The economic impact of electricity losses

Maria Teresa Costa-Campi* Daniel Daví-Arderius† Elisa Trujillo-Baute*

Abstract

Although electricity losses constitute an important, but inevitable, amount of wasted resources (and a portion that has to be funded), they remain one of the lesser known components of an electricity system, and this despite the fact that the decisions of generators, transmission and distribution system operators and consumers all impact on them. In this paper we analyse the effects of such losses from two perspectives: from that of consumption and from that of generation.

Given that end-user consumption varies across the day, consumption has direct implications for electricity losses. Indeed, demand-side management policies seek to encourage consumers to use less energy during peak hours and to reduce network congestion. At the same time, from the perspective of generation, the recent growth in distributed generation has modified the traditional, unidirectional, downward flows in electricity systems. This affects losses as energy is produced in the lower voltage network, which is closer to points of consumption.

In this paper we evaluate the impact of consumption patterns and different generation technologies on the energy losses and the cost of losses. To do so, we draw on data from a real electricity system with a high level of renewable penetration, namely, that of Spain between 2011 and 2013. To the best of our knowledge, this is the first paper to analyse the real impact of consumption and the effect of each generation technology on energy losses, offering an opportunity to evaluate the potential benefits of demand-side management policies and distributed generation. Losses are divided between transmission and distribution levels, which is also a novelty that allows us to better define our regulatory recommendations aimed at exploiting to the full these potential benefits. Our results should serve as a baseline for countries at the early stages of implementing these policies.

JEL classification: L51, L94.

Keywords: regulation, networks, energy losses, distributed generation.

*University of Barcelona and Chair in Energy Sustainability, Barcelona Institute of Economics.

†Corresponding author. University of Barcelona and Chair in Energy Sustainability, Barcelona Institute of Economics. E-mail: daniel_davi@yahoo.es

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. 1) and Q_L is the meter consumption with the energy losses incurred (Eq. 2):

$$Q = \sum_i q_i \tag{1}$$

$$Q_L = \sum_i (q_i + \delta_i) = \sum_i q_{il} \tag{2}$$

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, decreases 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.

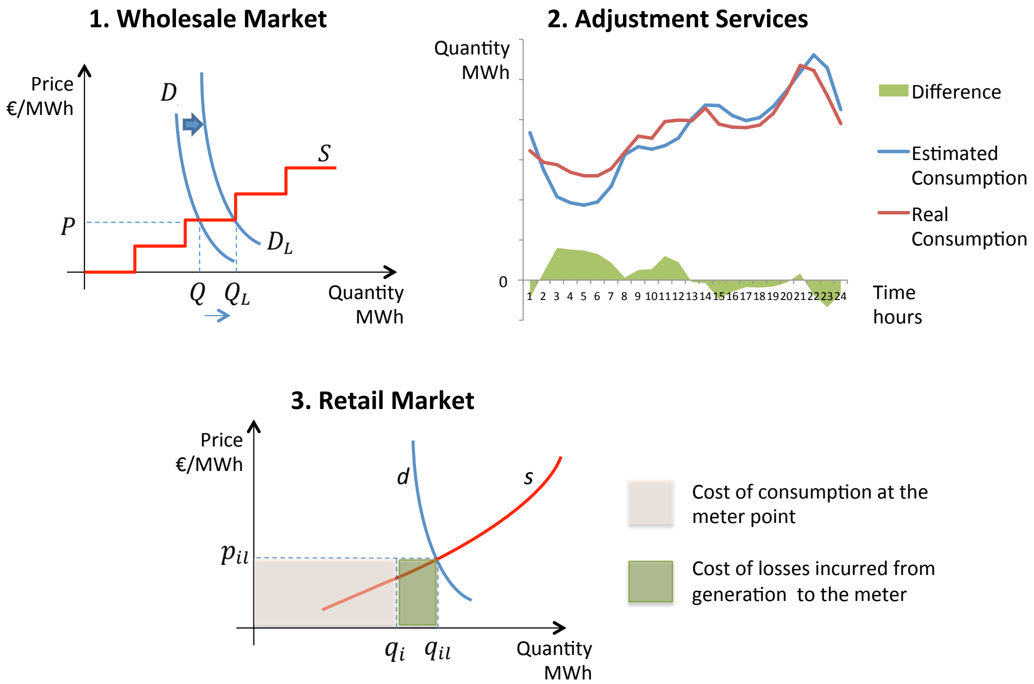
The mechanism by which energy losses affect the retail price is illustrated in Figure 1. First, based on the characteristics of the formation of the electricity wholesale price (WP), energy losses exert an upward pressure on total demand, so that the D curve is displaced upwards to D_L. Second, real 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

[1] Following the Spanish Regulatory Framework (see Section 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.

[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).

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].

Figure 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.

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 regarding 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

[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.

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 (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

[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.

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.

In this paper, 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 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

[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 this paper.

[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).

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 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 paper.

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) and 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.

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

[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.

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 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 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 this paper because this would require a longer period of time to achieve robust conclusions.

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.

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 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

[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).

[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.

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) ssuggests 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).

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

[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 paper 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.

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 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 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 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, Table 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.

[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.

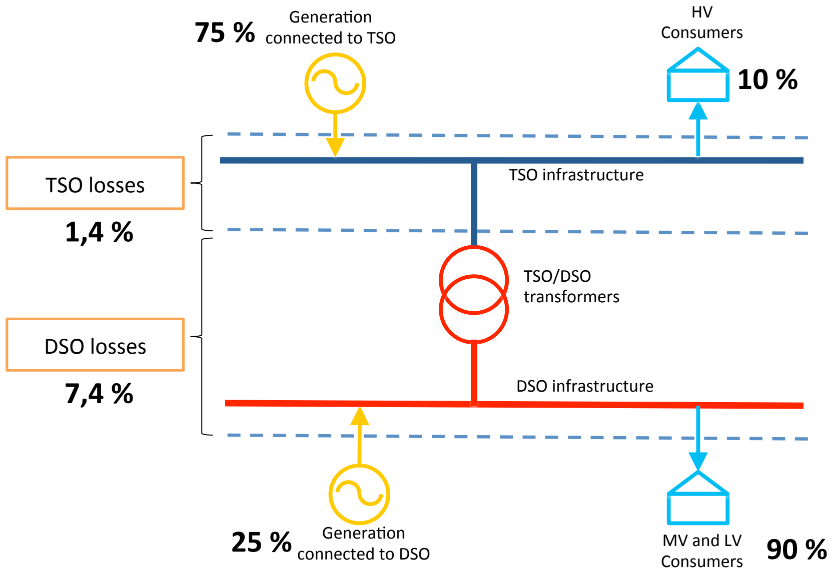
[19] Annual income for all DSOs is about 4,000M€, so 1% represents 40M€. The annual cost of losses in distribution was 915M€ in 2011, 980M€ in 2012 and 940M€ in 2013.

[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.

Figure 2: Share of total generation and consumption at TSO and DSOs in Spain (2011-2013).



Source: Own elaboration from REE (2014) and Ministry of Industry (2015).

Table 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 production curve is flat over the whole day.	Almost 85% is injected into distribution.

Note: Technologies are as follows: N_t Nuclear, CO_t Coal, CC_t Combined Cycle, H_t Hydropower, W_t Wind, SOL_t Solar, PG_t Pumping Generation, I_t imports and CHP_t Combined Heat and Power.
Source: Based on CNMC (2013).

Table 2: Behaviour of agents at each stage with regard to energy losses and their costs 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 have an impact on TSO and DSO energy losses depending on the distance to loads and when produce. A common UoS charge of 0.5€/MWh is applied to generation since 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 in the regulatory framework. 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 key performance indicator in the regulatory framework: incentive equals to $\pm1\%$ 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 to reduce the voltage. 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.

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. (3):

$$L_t = f(flows_t) \tag{3}$$

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. (4)). This allows us to better evaluate the individual impact of the different components at each level of the electricity system.

$$L_t = LT_t + LD_t \tag{4}$$

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, 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.

4.1 Demand-Side (Consumption) Perspective

The demand-side perspective, represented in Eqs. (5) and (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

[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 paper 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.

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. (5) and (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 €.

$$\begin{aligned}\Delta LT_t^i = \beta_0 + \beta_1 \Delta LT_{t-1}^i + \beta_2 \Delta C_t + \beta_3 \Delta E_t + \beta_4 \Delta PC_t + \beta_5 PEAK_t + \\ + \beta_6 FES_t + \sum_{d=1}^{6} \delta_d D_{dt} + \sum_{m=1}^{11} \alpha_m M_{mt} + \sum_{y=1}^{2} \gamma_y Y_{yt} + \beta_7 \Delta CF_t + \varepsilon_t\end{aligned} \tag{5}$$

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

As electricity demand varies throughout the day, a dummy variable ($PEAK_t$) is included in the demand models, Eqs. (5) and (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 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.

4.2 Supply-side (Generation) Perspective

The supply-side perspective, represented in Eqs. (7) and (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)

[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.

and distribution (LD_t) because 90% of consumption is in distribution. In Eqs. (7) and (8), the endogenous variable and its lagged are both measured in MWh and in €:

$$\begin{aligned}\Delta LT_t^i = \beta_0 + \beta_1 LT_{t-1}^i + \beta_2 \Delta N_t + \beta_3 \Delta CC_t + \beta_4 \Delta CO_t + \beta_5 \Delta H_t + \\ + \beta_6 \Delta PG_t + \beta_7 \Delta SOL_t + \beta_8 \Delta W_t + \beta_9 \Delta CHP_t + \beta_{10} \Delta I_t + \\ + \beta_{11} FES_t + \sum_{d=1}^{6} \delta_d D_{dt} + \sum_{m=1}^{11} \alpha_m M_{mt} + \sum_{y=1}^{2} \gamma_y Y_{yt} + \beta_{12} \Delta CF_t + \varepsilon_t\end{aligned} \tag{7}$$

$$\begin{aligned}\Delta LD_t^i = \beta_0 + \beta_1 LD_{t-1}^i + \beta_2 \Delta N_t + \beta_3 \Delta CC_t + \beta_4 \Delta CO_t + \beta_5 \Delta H_t + \\ + \beta_6 \Delta PG_t + \beta_7 \Delta SOL_t + \beta_8 \Delta W_t + \beta_9 \Delta CHP_t + \beta_{10} \Delta I_t + \\ + \beta_{11} FES_t + \sum_{d=1}^{6} \delta_d D_{dt} + \sum_{m=1}^{11} \alpha_m M_{mt} + \sum_{y=1}^{2} \gamma_y Y_{yt} + \beta_{12} \Delta CF_t + \varepsilon_t\end{aligned} \tag{8}$$

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.

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 (2014), 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 3 shows descriptive statistics of variables used in this paper. Energy losses are quantified in MWh, the cost of losses in € and the rest of the variables in MWh[27].

Having described the variables and data sources, we evaluate the stationarity of the time series variables used in this paper. 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

[26]There are five monthly settlements in Spain depending on the time elapsed since the last day of the month. This paper 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 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 consumers 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 3: Statistical summary of hourly variables.

Variable	**Units**	**N**	**mean**	**Std.Deviation**	**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.

cost change due to variations in the explicative variables. In the next section, the results of the estimations are presented and discussed.

Table 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

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

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.

5.1 Loss analysis from the consumption perspective

Table 5 shows the results of the loss estimations from the consumption perspective: Eqs. (5) and (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€).

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 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 5, we calculate the short- and long-run marginal effect on the cost of losses[28] in Table 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).

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

[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).

Table 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-$R^2 = (\sum(Y_t - \bar{Y})^2 - \sum(\hat{Y} - Y_t)^2)/\sum(Y_t - \bar{Y})^2$

Table 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 5, columns (3) and (4).

of losses or 0.31% of the annual energy losses. These results are similar to those reported by Shaw et al. (2009). Pumping Consumption is analysed in the next subsection together with Pumping Generation.

5.2 Loss analysis from the generation perspective

Table 7 shows the results of the loss estimations from the generation perspective: Eqs. (7) and (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 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 paper 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). 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.

Table 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-$R^2 = (\sum(Y_t - \bar{Y})^2 - \sum(\hat{Y} - Y_t)^2)/\sum(Y_t - \bar{Y})^2$

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) and 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 this paper 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 generated 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 5) to the 3.352€ of the cost of losses in transmission and 17.54€ in distribution (Table 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 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 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. 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.

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

[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).

Table 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 7, columns (3) and (4).

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.

5.3 Additional post-estimation analysis

In this section, we use the results reported above in Table 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 9.

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 with demand. These results are in line with those reported by Hung et al. (2013) and appear

[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 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 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).

Table 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 7, columns (1) & (3), and (2) & (4).

to demonstrate the potential benefits of a more dispatchable DG source.

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. Moreover, we should also bear in mind that a smoother demand

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

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.

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 (CEER, 2015). 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,

[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 (REE, 2015).

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.

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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