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“Power system integration of renewables: an economic approach”

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“POWER SYSTEM INTEGRATION OF RENEWABLES: AN ECONOMIC APPROACH”

PH.D. DISSERTATION

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We STATE that the present study, entitled "**POWER SYSTEM INTEGRATION OF RENEWABLES: AN ECONOMIC APPROACH**", presented by Joan Batalla-Bejerano for the award of the degree of Doctor of Philosophy in Economics, has been carried out under the supervision of the Department of Economics of this University and that it fulfils all the requirements to receive the Doctorate Distinction.

Reus, November 7th, 2016

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"As you set out for Ithaca
hope the voyage is a long one,
full of adventure, full of discovery."

C.P. Cavafy

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LYST OF ACRONYMS

ACER	Agency for the Cooperation of Energy Regulators
ASC	Adjustment Service Cost
CCPP	Combined Cycle Power Plant
CEER	Council of European Energy Regulators
CNMC	Comisión Nacional del Mercado y la Competencia
CSP	Concentrating Solar Thermal Power
DSO	Distribution System Operator
EC	European Commission
EMC	Energy Market Balance
ENTSO-E	European Network of Transmission System Operators for Energy
EU	European Union
FIT	Feed-in-Tariff
GHG	Greenhouse Gas
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRENA	The International Renewable Energy Agency
KWh	Kilowatt Hour
MW	Megawatt
MWh	Megawatt Hour
OMI	Operador del Mercado Ibérico
PV	Photovoltaic
RDA	Real Demand Adjustment
REE	Red Eléctrica de España
RES	Renewable Energy Sources
RES-E	Electricity from Renewable Energy Sources
SO	System Operator
TW	Terawatt
TWh	Terawatt Hour
UNFCCC	United Nations Framework Convention on Climate Change
VRES-E	Electricity from Variable Renewable Energy Source

1. INTRODUCTION

Climate change is undoubtedly one of the main threats to sustainable development, representing one of the greatest environmental challenges with effects on the economy, health and social welfare of our generation and generations to come, making it necessary to tackle the questions posed urgently and effectively.

Studies published over the last two decades, such as the Stern Report (Stern, 2006) or the various assessment reports of the Intergovernmental Panel on Climate Change (IPCC, 1992, 1995, 2001, 2007 and 2014), have contributed to increased awareness and knowledge of the long-term consequences of climate change, bringing the issue of climate change to the field of economics from a detailed analysis of its consequences.

Consequences which have not gone unnoticed in Europe where, in 2007, the European Council itself, based on the recommendations made by the European Commission, emphasized the need for international collective action in framing an effective, efficient and equitable response to the challenges posed by climate change[1]. In this regard, it should be highlighted the commitment of the European Union (EU) to make energy policy compatible with climate policy when transforming Europe into a highly efficient energy economy with low emissions of greenhouse gases (GHG). With this integrated approach the goal was set of achieving at least a 20% reduction of emissions of greenhouse gases by 2020, compared to 1990 levels.

Therefore, initiatives have been launched to promote energy savings and improve energy efficiency, and additionally, given the scale of the challenge both globally and in Europe, the full potential of energy generation from renewable sources is being sought when replacing conventional sources of generation from more highly polluting fossil fuels. As a result of these policies it can be said that renewable energy plays a leading role in the current energy scenario, not being a purely circumstantial phenomenon but a clear commitment for the future.

Such a determined commitment to this type of energy should be understood in terms of the significant and growing advantages associated with this type of electricity generation in three key areas: the environment, security of energy supply and economic development. From an environmental point of view, renewable energy, unlike electricity generation from fossil fuels, does not emit greenhouse gases. From the perspective of energy supply, its marked local character reduces external dependence for economies that are committed to promoting it. This

[1] Council of Europe. Presidency Conclusions. Brussels, 8th and 9th March 2007 (7224/1/07 REV).

undoubtedly contributes to improvements in security of supply, an issue of high importance for countries without readily available energy resources. Finally, and not least importantly, renewable energy is a driving force for economic and social development.

For all these reasons, renewable energies play a leading role in shaping energy models both at the European and global level. The growing share of renewable energies in the electricity generation mix, encouraged by the many advantages this entails, is not without challenges of a different nature which account for a penetration below the social optimum (IEA, 2011a; 2011b).

Technologies of power generation from renewable energy sources (RES) face a serious problem resulting from their high investment costs. This is compounded by the absence of full internalization of costs of conventional energy - notably some of an environmental character and others related to supply risk - as well as the current economic crisis that is calling into question the various mechanisms to promote such technologies for generating electricity from renewable sources. The result of all this, despite the significant reductions in costs that have occurred, is the remaining difficulty for a significant share of renewable technologies to compete in economic terms.

This circumstance means that achieving development goals for renewable energy requires not only technological advances to reduce unit costs but also regulatory frameworks to support them and encourage investments by private parties, giving Athem an opportunity to obtain a degree of profitability consistent with the risks involved.

Regulation supporting renewable energy is a key factor for its development. A regulation that focuses not only on economic terms but also provides predictable, stable and better support tailored to the needs of a very specific type of project, such as capital intense long term renewable energy projects. This issue has been extensively addressed (Ragwitz, et al., 2007; Finon and Menanteau, 2008; IEA, 2011a; del Río et al., 2012), by works which make a comparative analysis of the various public policies designed to promote a greater take up of renewable energy as well as highlighting the advantages and disadvantages of such policies.

Thanks to these policies, the percentage of renewable energies in the primary sector mix has grown significantly over recent years, especially in the electricity generation segment. We are moving towards an electricity-dominated global energy mix. Shift that will be accelerated thanks to the decreasing costs and sector concerns over climate change, energy security and air pollution. In combination, these drivers could lead to renewable-sourced electricity replacing fossil fuels as the dominant form of primary energy used in the global economy for most industrial, commercial and personal activity.

The world's energy landscape is transforming rapidly as the cost of renewable-based electricity, particularly from wind and solar, declines to become competitive in comparison with other conventional generation technologies. In this regard, the continued growth of renewable energy in covering energy demand poses new challenges in relation to their integration into existing electrical systems.

This thesis will also focus on the electricity sector and this process of decoupling economic growth capacity and volume of GHG emissions, and how the electricity sector is being called to play a leading role in achieving the objectives of transforming the current energy system. The process of the increasing electrification of the energy mix at a European level is expected to double its share in final energy demand accounting for 39% in 2050 (EC, 2011). Electricity's progressive presence as an alternative fuel capable of meeting the energy demand of cars and light commercial vehicles, or the use of renewable energies in the electricity generation process, makes it especially relevant in the process of decarbonisation, necessary to respond to the challenges of climate change.

For every electrical system, a basic principle of operation is security of supply, understood as the ability to ensure continuity of supply to consumers. A matter of central importance as electrical output must equal consumption accurately and instantly and electricity cannot be stored in large quantities. The security and reliability of supply is a key element in the proper functioning of an increasingly electricity-dependent society having different meanings depending on the time scale considered.

In the short term, security of supply means having sufficient production capacity and operating procedures to ensure a safe operation of the electrical system - security. In the medium term, it involves managing the installed production capacity aimed at ensuring an adequate margin of reserve – strength, while in the long term this involves ensuring that there is sufficient installed capacity to meet expected demand in the coming years - sufficiency. Each one is a significant challenge but with problems that require different response mechanisms at both a technical and regulatory level.

In terms of electrical system operation, the continued growth of renewable energy globally poses additional challenges. The integration of renewable generation makes system operation more complex:

- Firstly, the problem arises of cost recovery for displaced power stations. In most electrical systems, a preference dispatch for renewable energy is established. All these type of facilities have a market share as price taker technologies, so displace more expensive conventional technologies in order of merit, with the consequent implications in terms of returns on investment.

With little or practically zero marginal costs and regulation in force in most electricity systems with a preference to dispatch renewable energy, the increasing use of generation from renewable sources affects wholesale market prices. This modification of the order of merit where conventional power plants with higher marginal costs are displaced by generation from renewable sources (merit order effect) depresses final prices in spot markets and raises the issue of recovering costs from displaced power stations. Lower prices in wholesale markets for a high number of hours may end up reducing revenues for conventional producers to even below the necessary to ensure sufficient capacity to meet demand when wind or solar power is not available. Unless prices are relatively high at those times, these power stations would not be economically viable to the extent that they would not recover their fixed operating or capital costs. This issue, widely analysed in the literature (Sensfuß et al., 2008; Gelabert et al., 2011; among others) and for which there is no single ideal solution, raises the need for mechanisms for capacity payments in order to provide certainty in terms of security of supply.

- Secondly, and also highly relevant, is the need to ensure additional power reserves to cope with the intermittent nature that characterizes generation from renewable sources.

  Unlike other conventional technologies, electricity generation from renewable sources - mainly wind and solar photovoltaic - presents a number of features, which distinguish it and must be taken into consideration in the design of all electricity markets. These special features are derived from its variability in production, conditioned by the availability of renewable resources, and their unpredictable nature.

  The lack of fimnesss of generation from renewable sources requires the incorporation of new, fast, flexible and responsive power systems (storage systems, pumps and gas turbines), as well as more complex technical system management. Today, electricity cannot be stored on a large scale, and that is why it is essential to strike a balance between the power generated and a constantly shifting demand. Since the operation of an electrical system must permanently ensure this balance between energy demand by consumers and the energy produced by power plants, it is necessary to have market mechanisms able to respond to this challenge, including market adjustment services or deviation management

This last aspect is of great importance to the extent that, in recent years, the massive incorporation of renewable energy into the electricity system, whose primary energy sources – basically sun and wind - are not manageable due to their high variability and extreme difficulty in terms of prediction, constitute an additional factor of risk faced by system operators in their daily management.

Definitely, the rapid deployment of renewable energy already poses challenges for the electricity system in particular, which needs to adapt to increasingly decentralised and variable renewable generation. The challenge of decarbonisation of the various electrical systems without compromising the security of supply poses new challenges such as the availability of flexible resources. As the contribution of intermittent generation from renewable energies increases, the need for backup generation, storage and management mechanisms, which are flexible enough to respond to the variability that characterizes RES generation, arises.

In economic terms, this adaptation process is not neutral. Even if the penetration of renewable energy improves sustainability and security of supply, it also entails additional costs in terms of system operation and electricity markets, which must be able to provide greater flexibility to respond to the challenge of the variability and intermittency in production from renewable sources.

It is precisely this area to which this thesis is addressed, its main objective being the analysis of the explanatory factors that determine the success of RES integration into power systems. While addressing the issues of slippage and sufficiency, this thesis aims to give an in depth analysis of the current design of electricity markets and the economic impact of renewable energy on the final price of electricity paid by consumers. Within these electricity markets, this thesis will pay particular attention to adjustment markets, essential for the development and implementation of renewable energy, in order to understand its functioning, identify areas for improvement and assess their impact on the end cost to consumers.

From the perspective of electrical systems and their operation, the problem to be solved is how to integrate generation from renewable sources into the system when availability is random, freely located and which when faced with unstable conditions disconnects itself from its own electrical system, forcing the rest of the generation to increase its share in real time in order to ensure the permanent balance between supply and demand called for by any electrical system for proper operation. Any operator of an electrical system knows it is necessary to ensure additional power reserves to cope with deviations from intermittent renewable generation sources.

Spain, like other countries that have experienced an increasing share of renewable energy in their respective electrical systems, faces the challenge of integrating large amounts of renewable energy, which makes it an excellent field of analysis of the economic consequences of the changes in the generation mix.

In the Spanish case, in recent years there have been significant changes that have altered the existing scenario from the beginning of the process of liberalization of the energy sector in the late nineties. The impressive integration of renewable energies - mostly unmanageable by nature - the integration of the Spanish market with the Portuguese under the Iberian Electricity Market (MIBEL), progress in achieving an internal energy market at EU level in a market with a low degree of interconnection in comparison with the rest of Europe or the drastic drop in electricity demand resulting from the recent economic crisis, among many other factors, are affecting the operation of the wholesale electricity market. All this signifies the need to review the current design of an electricity market that aims to reconcile the objectives of competition, security of supply and the integration of renewable energy.

From a methodological point of view, this thesis aims to take a close look at the current design of the electricity market and the economic impact of renewable energy on the final price of electricity paid by consumers. Within these electricity markets, the thesis will pay particular attention to adjustment services markets, essential for the development and implementation of renewable energy, in order to understand their operation, identify areas for improvement and assess their impact on the cost to consumers.

At a time like the present, in which the European Commission is analysing and discussing what the optimal regulatory framework should be to stimulate effective market integration capable of generating the necessary incentives in terms of flexibility, this thesis focuses on this issue, tackling the economic impact of the integration of renewable energies in the case of the Spanish electricity system.

The proposed structure is as follows:

- After this *first introductory chapter*, *chapter two* will analyse the current electricity scenario and the situation of renewable energy in Spain. As it is not possible to decontextualize the evolution that has occurred in Spain from tendencies globally, trends observed in the last two decades at both a European and global level will also be addressed.

  Spain’s energy market is of great importance for its size. With an annual electricity demand in excess of 260 TWh, it is the fifth largest energy market in Europe. Also, and perhaps this is where the biggest attraction lies when studying the Spanish electricity market, the presence of renewables has grown in recent years to cover 36% of demand in 2015 – 42% in the previous year-. If we add to this the limited capacity of existing electrical interconnection with other European markets, it is easy to understand the relevance of markets and system operation throughout this transformation process when providing the system with sufficient flexibility at reasonable economic cost.

The analysis of the increased presence of renewables in the operation and management of the electrical system requires prior knowledge of the operation of the electricity market. To this end, this chapter will present the Spanish energy market. As in other countries of the European Union, it is organized as a sequence of markets and services in which the generation and demand for electricity are exchanged over different time horizons.

The variability in production of electricity from renewable sources, as well as the variability of demand, means markets that close after daily markets have become much more relevant. Markets that allow for adjustments in demand and supply prediction errors made by the agents.

Also, adjustment services allow the system operator to manage a real-time balance between generation and demand at the time of release of energy. These services are intended to adapt production programs resulting from physical bilateral contracts and the daily and intraday markets to ensure compliance with quality and safety conditions required for the supply of electricity. Today, renewable energy cannot be managed because of its intermittency, which makes the design of these markets crucial. Any process of reform of these markets requires an economic analysis of the impact of various factors, from both the supply and demand sides, which affect the final cost to the consumer of providing adjustment services. This chapter is given particular attention due to its importance.

- After these first two descriptive chapters of the current situation and global trends in renewable energy and the challenges associated with its integration, the second part of the thesis contains the *empirical analysis*.

  Structured around three chapters, the empirical approach seeks to give an in-depth analysis of the current design of the electricity market and the economic impact of renewable energy on the final price of electricity paid by consumers. Using the information from an exhaustive collection of hourly data for the Spanish electrical system of the final hourly price of electricity and employing different econometric specifications, this thesis seeks to give a quantitative analysis of how the massive integration of renewable energy affects adjustment services. In this sense:

- The *third chapter*, *"The sensitivity of electricity system operational costs to deviations in supply and demand"* analyses how adjustment services and factors, on both the supply and demand side contribute to the final cost to be paid by consumers.

  Adjustment service markets are a set of mechanisms of a competitive nature that are managed by the system operator and are intended to adapt production programs resulting from physical bilateral contracts and the daily and intraday market needs in real time. All with the objective of ensuring compliance with quality and safety conditions required for the supply of electricity. Currently, renewable energy cannot be managed because of its intermittency, which makes the design of these markets crucial.

  Increasing renewable participation has given rise to a series of challenges as regards the ability of electricity systems to balance supply and demand, particularly with high levels of intermittent renewable generation. Real-time network management requires a detailed quantitative assessment of the way in which the electricity system might both deliver and accommodate higher levels of renewable generation and of the associated economic costs for the consumer. Nevertheless, the estimations reported in this chapter for the Spanish electricity system stress the importance of demand imbalance when accounting for the cost of balancing services, in contrast with previous studies that have focused their attention more specifically on supply effects.

- Given the relevance of deviations from demand, the *fourth chapter*, *"Collateral effects of liberalisation: metering, losses, load profiles and cost settlement in Spain's electricity system"* highlights the role of demand and prediction errors in determining the additional costs that consumers face. In the Spanish case, as the results show, the deviations from demand are central in order to understand the reasons for this. What lies behind this, as shown in this chapter, is the current regulatory framework and the greater or lesser success it has had in the liberalization process adopted at a European level.

  European energy markets have undergone a major transformation as they have advanced towards market liberalisation and it is vital that the details of these developments be carefully examined. The success of liberalisation is based on smart regulation, which has been capable of providing solutions to unforeseen events in the process. This work seeks to contribute to existing understanding of the unexpected and collateral effects of the liberalisation process in the power system by examining a natural experiment that occurred in Spain in 2009. In that year, the electricity supply by distribution system operators disappeared. This change in retail market competition, as proved in this analysis, has had an unexpected effect in terms of the system's balancing requirements. A rigorous assessment of the economic consequences of this policy change for the whole system, in terms of its impact on final electricity prices, has been undertaken.

- Finally, after analysing the effects caused by demand factors, in the *fifth chapter*, *"Impacts of intermittent renewable electricity generation on system costs"*, the analysis focuses squarely on the effects of the integration of renewable energies.

  As shown in this chapter, a successful deployment of power generation coming from variable renewable sources, such as wind and solar photovoltaic, highly depends on the economic cost of system integration. This analysis, in seeking to look beyond the impact of renewable generation on the evolution of the total economic costs associated with the operation of the electricity system, aims to estimate the sensitivity of balancing market requirements and costs to the variable and non-fully predictable nature of intermittent renewable generation. The estimations reported in this work for the Spanish electricity system stress the importance of both attributes as well as power system flexibility when accounting for the cost of balancing services.

- Based on the results and evidence from an empirical approach, the *sixth chapter* presents the conclusions drawn and considers proposals and recommendations for future improvement in order to mitigate the possible adverse effects identified.

With the aim of contributing to this emerging analysis of the economy of the energy sector, the empirical approach adopted here pays special attention to the sensitivity of final electricity prices to the new requirements of flexibility of the system to deviations in forecasts, both in terms of demand and supply. All relationships and issues identified in the operation of the various electricity markets are specified in a range of econometric models that attempt to explain the factors which lie behind the final price of electricity. From the results, the implications for the efficient functioning of electricity markets are analysed, providing recommendations on the most effective policies to be implemented to achieve optimal functioning of markets from an economic, technical, social and environmental position.

This work falls within the area of energy economics analysing the various effects of promoting renewable energies on the setting up and functioning of electricity markets and the economic evaluation, in terms of efficiency and effectiveness of these markets from an econometric approach which seeks to assess the relevance, in terms of budget overruns, of the various explanatory factors associated with the provision of flexibility in the various electricity markets.

An overview of the situation, opportunities and challenges of renewable energy is needed when defining a new economic model, which is more sustainable, both economically and environmentally. This is the deep purpose of this dissertation.

2. EVOLUTION OF RENEWABLE ENERGY

2.1. INTRODUCTION

Worldwide, the use of renewable energy has grown considerably over the last two decades having partially replaced fossil fuels in many areas: electricity generation, thermal applications - heat for industrial processes and hot water in the domestic sector, amongst others -, fuel and energy services for those without a network connection in isolated rural areas (André et al., 2012).

Such a broad commitment to this kind of energy can only be explained by the significant and growing benefits associated with this type of technology in three key areas: the environment, security of energy supply and economic development. Not only does it contribute to reducing emissions of greenhouse gases given its renewable nature but it improves security of supply, as it uses domestic energy sources. In addition, renewable energies are an important force for economic and social development, encouraging innovation and the creation of high added value jobs - 8.1 million direct and indirect jobs in 2015 (REN21, 2016).

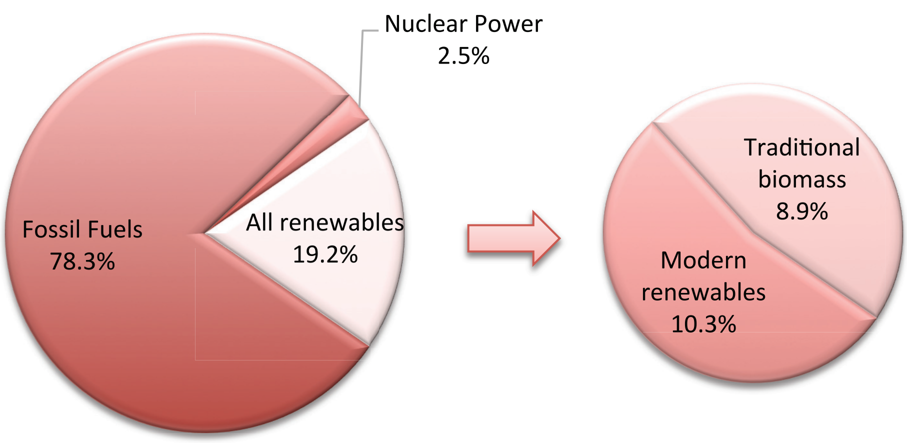
Therefore, renewable energies occupy an important place in the current energy landscape, becoming a significant component of the energy supply. This is not a temporary phenomenon, but a decision for the future. Proof of this is the agreement adopted in December 2015 at the United Nations Framework Convention on Climate Change's (UNFCCC) 21st Conference of the Parties (COP21) in Paris, where 195 countries agreed to limit global warming to well below 2 degrees Celsius. In order to accomplish this objective, a majority of countries committed to scaling up renewable energy and energy efficiency through their Intended Nationally Determined Contributions (INDCs).

Given its importance, the aim of this chapter is to provide an overview of the development of renewable energy in recent years and its current international situation, globally, in the European Union (EU) and in Spain in particular. In addition, a review is made of the main challenges facing all electricity systems to ensure effective integration. Section 2.2 looks at the evolution of different energy sources in recent years, while section 2.3 deals with this development in the EU in the last decade and the fourth section this analysis is brought to the case of Spain. Finally, in the last section, the Spanish electricity market is described, with a more detailed description of the way in which the imbalance markets have evolved and function, along with an analysis of the contribution of the various sub-markets that make up the Spanish electricity market.

2.2. THE SITUATION OF RENEWABLE ENERGY GLOBALLY

As of 2014, renewable energy provided an estimated 19.2% of global final energy consumption (Figure 1). Of this total share, traditional biomass, used primarily for cooking and heating in remote and rural areas of developing countries, accounted for about 8.9%, and modern renewables (not including traditional biomass) increased their share slightly over 2013 to approximately 10.3% (REN 21, 2016). Among renewable generation, hydropower accounted for an estimated 3.9% of final energy consumption, being the most substantial generating technology.

Figure 1: Estimated renewable energy share of global final energy consumption (%), 2014

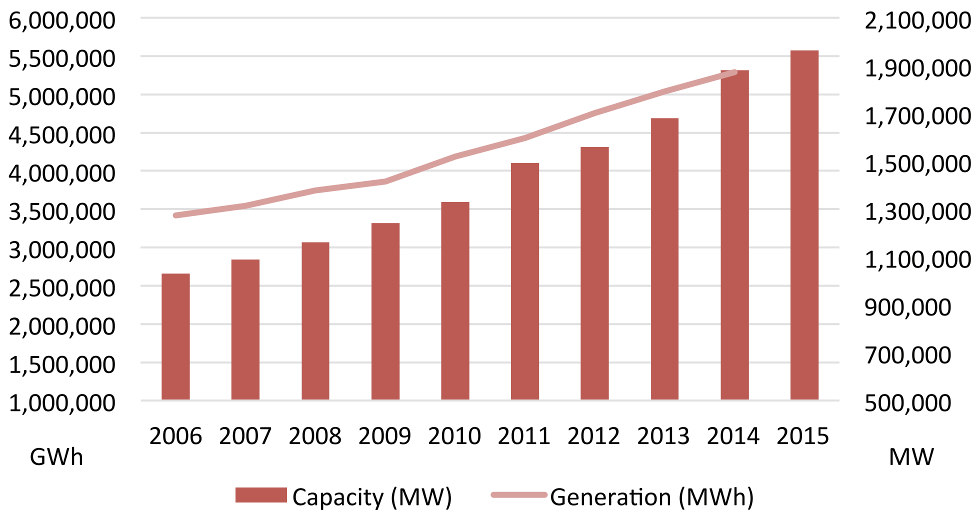


Source: REN 21 (2016)

The percentage of renewable energies in the primary energy mix has grown significantly over recent years, especially in the electricity generation segment. Despite the important contribution of the heating and transport sectors to energy demand and global emissions – together these sectors account for about two-thirds of final energy consumption and more than half of global greenhouse gas emissions – policy makers have focused predominantly on the power sector, a trend that has helped to shape the current landscape. The design and implementation of support policies focused on the promotion of electricity generation from renewable energy sources - especially in the case of Europe - and the increasing cost competitiveness of these technologies, are the reasons behind this.

The result of this has been that the most substantial growth in terms of capacity has occurred in the electricity sector, led by hydro, wind and solar PV. Globally, the power generation capacity from renewable energy sources amounted to 1,964 GW in 2015 with a cumulative annual growth rate of 7.42% since 2006 (Figure 2).

Figure 2: Evolution of worldwide renewable energy capacity (MW) and electricity generation (MWh), 2006-2015



Source: Own elaboration based on data from IRENA (2016)

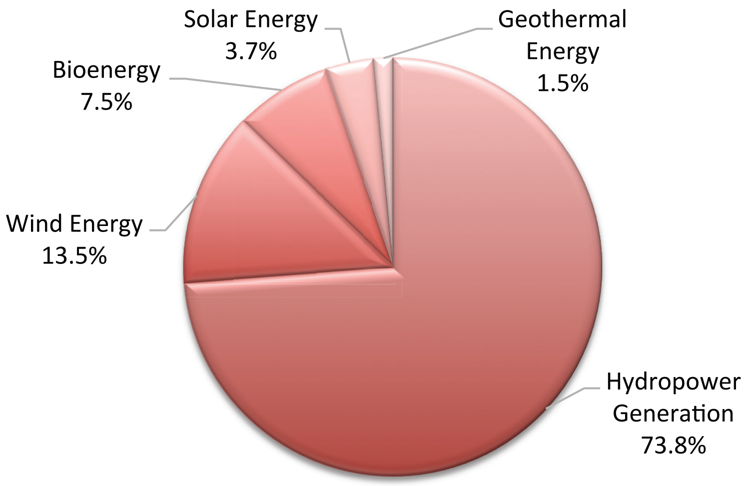
The total amount of electricity generated from renewable sources in 2014 amounted to 5,294 TWh, being the hydropower the most relevant with a 72.8% (Figure 3). Hydropower generation with 3,907 TWh accounted for almost three-quarters of total renewable generation, followed by wind generation (13.5%), bioenergy (7.5%), solar energy (3.7%) and geothermal energy (1.5%). Inside hydropower, large-scale plants of over 10 MW of installed capacity dominate this kind of generation.

Renewable electricity generation in 2014 was 255 TWh higher than in 2013, an increase of 5%. Electricity generation from wind and solar performed particularly strongly in 2014, with growth of 12% and 39% respectively, continuing the double-digit growth seen in previous years.

Beyond the relative importance of each renewable technology in terms of installed capacity, it is extremely interesting to analyse the significance of renewable technologies in terms of net additions to global electricity generation capacity.

In 2015, 147 GW of renewable power accounted for approximately 58% of net additions in the capacity of electricity generation, the largest annual increase in a context such as the current one with reduced fossil fuel prices. With a total installed capacity of 1,849 GW, renewable energies at this time already represent 27% of the generation capacity on the planet, capable of supplying 22% of global electricity demand in 2015.

Figure 3: Worldwide renewable electricity by renewable technologies (%), 2014



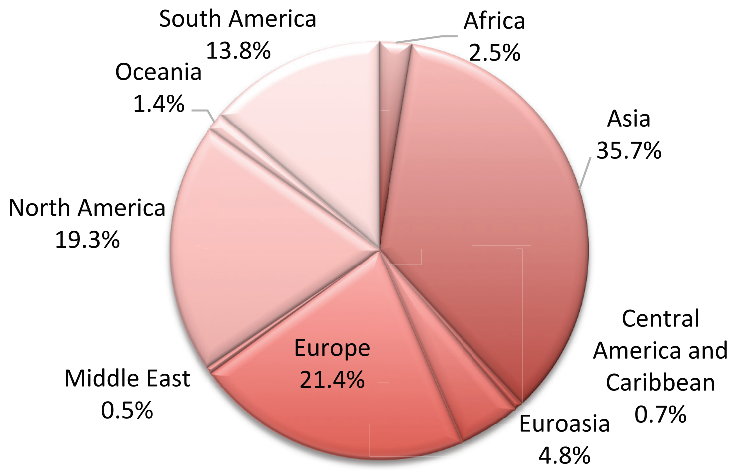
Source: Own elaboration based on data from IRENA (2016)

Hydropower generation, wind and solar photovoltaic were the technologies that dominated the market. Approximately 28 GW of new hydropower capacity (excluding pumped storage) was commissioned in 2015 representing 19% of new generation capacity. Wind and Solar PV accounted for 42% and 34% respectively of all new power generation capacity in 2015. In the particular case of solar PV, it has to be taking into account that the installed capacity multiplied by more than five, growing the global installed capacity from 40 GW to 227 GW.

This evolution of renewable generation capacity by technologies is relevant in terms of system operation given the intermittent nature of this kind of generation. Response to rising shares of variable generation means new challenges for power system operators requiring efficiency improvements and system flexibility.

In 2015, Asia dominated renewable electricity generation with a share of 39.7%. Europe and North America each accounted for 25.1% and 16.6% respectively, followed by South America (9.3%) and Eurasia (4.6%). Although the growth of renewables is widespread in all regions, the source of renewables used to generate electricity varies considerably between regions. Hydroelectricity is by far the most important source of renewable electricity in Africa, Eurasia, the Middle East and South America. It also accounts for 80% of renewable generation in Asia, although wind and solar energy are increasingly prominent. Hydroelectricity is less dominant in Europe and North America, where wind, bioenergy and solar energy account for relatively high shares of total renewable electricity production (Figure 4).

Figure 4: RES installed capacity by region (%), 2014



Source: Own elaboration based on data from IRENA (2016)

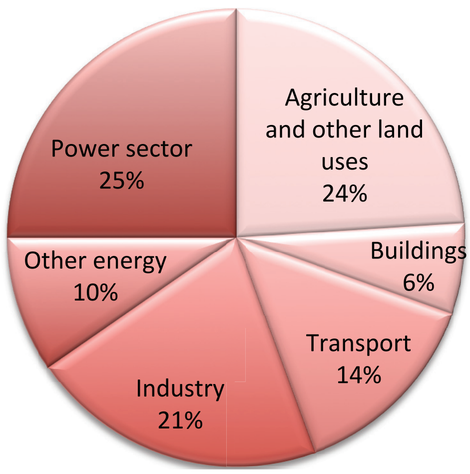
2.3. THE SITUATION OF RENEWABLE ENERGY AT EUROPEAN LEVEL

In recent years, the promotion of renewable energy has been a political priority for the European Union as a leader in the fight against climate change, as well as a concern for having domestic energy sources capable of reducing external energy dependence, something that characterizes Europe (Del Rio, 2009). That is why, despite increasing economic costs and their impact on final prices paid by consumers, we can say that renewable energies have experienced a boom over the last fifteen years.

Over recent years, concern for the effects resulting from climate change associated with emissions of greenhouse gases (GHG) have been added to energy access and cost concerns. According to IPCC, the power sector is responsible for 25% of CO_2 emissions (Figure 5) so it has been necessary to incorporate an environmental dimension in defining the objectives of energy policy at Community level.

To meet this need, the European Union has integrated climate and energy targets in a single EU policy to comply with the triple objective of competitiveness, environmental sustainability and security of supply. The main idea behind this policy is the conviction that it is necessary to move towards a new low emission energy model capable of ensuring access to energy at competitive price.

Figure 5: Direct emissions of greenhouse gases by economic sectors, 2010



Source: IPCC (2014)

The adoption in 2009 of an integrated climate and energy policy[2] set ambitious targets for Horizon 2020 in terms of reducing emissions of greenhouse gases relative to 1990 levels (the reference year for the Kyoto Protocol); increasing the presence of renewable energy in the primary energy mix, as well as improving energy efficiency. This represented the starting point in this process of transforming the energy model.

In recent years, this policy has been reinforced by the definition of a vision beyond 2020. In 2013, the European Commission published a communication, which defines

[2] The climate and energy package consists of four legislative texts:

- Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009, amending Directive 2003/87/EC to improve and extend the Community system of trading on gas greenhouse emissions.
- Decission 406/2009/EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their emissions of greenhouse gases in order to fulfil the commitments made by the Community to 2020.
- Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009, on the promotion of the use of energy from renewable sources.
- Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009, on the geological storage of carbon dioxide.

the roadmap for 2050[3], which identifies the challenges and opportunities that Europe has to face in the process of decarbonising its economies. This view was reinforced in 2013 with the proposal on energy and climate policy for sustainable economic growth in Horizon 2030[4]. In both scenarios, the promotion of renewable energy sources and energy efficiency play a pivotal role. In the case of 2030, Europe has set a target of reducing emissions of greenhouse gases (GHG) to at least 40% compared to 1990. Also, objectives have been set to achieve at least a 27% reduction in energy consumption and renewables will provide 27% of energy in overall energy consumption.

The roadmap for Horizon 2050 indicates that the European Union should reduce its emissions by 80% in relation to 1990 levels through domestic reductions. It also shows how the main sectors responsible for emissions in Europe; power generation, industry, transport, building and construction, and agriculture, can make the transition to a profitable low carbon economy.

Renewable energies play a central role in this process of transformation towards a low emission economy. The coming into force of this new European strategic framework to support the development and integration of renewable energy on the basis of quantified targets became the catalyst for European investments in renewable energy, thus contributing to its growth over the last decade as an energy source.

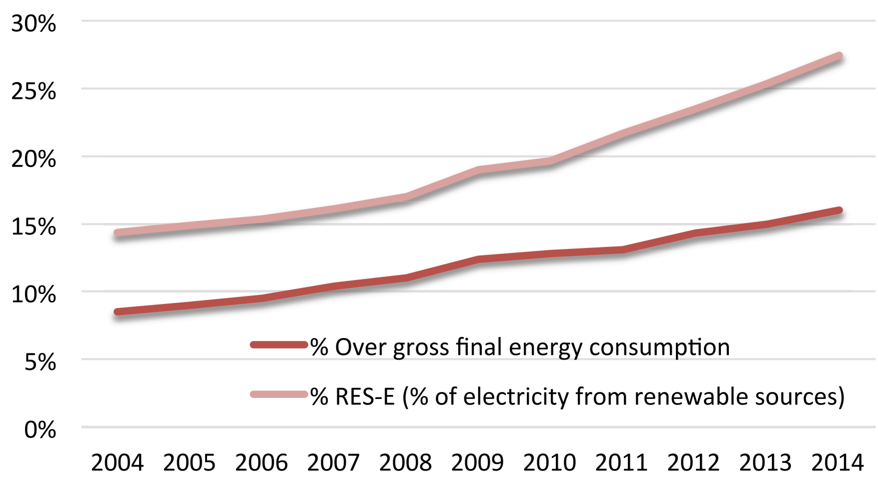
With a share of gross final energy consumption of 15.3% expected in 2014, the European Union and most Member States are making good progress towards the goals set for 2020 (Figure 6). However, the recent economic crisis and the growing concern about the effects that some final electricity prices have on economic competitiveness may jeopardize the achievement of these objectives.

By uses, 46% of final energy consumption in the EU is used for heating and cooling. In 2014, the share of renewable energy used in the heating and cooling sector was estimated at 16.6% (EC, 2015). Renewable energy is increasingly used as a safe and profitable alternative to fossil fuel in district and local heating systems of the Member States.

[3] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: Energy roadmap for 2050.

[4] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: A policy framework for climate and energy in the period from 2020 to 2030.

Figure 6: Renewable energy in terms of gross final energy consumption and electricity generation (%) in EU-28, 2004-2014



Source: Own elaboration based on Eurostat

Power generation is the arena where there has been more significant progress. In 2014, 27.5% of electricity generated in the EU is from renewable energy sources. In terms of generation technologies, highly relevant in operational terms to electricity systems at the moment, about 10% of total EU electricity comes from variable renewable sources such as wind and solar.

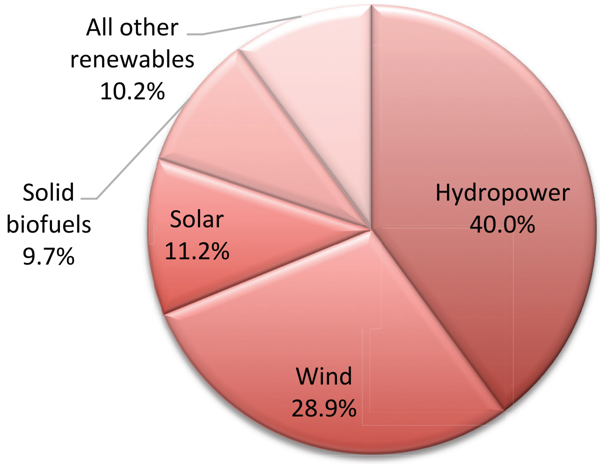
In 2014, the gross production of electricity from renewable energy sources amounted to 823 TWh, an increase of 11% compared to 2013, with electricity generated from solar energy having the highest growth compared to the previous year (20%).

By generation technology, as seen in Figure 7, hydropower plants generated the largest share of electricity produced from renewable energy, although their presence has been reduced over time as other renewable technologies have broken through, especially wind and solar photovoltaics.

Wind power generation increased more than threefold during the period 2005-2014 and has become the second largest contributor to the renewable energy share. In 2014, electricity production from wind power stood at 247 TWh (28.9%), compared to 234 TWh for the previous year. By country, Germany, Spain and the United Kingdom are the three major producers of wind energy in the European Union.

The generation of electricity from solar energy has also increased rapidly, and in 2014 accounted for 11.2% of total electricity produced from renewable energy, currently the third most important source of renewable energy for the production of electricity.

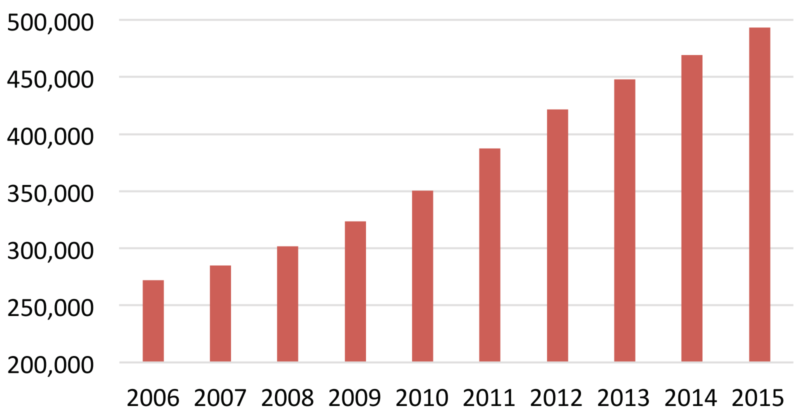
Figure 7: Electricity generation from renewable sources by technology (%), 2014



Source: Own elaboration based on Eurostat

The total installed capacity of electricity generation from renewable energies has increased considerably in the last 20 years, particularly with the rapid growth of the installed capacity of wind and photovoltaic power. In 2015 the capacity of electricity generation from renewable energies stood at around 493 GW, with a cumulative annual growth rate of 6.84% since 2006 (Figure 8). Hydropower generation constitutes the most relevant RES generation technology in terms of installed capacity.

Figure 8: Evolution of RES capacity in Europe (MW), 2015



Source: Own elaboration based on data from IRENA (2016)

2.4. THE STATUS OF RENEWABLE ENERGIES IN SPAIN

The structure of primary energy sources is very different depending on whether the global situation is analysed as a whole or only the most economically developed countries. In the Spanish case, this structure has changed substantially over recent years, a change largely explained by the evolution of renewable energies.

Renewable energies in Spain have undergone an exponential evolution in recent years, from 1,000 MW in 1990 to nearly 10,000 at the end of the decade. We have gone on to have a renewable power source of more than 30,000 MW by the end of last year.

This evolution has turned Spain into a leader country with respect to the introduction of renewable energies. The rapid development of renewables in Spain was a direct outcome of national energy policies including regulatory changes focused on facilitating the grid integration of electricity generation from renewable energy sources (RES-E) and economic and financial incentives. Until it has been reformed in 2013 with the approval of an in-depth reform process[5], Spain basically followed the "feed-in-tariff" (FIT) policy approach based on the determination of a long-term fixed price for RES-E production or fixed premium tariffs paid on top of the spot market price for electricity. This policy has encouraged, besides the country's great renewable potential itself, investment in renewable energy technologies resulting in an increase in the RES-E installed capacity. With 51,095 MW at the end of 2015, RES-E technologies accounted for almost half of total installed capacity in Spain (48.09%). Furthermore, this impressive RES-E deployment has resulted in a diversified energy mix where a great variety of generation technologies are present satisfying the electricity demand (Figure 9).

The national electricity generation, which encompasses the production of the Spanish Peninsula and the non-peninsular systems stood at 267,584 GWh. Despite electricity demand grew by 0.3% compared to 2014, electricity consumption in 2015 reached levels only slightly higher than those in 2005. By technology, renewable energy on the peninsula, although continuing to maintain a prominent role in the structure of the peninsular electricity generation mix with a share of 36.9%, fell compared to 2014 (Figure 10).

[5] The evolution of the costs of promoting renewable energies fruit of the various support policies that have occurred in our country, led to a reform process and in-depth review of the support framework promoting renewable energy aimed at ensuring the economic and financial viability of the power system in the long term, with implications in terms of investment in new capacity. Electricty system reform involved a set of measures to prevent tariff deficit from growing: increases in access tariffs to final customers, reductions in the remuneration paid to regulated activities and cutting incentives, including those for renewable power.

Figure 9: Coverage of electricity demand from renewable sources (%), 2015

Source: Own elaboration based on data from CNMC and REE

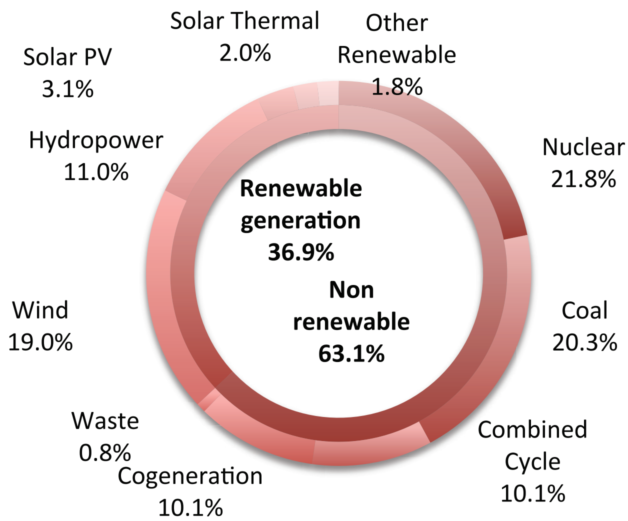
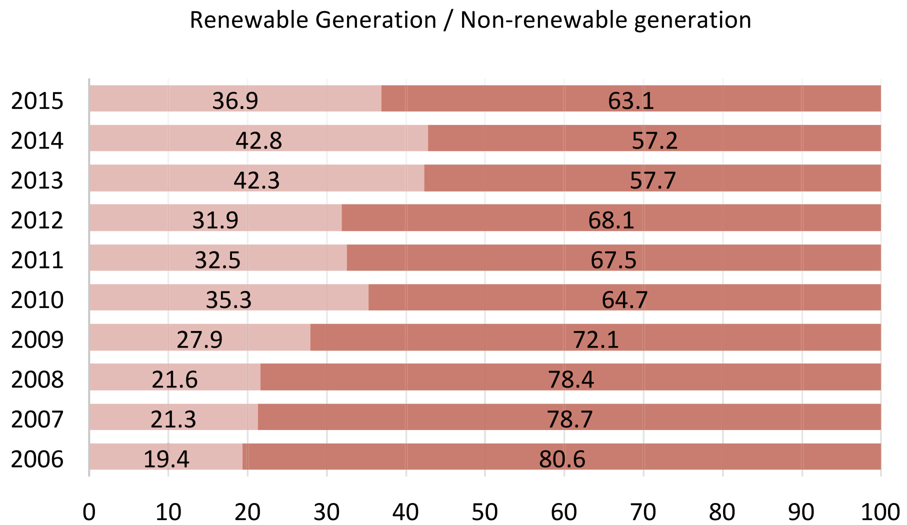


Figure 10: Evolution of renewable and non-renewable generation in Spain (%), 2006-2015



Source: Own elaboration based on CNMC and REE

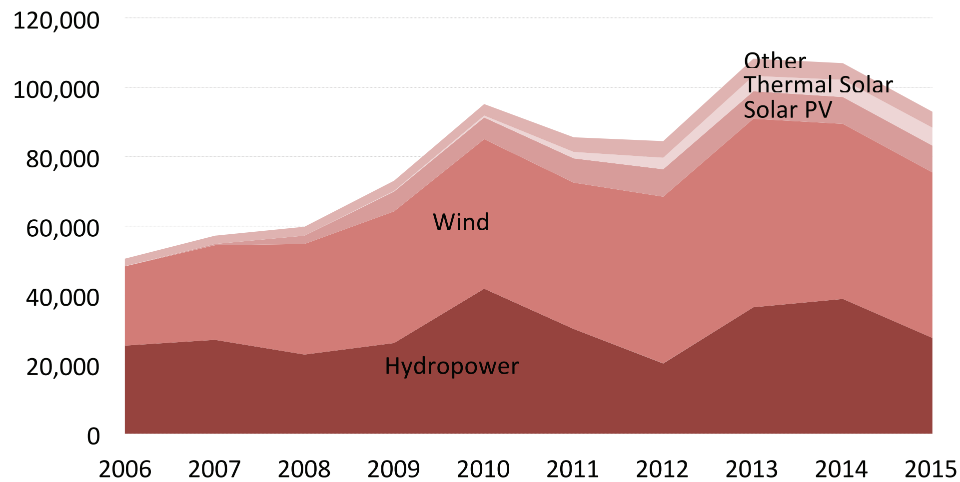
Spanish RES-E generation has grown from 45 TWh in 2004 to 100 TWh in 2014 and 92 TWh in 2015 with a peak in RES-E generation in 2014 when it represented 42% of total electricity demand. In 2015, the first effects of the renewable reform arose. Renewable energy on the peninsula, although continuing to maintain a prominent role in the structure of the peninsular electricity generation mix with a share of

36.9%, fell compared to 2014. At the same time, hydroelectric generation had a significant impact in this fall as it reduced production by 27.5%, while wind power, a key renewable source, registered a drop of 5.8%. Figure 10 illustrates the contribution of RES-E to national electricity consumption in the period between 2006 and 2015.

As illustrated in Figure 11, electricity produced from renewable energy sources - electricity generation from hydro plants (including large hydro), wind, solar photovoltaic and renewable thermal – has been growing up for the last decade and continued to maintain a prominent role in the overall production of energy in the electricity system.

In addition to the high and fast growing RES-E generation take up until 2013 and the diversified power system, Spain also makes a relevant case study because of the isolated nature of its electricity system, with low interconnection capacity with neighbouring countries (France, Portugal, Morocco and Andorra). This represents additional challenges when integrating electricity generation from variable renewable electricity sources.

Figure 11: Evolution of electricity generation from renewable sources (MWh), 2000-2014



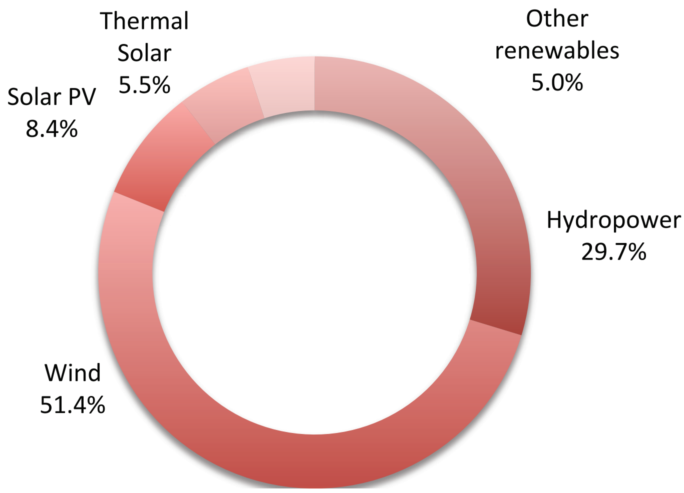
Note: Data for the Spanish peninsula; Renewable capacity includes hydro, wind, solar photovoltaic, solar thermal and other renewables (punped storages is not included); Non-renewable generation includes nuclear, coal, fuel/gas, combined cycle and cogeneration and waste.

Source: Own elaboration based on CNMC and REE

Among the different RES-E generation technologies, renewable generation from variable sources (VRES-E) (albeit primarily wind and solar photovoltaic power), based on sources that fluctuate during the course of any given day or season has grown until it represented 59.8% of total RES-E production in 2015.

Taking a closer look at the different VRES-E technologies (Figure 12), wind (51.4%) and solar PV (8.4%) play a significant role in the Spanish power system. Both technologies are characterised by their intermittency, meaning that both present non-controllable variability and partial predictability, their integration having important system operation implications. VRES-E production is determined by weather conditions and cannot be adjusted in the same way as the output of dispatchable conventional power plants (Hirth et al., 2015). As it can be seen in chapter 5, on the one hand, solar photovoltaic generation is characterised by a diurnal pattern, where peak production occurs in the middle of the day (around 2 pm). On the other hand, wind generation is more variable over time and is mostly explained by fluctuations in wind conditions – mainly speed -. Although wind power output may display some daily and seasonal characteristics, it follows much less regular patterns than does load.

Figure 12: Renewable electricity generation by technology, 2015 (%)



Source: Own elaboration based on CNMC

Furthermore, variable generation is not necessarily correlated with load, with the consequent implications that this has in countries with relatively limited storage capacity, such as Spain. Depending on the time scale considered, the load profile presents different daily, weekly, monthly, seasonal or even yearly patterns. Figure 5 shows how Spanish electrical demand varies throughout the day with peaks of demand at noon and in the early hours of the night.

Variability is not new to power systems, which must constantly balance the supply and variable demand for electricity and face all kinds of contingencies (IEA, 2009, 2011a and 2011b). From a system management perspective, several factors coming from both supply and demand variables might cause active power imbalances in an electricity system.

Aspects such as unplanned contingencies in the conventional or renewable generation capacity or in the interconnection capacity, forecast errors in VRES-E generation due to its intermittent nature or load forecast errors increase the need for balancing power. However large shares of variable renewables in supply imply additional pressure on power systems, which may need increased flexibility to respond to this balancing issue. Aspects such as the availability of flexible capacities within the electricity generation mix, interconnection capacity, storage - e.g. pumped-hydro plants - or improved load control and management empowered by smart grids are relevant to provide the required flexibility.

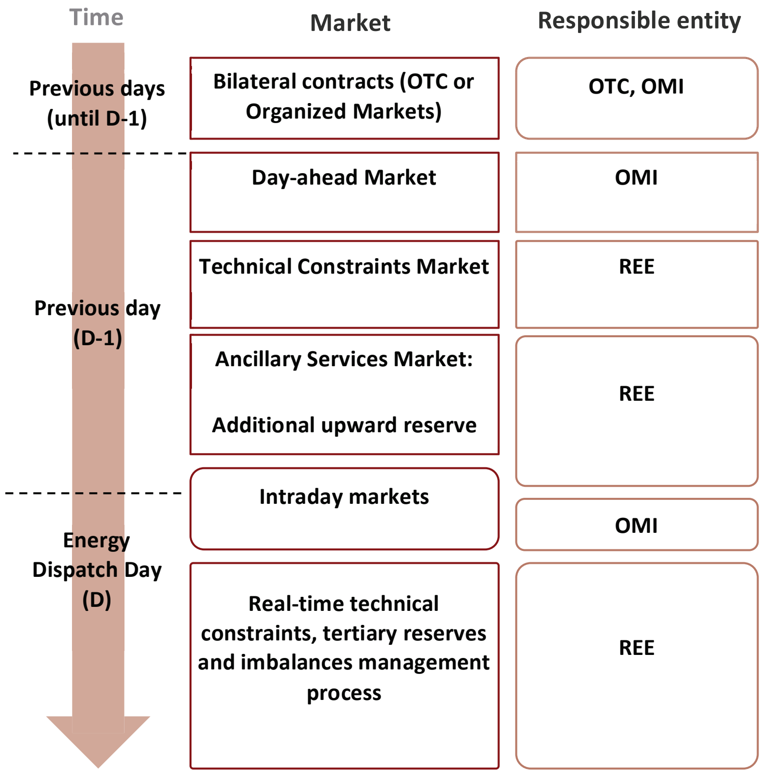
2.5. ELECTRICITY MARKET AND ADJUSTMENT SERVICES IN SPAIN

The Spanish electricity market comprises various sub-markets: a daily market, an intraday market, ancillary services, and system operation services beginning with the day-ahead market and culminating in real time. At different market sessions held the day prior to or even on the day of delivery, the final price of electricity is determined as the sum of the different prices and costs associated with each of these markets.

Day-ahead sale and electricity purchase transactions are carried out during daily market sessions, structured into twenty-four consecutive periods of one hour, at which producers participate by presenting their hourly bids. Once the day-ahead market process has been concluded and the operating schedule obtained, the system operator is in a position to obtain the viable daily schedule. On the intraday markets, sellers of electricity on the daily market may make adjustments – by selling or purchasing energy – in order to reduce possible deviations in the scheduled power production established after day-ahead market closure. The purpose of the intraday market (which in Spain comprises several sessions) is to match energy supply and demand arising in the hours following the viable daily schedule.

The Spanish electricity system is managed by two operators: the market operator (Operador del Mercado Ibérico - OMI), which is responsible for the economic management of the market, and the system operator (Red Eléctrica de España - REE), which is responsible for the technical management.

Figure 13: Spanish Electricity Markets



Source: Own elaboration based on Operating Procedures for the electricity system (REE)

Under the concept of market adjustment services system, a set of mechanisms of a competitive nature are grouped together and managed by the system operator. As illustrated in Figure 13, the system adjustment services include the resolution of system technical constraints, ancillary services and markets imbalance (Carbajo, 2008). In the process of generation scheduling and system operation, responsibility lies with Red Electrica de España (REE) the Spanish System Operator (SO), and focuses on three main aspects:

- The resolution of *technical constraints* identified in the programs resulting from physical bilateral trading and production markets (daily and intraday) as well as all the technical constraints that may arise during the actual operation in real time. Technical constraints appear when market clearing is technically incompatible and requires a modification of the schedules in order to comply with the operation and security criteria for operating the system. The modification of the initial electricity schedule implies a re-balancing generation-demand process.

- *Ancillary services* that defined as the services necessary to ensure the electricity supply under suitable conditions of security, quality and reliability. Without going into excessive detail, in the case of Spain, ancillary services include additional upward reserve power, primary control, secondary control, tertiary control and voltage control of the transmission grid.

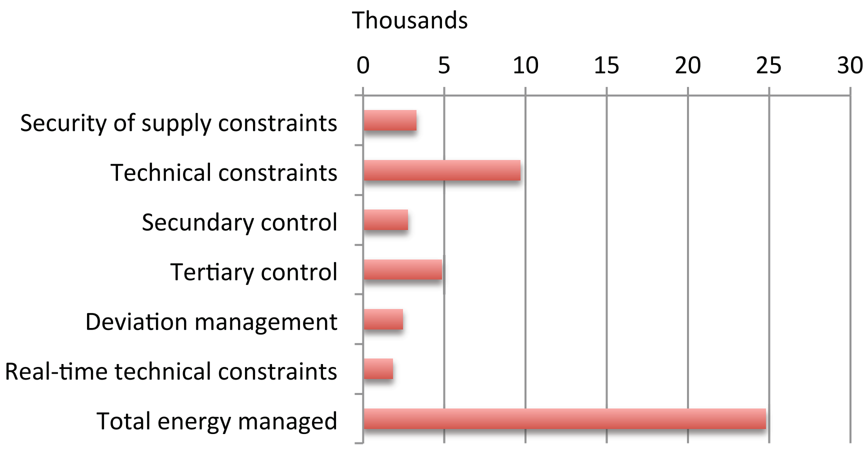
- *Imbalance markets*. Management of deviations between generation and consumption as an essential measure to ensure balance between production and demand to guarantee availability of regulatory required reserves at all times. This is to repair the deviations between generation and consumption that may appear after the close of each intraday market session and the start of the horizon of effectiveness of the next session and are of great importance to ensuring the permanent balance between supply and demand in real time.

The growing share of renewable energies in the coverage of demand has implications in the functioning of these markets and adjustment services as is clear from the empirical analysis presented in the context of this thesis. Since electricity generation from renewable sources has, in many cases, an unmanageable character and shows great variability in terms of energy delivery, it stands to reason that in recent years there has been increased use of energy balance and tertiary regulation to ensure coverage of demand. It has also led to more power programming to solve technical constraints in order to have sufficient power margins to deal with rises and falls in the electrical system, to deal with possible deviations from the program that may arise as a result of the high share of energy from renewable sources in the mix of generation in the Spanish electricity system.

In short, the adjustment markets managed by the system operator are intended to adapt production programs resulting from physical bilateral contracts and the daily and intraday markets to ensure compliance with the conditions of quality and safety required for the provision of electric power. Though these markets existed before the uptake of renewable energy and were essential for the proper functioning of the electrical system, they have now acquired even greater relevance. In other words, system adjustment services are vital to ensure the security and quality of the electricity supply.

The volume of energy managed in the system adjustment services in 2014 was 24,780 GWh (Figure 14). In economic terms, adjustment services, although not being the main factor in final electricity prices, have had an increasing impact on the cost of electricity.

Figure 14: Energy managed in the system adjustment services (GWh), 2014



Source: REE (2015)

During 2015, the cost of the adjustment services was € 1,517 million. Besides the economic impact over final price for consumers, the evolution of the costs associated with adjustment services (Table 1) has a marked impact on the results of independent electricity retailers. While the price risk associated with unexpected variations in the day-ahead market price can be covered via future markets, unforeseen variations in the cost of adjustment services cannot be covered. This being the case, an unexpected increase in the adjustment service costs has a direct impact on the business results of retailers – especially those without generation. This highlights the relevance of an in-depth understanding of the explanatory factors behind the evolution of the operational costs, given that this knowledge will ultimately be helpful when introducing improvements to market design.

Table 1: Annual evolution of electricity final price (€/MWh) by components, 2010-2014

Concept	2010	2011	2012	2013	2014
Day-ahead and intraday market price	38.4	50.9	40.8	46.1	43.4
Adjustment services cost	3.8	3.2	4.7	5.5	5.7
Capacity payments	3.6	6.1	6.1	6.0	5.8
Final price	45.8	60.2	59.6	57.7	55.0

Source: Based on data provided by e-sios (REE)

Beyond their relative importance in terms of the functioning of electricity markets, such services have other implications of great importance in ensuring effective competition in both the wholesale and retail electricity markets.

3. SENSITIVITY OF ELECTRICITY SYSTEM OPERATIONAL COSTS TO DEVIATIONS IN SUPPLY AND DEMAND

3.1. INTRODUCTION

In recent years, there has been a marked increase in the presence of renewable energies in electricity systems. Unprecedented technological advances and the rapid deployment of renewable energy technologies have demonstrated the immense potential of renewable energy sources (RES)[6]. These energies provided an estimated 19% of global final energy consumption in 2012 and continued to grow in 2013 (REN21, 2014). Indeed, in 2013, share of energy from renewable sources in gross final consumption of energy reached 15% in the European Union (EU-28), compared with 8.3% in 2004. The implementation of legally binding targets and support policies for renewable energies has resulted in the increased weight of these sources in the coverage of electricity demand. In 2014, electricity generated from renewable energy sources (RES-E) contributed 27.5% to the EU's total electricity consumption (Eurostat, 2015).

Thus, we are moving from electricity systems characterized by the strong presence of conventional generation in the supply matrix (which have proved capable of providing the flexibility required in times of peak demand), towards a new model characterized by the growing presence of RES-E generation. To put into perspective electricity generation capacities from renewable sources, which in 2014 according to Eurostat data was in total around 400 GW, the existing electricity generation capacity of fossil fuel plants in the EU was around 450 GW in 2014.The growth in RES-E generation during recent years largely reflects the expansion of two main sources, namely wind and solar power. Since 2004, these sources increased overall by 461% reaching 200 GW of total electrical capacity in EU-28. Among the different renewable technologies, wind and solar generation are both intermittent, which means that energy production from these sources is variable over time and non-fully predictable. Therefore, the integration into the power system of the electricity from these variable renewable energy sources (VRES-E) places enormous stress on System Operators (SO) responsible of power system management.

Under this new scenario, SO, permanently seeking to match generation and load on different time scales, have to provide a degree of flexibility for which they were not

[6] Renewable energy sources cover solar thermal and photovoltaic energy, hydro, wind, geothermal energy and all forms of biomass.

originally designed. This has given rise to an intense debate, at the European level (ACER, 2014), about the adequacy of current adjustment markets when having to respond to the increasing need for flexibility of their respective electricity systems. Most present-day adjustment mechanisms were designed at the beginning of the reform and liberalisation of the energy sector, when the context was very different from that which prevails today with the high penetration of generation based on VRES-E.

Within the aforementioned debate, the aim of this chapter is to analyse the relationship between the operational costs of the electricity system and the integration of increasing volumes of renewable generation taking into account the effects of supply and demand. The integration of larger shares of VRES-E generation increases the flexibility requirements of the complementary system, which needs to balance the fluctuations in variable generation.

Although there is a number of different links between VRES-E and its associated balancing requirements[7], in this paper we explore the nexus between forecast errors and the consequent need for balancing power. The secure operation of power systems requires that supply and demand have to be balanced continuously, implying an additional challenge to system managers. In this regard, the variability of renewable generation requires the power system to be operated with a high degree of flexibility. This output variability involves short and long-term impacts on power system that have to be addressed by system operators.

From a system management perspective, several factors on both the demand and supply side might cause active power imbalances in the electricity system (Hirth and Zieenhagen, 2013). Unplanned contingencies in the conventional and renewable generation capacity or in the interconnection capacity, forecast errors from VRES-E generation due to its intermittent nature or load forecast errors can all increase the need for balancing power.

Among the different uncertainty sources, the analysis is focused on unexpected fluctuations in renewable production as well as unexpected fluctuations in electricity demand. Although electricity consumption adheres to predictable diurnal and seasonal patterns, prediction errors in the Spanish system are relevant at around 3% of hourly load. At the same time, VRES-E forecast errors on average are around 2%

[7] There is a multitude of names for the different services to restore the supply-demand balance in power systems (see Hirth and Ziegenhagen, 2013 and Rivero et al., 2011 for a comprehensive comparison of European balancing markets). This heterogeneity could be hampering a comparative analysis of the balancing services across Europe. Considering that European transmission system operators are using the term “operational reserves” (ENTSO-E, 2012), in this dissertartion we use the concept “operational costs” in a broad sense when referring to the costs associated with the provision of these services.

of houly load. This means that both rates are crucial when explaining the flexibility requirements of the electricity system. Given that power system management is concerned with ensuring that enough generation is available to respond to unexpected demand and supply deviations from scheduled, the economic consequences in terms of final energy prices should be examined in the context of power system flexibility.

Drawing on real data for Spain for the period 1st January 2010 to 30th June 2014, the aim of this analysis is two-fold. First, it assesses the power system balancing costs associated with real-time deviations by addressing the interaction between real-time demand and RES-E generation imbalances, and the economic cost that its correction entails for the consumer.

Deviations between scheduled and consumed electricity are addressed through ancillary services based, in most instances, on market procedures, such as secondary and tertiary reserve, and the imbalance management process, and so there is a direct relationship between the size of the deviation and the cost incurred by the system in resolving it. Second, it analyses the sensitivity of the system costs to demand and RES-E generation deviations. The estimations presented here clearly show the relevance of demand and supply deviations when explaining the cost of balancing services.

In the context of operational cost analyses of an electricity system, Spain constitutes a highly interesting case for several reasons. With 50,481 MW – including hydro (19,897 MW) - at the end of 2014, Spain had occupied a privileged worldwide position in terms of RES-E penetration. Among the different RES-E generation technologies, VRES-E generation (albeit primarily wind and solar photovoltaic power), based on sources that fluctuate during the course of any given day or season has grown until it represented 52% of total RES-E production in 2014

In 2014, Spain ranked fourth in the world in terms of RES power (not included hydro), behind only China, the United States and Germany, or by technologies, first in concentrating solar thermal power (CSP) and fourth in wind power (REN21, 2014). Among the different RES-E generation technologies, VRES-E generation (albeit primarily wind and solar photovoltaic power), based on sources that fluctuate during the course of any given day or season has grown until it represented 52% of total RES-E production in 2014. In addition to the high and fast growing VRES-E generation penetration, Spain also makes a relevant case study because of the isolated nature of its electricity system. This represents additional challenges when integrating electricity generation from variable renewable electricity sources.

The remainder of this chapter is structured as follows. Section 3.2 provides an overview of academic research on power generation from RES-E and its role in system operational costs. The model specification and the data used are presented in Section 3.3. Estimation results are presented in Section 3.4. The chapter ends with a final section summarising research conclusions and presenting the policy and regulatory recommendations.

3.2. LITERATURE

The integration of renewable energy generation is a key pillar among energy and climate objectives aimed at reducing greenhouse gas emissions, improving the security of energy supply, diversifying energy supplies and improving Europe's industrial competitiveness.

The generation of power from RES-E as a tool for mitigating climate change has attracted the attention of academia worldwide. And over the last decade a number of aspects of renewable energy research have attracted particular attention, most notably, the impact that financial support to renewable energy has on climate change and the security of supply (Helm and Hepburn, 2009); the design of public policies for the promotion of renewable energy sources (Finon and Menanteau, 2008; IEA, 2011a; del Río et al., 2012); and the implications and challenges of the generation of renewable electricity markets (Sensfuß et al., 2008; Gelabert et al., 2011; among others).

The risks associated with renewable energy deployment (IEA, 2011a) stem from underlying techno-economic factors as well as from other obstacles, including regulatory and policy uncertainty and institutional and administrative barriers. Among the main techno-economic risk factors, VRES-E investment costs and the intermittency of its production (being very much dependent on wind conditions and sunlight) represent major challenges for the expansion of renewable energies.

In order to incorporate these intermittent sources, power systems need to be sufficiently flexible to accommodate short-term predictions and generation variability. In this regard, a number of studies have looked at ways of guaranteeing the technical and economic integration of an increasing volume of VRES-E generation into power systems and have identified the main obstacles that need to be overcome (Joskow and Tirole, 2007; IEA, 2011a; IEA, 2011b; OECD, 2011; REN21, 2014).

The variability and uncertainty of VRES-E generation have a number of impacts on power systems, which can become a challenge at high penetration levels (IEA, 2009; ERCOT, 2010; and Pérez-Arriaga and Batlle, 2012). As real-time deviations in renewable power generation affect daily markets resulting in higher balancing costs and greater fluctuation in the reserve requirement (Vandezande et al., 2010), the evaluation of the effects of the increasing penetration of intermittent VRES-E generation on the integral electricity system constitutes a prerequisite for the efficient economic integration of renewable generation. In this regard, analyses need to be undertaken so as to gain clearer insights into the costs and impacts associated with incorporating renewable energy into electricity networks (Gross and Heptonstall, 2008). Some of the uncertainty into how exactly systems will be impacted with high penetrations of variable generation is because the lack of data (Ela et al., 2011; Swinand and Godel, 2012; Brouwer, 2014).

The contribution of renewable generation to the overall mix has for a long time been negligible, meaning empirical studies have been of limited value. However, such information is now becoming available, especially in countries with significant RES-E generation. As a result, estimations of the characteristics of RES generation and their effects on the power systems in terms of balancing costs using market data are becoming more common (Holttinen, 2005; Cossent et al., 2009; Holttinen et al., 2011; Huber et al., 2014; Ketterer, 2014).

The more this data becomes available as larger penetrations of different RES-E technologies enter the grid, the better these statistical analysis of historical dataset become.

In line with this approach, our estimation of the impact of real-time demand and supply deviations on balancing costs is performed using real data for a country with high RES-E penetration (Spain). A large, highly detailed hourly database allows us to tackle aspects related to seasonal variations, while our economic approach overcomes the need for a complex simulation modelling of the operation of balancing markets.

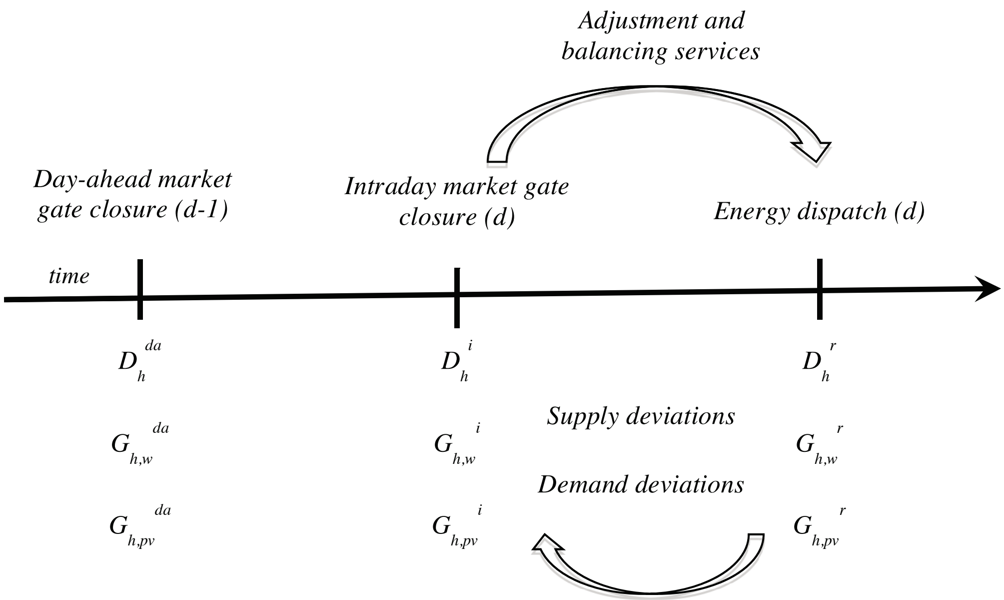
The approach we adopt in this study not only considers unexpected fluctuations in VRES-E as being relevant but also takes into consideration unexpected fluctuations in electricity demand. The richness of the dataset for both types of deviation, demand and supply, allow us to undertake a detailed analysis of their economic effects on system adjustment services.

3.3. DATA AND EMPIRICAL STRATEGY

In this section, we present the empirical strategy and data used to evaluate the effect of power imbalances – mainly load and variable renewable electricity forecast errors – on operational costs.

Adjustment and balancing services definitions are provided in Figure 15. In Spain, as in the majority of electricity systems, market clearing takes place the day prior to delivery so as to be able to program the dispatch of unconventional generation units. Given that the intraday markets (with gate closures times closer to real time than day-ahead) provides the last opportunity to update energy forecasts closer to real time with better forecasts - but also offers arbitrage opportunities - and to adjust and correct previous schedules made in the day-ahead market, demand and supply deviations are calculated with reference to the intraday market gate closure.

Figure 15: Variable nomenclature



where:

D_h^{da}, D_h^{i}	Foreseen demand in the day-ahead *(da)* and intraday *(i)* markets for the hour under consideration *(h)*
D_h^{r}	Real demand in the hour under consideration *(h)*
$G_{h,w}^{da}$, $G_{h,pv}^{da}$	Wind (*w*) and photovoltaic *(pv)* generation sold in the day-ahead market *(da)* in the hour under consideration *(h)*
$G_{h,w}^{i}$, $G_{h,pv}^{i}$	Wind (*w*) and photovoltaic *(pv)* generation in the hour under consideration *(h)* after adjustments made in the different sessions of the intraday markets *(i)*
$G_{h,w}^{r}$, $G_{h,pv}^{r}$	Wind (*w*) and photovoltaic *(pv)* generation finally dispatched in the hour under consideration *(h)*

Although several factors[8] could cause active power imbalances in power systems, our empirical approach focuses on demand (D_h^r-D_h^i) and on VRES-E generation deviations due to forecast errors ($G_{h,w}^r$- $G_{h,w}^i$ for wind generation; $G_{h,pv}^r$- $G_{h,pv}^i$ for photovoltaic generation).

The demand imbalance *(DI)* is defined as the relative downward/upward demand deviation, which takes place when real-time consumption is higher/lower than that scheduled in the intraday market gate closure. Only demand deviations that require system adjustments are considered[9]. In keeping with this approach, *DI* variable is defined as follows:

$$DI = (D_h^r - D_h^i) / D_h^r \qquad (1)$$

The VRES-E supply imbalance *(SI)* is defined as the relative downward/upward deviation, which takes place when real-time renewable generation is higher/lower than that scheduled in the intraday market gate closure. Considering that VRES-E generators may update the prediction made to the day-ahead market in the intraday markets when forecasts with higher accuracies are available, the differences between power bids at intraday market gate closure and the power delivered to the power system are considered the best measure of VRES-E generation imbalances. This supply imbalance can be divided by technologies in wind supply imbalance *(SWI)* and photovoltaic supply imbalance *(SPVI)*. Therefore, *SI* variable is defined as follows:

$$SI = SWI + SPVI = (G_{h,w}^r - G_{h,w}^i) / D_h^r + (G_{h,pv}^r - G_{h,pv}^i) / D_h^r \qquad (2)$$

Given that we aim to assess the economic cost of deviations, in this study the costs of demand and supply imbalances are not measured in terms of up and down price regulation[10], but in terms of the average impact of system adjustment costs on the final price of energy. In this way, these relative deviations are presented in absolute terms.

[8] Unplanned plant outages in thermal and hydro generation, forecast errors in RES-E generation, unplanned line outages of international interconnectors and forecast errors of load, among others.

[9] Demand and renewable production could be correlated presenting similar seasonal patterns with periods of high (low) demand coinciding with periods of high (low) renewable energy production. If this happens, any source of variability in the amount of renewable energy generated could be absorbed by consumer demand with the consequent reduction in net load fluctuations (or vice versa) and, therefore, in flexibility requirements and adjustment costs.

[10] In Spain, a two-price model in the settlement of imbalances is used. This means that regulation price exists only for either up (when RES power production is lower than has been bid to the market) or down (when RES power production is higher than has been bid to the market), depending on the direction of the system imbalance.

As pointed out in earlier sections above, deviations between scheduled energy and real time demand are addressed through ancillary services, most of which are based on market procedures, such as secondary and tertiary reserve, and the imbalance management process. Thus, there is a direct relationship between the size of the deviation and the cost incurred by the system in resolving it.

When assessing the power system balancing costs associated with real-time deviations, the adjustment (or operational) service cost *(ASC)* is defined as the economic cost of the balancing mechanisms required when demand or VRES-E supply deviations appear. This cost has been defined as the difference between the final electricity price and the price at the end of the last intraday market session. After the intraday market, deviations between scheduled and measured energy are addressed by System Operator through market procedures, such as secondary reserve, tertiary reserve and the imbalance management process.

The costs associated with these balancing markets are captured by this spread, which measures the additional costs for delivering one MWh of electricity on top of the day-ahead and intraday price. When obtaining this spread, capacity payments are not considered[11]. In other words, the *ASC* variable results from the aggregate of overall system adjustment services managed by the system operator – technical and real-time constraints, power reserve, secondary and tertiary control band and deviations process management services (expressed in €/MWh) and can be defined as follows:

$$ASC_t = FP_t - DAMP_t - IMP_t - CP_t \qquad (3)$$

being:

- ASC_t: Adjustment service cost
- FP_t: Electricity final price
- $DAMP_t$: Day-ahead market price
- IMP_t: Intraday market price
- CP_t: Capacity payments

When analysing the evolution of system adjustment costs we have identified an inertial behaviour. This behaviour could be related to the criteria followed by the System Operator (SO) when assessing the control reserves. In Spain, as in the

[11] Capacity payments correspond to the regulated retribution to finance the medium- and long-term power capacity service offered by the generation facilities to the electricity system. Given that it is not directly related to the procurement of flexibility to the system, this cost is not included.

majority of European countries, the assessment of secondary and tertiary reserves is performed using deterministic and probabilistic approaches. In line with these approaches, the final amount of reserves contracted by SO[12] depends on such variables as the expected peak load in a given period or the largest loss of power expected within the control area. Provided these variables present an inertial evolution, the costs associated with the provision of the adjustment services will present the same behaviour. In order to capture these effects, the introduction of a dynamic component in the model specification is required.

In addition to the variables presented above, a set of variables was introduced as control variables. In recent years, the Spanish electricity system has been affected by various reform processes. Although this broad set of measures has affected all market parties, the national coal policy (the so-called restrictions of guarantee of supply) deserves special attention given its effects on the flexibility of the system (see Huisman and Trujillo-Baute, 2014) in the context of adjustment services. Demand for national coal for generating electricity in Spain fell as a consequence of the contraction of electricity demand, the high price of national coal relative to international coal, and the development of other production technologies.

The combination of these circumstances resulted in a sizeable excess of national coal production that was not absorbed by energy production, which became a source of major concern for the coal sector. In February 2011 a new regulatory framework to deal with the coal sector’s concerns was implemented in the electricity market. This took the form of a preferential dispatch mechanism for Spain’s coal power plants, where the electricity generated by these plants is remunerated at regulated prices.

This scheme modifies the operations of the energy market by introducing an adjustment that takes place immediately after the daily market match. The adjustment means altering the market result by removing volume offered (usually) by combined cycle plants and replacing them with units produced with national coal. Huisman and Trujillo-Baute (2014) show that the Spanish power market became less flexible after the policy change as the share of national coal production increased while the share of the combined cycle plants decreased, resulting in an increase in adjustment costs.

[12] In Spain, the assessment of the secondary reserve is based on the Empiric Noise Management Sizing Approach. REE applies two formulas: one for last load variation ($6\sqrt{Lmax}$) and the other for normal conditions ($3\sqrt{Lmax}$), where *Lmax* represents the expected peak load for a given area in a given period. Tertiary reserve assessment is based on the Loss Of the Largest Production Unit (LOLPU) method considering the amount of reserve needed to cover the lack of the capacity of the largest unit.

In the empirical approach, we control the economic impact on adjustment costs of this new regulatory framework by incorporating a dummy variable, Regulatory Framework (*RF*) (=1 after February 2011).

Finally, it is important to highlight that the seasonality it is controlled using three sets of dummies variables: quarterly (Q), weekly (W), and hourly (H) dummies.

Hourly data from the Spanish Power System Operator for the different markets (daily and intraday markets, technical constraints daily market, imbalances markets and other ancillary services) are used. The analysis covers the period between 1st January 2010 and 30th June 2014. In Table 2, we present the descriptive statistics of the variables as explained above.

Table 2: Descriptive Statistics

Variable	Obs.	Mean	Median	Std. Dev.	Min	Max
ASC	39,408	4.4972	3.6200	3.6795	0.0100	93.8712
DI	39,408	0.0354	0.0285	0.0293	0.0000	0.2848
SI	39,408	0.0193	0.0149	0.0170	0.0000	0.1465
SWI	39,408	0.0178	0.0134	0.0166	0.0000	0.1465
SPVI	39,408	0.0048	0.0008	0.0075	0.0000	0.0675
RF	39,408	0.7411	1.0000	0.4379	0.0000	1.0000

Having described the variables and information employed, we now present the stationary time series analysis. 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. While the results of the ADF test (see Table 3) in levels indicate that we cannot reject the null hypothesis of a unit root in any variable at a reasonable level of significance, the results in logarithms indicate that we can reject the null hypothesis of a unit root for all series. In addition, the KPSS results in levels indicate that we can reject the null hypothesis of stationarity in all cases, and in logarithms that we cannot reject the null hypothesis of stationarity at the 1% level of significance. Both tests confirm that the series are stationary in logarithms, so we estimate the models using all series in logarithms.

In addition to the time series properties of the variables, a deep outlier analysis was performed. To analyse the outliers in the series, a three-step approach was followed. In the first step we confirm the existence of outliers with the blocked adaptive computationally efficient outlier nominators (BACON) algorithm proposed by Billor et al. (2000) and further developed by Weber (2010)). In the second step we identify the most relevant outliers drawing on the approaches proposed by Fox (1991) and

Bohernstedt and Knoke (2002). And in the third step we check most relevant outliers validity in the original dataset by contrasting their values with those in the original data set and with a Spanish Power System Operator specialist. The results of this analysis (See Appendix A) indicate that there are extreme values of observed variables. This is carefully handled in the estimations.

Table 3: Augmented Dickey-Fuller and Kwiatkowski–Phillips–Schmidt–Shin test

	ADF test		KPSS test	
	Levels	**Logarithms**	**Levels**	**Logarithm**
ASC	-2.232	-9.865***	10.700***	0.000
DI	-3.105	-19.191 ***	2.610***	0.001
SI	-2.936	-20.791 ***	3.860***	0.000
SWI	-3.057	-20.892 ***	5.080***	0.000
SPVI	-2.949	-8.820 ***	7.530***	0.000

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%

The time series regression models constructed for the analysis of the imbalance effects on the adjustment service cost (*ASC*) is defined in the following equation:

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 DI_t + \alpha_3 SI_t + \alpha_4 RF_t + \alpha_5 Q_t + \alpha_6 M_t + \alpha_6 H_t + \varepsilon_t \qquad (4)$$

where, we take into account differences in the effect originating from demand (DI_t) and supply (SI_t) imbalances, and we introduce an autoregressive component (ASC_{t-1}) to capture the effects of dynamics. Likewise we introduce control variables for seasonal patterns (Q_t, M_t and H_t) and for differences in the regulatory framework (RF_t).

Finally, to disentangle the VRES-E supply side imbalances originating from the two main intermittent power sources, in Eq. (5), we separately account for wind (SWI_t) and solar ($SPVI_t$) supply imbalance effects. The same consideration for the time series integration is also made.

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 DI_t + \alpha_3 SWI_t + \alpha_4 SPVI_t + \alpha_5 RF_t + \alpha_6 Q_t + \alpha_7 M_t + \alpha_8 H_t + \varepsilon_t \qquad (5)$$

3.4. RESULTS

Given the confirmed validity of outlier observations (the outliers are likely to be real observations) and the dynamic nature of the model, we face potential problems from both outliers and endogeneity implying that, if regressions are performed using least square methods, can distort estimates of regression coefficients. As a reference point, columns (OLS) in Table 4 show the ordinary least square results for Eq. (4) and Eq. (5), with aggregated and disaggregated supply imbalance, respectively.

In the least squares estimation of dynamic models the unobserved initial values of the dynamic process induce a bias. The instrumental variable (IV) methods are able to produce consistent estimators for dynamic data models that are independent of the initial conditions.

These estimators are based on the idea that lagged (or lagged differences of) regressors are correlated with the included regressor but are uncorrelated with the innovations. Thus, valid instruments are available from inside the model and these can be used to estimate the parameters of interest employing IV methods. We use this rationality for the construction of instruments, using values of the dependent variable lagged two periods and the lags of the exogenous variables, which are all independent of ε_t, to perform estimations using the instrumental variable regression method. The two stages least squares IV results are show in columns (IV) for Eq. (4) and Eq. (5), respectively.

As a test of the instruments validity we used the Sargan statistic for overidentification restriction under the null hypothesis that the instruments are uncorrelated with the error term, and that the excluded instruments are correctly excluded from the estimated equation. From the test results (χ^2 (3) p-val of 0.231 and 0.411) we cannot reject the null hypothesis at any acceptable confidence level, hence, our instruments can be considered as valid instruments.

To alleviate the effects of the outliers we perform a quantile regression on the median. The quantile approach is not as sensitive as the least squares approach to outliers because it does not give much weight to them (at the median it gives symmetric weights to positive and negative residuals), but at the same time, unlike robust estimation, the quantile estimation does not sacrifice observations with relevant information specially important in our model given its dynamic component. The quantile regression results are show in columns (Q) in Table 4.

Finally, as in the least squares estimation of dynamic models, in the case of the quantile regression it is evident that the unobserved initial values of the dynamic process induce a bias. Thus, we use the same –validated- instruments as in the IV estimations to perform estimations using the instrumental variables quantile (IVQ) regression method (based on Chernozhukov and Hansen, 2006; 2008). The instrumental variables quantile regression results are presented in columns (IVQ) in Table 4.

Summarizing, we performed eight sets of estimations corresponding to the two equations with aggregated and disaggregated supply deviations presented in the previous section and report the results in Table 4.

Table 4: Effects of Demand and Supply Imbalance on Adjustment Service Costs (ASC)

	With Aggregated Supply				With Disaggregated Supply			
	(OLS)	(IV)	(Q)	(IVQ)	(OLS)	(IV)	(Q)	(IVQ)
DI	0.042***	0.040***	0.025***	0.024***	0.043***	0.041***	0.025***	0.024***
	(0.002)	(0.002)	(0.001)	(0.001)	(0.001)	(0.002)	(0.001)	(0.001)
SI	0.010***	0.009***	0.007***	0.006***				
	(0.002)	(0.002)	(0.001)	(0.001)				
SWI					0.005**	0.004**	0.007***	0.006***
					(0.002)	(0.001)	(0.001)	(0.001)
SPVI					0.009***	0.008***	0.005***	0.005**
					(0.001)	(0.001)	(0.001)	(0.001)
RF	0.089***	0.077***	0.037***	0.035***	0.083***	0.071***	0.032	0.032***
	(0.005)	(0.005)	(0.003)	(0.003)	(0.005)	(0.005)	(0.003)	(0.003)
L.ar	0.801***	0.830***	0.881***	0.894***	0.800***	0.829***	0.880***	0.893***
	(0.003)	(0.004)	(0.002)	(0.002)	(0.003)	(0.003)	(0.002)	(0.002)
Constant	0.387***	0.351***	0.326***	0. 306***	0.437***	0.393***	0.362***	0.342***
	(0.015)	(0.015)	(0.011)	(0.012)	(0.019)	(0.019)	(0.013)	(0.013)
Seasonal								
Quarter	Y	Y	Y	Y	Y	Y	Y	Y
Month	Y	Y	Y	Y	Y	Y	Y	Y
Hour	Y	Y	Y	Y	Y	Y	Y	Y
Obs.	39,407	39,407	39,407	39,407	39,407	39,407	39,407	39,407
R^2	0.738	0.737	0.554	0.6952	0.738	0.737	0.554	0.6976

Notes: Standard errors in parentheses*** p<0.01, ** p<0.05, * p<0.1. IVQ results with weighted bootstrap Standard error.

Given that the instrumental variables quantile regression method allows to alleviate and avoid the empirical concerns mentioned above, next we analyse the results presented in columns (IVQ) in Table 4, which in any case are highly consistent across specification and estimation methods. Overall, the estimation results point to a significant effect of demand and VRES-E supply imbalances on adjustment costs. The results indicate that a 1% aggregated supply deviation increases the system adjustment costs by 0.006%. This outcome is in line with the literature examining the effects of variable VRES-E generation. Much more original and interesting are our results related to the positive and significant effects of demand deviations on system adjustment costs. We find that a demand deviation equivalent to 1% increases the adjustment costs by 0.024%.

In sum, the respective intensities of the impacts of demand and supply deviations are statistically different, being always higher in the case of the demand deviations.

The estimations performed for the Spanish electricity system highlight the importance of demand imbalances when explaining the cost of balancing services.

In the case of disaggregated supply imbalances, both wind and solar photovoltaic deviation in generation exert a positive and significant effect on adjustment costs. Nevertheless, it should be stressed that when considering the two main VRES-E technologies separately, the results show that wind supply deviations have a greater economic impact than that of photovoltaic supply deviations presenting a higher elasticity. Although very similar, the SWI coefficient (0.006) is slightly higher than corresponding to SPVI (0.005).

In this regard, the economic impact of intermittent generation on system operating costs not only depends on the size of the deviation from scheduled but also on the specific context. The specific properties of VRES-E generation – production patterns, location, and correlation with load, among others - together with the flexibility of the power system into which renewable output is integrated determine the final economic impact. Solar photovoltaic generation is characterised by a diurnal pattern, where peak production occurs in the middle of the day (around 14.00). On the other hand although wind power output may display some daily and seasonal characteristics, its production is more variable over time and follows much less regular patterns than does load. As the interaction of all these generation patterns have an effect on how intermittent generation is assimilated into the system, the economic impact of solar and wind deployment not necessary has to be the same.

To gain additional insights from these results in Table 5 we present the estimated economic impact of 1 MWh demand and VRES-E supply deviation over adjustment services. As demand and supply deviations differ in their magnitudes, an additional rough indicator of the effect of both kind of deviations could be to calculate which is the economic cost for the system of a demand or supply deviation from scheduled equivalent to 1 MWh.

Table 5: Economic effects (€/MWh) from 1 MWh deviation in supply and demand

	DI	SI	SWI	SPVI
ASC	0.1079	0.0270	0.0270	0.0225

It should be stressed that when considering the two main VRES-E technologies separately, the results show that wind supply deviations have a greater economic impact than that of photovoltaic supply deviations. According to our estimates, the economic impact of 1MWh deviation in wind supply is 0.0270 €/MWh.

As expected, the adjustment service costs depend heavily on their value in the previous hour. Hence, a 1%-increase in the level of gross adjustment costs in the previous hour increases, on average, the adjustment service costs by 0.89%. The inertial behaviour of system adjustment costs, related with the criteria followed by the System Operator (SO) for the assessment of control reserves, seems to account for these outcomes. It must be born in mind that the adjustment cost includes overall - costs secondary reserve, tertiary reserve…- and not just those directly related to the imbalance management process. This inertial behaviour might be related with the fact that high VRES-E penetration rates are likely to increase both secondary and tertiary reserve requirement, even if forecast errors are minimised, and the cost associated with this reserve procurement not directly related with real-time deviation is included in the ASC variable.

Our econometric results for the regulatory framework variable are consistent with those published in previous studies. Thus, the regulatory framework is relevant when we consider the evolution of adjustment costs: a reduction in supply flexibility (an increase in the share of coal production and a reduction in power from combined cycle plants) results in an increase in adjustment costs. Hence, regulatory factors that affect supply flexibility exert a positive and significant effect on adjustment costs.

3.5. CONCLUSIONS AND POLICY IMPLICATIONS

Increasing VRES-E penetration has given rise to a series of challenges as regards the ability of the electricity system to balance supply and demand, especially with high levels of intermittent renewable generation. This new scenario requires a detailed quantitative assessment of how the electricity system might both deliver and accommodate higher levels of RES-E generation and of the associated economic costs for the consumer. Given that the electricity system has to deal with other sources of uncertainty – primarily of demand – here we have evaluated and compared the economic costs of additional demand for reserve and the response operations associated with each source of uncertainty.

Our study has stressed the importance of demand effects on operational costs, in contrast with other studies that have focused their attention more specifically on supply effects. The estimations for the Spanish system reported here demonstrate that demand imbalances cannot be ignored when evaluating the cost of balancing services. In summary, under the assumed hypothesis, the estimations performed allow the following conclusions to be drawn:

- First, our results point to the relevance of demand imbalances. Indeed, the effects on adjustment costs are always stronger for deviations from the demand side than they are for those from the supply side.

- Second, in Europe where renewable power capacities will soon be predominant in the generation mix, it is crucial that the volume of electricity imbalances within systems be minimized and the associated costs to end consumers be reduced. There are several reasons for these imbalances between generation and consumption, but our evaluation of the operational costs in the Spanish electricity system suggests that the demand effect cannot be ignored.

- The dynamic effects of these explanatory variables require further evaluation. Yet, our results indicate that the provision of stronger incentives to invest in technologies (e.g., better forecasting tools) is needed in order to minimize imbalance risks.

This chapter has examined the balancing power used to quickly restore the supply-demand balance in Spain's power system and the associated economic costs when real-time supply and demand deviations emerge. We have reported that variable renewable generation is a source of potential deviation that can increase short-term balancing needs. At the same time, errors in demand forecasts constitute an additional source of uncertainty that require balancing services. Interestingly, we have highlighted the relevance of demand effects on operational costs. All in all, however, supply and demand effects are crucial in the design of new balancing services.

4. COLLATERAL EFFECTS OF LIBERALISATION: METERING, LOSSES, LOAD PROFILES AND COST SETTLEMENT IN SPAIN'S ELECTRICITY SYSTEM[13]

4.1. INTRODUCTION

In the 1990s, when most national electricity and natural gas markets were still monopolies, the European Union and its Member States opted for the gradual opening up of these markets to competition. Significant progress has since been made in this direction in the case of the electricity market thanks to the gradual introduction of competition via a number of legislative packages. Underlying these proposals is the strong conviction that liberalisation increases the efficiency of the energy sector and the competitiveness of the European economy as a whole.

Spain has been no exception in this liberalisation process. In line with the European trend, the Spanish government established as a priority the opening up of the electricity sector to competition. The Electric Power Act 54/1997 represented the first step in this liberalisation process, with the establishment of a general framework for the electricity sector aimed at guaranteeing competition and competitiveness. Under this new framework, the government defined a transition period towards full liberalisation and while the introduction of tariffs of last resort in the residential electricity market did not increase liberalisation per se (Federico, 2011), it did represent a starting point in the drive to the deregulation of the retail market.

An evaluation of the liberalisation process conducted to date across Europe shows that not all the expected changes, especially those concerning lower electricity prices and effective retail market competition, have yet to be achieved. However, it is not the aim of this work to analyse the results of the liberalisation process; rather, our objective is to examine some collateral or unexpected effects of the liberalisation process in the energy sector by examining a natural experiment conducted in Spain in 2009.

The Second Electricity Directive [14] and its transposition to national regulation included a number of measures directly concerning distribution system operators (DSOs). Thus, the regulatory framework required the separation of distribution

[13] This chapter is based on Batalla-Bejerano et al. (2016).

[14] Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal electricity market.

activities from other segments of the electricity value chain (i.e., generation, transmission and supply activities). In the case of Spain, prior to June 2009, distribution companies had also been responsible for supplying consumers under a regulated tariff. However, in July 2009, this regulated supply disappeared and was substituted by a last resort supply system, managed by suppliers of last resort. This change in retail market competition, as demonstrated in this chapter, has had consequences in terms of the system's balancing requirements.

An increase in the adjustment service costs of tertiary regulation and deviation management have been observed since 1st July 2009, together with an increase in the corresponding adjustment service costs incorporated in the final electricity price paid by consumers. The aim of this study is to provide a better understanding of the impact of liberalisation on the costs of volume adjustment.

We exploit this policy event to compare the costs of adjustment in the periods before and after the policy change. Although demand forecast methods have received special attention from the academia (Cancelo et al., 2008; Ramanathan et al., 1997; Soares and Medeiros, 2008; Taylor, 2006), when explaining the cost of balancing services, demand deviations effects have not been as deeply studied as the effects that stem from intermittent renewable generation (Ela et al., 2014; Frunt, 2011; Glachant and Finon, 2010; Haas et al., 2013; Hirth and Ziegenhagen, 2015; Hirth et al., 2015; Vandezande et al., 2010).

Within the overall liberalisation process, during which European energy markets have undergone a major transformation, the issue analysed - energy market balance - could be considered a minor question. However, the success of any transformation process lies in applying smart regulations that can provide solutions to unexpected aspects of the process so as to exploit its potential benefits for society.

In this new liberalised paradigm, the System Operator (SO) has to be more concerned with real-time system operations and the ability to manage supply and demand constantly given that additional demand deviations induced by the energy market balance can potentially result in new operational reliability issues that need to be analysed.

In this context, drawing on data for the Spanish power market for the period just before and after the regulatory change became effective, this study aims to address the question of the collateral consequences of the liberalisation process in terms of system reliability.

The work done seeks to determine whether this policy change means that additional system flexibility is required thus affecting final electricity prices insofar as increasing energy market balance is addressed through ancillary services. Although the liberalisation process undertaken in Spain goes beyond the disappearance of the regulated supply and its impact on power system balancing costs, it is crucial to assess its economic consequences, especially if the last intention of the regulatory change is to benefit all electricity consumers.

The remainder of this chapter is structured as follows. Section 4.2 provides an overview of the policy change under revision and its economic implications. The data used, empirical strategy and model specification are presented in Section 4.3. Estimation results are presented and discussed in Section 4.4. The chapter ends with a final section summarising research conclusions and presenting the policy and regulatory recommendations.

4.2. THE POLICY

Policy design

2009 was a key year for Spain’s electricity sector and, in particular, for its retail markets. On 1st July 2009, end-user regulated electricity prices disappeared along with the DSOs’ role as suppliers. Prior to that date, consumers had been able to choose between being supplied by distribution companies – through end-user regulated prices – or by retailers under free market conditions. Distribution companies would no longer be able to supply electricity to their customers.

However, these reforms, which were designed to foster competition in the retail market and to promote progress towards the creation of an efficient Internal Energy Market in the European Union, had collateral and negative consequences for balancing markets in relation to electricity system losses and the estimation process of the electricity consumption for those customers without hourly metering. As the energy metered at distribution network entry points (transmission nodes and embedded generation) is not the same as that metered at distribution network exit points owing to the existence of losses, energy demand at the power station busbars[15] is estimated using a regulated standard coefficient of losses.

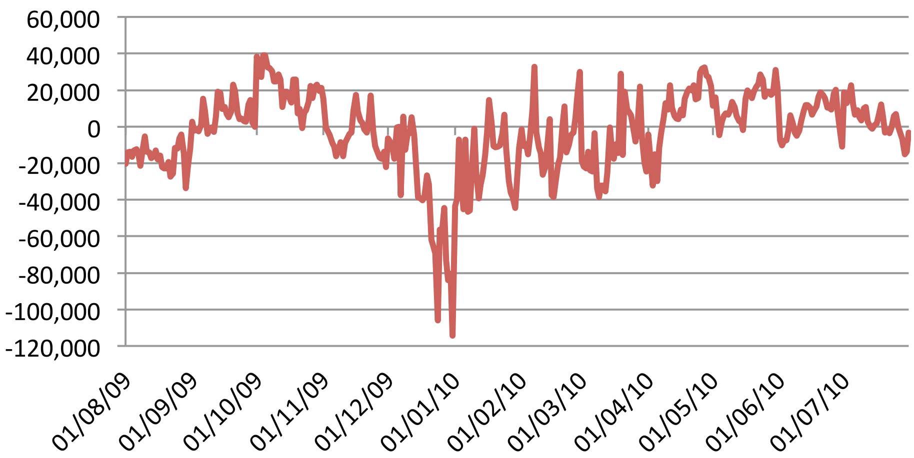
It should be stressed that the energy estimated according to this procedure does not have to coincide with the amount of energy eventually dispatched, arising hourly energy imbalances (see Figure 16). As a result, the energy dispatched to meet the customers’ energy requirements is not necessarily the same as that initially expected

[15] The power plant busbar is that point beyond the generator but prior to the voltage transformation in the plant switchyard; it is the starting point of the electric transmission system.

by the suppliers, appearing a positive or negative energy difference, for which a balancing process is required.

The main difference since July 2009 is the way in which this new energy imbalance is addressed[16]. In the pre-liberalisation system, the energy imbalance was resolved by the DSOs permanently matching electricity demand forecasts with the energy actually dispatched. Under liberalisation, this system is no longer valid. From a regulatory perspective, the electricity imbalances resulting from the difference between the average transport and distribution losses and the standard losses used in balancing the system as a whole are considered additional system deviations.

Figure 16: Energy imbalances (MWh)
explained by differences between real and estimated electricity losses



Source: Own elaboration based on data from CNMC

This difference, defined as the energy market balance (EMB), requires additional adjustment services to ensure that energy generation and demand are in permanent equilibrium. Addressing the energy market balance is achieved through ancillary and energy balancing services based, in most instances, on market procedures such as the secondary and tertiary reserves and the imbalance management process, so there is a direct relationship between the size of the deviation and the cost to the system when solving it.

[16] See Appendix B for a detailed explanation of the technical aspects underpinning the energy market balance (EMB).

The analysis of the relationship between the energy market balance and the final electricity price is the main objective of this analysis. When a difference arises between the energy measured at the power station busbars and the energy scheduled in the market, the system has to manage that difference by increasing production through the adjustment markets in real time. As explained next, the energy market balance implies economic consequences for both suppliers and consumers, who have to face increasing balancing costs related to the energy adjustment mechanism required to maintain generation and load in permanent equilibrium.

Implications and research hypothesis

From a system management perspective, several factors on both the demand and supply side might cause active power imbalances in the electricity system (see Table 6). Together with physical imbalances, above and beyond the deviations between the stepwise (discrete) demand and supply schedules and continuous physical variables (scheduled leaps), other variables may result in imbalances. Thus, unplanned contingencies in the conventional or renewable generation capacity or in the interconnection capacity, forecast errors from VRES generation due to its intermittent nature or load forecast errors can all increase the need for balancing power. As the electrical system has to be in permanent equilibrium, balancing power (regulating frequency-control power) is used in rapidly restoring the supply-demand balance in systems when an active power imbalance arises.

Table 6: Variables that cause system imbalances

	Variable	Imbalance source
Supply	Conventional generation	- Unplanned plant outages - Schedule leaps
	VRES generation	- Forecast errors - Schedule leaps
	Interconnectors	- Unplanned line outages - Schedule leaps
Demand	Load	- Forecast errors - **Deviations from standard losses** - Schedule leaps

Source: Own elaboration based on Hirth and Ziegenhagen (2015)

As explained above, total losses produced in the transmission and distribution networks may be another source of power imbalance. The methodology employed in the Spanish regulatory framework in relation to such losses involves allocating a percentage of these losses to each customer using loss factors or standard coefficients that take into account their consumption characteristics. This procedure means that if actual losses differ from standard or regulated losses, the power system has to face a new source of imbalance.

The existence of demand deviations in power systems is not something new. The aim behind the liberalisation process across Europe implemented during the last decade was to open up the electricity supply to competition. At that moment, and in order to avoid huge and prohibitive costs of putting smart metering into every customer, it was a common approach that some specific electricity consumers – mainly residential – would be settled using load profiles and ex-ante fixed loss coefficients. In this sense, deviations from standard losses have to be considered as an additional source of uncertainty to power system managers together with the inherent forecast errors and schedule leaps.

In this context and even with perfect VRES-E generation forecasting, *ceteris paribus* the consequences for electricity systems of an increasing difference between the estimated demand and the final load should be a need for additional flexibility. In terms of system operation, this energy gap should stress the need for an appropriate number of reserve power plants with flexible dispatch capable of providing the necessary stability and ancillary services to deal with problems of electricity market balance.

In this chapter, we test whether a sub-optimal definition of the standard coefficient of losses means that the system operator has greater losses to solve in real-time in order to balance the markets. At the same time, we examine whether the way in which this policy consequence is being addressed affects the market price signals for the rest of the balancing energy required.

The Spanish electricity market is organized as a sequence of different markets – a day-ahead market, an intraday market, ancillary services – and system operation services beginning with the day-ahead market and culminating in real time[17]. Once the day-ahead market closes, additional short-term tools have to be implemented to enable participants or the system operator to improve the schedules defined during the previous day (Pérez-Arriaga and Batlle, 2012). Under trading enabling them to react when supply or demand situations change with respect to the estimates cleared on the day-ahead market. Finally, ancillary services include the set of

[17] For a more detailed description of the Spanish electricity market see Bueno-Lorenzo et al. (2013).

products that are separated from the energy production, and which are related to the power system's security and reliability (Lobato et al., 2008). These services, though not including voltage control ancillary services, are designed to ensure the necessary equilibrium between generation and demand and include load-frequency control and balancing ancillary services.

Although a detailed description of the design and characteristics of the different ancillary service (AS) markets – primary control, secondary control, tertiary control and balancing ancillary services – lies beyond the scope of this chapter, Figure 17 illustrates the expected effects of the policy under analysis on ancillary services markets. To understand these effects properly, a number of considerations must be firstly taken into account.

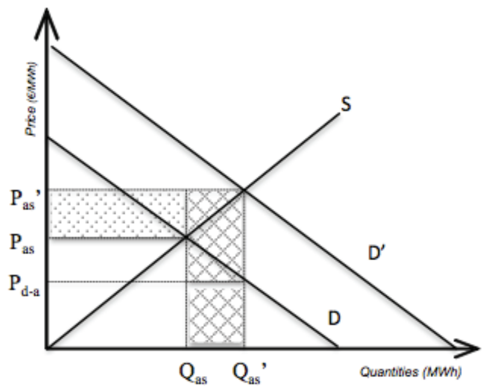
In Spanish power system, several types of balancing power are employed simultaneously to address power and load imbalances. These balancing power types can be distinguished along several dimensions (Hirth and Ziegenhagen, 2015): operating vs. contingency reserves, spinning vs. stand-by reserves, fast vs. low regulation in terms of the activation time, positive or upward regulation vs. negative or downward regulation, etc.

Depending on the type of balancing power market, the technical characteristics of the service provided differ. Thus, each has different market designs and different ways of addressing resource adequacy and reserve margin issues. To explain the expected consequences of the policy change in the ancillary services market, in Figure 17 we assume that all the balancing energy required to solve imbalances is cleared in a single competitive balancing market, where suppliers of balancing power only receive compensation for energy (and none for capacity) based on the marginal price.

In the simplified ancillary services market, the market equilibrium price (P_{as}) results from the intersection of the demand (*D*) and supply (*S*) curves. This price determines the economic cost associated with the provision of the balancing energy required (Q_{as}) by the System Operator to stabilize the active power balance on short time scales. The electricity market balance process used to solve biased loss estimations might increase the total amount of balancing power needed thus leading to a change in demand. Graphically, this new balancing requirement ($Q_{as}{'} – Q_{as}$) involves a shift in the demand curve to the right (*D'*) resulting in a new market price equilibrium ($P_{as}{'}$).

Two direct economic effects can be identified if we examine the policy implications of balancing market. The first (the *quantity effect*) concerns the increase in the total balancing cost needed to reserve the band of secondary regulation and for the additional spinning reserves for tertiary purposes caused by EMB $((Q_{as}{'} - Q_{as}) \times P_{as}{'})$. Additionally, an increase in demand will shift prices upward, increasing the overall economic value of balancing relative to the prior equilibrium point. This second impact (*price effect*) concerns the increase in the total balancing cost explained by a higher equilibrium price than that at which the previous equilibrium quantity is cleared *(Q_{as} x ($P_{as}{'}$ - P_{as})).* Both effects refer to the total economic cost of balancing power procurement. In this sense, we test if liberalisation (i.e., the policy change) results in a shift of both the price and quantity in balancing markets, increasing the overall cost of the provision of this service relative to the prior equilibrium point.

Figure 17: Expected effects of the policy on ancillary services market



At different market sessions held the day prior to or even on the day of delivery, the final price of electricity is determined as the sum of the different prices and costs associated with each of these markets. The determination of the economic cost associated with each electricity market and the allocation criteria of this cost strongly depend on market design characteristics. Increasing energy market balance is addressed through ancillary and energy balancing services based, in most cases, on market procedures such as secondary and tertiary reserves and imbalance management processes, so there is a direct relationship between the size of the deviation and the cost to the system for solving it. Demand for larger balancing energy might have economic impacts on final electricity prices and the analysis conducted seeks to obtain empirical findings of this nexus based on Spanish market data.

Power system reliability and resource adequacy are complex elements of market operations where the final cost is influenced by multiple factors. While there is, in principle, a general consensus on the nexus between energy loss deviations from expected and balancing power, no empirical analyses have examined the size of the impact.

The absolute economic impact of the policy change in terms of balancing costs is by no means a straightforward question due to the complex nature of wholesale, intraday and ancillary services markets where many variables can impact on final prices and generator revenues (location, raw material costs, generation mix, level of demand, size of the electricity imbalances, etc.). The aim of this chaper is to contribute to a better understanding of the economic consequences of the liberalisation by undertaking an evaluation of its impact on final balancing power cost.

From a welfare perspective, the economic consequences for consumers are evident as the energy imbalance is addressed in posterior markets where prices are typically higher. Real-time market clearing prices, also known as balancing energy prices, are generally by their nature much more volatile and higher than day-ahead prices. Therefore, an increase in the volume of balancing energy required to solve deviations between estimated and real loads should have an economic impact on the final hourly electricity price paid by the consumers.

4.3. DATA AND EMPIRICAL STRATEGY

As explained in Chapter 2, the Spanish electricity market comprises different sub-markets: a daily market, an intraday market, ancillary services and system operation services beginning with the day-ahead market and culminating in real time. The system operator, Red Eléctrica de España (REE), manages the primary, secondary and tertiary regulation, in order to guarantee the stability of the system.

All the adjustment services are made available via different system operation processes defined by REE. One of the most remarkable features of the Spanish system is that, since the beginning of the liberalisation process, the regulatory framework has promoted the provision of these services through market mechanisms, along with the creation of the market as a platform for energy transactions.

Drawing on data for these markets, operating reserve costs have been calculated. Operating reserves, often referred to as ancillary services, include contingency reserves – the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage – and regulation reserves – the ability to respond to small and random fluctuations around the expected load (Ela et al., 2014; Hummon et al., 2013; IEA, 2009, 2011a, 2011b and 2014; Müsgens et al., 2012).

As pointed out in previous sections, deviations between scheduled energy and real time demand are addressed through ancillary services, most of which are based on market procedures, such as the secondary and tertiary reserves and the imbalance management process. Therefore, there is a direct relationship between the size of the deviation and the cost to the system of solving it. Using hourly market data for Spain, the weighted average cost of the system adjustment services – technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints – is used as the dependent variable in the econometric estimation.

To examine the impact of the policy we distinguish between two periods. The first covers the 12-month period prior to policy change, from 1st July 2008 to 30th June 2009. The second covers the 12-month period after the policy became effective, from 1st July 2009 to 30th June 2010. We choose one-year periods to minimise the probability that seasonal patterns might account for the results we find. We looked for information about other related policy changes in both periods that might affect our research, but to the best of our knowledge there were none. Hence, we are confident that the policy change under consideration is the sole policy event in our sample.

The adjustment cost, defined as the economic cost of the balancing mechanisms that are required when demand or supply deviations appear, is defined as the price spread between the final electricity price and the price at the end of the last intraday market session. After the intraday market, deviations between scheduled and measured energy are addressed through market procedures, such as secondary reserve, tertiary reserve and the imbalance management process.

The costs associated with these balancing markets are captured by this spread, which measures the additional costs for delivering one MWh of electricity on top of the day-ahead and intraday price. When obtaining this spread, capacity payments[18] are not considered. In other words, the adjustment cost results from the aggregate of the overall system adjustment services managed by the SO – technical and real-time constraints, power reserve, secondary and tertiary control bands and deviation management services -

Based on the foregoing considerations and bearing in mind that the final electricity price is determined as the sum of the different prices and costs associated with each of the markets that integrate the power system, the adjustment service cost (ASC) is obtained as shown in the following equation (with all variables expressed in €/MWh):

---

[18] Capacity payments correspond to the regulated retribution to finance the medium- and long-term power capacity service offered by the generation facilities to the electricity system. Given that they are not directly related to the procurement of flexibility to the system, this cost is not included.

$$ASC_t = FP_t - DAMP_t - IMP_t - CP_t \qquad (6)$$

where:

ASC_t:	Adjustment service cost
FP_t:	Electricity final price
$DAMP_t$:	Day-ahead market price
IMP_t:	Intraday markets price
CP_t:	Capacity payments

Although several factors – unplanned plant outages in thermal and hydro generation, forecast errors in VRES-E generation, unplanned line outages of international interconnectors and forecast errors of load, among others – could result in active power imbalances in electricity systems, our empirical approach focuses on demand deviations explained by differences between the real losses of the system and those resulting from the application of a standard coefficient of losses and load profiles.

To understand how this explanatory variable is calculated, we first need to provide an overview of how active power imbalances are addressed in Spain's electricity system.

As electricity cannot be stored in large quantities, the amount of energy demanded must be generated with great precision in the exact moment that it is required, ensuring a constant balance is maintained between generation and consumption. Using day-ahead market and physical bilateral contracts, purchase and sales bids are made resulting in the scheduled energy program.

From the perspective of energy flows (Figure 18), demand and supply are integrated by different components. Following intraday market gate closure, the SO has to adjust the resulting program to compensate for any modification or deviation in any of these components.

Energy deviations that occur after the intraday gate closure constitute real demand adjustments (RDAs), the latter being attributable to several possible factors. Any difference between expected and real demand from liberalised and last resort retailers (without considering technical and commercial losses) or any real losses different from expected standard losses, increase the need for energy used in the RDA process. Given that demand deviations explained by EMB constitute one of the most relevant explanatory variables accounting for RDAs, they have been used as a proxy variable of the effect of the policy under analysis.

Figure 18: Spanish (peninsular) electricity balance

SUPPLY	Total net generation	=	Liberalised suppliers	DEMAND
	- Conventional - Pumped generation - RES generation - Cogeneration and rest		Last resort suppliers	
			Auxiliary services consumption	
			Direct consumers	
			Balearic demand (HVDC Link)	
			Pumped storage	
			Standard losses	
			Exports	
	Imports		**Real demand adjustments**	

Source: Own elaboration

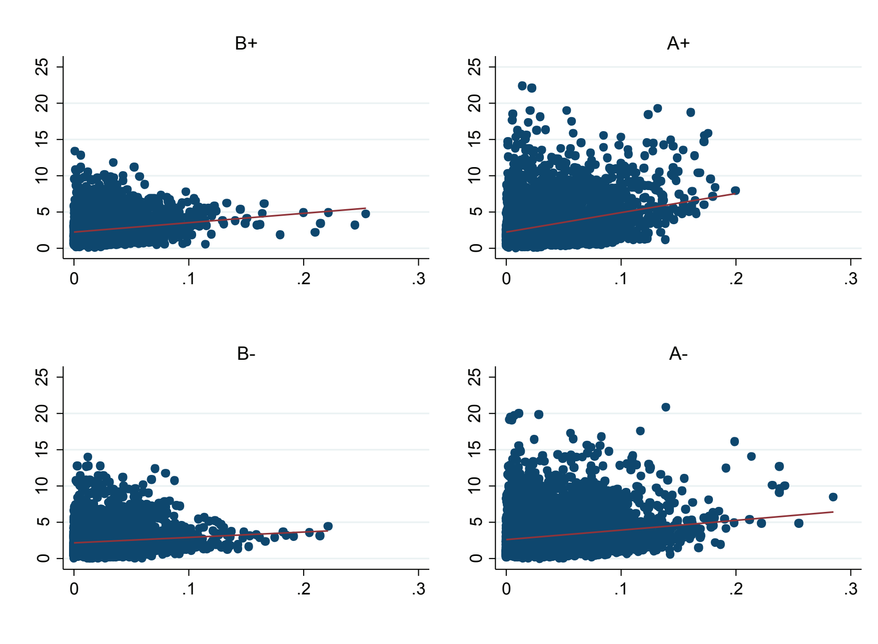
Figure 19 shows the relationship between RDAs in relative terms and the ASCs in the Spanish market as a price spread. The graphs on the left show this relationship before the policy change while the graphs on the right show the relationship after the policy change.

Given that for the Spanish electricity market, according to the imbalance price policy, a two-price system scheme is used depending on the overall system situation, the analysis of the relation between the two variables needs to take this into consideration. Therefore, for the graphical representation we split the sample in two, depending on whether the system is characterised by over-deviations (long system position) and requires downward regulation energy (-) or by under-deviations (short system position) and requires upward regulation energy (+).

As a different imbalance price is applied to positive and negative imbalance volumes, the analysis of the relationship between RDA in relative terms and adjustment services takes into consideration this fact, resulting in four possible scenarios: the relationship prior to policy change for hours requiring upward regulation energy (B+) or downward regulation energy (B-) and after the policy change for hours requiring upward regulation energy (A+) or downward regulation energy (A-).

It seems quite apparent that the policy change has affected the relationship between RDAs and ASCs. First, both the graphs (Figure 19) and statistics (Table 7) suggest an increase in dispersion in terms of adjustment services with the highest costs being recorded following liberalisation. As for RDAs, the graphs suggest a similar increase. At the same time, graphic analyses seem to indicate a change in the nature of the relationship between the two variables.

Figure 19: Adjustment service costs versus real demand adjustments



Note: This figure shows the relationship between the price spread explained by adjustment service costs (€/ MWh) (y-axis) and real demand adjustments[19] (x-axis) before (B) (left hand side) and after (A) (right hand side) the policy change.

Table 7: Statistical representation of Figure 19

			Obs.	Mean	Std. Dev.	Min	Max
Real Demand Adjustments	**Before**	Negative	5,219	0.02908	0.02484	0	0.22114
		Positive	3,540	0.02632	0.02422	8.81E-06	0.25394
	After	Negative	5,193	0.04491	0.0348	0	0.28484
		Positive	3,566	0.03963	0.0319	3.13E-06	0.19958
Adjustment Service Costs	**Before**	Negative	5,219	2.35953	1.62451	0	13.91
		Positive	3,540	2.54883	1.67132	0	13.34
	After	Negative	5,193	3.18603	2.5450	0	20.79
		Positive	3,566	3.25166	2.93304	0	22.37

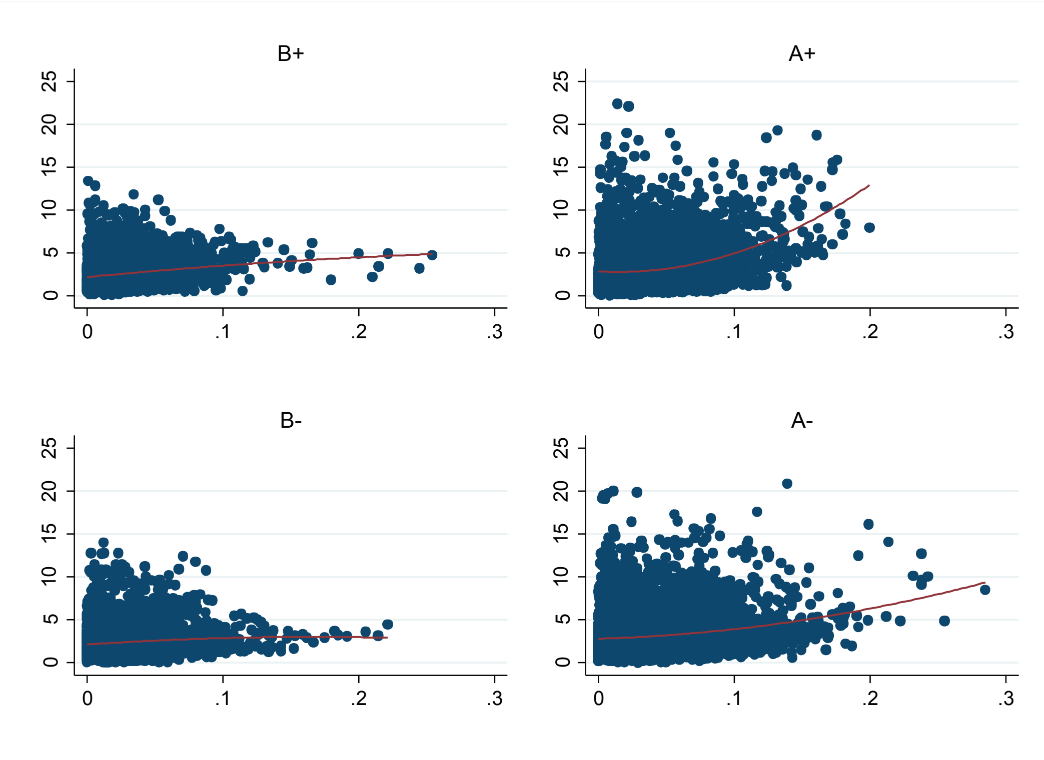
After the policy change, in contrast with the situation prior to liberalisation, the graphic representation suggests that the relationship is no longer linear and is better fitted by a quadratic function. Indeed the scatter plots in Figure 20 seem to reveal a

[19] For simplicity of exposition we refer to the real demand adjustment in relative terms (% over hourly final electricity demand) as real demand adjustment.

slight curvilinear shape to the data suggesting that a second-degree polynomial might be appropriate for modelling the data after the policy change.

Therefore, both the linear and quadratic specifications are tested econometrically by performing two separate regressions (before and after the policy change). By including a dummy variable for liberalization interacted with the real demand adjustment (RDA) variable we could be able to capture the effect from the variable of interest. Nevertheless, when using the interacted dummy an underlying assumption is that the relation between the adjustment service cost (ASC) and the RDA it is linear during all the period. Given that for the period after the regulatory change the relation it is better fitted by a quadratic function, it seems more appropriate to split the sample instead of using the interacted dummy over the entire period.

Figure 20: Adjustment service costs versus real demand adjustments (quadratic relationship)



To conduct the econometric test, we use hourly market data for Spain for the period between 1st July 2008 and 30th June 2010, and construct a time series regression model controlling for seasonality. As the dependent variable, the econometric estimation uses the average weighted cost of the adjustment services. This variable, obtained as a price spread, includes the economic cost associated with all adjustment services – technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints. Hourly RDAs are used as the main explanatory variable.

Additionally, and in line with other electricity market price studies, we introduce an autoregressive component to capture dynamic effects on the adjustment costs. We introduce two additional control variables in our models. First, to control for consumption patterns on working and non-working days, we introduce a working day variable (*WD*). As electricity demand varies across the week, this temporary variable is introduced in the specification of the model in order to address aspects related to seasonality. Given notable differences between working days and the weekend, the model specification incorporates a dummy variable (=1 if a working day). Second, as the price of balancing power differs being on average positive balancing more expensive than negative balancing (Table 7), we introduce a second control variable (*UpR*) for upward and downward energy regulation (=1 if the electricity system requires upward regulation). In Table 8, we present the descriptive statistics of the variables employed.

Table 8: Summary statistics

Variable	Obs.	Mean	Std. Dev.	Min	Max
ASC	17,518	2.82441	2.27529	0	22.37
RDA	17,518	0.03536	0.03048	0	0.28484
WD	17,518	0.69726	0.45946	0	1
UpR	17,518	0.40570	0.49104	0	1

Before presenting the time series regression models constructed for the analysis of the impact of the real demand adjustment on the adjustment cost, a stationary time series analysis was performed. 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 confirm that the series are stationary in levels. In addition to the time series properties of the variables, an outlier analysis was performed rejecting the existence of extreme values.

The model specification is defined in the following equations:

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 RDA_t + \alpha_3 WD_t + \alpha_4 UpR_t + \varepsilon_t \qquad (7)$$

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 RDA_t + \alpha_3 RDA_t^2 + \alpha_4 WD_t + \alpha_5 UpR_t + \varepsilon_t \qquad (8)$$

The main difference between Eq. (7) and (8) is the inclusion of a quadratic component in the econometric model to test for a linear or polynomial relationship between the variables. In the least squares estimation of this dynamic model, it is evident that the unobserved initial values of the dynamic process induce a bias. Instrumental variable methods are able to produce consistent estimators for dynamic data models that are independent of the initial conditions. These estimators are based on the idea that lagged (or lagged differences of) regressors are correlated with the regressor included but are uncorrelated with the innovations. Thus, valid instruments are available from within the model and these can be used to estimate the parameters of interest employing instrumental variable methods. The construction of instruments is done using values of the dependent variable lagged two periods and the lag of the exogenous variables, which are all independent of ε_t, to perform estimations using the instrumental variable regression method.

4.4. RESULTS AND DISCUSSION

To test the hypothesis of a differentiated impact of real demand adjustments on the costs of the system adjustment services resulting from the liberalisation we performed four sets of estimations corresponding to the two equations and time periods explained above. The estimation results are presented in Table 9, where the first two columns correspond to the linear model estimates (Eq. (7)) before and after the policy change. The first period covers the 12-month period before the policy change (from 1st July 2008 to 30th June 2009) and the second period covers the 12-month period after the policy became effective (from 1st July 2009 to 30th June 2010). Analogously, the results in columns (3) and (4) correspond to the quadratic model estimates (Eq. (8)) before and after the policy change.

Overall, the results show that, as a consequence of liberalisation, the system's ASCs increased. In general, the constant is higher after the policy change than before; hence, regardless of the impact of the RDAs, the weekly seasonality and the type of energy regulation, the ASCs increased after liberalisation. These results are indicative of the general impact but they are not specifically what we are interested in, as our objective is to determine if the ASCs fluctuate as a consequence of the change in the relation between the costs and the real demand adjustments attributable to the new role played by the DSO following liberalisation.

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of the general impact but they are not specifically what we are interested in, as our objective is to determine if the ASCs fluctuate as a consequence of the change in the relation between the costs and the real demand adjustments attributable to the new role played by the DSO following liberalisation.

Table 9: Impacts on the system adjustment service costs before and after liberalisation

	Linear		Quadratic	
	(Before) (1)	(After) (2)	(Before) (3)	(After) (4)
RDA	2.766***	6.200***	2.259***	1.875*
	(0.339)	(0.445)	(0.694)	(1.090)
RDA^2			4.901	34.04***
			(5.851)	(7.814)
WD	0.0603***	0.0792**	0.0609***	0.0848***
	(0.0181)	(0.0321)	(0.0181)	(0.0321)
UpR	0.0848***	0.155***	0.0843***	0.153***
	(0.0167)	(0.0298)	(0.0167)	(0.0298)
L.ar	0.871***	0.851***	0.871***	0.848***
	(0.00569)	(0.00639)	(0.00570)	(0.00640)
Constant	0.161***	0.0962**	0.167***	0.186***
	(0.0224)	(0.0389)	(0.0239)	(0.0438)
Observations	8,759	8,759	8,759	8,759
R-squared	0.786	0.746	0.783	0.741
dydx (RDA & RDA^2)			2.5767	4.0833***

Note: Robust standard errors in parentheses *** p<0.01, ** p<0.05, * p<0.1

Based on the graphical representation presented in section 3 above, we hypothesised that the nature of the relationship between RDAs and ASCs differed before and after the implementation of the policy, and we estimated linear and quadratic functions to test this. The results confirm that, while before liberalisation the relationship between the two variables had a linear form (the coefficient of RDA^2 in column (3) is not significant), after the policy change it takes a quadratic form (the coefficient of RDA^2 in column (4) is significant). These results are of particular relevance since they imply that following liberalisation the impact of demand adjustments on the ASCs have become increasingly stronger.

The short-run marginal effects of these regression results provide additional insights into the magnitude of the implications of the policy change (see Table 10). Before liberalisation each MWh of RDA generated an adjustment services cost of 2.76 €/MWh; after liberalisation the same demand adjustment generates an ASC of 4.08

€/MWh. This means that the immediate direct effect of the policy change is an increase of 47.8% (see first line of Table 10). However, to place these figures in the right perspective, we need to take into account that the ASCs differ in both periods; hence, we divided the previous effects by the average value of the ASCs. The results indicate that on average each MWh of RDA generated a 12.7% increase in ASCs before and 26.90% after liberalisation (see second line of Table 10).

Table 10: Short-Run Marginal Effects

	Before	After	Diff (B vs. A)
dy/dx (€/MWh)	2.76	4.08	47.80%
(dy/dx)/$\bar{y}$	12.70%	26.90%	14.20%

The difference in the marginal effects from each MWh of RDA on the average ASCs can be used to measure the monetary cost of the policy. By multiplying this difference in the marginal effects (14.20%) and the average ASCs after the regulatory change, we find that the additional cost is 0.348 € per MWh consumed. With this information, and taking into account that total consumption in the 12-month period following the policy change (July 2009 to June 2010) was 257 TWh, the impact of liberalisation on the adjustment services represented an overall cost of 90 million € /year.

As for the dynamic component, our results indicate that the ASCs depend heavily on their value in the previous hour. Hence, depending on the model and period considered, a 1€/MWh increase in the level of ASCs in the previous hour increases the costs by between 0.84 and 0.87 €/MWh. The inertial behaviour of the system adjustment costs, related to the criteria followed by the SO to assess control reserves, seems to account for these outcomes.

Finally, our results for the additional control variables are in line with expectations. First, we find that the effect of the positive energy market balance on the adjustment costs is always higher than that of the negative balance. These results are as expected for this control variable, since it captures the fact that adjustment services are more costly when the system requires upward regulation than when it requires downward regulation. The costs of balancing power are heavily dependent on the kind of generation technology used for regulation (Holttinen, 2005, Holttinen et al., 2011), with hydropower being the cheapest option and gas turbines the most expensive, as well as the overall situation of the system. From a cost perspective, it is not the same to be in a long system position requiring downward regulation energy, as it is to be in a short system position requiring upward regulation energy.

The explanation for this price differential lies in the fact that to provide upward regulation, the generation resources must set some generation capacity aside, which could otherwise have been traded in the power markets. The provision of downward regulation merely requires that the generation unit be able to ramp down (Sorknaes et al., 2013; van der Veen et al., 2013; de Vos et al., 2012).

And second, the variable capturing the seasonality of electricity demand across the week is positive and significant in all regressions. This positive effect seems to be related to the amount of generation connected to the system that is capable of providing flexible services to the system. Over the weekend, a similar pattern of VRES generation to that recorded on a working day may result in a low net demand. Under such a scenario, conventional generation could increase its participation in the adjustment services markets in order to complete the generation program and in this way avoid shutting down only to have to start up a few hours later.

4.5. CONCLUSIONS AND POLICY IMPLICATIONS

Electricity markets across Europe have undergone an institutional transition. To enhance economic efficiency and improve services to the consumer, European electricity markets had been liberalised, leading to the introduction of competition and opening of the markets. In this process, the current role of some agents, such as DSOs has changed being its role strongly influenced by the unbundling measures introduced in the regulatory framework. In this regard, the Second Electricity Directive implied a change in the duties and responsibilities of Spanish DSOs.

When discussing the best way to achieve competitive and integrated European electricity retail markets, this change has to be considered in general terms as positive and DSOs should be seen as key agents in the liberalisation process (Eurelectric, 2010). For this reason, the exercise has not sought to question the decisions taken in Spain within the framework of the EU’s directives.

Indeed, DSOs have been shown to be instrumental in the roll-out of smart grids and smart meters, and to have played a leading role in aggregation, demand response and energy efficiency, among other relevant aspects. The drawback analysed is not that distribution companies are not suppliers of energy in the retail market, but rather that the regulatory framework should have anticipated the economic impact associated with the change of scheme by establishing corrective measures.

Under the new liberalised scenario, energy suppliers have to estimate demand in order to make sure that sufficient supply is available on different timescales. Calculating both the total electricity demand and the specific electricity demand for different uses based on limited metered data constitutes a common problem across Europe, not being Spain an exception.

Under a similar methodological approach to estimate the electricity demand, differences arise when considering the technical aspects involved in the construction of the different load profiles and losses coefficients trying all these methods to provide the most representative patterns for electricity usages for the different segments of liberalised customers.

In this sense, the policy change introduced in July 2009 regarding the role of the DSOs is relevant for the evolution in adjustment costs in Spain. From this date, the suppliers are the only ones responsible to estimate demand in order to make sure that sufficient supply is available on different timescales. Hourly consumption for all customers on a daily basis is estimated based on load profiles and loss coefficients determined ex-ante.

To the extent that electricity balance, resulting from the difference between the measured losses in transmission and distribution and the standard losses used in the balancing procedure of the system as a whole, requires additional adjustment services, the policy directly increased the energy requirements associated with the electricity market balance. In this sense, this chapter provides an economic estimation of the economic impacts of this policy on adjustment services costs and, hence, on final electricity prices.

Although in 2009 the combined day-ahead and intraday market prices accounted for 89% of the final price, whilst the cost resulting from the management of system adjustment services accounted for just 6.3%, the impact of these latter costs on the final price of energy has grown substantially. In the first year of policy change, the amount of energy managed in the system adjustment services markets was 23,918 GWh, 34.9% higher than in the previous year, a clear indication that something was amiss in the adjustment services markets. Isolating the economic effects attributable to the policy change, we find that the extra cost in relative terms was around 0.348 € per MWh consumed. Thus, in the first year alone, the effects of liberalisation via the real demand adjustment on the adjustment services represented an overall cost of 90 million €.

This increase in terms of the costs linked to adjustment services is relevant both from a macro and microeconomic point of view. At a time when energy prices are raising concerns about the impact on economic competitiveness, it becomes increasingly relevant from a macroeconomic perspective to identify any source of distortion affecting final electricity prices. At the same time, from a microeconomic perspective it should be stressed that any unexpected increase in the adjustment service costs has a marked impact on the results of independent electricity retailers. While the price risk associated with unexpected variations in the day-ahead market price could be covered on the futures markets, unforeseen variations in the cost of adjustment services could not be covered. Therefore, an unexpected increase in adjustment service costs has a direct impact on the business results of retailers – especially on those of new entrants. This highlights the importance of the analysis undertaken in this chapter.

From a short- and medium-term perspective, improvements have to be introduced. Smart metering is a highly promising technology, which will greatly empower electricity customers to become active managers of their consumption. At the same time, smart meters should result in the optimisation of the overall electricity distribution infrastructure. The expected large-scale deployment of smart meters in Spain will enable both suppliers and DSOs to use more accurate individual consumption data (load profiles) in their processes. Nevertheless, in the short-term, measures such as those introduced in June 2014, aimed at establishing standard coefficients of losses and load profiles that take into account different time and seasonal patterns should facilitate a reduction in associated costs.

Since the initiation of liberalisation, costs of at least 450 million € have been borne by final consumers. The transformation would probably have been faster if instead of socialising through the final price of electricity, the extra cost had been assigned to a specific agent (e.g., the last resort or liberalised supplier). During this five-year period, no price signal was given to the suppliers – or to the regulator who had ultimate responsibility for determining the standard coefficients of losses – because of the greater requirements of flexibility expected in the system.

Behind every major change, such as the transformation ushered in by the liberalisation of the electricity market, it is critical that the details of the process be carefully examined. The challenges faced in attaining the goals set are largely determined by regulatory issues or, more specifically, by micro-regulations and their implementation. It is, obviously, vital to assess the economic consequences for the whole system of any policy change, especially if the intention of a smart regulation is to benefit all consumers.

In the context of growing concern about competiveness, the wise use of available resources and the employment of smart market policy tools are essential if we are to benefit fully from sustainable and reliable power systems.

Although this study is applied to Spain, the results are of general interest to other countries mainly because the most common regulatory design within the EU on liberalisation promotion is applied. The Spanish experience provides useful insight to other countries where the process of liberalisation of the retail market is at early stages.

5. IMPACTS OF INTERMITTENT RENEWABLE GENERATION ON ELECTRICITY SYSTEM COSTS[20]

5.1. INTRODUCTION

Considering its benefits, not only in reducing greenhouse gas emissions from energy generation and consumption but also in reducing external dependence on imports of fossil fuels, the promotion of renewable energies in electricity systems has become a policy priority for governments all over the world (Mir-Artigues et al., 2015).

In December 2008, the European Union (EU) adopted its Energy and Climate Package, a framework where specific objectives in terms of overall share of energy from renewable sources (RES), GHG emissions reduction (compared to 1990) and energy efficiency were established. With regards to renewable energies, an ambitious target has been set. For 2020, a 20% share of renewable energy sources in final energy consumption has to be achieved. A direct consequence of this objective is that renewable energy sources (RES-E) in electricity generation are expected to expand from 20.3% of electricity output in 2010, to around 33% in 2020, in order to meet the objective set by the European Commission.

This promotion of renewable energy has had a predictable impact on energy market prices, the relationship between RES-E deployment and wholesale and retail electricity price being a current area of interest for researchers (Ciarreta et al., 2014; Costa-Campi and Trujillo-Baute, 2015; Edenhofer et al., 2013; Gelabert et al., 2011; Sensfuß et al., 2008). In general terms, consumers finally pay for support for renewable electricity in their electricity bills. Through the access tariffs the money to finance the burden associated with the promotion of RES-E promotion schemes is raised. At the same time, RES-E generation with priority of dispatch on the wholesale market displaces and reduces the demand for conventional electricity – with higher variable costs -. The substitution of conventional generation plants by RES generation therefore reduces the wholesale marginal price (merit order effect). The combined final impact on consumers of both effects depends on whether the reduction in the wholesale electricity market offsets the increase in final price due to RES-E support mechanisms.

Nevertheless, RES-E deployment involves other interactions that may affect final electricity prices. The growth in RES-E during recent years largely reflects the expansion of two main sources, namely, wind and solar power. In the EU the quantity of electricity generated from wind turbines has increased more than ten-

[20] This chapter is based on Batalla-Bejerano and Trujillo-Baute (2016).

fold since 2000 according to Eurostat data, and the growth in electricity generated from solar power has been even more dramatic, rising from just 0.8 TWh in 2000 to reach 79 TWh in 2014. These changes in the energy mix present profound implications for many aspects of power system operation and control (IEA, 2009; Pérez-Arriaga and Batlle, 2012) due to the nature of both wind and solar technologies. Wind and solar photovoltaic (PV) generation are both intermittent technologies, which means that energy output coming from these sources is variable over time and non-fully predictable.

A high penetration of generation from variable renewable sources (VRES-E) imposes additional flexibility requirements on System Operators (SO) in guaranteeing instantaneous equilibrium between demand and supply (Ela et al., 2014; Frunt, 2011; Glachant and Finon, 2010; Haas et al., 2013; Hirth and Ziegenhagen, 2015; Hirth et al., 2015; Vandezande et al., 2010). The variability of renewable generation requires that the power system be operated with a high degree of flexibility, so as to keep pace with the fluctuating net load, defined at each instant as the difference between total energy consumption and total variable renewable production.

The application of these flexibility requirements can affect final prices and the costs of renewable market integration, such as balancing costs, need to be considered to compute the economic impacts of an increasing penetration of variable VRES-E on electricity markets. Due to this limited predictability and variability of VRES-E generation, SO might be required to provide significantly higher volumes of these ancillary services than in the past implying additional costs.

In this regard, drawing on real data for the Spanish power market for the period 1st January 2011 to 31th December 2014, the present chapter aims to contribute to a better understanding of these economic consequences by evaluating the impact of VRES-E generation on balancing market requirements and costs. In this analysis, we disentangle the economic effect caused by the variability of the effect caused by uncertainty. In terms of system operation both intermittent characteristics are relevant, but given that even with perfect VRES-E generation forecasting, the variability of wind and solar PV output introduce additional system flexibility requirements.

Variability and non-fully predictability stress the need for an appropriate number of reserve power plants with flexible dispatch capable of providing the necessary stability and ancillary services to deal with problems of electricity market balance. At the same time, given that the integration of variable generation in a power system non-only depends on both properties of intermittent generation, but also on the power system characteristics into which VRES-E is integrated, the analysis will take system characteristics in terms of flexibility and electricity demand into account.

Although power system reliability and resource adequacy are complex elements of market operations and the RES integration cost is influenced by multiple factors, we examine individually the size of the impact of each attribute of the intermittent generation.

Although this study is applied to Spain, the results are of general interest for other countries where the renewable promotion is at early stages and VRES-E penetration is lower. In this sense, over the last decade Spain had become a leader country with respect to the introduction of renewable energies. The rapid development of renewables in Spain was a direct outcome of national energy policies including regulatory changes focused on facilitating the grid integration of RES-E production and economic and financial incentives[21].

This policy has encouraged, besides the country's great renewable potential itself, investment in renewable energy technologies resulting in an increase in the RES-E installed capacity. With 50,481 MW - including hydro - at the end of 2014 – Spain had occupied a privileged worldwide position in terms of RES-E installed capacity. In terms of output, Spanish RES-E generation has grown from 26 TWh in 2000 to 111 TWh in 2014, when it represented 42.8% of total electricity demand. Among the different RES-E generation technologies, wind and solar PV represented 52% of total RES-E production in 2014. The relevance of both technologies, characterised by their intermittency, presents important system operation implications.

In this way, the results based on one of the countries, within the EU, with the highest renewable power capacities, and one of the most significant wind and solar power generation penetration provides useful insight to other countries. Furthermore, Spain also makes a relevant case study because of the isolated nature of its electricity system, with low interconnection capacity with neighbouring countries (France, Portugal, Morocco and Andorra). This represents additional challenges when integrating electricity generation from variable renewable electricity sources.

Even though variability and non-fully predictability need not be a barrier to increased renewable energy deployment, at high levels of VRES-E market penetration a careful economic analysis of the implications in terms of system operation is required. A strong presence of intermittent renewable generation is changing the way power systems are operated and controlled. In this sense we contribute to this analysis by exploring the relationship between the operational costs of the electricity systems, the variability and uncertainty of VRES-E generation

[21] Spain basically followed the "feed-in-tariff" (FIT) policy approach based on the determination of a long-term fixed price for RES-E production or fixed premium tariffs paid on top of the spot market price for electricity.

and the flexibility requirements of the complementary system necessary to balance the power system.

The remainder of this chapter is structured as follows. Variables, empirical strategy, model specification and the data used are detailed in Section 2. Estimation results are presented in Section 3. The chapter ends with a final section summarising research conclusions and presenting policy and policy implications.

5.2. DATA AND EMPIRICAL STRATEGY

As it has been pointed out in the previous section, the electrical system has to be in permanent equilibrium. For this purpose, balancing power (regulating and frequency-control power) is used to quickly restore the supply-demand balance in systems after active power imbalances arise. Adjustment services managed by the SO are responsible for adapting hourly production programmes resulting from the day-ahead market to the requirements of demand and supply deviations in real time, thus guaranteeing the above-mentioned balance and meeting the conditions of quality and safety required for the supply of electric power. In the process of programming the generation, the operation of the system is focused on three fundamental aspects: a) the resolution of technical restrictions identified in the programming resulting from the day-ahead and intraday markets, and from the operation itself in real-time; b) the management of the system adjustment services corresponding to the complementary services of frequency and voltage regulation and control of the transmission network; and c) the deviation management process as an essential way of guaranteeing the balance between production and demand, ensuring the availability at all times of the required regulatory reserves.

System adjustment services make it possible to guarantee the permanent equilibrium of the electricity system contracting the active and reactive power reserves necessary to ensure the reliable and safe operation of the electrical system, but implies higher system costs and at the end higher final electricity prices for the consumers. The evolution of the cost of these adjustment services is presented in Table 11.

Table 11: Evolution of adjustment services costs (€/MWh), 2011-2014

Concept	2010	2011	2012	2013	2014
Adjustment services cost	3.8	3.2	4.7	5.5	5.7

Source: Own elaboration based on CNMC

Although, power system reliability and resource adequacy are complex elements of market operations where final cost is influenced by multiple factors, we isolate and quantify the economic impact of the deployment of variable renewable energies on adjustment services. In this regard, from market data for Spain for the period comprised between 1st January 2011 and 31st December 2014, the cost of system adjustment services - technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints – is used as the dependent variable in the econometric estimation. This adjustment cost has been defined as a price spread between the final electricity price and the price after the last intraday market session.

Deviations between scheduled and measured energy after the intraday market are addressed through market procedures, including secondary reserve, tertiary reserve and the imbalance management process.

The costs associated with these balancing markets are captured by this spread, which measures the additional costs for delivering one MWh of electricity on top of the day-ahead and intraday price. When obtaining this spread, capacity payments[22] are not considered. In other words, the adjustment cost results from the aggregate of overall system adjustment services managed by the SO – technical and real-time constraints, power reserve, secondary and tertiary control band and deviation management process services.

Taking into account the above considerations, and bearing in mind that the final electricity price is the sum of the different prices and costs associated with each of the markets that integrate the power system, the adjustment service cost (ASC) is obtained as shown in the following equation (with all variables expressed in €/MWh):

$$ASC_t = FP_t - DAMP_t - IMP_t - CP_t \tag{9}$$

being:

ASC_t:	Adjustment service cost
FP_t:	Electricity final price
$DAMP_t$:	Day-ahead market price
IMP_t:	Intraday markets price
CP_t:	Capacity payments

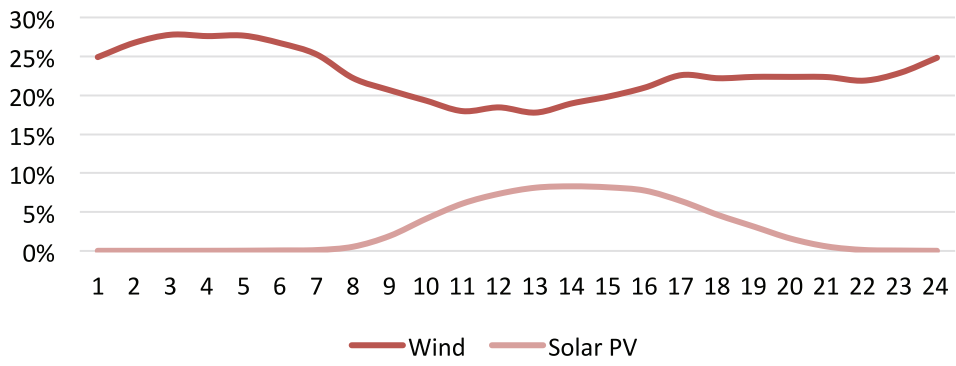
[22] Capacity payments are the regulated payments to finance the medium and long-term power capacity services supplied by the generation facilities to the electricity system.

When assessing the determinant factors behind power system balancing costs the following variables are used:

VRES-E generation (VRES G)

The introduction of large amounts of variable and uncertain power sources, such as wind power, into the electricity grid presents a number of challenges for system operations. One issue involves the uncertainty associated with scheduling power that wind will supply in future timeframes. Although wind and solar photovoltaic power output may display some daily and seasonal characteristics and the forecast models have improved significantly over the past years, electricity generation from wind and solar sources is uncertain, implying unforeseen deviations from scheduled electricity programs. The greater range of variability experienced, even by aggregations of wind and solar PV power plants, also adds to the difficulty of forecasting output on the day-ahead timescale. VRES-E generation imbalances imply economic costs given that their correction entails the use of balancing power.

Figure 21: Hourly average wind and solar photovoltaic generation, 2011-2014
(% over total hourly demand)



Source: Own elaboration based on CNMC and REE

Deviations between scheduled and consumed electricity are addressed through ancillary services based, in most instances, on market procedures, such as secondary and tertiary reserves, and the imbalance management process, and so there is a direct relationship between the size of the deviation and the cost incurred by the system in resolving it. Therefore, there is a direct relationship between VRES-E generation and the expected total costs in terms of adjustment services. Given that, as shown in Figure 21, wind and solar PV production seem to be negatively correlated presenting different –potentially complementary- diurnal patterns with different periods of high (low) output, the variable VRES-E generation (*VRES G*) is defined on an aggregate basis. In this way, *VRES G* is defined as the sum of hourly wind and solar PV production scheduled in the day-ahead market[23] (in relative terms over hourly demand).

VRES-E ramp (VRES R)

Even with perfect forecasting for VRES-E generation, ceteris paribus the consequence for electricity systems of increasing variability in the RES-E output constitutes an additional source of stress on system operation (Huber et al., 2014; NERC, 2010; Ulbig and Anderson, 2012). In this sense, some studies (Eurelectric, 2010) consider that another relevant factor besides the power production profile is power ramps or gradients over different time horizons. Whilst traditional variability of demand or load has always required a certain amount of flexibility, power ramps will introduce a step change in the way electrical systems are operated. Sudden hourly VRES-E schedules imply additional operational requirements to the system considering that sufficient generation has to be committed to accommodate these variations.

Variable renewable generation ramps (*VRES R*) have been defined as the change of power in a given time interval – in our case from hour to hour -. Changes in operational requirements due to *VRES R* normally take place in the morning and early evening hours. As illustrated in Figure 21, the ramp up in solar generation in the mid-morning and the solar ramp down in early evening can increase the energy regulation requirements of the system. At the same time, solar and wind ramps do not necessarily happen at the same moment. In many hours, the combination of solar and wind resources can lessen operational requirements because solar resources are ramping up when wind resources are ramping down, and vice-versa, the aggregated variability of both technologies together being less than each are individually.

Considering that the geographic diversity and dispersion of wind and solar PV output reduces aggregate variability over large geographic areas, the ramp variable has been defined on an aggregate basis. As in the case of the variable corresponding to

[23] Hourly wind and solar PV generation scheduled in the Daily Base Operating Program (PDBF by its acronym in Spanish).

renewable generation, the gradients of renewable production are expressed in relative terms on the hourly demand, and in absolute terms.

Conventional generation flexibility (CGF)

In order to maintain reliable power system operation as variable energy resources provide a larger proportion of our electric energy supply, sufficient system flexibility will be required. Operational flexibility is an important property of electric power systems. The term flexibility is widely used in the context of power systems although at times without a proper definition. The role of operational flexibility for the transition from existing power systems, many of them based on fossil fuels, towards power systems effectively accommodating high shares of VRES-E has been widely recognized. Integrating large shares of VRES-E generation, in particular wind and solar PV, can lead to a sharp increase in flexibility requirements for the complementary power system (Huber et al., 2014). In the case of Spain, this complementary or conventional system is mainly composed of combined cycle, coal, fuel oil and gas generation, and these have to balance the fluctuations of variable generation.

Categorizing different types of operational flexibility constitutes a complex question (Ulbig and Andersson, 2012) due to the existence of different flexibility metrics. As the flexibility strongly depends on the total contribution of wind and solar energy to hourly electricity consumption and load evolution, *Conventional Generation Flexibility* (CGF) from flexible sources is defined in terms of power portfolio connected to the system able to provide balancing energy to the system. Nuclear and hydroelectric generation are considered to be inflexible given that these generation technologies are currently operated in a base-load mode.

The presence of intermittent generation in power systems with priority of dispatch together with a large quantity of inflexible conventional generation alters and reduces the net load to be satisfied with flexible generation able to start up and shut down generation as the system requires. Sudden and massive requests for power, in terms of power ramps, create new requirements for conventional generators. We have defined conventional generation from flexible sources (*CGF*) as final production from flexible technologies - coal, fuel oil, and gas (open and combined cycles) -.

Given that these flexible generation technologies have different characteristics – costs and time required to start, ramping limits – which determine their capacity to start up quickly and increase their production when the system requires, the importance of the combined cycles power plants (CCPP) in terms of system operation will be assessed independently (*CCPP* variable) from the rest of flexible generation technologies (*OTHERS* variable). Combined cycle technology is one of the most important back-up technology able to adjust its generation to provide power when it is most needed (Eurelectric, 2010). With more than 25 TW of installed capacity – 24.8% of total peninsular installed capacity, as at 31st December 2014-, combind cycles are normally particularly suited to adjusting their output to net load-following operations. At present, CCPP allows SO to deal with both upward and downward VRES-E ramps that may reach 2,000 MWh from hour to hour.

Regarding the econometric approach, using hourly market data for Spain over the period comprised between the 1st January 2011 and the 30th December 2014, a time series regression model controlling for seasonality was constructed. The econometric estimation uses the average weighted cost of system adjustment services (*ASC*) as the dependent variable. This variable, obtained as a price spread, includes the economic cost associated with all adjustment services - technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints -. VRES-E output (*VRES G*), VRES-E gradients or ramps (*VRES R*) and conventional power generation (*CGF*) are used as the main explanatory variables.

In addition, as in other electricity market price studies, we have introduced an autoregressive component to capture the dynamic effects on the adjustment costs. Two additional variables were introduced as control variables. First, to control for consumption patterns in peak and off-peak demand hours we introduced a temporary variable (*Peak Demand (PD)).*

As electricity demand varies through the day, this dummy variable (=1 if a peak demand hour) was introduced in the specification of the model in order to address aspects related to seasonality. Second, as VRES-E generation is not the only source of variation in a power system, a second control variable was introduced to control for other possible power imbalances. The demand for electricity, or load, also varies, and the power system was designed to handle that uncertainty. After intraday market gate closure, SO have to adjust the resulting program to any demand and supply deviations from that scheduled. The required balancing energy to handle electricity deviations coming after intraday gate closure *(Real Demand Adjustment (RDA))* was included in the model specification. As in the case of the rest of variables, *RDA* is expressed in relative terms on hourly demand.

Table 12 presents the descriptive statistics of the variables used.

Table 12: Summary statistics

Variable	Obs.	Mean	Std. Dev.	Min	Max
ASC	35,039	4.8333	3.7475	0	93.86
VRES G	35,039	0.2551	0.1137	9.09E-03	0.7121
VRES R	35,039	0.0126	0.0109	2.95E-06	0.3334
CGF	35,039	0.2184	0.1151	0.0087	0.5234
CCPP	35,039	0.0731	0.0528	1.00E-05	0.3196
OTHERS	35,039	0.1426	0.0889	0.0074	0.4625
RDA	35,039	0.0349	0.0289	2.59E-10	0.2480
PD	35,039	0.4166	0.4930	0	1

Before presenting the time series regression models constructed for the analysis of the impact of RES-E integration on adjustment costs, it should be pointed out that a stationary time series analysis was carried out. 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, reported in table 13, confirm that the series are stationary in logarithms, so we estimate the models using all series in logarithms.

Table 13: Augmented Dickey-Fuller and Kwiatkowski–Phillips–Schmidt–Shin test

	ADF test		KPSS test	
	Levels	Logarithms	Levels	Logarithm
ASC	-1.209	-8.583***	9.673***	0.000
VRES G	-2.496	-11.425 ***	6.245***	0.000
VRES R	-2.532	-18.451 ***	3.879***	0.002
CGF	-3.021	-19.152 ***	3.236***	0.001
CCPP	-2.547	-11.634***	4.275**	0.001
OTHERS	-3.038	-20.215 ***	6.480***	0.000
RDA	-2.825	-8.672 ***	7.923***	0.001

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%

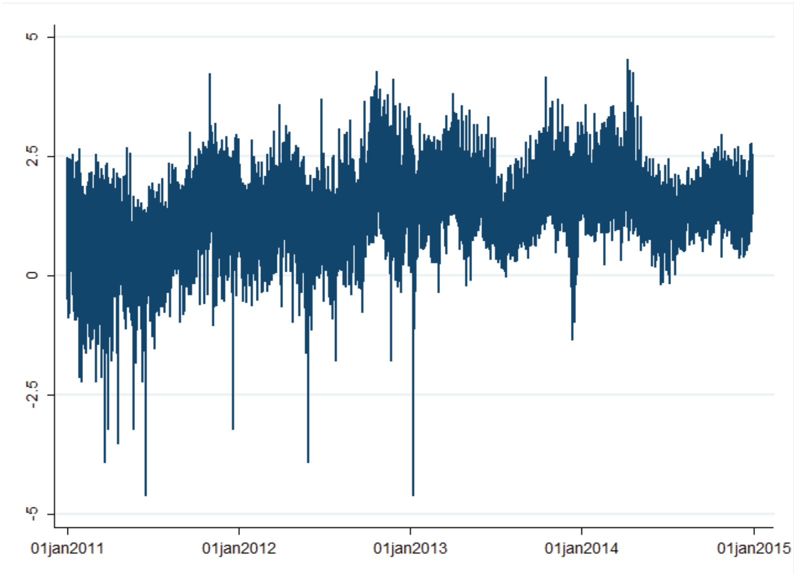
With all the above considerations, the model specification is defined in the following equation:

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 VRES\ G_t + \alpha_3 VRES\ R_t + \alpha_4 CGF_t + \alpha_5 RDA_t + \alpha_5 PD_t + \varepsilon_t \qquad (10)$$

Based on the information from the summary statistics of the dependent variable – specifically the high standard deviation and the maximum value- and the graphical representation of this series (see Figure 22) in which extreme values are observable even in logs, we are suspicious about the existence of outliers.

A deep outlier analysis was carried out to confirm the existence of extreme values. We used the blocked adaptive computationally efficient outlier nominators (BACON) algorithm proposed by Billor et al. (2000) and further developed by Weber (2010) to detect outliers in our multivariate data. The results for the BACON test (see Appendix) confirm the existence of extreme values of the observable variables.

Figure 22: Adjustment Service Costs (in logarithms)



The presence of the outliers, which has been confirmed as valid observations, might drive to biased results. In the context of this study, either by ignoring or excluding the outliers might distort the resultant effects from renewable generation on system costs. On the one hand, by ignoring their presence and performing the estimations through Ordinary Least Square (OLS), would assign the same weights to the extreme observations and leads to different coefficients than the actual relation between the variables. On the other hand, by acknowledging the problem but using robust regression to exclude the outliers could also affect the magnitude of the estimated effects. For these reasons, we perform the estimation of Eq.(10) using quantile regression on the median. The quantile approach is not as sensitive as the least squares approach to outliers because it does not give much weight to them (at the median it gives symmetric weights to positive and negative residuals), but at the same time, unlike robust estimation, quantile estimation does not sacrifice observations with relevant information[24].

Our methodological choice, although properly tackling the complexity of this study, is based on the principle of simplicity. First, we could apply more sophisticated modelling technics (for instance as the error correction models, which would allow us to observe the speed at which the ASC returns to the equilibrium) that would be beyond the direct goal of this research. Second, given that the variables are stationary in logs, a simple autoregressive linear regression model it is sufficient to perform the analysis. Finally, provided that the series content outliers, we need to consider a more sophisticated technique would complicate further the study.

As in the least squares estimation of dynamic models, it is evident that the unobserved initial values of the dynamic process also induce a bias in the context of quantile regression. The existence of unobserved initial values of the dynamic process arises from the fact that the history of the process begins prior to the first period of observed data. Given that the exogeneity is defined from the concept of predetermined values, the existence of unobserved initial values implies that the classical liner model assumption of strict exogeneity is violated and OLS estimates of the coefficients become biased. The same is true for quantile estimates in an autoregressive linear model, the coefficients must absorb the effects of each lagged error, and the model residuals no longer represent true changes in the dynamic process. Hence, it become necessary to correct this bias in order to obtain coefficients capturing more accurately relation between the variables. Instrumental variable methods are able to produce consistent estimators for dynamic data models that are independent of the initial conditions. These estimators are based on the idea that lagged (or lagged differences of) regressors are correlated with the included regressor but are uncorrelated with the error terms. Thus, valid instruments are available from inside the model and these can be used to estimate the parameters of interest employing instrumental variable methods. The construction of instruments is carried out using values of the dependent variable lagged two periods and the lag of the exogenous variables[25], which are all

[24] As a further robustness test we have estimated Eq. (10) using robust regression. The results of the two stages robust estimations, not reported but available upon request, are consistent with those of quantile IV (reported below) in terms of sing and significance of coefficients. As expected from the exclusion of outliers and from the use of the mean when performing robust regression, the value of coefficients differs from those of the quantile regression, although the magnitudes are similar.

[25] As an additional robustness test we have estimated Eq. (10) by quantile IV using a different transformation of the variables, i.e. the square of variables, as instruments. The results, not reported but available upon request, are highly consistent with those obtained with the lag variables as instruments.

independent of ε_t, to perform estimations using the instrumental variable quantile regression method.

5.3. RESULTS AND DISCUSSION

In order to evaluate the effects of VRES-E generation *(VRES G)*, VRES-E variability *(VRES R)*, and conventional generation flexibility *(CGF)* on adjustment costs *(ASC)* we performed five sets of estimations based on Eq. (10) as presented in the previous section with different groups of control variables. We first estimated the impact of VRES-E generation on ASC including only the additional controls *(RDA and PD*), these results are reported in column (1) of Table 14.

In the second set of estimations - column (2) - we also included the ramp or gradient of VRES-E *(VRES R)* to test if along with the penetration of VRES-E there is also a relevant intensity of sudden changes in consecutive hours. In the third set of estimations –column (3) – we introduce the penetration of aggregated conventional flexibility *(CGF)* in order to evaluate its potential in reducing adjustment costs. Finally, in the last two sets of estimations we evaluate the contribution of the most flexible technology *(CCPP)*, by first introducing only CCPP –column (4) – and then adding the other sources of flexibility *(OTHERS)* –column (5).

From a system management perspective, several factors, coming from both supply and demand variables, might cause active power imbalances in electricity systems. From the supply side, the results of the estimations support a significant and positive effect of VRES-E generation on adjustment services costs. Short-run elasticity of VRES E ranges between 0.01 and 0.05 depending on the group of control variables, being consistently around 0.02 – 0.03 with the full set of controls clearly showing that renewable generation from variable sources such as wind and solar PV introduce additional variability and uncertainty into the power system. In order to maintain reliable power system operation as variable energy resources provide a larger proportion of our electric energy supply, sufficient system flexibility will be required exerting a positive and relevant effect on the adjustment cost.

Although there are different links between VRES-E and its associated balancing requirements[26] (Hirth and Ziegenhagen, 2013), we disentangle the economic effect

[26] There is a multitude of names for the different services available to restore the supply-demand balance in power systems (see Hirth and Ziegenhagen, 2013 and Rivero et al., 2011 for a comprehensive comparison of European balancing markets). This heterogeneity could be hampering the comparative analysis of balancing services across Europe. Considering that European transmission system operators are using the term "operational reserves" (ENTSO-E, 2012), in this

coming from variability than from non-fully predictability in VRES-E output. In this regard, when the ramp or gradient of VRES-E *(VRES R)* is included in the estimation – column (2) – it is demonstrated that sudden changes in VRES-E output also exert a positive and significant effect on adjustment costs. Although not so relevant as VRES G, short-run elasticity of VRES G ranges consistently around 0.01.

Table 14: Impacts on the adjustment services costs

	(1)	*(2)*	*(3)*	*(4)*	*(5)*
L.ar	0.8978***	0.8949***	0.8798***	0.8783***	0.8786***
	(0.003)	(0.004)	(0.004)	(0.003)	(0.003)
VRES G	0.0482***	0.0465***	0.0123***	0.0298***	0.0268***
	(0.004)	(0.005)	(0.006)	(0.004)	(0.004)
VRES R		0.0129***	0.0113***	0.0123***	0.0121***
		(0.002)	(0.002)	(0.001)	(0.001)
CGF			-0.0355***		
			(0.002)		
CCPP				-0.0190***	-0.0179***
				(0.001)	(0.001)
OTHERS					-0.0028***
					(0.001)
RDA	0.0097***	0.0095***	0.0089***	0.0090***	0.0089***
	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
PD	0.0001***	0.0020***	0.0056***	0.0058***	0.0065***
	(0.000)	(0.001)	(0.001)	(0.002)	(0.001)
Constant	0.2577***	0.3192***	0.2134***	0.2506***	0.2409***
	(0.002)	(0.015)	(0.002)	(0.002)	(0.003)
Observations	35033	35033	35033	35033	35033
Pseudo R2	0.7654	0.8191	0.8368	0.8678	0.8752

Note: Quantile instrumental variables results with weighted bootstrap standard error in parentheses (weights generated from the standard exponential distribution) *** p<0.01, ** p<0.05, * p<0.1.

In terms of system operation, these results are showing up that, even with perfect forecast tools, the variability of renewable generation requires that the power system should be operated with a high degree of flexibility. Although, variability is not new to power systems, which must constantly balance the supply and variable demand for electricity and face all kinds of contingencies (IEA, 2009, 2011a, 2011b), large shares of intermittent renewable generation in supply imply additional pressure on power systems. Renewable variability requires increased flexibility

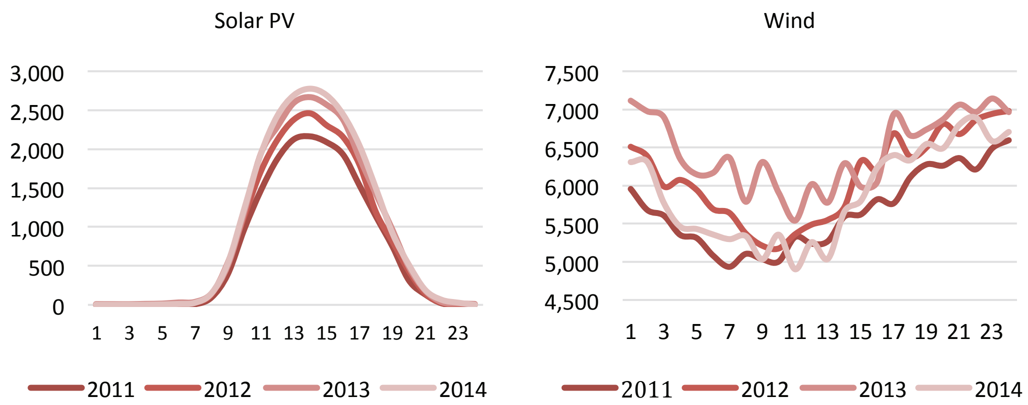
dissertation we use the concept "operational costs" in a broad sense when referring to the costs associated with the provision of these services.

where aspects such as the availability of flexible capacities within the electricity generation mix, interconnection capacity, storage - e.g. pumped-hydro plants - or improved load control and management empowered by smart grids acquire more relevance.

Therefore, the results confirm that, along with the penetration of VRES-E, adjustment services costs increase with the intensity of VRES-E generation changes in consecutive hours, the ramp (VRES R). Although initially a higher intensity of this effect might be expected, the magnitude of the parameter VRES R seems to be capturing that the interaction between wind and photovoltaic ramping hours are complementing each other, and hence exerting a relatively reduced effect on the system adjustment services costs (see Figure 23).

VRES-E production is determined by weather conditions and cannot be adjusted in the same way as the output of dispatchable conventional power plants (Hirth et al., 2015). As can be seen in Figure 23, on the one hand, solar photovoltaic generation is characterised by a diurnal pattern, where peak production occurs in the middle of the day (around 2pm). On the other hand, wind generation is more variable over time and is mostly explained by fluctuations in wind conditions – mainly speed -. Although wind power output may display some daily and seasonal characteristics, it follows much less regular patterns than does load. In the period comprised between 2011 and 2014 the yearly average of wind generation for each hour fluctuated between 4.9 and 7.1 GWh, with an average hourly production of 6 GWh. Wind power output tends to be higher during the night period followed by a downward ramp in wind production in the morning and a later increase from noon.

Figure 23: Hourly average wind and solar photovoltaic generation (MWh), 2011-2014

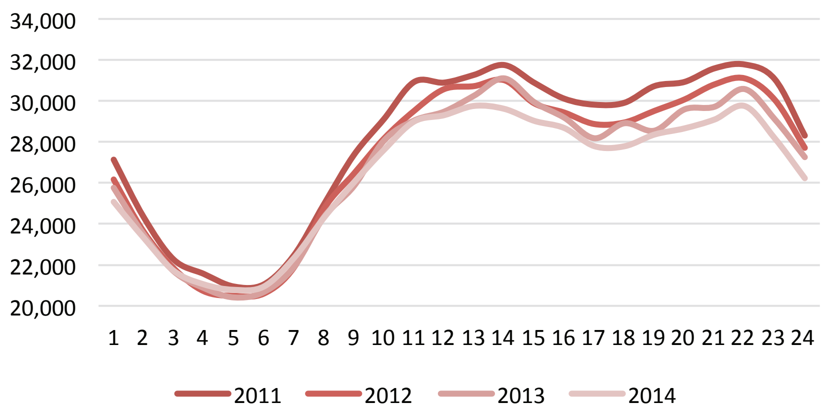


Source: Own elaboration based on CNMC

Furthermore, variable generation is not necessarily correlated with load with the consequent implications that this has in countries with relatively limited storage capacity such as Spain. Depending on the time scale considered, the load profile presents different daily, weekly, monthly, seasonal or even yearly patterns. Figure 24 shows how Spanish electrical demand varies throughout the day with peaks of demand at noon and in the early hours of the night.

Even though several factors are behind, VRES-E integration costs strongly depend on power system characteristics. The evolution of installed intermittent capacity constitutes a relevant factor but not the only one involved. From the point of view of power system operation and management, a scenario of low penetration of renewable energies in the generation mix is not the same as a scenario where renewable power is one of the main generating sources, as is the case of Spain.

Figure 24: Hourly average load (MW), 2011-2014



Source: Own elaboration based on CNMC

Sudden hourly VRES-E schedules or deviations from scheduled energy imply additional operational requirements to the system considering that enough generation has to be committed to accommodate these variations. In this regard, the availability of flexible conventional generation connected to the system constitutes a relevant question when addressing the question of the explanatory factors behind the evolution of the adjustment services.

This issue is evaluated in our model when the availability of flexible generation sources is incorporated as explanatory factor of the adjustment costs – estimations presented in columns (3) to (5) -. When considering all the flexible generation together, from an aggregated perspective, the short-run elasticity is 0.03 – see column (3). When CCPP, as the most flexible technology, is separated from the rest *(OTHERS),* the results show that CCPP elasticity is 0.02 and for the rest it is 0.003 – see columns (4) and (5).

Therefore, the results confirm that conventional flexible generation decreases adjustment services costs and that the CCPP cost saving effect is greater than it is in the case of other technologies.

In general terms, these results confirm the relevance of other aspects when explaining the system adjustment costs. The estimations support a significant and positive effect of VRES-E penetration on balancing costs. However, as we demonstrate, the cost associated with the integration of renewable energies depends on other aspects. Questions such as VRES-E output measured in terms of power ramps over different time horizons or the availability of flexible conventional generation connected to the system are also relevant.

The results for the additional control variables, *RDA* and *PD*, are consistent across the different sets of estimations and in line with expectations. Regarding the *RDA*, our results confirm that demand adjustments are considered to be a factor increasing adjustment services costs. Likewise, the peak hour control captures the hourly consumption pattern during the day, and shows that during peak hours adjustment services costs are higher. Both control variables are significant, and in the context of this study, are important for guaranteeing the proper estimation of the parameters of interest.

In order to provide additional insights, Table 14 summarizes the relevant long-run elasticity from the analysis performed.

Table 14: Long run elasticities

	Elasticity	Direction of the effect
VRES G	0.22	↑
VRES R	0.09	↑
CCPP	0.14	↓
OTHERS	0.02	↓
CGF	0.29	↓

Note: In all cases the long-run effects are calculated as $\alpha_i /(1-\alpha_1)$, where α_i it is the estimated coefficient for each variable.

On the one hand, we observe that if there were an increase of 10% in *VRES-E* penetration with the same flexible generation, in the long run the system would face an increase in the adjustment cost of 2.2%. On the other hand, ceteris paribus, if the penetration of aggregated flexible generation were increased by 10% a saving would be made of 2.9% on adjustment services costs. These results highlight the importance of the interaction – counterbalance effects - between *VRES G* and *CGF* from the system perspective, and consequently on the adjustment services costs.

Finally, a highly interesting result comes to light with the comparison of the long run elasticity between generation from CCPP and the other sources of flexibility. While a 10% increase in CCPP penetration would lead to a decrease of 1.4% in adjustment services costs, an equivalent increase of the other conventional sources would imply savings of only 0.2%.

5.4. CONCLUSIONS AND POLICY IMPLICATIONS

At the end of 2013, renewable energy sources covered approximately 14.7% of Spanish final energy consumption. Given that by the year 2020 Spain is required to meet the European target of covering 20% of the energy demand using renewable sources, it is expected an increase of VRES-E to comply with the approved European objectives. The power system integration of this VRES-E output impacts on system operation, the final cost depending on multiple factors. A critical issue in power system operation is the amount of balancing and operating reserves that will be needed to keep the power system functioning securely and efficiently (Holttinen et al., 2011; Pérez-Arriaga and Batlle, 2012) and this study evaluates the nexus between power system balancing costs evolution and the increasing presence of intermittent renewable production.

Although the factors that might cause power imbalances in relation to the daily scheduled programs are varied and of different nature[27], the integration of variable and uncertain renewable generation sources increases the flexibility needed to maintain the load-generation balance. From a system perspective, integrating non-manageable generation constitutes a challenging task. Aspects such as low availability, lack of correlation between VRES-E generation and energy load, and absence of firmness in generation programs, among others, impose new power

[27] From a system management perspective, several factors coming from both supply and demand variables might cause active power imbalances in an electricity system. From the supply side, aspects such as unplanned contingencies in the conventional and renewable generation capacity or in the interconnection capacity, or variability and forecast errors of VRES-E generation due to its intermittent nature increase the need for balancing power (Huber et al., 2014). From the demand side, aspects such as load forecast errors have a similar effect.

balance challenges given that electricity systems should be constantly adjusting to fluctuations in demand and supply.

Therefore, power generation coming from variable renewable sources can affect the design of balancing markets in different ways. First, the variability and uncertainty of wind and solar PV energy increases requirements for various ancillary services, affecting the scheduling and pricing of those services. Second, VRES-E impacts strongly depend on system conditions (demand situation, importance of renewable generation in electricity programs, scheduling regime of the other conventional generation facilities, mix of generation technologies, existing flexible generation…), which make the demand for ancillary services difficult to generalize across timescales and systems.

In addition, the variability and uncertainty associated with VRES-E generation implies real-time deviations in renewable power generation, explained by its non-full predictability, affect daily markets and result in higher balancing costs and greater fluctuation in the reserve requirements. At the same time, the variability of renewable electricity production, with an availability ratio - production in relation to the installed capacity - ranging between 5% and 70%, implies the need for flexible power capable of covering those moments when renewable generation is not available.

As expected, the results point towards a significant effect of VRES-E integration on system costs. According to our estimates, both VRES-E attributes – uncertainty and variability – exert a positive and significant effect on adjustment costs, their respective intensities being statistically different, always higher in the case of the variable responsible for capturing the uncertainty derived from the non-full predictability of VRES-E generation. These results highlight the relevance of forecast errors when explaining integration costs. Deviations between scheduled energy and real time demand are addressed through ancillary services, which are mostly based on market procedures, such as secondary and tertiary reserves and imbalance management processes. Therefore, there is a direct relationship between the size of the deviation and the cost to the system of solving it.

At the same time, power ramps introduce a step change in the way electrical systems are operated, exerting a positive impact on system costs. Variability implies additional operational requirements to the power system considering that additional generation has to be committed to accommodate these variations.

From the broader perspective of energy policy and sector regulation, a key question when evaluating the evolution of RES integration refers to the availability of sufficient operational flexibility. As demonstrated, this additional flexibility, a necessary precondition for the grid integration of large shares of VRES-E power, is provided by conventional generation.

The system integration of VRES-E generation requires flexible technologies able to modulate their production to provide coverage for demand. In an isolated country such as Spain, with low cross-border interconnection capacity, the availability of flexible plants acquires increasing importance. Power plants able to work on a part-time operational schedule and ready to provide the upward/downward power are required by the system. Among these flexible technologies, the results indicate the importance of combined cycles. CCPP allows the SO to deal with sudden up and down VRES ramps at the most competitive cost in comparison to other flexible technologies.

In Spain, this last issue is of great importance. Although the system has more than 25 TW of installed capacity using combined cycles, the fall in electricity demand as well as a growing share of the renewable in the demand means that a very small part of this power is connected to the network when the system requires it. The low availability of mid-merit power technologies able to change their output dynamically in contrast to baseload conventional technologies, as we demonstrate, has its economic consequences in terms of adjustment costs.

Minimising total system costs at high shares of VRES-E requires a strategic approach to adapting and transforming the energy system as a whole. To meet this goal, all countries where VRES-E is becoming a mainstream part of the electricity mix should make better use of existing flexibility by optimising system and market operations. Sending the correct signals to participants, to encourage them to look for the optimum technical solutions, entails an in-depth knowledge of cost drivers as provided by this chapter. Success in adapting the power system lies in analyses able to provide clearer insights into the costs and impacts associated with incorporating renewable energy into electricity networks.

6. CONCLUSIONS

Renewable energies are becoming an accepted source of energy called to play a leading role in the global struggle against climate change. Europe as a whole and Spain in particular have figured prominently in the path of these technologies to grow into their global role. A regulatory framework which emphasizes a directive on renewable energy, with legally binding European and national objectives and a target of 10% renewable energy in transport, has been the main driving force for European investments in renewable energy internationally and policies supporting these energies beyond the borders of Europe.

Renewable energy must continue to play a fundamental role in the transition towards a more competitive, secure and sustainable energy system. This transition will not be possible without significantly higher shares of renewable energy. Moreover, most renewables development in the EU is driven by national support schemes, which can address national and regional specificities but at the same time can hinder market integration and reduce cost-efficiency.

Within electricity generation from sources of renewable origin, there is a great variety of technologies, each having its own characteristics. In terms of new installed power, as shown in the second chapter of this thesis, wind generation and solar photovoltaic are the two most significant technologies. From the point of view of integration in the electrical system, the main characteristic of these two technologies is that their operating regime depends exclusively on the meteorological conditions existing at each site. Electricity generation from these renewable energy sources depends on the sun or wind conditions available and not necessarily on the needs the electrical system may have at that moment.

The stochastic (non-manageable) nature of new renewable generation will have a significant direct effect on the operation of the electricity system, as the variability in electricity generation must be compensated by other generating technologies of a manageable nature and capable of covering these variations in renewable production. For the correct functioning of the electricity system it will be necessary to have generation technologies of a manageable and flexible character (basically thermal and hydraulic technologies).

Thus, we are moving from electricity systems characterized by the strong presence of conventional generation in the supply matrix (which have proved capable of providing the flexibility required in times of peak demand), towards a new model characterized by the growing presence of variable and relatively unpredictable generation.

The volatility and difficulty of forecasting the non-manageable production means that the System Operator must have manageable generation capacity sufficient to cope with a significant variation in the forecast of that generation at all times. It is precisely in this area that the present doctoral thesis is circumscribed.

One of the characteristics of electrical power is that it cannot be stored on a large scale. This means that for the correct functioning of the electrical system there must be a permanent dynamic balance between production and consumption. Any imbalance between demand and generation becomes a frequency deviation from its nominal value. Faced with electrical systems where the main source of uncertainty came from the evolution of demand, we are moving towards new electrical systems where uncertainty also comes from supply. The intermittent nature of renewable generation leads to uncertainty for the system operators that must anticipate, and be able to react to, changes in both supply and demand, which raises the need for transitional procedures by the system operator.

This transition places enormous stress on adjustment systems, that is, the systems that are permanently seeking to match generation and load on different time scales. Under these new circumstances, electricity systems must provide a degree of flexibility for which they were not originally designed. Provision is guaranteed by greater use of system adjustment mechanisms (correction of deviations and tertiary reserve) due to deviations in the generation program from renewable sources caused by forecast errors.

Undoubtedly, the safe integration of renewable energies is one of the major challenges for electricity system operation. The rapid deployment of renewable energy already poses challenges for the electricity system, which needs to adapt to increasingly decentralised and variable production (solar and wind). The ability of electricity systems to accommodate VRES-E constitutes one of the main challenges for the future.

From a system operations perspective, this increasing penetration of RES-E generation has gone hand in hand with rising network congestion. Electricity generation is not always located near the points of consumption and existing networks were not designed taking into consideration the location of these new energy sources, i.e., centralised generation. This has given rise to an intense debate, at the European level, about the adequacy of current adjustment markets when having to respond to the increasing need for flexibility of their respective electricity systems. Most present-day adjustment mechanisms were designed at the beginning of the reform and liberalisation of the energy sector, when the context was very different from that which prevails today with the high penetration of generation based on variable renewable sources.

Compared with conventional energy systems, in which the sources of uncertainty were not so great, electricity systems today must deal with the uncertainty associated with RES-E generation. There are many aspects associated with the integration of renewable generation; this dissertation has focused on an economic assessment of the knock-on effects that impact on the final price to be paid by consumers, both domestic and industrial.

The process of managing deviations between generation and consumption, as an essential means to guarantee the balance between production and demand, requires ensuring the availability of the required regulatory reserves at all times. In economic terms, the set of adjustment services of the system, although not the main element in the final cost of electricity supply, have grown in relevance in recent years. Insofar as they are vital to guarantee the safety and quality of the electricity supply, it was considered necessary to analyse the determinants that explain this evolution as well as the incidence of the deviations in both demand and supply.

Unexpected fluctuations in RES-E as being relevant, we also take into consideration unexpected fluctuations in electricity demand. Although the economic analysis that has been developed has focused on the impact derived from the integration of generation from sources of renewable origin, it should not be forgotten that this is not the only source of uncertainty. For this reason, the empirical analysis carried out by this doctoral thesis takes factors of supply and demand as its starting point in explaining the evolution of the economic costs associated with adjustment services.

In this sense, the main contribution of the third chapter lies in the differentiation we draw between demand and supply deviations. Individual data for both types of deviation allow us to undertake a detailed analysis of their economic effects on system adjustment services. In contrast with other studies that seek to estimate the economic costs of a specific balancing market (Strbac et al., 2007; Swinand and Godel, 2012), it is estimated the adjustment cost on an aggregate basis. By reducing the complexity, we are able to focus our analysis on the economic impact of real-time variations on balancing costs using information on final electricity prices and this shows the relevance of demand variations.

Surprisingly, variations in demand are relevant in economic terms, creating the need to analyse what possible technical or economic aspects could underlie this empirical evidence.

In this regard, in chapter four possible explanatory reasons are analysed. Most of them related with the institutional and liberalisation transition process undergone across Europe.

To enhance economic efficiency and improve services to the consumer, European electricity markets had been liberalised, leading to the introduction of competition and opening of the markets. In this process, the current role of some agents, such as DSOs has changed being its role strongly influenced by the unbundling measures introduced in the regulatory framework. In this regard, the Second Electricity Directive implied a change in the duties and responsibilities of Spanish DSOs.

In terms of policy implications, when analysing this kind of policy changes, the most relevant question to be addressed is the relevance of the regulatory framework and its ability to anticipate the effects that stem from these changes being able to provide satisfactory answers. The success of this kind of transformation process is what underpins a smart regulation; that is, one that is capable of providing solutions to unexpected outcomes during the process.

This research has sought to contribute to existing knowledge regarding the economic effects of liberalisation in the power system by examining a natural experiment associated with the regulatory changes introduced in Spain in 2009. Since then, regulated supply by DSOs has disappeared. This positive change in terms of retail market competition, as we demonstrated in this dissertation, had unexpected collateral effects in terms of the system's balancing requirements.

Although demand factors may not be considered as crucial in the analysis of the aspects associated with the integration of renewable energies, the results show that the growth in costs associated with adjustment services may be camouflaging other aspects that are not necessarily related to the integration of renewable energies. Aspects such as deficiencies or shortcomings in the regulatory design itself that require corrective actions in order to prevent costs from continuing to be transferred to the final prices paid by consumers.

Minor aspects which, although they do not question the successes and advances in the process of liberalization of energy markets achieved in the last few years, should be taken into consideration and corrected. In short, the results obtained in the analysis developed within the framework of this thesis, reveal the relevance of detailed regulation. Obviously, in any process of model change, it is not possible to anticipate all effects. There will always be unexpected side effects. What really matters is that the regulation is flexible enough to adapt to these unforeseen issues. All of this with the objective of not incurring additional costs, as in the case studied here, to consumers through the cost associated with the adjustment services of the electrical system.

Finally, in the last chapter, the thesis focuses specifically on the analysis of the effects associated with the integration of renewable energies.

Besides liberalisation effects, the penetration of intermittent generation – especially wind and photovoltaic power – has developed to levels that were unthinkable a decade ago. Technical improvements coming from both VRES-E power producers (fault-ride-through capabilities, visibility and controllability of VRES-E power, reactive power control…) and the system operators (specific control centre for RES energies, forecasting tools…) are behind this success in quantitative terms.

Nevertheless, given that VRES-E market integration is crucial, a comparative quantification of the overall system-related costs and benefits of the increase in VRES-E is required. From this analysis performed in chapter 6, it can be stated that additional flexibility requirements should not be considered as the main constraint limiting the deployment of renewables in the power sector. There are a number of additional non-technical constraints that might also limit the deployment of RES-E generation, including the policy framework or the availability of finance and public support.

This thesis, in seeking to look beyond the impact of RES-E generation intermittency on the evolution of the total economic costs associated with the operation of the electricity system, represents the first attempt to estimate the sensitivity of these costs to other variables, above all real-time adjustments to electricity demand arising from inaccurate predictions.

From the broader perspective of energy policy and sector regulation, the key question here concerns how to improve the functioning of the adjustment services – integrated from several markets, including the resolution of the system's technical restrictions, the allocation of ancillary services and the management of deviations – without increasing their relative costs.

The adjustment services in operation in most electricity markets today were established when RES-E penetration had yet to achieve a significant level and as such they need to be improved. An in-depth understanding of the way in which these markets function and of the role played by the different explanatory variables, with a particular emphasis on demand and supply characteristics, is crucial to ensure a successful reform process. Among other objectives, minimizing program deviations must be one of the main goals of this reform. In this regard, the introduction of sufficient incentives to minimize imbalances and ensuring an active participation of RES-E generators in power balancing could form part of the solution.

The rapid deployment of renewable energy sources also affects the competitiveness of other energy sources that will continue to be fundamental for the EU's energy system and reduces investment incentives for generation capacity that will be needed for the transition towards a more competitive, secure and sustainable energy system (e.g. as backup to variable renewable energy). In the ambit of availability, operating stop-start day regimes and charge level technical minimum that will lead the combined cycles to provide reserves for the system before deviating to renewables, could pose a greater risk of failure and maintenance cost for these power plants.

In this context, security of supply should be planned and managed by the competent authorities in response to these different time horizons with adequate energy policies, which facilitate the proper operation of the electricity system for the benefit of all consumers. In this context, this thesis focuses on the analysis of the effects of the integration of renewable energy in the operation of adjustment markets. Not forgetting that these are not the only factors for explaining the costs associated with providing such services.

An economic analysis is absolutely necessary at a time like the present when the design and implementation of the single electricity market at European level is being undertaken. In the future, in the provision of balance and tertiary regulation, external interconnected systems must also be involved, as this will increase the interchangeability between different electrical systems.

It is precisely this type of analysis which is carried out in the fifth chapter of this thesis, which analyses the sensitivity of the costs associated with adjustment services due to the increasing uptake of renewable energies. A novel aspect in the analysis carried out lies in the varying approaches taken to solar photovoltaic technology in relation to wind power. Despite both being technologies of renewable origin, the results obtained in this analysis indicate that the effect on costs of adjustment services is not the same in the case of one or the other technology. Empirical evidence of differentiated patterns of generation was found. Likewise, the empirical approach followed seeks to disentangle the impact associated with both variability and non-total predictability, both intrinsic properties of renewable generation.

Interestingly, it has been demonstrated that the costs of the adjustment services are conditioned by the availability of flexible generation coupled to the system. The uptake of renewable energies not only affects the number of hours of operation of the remaining manageable and flexible technologies, but also the cost associated with the provision of flexibility services.

In the Spanish case, characterized by the difficulty of obtaining new hydraulic sites, this flexibility is basically provided by combined natural gas cycles. Natural gas is not only required to provide coverage at those times of maximum demand or minimum renewable production, but is called on to respond to the growing needs of the operation reserve. All this with the objective of guaranteeing a response to sudden changes in variable production that will become more frequent with the expected increase in the use of wind and solar energy.

Such an exercise, as the one carried out in this thesis, is vital in the future design of adjustment services. This exercise is necessary both at the level of each of the countries with increasing participation in generation of renewable origin and at the regional level too. In the present case of Spain, we are immersed in a process of the creation of an internal energy market. In the energy sector, the completion of the EU internal market requires the removal of numerous trade barriers, and requires fiscal and price policies and measures on standards to be brought in line, as well as environmental and safety regulations. The objective of all this is to guarantee the operation of the market, for the benefit of all its consumers.

In the case of Spain, such integration has meant a great and highly complex challenge to our system due, in part, to the limited interconnectivity with the rest of continental Europe and the morphology of the demand curve for electricity in the peninsula.

Jointly with levels of interconnection, which can finally end the situation of isolation in terms of European networks, which is the condition of certain member states, the need for regulatory harmonisation is patently clear. A process of harmonisation which should reach all segments of the electrical system. Adjustment services cannot and should not be an exception.

In the coming years, with the establishment of a single market for electricity and coordinated interconnection between different electrical systems, energy exchanges should not only be limited to mere trade in energy, but also to the exchange of balancing services such as developing a greater integration and harmonization of existing regulatory and balancing services in the different electrical systems.

Other issues including the possible claim for the provision of these services for tertiary regulation and balance should also be taken into consideration as they exist in other energy markets. All questions to be taken into account in the new design model for these markets, where an economic analysis is undoubtedly a very necessary preliminary step. An in-depth understanding of the factors that account for the evolution of operational costs will ultimately be helpful when making improvements to the regulatory framework to facilitate the success of retail market competition, especially in a context where the flexibility requirements have increased over the last few years.

Although this thesis is applied to Spain the results are of general interest to other countries mainly because the more common regulatory design within the European Union on liberalisation promotion is applied. The Spanish experience provides useful insight to other countries where the process of liberalisation of the retail market is at early stages or where an increase of the participation of VRES in electricity markets is foreseen.

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A. APPENDIX CHAPTER 3: OUTLIERS ANALYSIS

From the summary statistics (see Table 2 in the Chapter 3) and from a basic examination of the series, some concerns arise regarding the possible presence of extreme values for some of the observed variables. To analyse the outliers in the series, a three-step approach was followed: in the first step we confirm the existence of outliers, in the second we identify the most relevant outliers, and in the third step we check their validity in the original dataset.

We used the blocked adaptive computationally efficient outlier nominators (BACON) algorithm proposed by Billor et al. (2000) and further developed by Weber (2010) to detect outliers in our multivariate data. The algorithm starts from the identification of an initial subset of m outlier-free observations out of a sample of n observations and over the p variables of the model, where the subset size m is given by the product of the number of variables p and a parameter x chosen to determine the percentile $(1 - x)$ of the chi-squared distribution to be used as a threshold to separate outliers from non-outliers. After an iterative process (see Weber, 2010) those observations excluded from the final basic subset are nominated as outliers, whereas those inside the final basic subset are non-outliers. We chose six percentiles $(1 – x)$ to perform the test for the four models. The results of the BACON test (Table A1) confirm the existence of extreme values of the observable variables in all four models with different thresholds.

Table A1: BACON Test for Outliers Detection

Model	(1-*x*=0.15)	(1-*x*=0.20)	(1-*x*=0.25)	(1-*x*=0.30)	(1-*x*=0.35)	(1-*x*=0.40)
(1)	6	74	183	361	468	612
(2)	1	5	19	55	135	255
(3)	4	81	210	353	483	657
(4)	1	6	21	58	167	266

To identify the most important outliers we draw on the approaches proposed by Fox (1991) and Bohernstedt and Knoke (2002). Thus, for each model the top ten observations with the highest standardized residual (five positive and five negative) were selected. In Table A2 we present the standardized residuals, standardized DF Betas and Cook's distance values for the selected observations.

Table A2: Top Ten Relevant Outliers

Model	Obs. ID	Standardized Residuals	Standardized DF Betas	Cook's Distance
(1)	10494	-8.208313	-0.0341513	0.0022176
	12776	-8.11655	-0.0252596	0.0012077
	26495	-7.997363	-0.0153401	0.0006631
	8161	-6.956773	0.0124462	0.0007821
	8381	-6.945102	0.0184553	0.0009952
	25460	4.166198	0.0121760	0.0002074
	24645	4.542363	0.0125443	0.0002695
	7985	4.556850	0.0273400	0.0003517
	7986	4.594662	0.0229944	0.0003426
	16087	5.390295	-0.1384459	0.0043362
(2)	12776	-8.181914	-0.0245499	0.0012909
	10494	-8.167716	-0.0316382	0.0022665
	26495	-8.081288	-0.0160225	0.0006986
	8381	-7.024498	0.0194422	0.0011738
	10688	-6.941783	0.0225344	0.0006673
	24549	4.290016	0.0067373	0.0004076
	7985	4.489459	0.0267988	0.0003420
	24645	4.504580	0.0110940	0.0001893
	7986	4.543151	0.0227738	0.0003522
	16087	5.420996	-0.1402424	0.0037737
(3)	10494	-8.208313	-0.0341513	0.0022176
	12776	-8.116550	-0.0252596	0.0012077
	26495	-7.997363	-0.0153401	0.0006631
	8161	-6.956773	0.0124462	0.0007821
	8381	-6.945102	0.0184553	0.0009952
	25460	4.166198	0.0121760	0.0002074
	24645	4.542363	0.0125443	0.0002695
	7985	4.556850	0.0273400	0.0003517
	7986	4.594662	0.0229944	0.0003426
	16087	5.390295	-0.1384459	0.0043362
(4)	12776	-8.181914	-0.0245499	0.0012909
	10494	-8.167716	-0.0316382	0.0022665
	26495	-8.081288	-0.0160225	0.0006986
	8381	-7.024498	0.0194422	0.0011738
	10688	-6.941783	0.0225344	0.0006673
	24549	4.290016	0.0067373	0.0004076
	7985	4.489459	0.0267988	0.0003420
	24645	4.504580	0.0110940	0.0001893
	7986	4.543151	0.0227738	0.0003522
	16087	5.420996	-0.1402424	0.0037737

The standardized residual is the residual divided by its standard error. When the distribution of the residuals is approximately normal, 95% of the standardized residuals should fall between -2 and +2. If many of the residuals fall outside of + or – 2, then they can be considered unusual, which is the case for all the selected observations in our four models. The standardized DF Betas measure the extent to which an observation has affected the estimate of a regression. Values larger than $2/\sqrt{n}$ in absolute value (0.0101 in our data) are considered highly influential; this condition is met for all the selected observations. Finally, the Cook's distance measures the aggregate impact of each observation on the group of regression coefficients, as well as on the group of fitted values. Values larger than $4/n$ (0.0001 in our data) are considered highly influential; this is the case for all the selected observations in our four models.

These analyses lead us to the conclusion that the extreme values for some of the observed variables are likely to have a highly influential impact on the estimates. Clearly, estimations performed using least square methods that include the outliers would result in biased outcomes. We proceeded to confirm the validity of the identified outliers by contrasting their values with those in the original data set and with a Spanish Power System Operator specialist. As a result, we can confirm that the outliers are real observations.

B. APPENDIX CHAPTER 4: TECHNICAL ASPECTS UNDERPINNING THE ENERGY MARKET BALANCE

In a liberalised framework, suppliers buy the total amount of energy required to fulfil the expected demand of their customers on the electricity markets. Suppliers determine hourly electricity demand using different forecast methods and techniques. In order to avoid the extra-costs associated with higher prices on the different markets after day-ahead market gate closure, the supplier seeks to achieve the best possible demand estimation. In this way, suppliers aim at covering their demand on the day-ahead market without their having to make adjustments on posterior markets, which typically are more expensive.

As the majority of customers are connected at low voltage (LV) level (< 1 kV), the suppliers' demand has to take into account total network electricity losses. For each hour and for each voltage level, suppliers have to include total estimated losses[28] in their bids for the day-ahead market. According to the methodology established by Spain's electricity legislation, energy losses are allocated to each consumer taking into consideration their consumption characteristics. More specifically, the allocation of losses is the result of multiplying the end- use meter data of each consumer by a standard loss coefficient (transmission and distribution loss factor). Therefore, the expected hourly electricity demand of each supplier, measured at the power station busbars, is:

$$E_j^h = \sum_{i=1}^{n}(E_i^h \cdot (1 + K_i^h)) \qquad \text{(B1)}$$

being:

E_j^h: Expected hourly electricity demand of each supplier (*j*), with *h = 1,...,24.*

E_i^h: Expected hourly electricity demand of each category of consumer differentiated by voltage level (*i*)[29].

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[28] Total losses are determined as the difference between the energy metered at transmission and distribution network entry points and the energy metered at distribution network exit points (energy billed to customers). Total losses can be divided (Sáenz et al., 2011) into two different groups depending on their nature: technical losses caused by current flowing though the network and non-technical losses mainly caused by theft, fraud or administrative errors among other explanatory factors.

[29] In Spain, coefficients are differentiated according to the voltage level (n) of the network to which the customer is connected: high voltage (HV) network (36-220 kV), medium voltage (MV) network (1-36 kV) and low voltage (LV) network (<1kV). In this regard, the expected hourly demand (E_i^h)

K_i^h: Hourly standard losses coefficient differentiated by voltage level (*i*), with *i= 1,…,n*.

Standard loss coefficients (K_i^h) are used to calculate the standard network losses of the distribution companies, which are charged to consumers through full-service and access tariffs.

According to Eq. (B1), the energy metered at each connection point between the transmission and distribution grids has to be increased by the corresponding percentage of losses. For those consumers – mainly domestic and residential – that are not metered on a time interval basis, electricity demand is calculated using load profiles. In general, adopting different approaches, load profiles seek to characterize domestic electricity patterns of use on an intra-daily, diurnal and seasonal basis as a function of consumer characteristics. In the case of Spain, static profiles are derived from consumption data for each time interval considered, as collected from existing historic demand records for a sufficiently large sample of customers. With this information, which takes into account factors that might affect consumption and which might vary from day to day as well as from year to year (variations in the weather, holiday periods, etc.), domestic standard load profiles are constructed aimed at determining aggregate electricity consumption for all households without hourly metering across a 24- hour period. Profiling enables an electricity supplier to calculate the electricity consumption for every pricing period on the market (hourly time intervals in the case of Spain) for its customers that do not have a time interval meter installed.

Load profile-based metering implies that the expected hourly electricity demand of each category of consumer (E_i^h) is calculated as:

$$E_i^h = \sum_{i=1}^{n}(E_i^d \cdot L_i^h) \qquad (B2)$$

being:

E_i^d: Expected daily electricity demand.

L_i^h: Average load profile of a class of customers (i) over a given hour (*h*).

In short, the expected hourly electricity demand (E_j^h), based upon estimates using standard loss coefficients (K_i^h) and load profiles (L_i^h), constitutes the basis for the supplier to purchase from the wholesale market the electricity required by its customers. However, the use of both adjustment parameters has certain implications for the energy finally contracted. As the annual losses have been

results from the load aggregation corresponding to customers connected to the n different voltage levels.

determined ex ante using standard loss coefficients, their value will not coincide with the real value of annual technical losses in the network. Likewise, the use of load profiling to determine a consumer's electricity consumption inherently introduces discrepancies between estimated and real load (E_r^h), therefore:

$$E_s^h \neq E_r^h \qquad \text{(B3)}$$

being:

E_s^h: Expected total hourly electricity demand obtained as the sum of the expected hourly electricity demand of each supplier (*j*):

$$E_s^h = \sum_{j=1}^{J} E_j^h \qquad \text{(B4)}$$

E_r^h: Real hourly electricity demand

As discussed above, given that the energy finally dispatched to meet the customers' energy requirements, is not necessarily the same as that initially expected by the suppliers, a positive or negative energy difference arises, for which a balancing process is required. The electricity market balance requires additional adjustment services to ensure that generation and demand are in permanent equilibrium. This duty lies primarily with the system operator (SO). As the entity with overall responsibility for short-term system operation, the SO normally handles the balance-settlement and generation-load reconciliation process via processes of adjustment services management.

The post-liberalisation model of energy imbalance described above differs from the pre-liberalisation model. Under the pre-liberalisation system, the energy imbalance was resolved by the DSOs permanently matching electricity demand forecasts with the energy actually dispatched. Here, the electricity supply (E_s^h) was provided at a regulated tariff (E_{reg}^h) through a distribution company or at a market price (E_{lib}^h) through a supplier. The energy demanded in the wholesale market was equivalent to consumption measured at the power station busbars thanks to DSOs who adjusted their demand in the power exchange in an attempt at minimising the energy market balance.

In this pre-liberalisation scheme, where the liberalised and regulated supply coexisted, demand from distribution companies (E_{reg}^h) was determined at the border point in the distribution grid – affected by the corresponding loss profiles and standard coefficients – after subtracting the energy belonging to the liberalised customers (E_{lib}^h) connected to the distribution area. In the post-liberalisation model, with the disappearance of the distributor as a supplier of electricity, the previous scheme was no longer valid. The estimated hourly electricity demand is calculated as it was previously for the consumption of the liberalised customers but distributors make no adjustments. This means that the hourly energy demand on the market estimated by suppliers does not coincide with the electricity finally dispatched. The SO therefore uses ancillary services to correct this difference. The pre- and post-liberalisation loss adjustment schemes are summarised in Table B1.

Table B1: Main implications in terms of electricity losses

	Before July 2009	**After July 2009**
Estimated versus real load	$E_s^h = E_r^h$	$E_s^h \neq E_r^h$
Losses adjustment process	$E_{reg}^h = E_s^h - E_{lib}^h$	$E_r^h - E_s^h$ = *EMB* *EMB is adjusted in the balancing markets*

Under a similar approach aimed at reducing system costs through the use of standard coefficient of losses that better capture time and seasonal patterns, across Europe the differences from system to system remain in the specificities. Technical aspects related with the methods for establishing the difference between estimated and actual consumption and the price at which this difference is settled constitute the main difference from system to system. According to Spanish legislation, the day-ahead price is used to clear the differences between the system's real losses and those resulting from the application of a standard coefficient of losses.

C. APPENDIX CHAPTER 5: OUTLIERS ANALYSIS

From the summary statistics (see Table 12 and Figure 22 in Chapter 5) and from a basic examination of the series some concerns arise regarding the possible presence of extreme values for some of the observed variables in logarithms. To analyse the outliers in the series, a three-step approach was followed: in the first step we confirm the existence of outliers, in the second we identify the most relevant outliers, and in the third step we check their validity in the original dataset.

We used the blocked adaptive computationally efficient outlier nominators (BACON) algorithm proposed by Billor et al. (2000) and further developed by Weber (2010) to detect outliers in our multivariate data. The algorithm starts from the identification of an initial subset of m outlier-free observations out of a sample of n observations and over the p variables of the model, where the subset size m is given by the product of the number of variables p and a parameter x chosen to determine the percentile $(1 - x)$ of the chi-squared distribution to be used as a threshold to separate outliers from non-outliers. After an iterative process (see Weber, 2010) those observations excluded from the final basic subset are nominated as outliers, whereas those inside the final basic subset are non-outliers. We chose six percentiles $(1 - x)$ to perform the test for the four models. The results of the BACON test (Table C1) confirm the existence of extreme values of the observable variables in all five models with different thresholds.

Table C1: BACON Test for Outliers Detection

Model	(1-*x*=0.15)	(1-*x*=0.20)	(1-*x*=0.25)	(1-*x*=0.30)	(1-*x*=0.35)	(1-*x*=0.40)
(1)	572	718	789	864	1029	1398
(2)	526	541	602	743	837	938
(3)	524	526	532	553	605	938
(4)	525	1002	1010	1030	1083	1204
(5)	524	524	1002	1004	1011	1031

To identify the most important outliers we draw on the approaches proposed by Fox (1991) and Bohernstedt and Knoke (2002). Thus, for the model with the highest level of information (model 5) the top ten observations with the highest standardized residual (five positive and five negative) were selected. In Table C2 we present the standardized residuals, standardized DF Betas and Cook's distance values for the selected observations.

Table C2: Top Ten Relevant Outliers

Obs. ID	Standardized Residuals	Standardized DF Betas	Cook's Distance
4016	-8.812136	-8.821795	0.0770041
17710	-8.736793	-8.746203	0.0483108
1928	-7.92991	-7.936924	0.0005516
12374	-7.649826	-7.656116	0.005504
2622	-7.258068	-7.263429	0.0073262
15764	4.429094	4.430271	-0.0389421
24451	4.483734	4.484958	-0.0187222
16675	4.507164	4.508407	0.000093
28677	4.618795	4.620136	-0.0503738
15860	4.84721	4.848767	-0.0310142

The standardized residual is the residual divided by its standard error. When the distribution of the residuals is approximately normal, 95% of the standardized residuals should fall between -2 and +2. If many of the residuals fall outside of + or – 2, then they can be considered unusual, which is the case for all the selected observations. The standardized DF Betas measure the extent to which an observation has affected the estimate of a regression. Values larger than $2/\sqrt{n}$ in absolute value (0.0101 in our data) are considered highly influential; this condition is met for all the selected observations. Finally, the Cook's distance measures the aggregate impact of each observation on the group of regression coefficients, as well as on the group of fitted values. Values larger than $4/n$ (0.0001 in our data) are considered highly influential; this is the case for all the selected observations.

These analyses lead us to the conclusion that the extreme values for some of the observed variables are likely to have a highly influential impact on the estimates. Clearly, estimations performed using least square methods that include the outliers would result in biased outcomes. We proceeded to confirm the validity of the identified outliers by contrasting their values with those in the original data set and with a Spanish Power System Operator specialist. As a result, we can confirm that the outliers are real observations and therefore relevant for the empirical study.