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MÁSTER UNIVERSITARIO EN TECNOLOGÍA ENERGÉTICA PARA EL DESARROLLO SOSTENIBLE

EVALUATION OF ELECTRICITY SYSTEM STRATEGIC PLANNING FOR THE INTEGRATION OF HIGH SHARE OF INTERMITTENT RENEWABLE ENERGIES. ASSESSMENT OF THE SPANISH ENERGY PLAN (PNIEC), FOCUSING ON ENERGY STORAGE REQUIREMENTS AND ITS DEPLOYMENT STRATEGY.

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Summary

The use of renewable energy sources represents a key strategy to decarbonize the economy. As the potential of hydro and biomass generation is limited in many countries, wind and solar photovoltaic are playing an increasingly important role in the transition to green energy systems. The major obstacle to the efficient deployment of these technologies is their intermittence, which can cause a temporary mismatch between supply and demand.

The Master's Thesis will be based on modelling, from a system perspective, the optimal combination of curtailment and storage to meet electricity demand with a high penetration of renewable generation. In this sense, special attention will be given to take advantage of different storage technologies to benefit from each specific features.

The object of the study will be the Spanish electricity system, by which the strategy presented in the National Integrated Energy and Climate Plan (PNIEC) will also be analysed, with the purpose of verifying the consistency of the numbers.

An extensive bibliographic research on the modelling of energy systems and the technical-economic characteristics of the different generation and storage technologies will be carried out. The process and the assumptions made for the definition of the methodology will be described, and the structure and the equations of the model will be presented.

Different renewable generation scenarios will be modelled and analysed for an adequate understanding of the importance of storage, and different demand scenarios will be presented to provide a sensitivity analysis. The results will be used to investigate the expectable effectiveness of the PNIEC and, finally, to suggest the changes needed to build a regulatory framework that can drive the proposed energy transition efficiently.

It is expected that this Thesis Project will provide a model for planning investment in renewable infrastructure and storage, looking for replicability options in other countries.

Keywords: Energy; Storage; Optimization; Renewable energy sources; PNIEC

Resumen

El uso de fuentes de energía renovables representa una estrategia clave para descarbonizar la economía. Debido al potencial limitado de desarrollo de la generación de energía hidroeléctrica y de la biomasa en muchos países, la energía eólica y la energía solar fotovoltaica juegan un papel cada vez más importante en la transición ecológica. El principal obstáculo para un despliegue eficiente de estas tecnologías es su intermitencia, que puede causar desajustes temporales entre la oferta y la demanda.

El Trabajo Final de Máster se basará en modelizar, desde la perspectiva del sistema, la combinación óptima de vertidos a la red eléctrica de energías renovables y almacenamiento de energía eléctrica para satisfacer la demanda de electricidad con una alta penetración de generación renovable. En este sentido, la combinación de diferentes tecnologías de almacenamiento constituirá el enfoque del análisis estratégico, para beneficiarse de las características de cada uno.

El objeto del estudio, además, será el sistema eléctrico español en relación a la estrategia presentada en el Plan Nacional Integrado Energía y Clima (PNIEC), con el propósito de verificar la consistencia de los números a través del modelo.

Se realizará una búsqueda bibliográfica sobre la modelización de sistemas energéticos y las características técnico-económicas de las diferentes tecnologías de generación y almacenamiento. Se describirá el proceso y las hipótesis asumidas para la definición de la metodología y se presentarán la estructura y las ecuaciones del modelo.

Se modelarán y analizarán diferentes escenarios de generación renovable para una adecuada comprensión de la importancia del almacenamiento, y diferentes escenarios de demanda para proporcionar un análisis de sensibilidad. Los resultados se utilizarán para investigar la previsible eficacia del PNIEC y, finalmente, sugerir los cambios necesarios para construir un marco normativo que pueda impulsar la propuesta transición energética de manera eficiente.

Se espera, finalmente, que este Trabajo Final de Máster contribuya a desarrollar un modelo para la planificación de la inversión en infraestructura renovable y almacenamiento, buscando opciones de replicabilidad en otros países.

Palabras clave: Energía; Almacenamiento; Optimización; Energías Renovables; PNIEC

Resum

L'ús de fonts d'energia renovables representa una estratègia clau per a descarbonizar l'economia. A causa del potencial limitat de desenvolupament de la generació d'energia hidroelèctrica i de la biomassa en molts països, l'energia eòlica i l'energia solar fotovoltaica juguen un paper cada vegada més important en la transició ecològica. El principal obstacle per a un desplegament eficient d'aquestes tecnologies és la seva intermitencia, que pot causar desajustaments temporals entre l'oferta i la demanda.

El Treball Final de Màster es basarà en modelizar, des de la perspectiva del sistema, la combinació òptima d'abocaments a la xarxa elèctrica d'energies renovables i emmagatzematge d'energia elèctrica per a satisfer la demanda d'electricitat amb una alta penetració de generació renovable. En aquest sentit, la combinació de diferents tecnologies d'emmagatzematge constituirà l'enfocament de l'anàlisi estratègica, per a beneficiar-se de les peculiaritats de cadascun.

L'objecte de l'estudi serà el sistema elèctric espanyol, pel qual s'analitzarà també l'estratègia presentada en el Pla Nacional Integrat Energia i Clima (PNIEC), amb el propòsit de verificar la consistència dels números a través del model.

Es realitzarà una cerca bibliogràfica sobre la modelització de sistemes energètics i les característiques tecnicoeconòmiques de les diferents tecnologies de generació i emmagatzematge. Es descriurà el procés i les hipòtesis assumides per a la definició de la metodologia i es presentaran l'estructura i les equacions del model.

Es modelaran i analitzaran diferents escenaris de generació renovable per a una adequada comprensió de la importància de l'emmagatzematge, i diferents escenaris de demanda per a proporcionar una anàlisi de sensibilitat. Els resultats s'utilitzaran per a investigar l'eficàcia del PNIEC i, finalment, suggerir els canvis necessaris per a construir un marc normatiu que pugui impulsar la transició de manera eficient.

S'espera que amb aquest Treball Final de Màster s'obtingui un model per a la planificació de la inversió en infraestructura renovable i emmagatzematge, buscant opcions de replicabilidad en altres països.

Paraules clau: Energia; Emmagatzematge; Optimització; Energies Renovables; PNIEC

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Glossary

Abbreviation	Definition
AC	Alternating current
am	*Ante meridiem*
CCAA	Comunidades autónomas. Spanish regions
CCGT	Combined cycle gas turbine
CNE	Comisión nacional de energía, National commission of energy
CNMC	Comisión nacional del Mercado de valores. National commission of markets and competition
CAES	Compressed Air Energy Storage
CES	Chemical Energy Storage
CO	Carbon Monoxide
CO2	Carbon dioxide
CSP	Concentrated Solar Power
DC	Direct Current
DR	Demand Response
EU	European Union
EVs	Electric Vehicles
FES	Flywheel Energy Storage
GES	Gravity Energy Storage
GHG	Green House Gasses
GPM	Gravity Power Module
GWh	Gigawatts hour
h	Hours
HES	Hydrogen Energy Storage
PNIEC	Integrated National Energy and Climate Plan
Li-ion	Lithium-Ion
km	Kilometres
kV	Kilovolts
MAX	Maximise
MC	Marginal cost
MIBEL	Iberian electricity market
MO	Market operator
MW	Megawatt

MWh	Megawatt hour
OMIE	Operador del Mercado Ibérico de Energía, Polo Español, S. A. Spanish MO
NaS	Sodium Sulphur energy storage
PbO2	Lead Acid
PHES	Pumped Hydro Energy Storage
pm	Post meridiem
PV	Photovoltaics
RD	Royal decree law
REE	Spanish National Grid (Red Eléctrica Española)
REN	Renewable
RES	Renewable energy sources
SCs	Supercapacitor Energy Storage
SG	Self-generation
SMES	Superconducting Magnetic Energy Storage
SO	System operator
T&D	Transmission and Distribution grid
TOU	Time of use
TSO	Transmission system operator
TWh	Terawatt hour
UK	United Kingdom
USA	United Stated of America
VRB	Vanadium Redox Battery
VPP	Virtual power plants
W	Watt
ZnAir	Zinc Air Battery

1. Introduction

Background

The rise of Green House Gasses (GHG) emissions from anthropogenic sources has led the Earth to face the phenomenon known as climate change. Scientific evidence is overwhelming; climate change threatens our habitat and has global risks that need to be addressed universally and urgently (Stern, 2007). This issue has generated a lot of discussion about the necessity for reducing emissions and how this can be accomplished. Electricity generation, that traditionally has been based on fossil fuel burning, has been in the spotlight since the advent of renewable energy sources (RES).

As the potentials of hydro, biomass or geothermal energy are limited in many countries, wind power and solar photovoltaics (PV) play an increasingly relevant role. Opposed to dispatchable technologies like coal- or natural gas-fired power plants that can produce whenever economically attractive, electricity generation from wind and solar PV plants is variable: it depends on exogenous weather conditions, the time of day, season, and location (Edenhofer et al., 2013; Joskow, 2011). At the same time, maintaining power system stability requires to continuously ensure that supply meets demand. The potential temporal mismatch of supply and demand raises two fundamental questions: how to deal with variable renewable energy at times when there is too much supply, and how to serve demand at times when supply is scarce (Brown et al., 2018). Evidently, electrical storage can provide a solution, for instance, in the form of batteries or pumped-hydro storage plants, allowing to shift energy over time (Zerrahn et al., 2018).

Recent literature has focused on whether electrical storage requirements may become excessive and could thus impede the further expansion of variable renewables. In a recent analysis (Sinn, 2017), it has been shown that without storage a fully renewable electricity supply would imply not using 61% of the possible power generation from wind and solar generators. In contrast, to avoid any “waste” of renewable energy, storage requirements to take up renewable surplus energy quickly rise to huge numbers. These considerations deserve merit, as they illustrate essential properties of intermittent renewable energy sources and introduce the necessity of balancing curtailment and storage. On this topic Alexander Zerrahn et al. (Zerrahn et al., 2018) performed an extensive study, clarifying Sinn’s findings and concluding that storage is unlikely to limit the transition to renewable energy. As a matter of fact, looking for an economically efficient solution – or rather minimizing costs of the system - to reach a specified proportion of renewables in the energy mix requires to move away from corner solutions. Trading off the costs of investments into storage plants, renewables that may get curtailed at times, and other assets of the electricity value chain represents the cleverest way of addressing this problem. They concluded that investment in energy storage are necessary but moderate – no need to completely avoid curtailment – to efficiently integrate renewables in the energy mix. Thus, energy storage represents a fundamental asset to decarbonize the electricity infrastructure and needs to be accurately sized and operated to optimize its usage.

Storage technologies can be categorized in short- and long-term, depending on their characteristics, which ultimately define the specific-to-power and specific-to-energy costs. Lower specific-to-power costs correspond to short-term, whereas lower specific-to-energy costs correspond to long-term storage. In this context, seen the existence of different storage technologies gaining relevance and maturity, and the importance of economic research on renewables in informing policymakers, a parsimonious optimization model considering various options in terms of energy storage systems would be useful in defining better strategies for sustainable infrastructure planning.

Main aims

The main objective of this project is to understand, from a system perspective, the storage requirements to satisfy electricity demand with high share of renewable generation. The project is built around the Spanish Electricity System, in order to assess and validate the electricity generation infrastructure planned for 2030 in the national energy strategy (PNIEC).

The specific characteristics of a variety of promising storage technologies will be considered in order to reach better reliability, lower costs, and a more diversified approach, that would eventually make the system more adaptable to technology advancement. Therefore, this thesis helps to understand in which direction investments should head, to balance curtailment and storage, and to reach an optimal combination of flexibility options to reach high penetration of renewables. Information obtained from this project serves as a powerful tool for policy makers and will be accompanied by specific policy recommendations for the Spain's case study.

The main research prior to this study has been carried out in ref. (Zerrahn et al., 2018), but no study assessing the real potential of efficiently combining several energy storage technologies was found, and no model was specifically developed or used for the Spanish electricity system. In addition, considerations regarding the economic viability of seasonal storage are going to be made based on the model's results, and policy recommendations for an effective deployment of storage technologies will be suggested.

Structure

The thesis is organized as follows:

- Chapter 2 presents an overview of the current Spanish electricity system, focusing on generation and demand, and sets the baseline of the case study.
- Chapter 3 presents the main targets set for 2030 in the integrated national energy and climate plan, especially regarding electricity generation capacity and energy storage.
- Chapter 4 introduces the problem of balancing curtailment and storage, assessing the research on energy policy modelling, particularly on energy storage requirement optimization.
- Chapter 5 focuses on storage technologies and applications, to present its functioning principles and to outline the importance of its integration in the electricity infrastructure.

- Chapter 6 describes the methodology to respond to the research hypothesis and goals. It also presents the assumptions and the data search.
- Chapter 7 contains the evaluation of the case study, with a sensitivity analysis correspondent to different renewable penetrations, and an in-depth assessment of the 2030 national energy plan objectives.
- Chapter 8 presents different storage applications and revenue schemes, suggesting different paths for an effective deployment of storage technologies.
- The final chapter recollects the main considerations extrapolated from the study and gives some policy recommendations, especially regarding the planning of energy storage integration both from a technical and regulation standpoint.

2. Background of the Spanish system

During the first third of the XX century, electricity sectors of the industrialized countries followed similar process of public ownership (C. L. González, 2015). European countries set as a priority the development of a reliable electrical supply infrastructure, to achieve higher living standards and economic development. Economies of scale were thought to be the most efficient strategy to guarantee a reliable electrical system, but the oil crisis in the 70s and the high dependence on fossil fuel imports challenged the economic sustainability of public owned utilities. Economists around the world pointed out that state owned systems were characterized by low productivity, overinvestment, and low incentives to innovation. During the late 80s and 90s, most of the developed world went through a process of liberalization of electricity markets. In Spain, the liberalization was implemented a bit later – in 1996 – when the Directive 96/92 from the EU was ratified.

Since 1998 the Spanish electricity sector has been structured after the Electricity Sector Act 54/1997. This act introduced competition into both electricity generation and retail markets, and kept transmission and distribution activities as regulated, since these are natural monopolies and competition is unlikely to improve the efficiency of the system. Nowadays, the liberalization of electricity markets has become the norm. After 20 years from the start of the liberalization, this process has become globally widespread. Nevertheless, there is no clear evidence of the efficiency gains and there is a lack of obvious direct benefits to consumers in several countries (Pollitt, 2012).

In recent years, since electrical supply in developed countries has been guaranteed, the main object of discussion has switched to be sustainability, seen the growing concerns for the environmental impacts of humans' actions. In this context, the liberalization has not necessarily made it easier to make the required changes. A strong regulatory framework is necessary to reach the sustainable goals set for the future.

2.1. Electricity system characteristics

Spain´s dependence on primary energy imports has substantially decreased from about 80% of the energy supply in 2008 to around 70% in 2014 (IEA, 2015). The explanation for this phenomenon has to be found in the increase of renewable penetration in the electricity system. Moreover, during the recession, the demand for electricity declined. This has raised several critics for the overcapacity of the fossil fuel power plants. During the 00s many CCGT facilities were built. These generators are now kept largely on reserve to guarantee security of supply, but these reserves might be over contracted. Both the CNMC and the European Commission have asked REE to justify the need to auction so much power. Spain could be paying more than necessary to the electricity utilities to guarantee supply, paying around €700 million euros per annum for three types of reserve capacity, that can be overlapping. All these factors have resulted in price increases, which follow directly from governmental policies. These costs are paid either through taxes on generation or in tariff accesses, which then are passed to consumers. Figure I comes from the annual report of REE (Red Eléctrica de España, 2020b) and shows the average cost of electricity in 2019 (53.43 €/MWh). Capacity payments account for 4,96% of the total cost of electricity, therefore for around 700 million euros considering that the demand during 2019 has been of 264.550 GWh.

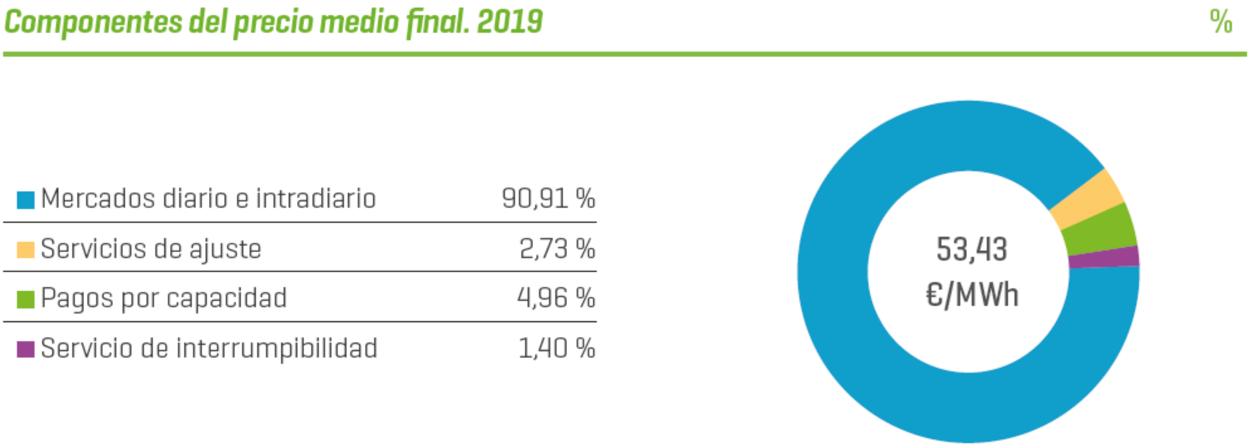

Figure I: 2019 Average electricity final cost in Spain (Red Eléctrica de España, 2020b).

2.1.1. Capacity

Spain has a large and well-diversified generation system. The system presents high reliability and has successfully integrated a large share of RES with little generation curtailment (IEA, 2015). Since international connections are relatively small, the variations on the Iberian system must be dealt within the region. Figure II presents the peninsular installed capacity at the end of 2019.

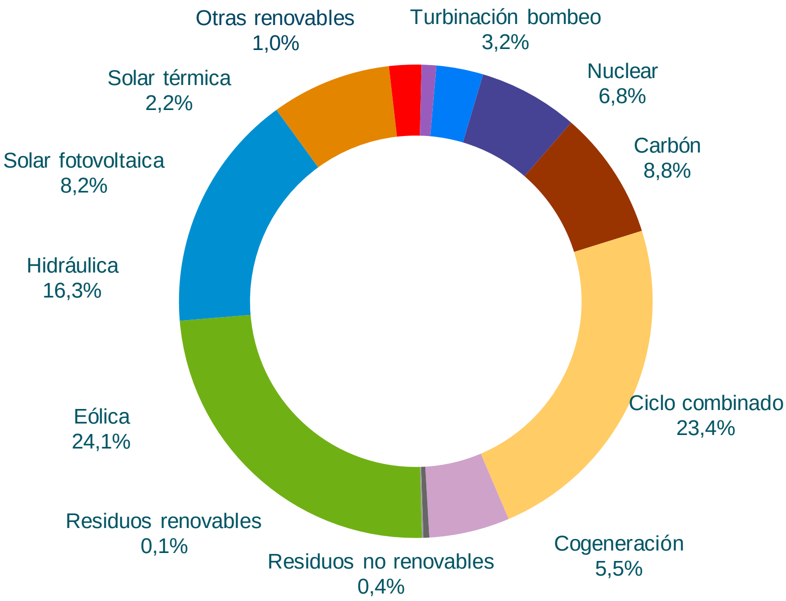

Figure II: Electric power installed in Spanish peninsula on the 31st December 2019 (Red Eléctrica de España, 2020b).

The Spanish electricity generation system is increasingly renewable. During 2019, the installed power from renewable sources has experienced a growth of 13.4%, with the entry into operation of more than 6,500 new 'green' MW. In this way, renewable energies now represent 50% of the installed generation capacity in Spain.

2.1.2. Generation

The electricity generation and consumption peaked in 2008. After booming for years, 311 TWh were consumed that year. The 2008 financial crisis meant the start of a decreasing trend in electricity consumption. In 2019 the electricity demand in Spain accounted for 264.55 TWh (Red Eléctrica de España, 2020b). Since demand levels have not changed much, neither generation has, but the generation mix has changed. In 2019 38.4% of the electricity produced in Spain came from RES, wind represents 20.9% of the total electricity, PV and solar thermal account for 5.5% and hydro represents 10.3%, in line with previous years data.

In terms of thermal sources, nuclear represents the major contributor with 22% of the generated electricity. It is important to point out its role as base load since this source only represents 7.7% of the total capacity. Figure III presents the energy mix of the Iberian Peninsula in 2019.

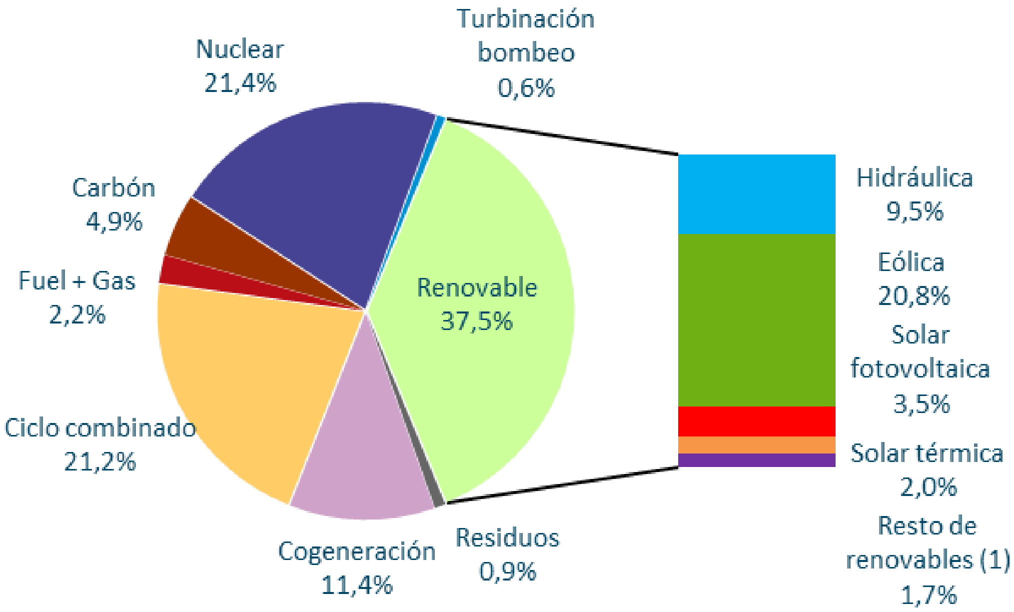

Figure III: Energy mix in the Spanish peninsula during 2019 (Red Eléctrica de España, 2020b).

Figure IV presents the evolution of renewable share during the last ten years. Even though throughout the years the renewable capacity installed has largely increased, the generation output has not necessarily done the same. This phenomenon is to be attributed to hydro power plants, and specifically to their dependency on hydrogeological resources. In fact, despite the relevance of hydropower for current and future energy systems, there are several other usages of water - catchments, flows, irrigation, etc. – that end up determining hydropower operations throughout the year. The availability and variability of hydrogeological resources represent the major explanation for the changes year over year of renewable share illustrated in Figure IV.

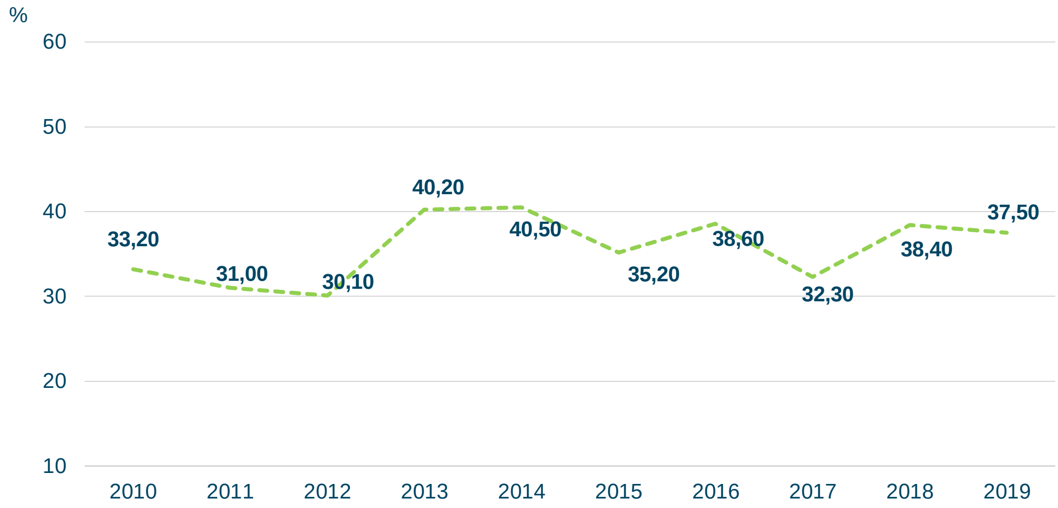

Figure IV: Renewable electricity generation evolution (Red Eléctrica de España, 2020b).

2.1.3. Consumption

As well as generation, consumption presents a decreasing trend during the last decade. Figure V shows a typical daily demand curve in the Spanish electrical system. A characteristic feature of this curve is the second consumption peak, that appears at around 8 pm. The reason has to be found in the lifestyle habits; people leave from work at around 7 pm and by the time that they get home and switch on all the electrical appliances or they go out for dinner it is 8 pm.

Generation peaks from PV correlates well with the times of the first peak of curve. Therefore, this source can cover the demanded energy at those peaking times without the necessity of installing storage or new non-renewable capacity (Urbina, 2014). However, it is important to note that while the first peak can be easily covered with PV, the second peak cannot be addressed with this generating source.

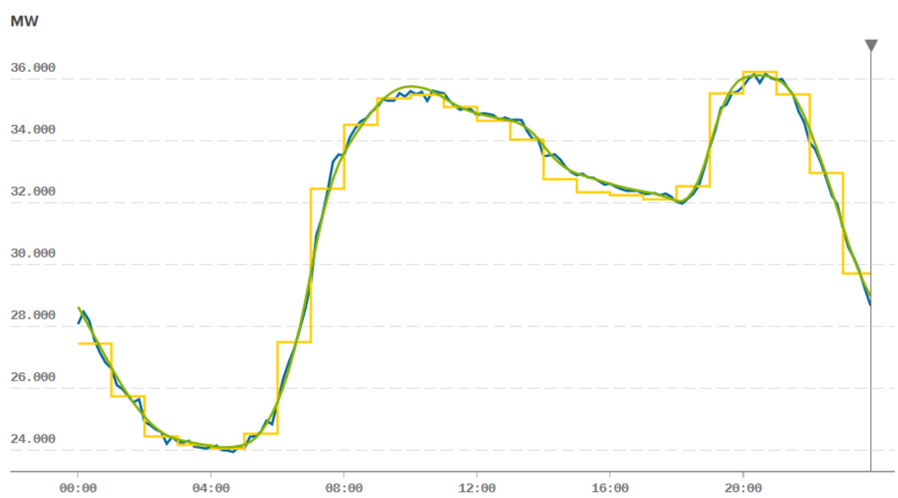

Figure V: Demand on the 14th of February of 2019 (Red Eléctrica de España, 2020a).

2.2. Electricity Market

The electricity market is organised in two main markets:

• A future market where long-term contracts can be signed between parties under their own conditions, also known as OTC.

• Or a standardised future market that is managed by the Portuguese OMIP for the whole Iberian Peninsula. This kind of contracts are signed months or even years before the physical contracts take place.

Commonly, the preferred marketplace for electricity transactions is the day-ahead market, often referred to as spot market. This market represents more than 70% of the total purchased electricity of Iberian market (IEA, 2015), while the future market represents only 30% and contracts are normally indexed to spot prices.

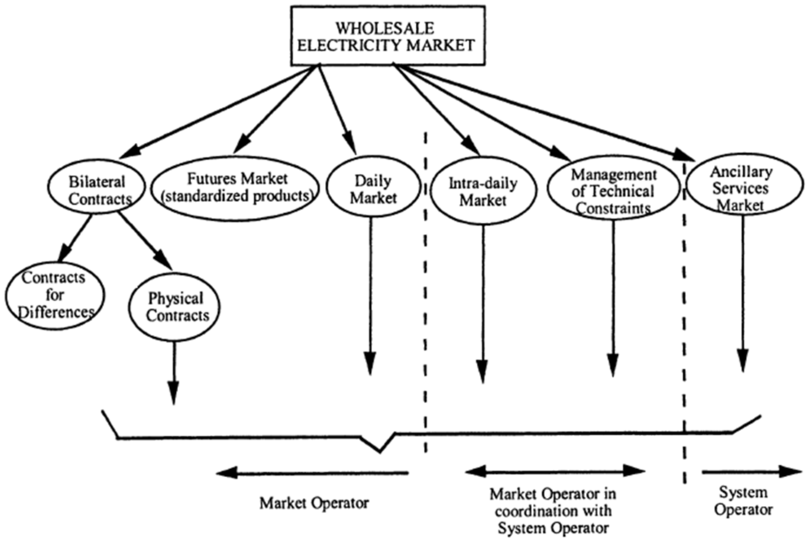

Figure VI: Structure of the market.

The market works as a two-sided auction, where producers submit offers for delivering electricity at a certain price and time of the next day, while retailers and large consumers submit bids for withdrawing electricity from the grid at a certain price and time.

Historically, only OMIE oversaw the market clearing, determining supply and demand curves by aggregating the offers. Today a single integrated market within EU boundaries has been developed and the final clearing is overseen by an entity called Market Coupling Operator (MCO). Under non-discriminatory rules for access conditions to the network for cross-border exchanges and rules on capacity allocation and congestion management for interconnections (ENTSOE, 2016), the Union's Energy Market matches offers and bids through an iterative elaboration of the information provided by nominated electricity market operators (OMIE for Spain) and transmission system operators (REE for Spain). The market price is determined by the highest bid among the ones dispatched, thus – indirectly - by the marginal cost of production of the most expensive generating unit dispatched.

After the day ahead schedule, intra-day markets play a key role in adjusting renewable generation and load adjustment (Weber, 2010). Finally, REE uses the last resource of the market in order to match consumption and production. This is known as the balancing market, that is used to solve any unwanted deviations that might occur in the market. The TSO uses the contracted ancillary services and other technical procedures to guarantee the security of the supply.

Until the liberalisation of the market, the electricity dispatch (constant match of supply and demand) was seen as an optimisation problem where the system operator (SO) tried to minimise the cost. The structure of the new liberalized markets created huge challenges in the optimization of the generation systems, and the advent of renewables made things even more complicated. In fact, since these sources are non-dispatchable and their marginal cost is close to zero, in the current bidding system they are the ones entering the market first and shifting the cost curve to the right, as shown in Figure VII. It is obvious that since RES have a 0-offering cost in the electricity pool, they push the wholesale market price down. In a similar day, if more renewables enter the market due to good meteorological conditions, the price will be lower than if no renewables were into the market.

In summary, the great resistance to a further integration of renewable energies in the energy mix has to be found in their intermittency and the difficulty in forecasting with accuracy their generation. Dispatchable technologies are needed to perfectly balance the electricity system at each time step. Now this “service” is offered mainly by hydropower and natural gas generation facilities, which have enough capacity to deal with the current variability of renewable generation. However, in the long run, in order to reach the very ambitious goals set in terms of decarbonization, to rely on these technologies for offering balancing services would imply an extensive overcapacity of fossil fuel power plants, which would be underexploited, in addition to an overcapacity of renewables, which would be largely curtailed. All this considered, an adequate planning of the electricity infrastructure is required to avoid excessive overgeneration of renewables and expensive capacity payments to fossil fuel power plants due to their underusage.

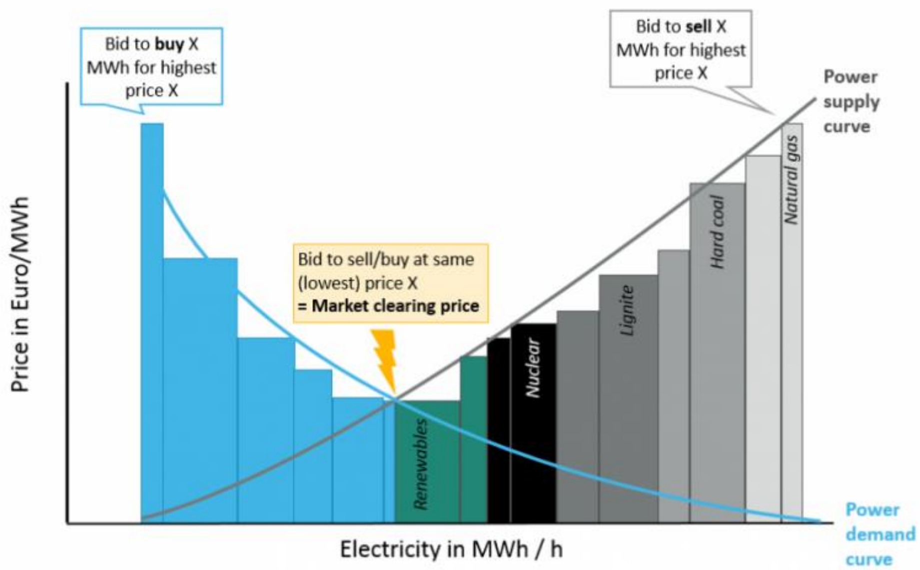

Figure VII: Market clearing scheme.

3. Integrated National Energy and Climate Plan

As outlined in the first chapter of the Regulation (EU) 2018/1999, the new governance regulation “sets out the necessary legislative foundation for reliable, inclusive, cost-efficient, transparent and predictable governance of the Energy Union and Climate Action (governance mechanism), which ensures the achievement of the 2030 and long-term objectives and targets of the Energy Union” (European Commission, 2019). This monitoring is essentially based on the Integrated National Energy and Climate Plan (PNIEC): a national report containing the overview of the current energy system and policy situation of the Member State, setting out national objectives covering ten-year periods (2021-2030) and including all the different sectors. The guidelines for the drafting of the document are described comprehensively in the Regulation, whilst the transparency is ensured by public consultation, as well as integrated reporting, monitoring and data publication.

Hence, each Member State was required to submit a draft PNIEC report by December 2018, to be assessed by the Commission in the following months and resulted on the publication of the global assessment of the cumulative impact of these draft plans by 18 June 2019. That report included recommendations to be considered to improve the PNIEC before submitting the final version by the end of 2019 (European Commission, 2019).

In the following subchapters, Spanish national targets for the power sector will be detailed as result of the personal consultation and recommendations from third parties.

3.1. Main targets

The measures described in the “Plan Nacional Integrado de Energìa y Clima” (PNIEC) are supposed to lead the achievement in 2030 of the targets specified in Table 1.

Table 1: Main energy and climate parameters of Spain for the 2030 horizon. Adapted from: (Ministerio para la Transición Ecológica y el Reto Demográfico, 2020).

	Renewables	Energy efficiency	GHG emissions[1]	Energy dependency	Renewables electricity	Renewables transport	Interconnections
2020 Target	20%	26.1%	10.3%	71%	40%	10%	10%
2030 Target	42%	39.5%	-23.3%	61%	74%	22%	15%

Spain starts from a relatively low contribution of renewable energy in 2020, with a share equivalent to the overall objective of the European Union (20%), but set his 2030 RES target at 42%, which consist of a challenging growth of +22% in the next decade. Electricity from RES target will be the focus of the next subchapter.

[1] The GHG emission targets were computed on 1990 levels

3.2. Electricity system planning

The Spanish PNIEC provides more in detail its generation system in the upcoming years, specifying all the technologies and distinguishing between the Target Scenario and the Baseline Scenario. Table 2 presents a summary of the main technologies planned for the Spanish generation system:

Table 2: Spanish generation system in the Business As Usual (BAU) & Target Scenarios [GW]. Adapted from: (Ministerio para la Transición Ecológica y el Reto Demográfico, 2020).

Year	2015	2020	2025		2030	
Scenario	Current	BAU	BAU	Target	BAU	Target
Hydro[2]	20.1	20.1	20.1	21.3	20.1	24.1
of which pure hydro	14.1	14.1	14.1	14.4	14.1	14.6
of which mixed pumping	2.7	2.7	2.7	2.7	2.7	2.7
of which pure pumping	3.3	3.3	3.3	4.2	3.3	6.8
Wind	22.9	28.0	33.0	40.6	38.0	50.3
Solar Photovoltaic	4.9	8.9	13.9	21.7	18.9	39.2
CSP	2.3	2.3	2.3	4.8	2.3	7.3
Biomass	0.7	0.6	0.6	0.8	0.6	1.4
Other Renewables[3]	0.8	0.7	0.5	0.5	0.4	0.5
Coal	11.3	7.9	2.2	2.2	2.2	0.0
Natural Gas & Oil	36.4	35.5	34.6	33.6	32.7	32.1
Waste	0.2	0.2	0.2	0.2	0.2	0.2
Nuclear	7.4	7.4	7.4	7.4	7.4	3.2
Total	**107.2**	**111.7**	**114.9**	**133.8**	**122.9**	**160.8**

With regards to the 2030 Target Scenario and compared to 2015, the evolution of the renewables is evident. An increment of +32 GW (653% relative growth) of solar photovoltaic followed by +27 GW of wind (120% relative growth), complemented by an additional capacity of 3.5 GW pure pumped-hydro energy storage (PHES), 5 GW of solar thermoelectric technologies (CSP) and 2.5 GW of batteries with a maximum of two hours' storage at full charge, whose precise composition and operation will be determined by the technological evolution and availability.

In the period 2021-2030, the planned closing of electricity generation from any coal-fired power plants will continue, phasing out a total capacity of 11 GW. However, the PNIEC leaves the possibility of maintaining operational part of the capacity in the case of additional investments to comply with the EU framework. Nuclear will undergo the same phasing out process, whose reactors' closure is foreseen to start in 2025 and to be completed by 2035.

[2] PHES is generally distinguished in two different types namely "pure" and "pump-back" PHS. Pure PHS (also "closed-loop" PHES) refers to stations not receiving natural inflows, located far from streams, and purely serving energy storage purposes. Pump-back PHES (also "mixed" PHS) utilizes both stored water and natural inflows to produce electricity.

[3] Biogas, geothermal, marine energy, and renewables cogeneration.

3.2.1. Electricity generation per technology

The plan also presents the energy generated from each source, calculated by considering a specific capacity factors for each technology. This is express in terms of annual operating hours, or rather the energy generated in a year divided by the maximum possible power output of the installation. Table 3 illustrates the annual operating hours of the main technologies, as shown in the PNIEC. The values are consistently higher than the ones registered during the last few years. These will be illustrated and compared in chapter 6, with the analysis of the model assumptions.

Table 3: Annual operating hours assumed in the national energy plan (Ministerio para la Transición Ecológica y el Reto Demográfico, 2020).

	2025 Target	2030 Target	2025 BAU	2030 BAU
Eolic onshore	2.100/2.300/2.500	2.100/2.300/2.500	2.100/2.300/2.100	2.100/2.300/2.100
Eolic offshore	3.100	3.100	-	-
Existing CSP	2.558	2.558	2.558	2.558
New CSP	3.594	3.594	-	-
Photovoltaics	1.800	1.800	1.800	1.800
Cogeneration	4.825	4.609	5.145	4.845
Other REN	6.780	7.055	6.771	6.963

In addition, the national plan presents the value for the expected energy generated in the different scenarios. Since the focus of this analysis is the evaluation of the planned targets, Table 4 presents the numbers referring to the objective scenario.

Table 4: Annual energy generated in the target scenario according to the national energy plan [GWh] (Ministerio para la Transición Ecológica y el Reto Demográfico, 2020).

Years	2015	2020	2025	2030
Wind (onshore and offshore	49.325	60.670	92.926	119.520
Solar photovoltaic	8.302	16.304	39.055	70.491
Solar thermoelectric	5.557	5.608	14.322	23.170
Hydroelectric power	28.140	28.288	28.323	28.351
Pumping	3.228	4.594	5.888	11.960
Biogas	743	813	1.009	1.204
Geothermal energy	0	0	94	188
Marine energy	0	0	57	113
Coal	52.281	33.160	7.777	0
Combined cycle	28.187	29.291	23.284	32.725
Coal cogeneration	395	78	0	0
Gas cogeneration	24.311	22.382	17.408	14.197
Petroleum products cogeneration	3.458	2.463	1.767	982
Other	216	2.563	1.872	1.769
Fuel/Gas	13.783	10.141	7.606	5.071

Renewable cogeneration	1.127	988	1.058	1.126
Biomass	3.126	4.757	6.165	10.031
Cogeneration with waste	192	160	122	84
Municipal solid waste	1.344	918	799	355
Nuclear	57.196	58.039	58.039	24.952
Total	**280.911**	**281.219**	**307.570**	**346.290**

With the generation assets introduced above, and the correspondent energy generation presented in Table 4, the result regarding renewable share in the electricity mix is shown in Figure VIII. Aiming to reach 60% by 2025 and 74% by 2030, Spain will be required to put a big effort to achieve a net growth of +34% in 10 years, increasing by an ambitious 9% per year in the 2020-2025 period.

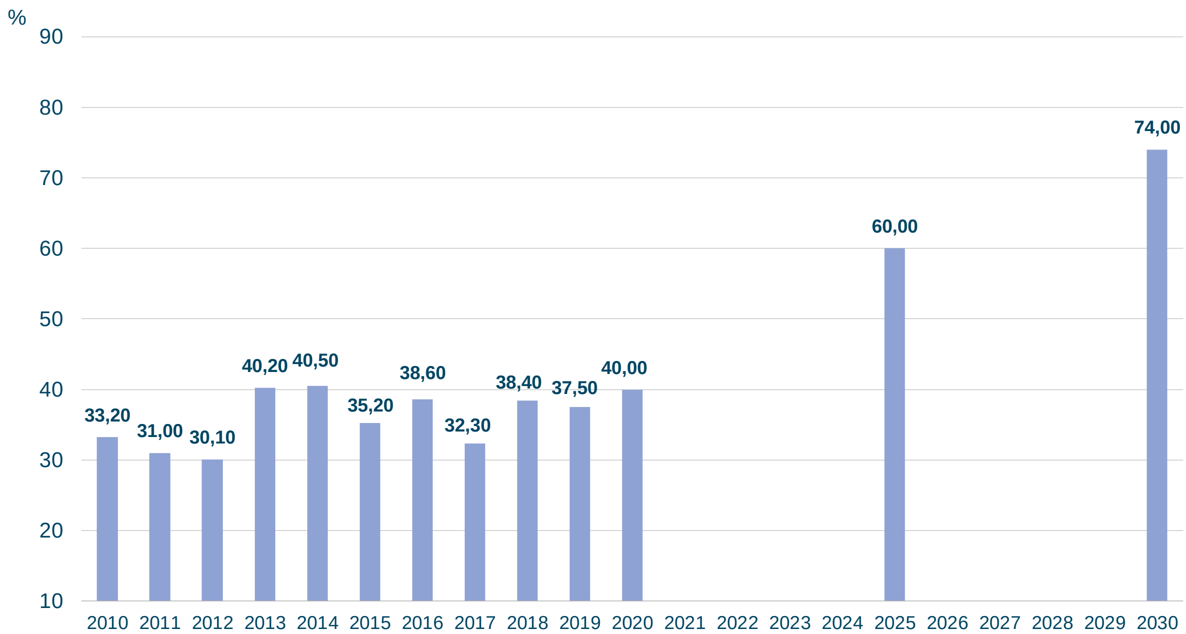

Figure VIII: Evolution of the renewable energy share in the Spanish electricity mix. Adapted from: (Ministerio para la Transición Ecológica y el Reto Demográfico, 2020; Red Eléctrica de España, 2020b).

3.3. Demand management and storage

The Plan seeks to make the system flexible by allowing demand and storage management to contribute to the security and quality of supply, reducing dependence. Both the development of storage and demand management are promoted to support the integration of renewables in the electricity sector.

Electricity demand management is the series of actions performed directly or indirectly by consumers themselves – energy services companies, large consumers, independent aggregators, etc. - on their energy demand in order to adapt it to follow the generation curve. Demand management is favoured by the coupling of sectors, i.e. the alignment with other uses of energy, such as electric vehicle charging, heat or cold generation for industrial or air-conditioning uses, hydrogen production, etc. that makes it possible to obtain flexibility in the electricity demand, while also making greener other sectors that not necessarily consume energy in form of electricity, such as transportation or heat generation.

With regard to storage, the National Plan foresees that by 2030 an additional capacity of 6 GW (including pumping and other storage technologies) will have to be installed, to provide greater capacity for managing REN generation and contribute to security of supply.

The decrease in the costs of renewable energy for electricity generation and storage is significantly altering the profitability assumptions for the different technologies, and therefore the future composition of the storage technology mix will depend on technology development and the relative merits of each alternative.

However, the current guidelines indicate that the technologies that will have to be developed are the following:

- Electricity storage, with and without electric vehicles, considered specifically for grid storage support. As outlined above, the technology is not defined, even though currently Li-ion represents the most promising one.
- Thermal storage, especially associated with concentrated solar power (CSP) installations, which increase their installed capacity by 5 GW between 2021 and 2030, and that have nine hours of storage using molten salt tanks.
- Hydroelectric storage. The use of non-flowing public water resources to generate electricity in any new concessions granted will prioritise the support for the integration of intermittent REN sources. To this end, reversible hydropower plants will be promoted to enable the management of renewable production, always under the conditions of respecting a flow regime that is compatible with the efficient management of water resources and their environmental protection. It is relevant to say that the application of new pumping operation schemes will be considered to take advantage of all the storage potential to provide flexibility for no-dispatchable generation systems.
- Chemical storage in the form of hydrogen, either by using electrolysis and consumption in fuel cells, or by mixing it with natural gas in the transmission network, which means exploiting the potential for coupling the gas and electricity sectors for joint demand management of both sectors.

The PNIEC outlines the necessity of developing a regulative and legislative framework that can adequately adapt the energy market to make investments in demand management and energy storage more attractive. The instruments to promote demand management can be economic incentives, the introduction of more efficient technologies and techniques, or influence on consumer habits.

The figure of the aggregator is proposed as solution. Different players can participate in services that are essential to the system through its figure, ultimately acting as a demand management planner. Similarly, to foster energy storage deployment, the definition of the storage operator in the sectoral legislation would prevent this figure from being penalised by being assimilated to a producer/consumer.

To ensure that the electricity system reaches the abovementioned storage capacity, a remuneration scheme has to complement the revenue generated on the energy markets, taking into account the degree of maturity of the different storage technologies. The design of these mechanisms has to be determined by capacity analyses carried out by the system operator over the different time horizons.

4. Modelling storage in energy systems

4.1. Usage of models in energy policy

The oil crisis in the 1970s arose the necessity of accurately assess the potential impact of macrotrends and unexpected events on the energy – thus the economic – infrastructure. Since then modelling has played a key role in energy policy, used by governments to analyse the complexity of energy issues and their dependence on third parties. Approaches to energy planning and policy require more sophisticated and analytical tools than the ones previously used (Munasinghe & Meier, 1993). Over the years, modelling has proved to be a powerful decision support tool.

When modelling energy systems, models are normally formulated using both theoretical and analytical methodologies coming from several fields such as economics, engineering, management science and operational research (Hoffman & Wood, 1976). This combination of methodologies allows to evaluate policies considering all their implications on both energy systems and the society. However, it is important to notice that models are all based on simplifications, assumptions and often require data which may not exist. Seen the uncertainties correlated with long-term energy policy planning, the identification of reliable strategies requires to take into account, among others, the stochasticity of natural phenomena and renewable output, international macroeconomic trends or public opinion, technology cost evolution and response to policy measures. Not taking into account these uncertainties or failing into catch them can make optimal solutions less meaningful from a practical point of view (Ben-Tal & Nemirovski, 2000). Consequently, optimal results from models must be treated extremely carefully.

Summarizing, whilst models are extremely powerful tools to analyse different policy options and economic scenario, their results must not be taken as undeniable truths. As the famous quote from G. Box goes: “All models are wrong, but some are useful”.

4.2. Optimisation

As explained above, models try to replicate reality with the aim of explaining how real world works through mathematical equations. Optimisation is a branch of applied mathematics interested in the maximisation or minimisation of a mathematical function under certain constraints.

Optimisation models are widely used in statistics, physics, engineering, economics, and policy making. This kind of models tends to have a structure characterized by three main elements:

- An objective function where minimisation or maximisation is often considered (i.e. cost and total welfare respectively). Financial and environmental goals can also be used.
- A set of decision variables that represent the output of the model.
- A set of constraints that ensure the feasible range of the decision variables.

Optimisation is known as an effective decision-making instrument when trying to find optimal solutions within complex systems.

Conventionally, deterministic models haven been used for planning electricity systems operation and expansion, for GHG emissions mitigation policies, and for the optimal electricity dispatch. In this kind of modelling, the parameters and coefficients are specified as deterministic, thus assuming supposed known values. However, these parameters present some degree of uncertainty in real energy systems, and the usage of sensitivity analysis to assess the potential impact of their variations on the output represents a powerful tool to give consistency to the model.

4.2.1. Optimisation in Energy Systems Planning

Over the recent decades, several optimization models were developed for aiding in the planning of the expansion and management of energy systems under multiple scales. The models were widely used for supporting an optimum allocation of energy resources and technologies under one or more specified technical or economic objectives.

For example, Kavrakoğlu developed a dynamic linear programming model for the planning of energy systems at a national scale (Kavrakoglu, 1981). Smith proposed a linear optimization model for the planning of New Zealand's energy supply and distribution system (Smith, 1980). Samouilidis et al. made a thorough evaluation of the modelling approaches for electricity and energy systems planning by designing a two linear optimization model - a global energy system model and an electricity generation subsystem - (Samouilidis et al., 1984). Kahane made a thorough review on optimization modeling for the management of various energy systems (Kahane, 1991). Huang et al. comprehensively investigated public policy discourse, energy systems planning methods, as well as relevant measures towards sustainable energy development in Canada (Liming et al., 2008).

4.3. Balancing curtailment and storage

As stated above, an important application of optimization models has been the planning of electricity systems expansion and the minimization of electricity dispatches' costs. The efficient integration of intermittent renewable energy sources in the energy mix, object of this study, can be approached with this methodology.

In this case the objective is not merely the cost efficiency, rather it is subject to the constraint of satisfying demand with a specific share of renewables. This constraint stems from the fact that, besides all renewables' benefits, this new way of generation also requires the solution of several technical challenges to achieve high penetration in the energy mix. Frequency regulation, ramping constraints, voltage control, consumption matching, and billing complexity suppose some of these challenges.

This project's focus is on consumption matching, or rather tackling the potential temporal mismatch of supply and demand. This consists in dealing with variable renewable energy at times when there is too much supply, and in serving demand at times when supply is scarce. Evidently, energy storage can provide a solution, allowing to shift energy over time.

The planning of an efficient electricity infrastructure that guarantees reliability with high share of renewables can be seen as the process of balancing energy storage and curtailment. As a matter of fact, the two extreme cases, in which either all surplus energy is stored or none, are unlikely to be the most economically efficient solution. However, the optimal requirements of energy storage can vary a lot depending on the dispatch strategy applied.

4.3.1 Program storage discharging

A variety of options of storage dispatch is available: (i) basic, (ii) time of day, (iii) peak-shaving.

(i) In the basic dispatch program, it is assumed that each hour the available REN generation is first used to supply as much of the load as possible. Whatever load remains is the “net load”. In case it is positive, the energy is supplied by the storage to the extent that there is enough energy stored.

(ii) In a typical utility situation, the load is supplied by a combination of generators, base load, intermediate load, and peaking plants. Power from peaking plants is more expensive than intermediate load plants, and power from those plants is more expensive than that from base load plants. Accordingly, it may be desirable to use stored energy as much as possible during the hours of the day when the load is generally higher.

(iii) Another approach to address the peak load problem is to use energy storage to keep a peaking plant from being on, and possibly to not even maintain it in function. Storage can be used for just that purpose with respect to the most expensive generation technology. In every time step, the amount of energy that is required to keep the most expensive generator off is determined. If there is enough energy stored, the most expensive generator is kept off and the required energy is taken from storage. This allows to avoid both the CAPEX associated with the over-capacity of the system and the running costs of expensive peaking plants.

5. Energy Storage

5.1. Technology overview

Energy storage can be achieved by converting electrical energy into another form. In fact, a typical manner for the categorization of storage technologies is the form of energy which electricity is converted in. In this sense, Figure IX presents a scheme illustrating the more common classification.

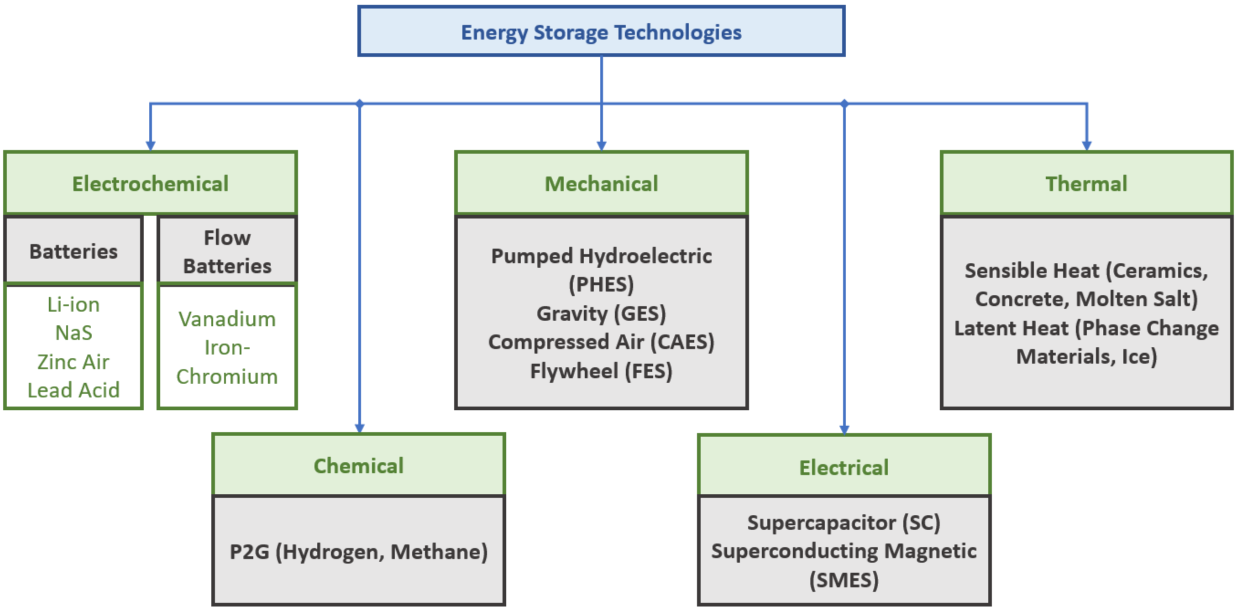

Figure IX: Map of storage technologies.

After a comprehensive literature review and analysis of tendencies for the most promising storage technologies, three were selected for the scope of the study. These represent the ones that offer the best combination of technical performance, cost efficiency and limited environmental and safety risks. Pumped hydro, Lithium-Ion and Hydrogen energy storage are the technologies selected. It is relevant to mention that these storage systems are also the ones on which the national energy strategy is based. Here below, a brief description of each one of these technologies is provided.

5.1.1. Electrochemical storage

Batteries are an advanced technique for storing electrical energy in electrochemical form. The flexibility they can offer in terms of operational voltage and current levels through series or parallel connections of cells makes them suitable for several applications. The most commonly used and most promising technologies are the following: lithium ion battery, sodium sulphur battery, sodium nickel chloride battery, vanadium redox battery, iron chromium battery, zinc bromine battery, zinc air battery, lead acid battery, nickel cadmium battery. For grid time shifting - on either the utility or customer side of the meter - and for frequency regulation services, the technology with better perspectives - and ultimately selected for this study - is the Lithium ion (Li-ion) battery. These batteries use lithium metal or lithium compound as anode. The Li-ion batteries are lighter, smaller and more powerful than other batteries which make it especially attractive for consumer electronics. Their energy and power density range from 90 to 240Wh/kg and 500 to 2000 W/kg. They also have high efficiency and low self-discharge rate making it suitable for EV solutions. Their major drawback is that they are fragile with temperature dependent life cycle. They usually require a special protection circuit to avoid overload.

5.1.2. Mechanical storage

Mechanical storage is the most diffuse strategy for storing energy at grid level. It basically consists in converting electrical energy in either kinetic or potential – gravity or pressure – that are forms of energy easily storable. Examples of mechanical based energy storage systems include flywheels, pumped hydro energy storage, gravity power module, compressed air energy storage, liquid-piston energy storage. Pumped Hydroelectric Energy Storage (PHES) is the most mature and widely used large scale energy storage technology. According to the Electric Power Research Institute, PHES makes up more than 99% of the global large-scale energy storage installation. The functioning principle is gravity-based, it charges by pumping water uphill and discharges by realising water downhill to the lower reservoir through turbines. The time response is relatively short (typically within 1 minute), and its efficiency is in the range of 65–85%, with some installations claiming to have achieved an efficiency of 87%. PHES systems can be either incorporated into natural lakes or reservoirs or can be constructed independently of existing natural water sources, as pure storage systems. One limitation of PHES is that it requires specific natural geological features to be accommodated.

5.1.3. Chemical Energy Storage (CES)

Chemical energy storage envelopes all technologies where the electrical energy is used to produce chemical compounds which can be stored and used when needed for energy generation. Most chemical compounds which are used as energy storage media has higher energy density than pumped hydro and CAES and this makes them an ideal energy storage medium. There are several chemical compounds which are currently been considered for energy storage application. They include hydrogen, methane, hydrocarbons, methanol, butanol, and ethanol. Butanol and ethanol are mainly produced through fermentation of biomass and thus are not considered as electrical energy storage technique. Amongst the remaining listed compounds, hydrogen is regarded as the shortest route to chemical compound from electricity. Hydrogen is produced through the electrolysis of water and all other compounds (i.e. methane, hydrocarbons and methanol) can be produced from hydrogen in the presence of a carbon source such as CO and CO2 using the Fischer-Tropsch synthesis (Djinović & Schüth, 2015). For electricity generated through fossil fuels, it is worthless to store the electricity by hydrogenating CO2 to produce liquid hydrocarbon or methanol as this can lead to too many losses. Hence, the conversion of the hydrogen directly to electricity should be the most promising technology. Hydrogen energy storage is one of the most popular chemical energy storage systems. Hydrogen is storable, transportable, highly versatile, efficient, and clean energy carrier. It also has a high energy density. For energy storage application, off peak electricity is used to electrolyse water to produce hydrogen. The hydrogen can be stored either as compressed gas, liquefied gas, metal hydrides or carbon nanostructures (Aneke & Wang, 2016). The choice of the storage technology depends on the characteristics of available technologies in terms of technical, economical, or environmental performance. During the discharge phase, the stored hydrogen is either used in fuel cell or burnt directly to produce electricity. One major drawback in using hydrogen for electricity storage is the substantial energy losses during a single cycle. For example, electrolysis currently have an efficiency of 60%, transport and compression for storage may lead to another 10% efficiency loss (although this can be lower) while reconversion to electricity has a efficiency of about 50% for fuel cell application (higher efficiency is anticipated for combustion based power generation if cogeneration of heat is integrated). Thus, the overall round trip efficiency may be in the neighbourhood of 30%. This is partially compensated by the high storage density (Aneke & Wang, 2016).

5.2. Mapping of energy storage applications

Energy storage has been considered of great interest to electric utilities for a long time because of the potential functionalities they offer to support the electric grid. Traditionally, load levelling was considered one of the most important services provided by energy storage as it enabled the reduced use of expensive peak energy generation systems. However, with the high integration of renewable energy systems, this application has been extended to include other functionalities to support the intermittent nature of renewable energy sources. For example, electric utilities have recently started considering energy storage as an alternative to power grid system upgrade as it contributes to the optimization of its infrastructure and hence defers the development and installation of new electric power lines (Berrada & Loudiyi, 2019).

The continued interest in the development and deployment of energy storage systems is driven by the growing importance of the potential services provided by these systems. These functionalities can be classified into the following categories:

- Energy supply
- Power grid operations
- Grid infrastructure
- End user
- Renewable energy integration

Energy storage has become an important component of the traditional electricity value chain, which consists of energy source, generation system, transmission and distribution (T&D) system, as well as end-user side. Because of the rich spectrum of services it provides, energy storage has created a more responsive energy market (Kousksou et al., 2014).

5.2.1. Energy Supply

The benefits associated with electric supply provided from energy storage include energy time-shift and energy supply capacity.

i) Energy time-shift

This service involves the charging of the storage system when energy prices are low; the stored energy is later sold at higher values during peak energy demand. The objective behind the use of energy storage for time-shift application is the utilization of low-priced electricity during periods of high energy prices. During peak demand, the cost of energy production is high due to the use of peaking power plants. Therefore, the stored energy comes from baseload generation systems such as combined cycle plants whose production of energy has to remain constant, from wind plants whose generation outputs occur during periods of low energy demands, or from energy generation systems whose incremental cost of energy production is low such as hydroelectric and geothermal power plants (Energy Storage Association, 2018). Electric power utilities may use electric time-shift service to decrease energy-related cost driven by i.e. the need for generation fuel. This service may be used also by commercial owners of energy storage to make profit from buying low-cost wholesale energy and selling it at higher prices.

ii) Electric supply capacity

Providing energy supply capacity is another service offered by energy storage. Electric supply capacity is reduced by energy storage discharged power. The main objective of this storage functionality is to reduce the need for power generation equipment. The deferred energy supply capacity resource includes expensive and less efficient combustion turbines, combined cycle generators, and natural gas baseload generation. Electric power utilities may use energy storage to provide electric supply capacity to decrease capacity-related costs. This service may be used by owners of energy storage plants to make profit in a capacity market.

5.2.2. Grid Operation

The use of energy storage enhances grid operation by providing what is known as ancillary services. These services are defined as functionalities necessary to maintain and support the operation of the transmission system in a reliable manner. Energy storage systems are well positioned to provide various ancillary services needed for a reliable and stable electricity grid. The provision of ancillary services by energy storage reduces the use of other generation systems and fuel and decreases air emissions.

i) Load following

During period referred as peak hours or shoulder hours, energy storage provides load following. Load following up is offered by discharging more energy from the storage, whereas load following down is performed by increasing the charging of the system. An increase of energy demand requires energy storage to provide load following up by increasing the discharged energy. Conversely, a decrease of energy demand leads to a reduction of generation output to provide load following down. Load following service offers a number of benefits such as reducing the need for other energy generation systems, energy production variability and fuel use, as well as negative environmental impacts (air emissions).

ii) Frequency regulation

Frequency regulation, also known as area regulation, is an ancillary service whose aim is to match moment-to-moment energy demand and supply. The main objective of this service is to maintain the stability of alternating current frequency within a certain area. During excess energy supply, frequency regulation down is required to balance the demand with the supply. Contrariwise, frequency regulation up is necessary when energy supply is momentary less than energy demand. The significant penetration of renewable energy systems in the electric grid such as wind and solar energy technologies will cause energy generation output to vary along with energy demand. Frequency regulation service is offered by energy storage in a similar manner to load following, however different technologies are better suited for this application, and specifically the ones that are characterized by high energy efficiency and small time of response.

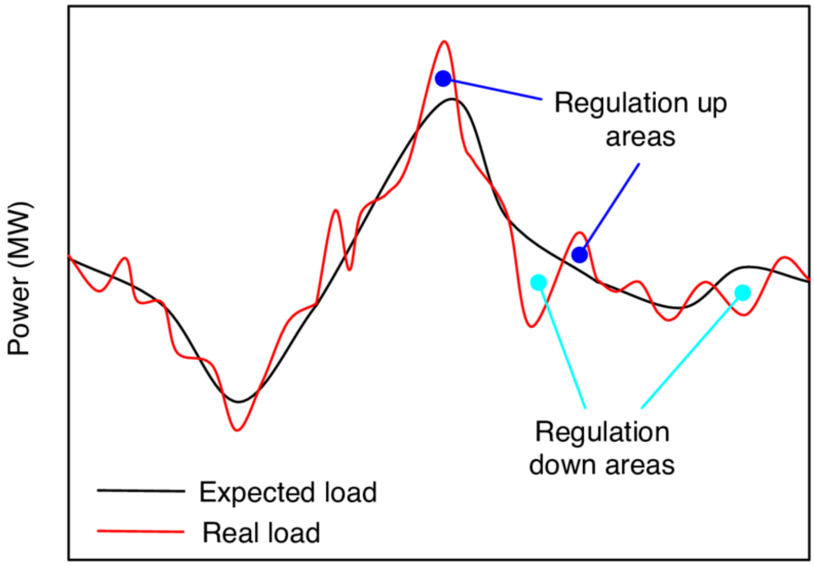

Figure X: Example of frequency regulation (Escudero-Garzas et al., 2012).

iii) Frequency response

Frequency response is an ancillary service, which can be provided by energy storage systems with a very fast ramp rate. The role of storage is to control the frequency and respond to anomalies over the time span of milliseconds. The purpose of this service is to maintain frequency close to the targeted one. The difference between frequency regulation and frequency response is that the first service responds indirectly to frequency with the use of control signals which reflect the variation between energy demand and supply, whereas the second one controls AC frequency directly. In addition, the response time of the aforementioned services is different. That is, the variation of output from resources used to provide frequency response should be faster than the output variation of other resources performing area regulation service. Only few systems are characterized by a fast ramp rate, among them energy storage. Fast storage systems are perfectly suited for frequency response application. The use of these devices in the power grid offsets the need for quick response generation resources.

iv) Ramping

Ramping refers to high changes of energy output ranging from few seconds to minutes. A good example could be variation in wind power generation due to quick changes in wind speed, which results in ramps up or down outputs. Power system operators have to deal with this challenge to ensure the stability of the grid. The impact of ramping increases as more renewable energy generation systems are integrated into the grid. Resources involved in ramping services should hence be capable of providing energy output variability by increasing or decreasing output to match changes in energy generation. Most conventional generation resources are not very well suited for this service as they should be characterized by a rapid varied output, whereas energy storage is an interesting solution since it provides both ramping up and down options. By reducing storage charging or/and increasing the discharging of this, energy storage offers ramps up. Inversely, by increasing storage charging or/and decreasing its discharging, the system offers ramping down service.

v) Reserve capacity

Reserve capacity is a backup energy generation capacity that is used by the electric grid in the occurrence of unexpected fault, such as the unavailability of a power plant. Energy storage systems can both participate in the current capacity market or reduce the capacity auctioned. This service is divided in three categories:

- Spinning reserve: Also referred as synchronized reserve, this type of reserve capacity is the first one used during the occurrence of a shortfall. It is an unloaded online generation capacity used for compensation of transmission or generation outage. It has a response time of 10 min.
- Supplemental reserve: This type of reserve capacity is used after spinning reserve. It may be an offline generation capacity, which can respond within 10 min.
- Back supply: It is considered as a backup for both supplemental and spinning reserves.

vi) Voltage support

Maintaining the stability and the required voltage level of the electric grid is the most challenging technical work of grid operators. These aspects are achieved through proper management of reactance at the grid level. Electric grid operators make use of voltage support, which is an ancillary service to manage grid reactance. Historically, this service has been provided by generators through the production of reactive power. Today this service is always more often offered by new technologies, such as power electronics, energy storage, and control and communication systems. Distributed energy storage systems located close to end users are well suited for this grid application and have gained great interest. The main reason behind the use of distributed storage for such service is because reactive power is not transmitted effectively over long distances. Therefore, voltage support is well provided by distributed storage located in regions where most reactance happens.

vii) Black start

Back start system refers to units able to energize the electric grid after an outage. These systems are capable of starting up on their own without the provision of power from the grid. Most energy storage systems are able to provide this service and are classified as black start resources due to their ability to operate without a need for any special equipment.

5.2.3. Grid Infrastructure

Energy storage is expected to play an important role not only in the power grid but also as an important asset of the utility T&D system because of its modularity, flexibility, and operational characteristics. It increases the performance of T&D facilities, by improving their carrying capacity and their reliability. Furthermore, energy storage can be used to avoid T&D congestion, extend the life span of T&D equipment, and defer the upgrade and the use of additional T&D capacity and equipment.

i) Transmission support

Energy storage systems are used to support transmission by improving the performance of the T&D system. This is done through compensating for power disturbance and anomalies, such as voltage instability and sags. Transmission support benefits are highly dependent on the site and its location.

ii) Transmission congestion management

During peak demand periods, a high number of transmission systems are congested due to the increasing use of distributed energy resources and renewable energy generation. The addition of transmission capacity does not keep up with the growing deployment of renewable generation, which results in charges associated with transmission capacity congestion. To avoid these charges, utilities or end users should make use of energy storage system. This can be sited near the congested part of the transmission system to reduce transmission capacity congestion. In the absence of transmission congestion, energy storage is used to store energy. During peak demand, load is served by the stored energy, which is discharged from the storage system, hence, reducing the need for energy, which must be provided by the transmission system.

iii) Transmission and distribution upgrade deferral

Upgrade investments in T&D system can be delayed or avoided by the use of energy storage. This energy storage service is known as T&D upgrade deferral. It could be that at a specific time of the day, peak demand surpasses the loadcarrying capacity of the T&D system. A typical solution to avoid this problem is increasing the T&D loadcarrying capacity few years before the occurrence of this expected overload. It should be noted that extra capacity cannot be practically added to the T&D system. Rather, the existing equipment has to be replaced by equipment with higher rating capacity. Another alternative could be the addition of much equipment to increase the capacity of the existing one. The use of energy storage as an alternative to T&D upgrade has gained attention in recent years. Energy storage systems are placed downstream the T&D overloaded equipment to lessen peak demand, which has to be provided by the aforementioned equipment. The benefits received from performing this T&D service are interesting and can be in the range of hundreds of dollars per kW per year. More details about T&D upgrade deferral benefits are found in a study conducted by Sandia National Laboratories (Eyer, 2011).

iv) Transmission and distribution equipment life extension

Very much like T&D upgrade deferrals service, T&D equipment life can be extended by the use of energy storage in the grid. By reducing loading, energy storage can reduce the existing equipment wear and extreme heating, thus, extending their expected useful life span. For example, the use of storage can extend the life of underground distribution cables by decreasing their peak loading and hence reducing the insulation degradation of the cable and reducing the occurrence of ground faults, which may have a negative effect on the cable lifetime. This is an attractive storage service especially when equipment is located in populated and developed regions characterized by high replacement costs. This high investment could be delayed especially if the occurrence of the highest loads on a T&D system node is only few hours per year. Additionally, the use of energy storage is more attractive when it is located in areas with uncertain load increase.

v) On-site power

A high number of electrochemical batteries are owned by electric utilities for the provision of on-site power back up at substations. During the unavailability of grid power, energy storage systems are operated to deliver power to control and communication equipment.

5.2.4. End User

Energy storage owned by end users could be used for a number of applications. Customers can use energy storage to control their energy bills and make profit through power purchase agreement for ancillary services, energy, and capacity in the spot market. Likewise, power merchants can aggregate on-site storage systems for the provision of other applications. A number of benefits can be received from the use of end-user sited energy storage system such as management of time of use (TOU) energy cost and demand charge, as well as electric service reliability and power quality. The two first services enable the end user to manage his bill by reducing TOU energy cost and demand charges. Whereas the two other services are complementary as they allow customer to ensure reliability and power quality of the electric service and hence avoid costs.

i) Cost management

Cost associated with TOU energy can be reduced by customers with the use of energy storage. This can be done by charging the storage when the retail energy price is low during off-peak energy demand. The stored energy is used during periods of high energy demand when its price is high. This storage application is very similar to the application of energy time-shift, also known as arbitrage. The qualification of energy end uses depends on the type of retail tariff involving energy prices, which represent time-specific rates. Tariffs for energy TOU include rates that are particular to energy time-of-day, day of week, and season (usually summer and winter).

ii) Demand charge management

An interesting energy storage application for end users is demand charge management. The objective of this application is the reduction of energy demand with an aim to offset or avoid peak energy demand charges. Utility tariffs for commercial end users include distinct charges for power and energy; that is why the opportunity of managing demand charge exists. Demand charges (power-related) are evaluated based on the maximum power used by the customer. Similar to TOU energy, energy charges are also particular to time of day, season, and day of week. To avoid demand charges within a given period, demand should be minimized during all peak-demand periods. Energy is stored during periods of low demand charges to reduce energy purchased from the grid when demand charges are high.

iii) Electric service reliability and power quality

Energy storage systems are commonly used to avoid electricity interruption and ensure electric service reliability and quality. In these terms, the role of storage is to guarantee continuity of supply in case of an outage, and to protect the equipment from the impact of grid poor power quality. The main causes of poor power quality include variation of voltage (dips, sags, surges, or spikes) and electrical noise that is the occurrence of oscillations and high frequency transients. The benefits received from the use of energy storage in electric service power quality are based on avoided charges associated with damage of equipment, substandard equipment operation, and equipment downtime (Berrada & Loudiyi, 2019).

5.2.5. Renewable Energy Integration

As far as renewable integration is regarded, in this thesis the focus has been on effectively time-shifting the energy generated from REN energy sources to reduce the use of conventional generation systems. Nevertheless, energy storage can address several other issues that come with the integration of high quantity of intermittent REN – such as power output variability and undesirable electrical impact on the grid. In fact, the short power output variability of renewable energy systems, due to i.e. inconsistency of wind speed or clouds, needs to be offset, and energy storage, as illustrated in Grid Operation, can provide this service. Nonetheless, storage can be used to address other power quality issues resulting from renewable integration, such as voltage variability. Thus, renewable energy systems and energy storage are considered somewhat complementary as they have several synergies that can be summarized in the following:

- Reducing the use of conventional energy generation systems.
- Avoiding power quality anomalies.
- Enabling the integration of variable RE systems.
- Reducing the use of a number of power-conditioning equipment.
- Increasing the value of energy produced by REN sources.

Figure XI represents a graphical recap of the main storage applications, categorized by the beneficiaries (on the left side) and the duration (on the upper side) of the services provided.

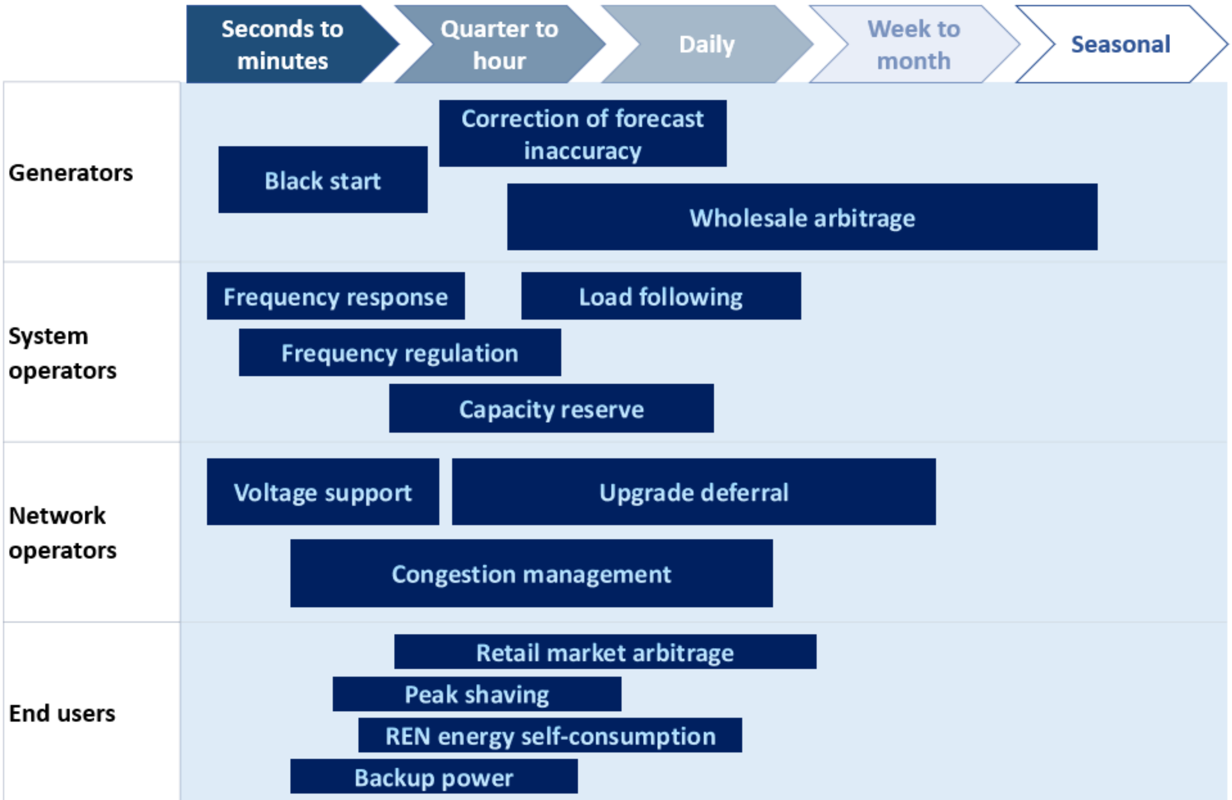

Figure XI: Summary of storage applications in each part of the electricity value chain.

5.3. Worldwide storage deployment

For the first time in nearly a decade, annual installations of energy storage technologies fell year-on-year in 2019. Around the globe, 2.9 GW of storage capacity were added to electricity systems – almost 30% less than in 2018. The factors behind this trend underline how much storage remains an early-stage technology, present in only a few key markets and heavily dependent on policy support. As a matter of fact, Korea, USA, China and Germany together account for more than 60% of the capacity installed in 2019 (Figure XII).

In 2019 grid-scale storage installations dropped 20%, while behind-the-meter storage remained flat overall despite a near-doubling of residential batteries, consolidating a shift towards behind-the-meter storage. This trend is particularly strong in Japan, with the phaseout of the solar feed-in scheme – which rewarded the export of self-produced power to the grid - acting as a catalyst, California and Australia, where growth in storage for back-up power was largely prompted by concerns over grid resilience to wildfires.

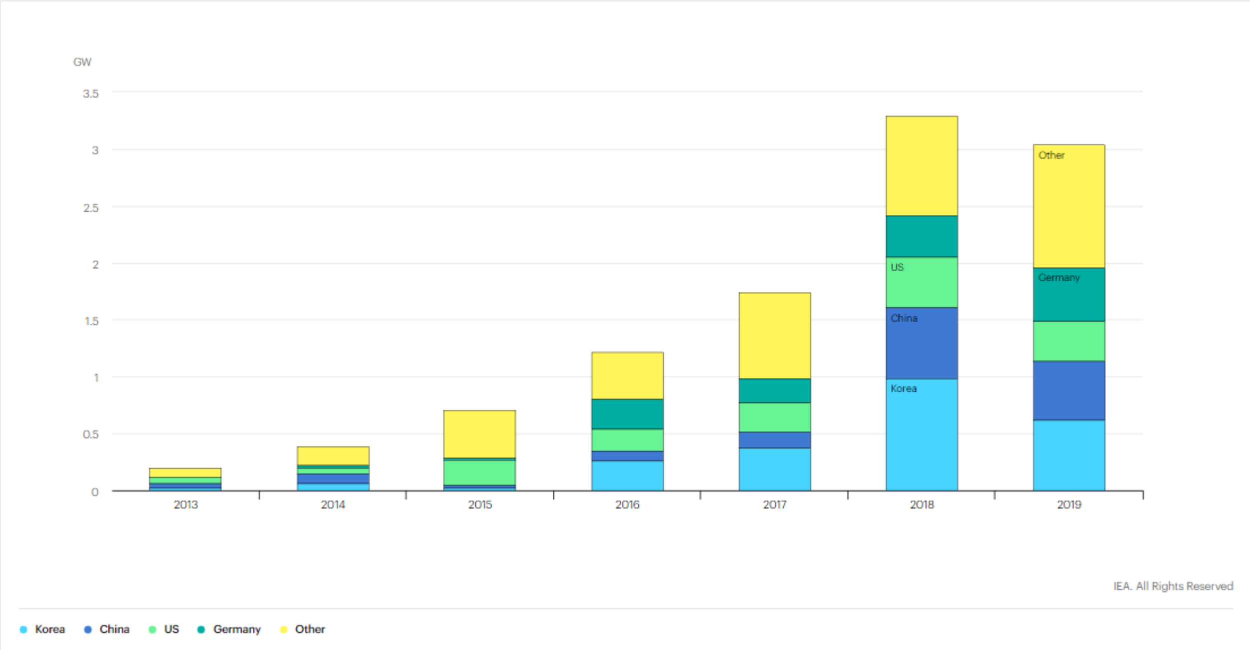

Figure XII: Annual energy storage deployment by country, 2013-2019 (IEA, 2020).

A key driver of growth in energy storage has been the co-location of renewable energy production facilities with energy storage assets, which stabilises production and ensures firmer capacity during peak demand periods. India explicitly began rewarding this application in 2019 with a 1.2-GW auction of solar-plus storage, mandating storage capacity for 50% of generation installed. Same occurs in the United States, with co-located storage projects with solar PV could encompass as much as 15 GW in the near future.

In Europe, the Clean Energy Package has defined storage as an entity separate from generation and consumption, preventing it from being double-taxed when charging and discharging. Nevertheless, continued uncertainty in Korea – a key growth market - due to growing concern over several fires at grid-scale storage plants, as well as the storage capacity installation rate in Europe that slowed by 40% year-on-year, highlighted how fragile growth in these technologies remains, as they continue to depend heavily on policy intervention through direct support or market creation.

As far as technology is regarded, with 153 GW pumped hydro storage systems account for the majority of storage capacity, while battery storage systems total around 4 GW (IEA, 2018). However, while pumped hydro storage is projected to grow in the next decade, the technology deployment is constrained by geological requirements.

On the other hand, battery storage systems do not present strict limitations to their deployment, and their modularity makes them suitable for several applications. In recent years lithium-ion is the most widely used technology, making up the majority of the new installed capacity. Benefitting from the indirect effects of innovation and cost reductions in electric mobility applications, around 60% of grid-scale batteries are nickel-manganese-cobalt blends – the technology of choice in EVs (IEA, 2020).

As supply chains advance to the next higher-performing blend or chemistry, technology that may become less attractive for EVs can be deployed at a lower cost for stationary applications on the grid, and this trend that sees lithium-ion as the main player could be consolidating. As a matter of fact, lithium iron phosphate batteries were used for the majority of grid-scale installations in 2019 in China because the government tightened energy density requirements for EV batteries, and the resulting manufacturing overcapacity in this relatively lower-density technology was shifted to grid-scale applications.

However, lithium-ion is best suited for applications that require short-term storage. For applications with longer storage durations other battery types, including sodium sulfur and especially flow batteries, are playing an increasing role, attracting interest all over the world.

6. Model

For this dissertation, a linear deterministic optimization has been developed. The model is based on existing energy infrastructure modelling techniques, such as in ref. (Steffen & Weber, 2013; Zerrahn et al., 2018). As such, it is structured to find, from an economic perspective, the least-cost solution, that is, the cost-minimal combinations of energy storage and curtailment. This approach addresses both challenges of renewable energy integration. First, it determines efficient energy generation and storage capacities to fulfil demand at any point in time. Second, it delivers the optimal dispatch strategy to the trade-off how much and when renewable surplus energy to curtail, and how much and when to store.

The model has been developed to include new features, such as the optimization of the generation curve by giving more degrees of freedom in terms of generation technologies, the combination of different storage technologies to take advantage of each specific characteristic, as well as other flexibility options as demand response, and the technical requirements of the system, such as the correlation between rotational inertia and frequency reserve for ancillary services. Inevitably, some simplifications have been made to obtain a modelling environment that could be more effective in providing answers to the problems assessed. The main ones can be summarized as:

- The model assumes to have complete information, thus being able of forecasting with good accuracy demand and generation capacity of each technology, in order to optimize storage dispatch.
- The development of grid infrastructure and the distribution of renewable generation allow to avoid transmission and distribution constraints, which goes in parallel with an adequately distribution strategy of the generation capacity to be installed as a result of the study.
- Imperfect competition and markets dynamics are not considered. The problem is optimized within a system perspective, without considering agent behaviour of the different companies and agents involved in the market. The results of the model can be interpreted as long-run equilibria under the assumption of perfect competition and complete information. The model mimics a first-best social planner approach.
- No stochastic evaluation of demand and renewable generation is performed. The stochasticity is taken into account by working with sufficiently large timeframes and considering the variability historically registered.

This optimization model aims at being an effective decision-making instrument when planning electricity systems expansion. It can be referred to as a deterministic optimization model with several variables. While modelling, the parameters and coefficients are specified as deterministic (a supposed known value). Although not entering in behavioural analysis or grid modelling, the model represents how, under the assumptions illustrated above, high penetration of renewable energy sources can be achieved in a reliable and cost-efficient manner. This translates in the fact that this model does not aim at forecasting future energy system behaviour, rather aims at being a tool for the elaboration of regulatory frameworks and alternative markets, such as for capacity, showing the most cost-efficient infrastructure to reach the goals set in terms of reduction of the emissions in the electricity sector.

The assumptions, thus the model, would gain further consistency if the results were used to plan renewable and flexibility technologies auctions with geographical and technological specifications, providing a reliable green generation infrastructure and lower investment costs of the system.

This section is divided in four subchapters. First, a detailed explanation of the definition and structuring of the model is presented. Then, the process of definition of the hourly parameters representing renewable generation and demand is presented, followed by the techno-economic characteristics of each technology, resulted from an extensive literature review. Lastly, the mathematical representation of the model – the entire code is included in the annex for completeness of information – is presented and analysed.

6.1. Methodology

When developing energy policies, one of the major concerns is GHG emissions. Often the reduction of the emissions is set as a target and a strategy is developed around that goal. Similarly, the model aims to satisfy demand with a specified share of renewables as target, seeking economic efficiency from a system perspective. The model, based on the generation system existing at the end of the year 2019, evaluates the new generation and storage capacity required to integrate high shares of renewables taking into account all the costs and operating characteristics of the different technologies considered. As far as the existing generation capacity, it is considered that the capacity of wind, solar photovoltaic, hydroelectric, solar thermoelectric, biomass, biogas and urban solid waste technologies that reach the end of their useful life will be repowered to either a greater or equal degree. The costs of dismantling generating units currently in service and not considered in the scenario to be evaluated, possible costs of extending the useful life of generating units or other factors (tariffs, taxes) that may form part of the generation's supply strategy are not considered. In relation to the new technologies considered in the model, it has been assumed that these will be solely renewable energy systems, storage facilities, demand response and combined cycle gas turbine power plants. Specifically, the technologies considered are the following:

- Photovoltaics
- Wind energy
- Concentrated Solar Power
- Li-Ion batteries with 3 hours of storage capacity
- Pumped hydro energy storage
- Hydrogen energy storage
- Demand response (load curtailment and load shifting)
- Combined Cycle Gas Turbines

The different generation technologies, both existing and new, have a defined operating profile through the availability factor. This is expressed as a percentage and relates the hours when the technology is available during a period to the total hours of that period. The definition of availability factors in each time period is especially relevant in the case of renewable energy generation technologies, which will have greater or lesser availability depending on the availability of the resource they leverage to generate electricity. Thus, there will be technologies that are less available at times when electricity demand is high, and others, on the other hand, where their greater availability coincides with peak demand hours, depending on the season of the year and the period considered. For the development of this study, the availability factors have been extrapolated from the historic performances of each technology. In the case of conventional generation technologies, availability factors per period are usually constant, depending only on the hours when the technology ceases to be available due to maintenance activities, technical restrictions, or other causes. In the following subchapter - that presents the hourly parameters - the process of elaboration of these data is illustrated.

As indicated above, the study does not consider grid restrictions, assuming that the transport and distribution infrastructures are sufficiently developed as presented in (Ribó-Pérez et al., 2019), and the generation and storage facilities are optimally located. The electricity system is modelled as a single node system, including Baleares Islands, although account is taken of the losses inherent in the network, as well as the different cross-border connections and the expected increase in their capacity. It is important to stress that the model assumes that the transmission network of the Spanish peninsular system will have sufficient capacity to evacuate all the modelled generation and transport it to the points of consumption. This will require the development and adaptation of that grid, so that renewable curtailment or additional needs for thermal generation in the internal network are minimised and the distortion to this single-node assumption is minimized.

Regarding interconnections, these were stylized and seen as an ultimate resource for imports (most expensive solution to satisfy demand) and as a low profitable activity in the case of imports. These assumptions derive from the necessity of avoiding the modelling of the infrastructure planned in neighbouring countries and their future demand, which would have made the model more complex and subject to even more variables and assumptions, not necessarily improving the quality of the results as the energy planning is currently being dealt within countries. Also, it is unlikely that a country is going to rely on foreign generation power plant - even if at a European level – since it could mine the supply security of the country for either technical problems at the interconnections or the inevitable choice of prioritizing own country interest in case of shortage of energy resources, or simply generate an economic disadvantage at the moment of taking advantage of higher electricity prices. In the interconnection’s section more details regarding the elaboration of the assumptions for the interconnections are provided.

Future electric grid might be more vulnerable to frequency contingencies due to higher penetrations of renewable energy generation along with retirements of synchronously connected generators. Without a consistent supplementary supports such as frequency triggered battery energy storage systems (BESS), insufficient rotational system inertia can lead to extreme frequency deviations including high rates of change of frequency (ROCOF) in the event of an imbalance between generation and demand (Mehigan et al., 2020). A high ROCOF event that exceeds the tolerances could lead to involuntary shedding of customer load and generation.

System inertia can be defined as the amount of stored kinetic energy from direct (synchronously) connected machines that offer resistance to any change in the frequency at the centre of inertia. The inertia from France alone is currently more than sufficient to provide the inertia required for the CE synchronous area for the most severe constraint to limit ROCOF to 0.5 Hz/s (Mehigan et al., 2020). However, in the long run, dismantling nuclear power plants, France will not be able to generate enough inertia for Spain. In the simulations presented, a correlation between the rotational inertia and the frequency reserve requirements has been implemented in order to guarantee the dynamic stability. Power-frequency control reserves was set to be satisfied only with storage, demand response and conventional power plants, and it was assumed that half of it is activated.

Storage technologies do not represent the only flexibility providing solutions. Utilities have been recently showing increasing interest in developing Demand Response (DR) programs in order to match generation and demand in a more efficient way. Incentive- and price-based DR programs aim at enabling the demand side in order to achieve a range of operational and economic advantages, towards developing a more sustainable power system structure. In the model account is taken for load curtailment and load shifting, with the specific purpose of evaluating how optimal storage requirements vary under different scenarios of penetration of DR programs.

The model has been built in Python, utilizing an open source library called "Pyomo", that allows to write lineal optimization problems in an algebraic manner and to solve them by means of external solvers, such as GUROBI, used in this thesis under the academic license. The model minimizes the global generation cost to determine the optimal dispatch to satisfy demand of the electrical system considered. The model ability to perform storage coordination in economic dispatch makes it possible to carry out complex studies to minimise thermal generation costs through hydroelectric generation or optimised management of pumping or battery storage resources.

The model is used to study the storage requirements while increasingly decarbonizing the energy mix and to assess whether the national energy strategy's objectives can be reached by means of the planned infrastructure. In each simulation, a complete assessment of the generation dispatch of the Spanish system during each hour of the timeframe considered was carried out, respecting all restrictions. As a result, the marginal cost values and the energy balance values are obtained, with a detailed schedule. Nuclear is considered in the model, as is renewable generation, with zero variable cost, which gives them priority for dispatch over other technologies. It is very important to stress that cost results should not be interpreted as prices, since the model only considers the marginal cost of each technology.

6.2. Hourly parameters

The process of defining the demand and hourly capacity factors of renewable facilities is presented in this subchapter. These are provided as input for the model for each hour of the timeframe simulated. To consider a sufficiently wide range of situations, the simulation timeframe is set to be at least 4 years, during which the demand and renewable generation profiles never repeats.

6.2.1. Demand

The demand considered in the study is the electricity demand deterministically estimated in the PNIEC's 2030 Target Scenario and adapted to the peninsular electricity system by removing Canarias Islands, which do not present interconnections with the Spanish peninsula.

The initial simulations, mainly used for sensitivity and validation, are based on the hourly demand from 01/01/2016, 00:00 to 31/12/2019, 23:59. This data can be found in www.esios.es, and are provided by REE. The model was also tested on data presenting higher resolution, considering timesteps of 10 min, but it was found that the variation of the results is not relevant for the type of study, therefore not offering a proper trade-off for the longer time of execution.

The demand for the object of the study, or rather the 2030 Spanish electricity system, comes from www.ENTSO-e.eu. The European Network of Transmission System Operators published different scenarios for each country in which its members operate. These scenarios take into account different variables, such as the level of integration of renewables and historic climatic data. The one selected for the study is the DG scenario (Distributed Generation), since also the Spanish PNIEC has been built around this case. This distributed generation scenario corresponds to a scenario of prosumers as central figures in the System, small-scale renewable generation, large-scale implementation of batteries and an empowered society committed to the energy and power transition, which changes its consumption habits and its energy vector towards electricity. The three different climatic variations presented by ETNSO-e are considered by queuing them up, and, in case of simulations longer than three years, repeating them (All simulations last at least 3 years, demand is repeated if the simulation works with longer time periods). Figure XIII illustrates the hourly demand for each month and in each of the climatic variations presented by ENTSO-e. From the box-and-whisker diagram, it is clear that the climatic variations affect demand especially during the coldest months - January, February and March. However, when comparing the total demand on a yearly basis, the difference between the three climatic scenarios is very small, accounting for less than 1% of the total demand.

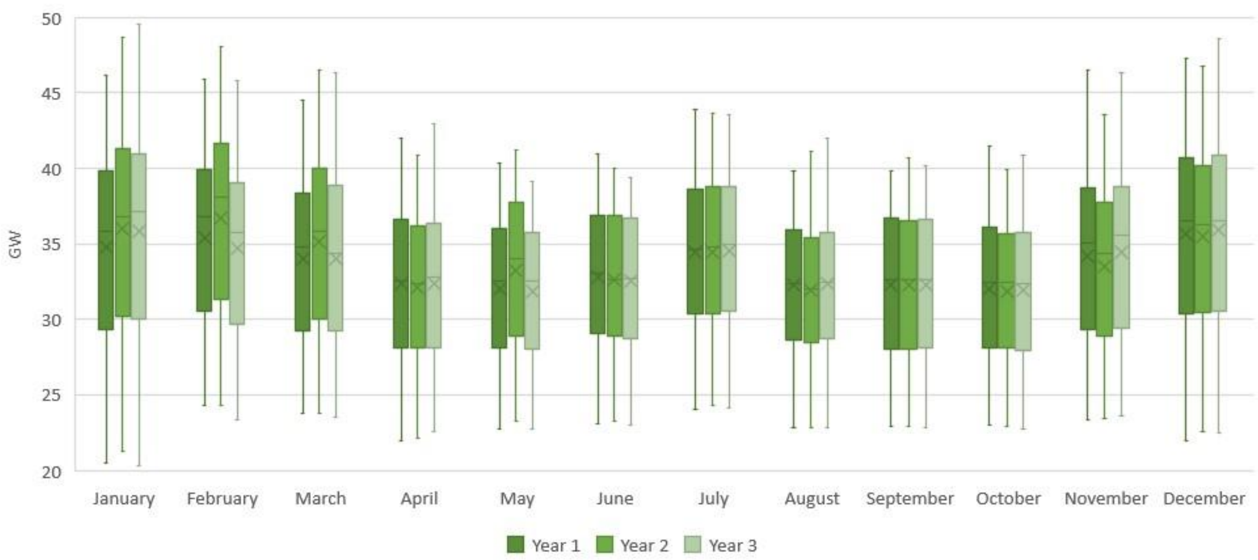

Figure XIII: Energy demand in the ENTSOE-e DG scenario (Based on data set of ENTSO-e).

On these data, a consistency check has been done with the demand data presented in PNIEC. The average yearly demand of the DG scenario considering the three years climatic variations is 294.6 TWh. Figure XIV indicates that net electricity generation in 2030 will account for 336.1 TWh, of which 48.32 TWh will be exported and import will sum 8.2 TWh. The balance (1) considers that inefficiencies in pumping and batteries account for 20%, giving a final electricity demand of 292.93 TWh, that results in line with the data download from ENTSO-e.

$$Demand = Net\ electricity\ generation + Export + Import + Consumption\ in\ pumping\ and\ batteries * (1 - efficiency\ of\ pumping\ and\ batteries) \quad (1)$$

Target Scenario electricity mix (GWh)				
Years	2015	2020	2025	2030
Gross electricity generation	281,021	281,219	307,570	346,290
Consumption in generation	-11,270	-10,528	-10,172	-10,233
Net electricity generation	269,751	270,690	297,398	336,056
Consumption in pumping and batteries	-4,520	-6,381	-7,993	-15,262
Export	-15,089	-9,251	-26,620	-48,325
Import	14,956	18,111	12,638	8,225
Demand in power plant busbars	265,098	273,170	275,424	280,694
Consumption in energy transformation sector	-6,501	-7,552	-6,725	-6,604
Transmission and distribution losses	-26,509	-25,161	-25,022	-24,868
Final electricity demand from non-energy sectors	232,088	**240,457**	**243,677**	**249,222**

Figure XIV: Target scenario electricity mix (PNIEC, 2020).

6.2.2. Renewables hourly capacity factors

While developing the model, the hourly capacity factors of REN energy sources are the other parameters used for considering the variability of energy systems. On the power supply side, to take into account for the intermittency of these generation technologies, data representing the energy generated from 01/01/2016, 00:00 to 31/12/2019, 23:59 were downloaded from esios.es. These data have been analysed in parallel with the capacity installed to obtain the hourly capacity factors of each technology for a total duration of 35040 hours, or rather 4 years, by means of the following formula.

$$CF^{Ren}{}_{z,t} = \frac{G^{Ren}{}_{z,t}}{P^{Ren}{}_{z}} \qquad \forall t \in T, \forall z \in Z \tag{2}$$

However, since the data corresponding to the capacity installed are available only for the last day of the year, linear correlation was adopted between the capacity installed year-to-year, in 2016, 2017 and 2018 reasonable values for the capacity factors of each technologies were found. In 2019, due to the deadline for the project delivery of the installations that won the previous auction, several plants were put in place in the last few weeks of the year. This is particularly relevant for PV installations, that in 2019 increased their total capacity by 89%. To find reasonable capacity factors for the year, again linear correlation was used, but the year was split in three time periods. It was considered that during the first two months of the year no additional installations were installed. Then, during the following 8 months 30% of the additional capacity was installed (1.26 GW). In the last two months it was assumed that the other 70% of the installations – corresponding to 2.94 GW - were put in place. As in Figure XV by applying this hypothesis the data obtained are in line with previous years generation patterns and are assumed to be reasonable for the scope of the study.

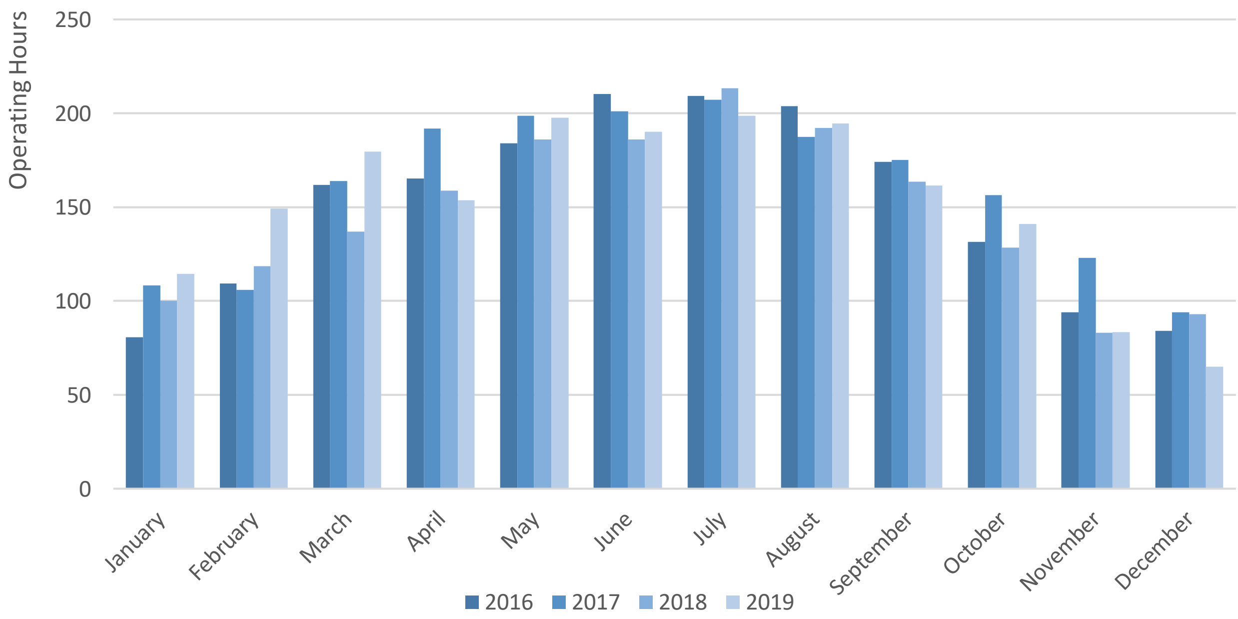

Figure XV: Solar photovoltaics monthly equivalent operating hours at peak capacity.

This practice of attributing to each technology an hourly capacity factor based on historical data instead of considering the best-case scenarios of new installations, allows to take into account geographical variability and systems degradation. It is in fact unlikely that a PV system is going to generate the same in the north and south of the peninsula, and seemingly unlikely that a PV system installed 10 years before is going to perform as a brand new one.

This methodology was applied to nuclear and renewable technologies, except for hydro, that deserve special considerations. Pure hydroelectric power plants are not expected to increase in number, both for geological unavailability and legislative constraints. However, new installations of pure pumped hydro will have to be developed, since this technology remains a key for the transition to renewables. In the national energy plan this is outlined several times, putting the accent on the necessity of law modification to allow the construction of new PHES systems, and planning the installation of additional 3.5 GW of pumped hydro.

While developing the model, pumped hydro energy storage was considered as a separate entity from pure hydro, in order to evaluate the effective contribution of storage in the system economics. Under these considerations, the hourly capacity factor attributed to hydro has been calculated by reducing the one historically registered by an amount corresponding to the energy used, over the same period, to pump water in upper reservoirs. This was done since the hydro output data - downloadable from esios.es - does not distinguish between the one that comes from natural water flows and the one proceeding from previously pumped water. It is assumed that the energy used to pump water in upper reservoirs is completely discharged throughout the considered period. This is done by reducing the power output whenever it is higher than 40% of the total installed capacity. Specifically, the output of hydro power systems is reduced by 15%. Figure XVI shows the original and adjusted energy output of hydroelectric power plants in 2016 and 2017, to present the effects of this methodology.

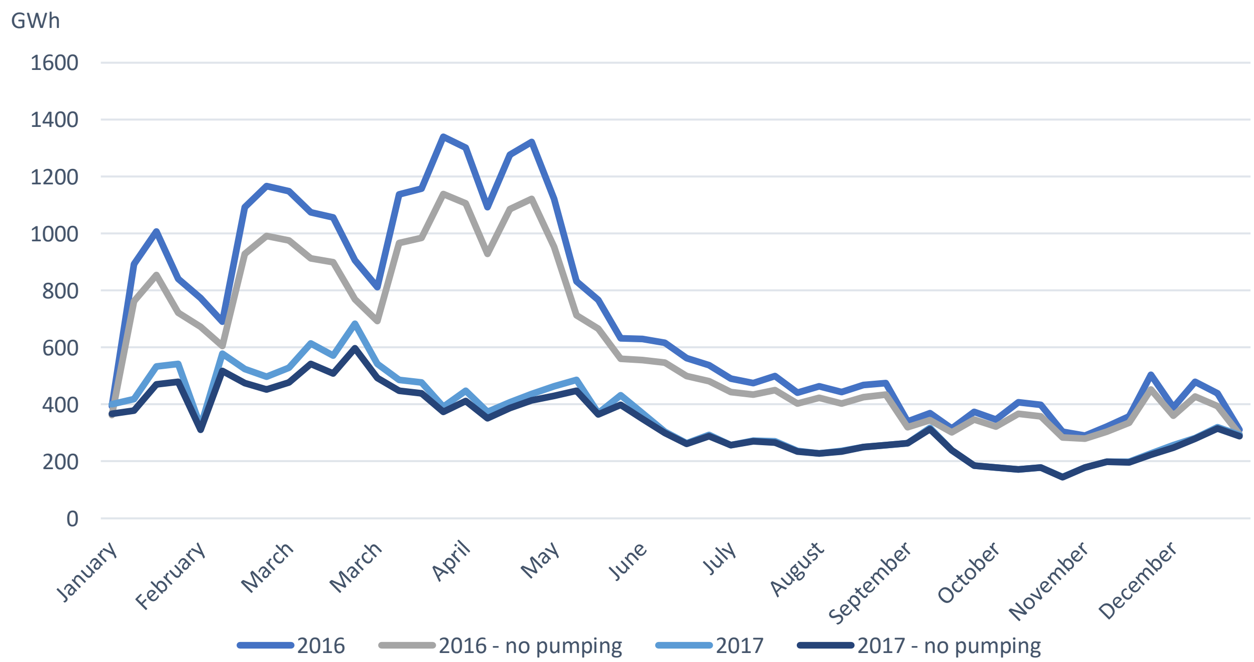

Figure XVI: Hydro power output throughout the year.

As far as the additional generation capacity that the model needs to evaluate, only three technologies have been considered, since the others present intrinsic limits to their expansion. Thus, the ones considered for the optimization of the system are wind turbines, photovoltaics panels and solar thermal power plants, endogenously optimized by the model to find a cost-efficient solution. Only these technologies were considered since they are the only not presenting resources limitations to their deployment (i.e. biomass is unlikely to supply even only 1 GW due to the scarcity of potential renewable fuels). The capacity factors used are the ones calculated as described here above.

For the PNIEC simulation, the same methodology illustrated above is applied. In this case, however, the hourly capacity factor of each technology is adapted in order to resemble the values assumed in the elaboration of the national energy strategy. To do so, the hourly capacity factor of each technology is multiplied for a factor, with the condition of never overcoming the maximum registered historically. This is done to avoid distortions such as technologies that present capacity factors higher than 0,95 during certain hours, which at the national scale is very unlikely. This approximation makes this scenario very favourable, compared to the one directly elaborated from historical registered values, since it not only increases the annual generation of renewables, but also reduces the fluctuations "softening" the output curve. Table 5 illustrates the factor for which the historic average yearly operating hours of each technology needs to be multiplied – thus increased – to attend the PNIEC hypothesis.

Table 5: Annual operating hours derived from historical values and adapted to PNIEC assumptions.

	PV	Wind	Other renewables	Renewable waste	CSP
2016	1614	2047	7818	4050	2195
2017	1708	2075	8227	4551	2321
2018	1571	2102	7281	4581	1920
2019	1561	2191	6702	4618	2242
Historical Average	1614	2104	7507	4450	2170
PNIEC	1800	2450	7000	7000	3000
Factor applied	1,11	1,15	1	1,55	1,4
Derived values	1791	2419	7507	6898	3036

Nevertheless, it must be noticed that the annual operating hours assumed for the elaboration of the PNIEC are very optimistic. These come from the Joint Research Centre (JRC), according to the national energy strategy. Figure XVII shows the annual operating hours registered in Spain during 2016, 2017, 2018 and 2019, and the one assumed for the structuring of the plan. Except for "other renewables"

– that anyway presents only a marginal relevance both in the present and in the strategy – the other technologies assume values at least 10% higher in the PNIEC compared to the historical performances. In fact, photovoltaics has generated on average the equivalent of 1630 hours at full load per year during the last 4 years. As stated in this chapter, considering the energy output at the national scale allows to take into consideration the climatic conditions that enable renewables in a more or less favourable way. The planned 1800 hours expected in the PNIEC for PV are 10% higher than the historic average. Similarly, a 15% increase in the hourly energy output of wind turbines is assumed in the plan. But it is especially concentrated solar power – that in the strategy is considered to be key for the transition and of which 5 more GW are expected to be installed by 2030 – at presenting very optimistic data. Under the PNIEC hypothesis, new CSP power plants are able to generate during 3500 hours per year at full load. Historical data indicates that yearly output of CSP is on average around 2200 hours. To reach 3000 operating hours – calculated as the weighted average of already installed power plants output and the new planned ones – a factor of 1.4 was applied to current generation, thus increasing its current output of more than 40%. Generation from renewable waste was increased even more, but since its capacity installed is small compared to other technologies, its output plays a marginal role in the national energy mix.

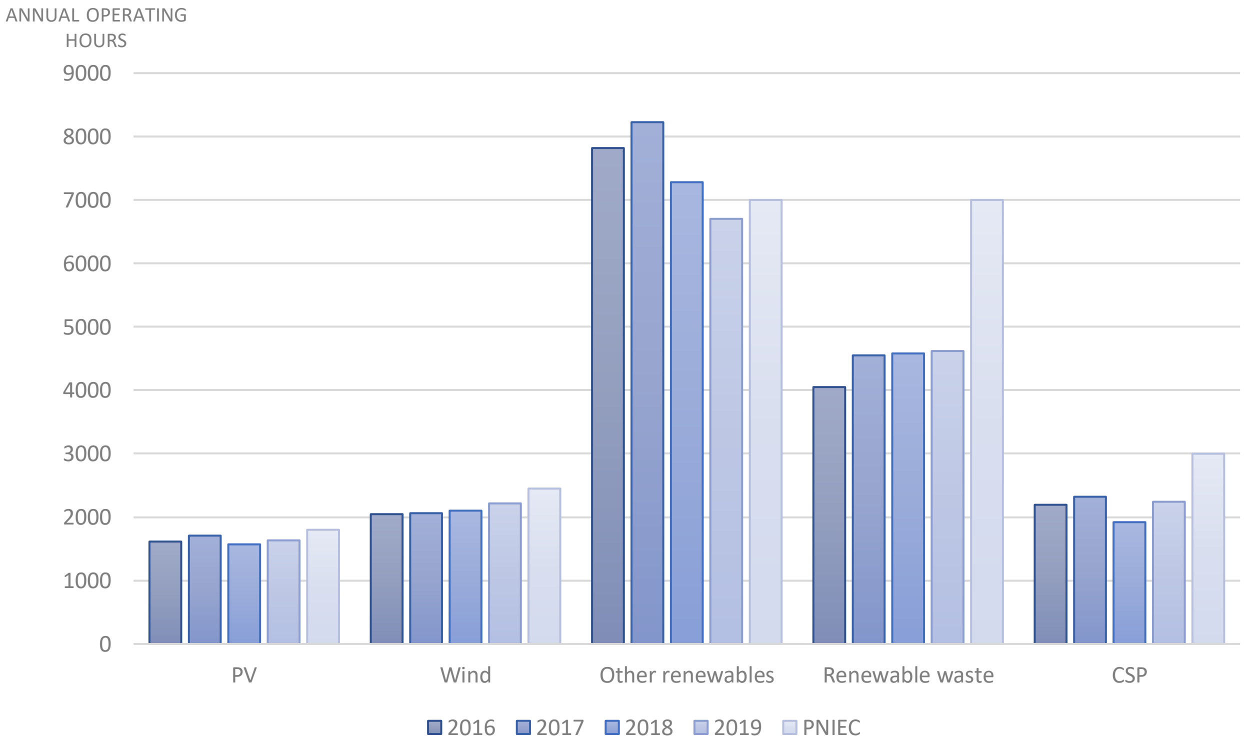

Figure XVII: Historical annual operating hours of each technology and PNIEC expectations.

6.3. Technology parameters

As already introduced, to approximate the behaviour of the model to reality, it is necessary to establish a series of restrictions related to the techno-economic characteristics and operation of generation and storage technologies. In this subchapter, the characteristics considered and their respective values are presented.

Table 6 the input parameters for renewable generation technologies are presented. These come from an extensive literature review and, especially regarding investment costs, have been compared with data from real projects (Generalitat Valenciana, 2020). OPEX and CAPEX are specific to the Spanish market, even though they do not differ much for other European countries. Replacement costs are calculated by dividing CAPEX for the lifetime of the installation to take into account its degradation.

Table 6: Renewable generation technologies' main techno-economic characteristics (Generalitat Valenciana, 2020; Steffen et al., 2020).

Technologies	Eolic	PV	Solar Thermal
Specific-to-power investment costs [EUR/kW]	1100	700	4000
Specific-to-power O&M costs [EUR/(kW*year)]	30	10	44
Lifetime [year]	30	30	30
Specific-to-power replacement costs [EUR/(kW*year)]	37	23	133

Table 7 illustrates the characteristics of storage technologies. After an extensive literature review, storage costs were structured as specific-to-energy and specific-to-power in order to take into account the characteristics of each technology. This allows to consider that there are technologies more cost-efficient in terms of power whereas others are cheaper in terms of energy. An example can be found comparing batteries with Power-to-Gas, batteries are likely to have lower costs for power whereas a higher cost for energy. On contrary Power-to-Gas presents low costs for unit of energy stored, since it can take advantage of the existing gas infrastructure and not incur in any costs. This distinction is applied also to operational costs, which in case of power consist of a fixed amount per year, whereas energy costs are proportional to the energy that goes through the storage. In the model the ratio between energy and power is fixed, thus defying capex and, consequently, replacement costs, as in equation (2).

$$C^{Sto,Replace} = \frac{C^{Sto,capex,p} + (C^{Sto,capex,e} * Ratio\ Energy\ to\ Power)}{Lifetime} \qquad (3)$$

As far as storage technical characteristics, account is taken for the maximum depth of discharge and the efficiencies in input and output. Lastly, for pumped hydro, a limit to its potential expansion is set, assuming that, since it represents by far the most economic viable technology, the capacity that can be potentially installed by 2030 has been already considered in the national energy strategy.

Table 7: Energy storage technologies' main techno-economic characteristics (Cebulla et al., 2017; Cole & Frazier, 2030; Schill & Zerrahn, 2018).

Technologies	Li-Ion	Pumped Hydro	H^2
Specific-to-power investment costs [EUR/kW]	100 (50-150)	1100 (550-1650)	1500 (750-2250)
Specific-to-energy investment costs [EUR/kWh]	150 (75-225)	10 (5-15)	10 (5-15)
Specific-to-power O&M costs [EUR/(kW*year)]	5	15	20
Specific-to-energy O&M costs [EUR/(kWh)]	0,0015	0,0025	0,0025
Specific-to-power replacement costs [EUR/(kW*year)]	36,67 (18,33-55)	24,4 (12,2-36,6)	76,44 (38,22-114,66)
Ratio Energy/Power	3	12	22
Storage maximum DOD	0,9	0,95	0,95
Storage cycle life	3500	15000	10000
Storage output efficiency [%]	0,96	0,93	0,7
Storage input efficiency [%]	0,95	0,87	0,6
Lifetime [years]	15	50	22,5
Potential Limit [MW]	99999	9500	99999

In the model account is taken for two mechanisms of demand response: load curtailment and load shifting. The first should resemble the services that can be interrupted under electricity contracts that allow for interruptions to electric service in exchange for financial compensation. For these, two different types were considered, cheap and expensive curtailment, both with nearly zero investment costs but quite considerable compensation during outages. Instead, load shifting comprises those technologies that can shift their consumptions, functioning similarly to a storage system. In the model we consider vehicle-to-grid, climatization and heat pumps, and industry. The relatively high costs of operation could apparently be in contrast with the assumptions made in the model, which is based on costs and neglects marginal profits and market dynamics. However, it is important to notice that in this case the flexibility is provided at the cost of reducing the quality of other services (such as the charging of electric vehicles), reason why it is reasonable to consider a cost for the actual shifting.

The potential of demand response has been calculated under own assumptions of the author – the 250 MW of flexibility provided by V2G, for example, have been established assuming the deployment of 2,5 million electric vehicles, and considering that as the maximum availability that can be offered constantly during each hour of the year – and are in line with the numbers provided by a study of 2017 of the European Parliament, that indicates that during peak demand the potential of DR is 15% (Paterakis et al., 2017). Here below the specific characteristics used for modelling are presented.

Table 8: Load curtailment's characteristics modelled (Gils, 2014; Paterakis et al., 2017).

Load curtailment	Industry cheap	Industry expensive
Curtailment cost [EUR/kWh]	0,5 (0,25-0,75)	1,5 (0,75-2,25)
Specific-to-power investment costs [EUR/kW]	10 (5-15)	10 (5-15)
Specific-to-power O&M costs [EUR/(kW*year)]	1 (0,5-1,5)	1 (0,5-1,5)
Specific-to-power replacement costs [EUR/(kW*year)]	1 (0,5-1,5)	1 (0,5-1,5)
Maximum duration [h]	4	4
Recovery time [h]	24	24
Lifetime [years]	10	10
Potential Limit [MW]	1000 (500-1500)	1500 (750-2250)

Table 9: Load shifting's characteristics modelled (Paterakis et al., 2017; Rodríguez-García et al., 2016).

Load shifting	V2G	Climatization and heat pumps	Industry
Shifting cost [EUR/kWh]	0,02 (0,01-0,03)	0,01 (0,005-0,015)	0,05 (0,025-0,075)
Specific-to-power investment costs [EUR/kW]	200 (100-300)	500 (250-750)	10 (5-15)
Specific-to-power O&M costs [EUR/(kW*year)]	0	0	0
Specific-to-power replacement costs [EUR/(kW*year)]	20 (10-30)	50 (25-75)	1 (0,5-1,5)
Maximum duration [h]	1	2	3
Lifetime [years]	10	10	10
Potential Limit [MW]	250 (125-375)	1250 (625-1875)	1500 (750-2250)

Regarding fossil fuel generation, since the national strategy is based around the exploitation of already installed CCGT plants, this technology is the one assessed in this study. Similarly to the technologies previously described, replacement and O&M costs were considered, and, in addition to that, the marginal cost of generation was included since in this case the generation facility requires fuel to run.

CCGT capability of providing flexibility is restricted by the heat recovery steam generator. These turbines do normally achieve full start-up in 1 – 4 hours (International Renewable Energy Agency, 2013). Therefore, since the problem is assessed on a national scale, a ramp rate of 30% of total installed capacity seems reasonable and is assumed for the scope of this study. This assumption gains further consistency when considering CCGT historical output. Based on data download from esios.es (Red Eléctrica de España, 2020a), in Spain the fastest hourly ramp registered from this technology is less than 20% of total installed capacity.

As already mentioned, the cycling of this type of facilities are pivot when making scheduling decisions due to their impact on the system costs, both in terms of start-up costs and the accrued damage and resulting maintenance costs (J. F. González & Ruiz Mora, 2014). For this reason, these costs were included. Additionally, a factor of unavailability was established, for simplicity set as a percentage of total installed capacity. In the following table the values used for the study are presented.

Table 10: CCGT investment and operational costs (J. F. González & Ruiz Mora, 2014; Hermans & Delarue, 2016; Schill et al., 2017).

Conventional power plants	CCGT
Specific-to-power investment costs [EUR/kW]	650
Specific-to-power O&M costs [EUR/(kW*year)]	10
Specific-to-power replacement costs [EUR/(kW*year)]	16,25
Marginal cost of generation [EUR/kWh]	0,035 (0,0175-0,0525)
Hourly ramp rate [%]	0,3
Ramping up cost [EUR/kW]	0,035 (0,0175-0,0525)
Lifetime [years]	40
10%Unavailability Rate	10%

Regarding interconnections, the model sticks to the PNIEC guidelines in terms of transmission capacity, which are set to increment to 12 GW by 2030. With Portugal and France, both import and export capacity with these countries were considered jointly. With regard to the interconnection capacity with France, it should be noted that the projected increases in this capacity were taken into account, reaching 5,000 MW in 2025 and 8,000 MW in 2030.

The model uses a constant value of commercial exchange capacity at all times on the simulation time frame, accounting for the variations that would correspond to different operating situations and for reductions due to unavailability of the transmission network or other circumstances by considering 70% of total capacity as available for exchanges.

Due to proximity and geographic and climatic characteristics, it is unlikely that neighbouring countries could register excess of REN generation at times in which Spain is not. Therefore, it has been assumed that the energy imported comes predominantly from non-renewable energy sources and, consequently, that the energy comes at a relatively high cost of 45 €/MWh. On contrary, the revenue that comes from exports was set to be 10 €/MWh. This low value was adopted in order for the system not to oversize REN generation units, since when there is excess of renewable generation – either it to be exported or curtailed – the pool price diminishes, and revenue from the market is consequently low.

This simplification can mainly affect the actual energy balance of the system, which could possibly be characterized by more imports than the ones presented in the results - due to the markets dynamics - and, depending on the development of REN infrastructure at a pan European level, more or less exports. To obtain more precise results, as already mentioned, the infrastructure and future demand of each interconnected country in the EU should be addressed. However, this would make the model much more complex and would imply to do further hypothesis, not necessarily improving the quality of the results. For this reason, in the following table the main interconnections' characteristics given as input to the model are presented.

Table 11: Interconnections' characteristics.

Characteristics	Interconnections
Export capacity [MW]	8540
Import capacity [MW]	8050
Share of REN Imports	5%
Revenue Exports [EUR/kWh]	0,01
Costs Imports [EUR/kWh]	0,045

Lastly, in the simulations presented, the frequency reserve provision required to guarantee dynamic stability was set to be linearly dependent on the rotational inertia of the system. To calculate the amount of rotational inertia produced by a non-linear generator, an "inertia constant" is needed. This constant is specific to an individual generator and depends on the generator's physical specifications. The inertia constant is multiplied by a generator's capacity to determine its rotational inertia contribution. It must be noticed that this is an approximation, since to correctly use a generator's inertia constant, the unit's apparent power capacity must be known. The inertia constants for each type of generation are presented in the following table.

Table 12: Rotational inertia constant of each technology (Independent Market Monitor for ERCOT, 2019; Mehigan et al., 2020).

Technologies	Rotational Inertia Constant [s]
Nuclear energy	5,5
Natural gas CCGT	6
Hydropower	3,5
Biomass	3
CSP	3
Interconnections	2,5

6.4. Mathematical representation

Figure XVIII illustrates the conceptual structure of the model. The script reads a series of spreadsheets in which the hourly parameters of demand and RES capacity factors for each hour of the timeframe simulated (4 years), and the main techno-economic characteristics of the technologies object of the study are provided. After having read the inputs, a first simulation is run with the initialized value of each decision variable, indicated in the model flow chart as energy system components. The model simulates verifying that all constraints are respected and calculates the total costs. If the solution is not optimal or the constraints have not been respected, either the value of a decision variable is changed and another simulation begins, or the values of the auxiliary variables (mainly representing the hourly energy flow) are modified. Only when the optimal solution is reached the model exits the simulation process and gives the output. The result consists in a cost-minimal combination of REN, storage, other flexibility options, and combined cycle gas turbines capacity, accompanied by their optimal hourly dispatch. The model basically solves the problem that was presented in chapter 4, or rather finds the perfect balance between the use of storage to integrate surpluses and larger renewable capacities plus curtailment.

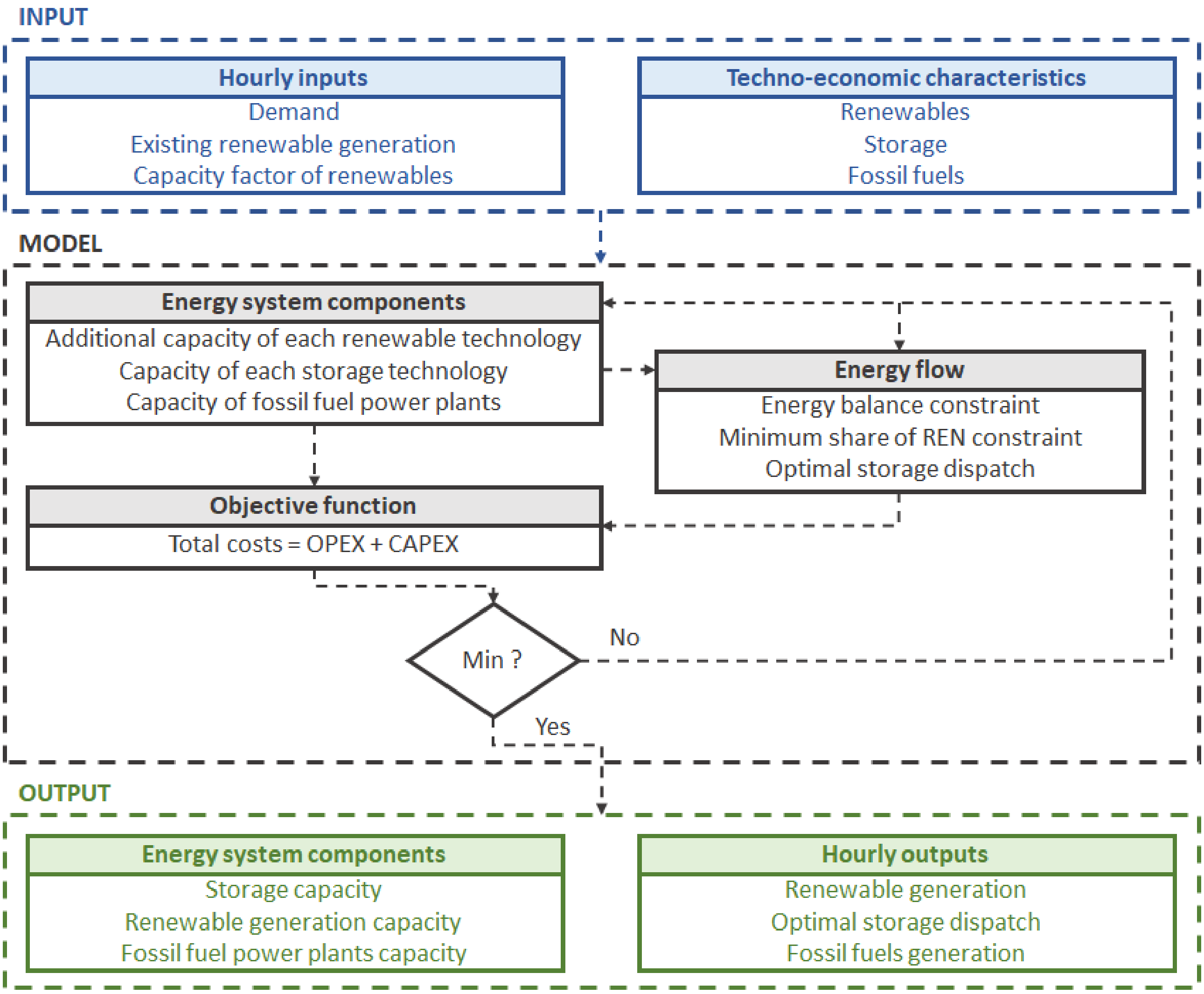

Figure XVIII: Model flow chart.

6.4.1. Glossary

Table 13: Indices.

Set	Description	Unit
t	Time periods	h
r	Existing renewable generation technologies	none
z	Additional renewable generation technologies	none
s	Storage technologies	none
f	Fossil fuel generation technologies	none
p	Load curtailment options	none
e	Load shifting technologies	none

Table 14: Sets.

Set	Description	Unit
T	Set of time periods in a year	h
R	Set of all existing renewable generation technologies	none
Z	Set of all additional renewable generation technologies	none
S	Set of all storage technologies	none
F	Set of all fossil fuel generation technologies	none
P	Set of all load curtailment options	none
E	Set of all load shifting technologies	none

Table 15: Parameters.

Parameters	Description	Unit
DE	Demand	kW
α	Share of renewable set as objective	none
$G^{Ren,e}$	Existing renewable generation	kW
G^{N}	Nuclear generation	kW
CF^{Ren}	Hourly capacity factor of each renewable technology	none
$\mathrm{C}^{\mathrm{Ren,opex}}$	Specific-to-power investment cost of renewable generation technologies	€/kW
$\mathrm{C}^{\mathrm{Ren,opex}}$	Specific-to-power O&M cost of renewable generation technologies	€/kW*year
$\mathrm{C}^{\mathrm{Ren,Replace}}$	Specific-to-power replacement cost of renewable generation technologies	€/kW*year

$C^{\mathrm{ff,capex}}$	Specific-to-power investment cost of fossil fuel generation technologies	€/kW
$C^{\mathrm{ff,opex}}$	Specific-to-power O&M cost of fossil fuel generation technologies	€/kW*year
$C^{Ramping,ff}$	Specific-to-power cost of ramping fossil fuel power plants	€/kW
C^{ff}	Specific-to-energy costs of fossil fuel power plants	€/kWh
U_f	Unavailability factor of fossil fuel generation technologies	none
R_f	Ramping factor of fossil fuel power plants	none
$C^{\mathrm{Sto,capex,p}}$	Specific-to-power investment costs of storage technologies	€/kW
$C^{\mathrm{Sto,capex,e}}$	Specific-to-energy investment costs of storage technologies	€/kWh
$C^{\mathrm{Sto,opex,p}}$	Specific-to-power O&M costs of storage technologies	€/kW*year
$C^{\mathrm{Sto,opex,e}}$	Specific-to-energy O&M costs of storage technologies	€/kWh
$C^{\mathrm{Sto,Replace}}$	Specific-to-power replacement costs of storage technologies	€/kW*year
$\eta^{Sto,\mathrm{o}}$	Storage output efficiency	none
$\eta^{Sto,i}$	Storage input efficiency	none
PE	Power to energy ratio of storage technologies	none
DOD	Depth of discharge of storage technologies	none
$S^{Potential}$	Potential of storage technologies	kW
$C^{\mathrm{LC,opex}}$	Specific-to-power O&M costs of load curtailment options	€/kW*year
$C^{\mathrm{LC,Replace}}$	Specific-to-power replacement costs of load curtailment options	€/kW*year
C^{LC}	Specific load curtailment cost	€/kWh
LC^{Max}	Load curtailment maximum duration at full capacity	h
LC^{Rec}	Load curtailment recovery time	h
$LC^{Potential}$	Potential of load curtailment	kW
$C^{\mathrm{LS,opex}}$	Specific-to-power O&M costs of load shifting technologies	€/kW*year
$C^{\mathrm{LS,Replace}}$	Specific-to-power replacement costs of load shifting technologies	€/kW*year
C^{LS}	Specific load shifting cost	€/kWh
LS^{Max}	Load shifting maximum duration at full capacity	h
$LS^{Potential}$	Potential of load shifting	kW
C^{Imp}	Cost of energy imported	€/kWh
R^{Exp}	Revenue from energy exported	€/kWh
α_{Imp}	Share of renewables in imports	none
$ImpC$	Import capacity	kW
$ExpC$	Export capacity	kW

Table 16: Variables.

Variables	Description	Unit
C^{t}	Total investment cost of the system	€
$\mathrm{P}^{\mathrm{Ren}}$	Additional renewable generation capacity installed	kW
P^{ff}	Fossil fuel generation capacity	kW
S^{p}	Storage power capacity	kW
S^{e}	Storage energy capacity	kWh
$\mathrm{LC}^{\mathrm{Capacity}}$	Load curtailment capacity	kW
$\mathrm{LS}^{\mathrm{Capacity}}$	Load shifting capacity	kW
$G^{Ren,e}$	Existing renewable generation	kW
$G^{Ren,a}$	Renewable generation from additionally installed plants	kW
CU^{Ren}	Curtailment of renewables	kW
G^{ff}	Fossil fuel power plants generation in wholesale segment	kW
φ^{ff}	Fossil fuel power plants generation in ancillary services segment	kW
$\mathrm{C}^{\mathrm{ff,Ramp}}$	Ramping costs of conventional power plants	€
$S^{content}$	Storage content	kWh
S^{input}	Storage input	kW
$\mathrm{S}^{\mathrm{output}}$	Storage output in wholesale segment	kW
$\varphi^{\mathrm{Storage}}$	Storage output in ancillary services segment	kW
LC	Load curtailed	kW
LSD	Load shift down in wholesale segment	kW
LSU	Load shift up in wholesale segment	kW
$LS^{Cumulated}$	Load shifting cumulated	kWh
φ^{LS}	Load shift in ancillary services	kW
Imp	Energy imported	kW
Exp	Energy exported	kW
Y	Frequency reserve factor	none
I	Rotational inertia of the system	kWs
RI	Inertia factor	s

6.4.2. Objective function

The objective is the minimization of the cost function C^t consisting in the sum of operational and replacement costs of the infrastructure required to satisfy demand with the specified penetration of RES in the energy mix.

$$\min(\mathrm{C^t}) = \sum_{z=1}^{Z}\left[\mathrm{P^{Ren}}_z * \frac{\left(\mathrm{C^{Ren,opex}}+\mathrm{C^{Ren,Replace}}\right)_z}{8760} * \mathrm{T}\right] + \sum_{f=1}^{F}\left\{\left[\mathrm{P^{ff}}_f * \frac{\left(\mathrm{C^{ff,opex}}+\mathrm{C^{ff,Replace}}\right)_f}{8760} * \mathrm{T}\right] + \sum_{t=1}^{T}\left[\left(\mathrm{G^{ff}}_{f,t} + \varphi^{\mathrm{ff}}{}_{f,t}\right) * \mathrm{C^{ff}}_f + \mathrm{C^{ff,Ramp}}_{f,t}\right]\right\} + \sum_{s=1}^{S}\left\{\left[\mathrm{S^p}_s * \frac{\left(\mathrm{C^{Sto,opex,p}}+\mathrm{C^{Sto,Replace}}\right)_s}{8760} * \mathrm{T}\right] + \sum_{t=1}^{T}\left[\mathrm{C^{Sto,opex,e}}_s * \left(\mathrm{S^{output}}_{s,t} + \varphi^{\mathrm{Storage}}{}_{s,t}\right)\right]\right\} + \sum_{p=1}^{P}\left\{\left[\mathrm{LC^{Capacity}}_p * \frac{\left(\mathrm{C^{LC,opex}}+\mathrm{C^{LC,Replace}}\right)_p}{8760} * \mathrm{T}\right] + \sum_{t=1}^{T}\left(\mathrm{C^{LC}}_p * \mathrm{LC}_{p,t}\right)\right\} + \sum_{e=1}^{E}\left\{\left[\mathrm{LS^{Capacity}}_e * \frac{\left(\mathrm{C^{LS,opex}}+\mathrm{C^{LS,Replace}}\right)_e}{8760} * \mathrm{T}\right] + \sum_{t=1}^{T}\left[\mathrm{C^{LS}}_e * \left(\mathrm{LSD}_{e,t} + \varphi^{\mathrm{LS}}{}_{e,t}\right)\right]\right\} + \sum_{t=1}^{T}\left(\mathrm{Imp}_t * \mathrm{C^{Imp}} - \mathrm{Exp}_t * \mathrm{R^{Exp}}\right) \tag{4}$$

The first term comprises OPEX and replacement costs of the additional renewable generation systems: P^{Ren} represents the additional REN capacity, which is multiplied for the operational $C^{Ren,opex}$ and replacement $C^{Ren,Replace}$ costs that, being specific to both the power installed and the lifetime of the installation, are also multiplied for the total duration of the time period considered for the simulation T, and divided for 8760 (number of hours in a year). Renewable energy does not incur any variable costs, and no costs are directly imposed for curtailment. As the objective function comprises the investment costs of renewable plants, it accounts for the full cost of renewable energy irrespective whether it eventually satisfies demand or is curtailed at times.

The second term represents operational and replacement expenditures of fossil fuel power plants, which follow the same principles of REN expenditures, thus the specific OPEX $C^{ff,opex}$ and replacement $C^{ff,Replace}$ costs are multiplied for the power installed P^{ff} and $\frac{T}{8760}$, since they have been defined as annual costs. Fossil fuel costs depends of course also on fuel consumption, that is considered in the third term of the expression by multiplying the total energy output (as the sum of hourly power output in wholesale segment $\mathrm{G^{ff}}_t$ and in ancillary services $\varphi^{\mathrm{ff}}{}_t$ throughout the duration of the time period considered in the simulation) for the specific cost of generating with the respective technology C^{ff}. In addition, fossil fuelled power plants are characterized by high costs of start-up, which ultimately affect their bidding strategy. Even though in this project imperfect competition is not taken into account, ramping costs $RC^{ff}{}_t$ are considered since a conventional power plant is more efficient when running stably. Lastly, by analogy with the neglection of curtailment costs for renewables, also the use of conventional plants below a number of hours that can guarantee their economic feasibility does not receive any penalty in the objective function.

The third term represents storage costs, that are calculated with a similar approach to the ones already described. The storage power capacity $\mathrm{S^p}$ is multiplied for the operational $\mathrm{C^{Sto,opex,p}}$ and replacement $\mathrm{C^{Sto,Replace}}$ costs that, being also specific to the time period considered, are also multiplied for the total duration of the simulation T, and divided for 8760 (number of hours in a year). In this case however, besides replacement and operational costs, an additional term for OPEX that depends on the energy flow through the storage system is considered. The specific operational costs of each technology $\mathrm{C}^{\mathrm{Sto,opex,e}}$ are multiplied for the energy output of the storage systems, as the sum of the hourly power for the wholesale segment $\mathrm{S^{output}}_{\mathrm{t}}$ and for the ancillary services $\mathrm{\varphi^{Storage}}_{\mathrm{t}}$. Only the energy flow out of the storage system is accounted to avoid charging twice for the utilization of the system.

The fourth term refers to load curtailment, or rather the reduction of demand in one period without any recovery of the energy not consumed. As in the other cases, the operational $\mathrm{C}^{\mathrm{LC,opex}}$ and replacement costs $\mathrm{C}^{\mathrm{LC,Replace}}$ are multiplied for the power capacity $\mathrm{LC}^{\mathrm{Capacity}}$ and the total duration of the simulation T, and divided for 8760. In this case, there is a variable cost for the activation and usage of this resource. The specific cost C^{LC} is multiplied for the load actually curtailed at each timestep $\mathrm{LC_t}$.

The fifth term correspond to load shifting, or rather the delay of demand at moments with more availability of generation resources. Here as well, the specific operational $\mathrm{C}^{\mathrm{LS,opex}}$ and replacement costs $\mathrm{C}^{\mathrm{LS,Replace}}$ are multiplied for the capacity $\mathrm{LS}^{\mathrm{Capacity}}$ and $\frac{T}{8760}$. Additionally, as for storage technologies, the variable operational costs C^{LS} for shifting demand are obtained by multiplying the specific costs C^{LS} for the amount of energy shifted both in the wholesale $\mathrm{LSD_{e,t}}$ and frequency regulation segment.

Finally, the last term takes into account imports and exports. These are parametrized as described in the previous subchapter. There is a fixed costs for imports C^{Imp} as well as a fixed compensation for exports R^{Exp}, that are multiplied respectively for the energy imported Imp_t and exported Exp_t.

6.4.3. Constraints

The variables determining the cost function are the capacity installed of each technology, the energy dispatch strategy and the amount of energy imported and exported. The optimization function illustrated above is subject to the following constraints:

At each timestep the market clearing conditions make sure that demand is satisfied by either RES, storage, demand response, fossil fuels or imports. Thus there must be energy balance between the existing renewable generation $G^{Ren,e}$, nuclear generation $G^{N}{}_{t}$, generation that comes from additionally installed REN power plants $G^{Ren,a}$ (or rather the ones recommended by the model on top of the existing or planned generation infrastructure, depending on the input), storage output S^{output}, load shift down LSD_t, load curtailment LC_t, fossil fuel generation G^{ff}, and imports Imp on one side, and demand DE, energy storage input S^{input}, load shift down LSU_t, curtailment CU^{Ren} and exports Exp on the other side.

$$\sum_{r=1}^{R} G^{Ren,e}{}_{r,t} + G^{N}{}_{t} + \sum_{z=1}^{Z} G^{Ren,a}{}_{z,t} + \sum_{s=1}^{S} S^{output}{}_{s,t} + \sum_{e=1}^{E} LSD_{e,t} + \sum_{p=1}^{P} LC_{p,t} +$$

$$\sum_{f=1}^{F} G^{ff}{}_{f,t} + Imp_t = DE_t + \sum_{s=1}^{n} S^{input}{}_{s,t} + \sum_{e=1}^{E} LSU_{e,t} + CU^{Ren}{}_{t} + Exp_t \quad \forall t \in T \tag{5}$$

The previous equation illustrates the balance that we refer to as wholesale, or rather the demand on which the analysis is based. However, in the model we have also included reserve for ancillary services, specifically in terms of reserve upwards and assuming that half of the balancing reserve is activated at each timestep. The frequency reserve demanded at each time step is obtained by multiplying demand DE_t for the factor Y_t, that depends on the rotational inertia in that timestep. This is imposed to be equal to the sum of the contribution of each technology that was assumed to be effective for this scope, thus storage $\varphi^{Storage}{}_{t}$, conventional power plants $\varphi^{ff}{}_{t}$, and load shifting $\varphi^{LS}{}_{t}$, multiplied for 2, to account for the fact that only half of the reserve provision is activated in the model.

$$DE_t * \; Y_t = 2 * \left(\sum_{s=1}^{S} \varphi^{Storage}{}_{s,t} + \sum_{f=1}^{F} \varphi^{ff}{}_{f,t} + \sum_{e=1}^{E} \varphi^{LS}{}_{e,t}\right) \qquad \forall t \in \mathrm{T} \tag{6}$$

At each timestep, the hourly renewable energy generation from the additional installations $G^{Ren,a}{}_{t}$ is the result of the power installed P^{Ren} of each technology multiplied for the hourly capacity factor $CF^{Ren}{}_{t}$ of the corresponding technology.

$$G^{Ren,a}{}_{z,t} = P^{Ren}{}_{z} * CF^{Ren}{}_{z,t} \qquad \forall t \in T, \forall z \in Z \tag{7}$$

Existing renewable generation is calculated in the exact same way but, since the capacity installed is not a variable but a parameter, it is calculated beforehand in excel and provided as an input for the model.

The energy content of the storage system at each time step $S^{content}{}_{t}$ must take into account the previous hour content $S^{content}{}_{t-1}$, the inflow S^{input} and outflow $S^{output}{}_{t}$ of energy and the corresponding efficiencies $\eta^{Sto,i}$ and $\eta^{Sto,o}$. It has to be noticed that the energy content $S^{content}{}_{t}$ at each timestep corresponds to the energy stored at end of the hour considered. Moreover, the flows of energy $S^{input}{}_{t}$ and $S^{output}{}_{t}$ are to be intended as the actual flows for the energy balance since the losses – thus the efficiencies – are parametrized as internal to the storage systems. At the beginning of the simulation it is imposed that the storage technologies are discharged till their specific depth of discharge.

$$S^{content}{}_{s,t} = S^{content}{}_{s,t-1} + S^{input}{}_{s,t} * \eta^{Sto,i}{}_{s} - \frac{\left(S^{output}{}_{s,t} + \varphi^{Storage}{}_{s,t}\right)}{\eta^{Sto,o}{}_{s}} \qquad \forall t \in [2, T], \; \forall s \in S \tag{8}$$

$$S^{content}{}_{s,t} = S^{e}{}_{s} * (1 - \mathrm{DOD}_s) + S^{input}{}_{s,t} * \eta^{Sto,i}{}_{s} - \frac{\left(S^{output}{}_{s,t} + \varphi^{Storage}{}_{s,t}\right)}{\eta^{Sto,o}{}_{s}} \qquad \text{con } t = 1, \; \forall s \in S \tag{9}$$

Capacity constraints impose that the hourly energy charged $S^{input}{}_{t}$ and discharged in both the wholesale $S^{output}{}_{t}$ and ancillary services segment $\varphi^{Storage}{}_{t}$ (a factor of 2 is applied since $\varphi^{Storage}{}_{t}$ represents the energy activated for balancing, which is half of the actual provision for power reserve) does not exceed the installed power capacity of the storage system S^{p} and that the storage content level $S^{content}{}_{t}$ never exceeds the installed energy storage capacity S^{e}.

$$S^{output}{}_{s,t} + S^{input}{}_{s,t} + 2 * \varphi^{Storage}{}_{s,t} \leq S^{p}{}_{s} \qquad \forall t \in T, \; \forall s \in \mathrm{S} \tag{10}$$

$$S^{content}{}_{s,t} \leq S^{e}{}_{s} \qquad \forall t \in T, \forall s \in \mathrm{S} \tag{11}$$

Most battery chemistries degrade as they are charged and discharged, gradually reducing their ability to store energy. This affects the length of the battery’s operational life, as well as the total number of kilowatt-hours it will be able to store over that lifetime. Thereby a specific maximum depth of discharge DOD for each storage technology is applied by imposing a minimum energy content $S^{content}{}_{t}$ equal to the energy capacity S^{e} multiplied for the factor representing the share of the total capacity that is not exploited to avoid degradation, or rather $(1 - \mathrm{DOD}_s)$.

$$S^{content}{}_{s,t} \geq S^{e}{}_{s} * (1 - \mathrm{DOD}_s) \qquad \forall t \in T, \forall s \in \mathrm{S} \tag{12}$$

Additionally, the ratio between the energy and the power capacity of each storage technology is defined by means of the factors previously illustrated PE.

$$S^{e}{}_{s} = S^{p}{}_{s} * \mathrm{PE}_s \qquad \forall s \in \mathrm{S} \tag{13}$$

Since generation from renewable energies needs to satisfy a minimum share of demand $\alpha \in$ [0, 1], for reason of convenience the constraint is imposed as a maximum share of fossil fuel generation, defined as the sum of fossil fuels power output in the wholesale segment $G^{ff}{}_{t}$ and in ancillary services $\varphi^{ff}{}_{t}$, nuclear generation $G^{N}{}_{t}$, and the fraction of imports that does not come from RES during the entire duration of the simulated timeframe. This must be less or equal to the sum of demand in wholesale DE_t and ancillary services $\left(DE_t * \frac{Y_t}{2}\right)$ minus the load curtailed and not recovered LC_t during the same time frame, multiplied for $(1-\alpha)$ that represents the maximum share of generation from non-renewable energy sources.

$$\sum_{t=1}^{T}\left[\sum_{f=1}^{F}\left({G^{ff}}_{f,t}+{\varphi^{ff}}_{f,t}\right)+\ {G^{N}}_{t}+\ Imp_t\ *\ \left(1-\alpha_{Imp}\right)\right]\ \leq\ (1-\alpha)\ *\ \sum_{t=1}^{T}\left[DE_t\ * \left(1+\ \frac{Y_t}{2}\right)\ -\sum_{p=1}^{P}LC_{p,t}\right] \tag{14}$$

Even though in the current Spanish electricity system there is already installed a significant capacity of efficient CCGT power plants, the model considers that for these to be available investments should be made. This is done to evaluate the real requirements of fossil fuel power plants, with the aim of avoiding subsidizing unnecessary capacity as reserve. Thus, hourly generation from fossil fuels in the wholesale segment ${G^{ff}}_t$ and hourly capacity destined to balancing services $2*{\varphi^{ff}}_t$ are limited by the power installed P^{ff}, that is taken into account in the objective cost function. The factor $\left(1-U_f\right)$ represents the reduction of available capacity due to maintenance, blackouts or any other problem in which these plants can incur. The problem and the code are formulated in order to consider different non-renewable generation sources - which allows to either simulate with different CAPEX and OPEX (such as OCGT and CCGT), or the same technology but with different dispatch strategies, that affect the ramp rate and the maintenance and operational costs (CCGT used with either slow or fast start-ups).

$$ {G^{ff}}_{f,t}+2*{\varphi^{ff}}_{f,t}\leq\left(1-U_f\right)*{P^{ff}}_f \qquad \forall t\in T,\ \forall f\in F \tag{15}$$

An additional constraint is the ramping of fossil fuels power plants. In order to take into consideration ramping both upwards and downwards, two constraints are defined:

$$ {G^{ff}}_{f,t}+2*{\varphi^{ff}}_{f,t}-{G^{ff}}_{f,t-1}\leq R_f*{P^{ff}}_f \qquad \forall t\in[2,T],\ \ \forall f\in F \tag{16}$$

$$ {G^{ff}}_{f,t-1}+2*{\varphi^{ff}}_{f,t-1}-{G^{ff}}_{f,t}\leq R_f*{P^{ff}}_f \qquad \forall t\in[2,T],\ \ \forall f\in F \tag{17}$$

Basically, the power output in each timestep t cannot imply an increment or a decrease in in respect to the previous timestep $t-1$ of more than the power installed P^{ff} multiplied for the ramp rate R that the technology allows. In these equations both the wholesale ${G^{ff}}_t$ and balancing provision $2*{\varphi^{ff}}_t$ of fossil fuelled power plants are considered in order to guarantee that even in case of requiring the entire output set as provision, the ramp rate does not represent a limitation.

The relative share of start-up costs in overall variable costs of thermal power plants represents around 0.9% for shares of 30% of renewables (Schill et al., 2017). Even with these relative low shares, the operators of these plants take start-up costs into serious account when defining their bidding strategy. Considering the high penetration of renewables that is expected in the coming years, the impact of start-ups in the final costs will consistently increase. The more frequent cycling of conventional fossil fuel power plants to provide flexibility will have both short- and long-term repercussion on the costs of the plants, ultimately increasing the costs se generating technologies (Hermans & Delarue, 2016). In the modelling process, ramping up and down costs were considered jointly, since from a mathematical standpoint the differentiation would not have any effect on the results. Penalize the plants' switching off, due to the loss of the inertia accumulated, by adding a cost for their shutting down, bring to the same output of considering a higher ramping up cost. At each time step, ramping costs ${RC^{ff}}_t$ are equal to the difference between the power output $\left({G^{ff}}_t + {\varphi^{ff}}_t\right)$ of the hour considered minus the one corresponding to the previous hour $\left({G^{ff}}_{t-1} + {\varphi^{ff}}_{t-1}\right)$, multiplied for the specific costs of ramping $C^{Ramping,ff}$. ${RC^{ff}}_t$ is defined as a positive value, so that when the power output decreases, it assumes a value of 0.

$$ {RC^{ff}}_{f,t} = \left[{G^{ff}}_{f,t} + {\varphi^{ff}}_{f,t} - \left({G^{ff}}_{f,t-1} + {\varphi^{ff}}_{f,t-1}\right)\right] * {C^{Ramping,ff}}_f \qquad \forall t \in [2,T], \forall f \in F \qquad (18) $$

As already anticipated, system flexibility can be provided by demand response. In this model two types of DR were considered, load curtailment and load shifting. Load curtailment implies the reduction of demand without recovery at later time. The first constraint for this type of DR is the limitation of the actual curtailment at each timestep LC_t to the capacity developed for this purpose $LC^{Capacity}$.

$$ LC_{p,t} \leq {LC^{Capacity}}_p \qquad \forall \mathrm{p} \in \mathrm{P}, \ \forall \mathrm{t} \in \mathrm{T} \qquad (19) $$

The second constraint for load curtailment is its limitation to the maximum curtailed allowed in terms of duration and to the time of recovery. Basically, it is imposed that in each timestep t the sum of actual curtailment LC_i during the time period that goes from $i = \left[t - {LC^{Rec}}_p + 1\right]$ to $i = \left[t + {LC^{Rec}}_p - 1\right]$ must be equal or less to the maximum duration LC^{Max} multiplied for the capacity $LC^{Capacity}$. This constraint guarantees that load is not curtailed beyond its maximum duration and respects the recovery time ${LC^{Rec}}_p$.

$$ \sum_{i=t-{LC^{Rec}}_p+1}^{t+{LC^{Rec}}_p-1} \left(LC_{p,i}\right) \leq {LC^{Max}}_p * {LC^{Capacity}}_p \qquad \forall p \in P, \ \forall \mathrm{t} \in \left[{LC^{Rec}}_p - 1, \ T - {LC^{Rec}}_p + 1\right] \qquad (20) $$

The second DR modelled is load shifting, that functions as a sort of storage system. The analogy is that load shifting up is equivalent to storage output, whereas load shifting down equals storage input. The first constraint in this sense is the capacity limit, for which the sum of load shifting down in wholesale LSD_t and balancing $2 * {\varphi^{LS}}_{e,t}$, and load shifting up LSU_t, must be equal or less of the capacity deployed $LS^{Capacity}$ at each timestep.

$$LSD_{e,t} + LSU_{e,t} + 2 * \varphi^{LS}{}_{e,t} \leq LS^{Capacity}{}_{e} \qquad \forall t \in T, \forall e \in \mathrm{E} \tag{21}$$

Following with the analogy with energy storage systems, we impose a correlation between the current and previous hour amount of energy "cumulated" in the shifting process, respectively $LS^{Cumulated}{}_{t}$ and $LS^{Cumulated}{}_{t-1}$, and load shifted down in wholesale LSD_t and ancillary services $\varphi^{LS}{}_{t}$, and shifted up LSU_t. At the first timestep, since there is no "previous hour", we eliminate $LS^{Cumulated}{}_{t-1}$ from the equation, assuming that at the beginning of the simulation no energy has been "cumulated" for the shifting of the load.

$$LS^{Cumulated}{}_{e,t} = LS^{Cumulated}{}_{e,t-1} + LSD_{e,t} - LSU_{e,t} + \varphi^{LS}{}_{e,t} \qquad \forall e \in \mathrm{E}, \forall t \in [2, T] \tag{22}$$

$$LS^{Cumulated}{}_{e,t} = LSD_{e,t} - LSU_{e,t} + \varphi^{LS}{}_{e,t} \qquad \forall e \in \mathrm{E}, t = 1 \tag{23}$$

To complete the analogy with storage modelling, the amount of energy shifted $LS^{Cumulated}{}_{t}$ is limited by the maximum capacity of each technology, as the product of output capacity $LS^{Capacity}$ and its maximum duration LS^{Max}.

$$LS^{Cumulated}{}_{e,t} \leq LS^{Capacity}{}_{e} * LS^{Max}{}_{e} \qquad \forall e \in \mathrm{E}, \forall t \in T \tag{24}$$

Since there are technologies that require specific geological or territorial characteristics (such as pumped hydro energy storage) to be deployed or that present only a marginal fraction of future demand (such as electric vehicles), we introduce a limit to their potential expansion. This is done for storage, load shifting and load curtailment, according to the parameters illustrated in the previous subchapter.

$$S^{p}{}_{s} \leq S^{Potential}{}_{s} \qquad \forall s \in S \tag{25}$$

$$LC^{Capacity}{}_{p} \leq LC^{Potential}{}_{p} \qquad \forall p \in P \tag{26}$$

$$LS^{Capacity}{}_{e} \leq LS^{Potential}{}_{e} \qquad \forall e \in \mathrm{E} \tag{27}$$

A technical constraint was imposed to correlate the rotational inertia of the system with the balancing provision requirements in order to guarantee the system stability. By means of the inertia constant defined in the previous subchapter, we calculate the inertia of the system I_t (Independent Market Monitor for ERCOT, 2019; Mehigan et al., 2020). This is set to be equal to the sum of the inertia provided by each power generating unit, obtained as the product of the power output for the respective inertia constant RI. The inertia of the system is then used to calculate the frequency reserve requirements Y_t, defined as a percentage of demand. The equation was deterministically determined starting from the values of balancing reserve in current energy systems, and expectations of requirements in future energy systems (It has to be noticed that in the model we give as input data in MW). We impose a minimum of 4% of frequency reserve, to avoid distortions for values of rotational inertia higher than 100.000 MWs.

$$\sum_{r=1}^{\partial}\left(G^{Ren,e}{}_{r,t} * RI_r\right) + G^N{}_t * RI_N + \sum_{z=1}^{Z}\left(G^{Ren,a}{}_{z,t} * RI_z\right) + \sum_{f=1}^{F}\left(G^{ff}{}_{f,t} * RI_f\right) + Imp_t * RI_f = I_t \qquad \forall t \in T \tag{28}$$

$$Y_t = 0{,}24 - 0{,}000003 * \ I_t \qquad \forall t \in T \tag{29}$$

For security of supply reasons, each country is likely to subsidize some generation power plant that would otherwise shut down for the lack of economic availability. Recently this has been done in other countries (such as Italy) through capacity remuneration mechanisms, where a bidding process determines the remuneration for this extra capacity that is used to guarantee security of supply. Current practice for the calculation of the capacity required is based on the value of lost load (VoLL), a monetary indicator expressing the costs associated with an interruption of electricity supply. Even though the evaluation of a capacity market is out of the scope of the project, it was set that the national installed capacity should always be sufficient to satisfy demand, in order to guarantee security of supply. In this sense, the lost load is partially considered by considering load curtailment. Thus, the sum of the existing renewable generation $G^{Ren,e}{}_t$, nuclear generation $G^N{}_t$, the generation that comes from additionally installed REN power plants $G^{Ren,a}{}_t$, storage output $S^{output}{}_t$, fossil fuel installed capacity P^{ff} multiplied by its availability factor $\left(1 - U_f\right)$, and demand response LSD_t and LC_t, needs to be equal or greater than demand DE_t at each timestep.

$$\sum_{r=1}^{\partial} G^{Ren,e}{}_{r,t} + G^N{}_t + \sum_{z=1}^{Z} G^{Ren,a}{}_{z,t} + \sum_{s=1}^{S} S^{output}{}_{s,t} + \sum_{f=1}^{F}\left(1 - U_f\right) * P^{ff}{}_f + \sum_{e=1}^{E} LSD_{e,t} + \sum_{p=1}^{P} LC_{p,t} \geq DE_t \qquad \forall t \in T \tag{30}$$

The last constraint refers to interconnections exchange limitation, according to the assumptions previously described. Imports Imp and exports Exp at each time step needs to be lower than the capacity limits of the interconnections, respectively $ImpC$ and $ExpC$.

$$Imp_t \leq ImpC \qquad \forall t \in T \tag{31}$$

$$Exp_t \leq ExpC \qquad \forall t \in T \tag{32}$$

The time frame considered for the simulations is 4 years, with a resolution of 1 hour. Smaller time frames were tested but seemed to distort the results, mainly due to the sensitivity to REN output. Instead, simulations based on longer time frames (i.e. 10 years) present results only slightly different - supposedly more precise - but computationally far more complex to be obtained. For the scope of the study, a 4-year time frame was selected as a good trade-off between accuracy of results and time required for the script to find the optimal solution.

6.5. Limitations and other considerations

In this chapter the model has been presented in detail, with an extensive explanation of its working principles, the elaboration of the parameters and the major assumptions. In this section the most relevant limitations of the model and the way in which these may affect results are discussed.

However, before going any further, it is important to stress that the aim of this model is to provide benchmarks for storage capacity in an optimized future power system with high penetration of renewable energies. In fact, we do not enter in behavioural analysis or grid modelling, and do not investigate the best path for the transition, always assuming long-run equilibrium, which restricts the potential to draw policy conclusions regarding the optimal transformation path toward future highly renewable energy systems. This analysis should rather guide policy makers to understand the requirements of flexibility-providing technologies and their sensitivity to different future scenarios, in order to design regulatory framework that can facilitate the adoption of these technologies. Results should not be interpreted as a forecast, but rather as a benchmark for the development of such optimized energy system.

First, it is relevant to mention the linearization of technical constraints that would otherwise be impossible to model in a linear modelling environment. For example, the ramping costs of fossil fuels represent the costs of start-up of conventional power plant, and similarly the ramping limits are based on the whole capacity installed, thus neglecting start-up restrictions or minimum load of single facilities.

The model is built around the Spanish energy system, which has required an extensive research regarding the modelling of each generating technology, the assessment of the demand, the potential for future technologies deployments and the modelling of the interconnections. This last point is especially tricky since it could distort the results because of the possibility of real energy systems of smoothing both renewable intermittency and power demand by balancing over larger geographical areas. However, as already said, a better approximation would imply to simulate other countries' demand and renewable generation, which are interdependent to their respective national strategies and possible future scenarios, consequently increasing the computational complexity and the number of hypothesis of the model without necessarily improving the quality of the analysis.

Another limitation that may distort results is that demand profile may become smoother in the future because of demand-side innovations and behavioural changes. This goes side by side with new flexibility options and new flexibility requirements that may arise from the coupling with other sectors, such as transport and heat. In fact, in this study we focused on the electricity system, simulating the demand according to different sources, without addressing a possible increasing integration among energy systems. Examples of this are power-to-heat applications that may take up temporary renewable surpluses and flexible electrolysis that may be used to generate hydrogen, which could be used for many purposes besides electricity generation.

Even though in the model we use a time frame possibly large enough to take into consideration the majority of the renewable output situations, an aspect that could improve the quality of the results consists in the usage of meteorological data for a bottom-up determination of the hourly capacity factors of variable renewable generators.

Despite what has been said in this subchapter, the simplifications illustrated makes possible the formulation of the model and enables the development of several sensitivity analysis, which is extremely important seen the uncertainty of the parameters characterizing future energy systems.

We believe that the model represents a powerful tool for analysing the future needs of energy storage and to build regulatory framework with the aim of reaching an optimized energy system fully beneficial to all consumers.

7. Results and discussion

In this chapter the main findings from the model simulations are presented. First, an analysis for different penetration of renewables is illustrated, in order to understand how the optimal electricity infrastructure changes while increasingly decarbonizing the energy mix. The model is then used to validate the national energy plan, assessing whether the planned electricity infrastructure will be able to achieve the targets set for 2030. The evaluation of the plan comprises an analysis of storage requirements corresponding to different forecasted operating hours of renewable energy sources, in order to assess whether less optimistic capacity factors than the ones considered in the PNIEC would increase the capacity requirements of both storage and RES. Moreover, a sensitivity analysis as far as the cost parameters is performed to understand the relative influence of the parameters and the consistency of the results. Lastly, some considerations regarding the hourly electricity balance are given.

7.1. Storage requirements for different penetration of renewables

The model, as extensively explained in the previous chapter, optimizes the storage requirements for an efficient integration of renewables. Balancing storage and renewable excess generation – that is either exported or curtailed - is key to achieve the optimal solution, and the optimal ratio between these two depends on many factors, such as the price and efficiency of the different technologies, the demand profile and the renewable penetration target. This last factor is the object of this subchapter. The objective is to assess how the increase of required renewable generation in the energy mix affects the infrastructure planning.

The sensitivity analysis is developed around the current Spanish electricity system. Hourly demand has been downloaded from ref. (Red Eléctrica de España, 2020a) and corresponds to the one from 01/01/2016, 00:00 to 31/12/2019, 23:59. The existing renewable generation and the capacity factors of renewables are based on the historical data downloaded from ref. (Red Eléctrica de España, 2020a) as well and correspond to the period that goes from 01/01/2016, 00:00 to 31/12/2019, 23:59. They have been adapted in order to take into account for the increase of capacity throughout the years by following the same process described in the previous chapter. For the purpose of this analysis, nuclear generation is neglected, since in the model its power capacity and generation profile are given as inputs - that is that there is no evaluation of the capacity to either be dismantled or maintained, the capacity is set by the user – and thereby it would either represent a limit for the increase of renewable share beyond 85% or require to be gradually diminished in input while increasing the share of renewables.

The model has run with different shares of renewables as target, more precisely between 50% and 100%, with a resolution of 10%. Figure XIX illustrates the results in terms of additional power capacity of generation and storage technologies required to efficiently integrate the specified share of renewables in the optimal configuration. As it was expected, photovoltaics is the predominant technology thanks to low costs and the favourable climatic conditions of Spain, characterized by high levels of solar irradiation throughout the entire year. Eolic plays an important role, especially when significantly increasing the penetration of RES. Concentrated Solar Power does not appear as a convenient solution based on the techno-economic characteristics considered in the modelling process.

As far as storage is regarded, PHES represents the most economic efficient solution, reaching the limits set to its potential expansion already at a share of 70% of renewables. The other two technologies assessed presents very different characteristics. The energy-to-power E/P ratio is an important metric to characterize a storage technology and reflects its temporal layout: a 6 hours storage is a typical short-to-medium-term storage to compensate diurnal fluctuations, such as of solar PV generation, whereas a long-term storage aims at compensating weekly or even seasonal fluctuations. This difference highlights the importance of considering both rather inexpensive storage energy and rather expensive storage power separately to evaluate the optimal system configuration. From our simulation, Li-Ion is the technology preferred, indicating higher requirements in terms of power rather than energy capacity. The explanation for this result must be found in the lower specific-to-power cost of Li-ion, that makes this technology interesting when there is no excessive requirement of energy capacity. From our simulations, no need for a true long-term storage arises, that is, storing energy for months, unless the target is raised to 100%, where Power-to-Gas becomes essentials and plays a relevant role if there is no possibility of further expansion for pumped hydro.

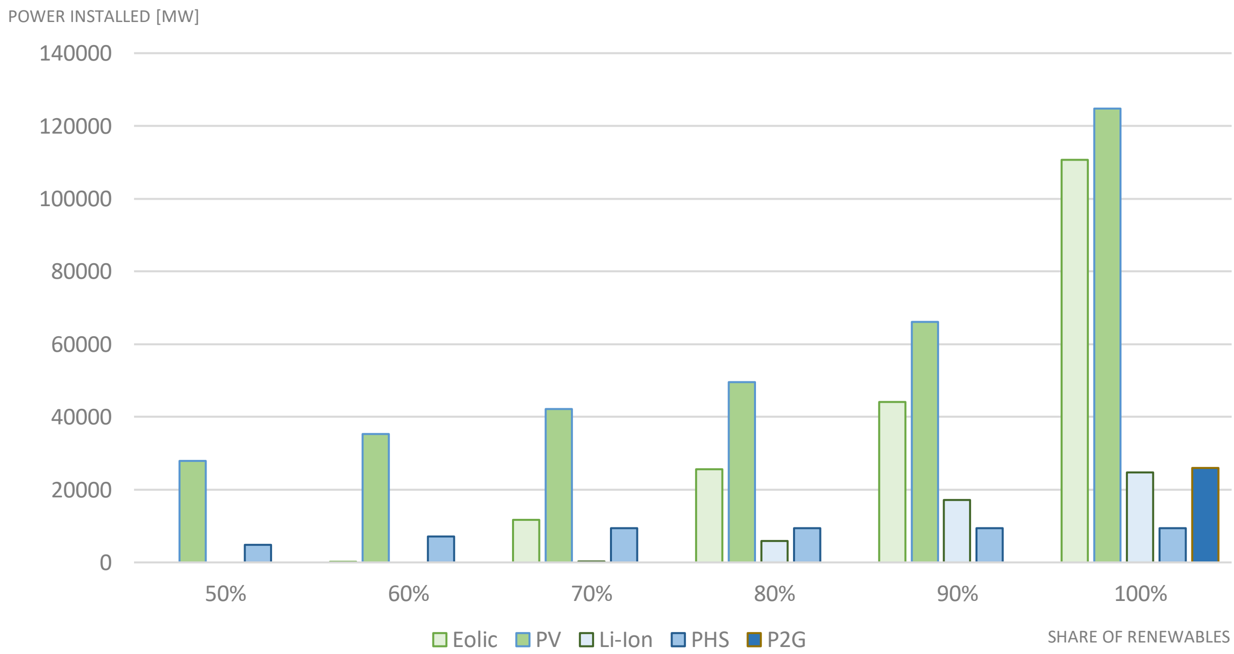

Figure XIX: Generation and storage power capacity to satisfy demand with different share of RES.

Figure XX presents the results of the same simulation but focusing on energy storage. Optimal storage capacities, both with respect to energy and power, rise in parallel with the increase of variable renewable energies in the energy mix. However, overall storage requirements remain moderate. For instance, a storage power capacity of 4,9 GW would be sufficient to achieve a share of 50%

renewables in the energy mix. Yet it is less than the capacity installed in Spain in form of pure pumping and mixed pumping PHES by 2020.

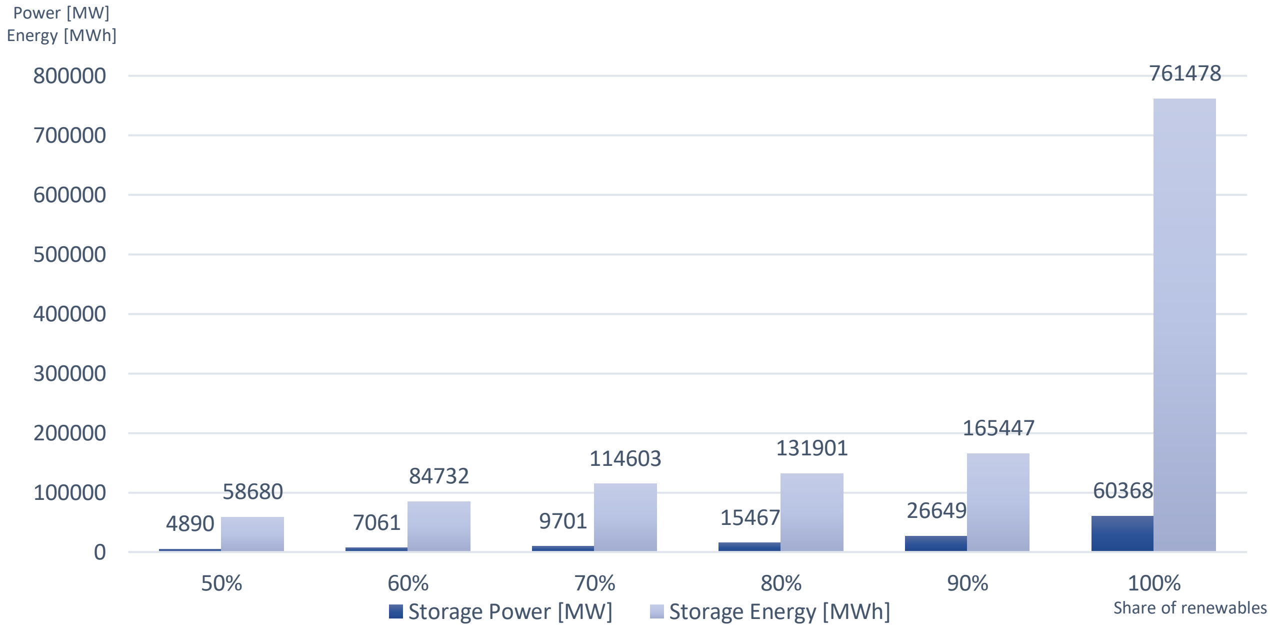

Figure XX: Storage power and energy requirements to satisfy demand with different penetration of REN.

As presented in the previous chapter, storage is not the only flexibility providing technology assessed, since account is taken for two types of demand response. In the following figure it is possible to appreciate the relative weight of each technology in terms of power installed. According to our assumptions, demand response – and especially the industrial contribution - plays a relevant role for lower share of renewable energy, whereas its relative weight diminished with respect to storage technologies when increasing the share of renewables.

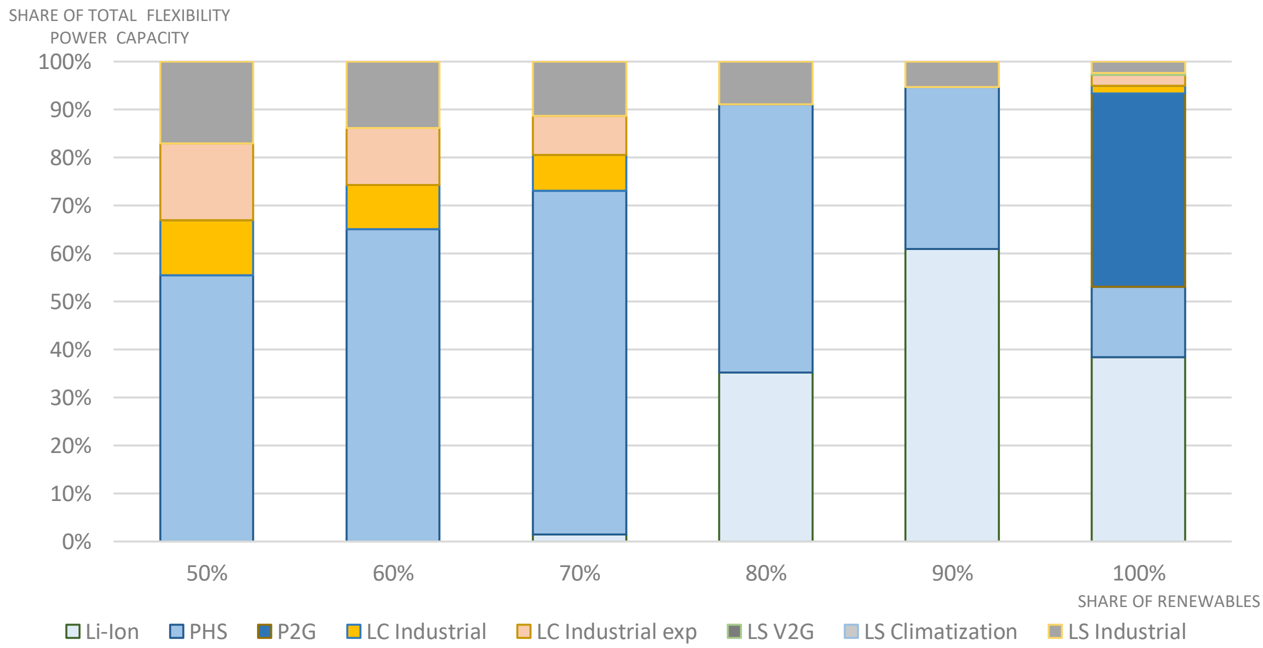

Figure XXI: Share of each technology's power capacity of the total of flexibility providing technologies' capacity.

Figure XXII presents the data regarding energy curtailed and stored on a yearly basis. The line, which has its referral axis on the right, represents the ratio between energy stored and curtailed. It can be seen that an increase in the share of renewables implies that the amount of energy stored throughout the year increases accordingly but, at the same time, it implies the curtailment of a good portion of the excess energy. This indicates that it is not efficient to completely avoid curtailment, which also grows in parallel with higher minimum renewables shares. As such, the economics of renewable electricity provide no reason why curtailment should be avoided. It can be more efficient not to use available renewable energy at times despite costly investment into wind and PV plants. Thus, the optimal solution combines conventional plants, storage, demand response, and renewables, part of which being curtailed at times.

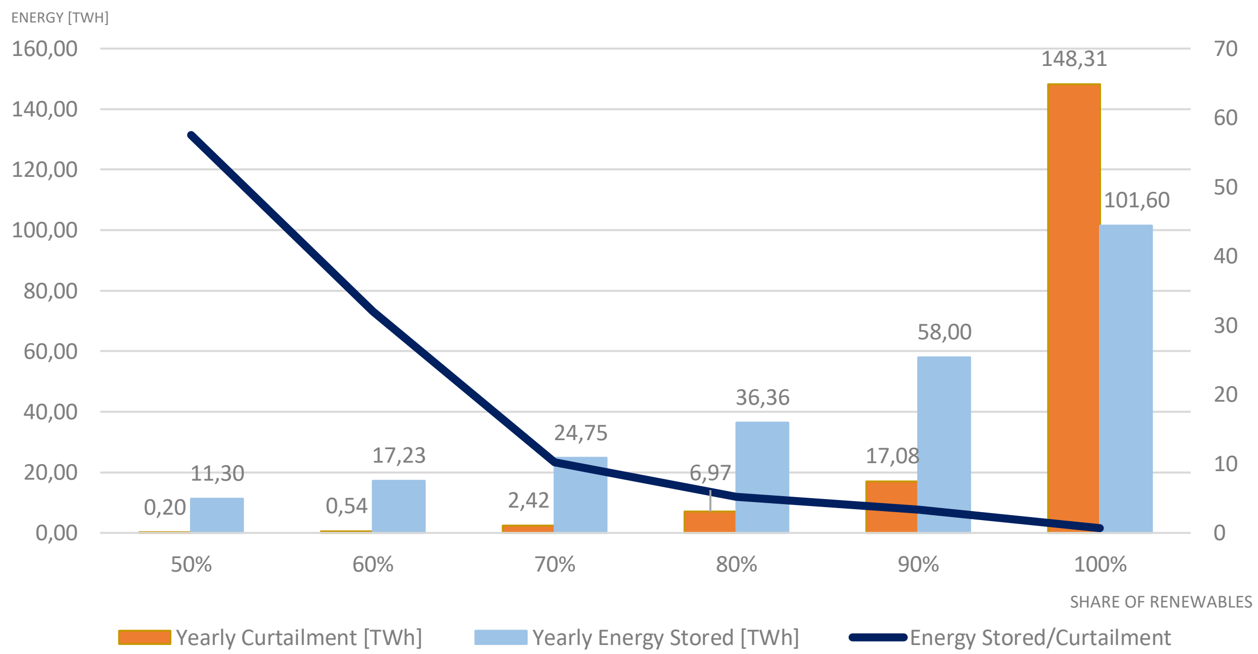

Figure XXII: Energy stored and curtailed for different penetration of REN.

To summarize the results of the parsimonious optimization model applied to different shares of renewables, here are the main findings:

- Despite its limited dispatchability, photovoltaics is the preferable technology thanks to its low cost and the high irradiation that characterizes the Spanish peninsula. Wind turbines will play a relevant role as well in decarbonizing the energy mix, whereas CSP is not considered cost-efficient compared to the other two technologies assessed.
- Storage requirements remain moderate, the capacity currently installed in Spain is already sufficient to accommodate renewables up to almost 60% of final demand. Power-to-Gas seems to be part of the optimal solution only when moving towards the complete decarbonization of the energy mix.
- Seen the low costs of renewable power systems and the still relatively high costs of storage technologies, the optimal configuration implies to curtail a portion of REN generation.

7.2. Spanish PNIEC analysis

The model for the evaluation of the Spanish energy plan has been built around the one used in the previous subchapter but reduced in its degrees of freedom to only assess the storage requirements. Therefore, no additional renewable generation capacity can be used to reach the specified share of renewables in the energy mix. The aim of this simulation is to verify if the generation and storage infrastructure planned for 2030 can consistently reach the 74% of renewables in the energy mix, that is target set in the national energy plan.

To simulate the 2030 scenario, an accurate review of the Spanish energy plan has been performed, especially regarding demand and power installed of each technology. The demand used for the plan definition comes from the ENTSO-e analysis, and specifically refers to the Distributed Generation scenario (DG). The scenario elaboration has been done to result as realistic and technically sound, based on forward looking policies, whilst also being ambitious in nature and aiming at reducing emissions by 80 to 95% in line with EU targets for 2050 (ENTSO-E & ENTSOG, 2018). As far as REN generation is regarded, the capacity factor of each technology is determined considering generation registered by REE and downloaded from esios.es for the time period from 01/01/2016, 00:00 to 31/12/2019, 23:59. As described in chapter 6 Methodology, a linear relation between the power installed year-to-year has been used to calculate the hourly capacity factor of each technology at a national level. Then these data have been considered in parallel with the annual operating hours presented in the PNIEC and, in order to simulate under the same assumptions, the hourly capacity factors of each technology have been adapted to obtain the same annual operating hours of the national plan (as described in chapter 6). This is done in order to work with data as close as possible to the ones used for the actual planning of the strategy, and at the same time consider historical data for the variability of REN energy sources.

7.2.1. Validation of the model

The input elaborated for this simulation were validated by considering the yearly renewable generation output, set to be – on average - 264 TWh in the simulation, against the 266 TWh according to the PNIEC. The storage requirements to efficiently satisfy 74% of demand with RES are illustrated in Figure XXIII, where these are presented in parallel with the planned capacity in the PNIEC. The results are consistent, in terms of both total capacity – 12 GW in the PNIEC and 11,2 GW in the simulation – and technology mix. These results were extremely useful since they provided a reliable validation of the model and allowed the study of the behaviour of the system and the simulation of different scenarios.

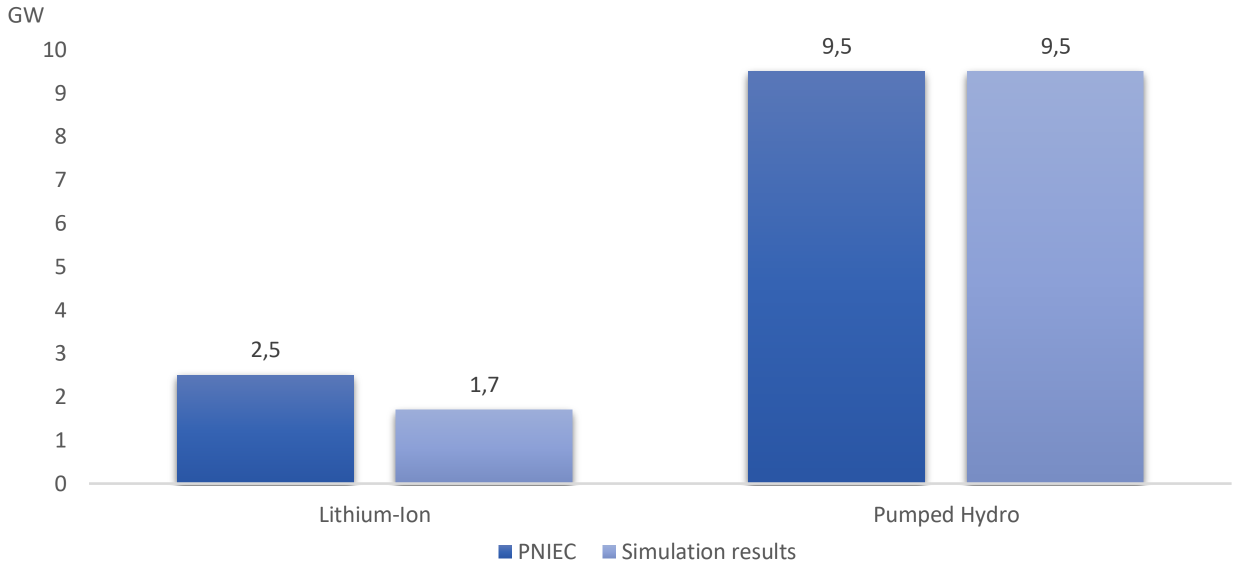

Figure XXIII: Storage requirements planned in the PNIEC in comparison with the output of the simulation.

An interesting aspect of the optimization is that requirements in terms of fossil fuels capacity - for flexibility and back up purposes - only accounts for 20.6 GW, according to the model. This is interesting especially in comparison with the 32.1 GW that the plan set to maintain in function in 2030. In this sense, it is important to notice that in 2030 there will be nuclear power plants still running, but, in a longer perspective, these will be dismissed and CCGT will play an even more important role, also providing base load. Moreover, the model considers timesteps of 1 hour, whereas peaks can last minutes or even seconds, and the intrinsic stochasticity of renewable output could generate extreme situations that did not concretize during the period 2016-2019, which is the one adopted for the purpose of this study.

7.2.2. Residual load curve

The residual load is a time series that is derived by subtracting the time series of the potential non-dispatchable electricity generation - in this case all renewables and nuclear - from the time series of power demand. Sorting this residual load in descending order gives the RLDC (Residual load duration curve). This RLDC contains information about key aspects related to the integration of intermittent renewable energy sources, such as the reduction of operating hours of thermal power plants and the amount of excess energy (possibly leading to curtailment). Different authors have highlighted the importance of the RLDC for the investment planning problem (De Jonghe et al., 2011; Edenhofer et al., 2013). Residual load is an indicator in a power system. It shows how much capacity is left for conventional power plants to operate. Traditionally, when variable renewable energy sources are small in scale comparing to the demand load, conventional power plants vary their power output in accordance with the demand load curve. As the capacity of VRE grows, its power output begins to affect the load balance of the power system. A new indicator is needed to describe the situation, giving birth to this terminology.

Figure XXIV presents three RLDCs, one without any storage contribution, another considering only Li-Ion batteries contribution, another with pumped hydro energy storage contribution and finally one that take into account all storage technologies resulted from the model, or rather demand response in addition to the previous ones. The representation of these curves is useful to understand the role of fossil fuel power plants both in terms of capacity installed and energy generation, but especially to visualize the storage dispatch behaviour. The graph consists of an area chart (simple, not stacked), with the power on the vertical axis and the time periods on the horizontal axis. In order to better understand how to read the chart, the data of the curves are sorted in descending order, therefore time on the horizontal axis is a cumulative indicator, representing how much time either fossil fuel power plants need to operate (on the left), or energy is curtailed (on the right). To facilitate the comprehension of the graph, the residual load duration curve that results from subtracting renewable and nuclear generation from the demand is the one in dark blue represented behind. The second layer – in green - represents the residual load curve taking into account Li-Ion power input and output, while the third layer – the grey one - represents the final load curve obtained by considering all storage technologies (Batteries and pumped hydro in this case). Finally, the layer in front – light blue – is the one comprising the demand response mechanisms contribution. To further clarify, the visible green area of the chart corresponds to the energy that flows through the PHES systems, on the right side of the graph – characterized by negative values – pumped hydro upper reservoirs are filled, whereas on the left the energy is discharged. In the same way, the dark blue area represents the energy flows through the batteries and light blue one is the result of all flexibility services provided by charging and discharging storage and shifting or curtailing load.

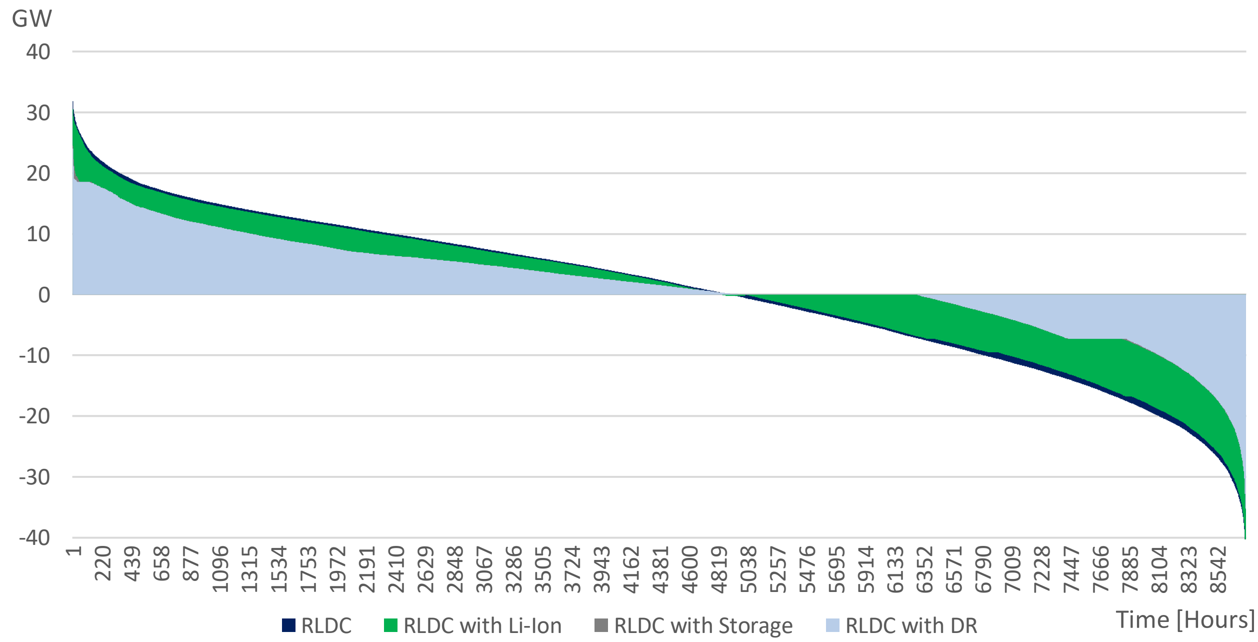

Figure XXIV: Analysis of the residual load duration curve of the PNIEC simulation.

Figure XXV presents again the RLDC, but this time it only takes into account the hours presenting values of residual load closer to zero, thus excluding the ones characterized by the highest and lowest values, in order to analyse the graph with higher resolution on the vertical axis and better distinguish among each technology contribution. It must be kept in mind that the RLDC is a very powerful tool to analyse the system behaviour, but its limitation is its intrinsic dissolution of the temporal sequence of timesteps. With the present patterns of demand and renewable output, it is unlikely that to an hour with very high residual load follows closely an hour with renewable surplus generation. Despite that, the results of this simulation indicate that storage is not discharged necessarily whenever the residual load turns positive, but it rather stores energy for time of greater scarcity.

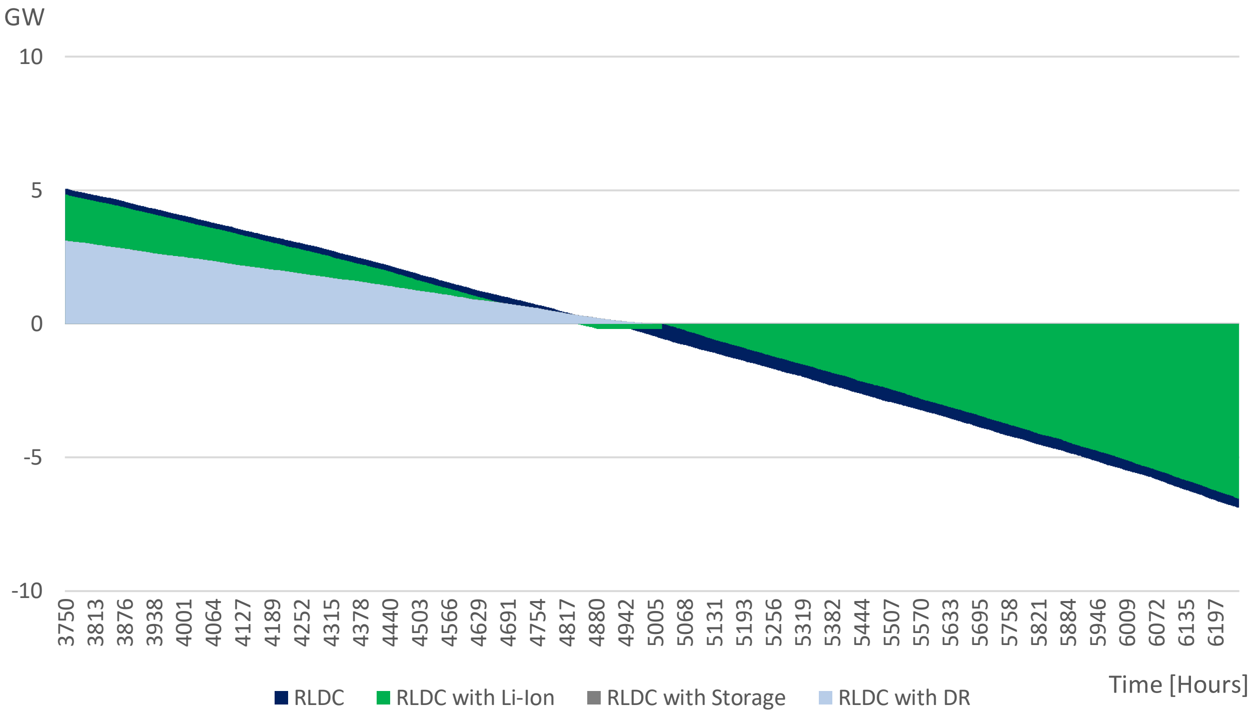

Figure XXV: Analysis of the residual load duration curve of the PNIEC simulation.

Figure XXVI shows more in detail the 500 hours that are characterized by the highest RLDC. By simply giving a look at the chart, one can infer that the optimal storage dispatch strategy implies to provide peak shaving in order to limit fossil fuels required capacity. The model, considering the additional contribution of imports that do not appear in the chart, recommends to maintain roughly 20.7 GW (there is an additional contribution of imports that allows to further shave the peak), instead of the 35 GW of fossil fuel generation systems that would be otherwise required if no storage system and demand response mechanism were deployed. The additional capacity of 14.1 GW – corresponding to more than 50% of the capacity installed in the optimal configuration – would be required to run during roughly 120 hours per year (or rather 1% of the time) and not even at full power. This translates into a generation output of only 590 GWh per year, corresponding to less the 50 operating hours at full speed. Peak shaving results therefore to be a fundamental feature of storage systems, avoiding the installation of fossil fuel power plants that would eventually be under exploited.

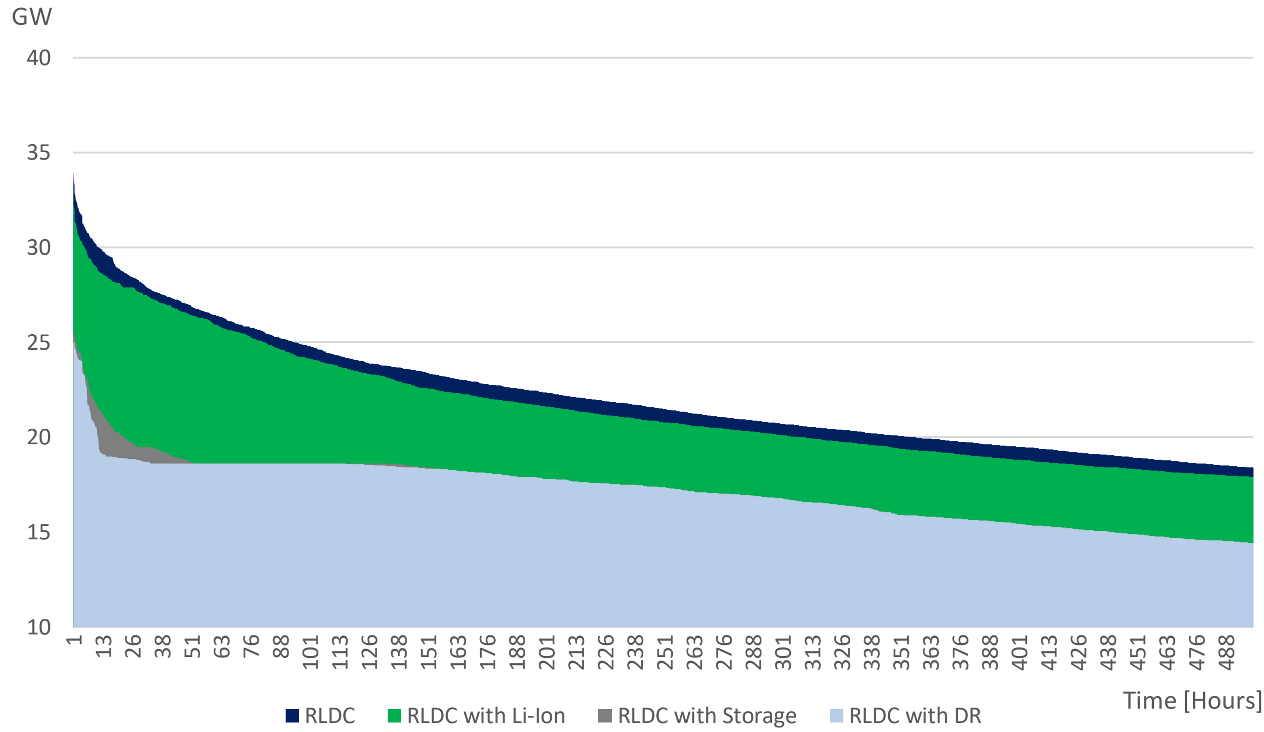

Figure XXVI: Residual load curve during the yearly 200 hours of RLDC's peak.

The main findings from the analysis performed on the residual load duration curve are that storage optimal dispatch strategy does not consist in discharging it necessarily whenever the residual load turns positive, but rather to take advantage of it during moment of greater scarcity, and it implies its usage to provide peak shaving, avoiding in this way additional fossil fuel power plants, that otherwise would be running less than 120 hours a year.

7.2.3. Questioning the PNIEC assumptions

In the previous subchapter the model has been simulated trying to follow the hypothesis assumed in the PNIEC as closely as possible. As expected, the results are consistent - both in terms of storage requirements and energy flow – with the ones presented in the plan. However, as already discussed in chapter 6, the assumptions on which these results are based are quite optimistic. In fact, even though technology may advance, and capacity factors may increase, they would have to improve a lot to outperform current power plants, which have already occupied the best spots.

With the aim of verifying the robustness and reliability of the planned infrastructure, the model has been simulated assuming different capacity factor. Specifically, the planned infrastructure for 2030 has been tested assuming that the specific output of the installed capacity resembled the output historically registered and downloaded from esios.es, as described in chapter 6.

Figure XXVII presents a comparison – differentiated for technology - between the optimal energy storage requirements in the two scenarios. The increase shown in the chart is notable. The requirements of Lithium-Ion rise substantially and P2G – corresponding to hydrogen energy storage

– becomes a necessary tool for the transition. Overall, when simulating with historical capacity factors, storage power requirements are more than twice the ones found adopting the PNIEC assumptions (24.5 compared to 11.2 GW).

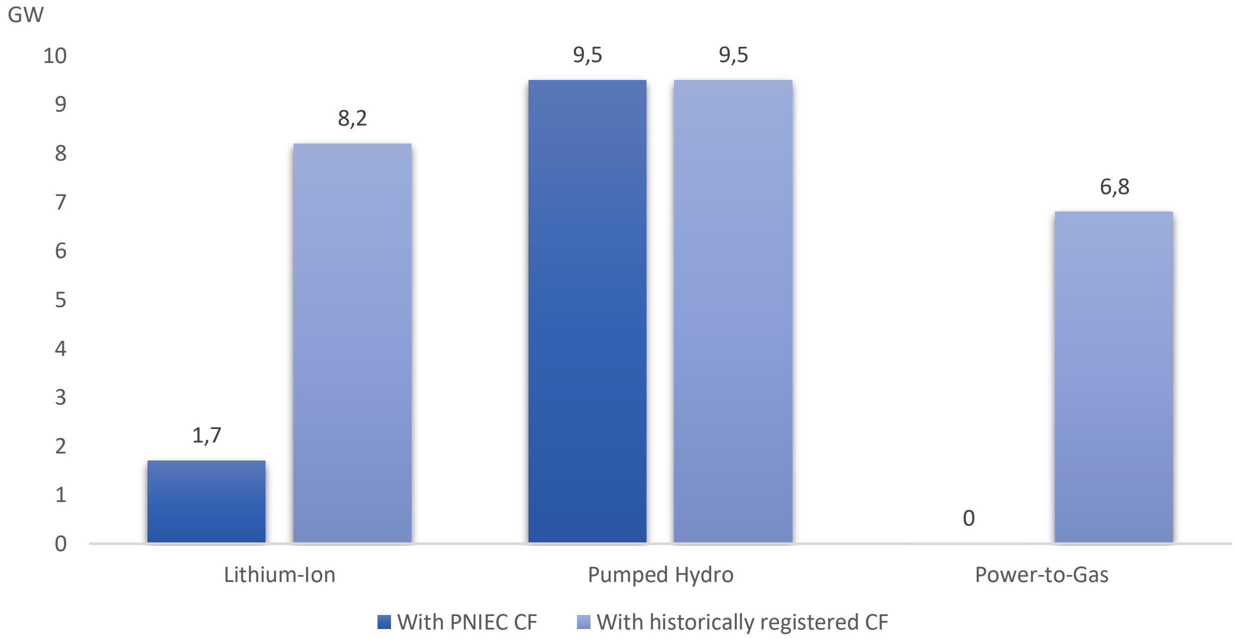

Figure XXVII: Comparison of the optimal energy storage technology mix in the two scenarios.

To better contextualize the infrastructure requirements illustrated in the previous chart, the residual duration curve provides an insight on the system energy flow (Figure XXVIII). The area in light blue, corresponding to the RLDC with storage inflow and outflow and demand response considered, shows why the storage requirements - especially of P2G – increase that sharply. Almost all the excess of renewables - right side of the chart - is stored for later use. Considering the same installed capacity as in the previous simulation, but with different hourly capacity factors, the energy generated from renewables varies, thus modifying the residual load curve. Since the annual operating hours of this second simulation are lower, the RLDC with no storage contribution is shifted towards right. This requires more energy to be stored for later use, thus moving it from the right negative part of the curve to the left positive side, as in Figure XXVIII.

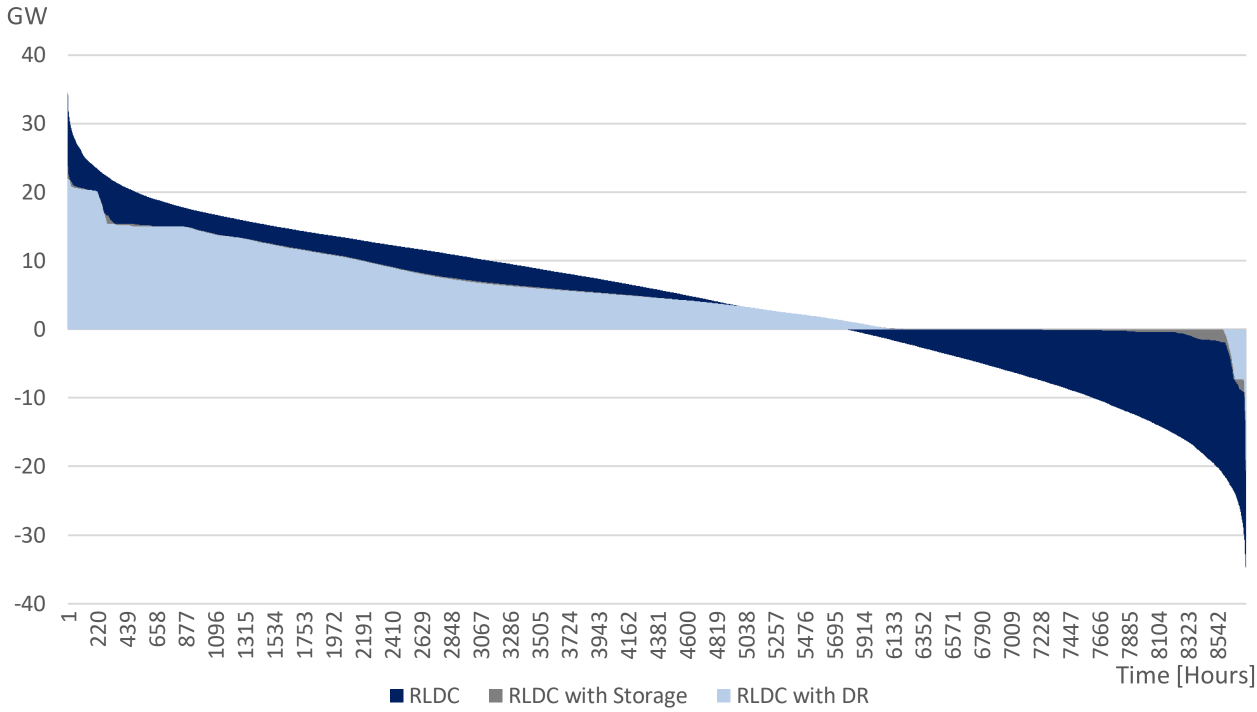

Figure XXVIII: Residual load duration curve resulted considering historical registered capacity factors.

To put it in perspective, in the first simulation the excess renewable energy generation throughout the year was around 48.2 TWh, of which 19.6 were stored and 28.6 either curtailed or exported. In this second simulation, because of the smaller excess of renewable energy, almost every kWh needs to be stored to achieve the target of 74% of renewables in the energy mix (29.6 out of 30.6 TWh need to be stored in this second case, thus requiring more storage capacity for long-term applications). Figure XXIX shows an illustration of these values.

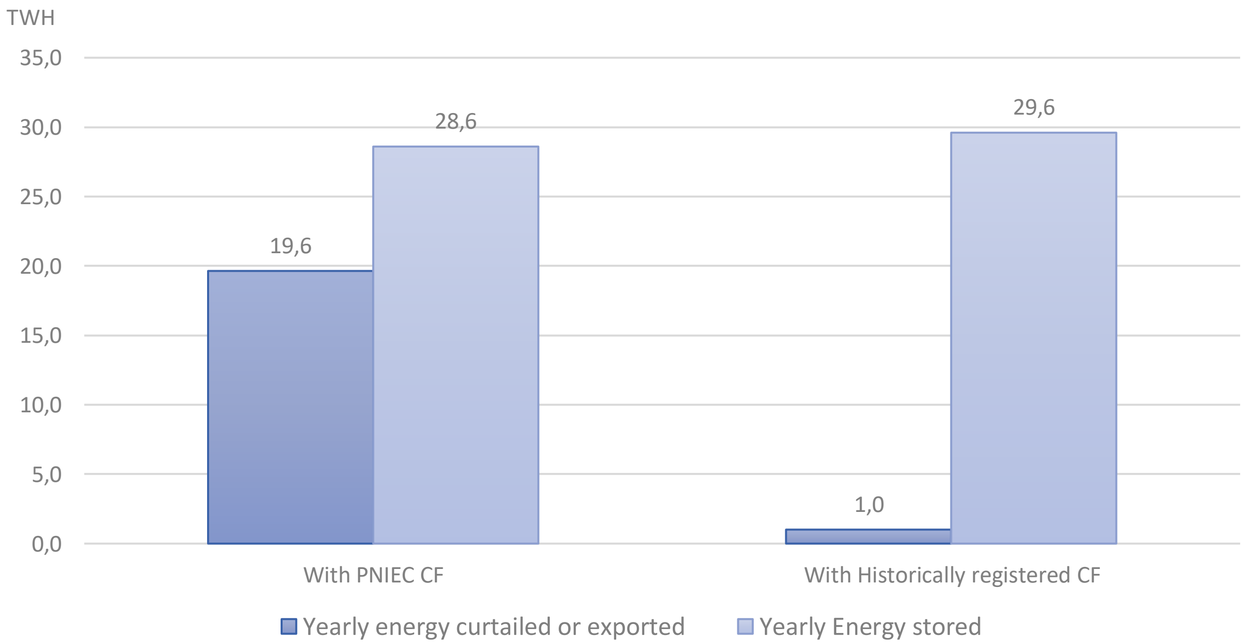

Figure XXIX: Comparison of renewable excess usage in the two scenarios.

In this subchapter it has been outlined the importance of performing an assessment of the robustness of the assumptions when planning energy systems infrastructure investment. In this specific case, the results of the simulation are very susceptible to the annual operating hours assumed, that therefore needs to be evaluated with more attention, in order to avoid the underestimation of the generation and storage infrastructure.

7.2.4. Robustness of the national energy strategy

In the previous subchapter the storage requirements based on historical operating hours of renewable technologies were assessed. However, the model used had only the freedom of installing additional storage, and no additional generation capacity was allowed. This resulted in extremely high storage requirements since almost no energy could be curtailed. In this chapter the same problem has been assessed, but the degree of freedom of adding additional renewable capacity was added. In fact, as it was found in the sensitivity analysis, the optimal solution from a system perspective implies a certain amount of curtailment.

Figure XXX shows the storage requirements of this simulation in comparison with the ones resulted from subchapter 7.1 and the actual capacity planned in the national energy strategy. By looking at the bar chart it can be inferred that storage seems to be appropriately planned in the PNIEC. In fact, both the simulations – assessing different operating hours of renewables – indicate storage capacity requirements in line with the ones planned. However, it is important to notice that, to reach the target of 74% of renewables in the energy mix, this last simulation – considering historical annual operating hours of renewables - implies the installation of additional 6 GW of solar photovoltaics on top of the power capacity already planned for 2030.

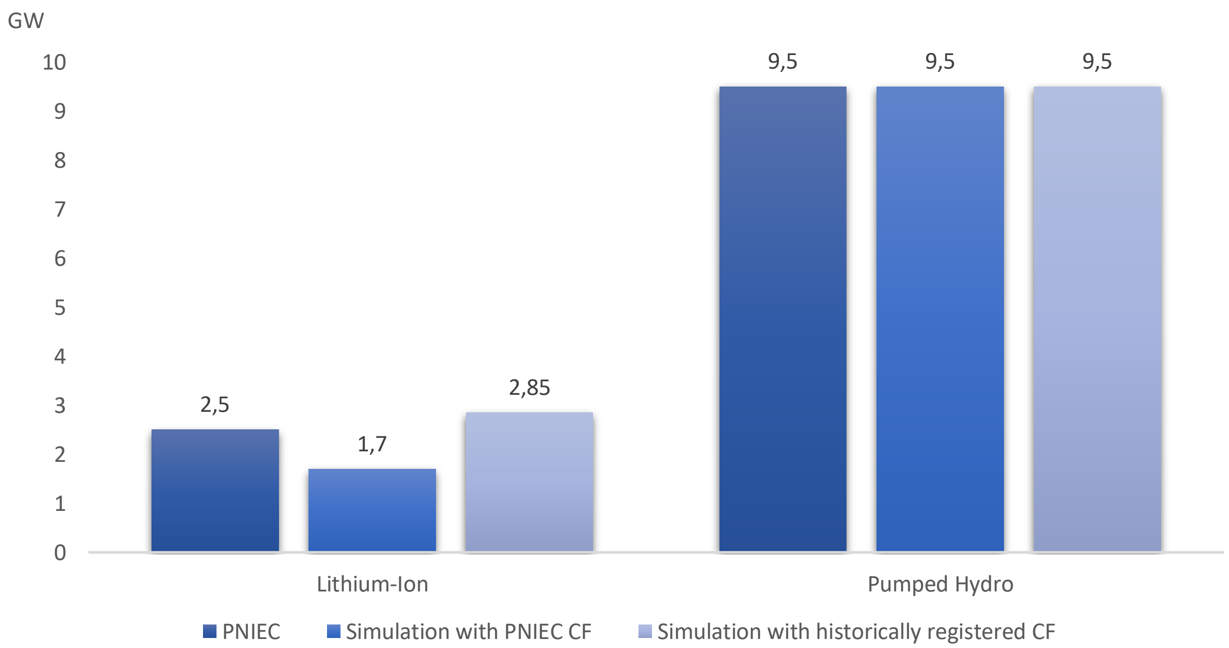

Figure XXX: Comparison of renewable excess usage.

Since the model allows the traceability of the output, to further validate the consistency of the results, an assessment of the parameters that were expected to be more impactful on the results have been performed. The scenarios have been evaluated simulating with the historically registered hourly capacity factors and compared with the baseline scenario, whose results have been already illustrated. The specific variability of the parameters is illustrated in subchapter 6.3 in each respective table; however, the scenarios are briefly summarized here:

- Natural gas costs are doubled and halved, which only impacts the cost per kWh of energy generated and the cost of ramping;
- Demand response potential expansion limit of each technology is both doubled and halved;
- Demand response specific CAPEX and OPEX of each technology are both doubled and halved;
- Storage specific CAPEX are doubled and halved.

In Figure XXXI the results are presented. One can easily infer that, except for the variation in cost of storage technologies, the output of the model suffers minimal variations in terms of power installed of each technology.

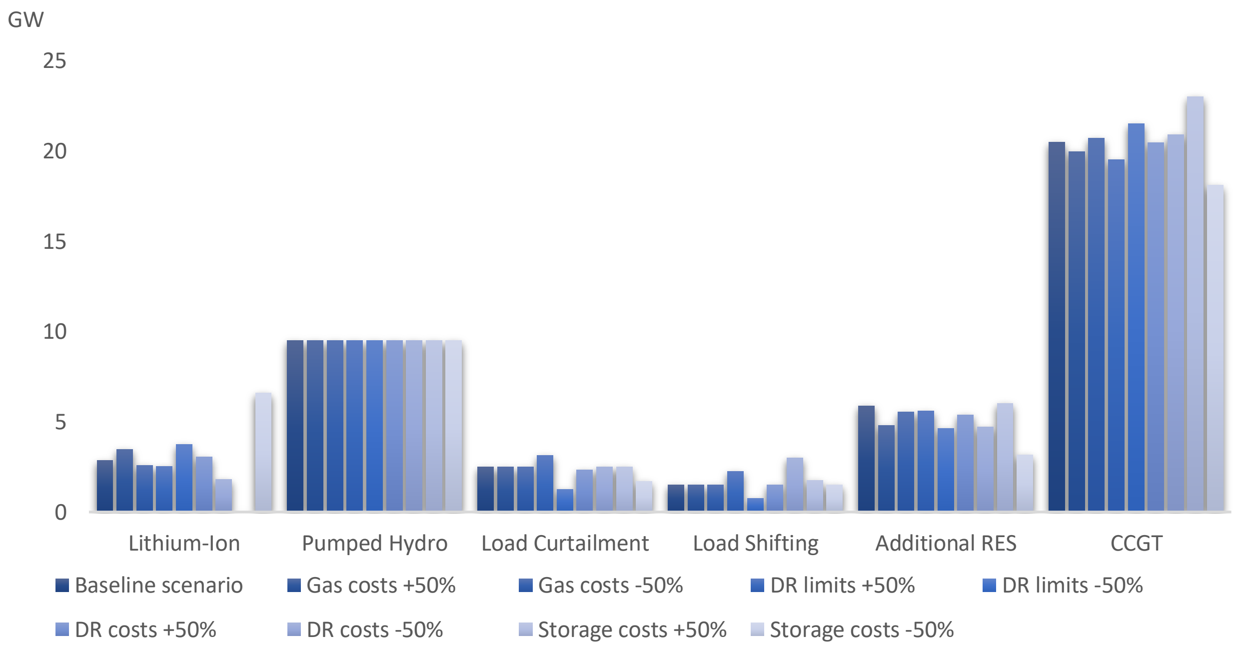

Figure XXXI: Sensitivity analysis of the parameters.

When analysing the sensibility to the variations of these parameters, the probability that the scenarios can be concretized have to be weighted. This is especially relevant with scenarios that strongly affect the results in comparison to the baseline one. Figure XXXII focuses on the sensitivity of storage requirements to the parameters assessed. The power storage requirements in respect to the ones in the baseline scenario oscillate between a limited range (-1.04 GW; 0.89 GW) in each scenario, if we neglect the ones with costs of storage 50% higher and 50% lower. These last two scenarios deserve specific considerations.

A cost 50% higher for storage technologies would only affect Li-Ion storage requirements, whereas PHES would still be the most competitive flexibility provider. However, according to Bloomberg New Energy Finance (BNEF), utility scale Lithium-Ion batteries installations have already reached total investment cost of 180 $/kWh, which is in line with the parameters adopted in the baseline scenario. Again, according to BNEF, battery pack should be around 94 $/kWh by 2024 and 62 $/kWh by 2030. For this reason, we are quite confident this scenario does not present much relevancy when defining a strategy for planning the electricity infrastructure of the future. On contrary, seen the prediction of drastic reduction of battery cost for the near future, it cannot be discarded that the optimal battery storage requirements to reach better cost efficiency for the system could be as high as 6.6 GW, as accordingly to the last simulation represented in the following figure.

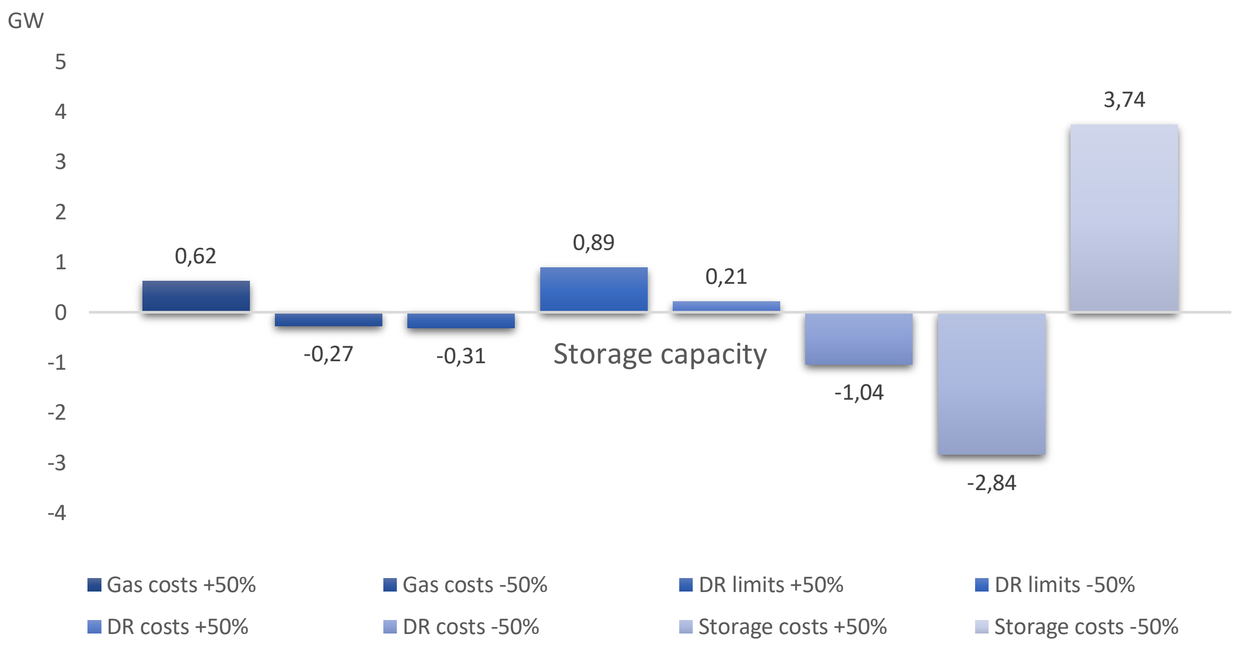

Figure XXXII: Storage requirements' variation from the baseline assumptions under different scenarios.

7.3. Storage dispatch analysis

In this section an analysis of storage energy flow is done by assessing how the model recommends operating this technology in order to maximize the system cost-efficiency. First the energy flow of the entire system is analysed for typical days of summer and winter, then the usage of the storage on a yearly basis and distinguished for technology is presented.

7.3.1. Hourly energy balance

By taking a sample of 168 hours – corresponding to a week - as a representation of the system energy balance during winter and summer days, it is possible to have an insight on how the system behaves while dealing with intermittent RES. Storage dispatch operation during summer days is quite predictable. Due to the high generation of Photovoltaics and CSP, during the day there is an excess of renewable generation, that ultimately translates in energy that is stored for later use. Figure XXXIII presents the actual energy balance resulted from the simulation, that confirms expectations. Energy storage is generally discharged during the second peak of the day – at around 8pm – and its energy content follows daily fluctuations (Green line, referring to the secondary vertical axis).

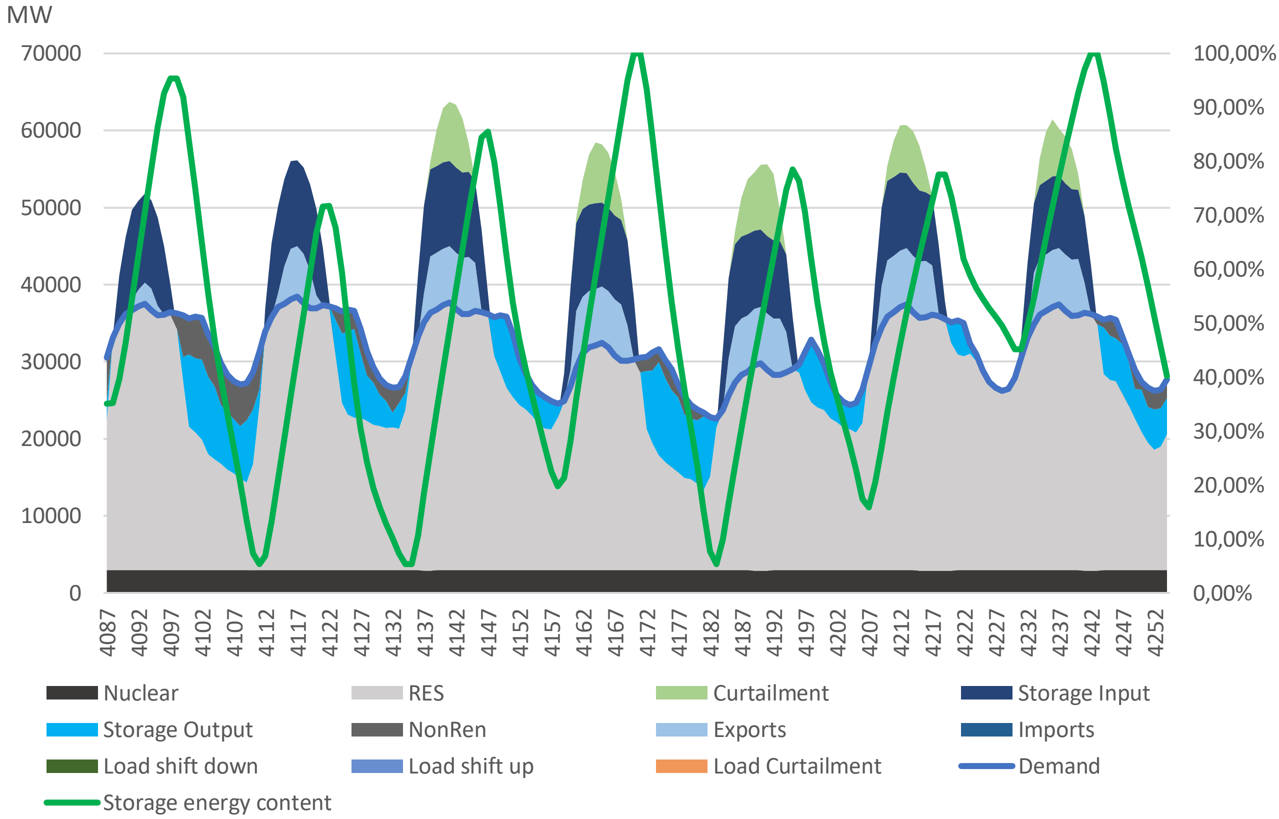

Figure XXXIII: Energy balance during typical summer days.

Figure XXXIV represents the winter week. Here the operations of storage charging and discharging are different. First of all, it can be seen that fluctuations are not daily, storage can be left aside without charging or discharging during several hours. The second interest finding is that storage is charged with energy proceeding from fossil fuel power plants. This could sound counter-intuitive since the main object of storage is to time-shift renewable energy output for moments of low REN generation. However, the explanation is that the energy stored is then used to do peak shaving, thus avoiding the installation and maintenance of additional fossil fuel capacity. In fact, by looking at Figure XXXIV, storage dispatch – represented by the areas in light blue – happens during hours in which the residual load from nuclear and renewables is at its highest values.

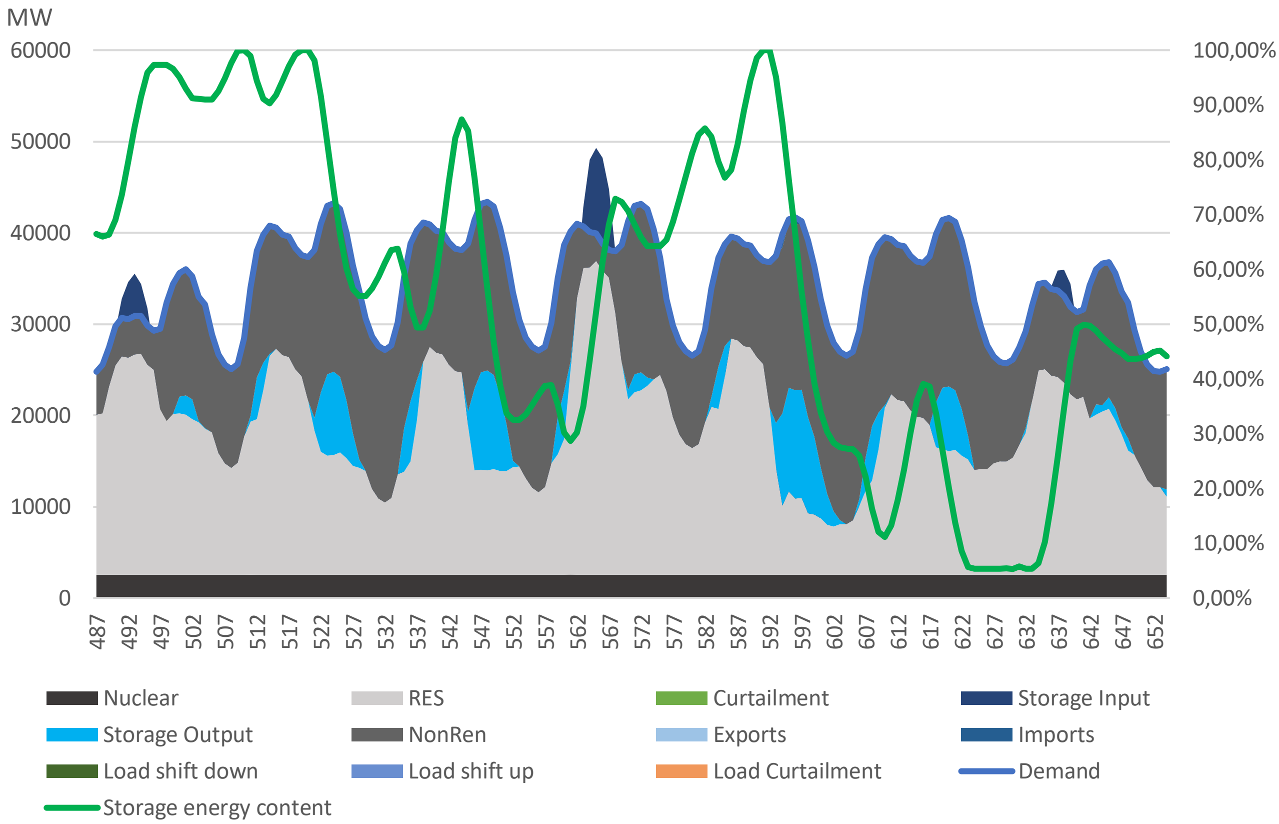

Figure XXXIV: Energy balance during typical winter days.

7.3.2. Storage energy content analysis

When analysing the energy balance of the system on a yearly basis, it is important to assess curtailment and fossil fuel generation. Figure XXXV presents an illustration of these two variables. Curtailment – the orange area - is particularly accentuated in spring, when wind blows with more intensity and the output of hydro power plants is enhanced by more frequent rains. During winter times, especially in December, renewable generation is limited due to the climatic conditions, and gas – the blue area in the chart - becomes essential to satisfy demand.

These considerations gain more relevance when analysed in parallel with energy storage usage. Figure XXXVI illustrates the energy content variation as a percentage of total capacity installed. By looking at the two charts in parallel it can be inferred that storage usage – considering both charging and charging – is more frequent in periods that are characterized by low fossil fuels consumption. This is no surprise, since - as it was presented in the previous subchapter - during summer there is a daily excess of renewable generation that increases the frequency of storage operations. During winter days things work differently. As illustrated in the previous subchapter, storage is mainly used to avoid peaks, since there is almost no excess of renewable generation. Therefore, CCGT power plants become fundamental, since the optimal configuration to reach this penetration of renewables does not imply to use storage to compensate for seasonal variations, not planning any P2X capacity and not adopting nor pumped hydro nor Li-Ion for this purpose.

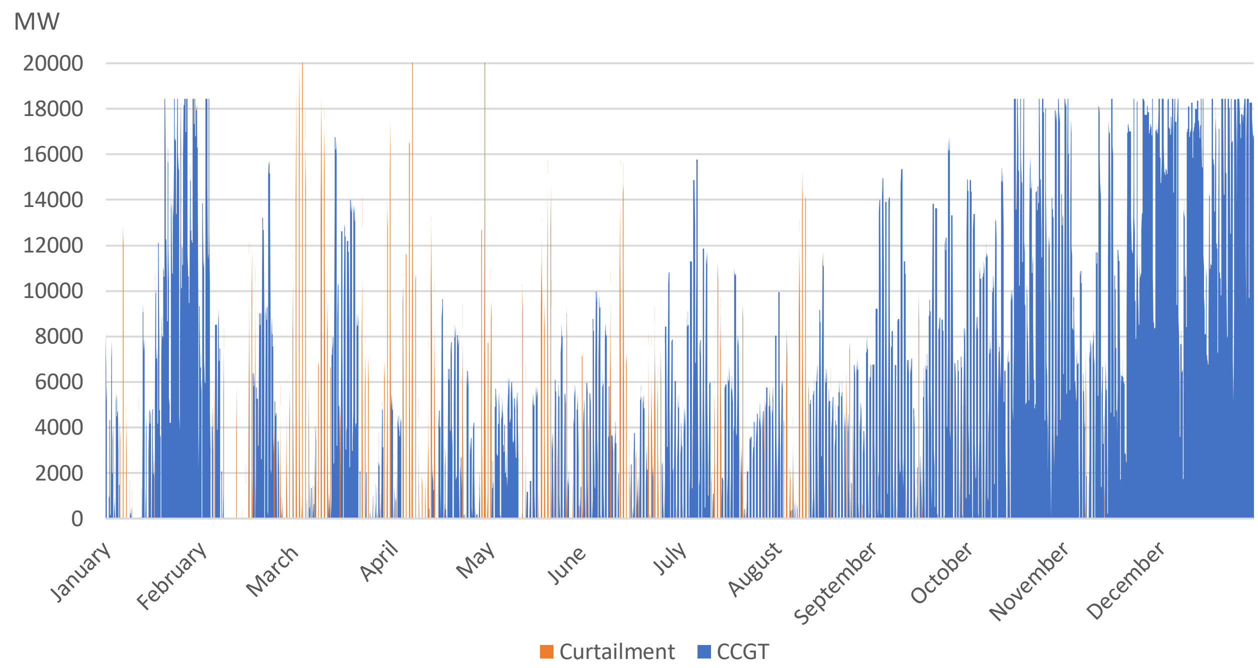

Figure XXXV: Energy curtailment and gas generation throughout the year.

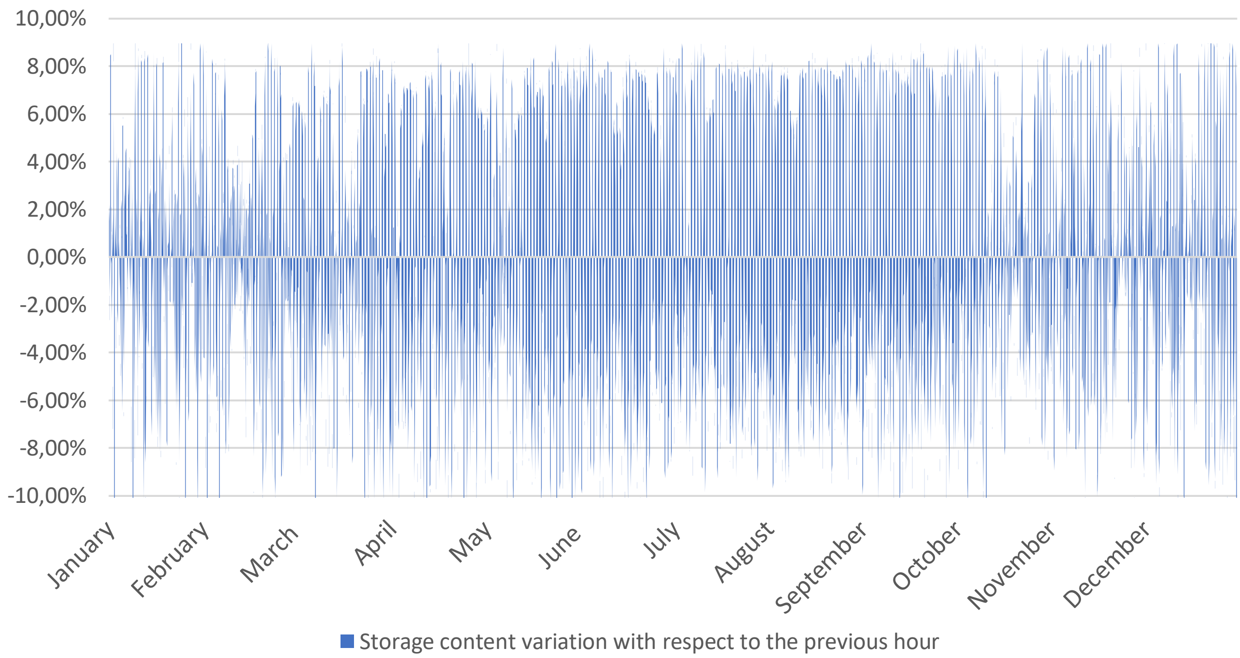

Figure XXXVI: Energy content variation as a percentage of total installed capacity throughout the year.

Figure XXXVII presents the analysis of storage content as a percentage of capacity installed (distinguished for technology). The chart presents 30 days of winter (specifically at the very beginning of the year, or rather in January). It can be seen that the frequency with which Li-Ion is completely charged and discharged is much higher. This technology in fact represents a good solution for dealing with fluctuations of a few hours. Hydro storage content follows cycles of charging and discharging that are longer, indicating that its main purpose is to time shift energy for its usage days after and not necessarily in the range of a few hours as for Lithium-Ion. These considerations are translated into numbers by looking at the yearly equivalent cycles of each technology. Lithium-Ion completes the equivalent of 260 cycles, whereas PHES 145.

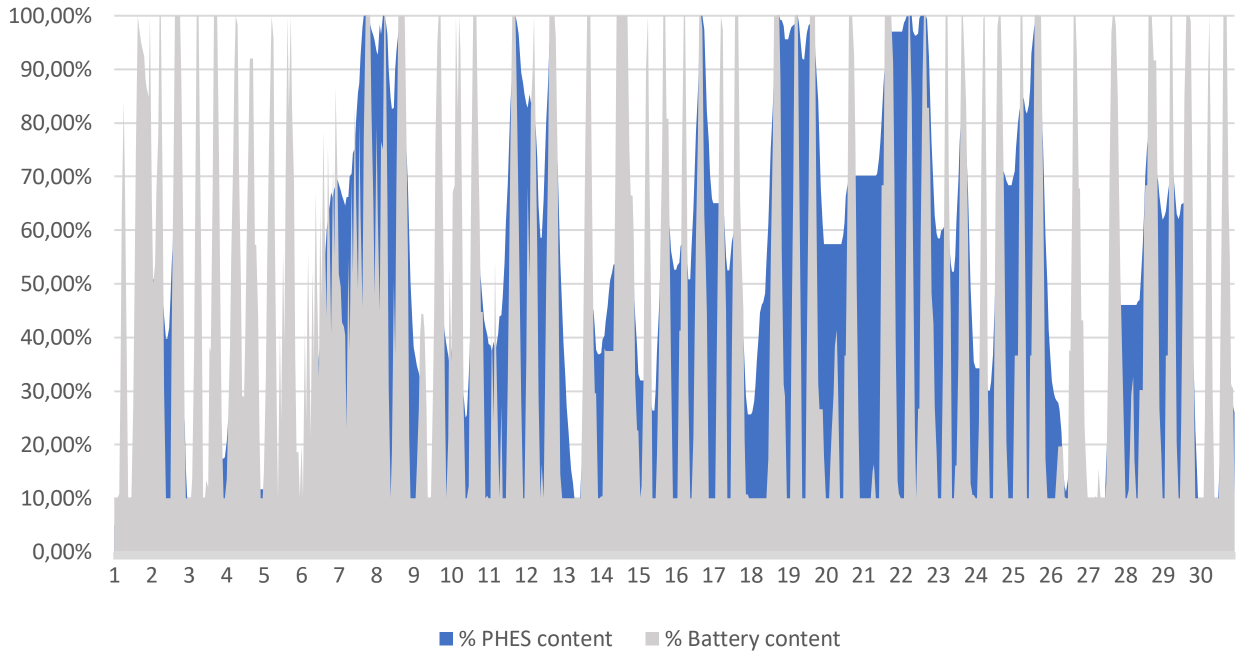

Figure XXXVII: Energy content as a percentage of installed capacity in January.

8. Storage deployment and policies assessment

The storing of energy for use at a different time is considered one of the many services and applications of energy storage systems. Throughout this thesis several other usages were presented, such as regulating frequency and ensuring the delivery of uninterruptible power to critical services.

One of the main issues with the integration of storage in the current electricity infrastructure is the lack of clearness on how to remunerate storage services. In this chapter the revenue schemes of storage will be recap, the ownership and operation of storage assets will be discussed and a mapping of worldwide development in policies will be presented. Finally, a summary of the main barriers for an effective deployment of storage will be presented, and some recommendation for Spain will be illustrated.

8.1. Financial benefits of energy storage

The different applications of energy storage that have been presented in the previous subchapter - and summarized in Figure XI – are here analysed from a financial perspective, to offer an overview of the financial benefits that could be obtained from the use of energy storage.

(i) Bulk energy arbitrage.

This service is about charging the storage system during periods of low energy demand by purchasing cheap excess electricity. The stored low-priced energy is then sold during periods of high electricity prices.

(ii) Centralization of generation capacity.

The use of energy storage in regions characterized by a tight energy generation capacity is financially beneficial and can be used to offset the cost of installing new generation systems or to avoid the renting of generation capacity in the wholesale marketplace.

(iii) Increase of revenues by the provision of ancillary services

Energy storage systems offer a number of ancillary or support services to the electric grid to ensure its proper operation such as load following, regulation, and reserve capacity.

(iv) Reduction of transmission congestion costs

The performance of the T&D system is improved by the use of energy storage. This ensures voltage stability and provides utilities with the ability to increase the transfer of energy. Therefore, charges resulting from transmission congestion are avoided by the use of these technologies in the electric grid.

(v) Reduction of energy demand-related costs

By reducing the end-consumer use of energy during peak periods or when energy prices are high, demand charges are reduced. This could be achieved by the use of energy storage.

(vi) Prevention of energy reliability-related charges

Power outage associated costs can be avoided by the utilization of energy storage. This financial benefit concerns mainly industrial and commercial end users, which could be significantly affected by power outages.

(vii) Reduced financial losses related to power quality

Power quality issues results in financial losses that could be avoided by the use of energy storage. Such power quality anomalies have negative effects on loads and can cause equipment damage.

(viii) Energy time-shift

During periods of low energy demand and electricity prices, energy can be stored. The stored energy could be used when renewable energy generation is low and when electricity price and demand are high.

The financial benefits illustrated here point out that energy storage has various sources of revenues due to the different functions it performs, which should be considered when investigating the profitability of energy storage technologies in combination with renewable energy systems.

8.2. Storage ownership and operation

Analysing the summary at the previous subchapter, presenting storage revenue schemes, the existing of a possible conflict of interest between regulated and unregulated activities is undeniable. New regulations for the sector are required, especially to assess who is in charge of operating the storage assets and how the revenues for the different services is quantified. In fact, for energy storage to play a significant role in the future energy industry, potential operators need to make long-term investment in both R&D and technology deployment. In 2019 the number of markets ruling or revising regulations on the topic increased. Here below, different structures of ownership and operation of storage technologies are presented.

(i) The System operator owns the storage asset and captures network value only.

In this model, the investment is made by TSOs and DSOs to provide network services only, i.e., services which are today already provided by the operators with other technologies and infrastructure. The energy storage asset is integrated in its regulated assets base, and so is eligible for cost recovery through regulated revenues. The transmission or distribution network operator can keep the whole control of the system, regulating the dispatch of stored energy in case of congestion or reliability events or subcontracting it to a third party (e.g. stakeholders with specific skills for optimizing and managing energy storage devices). This business model presents two main features: on one hand, it is expected to be easier to implement and less subject to regulatory constraints as has been shown by Terna in Italy, since only regulated revenues are captured (investment deferral, network reliability). This indeed does not threaten the unbundling principle. On the other hand, the revenue base is limited to regulated revenues only, which could hamper the economic viability of this storage application, demotivate the investment decisions of TSOs and DSOs and slow the transition to renewable energies.

(ii) The system operator owns the storage asset and captures both network and market values.

In this model, the investment is made by the transmission or distribution network operator to provide network services as in the previous case, but also seek for unregulated revenues from market services. The storage system then requires a specific regulatory status in unbundled markets. The TSO or DSO have then a partial control of the system, at least for the dispatch in case of congestion or reliability events. In unbundled markets, one or several third parties are likely to take the market dispatch responsibilities. This business model presents two main features: on one hand, it is expected to be more complex than the other models to implement and subject to regulatory constraints, since both regulated and unregulated revenues are sought for; this requires third parties to be involved in order to capture unregulated services. On the other hand, the revenue base is larger than for the above model, which could strengthen its economic viability.

(iii) A third party owns the asset and captures both network and market value.

In this model, the storage asset is owned by an independent party, which can be registered as a generator and/or a customer on the market. The third party has a contractual agreement with the TSO or DSO to value the network services. The expenses of the TSOs and DSOs then qualify as OPEX and can be recovered through the fee charged for using the network. The third party keeps the control of the storage system and can optimize the use of the system according to its own interest (market operations, etc.) as well as the requirements of the TSO or DSO. On one hand, it is expected to be more complex to implement due to different contractual agreements and revenue streams. The legal feasibility of this model is moreover not clear. On the other hand, the revenue base is larger than for the first model and this could strengthen its economic viability. In this case, it is important to consider that TSOs and DSOs may cooperate with the third party.

(iv) The System operator owns the storage asset to only captures network value and third-party own assets to capture the market value.

In this model, the storage assets are owned by DSOs and TSOs provided that it allows them to conduct their network services with energy storage. The third party then invest in energy storage and own assets that are deemed for market services. In this model, the third party can control the system and market operations according to its interests as long as it complies with the requirements of DSOs and TSOs. On one hand, this business model is more complex to implement since the third party and the system operators needs to align their work together and could influence each other markets. Also, this business model necessitates enactment of new policies. On the other hand, this business model could generate revenue for the system operators, provided that energy storage technologies become cost competitive. Also new market players can enter the energy landscape and lead innovation (Darmani, 2018).

8.3. Worldwide policies development

Considering what has been described here above, it is clear that the ownership and operation of energy storage systems will strongly affects its deployment pace. The definition of a clear regulation framework ruling these aspects is therefore fundamental and needs to be accelerated.

8.3.1. Most relevant policies

While stakeholders may not agree on how to define energy storage operation and ownership, they seem to concur that its deployment pace is high dependent on whether this technology can be compensated for the full range of services it can provide. The ability to derive multiple value streams by providing a range of services with one storage system is widely known under the name of revenue stacking.

In many countries, to allow revenue stacking, several barriers will have to be overcome. It will be required to change the market structure and regulations, to create new markets for ancillary grid services and to provide clarity around which entity has priority to dispatch a battery when it is utilized for more than one purpose by multiple parties. It will also be fundamental to clearly define the figure of the aggregator, to maximize the contribution of behind-the-meter systems in ancillary services. In this sense, California is the first state to approve rules allowing battery storage systems to generate multiple revenue streams, spanning usage in transmission and distribution as well as generation. California is considered to be a leader in its efforts to facilitate the adoption of energy storage. Noteworthy energy storage initiatives in California include:

- A storage procurement mandate for the investor-owned utilities (1.325 GW of storage before 2024);
- The Self Generation Incentive Program (SGIP), which provides incentive payments to behind-the-meter storage;
- CAISO's implementation of new wholesale market products that are amenable to storage, such as the flexible ramping product;
- CAISO's Energy Storage and Distributed Energy Storage (ESDER) stakeholder group, which works to enhance the market participation of grid-connected storage;
- California Public Utilities Commision (CPUC) proceedings to quantify the locational value of distributed energy resources; and
- The CPUC requirement that load serving entities contract for sufficient flexible capacity, which storage is eligible to provide (Heidi Bishop, Ryan Hledik, Roger Lueken, 2017).

These rules have put California at the forefront of storage deployment and opened the way for others to follow. However, as outlined above, outdated policies need to be changed, and this, in many countries, is unlikely to happen overnight. For this reason, robust and easily available valuation tools are needed to assess the potential multiple cost savings from battery systems, from ancillary services to transmission and distribution congestion relief, and investment deferral (International Renewable Energy Agency, 2017).

Since it can take years to redesign retail and wholesale electricity markets, storage providers are looking other deployment strategies, focusing on services that are lucrative the most, such as transmission and distribution deferral that allows to find a fast and cost-effective alternative to construct new long transmission lines that could take even years to be completed. Other storage providers are focusing on niche, high-growth segments such as data centres, and still others see opportunities in deploying storage as part of micro-grids to increase their profitability.

The effect of climate change and more severe storms and wild fires has led to a sense of urgency regarding the latter, with storage companies playing a significant role in rebuilding and upgrading the electricity infrastructure on hurricane-ravaged islands and areas that gets isolated by natural fires - such as Australia - both to provide emergency power in the short-term and greater system resiliency in the long run.

Frequency regulation - which includes “Reg Up” and “Reg Down” – and spinning reserve represent others lucrative applications for energy storage. The high degree of operational flexibility in battery storage makes it ideally suited to provide this service, in fact more than 50% of current installed electrochemical capacity in the US is currently used for this purpose (International Renewable Energy Agency, 2017). However, it is important to note that the frequency regulation market can quickly saturate. In Spain frequency regulation requirements are well below 1 GW, and even if this market is going to grow while further decarbonizing the grid, it is forecasted that around 10%-15% of total installed capacity by 2030 will be used for this purpose (International Renewable Energy Agency, 2017).

8.3.2. Updates in 2019

The European CEP, approved in May 2019, allows transmission and distribution operators to own and operate storage only under exceptional circumstances, which have yet to be codified in national legislation. The e-Directive differentiates two separate derogations for storage facilities ownership. Energy storage systems that can be referred to as “fully integrated network components” can be own and operated by TSO and DSO. However, these systems need to present specific characteristics, that help ensure network security and reliability. Capacitors and flywheels fall into this category. In general, the idea of limiting storage ownership is to prevent DSOs and TSOs from owning storage assets that they use in congestion management and balancing, as they should procure these services in a market based process and owning some of these assets represents a conflict of interests (European Commission, 2019).

US states are working to further clarify the role of storage. CAISO is constantly reviewing its incentives for energy storage. The Midwest Independent System Operator requested the federal regulator’s permission to use storage as an alternative to transmission; and ERCOT, the Texan grid operator, appointed an internal task force to define storage as an entity separate from generation or load.

Other jurisdictions are actively planning to deploy storage in networks: in Germany, a slew of projects under the Netzbooster programme will evaluate storage as a transmission asset, and a similar programme in France (Ringo) received regulatory approval to begin development in 2020 (IEA, 2020). In Australia, grid companies are allowed to own storage assets under certain conditions, and in Chile the national law was changed to allow for storage to serve as transmission network reinforcement in emergency cases.

China also reviewed its regulations in 2019, and, similarly to the directives set in Europe, grid companies are no longer permitted to include storage costs in their transmission and distribution fees. As a result, the announcement of new projects was frozen and installations throughout the year shrank by one-third. The storage market in China is now shifting towards the colocation of storage and reducing the curtailment of onsite renewable power generation.

8.4. Barriers for an effective storage deployment

Storage remains strongly dependent on favourable and stable policy environments. At the core of the issue for an effective deployment of this technology is whether storage can provide services to electricity grids, including transmission and distribution deferral, together with flexibility and balancing services in energy and capacity markets. In this context it is important to continuously revise the status of storage in regulatory frameworks, clearly identifying the services that regulated transmission and distribution operators can provide and defining surveillance methodology to assess that the regulations are being respected and no competition with other services is created.

As extensively explained in the previous subchapter, storage ownership needs to be defined precisely to avoid barriers to regulated as to un-regulated activities. Expanding the role of storage in ancillary service and flexibility markets could be complex from a regulatory perspective, but experience in the United States, Europe and Australia has shown that rewarding how quickly or how often system assets respond – or reducing regulatory barriers to make storage part of ancillary services – could help developers monetise the value of storing electricity. The participation in flexibility markets could be done by the recently born figure of the aggregator or by the traditional energy marketing companies, through retail rate redesign. It would be a valuable future research activity to comprehensively evaluate all opportunities that a better alignment of retail rates with the underlying structure of energy markets could offer in terms of both storage behind-the-meter adoption and system operation benefits.

Again, the necessity of assessing the economic values of storage services in existing and future energy markets is the key for a proper integration of this technology. This would allow to operate batteries to capture "stacked" benefits, thus unlocking significantly more value than using batteries to pursue a single revenue stream. However, challenges to simultaneously capturing multiple value streams remain. Some of the barriers are technical in nature and may be overcome as new battery management algorithms and software are developed. Other barriers may be overcome through new policy initiatives. Offering new or revised rate designs which more fully reflect the time-varying nature of the cost of generating and delivering electricity is one of many possibilities.

An easier way, at least from a regulatory standpoint, of deploying storage is to insert it in renewable auctions requirements through procurement mandate. This practice – called co-siting renewables and storage – may represents the second-best option for deploying system flexibility. The main issue with this strategy is the not optimal siting of storage systems, that would more difficultly offer services such upgrade deferral.

Once discussed the barriers and the best way of deploying storage technologies, it is important to remind that the objective is system flexibility, and not the installation of as much as possible of a specific technology. To assess the economics and potential benefits, storage technologies need to be understood in the context of the services and applications they provide. In fact, these are suitable for several applications, but it is unlikely that they represent the only cost-efficient solution to foster renewables. In a proper assessment of the storage requirements of future energy systems, the real potential of other options, such as demand management and sector coupling, has to be understood and analysed.

Finally, even if storage may not always be the most attractive investment in current energy markets due to the lack of sufficient economic signals for the provision of flexibility, we considered critical to assess country and regional capabilities that will be relevant in the long term and decided to develop a model that can help for this purpose.

8.5. Policies recommendations for Spain

From the model output, the analysis of storage potential applications and the assessment of energy policies worldwide, several insights can be extrapolated. In this section a set of policies recommendations for an effective integration of high share of RES is presented. Even though these recommendations are the results of the assessment of the Spanish case study, they find relevancy also in the study of other electricity systems.

(i) Curtailment needs to play a role in future energy systems if cost efficiency is pursued. The problem with curtailment is that it reduces the profitability of in investment in RES. In order to address this issue, different strategies could be pursued. Curtailment could be remunerated by setting a minimum positive price in energy markets or in renewable auctions, to compensate the revenue losses derived from it and, more in general, from high integration of renewables. In fact, with higher penetration of RES, prices in the electricity markets – assuming that the markets continue operating under the same conditions of today – could get very low during hours of high renewable generation, making it more difficult to recover costs for investors. The structuring of renewable auctions or of new mechanisms that allow not to penalize the owners of REN facilities is recommended.

(ii) Fossil fuels power plants will still be key in the future to guarantee a reliable electricity supply. Especially CCGT - that represent a less polluting solution compared to other generation technologies such as coal – will be fundamental for the flexibility they offer in the integration of renewables, especially in dealing with seasonal fluctuations. However, it is interesting to notice that, with an effective deployment of storage technologies and an efficient management of charging and discharging, the fossil fuel capacity needed could be moderate. The model, with the limitations aforementioned, suggests that the capacity needed could be 30% less than the one planned in the PNIEC. An assessment of the actual needs of conventional generation capacity while integrating more renewables and storage facilities is suggested, in order to avoid additional costs for the system.

(iii) As widely discussed in this chapter, storage revenue definition is one of the main issues to foster the deployment of this technology. Clear methodologies are needed to evaluate the economic value of services such as T&D upgrade deferral, and storage participation in ancillary services markets should be facilitated and incentivized. Then, it is recommended to invest in R&D and in regulatory sandboxes in order to find a just remuneration for storage services, and to work on regulatory aspects of markets operations that could prevent storage owners from participating (such as requisites of minimum capacity).

(iv) Storage is going to gain always more relevance in the future. However, the model suggests that in Spain there is already enough storage capacity to reach efficiently a 60% share of renewables in the energy mix. This is interesting since it gives more flexibility at the moment of planning the investments in this technology. Storage geographical planning on and auctions could be organized in order to install just a small percentage of the planned infrastructure for 2030 during the first 5 years (the PNIEC guidelines set the share of renewables in 2025 to account for 60% of total demand), in order to analyse the operations and benefits of storage. This would help in understanding how storage can be optimized and deployed to build a cost-efficient electricity system that ultimately generates benefits for the entire con result.

(v) Demand response can play a role in future highly renewable energy systems. Especially when considering the process optimization of industrial manufacturing, DR programs are economical to apply. For this reason, it is recommended to facilitate its direct participation in the energy markets and to develop dynamic time of use tariffs that can incentivize the deployment of technologies that can provide flexibility.

9. Conclusion

Achieving the target set for the reduction of GHG emissions requires to understand and strategically plan how electricity systems will have to change to adequately tackle climate change. In this context energy modelling becomes a key tool for policy makers.

The model developed in this thesis allows to plan the optimal – from a system perspective - electricity generation and storage infrastructure to satisfy demand with high share of renewables. The model was tested on different penetrations of renewables, and it indicated that storage becomes an essential tool to make renewables more dispatchable.

From an in-depth analysis of the Spanish energy system and Integrated National Energy Plan, the potential of the planned infrastructure for 2030 was assessed in order to clarify whether it can reach the targets set from the EU. The results of the study indicate that the assumptions made in the structuring of the plan are quite optimistic, and the planned infrastructure could potentially reach the goals only in very favourable scenarios in terms of technology advancement and deployment. It was found through less optimistic - or more realistic – assumptions that the infrastructure planned will need to be enhanced.

From the model simulations it was also found that storage optimal dispatch strategy implies its usage for peak shaving services, allowing in this way to avoid over capacity of fossil fuel back up capacity, and that storage is not necessarily charged only with renewable energy. It can be efficient in fact to charge storage with conventional power plants during hours that precede a peak, in order to avoid the installation of long-term energy storage technologies or to maintain high level of storage content during many consecutive hours, thus impeding an efficient usage of the storage power capacity for short-term energy time shift.

Lastly, the simulations results indicate that curtailment does not need to be avoided at all costs, since an economic efficient solution for the integration of high share of renewables would require extremely high storage capacity.

Energy storage will become a fundamental player in electricity systems. Its flexibility makes it suitable to provide a wide range of services – grid upgrade deferral, voltage control, frequency response, etc - that are becoming every day more necessary to deal with renewable intermittency.

The main-use case for storage to 2030 is likely to be influenced by the economic opportunities to provide electricity time-shift services to increase self-consumption or avoid peak demand charges in the residential and commercial sectors. Frequency regulation is another market where storage is likely to become increasingly competitive as costs fall, given its rapid response characteristics.

By looking at energy storage deployment pace around the world, it comes out that this technology remains strongly dependent on favourable, stable policy environments. As a matter of fact, the majority of the new installed capacity is located in just a bunch of countries that offer either good incentives or a clear and strong regulatory framework.

The role of storage in network needs to be recognized and the value of its services needs to be quantified in economic terms, in order establish a clear governance of storage regulated and un-regulated activities. If emphasis were placed on developing markets for capacity and on facilitate the participation of distributed energy systems in ancillary services, storage could become an attractive investment, competing with other technologies and measures through revenue stacking.

Nevertheless, the role of storage in networks remains a contentious issue that it is unlikely to have a one-size-fits-all solution. The evolution of market operation and the results that come out of regulatory sandboxes - at local or even national level – will make clearer which are the best paths to foster storage deployment.

Futures lines of research based on the results of this study include the assessment of future spot market prices taking into account imperfect competition, the evaluation of strategies to integrate curtailment in energy markets - in order to avoid the penalization of renewable facilities owners – and the creation of tools and methodologies to quantify the economic value of the services provided by energy storage, recognizing its importance in energy markets and fostering its deployment.

10. Budgeting

In this section we quantify the cost of the study for the assessment of the generation and storage infrastructure required to integrate high share of renewables. The development of the project - taking into account the literary review, the data search, the development of the model, the benchmarking process, the assessment of the results and the elaboration of the thesis – and the process of revision of the final document required 10 months. An estimation for the value of the project is offered in this chapter, starting with the remuneration of human resources.

10.1. Human resources

The human resources involved in the development of the study are a student, a PhD candidate and a Professor. The project has been extremely time consuming, making human resources the most relevant cost of the final budget.

Table 17: Human resources' costs.

	Specific cost	Time employed	Total costs
Student	30 €/h	900 h	27.000 €
Professor	100 €/h	15 h	1.500 €
PhD. Candidate	50 €/h	40 h	2.000 €

10.2. Tools

The computer equipment amortization costs are illustrated in the table below. The amortized period has been calculated as an approximation of the time of use of the tool out of its total lifetime.

Table 18: Cost of computer equipment.

	Cost	Amortization period	Amortized period	Amortization cost
Laptop Asus F550L with Intel Core I7 4500U CPU, 6GB RAM	600 €	5 Years	10 months	100,00 €
SSD Crucial BX500	30 €	2 Years	6 months	7,50 €
Laptop HP EliteBook with Intel Core i5-7300U CPU, 16GB RAM	1.600 €	5 Years	6 months	160,00 €

10.3. Budget Summary

In the table below, the approximate total cost of the study is presented.

Table 19: Approximate total cost of the study.

	Costs
Human Resources	30.500 €
Computer equipment	268 €
Gross execution budget	30.768 €
Industrial margin (6%)	1.846 €
Industrial budget	32.614 €
VAT (21%)	6.848 €
Contractual budget	**39.463 €**

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ANNEX

Here below the code is presented for completeness of information. This is the main model, that evaluates investments in both generation and energy storage to obtain the optimal solution. The model used to evaluate only storage requirements is the same, but the renewable output constraint impose that the energy output of additionally installed renewables is 0.

As it can be seen in the following lines, the model is written in python, with the adoption of several libraries to facilitate the interactions with excel, the data handling and the solution of the problem. The Pyomo library deserves special mention since it allows to write the problem in an algebraic manner and solve it though the usage of an external solver, Gurobi in this case.

The laptop used for the simulations is equipped with an Intel Core i7 4500U @ 1.80GHz and 3 DDR3 of 2 GBytes each. The running time of the simulations performed ranges between 25 minutes and 15 hours, depending on whether the optimum implies the adoption of several technologies due to the reach of the expansion limits for the most economic viable technologies or not. However, on average, for a timeframe of 4 hours, the running time is around one hour.

CODE

```
# -*- coding: utf-8 -*-
"""
Created on Tue Apr 14 16:45:26 2020
@author: mauguadra
"""

import pandas as pd
from pyomo.environ import *
from pyomo.opt import SolverFactory
import numpy as np
from itertools import product
import sys
from datetime import datetime


############################################### TIMEIT ###############################################

now = datetime.now()
print("The simulation began at: ", now)
```

```
##################################### IMPORT DATA FROM EXCEL #####################################

## The indexes are imported from the first sheet
Indexes = pd.read_excel('model_inputs.xlsx',sheet_name='Indexes')
t = int(Indexes['TimeSteps'][0])
z = int(Indexes['Additional Ren Technologies'][0])
s = int(Indexes['Storage Technologies'][0])
r = int(Indexes['Non-REN Technologies'][0])
w = int(Indexes['Load Curtailment technologies'][0])
k = int(Indexes['Load Shifting technologies'][0])

## Import the hourly demand and generation of already installed facilities
EntryValues = pd.read_excel('model_inputs.xlsx',sheet_name='Demand & ExistingGen')
System_Param = EntryValues.to_dict()

## Import the hourly capacity factor of each generation technology
EntryValues1 = pd.read_excel('model_inputs.xlsx',sheet_name='Capacity Factors')

## Import technical and cost specs of each REN generation technology
EntryValues2 = pd.read_excel('model_inputs.xlsx',sheet_name='REN Characteristics',index_col='Characteristics')
REN_Specs = EntryValues2.to_dict('index')

## Import technical and cost specs of each storage technology
EntryValues3 = pd.read_excel('model_inputs.xlsx',sheet_name='Storage Characteristics',index_col='Characteristics')
Storage_Specs = EntryValues3.to_dict('index')

## Import technical and cost specs of convention power plants
EntryValues4 = pd.read_excel('model_inputs.xlsx',sheet_name='Non-REN Characteristics',index_col='Characteristics')
NonREN_Specs = EntryValues4.to_dict('index')

## Import rotational inertia constant of each technology
EntryValues5 = pd.read_excel('model_inputs.xlsx',sheet_name='Rotational Inertia')
Rotational_Inertia = EntryValues5.to_dict()

## Import interconnexions characteristics
EntryValues6 = pd.read_excel('model_inputs.xlsx',sheet_name='Interconnexions')
Intercon = EntryValues6.to_dict()

## Import load curtailment characteristics
EntryValues7 = pd.read_excel('model_inputs.xlsx',sheet_name='Load Curtailment',index_col='Characteristics')
LoadCurtailment_Specs = EntryValues7.to_dict('index')
```

```
## Import load shifting characteristics
EntryValues8 = pd.read_excel('model_inputs.xlsx',sheet_name='Load Shifting',index_col='Characteristics')
LoadShift_Specs = EntryValues8.to_dict('index')

################################### MODEL'S ELEMENTS DEFINITION ###################################

model = ConcreteModel()

## Indexes
model.t = Set(initialize = range(t), doc='Time Periods', ordered=True)
model.z = Set(initialize = range(z), doc='Additional renewable generation technologies', ordered=True)
model.s = Set(initialize = range(s), doc='Storage technologies', ordered=True)
model.r = Set(initialize = range(r), doc='Non-REN generation technologies', ordered=True)
model.w = Set(initialize = range(w), doc='Load Curtailment technologies', ordered=True)
model.k = Set(initialize = range(k), doc='Load Shifting technologies', ordered=True)

## Hourly parameters
model.Demand = Param(model.t, initialize=System_Param['Demanda real'], doc='Energy Demand')
model.ExistingGen = Param(model.t, initialize=System_Param['ExistingGeneration'], doc='Existing renewable generation')
model.Nuclear = Param(model.t, initialize=System_Param['NUCLEAR'], doc='Nuclear generation')
model.Hydro = Param(model.t, initialize=System_Param['Hydro with no pumping'], doc='Hydro generation')
model.CSP = Param(model.t, initialize=System_Param['Solar termica'], doc='CSP generation')
model.Bio_Mass_y_Gas = Param(model.t, initialize=System_Param['Otras renovables'], doc='Biomass generation')
EntryValues1 = EntryValues1.to_numpy()  # Here a dictionary with three keys is created, corresponding to the three technologies assessed)
EntryValues1 = EntryValues1.flatten()
Cap_Factor = dict(zip(product(range(t),range(z)), EntryValues1))
model.HourlyCF = Param(model.t, model.z, initialize=Cap_Factor, doc='Hourly capacity factor')

# Techno-economic parameters of RES
model.ReplacementCostsREN = Param(model.z, initialize=REN_Specs['Specific-to-power replacement costs [EUR/(kW*year)]'], doc='Specific-to-energy replacement costs of each technology')
model.SpecificOPEXREN = Param(model.z, initialize=REN_Specs['Specific-to-power O&M costs [EUR/(kW*year)]'], doc='Specific O&M costs of each technology')

# Techno-economic parameters of Storage
model.ReplacementCostsStorage = Param(model.s, initialize=Storage_Specs['Specific-to-power replacement costs [EUR/(kW*year)]'], doc='Specific-to-energy replacement costs of each technology')
model.SpecificToPowerOPEXStorage = Param(model.s, initialize=Storage_Specs['Specific-to-power O&M costs [EUR/(kW*year)]'], doc='Specific O&M costs of each technology')
model.SpecificToEnergyOPEXStorage = Param(model.s, initialize=Storage_Specs['Specific-to-energy O&M costs [EUR/(kWh)]'], doc='Specific-to-energy O&M costs of each technology')
```

```
model.InputEff = Param(model.s, initialize=Storage_Specs['Storage input efficiency [%]'], doc='Storage input efficiency [%]')
model.OutputEff = Param(model.s, initialize=Storage_Specs['Storage output efficiency [%]'], doc='Storage output efficiency [%]')
model.StoragePERatio = Param(model.s, initialize=Storage_Specs['Ratio Energy/Power'], doc='Storage energy to power ratio')
model.StorageDOD = Param(model.s, initialize=Storage_Specs['Storage maximum DOD'], doc='Storage depth of discharge')
model.LimitPotential = Param(model.s, initialize=Storage_Specs['Potential Limit [MW]'], doc='Storage capacity upper limit')

# NonREN parameters
model.NonRENReplacement = Param(model.r, initialize=NonREN_Specs['Specific-to-power replacement costs [EUR/(kW*year)]'])
model.NonRENOPEX = Param(model.r, initialize=NonREN_Specs['Specific-to-power O&M costs [EUR/(kW*year)]'])
model.nonRENGenerationCosts = Param(model.r, initialize=NonREN_Specs['Specific-to-energy costs of fossil fuels [EUR/kWh]'])
model.RampRateNonREN = Param(model.r, initialize=NonREN_Specs['Hourly ramp rate [%]'])
model.RampingUpCosts = Param(model.r, initialize=NonREN_Specs['RampingUP Cost [EUR/kWh]'])
model.Unavailability = Param(model.r, initialize=NonREN_Specs['Unavailability Rate'])

# Load Curtailment
model.LoadCurtailmentCosts = Param(model.w, initialize=LoadCurtailment_Specs['Curtailment cost [EUR/kWh]'])
model.LoadCurtailmentReplacementCosts = Param(model.w, initialize=LoadCurtailment_Specs['Specific-to-power replacement costs
[EUR/(kW*year)]'])
model.LoadCurtailmentOPEXCosts = Param(model.w, initialize=LoadCurtailment_Specs['Specific-to-power O&M costs
[EUR/(kW*year)]'])
model.LoadCurtailmentMaximumDuration = Param(model.w, initialize=LoadCurtailment_Specs['Maximum duration [h]'])
model.LoadCurtailmentRecovery = Param(model.w, initialize=LoadCurtailment_Specs['Recovery time [h]'])
model.LoadCurtailmentPotential = Param(model.w, initialize=LoadCurtailment_Specs['Potential Limit [MW]'])

# Load Shifting
model.LoadShiftingCosts = Param(model.k, initialize=LoadShift_Specs['Shifting cost [EUR/kWh]'])
model.LoadShiftingReplacementCosts = Param(model.k, initialize=LoadShift_Specs['Specific-to-power replacement costs
[EUR/(kW*year)]'])
model.LoadShiftingOPEXCosts = Param(model.k, initialize=LoadShift_Specs['Specific-to-power O&M costs [EUR/(kW*year)]'])
model.LoadShiftingMaximumDuration = Param(model.k, initialize=LoadShift_Specs['Maximum duration [h]'])
model.LoadShiftingPotential = Param(model.k, initialize=LoadShift_Specs['Potential Limit [MW]'])

# Interconnexions
model.Interconnexions = Param(range(5), initialize=Intercon['Interconnexions'])

# Technical parameters for additional constraints
model.RotationalInertia = Param(range(6), initialize=Rotational_Inertia['Rotational Inertia Constant [s]'])

## Decision Variables // Generation and storage capacity evaluated
model.PowerRen = Var(model.z, domain=NonNegativeIntegers, initialize=1)
model.StorageCapacity = Var(model.s, domain=NonNegativeIntegers, initialize=1)
model.StoragePowerCapacity = Var(model.s, domain=NonNegativeIntegers, initialize=1)
```

```
model.PowerNonREN = Var(model.r, domain=NonNegativeIntegers, initialize=1)
model.CurtailmentCapacity = Var(model.w, domain=NonNegativeIntegers, initialize=1)
model.LoadShiftingCapacity = Var(model.k, domain=NonNegativeIntegers, initialize=1)

## Auxiliar Variables // Energy flow y ramping costs
model.EnergyRen = Var(model.t, model.z, bounds=(0.0,None), doc='Energy generated from Renewables')
model.NonRenGeneration = Var(model.t, model.r, bounds=(0.0,None), doc='Energy generated from Gas', initialize=0)
model.StorageInput = Var(model.t, model.s, bounds=(0.0,None), doc='Energy input of storage')
model.StorageOutput = Var(model.t, model.s, bounds=(0.0,None), doc='Energy output of storage')
model.EnergyStored = Var(model.t, model.s, bounds=(0.0,None), doc='Energy content of storage')
model.Curtailment = Var(model.t, bounds=(0.0,None), doc='Energy curtailed')
model.LoadCurtailment = Var(model.t, model.w, bounds=(0.0,None), doc='Demand curtailed')
model.LoadShiftingDown = Var(model.t, model.k, bounds=(0.0,None), doc='Demand reduction')
model.LoadShiftingUp = Var(model.t, model.k, bounds=(0.0,None), doc='Demand increase')
model.LoadShiftingCumulated = Var(model.t, model.k, bounds=(0.0,None), doc='Energy that can be "shifted"')
model.Exports = Var(model.t, bounds=(0.0,None), doc='Energy exported')
model.Imports = Var(model.t, bounds=(0.0,None), doc='Energy imported')
model.RampingCostsAuxiliar = Var(model.t, model.r, bounds=(0.0,None), doc='StartUp costs of conventional power plants',
initialize=0)

## Auxiliar Variables // Ancillary services
model.RotInertia = Var(model.t, bounds=(0.0,None), doc='Rotanional Inertia')
model.Frequency = Var(model.t, bounds=(0.04,None), doc='Auxiliar for frequency regulation')
model.NonRenGenerationFreq = Var(model.t, model.r, bounds=(0.0,None), doc='Energy generated from Gas for ancillary services')
model.StorageOutputFreq = Var(model.t, model.s, bounds=(0.0,None), doc='Energy output of storage for ancillary services')
model.LoadShiftingDownFreq = Var(model.t, model.k, bounds=(0.0,None), doc='Demand reduction for ancillary service')



######################################## MODEL'S EQUATIONS ########################################

## Objective function
model.OBJ = Objective(expr=(sum(
                model.PowerRen[i] * (model.SpecificOPEXREN[i] +
                model.ReplacementCostsREN[i]) * (t/8760)
                for i in range(z)) +
              sum(
                model.StoragePowerCapacity[j] *
                (model.SpecificToPowerOPEXStorage[j] + model.ReplacementCostsStorage[j]) * (t/8760) +
                sum(model.StorageOutput[t,j] + model.StorageOutputFreq[t,j] for t in model.t) *
model.SpecificToEnergyOPEXStorage[j]
                for j in model.s) +
```

```
                    sum(
                        model.PowerNonREN[k] * (model.NonRENReplacement[k] + model.NonRENOPEX[k]) * (t/8760) +
                        sum((model.NonRenGeneration[t,k] + model.NonRenGenerationFreq[t,k]) * model.nonRENGenerationCosts[k] +
                            model.RampingCostsAuxiliar[t,k] for t in model.t)
                        for k in model.r) +
                    sum(
                        model.LoadCurtailmentCosts[w] * sum(model.LoadCurtailment[t,w] for t in model.t) +
                        (model.LoadCurtailmentReplacementCosts[w] + model.LoadCurtailmentOPEXCosts[w]) *
                         model.CurtailmentCapacity[w] * (t/8760)
                        for w in model.w) +
                    sum(
                        model.LoadShiftingCosts[k] * sum(model.LoadShiftingDown[t,k] + model.LoadShiftingDownFreq[t,k] for t in
model.t) +
                        (model.LoadShiftingReplacementCosts[k] + model.LoadShiftingOPEXCosts[k]) *
                         model.LoadShiftingCapacity[k] * (t/8760)
                         for k in model.k) +
                    sum(model.Imports[t] * model.Interconnexions[4] -
                        model.Exports[t] * model.Interconnexions[3] for t in model.t)), sense = minimize)

## Energy balance constraints
def hourlyenergybalance(model, t):
    return (model.Demand[t] + model.Curtailment[t] - model.ExistingGen[t] - sum(model.EnergyRen[t,i] for i in range(z)) +
            sum(model.StorageInput[t,j]-model.StorageOutput[t,j] for j in range(s)) - sum(model.NonRenGeneration[t,k] for k in range(r)) -
            sum(model.LoadCurtailment[t,w] for w in model.w) + sum(model.LoadShiftingUp[t,k] - model.LoadShiftingDown[t,k] for k in
model.k) +
            model.Exports[t] - model.Imports[t] == 0)
model.EnergyBalance = Constraint(model.t, rule=hourlyenergybalance, doc='Observe energy balance')


def hourlyenergybalanceAncillaryServices(model, t):
    return (model.Demand[t] * model.Frequency[t] -
            sum(model.StorageOutputFreq[t,j] for j in range(s))*2 -
            sum(model.NonRenGenerationFreq[t,k] for k in range(r))*2 -
            sum(model.LoadShiftingDownFreq[t,k] for k in model.k)*2 == 0)
model.EnergyBalanceAncillary = Constraint(model.t, rule=hourlyenergybalanceAncillaryServices, doc='Observe energy balance for
ancillary services')


## Renewable output constraint
def GenCapFactor(model, t, z):
    return (model.EnergyRen[t,z]-(model.HourlyCF[t,z] * model.PowerRen[z]) == 0)
model.CorrelationCapFactGen = Constraint(model.t, model.z, rule=GenCapFactor, doc='Renewable generation-capacity factor
correlation')
```

```
## Storage constraints
def BehavStorage(model, t, s):
    if t != 0:
        return (model.EnergyStored[t,s] - model.EnergyStored[t-1,s] +
            (model.StorageOutput[t,s]/model.OutputEff[s]) - model.StorageInput[t,s] * model.InputEff[s]
            + (model.StorageOutputFreq[t,s]/model.OutputEff[s]) == 0)
    else:
        return (model.EnergyStored[t,s] - (1 - model.StorageDOD[s]) * model.StorageCapacity[s] +
(model.StorageOutput[t,s]/model.OutputEff[s]) -
            model.StorageInput[t,s] * model.InputEff[s] + (model.StorageOutputFreq[t,s]/model.OutputEff[s]) == 0)
model.behaviourstorage = Constraint(model.t, model.s, rule=BehavStorage, doc='Energy storage correlation with privious hour state of charge')


def StorPowerLimits(model, t, s):
    return (model.StorageOutput[t,s] + model.StorageOutputFreq[t,s]*2 +
        model.StorageInput[t,s] <= model.StoragePowerCapacity[s])
model.StorLimit = Constraint(model.t, model.s, rule=StorPowerLimits, doc='Storage Limits')


def StorContLimit(model, t, s):
    return (model.EnergyStored[t,s] >= (1 - model.StorageDOD[s]) * model.StorageCapacity[s])
model.StorContentLimit = Constraint(model.t, model.s, rule=StorContLimit, doc='Storage Limits DoD')


def StorContLimitEnergy(model, t, s):
    return (model.EnergyStored[t,s] <= model.StorageCapacity[s])
model.StorContentLimitEnergy = Constraint(model.t, model.s, rule=StorContLimitEnergy, doc='Storage  energy limits')


def StorageRatio(model, s):
    return (model.StorageCapacity[s] == model.StoragePowerCapacity[s] * model.StoragePERatio[s])
model.PE_Ratio = Constraint(model.s, rule=StorageRatio, doc='Limit Ratio Energy to Power of each storage technology')


def StorageUpperLimit(model, s):
    return (model.StoragePowerCapacity[s] <= model.LimitPotential[s])
model.StorLimits = Constraint(model.s, rule=StorageUpperLimit, doc='Limit storage potential')


## Conventional generation constraints
def LimitNonRENShare(model):
    return (sum(sum(model.NonRenGeneration[i,k] + model.NonRenGenerationFreq[i,k] for k in range(r)) +
            model.Nuclear[i] + model.Imports[i] * (1 - model.Interconnexions[2]) for i in range(t))
        <= (26/100)* (sum(model.Demand[i] * (1 + 0.5 * model.Frequency[i]) - sum(model.LoadCurtailment[i,e] for e in range(w)) for i
in range(t))))
model.NonRenGenerationShare = Constraint(rule=LimitNonRENShare, doc='Gas generation limit to reach a specific share of
renewable generation')
```

```
def LimitGasGenerationRampUp(model, t, r):
    if t!=0:
        return (model.NonRenGeneration[t,r] + 2 * model.NonRenGenerationFreq[t,r] -
                model.NonRenGeneration[t-1,r] <= model.RampRateNonREN[r] * model.PowerNonREN[r])
    else:
        return (Constraint.Skip)
model.NonRenGenerationRampUp = Constraint(model.t, model.r, rule=LimitGasGenerationRampUp, doc='Gas generation limit to reach a specific share of renewable generation')


def LimitGasGenerationRampDown(model, t, r):
    if t!=0:
        return (model.NonRenGeneration[t-1,r] + 2 * model.NonRenGenerationFreq[t-1,r] -
                model.NonRenGeneration[t,r] <= model.RampRateNonREN[r] * model.PowerNonREN[r])
    else:
        return (Constraint.Skip)
model.NonRenGenerationRampDown = Constraint(model.t, model.r, rule=LimitGasGenerationRampDown, doc='Gas generation limit to reach a specific share of renewable generation')


def LimitGasGenerationToPowerInstalled(model, t, r):
    return (model.NonRenGeneration[t,r] + model.NonRenGenerationFreq[t,r]*2 <= (1 - model.Unavailability[r]) * model.PowerNonREN[r])
model.NonRenGeneration1 = Constraint(model.t, model.r, rule=LimitGasGenerationToPowerInstalled, doc='Gas generation limit to the capacity installed')


def StartUpCosts(mode,t,r):
    if t != 0:
        return (model.RampingCostsAuxiliar[t,r] >= (model.NonRenGeneration[t,r] + model.NonRenGenerationFreq[t,r] -
                                        (model.NonRenGeneration[t-1,r] + model.NonRenGenerationFreq[t-1,r])) * model.RampingUpCosts[r])
    else:
        return (model.RampingCostsAuxiliar[t,r] == 0)
model.RampingCostsConstraintUp = Constraint(model.t, model.r, rule=StartUpCosts, doc='Cost of starting non-REN power plants')


## Load curtailment constraints
def LimitLoadCurtailmentToPowerInstalled(model, t, w):
    return model.LoadCurtailment[t,w] <= model.CurtailmentCapacity[w]
model.LoadCurt = Constraint(model.t, model.w, rule=LimitLoadCurtailmentToPowerInstalled)


def LimitationToLoadCurtailmentCapacity(model, w):
    return model.CurtailmentCapacity[w] <= model.LoadCurtailmentPotential[w]
model.LoadCurtLimits = Constraint(model.w, rule=LimitationToLoadCurtailmentCapacity)
```

```
def RecoveryTimeLoadCurtailmentToPowerInstalled(model, t, w):
    if t >= model.LoadCurtailmentRecovery[w] - 1 and t <= 35040 - model.LoadCurtailmentRecovery[w] + 1:
        return (sum(model.LoadCurtailment[i,w]
                for i in range(int(t-model.LoadCurtailmentRecovery[w]+1),int(t+model.LoadCurtailmentRecovery[w]-1)))
            <= model.CurtailmentCapacity[w] * model.LoadCurtailmentMaximumDuration[w])
    else:
        return Constraint.Skip
model.LoadCurtRecovery = Constraint(model.t, model.w, rule=RecoveryTimeLoadCurtailmentToPowerInstalled)

## Load shifting constraints
def LimitLoadShiftingToPowerInstalled(model, t, k):
    return (model.LoadShiftingDown[t,k] + model.LoadShiftingDownFreq[t,k]*2 +
        model.LoadShiftingUp[t,k] <= model.LoadShiftingCapacity[k])
model.LoadShift = Constraint(model.t, model.k, rule=LimitLoadShiftingToPowerInstalled)

def LimitationToLoadShiftingCapacity(model, k):
    return model.LoadShiftingCapacity[k] <= model.LoadShiftingPotential[k]
model.LoadShiftLimits = Constraint(model.k, rule=LimitationToLoadShiftingCapacity)

def LoadShiftingCumulated(model, t, k):
    if t > 0:
        return (model.LoadShiftingCumulated[t,k] == model.LoadShiftingCumulated[t-1,k] +
            model.LoadShiftingUp[t,k] - model.LoadShiftingDown[t,k] - model.LoadShiftingDownFreq[t,k])
    else:
        return model.LoadShiftingCumulated[t,k] == 0
model.LoadShiftRecovery = Constraint(model.t, model.k, rule=LoadShiftingCumulated)

def LoadShiftingCumulatedMaximum(model, t, k):
        return model.LoadShiftingCumulated[t,k] <= model.LoadShiftingCapacity[k] * model.LoadShiftingMaximumDuration[k]
model.LoadShiftMaximum = Constraint(model.t, model.k, rule=LoadShiftingCumulatedMaximum)

## Interconnexions constraints
def LimitInterconnexionsToCapacityEXP(model, t):
    return model.Exports[t] <= model.Interconnexions[0]
model.InterconnexionsLimitsEXP = Constraint(model.t, rule=LimitInterconnexionsToCapacityEXP)

def LimitInterconnexionsToCapacityIMP(model, t):
    return model.Imports[t] <= model.Interconnexions[1]
model.InterconnexionsLimitsIMP = Constraint(model.t, rule=LimitInterconnexionsToCapacityIMP)

## Technical constraints
```

```
def MinRotInertia(model, t):
    return (model.Nuclear[t] * model.RotationalInertia[0] +
          sum(model.NonRenGeneration[t,k] + model.NonRenGenerationFreq[t,k] for k in range(r)) * model.RotationalInertia[1] +
          model.Hydro[t] * model.RotationalInertia[2] + model.Bio_Mass_y_Gas[t] * model.RotationalInertia[3] +
          (model.CSP[t] + (model.HourlyCF[t,2] * model.PowerRen[2])) * model.RotationalInertia[4] +
          model.Imports[t] * model.RotationalInertia[5] >= model.RotInertia[t])
model.MinimumRotationalInertia = Constraint(model.t, rule=MinRotInertia, doc='Minimum rotational inertia of the system')


def RotInertiaCorrelationFrequency(model, t):
    return (model.Frequency[t] >=  0.24 - 0.000003 * model.RotInertia[t])
model.FreqRotationalInertia = Constraint(model.t, rule=RotInertiaCorrelationFrequency, doc='Rotational Inertia - frequency
regulation')


def SecurityOfSupply(model, t):
    return (model.Demand[t] - model.ExistingGen[t] -
          sum(model.EnergyRen[t,i] for i in range(z)) -
          sum(model.StorageOutput[t,j] for j in range(s)) -
          sum((1 - model.Unavailability[k]) * model.PowerNonREN[k] for k in model.r) -
          sum(model.LoadCurtailment[t,w] for w in model.w) -
          sum(model.LoadShiftingDown[t,k] for k in model.k) <= 0)
model.NationalSecurityofSupply = Constraint(model.t, rule=SecurityOfSupply)



##################################### SOLVE AND PRINT RESULTS #####################################

## Solve the model
opt = SolverFactory("gurobi")
results = opt.solve(model).write()

## Print decision variables and objective on the console
Costs = {'Total cost of the system [million euros]': round(model.OBJ()/1000,2), 'Cost per kWh': round(model.OBJ() /
sum(model.Demand[i] for i in range(t)),2)}
print(Costs)
Renewables = pd.DataFrame.from_dict(model.PowerRen.extract_values(), orient='index', columns=[str(model.PowerRen)])
print(Renewables)
Storage = pd.DataFrame.from_dict(model.StorageCapacity.extract_values(), orient='index', columns=[str(model.StorageCapacity)])
StoragePower = pd.DataFrame.from_dict(model.StoragePowerCapacity.extract_values(), orient='index',
columns=[str(model.StoragePowerCapacity)])
StorageEnergyPower = pd.concat([Storage, StoragePower], axis=1, sort=False)
print(StorageEnergyPower)
NonREN = pd.DataFrame.from_dict(model.PowerNonREN.extract_values(), orient='index', columns=[str(model.PowerNonREN)])
print(NonREN)
```

```
LoadCurtailmentCapacity = pd.DataFrame.from_dict(model.CurtailmentCapacity.extract_values(), orient='index',
columns=[str(model.CurtailmentCapacity)])
print(LoadCurtailmentCapacity)
LoadShiftingCapacity = pd.DataFrame.from_dict(model.LoadShiftingCapacity.extract_values(), orient='index',
columns=[str(model.LoadShiftingCapacity)])
print(LoadShiftingCapacity)


############################################### TIMEIT ###############################################
end = datetime.now()
time = end - now
print("The simulation ended at: ", end, "with a total running time of:", time)


################################## PRINT RESULTS IN EXCEL & TXT ##################################

## Print time-indexed variables in a excel file
REN = model.EnergyRen.extract_values()
df = pd.DataFrame(REN.values(), index=pd.MultiIndex.from_tuples(REN.keys())).unstack(1)
StorageInput = model.StorageInput.extract_values()
df1 = pd.DataFrame(StorageInput.values(), index=pd.MultiIndex.from_tuples(StorageInput.keys())).unstack(1)
StorageOutput = model.StorageOutput.extract_values()
df2 = pd.DataFrame(StorageOutput.values(), index=pd.MultiIndex.from_tuples(StorageOutput.keys())).unstack(1)
EnergyStored = model.EnergyStored.extract_values()
df3 = pd.DataFrame(EnergyStored.values(), index=pd.MultiIndex.from_tuples(EnergyStored.keys())).unstack(1)
Gas = model.NonRenGeneration.extract_values()
df4 = pd.DataFrame(Gas.values(), index=pd.MultiIndex.from_tuples(Gas.keys())).unstack(1)
Curtail = model.Curtailment.extract_values()
df5 = pd.DataFrame.from_dict(Curtail, orient='index')
Exports = model.Exports.extract_values()
df6 = pd.DataFrame.from_dict(Exports, orient='index')
Imports = model.Imports.extract_values()
df7 = pd.DataFrame.from_dict(Imports, orient='index')
Rampingcostsup = model.RampingCostsAuxiliar.extract_values()
df8 = pd.DataFrame(Rampingcostsup.values(), index=pd.MultiIndex.from_tuples(Rampingcostsup.keys())).unstack(1)
LC = model.LoadCurtailment.extract_values()
df9 = pd.DataFrame(LC.values(), index=pd.MultiIndex.from_tuples(LC.keys())).unstack(1)
LShiftDown = model.LoadShiftingDown.extract_values()
df10 = pd.DataFrame(LShiftDown.values(), index=pd.MultiIndex.from_tuples(LShiftDown.keys())).unstack(1)
LShiftUp = model.LoadShiftingUp.extract_values()
df11 = pd.DataFrame(LShiftUp.values(), index=pd.MultiIndex.from_tuples(LShiftUp.keys())).unstack(1)
FreqUp = model.Frequency.extract_values()
```

```
df12 = pd.DataFrame.from_dict(FreqUp, orient='index')
Inertia = model.RotInertia.extract_values()
df13 = pd.DataFrame.from_dict(Inertia, orient='index')
StorageFrequencyUp = model.StorageOutputFreq.extract_values()
df14 = pd.DataFrame(StorageFrequencyUp.values(), index=pd.MultiIndex.from_tuples(StorageFrequencyUp.keys())).unstack(1)
GasFreqUp = model.NonRenGenerationFreq.extract_values()
df15 = pd.DataFrame(GasFreqUp.values(), index=pd.MultiIndex.from_tuples(GasFreqUp.keys())).unstack(1)
LShiftDownFreq = model.LoadShiftingDownFreq.extract_values()
df16 = pd.DataFrame(LShiftDownFreq.values(), index=pd.MultiIndex.from_tuples(LShiftDownFreq.keys())).unstack(1)
with pd.ExcelWriter('Results.xlsx') as writer:
    df.to_excel(writer, sheet_name='REN')
    df1.to_excel(writer, sheet_name='StorageInput')
    df2.to_excel(writer, sheet_name='StorageOutput')
    df3.to_excel(writer, sheet_name='EnergyStored')
    df4.to_excel(writer, sheet_name='NonREN')
    df5.to_excel(writer, sheet_name='Curtailment')
    df6.to_excel(writer, sheet_name='Exports')
    df7.to_excel(writer, sheet_name='Imports')
    df8.to_excel(writer, sheet_name='RampingcostsUp')
    df9.to_excel(writer, sheet_name='LoadCurtailment')
    df10.to_excel(writer, sheet_name='LoadShiftingDown')
    df11.to_excel(writer, sheet_name='LoadShiftingUp')
    df12.to_excel(writer, sheet_name='FreqReserve')
    df13.to_excel(writer, sheet_name='Inertia')
    df14.to_excel(writer, sheet_name='StorageFreqUp')
    df15.to_excel(writer, sheet_name='GasFreqUp')
    df16.to_excel(writer, sheet_name='LoadShiftingDownFreq')

## Print a summary of results in a .txt
original_stdout = sys.stdout
sys.stdout = open("ResultsSummary.txt", "w")
print("The simulation running time is :", time)
print(Costs)
print(Renewables)
print(StorageEnergyPower)
print(NonREN)
print(LoadCurtailmentCapacity)
print(LoadShiftingCapacity)
sys.stdout.close()
sys.stdout = original_stdout
```