# Modelling Renewable Energy Integration: Energy Storage in the 2030 Portuguese Power System

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## Electrical and Computer Engineering

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*To my family and friends*

I declare that this document is an original work of my own authorship and that it fulfills all the requirements of the Code of Conduct and Good Practices of the Universidade de Lisboa.

# Acknowledgements

I would like to thank professor Rui Castro for all the help provided. His guidance, encouragement and scientific supervision were enormous contributions during the execution of this work.

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# Abstract

The main goal of this thesis is to study the role of storage in the context of the Portuguese power system. Portugal is one of the countries in the world with more installed storage capacity, namely pumped hydro storage (PHS). Most of this work has been focused on the development to 2030 and the implications of increasing RES levels. This work adds value in relation to similar studies by modelling the power system in an hourly time-step instead of modelling, for instance, a typical week of each season. Therefore, it is more accurate in modelling the seasonal and daily fluctuations that occur throughout the year. It also adds value by using updated data on technology costs and on the decisions of the Portuguese government, excluding from the analysis the recent cancelled hydropower projects. PHS revealed important to avoid the curtailment of renewable energy. It was concluded that the predicted storage capacity for 2030 can accommodate the expected increase in intermittent renewable generation with no need for further investments in PHS or battery solutions in 2030.

# Keywords

Renewable energy, energy systems modelling, energy storage, pumped hydropower, batteries

# Resumo

O principal objectivo desta tese é o estudo do papel do armazenamento no contexto do sistema eléctrico português. Portugal é um dos países do mundo com maior capacidade de armazenamento, nomeadamente de bombagem hidroeléctrica. A maior parte deste trabalho é focado no desenvolvimento da rede Portuguesa até 2030 e as implicações do aumento de renováveis. Este trabalho acrescenta valor em relação a estudos semelhantes ao modelar o sistema eléctrico numa base horária, ao contrário da modelação através de uma semana típica de cada estação do ano. Este procedimento é mais preciso na modelação das flutuações diárias e sazonais que ocorrem ao longo do ano. Acrescenta igualmente valor ao usar custos actualizados e tendo em conta os recentes cancelamentos de projectos hidroeléctricos. A bombagem hidroeléctrica revelou-se importante em evitar o desperdício de energia renovável. Foi concluído que a previsão de capacidade de armazenamento para 2030 consegue acomodar o aumento de renováveis de carácter intermitente expectável, não sendo assim necessários mais investimentos em bombagem hidroeléctrica ou baterias em 2030.

# Palavras-chave

Energia renovável, modelação de sistemas energéticos, armazenamento de energia, bombagem hidroeléctrica, baterias

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# List of Acronyms

| | |
|---|---|
| APREN | Portuguese Association of Renewables |
| BES | Battery Energy System |
| CAES | Compressed Air Energy Storage |
| CCGT | Combined Cycle Gas Turbines |
| CEEP | Critical Excess Electricity Production |
| CHP | Combined Heat and Power |
| $CO_2$ | Carbon Dioxide |
| DoD | Depth of Discharge |
| ESS | Energy Storage System |
| ETS | Emissions Trading System |
| EU | European Union |
| GHG | Greenhouse Gas |
| LCOE | Levelized Cost of Energy |
| LCOS | Levelized Cost of Storage |
| Li-ion | Lithium-ion |
| MIBEL | Iberian Electricity Market |
| NaS | Sodium Sulfur |
| OSG | Ordinary Status Generation |
| PHS | Pump Hydro Storage |
| PV | Photovoltaic |
| SoC | State of Charge |
| SSG | Special Status Generation |
| T&D | Transmission and Distribution |
| V2G | Vehicle-to-Grid |

# List of Software

| | |
|---|---|
| EnergyPLAN Version 13.1 | Energy system analysis model |
| Mathworks MATLAB R2015a | Numerical computing software |
| Microsoft Excel 2017 | Calculation and graphical chart tool |
| Microsoft Word 2017 | Text editor software |

# Chapter 1

# Introduction

This chapter describes the context for this thesis, as well as the motivation for studying energy storage. The objectives and structure of the work are also presented.

## 1.1 Motivation

In the power system, there is one rule that has to be followed no matter what. The supply and the demand must be balanced at all moments. This is a challenging task due to the fact that, in general, electricity has to be generated at the exact moment that is demanded. In the past, this was relatively easy to accomplish, when the power system relied mostly on fossil fuels. Generation based on fossil fuels has the advantage of being dispatchable, i.e. controllable. However, the disadvantages of the utilisation of fossil fuels surpass the advantages. As it is known, fossil fuels are responsible for the emissions of greenhouse gases that contribute to the warming of the planet. For this reason, over the past years, we have witnessed the energy transition to clean renewable energy sources. However, some renewable sources like wind and solar are variant in time, as their production depends on weather conditions. The sun is not always shining neither the wind is always blowing. This represents an additional challenge to the grid operator to balance generation and demand. Demand has always been the non-controllable variable, but with dispatchable generation, the balancing problem was perfectly achievable. However, with the introduction of intermittent renewable generation in the grid, to maintain a constant balance between production and consumption is becoming increasingly hard. As previously stated, electricity has to be generated at the precise time that it is consumed, and there is only one possibility to make this maxim not entirely accurate, and that is precisely energy storage. For that reason, energy storage has gathered high expectations and is many times regarded as the fundamental piece of the future power grid. Theoretically, with energy storage, it would be possible to rely uniquely on wind and solar power to meet our electricity demand. These sources of energy are intermittent and this is why wind and solar are part of a group called variable renewable generation. In fact, the concept behind energy storage seems simple. When there is too much wind or solar production, the surplus of energy can be stored. When there is not enough production, the stored electricity can be used.

## 1.2 Objectives

The apparently easy concept behind energy storage attracts a lot of attention to the topic. Such impetus originates, many times, opposite reactions with some regarding it as the “Holy Grail” for the energy transition, while others are sneering at it. The reality is somewhere in the middle of this. It is imperative to increase grid flexibility if higher levels of variable renewable generation are to be achieved. Energy storage constitutes one of the available technologies that can enhance that grid flexibility. Nonetheless, it is necessary to prove the effectiveness of energy storage solutions in real-world cases, both from a technical and an economic perspective. To accomplish that, it is essential to create models that can simplify the complexity of energy systems. In this work, it will be studied a real case of the utilisation of

storage, that is its utilisation in the context of the Portuguese grid. In fact, Portugal is one of the nations with more deployment of energy storage. In mid-2017, Portugal was ranking 12$^{th}$ worldwide regarding pumped hydro installed capacity (PHS) [RaTa17]. The modelling of the Portuguese power system will be performed with the help of an energy systems simulation tool. First, 2014 was simulated as a reference year. The reference year is essential to get acquainted with the software, with the Portuguese grid and also to calibrate the model for the simulation of future scenarios. The evolution of Portugal's power system will be considered with a 2030 horizon. Further than 2030, it is both hard to predict how will the system as well as the prices of batteries evolve. Therefore, it was preferred to centre our attention in 2030 scenario. Both technical and economic simulations will be performed and included in the analysis. The objectives of the modelling of the Portuguese power system are the following:

- The prediction of the energy mix for 2030.
- The prediction of the utilisation of the storage capacity, namely with projections of the energy consumed by pumped hydro storage (PHS).
- The prediction of $CO_2$ emissions and percentage of renewable energy sources (RES) utilisation.
- The assessment of the necessary storage capacity to avoid renewable curtailment, i.e. wasted renewable energy.
- The assessment of the future needs to install further storage capacity, either with more pumped hydro capacity or with the introduction of batteries, i.e. try to evaluate if the planned/expected storage capacity for 2030 is enough or if it is required to add more capacity to the system.

The analysis performed will account for variations in weather conditions and in the evolution of the demand. A dry, a wet and a normal year will be considered, as well as a low, a medium and a high demand scenario. Furthermore, it will also be studied a scenario with higher levels of variable renewable generation (RES scenario). The inclusion of this scenario intends to survey if increasing levels of renewable energy will raise the needs for further storage capacity.

## 1.3 Structure of the work

This thesis is divided in six chapters and one annex. The present chapter intends to introduce the context and motivation for studying energy storage, as well as the objectives of this work. The structure of the thesis is also described.

Chapter 2 starts by giving an overview of the European context that Portugal is inserted. Specifically, it focusses on "2020 and 2030 Framework for Energy and Climate" that establishes several energy targets for these years. Then, a review on energy storage is presented, enhancing its wide range of applications and the economic evaluation of the costs of storage. Afterwards, different technological options are discussed, namely pumped hydro storage (PHS) and batteries. A comparison between the economics of PHS and batteries for large-scale energy storage is presented. The chapter ends with a state-of-the-art review where the work developed by other authors related to the subject of this thesis is presented.

Chapter 3 describes the methodology used in this work. The chapter starts by presenting the simulation tool EnergyPLAN. The rest of the chapter is dedicated to the modelling of the reference year. In this chapter, it is explained the most relevant aspects of EnergyPLAN and of the Portuguese grid. As it is discussed the parameters that it is necessary to insert in the model, it is described these parameters for the Portuguese grid like the interconnection capacity or the technological distribution of the generation.

Chapter 4 describes the evolution of the Portuguese power system in a 2030 horizon. The modifications in the system with respect to the reference year are detailed in this chapter.

Chapter 5 is composed of the results analysis. It is divided into the results performed with the technical simulation of EnergyPLAN and with the economic simulation.

Chapter 6 presents the conclusions of the work by highlighting the most relevant results and aspects addressed in this thesis. Moreover, it provides guidelines for improvement of this work and further scientific research that can be done related to this subject.

Annex A provides a description of the economic data considered in EnergyPLAN model, namely investment costs and fixed and variable O&M costs.

# Chapter 2

# Energy Storage: Context and State-of-the-art

This chapter starts by giving an overview of the European context in which Portugal is inserted. Then, a review on energy storage is presented, enhancing its applications and economics. Afterwards, different technological options are discussed, namely pumped hydro storage (PHS) and batteries. The chapter ends with a state-of-the-art review where the work developed by other authors related to the subject of this thesis is presented.

## 2.1 The European context

The rapid growth of the world population results in higher energy demand. In 2018, the world population was 7.6 billion and is expected to grow to 10 billion by 2055 [Worl18]. To meet the increasing energy needs is vital for economic growth. However, this should be accomplished with cleaner energy instead of the traditional generation mostly based on fossil fuels. Due to this fact, renewable energy has been a hot discussion topic. In the beginning, renewable energy was regarded with suspicion, but given the fast pace decrease in RES costs, these sources are becoming a proven solution and competing head-to-head with traditional generation. Renewable sources can be an opportunity for countries to meet their policy goals regarding access to reliable, secure and affordable energy for all individuals. Furthermore, reduce price volatility and promote social and economic development [RaTa17], and most of all, reduce greenhouse gas (GHG) emissions. In December 2015, at the Paris climate conference, 196 countries agreed on the first-ever global climate change deal, confirming the transition in course to a low carbon world economy. Paris Agreement mitigation plan intends to limit global warming to a maximum of 2ºC and increasing efforts for reducing this maximum, if possible, to 1.5ºC [UnNa15]. The European Union (EU) is making efforts to set an example and to lead decarbonisation of the economy. On November 2016, the EU presented a new package of measures entitled “Clean Energy for All Europeans”. The document seeks to provide the legal framework for a clean energy transition [EuCo17a] and allow the EU to reach the goals of the Paris Agreement. “Clean Energy for All Europeans” aims to the creation of an Energy Union.

The Energy Union seeks to provide all members with “secure, affordable and climate-friendly energy” [EuCo17b]. Security of supply is intended to be achieved by diversifying Europe’s energy sources and with close cooperation between EU members. On the other hand, an integrated market could contribute to affordable energy for all Europeans [EuCo17b]. A system without technical or regulatory barriers would improve the security of supply but also provide consumers better deals while fighting energy poverty. Although there are many visions of energy poverty, it can be defined as the inability to have sufficient energy to meet basic needs [Gonz15]. No access to adequate warmth or cooling, lighting or power for appliances to provide a decent and healthy level of living [EuCo17]. Energy poverty is related to health issues like cardiac and respiratory problems that can be caused for example by inappropriate cooking appliances that cause indoor air pollution. According to World Health Organization, around 3 billion people in the world cook and heat their households with solid fuels that produce high levels of household air pollution, causing 4 million premature deaths per year [WHO17]. This situation happens mostly in low-income countries. However, energy poverty is not exclusively a problem of developing countries, despite many times being regarded in such manner. The recently created Observatory for Energy Poverty estimates that more than 50 million households in the EU are experiencing energy poverty [EuCo17], which corresponds to 10% of the population. In Portugal, the residential electricity consumption (15.8%) is significantly lower than EU average (25.4%) [EuCo17d]. This is explained by the mild climate but also by the fact that Portugal has one of the highest electricity prices for household consumers [Euro18]. The high price of electricity, which is in part due to the high share of taxes in the

final price, impacts the level of energy poverty [EuCo17d].

The creation of the Observatory for Energy Poverty as part of “Clean Energy for All Europeans” is a signal that EU is trying to address Energy Poverty. Nonetheless, the primary concern of Energy Union is probably the decarbonisation of the economy in order to meet with the agreed targets illustrated in figure 2.1. The targets are part of the 2020 and 2030 Framework for Energy and Climate. For 2030, for instance, the framework has three key targets: to reduce by 40% the greenhouse gas emissions (GHG), to increase renewable energy by 27% and to increase energy efficiency by 30% in comparison to 1990 levels.


Figure 2.1 2020 and 2030 Framework for Energy and Climate [EuCo17e].

To reach the ambitious 40% reduction in GHG, European Union has a powerful tool, the Emissions Trading System (ETS). It started in 2005 as the first large-scale carbon trade market and remains up to the present the largest one, covering up 45% of EU greenhouse gas emissions [EuCo17f]. It works with the principle of “cap and trade”. A cap is established on the total amount of emissions that can be produced by the system. The cap is supposed to be progressively reduced over time so that emissions fall and the agreed targets are reached. Afterwards, the market participants, i.e. the companies that produce the emissions, have emission allowances allocated for free or must acquire them. The allowances act as certificates to cover up for their emissions. Allowances can also be traded between market participants with companies that have them in excess trading with companies that require more licenses. This allows the system to find a more cost-effective solution [ElCP10].

In figure 2.1, the framework set a 20% final energy consumption from renewable sources for 2020 and a 27% for 2030. In 2004, which was the first year that this data was available, only 8.5% of energy consumption in European Union came from renewables [Euro17]. In 2015, according to the Eurostat [Euro17], had nearly doubled to 16.7%.

EU members must commit to reaching this goal by implementing their own national renewable energy program to achieve 2020 and 2030 targets. However, the goals are not equal for every country. In 2004, Portugal already had a 19.2% of renewable energy consumption. Thereby, it would not make sense to compromise with an unambitious 20% target. Portugal compromised reaching a 31% target in 2020. However, in 2015 and 2016, renewables accounted for 28% and 28.5% respectively [EuCo17], showing

that further efforts should be taken if the target is to be reached.

In figure 2.2, the share of renewable energy consumption in the EU members can be visualised. Sweden leads the list with an impressive 53.9% share, having already surpassed their target for 2020 of 49%. In 2004, Sweden already had a 38.5% share of renewable energy. The top-ranking countries allow EU to be in an excellent position to meet 2020 target and compensate for nations like Netherlands, Luxembourg, Malta or Belgium with lower than 10% shares of renewable energy. While Netherlands and France are the countries that are far from meeting their targets with 8.2 and 7.8 percentage points from reaching their national objectives [Euro17]. Each state must develop a Renewable Energy National Action Plan.

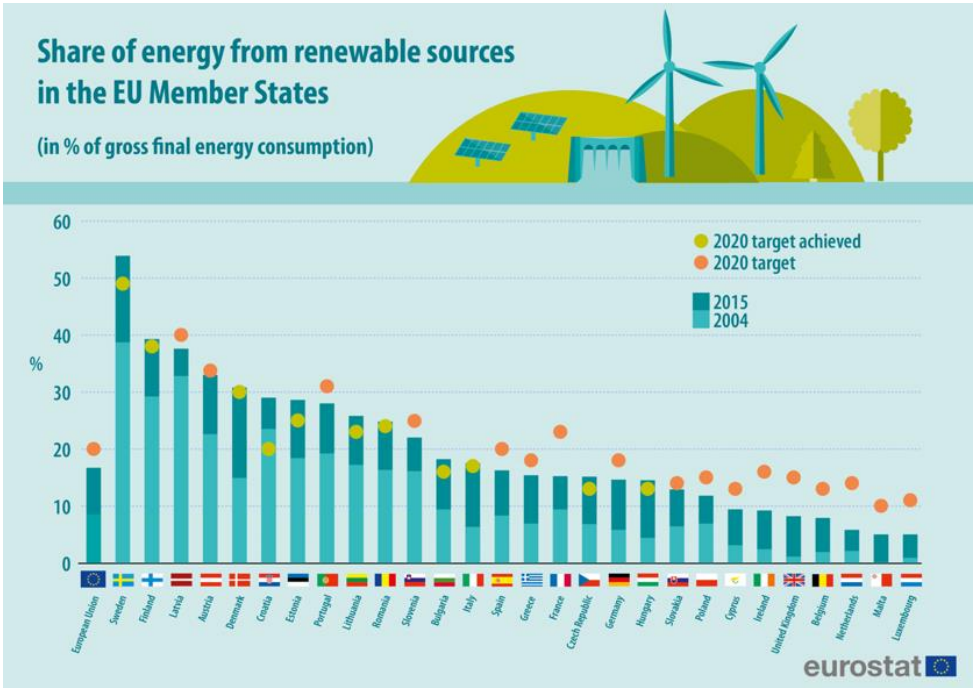



Figure 2.2 Share of renewable sources in EU [Euro17]

To reach the energy efficiency targets, 20% for 2020 and 30% for 2030 (in comparison to the estimated use of energy for 2020 and 2030), the EU implemented several measures like a minimum standard of efficiency for energy appliances, ensuring that large companies conduct energy audits every four years and mandatory energy certificates when buying or renting a household. Moreover, each country must develop its National Energy Efficiency Action Plan with adequate measures for each country's reality and present it to the EU.

Apart from previous measures, the installation of almost 200 million smart meters for electricity and 45 million for gas by 2020 [EuCo14] is a valuable step towards the objective of energy efficiency. Smart meters are devices that can monitor energy consumption and give adequate price signals for the consumer to make more informed decisions on their energy usage. A 2014 European Commission study showed that the installation cost in the EU on average is between 200€ and 250€ and, on average, a smart metering point can save €160 for gas and €309 for electricity, distributed by consumers,

distributors and suppliers [EuCo14]. Furthermore, the study showed to contribute to an overall energy saving of 3% [EuCo14].

Moreover, the interconnection capacity must be increased. In 2020, each country should have 10% of interconnection capacity in relation to the total generation capacity. This value should increase to 15% by 2030. The enhancement in interconnection capacity will improve the security of supply, contribute to a fully-integrated market and a more cooperative Energy Union.

The improvement of the interconnection capacity is one of the available ways that the countries have to enhance flexibility of their national systems and achieve higher levels of renewable energy penetration. Another method to improve flexibility could be to make a more extensive employment of energy storage resources.

## 2.2 Energy storage

There are several challenges in the integration of renewable energy sources in the power system. One is concerned with the fact that the renewable production is in many cases located geographically far from the load. Thus, the need for grid expansion has to be considered. One way to address this problem is to have a balanced geographical distribution of renewable energy production [KEMA14]. When selecting between different options of renewable energy, it should be taken into account not only resource availability but also proximity to the load. With decreasing costs in renewable energy, the preponderance of the costs of additional transmission and distribution capacity increases [KEMA14].

The other problem related to renewable energy integration is the intermittency or variability of renewable energy. Most of the renewable energy sources are variable in time like wind and solar. Energy storage is many times appointed as the solution to the variability of renewable energy. The energy would be stored when there is an excess of renewable energy production and would later be consumed on a more suitable occasion, i.e. when demand increases or when there is less renewable production.

In fact, energy storage can be useful in many contexts and have multiple applications in different stages of the grid, from behind-the-meter to front-of-the-meter or grid-scale applications. In this section, it will not be discussed the economics of energy storage. It will only be referred the main use cases that energy storage may have. The economics of energy storage work will be addressed in the next sections.

Behind-the-meter applications can include the installation of back-up capacity in microgrids. Although it is a hot research topic, there are different definitions of microgrids [SuIr17]. According to [CERT17], a key feature of a microgrid is its ability, during a disturbance, to separate and isolate from the utility grid with little or no disruption to the loads within the microgrid. After reestablishment from the disturbance, the microgrid should be able to automatically resynchronize and reconnect to the main grid in a successful way. Energy storage can provide power to small power systems, making them able to “island” and disconnect from the broader grid [Laza16]. Also, in physically isolated electricity systems like

islands, these can be designed to operate like a microgrid with storage providing stability and reliability to the system.

Energy storage could also provide demand response services for commercial and industrial consumers. Demand response gives the opportunity for these customers to shift part of their electricity usage from peak periods to off-peak periods, stimulated by tariff incentives from the grid operator. As it is represented in figure 2.3, the storage system could charge during off-peak periods, increasing consumption in off-peak periods (valley filling) and discharge during peak periods, decreasing consumption during peak hours (peak clipping).

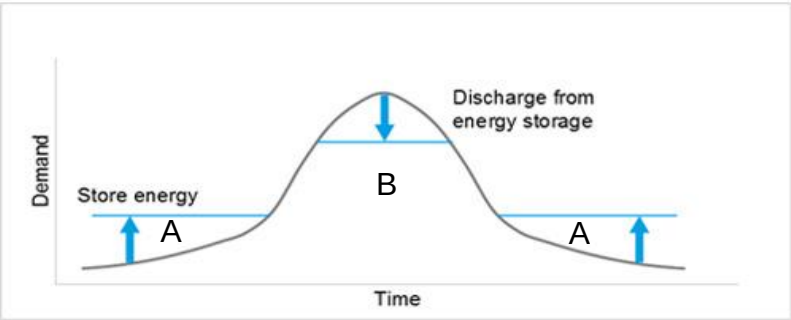



Figure 2.3 Demand response using energy storage. Valley filling (A) and peak clipping (B). Adapted from [Na4B17].

For residential clients, energy storage could provide back-up capacity and improve power quality. Furthermore, it can enhance the performance of photovoltaic (PV) residential systems, either increasing self-generation or controlling the flow of electricity sold to the grid [Laza16].

On a grid-scale, it can assist in the large-scale integration of variable renewable energy. It can improve the transmission system performance by providing voltage support, decreasing transmission losses and diminishing congestion [Laza16]. Furthermore, it can defer the investment in additional transmission capacity. There is also an opportunity for energy storage to replace thermal back-up capacity. With the increasing percentage of intermittent sources in the energy mix, there is a need for back-up capacity generation. This back-up capacity is supposed to be able to change its energy output in short periods of time. Examples of back-up capacity are gas turbines or dammed hydro, i.e. hydro with a reservoir. Not only is back-up capacity important to accommodate variable RES production, as it can adjust to sudden changes in demand. For instance, in peak periods, these sources are recruited for operation. Nonetheless, in the case of gas turbines, these are usually used during a reduced fraction of the time. This results in low utilisation factors, between 5 to 10% [Paul14]. Since these plants have higher marginal costs than other plants, they have their utilisation reduced to meeting peak demand and, for that reason, are sometimes called of gas-fired peaking plants. Having peaking plants providing capacity reserve is the most cited option in literature and often works as the benchmark to calculate the extra costs of integrating variable generation [GüSt05]. Furthermore, it has been the state-of-art in most countries. The limited utilisation of these power plants can constitute an opportunity for energy storage (ES). With the future decrease in ES prices, storage solutions may compete with peaking power plants. Moreover, a storage system can accumulate additional revenue by providing other services throughout

the rest of the year. For instance, it can provide ancillary services. Ancillary services are support services available to the grid operators, DSO and TSO, and are essential for maintaining power quality and ensure a secure and reliable electricity system [AlSS17]. Frequency regulation is one of the ancillary services that energy storage can provide. It consists of the close control of power imbalances between supply and demand and therefore maintaining grid frequency within desirable levels. This regulation service can be an adequate application for energy storage. According to [MLMN08], that evaluated the value of different regulation services based on their time response characteristics, the value of storage with a fast ramp rate can double the one from conventional generation as it can have a more accurate time response. Other ancillary services that energy storage could provide include the reactive power support in order to correct the power factor or adjust voltage levels [LMKB16]. Therefore, energy storage could have a business case providing ancillary services, though this segment has limited market size. In figure 2.4 is represented the variety of use cases that energy storage could provide.

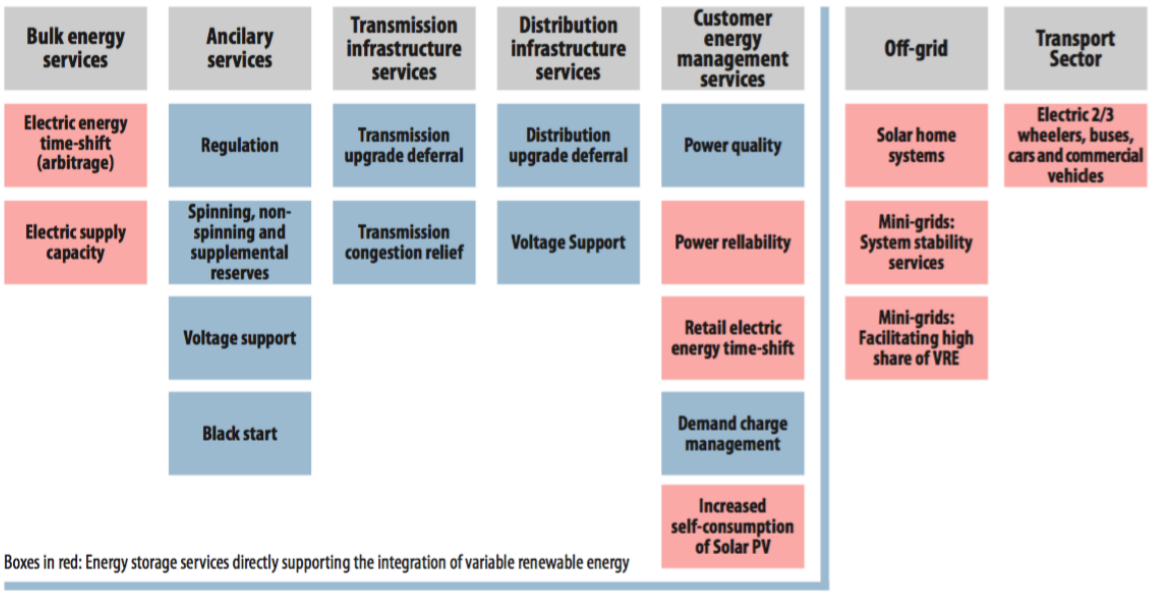



Figure 2.4 Range of use cases that energy storage could provide [RaTa17].

Energy storage could contribute to a more cost-efficient electricity system by taking advantage of the price differences between different periods, what is commonly called of electricity arbitrage. Electricity arbitrage involves acquiring electricity in off-peak periods when electricity prices are low and take advantage of this period to charge storage systems. Afterwards, in peak periods, the stored energy can be used or sold in periods with higher prices. In the same way, storage can be used in periods with an excess of wind or solar production in order to avoid curtailment of renewable energy. Curtailment means to voluntarily reduce the energy output of variable renewable generation to prevent grid imbalances. In these periods of excess, the prices of electricity are low and there is an opportunity to arbitrage the price through storage. Moreover, by storing energy during low demand hours for later use in high demand periods, it can prevent the system from investing in extra generation power capacity.

From the above use cases of energy storage, it is undeniable that energy storage can have multiple

utilisation scenarios. However, in most of the cases, energy storage is not applied due to its high investment/capital costs. Therefore, it is necessary to prove the economic feasibility of the earlier referred options to convince both investors and policymakers of the usefulness of energy storage. In order to do that, an adequate methodology should be presented as the already existent for generation, the LCOE (Levelized Cost of Energy). There should be a reliable and trusting methodology for storage, the LCOS (Levelized Cost of Storage).

## 2.3 Levelized Cost of Storage (LCOS)

The LCOS could provide a straightforward methodology in order to address the viability from the economical point of view of the investor. However, there is not a consensual methodology for LCOS calculation as there is for generation technologies with the widely used LCOE [BeDD16].

According to [LMKB16], LCOE is defined as the net present value of the entire cost of electricity generated over the lifetime of a generation asset divided by the total generated energy. It permits to compare different technologies which have different lifetimes, capacities, investment costs, fuel costs and efficiencies [LMKB16]. Nonetheless, the same technology can assume different LCOE dependently on the location. For instance, wind and PV are influenced by the weather conditions of a certain location and therefore its LCOE can assume different values dependently on the location of the wind turbines or PV panels.

With the help of the LCOE, it is possible to compare different generation technologies in terms of cost, providing a unified methodology. Additionally, it is possible to infer about the profitability of a project with the comparison between LCOE and the price of electricity (in the point of connection to the grid) [LMKB16]. In contrast to electricity generators that have mainly one purpose that is to produce energy, storage technologies can serve multiple applications. The design parameters of the energy storage system (ESS) vary accordingly to the service that is being provided. Unlike, generation technologies which are characterised by power capacity, ESS are described by power capacity and energy capacity. Power capacity is the maximum instantaneous amount of power that can be produced, usually measured in MW. Energy capacity is the total amount of energy that can be stored in an ESS, traditionally measured in MWh. These parameters, along with others like the number of cycles per year, influence the LCOS and therefore it is only possible to compare costs for different technologies for the same use case, i.e. the same application.

In the literature, there are different methodologies available for the LCOS. It is widely accepted that fuel costs and generated electricity, in the LCOE, should be replaced by charging costs and discharged electricity, respectively. In the first instance, the LCOS should have an analogical formulation to the one of the LCOE. It should reflect the discounted cost of electricity per unit of discharged electricity as it is represented in equation 2.1.

$$LCOS = \frac{\sum(CAPEX_t + O\&M_t + CC_t)\ (1+r)^{-t}}{\sum MWh_t\ (1+r)^{-t}} \tag{2.1}$$

Where:

$CAPEX_t$ = Capital expenditures in year t

$O\&M_t$ = Fixed operation and maintenance costs in year t

$CC_t$ = Charging cost in year t

$MWh_t$ = Electricity discharged in MWh in year t

$(1+r)^{-t}$ = Discount factor for year t

Apart from that, some authors [Jülc16][ZaSy15] developed LCOS methodologies specially adapted to particular technologies to represent their specific aspects. For batteries, for instance, a life cycle analysis should consider specific technological parameters like Depth of Discharge (DoD). DoD (%) represents how deeply the battery has been discharged in contrast to the State of Charge (SoC). Additionally, it is used as a parameter to inform about until which percentage can a device be discharged without permanently compromising the lifetime of the battery. Other factors should be taken into consideration when developing a life cycle cost methodology for storage. Firstly, as the prices of electricity vary over time, an average value for electricity should be used [Jülc16] [BeDD16]. Secondly, it should be taken into account that the storage capacity can limit the system to discharge and charge in the most optimal moments [BeDD16]. Finally, LCOS does not account for other services that energy storage could provide like ancillary services [BeDD16].

LCOS is a methodology solely based on costs. This can prevent investors from seeing the broader picture and the benefits and value of energy storage. A given energy storage system (ESS) can accumulate different sources of revenue by being used in different use cases. Although the system is usually designed and optimised for a specific application, the ESS can contribute with other sources of value by providing additional services [Laza16]. The only condition is that the different services do not interfere with each other. In figure 2.5, it is represented the value proposition for an ESS.

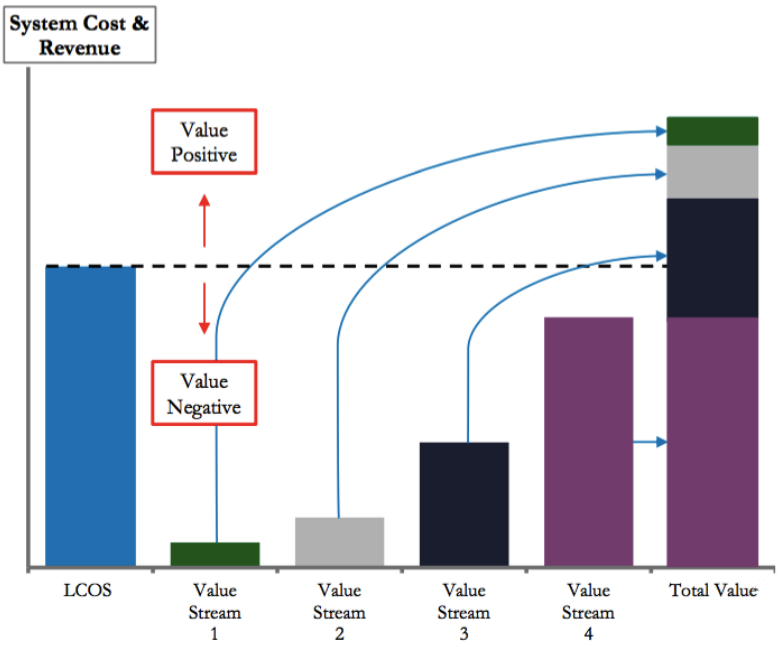



Figure 2.5 Energy storage value proposition [Laza16].

The “value stream 4” accounts for the most significant percentage of the total value system represented in figure 2.5. It was probably for this use case that the ESS was first idealised. Nevertheless, this value stream alone is less than the costs (LCOS). But if the ESS can incorporate other sources of revenue (“value stream 1”, “value stream 2” and “value stream 3”), the total value of the system could surpass the system costs. In figure 2.5, the “stacked” value is represented as a simple sum of the available streams, though, in practice, this can differ from a simple sum due to operational factors [Laza16].

## 2.4 Storage technologies

There is a wide range of different storage technologies, and according to the purpose they serve, some technologies are more appropriate for specific applications, dependently on their power and energy characteristics. Certain applications require a more extended time-scale shifting of energy, usually in the range of minutes to hours. These are considered energy applications. The continuous delivery of energy is more important than the rapid injections or absorptions of power. Energy applications can include electricity arbitrage, peak shifting and operational storage of electricity generated off-peak [MaKM11]. On the other hand, power applications require shorter time-scale injection or absorption of power in the range of seconds to minutes. Power applications can include frequency regulation, regulating voltage and smoothing of variable renewable generation. Two energy storage technologies can provide, at the same time, significant energy and power output. Due to their size, pumped hydro storage (PHS) and compressed air energy storage (CAES) can have large power ratings and discharge times of some hours, figure 2.6.

PHS will be given the most attention for the reason that it is the most used technology in the world with 96% of the total installed storage power capacity [RaTa17] and is the used technology in the Portuguese power system at a utility-scale. Batteries, on the other hand, have suboptimal performance when used on grid-scale applications due to their high costs, reduced power/energy capacities, and reduced lifetime due to performance degradation. Nevertheless, with the rapid decrease of battery costs and performance enhancements, there are high expectations in the potential of battery energy systems (BES). With future developments, the strict lines between technologies represented in figure 2.6 tend to disappear. Batteries could provide bulk power management which in the present is reserved to PHS and CAES, figure 2.6. For this reason, apart from the pumped hydro, battery technologies will also be analysed in this work.

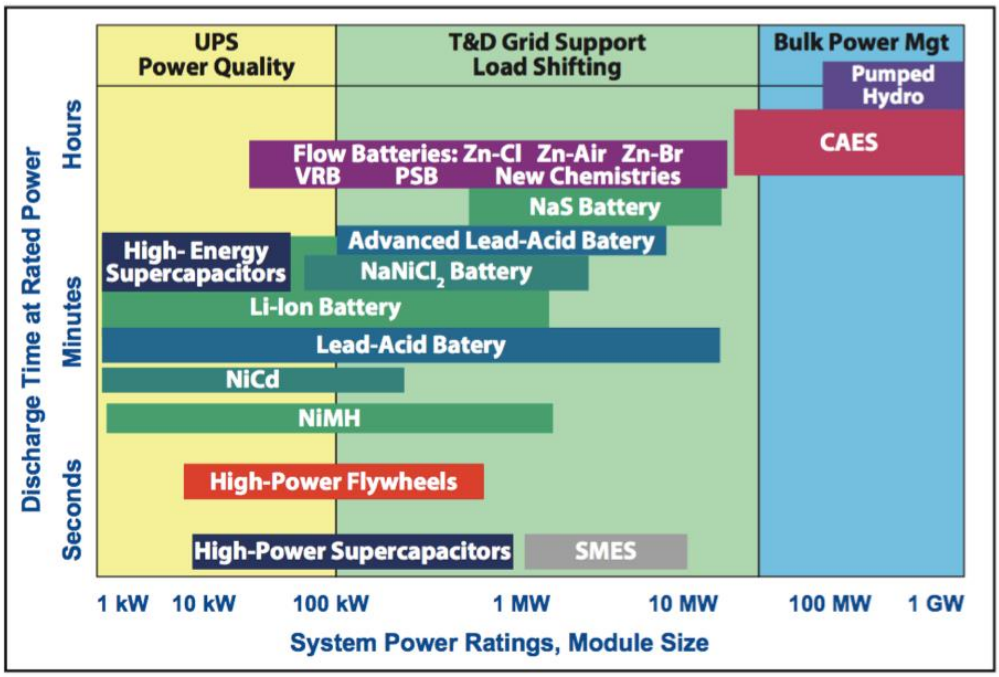



Figure 2.6 Positioning of energy storage technologies [HACK13].

The deployment of BES on front-of-the-meter applications has been reduced due to the high costs of batteries with large energy/power outputs. Most of the current applications on a utility-scale are reduced to providing ancillary services to the grid. In these cases, the BES can absorb energy from the grid, either when voltage or frequency is too high, or deliver energy to the grid when in frequency or voltage is too low [Poul13][LeSw12]. Battery systems have better performances than most of the other storage systems in frequency regulation, as they can respond rapidly and precisely to frequency deviations [HSSL17]. Batteries can have a better response than steam turbines, combined cycle, combustion turbines and hydropower [Lee17]. For this grid stabilisation service, large installations of lead-acid batteries are the standard technology [PuPD13]. New and more transparent markets are emerging for ancillary services and BES can have increased opportunities to see their good performance rewarded on these markets [RaTa17]. The current state-of-the-art can only provide short duration periods of energy, what makes the technology still inconsistent for giving support to large-scale RES or shifting loads, which will require longer charge/discharge durations and higher energy to power ratios [Poul13].

According to IRENA[1] [RaTa17], the primary market opportunity that batteries may have in the period to 2030 is in supporting small-scale PV systems. In European markets, three factors accentuate this tendency: the high electricity rates, the already settled and competitive cost structure for PV and the declining feed-in tariffs [RaTa17]. Portugal, in particular, has one of the highest commercial and residential electricity rates of Europe, a great solar potential and is decreasing or even eliminating feed-in tariffs at all. PV+BES can increase self-consumption and reduce peak demand. Along with time-of-use pricing, consumers can see their energy expenses significantly reduced.

Nevertheless, even on the utility-scale, the expected growth of BES in the period to 2030 is notable. Worldwide, it is expected to grow from 10 GWh in 2017 to between 45 and 74 GWh [RaTa17]. On utility-scale, different technological options are used in the present: lead-acid batteries, sodium sulfur batteries (NaS), lithium-ion and redox flow batteries [LuMa09].

Lead batteries are a mature and low-cost technology when compared to other batteries. They were developed more than 150 years ago and there is ample operational and manufacturing experience [RaTa17]. However, they are slow to charge, cannot be fully discharged and have low energy to volume ratio. Furthermore, there are environmental concerns around these batteries. The lead and sulfuric acid are extremely toxic and can create environmental hazards [Poul13]. There are some expectations regarding the development of advanced lead-acid batteries that can improve life-cycle durability and provide deeper discharges, comparatively to traditional lead-acid as it can be seen in figure 2.6.

Sodium-sulfur (NaS) batteries have high energy density and efficiency, long life cycle and are fabricated from inexpensive materials [KISF10]. Due to this, the largest battery systems use NaS batteries [Poul13] and these have been used to integrate large-scale renewable energy [KISF10].

When lithium-ion batteries are used on a grid scale, it is usually to perform power management services for short periods of time, no more than some minutes [Ferg10]. This technology is the preference for the electromobility industry. Thus it has registered rapid cost reductions. With that, its use in utility-scale applications has suffered a significant increase. Apart from that, a promising behind-the-meter technology for lithium-ion batteries is the vehicle-to-grid (V2G). V2G is the possibility of the EV to communicate with the grid and provide fast response storage to the fluctuations in load. It is an appealing concept as it would avoid the high capital costs of batteries. However, the frequent charging cycles would increase the stress on the batteries that are one of the most costly parts of the electric vehicle. This is one of the reasons that V2G has not reached a broader implementation.

Redox flow batteries are different from other solid-state batteries. Solid-state batteries store energy in a solid electrode material, whereas flow batteries sore energy in electrolyte liquids []. The electrolyte liquids are separated in two separate tanks with two independent loops. Energy capacity is defined by the quantity of electrolyte stored in the external tanks and hence it is proportional to the size of the tanks. Whereas power rating is scaled by the area of the electrodes. Therefore, flow batteries can be scaled

[1] IRENA - International Renewable Energy Agency

in order to offer different energy to power ratios. This flexibitlity in discharge time, power and energy capacities and low degradation of energy capacity throughout the lifetime of the battery are motivators for future research in this promising technology which is still in R&D phase [ZaSy15].

## 2.5 Comparison between PHS and batteries

Pumped hydro takes advantage of two storage reservoirs at different heights, using low-cost electricity to pump the water to the reservoir at a higher altitude and running as a conventional hydropower plant when electricity prices are high. PHS is characterised by large power capacity (100 MW-2000 MW), long lifetime, long discharge times and high efficiency, which favoured PHS over other technologies for bulk energy storage [ZaSy15]. Due to the large energy capacity, it can perform daily energy time shift, as well as seasonal storage.

PHS is a mature technology with multiple years of experience. In fact, it is a technology with more than one century of expertise. On the other hand, batteries are a new technology that is starting to see its range of applications extended to the grid-scale. PHS and batteries are probably the two storage technologies that have risen the most interest to the stakeholders and the general public over the last few years. PHS for the fact that is by far the most widely used storage technology and the only one that has proven to provide significative energy and power capacities in a cost-efficient way [ZaSy15].

It can be challenging to compare PHS and battery technologies. Firstly, for the fact that they are technically very different from each other. Secondly, one is a widely known mature technology, while the other is recent and is experiencing a rapid development. Thirdly, battery technologies are in formative stages and PHS are very site-specific, i.e. the technical solution is adapted to the geography of the location. This results in incongruencies in the cost data across the scientific literature. Finally, as it was observed before, batteries are divided in a wide range of families. Therefore, the term “batteries” applies to a significant number of different technologies. Apart from the previously mentioned groups of batteries: lead-acid batteries, sodium sulfur batteries (NaS), lithium-ion (Li-ion) and redox flow batteries, other battery families that were not considered because they are not usually used for grid-scale applications. Even among each family, there is often a wide range of subfamilies.

Nevertheless, a comparison between the PHS and batteries costs will be discussed, focusing on the levelized cost of storage methodology. In Lazard’s Levelized Cost of Storage [Laza16], the LCOS assessment for different storage technologies is performed. The LCOS for pumped-hydro ranges between 137 €/MWh to 179 €/MWh[2]. In 2016, battery costs ranged from 237 €/MWh to 709 €/MWh. This corresponds to the discounted costs through the lifetime of the storage system per MWh of

[2] Costs in Lazard’s LCOS analysis in USD/MWh. 2016 conversion rate (1 USD = 0.904)

delivered electricity. The capital costs are expressed as well in price per energy unit, though they are quantifying what investment must be made to acquire a storage system with a certain energy capacity. According to Lazard [Laza16], pumped hydro capital costs range from 192.5€/kWh to 283.0 €/kWh, while batteries range from 348.9 €/kWh to 1084.8 €/kWh. The wide range of costs in batteries is explained by the different stages of development of the different battery technologies. It is hard to predict how far the reduction in battery costs can go. However, according to IRENA[3] [RaTa17], it is expected a decrease in the range of 50%-60% in a 2030 horizon. With that, it is likely that the LCOS of batteries could decrease to around 150 €/MWh and 200 €/MWh, making batteries able to compete with PHS. Lazard's Levelized Cost of Storage calculations is based on a twenty-year project lifetime. However, considering that PHS has a much longer lifetime (50 to 100 years) and that batteries may need to be replaced every 10 or 20 years, the whole life cycle costs of batteries would be higher when longer lifetimes are considered.

Therefore, if the lifetime of the batteries is not significantly increased, it is unlikely that batteries can compete with pumped hydro in providing large bulk energy services in the near future. However, batteries can differentiate themselves from PHS by taking advantage of the downsides of pumped hydro. The implementation of PHS projects takes around five years to complete. Two or three years for optimising the technical solution, social and environmental studies and financing. Afterwards, another two or three years for construction. Apart from long project times, the high development risks involved in these projects can accelerate the utilisation of battery solutions. Furthermore, PHS carries adverse environmental impact and geographical restrictions, i.e. there are limited locations where it is possible to develop this sort of projects. With limited areas for PHS and with the expected increasing needs for energy storage, battery systems may have an opportunity in utility-scale storage.

## 2.6 State-of-the-art review

A state-of-the-art review is presented in this section, regarding the main topics of this thesis. The rising levels of variable renewable energy have increased the interest in the scientific community with solutions for integrating more RES and increase the flexibility of the energy system. Energy storage is many times looked as one of the best options to provide that flexibility.

In [CLMP12], it is investigated how large-scale energy storage can assist in the integration of intermittent renewable energy in the Irish grid. Pumped hydro storage (PHS) and wind power are used as case studies. Three main aspects are investigated related to PHS: operation, size and costs. It was concluded that PHS could increase the wind penetration in the Irish power system and also reduce its operational costs. Nevertheless, the results are sensitive to changes in PHS capacities, fuel prices and interest rates

and total annual wind energy produced.

In [LuMa09], the excess of electricity production is used to infer the success rate of integration of intermittent renewable energy. Behind this rationale is the fact that excess electricity usually has less value. The different renewables (PV, wind and wave power) are analysed with electricity production varying from 0% to 100% of electricity demand. The solutions of optimal mixes of energy that lead to less excess of energy are considered to hold greater value.

In [KrDC11], it is simulated Portugal's energy system with the goal of reaching a 100% renewable energy system. In this paper, it is given particular attention to the coupling of fluctuating renewable energy with storage systems solutions. It is estimated that 6000 MW and 4500 GWh of storage are needed to achieve a 100% energy system. The analyses are performed both in a closed system and an open system. The closed system considers zero transmission capacity and the open system the real capacity, allowing importation and exportation of energy. Naturally, in a closed system, it is harder to reach 100% renewable energy as it decreases the flexibility within the system. Storage systems revealed fundamental in achieving this target by avoiding rejection of renewable's potential and ensuring security of supply. Also in [FeFe14], different strategies are analysed while aiming towards a 100% RES system in Portugal. Such a scenario was found to be theoretically possible to simulate. Although, to ensure the supply during the summer, which is a period with less renewable generation, a substantial increase in total capacity has to be accomplished. This increase would raise overall costs and curtailment of renewable energy, i.e. the waste of RES production. This article makes use of the same analysis tool that will be used in this work, EnergyPLAN. EnergyPLAN has been used to simulate 100% RES scenarios in multiple countries: Denmark, Portugal, Croatia, Macedonia, among others. A necessary condition for reaching 100% RES systems is to be able to integrate and enhance the interactions between the three energy sectors: electricity, transports and heating/cooling and EnergyPLAN is a tool that is capable of performing that.

In [LuMü03], it is discussed different operational strategies to manage energy surplus in the Danish energy system. Energy surplus occurs when the electricity production exceeds the demand. The costs of investing in new transmission system are compared with the costs of increasing the flexibility of the energy system through storage. In particular with heat storage, that according to the authors, is a more cost-effective solution than electricity storage. At least, in a country with a significant heat demand like Denmark. It was concluded that increasing the flexibility is less expensive than investing in high voltage transmission lines.

In [ZaSy15], different energy storage technologies are analysed in a perspective of determining which technologies have the most potential for grid-scale applications with the objective of mitigating the intermittency in renewable generation. This study provides an overview of the different technologies while comparing the life cycle costs for each one. The technologies are examined in three distinct groups of applications: bulk energy storage, transmission and distribution support services and frequency regulation. An extensive review of the literature was performed in this study and costs estimations for energy storage systems were found to be quite diverse and inconsistent among different references. Nonetheless, the results showed that PHS and CAES are still the most cost-efficient options

for bulk energy storage. Among batteries, sodium-sulphur (NaS) offered relatively low life cycle costs for energy arbitrage and transmission and distribution (T&D) support applications. Since replacement costs are a critical share of batteries LCOS, optimal cycle numbers should be considered. The best option should be adopted considering the project requirements and each technology optimal cycle numbers.

In [HaPE09], a review for each energy storage technology is presented. However, the analysis is not so focused on cost but on the characteristics of each storage system and how those characteristics can be best suited for the large role of existing applications. In [MaKM11], also the cost is not the fundamental feature under analysis, but the value and how can the investor recover the investment costs of the acquired asset. A framework is provided for assessing the value of several storage applications like energy arbitrage, line congestion management and frequency regulation.

# Chapter 3

# Methodology

This chapter describes the methodology used in this work. The chapter starts by presenting the simulation tool EnergyPLAN. The rest of the chapter is dedicated to the modelling of the reference year, while explaining the most relevant aspects of EnergyPLAN and of the Portuguese grid.

## 3.1 Tools for analysing energy systems

Firstly, the distinction between tool and model should be made. A tool is the software used to analyse and evaluate an energy system [Conn12]. On the other hand, models are simplified representations of energy systems and are created with the help of tools [Conn12].

Converting from a system dependant on fossil fuels to one with more renewables requires measuring the consequences of the integration of renewables. It is time-consuming to create new tools for each further analysis [CLML10]. If there is an existing tool that can perform the analysis, it should be used. However, with a large number of different energy tools available, selecting the tool that is the most appropriate for each case is an important step to guarantee the quality of the results.

A review analysed 37 different energy tools and conducted an analysis of their characteristics [Conn15]. The methodology used in this review was to conduct a survey enquiring the tool developers about the following aspects of each tool:

1. General information
2. Typical applications
3. Technologies considered
4. Renewable energy simulated
5. Type of tool

General information consisted of the number of downloads, costs of acquiring the software, versions up to date and training available.

Typical application is related to the typical region, time-step and longest time duration that the tool can simulate.

Technologies considered refers to the capacity of the tool to simulate the three sectors of energy: electricity, heating/cooling and transports. It also applies to which technologies the tool can simulate, or even if the purpose of the technology is to simulate any specific type of technology. For example, E4cast is a tool with a specific focus on wind power.

Renewable energy simulated is about the ability of a system to simulate a 100% RE system. If that is not the case, up to what share of renewable energy can be included in the system?

It was noticed that the tool developers had some difficulties in answering the question of the type of tool. There was not available a clear nomenclature that would distinguish the different types of energy tools. The authors of this review, Connoly et al. [CLML10], created the following definitions for defining each type of tool:

1. **Simulation tool:** simulates the operation of an energy system, usually in hourly time-steps, making sure that the supply matches the demand.
2. **Scenario tool:** combines a short temporal series, typically a year, in a more long-term scenario,

usually 20 to 50 years.

3. **Equilibrium tool:** tries to explain the behaviour of supply, demand and prices in an electricity market. This type of approach assumes that agents are price takers and that an equilibrium can be identified.
4. **Top-down tool:** uses macroeconomic data to determine the evolution of prices and demand.
5. **Bottom-up tool:** identifies and analyses specific energy technologies, examining different investment alternatives.
6. **Operation optimisation tool:** seeks to optimise the operation of an energy system.
7. **investment optimisation tool:** seeks to optimise the investment of an energy system**.**

In table 3.1 is possible to observe the results of the survey conducted, according to the type of tool.

Table 3.1 Type of tool of the 37 tools analysed in the review [CLML10].

| Tool | Type | | | | | | |
|---|---|---|---|---|---|---|---|
| | Simulation | Scenario | Equilibrium | Top-down | Bottom-up | Operation optimisation | Investment optimisation |
| AEOLIUS | Yes | – | – | – | Yes | – | – |
| BALMOREL | Yes | Yes | Partial | – | Yes | Yes | Yes |
| BCHP Screening Tool | Yes | – | – | – | Yes | Yes | – |
| COMPOSE | – | – | – | – | Yes | Yes | Yes |
| E4cast | – | Yes | Yes | – | Yes | – | Yes |
| EMCAS | Yes | Yes | – | – | Yes | – | Yes |
| EMINENT | – | Yes | – | – | Yes | – | – |
| EMPS | – | – | – | – | – | Yes | – |
| EnergyPLAN | Yes | Yes | – | – | Yes | Yes | Yes |
| energyPRO | Yes | Yes | – | – | – | Yes | Yes |
| ENPEP-BALANCE | – | Yes | Yes | Yes | – | – | – |
| GTMax | Yes | – | – | – | – | Yes | – |
| H2RES | Yes | Yes | – | – | Yes | Yes | – |
| HOMER | Yes | – | – | – | Yes | Yes | Yes |
| HYDROGEMS | – | Yes | – | – | – | – | – |
| IKARUS | – | Yes | – | – | Yes | – | Yes |
| INFORSE | – | Yes | – | – | – | – | – |
| Invert | Yes | Yes | – | – | Yes | – | Yes |
| LEAP | Yes | Yes | – | Yes | Yes | – | – |
| MARKAL/TIMES | – | Yes | Yes | Partly | Yes | – | Yes |
| Mesap PlaNet | – | Yes | – | – | Yes | – | – |
| MESSAGE | – | Yes | Partial | – | Yes | Yes | Yes |
| MiniCAM | Yes | Yes | Partial | Yes | Yes | – | – |
| NEMS | – | Yes | Yes | – | – | – | – |
| ORCED | Yes | Yes | Yes | – | Yes | Yes | Yes |
| PERSEUS | – | Yes | Yes | – | Yes | – | Yes |
| PRIMES | – | – | Yes | – | – | – | – |
| ProdRisk | Yes | – | – | – | – | Yes | Yes |
| RAMSES | Yes | – | – | – | Yes | Yes | – |
| RETScreen | – | Yes | – | – | Yes | – | Yes |
| SimREN | – | – | – | – | – | – | – |
| SIVAEL | – | – | – | – | – | – | – |
| STREAM | Yes | – | – | – | – | – | – |
| TRNSYS16 | Yes | Yes | – | – | Yes | Yes | Yes |
| UniSyD3.0 | – | Yes | Yes | – | Yes | – | – |
| WASP | Yes | – | – | – | – | – | Yes |
| WILMAR Planning Tool | Yes | – | – | – | – | Yes | – |

As it can be observed, there is a great variety of energy tools that serve different purposes, apply different methods and focus on various aspects of energy systems. It is up to the user to select the most suitable tool to address each situation.

For the purpose of this thesis, EnergyPLAN tool was selected. The reasons for choosing EnergyPLAN will be explained in the next section.

## 3.2 EnergyPLAN

EnergyPLAN is a software tool initially created by Henrik Lund in 1999 and has been continuously developed at Aalborg University in Denmark, being currently on its 13th version. It assists in the design, planning and comparison of different alternatives for energy systems. EnergyPLAN initial versions were software implemented in an Excel spreadsheet. EnergyPLAN has now developed to a user-friendly energy tool that is able to study the whole energy system, including the power system, transports and heating [Lund15].

EnergyPLAN is a deterministic input/output model, i.e. a specific input will generate a certain output. It is not a stochastic model or a model that uses Monte Carlo methods [Lund15]. Inputs are essentially demands, installed capacities and hourly production of the intermittent production, costs and strategies to handle the excess of energy produced by fluctuating renewables. Outputs are annual productions by technology, electricity imports/exports, fuel consumption, fuel costs, $CO_2$ emissions and excess electricity production which is equal to the total generation minus the demand. In figure 3.1 is the schematic of the EnergyPLAN model. Input boxes are in white, generation units in yellow, storage or conversion of energy in blue and outputs in orange.

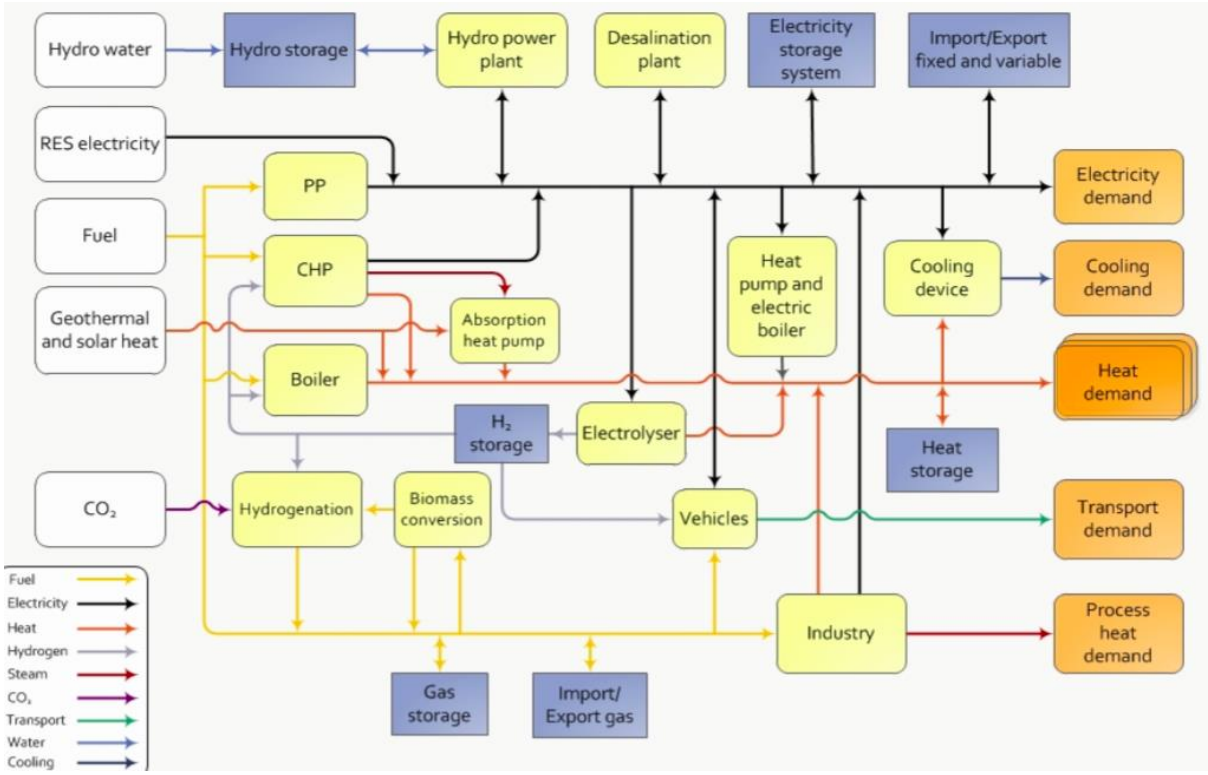



Figure 3.1 Schematic of the EnergyPLAN model. [Lund15].

### 3.2.1 Reasons for using EnergyPLAN

In this section, it is intended to explain why EnergyPLAN was selected as the software tool to study the Portuguese power system. From the review of the previous chapter, it is possible to have an idea of the vast number of energy tools available. Different tools differ in terms of regions they analyse, technologies included, among other aspects, being some tools more adequate for some purposes than others. In the case of this work, the reasons for choosing EnergyPLAN were:

1. EnergyPLAN is a user-friendly freeware tool with a training period that can vary from some days to a month, depending on the complexity of the application. On EnergyPLAN website [ENER17], there are plenty of training exercises and a forum, where users can get help from other users and developers. The quantity of information available online makes it easier for the user to get familiar with the large number of inputs required by the software.
2. EnergyPLAN is specially designed for studying future energy systems, more than present's systems. As the analysis of this thesis is focused on future energy systems, it was important to use a tool that was specially focused for future systems with large shares of renewables and dynamic smart grids.
3. The simulation model is very detailed, enabling the user to model novel technologies and different scenarios.
4. EnergyPLAN simulates a whole year in hourly time-steps. With this method, the software accounts for the effect of fluctuations in renewables production and demand for the entire year. Furthermore, it is imperative to use an hourly time step resolution when simulating storage.
5. The tool is continuously being used to support academic and scientific research.
6. Eng. Medeiros Pinto from APREN, the Portuguese association of renewables, mentioned in a conversation that EnergyPLAN was possibly an adequate tool for my case study. His advice was one of the reasons for choosing EnergyPLAN.

### 3.2.2 Smart energy systems

When professor Lund created the model, he intended to design a tool that would help engineers and energy system planners to simulate future energy systems with a high share of renewables [Lund15]. The model was specially conceived for future energy systems aiming for a 100% renewable energy system. A 100% RES system can only be achieved with the integration of the three main energy sectors: electricity, transports and heating/cooling.

In the typical energy system of our days, these three sectors are independent of each other with few interconnections, as it can be observed in figure 3.2.

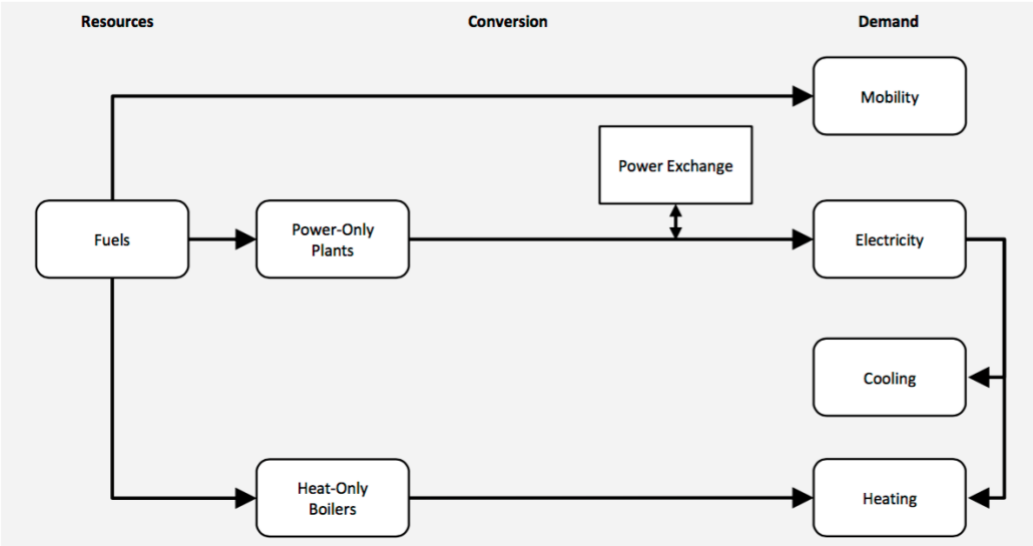



Figure 3.2 Typical energy system with few interactions between sectors [CMLM14].

All the three sectors are highly dependent on fossil fuels that have always provided the flexibility the system needed. In this model, fuel (resource) is consumed as it is required (demand) with few interactions in the conversion side. There is no need for storage or more flexibility in the conversion side, as the fuel itself is the stored energy in chemical form and provides the flexibility that the system needs. When more energy is needed, more fuel is consumed either in our cars (transports), power plants (electricity) or boilers (heating).

However, if we desire to depend less on fossil fuels and aim for a 100% RES system, an entirely different approach must be followed. The synergy between technologies, strategies and sectors has to be enhanced significantly. Figure 3.3 illustrates a future energy system with multiple interactions between energy the three energy sectors: electricity, transports and heating/cooling.

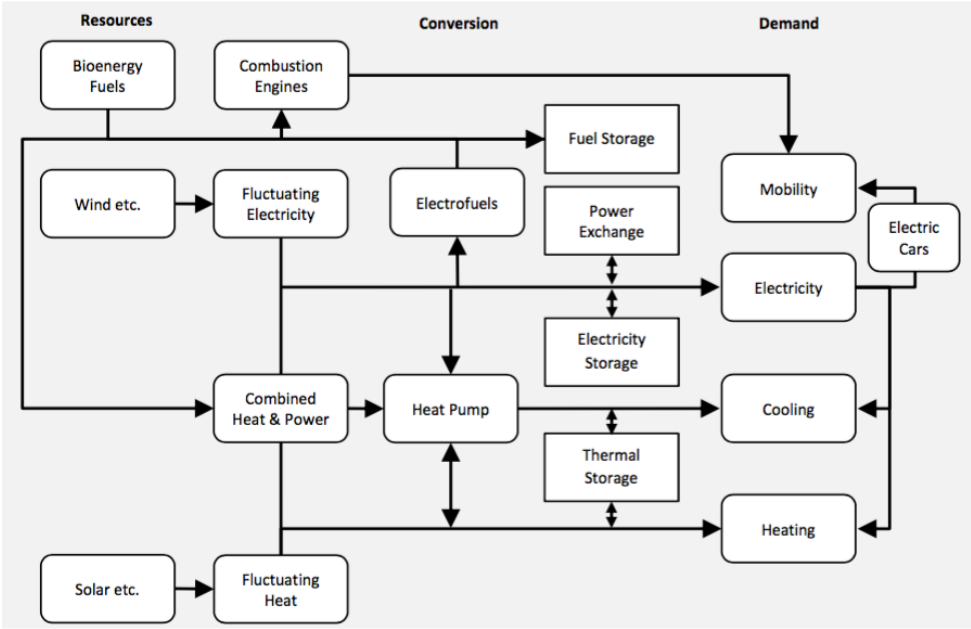



Figure 3.3 Future energy system with multiple interactions between sectors [CMLM14].

## 3.2.3 Model overview: input/output and technical/market optimisation

The inputs for the model consist of several demands. However, the user can insert only the electricity demand in case he/she just intends to study the power system. Electricity demand requires two inputs: the total energy demand in one year (TWh) and a distribution data with 8784 values with the demand in each hour during a whole year (MW). Besides electricity demand, all the non-dispatchable technologies as the fluctuating renewable energy need the same distribution data for one year. These distribution data sets consist of simple text files with 8784 values (the software always considers a leap year). The tool also requires the values for the capacities of each generation technology. For dispatchable generation also the efficiency values must be filled in.

Furthermore, some regulation strategies must be defined. For instance, it should be determined how to handle CEEP (Critical Excess Electricity Production) which is the excess of electricity in the system that cannot be exported because the transmission capacity may not be sufficient to export the entire energy surplus. For a market-economic simulation, the cost data for the energy system must be inserted in EnergyPLAN, as well as a distribution file with the market prices for each hour. Please refer to figure 3.4 for a better insight of the input and output data required by the tool.

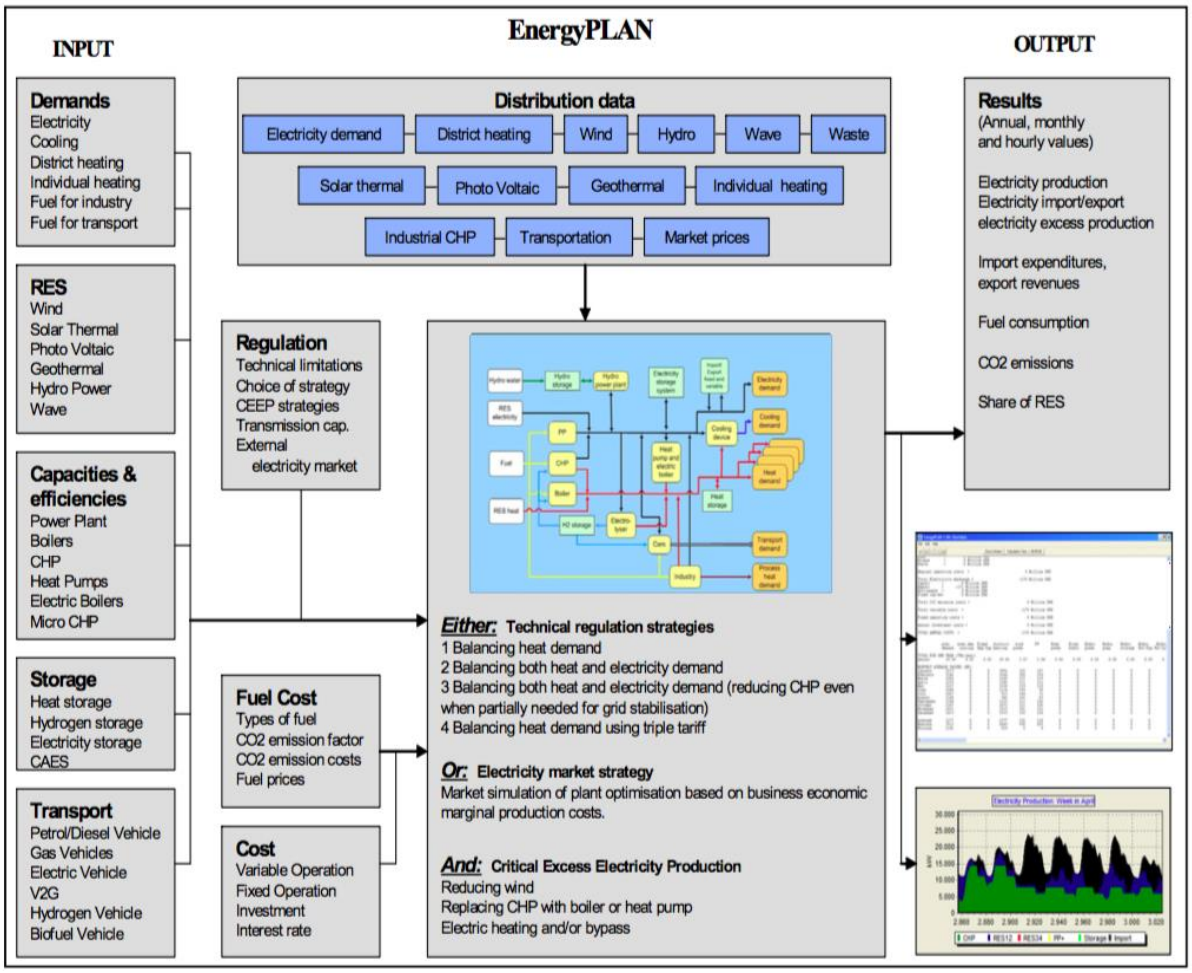



Figure 3.4 Model overview of EnergyPLAN [CLLM10].

As for the output, the software can display the results in a balance sheet, on the screen or export them to an Excel worksheet. The results consist of annual, monthly and hourly values of the electricity production per generation technology, exports/imports of electricity, excess electricity production, fuel consumption, costs of fuel, $CO_2$ emissions and the share of renewable energy.

The user can choose to perform two types of simulation: a technical or an economical. The first calculations of the software are the same, independently of the kind of simulation. The first step is the simple calculations that the software does instantly when the user types the data. The second step includes all the calculations that do not involve electricity balancing [Lund15]. Then, the algorithm has different ways of performing its calculations, figure 3.5.

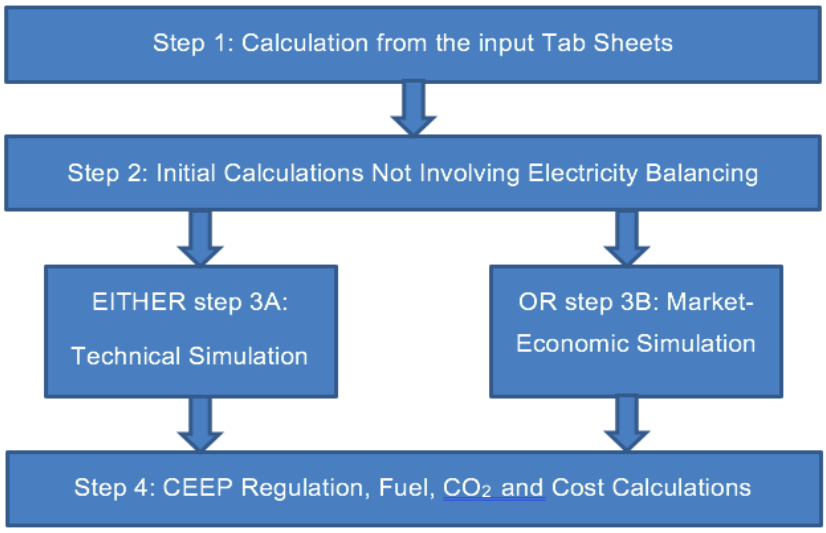



Figure 3.5 Technical and economic simulations in EnergyPLAN [Lund15].

A technical simulation minimises the consumption of fossil fuels and the CEEP (critical excess of electricity production). The market-economic simulation aims to minimise the operational costs of the system [Lund15]. The user must provide cost data so that the program is able to calculate the marginal costs of each technology. Then, the ascending order of the marginal costs defines the merit order of the different generation technologies.

### 3.2.4 Merit order

The merit order is a procedure to rank the different generation technologies available at each moment. It can solely take into account the short-run marginal costs as it is the case of the NordPOOL market [Lund15] or it can consider other factors as the dispatchability or if the source is renewable or from fossil fuels. Therefore, economic and technical aspects are usually analysed together to define a merit order.

The dispatchability is an essential factor for the merit order as it reflects the controllability of a generation source. These sources can be controlled by the grid operators and increase or decrease their production as it is more convenient. This way, these sources contribute for grid stabilisation, helping to maintain voltage and frequency within desirable intervals which prevents collapse of the system. The power

plants and dammed-hydro are examples of dispatchable sources. On the contrary, renewables as wind, photovoltaic, run-of-river hydro are non-dispatchable sources as they depend on the availability of the natural resources.

Non-dispatchable renewables come in first place in the merit order of EnergyPLAN. Then, hydropower with reservoir can be used to suppress the needs if those are not enough. Power plants only generate energy in case the renewable is not enough to match electricity demand. However, the software has a minimum grid stabilisation parameter (%) that reflects the minimum share of dispatchable energy that should be in the grid all the time. In addition, the user can establish a minimum power plant capacity production in order to reflect the technical difficulties associated with shutting down completely this kind of generation.

## 3.3 Creating EnergyPLAN reference models

In order to ensure that EnergyPLAN simulates the energy system correctly, it is necessary to simulate a reference year and compare the results with energy statistics from that year. If the output values of EnergyPLAN are in accordance with the historical data, the validity of the model is verified. If such does not occur, a calibration should be performed to approximate these values. It is important that the reference model is well-calibrated because this will be the reference for all the future scenarios. The reference model will be the starting point to the changes that will take place in the next years.

Moreover, creating a reference year is a valuable process. It enables the user to understand the energy mix and the specificities of a particular country and calibrate the software to simulate a system with these specificities adequately. To verify the validity of the model, it was defined a tolerance of 10%. This means that the results of the simulation must not differ from the historical data more than 10%. The calibration should constantly be repeated until this tolerance is achieved for all the values.

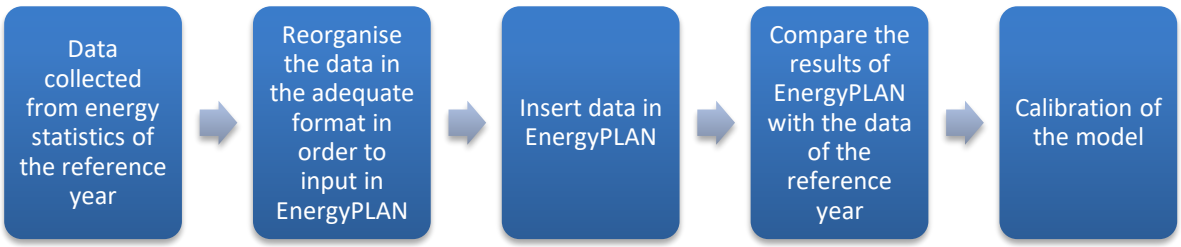



Figure 3.6 Steps for creating the reference model in EnergyPLAN.

## 3.4 Reference year: Portugal 2014

The chosen reference year was 2014. When the modelling of the reference year started, this was the most recent year with all the hourly information in one file that me and my supervisor had access to. The fact that the information is condensed in one data file is important in order to assemble the distribution data for every hour of the year, for the reason that it saves a great amount of time. Furthermore, the most recent year was 2016 and in this year, there was an impressive increase in hydro pumping capacity, from 1638 MW at the beginning of the year to 2437 MW by the end of the year [RENb17]. This fact could introduce some discrepancies in the results for the reference year.

Moreover, the primary purpose of the reference year is to work as a way of calibrating the energy system of a specific country to be in accordance with the algorithms of the software. It is convenient that the year is one of the most recent years, though it does not have to be the most recent. The crucial part is to have detailed information of that year and, when analysing future scenarios, consider the changes that will happen in the future with the reference year as the starting point for the changes that will occur.

As previously stated, the integration of the three energy sectors is a pivotal point to achieve high levels of renewable integration, close to 100%. However, in the scope of this thesis, only the power system is to be analysed. One of the goals of this thesis is to investigate the role of storage in the grid as an option for the increasing levels of fluctuating renewable energy. For this reason, storage for the heating and transports sectors was not included for the purpose of this thesis. Furthermore, the software used was developed in Denmark where an efficient heating sector is a key point for reducing primary energy consumption and having an efficient energy sector overall. Thus, the integration of the heating sector is of major importance for Denmark as well as for other Nordic countries. For what Portugal is concerned, the percentage of energy consumption by the heating sector is far less than in Denmark. For this reason, the integration of the heating sector has not been defined as a priority by the decision-makers of Portugal. On the contrary, electricity storage has been defined as one of the priorities. Portugal is currently investing and will continue to invest in storage, namely in hydro pump capacity. Therefore, it was considered more valuable to study the most probable options that will be considered in the future than other options that will most likely not be considered by the decision-makers.

### 3.4.1 Supply of electricity. SSG vs OSG

The supply of electricity in Portugal is divided in two different legal status: Special Status Generators (SSG) and Ordinary Status Generators (OSG).

The Special Status Generators, which in Portuguese stands for “Produtores em Regime Especial” (PRE), generally includes the generation from renewables, combined heat and power (CHP) and distributed generation. The main exception is hydropower generation with less than 10 MVA of power which is considered a SSG. This and other legal conditions to apply for SSG can be consulted in ERSE website [ERSE18].

The Ordinary Status Generators (OSG), which in Portuguese stands for “Produtores em Regime

Ordinário", includes the centralised and conventional non-renewable generation as well as the large hydropower.

By the end of 2014, total installed capacity in the Portuguese system was 17.83 GW [RENa15]. The installed capacities per generation technology are presented in table 2.2 [RENa15]. The capacity of the SSG was 6979 MW and of the OSG was 6979 MW.

Table 3.2 Capacities by technology generation in the end of 2014. Adapted from [RENa15].

| | **[MW]** |
|---|---|
| **TOTAL** | 17 834 |
| **Renewable** | 11 222 |
| Hydro | 5684 |
| Wind | 4541 |
| Thermal | 601 |
| Solar | 396 |
| **Non-Renewable** | 6611 |
| Coal | 1756 |
| Natural gas | 4717 |
| **OSG** | 10 855 |
| **SSG** | 6979 |

## 3.4.2 Distribution data required in EnergyPLAN

The non-dispatchable technologies in EnergyPLAN require a distribution file with information for all the hours of the year. This consists of a text file with 8784 values with the values of production for each hour. For the fact that EnergyPLAN considers a leap year, the last day of the year is replicated to ensure the file has the correct dimensions.

Distribution files were created for wind, photovoltaic and run-of-river hydro. This data was collected from an Excel file provided by REN and an extract of this file is shown in table 2.3. The data is organised in periods of 15 minutes. In order to change to an hourly distribution, it was calculated the average for each hour. Then, the data must be normalised by dividing all the values with the installed capacity. The user can decide not to normalise the values and the software will do it automatically, dividing the distribution by the maximum value of the distribution. This conducts to some discrepancies in comparison with the historical values. Thus, it is advisable to normalise the distribution using the installed capacity. However, the installed capacity may not be the same in the beginning and in the end of the year. Hence, the

average between capacities in the beginning and in the end of the year was calculated and this was the assumed value for the installed capacity.

Table 3.3 Extract of the load diagram of 2014 provided by REN.

| Date and hour | SSG Hydro | Run of River | SSG Wind | SSG Photovoltaic | Load Demand | Reservoirs | Imports | Exports | Pumping |
|---|---|---|---|---|---|---|---|---|---|
| 2014-01-01 00:00 | 333,6 | 1322,2 | 1995,9 | 0,0 | 5079,9 | 389,4 | 187,1 | 0,0 | 175,6 |
| 2014-01-01 00:15 | 333,3 | 1392,9 | 1950,5 | 0,0 | 5046,2 | 420,9 | 249,4 | 0,0 | 284,8 |
| 2014-01-01 00:30 | 332,7 | 1400,4 | 1923,0 | 0,0 | 5013,0 | 422,3 | 241,4 | 0,0 | 290,3 |
| 2014-01-01 00:45 | 330,6 | 1414,0 | 1911,7 | 0,0 | 4980,0 | 415,7 | 224,9 | 0,0 | 290,7 |
| 2014-01-01 01:00 | 329,8 | 1423,2 | 1943,2 | 0,0 | 4946,4 | 261,2 | 293,6 | 0,0 | 289,9 |
| 2014-01-01 01:15 | 331,6 | 1357,0 | 1945,4 | 0,0 | 4910,2 | 250,2 | 291,6 | 0,0 | 290,0 |
| 2014-01-01 01:30 | 331,7 | 1269,3 | 1945,1 | 0,0 | 4840,3 | 249,6 | 294,3 | 0,0 | 307,0 |
| 2014-01-01 01:45 | 331,6 | 1222,1 | 1978,9 | 0,0 | 4761,3 | 246,8 | 301,8 | 0,0 | 405,1 |
| 2014-01-01 02:00 | 332,1 | 1065,1 | 1971,3 | 0,0 | 4685,6 | 197,8 | 438,4 | 0,0 | 404,7 |
| 2014-01-01 02:15 | 331,6 | 985,1 | 1956,9 | 0,0 | 4616,8 | 196,9 | 457,7 | 0,0 | 405,8 |
| 2014-01-01 02:30 | 333,0 | 914,4 | 1950,8 | 0,0 | 4526,6 | 196,7 | 449,8 | 0,0 | 412,4 |
| 2014-01-01 02:45 | 332,7 | 847,9 | 1950,4 | 0,0 | 4435,7 | 196,7 | 465,2 | 0,0 | 447,1 |
| 2014-01-01 03:00 | 333,2 | 907,5 | 2000,8 | 0,0 | 4362,0 | 197,4 | 423,6 | 0,0 | 587,3 |
| 2014-01-01 03:15 | 333,0 | 822,1 | 2061,8 | 0,0 | 4301,7 | 197,1 | 432,8 | 0,0 | 635,0 |

In REN data, hydropower generation is grouped into three different types: with reservoir or dammed-hydro, run-of-river that includes large hydropower but without storage capacity and small hydro which includes generation with less than 10 MVA. Small-hydro is the only one of the three that is considered Special Status Generation. However, EnergyPLAN does not distinguish between small hydro and run-of-river. The software algorithm only distinguishes hydropower with storage capacity (dammed-hydro) and with no storage capacity that is called generically river hydro in EnergyPLAN model. For this reason, the data inserted in EnergyPLAN for river hydro is the result of the sum of small hydro (SSG hydro) and run-of-river from the REN data.

The model also requires an hourly distribution file for electricity demand, for the prices in the external electricity market and for the water supply to the water reservoirs.

The electricity demand was also retrieved from the load diagram of table 2.3. Electricity demand corresponds to the “load demand” column.

The hourly prices for the external electricity market were obtained online from the Operator of the Iberian Market [OMIE18].

The water supply distribution required by the model will be explained in the next section.

### 3.4.3 Hydropower

EnergyPLAN distinguishes between hydropower with storage, i.e. dammed-hydro and hydropower without storage capacity, i.e. river hydro. River hydro refers to all the hydro without storage which includes run-of-river and small-hydro. Run-of-river are large hydropower plants which do not have storage capacity. Small-hydro is river hydro with less than 10 MVA of apparent power and is considered a Special Status Generator (SSG).

Regarding installed capacity, it can be difficult to understand exactly what is the capacity of hydropower with and without storage. The information is usually condensed in hydropower installed capacity as it can be observed in table 2.2 in the section of the Supply of Electricity. In the Daily Statistics of REN

[RTID1], there is a description of all the large hydropower plants (> 10 MVA) divided in dammed-hydro (with storage) and run-of-river (no storage). This list does not include small-hydro. The capacity of each hydro facility was investigated in [APRE17]. The capacities for each type, with storage and without, were summed in order to know the installed capacity of each type of hydropower. It was concluded that hydro with storage (dammed-hydro) had an installed capacity of 2500 MW in 2014, table 2.4.

Table 3.4 Capacity of large hydropower plants in 2014. Adapted from [RTID18] and [APRE17].

| **Dammed-hydro capacity [MW]** | | **Run-of-river hydro capacity [MW]** | |
|---|---|---|---|
| Alto Lindoso | 630 | Miranda I e II | 369 |
| Touvedo | 22 | Picote I | 195 |
| Alto Rabagão | 68 | Picote II | 246 |
| Paradela | 54 | Bemposta | 240 |
| Venda Nova | 90 | Bemposta II | 191 |
| Frades | 191.4 | Pocinho | 286 |
| Salamonde | 42 | Valeira | 240 |
| Vilar. das Furnas | 125 | Régua | 180 |
| Caniçada | 62 | Carrapatelo | 201 |
| Vilar-Tabuaço | 58 | Crestuma | 117 |
| Aguieira | 336 | Torrão | 140 |
| Raiva | 24 | Fratel | 132 |
| Cabril | 108 | **TOTAL** | **2537** |
| Bouçã | 44 | | |
| Castelo de Bode | 159 | | |
| Pracana | 41 | | |
| Alqueva | 225.6 | | |
| Alqueva II | 220 | | |
| **TOTAL** | **2500** | | |

As for run-of-river hydro, it was calculated to have an installed capacity of 2537 MW, table 2.4. As previously stated, in the EnergyPLAN tool, river hydro should also include small-hydro. In 2014, the power capacity of small-hydro was 415 MW [RENa15]. Hence, the value inserted in the software was 2952 MW that corresponds to the sum of the two previous values, table 2.5.

In terms of energy produced, river hydro totalised for 11.28 TWh, table 2.5. Run-of-river and small-hydro values individual values were gathered by consulting the cumulative production of each source in December 2014, available in Monthly Statistics from REN [RTIM18].

Table 3.5 River hydro installed capacity and generation in 2014 [RTIM18].

| | **Capacity [MW]** | **Generation [TWh]** |
|---|---|---|
| Run-of-river | 2537 | 9.77 |
| Small-hydro | 415 | 1.51 |
| **TOTAL (River hydro)** | 2952 | 11.28 |

Moreover, hydropower with storage capacity requires an hourly distribution data file with the water supply to the water reservoir during the year. This data can be retrieved from the Daily Statistics of REN [RTID1]. However, this data is presented individually for each day. It would be very time-consuming to condense all the data of one year. For future analysis, the historical values of several years would have to be collected and would make this simply unfeasible. This data was gently provided by REN after contacting them.

In 2014, the hydro capability index was 1.27 [RENa15], what means that it was a wet year. When performing analysis for future scenarios, this fact will have to be considered. An average hydro production index is 1. The hydro index quantifies the deviation of the total energy produced by hydropower in comparison to the energy that would have been produced in an average year of water supply. Apart from the distribution of water supply, it is required to input the total annual water supply to the reservoirs. The water supply corresponds to a potential generation of energy. The sum of the water supply for each day resulted in a total energy/water supply of 7.13 TWh. In table 2.6 is summarized the necessary inputs for characterising the dammed-hydro in EnergyPLAN.

Table 3.6 Dammed-hydro inputs in EnergyPLAN

| | |
|---|---|
| Capacity [MW] | 2500 |
| Total water supply [TWh] | 7.13 |
| Turbine efficiency [%] | 90 |
| Storage capacity [GWh] | 3092.5 |
| Pump capacity [MW][4] | 1129 |
| Pump efficiency [%] | 85 |

[4] Average of the pump capacity in the beginning and in the end of the year

EnergyPLAN has two different types of storage. One corresponds to a pure reversibility cycle and the other corresponds to pump back capacity in a river flow dam.

The first corresponds to a closed cycle of water with two reservoirs at different heights. The water in the hydraulic system is always the same, as there is no water supply to the upper reservoir from a river flow. The model of a pure reversibility cycle should be used to simulate any type of storage as this is the only way that users can model storage in EnergyPLAN. However, a pure pumped-hydro storage system can be used to model any type of storage. For instance, it is able to model a battery. The user just has to insert the parameters for charging and discharging capacities (MW), as well as for the efficiencies (%). The same with the costs that should be updated to represent a battery. Essentially, the model works just as a mental abstraction, but it can model any type of storage. The developers chose to model storage this way, for the reason that pumped hydro is by far the most used storage technology. In the present moment, Portugal does not have any pure pumped-hydrocapacity. Carvão-Ribeira will be the first project of this type in Portugal if the project is implemented. However, there is some uncertainty concerning this project. According to the RMSA 2017-2030[5] [RMSA17] that is a document that analyses the evolution of the Portuguese power system with a horizon to 2030, if this project goes forward, it will not be implemented before 2030.

The type of storage widely used in Portugal corresponds to the second type mentioned: pumped-hydro with a reservoir that is connected to a river flow. EnergyPLAN requires the storage capacity in the reservoirs and the pump back capacity. In order to know the storage capacity, in the Monthly Statistics of REN [RTIM18], it can be observed that the reservoirs had 2072 GWh of energy storage in December 2014 and that this value corresponded to 67% of the storage capacity. Hence, the storage capacity can be calculated to be 3092.5 GWh. The pump back capacity, it was 1253 MW by the end of 2014 according to [RENa15]. During 2014, Baixo Sabor project improved national pumping capacity with 148.4 MW [APRE17]. That means that the capacity at the beginning of the year was 1105 MW. By performing the average of the capacities in the end and in the beginning of the year, the value considered for pumping capacity was 1179 MW.

Regarding efficiency, for the turbine mode was considered an efficiency of 90% [USBR05] and, for the pump mode, an efficiency of 85% [ReAA15]. This corresponds to a round-trip efficiency of 76.5%. This value is in accordance to the efficiencies usually considered for PHS of 70%-80% [ReAA15]. According to REN [RENa15], the consumption from pumps was 1079 GWh and the energy produced from PHS was 859 GWh, what indicates that REN considers pumped-hydro to have an efficiency of 79.6%. Thus, it is possible to verify that the round-trip considered of 76.5% is in accordance with the literature.

[5] RMSA - *Relatório Monitorização e Segurança do Abastecimento 2017-2030.* In English: Report for Monitoring and Security of Supply 2017-2030.

### 3.4.4 Thermal power generation

When analysing the Portuguese grid, it is essential to distinguish between two types of thermal power: condensing power that produces electricity only and combined heat and power (CHP) or cogeneration that produces both heat and electricity.

Combined heat and power (CHP) in the Portuguese grid is primarily used in industrial facilities that apart from their electricity demand, also have a high demand for heat. CHP can be used by the industrial agents for decreasing energy costs and obtain a better overall efficiency. In Portugal, the industry sectors that more intensively use CHP are the paper, the chemical, the refining of oil and the textile industry. In EnergyPLAN, it is possible to model different types of CHP, according to size and dispatchability. Being a software developed in Denmark, it is very focused and detailed in CHP technologies because of the country's heating demand. However, this is not the case of Portugal where cogeneration is used mainly in industrial contexts and is awarded with Special Status Generation (SSG) because it is not a dispatchable source. The grid operator cannot use industrial CHP to balance the grid as this is controlled by the industrial agent. In EnergyPLAN, the user should input the amount of energy generated by industrial CHP in a year. In 2014, the value of the electricity from CHP was 6.6 TWh [RENa15]. This value was inserted in the Industrial CHP tab in EnergyPLAN.

Cogeneration is not the only thermal power generation to be considered a SSG. Biomass, biogas and waste are also Special Status Generation for the reason that these are renewable energy sources. And these can be used for CHP or in conventional condensing power. From the 2.7 TWh generated from thermal renewable, 1.5 TWh were from CHP [RENa15].

In 2014, the condensing power mix was composed of coal, natural gas and biomass power plants. Portugal never had nuclear power and has decommissioned all the fuel oil power plants. The natural gas plants are most of combined cycle. These have higher efficiency, though higher marginal costs. For this reason, in 2014, the combined cycle gas turbine (CCGT) were had their utilisation reduced to 1.4 TWh [RENa15], despite the fact that this generation has a great amount of installed capacity with 3829 MW [RENa15]. In 2014, CCGT had a low utilization factor of 4.4% that reflects the fact that CCGT were a more expensive alternative in comparison to coal power plants. As for coal power plants, the capacity in 2014 was 1756 MW and the electricity generation was 11.1 TWh [RENa15].

Table 3.7 Annual thermal power generation in 2014. Adapted from [RENa15].

| | CHP [TWh] | Condensing [TWh] |
|---|---|---|
| Coal | 0 | 11.07 |
| Natural Gas | 4.92 | 1.41 |
| Biomass | 1.53 | 1.17 |
| **TOTAL** | 6.45 | 13.65 |

Table 3.8 Installed thermal capacity in 2014. Adapted from [RENa15].

| | CHP [MW] | Condensing [MW] |
|---|---|---|
| Coal | 0 | 1756 |
| Natural Gas | 888 | 3829 |
| Biomass | 343 | 1171 |
| **TOTAL** | 1231 | 6753 |

EnergyPLAN does not model thermal power plants in a very detailed manner. The argument given by the developers is that EnergyPLAN is a future oriented software and that thermal power plants will have a reduced utilization in future scenarios. However, to model the reference year, it would not be accurate to group together two very distinct kinds of generation: coal and natural gas. These have different efficiencies and generation costs. A work-around this problem is to model one of these technologies in the menu of the CHP power plants. In order to complete this task, the information with the capacity and efficiency of the power plant should be inserted in the *CHP condensing mode operation* tab. Thus, the unit will not work as CHP but as a conventional power plant, producing only electricity. This methodology has the advantage that EnergyPLAN gives priority to this condensing power plant that EnergyPLAN defines as PP1 (Power Plant 1). For the reasons previously stated, it was decided to give priority to coal power plants for the reason that their continued utilization is less expensive and in order to approximate the results with the historical data. Furthermore, it simulates coal power plants as in reality, i.e. as a base load. On the other hand, natural gas turbines are used for load following. With this, it was attempted to simulate the increased flexibility of natural gas units when compared to the coal power plants.

A description of the Ribatejo CCGT is presented in [OrEn18], which has an efficiency of 57.5%. Also in [OrEn18], it is mentioned that Sines and Pego, the two coal power plants in Portugal, have an efficiency of 36%. These two values were considered for CCGT and coal generation, respectively.

### 3.4.5 Interconnection and regulation

In 2014, the capacity to import in working days presented an average value of 2044 MW and the capacity to export an average value of 2065 MW [RENc14]. The average of these values was assumed as the interconnection capacity with Spain and this value was inserted in the software in the tab *Transmission Line Capacity.*

The energy balance between production and demand should be guaranteed every moment in order to ensure the reliability of the grid. For this reason, it is necessary that part of the generation is able to provide stabilization services to the grid. In order to provide stabilization, this generation has to be controllable and have a relatively fast response.

EnergyPLAN considers that the power plants that can provide stabilization services are dispatchable hydro and dispatchable thermal power plants [Lund15]. This excludes river hydro and industrial CHP. The parameter *Minimum Grid Stabilisation Share (MGSS)* refers to the minimum percentage of generation that should come from sources that can provide stabilization services, $e_{stab}$, in relation to the total production, $e_{total}$.

$$MGSS = MIN\left\{\left(\frac{e_{stab}}{e_{total}}\right)_1, \left(\frac{e_{stab}}{e_{total}}\right)_2, \dots, \left(\frac{e_{stab}}{e_{total}}\right)_{8760}\right\} \times 100 \tag{3.1}$$

EnergyPLAN advises to input 30% for this parameter in case there is no available information about this parameter. This means that at least 30% of the total production must have stabilisation properties for every hour. It was noted that 30% did not reflect the reality of the Portuguese power system and would contribute for an exaggerated value of thermal generation. Using the load diagram provided by REN which contains the hourly production by technology, it was possible to study the stabilisation share for the year 2014.

In 2014, the minimum stabilisation share was 3.8% and, on average, the share of generation with stabilisation capacity was 39.6%. Establishing 3.8% of *MGSS* in EnergyPLAN led to an average stabilisation share of 41.61%. Due to the proximity with the historical value, this value was considered suitable for the Portuguese case.

The thermal power plants have the flexibility to change their output power. However, sudden changes in the output power reflect in increased costs, commonly named as cycling costs. [TrDO10] These costs are especially evident in the starting of the power plants. Thermal power plants usually have long starting periods. Coal power plants are the ones with the most prolonged starting periods [ViMa14]. Therefore, it is generally preferable to operate thermal power plants at a minimum level than to shut them down completely. This is both done for technical and economic reasons. Therefore, apart from the minimum stabilisation share, one can specify a minimum thermal power production, *Minimum PP* tab. The minimum thermal generation in 2014 was 171.6 MW, hence it was the value adopted for the modelling.

### 3.4.6 Calibration

The calibration is an iterative process with the purpose to approximate the output from EnergyPLAN with the real data. The calibration is performed exclusively using a technical simulation. The reference model does not require economic inputs, for the reason that only the technical data is usually compared [Conn15]. An economic simulation seeks to minimise the short-term marginal electricity consumer costs and short-term district heating costs, thereby supplying the demand with the least-cost combination of production units. This strategy of simulation is very dependent on market conditions. For that reason, it is not necessary to match EnergyPLAN output with the collected historical data as this is not necessarily always based on the short-term least-cost combination of producing units.

The first step in order to guarantee the validity of the model is to compare the real data of the reference year with the output of EnergyPLAN, in terms of demand and generation per technology, table 2.9.

Table 3.9 Comparison of the real data of 2014 with EnergyPLAN output.

| | REAL DATA | ENERGYPLAN | Var. [%] |
|---|---|---|---|
| **Electricity Demand [TWh]** | 48.82 | 48.68 | 0.3 |
| **Electricity Generation [TWh]** | | | |
| Wind | 11.82 | 11.83 | 0.1 |
| Photovoltaic | 0.59 | 0.59 | 0.0 |
| River Hydro | 9.78 | 9.81 | 0.3 |
| Hydro with reservoir | 6.42 | 6.40 | 0.3 |
| OSG Thermal PP | 12.54 | 13.16 | 5.2 |
| Pump Consumption | 1.08 | 1.10 | 1.8 |
| **Share of renew. energy [%]** | 62 | 60 | 3.3 |

The only significant discrepancies in generation were in the thermal power plants. In a technical simulation, EnergyPLAN does not import any electricity if there is enough national capacity that can match the demand. For this reason, the dispatchable thermal or OSG thermal generation assumes the extra generation, i.e. CCGT and coal. From the technical point of view, there was no need to import and, thus, the energy that was not imported was replaced by the referred sources. In the case of CCGT, this is more evident for the fact that these power plants have a reduced utilisation in reality. It is sometimes a better economic option to import instead of using CCGT, depending on the natural gas prices and other market conditions.

The consumption of the hydro pumps was 0.2 TWh according to EnergyPLAN. This value is far from the historical value of 1.08 TWh [RENa15]. The technical simulation gives priority to exporting the excess of energy instead of using pumped storage. After contacting the developers of EnergyPLAN, it was confirmed that EnergyPLAN prioritises the export before pumped hydro and that, unfortunately, in the present version of EnergyPLAN was not possible to change the prioritisation. For instance, if at a certain moment, there is an excess of 2400 MW and the transmission capacity is limited to 2000 MW, 2000 MW will be exported and 400 MW will be used for pumping. However, the fact that there is available transmission capacity to export, does not mean that this capacity will be used. In a technical simulation, EnergyPLAN assumes that if there is enough transmission capacity, it is possible to export without taking in consideration if the external market is willing to absorb that energy. For instance, in Portugal, during off-peak, there is a high generation of wind energy that can lead to an excess of energy. However, due to the positive correlation of weather conditions between Portugal and Spain, wind generation is likely to be also high in Spain. Therefore, Spain may not have the capacity to import this excess or even if it has, this energy is likely to have low value and may not be profitable for Portugal to export it. Instead of exported, this energy may be used for pumping back the water to the upper reservoirs.

Having said this, an economic simulation is more adequate for the purpose of this thesis and will be given more emphasis in future analyses. However, technical simulation is a valuable resource of EnergyPLAN. In order to study PHS utilisation, the value of the interconnection had to be calibrated for the reasons explained above and also to simulate congestions in the internal national grid. A simulation with a 50% reduction in interconnection resulted in a consumption of the hydro pumps of 1.10 TWh, very close to the historical value of 1.08 TWh. For this reason, when analysing future scenarios, a similar reduction of the interconnection capacity should be considered when analysing the PHS utilisation.

This reveals the importance of the comparison of the historic data of 2014 with the one of EnergyPLAN, not only to validate the model, but as well as to have a better understanding of the algorithms applied by EnergyPLAN software.

# Chapter 4

# 2030 Simulation Scenarios

In this chapter, it will be explained what are the most probable changes to occur in the Portuguese power system in comparison to the reference year. This will constitute the central scenario for 2030. A scenario with plus 20% of wind and solar will be also analysed in order to evaluate the consequences of having further intermittent RES in the grid.

## 4.1 2030 scenarios

Two scenarios were considered in order to study the effects of integrating higher levels of renewable energy, the Central scenario and the RES scenario. The Central scenario was mostly constituted by data from the RMSA 2017-2030 document [RMSA17]. The RMSA 2017-2030 is a official document that analyses the evolution of the Portuguese power system with a horizon to 2030. The RES scenario is equal to the Central scenario in every aspect except that is characterised by a 20% increase of wind and solar power capacities.

Two sensibility analysis were considered for the Central and for the RES scenario. To investigate renewable integration on different consumption scenarios, 3 different demand scenarios were considered. A scenario of high, medium and low demand with growth annual rates for demand of 0.8%, 0.5% and 0.2%, figure 4.1. Three different scenarios of water availability were also analysed: a dry, a wet and a normal year.


Figure 4.1 Scenarios of the electricity demand growth.

For all the scenarios, the transmission capacity with external markets was considered to be 3.5 MW for 2030. For 2030, the interconnectivity level is supposed to be 15%. The interconnectivity level is calculated as the ratio between interconnection capacity and generation capacity of the country. With the expected total installed capacity of 21162 GW in continental Portugal [RMSA17], the interconnection capacity is supposed to be at least around 3.2 GW to comply with interconnectivity level. This value is soon to be reached with the conclusion of the ongoing Projects of Common Interest. The Projects of Common Interest are infrastructure projects that link energy systems of EU members [EuCo17]. The projects can include not only electricity but also new natural gas interconnections. In terms of electricity, it is being concluded a new over headline between Beariz and Vila Nova de Famalicão which will increase interconnection capacity to 3.2 GW [EuCo17]. Internal reinforcements between Beariz and Fontefría (Spain) and between Vila Nova de Famalicão and Ponte de Lima (Portugal) make part of the project in order to complement the cross-border section [EuCo17]. In the period of 2025-2030, it is estimated future developments towards a 3.5 GW interconnection capacity [RMSA17]. For that reason,

this was the considered in the analysis.

In the next sections, it will be described the development of both dispatchable power and intermittent renewable within the Central scenario.

### 4.1.1 Dispatchable power

It is predicted that by 2030, the electricity produced from coal will be zero. This signifies the decommissioning of Sines in 2025 and Pego in 2021 [RMSA17]. In table 4.1, the thermal Ordinary Status Generation (OSG) is represented in terms of capacity by year until 2030. To what natural gas generation is concerned, it is expected that the CCGT of Tapada do Outeiro with 990 MW will be decommissioned by 2024 [RMSA17].

Table 4.1 Thermal OSG capacity from 2014 to 2030. Adapted from [RMSA17].

| | 2014 | 2018 | 2022 | 2026 | 2030 |
|---|---|---|---|---|---|
| Sines | 1180 | 1180 | 1180 | 1180 | |
| Pego | 576 | 576 | -- | -- | -- |
| Tapada Outeiro C.C. | 990 | 990 | 990 | -- | -- |
| Ribatejo | 1176 | 1176 | 1176 | 1176 | 1176 |
| Lares | 826 | 826 | 826 | 826 | 826 |
| Pego CCGT | 837 | 837 | 837 | 837 | 837 |
| **Total** | **5585** | **5585** | **5009** | **4019** | **2839** |

In terms of hydropower, in 2008, it was estimated that Portugal was using only 46% of its hydro potential [MEIn08]. In comparison with other countries, Portugal still had a large potential for development in what hydropower is concerned, as it is possible to observe in figure 4.2. For this reason, the Portuguese government developed a national programme that analysed potential sites for installing large hydropower facilities.

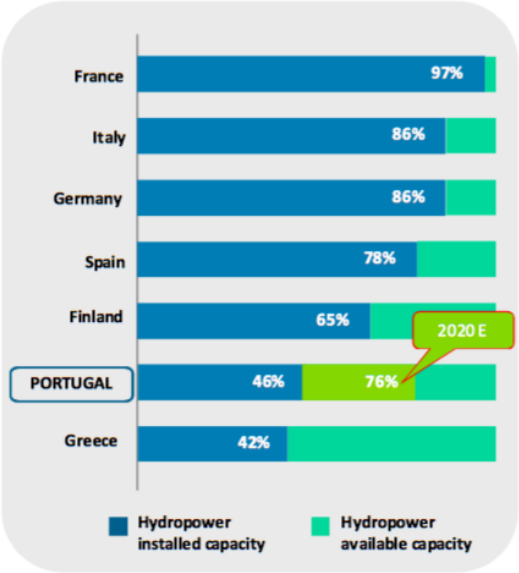



Figure 4.2 Potential of development in hydropower in 2008 [MEIn08].

This programme, called PNBEPH[6], consisted of an extensive study that was conducted to analyse new advantageous hydropower power plants, aiming to take advantage of 76% of Portugal's hydroelectric potential by 2020. The main reasons for the creation of the PNBEPH were to increase the independence from fossil fuels and to enhance the robustness of the system by adding more dispatchable energy and storage capacity.

The PNBEPH analysed 25 potential installations for hydropower facilities. From these, PNBEPH recognised ten of them to be economically feasible which are identified in the table 4.2.

Table 4.2 PNBEPH projects. Approved (green), suspended (orange), cancelled (red).

| Projects of the PNBEPH | Projects that attracted investors | Final approved projects |
|---|---|---|
| **Foz Tua** | | |
| **Alto Tâmega** | | |
| **Daivões** | | |
| **Gouvães** | | |
| **Fridão** | | |
| **Girabolhos** | | |
| **Alvito** | | |
| **Padroselos** | | |
| **Almourol** | | |
| **Pinhosão** | | |

From these, only seven found investors to advance with the projects. The majority of the analyses of the Portuguese electrical system consider that all the hydropower projects of the PNBEPH are implemented. This work intends to provide an updated analysis, taking in account the recent cancellation (2016) of the Alvito, Girabolhos and the suspension of the Fridão dam. Or, in some cases, the construction receives the green light, though the technical details are not the ones initially predicted, as the one of Foz do Tua which has a lower headwater for environmental reasons. This will result in less

[6] PNBEPH – *Plano Nacional Barragens com Elevado Potencial Hidroeléctrico*. In English: National Programme for Dams of Great Hydroelectric Potential

energy storage capacity and will influence the analysis.

Therefore, from the PNBEPH, only Foz Tua and the project of the Tamega river, which comprises three hydropower facilities: Alto Tâmega, Daivões and Gouvães have received permission to be implemented.

In relation to 2014, the new hydropower projects that have been implemented to the present day are Baixo Sabor, Foz do Tua, Ribeiradio-Ermida, and the power reinforcement projects of Salamonde II and Venda Nova III. There are uncertainties regarding the project of Carvão-Ribeira and Fridão.

Table 4.3 presents the new hydropower projects in relation to 2014. The installed capacity was 2500 MW in 2014 which will increase to 5139.6 MW by 2030. The pump capacity was 1253 MW by the end of 2014 which will increase to 3538.4 MW by 2030.

Table 4.3 Hydroelectric projects that will be constructed after the reference year (2014). Adapted from [APRE17] and [IBER17].

| | Installed capacity [MW] | Pump capacity [MW] | Date |
|---|---|---|---|
| Ribeiradio-Ermida | 73.6 | 0 | 2015 |
| Venda Nova III | 780 | 780 | 2015 |
| Salamonde II | 207 | 207 | 2016 |
| Baixo Sabor | 151 | 148.4 | 2016 |
| Foz do Tua | 270 | 270 | 2017 |
| Gouvães | 880 | 880 | 2021 |
| Daivões | 103 | 0 | 2022 |
| Alto Tâmega | 121 | 0 | 2023 |
| **TOTAL** | 2639.6 | 2285.4 | |

A piece of information that was difficult to retrieve was the energy stored in the dam reservoirs that have not been constructed. For the power plants that have been constructed and connected to the grid, it was straightforward to obtain in the Daily Statistics of REN [RTID18] and is presented in table 4.3. As it can be observed in table 4.4, the power reinforcements of Venda Nova III and Salamonde II did not increase the capacity of the reservoir. The reservoirs are the same of Venda Nova and Salamonde, respectively. These investments were made with the only purpose to increase the turbine and pump capacities.

Table 4.4 Storage capacity of the concluded projects. Adapted from [RTID18].

| | **Energy in reservoir** [GWh] |
|---|---|
| Ribeiradio-Ermida | 12.5 |
| Venda Nova III | 0 |
| Salamonde II | 0 |
| Baixo Sabor | 100.1 |
| Foz do Tua | 4.1 |
| **TOTAL** | 116.7 |

For the power plants that have not been constructed yet, the reservoir capacity was estimated by knowing the useful water storage [hm$^3$] and the net head [m]. The useful water volume or profitable volume refers to the water volume that can, in fact, be used to produce electricity. The net head refers to the gross head which is the real vertical distance from the intake to the turbine minus the losses in the hydraulic system. The net head is always less than the gross head due to friction in the pipeline [CaHy13]. With an accurate information of the head and useful water volume, it is possible to determine the energy stored in the reservoir, $E_{reservoir}$. $V$ stands for the useful volume of the reservoir, $\rho$ for the density of the water, $g$ for the acceleration of gravity and $h$ for the net head.

$$E_{reservoir} = \frac{V\,\rho\,g\,h}{3600} \times 10^{-9}\ [\mathrm{GWh}] \tag{4.1}$$

Table 4.5 Estimated energy in the reservoirs of the non-constructed hydroelectric projects.

| | **Volume of reservoir [hm$^3$]** | **Net head [m]** | **Energy in reservoir [GWh]** |
|---|---|---|---|
| Gouvães | 12.68 | 620 | 21.4 |
| Daivões | 66 | 67 | 10.3 |
| Alto Tâmega | 158 | 89 | 13.3 |
| **TOTAL** | - | - | 45.0 |

Thus, with the increase of the energy in the reservoirs represented in table 4.4 and 4.5 and knowing that, by the end of 2014, it was 3092.5 GWh, then in 2030 it is estimated to be 3254.2 GWh.

### 4.1.2 Fluctuating renewable generation

The fluctuating renewable generation considered for 2030 was photovoltaic power, river hydro, i.e. hydropower without storage capacity, and wind power.

There are some expectations that wave power will play a role in the future energy mix. Portugal could benefit from its long coast. However, the technology has not reached a mature state and according to [RMSA17], it is predicted that the country will have only 8 MW of wave power by 2030. Therefore, this technology was not included in the analysis.

The same procedure was done for the considered sources of energy. Below, it is explained the procedure for river hydro. In order to provide an accurate distribution of river hydro generation throughout the year, the hourly distribution inserted in the model for the year of 2030 was an average of the distributions from the years 2010 to 2016.

In table 3.6 is represented the hydro capability index for each year from 2010 to 2016. The average hydro capability index for these years was 1.03. This value is close to 1 that corresponds to an average year, neither wet or dry. This proves that by doing an average of the distributions from 2010 to 2016, the resulting distribution represents a normal year in terms of hydroelectricity. After obtaining the average distribution, this should be normalised with the average power capacity from 2010 to 2016.

Table 4.6 Hydro capability index from 2010 to 2016 and respective average [RENb17].

| Years | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Average |
|---|---|---|---|---|---|---|---|---|
| Hydro cap. index | 1.31 | 0.92 | 0.47 | 1.17 | 1.27 | 0.74 | 1.33 | 1.03 |

The expected power capacity for river hydro in 2030 is 3136 MW, which corresponds to the expected increase of 184 MW of small-hydro in comparison to 2014 [RMSA17].

The same procedure was followed for photovoltaic and wind power. The expected power capacity for photovoltaic in 2030 is 1773 MW [RMSA17]. Onshore wind power is expected to have 5554 MW of installed capacity and offshore to have only 52 MW [RMSA17], thereby offshore capacity was included in the wind capacity.

The data of the wet years from 2010 to 2016 was managed separately to model a typical wet year. This corresponded to the years of 2010, 2013, 2014 and 2016. The same was done to create a typical dry year, in which were considered the years of 2011, 2012 and 2015. The average of the hydro capability indexes for the wet and dry years was calculated to be 1.27 and 0.71 respectively.

Table 4.7 Hydro capability indexes of a normal, a wet and a dry year.

| | Normal year | Wet year | Dry year |
|---|---|---|---|
| Hydro cap. index | 1.03 | 1.27 | 0.71 |

# Chapter 5

# Results Analysis

This chapter is composed of the results analysis. It is divided into the results performed with the technical simulation and economic simulation in EnergyPLAN.

## 5.1 Technical simulation

In a technical simulation, the algorithm applied by the software tries to minimise the use of fossil fuels by essentially using the national capacity. It does not import electricity if there is enough installed capacity that can match the demand. Moreover, the algorithm implemented by EnergyPLAN only exports energy when in excess. The exportation of energy is prioritised over pumped hydro. Only when there is no more transmission capacity, then pumped hydro is used. For instance, if at a particular moment, there is an excess of 2400 MW and the transmission capacity is limited to 2000 MW, 2000 MW will be exported and 400 MW will be used for pumping.

The year of 2014 was a year with a high share of renewable energy and, consequently, less thermal OSG (coal and natural gas, does not include CHP), as it can be observed in table 5.1.

Table 5.1 Annual energy produced from thermal OSG from 2010 to 2017 [RTIM18].

| Years | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| Annual Energy Thermal OSG [TWh] | 17.30 | 19.44 | 17.78 | 12.46 | 12.47 | 18.92 | 19.07 | 27.09 |

Hence, the comparison of future scenarios with 2014 could be misleading. For this reason, the reference year of 2014 should also be simulated with normal conditions. The normal conditions correspond to the average of hydro and wind production for the years 2010 to 2016. This resulted in hydro and wind indexes close to 1, thereby it can be considered a normal year in terms of hydro and wind production.

Figure 5.1 corresponds to the results of EnergyPLAN simulations for different water scenarios and it shows that different water conditions will result in different energy mixes in 2030. The analysis of figure 5.1 shows that Portugal will still depend to some extent on fossil fuels by 2030, especially in a scenario of dry weather with natural gas compensating for the diminished hydro production. In a dry year in 2030, the percentage of energy from thermal OSG will be 32% which is roughly the same as the one generated in 2014 if this year had had normal conditions.

With the decommissioning of the coal power plants, it would have been expected that natural gas power plants would have less preponderance than the one that the technical analysis of EnergyPLAN predicts. In a technical analysis, it is likely that the OSG thermal generation is overestimated. This happens for the fact that the software, in a technical analysis, does not import if there is still national capability to produce the energy in need. In reality, part of the share of the natural gas production would probably be replaced by imports. Combined cycle gas turbines (CCGT) presents relatively high marginal costs and in a liberalised market MIBEL that Portugal makes part, it could be a better option to import than producing from CCGT. However, for a dry scenario, the dependency of natural gas is somehow concerning. This fuel represents around 41% of the energy mix (CCGT and CHP) in a dry scenario,

considering that 75% of CHP will have natural gas as its fuel. This dependence from only one fossil fuel source can make Portugal in a delicate position in terms of security of supply. According to [RMSA15], Portugal imported natural gas mainly from two countries: Algeria (49%) and Nigeria (25%). Possible political instabilities that might occur in these countries can lead to an increase in prices and it would be especially harmful in a dry scenario. Portugal should account for this scenario and diversify the energy mix.

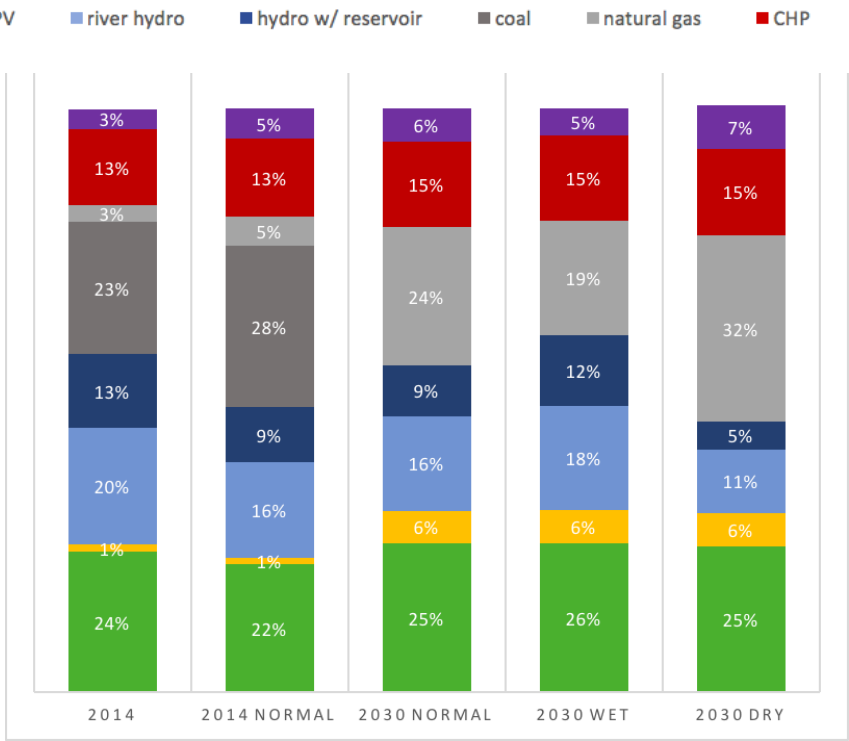



Figure 5.1 Energy mix in 2030 for different water conditions with technical simulation.

In terms of wind, the share of the energy mix is approximately the same, around 25%. Even comparing 2030 predictions with the wind output of 2014 with normal wind conditions, it can be observed that the share of wind energy does not increase significantly. Even though, it should be taken into account that the same share of energy in the different scenarios corresponds to different values of energy. For the reason that the demand expected for 2030 is higher than the one of 2014, 52.9 TWh and 48.8 TWh, respectively. Nevertheless, it is advisable to go beyond this value in terms of wind power. The most recent prediction for the wind power capacity, up to the date of this document, was based in the [RMSA17]. This document estimates that the wind capacity to be 5554 MW of onshore and 52 MW of offshore power in 2030. This value contrasts with the RMSA 2015-2030 that estimates 6400 MW of wind power (including onshore and offshore). The reasons for the reduction between the two reports are not explicit, but possibly is related with the cancellation of several pumped hydro projects that would increase the system flexibility and enable the system to integrate more intermittent wind energy. The analysis presented was performed using the value of the most recent report, the RMSA 2017-2030. Furthermore, it will be tested if pumped hydro is able to integrate a scenario with plus 20% of wind and solar capacities.

In terms of solar capacity, the large investment in photovoltaic capacity, from 315 MW in 2014 to 1773 MW in 2030 was rewarded with a major generation increase from 0.59 TWh to 2.95 TWh, which represented a growth from 1% up to 6% of the total demand, figure 5.1.

River hydro is expected to stay between the same values of the reference year due to no further investment in run-of-river hydro and only some minor investments in small-hydro power. Hydro with reservoir does not present any growth in terms of energy output, despite the major investments made in installed power. This is explained by the fact that the water supply to the reservoirs sets an upper limit of energy that is possible to extract without pumping the water. In a technical simulation, the limited use of PHS prevents the increase in hydropower production. Thus, the water supply assumes an extra importance in the hydro with reservoir production. In table 5.2, it is presented the annual water supply from 2010 to 2016. For 2014, the water supply to the reservoirs during the year was 7.11 TWh. Considering an efficiency of 90%, the generation is limited to 6.40 TWh if pumping is not considered. With the limitations in the storage capacity, the generation is often lower than that. For instance, in 2014 it was 6.23 TWh according to EnergyPLAN.

Table 5.2 Annual water supply to the reservoirs from 2010 to 2016 [RTIM18].

| Years | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|
| Water supply to the reservoirs [TWh/year] | 7.30 | 3.72 | 2.22 | 6.52 | 7.11 | 2.23 | 6.40 |

The investments in dammed-hydro did not increase significantly the water supply available each year to the reservoirs. Without pumped storage, it is difficult to increase the share of energy produced by dammed-hydro as this is limited by the water supply available each year.

Combined heat and power (CHP) in figure 5.1 relates essentially to industrial CHP and is expected to have a minor increase in line with the likely increase in installed capacity that industrial CHP is expected to have with the recovery of the Portuguese economy and, consequently, of the industrial sector. This technology uses mainly natural gas and biomass as fuel. It is expected that in 2030, the use of natural gas will be around 75% and 25% biomass for CHP generation.

Bioenergy is constituted by biomass waste-to-energy and biogas. These sources of energy are expected to have their production increased, especially in dry years where the dispatchable thermal generation will have to replace the missing hydro production.

The share of renewable energy will increase in comparison to 2014 for normal and wet conditions, but not for the dry scenario. Nevertheless, the $CO_2$ emissions decrease for the three scenarios in result of the substitution of the coal by natural gas, which is a less carbon-intensive fuel.

Table 5.3 Share of renewable energy in final electricity consumption and $CO_2$ emissions for each scenario with technical simulation

| Scenarios | % of RES | $CO_2$ emissions [Mt] |
|---|---|---|
| **2014** | 62 | 12.1 |
| **2030 normal scenario** | 65 | 6.6 |
| **2030 wet scenario** | 69 | 5.5 |
| **2030 dry scenario** | 54 | 8.9 |

The sensibility analysis performed with EnergyPLAN for different levels of demand for 2030 showed that for the high demand scenario, natural gas increases its share in the energy mix, figure 5.2. Natural gas generation is increased in order to meet electricity demand. For the low demand scenario, there is less need for OSG thermal resources and, therefore, the share of natural gas decreases to 20%.

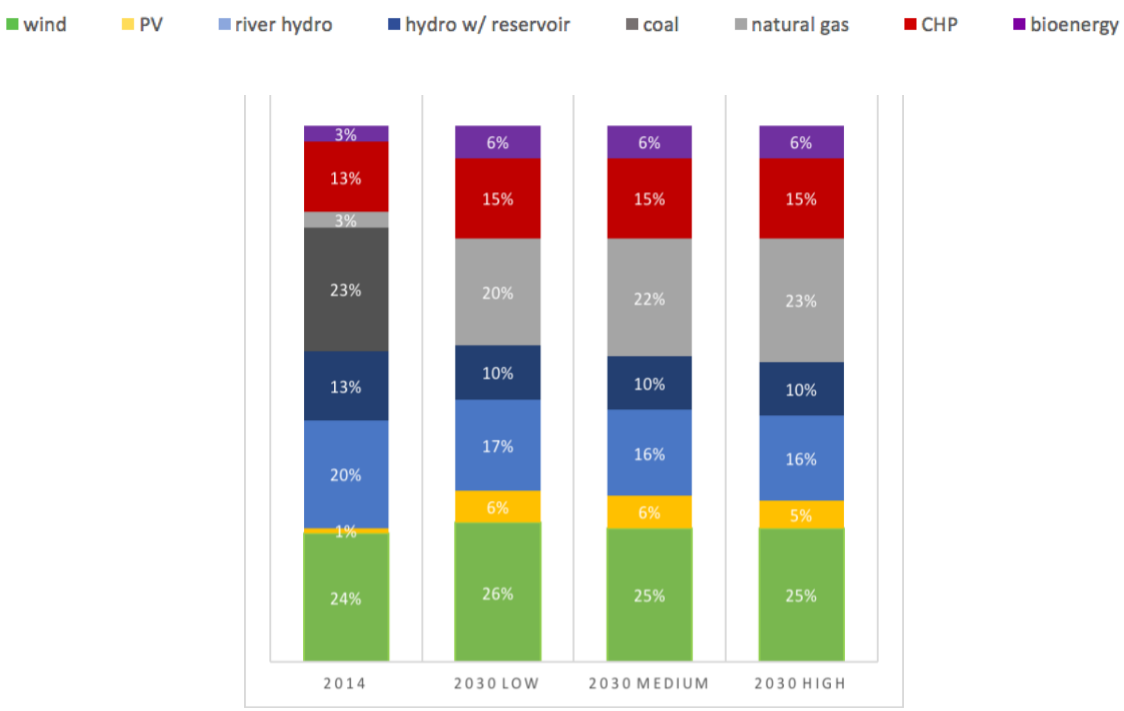



Figure 5.2 Energy mix for different demand scenarios.

As mentioned before, in a national power system, the supply and the demand must be continuously balanced. When the supply exceeds the demand, the output from dispatchable sources like hydropower or condensing power plants is reduced. However, in condensing power plants, the flexibility to adjust rapidly their production is limited and the excess has to be either exported, stored or the renewable energy production has to be reduced in what is known as curtailment. EnergyPLAN identifies this excess of energy that cannot be either exported or stored in a variable named CEEP (Critical Excess Electricity Production). To access the importance of storage in preventing curtailment, the system was simulated with varying levels of PHS power capacity. The results are presented in figure 5.3. A system without

storage would have 0.51 TWh of wasted renewable energy in a normal 2030 scenario. In a wet scenario, this value is higher for the reason that there is more intermittent generation from river hydro resources. Contrarily, there is the opposite effect in a dry year.

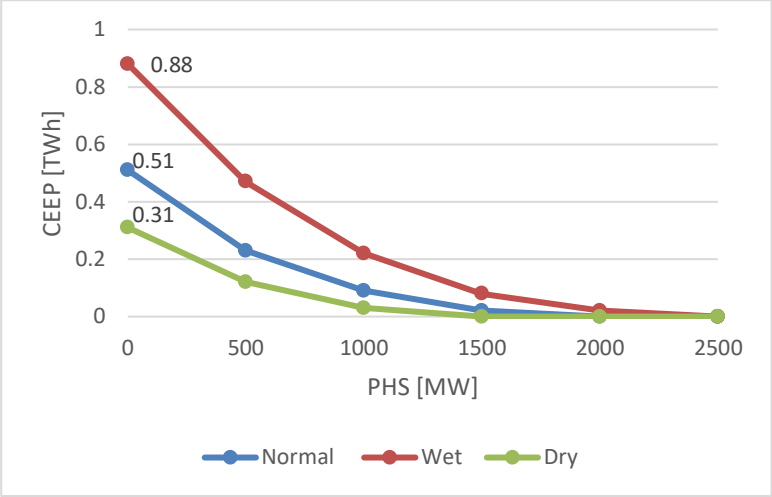



Figure 5.3 CEEP for different PHS power capacity. Normal, wet and dry 2030 year.

To provide some context to these results it may be important to remember that Portugal in 2014 had around 1100 MW PHS capacity, in the present it has around 2400 MW and is expected to have around 2750 MW in 2030.

The curtailed renewable energy decreases significantly when storage capacity is added. This is verified in the normal, wet and dry scenario. The CEEP is almost entirely reduced with 2000 MW of PHS for the three scenarios. Therefore, more installed capacity does not contribute in reducing curtailment of renewable energy.

However, more installed capacity could be necessary in a scenario with more variable renewable energy. Therefore, a scenario with plus 20% of wind and solar was simulated. This scenario was named "RES scenario" and the previously considered one was named "Central scenario". The new installed power capacities and annual generation are summarised in table 5.5.

Table 5.4 Power capacity and annual generation for Central and RES scenarios.

| | Installed Power Capacity [MW] | | Annual Generation [TWh] | |
|---|---|---|---|---|
| **Technology** | Wind | Solar PV | Wind | Solar PV |
| **Central** | 5560 | 1773 | 14.15 | 3.31 |
| **RES** | 6672 | 2127.6 | 16.98 | 3.97 |
| **Var. [%]** | +20% | +20% | +20% | +20% |

This new installed capacity contributed with an increase of 20% for wind generation and 20% for solar, table 5.5. However, to seize all of this new renewable energy generation and avoid curtailment, it is

necessary to have sufficient storage capacity. A similar analysis was performed again for the RES scenario and different water conditions, and the results are presented in figures 5.4 and 5.5.

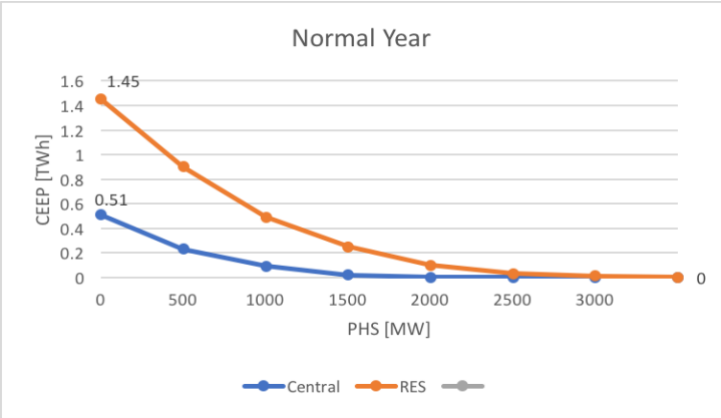
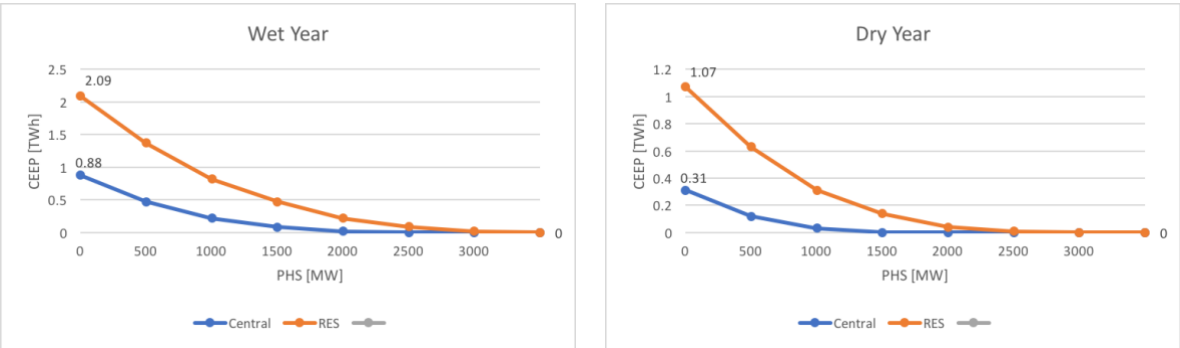



Figure 5.4 CEEP with varying PHS power capacity in the RES scenario. Normal year.




(a) Wet year (b) Dry year

Figure 5.5 CEEP with varying PHS power capacity in the RES scenario.

In the RES scenario, the curtailed renewable energy, or CEEP, increases substantially in systems without PHS capacity or low PHS capacities. This occurs in the three different water scenarios. This shows that in systems with more variable renewable energy, the storage capacity of the system assumes greater importance. But again, the system does not seem to benefit with more than 2000 MW of PHS as the reduction of the curtailment is not noteworthy past that point.

However, PHS can be used more extensively, not only as a technical solution to the excess of energy on the grid and reduce curtailment, as well as an economical option in order to take advantage of the price differences between peak and off-peak periods.

## 5.2 Economic simulation

The economic simulation in EnergyPLAN is designed to find the least cost solution while matching demand and supply, rather than on minimising fuel consumption. The simulation takes mainly two aspects in consideration. Firstly, the short-term marginal cost of producing electricity for each producing unit. Secondly, the least-cost solution of producing units is identified to match the demand [Conn15].

Pumped storage is used to optimise the system in a more efficient way by taking advantage of price variations in different time periods, known as price arbitrage. The algorithm does not prioritise pumped storage in particular.

In the previous section, after performing a technical simulation, it was noticed that despite the substantial investments in dammed-hydro power, the share of energy from this source did not increase from 2014 to 2030. This was because, as seen in the previous section, it is hard to increase the share of dammed-hydro because of the limited water supply available. However, performing an economic simulation, it was possible to increase the share of hydro with reservoir due to a more significant utilization rate of pumped storage, figures 5.6 and 5.7 in comparison to the figure 5.1. In normal conditions, the percentage of hydro with reservoir from the total energy produced, increased from 9% to 16%. With wet conditions, it increased from 12% to 18% and for a dry year, it increased from 5% to 14%. The dry scenario was the case in which the increase was most significant. Hence, pumped storage seems to be especially important in a dry year, for the reason that it contributes to a better management of the scarce water supply. In table 5.5, it is represented the expected electricity consumed by PHS according to EnergyPLAN simulations for the three different scenarios.

Table 5.5 Consumption of the pumps for the different water supply scenarios.

| Scenarios | 2014 (reference) | 2030 normal year | 2030 wet year | 2030 dry year |
|---|---|---|---|---|
| PHS [TWh] | 1.08 | 3.09 | 3.54 | 5.66 |

The increase in hydro production makes it possible to reduce the share of thermal energy. In an economic simulation, the share of bioenergy, i.e. biomass, waste and biogas is reduced due to the fact that these have larger marginal costs than natural gas production and is, consequently, less competitive. In reality, the share of bioenergy is expected to be larger than the one represented in figures due to the fact that these technologies benefit from a feed-in tariff or other economic incentives.

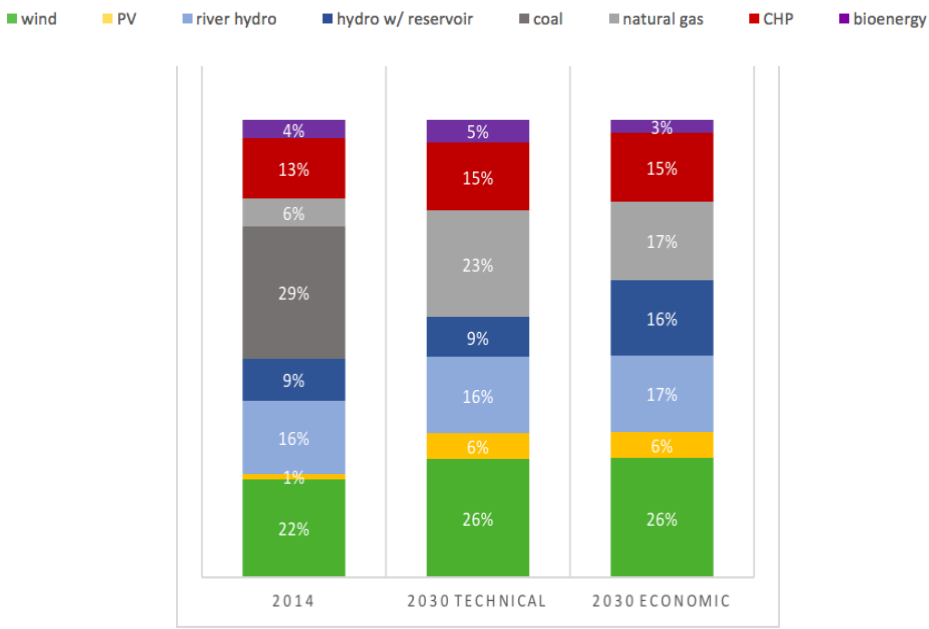



Figure 5.6. Energy mix for a normal 2030 year. Technical and economic simulation.

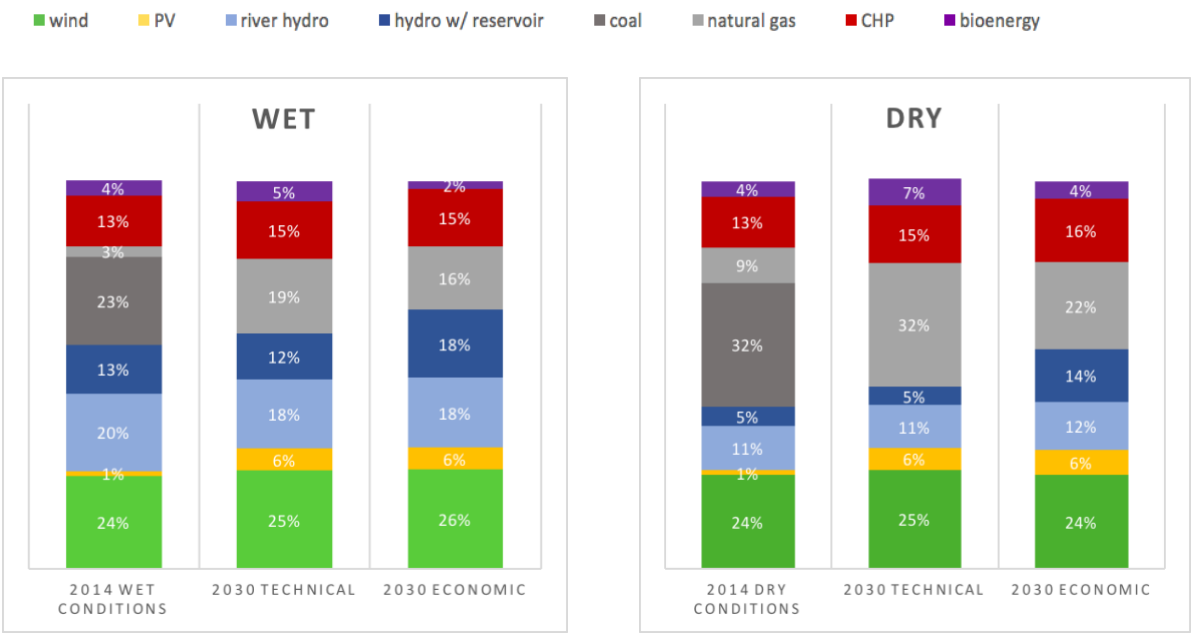



Figure 5.7 Energy mix for a wet and dry 2030 year. Technical and economic simulation.

As it was seen in the previous section, due to the decommissioning of the coal power plants, the $CO_2$ emissions had a meaningful decrease in relation to the 2014 levels (12.1 Mt). The results are again represented in table 5.6 with also the output from the economical simulation. The reduction in $CO_2$ emissions is even more significant if we take into consideration that 2014 was a wet year which consequently makes use of less thermal generation. In 2014, the percentage of renewables in final electricity consumption was 62% [RENa15]. The share of renewable energy in the energy mix increased

only partially in comparison to 2014 due to the fact that combined cycle gas turbines (CCGT) replaced most of the coal generation, and thus the percentage did not suffer any major increase.

The larger utilisation of PHS in an economic simulation reduces thermal generation and that reflects on higher shares of renewable energy and lower $CO_2$ emissions, as it can be noticed in table 5.6.

Table 5.6 Share of renewable energy in final electricity consumption and $CO_2$ annual emissions for each scenario with technical/economic simulation.

| | % of RES | | $CO_2$ emissions [Mt] | |
|---|---|---|---|---|
| Simulation / Scenario | Technical | Economic | Technical | Economical |
| normal | 66 | 72 | 6.6 | 4.5 |
| wet | 70 | 74 | 5.5 | 3.7 |
| dry | 58 | 64 | 8.9 | 6.7 |

Technical simulations were especially useful to see how much renewable energy would have to be curtailed with different storage capacities. Nonetheless, in the scope of this thesis, the economic simulation seems more appropriate for reason that employs PHS not only in a technical way, but more in a similar way to the reality of the Portuguese power system. During off-peak periods, the price of electricity is substantially lower and is a good option to import electricity and use the imported electricity to power the pumps. The economic simulation is capable of depicting the use of imports for that purpose. Afterwards, the previously pumped water provides the system with more flexibility in peak periods. This happens both in dry or wet periods. For instance, in January 2018, Portugal was facing very dry conditions. In the load diagram of figure 5.8, it is possible to see that imports were being used to pump hydro in off-peak periods. The national generation was practically matching the demand (thick dark line). For instance, in hour 0, the demand was 5500 MW and the generation was 5000 MW. However, about 1500 MW of electricity was being imported. More electricity than necessary to match the demand was being imported during off-peak period. The imported electricity was used for PHS and hence to prepare for peak periods. Additionally, it is possible to observe that hydro with storage is used almost exclusively in peak periods. Nevertheless, hydro with storage is not enough to meet peak demand. Natural gas and imports compensate for the rest of the missing electricity.

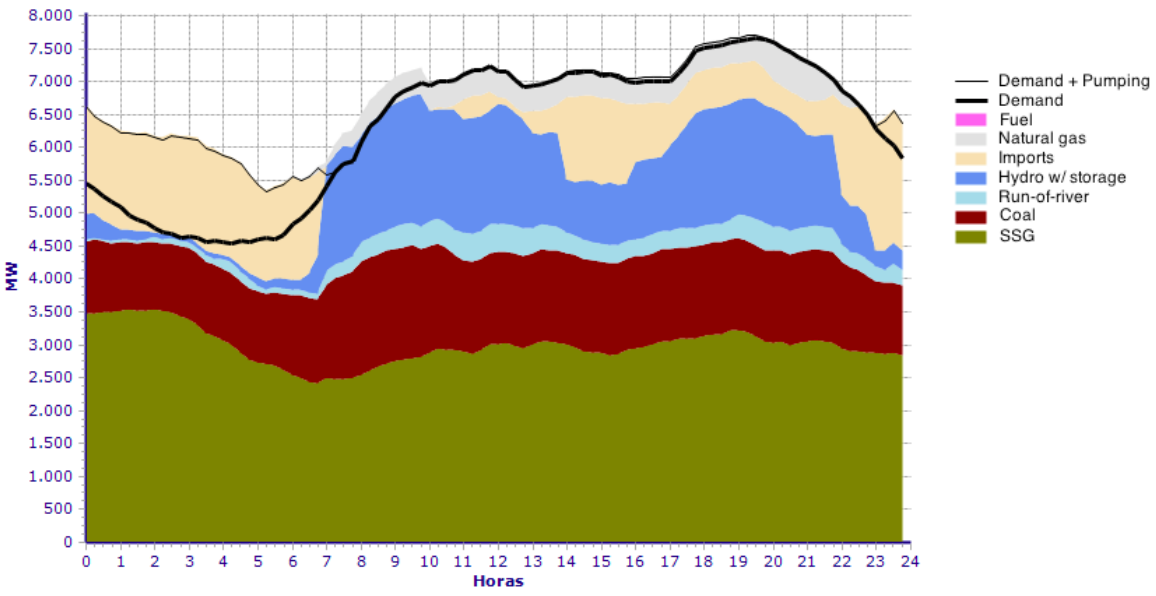



Figure 5.8 Load diagram of a dry day, 3rd of January 2018 [RTID18].

In an example of a wet day, electricity is also imported during off-peak for PHS utilisation, as it can be observed in the load diagram in figure 5.9. Afterwards, during peak hours, the electricity produced can even surpass the demand (the generation exceeds the thick dark line) and electricity is exported. This is more economically profitable since it is exported during peak hours. It is remarkable to notice that the system does not need to use any thermal generation. In fact, Portugal in March 2018, set a new record for renewable production, producing 103.6% of the total electricity demand for the month [APRE18]. Only in short periods of time, there was the need to incorporate thermal generation.

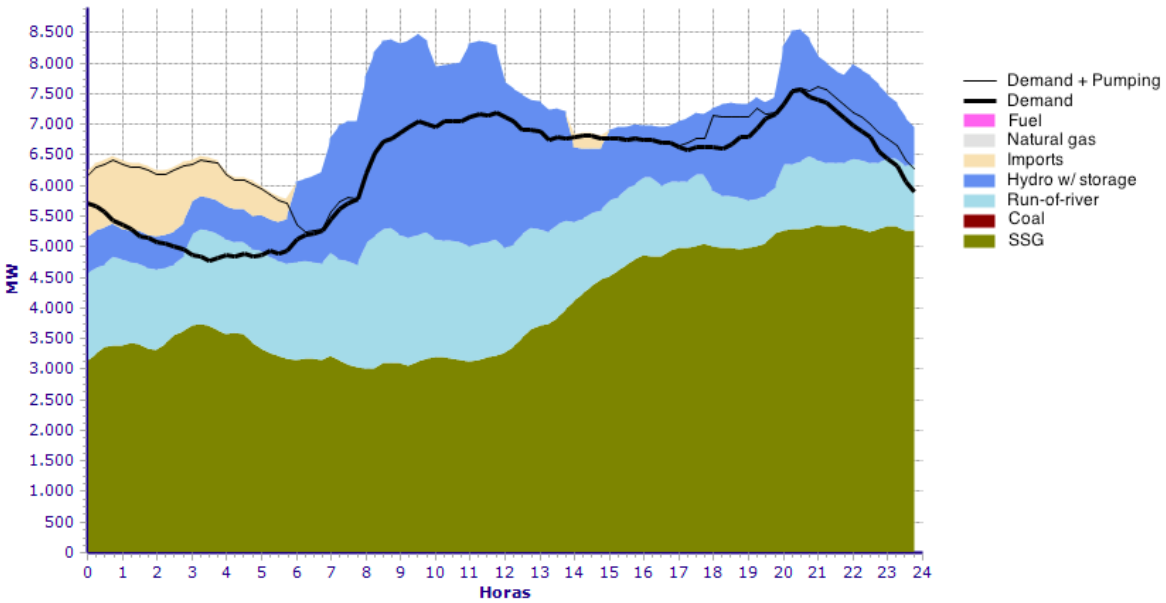



Figure 5.9 Load diagram of a wet day, 29th of March 2018 [RTID18].

The economic simulation registered export and import values that are more in accordance with this close

interaction that occurs in MIBEL market, table 5.7. The annual imports and exports values of the economical simulation are in accordance to the reality of the imports and exports of Portugal. For instance, in 2014, the exports and imports values were 4.2 TWh and 3.3 TWh respectively.

Table 5.7 Annual imports, exports and with technical and economical simulations.

| | **Technical Simulation** | | **Economic Simulation** | |
|---|---|---|---|---|
| Scenario | **Imports [TWh]** | **Exports [TWh]** | **Imports [TWh]** | **Exports [TWh]** |
| **Normal** | 0.48 | 0.73 | 4.73 | 2.29 |
| **Wet** | 0.24 | 1.16 | 4.55 | 2.39 |
| **Dry** | 1.68 | 0.13 | 8.49 | 0.51 |

However, EnergyPLAN developers advise that a technical simulation is more appropriate in works that intend to study future energy systems with very high levels of renewable penetration. For instance, EnergyPLAN is many times used to study systems with 100% renewable energy scenarios and a technical simulation is better in managing high levels of non-dispatchable sources and simulating the vast number of interactions between electricity, transports and heating/cooling sectors.

As explained in the previous section, the RES scenario considers a 20% increase of wind and solar installed capacities in relation to the Central scenario. In this scenario, the utilisation of the PHS would become more significant than in a scenario with less renewable energy, table 5.8.

Table 5.8 Consumption of the pumps for the different water supply conditions in the RES scenario.

| Scenario | **Central [TWh]** | **RES [TWh]** | **Var. [%]** |
|---|---|---|---|
| **Normal** | 3.09 | 3.71 | 16.7 |
| **Wet** | 3.54 | 4.36 | 18.8 |
| **Dry** | 5.66 | 6.23 | 9.1 |

### 5.2.1 Economic comparison of the Central and RES scenarios

In economic simulations, EnergyPLAN requires several cost data inputs. In Annex A is presented the cost data that was inserted into the model based on EnergyPLAN Cost Database for 2030 [Conn16]. The investment costs for generation units in M€/MW and for storage in M€/GWh, the lifetime of the project and the fixed operations and maintenance costs in percentage of the investment are filled in the model. Afterwards, the EnergyPLAN calculates the total investment costs according to the installed capacity of each technology type. Then, according to the typical lifetime of each technology, the tool annualises the costs, separating in annualised investment costs and annual fixed O&M costs. For solar PV, for instance, considering an investment cost for 2030 of 0.82 M€/MW [Conn16] and with the predicted installed capacity of 1773 MW in 2030, the total investment cost will be 1454 M€. Then, the annualised investment costs will be 74 M€, considering a 3% interest rate and a 30-year project lifetime. As it is exemplified for PV, EnergyPLAN does the same for the entire system, considering all generation technologies, storage capacity, pumping capacity and interconnection.

Other cost data that must be inserted in the software are the variable costs. Each technology has specific variable costs which refer to the costs of producing one additional unit of energy [€/MWh].

A comparison of the annual costs for the entire system is represented in figure 5.10 for the Central and RES scenarios. The costs are divided into annualised investment costs, in annual variable O&M costs and annual fixed operation costs.

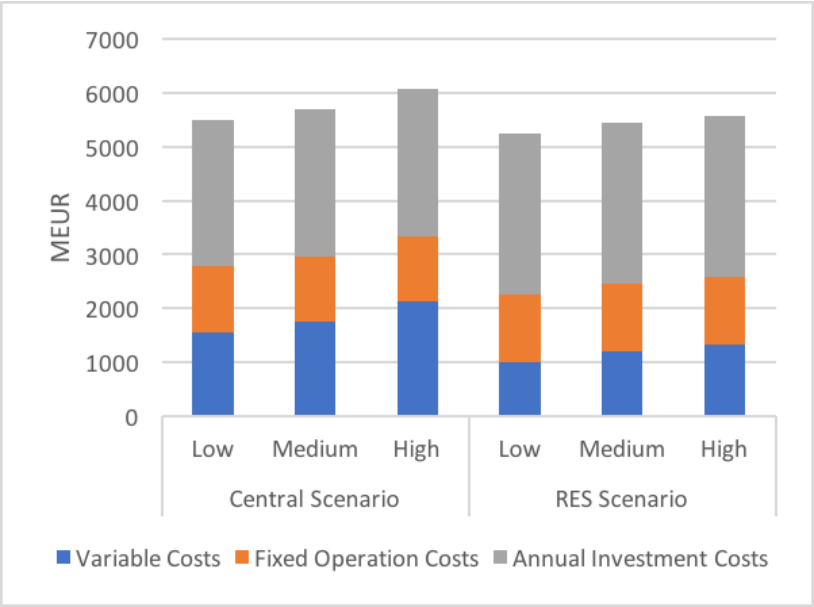



Figure 5.10 Annual cost distribution for Central and RES scenarios and different demands.

A sensibility analysis is performed for different demand levels, figure 5.10, and for dry and wet conditions, figure 5.11. In figures 5.10 and 5.11, it is possible to observe that the high annual investment costs in the RES scenario are compensated by lower variable costs, resulting in lower total annual costs for the system. This happens for all sensibility analyses performed, leading to the conclusion that the system would benefit from higher levels of solar and wind energy. The fact that wind and solar have null

variable energy costs, i.e. they have no further costs of producing an additional unit of energy, compensates for the higher investments in renewable energy. On the other hand, the Central scenario has higher variable costs because of a broader utilisation of thermal power plants that imply variable costs with fossil fuels.

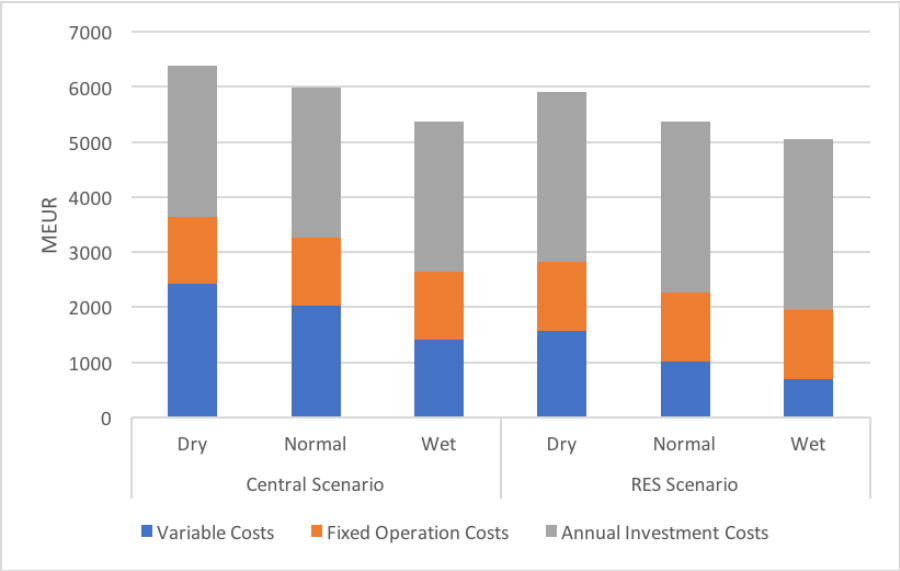



Figure 5.11 Annual cost distribution for central and RES scenarios and different water conditions.

## 5.2.2 Storage capacity evaluation

In this section, it will be presented a critical analysis of the predicted storage capacity for 2030. It will be assessed if this capacity is sufficient or if there are needs for installing further capacity, either more PHS capacity or with the introduction of battery energy systems (BES).

The expected PHS capacity for 2030, as can be read in chapter 4 was considered to be 3538.4 MW, together with the expected international interconnection capacity of 3500 MW, it avoids the existence of any renewable energy curtailment, i.e. the CEEP variable in EnergyPLAN assumes a zero value. Therefore, from the technical point of view, it is unnecessary to increase the storage capacity of the system. Nonetheless, with the arbitrage of the price, it could be beneficial from the economic perspective.

In the LCOS analysis, the parameters used in the calculation have to be the same in order to provide a fair comparison of different technologies. The parameters considered in Lazard's LCOS analysis for large-scale energy storage [Laza16] are summarised in table 5.10. A system with a power rating of 100 MW and storage capacity of 800 MWh is considered to complete a full cycle per day for 350 days of the year, what gives a total annual energy output of 280 GWh.

Table 5.9 Operational parameters for the LCOS calculation [Laza16].

| Project life [years] | Power rating [MW] | Storage capacity [MWh] | 100% DoD[7] cycles/day | Days/year | Annual Delivered Energy [MWh] |
|---|---|---|---|---|---|
| 20 | 100 | 800 | 1 | 350 | 280 000 |

Despite the fact that the system does not need any additional capacity from a technical point of view, it was considered to install more additional capacity with the intention to examine if the system would benefit from an economic perspective. Two options of supplementary storage capacity were considered: additional PHS capacity (open-cycle) or the introduction of BES with 100 MW and 800 MWh of power and storage capacity, respectively. This corresponds to the same parameters considered in the Lazard's analysis. The simulations showed that for pumped hydro, the additional storage capacity delivered an annual energy to the grid of 70 GWh, while for batteries it delivered 95 GWh. Both values are a fraction of the 280 GWh considered in the LCOS calculation. This would result in higher costs for than the ones predicted in the LCOS calculation. The LCOS would assume a higher value for these investments in particular, as the LCOS is inversely proportional to the energy delivered to the grid. On the one hand, batteries deliver more energy to the grid. On the other hand, the LCOS of PHS in 2030 is expected to remain lower than the LCOS of batteries. However, the additional delivered energy by batteries does not seem sufficient to compensate for the higher costs of batteries. The same total annual costs mentioned in the previous section were observed. EnergyPLAN calculates that a system with no more storage capacity will have 5326 M€ of overall annual costs, while a system with more PHS capacity will have 5331 M€ and a system with batteries 5337 M€. These values confirm that investing in more energy storage is not beneficial from an economic perspective. In case it is invested in more energy storage, PHS is expected to still present itself as a better option than batteries by 2030. For the RES scenario, the PHS delivered 130 GWh to the grid and batteries 155 GWh. The total annual costs were 5203 M€ with no storage, 5205 M€ for PHS and 5207 M€ for batteries. These results yield similar results to the Central scenario. Again, the justification of more investments in energy storage is not evident. However, the differences between costs of not investing in further storage and investing are lower than before, what corroborates that energy storage holds greater value in systems with larger RES penetration.

It is important to note that EnergyPLAN can only capture the benefits of performing the price arbitrage of electricity. However, energy storage could find other use cases that would increase its profitability by providing ancillary services for example. Therefore, these results should not be assumed as definitive and further simulations should be performed with other tools and models.

[7] DoD – Depth of Discharge

# Chapter 6

# Conclusions

This chapter summarises the work developed and highlights the main conclusions, while indicating possible perspectives for the development of future work.

In this work, it was studied the role of storage in a real-world case. The analysis was performed for the context of the Portuguese power system, though the methodology can be applied into any other national grid. In order to study the Portuguese power system, a model was developed with the help of EnergyPLAN simulation tool. A reference year was modelled to ensure that the model can simulate the energy system accurately. With a reference year, the user can compare the historical data with the output of the simulation. Besides, it enables the user a learning process of the tool algorithms and also of the energy system under study. Afterwards, the evolution of the power system was studied with a 2030 horizon. When investigating the development of the system regarding hydropower capacity, it was noticed that similar analyses did not include the recent cancellation of some of the hydropower and PHS projects initially planned. This constituted an additional motivation for investigating whether the storage capacity can integrate the rising levels of variable renewable energy predicted for 2030, and verify if the cancellation of the projects would affect the reliability of the system.

A technical simulation showed that in 2030, Portugal will still depend to some extent in ordinary status generation (OSG) thermal power, despite the decommissioning of coal power plants. Especially in a dry weather scenario, natural gas would have to compensate for the reduced hydro production with 32% of the energy mix. If CHP is included, natural gas would assume a preponderance of 41% in a dry scenario, which would put Portugal exposed to the volatility in natural gas prices. The PHS capacity assumes a valuable role in this situation. In a dry scenario, pumped hydro allowed for an increase of dammed hydro production from 5% to 14%. Conversely, it allowed for a reduction in OSG natural gas from 32% to 23%. Even in normal and wet conditions, the reductions in OSG thermal production induced by pumped hydro are substantial with a decrease from 23% to 17% for normal conditions and from 19% to 16% in wet conditions.

The reduction in $CO_2$ emissions from 2014 to 2030 is noteworthy: from 12 Mt to 6.6 Mt (technical simulation). This shows the importance of the decommission of the coal power plants. With an economic simulation, the reduction is even more significant (4.5 Mt) since the broader utilisation of PHS makes possible this further reduction. The share of renewable energy in the energy mix increased only partially in comparison to 2014. This is explained by the fact that combined cycle gas turbines (CCGT) replaced most of the coal generation, and thus the percentage of renewable energy did not increase significantly.

The economic simulation was observed to be more accurate in depicting the Portuguese reality, for the reason that it makes broader use of PHS as it occurs in reality. Furthermore, it depicts more accurately the interaction between Portugal and Spain, regarding exports and imports of electricity.

Regarding the ability of the storage system to integrate the rising levels of intermittent renewables in a 2030 horizon, the results showed that the predicted PHS capacity (3538.4 MW) was enough for avoiding the existence of any critical excess of energy. Critical excess is the energy that cannot either be exported or stored, leading to the curtailment of renewable energy, in order to avoid a collapse in the power system. For this inexistence of critical excess, the increase in interconnection capacity with Spain to 3500 MW also revealed to be fundamental. A scenario with more variable renewable energy generation

was also considered (RES scenario), namely a 20% increase in wind and PV capacity in comparison to the predictions of the RMSA 2017-2030. This scenario also presented no critical excess with the predicted PHS capacity for 2030. Simulations were run for lower PHS capacities. A system with no PHS capacity would have a critical excess of 0.51 TWh and this situation would accentuate with 0.88 TWh in a wet scenario due to the presence of higher levels of non-dispatchable river hydro generation. In a scenario with more renewables, the storage capacity assumes higher importance, avoiding the curtailment of more renewable energy than the central scenario. A PHS capacity of 2000 MW revealed to be enough to avoid most of the curtailment of renewable energy.

It was shown that the increase in renewable energy would decrease the overall costs of the system for all the different demand and weather scenarios, as the lower variable costs would compensate the higher investment costs of more RES. This fact, together with the fact that the system can integrate higher levels of RES with sufficient storage capacity, it leads to thinking that further efforts should be made in increasing RES power capacity, and go beyond the predictions for 2030 wind and solar installed capacities.

Regarding the need for more storage capacity, the system did not seem to benefit from a technical perspective as lower storage capacities were sufficient to avoid RES curtailment. From an economic perspective, the overall total costs presented higher values for more storage capacity, especially for battery solutions. Economically, PHS still seems to be a more cost-efficient option than batteries by 2030.

The results presented in this work should be considered with some caution as they are the output of a model that may not entirely depict the reality. In EnergyPLAN model, the generation capacity for each technology is aggregated in a sum of individual power plants. It is like only one power plant of each technology is used to simulate the whole generation capacity of a country. This makes the tool unable to account for the geographical location of the generation and loads, and possible congestions in the internal transmission system. For this reason, the task of integrating higher renewable energy shares can be somehow facilitated in comparison to reality. Moreover, PHS systems in particular may have improved capacity factors due to the aggregation of the installed power and storage capacities. Therefore, in fact, the needs for energy storage can be slightly higher than the ones here predicted. One perspective of future work could be to perform similar analyses but considering more individual data of the generation, loads and PHS systems. However, this would increase drastically the complexity of the model.

Other perspectives for future work could be to compare the costs of investment in storage with the costs of the alternatives. For instance, the costs of investing in thermal back-up capacity. Or additionally, to study the effects of climate change in the results. With climate change, it is expected more extreme seasons, i.e. longer periods of dry climate followed by periods of intensive rain. Therefore, the impact of climate change in the results could be interesting to examine. It is expected that PHS assumes a greater importance under such conditions, as it would contribute for a better management of the water supply.

# Annex A

## Cost Data

This annex provides the cost data used in the model for EnergyPLAN economic simulations. It is based on EnergyPLAN Cost Database [Conn16] with updated cost predictions for 2030.

## A.1 Investment costs and fixed O&M costs

Table A.1 – Investment costs and fixed O&M costs

| Technology | Investment Cost [M€/MW] | Lifetime [years] | Fixed O&M [% of investment] |
|---|---|---|---|
| Thermal PP | 0.98 | 27 | 3.16 |
| Interconnection | 1.2 | 40 | 1 |
| Industrial CHP | 68.3 | 25 | 7.3 |
| Wind | 1.3 | 25 | 2.59 |
| PV | 0.82 | 30 | 1 |
| River Hydro | 3.3 | 50 | 2 |
| Hydro Power | 3.3 | 50 | 2 |
| Hydro Storage | 7.5 [M€/GWh] | 50 | 1.5 |
| Hydro Pump | 0.6 | 50 | 1.5 |
| Pump | 0.6 | 20 | 1.5 |

## A.2 Variable O&M costs

Table A.2 – Variable O&M costs

| Technology | Variable O&M Cost [€/MWh] |
|---|---|
| Thermal PP | 2.65 |
| Interconnection | 0 |
| Industrial CHP | 2.70 |
| Wind | 0 |
| PV | 0 |
| River Hydro | 0 |
| Hydro Power | 1.19 |
| Hydro Storage | 0 |
| Turbine | 1.19 |
| Pump | 1.19 |

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