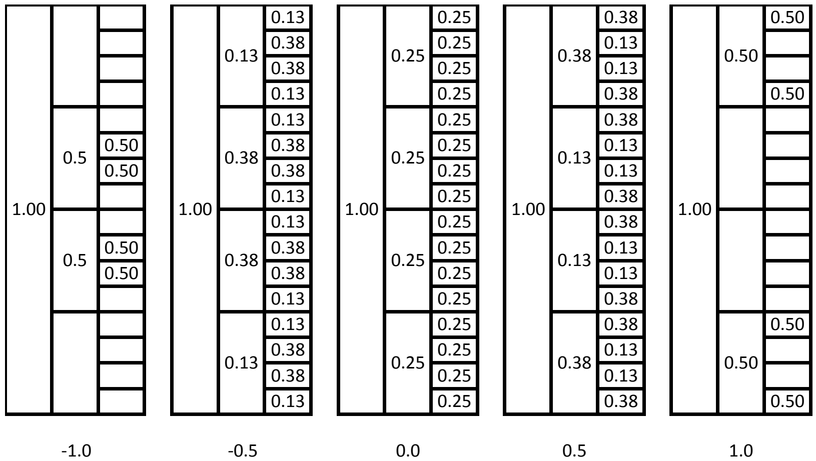

Figure 2.3: Probabilities in the scenario tree, as a function of the correlation coefficient.

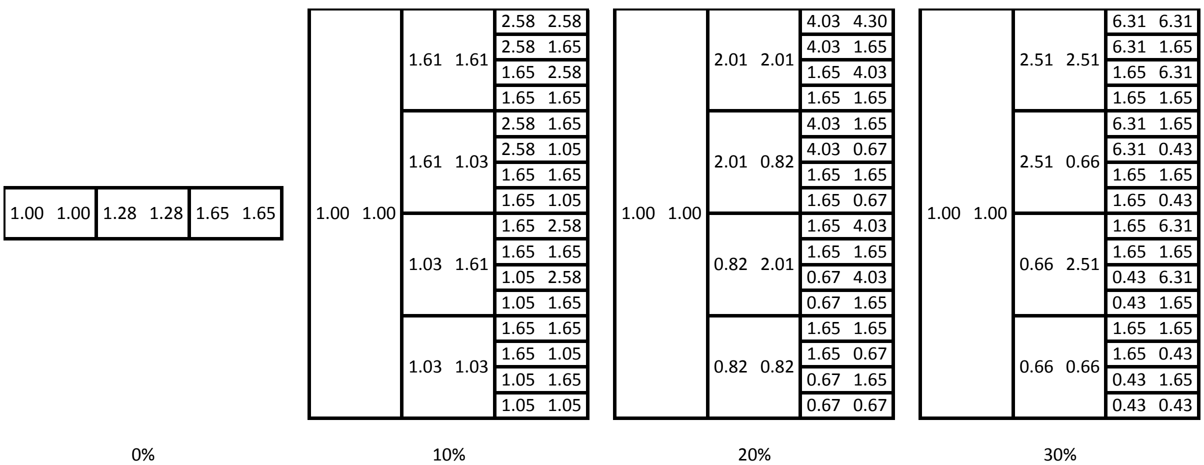

Figure 2.4: Demands in the scenario tree, as a function of the standard deviation.

In Figure 2.5 we include the expansion in number of lines for each corridor, for each of the three network building blocks, and crossing the different levels of the standard deviation and the correlation coefficient. The values are, from left to right, the expansion in the dedicated corridor that serves demand 1, then in the dedicated corridor that serves demand 2, and finally, for the radial and meshed design, in the shared corridor.

As observed in previous studies of newsvendor networks (Van Mieghem, 2007), the overall levels of investment increase with standard deviation, due to the higher importance of the margin and the costs of curtailment, relative to the costs of investment. The value of operational flexibility is clearly visible in the radial design, where the benefits from the pooling of demands in the upstream corridor lead to a lower investment being required for lower correlation coefficients. The results

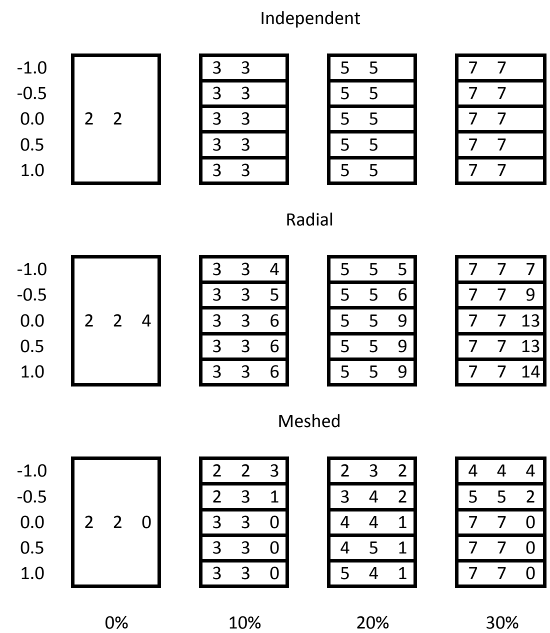

Figure 2.5: Evolution of network investment with standard deviation (columns) and correlation (lines), without postponement flexibility.

for the meshed design also show clearly the value of operational flexibility, with lower correlation coefficients featuring higher investments in the shared downstream corridor, which enables the use of both upstream dedicated corridors to be able to supply any of the two demands.

Without constraining the investments to time stage 0, the impact of postponement flexibility now becomes visible. The corresponding results are displayed in Figure 2.6. In the figure, we do not distinguish among levels of correlation due to the fact that, for the set of parameters that we consider in these case studies, the configuration of investments does not change with correlation. Investments tend to take place as late as possible, leading to network configurations that are in general very different from those obtained without postponement flexibility, and hardly make use of operational flexibility.

The benefits of operational flexibility however are still present. For the radial design, Figure 2.7 suggests increased value for higher standard deviations and lower correlations. In fact, at lower correlations the variability of the total demand is also lower, and in particular in the later transitions from time stage 1 to time stage 2, this leads to less overcapacity when the total demand decreases from one time stage to the next.

For the meshed design, in the final time stage there is investment in the shared downstream

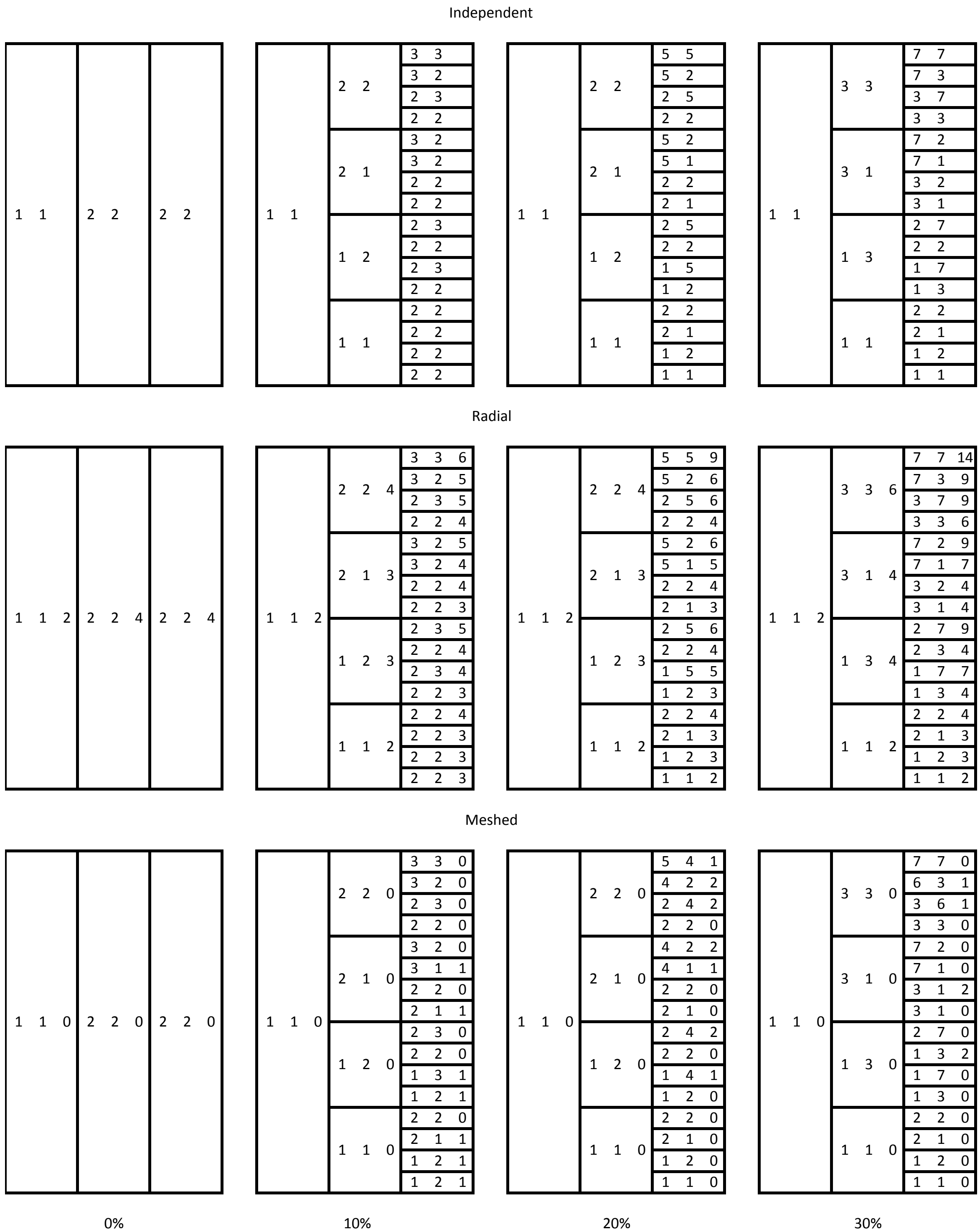

Figure 2.6: Evolution of network investment with standard deviation (columns), with postponement flexibility.

corridor in some scenarios. In this design the investment in the dedicated corridors creates the option to expand the supply to one of the demand buses by solely investing in the downstream

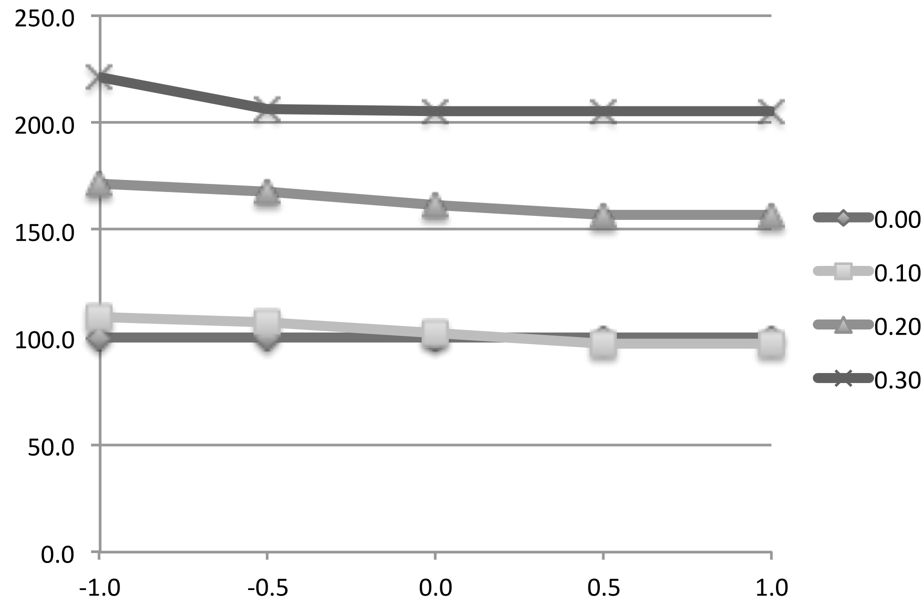

Figure 2.7: Evolution of the expanded net present value of the radial design with correlation (horizontal axis) and standard deviation (lines), with postponement flexibility (base 100 is the net present value of the optimal independent design under deterministic conditions).

corridor, which may be exercised in the case of a significant reduction in the other demand.

In Figure 2.7 there is also a clear example of the value of flexibility to address uncertainty, as for standard deviations of 0.20 or above, the expanded net present value of the project is more than 50% higher than the net present value under deterministic settings.

2.5 Conclusion

In this paper we propose a model for multistage investment in transmission networks under uncertainty, and use it to analyze the design of a set of fundamental network building blocks. Although our model can be used as a basis to provide specific recommendations to address real situations, that is not our aim in this paper. Instead we seek to develop insight on the value of postponement and other sources of operational flexibility to address uncertainty in the construction and operation of networked infrastructures.

Our results confirm the value of operational sources of flexibility, in our case studies related to the shared upstream and downstream transmission corridors, to address uncertainty in multistage investment settings. In addition, they show that postponement flexibility and the above forms of operational flexibility are to a certain point substitutes, but that they also interact in more subtle ways. In particular, we observed that in face of investment irreversibility, demand pooling is still able to bring additional benefits on top of postponement, and that due to path dependency, investments in some parts of the network in earlier periods may add value to investments in other parts of the network in later periods.

These results clearly point to the importance of explicitly addressing uncertainty in the design of transmission networks. They also show the value of considering multiple stages in the analysis, in order to effectively incorporate postponement flexibility, and using an analysis framework that addresses complex interactions between multiple sources of flexibility, to improve the design of networked infrastructures. Our model extends previous work to enable this improved analysis framework, and our analysis is an initial exploration of the impact of interactions between multiple sources of flexibility in networked infrastructures in multistage settings.

Future work with this type of analysis may allow the development of further insight, with the potential to improve the decisions of network planners in managerial or policy analysis contexts. Relevant future work could thus be directed to more thorough computational experiments, to the analysis of the impact of risk aversion, to the incorporation of generation and market operation decisions, and to the integration of distributed decision-making, which is also a key theme in network design.

Acknowledgments

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Chapter 3

Renewable integration through transmission network expansion planning under uncertainty

In this paper we bring together a stochastic mixed integer programming model for Transmission Network Expansion Planning, incorporating portfolios of real options to address the evolution in time of uncertain parameters, with the Adjusted Generalized Log-Transformed model, to expand the number of correlated parameters that can be modeled. We apply these methods to evaluate the potential contribution of underwater transmission investments to increase renewables penetration in the Azores archipelago. The approach also includes expansion lead times, due to the large timespans involved in the construction of new transmission lines. Our analysis focuses on a set of the four closest islands in the archipelago, Pico, Faial, S. Jorge and Terceira, and shows that even though investments are delayed and the future network configuration varies according to the evolution of renewable generation scenarios, an investment in underwater transmission, if technically feasible, within the assumptions of our model, could in fact contribute to increase renewables penetration, by enabling islands with an excess in generation from renewable sources to supply other islands in a deficit situation.

3.1 Introduction

Contemporary societies are highly dynamic, constantly challenging their energy infrastructures and requiring adjustments in generation and transmission networks. Electricity demand often exhibits significant shifts, driven by factors such as population dynamics or consumer habit changes. The evolution of supply, in turn, greatly depends on aspects such as available generation capacity, alternatives for expansion, costs of generation technology, or environmental concerns. In this sense, the transmission system seeks to optimally satisfy consumers by allowing demand to be reliably fulfilled at a minimum generation cost.

The prosecution of this goal periodically leads to the identification of beneficial investments in transmission lines, but these infrastructure developments can not be viewed simplistically as commitments in static contexts. Decisions on the timing, scale, location and type of capacity expansions need to consider how to best adjust to uncertainty (Davis et al., 1987), as they usually involve significant irreversible investment costs, feature initial long lead times related to construction, and then typically face uncertain circumstances to unfold throughout their long lifetimes. The ability to perform well under diverse and changing circumstances is thus a key requirement for transmission networks, and one that can best be addressed when sources of flexibility, i.e., real options (Dixit and Pindyck, 1994), are explicitly considered in long-term planning.

Engineering practice is typically focused on designing for specifications. From a traditional risk-management perspective, a project is seen as successful if it complies with expectations defined beforehand. This view, however, is myopic as it takes risk merely as the probable occurrence of negative outcomes, thus capping specifications to escape uncertainty and neglecting potential value from overdesign. In large-scale projects, such as electricity transmission networks, the magnitude of these uncertain costs and benefits can be significant, and their public impact considerable. Therefore, engineering systems design should, take a more holistic view of risk, which is common in finance, not only considering the chance of downsides, but also weighing in the positive outcomes that may result from exposure to risk.

Considering the limitations previously described, portfolios of real options emerge as an interesting approach to analyse investments in a transmission network.Brosch (2008) defines portfolios of real options as *"combinations of multiple assets and multiple real options written on these as-*

sets subject to constraints". Applying this definition to the transmission investment problem, the transmission lines are the multiple risky assets, the flexibility in the investments and in the use of the transmission lines translates to the multiple real options, and the physical characteristics of the network, influencing power flows and losses, establish the constraints.

In this paper, we adopt the perspective of a single Transmission System Operator (TSO) facing generation capacity uncertainty in a regulated context, with the ability to choose a single set of expansion decisions in the present, and contingency expansion decision plans for the future, considering potential alternative unfoldings of events. This is achieved by studying different future possible scenarios based on the evolution of uncertain parameters, and by using a decision process that weighs the consequences of decisions based on the probabilities of occurrence of the scenarios. This decision structure differs from the majority of current multi-stage models, whose outcome is a static investment plan, as in the case of Monte Carlo simulation-based approaches, which often consider multiple scenarios, but a single sequence of decisions.

We extend the work previously reported by two of the authors on a stochastic mixed integer linear programming (MILP) model for transmission planning (Loureiro et al., 2015), which was presented in the previous Chapter. The model consists of an expansion of an earlier single-stage model (Delgado and Claro, 2013) to a multi-period setting, using portfolios of real options (Brosch, 2008), and including contributions from capacity expansion (Ahmed et al., 2003) and transportation network design (Chow and Regan, 2010) research. Driven by practical concerns, we now extend that work to include a higher number of stochastic parameters. The method of Gamba and Trigeorgis (2007) allows us to increase the number of stochastic parameters to more than two. Moreover, we incorporate expansion lead times in the model presented herein to address the significant timespans involved in the construction of new transmission lines.

We apply this improved model to the analysis of transmission expansion in the Azores archipelago, in the scope of its efforts to reduce dependency on fossil fuels. The Regional Government of the nine-island archipelago, located off the Portuguese coast towards the middle of the Atlantic, has defined a goal of 75% for electricity generation based on renewable sources, to be achieved by 2018 (MIT-Portugal, 2010). However, the renewable potential differs among islands, leading to energy imbalances. While some remain in deficit, others not only will be self-sufficient, but in fact have the capacity to generate a surplus. Thus, this surplus could be used to improve the overall utilization of renewable electricity in the archipelago, if the excess power could be transferred between islands. We analyze this scenario, focusing on the possibility of using underwater transmission lines to connect four of the islands, and considering the joint behavior of their stochastic demands. To this effect we look at two different cases. First, we use estimated data, including the high correlations between renewable generation capacity evolution. Secondly, we consider uncertainty but assuming that these evolve without correlation. These solutions are compared to stress the differences between transmission expansion contingency planning with the aim of increasing renewable penetration.

The paper is organized as follows: Section 3.2 presents a review of prior literature on electricity transmission network expansion planning; Section 3.3 describes the methodology used; Section 3.4 introduces the case of the Azores islands and describes the data; Section 3.5 presents the results of the numerical study and sensitivity analyses; Section 3.6 closes the paper with conclusions and future work perspectives.

3.2 Literature review

It has long been asserted that transmission system expansion is a key enabler of renewable energy integration (Munoz et al., 2014). Much work in this field has focused on expanding transmission networks to remote areas with substantial renewable resources. The National Renewable Energy Laboratory's (NREL) four-year study on wind integration in the United States Eastern Interconnection found that high penetrations of wind power (20 - 30% of demand) require significant investment in new transmission capacity (Renewable Energy Laboratory , NREL). A similar massive modeling effort was commissioned by the European Union around the same time, and carried out by the EU transmission system operators (ENTSO-E, 2010b). The European Wind Integration Study identified 150 transmission projects within the EU that would be needed, to support wind integration. Out of that number, 35 projects were identified as essential for the sole purpose of integrating renewable energy into the EU power system (as opposed to congestion management) (ENTSO-E, 2010a).

Few studies, however, have used optimal transmission network expansion planning (TNEP) models to validate its relation to increased renewable energy production. Recently, several authors have included various uncertainties facing transmission planners into their optimal TNEP problem. For example, van der Weijde and Hobbs (2012) model a game between the transmission planners and the generating firms, considering uncertainties and the possibility to delay investments. They conclude that optimal transmission plans change dramatically when uncertainty is ignored. For a stylized case study of the Great Britian transmission system, they show that the cost of ignoring uncertainty ranges from 4 million pounds sterling to 111 million. In a similar vein, Munoz et al. (2012) add the cost of uncertainty with wind power production using a reserve market constraint and show the effect wind uncertainty has on the transmission expansions. Both studies, however, assume the addition of new renewable generation capacity. To the best of the authors' knowledge, this study is the first to demonstrate that transmission expansion itself increases renewable production in the power system, with neither specific regulation requiring this, nor new renewable generation investments.

Currently, wind is considered the most cost-effective source of renewable energy and with the least greenhouse gas emissions, but also the one with most variable output (Energy Information Administration, 2015). This volatility introduces complexity into modeling optimal integration of renewable energy into the electricity system, particularly when also considering optimal expansion of the transmission system. Uncertainty in renewable power generation is typically included in power system modeling via historical production information (Konstantelos and Strbac, 2015; Munoz et al., 2014), with generation predictions on an hourly timescale. Less common is an annual capacity factor approach to approximate renewable energy production (You et al., 2016). In this paper, we adopt a novel approach for inclusion of renewable generation uncertainty as an aggregated stochastic process. To the best of the author's knowledge, this representation of renewable generation uncertainty has not been used before in transmission expansion planning, though a recent paper on optimal, short-term dispatch adopts a similar uncertainty representation (Rajagopal et al., 2013).

Transmission Network Expansion Planning (TNEP) is a class of problems concerned with the identification of optimal decisions on the size, time, location and type of transmission line investments (construction or upgrade), considering the physics of power flows as well as relevant economic aspects, in varying degrees of complexity as suitable to the envisaged applications. TNEP literature is reviewed in Latorre et al. (2003) and Hemmati et al. (2013). Nonetheless they both fall short in categorizing uncertainty as the relevance of investment decisions under uncertainty with explicit consideration of a contingency plan. Within the present section we argue in favor of models with these characteristics.

Traditional approaches to solve TNEP addressed network expansion decisions in static settings, aiming at removing overloads (Garver, 1970) or reducing them to meet an acceptable minimum reliability threshold (Kaltenbach et al., 1970). To facilitate optimization, reliability has, in some approaches, been substituted by load curtailment costs (Gallego et al., 1997). Load curtailment can be viewed as the amount of energy demand that the network will not be able to satisfy, and its costs can be viewed as monetized social costs for under-design. On the other hand, a higher accuracy in the calculation of power flows has been achieved with the inclusion of transmission losses (Alguacil et al., 2003).

Another line of research has focused on dynamic settings, extending the above-mentioned approaches to address the evolution of TNEP parameters in time, considering the possibility of postponing expansions, in multi-period versions of TNEP. An early contribution by Dodu and Merlin (1981) featured continuous investment variables, constrained only by Kirchhoff's current law. More recent contributions in this line of work are da Silva et al. (2011), Rocha and Saraiva (2012), and Zhang et al. (2012).

Transmission system operators are exposed to a considerable number of uncertain factors in their activity, including demand evolution, generation costs, investment costs, discount rates, and availability of system components, among others (Blanco and Olsina, 2011). Explicitly addressing these uncertainties is relevant, due to the impact that they may have on the value of investments in transmission capacity expansion, the ability of the network to satisfy demand from the most desirable sources, as well as the network configuration itself. As stated by Bustamante-Cedeño and Arora (2008), *"ignoring uncertainty in system design, particularly when it is significant and costs for over designing and under designing are substantially different can lead to sub-optimal design decisions."*

A possible way to address these challenges is to use approaches developed for deterministic settings with expected values for the uncertain parameters. In general, the presence of nonlinearities, as in the case of TNEP, leads optimal solutions obtained with expected value formulations to differ significantly from the optimal solutions for the stochastic formulations, a situation known as *flaw of averages* (Savage, 2002; de Neufville and Scholtes, 2011). Appropriate exploration of the design space and appraisal of solutions must take into account the potential benefits of better than expected outcomes, besides avoiding possible downsides. Decision models should, therefore, incorporate a holistic perspective of risk, reflecting potential losses together with opportunity costs of missed upsides.

Nowadays, there is a general consensus in the literature on the importance of transmission network planning incorporating uncertainty.Nadira et al. (2003) have proposed a scenario-based model for TNEP, with uncertainty in the location of new power generators, and a step-by-step approach to determine expansion decisions. Additionally, Bustamante-Cedeño and Arora (2008) and Cedeño and Arora (2011) have addressed stochastic demand and generation costs with a model for optimal present time decisions, taking place before the realization of different possible future scenarios. Finally, Delgado and Claro (2013) have built on this approach to study the impact of demand uncertainty and risk-aversion on investment decisions in network building blocks.

These models, however, do not consider the evolution in time of TNEP parameters (Latorre et al., 2003). A longer-term longitudinal perspective is important, in particular due to the fact that network investment decisions will most likely differ between static and dynamic stochastic settings. In this vein, Silva et al. (2006) note that higher investments are expected under dynamic settings. Munoz et al. (2015) reinforce this claim stating that without the possibility of delaying expansions of the transmission system, we should expect *"overly conservative"* solutions. Thus contingency plans, the set of decisions that are dependent on the unfolding of uncertain sequences of events, become relevant in these contexts (Wang and de Neufville, 2004).

A substantial part of the literature on multi-period TNEP under uncertainty does not feature contingency plans, and instead considers a single multi-stage investment plan across all the scenarios. Foroud et al. (2010), Maghouli et al. (2011), Akbari et al. (2012), Liu et al. (2012), and Aguado et al. (2012) are references in this category. The first four works are also multiple objective approaches, focusing on criteria that include investment costs, load shedding, loading factor, congestion costs and reliability.

Given the modelling and computational challenges that multi-period investments under uncertainty present, some authors have focused their analyses on expansion decisions for single transmission lines instead of networks. Chamorro et al. (2012) have proposed a stochastic model to value single transmission lines under a significant number of uncertain variables, and Deng et al. (2001), Pringles et al. (2014), and Pringles et al. (2015) have developed *real options* models that consider the possibility of deferring investments.

Real options are rights over investment decisions that (1) are irreversible, (2) have at least some leeway regarding their timing and dynamics, and (3) have values that change depending on uncertainties (Dixit and Pindyck, 1994). In such contexts, the decision-maker has the flexibility, i.e., the right but not the obligation, to develop (exercise) the project, delay it, or discard it, according to the value of that flexibility. Transmission network expansions can be viewed as investment decisions over transmission lines between different pairs of buses. For each single transmission line investment decision, the three components of the above real options definition apply: (1) the investments are irreversible, as most of their value would be sunk if they were to be removed; (2) the decision maker may invest or not, do it sooner or later, and choose among different types of transmission lines; and (3) the value of the investments may depend on a number of uncertainties, as already pointed out. Fernandes et al. (2011) provide a review of applications of real options to energy investments.

Only recently, we are filling the research gap, and we are seeing the development of TNEP models that represent stochastic multi-stage formulations with contingency plans. To the best of our knowledge, the contemporary works of Loureiro et al. (2015) and Konstantelos and Strbac (2015) are the only references on TNEP with contingency plans. Loureiro et al. (2015) adopts portfolios of real options as the framework to address this category of problems. Using a similar reasoning, Konstantelos and Strbac (2015) develop a stochastic model that also includes investment decisions on phase-shifter and storage device introduction while guaranteeing the N-1 security criterion is met.

The usage of terms portfolios of real options and stochastic programming, this one used in the latter reference, are distinct in that portfolios of real options is a perspective on multiple real options modeled using stochastic programming. This definition is aggravated as standard option theory only considers already identified real options (Wallace, 2010) and their itemization is challenging (Van Mieghem, 2007). They include not only the most immediate call options on demand above capacity or options to delay, but also several other operational sources of flexibility, such as switching options arising from multiple sourcing, component commonality or resource redundancy.

Thus, it is our understanding that even though it is not named in that way, Konstantelos and Strbac (2015) also model a portfolio of real options, as its definition, given above, is also met.

Table 3.1: TNEP literature grouped by treatment of uncertainty, investment scope and timing of investment decisions.

<table>
<tr><th rowspan="3">Treatment of uncertainty</th><th rowspan="3">Investment scope</th><th colspan="3">Timing of investment decisions</th></tr>
<tr><th rowspan="2">Single stage</th><th colspan="2">Multi-stage</th></tr>
<tr><th>No contingency</th><th>Contingency</th></tr>
<tr><td>Deterministic</td><td>Network</td><td>Garver (1970)
Kaltenbach et al. (1970)
Gallego et al. (1997)
Alguacil et al. (2003)</td><td colspan="2">Dodu and Merlin (1981)
Rocha and Saraiva (2012)
Zhang et al. (2012)
da Silva et al. (2011)</td></tr>
<tr><td rowspan="2">Stochastic</td><td>Corridor</td><td>Chamorro et al. (2012)</td><td>Deng et al. (2001)
Pringles et al. (2014)
Pringles et al. (2015)</td><td>-</td></tr>
<tr><td>Network</td><td>Delgado and Claro (2013)
Bustamante-Cedeño and Arora (2008)
Nadira et al. (2003)
Silva et al. (2006)</td><td>Aguado et al. (2012)
Foroud et al. (2010)
Akbari et al. (2012)
Maghouli et al. (2011)
Liu et al. (2012)</td><td>Loureiro et al. (2015)
Konstantelos and Strbac (2015)</td></tr>
</table>

We present in Table 3.1 a summary of the reviewed TNEP literature, with a categorization according to treatment of uncertainty, investment scope, and timing of decisions.

3.3 Methodology

3.3.1 Portfolios of real options

From a portfolios of real options perspective, the optimal transmission network expansion plan includes the set of investment decisions that maximizes the total portfolio value. This is in contrast with other approaches that conduct this type of analysis focusing on individual real options. For example, a basic radial configuration of a transmission network, supplying two distinct demand buses from a single generation bus, through a single shared upstream corridor splitting downstream into two dedicated corridors, could be analyzed with either approach. However, an individual analysis of each of the three corridors, would not take into consideration, for instance, the operational dependence that results from the fact that the upstream and the downstream corridors act as mutual bottlenecks, or the existence of an ex post cost minimization option (Van Mieghem, 2007). In general, in the presence of interactions among assets, real options and constraints, the larger the set of potential configurations, the more complex and unpredictable becomes the portfolio dynamics. As new options are added to a portfolio, its value increases but generally in a subadditive way (Trigeorgis, 1993).

Determining the optimal transmission network expansion plan in such settings faces important challenges. In detail, decisions are usually contingent on each other, requiring path-dependency to be considered and precluding the application of backward induction, and the exponential growth of computational requirements with problem size.

The impossibility of using backward induction arises from the cumulative nature of installed capacity. All investment decisions in the nodes of the subtree of a certain node depend on the investment decisions in that node. As a consequence, in general, all investment decisions in all nodes depend on all other investment decisions in all other nodes, which requires evaluating the tree as a whole.

Four drivers contribute to the exponential growth of the size of the problem: investment alternatives, real options, uncertain parameters, and time stages. The way as the first two influence the complexity of the problem highly depends on its structure. As for the number of uncertain parameters U and the number of time stages T, they determine the number of nodes of the tree, considering that at each node of each time stage t each uncertain parameter evolves into two new nodes, such that $|\mathcal{N}| = \sum_{t=0}^{T}(2^U)^t$. The increase in computational complexity caused by the interdependences between all decision nodes and the existence of multiple stochastic demands is significant. Therefore, we limit our analysis to instances with two future time stages and four stochastic demands, for which the total number of decision nodes is 273, with 256 nodes in the final time stage.

3.3.2 Multidimensional binomial tree with correlation

Real options numerical models started to acquire relevance with the seminal work of Cox et al. (1979), who suggested an approach that divides time in discrete steps. With two new possible outcomes generated at each step for each of the outcomes in the preceding step, a binomial tree with probabilities is assigned to the outcomes based on the behavior of the uncertain parameter.

In problems with more than one uncertain parameter, modeling perfect correlation or independence is straightforward: for the former, the binomial tree for any of the parameters may be used, with values for all the other parameters computed from their relationships with that parameter; for the latter, the binomial trees for each parameter can be developed independently and used to generate all possible combinations of outcomes in each time step, with the probability of each joint outcome computed as the product of the probabilities of the corresponding individual outcomes. Other joint behaviors require less straightforward approaches, such as the one adopted in this paper, and outlined below.

To model correlated uncertain parameters, we use the Adjusted Generalized Log-Transformed (AGLT) model presented in Gamba and Trigeorgis (2007). In short, we first define a portfolio of uncorrelated renewable generation capacity variations with no correlation, named the synthetic variation, which are then used to obtain the portfolio of renewable generation capacities where correlations are considered.

We start by defining the evolution of renewable generation capacity $G_{i,n}$ in each bus i of a transmission network as a geometric Brownian motion (Marathe and Ryan, 2005) under risk-neutrality

$$\mathrm{d}\, G_i^R = \left(\mu_i - \frac{\sigma_i}{2}\right) G_i^R \,\mathrm{d}\, t + \sigma_i G_i^R \,\mathrm{d}\, W_i, \tag{3.1}$$

where μ_i and σ_i represent the historical growth rate of renewable generation capacity and respective standard deviation. W_i are Wiener processes with correlations ρ_{ij} such that $\mathrm{d}\, W_i \,\mathrm{d}\, W_j = \rho_{ij} \,\mathrm{d}\, t$.

AGLT requires us to define the demand covariance matrix Σ and its matrix of eigenvectors and vector of eigenvalues, respectively V and Λ. Synthetic renewable generation capacity variations are approximated using

$$g_{i,n} = \begin{cases} g_{i,a_n} + Z_{i,u}\sqrt{\lambda_i \Delta t} & , \forall n \in \mathcal{N} \setminus \{0\} \\ 0 & , n = 0 \end{cases} \tag{3.2}$$

with Z as a $U \times 2^U$ matrix where the columns are the distinct permutations with repetition of 1

and -1, representing up-moves and down-moves of the synthetic portfolio. The column c of Z is related to node n as it the remainder of $n/2^U$.

Demand values for the multidimensional binomial tree result from the conversion of the synthetic demand variations back to the original demand basis using

$$G^R_{i,n} = G^R_{i,0} \left[\exp\left(\mu t_n + V g_{t_n}\right)\right]_i, \forall t_n > 0 \tag{3.3}$$

where $G^R_{i,0}$ is a column vector of starting renewable generation capacities, and we express μ and g_{t_n} as vectors with size U. The conditional probabilities in AGLT are constant and equal to 2^{-U}. We can then define the probability of each branch m as $P_m = 2^{-2Ut} \quad \forall m \in \mathcal{M}$.

3.3.3 Mathematical programming model

To study the impact of transmission investments in renewables penetration we develop a long-term transmission network expansion planning model under uncertainty where the decision-maker has the ability to expand on the current network to harness the renewable surplus in a bus and prevent fossil fuel usage.

$$\min \sum_{m\in\mathcal{M}} P_m \left[\sum_{n\in\mathcal{S}(m)} \frac{\mathrm{OC}_n + I_n}{(1+r)^{t_n\Delta t}} + \frac{\mathrm{OC}_m(1+g)}{(r-g)(1+r)^{t_m\Delta t}} \right] \tag{3.4}$$

$$\text{s.t.} \quad \mathrm{OC}_n = \lambda^F \sum_{i\in\mathcal{B}} E^F_{i,n} \qquad , \forall n \in \mathcal{N} \tag{3.5}$$

$$I_n = \sum_{x\in\mathcal{X}} C_x \omega_{x,n} \qquad , \forall n \in \mathcal{N} \tag{3.6}$$

$$\Omega_{x,n} = \Omega_{x,a_n} + \omega_{x,a_n} \qquad , \forall n > 0 \in \mathcal{N}, x \in \mathcal{X} \tag{3.7}$$

$$\Omega_{x,0} = \varpi_x \qquad , \forall x \in \mathcal{X} \tag{3.8}$$

$$E^F_{i,n} + E^R_{i,n} - D_{i,n} = \sum_{x\in\mathcal{X}_i} f_{x,n} \qquad , \forall n \in \mathcal{N}, i \in \mathcal{B} \tag{3.9}$$

$$0 \le E^R_{i,n} \le G_{i,n} \qquad , \forall n \in \mathcal{N}, i \in \mathcal{B}_S \tag{3.10}$$

$$0 \le E^F_{i,n} \qquad , \forall n \in \mathcal{N}, i \in \mathcal{B}_S \tag{3.11}$$

$$-F_x^{\max}\Omega_{x,n} \leq f_{x,n} \leq F_x^{\max}\Omega_{x,n} \qquad ,\forall n \in \mathcal{N}, x \in \mathcal{X} \tag{3.12}$$

$$-(1-\Omega_{x,n})M \leq \frac{f_{x,n}}{B_x} + (\theta_{i,n} - \theta_{j,n}) \leq (1-\Omega_{x,n})M \qquad ,\forall n \in \mathcal{N}, x \in \mathcal{X} \tag{3.13}$$

$$\theta^{ref} = 0 \tag{3.14}$$

$$\omega_{x,n} = \{0,1\} \qquad ,\forall n \in \mathcal{N} \setminus \mathcal{M}, x \in \mathcal{X} \tag{3.15}$$

$$\Omega_{x,n} = \{0,1\} \qquad ,\forall n \in \mathcal{N}, x \in \mathcal{X}. \tag{3.16}$$

The first fraction of the objective function, Equation (3.4), describes the portfolio decision tree. For each branch m, it adds the present value of the investment costs I_n and operational costs OC_n on each of its nodes $\mathcal{S}(m)$ weighted by the probability P_m of occurrence of that particular branch. Operational costs are adjusted to the considered time period multiplying it by Δt. The second fraction of the objective function describes a perpetuity based on the operational costs of the last node of each branch of the decision tree. This assumes that after this time period no investments exist but the consequences of the final network configuration are accounted for.

Equation (3.5) models operational costs stating that for each node they are equal to all used fossil fuel $E_{i,n}^F$ multiplied by the fossil fuel usage cost λ^F. Investment costs are calculated in Equation (3.6) by summing the individual costs C_x of new transmission lines $\omega_{x,n}$. The network configuration in each node is preserved with Equation (3.7) where the transmission network $\Omega_{n,x}$ is updated with the last investment decisions. For the special case of the root node, it is stated that it is equal to initial network configuration ϖ_x in Equation (3.8). Kirchhoff's current law is modelled in Equation (3.9). Energy generation is defined as non-negative with Equations (3.10), for renewable based electricity ($E_{i,n}^R$) and (3.11) for fossil fuels supply. Renewable supply is also constrained to available generation capacity $G_{i,n}$. In opposition, fossil fuels are assumed to be sufficient to supply all electricity hence we do not consider an upper bound to their usage. Power flows are constrained to line transmission capacity $F_x^{\max}$ using Equation (3.12). These can only be non-zero if the line has been constructed. Equation (3.13) is binding when the transmission line is built, modeling the power flow as DC current considering susceptance B_x and the difference between phase-angles $\theta_{i,n}$ of the considered connected buses.

3.4 Application case and data

Thermal power generation in the Azores islands requires importing fuel or diesel, which represents a significant burden to the economy of the region. Due to its location in an area of considerable wind and geothermal potential, however, the archipelago has multiple feasible renewable generation investment alternatives available, which would allow it to decrease its dependency on fossil fuel, not only benefiting the region economically, but also environmentally.

As of 2010, only 28% of the electricity in the archipelago was obtained from renewable sources, with geothermal and hydro in S. Miguel, and wind in Terceira, having the key contributions (EDA, 2011). Further investments in renewable generation are thus required with the objective of increasing renewable generation to 49% by 2014, on the path to the 75% target defined for 2018. In the present case study we consider the four closest islands in the central region of the archipelago: Faial, Pico, S. Jorge and Terceira, where renewable electricity generation accounts only to 17.7% in 2015 (EDA, 2015).

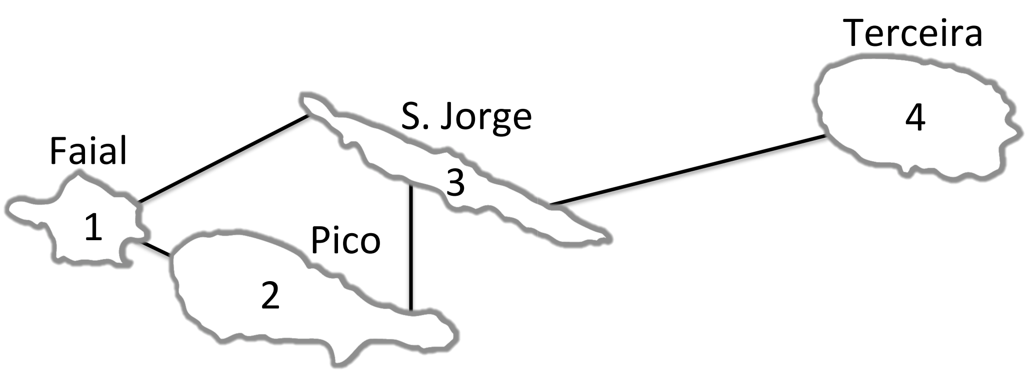

Figure 3.1: Network configuration.

In the standing time period each island is isolated in terms of energy production and supply, so $\varpi_x = 0, \forall x \in \mathcal{X}$, i.e., no lines are initially available. Assuming that there is a renewable electricity capacity surplus in one of the islands, it is not possible to use it to the benefit of another island. The introduction of underwater transmission cables could overcome this limitation, and namely allow a generation surplus in renewables in one island to be used, avoiding the use of fossil fuel in another island. To assess the interest in connecting the islands to increase renewables penetration, we consider possible connections between Faial and Pico, Faial and S. Jorge, Pico and S. Jorge and S. Jorge and Terceira as shown in Figure 3.1.

Table 3.2: Averages and standard deviations of the changes in annual generation capacities for the islands of Faial, Pico, S. Jorge and Terceira.

	Starting Generation (MW)	Generation Change (MW)	
		Average	Standard Deviation
Faial	0.92	6.9%	60.5%
Pico	0.68	0.0%	10.0%
S. Jorge	0.49	0.0%	43.8%
Terceira	4.28	20.9%	17.9%

Table 3.3: Correlation matrix of the changes in annual generation capacity variation for the islands of Faial, Pico, S. Jorge and Terceira.

	Faial	Pico	S. Jorge	Terceira
Faial	100%	87.53%	44.56%	-63.52%
Pico	-	100%	14.86%	-27.30%
S. Jorge	-	-	100%	-22.17%
Terceira	-	-	-	100%

Table 3.4: Static evolution of demand based on historical fixed yearly increases.

	2015	2020	2025	Yearly Increase
Faial	5.66	5.83	6.01	0.6%
Pico	5.22	5.35	5.49	0.5%
S. Jorge	3.25	3.30	3.35	0.3%
Terceira	21.89	22.33	22.78	0.4%

Data on demand and generation capacity was obtained in EDA (2015). Starting renewable generation capacities and demands were determined respectively by averaging the 2015 total renewable electricity consumption and total consumption to hourly values. Generation capacity growth was estimated based on expected consumption increases by the year of 2019. Standard deviations and correlations were calculated using 2010 to 2015 historical data. Demand is assumed to grow linearly considering the 2015 to 2019 projection. These are summarized within Tables 3.2, 3.3 and 3.4. To obtain the multinomial decision tree we parametrize AGLT considering two time stages, besides reference year 2015, using 5 year time steps. The reference value for the cost of resorting to fossil fuel is the O&M cost of gas and diesel engines, 40 €/kWh (European Commission, 2008). As an early, rough estimate of transmission line costs, we consider the upper limit of the range of values presented by MedReg (2014), rounded up to 2,500 €/(km-MW).

Distances between islands are approximately 12 km between Faial and Pico, 30 km between Faial and S. Jorge, as well as between Pico and S. Jorge, and 40 km between S. Jorge and Terceira. These values already assume that the underwater cables are not fully stretched. Interest rate is assumed at 10% based on the Foreign Utility Cost of Equity of 2009[1]. For resistance and reactance we used the values 0.028 Ω/km and 0.348 Ω/km, respectively (Kundur, 1994).

3.5 Results

We used IBM ILOG CPLEX to solve the case study. Resulting underwater transmission expansions for the base case, where estimated correlations are considered, are shown in Table 3.5. In the first time step (node 0) all investment decisions are delayed, a fact that is understandable, given the low probability of renewable-based power surplus. We observe that investments are considered in half the nodes in 2020. For the remaining nodes, the 8MW Faial - Pico connection is always considered. There is also the possibility of a second connection between Faial and S.Jorge with varying capacities.

A higher expected renewables penetration rate of 30.9% in 2025 is achieved, in contrast with the observed rate of 27.9% when underwater transmission investments are not possible. These rates are computed as the probability-weighted average of the ratios between dispatched

[1] http://people.stern.nyu.edu/adamodar/New_Home_Page/dataarchived.html

renewable-based power and demand. We also observe that it is certain that at least one line will be built between S. Jorge and Terceira, even though the desired line capacity is not known with certainty, and that in no case a meshed configuration with Pico, Faial and S. Jorge emerges.

Table 3.5: Investment decisions $\omega_{x,n}$ (MW) in the base case.

Year	Probability	Faial - Pico	Faial - S. Jorge	Pico - S. Jorge	S. Jorge - Terceira
2015	100%	0	0	0	0
2020	50%	0	0	0	0
2020	25%	8	4	0	0
2020	18.75%	8	2	0	0
2020	6.25%	8	0	0	0
2025	100%	0	0	0	0

Table 3.6: Investment decisions $\omega_{x,n}$ (MW) in the uncorrelated case.

Year	Probability	Faial - Pico	Faial - S. Jorge	Pico - S. Jorge	S. Jorge - Terceira
2015	100%	0	0	0	0
2020	25%	0	0	0	0
2020	18.75%	8+4	8	0	8
2020	18.75%	8+4	8	0	2
2020	18.75%	0	0	2	0
2020	6.25%	8	8	0	8
2020	6.25%	8	8	0	2
2020	6.25%	0	2	0	0
2025	100%	0	0	0	0

To analyze the impact of correlation on the timing and configuration of network investments, as well as the renewables penetration rate, we compared the base case results with those from a scenario with uncorrelated variations in demand.

Observing the results presented in Table 3.6, it is clear that in the absence of correlations, with more likely generation variation imbalances leading to a higher likelihood of transmission-warranting circumstances, higher levels of investment also become more likely. The benefit in terms of expected renewables penetration rate is similar to the base case, 32.5% vs. the 26.9% achieved in a scenario with no underwater transmission investments.

3.6 Conclusions

In this paper we bring together the stochastic mixed integer programming model for Transmission Network Expansion Planning of Loureiro et al. (2015), with the AGLT model of Gamba and Trigeorgis (2007), to evaluate the potential contribution of underwater transmission investments to increase renewables penetration in the Azores archipelago. The first incorporates portfolios of real options, which allows us to address the evolution in time of uncertain parameters. The second enables the consideration of a higher number of correlated parameters. Additionally, we incorporate expansion lead times in the former model to address the significant timespans involved in the construction of new transmission lines.

The investment in underwater transmission would enable islands with an excess in renewables based power supply to share a potential surplus with islands featuring a deficit, improving the overall usage of renewables in the region. Our results show that even though no investments are started in the current time period, and the future configuration of the connections between islands is not certain, an investment in underwater transmission, if technically feasible, within the assumptions of our model and analysis, could in fact contribute to increase renewables penetration.

The analysis could be improved by adding more time steps to the multidimensional binomial tree, in order to increase its granularity, or by adding scenarios in each of the nodes, e.g., to account for intra-annual seasonality. Nevertheless, this would lead to an increase in computational requirements, and would very likely require the use of decomposition methods or metaheuristics.

Our model currently assumes centralized decision-making. In the future we plan to incorporate market-based dispatch, in line with the recent regulation process taking place in the European Union, which has led to the separation of generation companies and TSOs.

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Chapter 4

Coordinating cross-border electricity interconnection investments and trade in market coupled regions

Investments in cross-border electricity interconnections are key to enable the integration of the European energy market. To analyze policy frameworks for these decisions, we propose a model where the transmission capacity investment between two regions is agreed upon through bargaining. We provide solutions where fair share cost allocation allows and forbids compensations, using respectively Nash-Coase bargaining and Nash bargaining. Each region has its own TSO, maximizing social welfare within its geography. The two markets are represented using linear supply and demand curves, and trade is enabled by the interconnection, whose capacity must be agreed upon. To account for the variability in the market conditions that may be met, we include scenarios in our model. We illustrate optimal cost allocation policies with a study of the Iberian market, using 2013 data. The results of the application of the models to the Iberian market suggest their ability to estimate realistic values for cross-border interconnection between two regions.

4.1 Introduction

The European Union sees the integration of its national electricity transmission networks into a single European energy market, as a key enabler of competition, and in general of the long term improvement of the social welfare in the Eurozone. This was already the objective when the Barcelona European Council, in 2002, set a target for the installed interconnection capacity in 2005, of 10% of the existing production capacity, even across the borders where congestion was not a concern at the time (Presidency Conclusions, 2002).

It has been argued in several fora that this policy target has failed to be met. Up until recently, the majority of the European countries, regardless of the capacity of their internal electricity transmission networks, were still featuring low interconnection capacities: the cross-border transmission bottlenecks that were present in 1996 were still in existence in 2007; up to 2004, only 4% of the electricity transmission investment was being directed to interconnections; and an interconnection priority project presented by the European Commission largely underestimated the required investments (Buijs et al., 2007). In the European Union, the most significant of these bottlenecks are four regions whose interconnection capacity with mainland Europe is significantly insufficient: the Baltic States, the Iberian Peninsula, Italy, and Great Britain and Ireland. All of these "electric peninsulas" have a high renewable generation development potential which is constrained if, in the long-term, interconnection capacity is not at least doubled in some of these regions, or increased up to 10 times, as in the case of the Iberian Peninsula connection to mainland Europe (ENTSO-E, 2014).

The interdependencies between the multiple national energy markets, and the multiple Transmission System Operators (TSOs), in Europe have increased significantly in recent years. Their increase can, for the most part, be attributed to the large development of renewable energy sources, and to the substantial ongoing efforts to liberalize the European electricity market. Thus, cross-border power flow growth can only be properly supported if an adequate electricity interconnection structure is in place (ENTSO-E, 2013).

Even though the European Union started managing border congestion through non-market-based methods, market-based methods are preferred as they provide reliable economic signals for necessary interconnection expansions (Kristiansen, 2007). Managing cross-border flows through transmission rights is a possibility where suppliers auction transmission rights. Joskow and Tirole (2000) show that these result in an increase of market power of a generator in the importing region. Another possibility, followed by the European Union, is to derive these prices implicitly through market coupling.

Market coupling, allows interconnection flows to be managed in a joint region Power Exchange (PX) that dispatchs power based on demand and available interconnection capacity. In this regard, seven European Power Exchanges joined efforts to launch the Price Coupling of Regions (PCR) initiative, with the objective of devising a single price coupling solution to define electricity prices and manage cross-border capacity in Europe. The North-Western Europe Day Ahead (NWE DA) project is a day ahead market coupling implementation project, that went live in February 2014, accounting for more than 75% of the total electricity consumption in Europe.This project is supported by the European Network of Transmission System Operators for Electricity (ENTSO-E) and coordinates the TSOs and the PXs of Austria, Belgium, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland and Sweden. Only a few months later, in May 2014, a new step in the integration of European Electricity Markets was given, with the extension of the day-ahead market coupling to Portugal and Spain, enabled by the interconnection between France and Spain.

The reinforcement of the interconnection infrastructure requires neighboring TSOs to reach an agreement and commit to a single interconnection investment solution able to deliver benefits to all involved parties. This single solution can be reached either through a top-down, centrally regulated and coordinated process, through voluntary local agreements for cross-border investment cooperation between the member states, or through a combination of these two processes (Buijs et al., 2010).

To the best of our knowledge, we present in this paper the first model to study cooperative decision-making in cross-border electricity interconnection investments. We value the option of trading electricity production between two regions to improve social welfare, by analyzing a two-stage, two-player, two-market, stochastic cooperative game. In stage one, the two regions decide jointly on the interconnection investment level. Then supply and demand curve uncertainties in both regions are resolved and both regions have the option to trade when deciding on their supply and demand levels in stage two, constrained by their earlier investment decision. To increase tractability, our model is simplified and deliberately focused on the economics of the problem, however it still features enough details, e.g, through the inclusion of scenarios, to be able to accommodate a rich set of empirical data and yield more relevant analysis results. Without ruling out the existence of strong assumptions and simplifications, and by specially stressing the novelty of our approach, we consider the present work a useful first iteration on top of which further developments might improve the representation of reality.

Based on a model with a single decision maker, which can be applied to the reference scenario with a centralized supraregional decision maker, we adapt it to consider bargaining, with two regions cooperating in the interconnection investment, considering an ex-ante fair share cost allocation. Our analysis is split into two instances. First, we accept any side payment value, thus allowing all the investment costs to be covered by a single player as well as a financial compensation to take place to pursue the other player into a higher transmission capacity investment. In the scope of this paper, however, we do not explore how such compensation could be implemented. Therefore, in a second instance we study the impact on the investment decision of restricting side payments to the total investment costs where no compensation can take place. Respectively, in the first instance as investment externalities can be fully incorporated (Coase, 1960), we seek a Nash-Coase bargaining solution. As for the second instance, forbidding compensations might withhold externalities to be fully accounted by each player on whose circumstances only Nash bargaining solutions (Nash, 1950) are found. To this end we use Karush-Kuhn-Tucker optimality conditions and explore the relationship between constraints to obtain methods to solve both instances of the model, where the fair share cost allocation procedure allows and disallows the existence of compensations.

We use sensitivity analysis and data for the Iberian market in 2013 to study how the variation in social welfare and optimal investment evolve with the cost of interconnection capacity (a proxy for economic, regulatory, physical, technical, and other costs and difficulties), in a setting in which each region features a predominant role as either importer or exporter. Variation in social welfare based on the investment in transmission capacity is chosen as the metric for decision-making as it represents the benefits accrued by society. Our model also allows us to examine the role of the bargaining power of each region on interconnection decisions and social welfare improvement, where bargaining power can be interpreted as the ex-ante expected fraction of total surplus generated by the bargaining game (Bakos and Brynjolfsson, 1993; Van Mieghem, 1999).

At lower transmission investment costs, the importer supports the whole investment, that can also lead to a necessary compensation to the exporter, if this is allowed. At higher costs, the exporter supports a higher share of the investment, asymptotically approaching the total investment. The variation in social welfare, and the investment in interconnection capacity decrease when the cost of interconnection capacity increases and transmission capacity costs are such that no compensation would be necessary. At the lowest of transmission investment costs where compensations could be necessary to obtain the decision that would maximize social welfare of both regions, its restriction implies that transmission capacity investments slightly increase with increasing transmission investment costs. This is due to the increasing bargaining power of the exporter.

For costs above the necessity of compensations, we see that for the importer, but not for the exporter, inverse U-shaped relationships are observed in the variation in social welfare. These results can also be interpreted as the evolution of social welfare and interconnection capacity investment with a decreasing social welfare "contribution margin", i.e., decreasing price-elasticities of demand and/or supply. Our model could also accommodate the analysis of the impact of the level of market uncertainties and correlations. Based on prior studies of capacity investment under uncertainty, we would expect the investment to increase with higher uncertainties and lower correlations (Loureiro et al., 2015).

As the European power system, the Internal Energy Market, comes to fruition and evolves into a trans-European infrastructure, cross-border interconnections become ever more critical, especially considering the recent new price coupling market rules. This topic would benefit from an increased attention from both researchers and practitioners.

The remainder of the paper is structured as follows: in the next section, we review prior relevant contributions to the literature; in section 4.3, we introduce the Interconnection Transmission Expansion Problem in Market Coupled Regions, and describe a case application focusing on the Iberian market; optimal interconnection investment policies are illustrated for the case application in section 4.4; section 4.5 closes the paper, with the presentation of conclusions, policy implications, and suggestions for future work.

4.2 Literature review

In energy markets that have undergone restructuring, the supply business and the transmission business are unbundled. This fosters an increase in competition, as the different producers of electricity come to stand on equal footing in terms of accessing the transmission network.

Historically, however, the number of operating electricity companies has remained small (Davies and Waddams Price, 2007; Domanico, 2007). Insufficient unbundling has been suggested as one of the key reasons for the presence of difficulties in increasing the interconnection of the European transmission networks (Dobbeni, 2007). A reduced level of interconnection capacity places limits to the imports and exports of electricity, and contributes to maintaining price differentials across the different regions, thus burdening social welfare with the congestion costs.

An additional important benefit of international power flows is the ability to improve the balance between generation uncertainty and demand uncertainty, by contributing to a decrease in the total level of required resources to guarantee an appropriate operation of the energy markets (Unteutsch and Lindenberger, 2014). The desired increment in competition remains challenged and thus, so does the possibility of being able to access cheaper generation sources, as well as a larger share of renewable resources (Amundsen and Nese, 2009).

It has been argued that the TSOs do not act independently of the political sphere (Buijs et al., 2007), a fact that leads to local goals interfering with the investments towards an interconnected Europe. With the possibility of trade and the existence of an electricity interconnection, the prices in at least one of the countries, *ceteris paribus*, must rise, even with the social welfare increasing in all the countries. In other words, the consumer surplus might decrease even if the sum of the consumer surplus and the producer surplus increases (Billette de Villemeur and Pineau, 2010). In the exporting regions, the generation increases, the prices increase, and both the consumer surplus and the demand decrease. The opposite happens in the importing regions, where the consumer surplus increases due to a decrease in the electricity prices, but the producer surplus decreases. This pattern of variations is a source of disagreement that may lead to politics interfering with the investment decision process. Parisio and Bosco (2008) identify these variations as volume effects. They show that a further bid effect also takes place where the increase in trade among regions changes generator dispatch strategies. Whereas in the former case price differentials decrease, the bid effect can also both result in a reduction or increase in price differentials. They find that for the exporting region, generators with higher marginal dispatch costs bid higher quantities and generators with lower marginal costs bid lower quantities. The reverse occurs to the importing region.

Apart from the complex authorization procedures that may be required, reaching an agreement between the TSOs is arguably the other key difficulty that is faced in this context (Ciupuliga and Cuppen, 2013). In particular, the TSOs may be interested in having different amounts of new installed electricity interconnection capacity. This justifies the need to reach an agreement on a single level of investment considering the allocation of transmission investment costs, satisfying the different regions. This decision can be made centrally by a supraregional planner, independently by each of the regional planners, or jointly in cooperation between the different regional planners.

To the best of our knowledge, the literature that has focused on this specific problem is relatively scarce. Buijs et al. (2011) propose two models for this problem, based on the first and second approaches outlined above. The first model is a Mathematical Program with Equilibrium Constraints, in which all the planners accept the decisions that maximize the total social welfare, as if a supraregional planner existed, and the transmission planner acts as a Stackelberg leader, preempting the market dispatching decisions. In the second model, each of the planners acts individually, with a responsibility only for the shares of the interconnection lines that are located in its own territory, and seeking to maximize the social welfare of its own region, but taking into account the decisions of the other planners. The problem is formulated as an Equilibrium Problem with Equilibrium Constraints, with a non-cooperative Nash equilibrium solution. In equilibrium, the capacity of each of the interconnections is the minimum of the values desired by each of the regions that it connects, as it effectively places a limit on the power flow in the interconnection. The circumstances in which all the planners might benefit from a different split of the investments costs, for instance with one of the regions covering a part of the costs of one of the other regions, are not considered, a fact that may lead to solutions with lower levels of investment in interconnection capacity.

Without a regulatory framework that is capable of leading the planners to consider the total social welfare, if such solution does not provide economic benefits for all the planners, it is extremely unlikely that it will be accepted by the unfavored regions. With this concern, Buijs and Belmans (2012) suggest an additional approach, which consists of restricting the solutions based on the supranational model to those solutions in which the social welfare of each of the individual zones is not reduced, even if the mix of the consumer surplus, the producer surplus and the congestion rents change. In this case, the benefits may accrue only to a subset of the regions, which suggests the need to devise a welfare transfer mechanism.

Saguan and Meeus (2014) analyze the impact of the regulatory framework on the optimality of the investments in transmission and the costs of renewable energy, comparing a circumstance of no-trade to a circumstance of perfect trade, as well as national transmission investment plans to supranational transmission investment plans. The model features a single market two-zone network, with a three-stage decision process in which the transmission capacity investment decisions precede the generation investment decisions, which in turn precede the market supply and demand decisions. The study concludes that the benefits from trade outweigh the investment costs.

Hobbs et al. (2005) study the effect of market coupling on market power, using the model proposed in Jing-Yuan and Smeers (1999), including individual electricity producers, that maximize profit from the sale of power and consider the existence of other producers, an arbitrager, that buys and sells power at different nodes, and a TSO, that guarantees the power flows. The prices are obtained using a Cournot-Nash approach. The model is applied to the Belgian market and the Dutch market, and considers power flows from Germany and France. The analysis shows that even though market power is still present when the two countries are market coupled, the undesired effects are greatly diminished. The effect of an increase in the interconnection capacity on market power is studied by Lise et al. (2008), with an application to the EU20 geographical area, concluding that the market power is mitigated and the price differences tend to decrease as the trade increases, even though the prices may slightly increase for some of the countries.

Bargaining models have had examples of prior application in transmission planning. Haurie and Zaccour (1991) present and discuss a model of power exchange between interconnected power utilities, seeking to minimize the costs of the investment in exchange capacity, the costs of the investment in generation capacity, and the costs of generation. Bai et al. (1997) study an open access electricity transmission model in which the utilities establish quantity and price contracts for transmission. Bargaining has also recently been used for the valuation of right-of-way costs between transmission line investors and land owners (Molina et al., 2012, 2013a,b). A review of the most important cooperative and non-cooperative game theory models and equilibria is provided in Molina et al. (2013a).

The approach that we present in this paper extends prior research by focusing on the sizing of the electricity interconnections in market coupled regions, considering the social welfare as an objective, and allowing the investment costs to be shared based on the benefits accrued to each region (the principle of allocating the investment costs according to the benefits that the infrastructure provides is already considered by the European Parliament and the Council (2013)).

4.3 Material and methods

4.3.1 Proposed approach

The Interconnection Transmission Expansion Problem in Market Coupled Regions (I-TEP-MCR) can be regarded as a particular case of the more general Transmission Network Expansion Problem, that considers the decision to invest in a single electricity transmission corridor, to establish, or to reinforce, cross-border electricity transfer between two regions that are part of a single coupled market. Each region has its own TSO, where we assume that they singly seek to maximize social welfare within its own geography, and is unable to force any additional artificial restrictions on the transmission capacity. We study the impact of transmission line investment costs in transmission capacity investments as well as the fair share allocation of costs that enables this investment, both considering no limitation of side payments and limiting them to avoid values above total transmission costs that would result in financial compensations.

Based on the Nash-Coase bargaining solution (Cherry and Shogren, 2005), we develop a new model where an electricity auction of the two markets that are part of the single coupled market is represented using linear supply and demand curves. Trade between them is made possible, and at the same time restricted, by the interconnection capacity, that must be agreed upon by the two regions. In line with tradition, we assume maximization of the variation of social welfare considering the respective investment costs for that solution as the objective function. To account for the variability in the market conditions that may be met, we include scenarios in our model that are weighted by the number of hours they represent in a year of operation. Due to the possible uneveness of benefits for each player a fair share cost allocation might require a side payment superior to the total investment cost, which can be viewed as a compensation. We consider both the situation where compensations are and are not possible. The model we define is non-linear and non-convex. Our strategy to solve it is to distinguish the type of results we may obtain and, through mathematical manipulation of constraints define different approaches to solve for each case: when investment compensations would never occur; and, when investment compensations must be avoided. Optimal interconnection investment policies are illustrated with a study of the cross-border investment between Portugal and Spain, using detailed data on the buy and sell bids in the Iberian market throughout the year of 2013. These regions and time frame were chosen due to availability of raw data for all bids that took place in that market.

For the sake of simplicity, and in order to sharpen the focus on the economical aspects of the problem, in this paper we do not model explicitly the electricity transmission networks, which may be seen as equivalent to assuming the absence of internal congestion in the networks, and the non-existence of transmission losses. In the model that we propose, we also do not consider wheeling, which may be interpreted in practice as the presence of restrictions, for instance of a geographic nature, that make it impossible to use a secondary region for power transfer. We also consider no distinction between consumer surplus and producer surplus, with the decisions focusing solely on the total increase in social welfare.

The markets are modeled considering perfect competition. Even though perfect competition is a strong assumption, the conditions of market coupling settings allow market power to be significantly mitigated (Hobbs et al., 2005; Gebhardt and Hoffler, 2013). This is further reinforced when expansions in the interconnections are possible (Lise et al., 2008). Küpper et al. (2009) also notes that even if the interconnections are not congested, they will still represent a competitive threat. We would expect the introduction of imperfect competition, à la Cournot, to have a marginal impact in interconnection investments.

Finally, even though the timing of the decisions of the players is relevant, similarly to the majority of the literature on game-theoretic capacity expansion models (Van Mieghem, 2003), we consider in our model a stationary setting, with a single decision, which is agreed by the two players, and addresses a single set of scenarios for the forecasts of supply and demand.

4.3.2 Centralized interconnection planning model

Trade between two regions is desired as long as there is a price differential between them. We consider the linear inverse demand function (4.1) and the linear inverse supply function (4.2) for two regions, and the corresponding demand function and supply function, in a scenario $s \in \mathcal{S}$,

$$P_{s,i} = \alpha_{s,i} - \beta_{s,i} D_{s,i} \tag{4.1}$$

$$P_{s,i} = -\gamma_{s,i} + \delta_{s,i} G_{s,i}. \tag{4.2}$$

The constant $\alpha_{s,i}$ and the constant $\gamma_{s,i}$ are the intercepts, and the positive constant $\beta_{s,i}$ and the positive constant $\delta_{s,i}$ are the slopes, of the demand and supply curves for region $i \in \{M, X\}$ in scenario s, with M and X denoting the importing region and the exporting region, respectively.

We can write the variation in social welfare (Appendix 4.A) based on the flows f_s from the exporting to the importing region as

$$\Delta \mathrm{sw}_{s,X} = \left(\frac{b_{s,M}}{a_{s,M}} - \frac{b_{s,X}}{a_{s,X}}\right) f_s - \frac{1}{2}\left(\frac{2}{a_{s,M}} + \frac{1}{a_{s,X}}\right) f_s^2, \quad \forall s \in \mathcal{S} \tag{4.3}$$

$$\Delta \mathrm{sw}_{s,M} = \frac{1}{2a_{s,M}} f_s^2, \quad \forall s \in \mathcal{S}, \tag{4.4}$$

where

$$a_{s,i} = \left(\frac{1}{\beta_{s,i}} + \frac{1}{\delta_{s,i}}\right) \tag{4.5}$$

$$b_{s,i} = \left(\frac{\alpha_{s,i}}{\beta_{s,i}} - \frac{\gamma_{s,i}}{\delta_{s,i}}\right), \tag{4.6}$$

and

$$f_s = \min\left\{f_s^{\mathrm{FT}}, K\right\} \tag{4.7}$$

with

$$f_s^{\mathrm{FT}} = \frac{a_{s,X}b_{s,M} - a_{s,M}b_{s,X}}{a_{s,X} + a_{s,M}}. \tag{4.8}$$

The optimal value for the interconnection capacity K^*, from the perspective of a supraregional transmission planner, can be obtained from the following mathematical model,

$$\max \quad \sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\left(\Delta\mathrm{sw_{s,X}} + \Delta\mathrm{sw_{s,M}}\right) - I \tag{4.9}$$

$$\mathrm{s.t.} \quad I = c(K) \tag{4.10}$$

$$f_s = \min\left\{f_s^{\mathrm{FT}}, K\right\}, \quad \forall s \in \mathcal{S} \tag{4.11}$$

$$\Delta\mathrm{sw}_{s,X} = \left(\frac{b_{s,M}}{a_{s,M}} - \frac{b_{s,X}}{a_{s,X}}\right) f_s - \frac{1}{2}\left(\frac{2}{a_{s,M}} + \frac{1}{a_{s,X}}\right) f_s^2, \quad \forall s \in \mathcal{S} \tag{4.12}$$

$$\Delta\mathrm{sw}_{s,M} = \frac{1}{2a_{s,M}} f_s^2, \quad \forall s \in \mathcal{S}. \tag{4.13}$$

The supraregional transmission planner maximizes, with Equation (4.9), a weighted sum of the increments in the total social welfare subtracted by the annualized interconnection investment cost I, considering a weight h_s for scenarios $s \in \mathcal{S}$. Weights h_s represent the number of hours of operation for a particular scenario s in a year. Investment costs are described in Equation (4.10) by an arbitrary cost function $c(K)$ of the interconnection capacity K. It should be noted that based on the current model the only variable controlled by the transmission planner is the amount of transmission capacity K to be built. All other variables can be obtained by defining K.

Market dispatch is resolved with Equation (4.11) considering free-trade flows f_s^{FT} that might be capped by the available transmission capacity K. Variations in social welfare due to electricity trade are obtained with the previously deduced Equations (4.12) and (4.13). In this particular formulation, we assume that a region either always imports or always exports, but the model can be generalized by having (4.12) and (4.13) change depending on the roles of the regions in preprocessing based on free-trade quantity values f_s^{FT}. We adopt this formulation for the sake of simplicity, and in line with the fact that the roles of the two regions do not change in the case that we consider later in the paper.

4.3.3 Decentralized interconnection planning model where compensations are possible

Using Nash-Coase bargaining to adapt the previous model to a game where the two regions agree on the level of investment in interconnection capacity, we introduce the requirement that the variation in social welfare for each of the two regions must compensate its part of the investment, defined for each region as I_X and I_M.

$$\max \quad \left(\sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\, \Delta \mathrm{sw_{s,X}} - I_X\right)\left(\sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\, \Delta \mathrm{sw_{s,M}} - I_M\right) \tag{4.14}$$

$$\text{s.t.} \quad I_X + I_M = c(K), \quad : \lambda_I \tag{4.15}$$

$$f_s = \min\left\{f_s^{\mathrm{FT}}, K\right\}, \quad \forall s \in \mathcal{S} \tag{4.16}$$

$$\Delta \mathrm{sw}_{s,X} = \left(\frac{b_{s,M}}{a_{s,M}} - \frac{b_{s,X}}{a_{s,X}}\right) f_s - \frac{1}{2}\left(\frac{2}{a_{s,M}} + \frac{1}{a_{s,X}}\right) f_s^2, \quad \forall s \in \mathcal{S} \tag{4.17}$$

$$\Delta \mathrm{sw}_{s,M} = \frac{1}{2a_{s,M}} f_s^2, \quad \forall s \in \mathcal{S} \tag{4.18}$$

$$I_X \leq \sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\, \Delta \mathrm{sw_{s,X}}, \quad : \mu_X \tag{4.19}$$

$$I_M \leq \sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\, \Delta \mathrm{sw_{s,M}}, \quad : \mu_M. \tag{4.20}$$

To model the bargaining decision, we adapt the objective function, Equation (4.14), to split the individual benefits for each of the two regions, which are multiplied (Nash, 1950). The investment costs are also separated (4.15) and constraints (4.19) and (4.20) model the requirements for benefits in each region.

We should note that for each of these models, the presence of Equation (4.11) and (4.16) yields either formulation as bilevel problems. These can be reformulated as Mathematical Problems with

Equilibrium Constraints by substituting each constraint by the ones presented in Appendix 4.B.

We define Lagrange multipliers λ_I, μ_X and μ_M for relevant model constraints. Useful Karush-Kuhn-Tucker optimality conditions to establish a relationship between the benefits for each region are then

$$\frac{\partial \mathcal{L}}{\partial I_X} = \sum_{s \in \mathcal{S}} h_s \, \Delta\mathrm{sw}_{s,M} - I_M - \lambda_I + \mu_X = 0 \tag{4.21}$$

$$\frac{\partial \mathcal{L}}{\partial I_M} = \sum_{s \in \mathcal{S}} h_s \, \Delta\mathrm{sw}_{s,X} - I_X - \lambda_I + \mu_M = 0 \tag{4.22}$$

$$\mu_X \left(\sum_{s \in \mathcal{S}} h_s \, \Delta\mathrm{sw}_{s,X} - I_X \right) = 0 \tag{4.23}$$

$$\mu_M \left(\sum_{s \in \mathcal{S}} h_s \, \Delta\mathrm{sw}_{s,M} - I_M \right) = 0. \tag{4.24}$$

Using the above conditions we write the equality,

$$\frac{\partial \mathcal{L}}{\partial I_X} = \frac{\partial \mathcal{L}}{\partial I_M} \Leftrightarrow \sum_{s \in \mathcal{S}} h_s \, \Delta\mathrm{sw}_{s,M} - I_M + \mu_X = \sum_{s \in \mathcal{S}} h_s \, \Delta\mathrm{sw}_{s,X} - I_X + \mu_M, \tag{4.25}$$

and by considering Appendix 4.C we show that $\mu_X = \mu_M$, allowing the simplification,

$$\sum_{s \in \mathcal{S}} h_s \, \Delta\mathrm{sw}_{s,M} - I_M = \sum_{s \in \mathcal{S}} h_s \, \Delta\mathrm{sw}_{s,X} - I_X. \tag{4.26}$$

In Appendix 4.D we prove that the Nash-Coase bargaining game solution is achieved. The optimal solution is such that the net changes in social welfare, i.e., the variations in social welfare subtracted of investment costs, are equal for both players. It follows that solving the original model is sufficient to obtain the solution for any unrestricted bargaining situation when we consider Equation (4.26) and define $I = I_X + I_M$.

4.3.4 Decentralized interconnection planning model where compensations are not possible

With the previous formulation it is possible that partial investment cost I_X or I_M is higher than the total investment cost I with the other variable having a negative value. This represents a situation where a compensation between players takes place. Whereas it could be up for debate if compensations are possible and how could these be executed, from now onwards we assume that these are not possible and compare solutions to understand what these additional constraints impose in the decision. To this end, we add $I_X \geq 0$ and $I_M \geq 0$ to the bargaining model defined by Equations (4.14)-(4.20).

Given that I_X and I_M are bounded by

$$0 \leq I_X \leq \sum_{\mathrm{s} \in \mathcal{S}} \mathrm{h_s} \, \Delta \mathrm{sw_{s,X}}, \tag{4.27}$$

$$0 \leq I_M \leq \sum_{\mathrm{s} \in \mathcal{S}} \mathrm{h_s} \, \Delta \mathrm{sw_{s,M}}, \tag{4.28}$$

we can identify the different combinations of results for variables I_X and I_M. An optimal solution with null investment costs implies no trade and hence no increases in either social welfare. This yields a null objective function value. If either bargaining side is responsible for as much investment costs as the respective social welfare benefits, objective function value is null rendering these results indifferent to a no investment decision. Assuming now an optimal solution that respects the above constraints as strict inequalities, it means that non-negativity of investment costs are unnecessary and as such, decisions with or without compensations should be the same. What we find is that when a compensation would normally occur, one player will be responsible for financing the whole investment. As we will see later this limitation reduces the agreed upon investment in transmission capacity.

Given the non-linearity of the model, and that all other variables are just functions of K, we solve it by varying it with incremental steps covering the whole domain between 0 and the highest f_s^{FT}.

4.3.5 Case application

With an implementation of the model in MATLAB, using CVX, a package for specifying and solving convex programs (CVX Research, Inc., 2012; Grant and Boyd, 2008), we apply it to the case of the Iberian market, to estimate the required level of interconnection capacity between Portugal and Spain.

In November 2001, Portugal and Spain signed the collaboration protocol for the creation of MIBEL, the Iberian Electricity Market, aiming at guaranteeing conditions of objectivity, transparency and equality to all interested parties. Later, in 2004, a new agreement was signed to enable the creation of a regulatory council to supervise the development of MIBEL. With further agreements in 2007 and 2008, a capacity payments mechanism was introduced, as well as a methodology to determine which agents act as dominant operators, and harmonized procedures to allow the consumers to switch their suppliers.

The day-ahead market was initially established in Spain, in January 1998, with Portugal joining only almost a decade later, in July 2007. With the creation of this market, power producers and distribution companies bid for the purchase and sale of electricity, to be delivered in the following day, in a process that leads to the settling of exchanged power at a single marginal price, that results from the matching of the offers. An additional market was created to bridge the differences in the day-ahead forecasts of supply capacities and demand needs, operating six times a day, in individual time blocks of four hours.

With the establishment of MIBEL, Portugal and Spain would be supposed to operate under a unique electricity price. As long as the interconnection capacity between the two regions is sufficient to allow the transmission of power without curtailment, this single market price holds. This, however, is not always the case. In certain hours of operation, the interconnection capacity may not be sufficient, and the prices in each region may then diverge, leading to a market split. Price differences, also known as congestion rents, are powerful signs of the need for further investment in interconnections. The evidence for the pivotal role of the creation of MIBEL in the suppression of transmission investment needs is clear. The average difference between prices in Iberia, calculated as the difference between the Spanish price and the Portuguese price, was 10 €/MWh in 2007. The difference has decreased significantly in the meantime to less than 1 €/MWh, and in

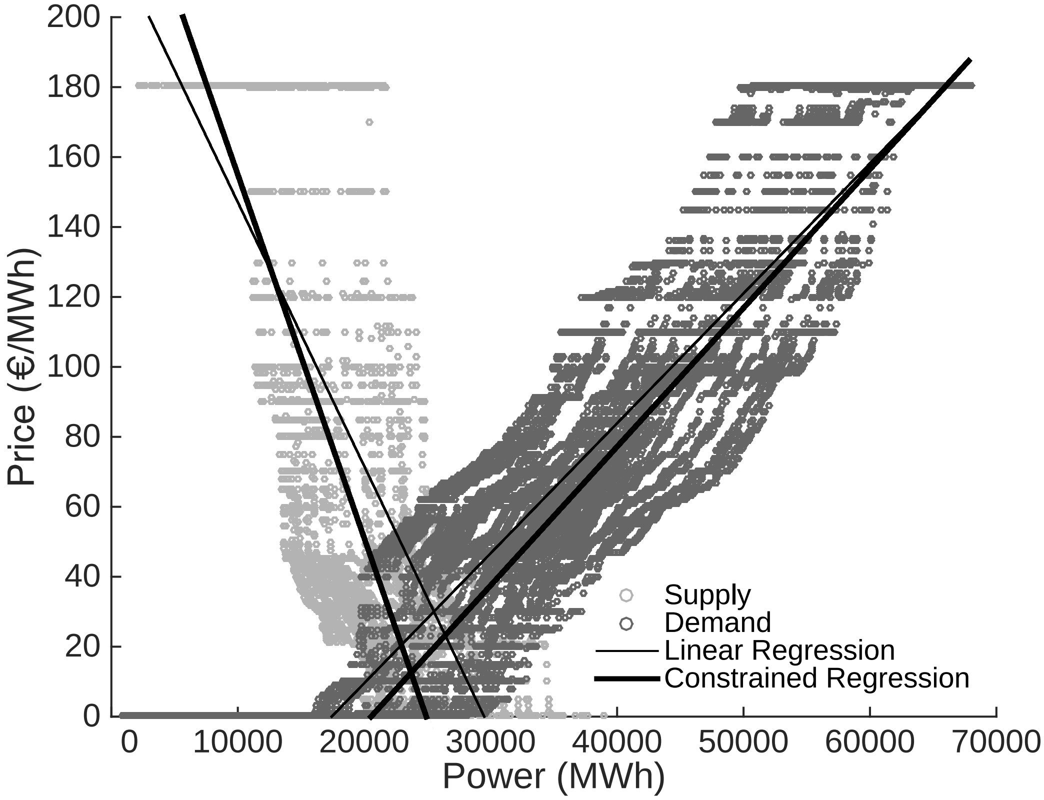

Figure 4.1: Off-peak hours of Spanish Sundays of January 2013. Linear regressions and linear regressions constrained to the average of the equilibrium values.

2014 there even was a slight difference to the benefit of Portugal, of 0.26 €/MWh.

We use daily bid data retrieved from OMIE, the daily and intraday Iberian electricity market operator[1], for the whole year of 2013, with approximately 15.7 million buy and sell bids. The bids are separated for Portugal and Spain, and to simplify, all bids that originate from interconnections to Spain other than the Portuguese, French and Moroccan, are assumed to be Spanish.

For each hourly slot throughout the year, we sort the bids by price and quantity to obtain hourly supply curves and demand curves, as well as equilibrium points. These data are then grouped in a total of 168 scenarios for different months, weekdays and peak/off-peak periods (the peak occurs between 9 a.m. and 10 p.m.).

For each scenario, we obtain linear regressions for the supply and the demand from all the

[1] http://www.omie.es/

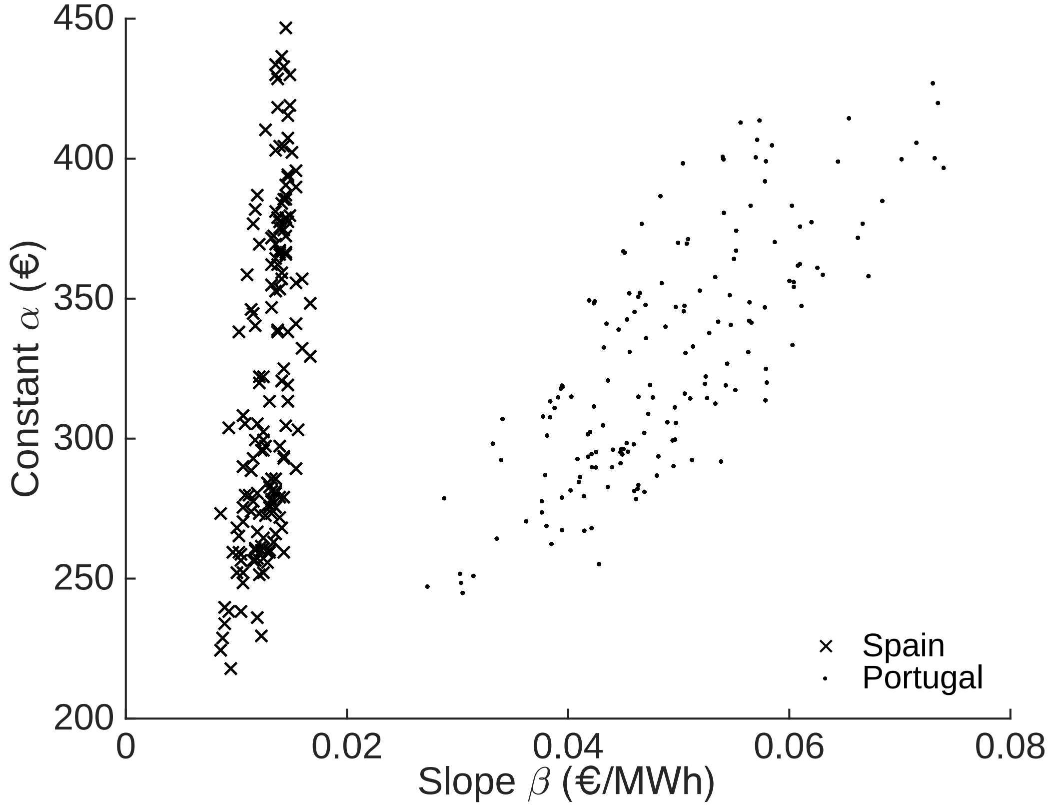

Figure 4.2: Demand parameters obtained using linear regression for the 168 scenarios.

points in the supply and demand curves, respectively, constrained to pass through the average of the equilibrium points of all the scenario's hourly slots. This allows us to avoid, for instance, negative equilibrium points, which may result from considering independent supply regressions and demand regressions. All these data operations were performed in R. We should note that across all the scenarios, the importer and exporter roles do not change - Portugal is the importer and Spain is the exporter in all 168 scenarios. Figure 4.1 shows a scenario for the Spanish market, with the results of the linear regression, and the results of the constrained linear regression.

Figures 4.2 and 4.3 present the constrained linear regression parameters for the different scenarios. Demands in both regions show similar and wide variations in the constant α, suggesting that the different scenarios represent a fair diversity of power needs. The slopes of demand in Spain are mostly stable at around 1 €/MWh, whereas in Portugal they vary in a range of values 3 to 7 times higher. Even if elasticity is not linear, *ceteris paribus*, demand in Portugal is more inelas-

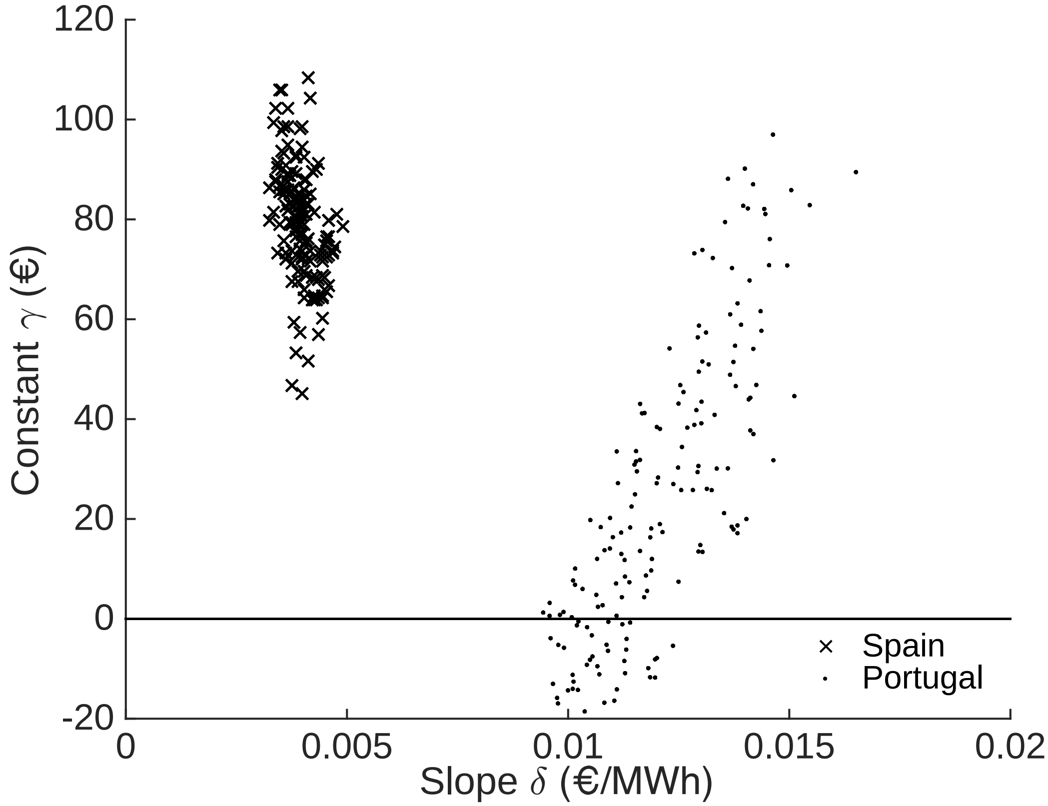

Figure 4.3: Supply parameters obtained using linear regression for the 168 scenarios.

tic than in Spain. On the other hand, generation in Spain is more concentrated in both constants γ and slopes δ. The considerable reliance on variable energy resources in Portugal may explain this greater variability.

The length of the interconnection line l is assumed to be 100 km. To work with the changes in social welfare and the investment costs in the same annual time scale, we compute an annualised investment cost, considering as the economic life for the investment T the mid-term to long-term threshold in ENTSO-E's cost benefit analysis, which is 10 years (ENTSO-E, 2013). The discount rate r is 6.04%, the highest cost of debt of the countries that finance the project, in this case the long term government bond yield of Portugal as of the end of 2013[2], also as suggested by ENTSO-E. For a transmission investment cost u_{ref}, the corresponding annualised investment cost u, is computed as follows (Ross et al., 2002),

[2]http://ec.europa.eu/eurostat

$$u_{\mathrm{ref}} \cdot l = u\left(\frac{1}{r} - \frac{1}{r(1+r)^T}\right) \Leftrightarrow u = u_{\mathrm{ref}} \cdot l\left(\frac{r(1+r)^T}{(1+r)^T - 1}\right). \quad (4.29)$$

4.4 Results and discussion

In this section we describe the results of an analysis of the behaviour of the desired total investment in transmission capacity, the share of investments between Portugal and Spain, and the variation of the social welfare, as a function of the transmission investment costs.

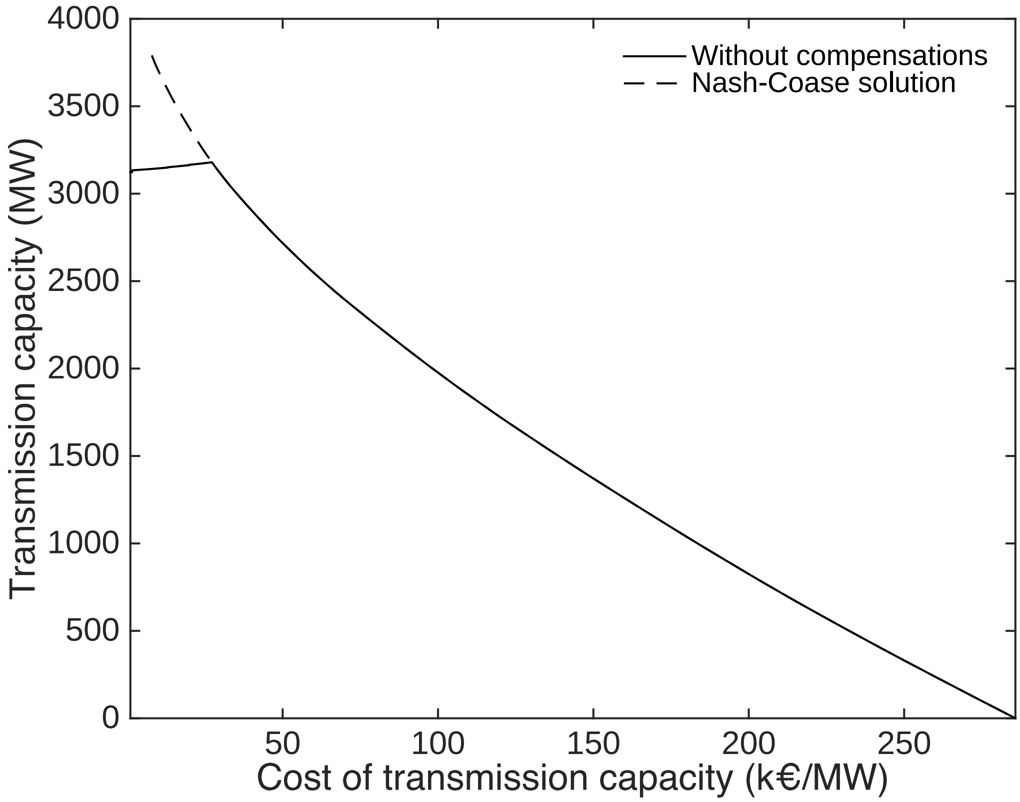

Figure 4.4: Representation of the desired total investment in transmission capacity considering different transmission costs.

Figure 4.4 shows that the total investment in transmission capacity decreases non-linearly with the transmission investment costs when considering a fair share allocation procedure with compensations. By limiting side payments to avoid the existence of compensations, investments in

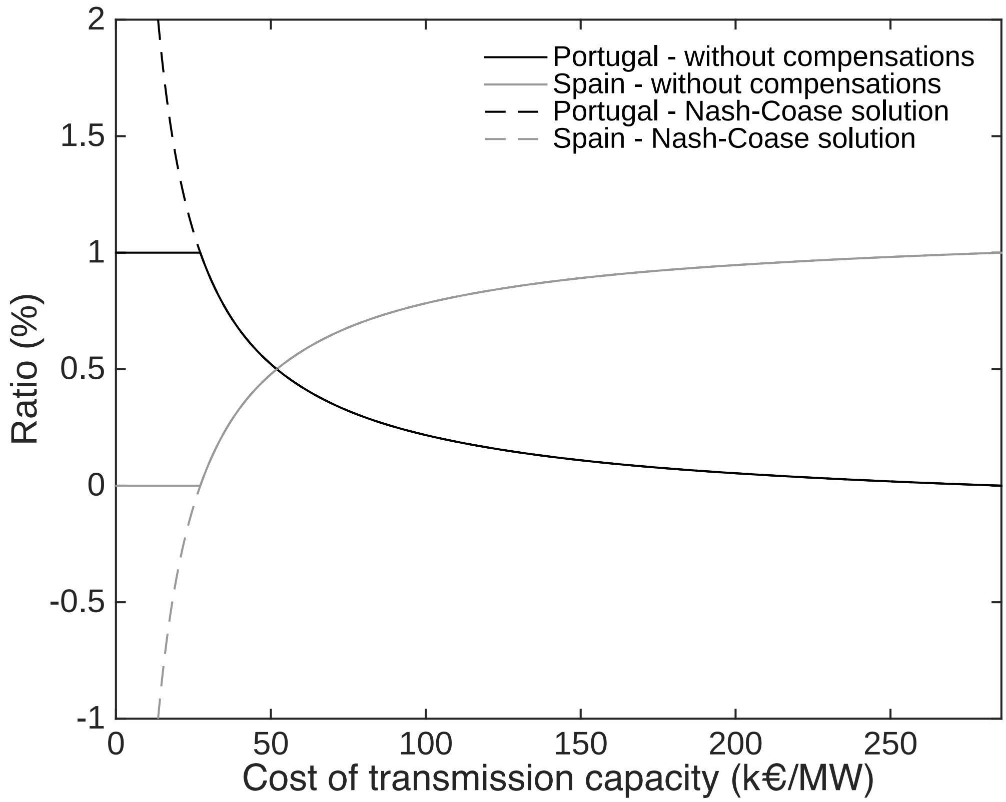

Figure 4.5: Share of investments between Portugal and Spain considering different transmission costs.

transmission capacity can only be the same or decrease when compared to the Nash-Coase solution. For values between 0 and 30 thousand €/MW, transmission capacity investments reduce, and remain generally stable around 3,100 MW. Note that the difference in transmission can be significant implying a maximum reduction of 900 MW. Contrary to expectations though, as transmission capacity costs increase, transmission capacity also increases, even if slightly, for the cost range where compensations would take place. To explain this we must consider that the importer (Portugal) benefits consists of the social welfare increase subtracted of the totality of investments whereas the exporter (Spain) benefits are only given by social welfare improvements. If we consider an increase in transmission costs, the importer is affected with a decreased benefit for any agreed upon transmission capacity whereas the exporter will keep having a benefit which remains independent of costs. This implies a relative increase in bargaining power of the exporter over the importer and thus, given this is a bargaining game, will only agree with the transmission capacity

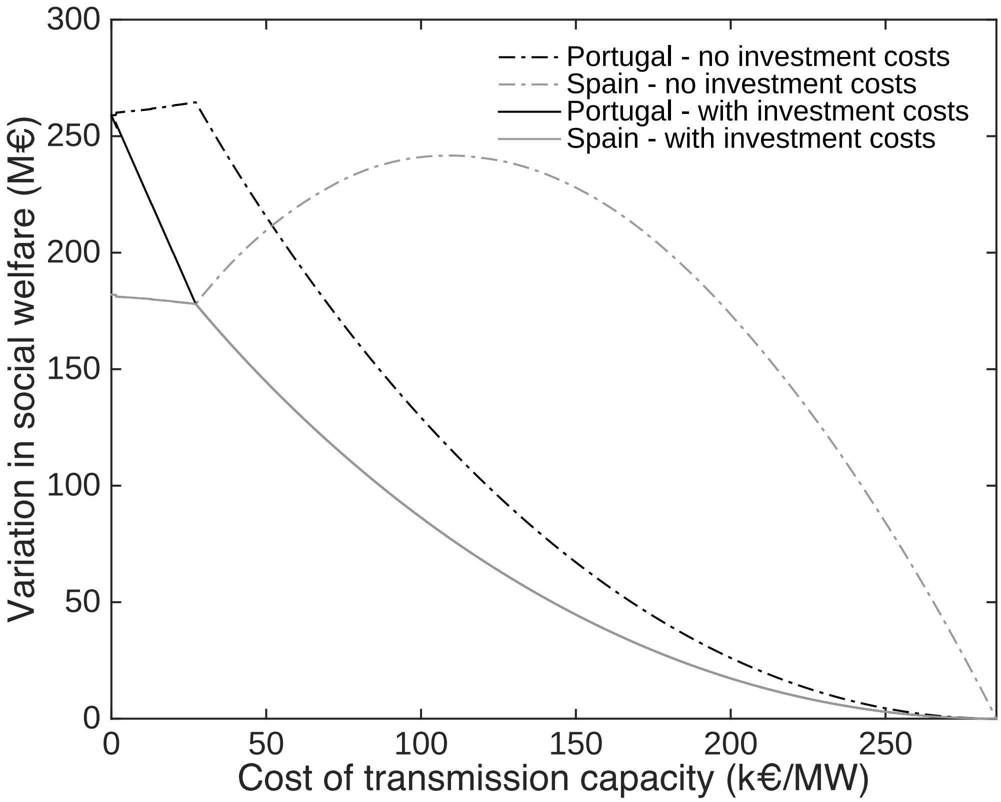

Figure 4.6: Variation in social welfare without compensations considering different transmission costs.

investment if it increases. When compensations would not naturally occur, transmission capacity costs above 30 thousand €/MW, optimal transmission capacity is indistinguishable from the Nash-Coase solution and, as such, decreases with increases in transmission capacity costs.

Although there is a significant uncertainty about the values of the transmission investment costs, in our analysis we use as a reference an upper-bound value u_{ref} of 3.2 thousand €/(MW-km), which is the maximum value reported in Lamy et al. (2014), converted here from USD to EUR. The corresponding annualized transmission investment cost, considering a length of 100 km, has a value of approximately 40 thousand €/MW. In the case of the Iberian market, considering this cost range, according to our model, we would expect a value for cross border capacity in the 3,000 - 4,000 MW interval capped to 3,100 MW in a fair share cross-border cost allocation procedure without compensations. Considering the ongoing projects for the reinforcement of the interconnection capacity between Portugal and Spain, a capacity value of 3,000 MW as expected for 2016 (REN, 2013). Our results are thus in line with the current investment plans, however, as previously noted, it should be emphasized that our model does not account for real world frictions such as the transmission losses or the internal congestion of the transmissions networks.

As the transmission investment costs increase, the allocation of the total interconnection investment costs switches from the importing region to the exporting region, as is clearly visible in Figure 4.5. For the values of the transmission costs in the range below 30 thousand €/MW, the proportion of the cost allocation for Portugal is higher than 100%, which means that the country should pay for the whole interconnection, on both sides of the border, and some form of economic compensation should be provided to the other country, for it to accept the desired level of interconnection capacity. When we do forbid financial compensations, investment costs cannot go over the total thus they are capped at 100%. When the transmission costs rise to 50 thousand €/MW, the total transmission investment costs should be equally shared by both countries. For higher values of the transmission costs, the exporting country (Spain) receives a higher allocation of the costs, which asymptotically approaches 100%. It should be noted that only the importing region can face a situation that implies an economic compensation to the other region.

Figure 4.6 shows the impact of transmission investment costs on the variation of social welfare specifically for the case where compensations are not possible. Considering the importing region Portugal, the variation in social welfare can be split for transmission cost values where the impossibility of compensations bounds the problem and where costs are not binding. In the first interval, between 0 and 30 thousand €/ MW, the variation in social welfare is high and increases slightly to a maximum with increasing costs. Between 30 and 300 thousand €/ MW, increasing transmission investment costs imply a non-linear decrease in the variation in social welfare. For the exporting region Spain, for the same interval, between 0 and 30 thousand €/ MW, the variation in social welfare is slightly decreasing. For transmission investment costs where there is no need for compensations, up to 100 thousand €/ MW we see that the variation in social welfare increases due to a curtailment in traded power that leads to an increase in the price differential of power between regions. Still, above 100 thousand €/ MW transmission capacity is highly curtailed and even with rising price differentials the variation in social welfare decreases. Subtracting investment costs and for transmission investment costs between 0 and 30 thousand €/ MW, we see that net social welfare in the exporting region is the same as its variation in social welfare. However, the importer is responsible for the totality of the investment costs and its net social welfare decreases. Net social welfare converges at 30 thousand €/ MW and for higher transmission investment costs decreases non-linearly and is always the same as Nash-Coase bargaining implies.

Assuming perfect competition, a centralized decision setting and a voluntary agreement setting lead to the same level of investment in interconnection capacity in a market coupled region when side payments are not restricted or compensations are not necessary. As we show, the outcome of the interconnection expansion planning models with a single decision maker may be a useful reference for the desirable level of interconnection capacity for transmission costs higher than 30 thousand €/ MW, the range where we can assume Nash-Coase bargaining.

In our analysis, we have used historical data to estimate the benefits to the social welfare from the investments in interconnection capacity, and our model does not explicitly consider the possibility of an adjustment of the generation bidding strategies. For this reason, we will be over-estimating the revenues from trade, which are expected to decrease in the long term (de Nooij, 2011), and underestimating the reduction in market power for the producers of the importing region (Turvey, 2006). Still, given all the limitations and simplifications in the I-TEP-MCR models, with proper parametrization we were able to obtain realistic results that are in line with the current expectations for these investments in our case application. Many of these limitations may be addressed in future work, but these models are nevertheless useful as fast screening models, capable of providing reliable approximations to optimal interconnection capacities.

4.5 Conclusions

One of the priorities of European policy makers for the energy area is building a pan-European integrated energy market, for which the integration of the national electricity transmission networks is foundational (European Commission, 2010). The reinforcement of the interconnection infrastructure is key for that integration, and requires neighbouring regions to agree on interconnection investment solutions that benefit all parties involved. A recent major step in this direction was given with the joint launching, by seven European Power Exchanges, of the Price Coupling of Regions initiative, to devise a single price coupling solution to define electricity prices and manage cross-border capacity.

In general, these cross-border investment solutions can be reached through centralized decision processes, voluntary local agreements, or combinations of both. In this paper we present an interconnection investment model that considers bargaining between market coupled regions, together with solutions for fair share cost allocation of investment costs in an unlimited setting and where compensations are not allowed.

Our bargaining solution provides a fair share cost allocation, dependent on the uneven increments in social welfare that might accrue to each region from trade, which is useful to address the 'user pays', 'beneficiary pays' and 'tax payer pays' principles that the European Commission has proposed to apply in establishing appropriate financing frameworks for infrastructure development (European Commission, 2010).

With a case study of the Iberian Peninsula, using market data of 2013, we show different patterns of cost allocation, depending on transmission investment costs. At very low costs, the importing country (Portugal) fully supports the investment and if allowed can provide an economic compensation to the exporting country (Spain). As the costs increase, the allocation switches from the importing country to the exporting country.

In both models, an increase in the overall social welfare comes at the expense of the consumers from the exporting region, who will pay a higher price for electricity, and the producers of the importing country, who may have difficulty in dispatching their most expensive generators. Policy makers must be aware of these trade-offs.

The models, however, provide only a *ceteris paribus* valuation of the benefits from electricity trade made possible by investments in the interconnection between two regions. Power consumption may increase as trade is fostered by investments in interconnections between regions, and generation companies may adjust the location and technology of their new generation investments and thus reduce the negative impact of imports in the social welfare in the long term. Populations may have a higher difficulty in adjusting to increasing electricity prices but if, also in this case, generation adjusts to the new scenario and increases capacity, the price increase may be mitigated through an increase in competition. Nevertheless, if these adjustments are insufficient or too slow, and no other wealth transfer mechanisms are put into place, public opinion may present a significant opposition to further steps towards integration and the creation of a single European electricity market.

The results of the I-TEP-MCR models suggest their ability to estimate realistic values for cross-border interconnection investments between two regions. In the case of the Iberian market, the results are in the 3,000 to 4,000 MW interconnection capacity range, when compensations are allowed, and up to 3,100 when these are restricted. Both these results nevertheless contain the projected value for 2016.

Iberia is currently one of the few "electric peninsulas" in Europe (ENTSO-E, 2014), and the interconnection between Spain and France might be one of the interconnections to deserve a larger expansion, to allow the European market to take advantage of the high electricity export capacity in Iberia, enabled by the recent investments in renewable energy. If both parties, Iberia and France, were to benefit from the expansion of the interconnection between Spain and France, a solution through bargaining would come naturally. To realize these investments, however, the expansion of the interconnection will have financial support from the European Union, through the Connecting Europe Facility initiative, the Structural Funds, and the European Fund for Strategic Investment, as well as the European Investment Bank (Madrid Declaration, 2015).

Our analysis suggests that, as a possible outcome of decentralized negotiations for interconnection expansion, a fair share cost allocation might yield a negative proportion, i.e., a direct economic compensation, for one of the regions. An intervention from a supraregional decision-maker, such as the European Union, in the form of a financial support such that uneven benefits accrue to the regions, would be a possible way to implement such compensation.

Modelling and analysing these scenarios would be a natural next step for the research presented in this paper. Further improvements to the models may increase their usefulness: independent consideration of consumer and producer surpluses in each region would allow the analysis of different policy preferences, namely from the Rawlsian perspective, requiring "that inequalities benefit all persons", as opposed to the utilitarian perspective, requiring that "only (...) the general interest be served" (Lyons, 1972); explicit modelling of the transmission networks would allow the assessment of investments in different interconnection corridors, as well as to account for wheeling effects, and to allocate relevant internal transmission investments necessary to relieve regional congestion, as needed for trade; explicit inclusion of long-term uncertainties, which are relevant due to the long construction time and lifespan of these projects; other relevant objectives, such as risk-aversion or environmental impact; additionally, the analysis of different mechanisms to implement the compensations between regions would also be of high relevance under circumstances where benefits from trade are significantly uneven.

Acknowledgments

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4.A Deriving the increase in social welfare constraints

The identification of the importing region and the exporting region roles is based on the comparison of the autarkic prices of the two regions, i.e., the equilibrium prices when trade is not possible, at the intersection of the demand curve (4.1) and the supply curve (4.2). The exporting region is the one featuring the lower autarkic price.

Substituting $D_{s,i}$ and $G_{s,i}$ by the autarkic quantity $q_{s,i}^{\mathrm{aut}}$, we obtain

$$\alpha_{s,i} - \beta_{s,i} q_{s,i}^{\mathrm{aut}} = -\gamma_{s,i} + \delta_{s,i} q_{s,i}^{\mathrm{aut}} \Leftrightarrow q_{s,i}^{\mathrm{aut}} = \frac{\alpha_{s,i} + \gamma_{s,i}}{\beta_{s,i} + \delta_{s,i}}. \tag{4.30}$$

The autarkic price $p_{s,i}^{\mathrm{aut}}$, obtained by substituting $q_{s,i}^{\mathrm{aut}}$ in (4.2), is

$$p_{s,i}^{\mathrm{aut}} = \alpha_{s,i} - \beta_{s,i} \frac{\alpha_{s,i} + \gamma_{s,i}}{\beta_{s,i} + \delta_{s,i}} = \frac{\alpha_{s,i}\delta_{s,i} - \gamma_{s,i}\beta_{s,i}}{\beta_{s,i} + \delta_{s,i}} = \frac{b_{s,i}}{a_{s,i}}, \tag{4.31}$$

with $a_{s,i}$ and $b_{s,i}$ defined in (4.5) and (4.6).

Introducing trade, we consider a same imported and exported F_s quantity:

$$F_s = G_{s,X} - D_{s,X} = D_{s,M} - G_{s,M} \Leftrightarrow \tag{4.32}$$

$$\Leftrightarrow \frac{P_{s,X} + \gamma_{s,X}}{\delta_{s,X}} - \frac{\alpha_{s,X} - P_{s,X}}{\beta_{s,X}} = -\frac{P_{s,M} + \gamma_{s,M}}{\delta_{s,M}} + \frac{\alpha_{s,M} - P_{s,M}}{\beta_{s,M}} \Leftrightarrow \tag{4.33}$$

$$\Leftrightarrow a_{s,X} P_{s,X} - b_{s,X} = -a_{s,M} P_{s,M} + b_{s,M}. \tag{4.34}$$

Assuming free trade, the traded quantity f_s^{FT} is such that the price differential is eliminated, and the single free trade price p_s^{FT} is given by:

$$a_{s,X} p_s^{\mathrm{FT}} - b_{s,X} = -a_{s,M} p_s^{\mathrm{FT}} + b_{s,M} \Leftrightarrow p_s^{\mathrm{FT}} = \frac{b_{s,X} + b_{s,M}}{a_{s,X} + a_{s,M}}. \tag{4.35}$$

For the free trade quantity:

$$f_s^{\mathrm{FT}} = a_{s,X} p_s^{\mathrm{FT}} - b_{s,X} = \frac{a_{s,X} b_{s,M} - a_{s,M} b_{s,X}}{a_{s,X} + a_{s,M}}. \tag{4.36}$$

With trade capped by the transmission capacity of the interconnection K,

$$f_s = \min\left\{f_s^{\mathrm{FT}}, K\right\}. \tag{4.37}$$

The social welfare, $\mathrm{sw}_{s,i}$, is defined as the sum of the consumer surplus and the producer surplus, i.e., the area under the demand curve and to the left of the demand in equilibrium $d_{s,i}$, subtracted of the area under the supply curve and to the left of the supply in equilibrium $g_{s,i}$. To account for trade, its profits and costs, i.e., the traded quantity multiplied by the price in the importing region, are also considered:

$$\mathrm{sw}_{s,X} = \int_0^{d_{s,X}} P_{s,X}\ \mathrm{d}D_{s,X} - \int_0^{g_{s,X}} P_{s,X}\ \mathrm{d}G_{s,X} + p_{s,M} f_s \tag{4.38}$$

$$\mathrm{sw}_{s,M} = \int_0^{d_{s,M}} P_{s,M}\ \mathrm{d}D_{s,M} - \int_0^{g_{s,M}} P_{s,M}\ \mathrm{d}G_{s,M} - p_{s,M} f_s. \tag{4.39}$$

Using appropriate substitutions and integrating we obtain:

$$\mathrm{sw}_{s,X} = \frac{1}{2}\left(\frac{\alpha_{s,X}^2}{\beta_{s,X}} + \frac{\gamma_{s,X}^2}{\delta_{s,X}} - \frac{b_{s,X}^2}{a_{s,X}}\right) + \left(\frac{b_{s,M}}{a_{s,M}} - \frac{b_{s,X}}{a_{s,X}}\right) f_s - \frac{1}{2}\left(\frac{2}{a_{s,M}} + \frac{1}{a_{s,X}}\right) f_s^2 \tag{4.40}$$

$$\mathrm{sw}_{s,M} = \frac{1}{2}\left(\frac{\alpha_{s,M}^2}{\beta_{s,M}} + \frac{\gamma_{s,M}^2}{\delta_{s,M}} - \frac{b_{s,M}^2}{a_{s,M}}\right) + \frac{1}{2a_{s,M}} f_s^2. \tag{4.41}$$

4.B Rewriting free-trade flows $f_s = \min\left\{f_s^{\mathrm{FT}}, K\right\}$

We substitute each constraint as the following optimization model

$$\max \quad f_s \tag{4.42}$$

$$\mathrm{s.t.} \quad f_s \le f_s^{\mathrm{FT}} \quad : \mu_{F,s} \tag{4.43}$$

$$f_s \le K \quad : \mu_{K,s}. \tag{4.44}$$

The above model can be substituted by the complementarity conditions,

$$1 = \mu_{F,s} + \mu_{K,S} \tag{4.45}$$

$$0 \le \mu_{F,s} \perp f_s^{\mathrm{FT}} - f_s \ge 0 \tag{4.46}$$

$$0 \le \mu_{K,s} \perp K - f_s \ge 0. \tag{4.47}$$

4.C Equality of μ_X and μ_M

μ_X and μ_M, in (4.25), are Lagrange multipliers of inequalities, and thus non-negative. We next consider combinations of null or positive values for the two multipliers.

With $\mu_X > 0$ and $\mu_M > 0$, from (4.23) $\sum_{s\in\mathcal{S}} h_s\,\Delta\mathrm{sw}_{s,X} = I_X$, and from (4.24) $\sum_{s\in\mathcal{S}} h_s\,\Delta\mathrm{sw}_{s,M} = I_M$. From (4.21) and (4.22) $\mu_X = \lambda_I = \mu_M$.

With $\mu_M > 0$, from (4.24) $\sum_{s\in\mathcal{S}} h_s\,\Delta\mathrm{sw}_{s,M} = I_M$, and from (4.21) $\lambda_I = \mu_X$. If $\mu_X = 0$, $\lambda_I = 0$, and from (4.23) $\sum_{s\in\mathcal{S}} h_s\,\Delta\mathrm{sw}_{s,X} - I_X = -\mu_M$, whereas from (4.22) $\sum_{s\in\mathcal{S}} h_s\,\Delta\mathrm{sw}_{s,X} - I_X \geq 0$, which are in contradiction. A similar result is obtained for $\mu_X > 0$ and $\mu_M = 0$.

Considering the above and also the case when $\mu_X = \mu_M = 0$, $\mu_X = \mu_M$, allowing the simplification of (4.25).

4.D Equality of the Nash-Coase bargaining and centralized interconnection planning model solutions

We define

$$\tau = \sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\,\Delta\mathrm{sw_{s,M}} - I_M = \sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\,\Delta\mathrm{sw_{s,X}} - I_X. \tag{4.48}$$

Objective function (4.14) can be rewritten as $\max \tau^2$. With (4.19) and (4.20), $\tau \geq 0$ and the same results are obtained using $\max \tau$ or

$$\begin{aligned}\max 2\tau &= \max \sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\,\Delta\mathrm{sw_{s,M}} - I_M + \sum_{\mathrm{s}\in\mathcal{S}} \mathrm{h_s}\,\Delta\mathrm{sw_{s,X}} - I_X = \\ &= \max \sum_{s\in\mathcal{S}} h_s\,(\Delta\mathrm{sw}_{s,M}\,\Delta\mathrm{sw}_{s,X}) - I,\end{aligned} \tag{4.49}$$

where $I = I_X + I_M$.

Equations (4.19) and (4.20) are redundant as $I = 0 \Rightarrow \Delta\mathrm{sw}_{s,i} = 0, \forall s \in \mathcal{S}, i \in \{X, M\}$, the objective value is zero and maximizing the objective function always results in a non-negative value.

Chapter 5

Transmission expansion planning and cost allocation under uncertainty

European power systems are undergoing a unification process, with the broader goal of improving the social welfare of European citizens, although currently with a more specific focus on improving renewable penetration, by means of resource sharing. As market coupling efforts advance, new interconnection development projects may be required, to address power transfer needs of Member States. Concurrently, the energy mix is changing in favor of less polluting generation technologies, a new reality that may also contribute to increase the pressure on transmission infrastructure. However, the extent to which this paradigm shift happens depends heavily on the uncertain adoption of environmental policies.

In this work, we propose a transmission planning model including a Stackelberg game in which the Transmission System Operators (TSOs) of two market coupled regions acting as leader, deciding on the long-term transmission investments, and the follower being an Independent System Operator (ISO), with responsibility for hourly dispatch. The model also includes a portfolio of real options framework, with the TSOs cooperating and acting as single multi-stage decision-makers with decisions that are contingent on the uncertain evolution of the generation portfolio and demand. Transmission investment costs are later split between regions using a fair share cost allocation procedure based on Nash-Coase bargaining. Using electricity bid data from the Iberian Electricity Market and considering an evolution according to ENTSO-E's four Visions for 2030, we study scenarios for the development of the Portugal-Spain interconnection during the period of 2015-2030.

This work results in a novel transmission expansion planning model that may assist TSOs in identifying transmission line investment requirements, considering their timing and the conditions in which they should be carried out, and also accounting for their contribution to regional social welfare improvement and a fair share allocation of investment costs.

5.1 Introduction

With the European Internal Energy Market perspective, the European Union (EU) power system infrastructure is going through a series of changes to transform regional transmission networks into a single pan-European infrastructure. Concurrently, electricity Power Exchanges (PXs) are being integrated, through the Price Coupling of Regions (PCR) initiative, with the objective of devising a single electricity market where all Member States trade power based on bid prices curtailed by network capacities including cross-border interconnection lines. The development of Roadmap 2050 aims at reducing carbon emissions by at least 80% below 1990 levels by 2050. As consequence, integration of increasing renewable energy sources (RES) must be secured by pairing the generation investments that these policies might foster, with transmission investments that allow power transfers between EU Member States with higher and lower renewable potentials. The European Network of Transmission System Operators for Electricity (ENTSO-E) identified four areas where transmission expansion that improves cross-border power flows with mainland Europe is critical (ENTSO-E, 2014). These four areas, being the Iberian Peninsula, the Baltic States, Italy, and Great Britain and Ireland, have in common a high RES development potential which cannot be availed when accompanying transmission investments are not secured.

Traditional methods of valuation and decision-making assume stable environments, in which costs and benefits can be well specified. In many important contexts, however, investment plans are subject to uncertainties, multiple agents acting according to their own interests and influencing each other, and the significant interaction between current and future investment decisions. In these contexts, the quality of decisions improves when the value of postponement and operational flexibility and the strategic value of reacting to other parties involved are explicitly considered (Smit and Trigeorgis, 2004).

In the specific case of interconnection planning in power systems, uncertainty in key decision parameters must be considered, given the magnitude of the investment costs, as well as the irreversibility of the investments and their impact in the overall development of a region. Moreover, the fact that cross-border interconnections have an impact on at least two neighbouring economies requires a fair share methodology to assign the responsibilities for investment costs, and to enable strategic coordination of TSOs. A source of this strategic value is the interaction between TSOs and market agents, generation companies (GENCOs) and consumer companies, as the TSOs must preempt electricity dispatch in both volumes, prices and network congestion. A further source is the cooperation required from neighbouring TSOs in realizing both the cross-border and the internal investments required to optimize social welfare. The topics of flexible and strategic decision-making are therefore very important for the integration process, but are not currently receiving appropriate attention, neither from the literature, nor from practitioners. It should however be emphasized that Munoz et al. (2015) suggest that sophisticated transmission expansion planning models consider features such as: joint expansion of transmission and generation; time granularity that encompasses multiple operating conditions; introduction of long-term uncertainty; and, inclusion of the option value to delay investment decisions.

It is our aim to present a novel Transmission Network Expansion Planning (TNEP) model with market based dispatch decisions where time-varying key variable uncertainties can be represented. Thus, we are able to obtain an expansion plan that suggests both present day investment decisions and future decisions contingent to the unfolding of events. This model addresses most significantly the two latter suggestions by Munoz et al. (2015), the inclusion of long-term uncertainty and the option value to delay investment decisions. We also present a post-processing method that provides a fair share cost allocation of the investment costs between regions, based on Nash Bargaining and the Coase Theorem, presented in Chapter 4.

We follow this introduction with a literature review in Section 5.2. We propose a new transmission expansion model under uncetainty and a fair share cost allocation method in Section 5.3. In Section 5.4 a case study based on Portugal and Spain is presented. We follow with a presentation of the case study results and discussion, respectively in Sections 5.5 and 5.6. We then conclude the current research paper with Section 5.7.

5.2 Literature review

Interconnection investments require coordination between neighbouring TSOs and are driven by interconnection congestion, which is defined in Regulation 1228/2003[1] as *"a situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnections and/or the national transmission systems concerned"*. Methods to relieve cross-border congestion between neighbouring regions can be grouped into non-market and market-based methods (Kristiansen, 2007).

Non-market-based methods in general are regulated efforts, leading the resulting congestion payments not to be priced according to their real economic value. This represents a shortcoming in the economic signals that these methods present to investments in the reinforcement of the transmission system. Market-based methods, on the other hand, have the distinct advantage that the prices arising from the interactions among different players are powerful economic signals to guide the expansion of the transmission system. In Europe, non-market-based methods were initially replaced by border auctions, in which the players had to bid for interconnection capacity, while simultaneously bidding in their respective transmission systems. The PCR initiative then changed this situation. Whereas auctions required explicit price arrangements for interconnection access, with market coupling, i.e., the unification of the individual markets, interconnection bidding became implicitly considered when GENCOs bid to dispatch or consumers bid to access power. Under market coupling, bids are placed in the players' PX location and trade between regions takes place as long as the existing interconnection capacity is enough. When market equilibrium is reached without limitations to the flows between regions, a single market price emerges. This solution is similar to Locational Marginal Pricing (LMP), except for the fact that with LMP different prices are expected in each network bus when congestion in transmission lines exists, and in market coupling, subsets of nodes are constrained to have the same price, whether internal congestion exists or not. Therefore, market coupling only accounts for congestion and price differentials across regions.

Interconnection expansion processes generally take 5 to 10 years to complete, and in some

[1]Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity.

extreme cases have taken up to 20 years (Ciupuliga and Cuppen, 2013): the process is intrinsically difficult, as decisions must consider timing, location and sizing of expansions (Davis et al., 1987), and multiple players must agree on the investment plan; obtaining permits to expand capacity is also a considerable difficulty (Dobbeni, 2007), that must be overcome in all related regions; and additional difficulties arise from the lack of public and political support.

Interconnections are key in this process, since suboptimal capacity levels will force a limit on imports and/or exports, require excessive generation capacity commitments for security of supply, maintain price differentials between regions, preclude more effective generation investments from being pursued (Amundsen and Nese, 2009), and require a larger amount of generation to guarantee market operation (Unteutsch and Lindenberger, 2014). For instance, the exploitation of the RES potential in the Iberian Peninsula will remain limited if insufficient cross-border capacity keeps limiting its ability to export this excess power to mainland Europe (Domínguez and Bernat, 2007). Another example is the fact that Belgium currently requires, and is prepared to subsidise, an increase in generation capacity, which its Dutch neighbours would already be able to satisfy, preventing investments in less profitable generators, as well as unnecessary government expenditures[2].

Buijs et al. (2007) have argued that one of the reasons for the interconnection capacity deficit in Europe is the interference of politics with TSO decisions. For instance, in exporting regions consumers will see an increase in the price of electricity to the benefit of a reduction in the price of the importing region. The accrued producer surplus in the exporting region and consumer surplus in the importing region compensate a reduction in the consumer surplus in the exporting region and in the producer surplus in the importing region. To the detriment of these latter agents, negative externalities are imposed and the political sphere might become discouraged to support market integration. Politicians might then be more willing to prioritize local goals in decision-making instead of corroborating the EU vision.

Buijs et al. (2011) and Buijs and Belmans (2012) present transmission expansion planning models where TSOs of different regions act independently, building new interconnection lines

[2] Energy Post, 03/02/2015, A "J'Accuse" from an ex-EU official: only a real Energy Union can save the EU energy market http://www.energypost.eu/jaccuse-ex-eu-official-real-energy-union-can-save-eu-energy-market/ (Accessed on 05/02/2015)

assuming responsibility for the share of investment in their territory. The players act individually and make decisions within a non-cooperative game. The obtained solution is a Nash equilibrium, thus worse than a supraregional decision where the benefits of all parties are jointly considered. These models suggest that TSOs have no possibility of colluding in the best interest of the regions in which they operate.

Another limitation that deserves to be addressed, although one in line with current practice, is the sharing of investment costs based on their geographical location. Even though most of the benefits might accrue to one of the regions, if the investments are mostly located in the other region, then the player with smaller benefits would also be the one to support the largest share of investments. This relaxation is reasonable in practice. For instance, in 2002 a local agreement between Italy and Greece unevenly split the investment costs of a new underwater transmission cable in 75% and 25% shares, respectively (Meeus and He, 2014). Reinforcement of cross-border interconnections must then consider agreement between the involved Member States, and transmission expansion planning models must take their cooperation into consideration.

To the best of our knowledge, our previous work, presented in Chapter 4, is the first that formally assumes a cooperative situation using Nash-Coase bargaining. One of the main results is that a Pareto efficient solution indistinguishable from centralized solutions is guaranteed while providing a fair share investment cost allocation procedure between the two players. This equivalence between cooperation and centralized decisions allow us to model the two players as a single decision-maker, a fact we explore in the current study. Fair sharing translates to a share of investment costs such that the transmission line investment net social welfare benefits are evenly split. It should be noted that a possible outcome is that one of the players is responsible for more than the total of the investment costs, which prefigures a direct economic compensation to the other player. Notwithstanding these models lack a long-term perspective on investment decisions.

5.3 Mathematical formulation

5.3.1 Strategy

Our proposed transmission planning model consists of a Stackelberg game. The TSOs of two market coupled regions cooperate and jointly act as the Leader. The Follower describes an Electricity Market Operator, in our case, due to market deregulation, an ISO. In short, the Leader is responsible for transmission lines investment decisions in the long-term, by anticipating market clearing and dispatch decisions, both in terms of supply and demand and regarding for transmission network constraints, of the myopic Follower. The latter only acts considering the existing transmission network, i.e. the starting transmission network configuration including the transmission lines invested up to the ISO decision moment. The TSOs cooperate and act as a single multi-stage decision-maker whose transmission line investment decisions are contingent to the uncertain sequences of events and rely on the uncertain evolution of the available generation portfolio and electricity demand. Based on the original capacities of supply and demand these change based on their stochastic nature. Subsequently, transmission investment costs are split between regions based on a fair share cost allocation procedure.

Without considering multiple players, Chapters 2 and 3 already presented a model for transmission network expansion plannign under uncertainty. Konstantelos and Strbac (2015) propose a model that treats expansion decisions contingent on the unfolding of a single uncertainty, consisting of a Stackelberg game where the Leader has a similar long-term strategic investment role and the Follower solves operational issues. Given the computational difficulties of solving such bilevel problem, their results are obtained using a multicut Benders decomposition formulation (Birge and Louveaux, 1988). Another possible strategy to simplify bilevel problems, the one we follow in the present study, is to reformulate them as Mathematical Problems with Equilibrium Constraints (MPEC).

A MPEC is a bilevel problem, an optimization problem with additional constraints representing equilibrium conditions of exogenous decision-makers (Gabriel et al., 2013), represented as a single level problem. We draw inspiration from Garcés et al. (2009) to model the Transmisison Network Expansion Planning Stackelberg game where KKT optimality conditions are used to reformulate the ISO Follower problem. We do not follow this approach however, as this method transforms inequality constraints into complementarity conditions that must either be expressed with non-linearities or extra binary variables as proposed by Fortuny-Amat and McCarl (1981). Our approach most closely resembles Pozo et al. (2013) in which three levels of decision-makers, TSOs, GENCOs and ISO are modeled as a trilevel problem under which the ISO, the third level, is reformulated using Duality theory, and the GENCOs, the second level, is reformulated using KKT optimality constraints.

Given the complexity of the model and the problems we faced to solve our case study, the strategy to reformulate the bilevel problem into a MPEC, where the ISO pertains to the second level and the cooperative solution of the TSOs is the first level, lies in avoiding the introduction of non-linearities or extra binary variables beyond the minimum required to keep track of investment decisions already existent in the original bilevel model. This approach is novel in that it considers: Duality theory for the specific case of linear problems as a basis; the mathematical manipulation of the second level constraints taking advantage of specific Karush-Kuhn-Tucker (KKT) optimality conditions; resorting to linearisation of non-linear terms; and, assuming weak Duality, introducing the duality gap in the MPEC objective function, in order to reduce computational times.

In contrast with Garcés et al. (2009) and Pozo et al. (2013), and similarly to Loureiro et al. (2015)[3] and Konstantelos and Strbac (2015), our formulation is driven by a long-term perspective with uncertain realization of events. The cooperant TSOs must act defining a set of investment decisions to be realized at the present as well as defining a contingency plan where transmission line investment decisions are only executed for a particular unfolding of events.

Uncertainties are implemented using the Portfolio of Real Options framework (Brosch, 2008; Loureiro et al., 2015). It consists of the definition of a path-dependent decision tree under which uncertain variables are given discrete values for each tree node. These values are obtained through tree generation methodologies that represent the variability that characterizes them. Conceptually, a root node representing the present situation leads to a new set of nodes that characterize the following time period. In turn, these nodes also lead to new nodes characterizing the following time period. This process is repeated a number of times, both in terms of the number of nodes generated by each preceding node and total number of time periods based on the desired granularity which, as trees grow exponentially, is generally limited by computational resources. In

[3]Loureiro et al. (2015) is reproduced as Chapter 2

the present formulation, each node in the tree corresponds to the different years of operations and alternative evolution of events. These nodes are represented by $n \in \mathcal{N}$.

Path-dependency is critical in network design as not only a given node in the tree influences expansion decisions, but also prior expansions have already forced adjustments leading to the current transmission capacities. If multiple branches converge to a particular node it is then not possible to keep track of what is the current configuration of the network. We adjust this by duplicating nodes such that each node in a given time period has a single node in each of the previous time periods leading to it. It is important to note however, that the nodes that are repeated into multiple branches are characterized by the same realization of underlying uncertainties, in our case supply and demand across all network buses, and, by following this approach, the tree increases considerably in size.

These different realizations of the uncertainties must be distinguished from the different operating conditions of the market. Such scenarios are represented by $s \in \mathcal{S}$, they pertain to intra-year variations of season, day of the week and operating hours.

In each pair $\{ns\} \in \mathcal{N} \times \mathcal{S}$ an explicit transmission network is considered, forcibly the same across all scenarios. Buses, $i \in \mathcal{I}$, are connected among each other according to transmission lines $x \in \mathcal{X}$ where x is a tuple $\{ijk\}$ from set $\mathcal{X} = \mathcal{I} \times \mathcal{I} \times \mathcal{K}$. We also define the opposite direction tuple $y = \{jik\} \in \mathcal{X}$. Transmission lines connecting the same pair of buses are indexed using $k \in \mathcal{K}$.

Whereas other references in this field of study use buses and nodes interchangeably to define network buses, we require a more strict definition to distinguish the transmission network from the path-dependent decision tree. Nodes only represent possible unfoldings of uncertainties through time, while buses pertain to the transmission network. Similarly, scenarios do not represent alternative representations of the unfolding of events but are exclusively used to represent multiple occurring operating conditions that take place within a year. This can be more easily understood in Figure 5.1 where the distinctions between nodes, scenarios, network and market, also specifying which concern the Leader and Follower in the Stackelberg game, are characterized. Given the long-term contingent investment decisions of the Leader (the TSOs), the Follower (the ISO), is aware of the structure of the decision tree, with its different nodes and scenarios. Without loss of generality the decision tree is dimensioned to represent the Case Study explored in the current

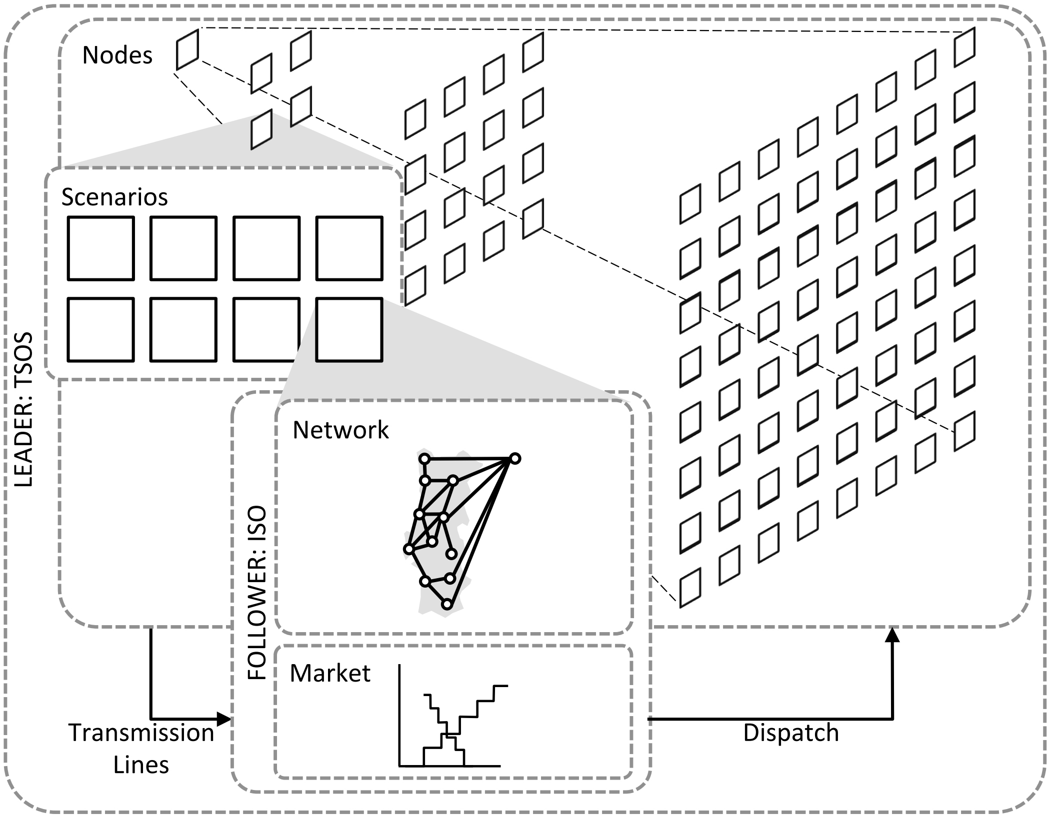

Figure 5.1: Representation of the bilevel problem.

research paper. For each time period t and for a horizon of T future time periods we obtain a total number of $|\mathcal{N}| = \sum_{t=0}^{T} 4^t$ nodes as we assume that each node expands to 4 nodes in the following time period. As will be seen in the Case Study, this number relates to a number of possible unfoldings of supply and demand. Even though scenarios are presented for a single node, they are represented with the same structure of 8 scenarios for all nodes. In what regards the Follower, the network topology and market dispatch should be considered. The Leader and Follower are dependent on each other's variables. Namely, the Follower requires the knowledge of which new transmission lines were invested in, ω_{nx}, updating the network topology, Ω_{nx}, which will allow for correct market dispatch. Given the market equilibrium, the Leader is aware of power dispatch, G_{nsib}, and satisfied demand, D_{nsib}, which it can use to estimate the improvement in social welfare.

After obtaining a solution to the model introduced above, a cost allocation procedure allows the TSOs of the two distinct market coupled regions to split investment costs. As we assume that the two regions cooperate to obtain their respective contribution to the total investments, Nash-Coase bargaining provides a fair share solution that specifies that the marginal benefit of the investments should be equally split (Cherry and Shogren, 2005; Loureiro et al., 2016).

Figure 5.2 presents a simplified explanation of the previous statement that Nash-Coase Equilibrium requires that marginal benefits in social welfare, SW_{np}, are equally split between entities. Considering that Nash Bargaining axiomatically requires Pareto efficiency (Osborne and Rubinstein, 1990), we represent a Pareto frontier using a solid line. Geometrically, the bargaining solution, illustrated by point NBE, is given by the intersection of this frontier with the rectangle inscribed within it and restricted to the positive quadrant that maximizes its area.

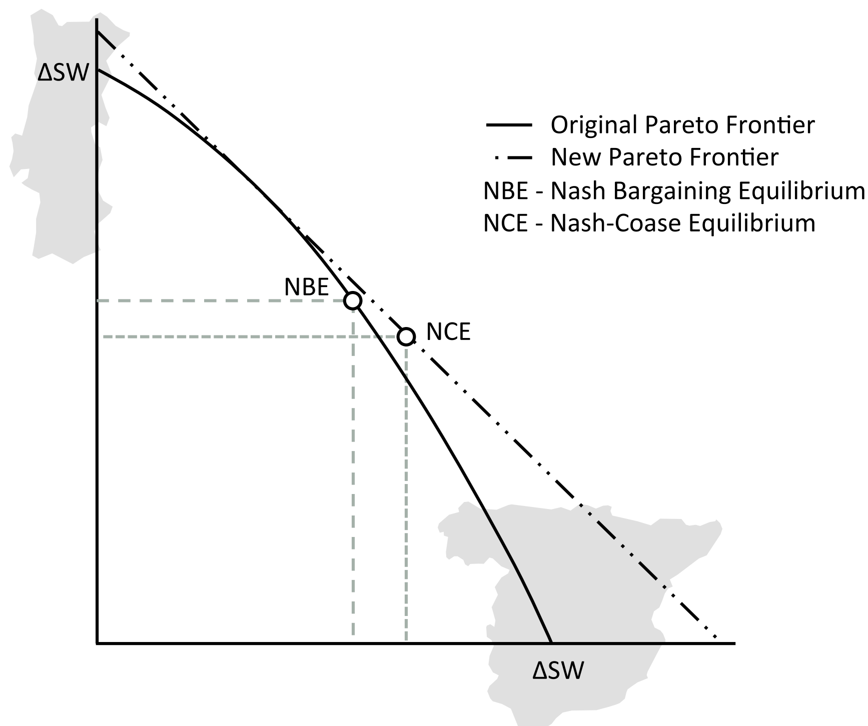

Figure 5.2: Representation of a Pareto frontier, Nash Bargaining Equilibrium and Nash-Coase Equilibrium.

The Coase Theorem states that under rationality and absence of both transaction costs and legal impediments, efficient solutions can be obtained through bargaining (Coase, 1937; Cooter, 1982; Calabresi, 1991). To obtain a Coasian efficient solution, our solution is such that joint profits are maximized and what remains is the distribution of the cooperative surplus. In other terms, we must obtain a new Pareto frontier where the sum of the benefits for both players equals the sum of the benefits of the efficient solution. Considering the above Figure, the new Pareto frontier, represented by a dashed-dotted line, results from finding the tangent to the original Pareto frontier with negative unitary slope. Accordingly, as the frontier is symmetric, we find that Nash-Coase bargaining solution, point NCE, requires the surplus of the cooperative effort to be equally split.

5.3.2 Mathematical problem with equilibrium constraints

The transmission planning model that simultaneously maximizes social welfare surplus under the TSOs and Market perspectives can be expressed as a bilevel programming model using Equations (5.1)-(5.13). Equations (5.1)-(5.7) correspond to the Leader problem, reflecting the cooperative perspective of the TSOs and maximizing long-term uncertain social welfare surplus considering costs for new transmission developments. The Follower problem, concerning the Market maximizing short-term social welfare independent of transmission investment costs, is reflected in Equations (5.8)-(5.13). Therefore,

$$\max \sum_{m\in\mathcal{M}} \rho_m \left[\sum_{n\in\mathcal{P}(m)\setminus m} \left(\mathrm{SW}_n\, \beta_n - \frac{I_n}{(1+r)^{t_n \Delta t}} \right) + \mathrm{SW}_m\, \phi_m \right] \tag{5.1}$$

$$\text{s.t.}\ \mathrm{SW}_n = \sum_{s\in\mathcal{S}} \sum_{i\in\mathcal{I}} \sum_{b\in\mathcal{B}} h_s P_b \left(D_{nsib} - G_{nsib}\right) \qquad ,\forall n\in\mathcal{N} \tag{5.2}$$

$$I_n = \sum_{x\in\mathcal{X}} C_x \omega_{nx} \qquad ,\forall n\in\mathcal{N} \tag{5.3}$$

$$\Omega_{nx} = \Omega_{a_n,x} + \omega_{a_n,x} \qquad ,\forall x\in\mathcal{X}, n\in\mathcal{N}\setminus\{0\} \tag{5.4}$$

$$\Omega_{0,x} = \Omega_x^{\min} \qquad ,\forall x\in\mathcal{X} \tag{5.5}$$

$$\sum_{n\in\mathcal{P}(m)} \omega_{nx} \leq \left(1-\Omega_x^{\min}\right)\Omega_x^{\max} \qquad ,\forall x\in\mathcal{X} \tag{5.6}$$

$$\omega_{nx} = \{0,1\} \qquad ,\forall x\in\mathcal{X}, n\in\mathcal{N}\setminus\mathcal{M} \tag{5.7}$$

$$G_{nsib}, D_{nsib} \in \arg\max \left\{ \sum_{i\in\mathcal{I}} \sum_{b\in\mathcal{B}} P_b \left(D_{nsib} - G_{nsib}\right) \right. \tag{5.8}$$

$$\text{s.t.} \sum_{b\in\mathcal{B}} \left(D_{nsib} - G_{nsib}\right) - \sum_{x\in\mathcal{X}_i} F_{nsx} = 0 \quad : \mathrm{LMP}_{nsi} \qquad ,\forall i\in\mathcal{I} \tag{5.9}$$

$$-(1-\Omega_{nx})M \leq \frac{F_{nsx}}{B_x} + \left(\theta_{nsi} - \theta_{nsj}\right) \leq (1-\Omega_{nx})M : o^-_{nsx}, o^+_{nsx} \qquad ,\forall x\in\mathcal{X} \tag{5.10}$$

$$0 \leq G_{nsib} \leq G_{sib}^{\max} \psi_{nib}^{G} \quad : g^-_{nsib}, g^+_{nsib} \qquad ,\forall i\in\mathcal{I}, b\in\mathcal{B} \tag{5.11}$$

$$0 \leq D_{nsib} \leq D_{sib}^{\max} \psi_{nis}^{D} \quad : d^-_{nsib}, d^+_{nsib} \qquad ,\forall i\in\mathcal{I}_D, b\in\mathcal{B} \tag{5.12}$$

$$- F^{\max}_{nx}\Omega_{nx} \leq F_{nsx} \leq F^{\max}_{nx}\Omega_{nx} \quad : f^{-}_{nsx}, f^{+}_{nsx} \qquad , \forall x \in \mathcal{X} \tag{5.13}$$

$$\Big\}, \forall n \in \mathcal{N}, s \in \mathcal{S}.$$

Objective function of the Leader problem, Equation (5.1), states that for each path weighted by its probability ρ_m, in each node of that path, the social welfare associated with each node (SW_n) and investment cost (I_n) are discounted to the present (β_n) and added to obtain an expanded net present value of the transmission plan. The present value of a perpetuity is also obtained by transforming the last social welfare in each path using multiplier ϕ_m. $\beta(m)$ and ϕ_m are explained in Appendix 5.A. Equation (5.2) defines social welfare in each node as the difference between demand and generation based on bid price and adjusted for the number of hours pertaining to a whole year, based on scenarios. Investment costs are defined in Equation (5.3) as the sum in each node of the investment costs C_x of new transmission lines ω_{nx}. Equation (5.4) states that the available transmission lines are defined as the existing network added of the transmission lines introduced in the previous node. The initial network is described with Equation (5.5). With this equation as well as Equation (5.6) we avoid defining Ω_{nx} as binary. This latter equation states that in each path a line can only be built once and only if it has not been built yet. Investment decisions are the single set of binary variables, as represented with Equation (5.7).

Considering now the objective function of the Follower, Equation (5.8), we see that it maximizes social welfare for each node and scenario. Equation (5.9) forces Kirchoff's current law, stating that the difference between supplied and consumed power in each network bus must flow to other connected buses. Equation (5.10) is a binding constraint for existing transmission lines, represented by $\Omega_{nx} = 1$, that characterizes linearized power flow between two buses, by the difference between phase angles and accounting for line susceptance. Equations (5.11) and (5.12), guarantee that supplied and consumed power, respectively, are non-negative and not higher than bided quantities. The ψ^{G}_{nib} and ψ^{D}_{nib} parameters are multipliers that act on bided quantities to adjust them to the respective node in the decision tree. Equation (5.13) states that flows cannot be higher, as absolute values, to the maximum flow of the transmission line. Where the transmission line does not exist, $\Omega_{nx} = 0$, no flow is possible.

Let us consider the Follower model, Equations (5.8)-(5.13), as our Primal problem. The Dual problem is given by

$$
\begin{aligned}
\min & \sum_{i\in\mathcal{I}}\sum_{b\in\mathcal{B}}(G^{\max}_{sib}\psi^{G}_{nib}g^{+}_{nsib}+D^{\max}_{sib}\psi^{D}_{nis}d^{+}_{nsib})+ \\
& + \sum_{x\in\mathcal{X}}F^{\max}_{nx}\Omega_{nx}(f^{+}_{nsx}+f^{-}_{nsx}) + \sum_{x\in\mathcal{X}}(1-\Omega_{nx})M(o^{+}_{nsx}+o^{-}_{nsx}) & (5.14) \\
\text{s.t.} & -P_b + \mathrm{LMP}_{nsi} + d^{+}_{nsib} \geq 0 \quad ,\forall i\in\mathcal{I}, b\in\mathcal{B} & (5.15) \\
& P_b - \mathrm{LMP}_{nsi} + g^{+}_{nsib} \geq 0 \quad ,\forall i\in\mathcal{I}, b\in\mathcal{B} & (5.16) \\
& -\mathrm{LMP}_{nsi} + \frac{o^{+}_{nsx}-o^{-}_{nsx}}{B_x} + \left(f^{+}_{nsx}-f^{-}_{nsx}\right) = 0 \quad ,\forall x\in\mathcal{X} & (5.17) \\
& \sum_{j\in\mathcal{I}}\sum_{k\in\mathcal{K}}\left(o^{+}_{nsx}-o^{-}_{nsx}\right) - \sum_{j\in\mathcal{I}}\sum_{k\in\mathcal{K}}\left(o^{+}_{nsy}-o^{-}_{nsy}\right) = 0 \quad ,\forall i\in\mathcal{I} & (5.18) \\
& o^{+}_{nsx}, o^{-}_{nsx}, g^{+}_{nsib}, d^{+}_{nsib}, f^{+}_{nsx}, f^{-}_{nsx} \geq 0 \quad ,\forall i\in\mathcal{I}, b\in\mathcal{B}, x\in\mathcal{X}. & (5.19)
\end{aligned}
$$

To simplify the objective function of the Dual of the Follower problem, we prove that

$$\sum_{x\in\mathcal{X}}(1-\Omega_{nx})M(o^{+}_{nsx}+o^{-}_{nsx}) = 0. \tag{5.20}$$

To assist this proof, we start by obtaining the following Karush-Kuhn-Tucker complementarity conditions,

$$
\begin{aligned}
0 \leq o^{+}_{nsx} \perp (1-\Omega_{nx})M - \frac{F_{nsx}}{B_x} - (\theta_{nsi}-\theta_{nsj}) \geq 0 \quad ,\forall x\in\mathcal{X} & \quad (5.21) \\
0 \leq o^{-}_{nsx} \perp (1-\Omega_{nx})M + \frac{F_{nsx}}{B_x} + (\theta_{nsi}-\theta_{nsj}) \geq 0 \quad ,\forall x\in\mathcal{X}. & \quad (5.22)
\end{aligned}
$$

Given that M is a sufficiently large number, $\forall x \in \mathcal{X}$ equations o^{+}_{nsx} and o^{-}_{nsx} are equivalently non-negative using

$$
\begin{aligned}
0 \leq o^{+}_{nsx} \perp (1-\Omega_{nx}) \geq 0 \quad ,\forall x\in\mathcal{X} & \quad (5.23) \\
0 \leq o^{-}_{nsx} \perp (1-\Omega_{nx}) \geq 0 \quad ,\forall x\in\mathcal{X}. & \quad (5.24)
\end{aligned}
$$

In the above, it follows that if $\Omega_{nx} = 1$ then $o^{+}_{nsx} \geq 0$ and $o^{-}_{nsx} \geq 0$ rendering $(1 - \Omega_{nx})M(o^{+}_{nsx} + o^{-}_{nsx}) = 0$. In the opposite case where $\Omega_{nx} = 0$, $o^{+}_{nsx} = o^{-}_{nsx} = 0$ and again $(1 - \Omega_{nx})M(o^{+}_{nsx} + o^{-}_{nsx}) = 0$. To simplify the objective function of the Dual, removing any dependence of M, we can substitute the result of Equation (5.20), by introducing new constraints,

$$o^{+}_{nsx} \leq \Omega_{nx}M \qquad ,\forall x \in \mathcal{X} \tag{5.25}$$

$$o^{-}_{nsx} \leq \Omega_{nx}M \qquad ,\forall x \in \mathcal{X}. \tag{5.26}$$

A further problem with the objective function of the Dual is that even if respective to the Follower model Ω_{nx} is a parameter, when considering the MPEC model, it is a variable controlled by the Leader. This implies that Equation (5.14) is non-linear as it includes the product of variables $\Omega_{nx}(f^{+}_{nsx} + f^{-}_{nsx})$. To all practical effects, Ω_{nx} is restricted to binary values if we consider Equations (5.4)-(5.7). We follow Pereira et al. (2005) to linearise this product by replacing this product with new variable γ_{nsx} and introducing constraints,

$$0 \leq f^{+}_{nsx} + f^{-}_{nsx} - \gamma_{nsx} \leq (1 - \Omega_{nx})M \qquad ,\forall x \in \mathcal{X} \tag{5.27}$$

$$0 \leq \gamma_{nsx} \leq \Omega_{nx}M \qquad ,\forall x \in \mathcal{X}. \tag{5.28}$$

As the Follower model is linear, based on Slater's condition, we know that the Strong Duality Theorem holds (Boyd and Vandenberghe, 2004). To obtain the MPEC we could add a constraint that forces the equality of primal and dual objective functions, Equations (5.8) and (5.14), to guarantee optimality of the Follower model. Due to the computational difficulty that this constraint would add to the MPEC optimization we relax the equality by considering only the Weak Duality Theorem. Given that the Follower Primal model is not written in standard form, the optimization function is to be maximized, and knowing that duality gaps gap_{ns} are non-negative, we define them as

$$\text{gap}_{ns} = \text{obj}_{ns}^{\text{DUAL}} - \text{obj}_{ns}^{\text{PRIMAL}} \quad, \forall n \in \mathcal{N}, s \in \mathcal{S}, \tag{5.29}$$

where

$$\text{obj}_{ns}^{\text{PRIMAL}} = \sum_{i \in \mathcal{I}} \sum_{b \in \mathcal{B}} P_b \left(D_{nsib} - G_{nsib} \right) \tag{5.30}$$

$$\text{obj}_{ns}^{\text{DUAL}} = \sum_{i \in \mathcal{I}} \sum_{b \in \mathcal{B}} (G_{sib}^{\max} \psi_{nib}^{G} g_{nsib}^{+} + D_{sib}^{\max} \psi_{nis}^{D} d_{nsib}^{+}) + \sum_{x \in \mathcal{X}} F_{nx}^{\max} \gamma_{nsx} \tag{5.31}$$

Adding a penalty to the MPEC objective function, using a sufficiently large number M, it forces optimal solutions to have $\text{gap}_{ns}^{\star} = 0$.

According to all of the above reformulations we end up with the MPEC,

$$\max \sum_{m \in \mathcal{M}} \rho_m \left[\sum_{n \in \mathcal{P}(m) \setminus m} \left(\text{SW}_n \, \beta_n - \frac{I_n}{(1+r)^{t_n \Delta t}} \right) + \text{SW}_m \, \phi_m \right] - \sum_{n \in \mathcal{N}} \sum_{s \in \mathcal{S}} \text{gap}_{ns} \, M \tag{5.32}$$

$$\text{s. t.} \, \text{SW}_n = \sum_{s \in \mathcal{S}} \sum_{i \in \mathcal{I}} \sum_{b \in \mathcal{B}} h_s P_b \left(D_{nsib} - G_{nsib} \right) \quad, \forall n \in \mathcal{N} \tag{5.33}$$

$$I_n = \sum_{x \in \mathcal{X}} C_x \omega_{nx} \quad, \forall n \in \mathcal{N} \tag{5.34}$$

$$\Omega_{nx} = \Omega_{a_n,x} + \omega_{a_n,x} \quad, \forall x \in \mathcal{X}, n \in \mathcal{N} \setminus \{0\} \tag{5.35}$$

$$\Omega_{0,x} = \Omega_x^{\min} \quad, \forall x \in \mathcal{X} \tag{5.36}$$

$$\sum_{n \in \mathcal{P}(m)} \omega_{nx} \leq \left(1 - \Omega_x^{\min}\right) \Omega_x^{\max} \quad, \forall x \in \mathcal{X} \tag{5.37}$$

$$\omega_{nx} = \{0, 1\} \quad, \forall x \in \mathcal{X}, n \in \mathcal{N} \setminus \mathcal{M} \tag{5.38}$$

$$\text{gap}_{ns} = \text{obj}_{ns}^{\text{DUAL}} - \text{obj}_{ns}^{\text{PRIMAL}} \quad, \forall n \in \mathcal{N}, s \in \mathcal{S} \tag{5.39}$$

$$\text{obj}_{ns}^{\text{PRIMAL}} = \sum_{i \in \mathcal{I}} \sum_{b \in \mathcal{B}} P_b \left(D_{nsib} - G_{nsib} \right) \quad, \forall n \in \mathcal{N}, s \in \mathcal{S} \tag{5.40}$$

$$\text{obj}_{ns}^{\text{DUAL}} = \sum_{i \in \mathcal{I}} \sum_{b \in \mathcal{B}} (G_{sib}^{\max} \psi_{nib}^{G} g_{nsib}^{+} + D_{sib}^{\max} \psi_{nis}^{D} d_{nsib}^{+}) +$$

$$+ \sum_{x \in \mathcal{X}} F_{nx}^{\max} \gamma_{nsx} \quad , \forall n \in \mathcal{N}, s \in \mathcal{S} \tag{5.41}$$

$$\sum_{b \in \mathcal{B}} (D_{nsib} - G_{nsib}) - \sum_{x \in \mathcal{X}_i} F_{nsx} = 0 \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, i \in \mathcal{I} \tag{5.42}$$

$$-(1 - \Omega_{nx}) M \leq \frac{F_{nsx}}{B_x} + (\theta_{nsi} - \theta_{nsj}) \leq (1 - \Omega_{nx}) M \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, x \in \mathcal{X} \tag{5.43}$$

$$0 \leq G_{nsib} \leq G_{sib}^{\max} \psi_{nib}^{G} \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, i \in \mathcal{I}, b \in \mathcal{B} \tag{5.44}$$

$$0 \leq D_{nsib} \leq D_{sib}^{\max} \psi_{nis}^{D} \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, i \in \mathcal{I}_D, b \in \mathcal{B} \tag{5.45}$$

$$-F_{nx}^{\max} \Omega_{nx} \leq F_{nsx} \leq F_{nx}^{\max} \Omega_{nx} \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, x \in \mathcal{X} \tag{5.46}$$

$$-\text{NTC}_{nsi} \leq \sum_{x \in \mathcal{X}_i} F_{nsx} \leq \text{NTC}_{nsi} \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, i \in \mathcal{I} \tag{5.47}$$

$$-P_b + \text{LMP}_{nsi} + d_{nsib}^{+} \geq 0 \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, i \in \mathcal{I}, b \in \mathcal{B} \tag{5.48}$$

$$P_b - \text{LMP}_{nsi} + g_{nsib}^{+} \geq 0 \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, i \in \mathcal{I}, b \in \mathcal{B} \tag{5.49}$$

$$-\text{LMP}_{nsi} + \frac{o_{nsx}^{+} - o_{nsx}^{-}}{B_x} + \left(f_{nsx}^{+} - f_{nsx}^{-}\right) = 0 \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, x \in \mathcal{X} \tag{5.50}$$

$$\sum_{j \in \mathcal{I}} \sum_{k \in \mathcal{K}} \left(o_{nsx}^{+} - o_{nsx}^{-}\right) - \sum_{j \in \mathcal{I}} \sum_{k \in \mathcal{K}} \left(o_{nsy}^{+} - o_{nsy}^{-}\right) = 0 \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, i \in \mathcal{I} \tag{5.51}$$

$$0 \leq o_{nsx}^{+} \leq \Omega_{nx} M \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, x \in \mathcal{X} \tag{5.52}$$

$$0 \leq o_{nsx}^{-} \leq \Omega_{nx} M \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, x \in \mathcal{X} \tag{5.53}$$

$$0 \leq f_{nsx}^{+} + f_{nsx}^{-} - \gamma_{nsx} \leq (1 - \Omega_{nx}) M \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, x \in \mathcal{X} \tag{5.54}$$

$$0 \leq \gamma_{nsx} \leq \Omega_{nx} M \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, x \in \mathcal{X} \tag{5.55}$$

$$g_{nsib}^{+}, d_{nsib}^{+}, f_{nsx}^{+}, f_{nsx}^{-} \geq 0 \quad , \forall n \in \mathcal{N}, s \in \mathcal{S}, i \in \mathcal{I}, b \in \mathcal{B}, x \in \mathcal{X}. \tag{5.56}$$

5.3.3 Cross-border cost allocation formulation

We assume a Nash-Coase bargaining problem where a player can provide financial compensations to pursue the other player to accept optimal investment decisions. Similarly to Chapters 2 and 3, uncertainties are modelled with a multidimensional binomial tree. We follow Riddell (1981), and consider that under uncertainty, as long as players commit to a strategy before the uncertainties unfold, and they perfectly foresee the distribution of payoffs, the bargaining is solved using expected payoffs. We also conceptualize payoff as net social welfare, the variation in social welfare subtracted of investment costs. The fair share cost allocation rule states that through bargaining each player increases the net expected social welfare by the same amount (Chapter 4).

Bargaining occurs in the decision tree nodes where at least a new transmission line is built. We define this subset of $\mathcal{N}$ as $\mathcal{O} = \{n \in \mathcal{N}\backslash\mathcal{M} : \exists n \forall x \in \mathcal{X}, \omega_{nx} > 0\}$. Starting in the last time period of decisions, for each node where there are transmission line investment decisions, $n \in \mathcal{O}$, bargaining requires us to calculate the expected marginal increase in social welfare that the investments bring. Investment costs of those investment decisions are split such that the expected net social welfare, expected social welfare subtracted of the share of investment costs, is equal for both parties. The same reasoning is performed for the previous time period, with the distinction that the share of investment costs already calculated must be subtracted, and the respective probability of occurrence must be considered. Continuing with backward induction we can obtain the shares of investment costs for the remaining nodes.

The following equations summarize the above cross-border cost allocation rationale,

$$\mathrm{SW}_{np} = \sum_{s\in\mathcal{S}} \left[\sum_{i\in\mathcal{I}_p} \sum_{b\in\mathcal{B}} h_s P_b \left(D_{nsib} - G_{nsib}\right) \pm \eta_{ns} \max\left(\mathrm{LMP}_{nsi}\right) \right] \quad , \forall n \in \mathcal{N} \tag{5.57}$$

$$I_n = \sum_p I_{np} \quad , \forall n \in \mathcal{N} \tag{5.58}$$

$$\mathrm{TSW}_{n^*p} = \sum_{\mathrm{m}\in\mathcal{M}\cap\mathcal{Q}(\mathrm{n}^*)} \rho_m \left[\sum_{n\in\mathcal{P}(m)\backslash m\cap\mathcal{Q}(n^*)} \mathrm{SW}_{np}\, \beta_n + \mathrm{SW}_{mp}\, \phi_m \right] \quad , \forall n^\star \in \mathcal{N}\backslash\mathcal{M}, p \in \mathcal{P} \tag{5.59}$$

$$\mathrm{TI}_{n^*p} = \sum_{\mathrm{m}\in\mathcal{M}\cap\mathcal{Q}(\mathrm{n}^*)} \rho_m \left[\sum_{n\in\mathcal{P}(m)\backslash m\cap\mathcal{Q}(n^*)} \frac{I_{np}}{(1+r)^{t_n \Delta t}} \right] \quad , \forall n^\star \in \mathcal{N}\backslash\mathcal{M}, p \in \mathcal{P} \tag{5.60}$$

$$\Delta\, \mathrm{TSW}_n = \mathrm{TSW}_{np} - \mathrm{TSW}_{0,np} - \mathrm{TI}_{np} \quad , \forall n \in \mathcal{O}, p \in \mathcal{P}.. \tag{5.61}$$

Equation (5.57) provides social welfare for each player $p \in \mathcal{P}$ considering the effects of trade, i.e., a quantity added to the exporter, or subtracted to the importer, equal to the quantity transferred between regions, η_{ns}, multiplied by the maximum locational marginal price observed in any given node. Equation (5.58) guarantees that the share of each player's investment costs, I_{np}, is equal to the total investment cost in each node. We obtain the present value of total social welfare for each player, TSW_{n^*p}, through Equation (5.59). $\mathcal{Q}(n^*)$ is defined as the subset of $\mathcal{N}$ that contains node n^* and all of its subsequent nodes. Similarly, to calculate the present value of total investment costs per player, TI_{n^*p}, we use Equation (5.60). To obtain the present value of the net social welfare for each player, $\Delta\,\mathrm{TSW}_n$, we must first obtain the total social welfare per player TSW_{0,n^*p}. This can be easily achieved by solving the MPEC defined in Equations (5.32)-(5.56) adding new constraints forcing ω_{nx} to be equal to the obtained solution, except for the node that precedes the node in analysis where investment decisions are forced not to occur. Equation (5.61) defines that the difference of these total expected social welfares, TSW_{np} and $\mathrm{TSW}_{0,np}$, subtracted of the total investment costs, must provide the same result for each player.

Fair share cost allocation is difficult to conduct when multiple solutions might exist for an equal net social welfare increase. Therefore we must identify which of the possible solutions is the best to be used to split investment costs. We define as a criteria that when multiple solutions exist, the best solution in terms of fair share cost allocation is the one that requires the least net transfer between regions. The reasoning is that even though a higher percentage of electricity can flow through the invested transmission lines we should only consider the minimum necessary that justified the investments. For this purpose we consider the bilevel model,

$$G_{nsib}, D_{nsib} \in \left\{ \min \quad \eta^+_{ns} + \eta^-_{ns} \right. \tag{5.62}$$

$$\text{s.t.} \quad \eta_{ns} = \sum_{x \in \mathcal{I}_p \times \mathcal{I}_{-p} \times \mathcal{K}} F_{nsx} \tag{5.63}$$

$$\eta_{ns} = \eta^+_{ns} - \eta^-_{ns} \tag{5.64}$$

$$\eta^+_{ns}, \eta^-_{ns} \geq 0 \tag{5.65}$$

$$\mathrm{gap}_{ns} = 0 \tag{5.66}$$

$$\left. \text{(5.39)} - \text{(5.56)} \quad \right\}, \forall n \in \mathcal{N}, s \in \mathcal{S}. \tag{5.67}$$

Equations (5.62)-(5.65) allows us to minimize the absolute flow between regions. Investment decisions ω_{nx} are now parameters and thus, by considering a duality gap of zero in Equation (5.66) the inclusion of Equations pertaining to the ISO, (5.39)-(5.56), allows us to obtain the solution for the same social welfare result where net flows between regions are minimized.

5.4 Case study

5.4.1 Portuguese simplified transmission network and interconnections with Spain

The transmission network used in this case study is based on transmission line data of REN (2015). Starting and end buses were assigned to different regions, and 400kV and 220kV lines used to connect distinct regions were used to compute a single equivalent line. To calibrate the model, transmission line maximum flows were adjusted proportionally and using the optimal power flow model, Equations(5.8)-(5.13), to obtain a net transfer capacity of approximately 3,000 MW, as this value is expected to be available in 2016 (REN, 2013). A graphical representation of the transmission network is provided in Figure 5.3, followed, in Table 5.1, with the necessary transmission line maximum flow and susceptance values.

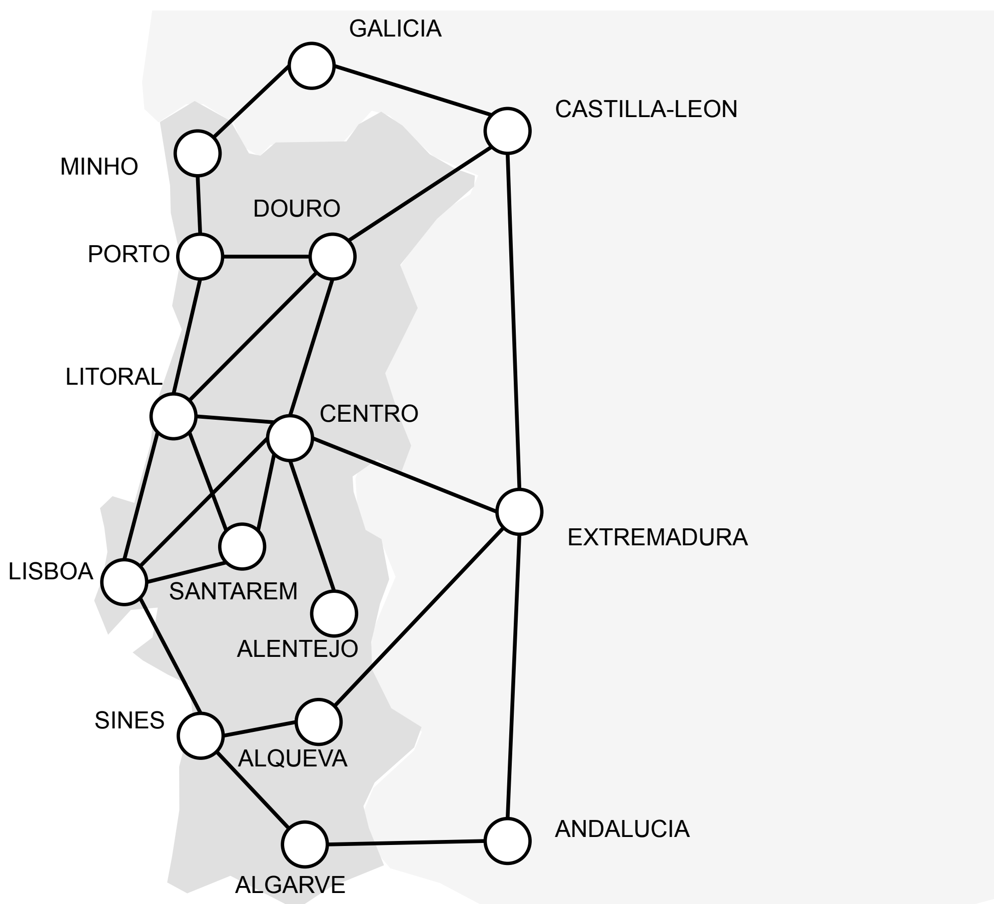

Figure 5.3: Graphical representation of the simplified Iberian transmission network configuration.

Table 5.1: Simplified Iberian transmission network line data.

Region 1	Region 2	Fmax (MVA)	B (pu)
MINHO	PORTO	1800	150
MINHO	GALICIA	1200	105
PORTO	DOURO	2800	40
PORTO	LITORAL	1900	50
DOURO	LITORAL	1650	25
DOURO	CENTRO	450	20
DOURO	CASTILLA-LEON	850	25
LITORAL	CENTRO	450	10
LITORAL	LISBOA	1650	55
LITORAL	SANTAREM	850	75
CENTRO	LISBOA	450	10
CENTRO	ALENTEJO	350	40
CENTRO	SANTAREM	1250	80
CENTRO	EXTREMADURA	800	175
LISBOA	SINES	1650	50
LISBOA	SANTAREM	1250	60
SINES	ALQUEVA	850	80
SINES	ALGARVE	850	50
ALQUEVA	EXTREMADURA	800	60
ALGARVE	ANDALUCIA	850	85
GALICIA	CASTILLA-LEON	1650	325
CASTILLA-LEON	EXTREMADURA	400	325
EXTREMADURA	ANDALUCIA	1350	265

Table 5.2: Available transmission line investments data.

Region 1	Region 2	Fmax (MVA)	B (pu)
MINHO	GALICIA	240	21
DOURO	CASTILLA-LEON	170	5
CENTRO	EXTREMADURA	160	35
ALQUEVA	EXTREMADURA	160	12
ALGARVE	ANDALUCIA	170	17

Regarding transmission lines available for investment we consider that they are possible in the corridors that join the regions of Portugal in Spain in 20% increments of maximum flow where the susceptance is proportionate such that the maximum phase angle remains the same. Table 5.2 presents a summary of the possible transmission line investments.

5.4.2 Supply and demand

To parametrize the model we first consider the 2014 daily supply and demand bid data available at OMIE[4], the Iberian electricity spot market operator, of MIBEL, the Iberian electricity market. This data is organized as independent comma-separated values (.csv) files, each of them considering a day of operation of MIBEL. Each record contains hour of operation, bidding unit, type of bid (identifier of supply or demand), bidding price, quantity, and whether this bid was dispatched or not. We split bids between Portugal and Spain, according to the location of the bidding unit. Portuguese generation bids are allocated to distinct regions considering the existing balancing areas using a relationship between generation bidding units and balancing areas available in the market website of the Portuguese TSO, REN[5]. The original bid files are also split according to the different scenarios. Each scenario is characterized by: season, Summer (months between April and September) and Winter (months between October and March); day, Weekday (days between Monday and Friday) and Weekend (Saturdays and Sundays); and hour, Off-Peak (1 AM until 7 AM) and Peak (remaining hours). In summary, the whole bid data of 2014 is split into 96 datasets

[4]http://www.omie.es/

[5]http://www.mercado.ren.pt/PT/Electr/InfoMercado/InfStructMerc/UnidMercado/Paginas/AreasBal.aspx

based on the 8 scenarios resulting from all combinations of the previously defined criteria and 12 considered regions.

Each bid in a distinct file is a pair of price and quantity at which electricity is bought or sold at a specific hour of the year and region. In the Iberian peninsula, bids are priced between 0€ and 180.3€ in intervals of 1 cent. Decreasing the total number of bids, per region and scenario, by adding the quantities of equally priced bids might not allow a considerable reduction of data. Even though we lose some precision, we cluster prices by rounding them to the nearest 20€ multiple, thus forcing each region in each scenario, to be characterized by 10 bids only, ie., we can define the vector of prices as $P = \{0, 20, 40, 60, 80, 100, 120, 140, 160, 180\}$.

Table 5.3: Bus data for Portugal.

Bus	**Country**	**Region**	**Special Regime Production**	**Demand**
1	PORTUGAL	MINHO	13%	10%
2		PORTO	3%	11%
3		DOURO	26%	12%
4		LITORAL	7%	14%
5		CENTRO	33%	9%
6		LISBOA	5%	27%
7		SANTAREM	4%	5%
8		ALENTEJO	1%	3%
9		SINES	0%	1%
10		ALQUEVA	6%	1%
11		ALGARVE	2%	7%

It should be noted that there exists a bidding unit, *EDPSVD1*, that represents special regime production (SRP). Special regime supply is electricity generated using biogas, biomass, cogeneration and renewable cogeneration, wind, photovoltaic, hydro and urban solid waste. Special regime supply, through its own legal system, is priced outside the market and it is represented within it with a bidding price of zero. We allocate for Portugal this generation using the special regime installed generation capacity data[6]. Portuguese demand is allocated to regions using electricity consumption data available at PORDATA[7]. In both cases data is disaggregated by Second-level Nomenclature of Territorial Units for Statistics (NUTS2). These values are listed in Table 5.3.

Table 5.4: Bus data for Spain.

Bus	**Country**	**Region**	**Special Regime Production**	**Conventional**	**Demand**
12	SPAIN	GALICIA	13%	7%	6%
13		CASTILLA-LEON	19%	3%	6%
14		EXTREMADURA	5%	17%	3%
15		ANDALUCIA	13%	14%	19%

Spanish supply and demand bids are calculated considering aggregated data for the whole country as we were not able to split bids by region. Considering data available in the website of the Spanish ISO, REE[8], we split the bids according to its relative share both in terms of SRP and conventional production. Demand is similarly treated for its relative weight we consider population data available at the website of the Spanish National Institute of Statistics[9]. We also assume that bids originating from outside of the Iberian peninsula pertain to the Spanish market. The underlying assumption is that there are no power flow restrictions by which these bids are traded in MIBEL. The data used is presented in Table 5.4. It should be noted that we are not modelling the whole Spain, therefore its total is under the 100% mark.

[6] http://e2p.inegi.up.pt/

[7] http://www.pordata.pt/Municipios/Consumidores+de+energia+el%C3%A9ctrica+total+e+por+tipo+de+consumo-18

[8] http://www.ree.es/es/estadisticas-del-sistema-electrico-espanol/series-estadisticas/series-estadisticas-por-comunidades-autonomas

[9] http://www.ine.es/prodyser/microdatos.htm

Table 5.5: Breakdown of a calendar year into scenarios.

Season	Day	Hour	Hours
Winter	Weekday	Off-Peak	910
Winter	Weekday	Peak	2210
Winter	Weekend	Off-Peak	364
Winter	Weekend	Peak	884
Summer	Weekday	Off-Peak	917
Summer	Weekday	Peak	2227
Summer	Weekend	Off-Peak	364
Summer	Weekend	Peak	884

As presented in Appendix 5.B we simplify the representation of different market working hours clustering bids based on season, day, hour and bus, after an exploratory analysis of the data. It was decided that splitting a day of operations would require categorizing night time as the first 7 hours of the day and day time as the remaining hours of operation. This led us to break the number of hours in a calendar year into the scenarios as presented in Table 5.5.

5.4.3 Multinomial path-dependent tree

In our previous research using real options (Loureiro et al., 2015), and in most real options applications, decisions trees are built assuming discretized values of uncertainties based on the assumption of their evolution using continuous-time stochastic processes such as the geometric Brownian motion (Cox et al., 1979; Brosch, 2008; Marathe and Ryan, 2005). To develop the case study of the current research paper, we built a multinomial path-dependent tree based on projected scenario outlooks presented in ENTSO-E (2015a).

ENTSO-E scenario outlooks provide a five to ten year time frame generation adequacy overview of all Member States for major players in the European electricity market. Targeting the year of 2030, four Visions were developed based on extreme realizations of two main axes for greenhouse gas emission reductions: meeting targets defined in the Energy roadmap 2050 (European Climate Foundation, 2010); the framework pursued to reach the targets, strong European coordination versus Member States defining their own strategies (ENTSO-E, 2015b).

The Visions for 2030 are a set of four distinct and plausible yet acute projections that bound, with a considerable degree of certainty, the future unfolding of events. These Visions are built considering two distinct considerations: the speed by which the Energy Roadmap 2050 is adopted; and, the level of integration of the European internal energy market. Visions 3 and 4 are on track for Energy Roadmap 2050. Common characteristics for such projections are the encouraging economic and financial conditions where high demands for electricity are expected, CO_2 prices are high, demand response is used, and there is a general adoption of electric plug-in vehicles. In opposition, Visions 1 and 2, consider a delay in the implementation of Energy Roadmap 2050, assuming a not as good economic and financial situation, with a respective lower electricity demand. Visions 2 and 4 consider a high degree of integration of the internal electricity market, where a common European energy policy is implemented, demand response and carbon capture and storage are deployed. In the other hand, Visions 1 and 3 focus on energy politics to be decided on the national level, and there is no commercial deployment of carbon capture and storage.

Table 5.6: Demand and generation capacity data.

	Demand (GWh)		**Generation Capacity (MW)**			
			Spain		**Portugal**	
	Winter	**Summer**	**SRP**	**Conventional**	**SRP**	**Conventional**
Reference Year 2015	525	420	54598	50024	10367	7224
Vision 1	558	433	78320	55445	15776	6115
Vision 2	592	454	78320	55445	15776	6115
Vision 3	639	496	116400	63538	18480	6345
Vision 4	682	521	154655	63538	23180	6345

Our strategy is to use demand data of all four Visions for 2030 and reference year 2015 (ENTSO-E, 2015a) as well as generation capacity data for 2030 (ENTSO-E, 2014) and 2015[10]

[10] https://transparency.entsoe.eu/

to determine multipliers of base generation capacity, split between renewables generation and fossil fuel added with nuclear generation, and demand. We present these values in Table 5.6.

We define a time step Δt of five years between 2015 to 2030, rendering us intermediate years of 2020 and 2025 and allowing us to restrict the set of time periods $t_n \in \mathcal{T} = \{0..3\}, \forall n \in \mathcal{N}$. We also consider that each node leads to four new equiprobable path-dependent nodes in the following time period, each of them leading more closely to the extreme possibilities of the four Visions for 2030. Hence, we build a path-dependent decision tree with $|\mathcal{N}| = |\mathcal{N}^{\mathrm{PD}}| = \sum_{t\in\mathcal{T}} 4^t = 1+4+16+64 = 85$ nodes. The multinomial path-dependent tree is related to a multinomial path-independent tree, or multinomial tree with recursion, with $|\mathcal{N}^{\mathrm{PI}}| = \sum_{t\in\mathcal{T}}(t+1)^2 = 1+4+9+16 = 30$ nodes. Path-dependency is necessary to keep track of previous investment decisions.

We start by building a a path-independent multinomial tree beginning with the last time period, composed of 16 nodes, arranged as a square matrix of size 4. Each of the 4 corners signifies the realization of a Vision. For these nodes, the relationship between the realization of a Vision for 2030 and reference year 2015 is given by a multiplier computed considering their ratio. The other nodes in the same time period are weighted combinations of those four nodes. To compute nodes in previous time periods, for each combination of nodes forming a size 2 square matrix, their weighted combination is obtained and exponentiated using the fraction of elapsed years. Path-dependency is included by repeating branches of a tree such that each node has unambiguous precedence. In Table 5.7 data pertaining to each node in the multinomial tree is presented.

5.5 Results

Solving the problem above in IBM ILOG CPLEX we obtain the results summarized in Table 5.8. For the five possible transmission line reinforcements, in intervals of a 20% maximum flow increase each, corridors MINHO - GALICIA and DOURO - CASTILLA-LEON are reinforced with a single line in 2015. Regarding 2020, two distinct expansion solutions exist. For nodes 1 and 2, the ones leading to the equally named 2030 Visions 1 and 2, there are no investments as social welfare increases would not be sufficient to compensate for the necessary investment costs. Considering nodes 3 and 4, the ones leading respectively to 2030 Visions 3 and 4, there is a single reinforcement of 20% in the corridor CENTRO - EXTREMADURA. In no situation was there the need for

Table 5.7: Multinomial tree under path-dependency data.

			Vision weights				Demand		Spain		Portugal	
Nodes	**a**	**t**	**1**	**2**	**3**	**4**	**Winter**	**Summer**	**SRP**	**Conventional**	**SRP**	**Conventional**
0	-	0	0.25	0.25	0.25	0.25	1.00	1.00	1.00	1.00	1.00	1.00
1	0	1	0.44	0.22	0.22	0.11	1.04	1.03	1.20	1.05	1.18	0.95
2	0	1	0.22	0.44	0.11	0.22	1.05	1.04	1.21	1.05	1.19	0.95
3	0	1	0.22	0.11	0.44	0.22	1.06	1.05	1.26	1.07	1.21	0.95
4	0	1	0.11	0.22	0.22	0.44	1.07	1.05	1.29	1.07	1.23	0.95
5	1	2	0.69	0.14	0.14	0.03	1.07	1.04	1.35	1.09	1.35	0.90
6,9	1,2	2	0.42	0.42	0.08	0.08	1.08	1.05	1.36	1.09	1.37	0.90
10	2	2	0.14	0.69	0.03	0.14	1.09	1.06	1.38	1.09	1.38	0.90
7,13	1,3	2	0.42	0.08	0.42	0.08	1.10	1.07	1.49	1.12	1.42	0.91
8,11 14,17	1,2 3,4	2	0.25	0.25	0.25	0.25	1.11	1.09	1.55	1.12	1.46	0.91
12,18	2,4	2	0.08	0.42	0.08	0.42	1.13	1.10	1.61	1.12	1.50	0.91
15	3	2	0.14	0.03	0.69	0.14	1.13	1.11	1.64	1.16	1.48	0.91
16,19	3,4	2	0.08	0.08	0.42	0.42	1.15	1.12	1.74	1.16	1.55	0.91
20	4	2	0.03	0.14	0.14	0.69	1.16	1.13	1.83	1.16	1.61	0.91
21	5	3	1	0	0	0	1.04	1.03	1.43	1.11	1.52	0.85
22,25,37	5,6,9	3	0.67	0.33	0	0	1.06	1.05	1.43	1.11	1.52	0.85
26,38,41	6,9,10	3	0.33	0.67	0	0	1.07	1.06	1.43	1.11	1.52	0.85
42	10	3	0	1	0	0	1.13	1.08	1.43	1.11	1.52	0.85
23,29,53	5,7,13	3	0.67	0	0.33	0	1.11	1.08	1.67	1.16	1.61	0.86
24,27,30 33,39,45 54,57,69	5,6,7 8,9,11 13,14,17	3	0.44	0.22	0.22	0.11	1.14	1.10	1.74	1.16	1.66	0.86
28,34,40 43,46,49 58,70,73	6,8,9 10,11,12 14,17,18	3	0.22	0.44	0.11	0.22	1.16	1.12	1.82	1.16	1.71	0.86
44,50,74	10,12,18	3	0	0.67	0	0.33	1.18	1.13	1.90	1.16	1.76	0.86
31,55,61	7,13,15	3	0.33	0	0.67	0	1.17	1.13	1.90	1.22	1.70	0.87
32,35,47 56,59,62 65,71,77	7,8,11 13,14,15 16,17,19	3	0.22	0.11	0.44	0.22	1.19	1.15	2.06	1.22	1.80	0.87
36,48,51 60,66,72 75,78,81	8,11,12 14,16,17 18,19,20	3	0.11	0.22	0.22	0.44	1.22	1.17	2.21	1.22	1.90	0.87
52,76,82	12,18,20	3	0	0.33	0	0.67	1.24	1.19	2.37	1.22	2.00	0.87
63	15	3	0	0	1	0	1.22	1.18	2.13	1.27	1.78	0.88
64,67,79	15,16,19	3	0	0	0.67	0.33	1.24	1.20	2.37	1.27	1.93	0.88
68,80,83	16,19,20	3	0	0	0.33	0.67	1.27	1.22	2.60	1.27	2.08	0.88
84	20	3	0	0	0	1	1.30	1.24	2.83	1.27	2.24	0.88

increasing the capacity of a transmission corridor by 40% or more by installing two transmission lines.

Cross-border cost allocation is performed using Equations 5.57-5.61. As the results above show, bargaining occurs in the decision tree nodes $\mathcal{O} = \{0, 3, 4\}$. In order to compute the net social welfare and investment costs allocated in the root node we must first calculate the values in the later stages of the decision tree, nodes 3 and 4, therefore these results are presented first to improve readability.

Table 5.8: Transmission line expansion results.

Region 1	Region 2	2015	2020: Visions 1 and 2	2020: Visions 3 and 4
MINHO	GALICIA	1	0	0
DOURO	CASTILLA-LEON	1	0	0
CENTRO	EXTREMADURA	0	0	1
ALQUEVA	EXTREMADURA	0	0	0
ALGARVE	ANDALUCIA	0	0	0

Table 5.9 summarizes the expected present values of social welfare and investment costs necessary for cross-border cost allocation of the transmission line in corridor CENTRO - EXTREMADURA assuming uncertainties are realized in the direction of the 2030 Vision 3. The obtained variation in total social welfare excluded of investment costs implies a loss of 42.7M€ for Portugal and a gain of 72.8M€ for Spain. Given that under Nash-Coase bargaining both players must earn the same net social welfare, the present value of the investment costs, 19.1M€, are split such that Spain pays 67.3M€ and Portugal is compensated by its social welfare loss of 48.2M€. In other words, Spain pays 352% and Portugal receives 252% of the investment cost which allows each country to obtain a net social welfare benefit of 5.5M€.

Table 5.9: Expected present values of social welfare and investment costs (M€) per time period, conditioned to the node in the first time period that leads to Vision 3.

Time period		**1**	**2**	**3**	**Total**
Variation in social welfare $\mathrm{TSW}_{3p} - \mathrm{TSW}_{0,3p}$	**Portugal**	-	0.0	-42.7	-42.7
	Spain	-	8.8	64.0	72.8
	Total	-	8.8	21.3	30.2
Investment costs TI_{3p}	**Portugal**	*-48.2 (-252%)*	-	-	-48.2
	Spain	*67.3 (352%)*	-	-	67.3
	Total	19.1	-	-	19.1
Net social welfare $\Delta\,\mathrm{TSW}_3$	**Portugal**	48.2	0.0	-42.7	5.5
	Spain	-67.3	8.8	64.0	5.5

Table 5.10: Expected present values of social welfare and investment costs (M€) per time period, conditioned to the node in the first time period that leads to Vision 4.

Time period		**1**	**2**	**3**	**Total**
Variation in social welfare $\mathrm{TSW}_{4p} - \mathrm{TSW}_{0,4p}$	**Portugal**	-	41.4	-27.6	13.8
	Spain	-	-35.7	51.7	16.9
	Total	-	5.6	24.1	29.7
Investment costs TI_{4p}	**Portugal**	*8.5 (45%)*	-	-	8.5
	Spain	*10.6 (55%)*	-	-	10.6
	Total	19.1	-	-	19.1
Net social welfare $\Delta\,\mathrm{TSW}_4$	**Portugal**	-8.5	41.4	-27.6	5.3
	Spain	-33.4	0.0	37.3	5.3

Results conditioned to uncertainties realized towards the 2030 Vision 4 are presented in Table 5.10. Variation in total social welfare excluded of investment costs is 13.8M€ for Portugal and 15.8M€ for Spain. As compared to the previous results, and even though the transmission line to be invested on is the same, in this instance both Portugal and Spain obtain social welfare benefits out of the investment. Investment costs are allocated such that Portugal is responsible for 8.5M€ while Spain has a responsibility of 10.6M€. Both countries obtain a net social welfare of 5.3M€ and in this situation no compensation is necessary as cost allocation implies shares of 45% for Portugal and 55% for Spain.

Table 5.11: Expected present values of social welfare and investment costs (M€) per time period, conditioned to the root node and considering the expected investment costs of Visions 3 and 4.

Time period		**0**	**1**	**2**	**3**	**Total**
Variation in social welfare $\mathrm{TSW}_{0p} - \mathrm{TSW}_{0,0p}$	**Portugal**	-	-55.6	86.1	-278.2	-247.7
	Spain	-	158	-38.7	663.9	783.2
	Total	-	102.4	47.4	385.7	535.5
Investment costs TI_{0p}	**Portugal**	*-467.9 (-713%)*	-9.9	-	-	-477.9
	Spain	*533.5 (813%)*	19.5	-	-	553.0
	Total	65.6	9.5	-	-	75.1
Net social welfare $\Delta\,\mathrm{TSW}_0$	**Portugal**	467.9	-45.7	86.1	-278.2	230.2
	Spain	-533.5	138.5	-38.7	663.9	230.2

Cross-border cost allocation for the root node is presented in Table 5.11. The reasoning is similar to the above instances. Portugal loses a variation in social welfare of 247.7M€ and Spain gains 783.2M€. To calculate the shares of investment costs, this time it is necessary to consider the expected present value of the investment costs pertaining to each country calculated when we conditioned the first time period to move towards 2030 Visions 3 and 4. These are for Portugal and Spain, -9.9M€ and 19.5€, respectively. Similarly we obtain a negative investment cost of 477.9M€ and a positive investment cost of 553.0M€ meaning that Spain would have to compensate Portugal in 7.13 times the investment cost of the two lines MINHO - GALICIA and DOURO - CASTILLA-LEON. This would lead each country to increase net social welfare in 230.2M€.

Figures 5.4 and 5.5 present histograms of the net social welfare obtained for Portugal and Spain. As can be seen, even though each country benefits on average 230.2M€ in net social welfare due to the investiments in cross-border capacity expansion, these are spread out differently. For Portugal net social welfare ranges between losses of about 150M€ and gains of 800M€ whereas for Spain ranges between losses of 100M€ and gains of 600M€. Portugal has a slightly higher variability which can also be verified by its standard deviation of 272.6M€ as opposed to 244.6M€ in Spain. It should be mentioned however that out of the 64 paths of the decision tree, 16 in Portugal and 12 in Spain represent losses even though, as can be seen in Figure 5.6, there is no path that leads to a loss when the two countries net social welfare are combined. Therefore there is a total of 28 paths out of the 64, 43.75% of cases, where either Portugal or Spain is at a loss. What this means though is that due to the high negative correlation of -0.92, Table 5.12, this cross-border cost allocation method implies a higher uncertainty in benefits when compared to a situation where benefits are accrued. A graphical representation of the net social welfare obtained by each country in each path is presented in Figure 5.7.

Table 5.12: Summary of statistics of net social welfare for each country (M€).

Statistic	**Portugal**	**Spain**	**Total**
Mean	230.2	230.2	460.4
Standard Deviation	272.6	244.6	107.2
Correlation	-0.92		

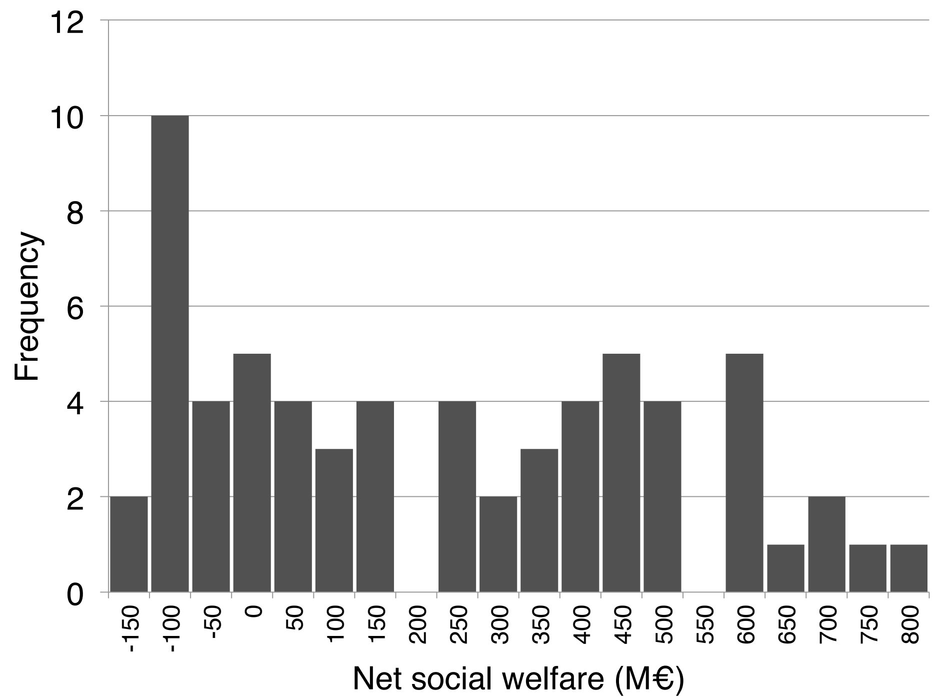

Figure 5.4: Histogram of net social welfare in Portugal obtained by following each path in the decision tree.

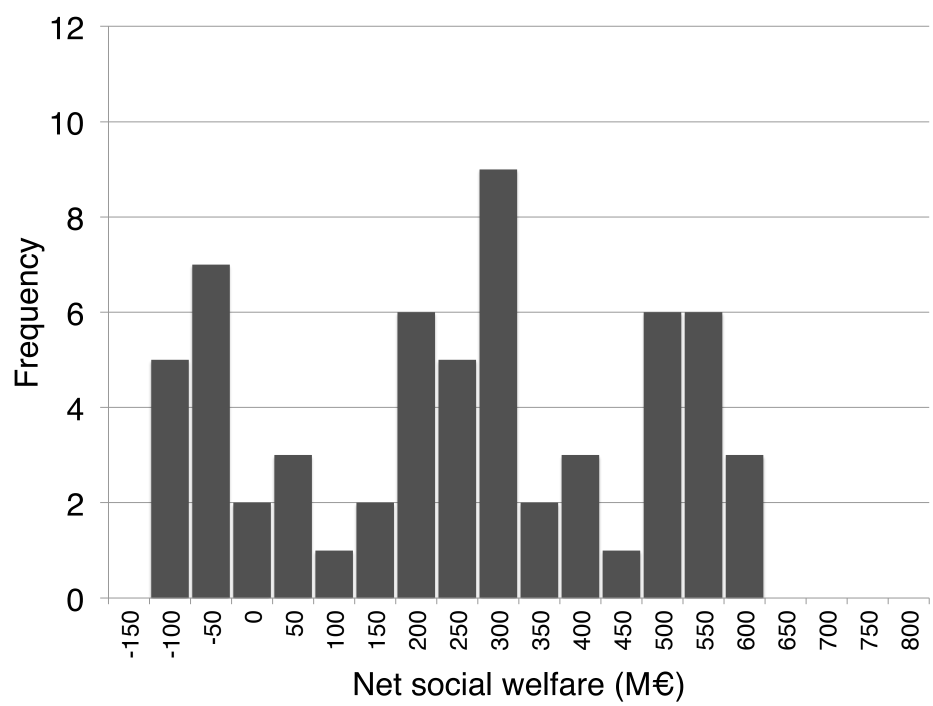

Figure 5.5: Histogram of net social welfare in Spain obtained by following each path in the decision tree.

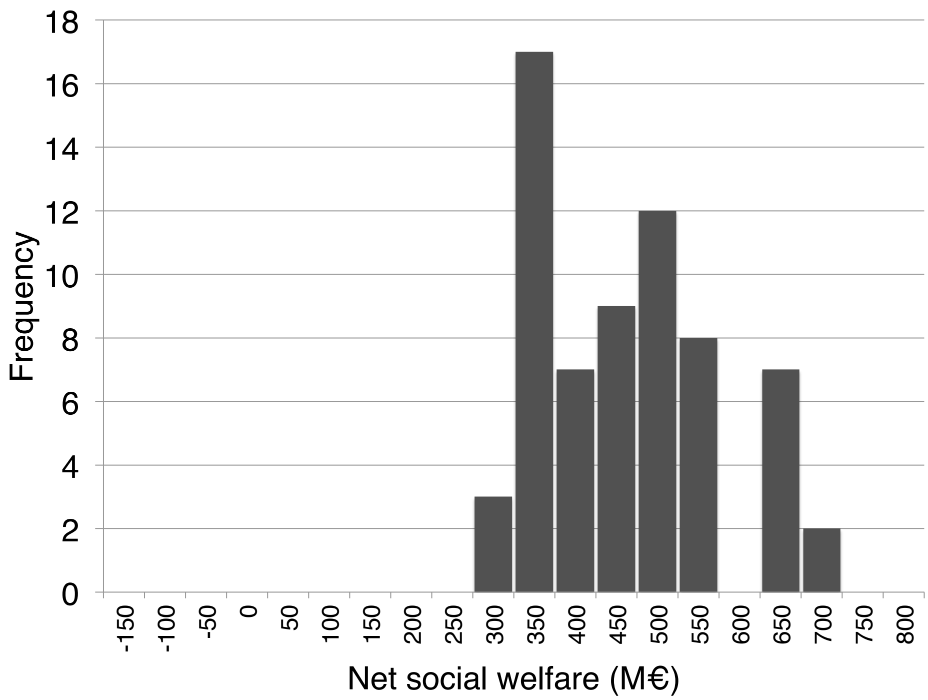

Figure 5.6: Histogram of net social welfare in the Iberian peninsula obtained by following each path in the decision tree.

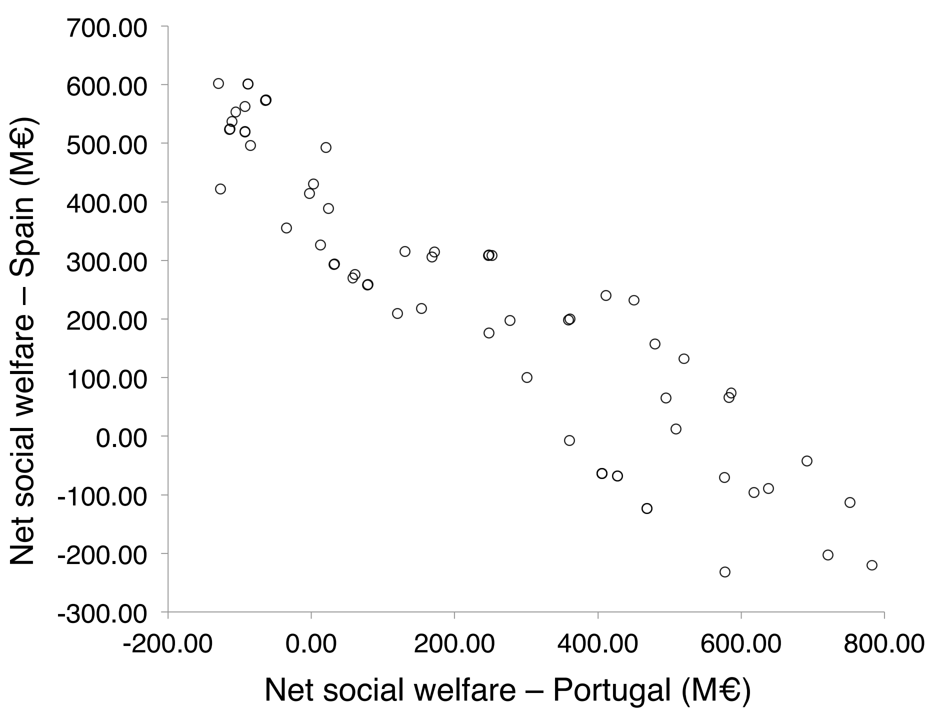

Figure 5.7: Net social welfare for Portugal and Spain obtained by following each path in the decision tree.

5.6 Discussion

Cross-border cost allocation is highly dependent on the benefit function being considered. As in our previous study, Chapter 4, we settled with social welfare, measured by the consumer and producer surpluses generated in the electricity market with an additional component for the cross-border flows cost transfer. As the argument of the current study is focused on the fair share allocation of investment costs for transmission network reinforcement, at the risk of oversimplification, we decided not to consider other factors. Since we do not have the intention of being exhaustive, we are aware that we could introduce additional social welfare measures. For example, an extra social welfare increase could be explicitly considered due to the change in generation mix from conventional electricity sources to special regime production, mostly as the latter are priced outside the market. Another example is the inclusion of emission trading costs based on greenhouse gas emissions of each energy source usage.

Another relevant assumption to mention is the perfect alignment between TSOs and governments, even though agency issues would impose a higher level of complexity and require its specific research. Also, Nash-Coase bargaining assumes both players as equals but given the differences in size and population of Spain and Portugal, it would be interesting to explore the implications of inequality as it is reasonable to consider differences in bargaining power.

In contrast with the results obtained in Chapter 4, the exporting region, Spain, tends to be the region with the higher gains with reinforced interconnections and thus is the one with a higher share of the investment responsibility and also with a need to compensate the other region, Portugal. The differences in benefits between regions are quite significant in two of the three nodes where investment decisions take place, leading us to conclude that if compensations were not possible then those investments would be unlikely to exist. Adjusting for the previously mentioned variations in social welfare, together with security of supply issues, and a more detailed transmission network could lead to higher benefits for each region thus a less uneven share of benefits.

It should also be mentioned that in contrast to these results, where the exporting region is the most likely to be responsible for transmission investments, in Chapter 4 we found no circumstance where the exporting region was responsible for the payment of the investment as well as being responsible for providing a compensation to the importing region. Several differences between models and case study explain this fact. First, the current model does not concern a single node representing each country, but multiple ones in each. Network topology plays a role such that changes in cross-border flows does not necessarily lead to an increase in price as happens with the previous methodology. For example, the increase in cross-border flows in the north might not necessarily mean a price adjustment if the node that sets the trading price is located in the south. In this situation we see an increase in flow, without a decrease in electricity price, as it is mandatory in the simplified previous model. A second reason to take into account is that to keep the ISO model as a linear optimization problem, bids are represented as blocks of quantities with an associated lumpy fixed price in intervals of 20€. Once again, flows can increase without price changes. A third difference worthy to be mentioned is that investments are set to specific increases in flow in a corridor as opposed to continuous increases.

The approaches used in these two Chapters are quite different. Their similarities are inly conceptual, as social welfare is calculated differently. In the former, data was simplified using linear regressions and, in the latter, data was aggregated by bus, averaged in order to obtain bid blocks with discreet price variations, evolving in uncertain ways and, therefore, leading for additional investments to be postponed and exercised. This is only a fast screening model and it is not necessary that the conclusions obtained also apply to the current study specially given the deterministic versus uncertain nature of each model.

These results also corroborate the need of transmission network reinforcement due to the implementation of green policies (Østergaard, 2003; Lund, 2005). Only when uncertainties are expected to follow paths where nodes pertaining to Visions 3 and 4 are included, which are characterized by following the Energy Roadmap 2050, we find the need for an additional postponed transmission line investment between Portugal and Spain.

Given the likelihood that social welfare benefits vary significantly depending on the uncertainty, it is possible to an external observer, not aware of its role in bargaining interconnection expansions, to analyse an investment in hindsight and presume that the bargaining was wrongly conducted. This is a risk faced by both parties and therefore we suggest decision-makers to expressly identify and present the uncertainties faced at the time of decision as well as including contractual mechanisms to mitigate net social welfare risk. Given the high negative correlation observed where almost half of the cases result in a region to incur in a social welfare loss, and considering that the expected present net social welfare is insensitive to this risk, we suggest that these contracts should include risk management measures. The inclusion of this complexity allows for less social welfare variability without compromising expected net social welfare.

5.7 Conclusions

The current study provides a bilevel problem and reformulates it as a MPEC, modelling the TSOs as Leaders and the ISO as the Follower. Our novel approach to reformulate the problem considers Duality theory, KKT optimality conditions, and linearisation of the product of variables to completely avoid the inclusion of extra binary variables or non-linearities thus reducing the complexity of the model to be solved.

Based on a case study of interconnection capacities between Portugal and Spain, we show that it is possible to model transmission planning in power systems resorting to: a long-term perspective under uncertainty where the investment decision plan is composed of actions to be acted at the present moment and a contingency plan with expansions to be invested based on the unfolding of events; a cross-border cost allocation procedure that considers time and uncertainties where two regions cooperate and establish a voluntary agreement.

Our results suggest that in 2015, the northernmost interconnection corridors of MINHO - GALICIA and DOURO - CASTILLA-LEON should be reinforced. Besides this decision to be acted immediately, as a contingency plan, considering that in 2020 the targets of Energy roadmap 2050 are likely to be met, a further reinforcement in the corridor CENTRO - EXTREMADURA is necessary.

A fair share cost allocation of these cross-border investments requires that the expected net social welfare to be equally shared among regions. Thus, we see that for the two transmission lines of 2015, Spain would need to compensate in about 7 times the total cost. Regarding the delayed decision, cost allocation differs based on the level of integration of the European energy market. When this integration is low, Spain, once again, should compensate in about 2.5 times the investment cost of the new interconnection line. In the situation where integration is high, we also see investment costs as being split among the two regions, Portugal would be responsible for 45% and Spain of the remaining 55% of the investment costs.

Based on the differences in gains evidenced in our results, to guarantee that voluntary agreements are established to optimally invest in power system infrastructure, namely in transmission lines, the nature of compensations for a fair share allocation of costs requires alternatives to be studied. It surpasses the goals of this study to identify whether financial compensations directly linked with the transmission expansion plan are sufficient, or whether compensation measures of a distinct nature could provide better results. Moreover, besides the need to fairly split investment costs, due to the realization of uncertainties, those benefits are likely to become uneven. We suggest risk measures to be explicitly incorporated into the voluntary agreement. Nevertheless, so far, we have not explored how these improved contracts could be designed.

In order for real world scenarios to be analysed, the size of the instance must increase significantly. Future work should introduce decomposition methods to split the decision tree into a more computationally manageable size besides the relationship between the two levels of decision, the transmission expansion decisions of the TSO and the dispatch decisions of the ISO. It should also be noted that under such decomposition, both levels of the decision-making process can take into account other factors, such as losses and security of supply, that were not presently considered. Given the size of such a problem an implementation where metaheuristics are used, can also provide the means to deal with more complex instances.

Acknowledgments

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5.A Mathematical finance

Multipliers are necessary to calculate the present value of social welfare for the years contained in a time period Δt as well as the present value of a perpetuity based on the social welfare obtained in the last time period. Respectively these multipliers can be calculated using

$$\beta_n = \frac{(1+r)^{\Delta t} - 1}{r(1+r)^{(t_n+1)\Delta t-1}}, \tag{5.68}$$

$$\phi_m = (r-g)(1+r)^{1-(t(m)+1)\Delta t}. \tag{5.69}$$

To obtain the present value of social welfare we must add the time adjusted social welfare of each year and then discount $t_n \Delta t$ time periods to represent it in the present. Simplifying and separating SW_n allows us to obtain the above β_n multiplier,

$$\frac{1}{(1+r)^{t_n\Delta t}} \sum_{t=0}^{\Delta t-1} \frac{\mathrm{SW}_n}{(1+r)^t} = \frac{\mathrm{SW}_n}{(1+r)^{t_n\Delta t}} \left(1 + \frac{1}{r} - \frac{1}{r}\frac{1}{(1+r)^{\Delta t-1}}\right) = \frac{\mathrm{SW}_n}{(1+r)^{t_n\Delta t}} \left(\frac{(1+r)^{\Delta t}-1}{r(1+r)^{\Delta t-1}}\right) =$$
$$= \mathrm{SW}_n \left(\frac{(1+r)^{\Delta t}-1}{r(1+r)^{(t_n+1)\Delta t-1}}\right) = \mathrm{SW}_n\, \beta_n \tag{5.70}$$

Similarly for the multiplier of the perpetuity, we separate SW_m and calculate ϕ_m,

$$\frac{1}{(1+r)^{t(m)\Delta t}} \sum_{t=0}^{\infty} \mathrm{SW}_m \left(\frac{1}{1+r}\right)^t = \frac{\mathrm{SW}_m}{(1+r)^{t(m)\Delta t}} \left(1 + \frac{1}{r}\right) = \frac{\mathrm{SW}_m}{r(1+r)^{t(m)\Delta t-1}} = \mathrm{SW}_m\, \phi_m. \tag{5.71}$$

5.B Supply and demand bid data

Table 5.13: Supply bids for reference year 2015.0 based on scenario and price (MW).

Season	Day	Hour	Bus	0€	20€	40€	60€	80€	100€	120€	140€	160€	180€
Winter	Weekday	Night	MINHO	1300.4	144.1	232.9	326.0	193.6	10.4	2.1	35.4	0.0	54.2
Winter	Weekday	Night	PORTO	174.1	0.0	3.6	1.7	0.0	0.0	0.0	0.0	0.0	1041.7
Winter	Weekday	Night	DOURO	3223.6	12.8	128.3	439.8	51.3	0.0	0.0	784.0	0.0	0.0
Winter	Weekday	Night	LITORAL	406.3	0.0	20.1	138.3	416.0	6.2	0.0	29.6	26.7	0.0
Winter	Weekday	Night	CENTRO	2398.8	31.2	77.2	221.9	80.3	0.5	24.6	47.8	30.1	302.8
Winter	Weekday	Night	LISBOA	290.2	0.0	0.0	55.2	751.6	263.0	0.0	87.8	0.0	0.0
Winter	Weekday	Night	SINES	559.2	1063.6	193.9	23.7	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekday	Night	ALENTEJO	58.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekday	Night	SANTAREM	373.7	160.7	365.0	12.7	327.3	0.0	0.0	370.0	0.0	262.5
Winter	Weekday	Night	ALQUEVA	436.9	50.7	115.1	158.3	26.3	2.3	3.1	7.5	0.0	64.6
Winter	Weekday	Night	ALGARVE	116.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekday	Night	GALICIA	5901.7	102.7	308.7	320.5	215.3	148.1	122.5	192.1	454.4	732.7
Winter	Weekday	Night	CASTILLALEON	8625.5	278.8	838.0	870.0	584.5	402.1	332.5	521.3	1233.5	1988.9
Winter	Weekday	Night	EXTREMADURA	2269.9	249.4	220.5	228.9	153.8	105.8	87.5	137.2	324.6	523.4
Winter	Weekday	Night	ANDALUCIA	5901.7	205.4	617.5	641.0	430.7	296.3	245.0	384.1	908.9	1465.5
Winter	Weekday	Day	MINHO	1408.8	205.8	335.3	445.6	204.3	10.4	2.1	35.4	0.0	53.7
Winter	Weekday	Day	PORTO	182.2	0.0	85.2	425.0	24.6	0.7	0.0	0.0	3	593.9
Winter	Weekday	Day	DOURO	4027.1	2.3	57.0	299.1	30.4	0.0	0.0	764.3	0.0	0.0
Winter	Weekday	Day	LITORAL	621.2	95.0	1.2	162.5	120.4	1.7	0.0	42.3	26.7	0.0

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Table 5.13 – Supply bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	**Day**	**Hour**	**Bus**	**0€**	**20€**	**40€**	**60€**	**80€**	**100€**	**120€**	**140€**	**160€**	**180€**
Winter	Weekday	Day	CENTRO	2703.0	41.8	118.2	285.7	85.4	0.5	6.8	27.1	41.2	240.8
Winter	Weekday	Day	LISBOA	999.0	11.7	0.0	217.4	136.9	18.8	0.0	94.7	0.0	0.0
Winter	Weekday	Day	SINES	627.0	1416.2	60.6	1.4	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekday	Day	ALENTEJO	60.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekday	Day	SANTAREM	505.1	277.9	631.5	237.1	300.4	0.0	0.0	43.8	0.0	33.6
Winter	Weekday	Day	ALQUEVA	464.2	74.6	172.9	225.7	26.6	2.3	3.1	7.5	0.0	63.2
Winter	Weekday	Day	ALGARVE	121.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekday	Day	GALICIA	6317.0	297.0	563.5	586.2	269.3	121.7	100.7	111.5	218.6	215.6
Winter	Weekday	Day	CASTILLALEON	9232.6	806.2	1529.5	1591.1	731.0	330.3	273.2	302.6	593.2	585.1
Winter	Weekday	Day	EXTREMADURA	2429.6	721.3	402.5	418.7	192.4	86.9	71.9	79.6	156.1	154.0
Winter	Weekday	Day	ANDALUCIA	6317.0	594.0	1127.0	1172.4	538.6	243.4	201.3	223.0	437.1	431.2
Winter	Weekend	Night	MINHO	1275.4	145.2	311.5	257.8	198.1	10.6	0.0	35.7	0.0	57.4
Winter	Weekend	Night	PORTO	162.8	0.0	0.5	1.7	0.0	0.0	0.0	0.0	0.0	1042.7
Winter	Weekend	Night	DOURO	3198.0	9.8	155.6	415.7	44.4	0.0	0.0	743.6	0.0	0.0
Winter	Weekend	Night	LITORAL	379.8	0.0	12.4	136.4	416.2	6.3	0.0	28.9	27.5	0.0
Winter	Weekend	Night	CENTRO	2341.2	43.0	110.9	180.5	71.0	0.0	18.8	39.1	28.5	286.6
Winter	Weekend	Night	LISBOA	271.3	0.0	0.0	50.3	761.2	267.0	0.0	88.5	0.0	0.0
Winter	Weekend	Night	SINES	456.5	920.5	253.5	47.3	0.0	0.0	0.0	0.0	1.5	0.0
Winter	Weekend	Night	ALENTEJO	54.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekend	Night	SANTAREM	354.8	136.0	351.6	15.5	301.7	0.0	0.0	377.7	0.0	261.5
Winter	Weekend	Night	ALQUEVA	423.4	41.2	157.5	125.2	22.9	2.5	2.7	7.9	0.0	68.2

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Table 5.13 – Supply bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	Day	Hour	Bus	0€	20€	40€	60€	80€	100€	120€	140€	160€	180€
Winter	Weekend	Night	ALGARVE	108.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekend	Night	GALICIA	5787.4	128.6	343.4	308.6	180.2	111.2	120.7	180.8	491.2	770.9
Winter	Weekend	Night	CASTILLALEON	8458.5	349.2	932.0	837.6	489.0	301.8	327.7	490.8	1333.3	2092.4
Winter	Weekend	Night	EXTREMADURA	2225.9	312.4	245.3	220.4	128.7	79.4	86.2	129.2	350.9	550.6
Winter	Weekend	Night	ANDALUCIA	5787.4	257.3	686.7	617.2	360.3	222.4	241.5	361.6	982.4	1541.8
Winter	Weekend	Day	MINHO	1329.2	163.5	356.7	281.1	201.8	10.6	0.0	35.5	0.0	59.4
Winter	Weekend	Day	PORTO	170.9	0.0	88.6	322.3	20.0	0.0	0.0	0.0	3.1	614.3
Winter	Weekend	Day	DOURO	3915.3	0.6	67.4	244.6	25.1	0.0	0.0	736.1	0.0	0.0
Winter	Weekend	Day	LITORAL	588.8	90.4	0.7	153.2	122.2	1.8	0.0	41.2	27.4	0.0
Winter	Weekend	Day	CENTRO	2591.6	45.8	130.5	197.5	72.4	0.0	8	27.7	34.6	231.7
Winter	Weekend	Day	LISBOA	972.2	11.4	0.0	212.8	140.6	19.4	0.0	96.0	0.0	0.0
Winter	Weekend	Day	SINES	522.9	1113.6	108.6	4.6	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekend	Day	ALENTEJO	57.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekend	Day	SANTAREM	490.3	232.6	524.9	257.6	274.3	0.0	0.0	45.8	0.0	32.0
Winter	Weekend	Day	ALQUEVA	441.1	54.3	171.6	143.8	23.6	2.5	2.7	7.9	0.0	69.2
Winter	Weekend	Day	ALGARVE	113.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter	Weekend	Day	GALICIA	6288.7	306.6	538.3	525.3	242.1	101.3	91.1	105.5	262.7	274.7
Winter	Weekend	Day	CASTILLALEON	9191.2	832.2	1461.0	1425.7	657.2	275.0	247.2	286.4	713.1	745.6
Winter	Weekend	Day	EXTREMADURA	2418.7	744.6	384.5	375.2	173.0	72.4	65.0	75.4	187.7	196.2
Winter	Weekend	Day	ANDALUCIA	6288.7	613.2	1076.5	1050.5	484.3	202.6	182.1	211.0	525.5	549.4
Summer	Weekday	Night	MINHO	591.3	58.1	230.9	631.7	194.0	7.5	10.1	35.8	0.0	50.9

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Table 5.13 – Supply bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	Day	Hour	Bus	0€	20€	40€	60€	80€	100€	120€	140€	160€	180€
Summer	Weekday	Night	PORTO	123.0	0.0	4.4	4.9	0.0	0.0	0.0	0.0	0.0	998.3
Summer	Weekday	Night	DOURO	2028.4	0.0	63.2	327.1	51.1	0.0	0.0	1254.1	0.0	0.0
Summer	Weekday	Night	LITORAL	295.4	0.5	0.0	168.5	405.1	7.0	0.0	29.6	70.8	0.0
Summer	Weekday	Night	CENTRO	1476.7	65.8	142.2	305.9	95.9	0.0	0.0	0.0	0.0	371.3
Summer	Weekday	Night	LISBOA	204.9	0.0	0.0	146.9	652.3	274.8	0.0	89.5	0.0	0.0
Summer	Weekday	Night	SINES	635.2	1440.3	63.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekday	Night	ALENTEJO	41.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekday	Night	SANTAREM	198.6	322.1	513.2	8.5	257.9	458.0	6.8	53.8	0.0	85.8
Summer	Weekday	Night	ALQUEVA	245.9	25.4	99.0	234.4	33.6	40.6	0.0	5.0	0.0	46.5
Summer	Weekday	Night	ALGARVE	82.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekday	Night	GALICIA	4662.2	65.3	376.5	357.6	190.3	74.2	84.0	205.9	507.5	740.2
Summer	Weekday	Night	CASTILLALEON	6814.0	28.0	161.4	153.3	81.6	31.8	36.0	88.2	217.5	317.2
Summer	Weekday	Night	EXTREMADURA	1793.2	158.7	268.9	255.4	136.0	53.0	60.0	147.1	362.5	528.7
Summer	Weekday	Night	ANDALUCIA	4662.2	130.7	753.0	715.2	380.7	148.4	167.9	411.8	1015.0	1480.4
Summer	Weekday	Day	MINHO	643.0	62.7	279.4	750.7	197.6	7.5	10.1	35.7	0.0	51.1
Summer	Weekday	Day	PORTO	134.5	0.0	186.9	366.3	0.1	0.0	0.0	0.0	0.0	589.2
Summer	Weekday	Day	DOURO	2463.6	0.0	34.3	261.4	37.2	0.0	0.0	1238.2	0.0	0.0
Summer	Weekday	Day	LITORAL	512.9	151.8	0.0	230.0	81.8	2.4	0.0	13.3	57.0	14.0
Summer	Weekday	Day	CENTRO	1724.0	70.7	180.3	353.7	97.7	0.0	0.0	0.0	0.0	317.4
Summer	Weekday	Day	LISBOA	921.2	11.7	0.0	242.6	122.4	17.6	0.0	99.2	0.0	0.0
Summer	Weekday	Day	SINES	656.0	1484.3	45.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 5.13 – Supply bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	**Day**	**Hour**	**Bus**	**0€**	**20€**	**40€**	**60€**	**80€**	**100€**	**120€**	**140€**	**160€**	**180€**
Summer	Weekday	Day	ALENTEJO	44.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekday	Day	SANTAREM	217.4	310.5	627.1	19.7	266.9	458.0	6.8	33.0	0.0	31.1
Summer	Weekday	Day	ALQUEVA	269.5	32.4	131.8	295.9	33.7	40.2	0.0	4.9	0.0	47.5
Summer	Weekday	Day	ALGARVE	89.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekday	Day	GALICIA	5716.8	294.2	728.8	572.5	224.6	86.5	67.2	106.4	242.6	219.9
Summer	Weekday	Day	CASTILLALEON	8355.3	126.1	312.3	245.3	96.3	37.1	28.8	45.6	104.0	94.2
Summer	Weekday	Day	EXTREMADURA	2198.8	714.4	520.6	408.9	160.4	61.8	48.0	76.0	173.3	157.0
Summer	Weekday	Day	ANDALUCIA	5716.8	588.3	1457.6	1144.9	449.2	173.0	134.4	212.9	485.2	439.7
Summer	Weekend	Night	MINHO	588.3	57.4	224.5	637.4	183.0	6.8	12.1	35.9	0.0	52.2
Summer	Weekend	Night	PORTO	122.3	0.0	0.9	2.4	0.0	0.0	0.0	0.0	0.0	1006.8
Summer	Weekend	Night	DOURO	2036.9	0.0	53.6	333.8	31.5	0.0	0.0	1305.3	0.0	0.0
Summer	Weekend	Night	LITORAL	285.7	0.0	0.0	182.1	432.4	8.3	0.0	21.5	44.0	0.0
Summer	Weekend	Night	CENTRO	1465.5	66.2	140.9	306.0	98.9	0.0	0.0	0.0	0.0	379.8
Summer	Weekend	Night	LISBOA	203.8	0.0	0.0	148.0	661.1	278.5	0.0	87.0	0.0	0.0
Summer	Weekend	Night	SINES	587.4	1328.9	133.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekend	Night	ALENTEJO	40.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekend	Night	SANTAREM	164.6	320.6	500.0	10.7	295.4	461.5	5.7	39.7	0.0	87.2
Summer	Weekend	Night	ALQUEVA	244.6	53.5	81.0	225.6	29.2	41.9	0.0	4.6	0.0	55.8
Summer	Weekend	Night	ALGARVE	81.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekend	Night	GALICIA	4694.8	72.4	357.5	338.6	161.2	74.2	82.2	204.9	545.0	771.3
Summer	Weekend	Night	CASTILLALEON	6861.6	196.6	970.5	919.1	437.5	201.4	223.1	556.2	1479.3	2093.5

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Table 5.13 – Supply bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	**Day**	**Hour**	**Bus**	**0€**	**20€**	**40€**	**60€**	**80€**	**100€**	**120€**	**140€**	**160€**	**180€**
Summer	Weekend	Night	EXTREMADURA	1805.7	175.9	255.4	241.9	115.1	53.0	58.7	146.4	389.3	550.9
Summer	Weekend	Night	ANDALUCIA	4694.8	144.9	715.1	677.2	322.4	148.4	164.4	409.9	1090.0	1542.6
Summer	Weekend	Day	MINHO	557.5	64.3	238.8	662.7	180.6	6.8	12.1	35.9	0.0	51.9
Summer	Weekend	Day	PORTO	115.6	0.0	133.9	261.4	0.0	0.0	0.0	0.0	0.0	615.7
Summer	Weekend	Day	DOURO	2247.8	0.0	26.0	241.8	22.4	0.0	0.0	1312.8	0.0	0.0
Summer	Weekend	Day	LITORAL	437.7	141.7	0.0	229.3	79.4	1.3	0.0	13.5	46.2	12.0
Summer	Weekend	Day	CENTRO	1522.9	73.7	152.3	312.9	99.1	0.0	0.0	0.0	0.0	318.7
Summer	Weekend	Day	LISBOA	878.0	11.6	0.0	240.2	122.2	17.8	0.0	97.9	0.0	0.0
Summer	Weekend	Day	SINES	604.0	1366.4	103.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekend	Day	ALENTEJO	38.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekend	Day	SANTAREM	163.2	302.9	588.0	19.2	284.5	461.5	5.7	26.9	0.0	30.1
Summer	Weekend	Day	ALQUEVA	231.2	62.1	91.3	243.5	29.3	41.9	0.0	4.6	0.0	55.8
Summer	Weekend	Day	ALGARVE	77.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Summer	Weekend	Day	GALICIA	5520.6	296.0	616.2	503.8	212.6	84.5	65.3	103.8	277.4	276.4
Summer	Weekend	Day	CASTILLALEON	8068.5	803.5	1672.6	1367.4	576.9	229.3	177.3	281.7	752.9	750.3
Summer	Weekend	Day	EXTREMADURA	2123.3	718.9	440.2	359.8	151.8	60.4	46.7	74.1	198.1	197.5
Summer	Weekend	Day	ANDALUCIA	5520.6	592.1	1232.4	1007.6	425.1	169.0	130.6	207.6	554.8	552.9

Table 5.14: Demand bids for reference year 2015.0 based on scenario and price (MW).

Season	**Day**	**Hour**	**Bus**	**0€**	**20€**	**40€**	**60€**	**80€**	**100€**	**120€**	**140€**	**160€**	**180€**
Winter	Weekday	Night	MINHO	39.9	40.0	38.0	2.9	11.9	11.0	14.4	1.8	0.4	938.6
Winter	Weekday	Night	PORTO	0.2	0.4	0.9	3.2	13.1	12.1	15.8	1.9	0.5	1032.5
Winter	Weekday	Night	DOURO	5.8	27.9	20.7	3.5	14.3	13.2	17.2	2.1	0.5	1126.3
Winter	Weekday	Night	LITORAL	0.2	0.5	1.1	4.1	16.7	15.4	20.1	2.5	0.6	1314.0
Winter	Weekday	Night	CENTRO	46.2	61.7	66.6	5.4	10.7	9.9	12.9	1.6	0.4	844.7
Winter	Weekday	Night	LISBOA	0.5	0.9	2.2	7.9	32.2	29.7	38.7	4.7	1.2	2534.2
Winter	Weekday	Night	SINES	0.0	0.0	0.1	0.3	1.2	1.1	1.4	0.2	0.0	93.9
Winter	Weekday	Night	ALENTEJO	0.1	0.1	0.2	0.9	3.6	3.3	4.3	0.5	0.1	281.6
Winter	Weekday	Night	SANTAREM	0.1	0.2	0.4	1.5	6.0	5.5	7.2	0.9	0.2	469.3
Winter	Weekday	Night	ALQUEVA	79.9	190.5	238.0	11.0	1.2	1.1	1.4	0.2	0.0	93.9
Winter	Weekday	Night	ALGARVE	0.1	0.2	0.6	2.1	8.3	7.7	10.0	1.2	0.3	657.0
Winter	Weekday	Night	GALICIA	453.2	116.5	146.0	75.4	168.5	49.2	77.7	22.9	10.8	1567.7
Winter	Weekday	Night	CASTILLALEON	453.2	58.2	73.0	37.7	84.3	24.6	38.8	11.5	5.4	783.9
Winter	Weekday	Night	EXTREMADURA	226.6	58.2	73.0	37.7	84.3	24.6	38.8	11.5	5.4	783.9
Winter	Weekday	Night	ANDALUCIA	1435.0	368.8	462.3	238.9	533.7	155.9	246.0	72.5	34.1	4964.5
Winter	Weekday	Day	MINHO	32.6	32.5	27.3	2.1	9.6	5.0	12.0	2.4	1.3	1269.5
Winter	Weekday	Day	PORTO	0.3	0.4	1.2	2.3	10.5	5.5	13.2	2.6	1.5	1396.5
Winter	Weekday	Day	DOURO	5.7	28.3	15.8	2.5	11.5	6.0	14.4	2.8	1.6	1523.4
Winter	Weekday	Day	LITORAL	0.4	0.5	1.6	2.9	13.4	7.1	16.8	3.3	1.9	1777.3
Winter	Weekday	Day	CENTRO	46.0	48.5	45.3	3.9	8.6	4.5	10.8	2.1	1.2	1142.5
Winter	Weekday	Day	LISBOA	0.7	0.9	3.0	5.5	25.8	13.6	32.5	6.4	3.6	3427.7

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Table 5.14 – Demand bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	**Day**	**Hour**	**Bus**	**0€**	**20€**	**40€**	**60€**	**80€**	**100€**	**120€**	**140€**	**160€**	**180€**
Winter	Weekday	Day	SINES	0.0	0.0	0.1	0.2	1.0	0.5	1.2	0.2	0.1	127.0
Winter	Weekday	Day	ALENTEJO	0.1	0.1	0.3	0.6	2.9	1.5	3.6	0.7	0.4	380.8
Winter	Weekday	Day	SANTAREM	0.1	0.2	0.6	1.0	4.8	2.5	6.0	1.2	0.7	634.8
Winter	Weekday	Day	ALQUEVA	56.5	138.1	152.3	7.5	1.0	0.5	1.2	0.2	0.1	127.0
Winter	Weekday	Day	ALGARVE	0.2	0.2	0.8	1.4	6.7	3.5	8.4	1.7	0.9	888.7
Winter	Weekday	Day	GALICIA	604.5	63.3	92.1	78.2	147.9	64.3	153.6	22.3	16.1	2204.4
Winter	Weekday	Day	CASTILLALEON	604.5	31.6	46.1	39.1	74.0	32.1	76.8	11.1	8.0	1102.2
Winter	Weekday	Day	EXTREMADURA	302.2	31.6	46.1	39.1	74.0	32.1	76.8	11.1	8.0	1102.2
Winter	Weekday	Day	ANDALUCIA	1914.2	200.3	291.7	247.5	468.5	203.5	486.3	70.5	50.9	6980.7
Winter	Weekend	Night	MINHO	32.1	49.6	33.4	2.5	11.0	12.3	14.6	2.6	0.4	907.8
Winter	Weekend	Night	PORTO	0.1	0.2	0.8	2.8	12.1	13.5	16.0	2.8	0.4	998.5
Winter	Weekend	Night	DOURO	9.5	35.0	11.7	3.0	13.2	14.8	17.5	3.1	0.4	1089.3
Winter	Weekend	Night	LITORAL	0.2	0.3	1.0	3.6	15.4	17.2	20.4	3.6	0.5	1270.9
Winter	Weekend	Night	CENTRO	45.1	64.0	45.5	5.9	9.9	11.1	13.1	2.3	0.3	817.0
Winter	Weekend	Night	LISBOA	0.3	0.6	2.0	6.9	29.7	33.2	39.3	6.9	1.0	2450.9
Winter	Weekend	Night	SINES	0.0	0.0	0.1	0.3	1.1	1.2	1.5	0.3	0.0	90.8
Winter	Weekend	Night	ALENTEJO	0.0	0.1	0.2	0.8	3.3	3.7	4.4	0.8	0.1	272.3
Winter	Weekend	Night	SANTAREM	0.1	0.1	0.4	1.3	5.5	6.2	7.3	1.3	0.2	453.9
Winter	Weekend	Night	ALQUEVA	114.1	194.6	176.9	4.7	1.1	1.2	1.5	0.3	0.0	90.8
Winter	Weekend	Night	ALGARVE	0.1	0.2	0.5	1.8	7.7	8.6	10.2	1.8	0.3	635.4
Winter	Weekend	Night	GALICIA	442.0	126.6	117.5	59.9	156.1	44.9	87.1	19.7	11.4	1572.2

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Table 5.14 – Demand bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	Day	Hour	Bus	0€	20€	40€	60€	80€	100€	120€	140€	160€	180€
Winter	Weekend	Night	CASTILLALEON	442.0	63.3	58.8	29.9	78.0	22.4	43.6	9.8	5.7	786.1
Winter	Weekend	Night	EXTREMADURA	221.0	63.3	58.8	29.9	78.0	22.4	43.6	9.8	5.7	786.1
Winter	Weekend	Night	ANDALUCIA	1399.5	400.9	372.1	189.6	494.2	142.0	275.9	62.3	36.3	4978.6
Winter	Weekend	Day	MINHO	30.8	40.5	28.1	2.6	4.1	6.6	18.2	4.3	1.6	1045.6
Winter	Weekend	Day	PORTO	0.4	0.6	1.4	2.9	4.5	7.2	20.0	4.7	1.7	1150.1
Winter	Weekend	Day	DOURO	9.8	32.3	13.7	3.2	4.9	7.9	21.8	5.1	1.9	1254.7
Winter	Weekend	Day	LITORAL	0.5	0.7	1.8	3.7	5.7	9.2	25.5	6.0	2.2	1463.8
Winter	Weekend	Day	CENTRO	42.0	57.0	38.3	6.0	3.7	5.9	16.4	3.9	1.4	941.0
Winter	Weekend	Day	LISBOA	1.0	1.4	3.4	7.1	11.0	17.7	49.1	11.6	4.2	2823.1
Winter	Weekend	Day	SINES	0.0	0.1	0.1	0.3	0.4	0.7	1.8	0.4	0.2	104.6
Winter	Weekend	Day	ALENTEJO	0.1	0.2	0.4	0.8	1.2	2.0	5.5	1.3	0.5	313.7
Winter	Weekend	Day	SANTAREM	0.2	0.3	0.6	1.3	2.0	3.3	9.1	2.1	0.8	522.8
Winter	Weekend	Day	ALQUEVA	90.5	179.6	134.7	4.7	0.4	0.7	1.8	0.4	0.2	104.6
Winter	Weekend	Day	ALGARVE	0.3	0.4	0.9	1.8	2.8	4.6	12.7	3.0	1.1	731.9
Winter	Weekend	Day	GALICIA	517.2	97.6	99.1	60.2	108.7	55.9	155.2	29.3	16.6	1843.1
Winter	Weekend	Day	CASTILLALEON	517.2	48.8	49.5	30.1	54.3	27.9	77.6	14.7	8.3	921.6
Winter	Weekend	Day	EXTREMADURA	258.6	48.8	49.5	30.1	54.3	27.9	77.6	14.7	8.3	921.6
Winter	Weekend	Day	ANDALUCIA	1637.7	309.2	313.7	190.7	344.1	176.9	491.4	92.9	52.6	5836.5
Summer	Weekday	Night	MINHO	18.1	33.9	8.3	4.2	8.2	19.7	9.2	0.0	0.0	883.2
Summer	Weekday	Night	PORTO	0.0	0.2	2.2	4.6	9.1	21.6	10.1	0.0	0.0	971.5
Summer	Weekday	Night	DOURO	14.1	43.3	77.9	5.0	9.9	23.6	11.0	0.0	0.0	1059.9

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Table 5.14 – Demand bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	**Day**	**Hour**	**Bus**	**0€**	**20€**	**40€**	**60€**	**80€**	**100€**	**120€**	**140€**	**160€**	**180€**
Summer	Weekday	Night	LITORAL	0.0	0.2	2.9	5.8	11.6	27.5	12.8	0.0	0.0	1236.5
Summer	Weekday	Night	CENTRO	22.1	37.9	224.0	6.4	7.4	17.7	8.2	0.0	0.0	794.9
Summer	Weekday	Night	LISBOA	0.0	0.4	5.5	11.2	22.3	53.1	24.7	0.0	0.0	2384.7
Summer	Weekday	Night	SINES	0.0	0.0	0.2	0.4	0.8	2.0	0.9	0.0	0.0	88.3
Summer	Weekday	Night	ALENTEJO	0.0	0.0	0.6	1.2	2.5	5.9	2.7	0.0	0.0	265.0
Summer	Weekday	Night	SANTAREM	0.0	0.1	1.0	2.1	4.1	9.8	4.6	0.0	0.0	441.6
Summer	Weekday	Night	ALQUEVA	16.4	81.3	397.2	17.4	0.8	2.0	0.9	0.0	0.0	88.3
Summer	Weekday	Night	ALGARVE	0.0	0.1	1.4	2.9	5.8	13.8	6.4	0.0	0.0	618.2
Summer	Weekday	Night	GALICIA	457.6	57.4	171.7	104.4	163.8	70.8	54.9	12.7	4.3	1421.4
Summer	Weekday	Night	CASTILLALEON	457.6	57.4	171.7	104.4	163.8	70.8	54.9	12.7	4.3	1421.4
Summer	Weekday	Night	EXTREMADURA	228.8	28.7	85.9	52.2	81.9	35.4	27.4	6.4	2.1	710.7
Summer	Weekday	Night	ANDALUCIA	1449.1	181.7	543.8	330.6	518.6	224.2	173.8	40.4	13.6	4501.1
Summer	Weekday	Day	MINHO	17.4	30.7	6.1	4.2	7.9	8.0	9.9	0.3	0.2	1156.6
Summer	Weekday	Day	PORTO	0.0	0.1	2.8	4.7	8.7	8.8	10.9	0.4	0.3	1272.3
Summer	Weekday	Day	DOURO	13.8	39.6	73.8	5.1	9.5	9.6	11.9	0.4	0.3	1388.0
Summer	Weekday	Day	LITORAL	0.0	0.1	3.6	6.0	11.1	11.2	13.9	0.5	0.3	1619.3
Summer	Weekday	Day	CENTRO	21.9	34.7	187.4	6.5	7.1	7.2	8.9	0.3	0.2	1041.0
Summer	Weekday	Day	LISBOA	0.0	0.2	6.9	11.5	21.3	21.6	26.8	0.9	0.6	3122.9
Summer	Weekday	Day	SINES	0.0	0.0	0.3	0.4	0.8	0.8	1.0	0.0	0.0	115.7
Summer	Weekday	Day	ALENTEJO	0.0	0.0	0.8	1.3	2.4	2.4	3.0	0.1	0.1	347.0
Summer	Weekday	Day	SANTAREM	0.0	0.0	1.3	2.1	4.0	4.0	5.0	0.2	0.1	578.3

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Table 5.14 – Demand bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	Day	Hour	Bus	0€	20€	40€	60€	80€	100€	120€	140€	160€	180€
Summer	Weekday	Day	ALQUEVA	13.7	72.6	307.2	16.2	0.8	0.8	1.0	0.0	0.0	115.7
Summer	Weekday	Day	ALGARVE	0.0	0.1	1.8	3.0	5.5	5.6	6.9	0.2	0.2	809.6
Summer	Weekday	Day	GALICIA	545.2	41.1	125.4	111.4	167.6	77.7	122.3	8.7	5.6	2044.9
Summer	Weekday	Day	CASTILLALEON	545.2	41.1	125.4	111.4	167.6	77.7	122.3	8.7	5.6	2044.9
Summer	Weekday	Day	EXTREMADURA	272.6	20.6	62.7	55.7	83.8	38.8	61.2	4.4	2.8	1022.5
Summer	Weekday	Day	ANDALUCIA	1726.4	130.3	397.2	352.9	530.9	246.0	387.3	27.6	17.8	6475.6
Summer	Weekend	Night	MINHO	21.5	30.2	1.5	3.2	7.2	20.9	10.8	0.0	0.0	849.1
Summer	Weekend	Night	PORTO	0.0	0.3	1.7	3.5	7.9	23.0	11.9	0.0	0.0	934.0
Summer	Weekend	Night	DOURO	16.2	40.9	74.7	3.9	8.6	25.1	13.0	0.0	0.0	1018.9
Summer	Weekend	Night	LITORAL	0.0	0.3	2.1	4.5	10.1	29.3	15.1	0.0	0.0	1188.7
Summer	Weekend	Night	CENTRO	29.1	57.6	184.1	2.9	6.5	18.8	9.7	0.0	0.0	764.2
Summer	Weekend	Night	LISBOA	0.0	0.6	4.1	8.7	19.4	56.5	29.2	0.0	0.0	2292.5
Summer	Weekend	Night	SINES	0.0	0.0	0.2	0.3	0.7	2.1	1.1	0.0	0.0	84.9
Summer	Weekend	Night	ALENTEJO	0.0	0.1	0.5	1.0	2.2	6.3	3.2	0.0	0.0	254.7
Summer	Weekend	Night	SANTAREM	0.0	0.1	0.8	1.6	3.6	10.5	5.4	0.0	0.0	424.5
Summer	Weekend	Night	ALQUEVA	36.6	64.6	404.4	0.3	0.7	2.1	1.1	0.0	0.0	84.9
Summer	Weekend	Night	ALGARVE	0.0	0.2	1.1	2.3	5.0	14.7	7.6	0.0	0.0	594.3
Summer	Weekend	Night	GALICIA	443.5	58.5	163.0	86.0	145.5	68.7	60.6	13.2	7.4	1382.1
Summer	Weekend	Night	CASTILLALEON	443.5	29.3	81.5	43.0	72.7	34.3	30.3	6.6	3.7	691.1
Summer	Weekend	Night	EXTREMADURA	221.8	29.3	81.5	43.0	72.7	34.3	30.3	6.6	3.7	691.1
Summer	Weekend	Night	ANDALUCIA	1404.5	185.3	516.2	272.4	460.7	217.5	191.8	41.8	23.4	4376.7

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Table 5.14 – Demand bids for reference year 2015.0 based on scenario and price (MW) (*Continued from previous page*)

Season	Day	Hour	Bus	0€	20€	40€	60€	80€	100€	120€	140€	160€	180€
Summer	Weekend	Day	MINHO	22.0	25.9	3.0	3.3	4.6	10.1	16.6	0.3	0.3	948.3
Summer	Weekend	Day	PORTO	0.0	0.3	3.3	3.7	5.0	11.1	18.3	0.4	0.3	1043.1
Summer	Weekend	Day	DOURO	16.2	39.4	75.0	4.0	5.5	12.2	19.9	0.4	0.3	1137.9
Summer	Weekend	Day	LITORAL	0.0	0.4	4.3	4.7	6.4	14.2	23.2	0.5	0.4	1327.6
Summer	Weekend	Day	CENTRO	29.7	52.6	184.1	3.0	4.1	9.1	14.9	0.3	0.2	853.5
Summer	Weekend	Day	LISBOA	0.0	0.7	8.2	9.0	12.3	27.4	44.8	0.9	0.7	2560.4
Summer	Weekend	Day	SINES	0.0	0.0	0.3	0.3	0.5	1.0	1.7	0.0	0.0	94.8
Summer	Weekend	Day	ALENTEJO	0.0	0.1	0.9	1.0	1.4	3.0	5.0	0.1	0.1	284.5
Summer	Weekend	Day	SANTAREM	0.0	0.1	1.5	1.7	2.3	5.1	8.3	0.2	0.1	474.1
Summer	Weekend	Day	ALQUEVA	40.4	54.1	364.5	0.3	0.5	1.0	1.7	0.0	0.0	94.8
Summer	Weekend	Day	ALGARVE	0.0	0.2	2.1	2.3	3.2	7.1	11.6	0.2	0.2	663.8
Summer	Weekend	Day	GALICIA	491.2	49.4	153.9	77.2	132.9	72.3	116.4	11.8	5.1	1622.5
Summer	Weekend	Day	CASTILLALEON	491.2	24.7	77.0	38.6	66.4	36.2	58.2	5.9	2.6	811.2
Summer	Weekend	Day	EXTREMADURA	245.6	24.7	77.0	38.6	66.4	36.2	58.2	5.9	2.6	811.2
Summer	Weekend	Day	ANDALUCIA	1555.5	156.3	487.4	244.6	420.7	229.0	368.5	37.4	16.3	5137.8

Chapter 6

Conclusions

6.1 Introduction

The current thesis was set out to study topics in transmission and interconnection expansion planning, key to the development of the Internal Energy Market in the European Union (EU). Specifically, it aims to enrich the discussion on transmission and interconnection expansion planning considering flexible decisions that account for time evolving uncertain parameters, contingency planning enabled by expansion postponement and the identification of a fair share cost allocation procedure for cooperative cross-border investments.

Infrastructure decisions, such as transmission and interconnection expansions, are costly endeavors whose success depends on the choice of the best investment decisions considering the constantly changing surrounding context. Among others, consumption needs vary based on population dynamics and consumption preferences. Similarly, there is also volatility in electricity generation as it is highly dependent on the available generation technology mix, weather conditions and the market cost of fuels. It follows that transmission and interconnection expansion planning occurs in a highly variable and uncertain context on which the exact future unfolding of events is impossible to predict. Given the irreversibility of power system investments and the uncertainty of future contexts, the need for robust decision-making models, that provide flexible power system expansion insights, is thus justified.

Concomitantly, the development of the Internal Energy Market requires Power Exchanges (PXs) of EU Member States to join together by means of the market coupling mechanism. With market coupling, cross-border power flow allocation is facilitated but still capped by available interconnections. Improving cross-border flows requires the investment in new interconnection capacity forcing Transmission System Operators (TSOs) to act cooperatively if they want to succeed in creating this pan-European infrastructure. However, cooperation is only possible if TSOs agree on invested transmission capacity as well as the associated allocation of investment costs.

Relevant literature in these topics is scarce and the enclosed contributions aim to enrich the discussion by answering the following research questions:

1. What is the impact of uncertain parameters evolving in time, and the value of postponement and other sources of operational flexibility, in transmission network expansion planning?

2. What is the level of investment, and what is a fair share allocation of costs, in the expansion of an interconnection between two regions, when they cooperate to establish a voluntary agreement?

3. What is the impact of uncertainty and transmission network configuration on the level of investment, and the fair share allocation of costs, in the expansion of the interconnections between two regions, when they cooperate to establish a voluntary agreement?

6.2 Key findings

For each study, key findings are available in the respective Chapters. In this section we summarize relevant findings to answer the proposed research questions:

1. *What is the impact of uncertain parameters evolving in time, and the value of postponement and other sources of operational flexibility, in transmission network expansion planning?*

   (a) Higher volatility and lower correlations in time evolving uncertain parameters act similarly. These lead to an increased likelihood of the expansion decision to be postponed.

   (b) Allowing investment decisions to be postponed encourages the transmission network to be customized to the unfolding of events. This reduces investment needs and makes it more likely for network configurations to evolve in more distinct ways.

(c) An increase in network complexity leads to a more significant number of combination of possible paths linking supply with demand. Transmission networks with this higher operational flexibility tend to require less transmission investments to guarantee power supply.

(d) Combining investment postponement with operational flexibility leads to a sublinear reduction in transmission capacity needs.

(e) The operational flexibility provided by transmission networks is able to improve renewable integration in power systems.

2. *What is the level of investment, and what is a fair share allocation of costs, in the expansion of an interconnection between two regions, when they cooperate to establish a voluntary agreement?*

   (a) Within unconstrained voluntary agreements, the level of investment decreases with an increase in investment costs.

   (b) If it is not possible for a region to pay for the whole investment and compensate the other to entice an agreement, overall investment levels decrease when compared with a situation where voluntary agreements are unconstrained. Due to the benefit imbalance of each region the exporting region gains bargaining power. It follows that is possible to observe a slight increase in transmission capacity investments with an increase in transmission costs.

   (c) A fair share allocation of costs must consider regional benefits while reducing its difference by as much as possible. This is not necessary in unconstrained voluntary agreements as decisions are expected to be the same, for both regions, with respect to a centralized decision.

3. *What is the impact of uncertainty and transmission network configuration on the level of investment, and the fair share allocation of costs, in the expansion of the interconnections between two regions, when they cooperate to establish a voluntary agreement?*

   (a) We found no evidence that suggests uncertainties to have a different role in transmission network expansions when regions cooperate and establish a voluntary agreement.

(b) Fair share allocation of costs is conducted in the same way independently of event uncertainty. Nevertheless, based on the unfolding of events it is possible for a region to obtain all the benefits and the other region to incur losses.

(c) Fair share cost allocation can increase the uncertainty of benefits for each region when compared with the aggregate benefits obtained by those regions.

6.3 Policy implications

In this section we enumerate key policy implications resulting from this thesis:

1. Explicitly addressing uncertainty is a considerable source of value in the design of transmission networks. Aware of this fact, policy makers should require TSOs to justify their expansion decisions. It is necessary to identify and take into account relevant uncertainties as well as defining a contingency plan. This contingency plan must list additional investment needs together with the necessary conditions for their execution to be worthwhile.

2. Regions can cooperate through voluntary agreements to solve interconnection capacity needs. Centralized decisions are not necessary to obtain optimal transmission capacity solutions that benefit the whole society. It should be taken into account that benefits are spread unevenly. Producers and consumers in either the importing and exporting regions can lose with cross-border trade. Decision-makers in each region must be aware of this fact and, if it is of interest, to devise redistribution policies to prevent these losses.

3. Voluntary agreements for transmission expansion planning might result in social welfare losses when uncertainties unfold. Moreover, the accrued benefits are less volatile than the benefits each region will obtain. Encouraging the introduction of risk management practices into contracts for the development of interconnection capacity, allows decision-makers to reduce the probability of incurring losses without compromising the expected benefit in social welfare these investments provide.

6.4 Recommendations for future research

Future developments can be technical in nature, expanding problem size and introducing new features, or delve into policy issues. The main recommendations are listed below:

1. Introduce decomposition methods to allow a computationally feasible increase in granularity in the transmission network and decision tree.

2. Identify metaheuristics that allow bigger instances to be solved without compromising significantly the obtained solution.

3. Study voluntary agreements for three or more regions. It is not certain if the solution would be similar to the solutions for each pair of regions or if this would lead either to a difference in network configuration or allocation of investment costs.

4. Study the impact that decision-makers with different risk profiles have in transmission network expansion planning when the postponement of decisions is possible.

5. Consider the effects risk-aversion in fair share cost allocation. This is especially relevant in situations where voluntary agreements can increase the chances of a region incurring in losses.

6. Design fair share cost allocation contracts that identify and incorporate risk management measures.

6.5 Final words

Transmission network expansion planning literature has evolved considerably since its inception with the works of Garver (1970) and Kaltenbach et al. (1970). Only recently are authors exploring the role of uncertainty, Chapters 2 and 3, and the existence of multiple players in the decision-making process, Chapter 4, of transmission and interconnection planning in power systems. This thesis provides a relevant contribution to the topic by presenting novel approaches to deal with those issues, both separately, in the previously mentioned Chapters and by considering them jointly, Chapter 5. In short, portfolios of real options are used to inspire the modeling of uncertainties and Nash bargaining together with the Coase theorem to obtain a fair share allocation of costs obtained in a cooperative voluntary agreement. To the best of our knowledge, the work presented in this thesis is the first to apply such methods into transmission network expansion planning. It should also be mentioned that Chapter 2, published as Loureiro et al. (2015), is the first contribution to the existing literature addressing a stochastic multi-stage transmission network expansion planning formulation where decision postponement is made possible through contingency planning. The remaining studies have already been submitted to journals and are currently under review.

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