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Economic regulation and efficiency of electricity systems

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To my beloved Cristina and Adrià

1 Aknowledgements

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Contents

1 Introduction

Environmental awareness is of increasing concern for society and leads heavy pressure to adopt challenging political decisions, in such diverse economic sectors as oil industries, automotive industries and electric utilities. Undoubtedly, all this goes beyond the environmental scope, entails reallocating significant financial resources and moving employment from one economic sector to another, with its corresponding impact on social welfare. Some examples of this transformation are the replacement of polluting coal and fuel generation plants by renewable energy sources (RES), the replacement of internal combustion engine vehicles by electric vehicles, new skilled occupations in energy efficiency improvements related to buildings, among others.

The UN Climate Conferences have contributed to this increasing awareness. The Kyoto Protocol (1997) came into force in 2005 and committed industrialized countries to limit and reduce greenhouse gases (GHG) emissions in accordance with agreed individual targets. Currently, there are 192 signatories to the Kyoto Protocol. In the Conference of Parties (COP21, Paris 2015) governments agreed to the urgent need to combat climate change by limiting global warming to well below 2°C above pre-industrial levels, and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels. From that point, each government had to decide on its own way forward. Finally, governments agreed to review progress towards the goal in a global stocktake every five years and starting in 2023 (ICCP, 2020).

These conferences reinforced the commitment of countries to pursue more ambitious objectives related to RES, which goes far beyond specific environmental concerns. For instance, RES also provide significant advantages in terms of security of supply, improve the commercial trade balance because they reduce external dependence on oil, creates employment in skilled activities, and open up economic opportunities in rural non-industrialized areas.

The European Union (EU) -which is the main focus of this PhD dissertation- could not fall behind and the Paris Agreement resulted in a new energy rulebook named the Clean Energy for all Europeans package, in 2015. Based on Commission proposals published in 2016, Clean Energy Package (CEP) was approved in 2019 after three years of long discussions and complex agreements. CEP aims to achieve ambitious environmental targets to deliver the EU's Paris Agreement commitments to reduce GHG in 2030 and also update the electricity market to efficiently integrate RES by a set of rules that involve RES, energy efficiency, governance regulation, energy market design and energy performance in buildings.

In the achievement of CEP environmental targets, electricity systems are a key pillar as the share of energy produced by RES is expected to duplicate by 2030. Recently, the EU Commission has launched the European Green Deal[1], an integral part of its Commission's strategy, to increase the EU's GHG emission reductions target for 2030 to at least 50% and towards 55% compared with 1990 levels. Undoubtedly, these targets will require connecting even more RES with the corresponding resource allocation in the electricity sector.

From the economic perspective, electricity consumption and gross domestic product (GDP) are very interrelated (Lee and Chang, 2005, 2007; Costa-Campi et al., 2018). Electricity is an input for most production processes, determining their overall efficiency and their production costs. In this regard, energy-intensive industries such as those engaged in the production of cement, pulp and paper, glass, iron and steel, chemicals, and refining are a particular case due to their extremely high consumption of electricity. In these production processes, electricity represents an important input cost that determines their competitiveness and export capacity.

In developed countries, electricity is increasingly important for small end-consumers as their consumption per capita is several-folder higher than developing countries[2]. Consequently, the final price of electricity is a sensitive issue that is often at the heart of political debate due to its potential effects on consumer price indexes and on the most vulnerable consumers. Lastly, many countries consider electricity as an essential good and have specific rules aimed to protect these vulnerable consumers.

In short, the final electricity price clearly affects social welfare because it affects both components: consumer and producer surplus.

The power sector is a capital-intensive industry with large amounts of long-term investments. In this regard, some electric infrastructures, such as networks and large generation plants, were built several decades ago and are still fully operative.

[1] Available at: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf

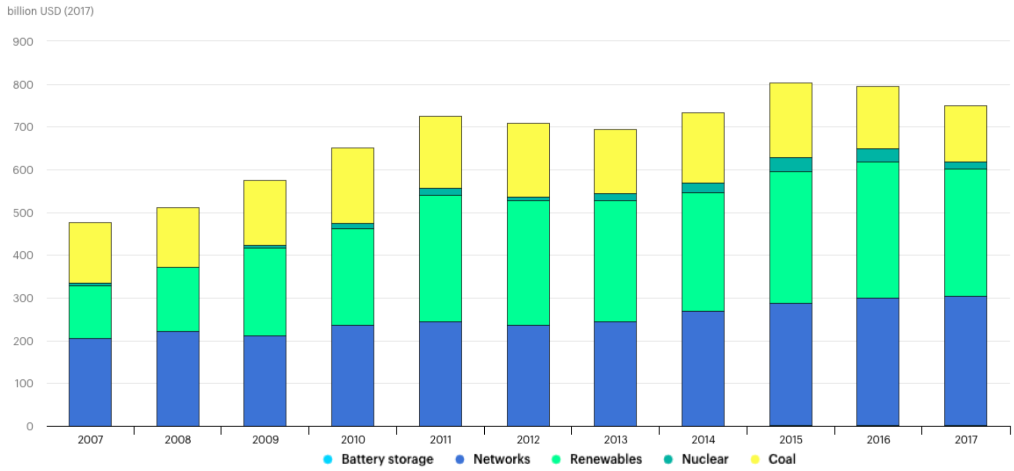
[2] Some examples of developed countries in 2014 are the following: 15,588 kWh/year in Canada, 12,993 kWh/year in the United States, 10,071 kWh/year in Australia, 7,035 kWh/year in Germany, 6,940 kWh/year in France, 5,356 kWh/year in Spain, 5,002 kWh/year in Italy, 3,927 kWh/year in China. Regarding undeveloped, 39 kWh/year in Haiti, 69 kWh/year in Ethiopia, 146 kWh/year in Nepal, 190 kWh/year in Sudan, 320 kWh/year in Bangladesh, 447 kWh/year in Pakistan. Source: World Bank Dataset - *Electric power consumption (kWh per capita)*. Available at https://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC (last consulted on 14 March, 2020).

In this context, studies of the efficiency of the resources allocated in this sector became important in the literature, especially since the unbundling and privatization of many publicly owned and vertically-integrated enterprises around the world in the 90s (Pollitt, 1995; Jamasb and Pollitt, 2003). Indeed, unbundling was a structural change aimed to foster competition in generation, and improve efficiency and performance from the networks, with the ultimate objective of reducing the final price of electricity (Joskow, 1997). In Europe, this process began with the Directive 96/92/EC, which established common rules regarding the organization and functioning of the whole electricity sector. These rules also aimed to increase competition in the electricity sector as a first step towards the European internal energy market.

After the Kyoto Protocol (1997), many countries prioritized new investment in RES generation plants to meet their nationals targets based on the reduction of GHG emissions. However, technologies associated to RES faced problems of high investment costs. Moreover, RES generation technologies were still in their infancy, and countries had to implement ambitious subsidies to improve their attractiveness to private investors. These policies allocated large amounts of private and public resources on RES during a short period of time and affected the final price of electricity by the combination of two opposite effects: a greater offer in generation capacity and the costs of RES subsidies themselves. This issue has been widely analyzed in the literature, but there is not a strong consensus on their impact on the final price of electricity (De Miera et al., 2008; Costa-Campi and Trujillo-Baute, 2015; Trujillo-Baute et al., 2018). The location of RES plants subject to subsidies across the countries has also been explored in the literature and some scholars find project developers did not compete in terms of price but for good sites, this is concentrating RES in resource-rich locations (IRENA and CEM, 2015; Newbery et al., 2018). Indeed, the location of RES and their impact on the efficiency and costs of the power sector is one of the main areas addressed in this thesis. Finally, other scholars explore the effect of RES on the volatility of the wholesale electricity price and find increases with RES (Ketterer, 2014).

Connecting RES also requires allocating many resources to grid infrastructure. Indeed, grid-related costs increase with the connection of high levels of RES (Hirth et al., 2015). This PhD dissertation focuses on the analysis of the grid-related costs in a decarbonized electricity system. To provide some context with real data, the annual global RES investments are almost equal to investments in networks, and the sum of both represents about 600 billion USD, accounting for 75% of total power sector investments (see Figure 3.1). Regarding the source of all power sector financial resources, the share of investment driven by state-owned enterprises was 40% in 2017 (IEA, 2020).

Figure 1.1: Global power sector investment, 2007-2017.



Source: IEA (2020).

This thesis focus on grid-related costs linked to RES. The replacement of conventional generation technologies by RES is one of the most important challenges for electricity systems in the last few decades because RES might be located far from actual conventional capacity and their production profile is very different, with the consequent impact on grid use, need and other costs. In this regard, grid-related costs also affect the performance of the power sector and impact on social welfare as they are recovered through the final price of electricity paid by consumers and firms. These costs can be classified in several groups despite all them being fairly interlinked in one way or another. In the analysis presented in this dissertation, attention is centered on *electricity losses*, *grid-congestions* and *grid-investments*.

First, *electricity losses* correspond to wasted energy through the grids and paid by consumers in the final electricity price. Clearly, these losses affect social welfare and the efficiency of the power sector. To provide some context, in Spain energy losses represented about 1,600M€ in 2017 (Ministry of Industry, 2018; REE, 2018).

In the literature related to *electricity losses*, some authors find that Demand Response (DR) policies and Distributed Generation (DG) exert a positive effect on this grid cost (Quezada et al., 2006; Venkatesan et al., 2012). Indeed, DR policies aim to mitigate peak consumption, and DG are small generation plants close to domestic consumers. However, the economic impact of DR or DG on *electricity losses* on a country-wide level has only been explored in few studies (Shaw et al., 2009; Cronenberg et al., 2012). An important hurdle impeding such analyses is related with data availability. The economic literature has also explored *electricity losses* in the context of efficiency and performance analyses of grid operators[3] after the unbundling of the electricity sector (Jamasb and Pollitt, 2003, 2007).

Second, *grid-congestion costs*[4] include compensations to generators facing partial or total curtailments resulting from temporary grid constraints or grid bottlenecks. These compensations are shared among all consumers as part of the wholesale price of electricity in a country. For reference, in Spain these compensations represented about 390M€ in 2017, which accounts for 2.6% of the annual wholesale price of electricity (REE, 2020). Moreover, this grid constraint means curtailing the production from a generation plant, and also means wasting decarbonized energy when RES are involved. It is important to highlight that these costs will hardly ever be zero as there are unforeseen events, not all situations are predictable, and the network cannot be endlessly reinforced. In this regard, only the most repeated events are those solved by reinforcing or building a new grid.

Some scholars have explored the relationship between *grid-congestion costs* and RES, finding an overall positive relationship between these costs and the amount of RES. Moreover, the concentration of RES in specific regions also increase *grid-congestion costs* due to grid bottlenecks (Joos and Staffell, 2018; Van den Bergh et al., 2015; Hitaj, 2015). Other authors have analyzed social welfare impacts when these *grid-congestion costs* are only paid by those closest to the grid constrain instead of all consumers, namely nodal prices. However, implementing nodal prices has other serious implications in electricity market functioning and beyond *grid-congestion costs* (Leuthold et al., 2008; Weigt et al., 2010; Neuhoff et al., 2013). Finally, the literature has not explored in detail the determinants of *grid-congestions* and how the energy produced by each technology contributes to them. This is one of the issues addressed in this thesis.

Third, and also highly relevant, *grid-investments* allocate economic resources to upgrade or build new networks. As is shown in Figure 3.1, they are very high and equivalent to the resources allocated in RES. New grids can reduce *grid-congestion costs* and *electricity losses*. In this regard, grids are essential to feed consumers from generators and some authors find a positive correlation between RES and *grid-*

[3] *Grid operators* term includes both the transmission system operator (TSO) and the distribution system operator (DSO)

[4] Also known as *technical constraint costs*.

investments because the lowest-cost wind power is often in remote locations and the actual grids have insufficient capacity (Borenstein, 2012). In Spain, planned annual *grid-investments* in transmission were 600M€ in 2015 and 950M€ in 2020 (REE, 2018). In this regard, the total length of the transmission networks, those used to send energy from the largest generation plants to the cities, have grown +58% from 1990 to 2016[5], coinciding in time with the connection of large amounts of RES. However, building new grids is costly and society is increasingly reluctant to do that[6].

Most studies of *grid-investments* are related to RES in very extensive areas, such as all of China or the European Union (Schaber et al., 2012; Fürsch et al., 2013; Lin and Li, 2015; Held et al., 2018). Typically, they use rather simplified network models due to grid complexity, which cannot capture specificities and characteristics from smaller areas, such as an European country. Finally, the existing academic literature has not explored *grid-investments* related to the accomplishment of a National Energy and Climate Plan defined in European Governance Regulation[7]. This regulation requires all European Member States to establish a 10-year National Energy and Climate Plan to meet energy and climate targets for 2030. Indeed, this is one of the issues addressed in this thesis.

Methodologically, exploring these grid-related costs means studying electricity flows, this is the energy that travels through the networks. From an empirical approach, the analyses in previous academic literature use optimization models, based on the optimization of nonlinear problems to simulate flows, taking into consideration network characteristics, generation and consumers. However, the major drawback of these models is that their outcomes depend on several key points, such as assumptions, constraints and optimization strategy (Schaber et al., 2012; Hitaj, 2015; Trepper et al., 2015; Van den Bergh et al., 2015; Schermeyer et al., 2018; Held et al., 2018; Fürsch et al., 2013). In the economic literature, there are other approaches used for the analysis of trade flows between countries, which have scarcely been explored in the analysis of energy flows, this is the case of gravity models (Anderson, 1979, 2011; Yotov et al., 2016). Part of the empirical analyses presented in this

[5]+58% corresponds to 27,680 km (1990) and 43,800km (2016) in the transmission grids (Ministry of Industry, 2018; REE, 2018).

[6]Social opposition to new grids is on the rise owing to their visual impact or environmental concerns. As an alternative there are technical solutions, based on underground lines or longer lines, but are much more expensive solutions. In either case, solutions are much more expensive and represent higher costs for consumers who pay for it in the final price of electricity.

[7]See: https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/governance-energy-union for further details.

PhD dissertation is based on gravity models, this thesis represents another contribution because these models have not been applied to the analysis of electricity flows within a country. The few existing studies using gravity models in the context of electricity flows are limited to the flows between countries, not within a country as is the case here (Antweiler, 2016; Batalla-Bejerano et al., 2019).

Without a doubt, fast deployment of RES affect all previous grid-related costs: *electricity losses*, *grid-congestion costs* and *grid-investments*. In economic terms, all these costs impact on social welfare through the final electricity price. The scope of this thesis is Spain, a particularly relevant case due to the extensive use of RES in the generation mix. In the years analyzed, the share of energy produced by RES is about 35-40%. Recently, the Spanish government has presented their ambitious environmental targets that aim to increase the share of energy produced by RES up to at least 74% by 2030. At times like the present, when there is an active debate about the best policies to achieve these targets, this thesis aims to contribute to the debate with an in depth analysis of the grid-costs determinants, and the optimal policies to maximize social welfare.

In short, the four empirical studies presented in the following Chapters offer detailed analyses of electricity system performance and efficiencies, which are used to define an optimal regulatory framework. The elements related to the regulatory framework include the design of incentives to improve efficiencies and new investments in electrical facilities, adapting market rules to the advent of new technologies of production, making markets and governmental mandates compatible, removing non-economic barriers, promoting market competition and mitigating market power, developing public-private partnership, and encouraging new business and financial models (Pérez-Arriaga, 2014). Although electricity sector reforms have significant potential benefits, they also carry the risk of significant potential costs if they are incompletely or incorrectly implemented (Joskow, 2006).

To make further progress in the qualitative analysis of grid-related costs, this thesis is structured in four closely linked analyses. Using operational data as the baseline, each study gradually incorporates additional data from electricity losses, CO_2 emissions, geographical information and planned RES by 2030. Moreover, each analysis collects results and conclusions from the previous studies, which enables better progress in the research and ensures a great traceability. The remaining part of this Chapter is divided into two sections, addressing the kind of analysis and the dimension of the variables included in the corresponding Chapters of this dissertation. The first section corresponds to studies based on one-dimensional variables (time) and summarizes Chapters 2 and 3. The second section corresponds to studies based on two-dimensional variables (time-space) and summarizes Chapters 4 and 5.

1.1 One-dimensional variable studies

This section includes Chapters 2 and 3, two studies based on time-series variables. Both Chapters present analysis of the performance of *electricity losses*, considering national-level variables.

Chapter 2 of this dissertation, *The economic impact of electricity losses*[8] (Costa-Campi et al., 2018), aims to explore whether *electricity losses* are affected by demand and supply aspects, namely consumer behavior and the role of generation technologies, respectively. In economic terms, this is exploring the determinants of electricity system efficiency and the final costs for consumers.

While developing this analysis the main challenge was related to the lack of information and hourly dataset. However, this was overcome by merging several hourly datasets published by the Spanish System Operator (SO) and including market information between 2011 and 2013. This empirical approach includes several Maximum Likelihood estimations, where the hourly losses are the endogenous variables, and explicative variables include the hourly consumption and the hourly production from each technology: nuclear, combined cycle, coal, hydropower, solar, wind, pumping, combined heat and power, and imports. Finally, several seasonal variables are used to control for seasonality.

From these results, some recommendations are provided for the optimal design of policies considering their impact on electricity losses. Of special interest are those policies aimed at easing the peak consumption, namely Demand Response (DR), and policies aimed at promoting the connection of DG.

Chapter 2 contributes to the literature through several elements, including but not limited to: the use of a long and hourly dataset, which includes disaggregated information between generation technologies, the hourly consumption of electricity, the hourly energy lost at transmission and distribution grid levels, and the hourly economic costs of these energy losses. The results explore how demand and supply affect electricity loses. Finally, this is one of the first papers to quantify the poten-

[8]https://doi.org/10.1016/j.eneco.2018.08.006

tial economic impacts of DR and DG in a real electricity system and at country size.

Chapter 3 of this dissertation, *CO_2 content of electricity losses*[9] (Davi-Arderius et al., 2017), aims to identify the contribution of *electricity losses* to the CO_2 emissions by the analysis of market closing technology and *electricity losses*. Indeed, *electricity losses* represent an additional consumption of electricity that determines the market closing technology and, consequently, the CO_2 emissions of the electricity system. In this regard, the analyses of these effects adds to our knowledge about the determinants of CO_2 emissions in power systems.

The dataset used in this study comes from Chapter 2 dataset and includes CO_2 emissions. The empirical approach includes several Ordinary Least Square estimations, where the hourly CO_2 emissions are the endogenous variable, and explicative variables include the hourly system load, *electricity losses* and the production of closing technologies in the market. Finally, several seasonal variables are used to control for seasonality.

From these results, some recommendations for the optimal design of policies are provided to reduce CO_2 emissions through *electricity losses*. Indeed, Chapter 3 contributes to the literature by the study of the impact of *electricity losses* on CO_2 emissions, and the analysis of the market closing technologies on CO_2 emissions.

1.2 Two-dimensional variable studies

This section includes Chapters 4 and 5, two studies based on time-spatial variables. Both Chapters present analyses of the performance of the networks, using datasets with time-spatial information. Indeed, the introduction of the spatial dimension is a great opportunity to get value from the grid analysis.

Chapter 4, *Analyzing electricity flows and congestions: looking at locational patterns* (Costa-Campi et al., 2020a) analyzes the transmission flows with the aim of knowing how the locations of different technologies explains energy flows, to identify locational patterns related to congestions and to evaluate how the generation produced in each region contributes to flows. In this way, the efficiency of the grids and the location of grid bottlenecks related to potential *grid-congestion costs* can be studied.

[9] https://doi.org/10.1016/j.enpol.2017.01.011

While developing this analysis the main obstacle is the lack of information and an hourly dataset. However, this is overcome by merging several hourly datasets published by the Spanish SO, the Spanish electric market operator and some geographical sources. In this regard, the use of GIS software with techniques to extract information from Google Maps and SQL databases has been essential. Final high-granularity dataset includes the hourly electricity flows for each transmission line, the individual hourly production from generators, grid topology and the location of generators and main consumption areas (cities).

The use of a gravity model instead of the traditional optimization models represents a significant contribution to the analysis of electricity flows from an empirical approach. One of the main advantages of a gravity model is that it accounts for both the source and destination conditions in the same model and provides different outcomes as it uses the actual information and does not optimize flows. Moreover, results are of specific interest because they include flows disaggregated between the two directions and it is possible to find the contribution of each technology to the said flows. Endogenous variable is the flow in each transmission line, while explicative variables include the production in each point of the network -also known as node- and classified by technology: nuclear, combined cycle, coal, hydropower, solar, wind, pumping, combined heat and power, and imports. Finally, several seasonal variables are used to control for seasonality.

From these results, several recommendations to match the actual regional network capabilities, regional weather conditions for RES, and the actual generation capacity in each region are provided. Chapter 4 contributes to the literature for several reasons. First, the empirical approach based on a gravity model, which has scarcely been explored previously in the literature about the analysis of electricity flows. Second, the use of a high-granularity dataset, which combines time and spatial information of an electricity system and at national level. Third, results on how efficiently generation technologies are located regarding consumption. Fourth, the identification of locations patterns to flows. Fifth, the quantification of regional electricity congestions and its correlation among the different technologies. Finally, an analysis of regional social welfare.

Chapter 5 of this dissertation, *Locational impact and network costs of energy transition: introducing geographical price signals for new renewable capacity*[10] (Costa-Campi et al., 2020b) explores how to make markets principles, economic signals

[10]https://doi.org/10.1016/j.enpol.2020.111469

and grid development compatible through the analysis of the grid costs associated with the connection of new RES. To do so, several simulated geographical scenarios following the Spanish National Energy and Climate Plan (NECP) are used to explore to what extent the potential locations of new RES might result in congestions that require *grid-investments* or produce extra *electricity losses*, both borne by consumers.

The database used in Chapter 5 is built on the data and results in Chapter 4. However, conventional capacity is replaced by RES as is defined in the drafted NECP sent by the Spanish government to the European Commission in 2019[11]. Spanish NECP aims to double the current wind capacity and increase current actual solar capacity five-fold, all this in less than ten years.

The results from Chapter 4 are used as the baseline to simulate several potential locations of new RES to study how they affect congestion in the grids, *electricity losses* and what corresponding *grid-investments* are necessary to solve bottlenecks. RES are sited in different locations and represented by scenarios. Locations correspond to the potential *market* and *social planner* choices. In the *market* choice, RES are only located in the most optimal locations considering wind and solar production, while the *social planner* choice considers RES locations that minimize *grid-investments* and *electricity losses*. *Grid-investments* are calculated from future *grid-congestions* and considering audited and recognized investments costs, and the real distance of potential new grids.

From these results, some policy recommendations are provided to match network capabilities, weather conditions for RES, and the actual generation capacity in each region. Chapter 5 contributes to the literature for several reasons: the use of a high-granularity dataset with time and spatial information, the detailed analysis of *grid-investments* and *electricity losses*, namely social welfare, related to the location of RES. Moreover, the analysis of these costs contribute to the literature related to RES auction mechanisms aimed to define future regulatory incentives for locating new RES. Finally, contemporary literature about the decarbonization of electricity systems has paid limited attention to questions of space and some authors suggest that future research should seek to increase the understanding of how energy transition is spatially constituted (Bridge et al., 2013).

With the objective of contributing to the analysis of grid-related costs in the de-

[11]See: https://ec.europa.eu/energy/sites/ener/files/documents/spain draftnecp.pdf for further details.

carbonization of electricity systems, the empirical approaches followed in all the Chapters of this dissertation aim to explore their determinants in detail and how these are affected by the decisions of third parties about RES. This work falls within the area of energy economics by the analysis of grid-related costs, a significant part of the final electricity price, but relatively little explored in the economic literature. This is the ultimate aim of this dissertation.

2 The economic impact of electricity losses

2.1 Introduction

Electricity networks serve to transport energy to consumption points, as generation plants are not always sited close to homes and industries. To guarantee the success of the system, four essential activities have to be successfully managed: generation, transmission, distribution and retailing. Traditionally, electricity is generated in large-scale plants located near raw materials, or reservoirs in the case of Hydropower. Economies of scale are critical at the generation stage before the energy can be sent to points of consumption via a transmission network comprising high-voltage lines. In recent years, a number of new, small generation plants have been connected to the distribution grid, and this is known as distributed generation (DG) (Ackermann et al., 2001). To distribute the electricity among consumers, low-voltage (LV) distribution lines are used to transport power to meters. Finally, retailing is responsible for billing.

Owing to certain physical phenomena, electricity systems always yield less than 100%, with some energy being lost as it flows through the components of the system: lines, electric transformers, etc. This means that when a consumer i wants to consume q_i units of energy (UoE) as recorded by their meter, $(q_i + \delta_i)$ UoE have to be produced by a generation plant, given that δ_i UoE are lost in the grids. In the aggregate, Q represents total meter consumption (Eq. 2.1) and Q_L is the meter consumption with the energy losses incurred (Eq. 2.2):

$$Q = \sum_i q_i \tag{2.1}$$

$$Q_L = \sum_i (q_i + \delta_i) = \sum_i q_{il} \tag{2.2}$$

Cross-country comparisons of electrical energy losses are far from straightforward, because, among other reasons, regulatory definitions vary; consumption out of the meter, or fraud, may or may not be considered as an energy loss. Different voltage levels are used by transmission system operators (TSOs) and distribution system operators (DSOs) (ERGEG, 2008). Energy losses in Spain in 2012 represented 8.9% of the total energy injected into the grid, resulting in an annual cost of 1,160 M€[1] that had to be borne by all consumers. This increases their final electricity bills, de-

[1]Following the Spanish Regulatory Framework (see Section 2.3.2), the annual cost of losses is calculated by multiplying the amount of hourly energy losses (MWh) by the hourly wholesale price of electricity (€/MWh). Both costs of losses in the transmission and distribution grid level are quantified at the same -wholesale- price (€/MWh) and included in the consumer bills. The costs of CO2 emissions and energy savings targets are not included in these calculations.

creases consumer surplus and impacts on social welfare. These effects are the main motivation for further exploring the economic impact of energy losses through this empirical analysis. To put this figure in context, total energy loss levels published in the World Bank Database[2] for other countries in the same year were 7.92% in the United Kingdom, 3.94% in Germany, 6.74% in France, 5.4% in Austria, 6.29% in the United States of America and 5.06% in Australia.

The mechanism by which energy losses affect the retail price is illustrated in Figure 2.1. First, based on the characteristics of the formation of the electricity wholesale price (WP), energy losses exert an upward pressure on total demand, so that the D curve is displaced upwards to D_L. Second, real hourly demand might differ from that estimated on the day-ahead wholesale market, which means additional adjustment costs are incurred. Third, when the cost of losses is totally or partially borne by the end-users, three possible mechanisms can be applied to fund them: the regular network tariff, as in France, Sweden, Norway, a special tariff, as in Austria, Poland, or other specific mechanisms as in Italy, Portugal, United Kingdom and Spain (ERGEG, 2008). In the end, regardless of the mechanism, when the cost of losses is borne by the end-users, the amount they pay ($q_{il} \cdot p_{il}$) and the consumer surplus are both affected (ENTSO-E, 2014). In the period 2011-2013, the cost of losses in Spain represented between 1.47 and 5.19% of the retail price of electricity[3].

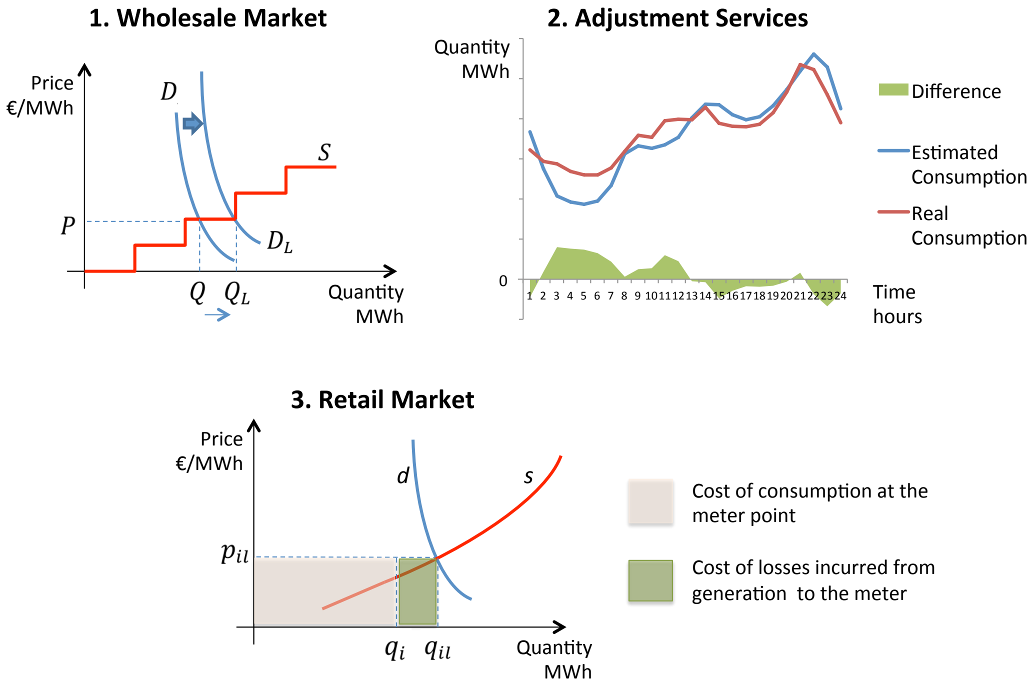
The implementation of policies that modify electricity flows, on the demand and supply side, could have an impact on energy losses. In Spain, as in other European countries, they include, for example, the massive introduction of intelligent meter systems, or smart meters, to promote the active participation of consumers in the electricity supply market via the use of innovative pricing formulas and the promotion of electricity generation from renewable energy sources (RES-E), which in most cases has been implemented in conjunction with a priority dispatch for generation from promoted technologies (European Directive 2009/72/EC).

On the demand side, the impact of consumers on energy losses is unequal, depending on the voltage of the network to which consumers are connected and how peaked their demand profile is (Shaw et al., 2009). DSOs must play a passive role regard-

[2]Source: World Bank Database - *Electric power transmission and distribution losses (% of output).* http://data.worldbank.org/indicator/EG.ELC.LOSS.ZS (last consulted on 15 September, 2015).

[3]These are average costs and vary with the level of voltage, where consumers are connected and the tariff scheme being implemented. In general, the lowest costs are associated with the heaviest consumers connected to the highest voltage grids.

Figure 2.1: General energy loss impacts on the retail market price.



Note: D is the aggregate demand curve of consumers at the meter (without energy losses); D_L is the D curve adding energy losses, which are an extra energy demand of electricity; S is the aggregate supply curve of generation; d and s are the demand and supply curve for a consumer i; q_i is the individual consumption at the meter (without energy losses); q_{il} is the individual meter consumption plus energy losses; p_{il} is the price associated with q_{il}; Q is the aggregation of q_i; Q_L is the aggregation of q_{il}; P is the wholesale price associated with Q and Q_L.

ing consumers since the unbundling of activities (European Directive 1996/92/EC), while the possibilities of modifying peak demand profiles depend on specific technological solutions, such as smart meters, which can provide consumers with clearer price signals that might in turn modify their behaviour. Along these lines, European Directive 2012/27/EC requires network tariffs and regulation improvements to support dynamic pricing for demand response by final consumers, such as time-of-use tariffs, critical peak-pricing, real time pricing and peak time rebates.

On the supply side, and in response to the 2020 European Strategy, the share of energy produced by RES-E in Europe (EU28) has increased from 14.32% in 2004 to 25.37% in 2013. This change has been accompanied by the installation of new small RES-E plants known as DG connected directly to DSO networks and located close to the points of consumption. This has had a significant impact on most electricity systems. For instance, in Spain, a quarter of the country's total generation between 2011 and 2013 was produced directly by plants connected to this network. These changes have modified traditional unidirectional flows from transmission to distribution, and some technical and operational problems have arisen in relation to their geographical dispersion, predictability, the flexibility of the remaining generation, the correlation between production and consumption profiles, and the extent to which the network can absorb the imbalances between them.

Although intuition tells us that a higher share of generation in close proximity to consumers would reduce energy losses and grid congestion, as the energy would have to travel over shorter distances, DG plants are not always properly sited close to the main points of consumption, their production is not always dispatchable[4] and the smaller plants are often operated and fully controlled by their owners (Eurelectric, 2013a). As a result, DG production might not coincide with demand requirements. A number of authors, including Quezada et al. (2006) and Marinopoulos et al. (2011), report that energy losses follow a U-shape curve as a function of the DG penetration in the networks[5], which means they tend to fall at low levels of DG capacity, but increase after a given level is reached. The Spanish regulatory framework[6] provides for the free location of electricity generation, which has resulted in the heterogeneous establishment of DG capacity throughout the country's grid.

The potential consequences, both problems and benefits, to be derived from the active participation of consumers through smart meters and the widespread penetration of DG have called the current DSO regulatory framework into question. In this regard, CEER (2015) proposes various ideas that need to be considered in the future. For example, in the case of consumption and smart meters, future tariffs should encourage consumers to reduce peak demand thereby increasing the efficiency of electricity systems. Moreover, tariffs should give clear economic signals, enable DSOs to recover their costs and be compatible with retail competition. In the case of generation, DG has increased the complexity of flows in the distribution grids and with them the challenges for their efficient management. Hence an evolution has been proposed of the relationship between the TSO and the DSO that adopts some principles: a whole system approach, greater coordination and exchange of data, more flexibility and a fairer cost sharing strategy. Moreover as interaction between, and communication with, consumers and producers increases the DSOs should arrange new activities and take on new responsibilities. Here, smart grid investments seem to represent a key facilitator (Farhangi, 2010; Joskow,

[4] *Dispatchable sources* are technologies the output of which can be adjusted or turned on/off on request. This is not the case of photovoltaic systems, where for a third of the day they do not produce, or small wind plants.

[5] *Level of DG penetration in a network* is the amount of energy generated by DG in an area in relation to total consumption.

[6] Royal Decree 54/1997.

2012).

To the best of our knowledge, most papers that have analyzed electricity grids up to now are based on Optimal Power Flow (OPF) algorithms from engineering and no previous studies have empirically and separately assessed (ex-post) the determinants of the energy losses from transmission and distribution grids from the demand and supply side in a whole country with a real electricity system, and with an economic approach. This is a novel approach to the subject and complementary to previous research. It aims to study energy losses and their costs from both the consumption and generation perspectives to better understand their contribution at each grid level, considering the consumption and generation profiles of each technology. In a nutshell, the analysis presented here offers a new approach to a subject that has been largely unexplored in the empirical energy economics field[7].

This empirical analysis is performed using data from Spain, which is a highly relevant case given that of the five biggest economies of Europe it had the highest share of RES-E[8], at 36.39%, in 2013. First we estimate the impact of consumption on energy losses and their costs, which allows us to quantify the potential energy loss reductions and potential savings due to lower levels of grid congestion, for policies aimed at smoothing the consumption demand profile. Second, we estimate the same impacts but for each power generation technology. An interesting comparison is conducted between DG technologies (Wind, Solar and CHP) installed during the last decade in Spain and all other traditional base sources (Nuclear, Coal, Combined Cycle), in which we evaluate their differences in terms of energy losses along with their economic costs and benefits. This allows us to make a contribution to the scarce literature examining economy-wide aspects of DG (Allan et al., 2015). Our results can be useful for regulators and policymakers in countries with a low penetration of RES-E, or that are at an earlier stage in the implementation of DG, in order that they might take better advantage of their potential. Indeed, distribution networks are used today for a different purpose than two decades ago.

[7] Although it would be also interesting to quantify the impact of energy losses on the wholesale price market, it would require price formation in the electricity markets to be studied, which is beyond the scope of Chapter 2.

[8] Between 2004 and 2013, the five biggest economies in Europe increased their RES-E share of energy production as follows; from 9.40 to 25.59% in Germany, 3.54 to 13.85% in the UK, 13.79 to 16.87% in France, 16.09 to 31.30% in Italy, and 18.98 to 36.39% in Spain. Source: Eurostat Database - *Short Assessment of Renewable Energy Sources* (% of electricity generation from all sources). http://ec.europa.eu/eurostat/web/energy/data/shares (last consulted on 24 September, 2015).

In this Chapter, Section 2 provides an overview of the related academic literature. The European regulatory framework for energy losses and the Spanish case are explained in Section 3, including definitions and characteristics. The model and empirical strategy are described in Section 4 and in Section 5 the results of the estimations are presented from the consumption and generation perspective. Energy losses are quantified in terms of energy (MWh) and the cost of losses (€) by using the hourly wholesale price (€/MWh). Finally, Section 6 includes conclusions, policy implications and regulatory recommendations.

2.2 Related Literature

The literature examining electrical energy losses can be classified according to the scope of the policy on either the demand or supply side. As previously stated, DG, DSM and their corresponding energy losses have been studied up to now in theoretical engineering papers using OPF models. However, our approach is different because we use econometrics, an ex-post real dataset and consider the country as a whole. This review section is organised according to this focus and on the impact of policies oriented at modifying either consumer or TSO/DSO behaviour.

In the case of demand policies impacting consumer behaviour, demand side management (DSM) is seen to play a key role. The main objective of DSM is to shift demand from peak to off-peak periods so as to obtain a better performance from the infrastructure, avoid the congestion problems affecting certain nodes[9], adapt demand to the generation production at each moment in time and reduce energy losses. DSM employs on various techniques: load limiters, load-interruptible programs, time-of-use pricing and smart metering (Strbac, 2008). Information and communication technology (ICT) is a major facilitator of the implementation of DSM. The impact of DSM on energy losses and their cost has been estimated by Shaw et al. (2009) and Cronenberg et al. (2012).

First, Shaw et al. (2009) simulate potential energy loss reductions by changing the shape of the demand profile for Electricity Network West (ENW), one of the 14 distribution network operators in Great Britain. The study focuses on domestic consumers, who present a strongly peaked demand profile, as they pay a single flat rate for each unit of consumption, irrespective of the time period. As the variable component of energy losses depends on the square of current, this could be reduced

[9] A *node* represents the physical location in a transmission or distribution network where energy is injected by generators or withdrawn by consumers.

if the peak load were delayed to off-peak periods. They use a spreadsheet model that combines network power flow and energy loss data with consumption profiles and report total energy loss reductions of up to 1.4%, depending on the reduction of the peak and to when this delay is allocated. Second, Cronenberg et al. (2012) simulate potential energy loss reductions from active demand (AD) programs aimed at reducing domestic peak loads in Spain, Germany, Italy and Belgium projected to 2020. They consider a constant and linear rate of energy losses and monetize reductions in the costs of losses from an aggregate perspective by multiplying the simulated results by the average hourly price of electricity. The total reductions in the costs of losses in Spain range between 1.2 and 4.81%, depending on the scenario considered, with the highest values coinciding with the combination of two effects: a 35% reduction in peak load and a 20% reduction in overall consumption.

Consumption out of the meter produces non-technical energy losses (NTLs), which have consequences for total electricity demand, the quality of supply, the system's total income, etc. NTLs have traditionally been a problem in developing countries; however, in the context of the present economic crisis they have become problematic in the developed world, too. Depuru et al. (2011) describe how such factors as unemployment, the straitened finances of consumers and rising electricity prices can increase NTLs. Among the policies proposed to alleviate these energy losses and their economic consequences we find subsidies to low-income consumers, thorough audits of electricity consumption at the distribution level, stricter law enforcement and smart metering. Unemployment reached record levels in Spain during the crisis, which strongly suggests that these energy losses should not be ignored. As Smith (2004) has noted, while NTLs cannot be precisely computed, they can at least be estimated, though this falls outside the scope of this Chapter.

In short, studies on the demand side report that demand policies have a significant and positive effect on both energy losses in transmission and distribution. However, Shaw et al. (2009) and Cronenberg et al. (2012) constitute simulations and ex-ante studies; moreover, they do not analyse the impact of each generation source covering the peak demand profile.

In the case of supply policies affecting TSO and DSO behaviour, the penetration of DG has given rise to an academic debate about its consequences for energy losses. Due to the mathematical complexity of this area, two different approaches, providing similar outcomes, are reviewed here. In the first, Quezada et al. (2006); Marinopoulos et al. (2011); Hung et al. (2013) estimate the impact of energy losses for a simple electricity feeder[10]. In the second, Delfanti et al. (2013) use a probabilistic approach to consider a larger electricity system.

Taking the simple feeder approach, Quezada et al. (2006) compute annual energy loss variations with different levels of penetration and concentration of DG in a radial line. They conclude that not all technologies have the same effect on energy losses. For instance, photovoltaic (PV) energy presents a higher correlation with consumption and a smaller impact on energy losses, while wind power is more random, does not match as well with consumption and, consequently, has a greater negative impact on energy losses. Marinopoulos et al. (2011) evaluate energy loss reductions with a dispersed PV penetration using stochastic processes for load time-varying and PV generation in a feeder located in a city in northern Greece. Their results are in line with those of Quezada et al. (2006): energy losses follow a U-shape curve according to the degree of PV penetration. The best solution is a uniform distribution of plants along a feeder, although this is extremely difficult to achieve in reality. Finally, Hung et al. (2013) identify the best locations, optimal sizes and power factors of DG units at various locations in order to minimize power energy losses. Among their results, it is interesting to highlight the finding that dispatchable DG units perform better than non-dispatchable units in terms of energy loss impact and voltage profile enhancement.

A different approach is adopted by Delfanti et al. (2013), in which they use a Monte Carlo process to estimate energy loss evolution with DG penetration. They consider ten DG rated powers from 0.5 to 10 MW and estimate the probability of energy loss variations for each case. They find energy loss reductions are nearly always achieved for low levels of DG penetration. A higher DG penetration level raises the likelihood of either increasing or reducing energy losses, mainly depending on the specific characteristics of each case: the DG production profile, its correlation with the demand profile, the presence of reverse flows, load locations, etc. An additional solution for potentially reducing energy losses for high DG penetration levels is network reconfiguration, which involves opening and closing switches in the distribution grid in response to flow changes (Lueken et al., 2012).

Strbac et al. (2007) point to the importance of well-located DG plants coinciding with peak-demand consumption to reduce energy losses, depending on technology, size, network topology, etc. The same generation technology in different locations

[10]An *electricity feeder* is a medium-voltage (MV) power line extending from a distribution substation to the transformers used for reducing the supply to LV, i.e., the voltage used by domestic consumers.

might have the opposite impact on energy losses. For instance, micro CHP production in the UK is better correlated with the winter peak load (5:30 pm) than is PV.

In the case of regulatory strategies, many regulators around the world have implemented incentive-based schemes to promote efficiency improvements in natural monopoly activities (TSO/DSO) in the 1990s. In addition to quality of service improvements, energy loss reductions have been another performance target. In traditional electricity systems, DSOs can decide whether to apply specific strategies to reduce energy losses in their infrastructure, such as strengthening or reconfiguring networks to reduce congestion, installing low-loss level transformers, etc. Moreover, within a single country, each DSO has its own specific characteristics, so incentive-based regulation is a general solution for all. In the UK, as in Spain, the quality of service and network energy losses are individually considered, separately incentivized, and affect the revenues of each DSO (Jamasb and Pollitt, 2007). Jamasb et al. (2012) estimated the marginal cost of improving quality in the UK DSO companies between 1995 and 2003. With regard to energy losses, the estimated average marginal cost was 2.4 pence per KWh, while the regulator's incentive or reward was 4.8 pence. However, this improvement was not equal across all companies because some were insufficiently incentivized and not all of them adopted the same strategies to reduce energy losses. Hence, incentives need to be well designed to make significant reductions in energy losses.

The significant increase in DG penetration in recent years has modified the traditional top-down approach to energy. Flows are becoming increasingly unpredictable and this has consequences for local congestion, voltage and system security. In general, DG curtailment and feed-in management rules are not in the hands of DSOs. Moreover, TSOs do not monitor distribution network conditions, which means that DSOs must react to DG actions and the operation of the distribution grids is therefore becoming more complex. In this new context, an active distribution system management[11] is proposed to ensure the better integration of DG/RES-E into the DSO. The idea is to provide the DSO with tools for the maintenance of network stability by means of ICT solutions (Eurelectric, 2013a). Other recommendations include the establishment of mechanisms to compensate the DSO for their increasing CAPEX and OPEX due to the presence of DG by paying special attention to their impact on energy losses, the implementation of local signals to promote DG contribution to peak demand such as differentiated use-of-system (UoS) charges for

[11] The *active distribution system management* is based on the interaction between planning, access and operational timeframes. It is based on the continuous monitoring of distribution network parameters to act on DG and consumers (Eurelectric, 2013a).

DG, and encouraging DG to provide ancillary services to help DSOs operate their networks, etc. (Frías et al., 2009).

Our research is closely related to the above literature, and seeks to estimate the contribution of the consumption profile and generation technologies to energy losses and their costs. In the next section we present Spain's current regulatory framework for energy losses within the broader European Union context. However, it should be noted that a study of the efficiency of regulator laws at the TSO and DSO energy loss levels is beyond the scope of Chapter 2 because this would require a longer period of time to achieve robust conclusions.

2.3 Regulatory framework of losses

European Directive 1996/92/EC concerning internal electricity markets establishes the rules for the unbundling of generation, transmission (i.e., transport on high-voltage grids) and distribution (i.e., transport on medium/low-voltage grids to consumers) activities. Below we discuss the main regulatory issues concerning energy losses in Europe and in Spain.

2.3.1 Regulation in Europe

In general, two complementary mechanisms are employed in determining how the costs associated with energy losses should be borne by generators and consumers in Europe. First, *zonal pricing* or *market splitting* uses the same market-based mechanisms as those used in the nodal price[12], but rather than setting an energy price for each node, a common price is fixed for the nodes located in a given area. This mechanism also takes into consideration the internodal congestion between regions or even between entire countries. It is employed in Italy, Nordel (Denmark, Finland, Iceland, Norway and Sweden) and MIBEL (Spain and Portugal). Second, *single energy pricing* sets the same price at the nodes in a given country or area and the effects of energy losses and constraints are addressed by employing other methods. For example, agents internalize energy losses in the prices that they bid, employing additional mechanisms such as corrective factors in supply-side bids or in the

[12]*Nodal price* is also referred to as the *spot price* or *locational marginal price*. The system fixes different energy prices at each node on the basis of the effects of consumer and producer decisions on congestion, grid constraints and energy losses. In the case of generation, the production of electricity at some distance from consumption means lower nodal prices than a production closer to consumption in a city. In the case of demand, the consumption of electricity in a generating area incurs lower nodal prices because this energy suffers low levels of energy losses. Among others, this system is used in Chile, New Zealand, New England, New Jersey and California.

sums of energy produced. Constraint management mechanisms such as re-dispatch, countertrading and capacity auctions address problems of congestion. This mechanism is used in many European countries (Pérez-Arriaga, 2014).

Energy to cover all energy losses needs to be procured and here there are two possible courses of action. In some European countries, including Austria, Belgium, Switzerland, France, Poland, Sweden, Denmark and Germany, the TSOs and DSOs are responsible for the procurement of this energy, in others, such as Spain, Greece and Portugal, this energy is procured by the suppliers, who have to inject their own production to offset the energy losses associated with end-user consumption. The two mechanisms have advantages and disadvantages, but in both instances energy has to be procured using non-discriminatory, transparent and market-based procedures (ERGEG, 2008; Eurelectric, 2013b).

The components of transmission and distribution energy losses are not the same, which in turn affects the regulatory mechanisms employed to improve efficiency. For instance, NTLs are mostly, or even exclusively, present in distribution, whereas transmission energy losses are affected by major external factors, including the availability of natural resources, the outcome of generation and consumption auctions, etc. When TSOs or DSOs procure energy for energy losses, there is an additional incentive if the energy loss rates funded by tariffs are capped, given that the surplus represents an extra operating cost for them. An additional, complementary mechanism is the establishment of rewards, or penalties, if energy losses are below, or above, previously fixed reference values (ERGEG, 2008).

When a TSO has to purchase energy to cover energy losses, Eurelectric (2008) suggests it should be allowed to charge pass-through costs for this. Similarly, Ofgem in the UK removed all financial incentives associated with energy losses in transmission, arguing that it had little control over them (Ofgem, 2015). Likewise, the regulations in Germany and Spain do not offer financial incentives to TSOs in relation to energy losses.

In the case of DSOs, several schemes are employed. For example, in the UK, Ofgem establishes an annual percentage of energy losses and so operators receive a reward or penalty linked to a set of performance indicators. Additionally, losses can be considered operational cost reductions in investment remunerations (Ofgem, 2015). In Spain, the incentive mechanism to reduce energy losses is based only on a reward or penalty with respect to past data. In Germany, there are no financial incentives to minimize energy losses and the TSOs and DSOs are able to recover costs when purchasing energy. There is a benchmark to ensure that energy is purchased efficiently. However, changes are expected in this regard in the future (Ecofys, 2013).

2.3.2 Regulation in Spain

In Spain, the electricity network is divided into two sections according to voltage: a voltage higher than or equal to 220kV[13] is considered transmission and is owned and operated by the TSO[14], the Red Eléctrica de España (REE). The system operator operates the transmission network and seeks to guarantee the system's security and continuity of supply (REE, 2014). The rest of the network is considered distribution, and is owned and operated by several DSOs. Although in Spain there are almost 350 registered DSOs (Ministry of Industry, 2015), five cover most of the territory (Endesa, Gas Natural Fenosa, Iberdrola, EDP and Eon).

In the Spanish transposition of European Directive 1996/92/EC[15], the distribution of electricity is defined as a regulated activity with appropiate levels of quality and energy losses. Consequently, the regulatory framework of 1997 established a common DSO remuneration to be shared between all the DSOs, without considering individual improvements in efficiency or the geographical specifics of the area covered by each. In 2008, a reference network model (RNM)[16] was introduced to achieve a better approach to the performance of the different DSO networks, and individual energy loss reduction incentives were established at between $\pm 1\%$ of the remuneration of the previous year. The cost of energy lost was valued at the hourly market price. In the following year[17], the remuneration was increased to $\pm 2\%$ of the previous year's income and zonal energy loss coefficients were included to better capture the specifics of the area covered by each DSO. Finally, in 2013[18] it was modified again and the reference energy loss levels were fixed as values based on the figures for several previous years. This incentive scheme is similar to the one

[13]This is a general classification because the Spanish TSO also owns and operates an electricity grids of less than 220kV in the Balearic and the Canary Islands. However, this Chaper limits its study to Continental Spain.

[14]Within the Third Energy Package, the Spanish TSO was organized in accordance with the Full Ownership Unbundling (OU) scheme. This model requires full independence of the transmission owner and operator from any company that generates, produces or supplies electricity. This scheme is also used in other EU countries such as the UK, Germany and Italy (European Directive 2009/72/EC).

[15]Law 54/1997 and Royal Decree 2819/1998.

[16]A *reference network model* (RNM) is a large-scale distribution network tool, which is able to define an optimal distribution grid using geographical location and electrical data from the TSO, DSO and consumers. Geographical constraints can also be considered in the simulations.

[17]Complementary Technical Instruction 2524/2009.

[18]Royal Decree 1048/2013.

used in the UK, but it is capped at $+1\%$ and -2% of the allowed revenue. In Section 5, we calculate the economic costs of losses following the same methodology.

To quantify the DSO incentive in the 2011-2013 period according to the current regulatory scheme, the annual maximum incentive reward for reducing energy losses among all the DSOs stood at about 40M€, while the annual average cost of losses in distribution was 945M€[19]. In transmission, the average annual cost of losses was 188M€[20].

In 1997, the generation sources were separately classified into two main groups: first, installations of 50 MW or less installed capacity that used RES-E, Combined Heat and Power plants (CHP) or waste; and, second, all other technologies: Nuclear, Coal, Combined Cycle, etc. This facilitated the implementation of several promotion schemes for the sources in the first group. In the period 2011-2013, RES-E plants already produced 40% of total generation. Figure 2.2 shows that 90% of consumption has been reached in the distribution networks, which implies a gap between generation and consumption. In our estimations, we also analyse whether the impact of consumption is similar with regard to transmission and distribution.

Table 2.1 summarizes the characteristics and operation of each generation technology in Spain. This is relevant because their respective impacts on energy losses are related to where and when they produce. Although Solar and CHP mostly generate to distribution, we expect indirect effects on transmission energy losses because they might displace other sources.

In Spain, DG curtailment and feed-in management rules can only be implemented by the TSO, independently of whether they are connected to transmission or distribution[21]. Today, this regulatory scenario is being questioned in order to facilitate the emergence of a more active DSO (CNE, 2012). From the final consumers' perspective, the cost of losses represents an extra cost of the power system they have to bear. The Spanish regulatory framework[22] states that the costs of both transmission and distribution energy losses are assessed at the wholesale market price for the corresponding hour. Hence, in this context, consumers are simply price takers. Finally,

[19] Annual income for all DSOs is about 4,000M€, so 1% represents 40M€. The annual cost of losses in distribution was 915M€ in 2011, 980M€ in 2012 and 940M€ in 2013.

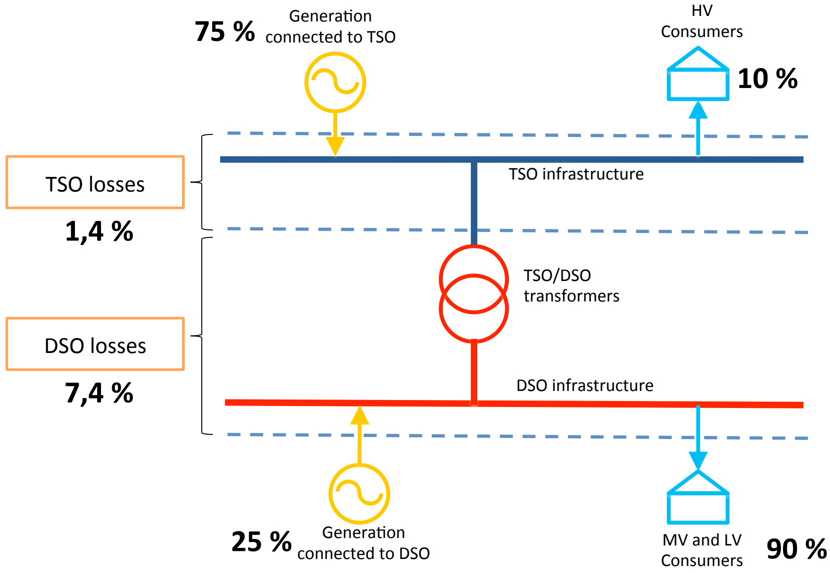
[20] The annual cost of losses in transmission was 215M€ in 2011, 180M€ in 2012 and 170M€ in 2013.

[21] In Spain, RES-E plants are only required to have a generation control centre as an interlocutor with the TSO if they have more than 10MW of installed power.

[22] Ministerial Order IET/3586/2011.

Table 2.2 summarizes the incentives for all agents involved in the electricity system in order to provide a better understanding of the impact of energy losses and their costs on decision making.

Figure 2.2: Share of total generation and consumption in Spain (2011-2013).



Source: Own elaboration from (REE, 2014a; Ministry of Industry, 2015).

Table 2.1: Characteristics and operation of generation sources (2011-2013).

Technol.	Role in the hourly balancing of energy	Network level where generates
N_t	Used as a base source.	Transmission
CO_t, CC_t	Used as a base source after Nuclear.	Transmission
H_t	Mainly Hydropower flowing. TSO can modulate its production by the connection/disconnection of groups.	Most large flow-Hydro plants inject into transmission. The rest into distribution.
W_t	Production depends on climate. TSO can modulate its production by the connection/disconnection of big plants.	More than 45% of energy is injected into distribution. The rest into transmission.
SOL_t	Production during sun hours. At evening peak, only Thermosolar plants.	About 80% of energy is injected into distribution. The rest into transmission.
PG_t	Basically used to cover high peak hours.	Transmission
I_t	Used to cover peak periods.	Transmission
CHP_t	Its hourly production profile is flat.	Almost 85% is injected into distribution.

Source: Based on CNMC (2013).

Table 2.2: Behaviour of agents with regard to energy losses in Spain (2011-2013).

Agent	Market Structure	Economic loss incentives
Generator	Liberalized activity	-The costs of losses are not considered when location and daily generation bid auctions are decided upon. However, both variables impact on TSO and DSO energy losses depending on the distance to loads and the time of consumption. -A common UoS charge of 0.5€/MWh is applied to generation (2011). -Non-optimal decisions at this stage might imply greater energy losses and higher costs of losses for all end-consumers.
TSO	Regulated activity	-Energy losses are not a key performance indicator (KPI) for them. -However, when investments are supposed to solve congestions problems, energy losses might de indirectly affected.
DSO	Regulated activity	-In contrast with the TSO, energy losses are a KPI in the regulatory framework: incentive=$\pm 1\%$ of the year's remuneration. -Investments, network operation and fight against consumption out of the meter are useful instruments. -It is important to highlight that decisions taken by generators, TSO and consumers might affect their level of energy losses and worsen their performance indicators.
Consumer	Liberalized activity	-Consumers can choose the voltage of the meter point. The higher the voltage is, the less they pay as costs of losses. However, this implies funding an expensive own electricity infrastructure. -Consumers are simply price takers of the costs of losses, although if a consumer decides to consume out of the meter, these energy losses are socialized among the rest. -To avoid this perverse behaviour, efficient regulatory incentives and punishments are necessary.

Source: Own elaboration based on the Spanish regulatory framework.

2.4 Data and Empirical Strategy

In this section, we present the empirical strategy and the data used to characterise energy losses and their costs in the Spanish Electricity System. In general, such energy losses (in MWh) can be defined by Eq. (2.3):

$$L_t = f(flows_t) \tag{2.3}$$

where $flows_t$ are explained by the consumption and generation of electricity at each t hour.

In this empirical analysis we divide the total system energy losses (L_t) into energy losses in the transmission (LT_t) and distribution grids (LD_t) according to the network where they are produced[23] (see Eq. (2.4)). This allows us to better evaluate the individual impact of the different components at each level of the electricity system.

$$L_t = LT_t + LD_t \tag{2.4}$$

For analytical purposes most electricity systems might be simplified as a unique node, where all generation plants and consumers are connected. In this setting, energy losses are a function of the consumption and the generation in the system. However, with a simplified system it is technically impossible to know what share of the energy produced by an individual plant is lost and does not arrive to the end consumers' meters. To tackle this limitation, it is possible to classify consumption and generation by their components, clustering similar patterns, market behaviours, operational costs and natural resource requirements. This is the approach followed in this empirical analysis. More precisely, from a demand-side perspective the relevant components are consumption and exports, while from a supply-side perspective the relevant components are all sources of generation and imports in the electricity system.

It is important to highlight that the demand side or consumption and the supply side or generation, are two alternative and non-additive points of view explaining the same outcomes: energy losses and the cost of losses. Therefore, the components encompassed in each perspective cannot be included in the same regression,

[23]The accuracy is higher in LT_t because of the widespread use of continuous meters. In distribution, small end-user consumption should be partially estimated with predetermined energy loss profiles known in advance. In Spain, smart meter installation is still not fully completed, the deadline being 2018. The methodology used in this Chapter is defined in *Operating procedure 5.0 for determining transmission losses and calculation of loss coefficients per node* published in BOE on 03/07/1999, Royal Decree 1048/2013 and Technical Complementary Instruction 2524/2009.

this would lead to severe multicollinearity, undermining the statistical power of the analysis. Below we present the equations used to evaluate the individual impact of the different -supply and demand side- components at each level of the electricity system on energy losses and their costs.

2.4.1 Demand-Side (Consumption) Perspective

The demand-side perspective, represented in Eqs. (2.5) and (2.6) by LT_t and LD_t, respectively, takes into account consumption and exports in the electricity system. Domestic, commercial and industrial end-user consumption is represented by C_t. PC_t represents the Pumping Consumption needed for the subsequent Pumping Generation (PG_t) in large storage-hydroelectricity plants. Pumping Consumption (PC_t) is used in the supply-side approach and is fully associated with transmission, so it is not included in distribution (LD_t).

International exchanges of energy are made between continental Spain and other countries such as Andorra, France, Portugal and Morocco. Depending on the direction of this flow, E_t is the country's exports and only used in transmission because 99.99% of the exported energy uses this grid. I_t represents the energy imports entering Spain and these are included in the supply-side perspective. Flows through the submarine electricity interconnection from the Spanish Peninsula to the Balearic Islands are also included in I_t and E_t.

Energy losses are expected to follow a dynamic process over time. By definition, energy losses depend on the energy flowing through the grids, which is affected by the inertial component of consumption as the consumption of one hour is highly correlated with that of the previous hour. Therefore, to properly capture the dynamic process of energy losses, we include a lagged endogenous variable as an additional explanatory variable (LT_{t-1} and LD_{t-1} in the corresponding equation).

In Eqs. (2.5) and (2.6), the endogenous variable and its lagged are both measured in MWh and in €. We use the i superscript in the dependent variables to represent the two measurement units used in the different set of regressions: $i = E$ for energy losses in MWh, and $i = C$ for the cost of losses in €.

$$\begin{aligned}\Delta LT_t^i = \beta_0 + \beta_1 \Delta LT_{t-1}^i + \beta_2 \Delta C_t + \beta_3 \Delta E_t + \beta_4 \Delta PC_t + \beta_5 PEAK_t + \\ + \beta_6 FES_t + \sum_{d=1}^{6} \delta_d D_{dt} + \sum_{m=1}^{11} \alpha_m M_{mt} + \sum_{y=1}^{2} \gamma_y Y_{yt} + \beta_7 \Delta CF_t + \varepsilon_t\end{aligned} \tag{2.5}$$

$$\begin{aligned}\Delta LD_t^i = \beta_0 + \beta_1 \Delta LD_{t-1}^i + \beta_2 \Delta C_t + \beta_4 PEAK_t + \\ + \beta_5 FES_t + \sum_{d=1}^{6} \delta_d D_{dt} + \sum_{m=1}^{11} \alpha_m M_{mt} + \sum_{y=1}^{2} \gamma_y Y_{yt} + \beta_6 \Delta CF_t + \varepsilon_t\end{aligned} \tag{2.6}$$

As electricity demand varies throughout the day, a dummy variable ($PEAK_t$) is included in the demand models, Eqs. (2.5) and (2.6), taking the value 1 during peak hours, for all the observations from 12 p.m. to 10 p.m., and 0 otherwise[24]. This allows us to calculate the additional energy losses and their cost related to higher congestion in the grids at this period.

In all equations, seasonality is controlled using a set of variables[25]: D_{dt} for the day of the week; $FES_t = 1$ for weekday holidays and 0 otherwise; M_{mt} and Y_{yt} capture the long-term seasonality. The inclusion of seasonality control variables allows us to consider time specificities in our estimations, i.e. the network operation, external facts, etc. An additional regressor or correction factor (CF) has also been included to better isolate the effect of consumption and generation on losses. The CF controls for NTL and day-ahead load prediction errors, as is shown in Figure 2.1.2. This variable is exogenously given and published by the Spanish TSO in the hourly settlements. There are moreover some prediction errors because there is no real observation of all the loss profiles, the CF variable provided by the TSO also controls for these errors.

2.4.2 Supply-side (Generation) Perspective

The supply-side perspective, represented in Eqs. (2.7) and (2.8) for LT_t and LD_t, respectively, takes into account all sources of generation and imports in the electricity system. Generation technologies included are as follows: N_t Nuclear; CC_t Combined Cycle; CO_t Coal; H_t Hydropower; PG_t Pumping Generation; SOL_t Photovoltaic and Thermosolar; W_t Wind; and CHP_t Combined Heat and Power. Imports (I_t) are included in both transmission (LT_t) and distribution (LD_t) because 90% of consumption is in distribution. In Eqs. (2.7) and (2.8), the endogenous vari-

[24] This classification is used for those LV consumers in Spain with two period tariffs (2.0DHA and 2.1DHA).

[25] D_{dt} comprises six dummy variables: one for each day from Tuesday (d=1) to Sunday (d=6), Monday is the base day of the week. Following the same approach, M_{mt} comprises eleven dummy variables: one for each month from February (m=1) to December (m=11), January being the base month. Finally, Y_{yt} comprises two dummy variables, one for 2012 (y=1) and another for 2013 (y=2). In this case, 2011 is the base year.

able and its lagged are both measured in MWh and in €:

$$\begin{aligned}\Delta LT_t^i = \beta_0 + \beta_1 LT_{t-1}^i + \beta_2 \Delta N_t + \beta_3 \Delta CC_t + \beta_4 \Delta CO_t + \beta_5 \Delta H_t + \\ + \beta_6 \Delta PG_t + \beta_7 \Delta SOL_t + \beta_8 \Delta W_t + \beta_9 \Delta CHP_t + \beta_{10} \Delta I_t + \\ + \beta_{11} FES_t + \sum_{d=1}^{6} \delta_d D_{dt} + \sum_{m=1}^{11} \alpha_m M_{mt} + \sum_{y=1}^{2} \gamma_y Y_{yt} + \beta_{12} \Delta CF_t + \varepsilon_t\end{aligned} \tag{2.7}$$

$$\begin{aligned}\Delta LD_t^i = \beta_0 + \beta_1 LD_{t-1}^i + \beta_2 \Delta N_t + \beta_3 \Delta CC_t + \beta_4 \Delta CO_t + \beta_5 \Delta H_t + \\ + \beta_6 \Delta PG_t + \beta_7 \Delta SOL_t + \beta_8 \Delta W_t + \beta_9 \Delta CHP_t + \beta_{10} \Delta I_t + \\ + \beta_{11} FES_t + \sum_{d=1}^{6} \delta_d D_{dt} + \sum_{m=1}^{11} \alpha_m M_{mt} + \sum_{y=1}^{2} \gamma_y Y_{yt} + \beta_{12} \Delta CF_t + \varepsilon_t\end{aligned} \tag{2.8}$$

As in the demand-side equations, in the supply-side equations we have also included the lagged endogenous variables to consider the dynamic process over time. We also use the same set of additional controls, except for the $PEAK_t$ control. These are aimed at capturing the energy congestion losses in the technologies that specifically cover them. This is practicable in the supply-side analysis since the nine supply technologies are included, each having different roles and periods of production.

2.4.3 Data

We use an hourly dataset from 2011 to 2013. Our geographical area is continental Spain, except for the Balearic and Canary Islands, which have been excluded because their electricity systems could bias our results. The data used comes from REE (2014a), whose monthly settlement reports[26] include hourly information for generators, end-consumers, TSO, DSOs, energy marketers, etc. If we compare our research with previous studies, our approach could be considered more accurate in approximating the overall costs of losses because we use their hourly cost in transmission and distribution, which is calculated using the wholesale price of electricity as defined by the Spanish regulatory framework. Table 2.3 shows descriptive statistics of variables used in this Chapter. Energy losses are quantified in MWh, the cost of losses in € and the rest of the variables in MWh[27].

[26] There are five monthly settlements in Spain depending on the time elapsed since the last day of the month. This Chapter uses C5, the most definitive report, which is published after 11 months. In May 2011 we use the C6 settlement, which is also available. For further details see the Resolution of the Ministry of Industry (28/07/2008) published in BOE on 31/07/2008: *General procedures for TSO settlements*.

[27] Note in Table 2.3 that the minimum values of LD_t^i are negative (both in MWh and €). The negative values of LD_t^i, which represent 3.24% of observations, comes from having, for some con-

Table 2.3: Statistical summary of hourly variables.

Variable	Units	N	mean	Std.Dev.	min	max
Energy losses in Transm.(LT_t^E)	MWh	26,304	446.25	102.14	11.81	991.20
Energy losses in Distrib.(LD_t^E)	MWh	26,304	2,274.70	1,262.47	-3,395.26	7,785.20
Cost of losses in Transm.(LT_t^C)	€	26,304	21,453.70	9,803.34	0	84,164.33
Cost of losses in Distrib.(LD_t^C)	€	26,304	108,020.3	76,090.23	-228,840.6	572,448
Nuclear (N_t)	MWh	26,304	6,379.79	825.78	3,291.23	7,524.35
Combined Cycle (CC_t)	MWh	26,304	4,206.00	2,477.80	295.09	15,982.49
Coal (CO_t)	MWh	26,304	4882.38	2,252.24	0	10,074.73
Hydro (H_t)	MWh	26,304	3,436.32	1,942.61	467.65	11,021.73
Pumping Generation (PG_t)	MWh	26,304	257.72	351.02	0	1,951.55
Solar (SOL_t)	MWh	26,304	1,239.28	1,496.41	0	5,565.68
Wind (W_t)	MWh	26,304	5,497.38	3,174.46	70.40	16,671.59
Comb. Heat & Power (CHP_t)	MWh	26,304	4,232.95	565.77	2,595.66	5,506.65
Imports (I_t)	MWh	26,304	648.53	536.71	0	3,089.74
Consumption (C_t)	MWh	26,304	28,184.98	5,082.955	14,095.6	42,941.02
Pumping Consumption (PC_t)	MWh	26,304	578.4314	807.5924	0.751	4,092.00
Exports (E_t)	MWh	26,304	1,641.47	692.91	27.26	4,172.76
Correction Factor (CF_t)	MWh	26,304	380.88	1,268.94	-5,492.29	6,123.43
Peak $(PEAK_t)$	-	26,304	0.417	0.493	0	1

Source: own elaboration.

Having described the variables and data sources, we evaluate the stationarity of the time series variables used in this Chapter. Firstly, we perform the augmented Dickey-Fuller (ADF) test (Dickey and Fuller, 1979) under the null hypothesis of a unit root and, secondly, the Kwiatkowski-Phillips-Schmidt-Shin (KPSS) tests (Kwiatkowski, et al., 1992) under the null hypothesis of stationarity. For the ADF, we reject the null hypothesis of a unit root for both levels and differences. However, for the KPSS, we reject the null hypothesis of stationarity in levels but not in differences. Both tests, therefore, confirm that our series are stationary in differences, so we estimate the models in differences. This also allows us to isolate estimators from their share in the total mix because our results show how energy losses and their cost change due to variations in the explicative variables. In the next section, the results of the estimations are presented and discussed.

sumers in specific hours, an estimated demand which is slightly higher than the real demand (see footnote 23). Results considering only observations where $LD_t^i > 0$, not reported but available upon request, are very similar to those presented here for all the variables, in terms of both sign and magnitude of estimated effect. In consequence, we have decided to avoid dropping observations and we use the whole dataset.

Table 2.4: Augmented Dickey-Fuller and Kwiatkowski-Phillips-Schmidt-Shin test.

Variable	Units	ADF Test Levels	ADF Test Differences	KPSS Test Levels	KPSS Test Differences
Energy losses in Transm. (LT_t^E)	MWh	-12.962***	-30.036***	17.10***	0.002700
Energy losses in Distrib.(LD_t^E)	MWh	-11.407***	-28.359***	8.74***	0.000197
Cost of losses in Transm.(LT_t^C)	€	-11.981***	-30.033***	20.2***	0.000282
Cost of losses in Distrib.(LD_t^C)	€	-12.743***	-29.005***	10.80***	0.000160
Nuclear (N_t)	MWh	-5.107***	-37.508***	79.10***	0.029000
Combined Cycle (CC_t)	MWh	-17.951***	-25.044***	12.60***	0.000615
Coal (CO_t)	MWh	-10.882***	-22.995***	91.40***	0.003520
Hydro (H_t)	MWh	-4.762***	-31.778***	154.00***	0.000565
Pumping Generation (PG_t)	MWh	-17.853***	-35.524***	5.04***	0.000121
Solar (SOL_t)	MWh	-9.225***	-31.468***	6.43***	0.000432
Wind (W_t)	MWh	-14.435***	-26.669***	12.00***	0.004250
Comb. Heat & Power (CHP_t)	MWh	-15.887***	-30.354***	40.60***	0.000421
Imports (I_t)	MWh	-13.039***	-31.873***	11.60***	0.000212
Consumption (C_t)	MWh	-18.271***	-29.836***	1.98***	0.000439
Pumping Consumption (PC_t)	MWh	-13.969***	-94.650***	12.50***	0.000240
Exports (E_t)	MWh	-12.627***	-31.182***	31.00***	0.000227
Correction Factor (CF_t)	MWh	-9.967***	-30.251***	5.91***	0.000188

* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

2.5 Results

In this section we present the results of the estimations performed with the equations described in the previous section. Energy losses and their cost are estimated from two perspectives: (i) consumption, and (ii) generation. Finally, an additional post-estimation analysis is performed with the generation results.

As explained, the inclusion of the lagged endogenous variable as a regressor seeks to capture the dynamic process of energy losses. However, this might cause an endogeneity problem because the residuals are correlated with this lagged variable. To avoid any potential bias that might arise when using the least squares method in the presence of lagged dependent variables, estimations are performed using maximum likelihood estimators.

2.5.1 Loss analysis from the consumption perspective

Table 2.5 shows the results of the loss estimations from the consumption perspective: Eqs. (2.5) and (2.6). The endogenous variable energy loss, in MWh, is in columns (1) and (2). The endogenous variable, the cost of losses in €, is in columns (3) and (4). The grid congestion effect is isolated by the inclusion of a PEAK dummy variable and all the associated coefficients are significant. In columns (3) and (4), one interesting result is the cost of losses for one additional MWh consumed. The cost of losses in distribution (9.077€) is much higher than those in transmission (1.641€).

Table 2.5: Consumption impact on energy losses and their cost.

	(Energy losses in MWh)		(Cost of losses in €)	
	ΔLT_t^E	ΔLD_t^E	ΔLT_t^C	ΔLD_t^C
	(1)	**(2)**	**(3)**	**(4)**
$\Delta(LT_{t-1}^E)$	-0.0473***			
	(-18.11)			
$\Delta(LT_{t-1}^C)$			0.0772***	
			(23.41)	
$\Delta(LD_{t-1}^E)$		-0.0725***		
		(-59.15)		
$\Delta(LD_{t-1}^C)$				0.137***
				(63.24)
ΔC_t	0.0179***	0.116***	1.641***	9.077***
	(124.24)	(475.59)	(147.70)	(314.32)
ΔE_t	0.00443***		-0.760***	
	(7.32)		(-17.68)	
ΔPC_t	0.0127***		-0.428***	
	(19.66)		(-8.50)	
$PEAK_t$	10.67***	10.66***	921.7***	2496.9***
	(26.80)	(7.70)	(26.66)	(19.40)
Constant	-4.749***	-4.527	-368.9***	-944.9***
	(-6.93)	(-1.79)	(-6.28)	(-4.30)
sigma				
Constant	31.92***	86.66***	2,405.4***	8,158.3***
	(669.40)	(1274.97)	(459.33)	(692.78)
CF	Y	Y	Y	Y
Seasonality	Y	Y	Y	Y
Year	Y	Y	Y	Y
Month	Y	Y	Y	Y
Fes	Y	Y	Y	Y
Dow	Y	Y	Y	Y
Observations	26,303	26,303	26,303	26,303
$pseudo-R^2$	.4085267	.9824951	.5684901	.9514313

z statistics in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$
Note: LT_t and LD_t are losses on transmission and distribution.
pseudo-$R^2 = (\sum(Y_t - \bar{Y})^2 - \sum(\hat{Y} - Y_t)^2)/\sum(Y_t - \bar{Y})^2$

Regarding energy losses in transmission, column (1), we find positive signs for exports (0.00443) and Pumping Consumption (0.0127), which implies higher energy losses, in MWh, for one additional MWh consumed in these two activities. However, these two variables present negative coefficients for the cost of losses in column (3). These signs are simply capturing the fact that exports and Pumping

Table 2.6: Marginal effect on the cost of losses (%).

	Short-run		Long-run	
	ΔLT_t	ΔLD_t	ΔLT_t	ΔLD_t
	(1)	**(2)**	**(3)**	**(4)**
$\Delta\overline{C_t}$	0.00765	0.00840	0.00829	0.00973
$\Delta\overline{PC_t}$	-0.00199	-	-0.00216	-
$\Delta\overline{E_t}$	-0.00354	-	-0.00384	-
$PEAK_t$	4.29602	2.31155	4.65517	2.67744

Note: Outcome based on Table 2.5, columns (3) and (4).

Consumption increase during low price periods, but as an energy loss they actually represent a cost. Therefore, their cost coefficients should be considered as absolute values in these cases.

To better understand the coefficients in Table 2.5, we calculate the short- and long-run marginal effect on the cost of losses[28] in Table 2.6. In the short-run, the marginal effect of consumption on transmission (0.00765%) is smaller than on distribution (0.00840%). In the long-run, it is also smaller on transmission (0.00829%) than on distribution (0.00973%). It seems obvious because most consumption is made on the distribution grids. Moreover, an important share of consumption connected to distribution does not use transmission because 25% of total energy generated is in distribution (see Figure 2.2).

We find potential savings in energy losses and their costs from DSM policies, aimed at fully smoothing the demand profile curve to reduce congestion in the grids, using the long-run marginal effect on the cost of losses corresponding to the peak period from 12 p.m. to 10 p.m. In Spain, potential annual savings in the cost of losses are 14.2 M€/year[29] for transmission plus distribution. To put this in context, this represents 1.25% of the annual cost of losses or 0.31% of the annual energy losses. These results are similar to those reported by Shaw et al. (2009). Pumping Consumption

[28]Transmission and distribution *short* and *long-run marginal effects on the cost of losses for each consumption* are calculated using coefficients from the cost of losses: $\beta_{oi}/\overline{LT}$ and $\beta_{oi}/\overline{LD}$, and $[\beta_{oi}/(1-\beta_1)]/\overline{LT}$ and $[\beta_{oi}/(1-\beta_1)]/\overline{LD}$, respectively. This allows us to compare impacts on transmission and distribution for each consumption.

[29]These potential savings are calculated using the *long-run marginal effect on the cost of losses* (%) associated with the peak, the average cost of losses and the 10 hours per day in the peak period: $365 \cdot 21{,}454 \cdot 10 \cdot (4.66\%) + 365 \cdot 108{,}020 \cdot 10 \cdot (2.68\%) = 14.2$ M€/year. We have not considered the carbon emissions avoided or other externalities. Moreover, we calculate the annual savings in energy losses using the *long-run marginal effect on the energy losses* for the peak period and following the same methodology. However, here we use coefficients related to energy losses, in columns (1) and (2), instead of coefficients related to the cost of losses, in columns (3) and (4).

is analysed in the next subsection together with Pumping Generation.

2.5.2 Loss analysis from the generation perspective

Table 2.7 shows the results of the loss estimations from the generation perspective: Eqs. (2.7) and (2.8). The endogenous variable energy loss, in MWh, is in columns (1) and (2). The endogenous variable, the cost of losses in €, is in columns (3) and (4). All associated coefficients are significant.

In general, our results show how energy losses and their costs evolve due to a change in each production technology because the explanatory variables are in differences and not in levels. From the results presented in Table 2.7, it is interesting to highlight those capturing the impact of Solar production on energy losses in transmission (-0.00124) and their cost (-0.0823€) in the same grid level for one additional MWh generated. Whilst at first glance these negative coefficients may seem counterintuitive, actually they are a relevant contribution of this Chapter that deserves to be discussed in more detail.

The negative coefficients of Solar for both energy losses and their cost tell us that a positive change in its production produces a negative change in transmission energy losses. Between 2011 and 2013 more than 80% of the Solar production in Spain was injected into the distribution grids, precisely where 90% of the energy consumption takes place (Figure 2.2). These high shares at the same level have two main implications. First, when hourly Solar production increases as the sun appears, the TSO must reduce -or not increase as much- the production from other technologies connected to the transmission network: Coal, Combined Cycle, etc. Second, and as a result of the above, the flows in the transmission grids are reduced -or not increased as much- and this affects congestion. Therefore, distribution grids are -to some degree- self-sufficient. These two effects on energy losses in the transmission network are captured in our estimations through the negative coefficient of Solar. This result does not mean that total energy losses decrease when Solar generates, but that when Solar production increases, the share of transmission energy losses related to this technology decreases. We do not observe this pattern in Wind, because its share of the energy injected into distribution (2011-2013) is much smaller (see Table 1).

Regarding CHP in transmission, the positive coefficient for energy losses (0.00698) and the negative for the cost of losses (-0.858€) at the same grid level can be explained in the same way as in the cases of exports and pumping consumption: a large quantity of CHP production takes place at night when the wholesale price is lower. As for exports and pumping consumption, we consider these costs of losses in absolute values in our analysis.

Finally, it is also worth noting the smaller cost of losses in transmission for one additional MWh produced by DG technologies (-0.0823€ for Solar, 0.858€ for CHP and 1.221€ for Wind) with respect to the other conventional sources (1.743€ for Nuclear, 1.639€ for Combined Cycle, 2.415€ for Coal and 2.660€ for Hydro). This confirms a lower impact of DG on the cost of transmission losses. Technologies like Solar, Wind and CHP, the production of which is mostly or partially injected into distribution grids close to consumers, have smaller cost of transmission losses than the rest, which inject into the transmission grid. DG production almost does not need to use that grid level.

Turning to distribution grid level in column (4), it is interesting to analyse the cost of losses for one additional MWh generated in distribution in detail. Solar (4.985€) and Wind (4.696€) costs of losses are smaller than those of the conventional sources: Nuclear (8.944€), Combined Cycle (10.18€), Coal (9.683€) and Hydro (8.925€). Large conventional plants are connected to the transmission network and their production should be reduced in HV transformers located at the border points between TSO and DSO, which further increase their corresponding losses.

CHP in distribution should be analysed in detail because of its very high cost of losses (14.68€), even though they are mostly connected to distribution and close to consumers. Intuitively CHP presents the U-shaped curve for energy losses in distribution, as proposed by Quezada et al. (2006); Marinopoulos et al. (2011) because of the combination of two factors: (i) its hourly production profile is not well-correlated with the consumption profile because CHP plants in Spain are mostly industrial plants that work the whole day, and (ii) these plants inject 84.25% of their total production (2011-2013) into distribution grids but in an unbalanced way. 26.52% goes into grids from 1kV to 36kV, 35.38% into grids from 36kV to 72.5kV, and 20.89% into grids from 72.5kV to 145kV (CNMC, 2013). The optimal arrangement would be to inject most of its production into grids from 72.5kV up to 145kV or into transmission, where energy losses are smaller because of the higher voltage.

Another interesting result of Chapter 2 comes from the total energy losses produced by each technology. It is technically feasible to add both coefficients in the transmission and distribution networks as in the following examples. A MWh gen-

Table 2.7: Generation impact on energy losses and their cost.

	(Energy losses in MWh)		(Cost of losses in €)	
	ΔLT_t^E	ΔLD_t^E	ΔLT_t^C	ΔLD_t^C
	(1)	**(2)**	**(3)**	**(4)**
$\Delta(LT_{t-1}^E)$	-0.111***			
	(-43.53)			
$\Delta(LT_{t-1}^C)$			0.0286***	
			(8.09)	
$\Delta(LD_{t-1}^E)$		0.104***		
		(106.17)		
$\Delta(LD_{t-1}^C)$				0.103***
				(41.34)
ΔN_t	0.0149**	0.0943***	1.743***	8.944***
	(3.03)	(4.88)	(4.45)	(4.47)
ΔCC_t	0.0114***	0.108***	1.639***	10.18***
	(28.46)	(97.67)	(55.39)	(97.23)
ΔCO_t	0.0231***	0.125***	2.415***	9.683***
	(27.87)	(52.25)	(36.61)	(37.54)
ΔH_t	0.0335***	0.0975***	2.660***	8.925***
	(75.81)	(82.06)	(77.06)	(68.80)
ΔPG_t	0.0160***	0.133***	3.352***	17.54***
	(15.81)	(50.31)	(43.53)	(63.95)
ΔSOL_t	-0.00124**	0.107***	-0.0823*	4.985***
	(-3.13)	(88.86)	(-2.12)	(33.91)
ΔW_t	0.0204***	0.0901***	1.221***	4.696***
	(45.09)	(58.03)	(31.08)	(31.41)
ΔCHP_t	0.00698***	0.400***	-0.858***	14.68***
	(6.92)	(150.01)	(-11.52)	(56.49)
ΔI_t	0.0311***	0.0841***	2.985***	10.12***
	(46.71)	(53.54)	(58.46)	(56.90)
Constant	-0.408	-0.617	11.98	100.5
	(-0.69)	(-0.26)	(0.21)	(0.45)
sigma				
Constant	30.22***	76.40***	2,417.1***	8,867.1***
	(697.00)	(1,478.27)	(450.41)	(656.33)
CF	Y	Y	Y	Y
Seasonality	Y	Y	Y	Y
Year	Y	Y	Y	Y
Month	Y	Y	Y	Y
Fes	Y	Y	Y	Y
Dow	Y	Y	Y	Y
Observations	26,303	26,303	26,303	26,303
$pseudo-R^2$	.4698359	.9863942	.5642682	.9426251

z statistics in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$
Note: LT_t and LD_t are losses on transmission and distribution.
pseudo-$R^2 = (\sum(Y_t - \bar{Y})^2 - \sum(\hat{Y} - Y_t)^2)/\sum(Y_t - \bar{Y})^2$

erated by Nuclear and consumed by small end-consumers, who are all connected to distribution, first travels through the transmission grid until a border point with the distribution grid, and then travels through the distribution grid to the meters of the small end-consumers. In the case of technologies that are connected to both the transmission and distribution grids such as Wind, we can follow the previous reasoning again with the difference that some Wind production is also injected into the distribution grid. An additional MWh produced by Nuclear has a total loss cost of 10.687€, compared to 4.903€ in the case of Solar, 5.917€ for Wind and 15.538€ for CHP. These results show the potential benefits for consumer welfare of Wind and Solar energy generation, as the total cost of losses is smaller than for the rest of the mix. As we see in the next section, the level of CHP energy losses and their corresponding cost might be reduced if its production could be lowered during periods of low demand. These results differ from those reported by Strbac et al. (2007), who find micro CHP is able to reduce energy losses by up to 40% in rural and 33% in urban areas of the UK, because its production is highly correlated with the electricity demand profile. In Spain, the installed capacity of micro CHP[30] is residual, which means the two results are not directly comparable.

As for Pumping Generation technology, the prerequisite for generation is Pumping Consumption. Consequently, we need to add 0.428€ from the cost of losses in Pumping Consumption (Table 2.5) to the 3.352€ of the cost of losses in transmission and 17.54€ in distribution (Table 2.7). Hence, for a consumer connected to distribution, the total cost of losses for Pumping Generation energy would be 21.320€. This generation technology is almost exclusively used during hours of maximum demand, consequently the energy losses are produced at the highest hourly price, which greatly increases their costs and so negatively affects the efficiency of the system.

As with the previous set of results, to better understand the coefficients in Table 2.7, we calculate the short- and long-run marginal effects on the cost of losses (see Table 8). In the short-run (columns (1) and (2) in Table 2.8), Pumping Generation in transmission (0.01562%) and distribution (0.01624%) have the highest effects. In transmission losses, Solar has the least, and even negative, effect on losses (-0.00038%). This is more than 20 times smaller than the effect of base sources such as Nuclear or Combined Cycle. The negative sign or effect seems to indicate that during hours of Solar generation, the flows from other technologies are displaced.

[30] In September 2013, the installed capacity of CHP plants of 1MW or less, also known as micro CHP, was below 200 MW, which barely amounts to 2.1% of the total CHP installed capacity in Spain (IDAE, 2014).

In terms of distribution, Wind (0.00435%) and also Solar (0.00462%) present the smallest effects on the cost of losses, being almost half those of the base sources. This points to the benefits of generating in distribution, i.e., close to points of consumption. However, CHP represents a special case (0.01359%), with more than 85% of production being generated at distribution. In the long-run (columns (3) and (4)), the coefficients do not vary greatly, because the lag coefficients are quite small.

Table 2.8: Marginal effect on the cost of losses (%).

	Short-run		Long-run	
	ΔLT_t	ΔLD_t	ΔLD_t	ΔLD_t
	(1)	**(2)**	**(3)**	**(4)**
$\Delta\overline{N_t}$	0.00812	0.00828	0.00836	0.00924
$\Delta\overline{CC_t}$	0.00764	0.00943	0.00786	0.01052
$\Delta\overline{CO_t}$	0.01126	0.00896	0.01159	0.01000
$\Delta\overline{H_t}$	0.01240	0.00826	0.01276	0.00922
$\Delta\overline{PG_t}$	0.01562	0.01624	0.01608	0.01811
$\Delta\overline{SOL_t}$	-0.00038	0.00462	-0.00040	0.00515
$\Delta\overline{W_t}$	0.00569	0.00435	0.00586	0.00485
$\Delta\overline{CHP_t}$	-0.00400	0.01359	-0.00412	0.01515
$\Delta\overline{I_t}$	0.01392	0.00937	0.01432	0.01045

Note: Outcome based on Table 2.7, columns (3) and (4).

In general, from the generation analysis, it can be seen that Nuclear performs as a base source with a small impact on energy losses and their cost. When a technology covers a greater share of the peak demand, its impact on energy losses increases because of congestion in the grids. Therefore, outcomes from different technologies requiring the use of both the transmission and distribution networks, such as Nuclear and Combined Cycle, do not have the same impact on energy losses. In the case of DG, its impact on both transmission and distribution is smaller than the impacts of the other sources. This is not the case for CHP in distribution where we deduce a U-shape curve attributable to the disproportionate amounts of energy injected for each network voltage and a lack of correlation between its production and the demand profile. In the extreme case, the impacts of imports and Pumping Generation are highest, confirming that a peaked demand profile has major consequences for energy losses.

2.5.3 Additional post-estimation analysis

In this section, we use the results reported above in Table 2.7 to calculate the hourly price effect[31]. This allows us to identify the time of day when the energy losses for each source are at their highest. The largest coefficients suggest that energy losses occur mainly during the highest hourly price periods, or during the highest total demand periods. In contrast, the lowest coefficients are associated with periods of low demand. The results are presented in Table 2.9.

Table 2.9: Hourly price effect on LT_t and LD_t in €/MWh.

	ΔLT_t **(1)**	ΔLD_t **(2)**
$\Delta\overline{N_t}$	116.94	94.87
$\Delta\overline{CC_t}$	144.08	94.50
$\Delta\overline{CO_t}$	104.46	77.70
$\Delta\overline{H_t}$	79.51	91.58
$\Delta\overline{PG_t}$	208.96	131.98
$\Delta\overline{SOL_t}$	66.52	46.62
$\Delta\overline{W_t}$	59.97	52.10
$\Delta\overline{CHP_t}$	-122.88	36.70
$\Delta\overline{I_t}$	95.91	120.34

Note: Outcome based on Table 2.7, columns (1) & (3), and (2) & (4).

Pumping Generation for both transmission (208.96) and distribution (131.98) obviously present the highest values as this technology is mostly used to cover the hours of peak demand, when prices are at their highest. The most interesting results are obtained when comparing conventional sources and DG in distribution. Solar (46.62), Wind (52.10) and CHP (36.70) have much smaller effects than Nuclear (94.87), Combined Cycle (94.50) and Coal (77.70). This might suggest that the energy losses produced by DG mainly occur during periods of lower demand, when the hourly price is lowest, because energy needs to travel further in the distribution grids until it finds a consumption point. These are the consequences of there being non-dispatchable DG connected, and there would be potential energy loss reductions if DSOs were able to operate them[32] and improve their correlation

[31] For each l source, the *hourly price effect* is estimated by the division of two coefficients: β_l^C/β_l^E, where β_l^C is in columns (3) and (4) of Table 2.7, and β_l^E in columns (1) and (2). Consequently, the *hourly price effect* is measured in €/MWh.

[32] In the case of Solar power, energy is very difficult to manage. It is divided between *photovoltaic cells* the production of which might be managed by the use of batteries, and *concentrated solar steam*

with demand. These results are in line with those reported by Hung et al. (2013) and appear to demonstrate the potential benefits of a more dispatchable DG source.

2.6 Conclusions and regulatory recommendations

In this study we have analysed the impact of demand (consumption) and supply (generation) on electrical energy losses in Spain. As outlined in the introduction, such energy losses are an intrinsic part of energy flows in any electricity system and they affect social welfare. Our analysis has involved a quantification of the marginal effect on losses in MWh and € from one additional MWh consumed or produced.

We have estimated the average cost of losses produced in transmission and distribution by one additional MWh consumed or generated. This is new in the literature and shows that the grid level with the gratest potential for improvement in terms of consumer surplus is the distribution level. With this in mind, why should the value of a MWh lost in transmission be assessed as equal to one lost in distribution? Using the opportunity cost principle, setting different prices might make sense in future regulatory schemes.

In terms of consumption, we estimated the average cost of losses produced in transmission and distribution, when controlling the peak effect by the inclusion of a dummy variable. In the Spanish regulatory scheme, these costs are borne by consumers in the retail market. The higher loss cost in distribution shows that policies designed to improve the efficiency of the system and consumer surplus should be focused on that grid level, where all LV end-consumers are connected.

Another key finding to emerge from this study is the maximum potential economic savings in relation the cost of losses that can be achieved by reducing network congestion via the implementation of DSM policies, such as the use of smart meters. These allow single or flat rate tariffs to be replaced by time-of-use tariffs and, thus, to smooth the aggregate demand profile. On average and in the long-run, the maximum cost savings associated with this policy would represent 1.25% of the annual cost of losses. Our results are in line with other ex-ante studies (Shaw et al. (2009) and Cronenberg et al. (2012)) and show that incentives to reduce energy losses are not enough to encourage DSOs to fund these DSM policies[33] by themselves. More-

power stations that use radiation to heat a fluid and generate electricity, the production of which is a little more flexible than that from cells (Pérez-Arriaga, 2014).

[33]It is estimated that more than 27 million smart meters, together with the corresponding infrastructure, have to be installed in Spain. However, it is very difficult to completely flatten the demand

over, we should also bear in mind that a smoother demand profile could modify the current generation mix.

In terms of generation, we have analysed short- and long-run marginal effects on the cost of losses. The key finding to emerge here is that the impact of each technology is heterogeneous in a real electricity system. Three circumstances account for these differences: the timing of production -during peak or off-peak periods-; the role in the demand curve coverage; and the specific grid level, transmission or distribution, to which they are connected. Regarding DG, the costs of losses for Solar and Wind are lower than all conventional sources, but the opposite is true for CHP. We conclude that CHP generation has a U-shaped impact on distribution energy losses, given that CHP injection into distribution is not optimally proportional to the grid voltage and not well correlated with the demand curve. Therefore, at certain times there might not be enough local load to absorb local production and then energy has to travel further along LV lines. This is an important result that should be considered in planning upcoming generation capacity in the system: new capacity should be connected to a grid voltage taking into account the correlation between the production and consumption profiles. The less correlation there is, the higher must be the voltage of the network. Spain's CHP installations are composed mainly of industrial plants with a smooth generation profile, while micro CHP plants are quite residual due to their poor economic viability (González-Pino et al., 2014). However, future technological developments and cost reductions might change this situation, and the market might be able to exploit the potential benefits identified by Strbac et al. (2007).

Regarding RES-E, our results suggest that an increase in Solar and Wind generation would reduce energy losses. However, at the limit, this might produce a U-shaped effect like that reported above in the case of CHP, and actually increase their respective contribution to energy losses. In this way, two other points should also be considered: the correlation of consumption and generation profiles affects losses, and, as is shown by our results, the potential need for other backup technologies might produce greater losses than DG. These trade-offs are often disregarded in the Cost Benefit Analysis when new generation capacity is to be connected to the grid. Hence, before allowing the massive connection of new DG capacity, the correlation between their specific production profiles and the consumption curves should first be assessed.

profile given that some consumption, such as lighting, cannot be delayed to off-peak periods.

The high cost of the losses associated with Pumping Generation is a direct consequence of the period of time during which this technology operates. They are able to start up and shut down in a matter of minutes, which makes them ideal for coping with the variability in RES-E production and for keeping the electricity system balanced. These plants consume mainly during periods of low demand when there is a surplus of generation, whilst they generate primarily during periods of peak demand, which results in a high average loss cost. In the future, the increased penetration of RES-E might increase the variability of the generation mix, and Pumping is expected to gain in importance (Eurelectric, 2015). However, the higher loss costs might counter the lower costs of Solar and Wind power, thus determining the overall efficiency of the electricity system.

Our results highlight the need to improve the relationship between TSOs and DSOs in order to consider a whole system approach with greater coordination, exchange of data and use of flexibility. In Spain's current regulatory framework, as in other countries, DG is controlled by the TSOs[34] and small plants are often fully operated and controlled by their owners. The passive role currently being adopted by DSOs will have to change in the future. Along these lines, Eurelectric (2013a) proposes DSOs become real system operators, better monitoring of MV and LV distribution network parameters in order to act on DG and consumers, a review of grid access regimes including priority and guaranteed grid access for renewables, and enabling the creation of new system services at distribution level, etc.

In the light of the results from the supply side, and adopting a broad system perspective, Spain's current regulatory scheme, in which suppliers purchase the energy required to cover energy losses the cost of which is, in turn, borne by consumers, needs to be subjected to a careful analysis to determine whether it remains valid. In the meantime, there is obvious room for improvement. Two potential areas for action are i) the substitution of flat tariff UoS charges in electricity production for differentiated charges that take impact on energy losses into consideration ; and ii) the implementation of locational marginal prices so that the costs of losses could be shared between generators and consumers. For instance, this might involve defining different areas in Spain in order to differentiate between low and high demand -and production- sites. In the long-run, this could serve as an efficient signal for locating new generator plants based on the efficiency of the whole system.

[34]In Spain, RES-E are monitored and controlled by a "Control Centre of Renewable Energies" (CECRE) operated by the TSO. Its objective is to integrate the maximum amount of generation from renewable energy sources into the electricity system under secure conditions. However, only wind farms of over 10 MW are connected to this control centre.

Future empirical studies of the economics of electricity losses could go a step further and use geographical and network data. However, this could imply other methodologies and approaches. As well as the impact of energy losses, it could be useful to focus on the impact on CO2 emissions, examining those attributable to each generation technology. In the case of consumption, the methodology proposed herein could be reapplied following the introduction of smart meters in order that the impact of current DSM policies on energy losses might be verified. Other potential lines of investigation include using these models to forecast the impact of charging electric vehicles during off-peak hours, or estimating the impact of energy losses on the wholesale market price -auctions- because of the greater demand for energy.

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3 CO_2 content of losses

3.1 Introduction

According to IPCC estimations, the power sector has the highest contribution to green house gases (GHGs): 25% emissions were related to the electricity and the heat production in 2010[1]. Indeed, most regulatory efforts in terms of emission reduction around the world are mainly focused in power generation[2]. In Europe, 1453 combined heat and power (CHP) generation plants have participated in the European Union Emission Trading Scheme (EU ETS), which is the regulatory instrument put in place by the European Commission (EC) in 2005 to cap CO2 emissions in line with the Kyoto Protocol targets (Berghmans and Alberola, 2013). In October 2014, the "2030 Energy and Climate Package"[3] has pushed forward the clean generation incentives by 2030: 40% cut in GHG emissions, 27% of energy from renewable sources and 27% improvement in energy efficiency. This Package is the ambitious development of its predecessor, the "2020 Energy and Climate package" enacted in 2009 by the EC pledging for: 20% cut in GHG emissions, 20% of energy from RES-E and 20% improvement in energy efficiency[4].

As stated by Monjon and Guivarch (2016), a low-carbon future world compromises energy security in Europe and is related to uncertainty regarding new technologies, fossil fuel resources, markets and economic growth. In fact, electricity systems are undergoing significant changes, mainly due to: the penetration of new renewable sources of electricity (RES-E) in the generation mix; the introduction of the information and communications technology (ICT) to monitor and grid control; the wide installation of smart meters at end-consumers, which empowers them through the implementation of demand side management (DSM) policies as well as electric vehicles (EV).

The incentives implemented in most European countries to promote RES-E are helping replace the traditional most polluting technologies (coal and fuel) by non-polluting generation plants: solar, wind, geothermal, etc. This has been accompanied by the wide-connection ofmnumerous small generation plants or distributed generation (DG). The important penetration of DG has modified the traditional top-

[1] See IPCC 2014 report at http://mitigation2014.org/report/summary-for-policy-makers

[2] See for example the recent North American efforts: RGGI and California-Quebec CO2 market.

[3] See https://ec.europa.eu/energy/en/topics/energy-strategy/2030-energy-strategy for further details.

[4] The 2020 Climate and Energy Package contains European Directive 2009/28/EC, European Directive 2009/29/EC, European Directive 2009/31/EC and Decision 406/2009/EC.

down energy flows (Ackermann et al., 2001)[5]. This is the case because energy is now generated closer to consumption, which directly reduces losses. The other aforementioned changes may also affect losses: ITC technologies allow the distribution system operators (DSOs) to operate the grid more efficiently and to optimize losses; DSM policies aim to delay peak consumption to off-peak hours in order to reduce grid congestion and their correspondent losses; and EV are expected to better integrate RES and consumption, which also reduce congestion. In the end, losses represent an extra amount of energy that must be generated in the electricity systems affecting economic efficiency and, depending on how this extra energy is produced, CO2 emissions.

Recent literature on losses has mainly focused on the analysis of demand (DSM) and supply policies (DG/RES-E). On the one side, DSM calls on various techniques to obtain a better performance of the infrastructure, reduce the congestion problems, adapt demand to the capacity of generation at each moment in time, and reduce losses (Strbac, 2008). The slightly small potential impacts of DSM on the loss reduction are shown in Chapter 2 and Shaw et al. (2009).

On the other side, the impact of DG on losses is based in their location, operation and hourly production. The decarbonisation of the electricity sector involves reconfiguring spatial patterns and potential changes in the location of the key energy system components (Bridge et al., 2013). Indeed, an argument to justify DG is that losses related to their use are expected to be lower because the distance to consumers is also lower. However, given that losses follow a U-shape trajectory with the degree of penetration of DG (Quezada et al. (2006); Delfanti et al. (2013)), unwanted effects might counterbalance their potential benefits. This trade-off was empirically proved in the Spanish case, where solar and wind perform better in terms of losses than the rest of traditional technologies, but the opposite is true for CHP since its production profile is quite flat and not well correlated with demand, as is found in Chapter 2.

In relation to the CO2 impact of the operation of electricity power systems, numerous papers have made contributions in different directions. Ummel (2012) calculates the CO2 impact of electricity production by plant worldwide, giving birth to the Carbon Monitoring for Action (CARMA) database[6], Marriott et al. (2010) simulate CO2 scenarios using alternative energy mixes in the U.S. and Feng et al.

[5] It is important to note that not all RES-E plants are considered DG because some are also large plants directly connected to the transmission system operator (TSO) networks.

[6] See http://www.carma.org.

(2009) estimate the CO2 content of regional energy consumption in China. More recently, the attention has shifted to the air pollution avoided due to renewable installation and the evaluation of the subsidy costs with respect the decrease of social damage due to pollution reduction. Using data from the Electric Reliability Council of Texas (ERCOT) market, Novan (2015) introduces the analysis of the external benefits due to renewables, which consists on the avoided CO2 emissions related to each technology when the time of production and the whole generation mix are considered. He states that renewable subsidies should provide more financial support to investments that provide larger external benefits on the pollution, instead of the current homogeneous policies (see also (Cullen, 2013) and Kaffine et al. (2013)). Finally, the papers closest to this Chapter are the ones that consider the CO2 impact of the system efficiency. This is the case of Amor et al. (2014) that documents the impact of congestion on CO2 emissions and Stoll et al. (2014) that study the impact of DSM policies by calculating an hourly CO2 signal applied to the hourly electricity market data in Great Britain, Ontario and Sweden. They find that load shifts from high-price to low-price hours results in carbon emission reductions, especially where price and CO2 intensity are positively correlated.

The previous literature review underlines the contrasted impact that electricity market design has on CO2 emissions. Additionally, a stylized fact in electricity markets is that, when extra generation is needed, fossil fuels are often used on account of their flexibility (in the absence of storage possibilities) increasing the CO2 content of the energy mix. That extra generation may also be needed due to positive shocks in demand, congestion or losses in the grids. To the best of our knowledge, the impact of electricity losses in CO2 emissions has not been studied yet, which is our objective here. The paper closest to our argument is Lindner et al. (2013), where they compare the CO2 content of generation versus consumption among different regions in China. Hydroelectric plants are sited in the southwest, coal plants (60% of CO2 Chinese emissions in 2010) in the north and northwest, while the growing electricity demand is in the eastern coast. They use a bottom up model to quantify the emissions embodied in the inter-provincial flows, and find a shift of environmental pollution away from economically well-off provinces to resource-rich, and less developed provinces. Although their study highlights regional flows, they do not consider losses as a parameter in their estimations, which is also presumably significant in terms of CO2 impact. Our approach is different because we study the country as a whole to focus on the understanding of the relation between losses and the system CO2 emissions.

Herein we assess the CO2 impact through losses. With this purpose, we empirically estimate the CO2 content of power generation as a function of the transmission and distribution losses using Spanish hourly data from 2011 to 2013. In particular, we study how the extra amount of energy required to cover losses is affecting the CO2 emissions in the electric system by looking at the marginal technologies that close the market. We consider Spain because, among the five biggest economies of Europe, it had the highest share of energy generated by RES-E in 2013 (36.39%) and its level of losses are in the average range for European countries[7]. From 2004–2013, the five biggest economies in Europe increased their RES-E share of energy production from 9.40% to 25.59% in Germany, 3.54–13.85% in the UK, 13.79–16.87% in France, 16.09–31.30% in Italy, and 18.98– 36.39% in Spain. Indeed, according to our calculations, energy losses in Spain represented the 8.90% of the amount of energy injected in the grids (2012), which represented an annual cost of 1160 M€[8] that is borne by all consumers. According to the World Bank Database[9] other European countries like Portugal and United Kingdom are in a close range with 10% and 8% losses, respectively, while the highest level of losses can be attributed to Croatia and Lithuania with 18% and 19%, respectively. Our results are not only be useful for Spain, but a reference for countries that are in an earlier stage in the implementation of energy transition measures with similar levels of RES-E penetration and/or similar or higher system losses. In this sense, Chapter 3 contributes to the evaluation of the energy and climate policy imposed on the power sector through losses.

The rest of this article is organized as follows. In Section 5.4 we describe the data, emphasizing the relationship between system losses and CO2 emissions. Section 3.3 details our empirical strategy while Section 3.4 includes the empirical test on the system losses contribution to the system CO2 emissions. Section 3.5 concludes and draws some policy implications.

3.2 Data description

In this section we present a detailed description of the hourly data over the three-years period (2011–2013) used to perform the empirical analysis on the impact of losses on CO2 emissions. We start by informing on our endogenous variable: the

[7]Source: Eurostat Database - Short Assessment of Renewable Energy Sources (% of electricity generation from all sources): http://ec.europa.eu/eurostat/web/energy/data/shares (last consulted on 24 September, 2015).

[8]Annual cost of losses by the multiplying hourly losses (MWh) by the electricity hourly Price (€/MWh). See Chapter 2 for further details.

[9]Source: World Bank Database - Electric power transmission and distribution losses (% of output). http://data.worldbank.org/indicator/EG.ELC.LOSS.ZS (last consulted on 6 June 2016).

system total CO2 emissions. This is followed by an apprise on the explicative variable of interest, the system losses, and on the additional control variables. Finally, we provide detailed information on the technologies operating at the margin of the market, as the key element defining the nature of the relation between the system CO2 emissions and losses.

The endogenous variable in our models is the hourly CO2 emissions in the electricity system $(CO2Tot_t)$ considering the mix of generation in each hour, which is calculated using the hourly production by technology and their corresponding Spanish conversion factors thattell us the CO2 content of each technology used. Data on the generation by technology (in MWh) is obtained from the Spanish system operator (SO; see REE (2014b)) and the data on conversion factors is published by the Spanish Ministry of Energy (IDAE, 2015) in CO2 Tons per MWh with values for 2011. The conversion factors are equal to 1 for coal, 0.74 for fossil fuels, 0.41 for combined heat and power (CHP), and 0.38 for combined cycle[10]. Although marginal emission rates vary according to the range of production of the plants, we are considering them constant by technology, as other authors do in the literature (Novan, 2015). On average, during the period considered, the energy mix included more than 33% from polluting technologies, and the system content reaches more than 8,220 CO2 Tons/h. Considering the average load of 30,785.76 MWh, in the Spanish system around 0.27 t/h of CO2 are emitted per each MWh of energy consumed. We will use this average when analysing the results on the system CO2 Tons/h per MWh for comparison purposes.

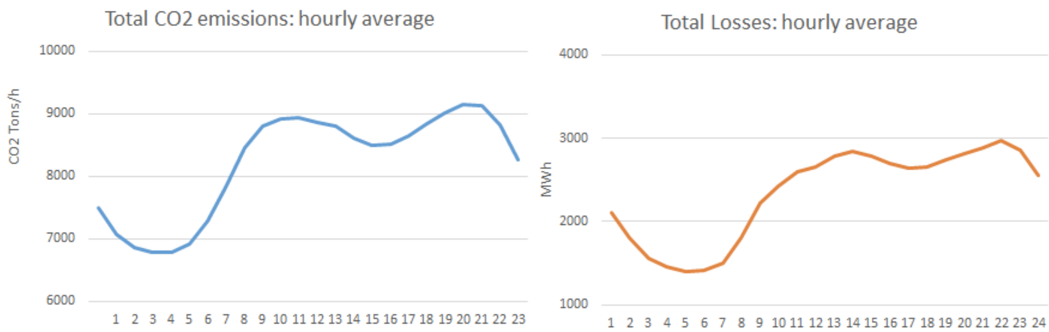
In Spain, the electricity grids with a voltage higher or equal to 220 kV are considered transmission and are owned and operated by the Spanish TSO (Red Eléctrica de España, REE by its acronym in Spanish), while the rest are considered distribution and is owned and operated by the DSOs. Methodologically, hourly losses at each level are calculated as the difference between the sum of energy injected by all generation plants and all energy withdrawn for consumers measured at their meters. Since we consider the electricity system as a whole and we are interested in the country CO2 emissions, in this article we use the sum of losses in the transmission and in the distribution levels. We exclude Balearic and Canary Islands, because their specific mix of generation and operation could bias our results. They are isolated electricity grids, whose operating procedures are not the same than Spain Continental. Moreover, their generation mixes are mostly based on pollutant technologies and the sum of their demands is only about a 5% of the total demand in Spain.

[10]The conversion factors of non-emitting technologies are zero.

Data used is published in the monthly settlement reports of the Spanish SO[11], where there is hourly information from generators, TSO, DSOs and consumers (REE, 2014b).

The resultant average hourly losses (L_t) and total CO2 emissions in the system $(CO2Tot_t)$ are shown in Figure 3.1. We observe that both variables follow a similar hourly pattern. As we will latter argue, the similarity on the series pattern may be explained by the use of the most pollutant generation as closing technologies in the peak hours. In addition, the monthly and daily averages of total CO2 emissions, presented in Tables 3.1 and 3.2, shows important variations within the year and the days of the week. These hourly, monthly and daily patterns call to control for load $(Load_t)$ and seasonality (month (M_t) and day of the week (DOW_t) when we analyse the impact of losses (L_t) on CO2 emissions in the next sections.

Figure 3.1: Average hourly CO2 emissions $(CO2Tot_t)$ and losses (L_t).



Source: own elaboration.

Table 3.1: Average hourly CO2 emissions $(CO2Tot_t)$ by day of the week.

Monday	**Tuesday**	**Wednesday**	**Thursday**	**Friday**	**Saturday**	**Sunday**	**Average**
8,333	9,058	9,136	9,046	8,829	7,130	6,026	8,223

Source: own elaboration.

With the data described we perform a first test on the impact of electricity losses on the system CO2 emissions. However, in order to obtain further insights of the nature of this relation, we study what happens at the margin when closing the electricity market.

[11]We use the last settlement report for each month, which is the most recent data available.

Table 3.2: Average hourly CO2 emissions ($CO2Tot_t$) by month.

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
8,309	8,755	7,129	5,551	6,988	8,086	9,711	9,150	9,412	8,871	8,001	8,669

Source: own elaboration.

As in most of the liberalized energy-only markets, generation plants bid their production in the wholesale market at their marginal cost in an ascending order. Each hour the more expensive technologies close the market. The integration of RES-E is causing important changes in the hourly market of electricity due to their variability and unpredictability, which requires the presence of dispatchable[12] backup technologies. These factors represent a major challenge in balancing generation with consumption, whose demand profile might not match the RES production hourly. This affects the market and operation of the traditional dispatchable fossil-fired plants (coal and combined cycle) that are used to cover peak demand (Eurelectric, 2011), which in turn impacts CO2 emissions. In this context, to better understand how the extra amount of energy required to cover losses is affecting the system CO2 emissions, we look at the marginal technologies that close the market.

We use data on the technologies closing the market for each hour ($Tech_{it}$) published by the Spanish market operator (OMIE), which considers a technology as closing at each hour if it is matches with and generates at least 5% of the total generation. Since the average level of losses is 7.6%, this allows us to discard technologies whose hourly production is too small compared to the level of losses, being unable to cover them.

Plants are classified into: coal (CO), combined cycle (CC), hydropower (H) and special regime (SR). In Spain and according to the Electricity Sector Law 54/1997, SR includes all subsidized technologies –mostly under a feed-in-tariff scheme: RES-E (photovoltaic, solar thermal, geothermal, wind, etc.), combined heat and power (CHP) and hydropower plants with less than 50 MW of installed capacity[13]. The rest of big hydropower plants (more or equal than 50 MW) are directly included in the H group. To unequivocally associate losses with specific technologies, we focus on the hours where a single technology closes alone. During the three years'

[12] *Dispatchable technologies* are the ones that can be regulated or flexible being able to match changes in demand and/or system requirements and which can be turned on and off based on their economic attractiveness (Eurelectric, 2011).

[13] It is worth noting that the Law cited is the one that was applied during the period of study of this Chapter. Nowadays Special Regime covering all this technologies no longer exists.

period considered here, in 70% of the hours a single technology closes alone, being hydropower the most frequent with 30.3% of the hours, followed by coal with 25.5% of hours. The least frequent ones are combined cycle that closes alone only in 10.2% of hours, and special regime that close alone in 2.9% of hours. In our models, we include a dummy variable equal to one for each technology when it closes alone, and zero otherwise: CO_t coal, CC_t combined cycle, SR_t special regime and H_t hydropower. Table 3.3 provides full summary statistics of the variables we use to perform our empirical analysis presented in the next section.

Table 3.3: Summary statistics.

Variable	Obs	Mean	Std.Dev.	Min	Max
$CO2Tot_t$	26,304	8,220.52	2,895.08	1,903.46	16,339.99
L_t	26,304	2,339.97	645.77	972.03	4,289.70
$Load_t$	26,304	30,785.76	4,669.14	20,319.16	46,124.55
M_t	26,304	6.521	3.449	0	11
DOW_t	26,304	2.997	2.001	0	6
CO_t	26,304	0.255	0.436	0	1
CC_t	26,304	0.102	0.303	0	1
SR_t	26,304	0.029	0.169	0	1
H_t	26,304	0.303	0.459	0	1

Source: own elaboration.

3.3 Empirical approach

We have performed a stationary time series analysis to assess the proper functional form of the regression models we use. We performed two tests. First, the augmented Dickey-Fuller (ADF) test (Dickey and Fuller, 1979) under the null hypothesis of a unit root, and second the Kwiatkowski-Phillips-Schmidt-Shin (KPSS) tests (Kwiatkowski et al., 1992) under the null hypothesis of stationarity. Both tests, as reported in Table 3.4, confirm that the series are stationary in levels, so we estimate the models using all series in levels.

Herein we present our empirical strategy to evaluate the impact of losses on the system total CO2 emissions. Firstly, we analyse the system CO2 emissions as a function of losses to assess whether there is a significant effect, and from there we obtain an estimate of the average effect of losses on CO2 emissions. Secondly, we estimate to which extent the effect of losses on the system CO2 emission depends

Table 3.4: ADF and KPSS tests with variables in levels.

	ADF test	KPSS test
$CO2Tot_t$	-27.382***	0.086
L_t	-80.107***	0.053
$Load_t$	-64.892***	0.075

Note: Test results are statistics. The Modified Akanke Information Criterion determines lag length. The trend was not significant in any case, and hence, it was excluded. ADF null hypothesis of unit root. KPSS null hypothesis of stationarity.
*** Significant at 1%.

on the market closing technologies as these are providing the extra generation required to cover losses.

We study whether losses are significant to explain in total CO2 emissions by estimating Equation (3.1), which captures the effects of losses (L_t) on total CO2 emissions $(CO2Tot_t)$ controlling for the system load $(Load_t)$ and seasonality patterns with the month (M_t) and day of the week (DOW_t). Hourly dummies would capture what happens with the inframarginal technologies in response to different system conditions during the day (including the underlying supply and demand effects). Unfortunately they cannot be included in our model due to the high correlation those dummies would have with the system load variable, provoking perfect multicollinearity that would bias our results. Combining the above consideration with the fact that system load is the best proxy to the system conditions at different time, we choose to include the load variable instead of the hourly dummies.

$$CO2ToT_t = \alpha_0 L_t + \alpha_1 Load_t + \alpha_2 M_t + \alpha_3 DOW_t + \varepsilon_t \tag{3.1}$$

After testing the effect of losses on the system CO2 emission, we evaluate to what extent this impact may be explained by the use of more or less pollutant generation sources as closing technologies. Hence, we assume that the closing technology in the market generates the extra amount of energy to cover losses. We are aware that this is not necessarily the case for all hours in the whole period. Nevertheless, in our data a technology is defined as *closing technology* in a certain hour if it covers at least 5% of the total generation. Given that the average level of losses is 7.6%, our hypothesis remains reasonable: it is most likely that the marginal technology is used to cover -an important part of- losses in each hour. Indeed, identifying the technology or technologies that are covering the mismatch between supply and demand would require a difficult simulation exercise that is far beyond the scope of

Chapter 3. As a consequence, we consider the marginal technologies to estimate how this extra amount of energy that must be produced to cover losses affects CO2 emissions.

With this purpose, we modify the model to incorporate the closing technologies into the analysis (see new specification in Equation (3.2). Accordingly, the effect that each technology has on the system CO2 emission ($CO2ToT_t$) is isolated through the inclusion of an interaction between the losses (L_t) and the technology closing alone at each hour ($Tech_{it}$).

$$CO2ToT_t = \alpha_0 L_t + \alpha_1 L_t \cdot Tech_{it} + \alpha_2 Load_t + \alpha_3 M_t + \alpha_4 DOW_t + \varepsilon_t \qquad (3.2)$$

$Tech_{it}$ is a set of four dummy variables CO_t; CC_t; H_t; SR_t, which are equal to one when the correspondent technology closes alone (CO_t for coal, CC_t for combined cycle, H_t for hydropower, and SR_t for special regime) and zero otherwise.

Our empirical approach relies on the assumption that in any given hour of any day between 2011 and 2013, the amount of grid losses (the difference between each hour generation injected in the grid and the amount of electricity consumed out of the grid) is exogenously given by nature: it depends on the grid structure, the location of the generation plants, the location of consumers, the generation technology and other whether and natural factors affecting the grid, both from the supply and from the demand side. Our methodological choice wishes to be simple and parsimonious. Given the assumption on the impact of the closing technology detailed above and that the variables are stationarity in levels, we use the Ordinary Least Square (OLS) method to perform the analysis.

3.4 Results: losses contribution to CO2 emissions

Herein we present the outcomes of our empirical evaluation on the impact of losses on the system total CO2 emissions. Results from estimations of Equation (3.1) are shown in Table 3.5, where each column represents a different outcome according to the variables and seasonality included. Indeed, they show that electricity losses (DOW_t) explain CO2 emissions $(CO2Tot_t)$ significantly, and that controlling for the system load is relevant. Considering the outcome in column (4), where both seasonality and load are included, results show that, on average, for each MWh of electricity generated to cover system losses 1.054 t/h of CO2 are emitted in the system. When comparing this result with average emission of 0.27 CO2 Tons/h per MWh of power in the system, we observe that losses not only contribute to the system emissions, but that the extra amount of energy required to cover losses is of great importance in the total system CO2 emissions. A further examination into the factors influencing the contribution of losses in CO2 emission might help to explore potential policy recommendation to alleviate the negatives implications of this finding.

Table 3.5: Effect of losses on total CO2 emissions.

	(1)	**(2)**	**(3)**	**(4)**
L_t	3.420***	0.630***	2.211***	1.054***
	(0.0067)	(0.0439)	(0.0163)	(0.0423)
$Load_t$		0.220***		0.128***
		(0.0034)		(0.0043)
Seasonality	No	No	Yes	Yes
Observations	26,304	26,304	26,304	26,304
R^2	0.907	0.920	0.938	0.943

Standard errors in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Results regarding the estimation of Equation (3.2) that captures the CO2 emissions explained by losses when different technologies are used to close the market, are presented in Table 3.6.

Since we focus on the hours when a technology closes alone, we individually estimate the effects that each technology has on the total CO2 emissions. From the results obtained we observe that polluting technologies -coal and combined cycle- (see columns 1 and 2) have a positive and significant effect while special regime[14] and hydropower (see columns 3 and 4) have a significant and negative effect.

By looking at the sum between the estimated parameters for losses and each interaction term in Table 3.6, it is possible to calculate the contribution of losses to CO2 emissions when each technology is closing the market and most likely covering losses. In Table 3.7 the estimate average effects of losses in the system CO2 emissions for each closing technology. In particular, the results show that 1.29 t/h of CO2 are emitted in average for each MWh of energy generated to cover losses when coal is the marginal technology. Likewise, when combined cycle is closing

[14] As was explained in Section 5.4, SR includes: RES-E, CHP and hydropower plants of less than 50MW. Big hydropower plants (more or equal than 50MW) are directly considered in the hydropower group.

Table 3.6: Effect of losses and closing technologies on total CO2 emissions.

	(1)	(2)	(3)	(4)
L_t	1.075***	1.063***	1.051***	1.040***
	(0.0422)	(0.0423)	(0.0431)	(0.0424)
$Load_t$	0.126***	0.125***	0.127***	0.128***
	(0.0043)	(0.0043)	(0.0043)	(0.0043)
$CO_t \cdot L_t$	0.207***			
	(0.0131)			
$CC_t \cdot L_t$		0.188***		
		(0.0182)		
$H_t \cdot L_t$			-0.011***	
			(0.0116)	
$SR_t \cdot L_t$				-0.074***
				(0.0251)
Seasonality	Yes	Yes	Yes	Yes
Observations	26,304	26,304	26,304	26,304
R^2	0.9427	0.9414	0.9453	0.9464

Standard errors in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

alone, 1.25 t/h CO2 are emitted in average for each MWh of energy generated to cover losses. Finally, 1.04 t/h CO2 and 0.96 t/h CO2 are emitted in average for each MWh of energy generated to cover losses when hydropower and special regime, respectively, are the marginal technologies. Note that even when the closing technology has an emission rate equal to zero (like it is the case for hydropower) the inframarginal technologies may be polluting, which makes emissions positive. The impact on our estimation due to market conditions determining the inframarginal technological mix is captured by the variable $(Load_t)$. The estimated coefficient associated with this variable is significant across specifications, suggesting the inframarginal technologies do influence the total system emissions, but do not interact with the estimation result regarding the closing technologies. Coefficients of the closing technology variables included in each regression captures the -superior or inferior- effect of losses on CO2 emissions when each of the technologies matched the market.

When comparing the results from theses technology-specific estimations with the average effect of losses obtained from the estimation of Equation (3.1) we observe that, when coal and combined cycle are the closing technologies the contribution of

Table 3.7: Average effects of losses on the system CO2 emissions for each closing technology.

Closing effect	Losses effect on CO2 emissions
Coal	1.29
Combined Cycle	1.25
Hydropower	1.04
Special Regime	0.96

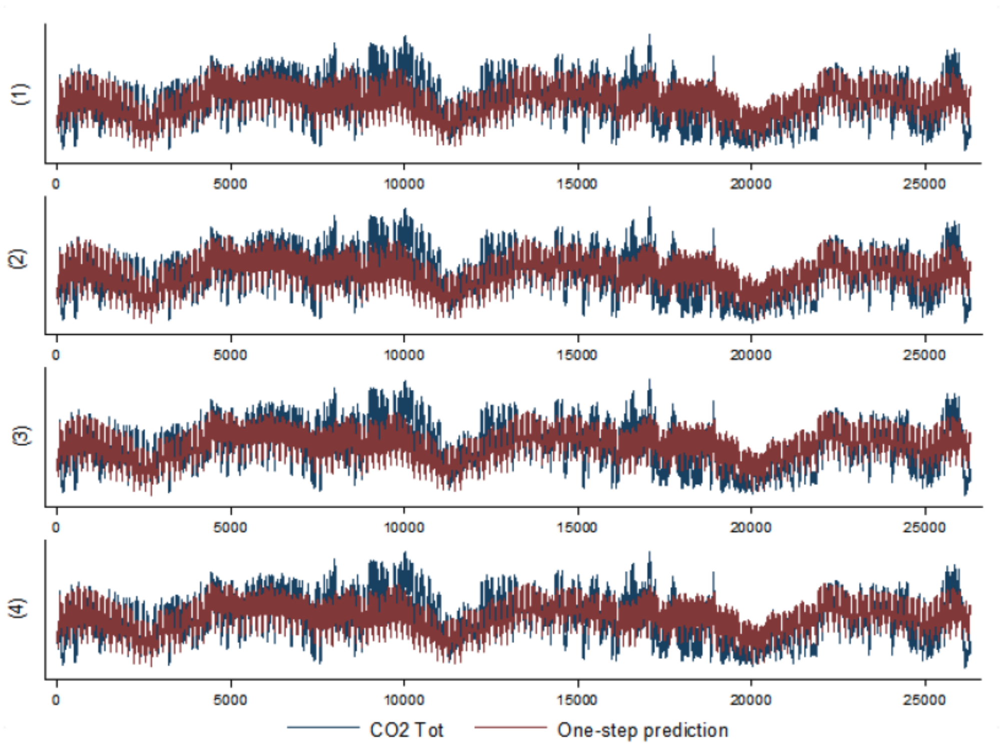
Note: The contribution of losses is calculated from results in Table 3.6 as the sum between the coefficient of losses and its interaction with each technology..

losses to CO2 emission is higher than the average (1.054 t/h CO2), while when the closing technologies are hydropower or special regime the opposite is true. Comparing these results with the system average emissions also helps to highlight the magnitude of these effects. The case of coal is particularly concerning because when this technology is closing, in average, for each MWh of energy generated to cover losses 1.29 t/h of CO2 are emitted, while the average level of emissions in the system is 0.27 t/h per MWh. This means that, if coal is closing the market alone (and most probably covering losses) the polluting contribution of losses is almost 5 times more important than average. Finally, weighting one thing against another, when coal is the single technology closing the market, the effect from losses for each MWh of energy generated to cover losses on CO2 emissions is 34% higher than when the single closing technology is part of the special regime.

The coefficients of the remaining explanatory variables are very similar across the specifications. Moreover, as measures of the reliability of the statistical estimates, Tables 3.5 and 3.6 show high R-squared in all estimations. Furthermore, the models' goodness of fit are very high as shown in Figure 3.2 which reports the observed against the predicted values from the four models estimated using Equation (3.2) with different technologies (numbers corresponding to numbers in Table 3.6 columns).

Our results are in line with the findings of Novan (2015) who studies the individual installation external benefits in terms of CO2 emissions. We find that important differences in the CO2 impact of losses arise when technologies that cover such losses are taken into account. Considering that the reason for those losses is in part the distant location between generation facilities and consumption, losses might represent an additional variable to include in what Novan (2015) calls the 'heterogeneous external benefits' related to each renewable technology.

Figure 3.2: Goodness of fit.



Source: own elaboration.

3.5 Concluding remarks and policy implications

Electricity systems have been transformed during the last years with the aim to improve energy security, efficiency and pollutionreduction, in particular Green House Gases due to the generation mix. Up to now, electricity losses have mostly been considered a matter of efficiency indicators for TSOs, DSOs, and regulators, or as an economical cost burden by consumers. However, in Chapter 3 we take a step further and contribute to this debate by empirically estimating the impact that electricity losses have on CO2 emissions.

Our results show that losses significantly explain CO2 emissions. Moreover, losses´ contribution to CO2 emissions is superior to the average emissions in the system. Finally, we find that the closing technology used to cover losses is particularly relevant to explain the previous difference in terms of emissions intensity. Indeed, when coal or combined cycle closes the market (alone), there is a significant and positive effect on CO2 emissions due to losses, while when special regime or hydropower are the closing technologies the impact is significant but negative, implying a lower effect from losses on the system emissions. From these results we conclude that the polluting impact of losses is important and that the closing technologies matters. These results should be taken into account in the future market design.

The policy implications derived from the previous results can be classified into two main groups: policies devoted to reduce the amount of losses and policies focused on the reduction of the CO2 emissions of the extra generation necessary to cover losses.

Regarding the amount of losses, the implementation of distributed generation near consumption goes in the right direction, with losses been proportional to the distance travelled by energy from generation to consumption points. Demand side management policies, which aim to reduce demand at peak periods through hourly prices of electricity, are another possibility to reduce losses by means of reducing grid congestion. Unfortunately, the impact of demand side management on losses is small as is found in Chapter 2. Since losses are proportional to demand, one alternative may be to implement energy efficiency measures in both the residential and the industrial segments.

Regarding the reduction of CO2 emissions in the extra generation necessary to cover losses, the penetration of RES-E is replacing the electricity generation from traditional pollutant plants. However, the wide-connection of RES-E plants is increasing the short-run variability of the whole generation mix, which has pros and cons depending on which (complementary) solution is applied to match the random generation capacity and consumption. The use of the traditional most pollutant technologies (e.g. coal or combined cycle) as back up plants is an extended used solution up to now, but has a severe impact on CO2 emissions particularly relevant when covering losses, as put in evidence by our results.

In line with Novan (2015) results we highlight that subsidies schemes for renewables should additionally consider the individual external benefits in terms of CO2 emissions. Up to now, generation incentives have mostly considered the quantity of RES-E installed capacity over their locations and individual offsets in CO2 emissions, but no considerations on the potential emissions savings which might emerge as a result of the lower pollutant effects from zero-emission technologies acting at the margin in some hours, and hence, coveringthe system losses[15].

[15] But what we study in Chapter 3 is the CO2 emitted due to losses showing that the CO2 content of losses is higher than the CO2 content of average production. Regulatory incentive for the future renewable capacity should take into account where the most pollutant plants and consumption are. Otherwise, new transmission grids could be necessary and the distance between new large renewable

In summary, electricity systems are very complex and there are several complementary policies to reduce the CO2 emissions effects of energy losses. The success of this path will depend on a deep understanding of its operation, features, and how to manage the equilibrium between them. Future research could extend the work on Chapter 3 in several directions to better understand the relation between losses and CO2 emissions, estimating the particular impact of demand-side management policies as well as other policies that could reduce emissions through the direct reduction of system losses. One of the closest assessments to the one presented in Chapter 3 could be the analysis of the impact of the RES-E installations location on CO2 emission through losses. Indeed, the RES-E location determines congestion as well as flows in the system. Depending on the type of RES-E this could reduce losses (like in the case of renewable distributed generation) or, on the contrary, it could increase losses (like in the case of big Hydroelectric generation). The feedback between those policies and losses as well as the consequence in terms of CO2 emissions should be further explored to enrich the discussion on policy´ implications drown from our findings.

3.6 Aknowledgements

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capacity and consumption could be higher, counteracting the non-pollutant effect

4 Analyzing flows and congestions: looking at locational patterns

4.1 Introduction

Europe has ambitious climate targets for 2030 aimed to reduce 40% greenhouse emissions through the improvement of energy efficiency and the connection of new renewable energy sources (RES). Recently, "Green Deal"[1] (2019) aims to go a step further and increase RES participation in the economy before 2030. Regardless the targets, a large amount of new RES should be connected, but this should always be conditioned to maximizing the social welfare. Certainly, fulfilling these conditions requires studying and deeply understanding the performance and efficiency of the electricity systems.

In the past and before the unbundling of the electricity systems, investments in generation and transmission were decided by vertically integrated companies: grids were planned and built to feed main consumption areas from specific large generation plants. However, the unbundling resulted in transmission as a regulated monopoly, and generation as a liberalized activity with its specific market incentives. This change of economic model required the adoption of a complex regulatory framework with the overall objective of maximizing the social welfare. The unbundling process was contemporary to investments in new large-scale gas fired and coal plants to satisfy the increasing electricity demand. At the same time, environmental awareness gained increasing importance and countries implemented the first policies aimed to promote RES. Accordingly, current generation mix is based on a diversity of technologies -nuclear, combined cycle, coal, combined heat and power (CHP), hydropower, solar and wind- with different locations, generation profiles, and annual hourly productions.

The design of an efficient regulatory framework to achieve the environmental targets and maximize social welfare, requires prior deep knowledge of the actual electricity flows and the performance of the grids. Indeed, electricity flows are result of the network topology, the location of the generation plants operating at each time and the sites where this energy is consumed. Flows might indirectly impact on consumer costs through the effect on congestions and electricity losses. The former are related to thermal limits constraints of grid elements and requires grid-investments funded by UoS charges or connection charges[2]. Indeed, the impact of RES on congestions is increasing and regional grid constraints might restrict their future connection (Van den Bergh et al., 2015). Electricity losses are consequence of a physical

[1] Available at: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf

[2] *Connection charges* are paid by RES promoters to cover grid-connecting costs.

phenomenon when flows travel through grids and represent an amount of wasted and non-consumed energy. In the Spanish regulatory framework, consumers borne them, which significantly impacts in the consumer surplus, as is found in Chapters 2 and 3.

The decarbonization of electricity system implies reconfiguring spatial patterns and changing the location of the key energy system components. Indeed, the lowest-cost wind power is often in fair remote locations to the demand sites, which implies costly grid infrastructure (Borenstein, 2012) and transmission planning might promote some regions over others depending on the strategy followed by transmission providers (Alagappan et al. (2011); Kemfert et al. (2016)). In this context, literature on low-carbon energy transition has paid little attention to questions of space (Bridge et al., 2013), even though higher level of RES impacts on congestions due to their intermittency and locations (Hitaj (2015); Joos and Staffell (2018)).

In Chapter 4, we analyze the actual flows and congestions in the 400kV transmission grid operated by the Spanish transmission system operator (TSO). We aim to increase the understanding on how the emplacement of the existing generation technologies and main consumption areas impact on flows, if congestions follow locational patterns and evaluate how the energy produced in each region contributes to the flows. Our results provide a deep knowledge of grids to better define regulatory framework related to the transmission planning and the location of future RES.

The traditional optimization models are commonly used the literature about the grid integration cost related to RES (Schaber et al. (2012); Hitaj (2015); Trepper et al. (2015); Van den Bergh et al. (2015)) and in the analysis of potential benefits from the implementation of nodal pricing (Leuthold et al. (2008); Weigt et al. (2010); Neuhoff et al. (2013)). However, these models do not consider past information and their outcomes might be affected by the selected optimization approach. Instead, we use a gravity model grounded on the Newton's law universal gravitation (Anderson, 1979), mostly applied to the analysis of trade between countries, and with little applications to the energy markets (Antweiler (2016); Costa-Campi et al. (2018); Batalla-Bejerano et al. (2019)). Gravity accounts both the source and destination conditions in the same model and provides insights on different outcomes since considers the actual information and does not optimize flows. Moreover, results are of high interest because include flows disaggregated between the two directions and it is possible to find the contribution of each technology to flows. We rely on a high-granularity dataset, which includes transmission lines with their corresponding flows, the hourly energy production by plants and geographical information about the location of main system components (nodes[3], generation plants and main cities) and the grid topology with the length of each line. To our knowledge, this is the first study that analyzes a country-scale electricity system using a gravity model to understand congestions and locational patterns.

This analysis is performed in Spain, which had the highest share of energy generated by RES-E[4] in 2016 (36.61%) among the five biggest economies in Europe. Moreover, past ambitious policies aimed to promote RES resulted in large capacity connected in regions not always close to main consumption. As consequence, important grid investments were necessary and transmission lines length increased 58% between 1990 and 2016[5]. The period analyzed is 2015-2017 because the new RES during this time was insignificant: 103 MW (+0.45%) in wind and 30 MW (+0.43%) in solar (REE, 2019a), which consequently provides a setting of high and stable RES penetration scenario.

Our primary findings can be summarized in three main groups. First, we find the location of generation does significantly impact on flows, and this impact differs by technology. Results point out that wind and imports are the less efficiently located with respect to the main consumption areas, while combined cycle is the most efficient. The highest efficiency for combined cycle might be explained by the raw material location -typically in seaports close to main cities- while wind plants are mostly in the countryside. Second, we find congestions among regions are not homogeneous and follow locational patterns. Particularly, regions in the North-West of Spain show congestions 400% upper than the average level. This confirms that areas with higher RES production have higher congestions and their future capacity to connect additional RES might be limited. On the opposite side, North-East and South regions have the lowest congestions. Third, we analyze how the energy produced in each region contributes to the flows as an indicator of the surplus/deficit of the actual generation and their use of the transmission grids. In line with previous

[3]A *node* or substation represents the physical location in the network, where transmission lines intersect between them. They can also connect with generation plants, industrial consumers or transformers to feed the distribution grids.

[4]From 2004 to 2016, the five biggest economies in Europe increased their RES-E share of energy production from 9.37 to 32.18% in Germany, 3.53 to 24.62% in the UK, 13.78 to 19.20% in France, 16.09 to 34.01% in Italy, and 18.98 to 36.61% in Spain. Source: Eurostat Database - *SHort Assessment of Renewable Energy Sources: SHARES 2016 results (% of electricity generation from all sources).* Available at https://ec.europa.eu/eurostat/web/energy/data/shares (last consulted on 08 September, 2018).

[5]Between 1990 and 2016, transmission grids increased from 27,680 km to 43,800km (+58%), while distribution from 272,787 km to 336,415 km (+23%) (Ministry of Industry, 2018); (REE, 2019b).

results, higher surpluses are related to regions with higher RES capacity. Finally, based on previous results is possible to sort regions in four groups considering actual congestions and the surplus/deficit of generation, to identify potential social welfare impacts related to the installation of more RES. Most efficient regions are Ctat.Valenciana, Extremadura, Catalunya and Andalucia, while the less efficient Galicia and Asturias. In summary, although seems that locating new wind capacity in the most resource-optimal regions -Galicia and Asturias- is a good choice, this might actually aggravate congestions and require new grids investments with the consequent social welfare impact. Therefore, it is essential to make deep Cost-Benefit-Analysis (CBA) and include all potential costs and benefits for both RES investors and consumers.

From all the previous results, we provide regulatory recommendations aimed to provide alternatives for the incorporation of locational incentives for future installed generation, namely RES. First, we discard splitting the unique bidding zone in Spain since congestions patters are very dependent on the location of the actual generation and might change according to the location of new RES. We also discard changing the current *shallow* connection charges by *deep* due to the challenges related to implementation of a transparent and non-discriminatory cost-allocation mechanism for the highest voltage grid. We suggest improving the transmission planning to align congestions and resource-optimal locations, which would also reduce RES connection time and the uncertainty related to the RES start-up times. However, this requires difficult agreements between the TSO, regional government and central government. We also consider including some locational incentives in future RES auctions. Finally and regardless the locational regulatory mechanism implemented, we conclude it is essential to provide high-quality energy and grid data easily available to all stakeholders since it enables businesses to invest wisely, facilitate the correct decisions and innovate practices. In line with results found in Chapter 4, this opened grid data should include locations with lower congestions and consequent lower likelihood to implement future generation curtailments, sites with available capacity without costly grid reinforcements, etc.

In Chapter 4, next section provides a literature review about the analysis of energy flows. Regulatory framework for the location of generation is explained in section 4.3, empirical approach and data used are described in section 5.3, and results are explained in section 4.5. Finally, regulatory recommendations and conclusions are included in section 4.6.

4.2 Literature

Within the grid-related costs' literature for RES, Joos and Staffell (2018) find a positive correlation between the level of RES connected to the grids and congestions that might require RES curtailment; Hitaj (2015) highlights the importance of the RES location and curtailment increases as higher are they concentrated; and others evaluate splitting the unique bidding zone[6] in Germany to provide locational incentives for RES and study their impact on RES curtailment and grid expansion (Trepper et al. (2015); Egerer et al. (2016)). At the end, RES integration costs are too large to be ignored in high-penetration assessments (Hirth et al., 2015). However, literature on low-carbon energy transition has paid little attention to questions of space although RES replace existing generation technologies and might require extra transmission capacity due to their intermittency and different location (Bridge et al., 2013).

In the analysis of the energy flows related to RES, optimization models -also known as optimal power flow models- are widely implemented and literature can be classified between: (i) the analysis of RES grid integration costs: Schaber et al. (2012) analyze the transmission grid extensions in higher shares of RES and considering backup generation capacity at European level and use a European power system model based on an optimization of the total system costs that include backup and storage capacity, operation, maintenance and fuel and carbon costs and the electricity transmission grid, Hitaj (2015) uses an optimal power flow model to study how different locations for RES and conventional power plants impacts on the CO2 emissions and congestions, but considering a theoretical network topology based on 30 nodes and not on an actual transmission grid, Trepper et al. (2015) use of three-stage modeling approach that optimizes flows and redispatch, and considers some flow constrains to estimate potential benefits from splitting bidding zones, and Van den Bergh et al. (2015) analyze the impact of RES on the grid congestions and redispatching in Belgium by using optimization models to minimize the redispatching costs; and (ii) studies of potential benefits from implementing nodal pricing[7] in Europe: Leuthold et al. (2008) study the social welfare impact related to its imple-

[6] *Bidding zones* are large geographical areas with structural congestions in their borders. Internal grid is considered as unrestricted and their corresponding methodologies and reports. and their congestion costs are shared between consumers and generators located into. For further details on the criteria for reviewing bidding zone configurations, see *Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management*.

[7] In *nodal pricing*, nodes represent the physical location in the network where transmission lines intersect between them. They have different -short-term- nodal prices based on the cost of energy, losses and congestions (Schweppe et al. (1988); Hogan (1992)).

mentation in the German electricity market, Weigt et al. (2010) study the impact of zonal, nodal and uniform price on the wind extensions in Germany, and Neuhoff et al. (2013) compare nodal pricing and implicit auctions of transmission capacity between nationally defined price zones; (iii) the evaluation of grid-planning approaches for small-RES, namely distributed generation (Tan et al., 2013).

However, optimization models have two main strong weakness. First, their outcomes might be extremely affected by some exogenously chosen issues: the pre-existing conditions, the assumptions and the optimization strategy (Qiu et al. (2009), Frank et al. (2012)). Indeed, methods include linear programming, quadratic programming, interior point methods, etc. (Momoh et al. (1999); Momoh et al. (1999)). Second, they do not consider actual flows in their results since aim to calculate electrical parameters as voltage, overloads and congestions, with limited potentials for the analysis in economic terms.

Instead, we apply a gravity model grounded on the Newton's law universal gravitation ((Anderson, 1979); Anderson (2011)) and mostly applied to the analysis of trade between countries (Dekle et al. (2008); Van Bergeijk and Brakman (2010); De Benedictis and Taglioni (2011); Baier et al. (2014)). Gravity have three great benefits compared to optimization models: (i) their results consider the actual flows, (ii) it is not necessary to exogenously choose a method, and (iii) they provide the disaggregated contribution of explicative variables in both flow directions. Indeed, the pre-existent conditions and the disaggregated contributions to bidirectional flows are the essence of the gravity approach. However, the literature of these models applied to electricity flows and energy markets is recently emergent: Antweiler (2016) study the electricity cross border trades between the United States and Canada; Costa-Campi et al. (2018) analyze the impact of the energy market integration on foreign direct investments; and Batalla-Bejerano et al. (2019) explore the electricity transborder flows between the European countries to estimate the effect of the economic, structural, cultural and institutional variables on them.

4.3 Regulatory framework

Regulatory framework have evolved. Before the unbundling of the electricity systems, investments in generation and transmission were decided by vertically integrated companies: grids were planned and built to feed main consumption areas from specific large generation plants. However, the European Directive 96/92/EC[8] requires an effective unbundling between the transmission and generation. Unbundling impacts on the grid functioning as transmission is subject to central management and control, and must be operated separately from other activities; while generation is opened to competition and must be independent from grid operators. Moreover, under the unbundling scheme, grid access is opened to promote transparency and facilitate negotiations between grid operators, customers oandr generation promoters. This process coincided in time with the connection of the first RES. Accordingly, actual generation mix is based on a great diversity of technologies - nuclear, combined cycle, coal, combined heat and power (CHP), hydropower, solar and wind.

In this section, we analyze the regulatory mechanisms that might -directly or indirectly- influence on the decision of locating generation plants, more specifically, RES. The relevance of locational decision relies on its potential impact on social welfare due to the requirement of subsequent grid investments or their impact on electricity losses as is found in Chapter 2 and in Bridge et al. (2013). Indeed, regulation mediates in these decisions by shaping incentives to agents. Next, we explain several issues related to the general regulatory framework that might settle locational incentives for new generation linked to the grid framework and to the RES support schemes.

4.3.1 Grid framework

Congestion pricing is a mechanism to charge public goods that might be congested and, in the context of electricity systems, is associated with the network use efficiency. In Europe, congestion pricing is based on zonal prices namely *bidding zones*, which consists on large geographical areas with a common wholesale price. All the redispatching costs due to congestion problems into each bidding zone are shared between consumers located within. Consequently, bidding zones do not provide specific locational incentives because they can be as large as a whole country (Pérez-Arriaga, 2014). On the contrary, nodal pricing mechanism is implemented in the US and other countries. This is calculated considering the scarcity or surplus of generation in each node. Consequently, nodal pricing provides specific locational incentives. Regarding RES, Hiroux and Saguan (2010); Van den Bergh et al. (2015) find that RES are behind the increase of congestions within bidding zones due to

[8] *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* and its corresponding national transposition *Ley 54/1997, de 27 de noviembre, del Sector Eléctrico*.

their geographical concentration and changes on the energy produced, which directly depends on the weather conditions. As we explain in the previous section, Leuthold et al. (2008); Weigt et al. (2010) and Neuhoff et al. (2013) evaluate the implementation of nodal pricing in Europe, and Trepper et al. (2015) and Egerer et al. (2016) study the potentials from splitting actual bidding zones to better provide locational incentives for RES.

Another regulatory element with potential to shape locational incentives are the connection charges, which are fees paid by RES promoters to cover their corresponding grid-connecting costs. As higher is the share of grid-connecting costs paid by RES promoters, higher is the incentive for them to identify resource-optimal sites considering the existing network capacity. Accordingly, there are three different choices: *deep cost* includes all connection costs and the upstream grid reinforcements; *shallow cost* includes only direct costs of the dedicated facilities and local reinforcements, but the rest of the upstream grid reinforcements are socialized; and *null cost* fully socializes all connection costs. Due to the grid characteristics, the design of connection charges is challenging to avoid gaming problems (Rious et al. (2008); Pérez-Arriaga (2014)). In Europe, *shallow cost* is the most implemented choice as is in Spain (ENTSO-E, 2018).

UoS charges are paid by consumers and generators when they are connected to the grid and cover the costs of operating, maintaining and building the network. Typically, they include a fix rate by the contracted power (MW) and/or another variable rate by the amount of consumption or generation (MWh) (Pérez-Arriaga, 2014). Most European countries -including Spain- implement *postage stamp usage fee*, which are the same rates for analogous generators and consumers[9] regardless their location in the country. However, the UK, Ireland, Norway and Sweden use regional UoS charges instead of *postage stamp usage fee* to reflect geographical deficits or surplus of generation, grid losses, etc. (ENTSO-E, 2018). While RES have no locational incentives under the *postage stamp usage fee*, regional UoS charges might lead to different incentives shaping the processes for specific RES locations.

Transmission planning might also provide some locational incentives for RES depending on the strategy followed. In the *anticipatory planning*, transmission planning anticipates future RES connections and builds the corresponding infrastructure, while in the *reactive planning*, construction is made after RES promoter requests for their connection. Alagappan et al. (2011) observes that *anticipatory*

[9]Consumers pay different depending on the voltage of their connection point to the grid, their power capacity, etc. However, all generators pay the same UoS charge.

planning improves RES energy development by the lower uncertainty to RES promoters who can better identify when, where and how to connect their plant. However, Spanish transmission planning is based in the *reactive planning*. Moreover, Schaber et al. (2012) study the potential transmission grid extensions considering several RES scenarios and conclude early transmission planning is crucial for the successful RES integration in Europe due to the relevant grid investments they find. Finally, Kemfert et al. (2016) explore this process in Germany and conclude that network planning approaches should be complemented by alternative congestion managements, such as the redispatch of generation.

4.3.2 RES support schemes

Since the late 1990s, ambitious environmental targets required important incentives and subsidies to RES since their technological development was still in a precommercial stage. Indeed, three *market-pull* policies were mostly implemented: *price*, *quantity* and *voluntary* instruments. A *Price* instrument provides economic incentives for the energy generated and can be either investment subsidies or an extra payments for the production. Thus, producers cash a fixed-price with a subsidy to guarantee a minimum price in Feed-in-Tariff (FIT), while producers cash the electricity market price plus a fixed premium in Feed-in-Premium (FIP). In a *quantity* instrument or green certificate, regulators settle a target quota for all the agents who have to comply by Tradable Green Certificates[10]. Finally, a *voluntary* instrument includes the possibility to sell green electricity for suppliers (Pérez-Arriaga, 2014).

Scientific literature agree that FIT was very effective at stimulating the fast development of RES in many countries (Couture and Gagnon (2010) and Hiroux and Saguan (2010)). However, FIT has some drawbacks with the most relevant related to locational incentives for new RES as project developers do not compete in price but for good sites. In consequence, some technologies - specially wind - are kept aside from day-to-day operation of electricity markets, etc. Moreover, the absence of direct locational constraints in FIT resulted in the selection of the highest-performing sites, this is concentrating RES in resource-rich locations (IRENA and CEM (2015); Newbery et al. (2018)).

Recently, auctions[11] have emerged as an efficient competitive alternative for set-

[10] *Tradable Green Certificates* are also known as *Renewable Energy Certificates*, *Green tags*, *Renewable Energy Credits* or *Renewable Electricity Certificates*.

[11] *Auctions* are also known as public tendering, demand auctions, reverse auctions or procurement auctions.

ting the remuneration of new RES(Del Río, 2017). They are competitive bidding procurements where the product can either be capacity in MW or energy in MWh (IRENA and CEM, 2015). As consequence of the strong price competition, promoters aim to seek resource-optimal sites, which results in higher concentration of RES in some locations with its corresponding social acceptability affection (Del Río and Linares, 2014). Locational incentives might be implemented including location-specific demand bands, project location components in the winner selection criteria, or location requirements for the auction participating projects (IRENA and CEM, 2015).

4.4 Empirical approach & Data

In this section, we explain the empirical approach followed to study how the location of the different technologies impacts on flows, evaluate if congestions follow locational patterns and explore how the energy generated in each region explains flows. Then we present the dataset used.

4.4.1 Gravity Model

Gravity models are based on the Newton's law universal gravitation (Anderson, 1979), according to which a mass of goods -or other factors of productions supplied- at a source i is attracted to a mass of demand for goods at destination j. Moreover, flows depend on the distance between source i and destination j (Anderson, 2011). As we have explained in the literature, gravity models tare commonly used in the analysis of international trade, but have scarcely been applied in the analysis of energy markets. Some exceptions are Antweiler (2016); Costa-Campi et al. (2018) Batalla-Bejerano et al. (2019)).

Our endogenous variable is the energy flow ($F_t^{i,j}$) at each time t in each transmission line composed by pairs of nodes and identified as i, j (see Figure 5.1). Based in what is more adequate in each case, we use two empirical approaches to answer our research questions. First, we analyze the contribution of each generation technology to flows, which allow us to identify how efficient is the location of each technology regarding the consumption. Moreover, we identify actual grid bottlenecks by the locational patterns related to congestions. Second, we study the contribution of the energy generated in each region to the flows, which inform us about the regional surplus and deficits of the energy generated.

Figure 4.1: Network (red lines) and nodes (black dots) considered in Chapter 4.

Source: Own elaboration.

In the first empirical approach aiming at identifying how the location of each technology impact on flows, we estimate the determinants of $F_t^{i,j}$ w.r.t. the energy produced by each technology (Equation 5.3).

$$logF_t^{i,j} = \hat{\beta}_0 + (\hat{\beta}_i logG_t^i) + (\hat{\beta}_j logG_t^j) + \hat{\beta_{17}} logDist^{i,j} + \hat{\beta_{18}} C_i^d + \hat{\beta_{19}} C_j^d + \hat{\beta_{20}} C_i^c + \\ + \hat{\beta_{21}} C_j^c + \hat{\beta_{22}} logD^i + \hat{\beta_{23}} logD^j + \sum_{ri=1}^{14} \hat{\theta_{ri}} NUTS2_i + \sum_{rj=1}^{14} \hat{\theta_{rj}} NUTS2_j + \\ + \sum_{d=1}^{6} \hat{\delta_d} D_{dt} + \sum_{m=1}^{11} \hat{\alpha_m} M_{mt} + \sum_{y=1}^{2} \hat{\gamma_y} Y_{yt} + \hat{\rho} PEAK_t + e_{i,j,t} \tag{4.1}$$

where G_t^i and G_t^j indicate the national energy produced by each technology and imports at i and j nodes, respectively[12]. $\hat{\theta_{ri}}$ and $\hat{\theta_{rj}}$ represent a dummy variable

[12] G_t^i and G_t^j represents the following:

$$\hat{\beta}_i logG_t^i = \left[\hat{\beta}_1 logN_t^i + \hat{\beta}_2 logCC_t^i + \hat{\beta}_3 logCO_t^i + \hat{\beta}_4 logH_t^i + \hat{\beta}_5 logW_t^i + \hat{\beta}_6 logSOL_t^i + \hat{\beta}_7 logI_t^i + \hat{\beta}_8 logCHP_t^i\right]$$

$$\hat{\beta}_j logG_t^j = \left[\hat{\beta}_9 logN_t^j + \hat{\beta_{10}} logCC_t^j + \hat{\beta_{11}} logCO_t^j + \hat{\beta_{12}} logH_t^j + \hat{\beta_{13}} logW_t^j + \hat{\beta_{14}} logSOL_t^j + \hat{\beta_{15}} logI_t^j + \hat{\beta_{16}} logCHP_t^j\right]$$

where each right side variable corresponds to the sum of the energy generated by each technology (nuclear, combined cycle, coal, hydropower[13], wind, solar, imports and combined heat and power) at each i and j node at the t time.

for the r region where the corresponding i and j node belong. Moreover, $Dist^{i,j}$ is the transmission line length in kilometres- between i, j; D^i and D^j are the shortest distance of nodes to a main city in km, respectively. They account for the relative distance from each node to the main consumption areas. Seasonality is controlled with a some dummy variables[14]: $PEAK_t$ for the peak time; D_{dt} for the weekday; M_{mt} and Y_{yt} for the year. The inclusion of seasonality allows us to consider time specificities in our estimations, i.e. the network operation, external facts, etc.

Some additional variables are also included to control for the relative position of each node w.r.t. the rest, avoiding a potential bias problem (De Benedictis and Tajoli, 2011). For that purpose, we use the *degree of centrality* (C_n^d) that considers the number of transmission lines connected to n (Equation 4.2), and the *closeness centrality* (C_n^c) that considers the closeness of n w.r.t. the rest (Equation 4.3):

$$C_n^d = \frac{d}{N-1} \tag{4.2}$$

$$C_n^c = \frac{N-1}{\sum\limits_{i \neq j}^{N-1} \delta_{ij}} \tag{4.3}$$

where d is the number of transmission lines connected to n, N the total number of n $(N = 98)$ and δ_{ij} its geodesic distance, i.e. the shortest path through lines between each two pair of n. Geographical data is calculated by a geographical information software (GIS), while the rest comes from OMIE (2019), REE (2019b) and Ministry of Industry (2018).

Regarding the estimation methodology and due to the presence of zeros in the endogenous variable, we cannot use OLS approach because these observations are dropped when logs are applied. Instead, we use the Poisson Pseudo Maximum Likelihood (PPML) estimator for Equation 5.3 following Silva and Tenreyro (2006), which also solves heteroskedasticity problems with the error terms. The final esti-

[14] D_{dt} for the day of the week; M_{mt} and Y_{yt} capture the long-term seasonality. D_{dt} comprise six dummy variables: one for each day from Tuesday (d=1) to Sunday (d=6), Monday is the base day of the week. Following the same approach, M_{mt} comprise eleven dummy variables: one for each month from February (m=1) to December (m=11), January being the base month. Finally, Y_{yt} comprise two dummy variables, one for 2016 (y=1) and another for 2017 (y=2). In this case, 2015 is the base year.

mated equation of this first empirical approach is represented in Equation 4.4:

$$F_t^{i,j} = exp \begin{bmatrix} \hat{\beta_0} + (\hat{\beta_i} logG_t^i) + (\hat{\beta_j} logG_t^j) + \hat{\beta_{17}} logDist^{i,j} + \\ \hat{\beta_{18}} C_i^d + \hat{\beta_{19}} C_j^d + \hat{\beta_{20}} C_i^c + \hat{\beta_{21}} C_j^c + \\ \hat{\beta_{22}} logD^i + \hat{\beta_{23}} logD^j + \\ + \sum_{ri=1}^{14} \hat{\theta_{ri}} NUTS2_i + \sum_{rj=1}^{14} \hat{\theta_{rj}} NUTS2_j + \\ \sum_{d=1}^{6} \hat{\delta_d} D_{dt} + \sum_{m=1}^{11} \hat{\alpha_m} M_{mt} + \sum_{y=1}^{2} \hat{\gamma_y} Y_{yt} + \\ + \hat{\rho} PEAK_t \end{bmatrix} + e_{i,j,t} \tag{4.4}$$

In the second empirical approach aiming at identifying how the energy produced in each region contributes to flows, we estimate the determinants of $F_t^{i,j}$ w.r.t. the energy generated by each technology located in each r region (Equation 5.1).

$$\begin{aligned} logF_t^{i,j} = \hat{\beta}_0 + \sum_{r=1}^{14} \hat{\beta}_i^r logGr_t^i + \sum_{r=1}^{14} \hat{\beta}_j^r logGr_t^j + \hat{\beta}_1 logDist^{i,j} + \hat{\beta}_2 C_i^d + \hat{\beta}_3 C_j^d + \\ + \hat{\beta}_4 C_i^c + \hat{\beta}_5 C_j^c + \hat{\beta}_6 logD^i + \hat{\beta}_7 logD^j + \\ + \sum_{d=1}^{6} \hat{\delta_d} D_{dt} + \sum_{m=1}^{11} \hat{\alpha_m} M_{mt} + \sum_{y=1}^{2} \hat{\gamma_y} Y_{yt} + \hat{\rho} PEAK_t + e_{i,j,t} \end{aligned} \tag{4.5}$$

where Gr_t^i and Gr_t^j indicate the energy produced in i and j sited in region r, respectively and the rest of variables are the same than Equation 5.3. In this case, $\hat{\beta}_i^r$ and $\hat{\beta}_j^r$ explain how the energy generated in nodes located in r contributes to flows. The PPML estimator for Equation 5.1 is represented in Equation 4.6:

$$F_t^{i,j} = exp \begin{bmatrix} \hat{\beta}_0 + \sum_{r=1}^{16} \hat{\beta}_i^r logGr_t^i + \sum_{r=1}^{16} \hat{\beta}_j^r logGr_t^j + \\ + \hat{\beta}_1 logDist^{i,j} + \hat{\beta}_2 C_i^d + \hat{\beta}_3 C_j^d + \hat{\beta}_4 C_i^c + \hat{\beta}_5 C_j^c + \\ + \hat{\beta}_6 logD^i + \hat{\beta}_7 logD^j + \sum_{d=1}^{6} \hat{\delta_d} D_{dt} + \\ + \sum_{m=1}^{11} \hat{\alpha_m} M_{mt} + \sum_{y=1}^{2} \hat{\gamma_y} Y_{yt} + \hat{\rho} PEAK_t \end{bmatrix} + e_{i,j,t} \tag{4.6}$$

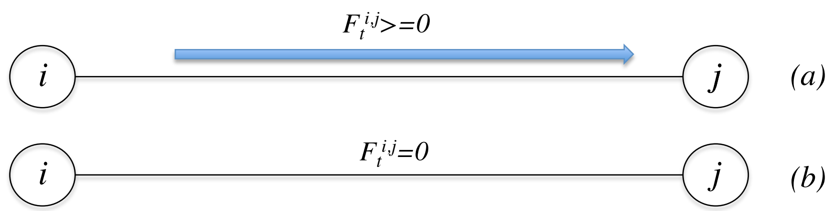
Finally, any concern on endogeneity problems from explicative variables in Equations 5.3 and 5.1 should be discarded since past decisions of locating generation were exogeneous to flows. Plants were sited close to their primary source of energy or raw material: coal plants near to mines, gas-fuel plants close to regasification plants in seaports, hydropower plants in water rivers, wind plants in areas with the most optimal wind-resource, etc. Moreover, there were not clear locational incentives in the regulatory framework considering the existing flows.

4.4.2 Data description

In this section we present a description of the three-years (2015-2017) dataset used to evaluate how the location of the different technologies impacts on flows, if congestions follow locational patterns and how the energy regional generation explains flows.

Endogenous variable is the energy flow ($F_t^{i,j}$) at each time t in each pairs of nodes and identified as i, j[15]. As means to consider both flow directions, each pair of nodes is included twice in our dataset, with $F_t^{i,j} \geq 0$ when the flow comes from i to j and $F_t^{i,j} = 0$ otherwise (see Figure 5.2).

Figure 4.2: Graphic representation for all pairs of nodes.



Note: i node in Figure 5.2.a (above) corresponds to j in Figure 5.2.b (below), and vice versa.
Source: own elaboration.

We use an hourly dataset from 2015 to 2017 with almost 20 million observations and our geographical area is Continental Spain. The hourly dataset is transformed into a twice-daily frequency - peak and off-peak hours - calculating the average values during each daily period. Moreover, we include a dummy variable ($PEAK_t$) that takes 1 during peak hours[16] and 0 otherwise. This energy flow definition has been previously used in Chapter 2 and in the literature (Albadi and El-Saadany (2008); Chevalier et al. (2003)).

We use two main groups of explicative variables on the supply side of flows, one for each empirical approach. In the first empirical approach, we use N_t^i, N_t^j, CC_t^i, CC_t^j, CO_t^i, CO_t^j, H_t^i, H_t^j, W_t^i, W_t^j, SOL_t^i, SOL_t^j, I_t^i, I_t^j, CHP_t^i and CHP_t^j,

[15] $F_t^{i,j}$ is calculated using Marginal Loss Factors in Appendix I. Flows are not represented in any specific energy unit (MWh, GWh...) because coefficients in the estimated equation are in logs (the use of units its irrelevant). We estimate elasticities: the proportional change of $F_t^{i,j}$ in response to a change in another.

[16] This classification is used for those low voltage consumers in Spain with two period tariffs (2.0DHA and 2.1DHA), with the peak period covering from 12 p.m. to 10 p.m.

which is the energy generated in i and j by nuclear, combined cycle, coal, hydropower (also includes Pumping Generation), wind, solar, imports and combined heat and power, respectively (see circles in Figure 4.3). This energy data[17] comes from OMIE (2019), REE (2019a) and Ministry of Industry (2018). We include all the electricity production regardless the voltage grid where plants are connected.

In the second empirical approach, we use Gr_t^i and Gr_t^j, which is the energy generated at each i and j located in each r region[18]:

$$Gr_t^i = N_t^i + CC_t^i + CO_t^i + H_t^i + W_t^i + SOL_t^i + I_t^i + CHP_t^i \quad for \quad \forall i \in r \quad (4.7)$$

$$Gr_t^j = N_t^j + CC_t^j + CO_t^j + H_t^j + W_t^j + SOL_t^j + I_t^j + CHP_t^j \quad for \quad \forall j \in r \quad (4.8)$$

On the demand side, we include the variable D^n defined as the shortest distance - in kmts - from each n node to the closest most populated city in Spain[19] (see Figure 4.3). Finally, Table 5.4 shows the summary statistics of all the variables.

4.5 Results

In this section we show results from our estimations. First, we perform an analysis by technologies and estimate their contribution to flows. This allow us to identify how efficient is the location of each technology regarding the consumption and we also identify the locational patterns related to congestions, which informs us about the actual grid bottlenecks that might require future network investments. Second, we perform a regional analysis and study the contribution of the energy produced in each region to the flows. This allow us to evaluate how would evolve flows if more generation was connected in each region. By the combination of all these results, we classify regions in terms of social welfare impact related to the connection of

[17] We use the *final hourly scheduled production*, also known as *Producción horaria final* in Spain, which is the scheduled electricity production for each *market unit* (generator) after all market settlements and the operational adjustments (technical constraints) proposed by the SO to guarantee their operational security rules. We assign the production considering the production from plants connected to or sited much closer. The available data for wind, solar and some hydropower is not fully disaggregated by plants and we assign them to n considering the installed capacity in each region and the *regional efficiency coefficient* for each technology, which is calculated as [MWh produced]/[MW installed]. This captures the different performance for every technology in each region, which is specially relevant for RES.

[18] r takes the following values: 1 for Andalucia, 2 for Aragon, 3 for Asturias, 4 for Cantabria, 5 for Castilla y Leon, 6 for Castilla y La Mancha, 7 for Catalunya, 8 for Valencia, 9 for Extremadura, 10 for Galicia, 11 for Madrid, 12 for Murcia, 13 for Navarra and Rioja, and 14 for Pais Vasco.

[19] Madrid, Barcelona, Valencia, Sevilla, Zaragoza, Malaga, Murcia, Bilbao, Alicante, Cordoba, Valladolid, Vigo, Gijon, Hospitalet de Llobregat, Vitoria and A-Coruña. All them represent 25% of the population in Spain.

Figure 4.3: Main generation plants (circles) and cities (rose areas) considered.

Note: Circle colors indicate the technology: red for nuclear, yellow combined cycle, brown coal, clear blue hydropower and dark blue pumping.
Source: Own elaboration.

new RES.

4.5.1 Energy flow analysis by technologies

Hereby, we present results of estimations from Equation 4.4, where all variables are in logs, and therefore, estimates ($\hat{\beta}_i$, $\hat{\beta}_j$) are the elasticities of flows w.r.t. the energy produced by each technology[20]. Before analyzing elasticities, it is important having in mind several issues:

- Our results include two coefficients for each technology: $\hat{\beta}_i$ and $\hat{\beta}_j$ for the impact on the energy generated in i and j, respectively. $\hat{\beta}_i$ refers to the source node and $\hat{\beta}_j$ to the destination considering flows (see Figure 5.2).

- We estimate how flows evolve when G_t^i and G_t^j change, and $\hat{\beta}_i$ and $\hat{\beta}_j$ are

[20] We estimate how flows $(F_t^{i,j})$ evolve when generation (G_t^i, G_t^j) change (Equations 4.9 and 4.10):

$$\hat{\beta}_i = \frac{\partial F_t^{i,j}/F_t^{i,j}}{\partial G_t^i/G_t^i} = \frac{[\%]}{[\%]} \tag{4.9}$$

$$\hat{\beta}_j = \frac{\partial F_t^{i,j}/F_t^{i,j}}{\partial G_t^j/G_t^j} = \frac{[\%]}{[\%]} \tag{4.10}$$

Table 4.1: Summary Statistics.

	N	Mean	Std.Dev.	Min.	Max.
$F_t^{i,j}$	678,900	0.0062388	0.0109806	0	0.1817
N_t^i, N_t^j	20,818,140	64.59839	305.0923	0	2,017.1
CC_t^i, CC_t^j	20,818,140	30.65951	115.3714	0	2,178.95
CO_t^i, CO_t^j	20,818,140	50.17001	184.4638	0	1,378.5
H_t^i, H_t^j	20,818,140	24.82642	46.75551	0	734.7238
W_t^i, W_t^j	20,818,140	49.20318	87.72776	0	1,248.627
SOL_t^i, SOL_t^j	20,818,140	15.82529	35.69988	0	258.7267
I_t^i, I_t^j	20,818,140	27.37232	119.6494	0	1,667.933
CHP_t^i, CHP_t^j	20,818,140	36.26291	36.26901	0	191.2189
$G1_t^i, G1_t^j$	20,818,140	42.63293	161.6872	0	2,430.652
$G2_t^i, G2_t^j$	20,818,140	15.67784	76.97765	0	1,085.627
$G3_t^i, G3_t^j$	20,818,140	17.04793	120.0196	0	2,141.392
$G6_t^i, G6_t^j$	20,818,140	2.342647	17.17407	0	243.8766
$G7_t^i, G7_t^j$	20,818,140	30.23989	102.9536	0	1,386.241
$G8_t^i, G8_t^j$	20,818,140	25.58127	122.6711	0	1,227.28
$G9_t^i, G9_t^j$	20,818,140	51.53446	263.025	0	2,374.776
$G10_t^i, G10_t^j$	20,818,140	20.84302	120.2706	0	1,834.653
$G11_t^i, G11_t^j$	20,818,140	27.34457	197.3159	0	2,146.636
$G12_t^i, G12_t^j$	20,818,140	34.86667	185.2269	0	2,599.453
$G13_t^i, G13_t^j$	20,818,140	2.092436	10.15576	0	180.0169
$G14_t^i, G14_t^j$	20,818,140	5.656881	48.5767	0	2,284.322
$G15_t^i, G15_t^j$	20,818,140	9.873682	100.7776	0	2,105.36
$G16_t^i, G16_t^j$	20,818,140	13.18393	81.9428	0	1,718.192
D^i, D^j	20,818,140	81.3507	57.61394	8.251244	276.4956
C_i^d, C_j^d	20,818,140	.032085	0.0145708	0.0103093	0.0824742
C_i^c, C_j^c	20,818,140	.0018513	0.0003356	0.0012386	0.0025592
$Dist^{i,j}$	20,818,140	551.8508	259.8601	7	1,342

unique at national-level by each technology. Therefore, they represent country-scale average impacts on flows.

- Grid has a network configuration and there are multiple impacts. Therefore, flows are not exclusively explained by the energy injected in the i and j, but also by the rest of the network. These effects are captured by the additional control variables.

Table 5.8 shows results for a set of estimations with different centrality controls, seasonality and fixed effects (FE). Column (1) represents results without centrality controls, seasonality and FE; column (2) includes centrality controls; column (3) adds seasonality; and finally, column (4) includes centrality controls, seasonality and FE. Our analysis focus in results from column (4), having the richest set of controls.

Regarding coefficients for generation, we perform three analysis. In the first analysis, we evalate $\hat{\beta}_i$ and $\hat{\beta}_j$ to identify the impact of each technology on flows. Coefficients in the source associated to nuclear, combined cycle and coal are 3.31, 4.90, 3.78. This means +1% of extra energy generated in the source node increases -in average- +0.0331%, +0.0490% and +0.0378% flows. Hydropower (includes pumping), wind and solar coefficients are +2.90, +4.45 and +14.0, respectively. The high coefficient for solar seems to be capturing the production of large thermosolar plants connected to transmission. It is important to highlight the negative coefficient for CHP in the source node, -20.0, which means that when CHP production increases 1%, flows decrease 0.20%. Indeed, most CHP plants in Spain are installed in large industrial plants and are a type of self-consumption, which means directly decreases flows in the grids.

In the second analysis, we calculate the *Distance Effect*[21] for each g technology (DE_g) to evaluate how efficient and resource-optimal is the location of each technology w.r.t. the main consumption areas. DE_g considers the difference between increasing the production in i or j, i.e. G_t^i or G_t^j. In technologies sited far from main consumption areas -large cities- we are expected to find $\hat{\beta}_i >> \hat{\beta}_j$, which means there is a relevant difference between increasing production in i compared to j. Table 4.3 shows the results, where the highest DE_g, 3.48 and 3.37, corresponds to wind and imports, respectively. This implies their locations are the less efficiently sited compared to others. In the opposite, combined cycle coefficient is very low (1.10) because these plants are -in average- much more efficiently sited due to their closeness to important seaports since they need gas liquefying plants. Finally, CHP coefficient is the lowest (-3.58) because these plants are self-consumption installations, this is directly connected in the consumption points ($\hat{\beta}_i < \hat{\beta}_j$).

In the third analysis, we study the average flow congestions in each NUTS2 region, which allows us to identify how congested are in average the transmission lines by regions. This analysis is particularly relevant given the potential implications on congestions. Indeed, a higher congestions imply: (i) a higher likelihood to apply curtailment (technical constraints) on generation due to congestions, (ii) existing grid should be reinforced; (iii) new grid should be build (Ministry of Industry

[21] *Distance Effect* (DE_g) for each technology g is calculated as $DE_g = (\hat{\beta}_i - \hat{\beta}_j)/ \mid \hat{\beta}_j \mid$ in pu. We divide each one by $\hat{\beta}_j$ to make all technologies comparable between them.

Table 4.2: Generation impacts on flows.

	(1) $F_t^{i,j}$	(2) $F_t^{i,j}$	(3) $F_t^{i,j}$	(4) $F_t^{i,j}$
PEAK	-0.0629***	-0.0844***	-0.104***	0.164***
	(0.00447)	(0.00445)	(0.00457)	(0.00677)
N_t^i (log)	0.0259***	0.0238***	0.0240***	0.0331***
	(0.000305)	(0.000310)	(0.000310)	(0.000405)
CC_t^i (log)	0.0364***	0.0435***	0.0437***	0.0490***
	(0.000414)	(0.000436)	(0.000437)	(0.000493)
CO_t^i (log)	0.0313***	0.0405***	0.0414***	0.0378***
	(0.000292)	(0.000302)	(0.000306)	(0.000371)
H_t^i (log)	0.0304***	0.0445***	0.0432***	0.0290***
	(0.000915)	(0.000867)	(0.000863)	(0.00110)
W_t^i (log)	0.0266***	0.0241***	0.0245***	0.0445***
	(0.000428)	(0.000407)	(0.000407)	(0.000807)
SOL_t^i (log)	0.0624***	0.0525***	0.0578***	0.140***
	(0.00133)	(0.00143)	(0.00146)	(0.00299)
I_t^i (log)	0.00858***	0.0211***	0.0216***	0.0118***
	(0.000469)	(0.000504)	(0.000503)	(0.000497)
CHP_t^i (log)	-0.111***	-0.133***	-0.137***	-0.200***
	(0.00149)	(0.00159)	(0.00162)	(0.00278)
N_t^j (log)	-0.0454***	-0.0422***	-0.0421***	-0.0606***
	(0.000615)	(0.000606)	(0.000605)	(0.000657)
CC_t^j (log)	0.0159***	0.0212***	0.0219***	0.0233***
	(0.000358)	(0.000392)	(0.000394)	(0.000443)
CO_t^j (log)	-0.0551***	-0.0524***	-0.0511***	-0.0608***
	(0.000625)	(0.000635)	(0.000637)	(0.000540)
H_t^j (log)	-0.0420***	-0.0403***	-0.0406***	0.0102***
	(0.000583)	(0.000567)	(0.000570)	(0.00110)
W_t^j (log)	-0.00416***	-0.00704***	-0.00698***	-0.0180***
	(0.000463)	(0.000423)	(0.000423)	(0.000619)
SOL_t^j (log)	-0.0111***	0.0107***	0.0158***	-0.212***
	(0.00125)	(0.00131)	(0.00134)	(0.00286)
I_t^j (log)	-0.0110***	-0.0138***	-0.0132***	0.00269***
	(0.000572)	(0.000635)	(0.000637)	(0.000653)
CHP_t^j (log)	-0.0567***	-0.0693***	-0.0734***	0.0776***
	(0.00166)	(0.00177)	(0.00180)	(0.00288)
$Dist^{i,j}(log)$	0.338***	0.374***	0.371***	0.383***
	(0.00362)	(0.00344)	(0.00345)	(0.00286)
Constant	-5.577***	1.055***	1.312***	0.900***
	(0.0347)	(0.0959)	(0.0972)	(0.293)
Observations	678,900	678,900	678,900	678,900
R^2	0.180	0.211	0.213	0.329
Centrality:				
Degree		Y	Y	Y
Closeness		Y	Y	Y
Seasonality:				
Year			Y	Y
Month			Y	Y
Day of week			Y	Y
Fixed effects:				
NUTS2:				Y

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 4.3: *Distance effects* (DE_g) for each technology.

g	$\hat{\beta}_i$	$\hat{\beta}_j$	DE_g
W_t	+0.044***	-0.018***	3.48
I_t	+0.012***	+0.003***	3.37
H_t	+0.029***	0.010***	1.83
SOL_t	+0.140***	-0.212***	1.66
CO_t	+0.038***	-0.061***	1.62
N_t	+0.033***	-0.061***	1.55
CC_t	+0.049***	+0.023***	1.10
CHP_t	-0.200***	0.078***	-3.58

Note: Technologies g sorted by DE_g.

and REE, 2015); or (iv) electricity losses are much higher with their corresponding economic costs for consumers and environmental impact on CO2 emissions (see Chapters 2 and 3). All them have relevant effects on social welfare. For this analysis we use $\hat{\theta_{ri}}$, the regional FE dummy variables from column (4) in Table 5.8 (listed in Table 5.11, Appendix I), with the corresponding average congestions $(Congest_r)$ for each r region (see Table 4.4[22] and Figure 4.4). It is interesting to highlight how coefficients corresponding to the Northwest areas have higher congestions $(Congest_r)$, precisely where most of the wind capacity is installed and more than a half of the annual wind production is generated (REE, 2019a).

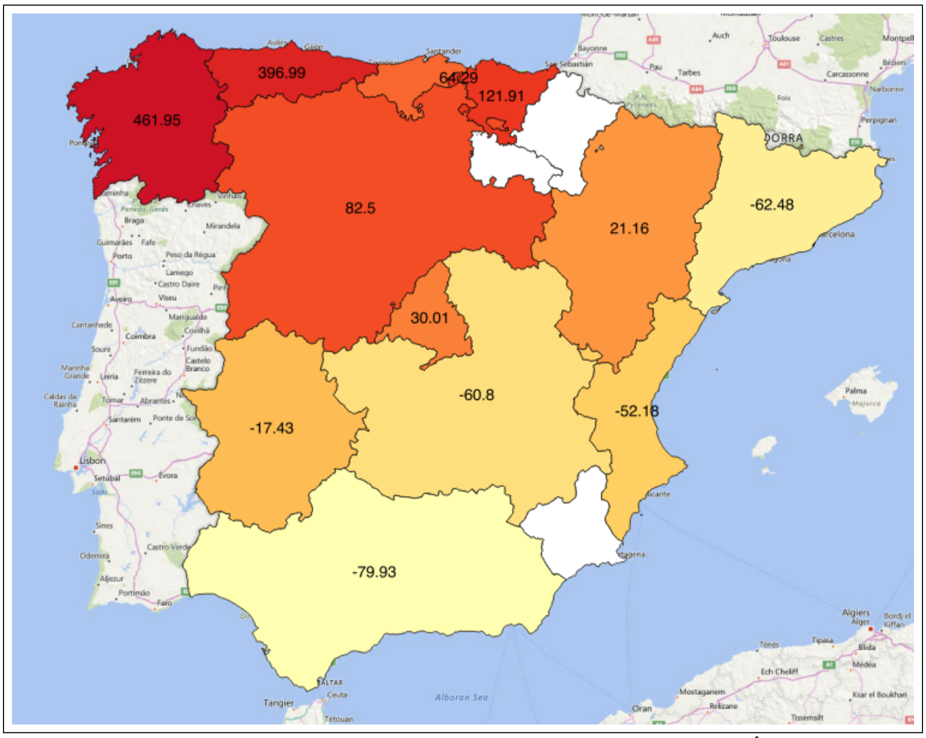
Table 4.4: Average flow congestions.

r=NUTS2	$\hat{\theta}_{ri}$	$Congest_r$
Galicia	1.726	+461.95%
Asturias	1.603	+396.99%
Pais Vasco	0.797	+121.91%
Castilla-Leon	0.602	+82.50%
Cantabria	0.496	+64.29%
Madrid	0.262	+30.01%
Aragon	0.192	+21.16%
Extremadura	-0.191	-17.43%
Ctat Valenciana	-0.738	-52.18%
Castilla-la-Mancha	-0.936	-60.80%
Catalunya	-0.980	-62.48%
Andalucia	-1.606	-79.93%

Note: $Congest_r$ calculated by $(exp(\hat{\theta}_{ri}) - 1) * 100$ [%].

[22] Coefficients for Navarra/Rioja and Murcia are not significant.

Figure 4.4: $Congest_r$ (in %).



Source: Own elaboration using $Congest_r$ from Table 4.4. Non-significant $\hat{\theta}_{ri}$ are represented in white color.

Finally, we validate the estimates from the first empirical approach by the analysis of the coefficient related to $PEAK_t$[23]: during peak periods, the share of energy that travels through transmission lines is 17.8% higher than offpeak, which is consistent.

4.5.2 Energy flow analysis by regions

Hereby, we present results of estimations from Equation 4.6, where all variables are in logs and therefore, estimates ($\hat{\beta}_i^r$, $\hat{\beta}_j^r$) are the elasticities of flows w.r.t. the energy produced in r region[24]. Table 4.5 shows results for a set of estimations with different centrality controls, seasonality and FE. Our results focus in results from column (4), having the richest set of controls.

[23]Calculated by $(exp(\hat{\rho})-1)*100$ [%].

[24]We estimate how flows ($F_t^{i,j}$) evolve when regional generation (Gr_t^i, Gr_t^j) change (Equations 4.11 and 4.12):

$$\hat{\beta}_i^r = \frac{\partial F_t^{i,j}/F_t^{i,j}}{\partial Gr_t^i/Gr_t^i} = \frac{[\%]}{[\%]} \tag{4.11}$$

$$\hat{\beta}_j^r = \frac{\partial F_t^{i,j}/F_t^{i,j}}{\partial Gr_t^j/Gr_t^j} = \frac{[\%]}{[\%]} \tag{4.12}$$

Table 4.5: NUTS2 Generation impacts on flows.

	(1)	(2)	(3)	(4)
	$F_t^{i,j}$	$F_t^{i,j}$	$F_t^{i,j}$	$F_t^{i,j}$
PEAK	0.0119***	0.00929**	0.00952**	0.0258***
	(0.00374)	(0.00372)	(0.00372)	(0.00317)
$G1^i$ (log) (Andalucia)	0.188***	0.182***	0.182***	0.271***
	(0.00195)	(0.00202)	(0.00203)	(0.0105)
$G2^i$ (log) (Aragon)	0.298***	0.284***	0.284***	0.100***
	(0.00207)	(0.00207)	(0.00207)	(0.0121)
$G3^i$ (log) (Asturias)	0.309***	0.301***	0.301***	1.038***
	(0.00193)	(0.00196)	(0.00196)	(0.0295)
$G4^i$ (log) (Cantabria)	0.270***	0.259***	0.259***	-0.124***
	(0.00244)	(0.00251)	(0.00251)	(0.0429)
$G5^i$ (log) (Castilla-Leon)	0.316***	0.302***	0.301***	0.194***
	(0.00210)	(0.00215)	(0.00215)	(0.00417)
$G6^i$ (log) (Castilla-Mancha)	0.231***	0.216***	0.216***	0.645***
	(0.00204)	(0.00210)	(0.00210)	(0.0102)
$G7^i$ (log) (Catalunya)	0.247***	0.237***	0.237***	0.222***
	(0.00189)	(0.00194)	(0.00194)	(0.0143)
$G8^i$ (log) (Ctat.Valenciana)	0.223***	0.213***	0.213***	-0.0334***
	(0.00205)	(0.00210)	(0.00210)	(0.00999)
$G9^i$ (log) (Extremadura)	0.250***	0.239***	0.239***	0.196***
	(0.00197)	(0.00204)	(0.00204)	(0.00591)
$G10^i$ (log) (Galicia)	0.318***	0.314***	0.314***	0.748***
	(0.00202)	(0.00204)	(0.00204)	(0.0171)
$G11^i$ (log) (Madrid)	0.226***	0.207***	0.207***	0.0670**
	(0.00225)	(0.00232)	(0.00232)	(0.0315)
$G12^i$ (log) (Murcia)	0.262***	0.257***	0.257***	-0.113***
	(0.00210)	(0.00208)	(0.00208)	(0.0127)
$G13^i$ (log) (Navarra-Rioja)	0.307***	0.292***	0.292***	1.072***
	(0.00208)	(0.00214)	(0.00214)	(0.0540)
$G14^i$ (log) (Pais Vasco)	0.288***	0.278***	0.278***	0.222***
	(0.00215)	(0.00218)	(0.00218)	(0.0136)
$G1^j$ (log) (Andalucia)	-0.143***	-0.129***	-0.130***	-0.347***
	(0.00241)	(0.00249)	(0.00251)	(0.00816)
$G2^j$ (log) (Aragon)	-0.264***	-0.241***	-0.242***	-0.147***
	(0.00270)	(0.00289)	(0.00292)	(0.0324)
$G3^j$ (log) (Asturias)	-0.290***	-0.273***	-0.274***	-1.137***
	(0.00248)	(0.00262)	(0.00264)	(0.0366)
$G4^j$ (log) (Cantabria)	-0.226***	-0.205***	-0.206***	0.300***
	(0.00270)	(0.00284)	(0.00286)	(0.0228)
$G5^j$ (log) (Castilla-Leon)	-0.250***	-0.226***	-0.226***	-0.222***
	(0.00261)	(0.00275)	(0.00277)	(0.00674)
$G6^j$ (log) (Castilla-Mancha)	-0.181***	-0.159***	-0.159***	-0.526***
	(0.00249)	(0.00266)	(0.00268)	(0.00874)
$G7^j$ (log) (Catalunya)	-0.186***	-0.172***	-0.173***	-0.183***
	(0.00254)	(0.00262)	(0.00265)	(0.00826)
$G8^j$ (log) (Ctat.Valenciana)	-0.132***	-0.113***	-0.113***	-0.106***
	(0.00255)	(0.00268)	(0.00271)	(0.00808)
$G9^j$ (log) (Extremadura)	-0.197***	-0.180***	-0.181***	-0.217***
	(0.00276)	(0.00280)	(0.00282)	(0.00522)
$G10^j$ (log) (Galicia)	-0.289***	-0.278***	-0.279***	-0.515***
	(0.00239)	(0.00244)	(0.00246)	(0.0176)
$G11^j$ (log) (Madrid)	-0.182***	-0.156***	-0.157***	-0.216***
	(0.00270)	(0.00297)	(0.00299)	(0.0193)
$G12^j$ (log) (Murcia)	-0.116***	-0.103***	-0.104***	0.178***
	(0.00249)	(0.00260)	(0.00262)	(0.0193)
$G13^j$ (log) (Navarra-Rioja)	-0.240***	-0.216***	-0.217***	-1.129***
	(0.00257)	(0.00276)	(0.00279)	(0.0661)
$G14^j$ (log) (Pais Vasco)	-0.252***	-0.234***	-0.235***	0.264***
	(0.00253)	(0.00271)	(0.00273)	(0.0200)
D^i (log)	0.159***	0.192***	0.192***	-1.927***
	(0.00368)	(0.00420)	(0.00419)	(0.330)
D^j (log)	-0.172***	-0.194***	-0.194***	0.497**
	(0.00358)	(0.00345)	(0.00346)	(0.228)
$Dist^{i,j}$ (log)	0.362***	0.368***	0.368***	-0.818***
	(0.00311)	(0.00327)	(0.00327)	(0.220)
Constant	1.222**	2.233***	2.149***	26.23***
	(0.485)	(0.507)	(0.509)	(5.741)
Observations	678,900	678,900	678,900	678,900
R^2	0.292	0.296	0.297	0.559
Centrality:				
Degree		Y	Y	Y
Closeness		Y	Y	Y
Seasonality:				
Year			Y	Y

Regarding coefficients for generation, we analyze $\hat{\beta}_i^r$ to identify how generation produced in r contributes to flows. Positive coefficients means that increasing production in region r increases flows. On the opposite, negative coefficients means a decrease of flows that might be explained by several reasons: a higher amount of energy connected to distribution grids instead of transmission, and/or a higher generation in r during the off-peak times. Moreover, coefficients close to 1 indicates a surplus of installed capacity in r, which implies that energy should travel to other regions. Indeed, the highest $\hat{\beta}_i^r$ corresponds to Navarra/La Rioja (+1.072), to Asturias (+1.04), and Galicia (+0.75). On the opposite, Murcia (-0.11) and Ctat.Valenciana (-0.03) and Madrid (+0.06) have the lowest (REE, 2019b).

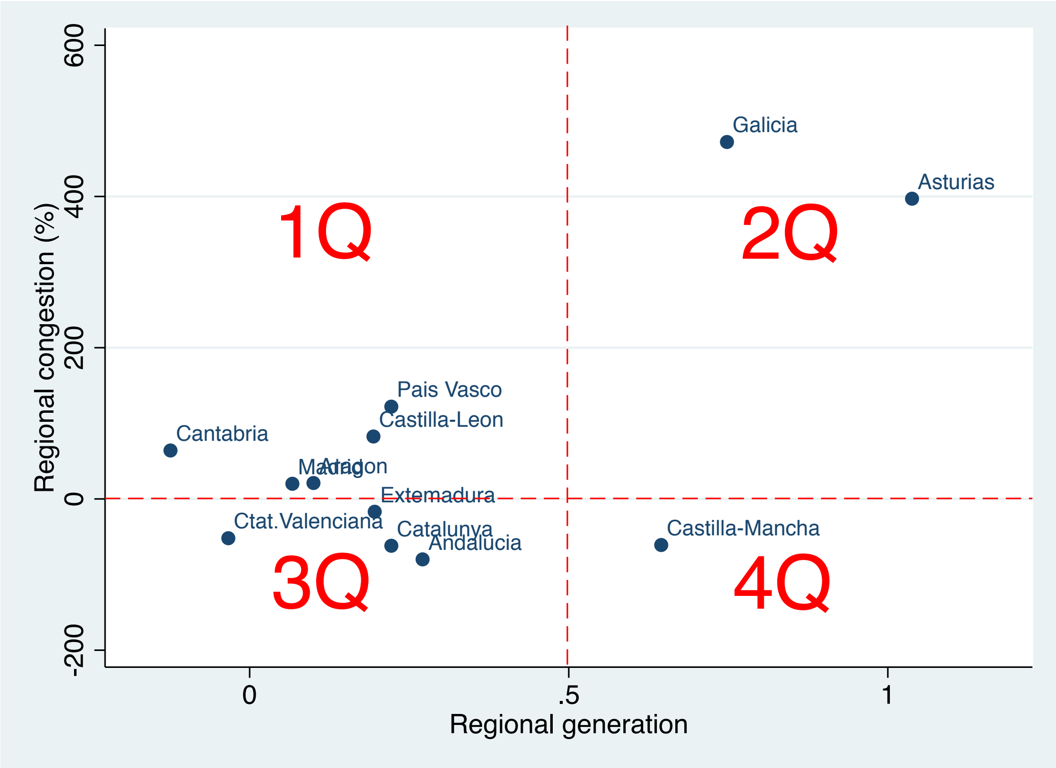
Finally to perform the social welfare analysis, we combine results from the first set of regressions (regional congestions or $Congest_r$) and the second set of regressions (regional contribution of generation to flows or $\hat{\beta}_i^r$). Both results are represented in Figure 4.5[25]. Regions in 2Q quadrant, Galicia and Asturias have the highest congestions and surplus of generation. Therefore, installing new RES in these regions seems not to be the most efficient solution because would aggravate existing congestions, require extra grid investments and energy would have to travel to other regions. On the opposite, regions in 3Q quadrant, Ctat Valenciana, Extremadura, Catalunya and Andalucia have the lowest congestions and the highest deficit of generation, which means that installing new RES in these regions would be the most efficient from the system point of view. Regions in 1Q quadrant show a deficit of generation but congestions above the average. Indeed, the connection of new RES in these regions would require case by case specific analysis since there might be different issues behind congestions: Castilla-Leon and Pais Vasco are close to borders; Cantabria is near to important RES areas (Galicia and Asturias); Madrid is the main consumption area; Aragon is close to Castilla-Leon. Finally, Castilla-la-Mancha in 4Q quadrant have lower congestions, but a surplus of installed capacity.

Finally, we validate the estimates from the first empirical approach by the analysis of the coefficient related to $PEAK_t$[26], which explains that flows are 2.61$\%$ higher in peak than offpeak, what is consistent. This coefficient is smaller than Table 5.8 (17.8$\%$), which might be explained by the different R^2 adjustments: 0.559 in Table 4.5 vs 0.329 in Table 5.8.

[25]We have not represented Navarra/Rioja and Murcia, whose regional generation coefficient is +1.072 and -0.113, respectively, because coefficients related to congestion are not significant in Table 5.8. In the first, there is an important surplus of generation, while a deficit in the second.

[26]Calculated by $(exp(\hat{\rho}) - 1) * 100$ $[\%]$.

Figure 4.5: Regional congestions ($Congest_r$) and regional contribution of generation to flows ($\hat{\beta}_i^r$).



Source: own elaboration.

In summary and comparing our results from the literature, they are aligned with results from other authors who find increasing RES increases congestions (Van den Bergh et al. (2015) and Joos and Staffell (2018)); and concentrating RES in some areas also increases congestions (Hitaj, 2015).

4.6 Conclusions and regulatory recommendations

Studying and deeply understanding the performance and efficiency of electricity systems is essential to successfully connect new RES and maximize the social welfare. In this context, the analysis of flows and congestions within an electricity system presented here goes in the right direction. Moreover, we contribute to bring out the potentials from the use of a gravity model in energy flow analyses, which has scarcely been explored in the literature.

First, we estimate the impact of each technology on flows as means to identify how efficient their locations are with the main consumption areas. These results are a novelty in the literature. We find that wind and imports are the less efficiently located. Wind capacity is mainly located in the North-West regions and far from main consumption areas, while import connections points are in the borders between France, Portugal and Morocco. On the contrary, combined cycle is efficiently located because it is mostly sited close to seaports and main cities. These results (along with those of other technologies) confirm that the location of generation from different technologies impacts on flows, which might result in different uses of the grids and different contribution to electricity losses[27] supporting what is found in Chapter 2, but adding the locational dimension. Second, we calculate the locational patterns of generation related to congestions. We find that congestions in North-West regions are the highest, while the lowest in North-East and South regions, confirming the existence of relevant grid bottlenecks in regions with large RES installed capacity. Third, we analyze how the energy produced in each region contributes to flows to proxy the use of the regional installed generation. Finally, combining both the locational patterns related to congestions and the regional contribution to the flows, we identify the less and most efficient regions -from the social welfare point of view- to connect new RES. In the top efficient regions we have Ctat.Valenciana, Extremadura, Catalunya and Andalucia, while in the opposite, Galicia and Asturias are the less efficient.

The above summarized results highlights that analyzing the performance of a real electricity system is a complex task, where congestions follow locational patterns and the location of new generation plants, among others RES, cannot be overlooked as has a major impact on the system costs. Although at first glance seems that locating new wind capacity in the most resource-optimal regions -Galicia and Asturias- is a good choice, this might actually aggravate the system congestions and require new grids investments. In other words, some RES locations might harm social welfare if require new grid investments or increase electricity losses when energy should travel further. Therefore, it is essential to plan in detail -at national level- locations for new RES in different scenarios but considering existing grid, flows, and potential grid investments. Accordingly, CBA should include all costs and benefits: private returns for investors, regional environmental and visual impacts, subsequent grid investments and electricity losses paid by all consumers, potential RES curtailments due to grid bottlenecks, and the security of supply[28], etc.

There are several regulatory mechanisms to provide locational incentives to future

[27]Electricity losses are directly proportional to the distance that energy travels from generation to consumption

[28]*Security of supply* can be economically quantified by the Value of Lost Load of electricity supply (Pérez-Arriaga, 2014).

RES. First, splitting the unique Spanish bidding zone in two -North and South- as we find that regional congestions are mostly located in the Northern regions. However, this choice requires further analysis since the replacement of conventional generation plants by RES might change the actual congestion picture and this would reduce its potential allocative locational incentives. Second, changing from *shallow* connection to *deep* connection charges could be an alternative. However, its practical implementation can not always be transparent and fair, specially in the highest voltage grids -400kV- since a transmission line can be used by multiple generators and only the first connected to the grid should fund it. Third, implementing regional UoS charges and regional congestions found in this Chapter might be a good basis. However, there are some points we should have always in mind: new RES might change actual regional congestions and impacts from generation on flows. Fourth, improving the transmission planning to align actual lack or surplus of grid capacity and some resource-optimal RES locations, which is specially useful in the Southern regions -Andalucia and Extremadura- whose potential solar production is higher than some Northern regions, such as Galicia, Asturias and Cantabria. This would also reduce the RES connection times as the grid would be already built, but this regulatory recommendation requires complicated agreements with regional governments and then informing RES promoters transparently. Fifth, implementing some locational incentive in future RES auctions, there are several alternatives in this direction: including economic incentives to offset the minor annual wind and solar production in some regions; including a list of technology-specific RES sites; or including different RES quotas for each region considering the actual grid capacity. All the previous choices have the caveat of requiring a higher regional coordination in policies and legal requirements to avoid undesired trade-offs or inefficiencies. In case some regions provide specific tax benefits or different legal permits, it is more difficult to define a transparent, efficient and non-discriminatory locational incentive.

An additional consideration coming from the overall analysis is that regardless the locational regulatory mechanism implemented, it is essential to provide high-quality energy and grid data easily available to all stakeholders since it enables businesses to invest wisely, facilitate the correct decisions and innovate practices. Moreover, this guarantees the non-discriminatory access to all grids users and allows to efficiently de-risk the financing of investments. The last is a main principle of the electricity regulation (Newbery et al., 2018) as the clean electricity systems are becoming more capital intensive. Indeed, an efficient clean transition requires good polices and data insufficiency could lead to unfavourable choices (IEA, 2018). In line with results found in Chapter 4, this includes locations with lower congestions and consequent lower likelihood to implement future generation curtailments, sites with available capacity without costly grid reinforcements, etc.

Future empirical studies could use our results to study how locating new RES impacts on grid congestions and electricity losses, which is essential to define efficient locational incentives in auctions.

4.7 Appendix I

Table 4.6: NUTS2 FE dummies from column (4) in Table 5.8.

(NUTS2)	Dummy	F2015_7FE4D
Andalucia	$\hat{\theta}_{1i}$	-1.606***
		(0.0256)
Aragon	$\hat{\theta}_{2i}$	0.192***
		(0.0215)
Asturias	$\hat{\theta}_{3i}$	1.603***
		(0.0332)
Cantabria	$\hat{\theta}_{6i}$	0.496***
		(0.0321)
Castilla-Leon	$\hat{\theta}_{7i}$	0.602***
		(0.0218)
Castilla-La-Mancha	$\hat{\theta}_{8i}$	-0.936***
		(0.0230)
Cataluña	$\hat{\theta}_{9i}$	-0.980***
		(0.0249)
Ctat Valenciana	$\hat{\theta}_{10i}$	-0.738***
		(0.0252)
Extremadura	$\hat{\theta}_{11i}$	-0.191***
		(0.0252)
Galicia	$\hat{\theta}_{12i}$	1.726***
		(0.0289)
Madrid	$\hat{\theta}_{13i}$	0.262***
		(0.0346)
Murcia	$\hat{\theta}_{14i}$	-0.032
		(0.0268)
Pais Vasco	$\hat{\theta}_{16i}$	0.797***
		(0.0282)

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

4.8 Appendix II

Electricity networks are composed by high voltage lines that connect nodes, also known as substations. A node represents the physical location in the network, where transmission lines intersect between them. They can also connect with generation plants, industrial consumers or transformers to feed the distribution grids. A pair of nodes (i, j) represents a HV line and its temporal flow ($F_t^{i,j}$) can be easily estimated using the Marginal Loss Coefficients (MLC_t^n) associated to both nodes. Next, we define Marginal Loss Coefficients and then we show to estimate flows ($F_t^{i,j}$) for each HV line. Precisely, this is the endogenous variable in this Chapter.

4.8.1 Marginal Loss Coefficients

As is defined in REE (2019b), MLC_t^n indicates how total system losses (LT_t) would change if energy generated (G_t^n) and injected in this specific n node increased (Equation 4.13):

$$MLC_t^n = \frac{\partial LT_{t0}}{\partial G_t^n} \tag{4.13}$$

For each t and n, TSO makes a ceteris paribus simulation, which is ΔG_t^n=1MWh, and recalculates all the new flows in the electricity system and the resultant electricity losses (LT_{t1}^n). Comparing both the initial losses (LT_{t0}) and (LT_{t1}^n), MLC_t^n is calculated (Equation 4.14):

$$MLC_t^n = \frac{LT_{t1}^i}{LT_{t0}^i} - 1 \ \texttt{[pu]} \tag{4.14}$$

Therefore, MLC_t^n inform us if there is a deficit or surplus of generation for each node:

- When $MLC_t^n < 0 \rightarrow$ There is a deficit of generation, or surplus of consumption, at the n at time t.

- When $MLC_t^n > 0 \rightarrow$ There is a surplus of generation, or deficit of consumption, at the n at time t.

4.8.2 Flows

Hourly flows ($F_t^{i,j}$) are calculated as follows (Equation 4.15):

$$F_t i, j = MLF_t^i - MLF_t^j \tag{4.15}$$

Three-phase apparent electric power (S_t) is defined as (Equation 4.16):

$$S_t = \sqrt{P_t^2 + Q_t^2} = \sqrt{3} * U_t * I_t \tag{4.16}$$

where P_t is the active power, Q_t is the reactive power, U_t is the voltage and I_t the current. To simplify, we consider $Q_t = 0$ and then $S_t \equiv P_t$. Therefore, electricity losses (Equation 4.17):

$$LT_t = I_t^2 * R \tag{4.17}$$

where R is the resistance. Combining both Equations 4.16 and 4.17, and including all constant parameters into k (Equation 4.18):

$$LT_t = \left[\frac{P_t}{\sqrt{3} * U_t}\right]^2 * R = P_t^2 * \left[\frac{R}{3 * U_t^2}\right] = P_t^2 * k \tag{4.18}$$

Therefore, Marginal Loss Factors (MLF_t) might be calculated as (Equation 4.19):

$$MLF_t = \frac{\partial LT_t}{\partial P_t} = 2 * P_t * k \tag{4.19}$$

Finally, flows between two pair of nodes $(F_t^{i,j})$ can be somehow calculated[29] as the difference between MLF_t^i and MLF_t^j (Equation 4.20):

$$F_t^{i,j} = MLF_t^i - MLF_t^j = 2 * k * (P_t^i - P_t^j) \tag{4.20}$$

In our dataset we are including each transmission line twice[30], then $F_t^{i,j}$ is either positive, negative or zero. Then, we only consider $F_t^{i,j} \geq 0$ and if $F_t^{i,j} < 0 \rightarrow F_t^{i,j} = 0$ (see Figure 5.2).

$F_t^{i,j} \geq 0$ implies that $MLF_t^i > MLF_t^j$. In other words, there is a surplus of generation at i node or/and a deficit of generation in j. Therefore, $F_t^{i,j}$ comes always from the i source node to the j destination node. This implies that if more energy is injected in i source node - where there is already a surplus of generation - this energy should travel through the transmission lines to find consumption and the impact on flows is expected to be positive. Regarding the j destination node, arguments are the opposite to i and if more energy is injected in j destination node - where there is deficit of generation - this energy does not need to travel from the source node i and $F_t^{i,j}$ reduces.

[29] *Note:* $F_t^{i,j}$ in Equation 4.20 is not represented in MWh. However, this is not relevant in our analysis because we calculate elasticities and only need $\partial F_t^{i,j} / F_t^{i,j}$ (see Equations 4.9 and 4.10). Moreover, it is not necessary calculating k because it is constant for each pair of nodes during all the period of time.

[30] In the first observation, i is the source node and j the destination. Vice-versa, in the second.

5 Locational impact & network costs of energy transition

5.1 Introduction

Paris Agreement within the United Nations Framework Convention on Climate Change (2015) mandates countries to commit with decisions to mitigate global warming. In 2016, the European "2030 Energy and Climate Package"[1] pushes forward the climate change targets by 2030: 40% cut in greenhouse emissions, 32% of energy from renewable energy sources (RES) and 32,5% improvement in energy efficiency from the existing 20% target for 2020. Within this framework, the Governance Regulation[2] requires to all European Member States to establish a 10-year National Energy and Climate Plan to meet the energy and climate targets for 2030. Consequently, the Spanish Government sends a draft of the Spanish National Energy and Climate Plan (NECP)[3] to the European Commission in 2019. This plan determines the national strategy to achieve: 21% of greenhouse reduction w.r.t 1990 levels, 42% of RES in the total energy end-use, 40% of energy efficiency and 74% of RES in the electricity generation mix. Moreover, this includes the expected installed generation capacity in 2030.

In this context, electricity systems in Europe are facing a relevant transformation explained by a set of simultaneous factors, which require large public and private investments (von Hirschhausen et al., 2014): the above-mentioned decarbonisation of the generation mix; a higher electrification of the demand by the electric vehicle, heating and cooling devices; the introduction of information and communication technologies to monitor and operate grids; the installation of smart meters and the emerging development of the demand response. Related to generation, the replacement of conventional technologies by RES might change electricity flows by the combination of two main factors: (i) RES are not usually installed in the same location than conventional plants; and (ii) their production profile is very different since conventional production depends on storable raw material -coal, gas or fuel-, while wind and solar on random and non-storable weather conditions. Therefore, the location of new RES must be deeply analysed since changes in flows might result in subsequent specific congestions[4] across the country, which require grid investments

[1] See: https://ec.europa.eu/clima/policies/strategies/2030_en for further details.

[2] See: https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/governance-energy-union for further details.

[3] NECP is also known as *Plan Nacional Integrado de Energía y Clima 2021-2030*. This plan represents a first draft to be discussed with the Commission with the aim of finalizing the Plans in 2019 and their subsequent application. With the exception of the CO2 emissions and energy efficiency targets, the rest of figures (42% of RES in the total energy end-use and 74% of RES in the electricity generation mix) are not mandatory targets to be achieved. See: https://ec.europa.eu/energy/sites/ener/files/documents/spain draftnecp.pdf for further details.

[4] *Congestions* are related to thermal limits constraints of grid elements.

hardly covered by connection charges[5] and subsequently paid by consumers. Moreover, these changes in flows might also affect the electricity losses that are borne by consumers in the Spanish regulatory framework as is shown in Chapters 2 and 3. In sum, RES location might impact on social welfare.

All the previous occur in a framework where transmission and generation activities have evolved from vertically integrated companies to an unbundling setting. In the past, investments in generation and transmission were taken joined. Nowadays, transmission is a regulated monopoly, while generation is a liberalized activity and grid access is regulated by an open access regime. Consequently, incentives and objectives for both activities might be not fully aligned. Additionally, transmission planning expansion might enhance competition or mitigate market power for generators (Wu et al., 2006). In Chapter 5, we see how RES locations decided by market agents might result in higher structural congestions and higher grid investments paid by consumers. Therefore, specific complementary instruments or locational economic signals to new RES are necessary to solve this failure (Pérez-Arriaga et al., 2008). In short, RES location is a textbook case where market instruments applied to the generation activity might not achieve a full-efficient allocation of resources on transmission.

Chapter 5 contributes to the literature on low-carbon energy transition with a geographical analysis. Indeed, contemporary work has paid only very limited attention to questions of space and research should seek to increase the understanding of how energy transition is spatially-constituted (Bridge et al., 2013). This Chapter is linked with the new RES grid-related costs since we perform a detailed economic quantification of these costs and their corresponding electricity losses. We are considering grid investments beyond the grid-connection infrastructure borne by RES promoters in Spain, as we explain in the following section. More in detail, we quantify the grid investments aimed to solve structural congestions considering several locations for new RES, which could trade-off other benefits related to RES. In the grid-related costs' literature, some authors study congestion costs related to RES and find they increase and congestions might result in important RES curtailment (Joos and Staffell, 2018); others identify the importance of RES location and find their curtailment increases as higher are they concentrated (Hitaj, 2015); others study benefits from splitting the unique bidding zone in Germany and their impact on consumers, grid expansion, redispatching and future RES (Trepper et al., 2015; Egerer et al., 2016). At the end, RES integration costs can be ignored in low pene-

[5] *Connection charges* are paid by RES promoters to cover grid-connecting costs (see section 5.2 for further details).

tration levels, but are too large to be ignored in high-penetration assessments (Hirth et al., 2015). In this context, Spain represent a relevant case due to its highest level of RES in its generation mix.

Additional contributions of Chapter 5 rely on the methodology and the data used. Most electricity flows' literature apply optimization models, which optimize nonlinear problems to simulate flows considering network characteristics, generation and consumers (Schaber et al., 2012; Hitaj, 2015; Trepper et al., 2015; Van den Bergh et al., 2015). Instead, we apply a gravity model, which has scarcely been used in the analysis of electricity flows, but was initially applied to analyze trade between countries (Anderson, 1979). The later incorporation of some theoretical foundations resulted in richer, more accurate estimations and the interpretation of spatial relations (Anderson, 2011; Yotov et al., 2016), which we exploit here. The literature of gravity applied to energy flows is scarce (Antweiler, 2016; Batalla-Bejerano et al., 2019).

As baseline for our simulations, we use the dataset and results from Chapter 4, where determinants of actual flows and congestions in the Spanish 400kV transmission grid are analyzed. Our dataset includes high-granularity information about flows, energy production by plants and the geographical location of nodes[6], generation plants and main cities. We follow an indicative energy planning process to calculate grid-related costs (Pérez-Arriaga et al., 2008): we select six different scenarios for new RES locations to represent potential market and social planner choices. Our results show that congestions and grid costs are the highest in the market choice scenario, where new RES are only concentrated in the four most optimal regions[7]. On the contrary, congestions and grid costs are the lowest when new RES are dispersed across the country, connected also in regions with less RES potentials. These lower congestions result in a lower likelihood to curtail RES (Joos and Staffell, 2018), which implies de-risking future low-carbon investments (Newbery et al., 2018). Results signal the existence of a market failure and ultimately highlights the relevance of building up locational incentives to balance costs between private investors and consumers by means of the regulatory framework.

Regulatory recommendations derived from our results include locational incentives to future RES capacity auctions to foster some locations over others, and encour-

[6] A *node* represents the physical location in the network, where transmission lines intersect between them. They can also connect with generation plants, industrial consumers or transformers to feed the distribution grids.

[7] *Optimal regions* refers to the sunniest or most windy regions.

age promoters to connect RES in regions that are the sub-optimal from a private perspective, but superior from the system -social- point of view. Indeed, our results could be used to design locational incentives in future auctions as we estimate real costs for consumers and investors. Another possible regulatory option includes identifying potential RES sites in future capacity auctions or using regional instead of national auctions. Regional use of system (UoS) charges is another possibility, but this also affects the existent RES generators and other technologies. Deep connection charges could be an option, but it is very difficult to define a clear and neutral mechanism to individually assign grid costs beyond to the nodes where RES are connected.

The remain of Chapter 5 is organized as follows. Section 5.2 provides a summary of the regulatory framework, section 5.3 details the empirical strategy, section 5.4 describes the data and scenarios simulated while section 5.5 includes the results. Finally, section 5.6 concludes and draws some policy implications.

5.2 Regulatory framework

Regulatory framework related to RES might provide direct or indirect locational incentives for future RES. Actually, there are several mechanisms through which these incentives are shaped: congestion pricing, connection charges, RES auctioning, transmission planning and UoS charges.

Regarding congestion pricing, there are zonal prices in Europe -also known as bidding zones-, which consists on geographical areas with a common wholesale price and congestion costs are shared in the entire zone. Therefore, bidding zones do not provide specific locationals incentives since they can be as large as a whole country. Indeed, congestions within bidding zones increase due to RES (Van den Bergh et al., 2015) and the System Operator (SO) should become more proactive to handle these congestions problems (Hiroux and Saguan, 2010). On the contrary, nodal prices -implemented in the US and other countries- provide short locational incentives because nodal prices are calculated considering the scarcity or surplus of generation in a node, i.e. in a small area. Some authors have studied the implementation of nodal pricing in Europe (Brunekreeft et al., 2005; Neuhoff et al., 2013), while others the potential benefits from defining smaller bidding zones (Trepper et al., 2015; Egerer et al., 2016).

Connection charges are paid by RES promoters to cover grid-connecting costs. As higher is the share of grid-connecting costs paid by RES promoters, higher is the effect on the locational incentive for them. There are three different possibilities: in *deep cost*, charges include all connection costs and the upstream grid reinforcements; in *shallow cost*, charges include only direct costs of the dedicated facilities and local reinforcements, while the rest of the upstream grid reinforcements are socialized; and in *null cost*, charges are null and all connection costs and the upstream grid reinforcements are fully socialized. Connecting charge design is challenging to avoid gaming or competence problems in the process of connecting some new RES plants in a row (Rious et al., 2008; Pérez-Arriaga, 2014). In Europe, *shallow cost* is the most common choice. Indeed, this the regulatory mechanism implemented in Spain (ENTSO-E, 2018).

In last years, auctions[8] have emerged as an efficient alternative for setting the remuneration of new RES and can also provide locational incentives (Del Río, 2017). Auctions are competitive bidding procurements and the product can either be capacity in MW or energy in MWh (IRENA and CEM, 2015). In auctions without specific locational incentives and as result of the high degree of competition, promoters tend to seek optimal sites, which results in higher concentration of RES in some locations with its corresponding social acceptability affection (Del Río and Linares, 2014). Del Río (2017) analyses auctions among several countries and concludes their efficiency depends on their own design elements. Location constraints can also be included to achieve either greater geographic diversity of projects, to ensure closeness to grid and loads or to address other considerations. Indeed, IRENA and CEM (2015) propose several mechanisms for this target: location-specific demand bands, project location components in the winner selection criteria, or location requirements for the participating projects.

Transmission planning might promote specific RES locations depending on the strategy followed by transmission providers. Here, there are two possible approaches: in the *reactive planning*, transmission planning construction occurs after RES promoter requests for their connection, while in the *anticipatory planning*, transmission planning anticipates future RES connections. Alagappan et al. (2011) conclude the last reduces uncertainty to RES promoters who can better plan its investment and see how, when and where to connect their plant. This is, *anticipatory planning* improves RES energy development. In Spain, transmission planning is based in the *reactive planning*. Some authors have also explored the impact of transmission planning in the RES penetration, Schaber et al. (2012) analyze the transmission grid exten-

[8] *Auctions* are also known as public tendering, demand auctions, reverse auctions or procurement auctions.

sions considering several scenarios of RES penetration and backup capacity across Europe in 2050 to identify main transmission corridors. They conclude that early transmission planning is crucial for the successful RES integration in Europe due to the important grid investments they estimate. Lastly, Kemfert et al. (2016) explore this process in Germany and conclude that network planning approaches should be complemented by alternative congestion managements, such as redispatch of RES and conventional generation.

Finally, generators and consumers pay UoS charges when they are already connected to the grid and cover the costs of operating, maintaining and building the network. Generally, these charges include a fix rate by the power capacity connected to the grid (MW) and/or another variable rate by the amount of energy consumed or generated (MWh) (Pérez-Arriaga, 2014). Most European countries and Spain use fix rates within their country *-postage stamp usage fee-* for the same kind of consumers or generators[9]. However, specific countries such as the UK, Ireland, Norway and Sweden use different (locational) UoS charges for the same kind of consumers and generators. In them, charges reflect geographical deficits or surplus of generation, grid losses, etc. (ENTSO-E, 2018). Therefore, different charges provide different locational incentives for RES.

5.3 Empirical approach

In this section we present the empirical approach of this study, starting with the gravity model whose estimated parameters are the baseline for our subsequent simulations. This is followed by a detailed explanation of the NECP energy mix implementation, built on top of the baseline. Finally, we define the geographical scenarios and strategies to estimate potential RES integration costs in our simulations.

5.3.1 Gravity Model

As we have explained in the introduction, we perform simulations relying on the results from Chapter 4, where a gravity model is estimated to find the disaggregated effect of some variables -technologies and regional generation- on electricity flows. Henceforth, gravity outcomes allow performing more realistic simulations unlike the traditional approach models that optimize theoretical flows. Indeed, the greatest weak point of the optimization models is they do not consider actual flows in their

[9]Consumers and generators are classified according to the voltage of their connection point to the grid, their power capacity, etc.

outcomes since are focused on validating electrical parameters -voltage drops, congestions, overcharges- and results are highly dependent on the assumptions made over pre-existing conditions. Moreover, optimization models do not consider the disaggregated contribution of some variables in both direction flows. Precisely, the pre-existent conditions and the disaggregated contributions to bidirectional flows are the essence of the gravity approach, based on actual data of the system conditions to simulate more realistic flows and congestions.

Gravity models are grounded on the Newton's law universal gravitation (Anderson, 1979): its foundation is that a mass of goods -or other factors of productions supplied- at an origin i is attracted to a mass of demand for goods or labor destination j, and the potential flows depend on the distance between i and j (Anderson, 2011). These models have mostly applied to the analysis of trade between countries (Dekle et al., 2008; Van Bergeijk and Brakman, 2010; De Benedictis and Taglioni, 2011; Baier et al., 2014). As we have explained in the introduction, the literature of gravity applied to energy markets is scarce: Antweiler (2016) analyze the electricity cross border trade between Canada and the United States; Costa-Campi et al. (2018) study the effect of energy market integration on foreign direct investment; and Batalla-Bejerano et al. (2019) analyze the energy trade flows between European countries to quantify the effect of economic, structural, cultural and institutional variables on the transborder flows.

In Chapter 5 Equation 5.1 shows the estimated equation in Chapter 4, with these parameters been the baseline for the simulated scenarios introduced in this Chapter:

$$\begin{aligned} logF_t^{i,j} = \hat{\beta}_0 + \sum_{r=1}^{14} \hat{\beta}_i^r logGr_t^i + \sum_{r=1}^{14} \hat{\beta}_j^r logGr_t^j + \hat{\beta}_1 logDist^{i,j} + \hat{\beta}_2 C_i^d + \hat{\beta}_3 C_j^d + \\ + \hat{\beta}_4 C_i^c + \hat{\beta}_5 C_j^c + \hat{\beta}_6 logD^i + \hat{\beta}_7 logD^j + \\ + \sum_{d=1}^{6} \hat{\delta}_d D_{dt} + \sum_{m=1}^{11} \hat{\alpha}_m M_{mt} + \sum_{y=1}^{2} \hat{\gamma}_y Y_{yt} + \hat{\rho} PEAK_t + e_{i,j,t} \end{aligned} \tag{5.1}$$

where $F_t^{i,j}$ is the flow at each time t between each pairs of nodes -transmission lines- identified as i, j (see red lines in Figure 5.1); Gr_t^i and Gr_t^j are the energy produced in i and j sited in region r, respectively; $Dist^{i,j}$ is the distance in kilometres between each pair of nodes identified as i, j, in other words, the transmission line length; C_i^d and C_j^d are the *degrees centrality* and C_i^c and C_j^c their corresponding *closeness centrality*; D^i and D^j are the shortest distance -in km- of nodes to a main city. Seasonality is also controlled with a set of dummy variables[10]: $PEAK_t$ for the peak time; D_{dt} for the day of the week; M_{mt} and Y_{yt} captures the long-term seasonality. The inclusion of seasonality control variables allows us to consider time specificities in our estimations, i.e. the network operation, external facts, etc. Finally, $\hat{\beta}_i^r$ and $\hat{\beta}_j^r$ estimators explain how the energy generated in nodes located in r region contributes to flows. In summary, estimated coefficients from Equation 5.1 (see Table 5.8.5.7.1 in Appendix I) picture the Spanish electricity system operating and are the baseline for our simulations.

Figure 5.1: Network (red lines) and nodes (black dots) considered in Chapters 4 and 5.

Source: Own elaboration.

Any concern on endogeneity problems from explicative variables should be discarded because past decisions of locating generation were exogenous to flows: plants were sited close to their primary source of energy / raw material (coal plants

[10] D_{dt} for the day of the week; M_{mt} and Y_{yt} capture the long-term seasonality. D_{dt} comprise six dummy variables: one for each day from Tuesday (d=1) to Sunday (d=6), Monday is the base day of the week. Following the same approach, M_{mt} comprise eleven dummy variables: one for each month from February (m=1) to December (m=11), January being the base month. Finally, Y_{yt} comprise two dummy variables, one for 2016 (y=1) and another for 2017 (y=2). In this case, 2015 is the base year.

near to mines, gas-fuel plants close to regasification plants in seaports, hydropower plants in water rivers, wind plants in areas with the most optimal wind-resource, etc.) and there were not locational incentives in the regulatory framework considering the existing flows.

5.3.2 NECP generation mix

The original data is treated to introduce the NECP generation mix (Table 5.1) with the following changes in each t time. First, we calculate the extra solar and wind production (RES_t) resulting from the new RES and the repowering the existing plants[11]. Second, we calculate the sum of the real energy produced by phased-out technologies (POT_t): 3 nuclear plants -Asco1, Trillo and Vandellos2- and all the coal plants. Third, we increase the energy injected in the grids -generated plus imports- to consider +18% electricity demand (EXT_t) between 2017 and 2030, as NECP[12] does.

Table 5.1: NECP installed capacity (MW).

Technology	2017	2030	Growth rate
Nuclear	7,399	3,181	-57%
Combined cycle	27,531	27,146	-1%
CHP	6,383	5,891	-8%
Coal	11,311	0	-100%
Hydropower	20,128	24,133	+20%
Wind	22,920	50,258	+119%
Solar	6,744	44,185	+555%

Source: NECP.
Note: CHP represents Combined-Heat and Power.

Given that an electricity system must always be in equilibrium between the energy produced and consumed, we calculate GAP_t as the difference between the extra energy generated by RES (RES_t), and the energy produced from the phased-out plants (POT_t) plus the extra electricity demand (EXT_t) after the NECP inclusion:

$$GAP_t = (RES_t) - (POT_t + EXT_t) \tag{5.2}$$

[11]NECP also considers an improvement in the ratio of energy produced by the RES installed capacity (GWh/MW): +3.9% and +7.4% for solar and wind, respectively. Therefore, we increase the solar and wind production as: 6.55*1.039=581% and 2.19*1.074=135%, respectively

[12]According to the NECP, the energy injected to the grids increases from 284,707GWh to 335,530GWh (+18%) between 2015 and 2030, where generation evolves from 269,751GWh to 327,305GWh and imports from 14,956GWh to 8,225GWh.

To guarantee the fulfilment of the equilibrium condition, we make adjustments when $GAP_t \neq 0$ and following the principles defined in the NECP:

- If $GAP_t < 0$: there is a deficit of energy generated to cover the total consumption at t. GAP_t is equally covered by combined cycle, hydropower -including pumping- and imports. In the case that any of the previous technologies have not enough available capacity to cover their part, this is assigned to combined cycle because plants are never operating at their maximum capacity.

- If $GAP_t > 0$: there is a surplus of energy generated to cover the total consumption at t, and the production of technologies is decreased in the following order: combined cycle, imports, hydropower and in last instance, wind and solar.

GAP_t is covered by technologies following simple rules and based on the nature of each one. Regarding combined cycle, we sort all plants by their historical operating rate[13]. Then, when we should assign more energy to this technology, we begin increasing the production of the plant whose historical operating ratio is the highest provided that it is not operating at their maximum capacity. On the contrary, when combined cycle production should decrease, we begin decreasing the production from plants whose historical operating ratio is the lowest. We continue both previous processes until the sum of the energy produced by all plants equals to the target. Regarding hydropower, we increase or decrease the production from all plants together; and finally for imports, we increase or decrease imports in all border points but considering a new connection between Spain and France by the Vizcaya Gulf in the Vasque Country. Finally, we recalculate the production in each node for each time t[14].

5.3.3 Simulated scenarios

As means to study the impacts of new RES on flows -congestions-, a two-level locational decision scheme is applied considering RES in the reference period -2017-

[13] We calculate the *historical operating rate* in %, sorting all combined cycle plants considering their energy generated in the period (2015-2017) over its maximum capacity.

[14] Additionally and for each t, we are always considering a minimum of 5,500MW of synchronous generation, which is the sum of nuclear, hydropower, combined cycle and CHP. This is necessary to ensure safety levels of frequency inertia in the electricity system, what is vital to guarantee minimum safety levels and avoid potential blackouts. This requirement is included in the NECP and comes from *Comision de Expertos sobre Escenarios de Transicion Energética. Analisis y propuestas para la descarbonización* technical report, which was written by experienced consultants in the energy field as recommendatory guide for the later Spanish energy transition.

as baseline: scenarios (or *between NUTS2*) and strategies (or *within NUTS2*). Consequently, scenarios simulated in Chapter 5 consider the following *between NUTS2 allocations*[15]:

- **Scenario 1**: New wind and solar capacity is located in the 4 most optimal NUTS2 regions[16]. Extra RES is proportionally assigned to each region considering the existing capacity.
- **Scenario 2**: New wind and solar capacity is located in the same regions than scenario 1. Extra RES is assigned to each region considering the existing capacity for each technology, but until we achieve the same RES density in MW/km^2.
- **Scenario 3**: New wind and solar capacity is located in NUTS2 regions whose RES performance is above the average for each technology. Extra RES is proportionally assigned to each region considering the existing capacity.
- **Scenario 4**: New wind and solar capacity is located in the same regions than scenario 3. Extra RES is assigned to each region considering the existing capacity for each technology, but until we achieve the same RES density in MW/km^2.
- **Scenario 5**: New wind and solar capacity is distributed across all NUTS2 areas[17]. Extra RES is proportionally assigned to each region considering the existing capacity.
- **Scenario 6**: New wind and solar capacity is located in the same regions than scenario 5. Extra RES is assigned to each region considering the existing capacity for each technology, but until we achieve the same RES density in MW/km^2.

We include scenarios with both the *proportional* and *non-proportional* growth in RES because the installed capacity in Spain is heterogeneous across the country (in the baseline year) and some regions have already a large RES installed capacity.

[15]See Tables 5.9.5.7.2 and 5.10.5.7.2 in Appendix II for further details.

[16]In either RES -wind and solar- regions are sorted considering their annual production over the installed capacity in GWh/MW. As an extreme scenario, we have not considered less than 4 NUTS2 areas since it is not technically feasible due to the lack of existing nodes where to connect to new RES.

[17]We make some exceptions to consider more realistic scenarios. In solar, we do not consider new capacity in Asturias and Cantabria due to their poor existing capacity (1 MW) in 2017. In wind, we do not consider new capacity in Madrid and Extremadura because there is no installed capacity in 2017. Therefore, we are directly discarting NUTS2 regions with extremely poor potential for each technology.

Therefore, RES density in the *non-proportional* strategy aims to approach the regional availability to accommodate more RES.

Moreover, we simulate the following 3 different strategies to locate new RES *within each NUTS2*:

- **Strategy a**: New wind and solar capacity is connected in all nodes located into the NUTS2 area.
- **Strategy b**: New wind and solar capacity is connected in the 50% nodes with the highest number of electricity lines connected to, within the corresponding NUTS2 area.
- **Strategy c**: New wind and solar capacity is connected in the node with the highest number of electricity lines connected to, within the corresponding NUTS2 area.

Table 5.2 summarizes the scenarios explained above. Table 5.3 includes the annual productivity, in GWh/MW, for the new wind and solar capacity installed in each scenario. It is important to highlight that in a free market framework, scenarios 1 and 2 would be the preferred option for the private investors perspective since the annual RES production is the highest (2.179 and 2.135 GWh/MW), 15% higher than the scenario on the other extreme (scenario 6).

Table 5.2: Scenarios simulated in Chapter 5.

Scenario	NUTS2 areas	RES capacity growth
1	4 areas with the highest RES performance	Proportional to existing in 2017
2	4 areas with the highest RES performance	Non-proportional to achieve the same RES density
3	Areas whose RES performance is higher than the average	Proportional to existing in 2017
4	Areas whose RES performance is higher than the average	Non-proportional to achieve the same RES density
5	All areas	Proportional to existing in 2017
6	All areas	Non-proportional to achieve the same RES density

Table 5.3: Annual RES production for all simulated scenarios (in GWh/MW).

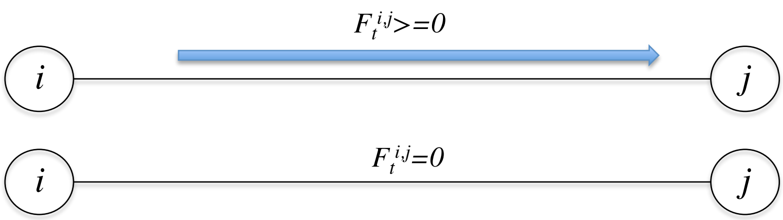
Scenario	New SOLAR	New WIND	Sum of new RES
1	2.084	2.308	2.179
2	2.029	2.279	2.135
3	2.026	2.229	2.112
4	1.891	2.175	2.011
5	1.980	2.076	2.020
6	1.800	2.026	1.895

5.4 Data description

In this section we present a description of the three-years (2015-2017) dataset used in our scenarios. Results from the gravity model estimation in Chapter 4 are the baseline for our simulations on the potential impacts of RES locations on flows. First, the endogenous variable of the gravity model is detailed and described along with an apprise on the explicative variables and the control variables. Afterward, summary statistics and main data employed to create scenarios are presented.

Endogenous variable is the energy flow ($F_t^{i,j}$) at each time t in each pair of nodes and identified as i, j[18]. In order to consider both flow directions, we include each pair of nodes twice in our dataset: $F_t^{i,j} \geq 0$ when the flow comes from i to j and $F_t^{i,j} = 0$ otherwise (see Figure 5.2).

Figure 5.2: Graphic representation for all pairs of nodes considered in Chapters 4 and 5.



Note: i node in Figure 5.2.a (above) corresponds to j in Figure 5.2.b (below), and vice versa.
Source: own elaboration.

We use a twice-daily frequency -peak and off-peak hours- dataset with more than 20 million observations, covering the geographical area of (continental) Spain. Each

[18] $F_t^{i,j}$ is calculated using Marginal Loss Factors in Chapter 4. Flows are not represented in any specific energy unit (MWh, GWh...) since coefficients in the estimated equation are in logs. We estimate elasticities: the proportional change of $F_t^{i,j}$ in response to a change in another.

observation represents the hourly average values in each period and the peak dummy variable ($PEAK_t$) takes the value 1 during peak hours and 0 otherwise[19]. This definition of flows has been previously used in Chapter 2 and in the literature (Chevalier et al., 2003; Albadi and El-Saadany, 2008). Energy flow data comes from REE (2019a) and Figure 5.1 represents the structure of the grid considered.

The sum of energy injected in i and j at the time t are represented by Gr_t^i and Gr_t^j, respectively. These values are used to capture the supply side effects on flows. Here, the location of nodes at NUTS2 level are represented by r, been the region[20] where the corresponding nodes are sited in, and calculated as follows:

$$Gr_t^i = N_t^i + CC_t^i + CO_t^i + H_t^i + W_t^i + SOL_t^i + I_t^i + CHP_t^i \quad for \quad \forall i \in r \tag{5.3}$$

$$Gr_t^j = N_t^j + CC_t^j + CO_t^j + H_t^j + W_t^j + SOL_t^j + I_t^j + CHP_t^j \quad for \quad \forall j \in r \tag{5.4}$$

where each right hand side variable corresponds to the energy generated by each technology (nuclear, combined cycle, coal, hydropower, wind, solar, imports and combined heat and power)[21] at each i and j node at the t time. Given that we use twice-daily frequency -peak and off-peak- observations, we are capturing the different role of each technology in the mix, i.e. nuclear generates in both peak and off-peak, solar capacity mostly generates in the peak, wind mostly in the off-peak, combined cycle in the peak time, etc.

On the demand side of the flows, we include D^n, defined as the shortest distance -in km- from each n node to the closest most populated city in Spain[22], to consider how close is each node from the main consumption areas. Some additional explicative variables are included to control for the relative position of each node w.r.t. the rest, avoiding a potential bias problem (De Benedictis and Tajoli, 2011): we use the *degree of centrality* (C_n^d) that considers the number of electricity lines

[19]This classification is used for those low-voltage consumers in Spain with two period tariffs (2.0DHA and 2.1DHA), with the peak period covering from 12 p.m. to 10 p.m.

[20]r takes the following values for each NUTS2 region: 1 for Andalucia, 2 for Aragon, 3 for Asturias, 4 for Cantabria, 5 for Castilla y Leon, 6 for Castilla y La Mancha, 7 for Catalunya, 8 for Valencia, 9 for Extremadura, 10 for Galicia, 11 for Madrid, 12 for Murcia, 13 for Navarra and Rioja, and 14 for Pais Vasco

[21]With Na_t^i, Nb_t^j, CCa_t^i, CCb_t^j, COa_t^i, COb_t^j, Ha_t^i, Hb_t^j, Wa_t^i, Wb_t^j, $SOLa_t^i$, $SOLb_t^j$, Ia_t^i, Ib_t^j, $CHPa_t^i$ and $CHPb_t^j$, are nuclear, combined cycle, coal, hydropower (also includes Pumping Generation), wind, solar, imports and combined heat and power, respectively

[22]Madrid, Barcelona, Valencia, Sevilla, Zaragoza, Malaga, Murcia, Bilbao, Alicante, Cordoba, Valladolid, Vigo, Gijon, Hospitalet de Llobregat, Vitoria and A-Coruña. All them represent 25% of the population in Spain (continental).

connected to n, and the *closeness centrality* (C_n^c) that considers the closeness of n w.r.t the rest. Finally, $Dist^{i,j}$ is the distance, in kilometres, between each pair of nodes (i,j). Geographical data is calculated by a geographical information system software, while the rest data comes from OMIE (2019) and REE (2019b). Table 5.4 shows descriptive statistics of variables used in Chapter 5. For further details, see Chapter 4.

Table 5.4: Summary Statistics.

	N	Mean	Std.Dev.	Min.	Max.
$F_t^{i,j}$	678,900	0.0062388	0.0109806	0	0.1817
$G1_t^i$, $G1_t^j$	20,818,140	42.63293	161.6872	0	2,430.652
$G2_t^i$, $G2_t^j$	20,818,140	15.67784	76.97765	0	1,085.627
$G3_t^i$, $G3_t^j$	20,818,140	17.04793	120.0196	0	2,141.392
$G6_t^i$, $G6_t^j$	20,818,140	2.342647	17.17407	0	243.8766
$G7_t^i$, $G7_t^j$	20,818,140	30.23989	102.9536	0	1,386.241
$G8_t^i$, $G8_t^j$	20,818,140	25.58127	122.6711	0	1,227.28
$G9_t^i$, $G9_t^j$	20,818,140	51.53446	263.025	0	2,374.776
$G10_t^i$, $G10_t^j$	20,818,140	20.84302	120.2706	0	1,834.653
$G11_t^i$, $G11_t^j$	20,818,140	27.34457	197.3159	0	2,146.636
$G12_t^i$, $G12_t^j$	20,818,140	34.86667	185.2269	0	2,599.453
$G13_t^i$, $G13_t^j$	20,818,140	2.092436	10.15576	0	180.0169
$G14_t^i$, $G14_t^j$	20,818,140	5.656881	48.5767	0	2,284.322
$G15_t^i$, $G15_t^j$	20,818,140	9.873682	100.7776	0	2,105.36
$G16_t^i$, $G16_t^j$	20,818,140	13.18393	81.9428	0	1,718.192
D^i	20,818,140	81.3507	57.61394	8.251244	276.4956
D^j	20,818,140	81.3507	57.61394	8.251244	276.4956
$Dist^{i,j}$	20,818,140	551.8508	259.8601	7	1,342
C_i^d	20,818,140	0.032085	0.0145708	0.0103093	0.0824742
C_j^d	20,818,140	0.032085	0.0145708	0.0103093	0.0824742
C_i^c	20,818,140	0.0018513	0.0003356	0.0012386	0.0025592
C_j^c	20,818,140	0.0018513	0 .0003356	0.0012386	0.0025592

5.5 Results

Herein we present the results from simulations to explore potential impacts of alternative RES locations on flows through a combined analysis of the scenarios and strategies defined in section 5.3.3. First, we analyze impacts of new RES capacity on flows and calculate the corresponding grid costs necessary to solve congestions. Second, we explore the impact on electricity losses.

5.5.1 Grid costs

For each strategy-scenario simulation, we find the estimated flow ($\hat{F_t^{i,j}}$). Therefore, comparing both the average estimated flows ($\overline{\hat{F_t^{i,j}}}$) and the average original flows ($\overline{F_t^{i,j}}$) for each pair of nodes, we calculate the additional congestions (ΔCg), as follows:

$$\Delta Cg = \frac{\overline{\hat{F_t^{i,j}}}}{\overline{F_t^{i,j}}} - 1\,[\%] \tag{5.5}$$

Table 5.5 shows ΔCg for each scenario -in rows- and strategies -in columns- (see Appendix III for the additional congestions in each region). Our first interesting result is the implementation of the NECP implies higher congestions regardless the scenario and strategy considered. This confirms replacing the generation mix significantly impacts on grids. Our second result corresponds to the strategies: concentrating RES in specific nodes (*within NUTS2*) -strategy c- results in higher congestions than disseminating RES between all nodes within the region -strategy a-. This might be explained because concentrating RES results in a local surplus of generation that needs further use of grids.

Table 5.5: Additional congestions (ΔCg) for each scenario-strategy.

Scenario	Strategy a	Strategy b	Strategy c
1	+9.92%	+13.54%	+14.29%
2	+9.83%	+13.91%	+14.59%
3	+7.80%	+11.98%	+13.55%
4	+8.73%	+12.61%	+14.14%
5	**+6.37%**	+9.16%	+11.95%
6	+6.60%	9.04%	+11.91%

Comparing ΔCg between different scenarios (*between NUTS2*), we find our third interesting result: concentrating RES in some specific NUTS2 regions (scenarios 1 to 4) results in higher congestions than disseminating across all the country (scenarios 5 and 6). However, there is not a relevant difference between increasing RES *proportionally* or *non proportionally* to the existing capacity (comparing pairs of scenarios 1-2, 3-4, 5-6). Moreover, ΔCg is different across regions for each scenario-strategy (see Appendix III), which is explained by differences in the current installed capacity, cities and grid infrastructure. Therefore, we conclude the concentration of new capacity across areas (*between NUTS2*) is the key element in terms of the resultant congestions when defining locational signals[23].

Using ΔCg for each pair of nodes -grid line- we calculate the corresponding grid investments using the audited and standard network costs published by the Spanish Ministry of Energy (Tables 5.12.5.7.4 and 5.13.5.7.4 in Appendix IV). Finally, we calculate the total grid costs ($Cost$) in M€ for each scenario-strategy and they are shown in Table 5.6.

Table 5.6: Total grid costs ($Cost$) for each scenario-strategy.

Scenario	Strategy a	Strategy b	Strategy c
1	3,190.5 M€	4,260.7 M€	3,828.1 M€
2	3,274.4 M€	4,300.9 M€	3,996.4 M€
3	3,062.7 M€	4,348.2 M€	4,402.5 M€
4	2,991,6 M€	4,171.5 M€	4,563.2 M€
5	**1,809.2** M€	3,090.3 M€	3,610.8 M€
6	2,156.8 M€	2,968.2 M€	3,460.2 M€

Comparing Tables 5.5 and 5.6, we find higher ΔCg corresponds to higher $Cost$. This complements our second result: concentrating RES in specific nodes (*within NUTS2*) -strategy c- requires higher grid investments ($Cost$) than disseminating between all nodes within the region -strategy a-. However, total grid costs in strategy c are not always higher than strategy b, which might be explained by the different characteristics of the grid involved in each strategy.

Regarding scenarios (*between NUTS2*), we find our fourth relevant result: there are differences in $Cost$ between increasing RES *proportionally* -strategy 5- and *non-proportionally* -strategy 6-. Indeed, the less expensive scenario-strategy corresponds to 5a (1,809.2 M€), where RES are disseminated across the country, increase *proportionally* (*between NUTS2*), and are connected to all nodes (*within the NUTS2*). The second less expensive scenario-strategy is 6a with 2,156.8 M€ (19% more expensive than 5a). In the other extreme, the most expensive scenario-strategy

[23]In Appendix III, results from Table 5.5 are desegregated by NUTS2 areas and represented in maps.

corresponds to 4c with 4,563.2 M€ (250% more expensive than 5a), where RES are connected to some NUTS2 areas, increase *non-proportionally* (*between NUTS2*), and are connected to specific nodes (*within the NUTS2*). Moreover, all the market choice scenarios imply higher total grid costs than 5a: 3,190.5 M€ in 1a, 4,260.7 M€ in 1b and 3,828.1 M€ in 1c.

In sum, there is a trade-off between the expected future income for RES promoters (Table 5.3) and grid costs bore by consumers (Tables 5.6): RES annual production for the less expensive scenario-strategy (5a) is 2.020 GWh/MW, fairly far from the market choice scenarios -1a, 1b and 1c- (2.179 GWh/MW). These results point out market instruments applied to generation activity do not achieve a full-efficient allocation of resources in grids, meaning there is a sub-optimal outcome from the social and network perspective. Therefore, there is a case to apply some regulatory changes aiming to provide locational incentive for new RES as means to increase the efficiency and the overall welfare.

5.5.2 Electricity losses

For each strategy-scenario simulation, we calculate how electricity losses change (ΔL) and its corresponding extra costs (ΔCL). Results are shown in Table 5.7 and further details about their calculations are available in Appendix V.

ΔL show very low rates as losses are inversely proportional to the voltage and we are considering the highest voltage grid. Comparing Tables 5.5 and 5.7, ΔCg and ΔL follow similar patterns: concentrating RES in specific nodes (*within NUTS2*) -strategy c- results in higher losses than disseminating across all nodes within -strategy a-. However, we find some negative values for ΔL in strategy a, which is our fifth relevant result: in specific scenarios the energy produced do not travel as far as in others. It is important to bear in mind that in our simulations, important large conventional generating plants are also disconnected -3 nuclear plants and all coal plants- and its production is replaced with new RES. From our results, we conclude flows are slightly "more balanced" across the country in scenario 5a, where ΔL reduces -0.000760$\%$.

Comparing all the different scenarios-strategies in Table 5.7, the lowest levels of ΔL corresponds to 5a. Moreover, when electricity losses (ΔL) are represented in its corresponding cost (ΔCL), we see similar patterns. The less expensive even cost saving option in terms of losses corresponds to the scenario-strategy 5a with -0.038 M€.

Table 5.7: Electricity losses changes (ΔL) and their costs (ΔCL) for each scenario-strategy.

Scenario	Variable	Strategy a	Strategy b	Strategy c
1	ΔCL	+0.015 M€	+0.160 M€	+0.325 M€
	ΔL	(0.000304%)	(+0.003165%)	(+0.006425%)
2	ΔCL	+0.028 M€	+0.195 M€	+0.450 M€
	ΔL	(+0.000545%)	(+0.003865%)	(+0.008898%)
3	ΔCL	-0.001 M€	+0.135 M€	+0.432 M€
	ΔL	(-0.000015%)	(+0.002662%)	(+0.008553%)
4	ΔCL	-0.007 M€	+0.123 M€	+0.388 M€
	ΔL	(-0.000136%)	(+0.002433%)	(+0.007673%)
5	ΔCL	-0.038 M€	+0.146 M€	+0.653 M€
	ΔL	(-0.000760%)	(+0.002895%)	(+0.012927%)
6	ΔCL	-0.036 M€	+0.127 M€	+0.670 M€
	ΔL	(-0.000703%)	(+0.002515%)	(+0.013253%)

Note: ΔL is the change of electricity losses w.r.t. baseline scenario (2015-2017) (in %), while ΔCL is its corresponding economic costs (in M€).

In summary and comparing our results from the literature, they are aligned with outcomes from other authors who find higher RES increases grid extensions (Schaber et al., 2012); increasing RES increases congestion within bidding zones - country zones- and increases congestion costs (Van den Bergh et al., 2015; Joos and Staffell, 2018); and concentrating RES in specific regions increases congestions (Hitaj, 2015).

5.6 Conclusion and Policy Implications

Electricity systems have transformed in last years and this process will continue due to the massive change in the generation mix from the replacement of conventional technologies by RES. In Chapter 5 we show how the location of future RES is highly relevant from the private and social perspectives. Moreover, future grid costs borne by consumers might also trade-off other benefits related to RES: decarbonization of electricity, impacts on wholesale prices, etc.

From our results -in all the scenarios-strategies- we conclude important grid investments will be required to accommodate the energy mix changes. This confirms connecting the planned new RES requires important funding regardless the location chosen by them, which might be explained by the higher variability of RES over traditional technologies that results in greater congestions. However, there are important differences between the decision aimed to locate RES considering the cheapest grid costs or considering the maximum profit for RES promoters. Indeed, promoters would prefer to locate their plants in the most optimal regions -with the highest annual production over the installed capacity (GWh/MW)- in case of an infinite grid capacity. However, this multiplies grid costs by more than two times and increases energy losses with their corresponding costs. The less expensive decision in terms of grid costs is not concentrating new RES in specific regions, but connecting them across all regions in the country and across all the nodes within each region. Moreover, dispersed RES reduces the likelihood to apply technical constraints to them, which also allows exploit better their installed capacity. We find a reduced impact on electricity losses, but non negligible. We should have in mind the previous costs are paid by consumers in the Spanish regulatory framework[24]. In other words, we identify a market failure related with the location of new RES and some regulatory mechanisms should provide the right incentives to foster the welfare enhancer options.

Accordingly, we provide several regulatory recommendations aimed to promote some locations over others for new generation. In the context of the current RES capacity auctions, there are several complementary options. First, including *locational incentives* to also promote RES in different regions than the most optimal -in terms of wind or sun-, which could offset the lower incomes related with their lower annual production in GWh/MW. Some countries have implemented something similar, such as Mexico. However, this choice requires quantifying in advance the locational incentive and there is an asymmetric information problem between the regulator, grid operators and RES promoters. As result, the incentive might not be as efficient as expected. Indeed, this happened in the first auctions with locational incentives in Mexico. As is stated in AURES (2017), a simple analysis of the winning projects locations showed they were not located as expected, which implied the allocate efficiency could be improved. In this line, results from Chapter 5 sheds the light in the grid costs to better improve locational incentives in future RES capacity auctions, as some authors also propose (Del Río et al., 2017). Second, including *potential RES sites* (Del Río and Linares, 2014), which are organized auctions for pre-identified sites and bidders submit a price per MWh produced for every site.

[24] In the Spanish regulatory framework, consumers pay all the electricity losses from the generation plant to their meter as is explained in Chapter 2.

China used this scheme for on-shore wind. However, this decreases competition due to a lower liquidity on bids, but increases the regional coordination. As alternative, these authors propose our third option, including *a list of technology-specific RES sites*, but this requires a difficult agreement between the regional and local governments, and the final approval from the SO. Although geographical diversity auctions could lead to lower allocate efficiency and higher support levels (Del Río, 2017), our results show they could be compensated with the avoided costs for consumers in grid reinforcements. Finally, our fourth alternative is making different *regional capacity auctions*, which would avoid calculating locational incentives in advance because final auction prices would internalize differences between regions in terms of RES potentials. However, the boundary definitions and RES quotas might result in delicate political discussions and also lower allocate efficiency.

Different UoS charges might also provide locational incentives since affect RES promoters in their future incomes and business plans. Nowadays, in Europe they are only implemented in the UK, Ireland, Norway and Sweden (ENTSO-E, 2018). However, this policy recommendation has two cons: (i) UoS boundaries should remain constant for many years to become an efficient incentive, which implies grid conditions should not change in the long-run, but as we find in our results, locations for new generation might affect regional congestions and change optimal grid locations in the short-run; (ii) their implementation -from a *postage stamp usage fee*- also implies changing rules for the connected consumers and generators. In other words, there might be undesired effects on many other agents who might argue the non-retroactivity principle of regulation to oppose.

The third regulatory mechanism is changing the connection charges from *shallow* to *deep charges*. In the last, the key issue is defining a clear, neutral and efficient mechanism to individually assign grid costs beyond the substation where RES are connected (Barth et al., 2008). Indeed, grid is fully interconnected and there are multiple interactions between nodes and grids as we find in our simulations. Therefore, high *deep charges* might discourage RES promoters to locate their capacity in some regions and/or enhance gaming between them. In this context, RES promoters related to many plants might have competitive advantages over small promoters in this gaming problem.

Finally, the fourth regulatory recommendation is based on the transmission planning. In Spain, there is a *reactive planning* scheme, where transmission planning occurs after RES promoter requests for their connection. This scheme could be changed to *anticipatory planning* because the Spanish NECP targets are too ambitious, RES connection process should be achieved in ten years, and it is crucial to reduce the uncertainty to the promoters' connection times. However, replacing the generation mix requires high grid investments regardless their location, as we find in this Chapter. This might foster grid operators to put on the table disproportionate grid investments in the transmission planning since there is an asymmetric information problem between them, the regulator and the corresponding ministry that should approve these investments. We should have in mind that a share of grid operators' incomes -and profits- come from the network building -CAPEX- and the subsequent maintenance -OPEX- during their operating time. Moreover, these anticipatory grid investments should be funded by UoS charges, which might need increasing or not reducing them. This affects all consumers -from large industrial plants to small household consumers- and generators. In other words, this might impact on the competitiveness of many economic sectors.

An intermediate solution between *reactive planning* and *anticipatory planning* is the establishment of a single authority competent for planning. Therefore, authorization and regulation might improve coordination between RES interests and grid operators. This was implemented in Germany. However, the elimination of regional competence triggered protests with the federal authorities (Steinbach, 2013). In Spain, this choice seems not be easily implemented since regional governments have increased some competences in energy planning during the last decades.

In sum, our policy recommendations are in line with the general principles for the market design improvement in a context of high RES penetration: first, using price signals and regulated network tariffs to reflect the value of all electricity services; second, delivering the least system cost solution, which ensures the right location of future RES investment at the lowest prices for consumers; and third, de-risking the financing of new RES generation investments as the lower congestions results in less likelihood to apply curtailments to RES. Indeed, low-carbon electricity systems become more capital intensive (Newbery et al., 2018). Finally, our recommendations would help to achieve a reasonable reliable energy supply at an affordable price, and with an acceptable environmental impact over the long term (Pérez-Arriaga et al., 2008). Future research could go a step further and use results from Chapter 5 to define locational incentives for auctions and also regional auctions.

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5.7 Appendix

5.7.1 Appendix I

Table 5.8.5.7.1 shows results from the estimation of Equation 5.1 in Chapter 4, which are used as baseline in our simulations:

Table 5.8: Generation impacts on flows.

	(1) $F_t^{i,j}$
PEAK	0.0258***
	(0.00317)
$G1^i$ (log) (Andalucia)	0.271***
	(0.0105)
$G2^i$ (log) (Aragon)	0.100***
	(0.0121)
$G3^i$ (log) (Asturias)	1.038***
	(0.0295)
$G4^i$ (log) (Cantabria)	-0.124***
	(0.0429)
$G5^i$ (log) (Castilla-Leon)	0.194***
	(0.00417)
$G6^i$ (log) (Castilla-Mancha)	0.645***
	(0.0102)
$G7^i$ (log) (Catalunya)	0.222***
	(0.0143)
$G8^i$ (log) (Ctat.Valenciana)	-0.0334***
	(0.00999)
$G9^i$ (log) (Extremadura)	0.196***
	(0.00591)
$G10^i$ (log) (Galicia)	0.748***
	(0.0171)
$G11^i$ (log) (Madrid)	0.0670**
	(0.0315)
$G12^i$ (log) (Murcia)	-0.113***
	(0.0127)
$G13^i$ (log) (Navarra-Rioja)	1.072***
	(0.0540)
$G14^j$ (log) (Pais Vasco)	0.222***
	(0.0136)
$G1^j$ (log) (Andalucia)	-0.347***
	(0.00816)
$G2^j$ (log) (Aragon)	-0.147***
	(0.0324)
$G3^j$ (log) (Asturias)	-1.137***
	(0.0366)
$G4^j$ (log) (Cantabria)	0.300***
	(0.0228)
$G5^j$ (log) (Castilla-Leon)	-0.222***
	(0.00674)
$G6^j$ (log) (Castilla-Mancha)	-0.526***
	(0.00874)
$G7^j$ (log) (Catalunya)	-0.183***
	(0.00826)
$G8^j$ (log) (Ctat.Valenciana)	-0.106***
	(0.00808)
$G9^j$ (log) (Extremadura)	-0.217***
	(0.00522)
$G10^j$ (log) (Galicia)	-0.515***
	(0.0176)
$G11^j$ (log) (Madrid)	-0.216***
	(0.0193)
$G12^j$ (log) (Murcia)	0.178***
	(0.0193)
$G13^j$ (log) (Navarra-Rioja)	-1.129***
	(0.0661)
$G14^j$ (log) (Pais Vasco)	0.264***
	(0.0200)
$Dist^{i,j}$(log)	-0.818***
	(0.220)
Constant	26.23***
	(5.741)
Observations	678,900
R^2	0.559

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

5.7.2 Appendix II

Table 5.9: New solar capacity by NUTS2 region in each scenario.

NUTS2	2017 (in MW)	SC1 (in MW)	SC2 (in MW)	SC3 (in MW)	SC4 (in MW)	SC5 (in MW)	SC6 (in MW)
Andalusia	1,878	+13,968	+15,034	+11,436	+7,563	+10,433	+6,225
Aragon	169			+1,027	+4,974	+937	+4,246
Asturias	1						
Cantabria	2						
C.Leon	495			+3,014	+9,660	+2,749	+8,221
C.Mancha	1,274	+9,476	+14,067	+7,759	+7,290	+7,078	+6,077
Catalunya	290			+1,766	+3,171	+1,611	+2,680
Valencia	398					+2,211	+1,753
Extremadura	1,413	+10,509	+6,625	+8,604	+3,074	+7,849	+2,438
Galicia	17					+93	+2,719
Madrid	64					+355	+679
Murcia	469	+3,488	+1,715	+2,856	+750	+2,605	+578
Navarra	161			+980	+959	+894	+800
Pais Vasco	27					+150	+643
Rioja	86					+478	+381
	6,744	+37,441	+37,441	+37,441	+37,441	+37,441	+37,441

Note: SC*x* column corresponds to the *x* scenario.

Table 5.10: New wind capacity by NUTS2 region in each scenario.

NUTS2	2017 (in MW)	SC1 (in MW)	SC2 (in MW)	SC3 (in MW)	SC4 (in MW)	SC5 (in MW)	SC6 (in MW)
Andalusia	3,327			+8,043	+12,608	+3,968	+6,592
Aragon	1,926	+6,990	+11,964	+4,656	+6,755	+2,297	+3,477
Asturias	518					+618	+683
Cantabria	35					+42	+567
C.Leon	5,591					+6,669	+5,078
C.Mancha	3,847					+4,589	+5,150
Catalunya	1,269	+4,605	+8,078	+3,068	+4,573	+1,514	+2,367
Valencia	1,205					+1,437	+1,428
Extremadura	0						
Galicia	3,343	+12,132	+5,266	+8,082	+2,037	+3,987	+6
Madrid	0						
Murcia	263					+314	+1,018
Navarra	995	+3,611	+2,030	+2,405	+895	+1,187	+182
Pais Vasco	153					+182	+666
Rioja	448			+1,083	+470	+534	+123
	22,920	+27,338	+27,338	+27,338	+27,338	+27,338	+27,338

Note: SC*x* column corresponds to the *x* scenario.

5.7.3 Appendix III

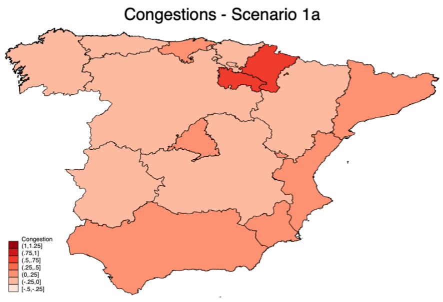

Figure 5.3: Congestions 1a.

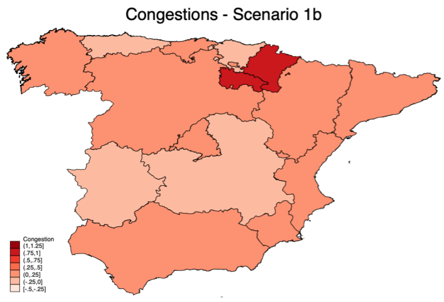

Figure 5.4: Congestions 1b.

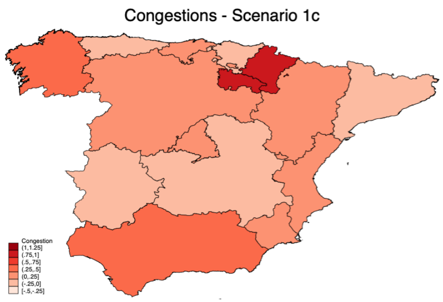

Figure 5.5: Congestions 1c.

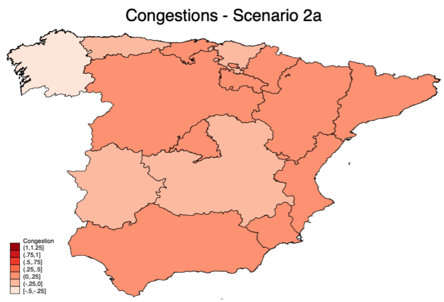

Figure 5.6: Congestions 2a.

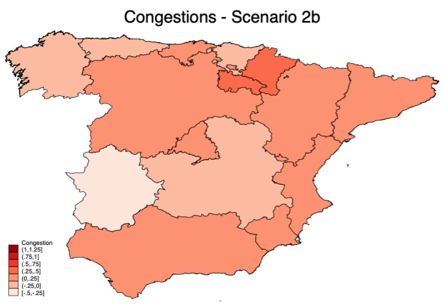

Figure 5.7: Congestions 2b.

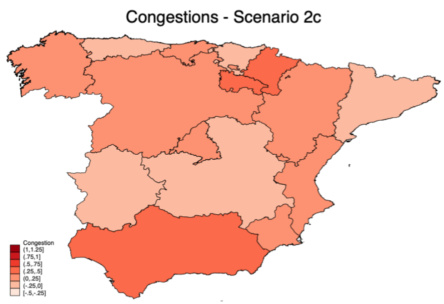

Figure 5.8: Congestions 2c.

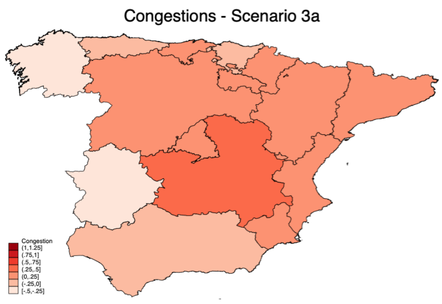

Figure 5.9: Congestions 3a.

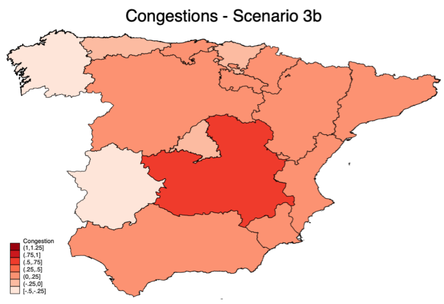

Figure 5.10: Congestions 3b.

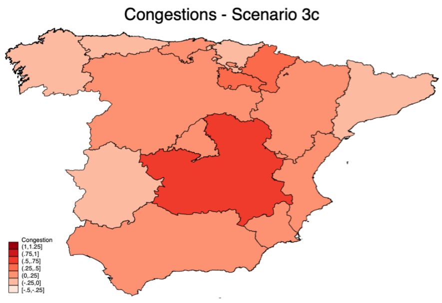

Figure 5.11: Congestions 3c.

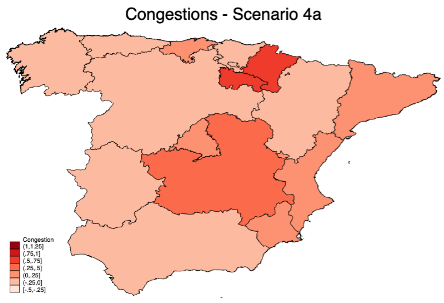

Figure 5.12: Congestions 4a.

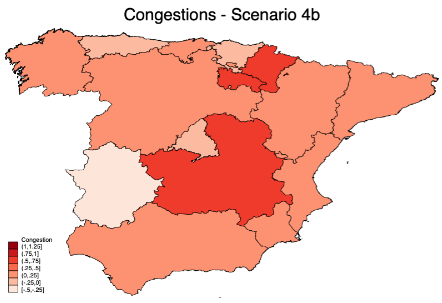

Figure 5.13: Congestions 4b.

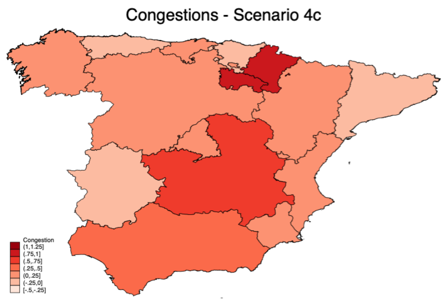

Figure 5.14: Congestions 4c.

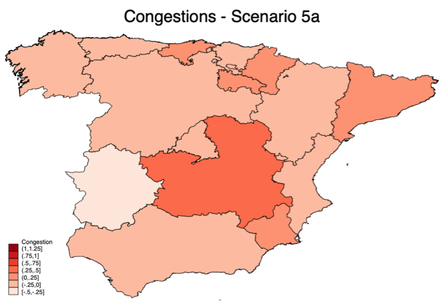

Figure 5.15: Congestions 5a.

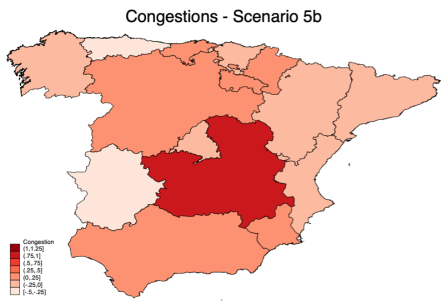

Figure 5.16: Congestions 5b.

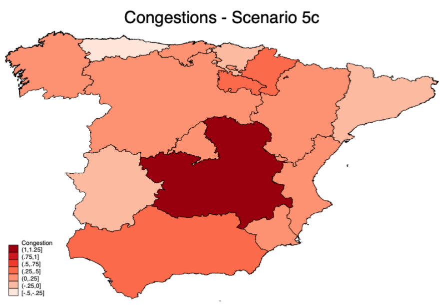

Figure 5.17: Congestions 5c.

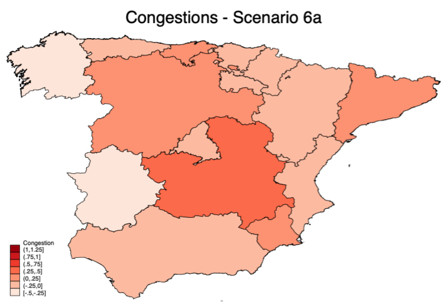

Figure 5.18: Congestions 6a.

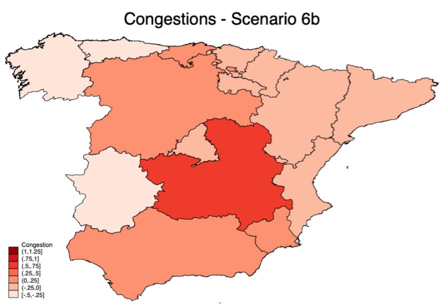

Figure 5.19: Congestions 6b.

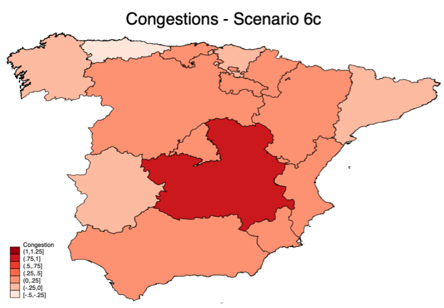

Figure 5.20: Congestions 6c.

5.7.4 Appendix IV

In this section we present the methodology followed to calculate the total grid costs ($Cost$) for each scenario-strategy. As baseline, we use the regional average congestions from Chapter 4 and shown in Table 5.11.5.7.4. Sorting regions from their average congestions, we classify them in A and B groups[25]:

Table 5.11: Average congestions (2015-2017) in each Spanish NUTS2 areas.

NUTS2 region	Average congestions (in%)	Group
Galicia	+461.95%	A
Asturias	+396.99%	A
Pais Vasco	+121.91%	A
Castilla-Leon	+82.50%	A
Cantabria	+64.29%	A
Madrid	+30.01%	A
Aragon	+21.16%	A
Navarra/Rioja	n/a	A
Murcia	-3.12%	B
Extremadura	-17.43%	B
Valencia	-52.18%	B
Castilla-LaMancha	-60.80%	B
Catalunya	-62.48%	B
Andalusia	-79.93%	B

We calculate the corresponding grid costs ($Cost_r^A$,$Cost_r^B$) for each r region by the combination of both the additional congestions (ΔCg) from Equation 5.5 and the standard costs recognized by the Ministry and published in the IET/2659/2015[26] (Tables 5.12.5.7.4 and 5.13.5.7.4):

Finally, we calculate the total grid costs ($Cost$) in each scenario-strategy:

$$Cost = \sum_{r}^{NUTS2} Cost_r^B + \sum_{r}^{NUTS2} Cost_r^B \tag{5.6}$$

[25]We consider Navarra/Rioja in the A group since their average congestion is not significant in the estimations performed by Chapter 4. This is a conservative approach.

[26]See: Boletin Oficial del Estado (12/12/2015) section I - Page 117250.

Table 5.12: Grid costs for group A-NUTS2 regions ($Cost_r^A$)

Threshold	Investment	$Cost_r^A$ (in M€)
$+25\% < Cg \leq +50\%$	Reinforcement of the actual line	$0.298437 * Dist^{i,j} * 0.5$
$+50\% < Cg \leq +100\%$	1 new line	$0.505047 * Dist^{i,j} * 1.25 + 2.087818 * 2$
$+100\% < Cg \leq +200\%$	2 new lines	$(0.505047 + 0.298437) * Dist^{i,j} * 1.25 + 2.087818 * 3$
$+200\% < Cg \leq +300\%$	3 new lines	$(0.505047 * 2) * Dist^{i,j} * 1.25 + 2.087818 * 4$
$+300\% < Cg \leq +400\%$	4 new lines	$(0.505047 * 2 + 0.298437) * Dist^{i,j} * 1.25 + 2.087818 * 5$
$+400\% < Cg \leq +600\%$	5 new lines	$(0.505047 * 3) * Dist^{i,j} * 1.25 + 2.087818 * 6$
$Cg > +600\%$	6 new lines, but connecting different nodes	$(0.505047 * 3 + 0.298437) * Dist^{i,j} * 3.00 + 2.087818 * 7$

Note: $Dist^{i,j}$ corresponds to the line length.

Table 5.13: Grid costs for group B-NUTS2 regions ($Cost_r^B$)

Threshold	Investment	$Cost_r^B$
$+50\% < Cg \leq +100\%$	Reinforcement of the actual line	$0.298437 * Dist^{i,j} * 0.5$
$+100\% < Cg \leq +200\%$	1 new line	$0.505047 * Dist^{i,j} * 1.25 + 2.087818 * 2$
$+200\% < Cg \leq +300\%$	2 new lines	$(0.505047 + 0.298437) * Dist^{i,j} * 1.25 + 2.087818 * 3$
$+300\% < Cg \leq +400\%$	3 new lines	$(0.505047 * 2) * Dist^{i,j} * 1.25 + 2.087818 * 4$
$+400\% < Cg \leq +500\%$	4 new lines	$(0.505047 * 2 + 0.298437) * Dist^{i,j} * 1.25 + 2.087818 * 5$
$+500\% < Cg \leq +700\%$	5 new lines	$(0.505047 * 3) * Dist^{i,j} * 1.25 + 2.087818 * 6$
$Cg > +700\%$	6 new lines, but connecting different nodes	$(0.505047 * 3 + 0.298437) * Dist^{i,j} * 3.00 + 2.087818 * 7$

Note: $Dist^{i,j}$ corresponds to the line length.

5.7.5 Appendix V

In this section we present the methodology followed to calculate the change on electricity losses (ΔL) and their corresponding costs (ΔCL) for each scenario-strategy.

We start from the premise that energy losses due to the Joule law (l_L) for each L line:

$$l_L = 3 * I^2 * R \tag{5.7}$$

where I is the current and R the resistance. Therefore, comparing the resultant energy losses (l_L^1) with the baseline energy losses in 2015-2017 (l_L^0), we find the energy losses change (Δl_L) for each L:

$$\Delta l_L = \frac{l_L^1}{l_L^0} - 1 = \frac{3 * R}{3 * R} * \frac{I_1^2}{I_0^2} - 1 = \frac{I_1^2}{I_0^2} - 1 \,[\text{in } \%] \tag{5.8}$$

In order to transform Δl_L to the change on the total electricity losses (ΔL_L), we use the corresponding L length ($Dist_L^{i,j}$) and the sum of all lengths ($\sum Dist^{i,j}{}_L$):

$$\Delta L_L = \Delta l_L * \frac{Dist_L^{i,j}}{\sum Dist^{i,j}{}_L} = (\frac{I_1^2}{I_0^2} - 1) * \frac{Dist_L^{i,j}}{\sum_L Dist_L^{i,j}} \,[\text{in } \%] \tag{5.9}$$

Finally, we calculate the total change of electricity losses (ΔL):

$$\Delta L = \sum_L \Delta L_L \,[\text{in } \%](5.10)$$

We calculate Δcl, the annual cost of ΔL, using the average hourly energy losses ($Losses$) in MWh and published by REE (2019a):

$$\Delta cl = \Delta L * \hat{WP} * 8760 * Losses \,[\text{in } €] \tag{5.11}$$

where $\hat{WP}$ is the expected future wholesale price of electricity and published in the NECP (56,8€/MWh). As cl is an annual cost and we are considering the decision of investing in RES, which are long-term investments, we calculate the net present value (ΔCL) as the economic flows from the year $y = 1$ to $y = 30$ and updated to the year $y = 1$ considering an interest rate of 2%.

6 Conclusions

There is a broad consensus an energy transition is the way to mitigate the effects of climate change and attain a more sustainable world. This includes the replacement of fossil fuels by non-polluting energy sources, namely renewable energy sources (RES). Indeed, both RES and energy efficiency can potentially achieve 90% of the required carbon reductions[1].

The impact of RES goes beyond the environmental framework. This provides advantages in terms of security of supply, improves the commercial trade balance because it reduces an external dependence on oil, creates employment in skilled activities with higher-added value, and opens up economic opportunities in rural non-industrialized areas. Due to all these issues, countries are considering RES as a strategic priority.

In the last two decades, technological progress and economies of scale have significantly decreased RES installation costs. Nowadays, wind and solar technologies are mature and fairly competitive in the market without large subsidies. As result, countries are changing RES promoting schemes based on large budget solutions to others which are more market-oriented, such as auctions.

Europe, and Spain in particular, have made significant headway in this path as shown by the high share of RES in their actual generation mix. However, the European Clean Energy Package and the recent European Green Deal[2] aim to go a step further and increase RES participation in the economy even more before 2030. All this poses a great challenge to national power sectors and all the agents involved: governments, regulators, grid operators[3], consumers and generators.

The stochastic characteristic of RES, owing to their direct dependence on weather conditions, makes it more challenging to replace fossil plants and integrate RES in electricity systems. This is further complicated because large scale storage is not available yet. Thus, electricity systems are moving to a more challenging operation based on an unpredictable and volatile generation mix.

In this energy transition, grids are the core of electricity systems as they have to allocate large amounts of RES. In this process, some grid-related costs might be

[1] Source: https://www.irena.org/energytransition

[2] Available at: https://ec.europa.eu/info/sites/info/files/european-green-deal-communication_en.pdf

[3] *Grid operators* term includes both the transmission system operator (TSO) and the distribution system operator (DSO)

significant and requires a deep analysis of the electricity system to avoid unwanted effects on social welfare. Indeed, this dissertation focus on the economic assessment of these costs, mostly paid by consumers through the final price of electricity.

The current network topology links the location of large-size urban areas, main industrial areas and large generation plants, such as nuclear plants. In the last two decades, the installation of RES in the countryside and far from main cities has required the allocation of many resources to reinforce actual grids and build others. These are known as *grid-investments*. Inevitably, the above-mentioned environmental targets will require the connection of many more RES and in a short time.

Undoubtedly, a safe, successful and affordable energy transition entails an efficient, optimal, and low-cost connection of RES. Otherwise, the expected future benefits from RES may not be fully achieved. This is a central focus of this thesis.

A fundamental aspect from the policy perspective is anticipating future scenarios and creating market-based frameworks aimed at achieving environmental targets, but also considering a maximization of social welfare and grid cost-efficiencies. In this regard, climate change policies should not create disproportionate costs in the final electricity bill, which would increase social inequality and affect its social acceptability. Accordingly, this thesis intends to explore some grid-related costs to know their determinants in detail, how the behaviours of agents are interrelated (consumers, generators and grid operators), and which might be the best choices. As in other economic activities, electricity information is slightly asymmetric among all the involved agents and regulatory agencies.

This research aims to contribute to existing knowledge of the economic impacts of the decarbonization of the electricity systems by several studies based on Spain, a country with a high level of RES in the generation mix. Results and policy implications from this thesis might be of great value for countries that are at a less advanced stage in this process.

This doctoral thesis seeks to fill this void by some linked empirical analyses at country-scale about *electricity losses*, *grid-congestions* and *grid-investments*. They are scarce in the literature despite representing very high costs for consumers, as is found in the previous Chapters.

Electricity losses are one of the most unknown grid-related costs. They are analyzed in Chapters 2, 3 and 5 of this thesis. Chapter 2 analyzes the economic determinants of *electricity losses*: the differentiation between two grid levels -transmission and distribution- and the two analyses performed, one from the demand side and another from the supply side. Indeed, these cross-sectional analyses provides interesting results. To that end, a powerful hourly dataset is made by merging data about: cost of electricity losses, electricity consumption and electricity generation.

In this regard, the estimated economic costs of *electricity losses* in distribution are five times higher than in transmission. In terms of policy implications, this suggests that policies aimed at reducing losses and improving social welfare should focus on distribution grid level; that is, in the grid that feeds all domestic consumers.

Surprisingly, potential benefits on losses from Demand Response (DR) policies - aimed at mitigating peak consumption of electricity- are small. This means potentials savings in *electricity losses* would hardly fund DR policies.

In generation, the results show that small generation plants close to consumers, namely Distributed Generation (DG), might have a positive effect on the reduction of *electricity losses*. However, there is a necessary condition that fully constrains these benefits: a good correlation between DG production and domestic consumption. Otherwise, the impact of DG on *electricity losses* might be the opposite. In this regard, most DG plants are small solar plants or small combined heat and power plants.

Finally, the costs of losses associated with hydro-pumping technology are high because there is a double cost-effect, one during the consumption of electricity to store energy, and another during the production of electricity. This is not necessarily a drawback, but these high costs should be borne in mind in the Cost Benefit Analyses in relation to this technology.

Chapter 3 goes beyond in the analysis of *electricity losses* and studies their impact on CO_2 emissions, which contributes to the literature about the decarbonization of power systems. Results from this Chapter suggest *electricity losses* do explain CO_2 emissions and the energy required to cover losses is of great importance in the total system CO_2 emissions. In this regard, the contribution of losses to CO_2 emissions is superior to the average emissions in the system. Moreover, the closing technology used to cover *electricity losses* is particularly relevant to explain the different contributions of losses on the CO_2 emissions: when Coal or Combined Cycle close the market, the impact of losses on CO_2 emissions is greater compared to the case when RES close the market. All this highlights an interesting finding: reducing *electricity losses* goes beyond to the reduction of wasted energy and also reduces the power system's CO_2 emissions. Indeed, this is one of the main contributions of Chapter 3.

Chapter 5 introduces the spatial dimension to evaluate how the location of new RES might affect *electricity losses* in an entire country's electricity system. In this regard, results show *electricity losses* increase when new RES are specially concentrated in small regions where solar and wind potentials are the best. Indeed, all these regions are in the countryside.

The high cost of losses and their contribution to CO_2 emissions demonstrate that policies should prioritize their reduction as they reduce the efficiency of the grids, represent a waste of resources, produce higher CO_2 emissions and lead to extra costs for consumers. In this regard, results from this thesis suggest several complementary policies:

First, optimal policies should focus on distribution grids and additionally foster matching DG production with domestic consumption. In countries with many small solar plants, these policies should boost electricity consumption at noon and during solar peak production. Although the wholesale price of electricity might already de decreasing at noon due to higher solar production, this is only a portion of the final electricity price paid by domestic consumers. Consumers also pay tolls to fund the grid infrastructure, namely Use of System (UoS) charges. In this point, reducing UoS at noon, also referred to as time-of-use tariffs, might be an efficient policy to encourage consumption at this time. However, the efficiency of this policy requires long-term stability and predictability as consumers are slightly reluctant to change their habits.

Second, grid operators assume the costs of *electricity losses* while receiving limited incomes. This is a strong incentive to reduce losses for them. However, this policy has two main weaknesses: it is challenging to define a transparent and non-discriminatory methodology to calculate incomes for each grid operator because their grids might not be comparable, and this could create some uncertainties in their future grid operators incomes, thus impacting on their Weighted Average Cost of Capital (WACC). In the end, consumers would pay a lower cost for losses, but also higher UoS charges to cover the higher costs paid by grid operators. Trade-offs between them would settle the final impact on the consumer surplus.

Third, generators also assume a part of the total costs of *electricity losses*. This is an economic incentive for generators to evaluate potential impacts of *electricity losses* in their future production schedules. However, there are several important handicaps: generators would subsequently increase their bid prices to cover their costs of *electricity losses*, which might distort the performance of electricity markets. Moreover, this policy might not be fully effective for solar and wind as they can hardly decide when to produce or not. Finally, the aggregate offer curve of the wholesale market would de displaced, and final electricity prices for consumers would not be as cheap as expected at first glance.

Fourth, future RES have locational economic incentives associated with the impacts of each location on future *electricity losses*. As with previous policies, this has a major drawback related with the calculations of these incentives, this requires previous thorough analyses of the power systems. In this context, Chapter 5 of this thesis represents a first step in the design of these locational incentives, as it quantifies the economic impact of losses associated to the location of future RES. This policy is explained in greater detail below.

Fifth, installing more efficient electricity assets (transformers) leads to less *electricity losses* when electricity travels through them. In this way, Directive 2009/125/EC of the European Parliament establishes a framework for the setting of ecodesign requirements for energy-related products and considers transformers as one of the priority groups to reduce *electricity losses*. These policies are useful but have limited potentials as they require installing more expensive and mature technologies.

Grid-congestions and *grid-investments* are also analyzed in this thesis. Chapter 4 explores the locational patterns of the actual electricity flows as a good proxy of the performance and cost-efficiencies of the grid, while Chapter 5 analyzes potential *grid-congestions* and their corresponding *grid-investments* associated with the location of new RES.

In this respect, the main contributions of Chapter 4 lie in the high-granularity dataset, the empirical approach followed and the results. The time-spatial dataset includes a combination of operating data, market data and geographical information. Accordingly, this study considers a range of different specific circumstances. The empirical approach includes a gravity model, very rarely used so far in the analysis of electricity flows despite their great potentials as demonstrated in the literature of international trade flows.

Estimates in Chapter 4 suggest the location of the generation technologies does explain energy flows through the networks, but there are some differences between technologies. To better assess and compare these differences, this Chapter includes a new indicator in the literature named *Distance Effect* that measures how efficient the location of each technology is with respect to the consumption sites. In this regard, Combined Cycle is the most efficiently located, which means a smaller use of transmission grids. Indeed, this technology is mostly close to main cities, where seaports and regasification plants are. Conversely, wind and imports are the least efficiently located. In effect, most wind capacity is located in the countryside and quite far from main urban areas. This interesting finding highlights that RES can harm the efficiency of the grids, thus requiring additional resources in *grid-investments* to connect them and minimize *grid-congestions*.

Other results include the average flows through the networks in each region. Estimators show that higher flows correspond to regions with more RES, while flows are lower in the opposite case. Therefore, the likelihood to curtail RES due to grid bottlenecks, namely *grid-congestion costs*, are also higher in this regions. Interestingly, higher flows do not correspond with the main consumption areas, namely industrial or metropolitan areas.

Results from Chapter 4 have great relevance and suggest the decarbonization of electricity systems might require allocating resources to *grid-investments* to minimize *grid-congestion costs*. Indeed, this is explored in detail in the following Chapter.

Chapter 5 studies *grid-congestions* and *grid-investments* related to the location of RES defined in the Spanish National Energy Climate Plan (NECP) within the ambit of the Clean Energy Package for all Europeans. Regarding the methodology, results from Chapter 4 are used as a baseline to simulate several potential locations of new RES to study how they affect *grid-congestions*, *electricity losses* and the corresponding *grid-investments*. RES locations correspond to the potential *market* and *social planner* choices. In the *market* choice, RES are only located in the most optimal locations considering wind and solar production, while the *social planner* choice considers RES locations that minimize total *grid-investments* and *electricity losses*.

Estimates in Chapter 5 suggest that connecting planned RES increases the average flows in transmission, regardless of their location. In short, *grid-investments* vary from 1,809M€ to 4,563M€ and the highest cost corresponds to *market* choice, this is concentrating RES in only a few regions, precisely those with the highest solar or wind productivity. Conversely, the less expensive, namely *social planner* choice, corresponds to the dissemination of RES across the whole country, including also the least productive regions. Moreover, the location of RES also affects future *electricity losses*: *market* choice increases losses, while the *social planner* choice can even reduce them.

Large *grid-investments* and the impact on *electricity losses* highlight the fact that RES locations are key in decarbonization of electricity systems, as they affect the final price of electricity. In this regard, a regulatory framework might be suitable to create incentives for minimizing *grid-congestion costs*, *grid-investments* and *electricity losses*, this is making an efficient usage of the grid. Accordingly, there are several complementary policies.

As connecting RES involves higher grid-costs regardless of their location, it is important to get the most out of the already installed RES. In this regard, the first policy is fostering the consumption of electricity at the times of maximum sunlight or wind, for instance including different hourly UoS charges[4], namely time-of-use tariffs. When consumption profiles are not well-correlated with RES production, the system operator might be forced to partially disconnect some RES and/or start pollutant plants to cover a deficit of generation. In this regard, it is necessary to study in detail the particular production profiles from RES in each country and the roles of wind and solar in the generation mix. For instance, wind peak production in Spain is usually at night. The efficiency of this policy can be enabled by a higher electrification of heat and transport -electric vehicles- and a wider implementation of the internet of things, which automates the use of home appliances.

Second, modifying grid planning criteria to allow for *flexible connection agreements* between grid operators and RES. Current grid planning criteria is very conservative and prioritizes large *grid-investments* to prevent any curtailment of generation due to grid bottlenecks. In this policy, the RES promoter pays cheaper connection costs and, in return, grid operators can curtail this RES plant production during certain hours per year under conditions previously agreed between them, normally without paying monetary compensations. Although this policy can delay some network investments, this has two main drawbacks: defining transparent and non-discriminatory playing rules for RES is challenging and there is a risk of gaming between RES entrants and incumbents.

[4]This policy includes reducing UoS to drop the final cost of electricity at night.

Third, including locational incentives in future RES auctions. In this regard, there are two main options. A possibility is adding *regional correction factors* to weight bids considering the location of the future RES and then offsetting bids for regions with worse weather conditions. However, defining *regional correction factors* is challenging as there is an asymmetric information problem between the regulator, grid operators and RES promoters. The other possibility is changing country level RES auctions to regional auctions. Accordingly, bidders submit bids considering RES potentials from each region. This last choice does not require *regional correction factors*, but defining regional quotas might be politically sensitive and requires complex coordination between the grid operator and the central, regional and local authorities. In any case, results from Chapter 5 represent a first step towards a more detailed definition of both choices.

Fourth, changing uniform UoS charges at country level to different regional UoS Charges for generators, namely locational tariffs. This economic incentive would offset the worst RES locations with minor UoS, which represents a lower future operative cost for RES. However, this policy might affect some main regulatory principles, such as simplicity, predictability and transparency. Moreover, its efficiency requires stable long–term locational incentives, which is challenging due to the changeable conditions of the grids.

In this regard, results from Chapter 5 are a first step in the definition of locational incentives for RES. Although no policy is perfect, results from Chapter 4 and 5 sheds light on their relevance and design.

Table 6.1 represents how policies aimed at reducing *electricity losses*, *grid-congestion costs* and optimizing *grid-investments* affect the final price of electricity paid by consumers.

Such an exercise as the one performed in this dissertation emphasizes the importance of grid-costs related to the connection of RES in the coming years. This exercise is necessary at country level, at regional level, but also at the European scale because the European Union is increasing the interconnection capacity between countries. This thesis also posits that some traditional empirical approaches can be complemented with other methodologies used in the analysis of economic flows.

The achievement of ambitious environmental targets in less than a decade cannot be an excuse to avoid an in-depth study of these grid-costs. Accordingly, national sup-

Table 6.1: Main impacts of each policy recommendation on the final electricity price.

		Policy recommendation						
Item	**Description**	**Time-of-use tariffs (hourly Uos)**	**Locational tariffs (regional UoS)**	**Locational incentives for RES**	**Flexible connect. agreem.**	**TSO/DSO pay losses**	**Generators pay losses**	**More efficient assets**
UoS Charges	Operating & building grids	$+/-$	$+/-$	$-$	$-$	$+$	$=$	$+$
Energy	Wholesale price of electricity	$-$	$-$	$-$	$=/-$	$-$	$+$	$-$
Losses	Costs of losses	$-$	$-$	$-$	$-$	$-$	$-$	$-$
Taxes	RES subsidies & others	$=$	$=$	$+$	$=$	$=$	$=$	$=$

Note: $+$ represents higher costs, while $-$ lower costs.
Source: Own elaboration.

port schemes and regulatory frameworks should be thoroughly revised to consider these targets, while also addressing the national and regional specificities, because RES and *grid-investments* are long-term capital investments. In this regard, any mistake in planning and defining the framework will affect the final price of electricity and consequently, household disposable incomes per capita and the country's competitiveness, in terms of social welfare.

Finally, it is fundamental to highlight that although this thesis applies to Spain, the outcomes are of general interest to most countries involved in this energy transition process. The Spanish experience provides interesting conclusions to achieve an efficient and affordable energy transition.

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