TÉCNICO LISBOA

Assessing the impact of Demand Response in the Portuguese Electric System

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Abstract

In order to maintain the global warming under an acceptable 2ºC increase, electricity systems need to evolve fast. Demand Response (DR) can be used as a tool, one among many, to improve the balance between demand and supply of electricity, specially in systems that rely heavily on intermittent generation, like wind, solar, hydro, wave energy, etc. Thus, it is important to understand up to what extent a countrywide system would cope with DR implementation.

Using the energy-modelling tool OSeMOSYS, a model of the Portuguese electricity system is used to assess the impact of demand response implementation in the long term – up to 2050. The theoretical potential of demand response is computed to better understand the impact of its implementation on the overall system, analysing three scenarios – a business as usual scenario, a carbon-free system scenario in 2050, and a scenario without a heavy carbon emission restriction (least cost).

DR impact in all three scenarios resulted in a decrease on the overall costs, on the capacity installed and in an increase of percentage of renewable capacity. Also, DR diminished the need for thermal backup capacity, reducing the capacity of biomass and natural gas power plants. Moreover, an economic analysis shows that DR takes 15 years on average to affect the average electricity cost, and that the reduction in total costs come, mainly, from avoided capacity investments. Finally, the study shows that a carbon-free system with DR implemented is less costly than a business as usual system without DR fully-implemented.

Keywords: Demand Response; Flexible electricity demands; Energy systems modelling; Renewable energy.

Resumo

As tecnologias de gestão de consumo adaptativo (DR) podem ser usadas, entre outras, de forma a equilibrar a procura e o fornecimento de eletricidade, especialmente em sistemas com grande quantidade de geração intermitente, como a energia solar, eólica, hídrica e ondas. Consequentemente, é importante perceber até que ponto estas tecnologias afectam o sistema eléctrico nacional.

Usando a ferramenta de modelação de sistemas de energia OSeMOSYS, foi desenvolvido um modelo do sistema eléctrico Português com vista à analise do impacto da implementação do consumo adaptativo a longo-prazo – até 2050. O potencial teórico de DR é calculado, e são desenhados três cenários – um cenário *Business as Usual (BaU)*, um cenário de emissões zero em 2050, e um cenário com menores restrições de emissões de carbono.

Em todos os cenários, o uso de DR resultou numa redução do custo total do sistema, da capacidade total instalada e num aumento na percentagem de penetração de capacidade renovável. A implementação de DR levou também à diminuição da necessidade de capacidade de reserva térmica, resultando numa diminuição da capacidade instalada de biomassa e de gás natural. Adicionalmente, a análise económica revela que o DR demora cerca de 15 anos para reduzir o custo médio de eletricidade, que se deve, em grande parte, aos investimentos evitados em nova capacidade. Finalmente, é demonstrado que um sistema sem emissões de carbono em 2050 com tecnologia DR implementada tem um custo menor do que um sistema de BaU e sem implementação de DR.

Palavras-chave: Consumo adaptativo; Procura flexível de eletricidade; Modelação sistemas de energia; Energias renováveis.

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Acronyms

CCS – Carbon Capture and Storage

CPP – Critical Peak Price

DESA – Division of Energy Systems Analysis

DGEG – Energy and Geology General Agency

DOE – Department of Energy

DR – Demand Response

DSO – Distribution System Operator

EC – European Commission

ENTSOE – European Network of Transmission System Operators for Electricity

ERSE – Energetic Services Regulatory Agency

EU – European Union

EU-ETS – European Union Emissions Trading System

GDP – Gross Domestic Product

HFO – Heavy Fuel Oil

IEA – International Energy Agency

MIBEL – Iberian Electricity Market

NG – Natural Gas

NGCC – Natural Gas Combined Cycle

OECD – Organisation for Economic Co-operation and Development

OMIE – Nominated Electricity Market Operator

OMIP – Iberian Energy Derivatives Exchange

PP – Power Plant

PRE – Production Special Regime

PV – Solar Photovoltaic energy

PRO – Production Normal Regime

RTP – Real Time Price

ToU – Time-of-Use

TSO – Transmission System Operator

1. Introduction and aim of study

1.1. Motivation

In 2010, Portugal's demand for electricity was 50.5 TWh – the all time peak [1], and in 2015 the demand was 49 TWh. The future estimated growth is a rate of 1.2% for OECD countries, and so, it is very likely that the electricity demand will surpass 2010's numbers [2].

European Union has energy targets to meet in 2050, namely the cutting 80% of carbon emissions. However, rigid policies for such a long-term period are hardly adopted, and the policies acting presently refer to 2020 targets. Thus, Portugal is preparing to meet these targets for sustainability and emissions for the year 2020 [3].

Based on the European directive and its targets, the future of energy and the correspondent hazardous emissions can be improved through increasing the percentage of energy generation that comes from clean resources and by reducing the amount of energy that is needed, and therefore generated. The former is already widely present in Portugal since the beginning of the century, and presently over half of the installed capacity is renewable. The later is being tackled with the increase of energy efficiency [2].

Renewable resources exploitation, due to the fact that these are intermittent and not balanced with the demand (such as wind and solar), is the main challenge. Demand side management strategies are seen as an important tool to help tackling this challenge. Demand response (defined in page 18) can decrease the amount of wasted electricity generated and create more balanced energy consumption throughout each day [4]. These strategies can allow Europe and Portugal to take a step further in the problem of intermittent generation from renewable sources [5].

However, there is a need to understand how can demand side strategies - and more specifically demand response - turn this potential into reality, and in which way could it change future electric system planning.

1.2. Objectives of study

The objective of this thesis is to provide a more informed insight on how these demand side strategies can help shape the future electric power systems. The main questions to be addressed are the following:

- Can the implementation of demand response lead to reduction of relevant power reserves that mostly run on fossil fuels?
- Can technologies like demand response enable us to increase the percentage of penetration of renewable energy sources?

- How much the percentage of implementation of demand response relate to the impact in the system?

To help gather the answers for these questions, a model of the Portuguese electricity system was developed as a case study. Also, equations that account for flexible processes (already existent) were implemented in the software. Results were exploited from business as usual scenario, a low carbon scenario and a least cost scenario for a long-term simulation. All the scenarios were tested with three different levels of demand response implementation – no implementation, 50% of demand response potential implementation and full demand response potential implementation. The model period is from 2015 and extends until 2050, and the main results focus on the capacity expansion and increase in the percentage of the renewable energy sources that supply the electric system that can be achieved with DR, and how it influences and impacts the way the electricity system is designed and planned in the long-term.

1.3. Structure of the thesis

In Chapter 1, an introductory part of this thesis with the motivation, objectives of the study and structure of the thesis, is presented.

Chapter 2 presents an overview of the world energy consumption and electricity generation panorama. A closer look is taken into Europe, before focusing directly on the Portuguese system.

Chapter 3 comprises the literature review of energy currently used models, new developments and demand response studies.

Chapter 4 reports the methodology used in the thesis: the first part focuses on the modelling of the energy system, and the second part on the implementation of shiftable loads.

Chapter 5 presents the case study of the Portuguese system, presenting all the data and assumptions gathered.

In Chapter 6 the results are presented and a correspondent analysis, comparing the designed scenarios, is discussed.

Finally, in Chapter 7 the main conclusions of the study are stated, as well as thoughts on future work and research.

2. The electricity system trends

2.1. World overview

The World has different levels of development through different regions and continents. Thus, it is difficult to set a general overview of the energy consumption and the evolution of the electricity system. However, is frequent to divide between non-OECD and OECD countries, since these pave the way for the developing world in energy generation technology.

Of the World's total primary energy consumption of 9424 Mtoe in 2014, 954 Mtoe (10.1%) was used for electricity generation. If we consider only OECD countries, this percentage increases to almost 15% [6]. Within OECD countries, electricity generation is expected to grow by 1.2%, and within non-OECD countries the rise is expected to be 2.6% [2].

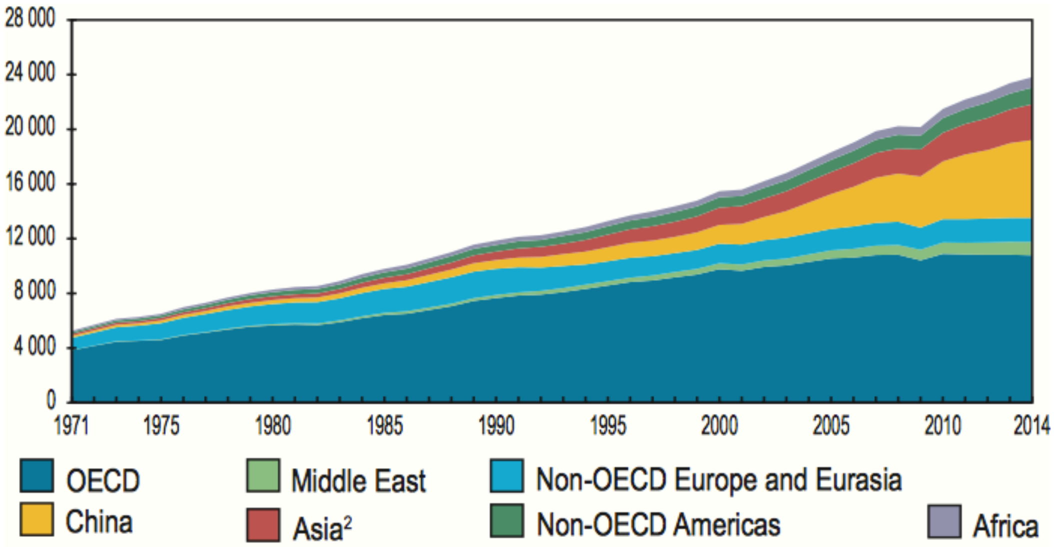

Figure 1: World Electricity Generation by Region (TWh) [7]

The generation of electricity is done through the use of fossil fuels, renewable energy sources or nuclear energy. From Figure 2 presented bellow, it is possible to see that renewables provide around 22% of today's electricity, nuclear 11% and fossil fuels 67%.

Due to the relation of CO_2 emissions with the steady rise of the world average temperature, and the consequences it can have in our way of living, fossil fuel usage for electricity generation has been highly discouraged by the majority of the world governments. To facilitate co-operation and dialog on emission targets, the Paris Agreement for Climate Action[1] was established in 2016, with 144 of total 197 parties ratifying the agreement. The

[1] http://www.unfccc.int/paris_agreement/items/9485.php

outcome of the convention was a common goal of maintaining the rise of the average global temperature well bellow 2º (above pre-industrial data).

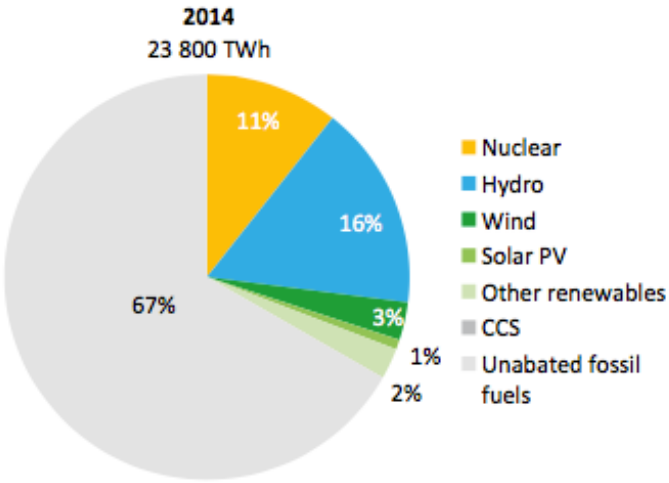

Figure 2: World electricity generation per source in 2014 [8]

As a response to the global climate challenge, renewable energy generation is expected to rise steadily in the future, at a rate of 2.9%. A large contribution to this rate is the investment in solar generation from China and hydro generation installation in southeast Asia [2]. As Figure 3 shows, from 2004 a large change in the annual market share of power plant investment has been made in the past decade.

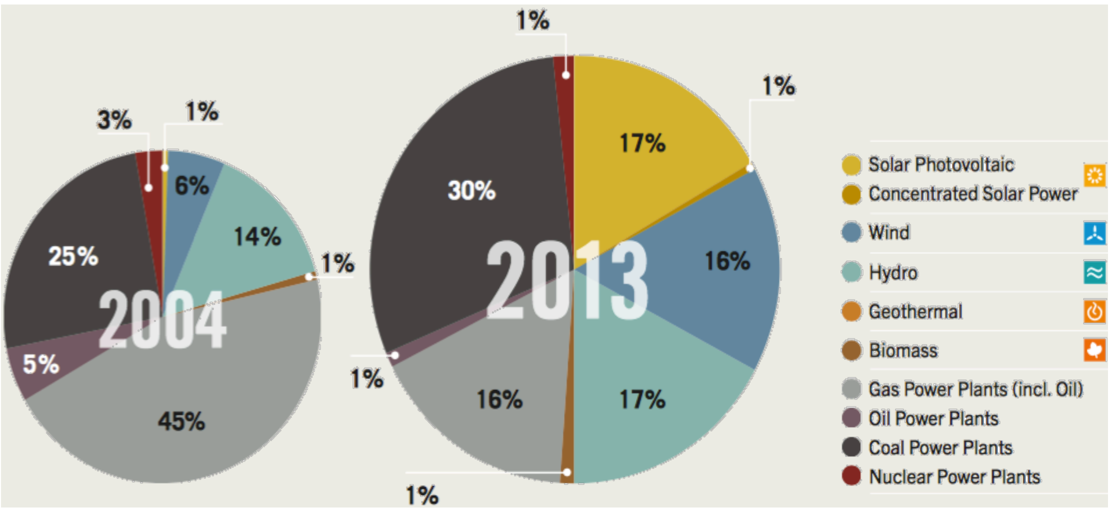

Figure 3: Global power plant market shares (%) [9]

The total global installed capacity is also patenting the difference seen in the market share towards renewables. From 2004 to 2014, global solar capacity increased from 0.1% (3 GW) to 2.9% (181 GW). Wind also shares this increase, from 1.3% (48 GW) to 6.0% (370 GW). Generally speaking, the global renewable capacity share increased from 21.4% to 27.7% [9].

However, even with developments in the renewable generation and with recent generation technologies with carbon capture and storage (coal and NG power plants), alongside technologies of energy storage, the targets that were discussed in the Paris agreement - of maintaining a ceiling well bellow 2ºC of rise in global temperature - are a challenging reality [8].

2.2. European overview

The year of 2006 marked a change in the field of energy and environment throughout Europe. It was the year where primary energy consumption hit the maximum of 1840 Mtoe in the EU28 [10]. Since then, Europe's primary energy consumption has been decreasing, reaching a value of 1605 Mtoe in 2014, a new low in 24 years of the present data series [10]. However, as seen in the previous section, the demand growth rate for electricity is estimated to be 1.2% yearly.

Europe is looking far ahead to a 2050 electric power system with low carbon emissions and high-energy efficiency. In this line of thought, the ultimate goal for the next era of the system is an European super grid that can exploit the potential of the European renewable resources: solar in the south, wind and hydro in the north and wave in the west [11]. In Europe, the electricity markets are being directed towards a centralized market, while the European super grid becomes a reality. Until then, the electricity markets operate separately in different regions. Table 1 shows us the European regions for the wholesale electricity markets.

Table 1: European electricity markets [12]

Market	Countries
Iberian Market	Portugal, Spain
Northern Market	Denmark, Estonia, Sweden, Finland, Latvia, Lithuania, Norway
Central Eastern Market	Czech Republic, Hungary, Poland, Romania, Slovakia, Slovenia
Apennine Peninsula	Italy
Southern Market	Greece, Bulgaria
Central Western Market	Germany, France, the Nederlands, Belgium, Austria, Switzerland

Despite the fact that 2050 is still a long way away, it is important to have a picture of the current reality. The policy that is currently operating is the directive towards 2020 targets. In the Third Energy Package, the European Commission (EC) set the following goals [3]:

- 20% reduction of Greenhouse Gas (GHG) emissions
- 20% of the final energy generated from RES
- 20% increase energy efficiency

As we move closer to 2020, European governments are also preparing the energy package for 2030. This package is built on top of the previous 2020 package, and sets the following goals [13]:

- 40% reduction of Greenhouse Gas (GHG) emissions

- 27% of the share of generation from renewable energy
- 27% increase energy efficiency

Figure 4 show that European electricity generation still largely relies on fossil fuel sources – almost half of the total. Another important aspect is the nuclear share of generation, which is very likely to shrink in the coming years, mainly due to the shift in the French and German energy policy, following Japan's nuclear power plant accident in Fukushima in 2011. This will create an opportunity for the replacement of nuclear generation with renewables, but the balance problem of demand and generation is then the rising problem. Demand side strategies might be one of the solutions to mitigate this challenge.

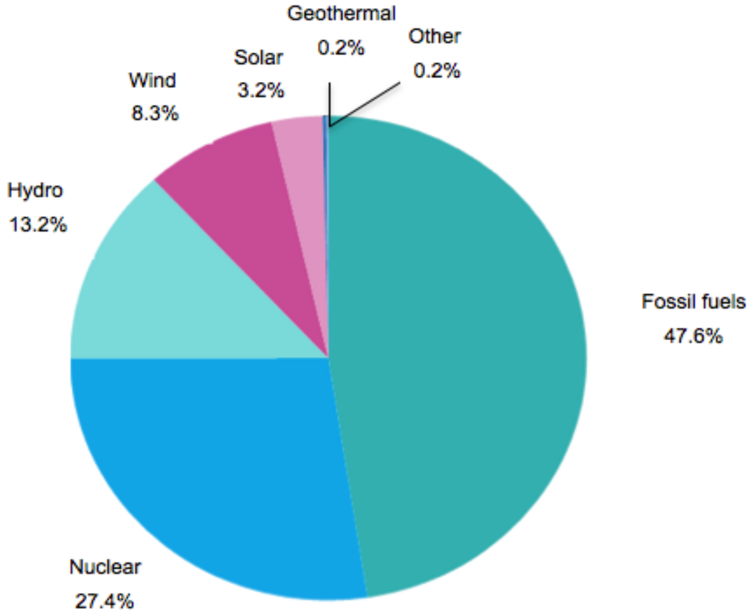

Figure 4: European Electricity Generation per resource in 2014 [10]

2.2.1. Demand side strategies in Europe

Given that almost half of the electricity generation in Europe is coming from fossil fuels, it is necessary to implement policies and strategies to invert this tendency. Demand side management strategies can provide a better balance between the demand and supply of electricity, especially when in presence of renewable generation, as well as an increase the energy efficiency of the present system [14].

Smart grid technologies that enable consumer engagement are being deployed throughout Europe, such as smart meters, for metering of electricity and gas consumption – with high temporal resolution. The European target, is to reach 80% of penetration of smart meters in the member states that had positive results in their cost and benefit analysis [15]. These smart meters are able to communicate with information hubs and with the retail companies to inform them better on which consumers are demanding more electricity in which periods. This can lead to the allocation of financial incentives directly to the consumers demanding more electricity in an instantaneous way, and can also lead to a better explanation of consumption to the costumers – with a discriminated monthly bill on the type of sources that provided the electricity in which periods.

Ultimately, demand response can benefit a lot with these new technologies, enabling consumer response to price signals, as well as energy planners more robust tools to choose low carbon generation sources. These price signals are being tested in some countries in the retail markets in the form of Time-of-Use (ToU) tariffs and in the wholesale markets with more complex incentives schemes, such as curtailment or indirect load control [16]. These concepts will be further analyzed and explained in Chapter 3.

2.3. Portugal's electricity system

Portugal followed the European trend of achieving the energy consumption peak in 2005. In that year, 26.5 Mtoe in primary energy was consumed. However, this number has decreased 18.3% in the year 2014, to 21.1 Mtoe, with 74.3% of it coming from fossil fuels [1]. The amount of endogenous resources that Portugal has regarding fossil fuels can be considered negligible. Thus, the country is obliged to import almost all the fuels that are needed, mainly for transportation, but also to generate energy. By doing this, Portugal has an almost intrinsic high rate of primary energy dependence that in 2013 was 74% and in 2014 was 72%, being the 8th highest rate in the EU [17], [18].

The final energy consumption follows the primary energy consumption's trend. It has also been decreasing from its high in 2005, and in 2013 was 15.17 Mtoe. Since 2004, Portugal's final energy consumption has been decreasing at a rate of 2.7% [17]. Portugal's final energy consumption can be separated into three main sectors: transports, domestic/commercial and industrial. Practically speaking, each of them account for one third of Portugal's final energy consumption. From primary energy supply, we can divide the energy sources that supply energy to be used in its final form into four main categories: natural gas, oil, coal and renewables (solar thermal and biomass).

For the purpose of this thesis, we focus in the electricity generation in Portugal and its role in leading Portugal to a more sustainable future. Although the electricity share was only 25% of final consumption in 2013, its share has been increasing (it was 20% in 2004) and it is expected to continue this trend [17].

2.3.1. Generation, consumption and GHG emissions

From the data previously reported, the work will focus in one of the most important energy vectors: electricity and electricity generation. The total installed capacity and its source is presented in Table 2. From the table, it can be seen that 57.8% of the installed capacity is renewable, which is a very high value comparing with the world average of 27.7% of renewables present in the capacity installed – mostly of it coming from hydro. This value is likely to rise in the future mainly due to the installation of more hydro power plants and to the decommission of the coal fired power plants by 2021 [19]. Portugal has a reserve margin of 1.26 – which means that it has 26% more installed capacity than the highest peak of load demand [18]. For example, in 2014 there was a peak demand of 8.3 GW during the month of January [1].

Table 2: Electricity capacity shares in Portugal 2013 [17]

Source	Total	Hydro	Wind	Coal	Gas	Fuel	Biomass	Solar	Geothermal
Capacity (MW)	**19622**	5535	4731	1871	4986	1453	718	299	29
%	**100**	28.2	24.1	9.5	25.4	3.6	3.6	1.5	0.14

However, due to the intermittence of renewables, it is frequent to rely on fossil fuels to balance demand and generation, given that electricity needs to be provided instantaneously, in case renewable generation drops. The fact that generation from some renewables is hard to predict is the one of the main challenges, since Portugal has had several hours running on 100% of renewable generation in conditions that allow it. This is also possible due to the very high capacity installed in Portugal of renewables.

In Figure 5, we can see the evolution of the generation of electricity in Portugal for the period 1973-2014. With a very high installed capacity of renewables, variability of the share of generated electricity by renewables is also high. For example: in 2012 Portugal had the biggest drought in the last 34 years, which resulted in the lowest generation of electricity coming from hydro. This shortage had to be compensated with fossil fuel generation. The graph also shows the increase of wind generation since 2003, and the solar energy uprising in 2010. In 2014, the generation of electricity was provided by: hydro (30%), wind (23.3%), coal (23%), natural gas (12.5%), biomass (6.4%), fuel (3.2%), solar (1%) and geothermal (0.6%).

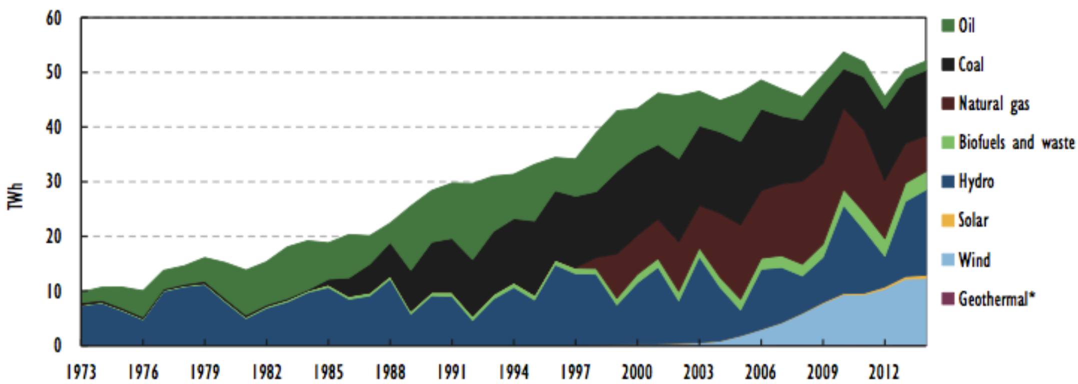

Figure 5: Generation of electricity in Portugal by source, from 1973 to 2013 [1]

Due to the grid interconnection totaling 3.2 GW, exchanges of electricity with Spain help to balance the system whenever it is needed. Portugal is in general a net importer of electricity from Spain with net imports of 0.9 TWh in 2014. This accounted for approximately 2% of domestic demand in that year [1], [20].

In terms of GHG emissions, specifically CO_2, the power generation sector is responsible for a big share of the overall emissions. In 2013 it emitted 15.8 Mtoe of CO_2 alone – 35.2% of the total emissions. However, overall emissions are on a downfall of 37.4% when comparing to 2005 numbers. In the European context, Portugal's emissions represents a rather low value (1.53%) when compared with countries such as Germany (share of 22% of emissions) [1]. With these numbers, and with the decommission of the heavy emitting coal power plants in the near future, Portugal is in a privileged position in the EU ETS – Emissions Trading System, where emission credits are bought and sold in order to comply with EU emission caps [12].

2.3.2. Electricity system and market design

There are several generation companies that provide electricity to the grid. These producers participate in the liberalized Iberian market (MIBEL) – mentioned in more detail bellow. The transmission system operator (TSO) – REN - is responsible for managing the grid and its demands, new infrastructure, and maintenance of substations and power lines.

In Portugal there are around 6.2 million consumers of electricity in low, medium, high and extremely high voltage. The consumption of electrical energy can be divided into 3 major activity sectors, as it can be seen in Figure 6. They have a consumption share of about a third each: industry has the highest consumption (35%), residential use 27% and commercial/services sector 30% [17]. This presents the need to study each sector independently for some reasons: each sector operates differently in terms of markets and technical specifications – industry works mainly with high or very high voltage, the commercial and services buildings with medium voltage, whereas the rest of the consumers operate mainly in low voltage.

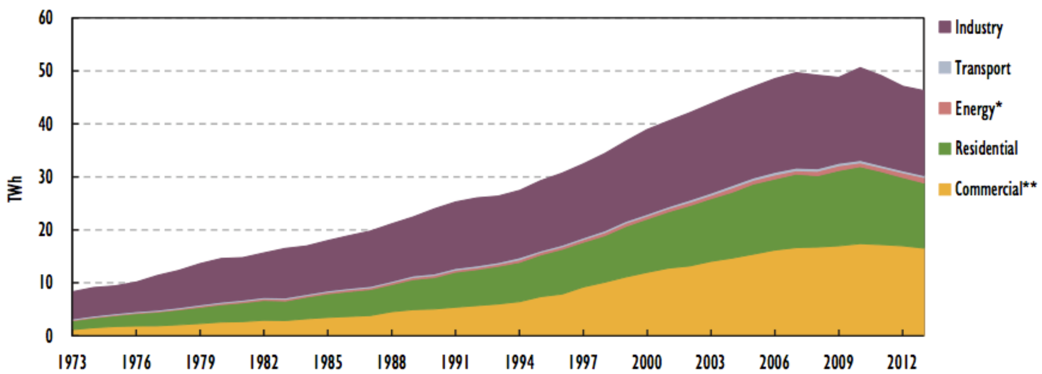

Figure 6: Electricity consumption in Portugal by sector [1]

The big industries and utilities operate and buy electricity in wholesale markets. In 2006 Portugal and Spain have integrated their electricity markets into a single Iberian wholesale electricity market, the MIBEL. They share a common spot market operator, OMIE, and a forward market operator, OMIP. OMIE has been operating in both countries since July 2007 and it is the Spanish part of the markets and OMIP, launched in July 2006, is the Portuguese regulated part. Since the foundation of the MIBEL, the percentage of time that the market is coupled – this means that traded prices are the same in both countries – has been increasing, and in 2015 reached 97.6% of the time, for the OMIE's daily market. The benefits of having an integrated market, especially with a high percentage of coupled market time range from higher integration of available renewable generation, prices according to marginal cost of each technology and reduction of load shedding [21], [22].

For the remainder of the consumers, electricity can be bought in the retail market. Portugal started in 2000 the liberalization process for both natural gas and electricity retail markets. Since the beginning of this process, the majority of the consumers have joined: 4,45 million out of 6 million consumers. The free market consumers represent today 90% of the total consumption[2]. This is an important matter concerning demand response, as it may promote market entry of new companies in the supplier level, which can lead to the increase of competitiveness, shrinking profit margins and increasing social welfare [1], [15].

2.3.3. Policies and future planning

Despite having a high share of renewable capacity and generation, and a privileged position in the EU ETS, decreasing the energetic dependency is one of the biggest targets of the present Portuguese energy policy. It is, however, one of its largest challenges as well. As previously stated, the Portuguese high dependency comes from the almost inexistence of fossil resources in Portugal, and the necessity to import these from abroad, like coal, natural gas and oil. For electricity generation, Portugal relies almost 45% of its generation on fossil fuels [17].

Following the National Renewable Energy Action Plan (PNAER) in 2007, Portugal started to develop pilot projects to promote renewable energy generation, such as wave energy and large solar photovoltaic (PV) power plants. In 2011 the PNAEE (National Energy Efficiency Action Plan) was presented to the EC, and it raised energy efficiency to top priority in energy policy [1].

Also, in 2010, Portugal set out a National Energy Strategy for 2020 (ENE 2020), that was based on five priorities: increase competitiveness, growth and independence both financial and energetic; more support and subsidies for renewable energy; the promotion of higher energy efficiencies; the set out of clear strategies for promotion of economic and environmental sustainability [1].

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[2] http://www.erse.pt

Portugal seems well set for the EU 2020 targets and with large chances of even surpassing these. Portugal can even capitalize this by using the EU-ETS (European Union Emission Trading Scheme) for its own benefit, helping other state members achieving their emission goals, taking advantage of generation surpluses of renewables [1].

2.3.4. Demand side strategies in Portugal

Demand side strategies have been present in Portugal mainly in the wholesale market. Here, the main industries have contracts that provide the supplier with the power to curtail the supply of energy, thus preventing power outages for the rest of the costumers. These are also known as interruptible contracts [21].

In the retail markets, this topic is still in the early beginnings. The Portuguese smart meter cost and benefit analysis required by the EC produced dubious results, which led the distribution system operator (DSO) not to pursue nationwide rollout [23]. Despite, the Portuguese company *EDP Distribuição* led a pilot project for the transition to a smarter distribution grid, called *InovGrid* project, developing and implementing smart grid concepts and technology. An important element of InovGrid has been the rollout of smart grid infrastructure in the Portuguese municipality of Évora, in 2011. The infrastructure spans to the entire municipality, reaching around 32000 electricity customers. The Évora experiment showed many of the benefits of smart grids, such as average savings of 4% in electricity consumption for households [1]. These results have enabled EDP, with the support of the Portuguese Government, to expand the deployment of 100 000 smart meters to consumers throughout the country, with the main objective of developing the supply chain, prepare for a countrywide rollout and understand new business models related to smart grids.

Demand side strategies require incentives to be effective. The liberalization of the retail market produced minor changes, but for a well-integrated smart grid system, a lot has to be done. This study is then necessary to understand the impact these strategies can have in the Portuguese reality.

2.3.5. Demand Response modelling needs

The Portuguese electricity system nowadays already absorbs a high share of renewable capacity. With the steadily increasing trend of decreased cost on technologies such as onshore wind and solar PV, and Portugal having high potentials for such renewables and more – due to its long cost line, Portugal has also big potential for wave energy and offshore wind deployment – it becomes necessary to analyse strategies that help us design a system with higher share of renewable technologies [24], [25].

The main issue arises with the intermittency of generation from renewable sources. This generation is not always aligned with consumption. Therefore all the technologies that can provide us with flexibility from the demand or generation are key to balance both ends of the system. Demand Response can provide such flexibility from the demand side [26].

It is important to understand up to what extent DR can help exploit the maximum potential of the renewable capacity. For this purpose, studies need to be performed, first in short-term models to analyse DR real potential and also in long-term models to understand what impact its potential has [5], [27].

3. Literature review

3.1. Energy modelling and tools

When modelling energy systems, one can choose from two main approaches: bottom-up and top-down. These two have been present in energy modelling since the 1950s, when the first macroeconomic studies appeared. However, techno economic studies only started after the oil crisis in 1973. Macroeconomic studies can be associated with a top-down approach and more technical studies with bottom-up, but during the last research period hybrid models have been developed to harmonize the advantages of both approaches and also to try and mitigate their flaws [28].

In summary:

- Bottom-up models: usually technological-detailed studies, mostly developed by engineers, scientists and companies to asses and plan energy capacity expansions;
- Top-down models: usually macroeconomic studies, mostly developed and used by economists and public administrations, with the main focus on economic and monetary policies, as well as social welfare

In the top-down approach there are four types of models: input-output models, econometric models, computable general equilibrium models and system dynamics. These models generally do not assess issues like energy efficiency gaps, technological details and other obstacles, but are used as a macroeconomic tool, for example, to give forecasts of price elasticity of a good, or rate of return of a certain investment.

Bottom-up models are divided into four categories: partial-equilibrium, optimization, multi-agent and simulation models. Bottom-up approaches have the characteristic to be input data intensive. The data includes detailed information in terms of technologies, forecasts of demand and supply maps, as well as the systems overall cost and weather related data – more related to the renewable energy generation, for example. This can be a challenge, since analysts have to rely on data availability in order to achieve reliable results [28].

Given the technical nature of this thesis, and with the focus being more on energy planning than on economical forecasts, bottom-up approach models seem more relevant due to its detailed nature. Thus, a closer look directly related with energy needs is to be taken. However, the study was done based on a hybrid approach, since the standard demand was approached more from a top-down perspective and the flexible demand (that is suitable for DR) was taken care to a more detailed level – using a bottom-up approach.

A big part of energy models are optimization models. Therefore, the review will focus more on such models, their characteristics and challenges. In general, optimization energy models use energy demand and supply as drivers to choose the best set of technologies and parameters to achieve the least cost scenario for the modelled period to achieve equilibrium [29], [30].

3.1.1. Optimization models

Energy modelling tools are diverse and broadly used in today's planning. In [31], 37 tools are reviewed and discussed based on their characteristics. Table 3 presents a small selection of tools – retrieved from the same review – that were chosen due to some key characteristics. Due to its individual importance and relevance TIMES and MESSAGE models are present in the table. Also present in the table is the PRIMES model, which is used by institutions such as the European Commission (EC). Moreover, REMix was previously used for DR studies and an open-source modelling tool such as OSeMOSYS, were also chosen. Below the table, a brief explanation is given for each model presented.

Table 3: Energy models and its characteristics

Model	Author	Applications, Studies	Main Challenges
TIMES	IEA	Energy planning and alternative scenarios testing; [32]	License cost
MESSAGE	IIASA	Medium to long-term energy planning and policy analysis; [33]	Complexity for beginners
OSeMOSYS	DESA (KTH)	Long term Energy planning; [27], [34]	Initial development
REMix	DRL	GIS (Geographic information system) integrated model for energy planning; [5], [35]	Complexity for beginners
PRIMES	NTUA	Price and cost projections, Policy recommendations; [36]	Code not available

The TIMES (The Integrated MARKAL-EFOM System) [30] is an economic model generator for energy systems. It is inspired in two bottom-up approach models: the MARKAL [37] and EFOM [38] models. Developed by the IEA, takes as inputs components from technologic, demand, supply and political origin and calculates the least overall cost to achieve the point of equilibrium. Due to a long list of present and future technologies, it is useful to study different alternatives to business as usual scenarios. TIMES is used for country wide models, such as Portugal [32]. This study is approached in the next sub-section.

MESSAGE was developed by IIASA, and hosts 11 regions with the possibility to compute the evolution of the energy sector up to 2100 [39]. It is an engineering optimization model used for medium to long-term energy systems planning. Other applications are also policy analysis and GHG studies. In the studies related to the GHG, it is used MAGICC (Model for Greenhouse gas Induced Climate Change) [39]. In 2010, a study used MESSAGE to analyse the future possibilities for energy resources in Syria [33].

OSeMOSYS is an open source software developed by dESA, at the Royal Institute of Technology - KTH [29]. It is a demand driven optimization-modelling software, which calculates the least cost for the equilibrium point of the energy system. A comprehensive description of the software is presented in Chapter 3. A study of sub-Saharan African was done, comprising 45 individually modelled countries in a model called TEMBA (The Electricity Model Base for Africa) [34].

REMix model was developed by DRL Institute of Engineering Thermodynamics [40]. It is a set of two main tools: a tool for data analysis like demand called REMix EnDAT and an optimization part that computes the least cost for the equilibrium called REMix-OptiMO. The optimization model is formulated in the programming language GAMS, and for beginners the learning curve is a big challenge. A model of Europe was devolved to assess the future potential of demand response deployment throughout the industrial, commercial and residential sectors [5].

The PRIMES model, developed by the National Technical University of Athens in 1993, focus mainly on market mechanism and prices influencing the demand and supply, as well as technology development [41]. The model can be classified as a hybrid, comprising modular engineering technologies and specifications, but also having a big economic component to be able to project the prices and costs. The model is used for some policy recommendation reports, such as for the European Commission [36].

3.1.2. Portuguese energy models

Since a Portuguese model is to be developed in this work, it is important to have an idea of models that have been developed and used in the past, and which assumptions they used.

In [32], the TIMES_PT energy model is used with a time span up to 2050 to study emission costs. The demand was split into 5 sectors, and these split into several sub-sectors. For industries, services and agriculture it is used a top-down approach, and for buildings and transports a bottom-up approach. The model was then used to calculate the marginal abatement costs (MAC) of CO_2 in Portugal, concluding that the ban on nuclear power increases MAC in 2 to 3% of the Portuguese Gross Domestic Product (GDP).

The TIMES_PT model was used also to assess the impact of climate change in the electricity generation from hydro power plants. As Portugal has a high percentage of hydro capacity in its system, the variation of its electricity generation in terms of the uncertainty related to climate change is valuable to allow policy makers to account for these impacts [42].

In [43], the authors used TIMES software to study de-carbonization pathways for the Portuguese system in 2050, analysing the influence that the interconnection with Spain had in the results, and how considering Portugal as an island contributed to a loss of effectiveness in renewable installation and electricity dispatch. The model considers Carbon Capture and Storage (CCS) technology, however it also allows conventional coal power plants to generate electricity after 2021 (which is the projected year of the de-commissioning of the remainder coal capacity installed in Portugal).

Also using TIMES, in [44] was studied how the carbon tax evolution can influence the choices of the installed capacity sources in the Portuguese electric system. Like the previous study mentioned, coal capacity is also present until the end of the model period and the hydro potential is projected too optimistically when compared with the data from DGEG (more than 9.8 GW of hydro capacity).

Scholz's Europe model using REMix also includes Portugal. Using a geographical information system for the location of power plants and transmission lines, the study focuses in the potential of lowering costs of renewable energy dispatch [35].

3.2. Smart grids

Following the International Energy Agency (IEA) definition, smart grids are a new design of the electric grid that follows and provides the grid users - with energy needs such as generators, operators, consumers - with increased efficiency, system reliability and minimized overall system costs [45].

Smart meters can really have a big role to play, as they open a space for technology to evolve, especially in fields such as energy efficiency and demand side management. In addition, it can provide load segmentation per household and help consumers find a financially better option to choose their retailer. Smart metering, together with enabling technologies are going to contribute a fair share to lead the way for smart grids, as it is already happening in the UK [46].

Smart grids will also trigger the integration of electric vehicles (EV) - both battery-driven (BEV) and plug-in-hybrid (PHEV) – in the electrical grid, as both technologies can help to reduce the mismatch between demand and supply, fostering demand response, by providing a storage option in periods when the generation exceeds the demand. Fattori et al. show that photovoltaic capacity is only able to cover part of transportation demand related to EV's charging when uncontrolled charging operates, increasing even more the peak load of the common load profile. However, when using strategies such as smart charging and *vehicle to grid*, the load profile flattens and relevant load flexibility occurs [47].

3.2.1. Demand side Management

Since 1994, the US Department of Energy compiled a report on demand side management activities within the country. All the reports until 2004 – year of the last of these - start with their definition of DSM:

"Demand-side management (DSM) programs consist on the planning, implementing, and monitoring activities of electric utilities which are designed to encourage consumers to modify their level and pattern of electricity usage." [48]

In 1994, Boivin addressed demand-side-management potential in France, in a paper for the EDF (*Electricite De France*). This paper is related to automation in low-voltage end consumption, like residential buildings [49]. This matter is being brought back to the smart-grid agenda, and some examples may be seen in the Swedish island of Gotland [50]. However, automation is present in other sectors and it is likely to be widespread across all the energy supply, since it's so efficient [51].

Pina et al. conclude that demand side strategies, with its different natures and origins, are key to achieve the sustainability of any region, even more where a high penetration of renewable generation is considered. Therefore, the future power systems need to consider a big part of its design on these strategies [52].

In Figure 7, one can see the wide system fostered by DSM. Demand response and energy efficiency provide strategies to improve the way electricity is consumed. Energy efficiency is a complex part of DSM with several applications and is also viewed by policy makers as a priority for short to long term targets [3].

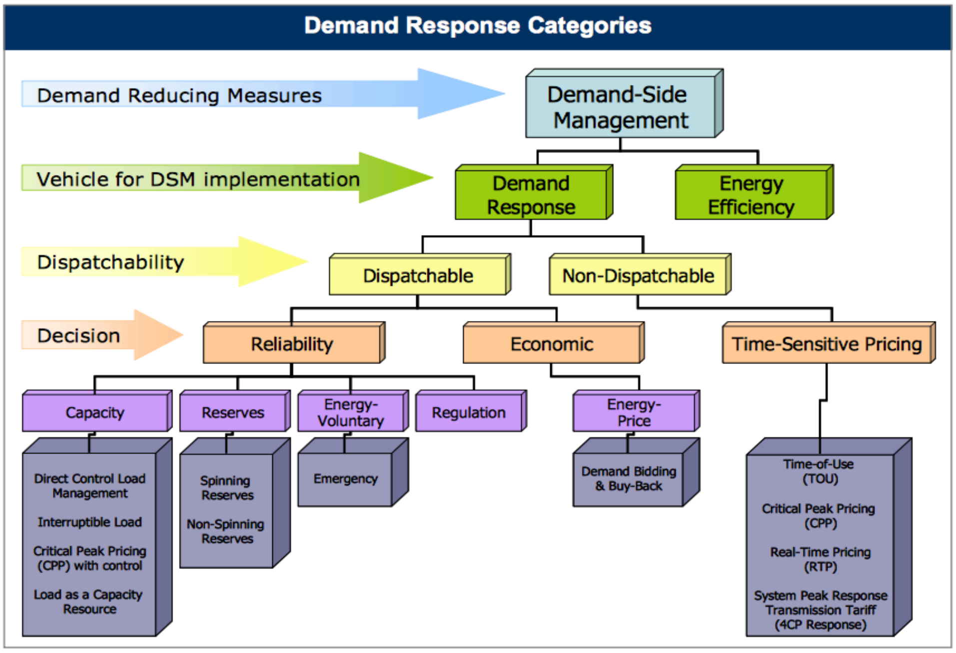

Figure 7: DSM categories [4]

An explanatory section of the services provided by demand response, as seen in Figure 7 is presented within the section related to demand response specifically. As this work focus mainly on demand response, energy efficiency will not be addressed in an extensive way.

3.2.2. Demand response

Since the California energy crisis in 2004, demand response has been present in the US discussion of energy planning. In 2005, the US energy policy act strongly encouraged: "time-based pricing and other forms of demand response" [53]. One year later, the European Network of Transmission System Operators for Electricity (ENTSOE) issued an explanatory document on demand side management and the definition of demand-response can be derived from it:

"Demand response (DR) is a voluntary temporary adjustment of power demand taken by the end- user as a response to a price signal (market price or tariffs) or taken by a counter-party based on an agreement with the end-user. DR during a short-term time (hours) has an impact on the system power balance and can be seen as economical optimization of the electricity demand rather than energy saving. DR during a longer period will also affect the energy balance in the power system and may also result in saving of energy." - [54]

The technical nature of demand response is derived from smart grid technologies. In Figure 8, the different strategies that demand response can use are explained graphically using a comparison between two profiles – a standard profile with a peak and a profile optimized with DR. The valley filling strategy uses as principle the increased usage of the installed capacity that is ready to generate electricity during most parts of the day in order to keep the balance of generation. Peak shaving decreases the need for offline capacity that is ready for dispatch, in a result of a decreased peak. Finally, load shifting uses a combination of the first two strategies [55].

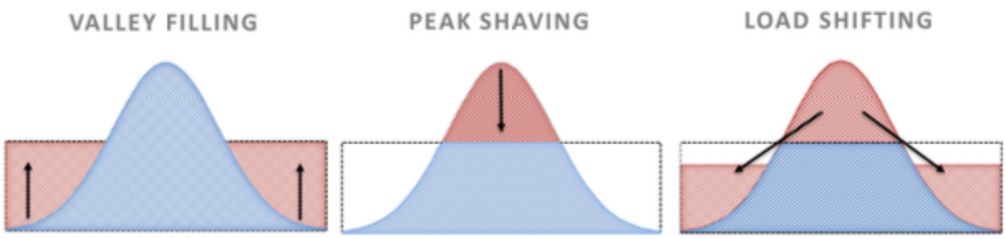

Figure 8: Demand response strategies [55]

Demand response implementation is not a linear and easy process, despite its potential. In order to change multiple routines of the system and of the organizations, first is necessary to deepen and validate this untapped potential. Concerning the technical aspects of DR, most studies presented in the literature, frequently focus on indicators to show the potential of this tool. These indicators are mostly: reduction of peak load, amount of load shed, the flexibility of the load curve, energy savings and monetary benefits. Thus, it is important to analyze these studies in different sections, dividing them on their main focus: pricing schemes, European wide studies or single country studies with segmented sectors of activity.

Demand response programs

As can be derived from the definition of DR, without variant tariffs or price signals, demand response may be hard to implement. As Strbac states: "*It is widely accepted that some form of real-time pricing arrangements are required to efficiently allocate DSM resources and fully inform users about the value of electricity at each point in time and location*" [14].

These incentives or tariffs are designed to best suit the type of costumers that they are aimed at. In order to understand the indicators and results in several studies is important that these incentives are well explained. As Figure 7 shows in the previous section, demand response can be dispatchable and non-dispatchable. Dispatchable demand response is related to incentive base programs and contracts - or also called capacity services. Non-dispatchable demand response is related to price-based programs.

In capacity services, mainly used by energy intensive costumers (typically industry), the most common types of contracts are direct control load management and interruptible load contracts. Direct control load management is a type of contracts that allow the supplier to directly control the load demand of the costumer through the power of switching on and off appliances individually. Interruptible contracts also operate with control from the supplier - however it has the power to stop the supply of energy for the whole load demanded from each costumer. Costumers are more likely to choose these types of contracts when they can change to an independent generator at the interruptible periods.

For costumers that operate with low energy intensities (residential and tertiary), dynamic tariffs are more common. Figure 9 explains the three more important types of contracts. Time sensitive pricing or price-based tariffs are related to some form of dynamic pricing, whether it is real time pricing (RTP), time-of-use (ToU), critical peak pricing (CPP), and rely on consumer responsiveness and behavior.

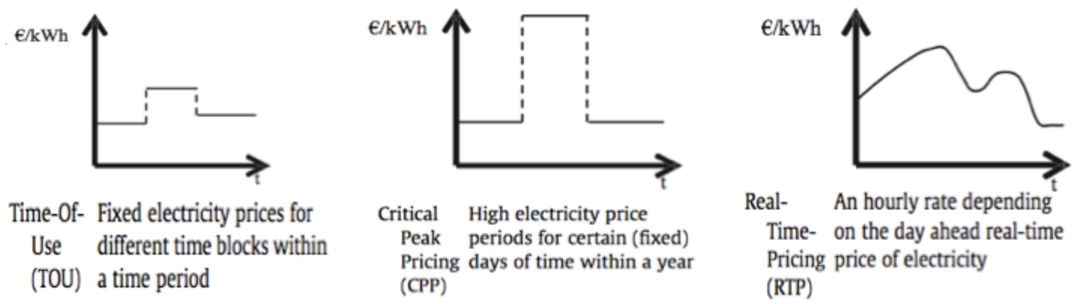

Figure 9: Types of time-sensitive pricing for DR [56]

Countless studies on this matter have been performed: Eid *et al.* give a brief and clear explanation of the several different tariffs; these tariffs can be combined in order to achieve better results [57], or they can be used as a single tariff with multiple results in different regions [58], [59]. Others studies support the idea that tariffs can be implemented at different stages of the societal appropriation of demand response [60].

European studies

In a study of the potential of DR in Europe, results show that aggregating all the hourly average load reduction potential adds up to 93 GW over all countries and consumers. It also shows that the potential load reduction to annual peak load to be between 7 to 26%. Using load shedding, delaying and advancing, depending on the utility and activity, these results are reached [5].

To assess the economic potential of DR in Germany, a methodology in a deterministic linear optimization program (REMix) was developed by the same author, Gils. The study divided the country in regions and used a set of equations to model how demand response mechanisms can help balance the load curve, which can lead to replace up to 5 MW in generation. Gils identifies different types of loads – loads that can be shifted, shaded and balanced – its associated costs, and tests its impact through several different scenarios [61].

In France, EDF developed a pilot program, marking days with colors (white and red) and separating off and on-peak hours. The pilot included small businesses and households, and resulted in a reduction in consumption of 15% on normal (white) days and of 45% on peak (red) days using different price signals for both, which led to 10% savings in the electricity bill [16].

In Spain, the “Optiges” project estimated that for each MW of load reduced during peak load, more than 500,000 € would be saved on the generation and transmission system [62]. However, Conchado et al. conclude that a household DR program on the Spanish generation and transmission system will not have significant benefits to be engaged. The benefits accounted for 0.5% of the electricity bill per household. The small benefits shown make it legit to question the social effectiveness of such programs [63].

In Portugal, it is already possible to choose the tariff of ToU that suits best the needs of each client. Either simple, two-times tariffs or three-times tariffs, being the day divided in one, two or three periods and each period assigned a price in the consumption of electricity [64]. However, no information is provided in the monthly bill presented to the costumer, and no description is present on when the electricity was consumed or from which sources it came from in what periods.

3.2.3. Segmented sector studies

Residential sector

One of the big challenges when talking about demand response in the residential sector is that the predictability of the load curve is low and therefore is difficult to control the amount of load available to shift from peak to valley periods. This challenge is being treated and studied: [65] studies single-occupied households and their consumption patterns throughout the day, and the concept of NIALM (Non-intrusive Appliance Load Monitoring) can be an important tool for reliable household load curve prediction. A brief introduction to NIALM and some methods used for this purpose can be found in [66].

In [67], the authors, who also mention NIALM, focus on incentive-based DR to study interruptible loads in Ireland – a system with high penetration of wind generation, like Portugal. Interruptible loads are often related to thermal inertia or storage, like refrigeration and space heating and cooling. The paper is useful, given the methodology for simulating household loads in 15-minute intervals using 10 different characteristic load curves to simulate household consumption. This methodology – following a bottom-up approach - divides the loads in 3 groups: interruptible, deferrable and reducible. As the study focuses more on direct load control, interruptible loads are highlighted. They conclude that an average of 182 MW of interruptible loads can be achieved, with minimum values of 75 MW during periods with extreme weather conditions.

In Europe, Albania is identified to have the highest share in reducible load potential in the residential sector (62%). In terms of segmenting loads per appliance, refrigerators/freezers for households show the highest rate of flexible loads (17%), through both delay and advance [5].

Price-based DR – ToU (time-of-use), CPP (critical peak pricing), RTP (real time pricing) - is expected to be more effective in the residential sector. The individual household characteristic load curve is heavily unpredictable and does not follow any rule except for the will of the consumer. Therefore, the consumer can change his habits by setting a specific time of day for the use of his appliances (ToU), or he can choose to receive signals on the change in electricity prices from his supplier or aggregator. A study done in Northern-Italy considered ToU for residential uses, and concluded that these tariffs might not be the perfect choice, as it resulted in an increased consumption while decreasing electricity bills. Nevertheless, the objective of relieving the system of its peak production was not reached. The study also states that time-based tariffs that fluctuate more with the marginal cost of electricity production might be more successful [59].

A study was done to optimize the electricity dispatch in a case study from a Portuguese island Corvo, Azores. DR is used to optimize the electric backup of domestic hot water equipment, reducing the consumption needs, and the electricity dispatch costs. Through the installation of solar thermal systems and heat pumps, and combining the island grid with DR, Corvo is able to be more energy autonomous [68].

Industrial sector

Gils relates the energy intensity of the industry of a country and the overall flexible load per inhabitant, as indicators for a successful implementation of DR. The number of energy intensive industries present in a certain country is directly related to the potential of its DR deployment, reaching 69% of load reduction in Luxemburg. Energy intensive industries, such as steel (9% of total load reduction), pulp and paper (7%) and cement industries (6%) have the biggest share in the overall load reduction potential [5].

In [69], it is explained the concept of LTDR (Long-term demand response), which relates to loads that can be shifted along period of days or weeks. One type of demand that can provide this service is a manufacturing industry. In the scenarios presented, LTDR implementation reached relevant figures when the percentage of penetration of renewables tended to 100. LTDR represented a reduction in installed capacity due to the reduction of peak demand.

The industry sector was the first to have access to some kind of DR programs, such as ancillary services, curtailment and direct load control. These can be classified as incentive-based demand response programs. In Portugal, ancillary services exist since 1994, and the main purpose is to control the systems frequency by the TSO. It is estimated that 0.5% of the end-user price is to subsidize these programs. These services are agreed by a contract that provides energy intensive industrial facilities incentives to stop production whenever the system is likely to expect a shortage in energy supply. However, Portugal has a safety margin that allowed these services never to be used in the last 15 years, and therefore no new innovations are expected to come in the future [70].

Since energy intensive industries have high rates of flexible loads, in [51] a summary of the studies made on this matter is presented. Several of the mentioned studies target tariffs and prices, and their impact on electricity markets. However, the survey also points several regulatory barriers, such as lack of risk analysis when demand management systems are implemented in industries - which can be a big issue preventing even more utilities to join these programs.

Commercial sector

For the commercial sector, it is common to have peak-load management programs. This is more related to the high use of air-conditioning, refrigeration and lighting [14].

From the study of [5], Ireland is the country that shows highest rate of flexible loads (45%), being the main contributors the commercial ventilation (15%) and the refrigeration systems used in retail businesses.

The “Optiges” project paper states that this is the most promising area for demand response action, with hotels, office buildings, large supermarkets and restaurants among the ones with highest interest due to heavy need of lighting and HVAC [62].

The authors in [71] state that commercial buildings are key to scale up relevant demand response in the energy system, however they point out the lack of economic benefits as a barrier for further developments. It refers to IDR (integrated demand response), which is being under serious research in the US, and how the prices and demand signals can be exchanged with the utility for several applications such as curtailment load calculations and demand profiles forecasting.

From the information gathered, it is fair to say that dynamic tariffs DR programs are more likely to be successful for the application to the commercial sector. It is more likely for businesses to plan their consumption than to respond to price signal for immediate flexibility.

3.2.4. Barriers

The social effectiveness of DR programs is also another big issue. Not only economically speaking, it relates directly with social behavior and societal appropriation of new day-to-day routines for the consumers.

On this matter, Jullien & Serkine count five important barriers for end-user empowerment: informational, technical, structural, economic and acceptance [72]. These barriers have to be tackled if a smooth and effective societal appropriation is to take place. In what the consumers are concerned: response fatigue, lack of incentives and time consuming DR events can lead to the rise of businesses such as aggregators, that can decide when to participate in DR events instead of the consumers. This can stretch further the DR participation to the fullest [60].

A study in Australia shows that households with children in the family have almost no flexibility of participating in DR events and ToU proved ineffective. This is linked to their highly organized routine concerning activities based on children care [73].

In [26], the report provides an extensive and dense review of the state of the art in demand response. Also focusing in economic aspects up to some extent, the paper talks about inexperience and extensive assumptions used for DR potential evaluation. Another topic is regulation barriers, which can diminish DR potential. The work of the SEDC can also be referred in this matter, appointing a lot of regulation barriers concerning DR, in each assessed country [74]. These barriers relate with market entry and bureaucracy related to the creation of new businesses such as aggregators.

Also, Kirby has a FAQ article that can be useful for newcomers to understand some principles of this new way of thinking about electricity systems, concerning types of demand response, prices and tariffs, amount of loads potentially reduced and so forth [75].

3.2.5. Demand response in long-term energy planning

The work presented in this thesis is based on long-term energy planning for a specific area, which in this case is the country of Portugal. The relevant feature of this thesis is the introduction of DSM strategies – more specifically DR - to assess the impact it has on the planning of capacity for said area. Given that this part is relevant to the development of the study, a special look was given to two studies - [27], [61]. Both studies are enhancements of existing software (OSeMOSYS and REMix) that focus on the modelling part of DR and its implementation. Thus, they are of key importance for the review and for the study itself.

In [27], a set of equations are proposed to enhance OSeMOSYS to better simulate smart grid technologies – such as DR. The software was developed in blocks, so its integration is made easier. Each set of equations presented in the study constitutes a block for OSeMOSYS integration. They include demand response strategies comprising the following: storage, variability in generation, prioritization of demand types and demand shifting. It is relevant to point out that the first two are already in place on the current version of OSeMOSYS. Focusing more in the last two blocks – that are assessed in a case study in [76] – to understand how the implementation can be achieved, both need to be explained:

- The prioritization of demand types scales the demand types in terms of priority, or importance - for a potential case where demand cannot be met, only the least important loads are left unmet- and all the costs associated with it. This is particularly important when prioritizing emergency services and other important institutions in a potential power outage. The block also allows for some demand to remain unmet when the cost of meeting it is higher than a pre-defined value;
- The demand shifting is better explained when considering the need of shifting and decoupling some demand when a peak of demand is occurring but not a peak in production – mostly due to renewable intermittence. This feature, that is the principle underlying demand response, is to use ultimately some demand types as storage that can be met during off-peak times, such as thermal inertia in air conditioners and heat pumps. The way it is implemented in OSeMOSYS follows the software's nomenclature and time approach.

All the algebraic formulation of the equations is presented in the study, further applying it to a case study of a fictitious town, with a given energy system.

In [61], the software used is the REMix optimization program. A study of the economic potential of demand response in Germany is presented for a time-span horizon until 2050. A big difference of REMix in comparison with OSeMOSYS is the hourly system operation, which is a big advantage for DR assessment. In addition, the modelling in this study uses regions and the interconnection between them instead of the country as a whole.

For the implementation of DR, some measures are included such as load shedding and demand shifting. The hourly definition really helps on the DR implementation, as several of the inputs of the program are sets of hourly data also comprising flexibility of loads. All the economic costs of implementation are taken into account as well.

As in the study considered above, the flexibility of demand is modelled as storage, which is linked with a specific duration of flexibility - from 1 up to 4 hours - and availability throughout the day. The input of the data related to each load is the flexible time and the cost of shifting demand, and the optimization program decides whether the load is met in advance or by delaying the electricity supply. However, the model sets a limit for a number of DR events and its duration.

Some differences arise from the analysis of [27] and [61]:

- An hourly definition is present in the second study compared with a time-slice definition from the first analyzed study;

- A number of DR events is limited in the second study, whereas as in the first study it assumes a continuous shape through time-slices and years;
- In the first study, there is not a flexibility duration associated with the loads but a prioritization of demands that serves as a tool to scale which loads should be shifted.

These two studies provide important and relevant tools for a framework of DR incorporation in long-term energy modelling. However, all the relevant equations are presented in the next sections and especially in Section 4. The challenge of this work is to try to capture the advantages of both approaches and combine them for a better, reliable and more realistic simulation.

4. Energy Modelling: Methodology

4.1. Creating an energy model on OSeMOSYS

The Open Source Energy Modelling System (OSeMOSYS), developed by KTH and several other stakeholders, is an open source software that gives us tools to optimize long-term energy planning. Using a bottom-up approach, it can optimize models for medium and long-term analysis. It assumes perfect market structures to reach the least general cost of the supply-demand equilibrium.

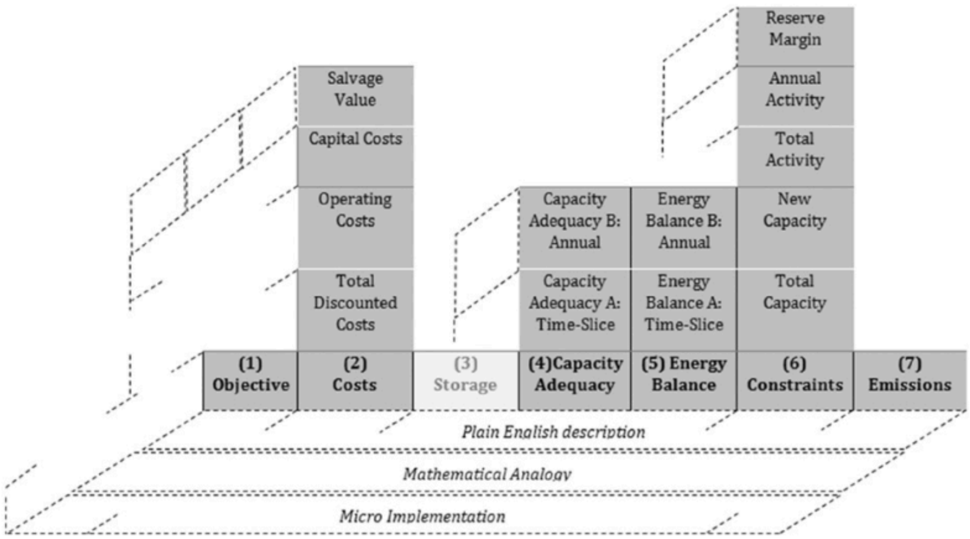

Figure 10: OSeMOSYS structure [29]

As observed in Figure 10, OSeMOSYS is a software built with different blocks. Each block represents a given feature of an energy system to be modelled. It is built in a way that facilitates the integration of new blocks, and also the improvement of existing ones [29]. The document [77] gives us a comprehensive beginner manual of how to better handle all the parameters and sets, as well as software related nomenclature.

For better clarity and understanding, it is important to explain important concepts concerning the software usage. The next sections explain the basic methodology to build a model in OSeMOSYS, all the assumptions that need to be accounted for, as well as the inputs that need to be gathered.

The inputs of OSeMOSYS are divided in sets and parameters. The sets are related to the structure of the model, and to how big and complex the model is. The parameters are the detailed inputs that will shape each model's characteristics and that fill the nodes of the grid displayed by the sets.

4.1.1. Objective function and units

The objective function – block 1 of Figure 10 - that is to be used for the optimization is the total cost of the system. This pure economic view is a tool to simulate what drives growth and investment in the real world. Equation 1 presents the objective function used:

$$\min \sum (DiscountedOperatingCost + DiscountedCapitalInvestment + DiscountedEmissionsPenalty + DiscountedSalvageValue) \quad (1)$$

The sum of the discounted costs of all the variables is computed to be the least of the possibilities. Operating costs relate to the variable and fixed costs of technologies. Capital investment costs are the costs associated with new investment in technologies. Emissions penalty costs are the costs that come from emitting particles subjected to any form of penalty. Salvage value is the market value in monetary units of the technology in any given year, related to the operational life and the size of the technology.

OSeMOSYS is an optimization software. Therefore, it does not deal directly with units, but with numbers. It is up to the user to choose the units. Thus, it is presented in the table below the units that were used in this thesis.

Table 4: Units of OSeMOSYS

Parameter	Capacity	Energy	Costs	Emissions	Emissions Penalty	Variable Costs
Units	GW	PJ	MUS$/GW	Mton	MUS$/Mton	MUS$/PJ

4.1.2. Sets

The sets are the main drivers of the energy modelling in OSeMOSYS. Each set is the assigned input value in the form of parameters, which will be defined bellow. The sets that should be defined are the following: Regions, Technologies, Fuel, Emissions, Time-slices, DayType, Year, Season, DailyTimeBracket, Mode of operation and Storage.

Fuels and technologies

An energy system is a structure of fuels and technologies that together make the reference energy system. In OSeMOSYS, technologies are defined as energy transformation units. *Technologies* can be of imports of fuel, extraction, production, imports and exports of energy, transmission and distribution. *Fuels* can also be looked at as energy carriers.

The technologies transform fuels in different types of energy. For example, the fuel Natural Gas is imported by an importation technology, and then it is transformed by a generation technology (power plant) to electricity, that becomes our new fuel. After that, this transformed fuel is then transmitted by a transmission technology, and consequently distributed to the desired location by another distribution technology.

Time resolution

The set *Year* defines the model period.

The concept of *TimeSlice* is important to understand how the model works. Time-slices are the periods of the year that are being studied and for which OSeMOSYS does the calculations. The time-slice may refer to the night period of a weekday, or a whole day during the summer – it is up to the analyst. This imposes a consequence that OSeMOSYS does not deal with chronological events, but with time-slices. It can be set up, for example, six time-slices per year that refer to all the nights and days during winter, summer and an intermediary season, with no distinction between weekdays and weekend days. The demand is given to the software per time-slice, so that it can calculate the capacity needed for each time-slice in order to meet that demand. Time-slices are related to the other sets by the formula given bellow:

$$Number\ of\ Timeslices = Seasons * DayTypes * DailyTimeBrackets \tag{2}$$

Season is a set that allows the user to define different types of seasons or months.

DayType is a set that defines the types of days the model is considering. For example, if the user wants to divide weekdays and weekend days, this is where it should be defined.

DailyTimeBracket defines the number of parts each day is to be defined. For example, if a day is divided in night and day, this set is given the value 2.

4.1.3. Parameters

Demand

Demand parameters can be defined by time-slice or annually. Annual demand, that does not require a specific time to be met, can be defined as *AccumulatedAnnualDemand,* given in units of energy per year. The demand that is specifically dependent of time needs two parameters: *SpecifiedAnnualStandardDemand,* given in units of energy per year and *SpecifiedAnnualStandardDemandProfile,* that defines the fraction of fuel demanded for each time-slice. The sum of all *SpecifiedDemandProfile* values per year for each fuel has to sum up to one.

Supply

Capacity factor, Availability factor and efficiency

The concept of *CapacityFactor* in OSeMOSYS is different from what it usually means when characterizing normal power plants. Here, capacity factor is a way to simulate the fraction of availability of a given technology for each time-slice. It can, for example, simulate the inactivity of solar PV's during the night. As it is time-slice dependent, it can also be used as a tool to simulate low hydro availability during the summer, or higher wind speed during winter. OSeMOSYS has also a parameter called *AvailabilityFactor* that refers to the time of which, during a year, a power plant is ready to generate electricity. In this way it is possible to simulate maintenance periods. In terms of efficiency, OSeMOSYS has two parameters to model this feature: *InputActivityRatio* and *OutputActivityRatio.* The former is defined as the number of units that a power plant has to be given of a certain fuel to generate one unit of energy, and the latter is defined as the number of energy units of output that are given by one unit of fuel. It is normal to define the *InputActivityRatio* as the fraction of the efficiency – one over the efficiency – and to define the *OutputActivityRatio* as one when modelling power plant efficiency.

Residual Capacity

Residual capacity is the total installed capacity present in a country or region. It is defined by year and technology. There are also *TotalMaxCapacity* and *TotalMinCapacity,* which are parameters that allow us to define if a power plant is to be constructed in the future, or to constrain the installation of more capacity of a certain technology, due to exploited maximum potential. If monetary constraints are to be take into account, the parameter *TotalMaxCapacityInvestment* and *TotalMinCapacityInvestment* can be used. These parameters work in a similar way as the ones previously mentioned, but the units of limitation are monetary units.

Costs

Costs are divided in *CapitalCost*, *FixedCost* and *VariableCost.* The first two are costs per units of installed capacity, while the third is given in costs by unit of energy of output.

Emissions

Emissions in OSeMOSYS can be defined for GHG emissions – normally CO_2 or NO_x. It is defined as *EmissionActivityRatio,* and it is given by emissions per unit of output of energy. Emissions can be restrained by annual emissions (*AnnualEmissionLimit*) and limited for the whole model period (*ModelPeriodEmissionLimit*). In addition, it can be defined a penalty for emissions with the parameter *EmissionsPenalty.*

4.2. Demand response implementation

The second part of the methodology is divided in two sections: the evaluation of the potential loads that contribute to demand response and its computational implementation in the reference energy system. Each of these two sections is based in previous doctoral theses that are also referenced in Section 3.2.4 [76], [78].

4.2.1. Theoretical Potential of shiftable demand

First it is important to understand the concept of theoretical potential and its consequences in the assumptions taken into account. This study is limited to the assessment of the theoretical potential, meaning that restrictions in DR use that result from economic, legal, societal and other types of barriers, are to be neglected from this point on.

The real implementation of DR accounts for several obstacles and challenges, therefore potentials can be defined: theoretical, technical, economical and practical.

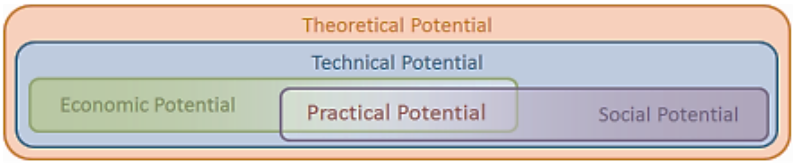

Figure 11: Types of DR potentials [78]

From the diagram shown above, it can be understood that theoretical potential includes all the potentials that can be evaluated for DR. Thus, limitations regarding technical reasons are not considered.

4.2.2. Shiftable Loads

The processes suitable for DR were identified in [5], and are divided in three sectors: industrial, commercial and residential. The equations used for the calculations of the load that can be shifted for each process are presented bellow, for each sector.

Industry

In the industry sector, for every process i, the total annual demand W_i is calculated multiplying the annual production C_i for the specific load for unit of production W_i^{spec} and the values for the percentage of usage of specific processes $s_{use,i}$. This was done by equation 3, and the annual productions of industrial processes were retrieved from [78].

$$W_i = C_i . W_i^{spec} . s_{use,i} \quad (MWh) \tag{3}$$

The processes suitable for DR in the industrial sector are: cement industry, wastepaper processing, air separation and paper machines.
As mentioned above, annual demand values for the industrial cross-sectional processes - ventilation (without process relevance) and cooling in food manufacturing - were retrieve from the country specific data present in the literature [78].

Tertiary

In the tertiary sector, for every process i, the total annual demand W_i is calculated multiplying the annual demand of the sector $W_{Tertiary}$ and values for the percentage of specific demand for each process $s_{demand,i}$, as it is shown in equation 4. The parameter $W_{Tertiary}$ is the total annual demand of the tertiary sector in Portugal, which was retrieved from [78] – as well as the $s_{demand,i}$ parameter.

$$W_i = W_{Tertiary}.s_{demand,i} \quad (MWh) \tag{4}$$

For tertiary sector the following processes were considered: cooling in food retailing, cold storages, cooling in hotels and restaurants, commercial ventilation, commercial air conditioning, commercial storage water heater, commercial storage heater, pumps in water supply and waste water treatment.

Residential

In the residential sector, for every process i, the total annual demand W_i is calculated using the annual demand of a unit of each process (domestic appliance) W_i^{unit}, the number of households N_{HH}, and equipment specific rates r_i to model each device´s penetration.

$$W_i = N_{HH}.r_i.W_i^{unit} \quad (MWh) \tag{5}$$

The electricity demand for each device W_i^{unit} has then to be calculated. For washing equipment - such as washing machines, tumble driers and dishwashers – the electricity demand is calculated in a cycle base equation, where $P_{cycle,i}$ is the power demanded in one cycle, $d_{cycle,i}$ is the duration of the cycle and $N_{cycle,i}$ is the number of cycles that are required in a year (Equation 6).

$$W_i^{unit} = P_{cycle,i}.d_{cycle,i}.N_{cycle,i} \quad (MWh) \tag{6}$$

For processes of space heating, hot water generation and air conditioning, Equation 7 is used - where $P_{\substack{unit \\ installed},i}$ is the capacity installed of every device and n_i^{FLH} is the number of full load hours in a year.

$$W_i^{unit} = P_{\substack{unit \\ installed},i}.n_i^{FLH} \quad (MWh) \tag{7}$$

For residential sector the following processes are considered: freezer and refrigerator, washing machines, tumble dryers and dish washers, residential AC, residential electric water heater, residential heat circulation pump, residential electric storage heater.

4.2.3. Implementation in OSeMOSYS

In order to evaluate the impact of shiftable loads in the energy system it is necessary to implement changes in the software that account for flexibility in the demand side. For demand response implementation in OSeMOSYS, the work from [76] was used and the equations presented in this section were introduced into the existing OSeMOSYS code. Here, flexible demand equations and constraints to the model are shown and explained. This explanation is needed since no country-specific study was done using these equations. In bold are presented the parameters given by the user. For explanatory purposes only delayed loads equations will be presented, since the equations are equivalent for the both parameters, analogously.

Rate of demand

The equation of the rate of demand in the standard OSeMOSYS code has to be changed to incorporate the flexible demand. The *RateofDemand* represents the amount of electricity demanded per timespan and the *DaySplit* represents the amount of time in each bracket.

$$RateofDemand \; = RateofStandardDemand + \sum RateofDailyFlexibleDemand \tag{8}$$

The rate of flexible demand combines the daily flexible demand – related to the total amount of flexible demand - and daily flexible demand profile – related to how the demand is located in a daily period - to set the flexible demand where it is needed throughout the day for each demand type (process).

$$RateofDailyFlexibleDemand = \frac{\boldsymbol{SpecifiedDailyFlexibleDemand * SpecifiedDailyFlexibleDemandProfile}}{\boldsymbol{DaySplit}} \tag{9}$$

Constraints

The calculation of the flexible demands and how the software handles them can be explained as an analogous way as the charging occurs for storage. When a load is advanced, the period where it placed receives an increase in load, and the period where it was suppose to be met receives a negative charge – that will then sum up to all the load in the given period, decreasing the total value, since the load was already met. In the opposite way, when a load is delayed, the period where the load would be met receives a positive charge, so that when that period is calculated by the energy balances, the load is then discharged, and the demand in that period gets a higher value due to the load that was transferred to that period. The following equations explain the constrains needed to make the loads work within the software.

After the rate of demand is calculated, the rate of net charge is calculated summing the loads that are to be advanced and delayed – related to the maximum delay and advance. If a load is advanced, the rate of net charge (for that specific load) will be the negative value of that load.

$$RateofNetCharge \;=\; Rate\;ofNetChargeDelayed \;+\; Rate\;ofNetChargeAdvanced \qquad (10)$$

The rate of net charge of a load that is delayed is the subtraction of its charge with its discharge. Therefore, if a load were met at the time that is demanded, the rate of net charge delayed would be zero.

$$RateofNetChargeDelayed \\ = Rate\;ofChargeDelayed - \;Rate\;ofNetDishargeDelayed \qquad (11)$$

For each day, the discharge of a flexible load has to be equal to the charge of the same flexible load, meaning that after each day, all the loads have to be met.

$$\sum RateofChargeDelayed * DaySplit \;\leq \sum Rate\;ofDishargeDelayed * DaySplit \qquad (12)$$

For every daily bracket, the maximum discharge is constrained to the load that was charged beforehand.

$$for\;x = 1\;to\;lh \sum RateofChargeDelayed * DaySplit \\ \geq \sum Rate\;ofDishargeDelayed * DaySplit \qquad (13)$$

The loads delayed have to be shifted to a future period no longer than the set up time maximum delayed, defined by the user.

$$for\;x = 1\;to\;(lh - \boldsymbol{MaxDelay}){:}\; \sum_{lh=0}^{x} RateofChargeDelayed * \boldsymbol{DaySplit} \\ \leq \sum^{x+\boldsymbol{Maxdelay}} Rate\;ofDischargeDelayed * \boldsymbol{DaySplit} \qquad (14)$$

The user can define the maximum share of a shiftable load, and the constraint bellow doesn’t allow for the rate of net charge to be bigger than its maximum share.

$$RateofNetCharge \leq \boldsymbol{MaxShareShiftedDemand} * RateofDailyFlexibleDemand \qquad (15)$$

Costs

Over the year, the sum of all the daily flexible demands that were delayed and advanced is calculated through the sum of the net charge. So, the equation bellow calculates all the demand that is met later over the year, multiplied by the duration of every daily bracket in which they were not met. After this sum, the value needs to be multiplied by the duration of time in hours, so the value we get is in hours. This value in hours allows it to be multiplied by the cost of shifting one hour of each flexible demand – explained in equation 17.

$$\begin{aligned} Sum\ of DailyNetChargeDelayed \\ &= \sum \boldsymbol{DaySplit} * 365 * 24 \\ &* \sum (Rate\ of ChargeDelayed - Rate of DischargeDelayed) \\ &* \boldsymbol{DaySplit} * 365 * 24 \end{aligned} \tag{16}$$

The costs of shifted loads are then calculated by using the sum of the loads delayed and advanced. All the loads that were shifted (advanced or delayed) multiply by a cost factor, in order to obtain the costs of shifting demand. The parameter *DaysInDayTime* represent the number of days there are in weekends and in weekdays (the two day-types considered), and the parameters named *Conversion (ls, ld, lh)* are needed to assign each time slice to a day type, season and daily bracket.

$$\begin{aligned} CostShiftedDemand \\ &= \boldsymbol{CostfactorShiftedDemand} \\ &* \sum \left\{ \sum (Sum\ of DailyNetChargeDelayed \right. \\ &+ Sum of DailyNetChargeAdvanced) * \boldsymbol{DaysInDayType} \\ &\left. * \sum \boldsymbol{YearSplit} * \boldsymbol{Conversion\ ls, ld, lh} * 52 \right\} \end{aligned} \tag{17}$$

The objective function presented in Section 4.1 is then changed to account for the discounted costs of shifting the demand – from which is assigned a value given by the user. The new objective function is the following:

$$\begin{aligned} \min \sum (&DiscountedOperatingCost + DiscountedCapitalInvestment \\ &+ DiscountedEmissionsPenalty + DiscountedSalvageValue \\ &+ DiscountedCostsShiftedDemand) \end{aligned} \tag{18}$$

5. Case Study: Portugal

Energy models require sets of data to operate. These include technologies, energy carriers, a reference energy system, demand and supply maps and all associated costs. Simplification assumptions had to be taken into account in the present study to diminish its control area and complexity.

The case study chapter is divided into five sections. In the first section it is presented the reference energy system. Subsection 5.2 and 5.3 divide the supply and demand data and inputs. The validation of the model performed with 2015 data is shown and explained in subsection 5.4 and the demand response potential in Portugal is presented in subsection 5.5. In the final section of the chapter the three scenarios that were designed for the study are presented.

5.1. Reference Energy System

The diagram presented in Figure 12 is the Portuguese reference system, with data retrieved by the IEA, and put together in the development of the Open Source Energy Model Base for the European Union (OSEMBE). It is important to understand the connections between each stage of the energy carriers (fuels) and its conversions (technologies). For the purpose of this thesis, only the electric system is considered.

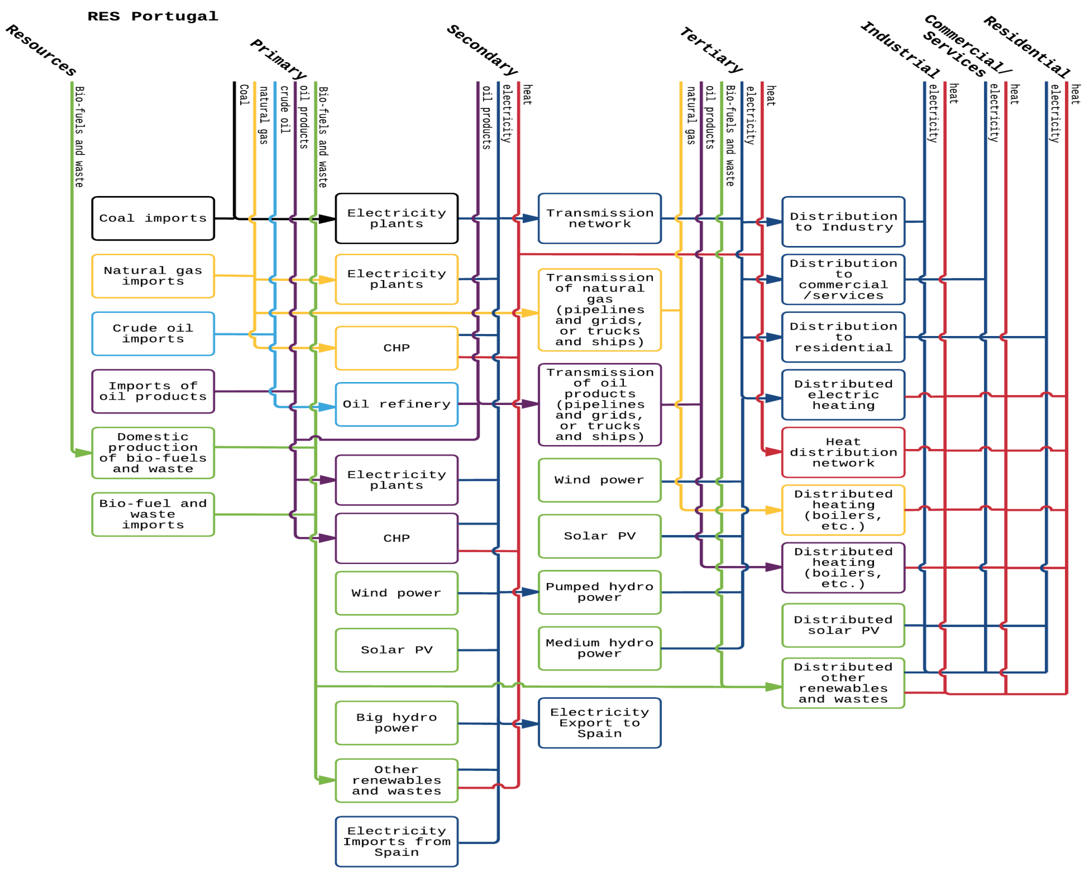

Figure 12: Portuguese Reference Energy System

The fuels modelled represent all the fuels that are present in the current Portuguese energy mix. As Portugal is scarce in fossil fuel resources – as observed in the reference energy system - it imports all of its fuels from other countries, apart from some biomass and industrial waste. The fuels that are imported to the primary level are: natural gas, oil and oil products, coal, bio fuels and waste. From the secondary level to the final demand, only the electricity is considered a fuel, since all the technologies transform the imported fuels in electricity. For secondary and tertiary power plants, it is assumed a direct supply of fuels from the primary level.

5.2. Supply

5.2.1. Installed Capacity

The existing installed capacity data was retrieved from the Portuguese national energy authority (DGEG) and crosschecked with the national TSO (REN).

Table 5: Residual Capacity in Portugal [18], [25]

Residual Capacity (MW) - 2015						
Hydro	Wind	Solar	Biomass	Coal	Natural Gas	**TOTAL**
5.857	4.959	0.454	0.839	1.878	4.663	**18.650**

To better calculate the minimum operational cost according to reality, planned power plants and future decommissions were taken into account, apart from the normal operational life assigned to the technologies.

For coal power plants, it is assumed that all the existing power plants are fully decommissioned in the end of 2021. For gas combined cycle power plants, the decommissioning of 1.6 GW is planned for 2025. The data for the decommissioning was retrieved from [79]. It is possible that the data for the decommissioning of power plants changes. However, the data used is according with the reference mentioned above.

The future planned power plants are part of the large investment in hydro: 0.8 GW in 2022 and 1.1 GW in 2029.

5.2.2. Technology parameters

All the costs associated with technologies were retrieved from the ETRI report: capital costs, fixed costs and variable costs [80]. For the fuel oil technologies, costs were retrieved from the 1.0 version of OSEMBE. Below it is presented in Table 6, the average costs of each technology source for the reference year of all the scenarios. An average is presented for better readability, given that, for some sources, more than one technology is considered.

Concerning the national grid, for the validation year transmission lines are assumed to be already installed. This can be an important challenge in the energy planning, however the security of supply is out of the scope of this thesis and so its barriers are not taken into account.

Table 6: Technology parameters [80]

Technology parameters							
Technology	**Capital (M$/GW)**	**Fixed (M$/GW)**	**Variable (M$/PJ)**	**Emissions (mton/PJ)**	**Efficiency (%)[3]**	**Availability Factor**	**Operational Life**
Hydro	2,317	154.49	1.9	0	-	1	60
Pumped Hydro	3,476	61.64	0	0	70%	1	60
Wave	6,950	311	0	0	30%	1	20
Wind Onshore	1,559	46.03	0	0	-	1	25
Wind Offshore	3,779	175.88	0	0	-	1	25
Solar	1,225	36.78	0	0	-	1	20
Biomass	3,959	195.53	2.19	0	35%	85%	25
Coal	2,270	54.79	1.66	0.247	45%	85%	40
Natural Gas	917	37.08	1.07	0.121	56%	85%	30
HFO	2,270	62.63	2.01	0.193	46%	80%	25

For biomass and waste power production, the CO_2 emissions were not taken into account, in accordance to EU policy [81].

5.2.3. Fuel costs

The costs of fuel were retrieved from two main sources: DGEG national report and EDP's annual report on electricity generation [17], [18]. The import and export costs of electricity were retrieved from the MIBEL report [22], and remain constant throughout the model period.

Table 7: Fuel Costs year 2015

Fuel cost (€$_{2015}$/GWh)						
Imp. Coal	Imp. Natural Gas	Imp. Heavy fuel oil	Imp. Bio	Biomass	Electricity imports	Electricity exports
6.36	20	20.5	37.3	18	45	-45

[3] For renewable generation sources, efficiency is taken into account calculating the capacity factor. Also, the availability factor is assumed to be one, given that the maintenance operations can be performed when generation of electricity is not taking place.

For future prospects of the price of fuels, the reference used was the projections from the World Bank until 2030, and from 2030 onwards, the average percentage of increase in the forecasted years was applied. For each scenario, these projections were calculated by a factor, described in the scenarios section.

5.2.4. Capacity Factor

Hydro

For the hydro load factor (in OSeMOSYS capacity factor), the data was gathered from REN monthly generation data. The monthly annual data from 2011 until 2016 was gathered and averaged to get monthly average values for the production of hydro, as well as percentage of pumped storage reservoir capacity.

The year 2012 was the driest year for 34 years, which led to a deviation on the average of monthly production, especially in the winter months. Further consequences of these assumptions will be discussed in Chapter 6.

Wind

For the wind capacity factor an hourly database from the JRC of the last 30 years was used. From this database, the hourly capacity factor of one specific day of each month of the years 1985, 1990, 1995, 2000, 2005, 2010 and 2015 was gathered and then averaged. For the capacity factors computed, the average and the time-slice equivalent values are presented in the annexes [82].

Solar

The solar capacity factor was retrieved from an Internet website[4], which has the European solar PV capacity factor database CM-SAF SARAH. The database is used for several publications and other academic uses.

The data has an hourly time resolution of the years 1985-2015 and the methodology used was the same as for the wind capacity factor [83], [84]. For the capacity factors computed, the average and the time-slice equivalent values are presented in the annexes.

5.2.5. Renewable potential

In Table 8 is presented the renewable potential for the year 2050 [24], which is used to constrain the model to the availability of the resources.

For solar capacity, divided in utility scale and small scale, a restriction in the amount of installed capacity that could be invested in each year was used in order to be in line with the

[4] https://www.renewables.ninja

Portuguese legislation [85]. This results in allowing the installation of 10 MW of small-scale solar panels and of 500 MW of utility scale solar panels.

Table 8: Renewable potential in Portugal [24]

Renewable Potential in Portugal			
Source	**Unit**	**2015**	**2050**
Wind On	GW	5.034	7.8
Wind Off	GW	0	10.0
Solar	GW	0.451	9.3
Hydro	GW	6.914	9.0
Wave	GW	0	7.7
Biomass	PJ	0.726	53.1

5.2.6. Further assumptions

The model considered Portugal as the continental part, excluding the islands of Azores and Madeira, due to the existence of independent energy systems in the islands.

Regarding operation constraints, a reserve margin of 15% was assumed for the modeled period. The reserve margin is a parameter that constrains the model to have always 15% more capacity available than the capacity needed to meet the peak every year. However, renewables like wind and solar do not account for the reserve margin, due to their variability and intermittency.

Finally, for the investments, a discount rate of 5% was assumed.

5.3. Demand

Demand input was retrieved from the ENTSOE's hourly load demand data. For better demand response implementation, demand was segmented into three sectors – industrial, residential and commercial. Analyzing [17] and several other sources characterizing demand of electricity in the country, it was assumed that each sector is responsible for a third of the demand.

Segmenting the demand requires the division of the load profiles for each sector. From the Portuguese energy regulatory agency ERSE, hourly load profiles for low and medium voltage can be assessed publicly. It was assumed that the residential sector operates in low voltage and the commercial sector operates in medium voltage. Since the total load of the system is also available from REN/ENTSOE, for each hour of the year, industrial load profile was obtained by subtracting the low and medium voltages, and the losses on high voltage to the total amount of demand.

Operating in time-slices requires aggregation of data beyond hourly time resolutions. These time-slices have to be in accordance with the demand peaks to better simulate reality, while keeping low computational times for the simulation. Therefore, load profiles from the three different sectors, from each month and day-type (weekend and weekday), were analyzed.

The average weekday load profiles for each sector are presented in Figure 13. The black line is mere representative of the daily brackets chosen (based on the residential curve) and has no numerical significance.

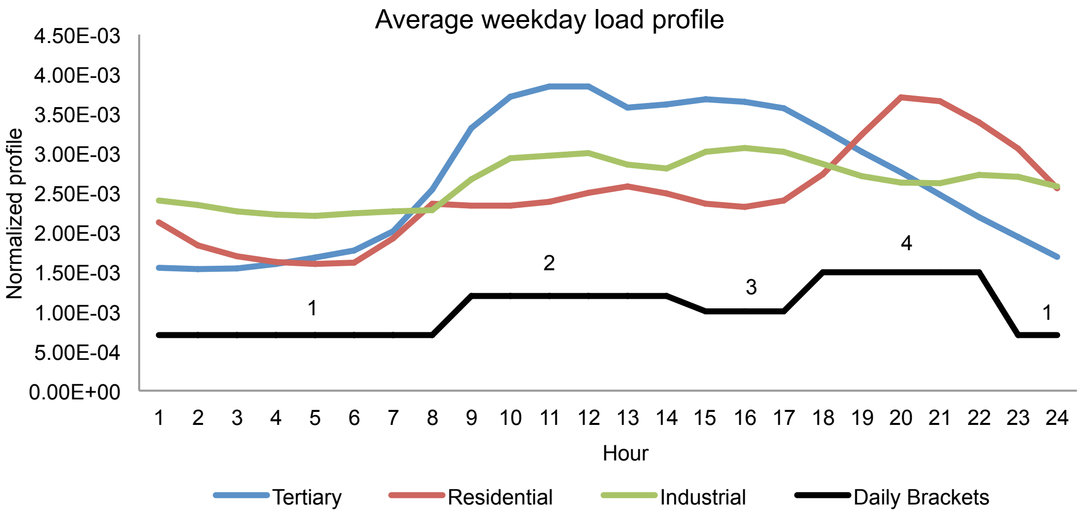

Figure 13: Average weekday load profiles and daily brackets

From the profiles, four time-slices per day were chosen, equaling to 96 time-slices in total – 12 months, 2 day-types and 4 daily time brackets. For each time-slice, the methodology used to calculate the profile was the same: hourly data from a typical day-type for each month for the years 2013, 2014, 2015 and 2016 was used and averaged.

5.4. Validation of the model

For the validation, the model results were compared with real data for the year 2015. Real data for the installed capacity and demand were used as inputs to the model.

Capacity factors for wind, solar and hydro power plants were calculated based on their real data. The sources used were the same as for the methodology described in 5.2.4, though only data from 2015 was used. Therefore, for the solar and wind capacity factor an hourly average capacity factor was calculated based on five days of each month. For the hydro capacity factors, the values retrieved from REN were already given in a monthly basis for the year 2015.

The results were then compared with historical data of the year 2015. The monthly production data provided by the TSO (REN) is available in the company's website[5]. A data sheet was compiled with the monthly data of the production of electricity by source, and the graph bellow shows the comparison between the real data and the data from the model simulation.

For the validation of the model, calculation of the error percentage was made. In order to compute these values, the error function used was the following:

$$\%\ Error = \frac{Real\ net\ production - Simulated\ net\ production}{Real\ net\ production} \tag{19}$$

The calculated errors for each source for the year of 2015 use real energy production data from REN. The table below presents the model results and the data retrieved from REN.

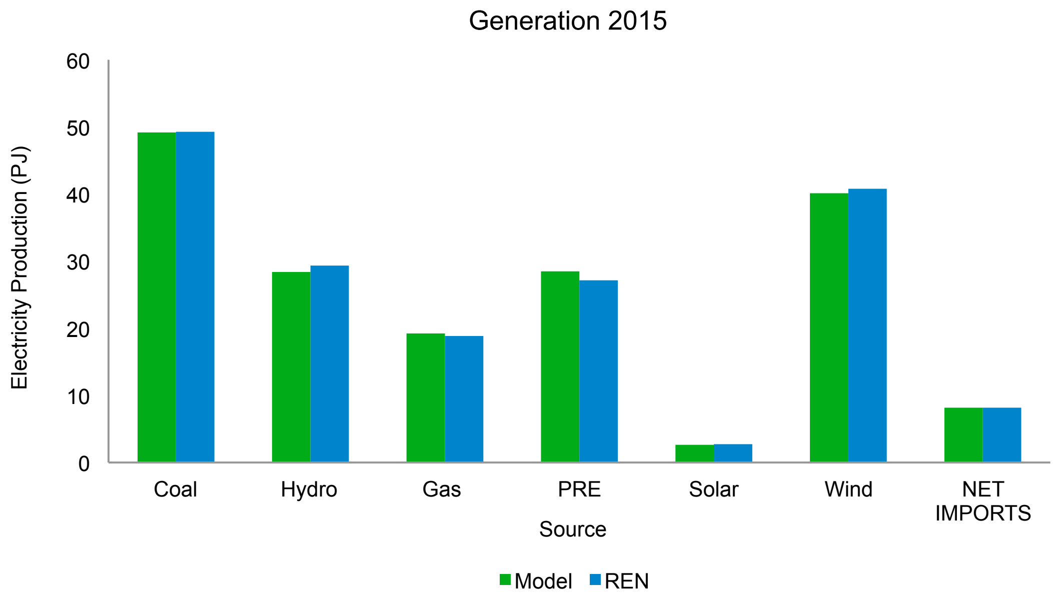

Figure 14: Model validation with 2015-generation data

The way the data is presented by REN accounts for PRE – Production in special regime and PRO – production ordinary regime. In the PRE, it is considered all the renewable sources and thermal plants in special regime - co-generation, biomass and waste power plants. All the remainder is considered PRO.

The refinement of the model was performed after simulations with all the inputs and assumptions unchanged, and a table of errors was used as base to validate the model. From Table 9, where the computed errors are presented, it can be seen that the highest error is from generation in special regime. This can be explained as this generation is linked to multiple technologies. Special regime production in Portugal is subject to incentives from the

[5] http://www.centrodeinformacao.ren.pt

government, as the priority on dispatch, which have to be accounted by the model by decreasing the variable costs of operating PRE power plants. For example, the costs of combined cycle gas power plants (NGCC) used as inputs to the model are low (compared with the PRE generation), and this led the model to produce the total amount the installed capacity can generate from gas. Thus, the cost inputs were refined.

Concerning net imports, the model would choose to import electricity from Spain whenever it was available (due to lower levelized cost of electricity). Thus the availability factor linked to the import technology was adjusted according with historical data.

The remainder technologies generate the expected amount of electricity, mainly because it is directly related to its availability or capacity factor. These are validated by the low percentage in the error computed.

Table 9: Model Validation errors

Source	Model production (TWh)	Real production (TWh)	Error %
Coal	13.615	13.637	0,2
Hydro	7.872	8.122	3,1
Gas CC	5.314	5.227	-1,7
PRE (thermal)*	7.896	7.518	-5,0
Wind	11.110	11.304	3,8
Solar	730	758	1,7
NET Imports	2.264	2.257	0,3
TOTAL	48.804	48.826	0,05

5.5. Flexible load potential

The flexible load potential for Portugal was calculated based on the methodology presented in 4.2.1. The equations presented in the above-mentioned section were retrieved from the study [5], alongside with the assumptions for the Portuguese case – since it is an European wide study. For better understanding, these inputs will be presented in a sector basis.

In Figure 15, presents the potential for demand response in Portugal, which was used as an input to the model for the year 2015. The numbers on top of the bars represent the number of daily brackets that each process provides as flexibility – advance and delay. The flexibility time was retrieved from the study mentioned above and converted into daily brackets –see Annex C. Note that the flexibility time in the table mentioned above – Annex C - is presented in hours, and so it is necessary to adjust the temporal resolution to time-slices. This has a consequence in the conversion of time into brackets, especially for processes that allow only for a flexibility of 2 hours, due to the fact that some brackets are larger than 2 hours of corresponding time, which might lead to optimistic results. However, the processes that allow for 12 hours were given a two-brackets period of flexibility, which in some cases might have the opposite result – when the sum of the period of the two-brackets is less than 12 hours.

Until the final year of the model, an annual 0.8% of increase in consumption was assumed for every process to be coherent with the same value for the overall demand. For the references of the profiles of all the processes considered from industrial and tertiary sector, see Annex C.

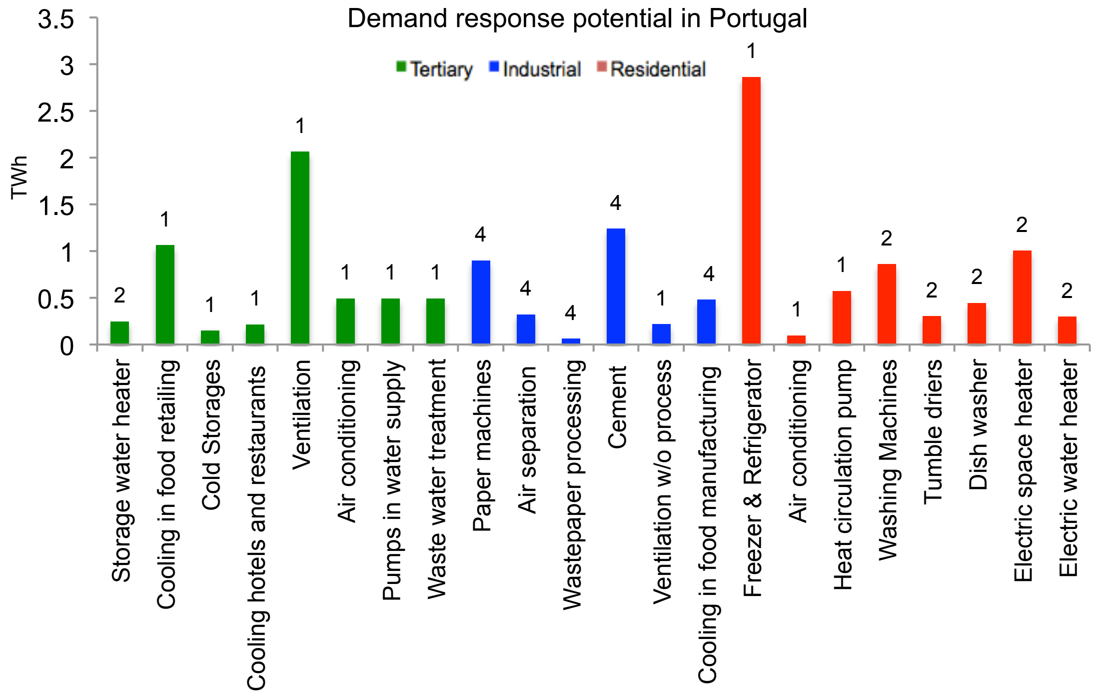

Figure 15: Demand Response Potential in Portugal

5.5.1. Tertiary

The tertiary load potential was calculated based on the Equation 4 from subsection 4.2.2. The eight processes identified by [5] and here considered are the following: storage water heater, cooling in restaurants and hotels, cold storages, cooling in food retailing, ventilation, air conditioning, water pumps in water supply and waste water treatment. The potential for each process was calculated assuming a percentage of total tertiary demand for each process [5].

The wastewater treatment process shares the load profile of the process pumps in water supply. The same happens for cooling in hotels and restaurants and cooling in food retailing, and for ventilation and air conditioning, respectively.

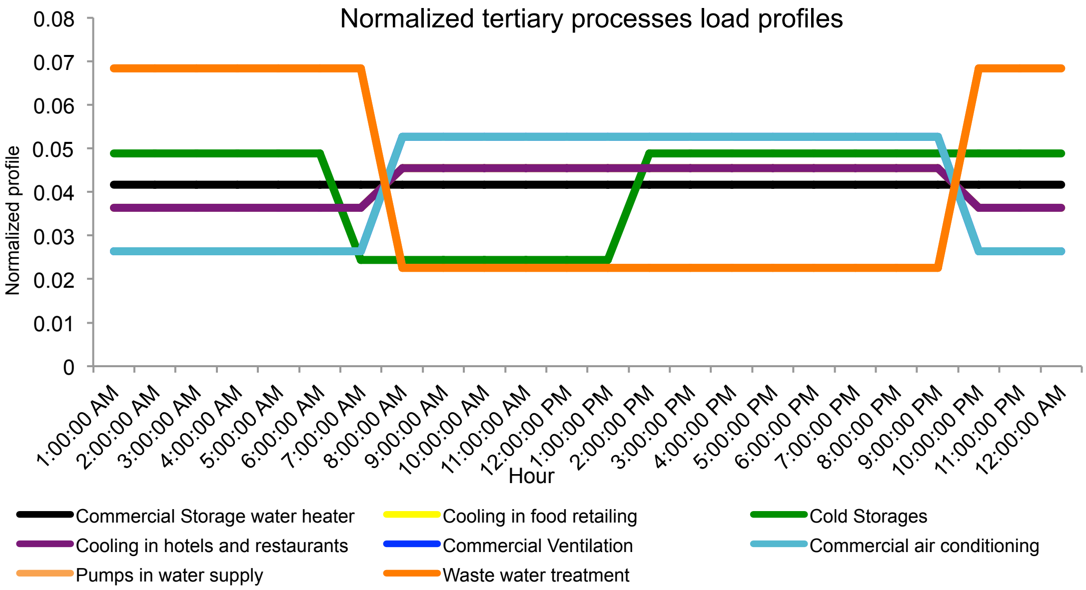

Figure 16: Normalized tertiary processes load profiles

5.5.2. Industrial

According to [5], the industrial potential was divided into six processes: paper machines, air separation, cement industry, wastepaper processing, ventilation and cooling in food manufacture. Note that the last two processes mentioned are cross-sectional processes and are not directly related to the production of its industry. This is important because the flexible load potential for the industrial processes was calculated based on their annual output production through Equation 3. However, for the cross-sectional processes specific demand data were used from [78].

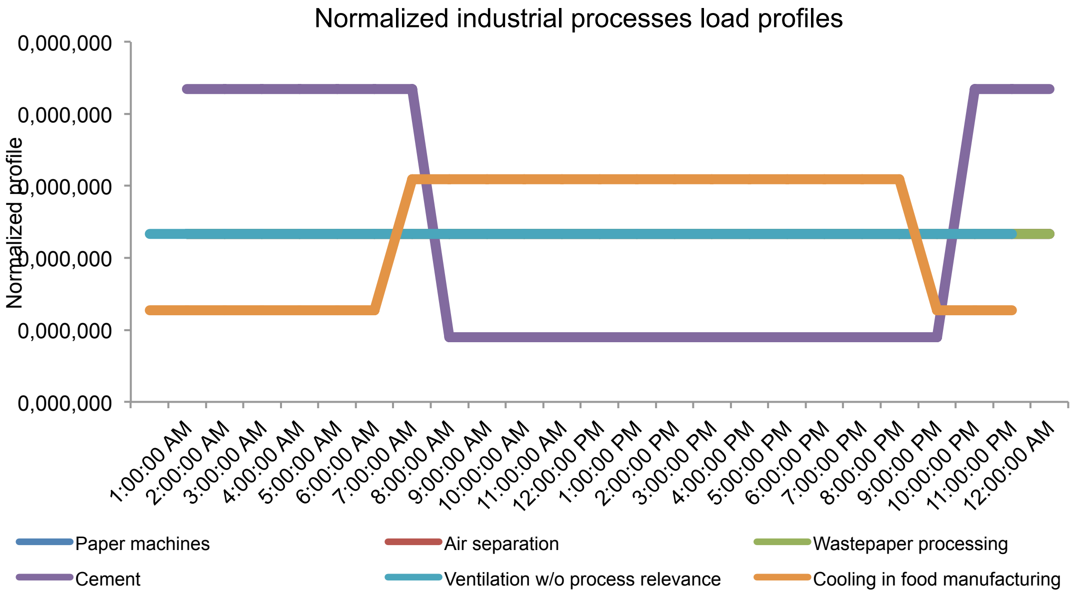

Figure 17: Normalized industrial processes load profiles

In Figure 17 the daily load profiles for the industrial processes are shown. The following processes share the same load profile: air separation, wastepaper processing, paper machines and ventilation.

5.5.3. Residential

The residential potential considers mainly household appliances: freezer and refrigerator, residential air conditioning, tumble driers, washing machines, dish washer, heat circulation pumps, electric space heaters and electric water heater. For these, a percentage of penetration for each appliance in the Portuguese households was retrieved, and then multiplied by its consumption and number of households in Portugal, according to Equation 5 [5]. In Figure 18, the load profiles of all the residential processes considered for DR are presented. The load profile of the electric space heater is the same as for the heat pump.

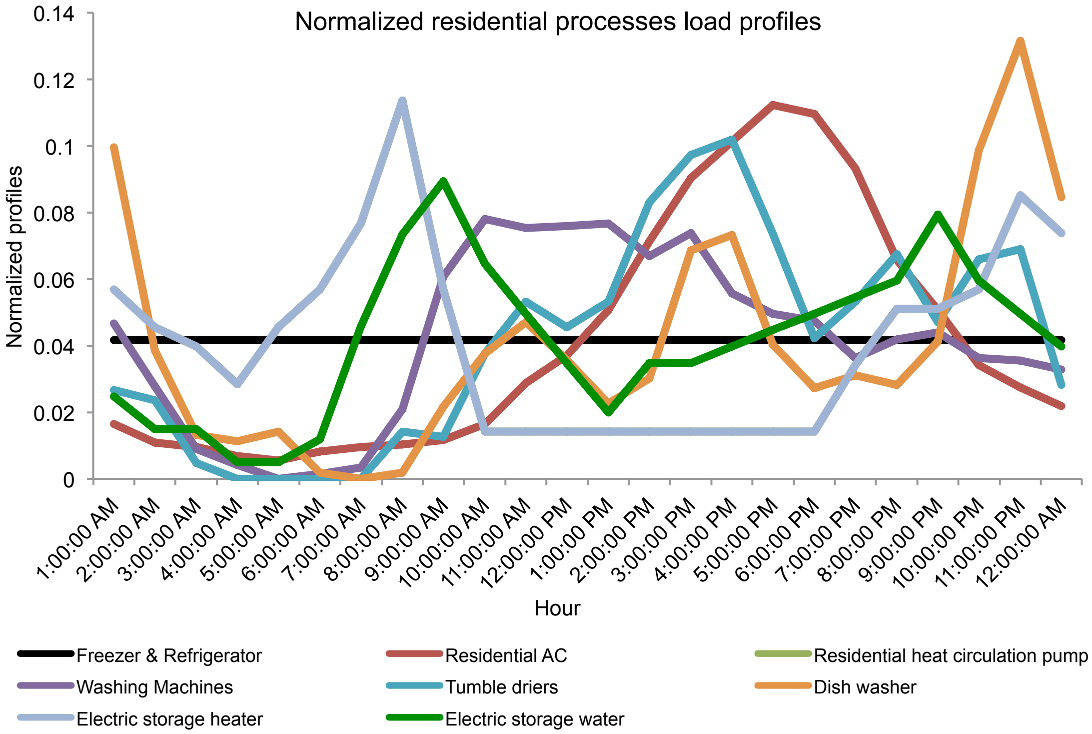

Figure 18: Normalized residential processes load profiles

5.5.4. Cost of DR

For this study, associated costs related to installation of devices that allow the participation in DR events, incentives or variable costs related to providing flexibility were not taken into account.

5.6. Definition of Scenarios

Three scenarios were designed to better assess the model results towards 2050, considering the future of the energy system. The reference scenario (*BaU*) is generally based in the framework from EU policy and legally binding targets. Then, two other scenarios were designed using the reference scenario as base – a more optimistic scenario in terms of a low carbon energy system (*Low Carbon*), and a less policy restrictive scenario where economic growth is the priority (*Least Cost*). Table 10 summarizes the main characteristics of each scenario, its targets and requirements.

Table 10: Scenarios

LowCO2	**2015**	**2030**	**2050**	**Source**
Targets for renewable generation	-	70 %	100 %	[86]
Renewable Technology Costs	1	-	--	[8]
Fuel Prices	1	+	+	[87]
Consumption Increase (yearly increase)	0.80 %			[8], [86]
Limits on emissions (Mton)	-	3	0	[86]
Cost of CO_2 in 2050 (M$/mton)	$8.50	$50.00	$140.00	[86]
Demand (TWh)	48.80	54.85	64.50	[8], [86]
BaU	**2015**	**2030**	**2050**	**Source**
Targets for renewable generation	-	40 %	80 %	[86]
Renewable Technology Costs	1	-	-	[8]
Fuel Prices	1	+	+	[87]
Consumption Increase (yearly increase)	0.80 %			[8], [86]
Limits on emissions (Mton)	-	3	1	[86]
Cost of CO_2 in 2050 (M$/mton)	$8.50	$30.00	$90.00	[86]
Demand (TWh)	48.80	54.85	64.50	[8], [86]
LeastCost	**2015**	**2030**	**2050**	**Source**
Targets for renewable generation		30 %	60 %	[86]
Renewable Technology Costs		-	-	[8]
Fuel Prices		+	++	[87]
Consumption Increase (yearly increase)	0.8 %			[8], [86]
Limits on emissions (Mton)		10	7,5	[86]
Cost of CO_2 in 2050 (M$/mton)	$8.50	$15.00	$30.00	[86]
Demand (TWh)	48.80	54.85	64.50	[8], [86]

The *BaU* (business as usual) scenario is the reference scenario. It is somehow in between the other two scenarios. This scenarios was based on three main sources: ENTSO-e's visions for 2030, EU´s 2016 Reference Scenario and the Energy Roadmap 2050, from the European Commission [86], [88], [89], and the projected costs for technologies are the ones provided by the document from the JRC – ETRI [80].

The *LowCO2* scenario is more optimistic than the *BaU* scenario. This scenario has ambitious targets for percentage of renewable generation, emission reductions, as well as a steeper drop in green technologies costs and some increase in fossil fuels prices.

The *Least Cost* scenario is more conservative in renewable deployment and more focused on economic growth, as it is the least cost-operating scenario.

For every scenario, technology restrictions were applied: no nuclear, no new conventional Coal PP, no new conventional open gas cycle PP and a maximum investment of 10 MW of annual residential solar PV and 500MW of utility level solar PV. Further, for renewable energy sources, the applied potential was gathered from the report [24]. Also, a maximum investment of 0.5 GW of new annual capacity from each technology was assumed.

6. Results and discussion

In this section the results from the scenarios analysis are presented. Simulations using the three scenarios were done for 0%, 50% and 100% demand response implementation. The extent of all the results is large, therefore the presentation of the results in this chapter will follow mainly the *BAU* scenario, and the other two scenarios will be used as a comparison.

In order to better analyse the results it is important to understand well the three scenarios presented in subsection 5.6 and their consequences in the system's evolution. The main driver of the scenarios is the limit on the emissions from the generation of electricity. Given that in 2014 the Portuguese electric system emitted 16 Mton of CO_2 , the emission targets for 2050 both in *BAU* (1 Mton) and *LowCO2* (0 Mton) scenarios are important when compared with the target in the Le*astCost* scenario (7.5 Mton).

Given these assumptions, *BAU* scenario is compliant with the vision of the EU for 2050, however *LowCO2* scenario results in a carbon free electric system in the same year. The *LeastCost* scenario does not comply with any present emission target, although it can work in a World more focused in steady economic growth rather then environmental concerns.

6.1. Results without active demand response

6.1.1. Capacity

In Figure 19, the evolution of the installed capacity is shown for the BAU scenario with 0% of demand response implementation. There is an increase in renewable capacity from 60.9% in 2015 to 96.8% in 2050. To this change there is contribution both of decommission of fossil fuel plants and installation of new renewable capacity. The total capacity installed in 2050 is 31.74 GW.

In terms of decommissioning of power plants, the coal capacity becomes non-existent in 2021 and the heavy fuel oil (HFO) capacity slowly decreases through the first 20 years of the model period. In terms of natural gas, it shrinks its capacity from 4.66 GW in the first year to close to 1 GW in 2050.

Concerning new renewable capacity: from 2029, the biomass capacity increases from 2029 in order to substitute some of the NG roll out of the system's thermal backup (since its considered to be a non-emitting technology). Hydro and Wind-Onshore maintain their total available potential of capacity throughout the model period. Solar PV installation begins steadily to increase when the system is in the need for new non-emitting capacity, given that hydro and wind onshore are already non-available from the year 2025. Solar reaches its full potential of 9.3 GW around the year 2045. However, substantial installation of offshore wind starts in 2039 until it reaches close to 4 GW in 2050. Also, 0.5 GW of wave energy is installed in 2050, as the overall system reaches 31.74 GW of total installed capacity.

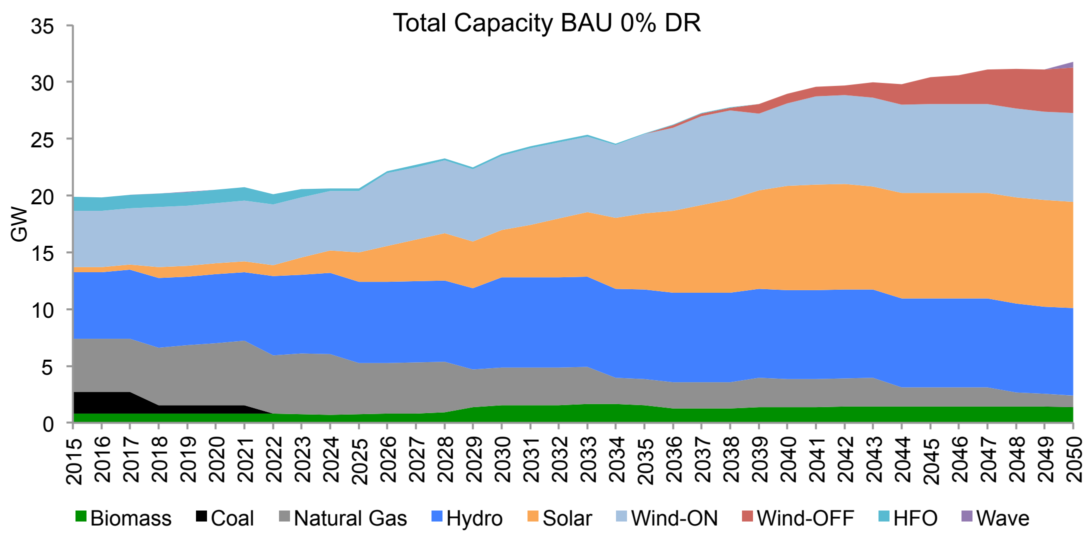

Figure 19: Results: Total Capacity BAU 0% DR

Comparing the results of the BAU scenario with the LowCO2 and the LeastCost scenario for the years 2030 and 2050, some differences arise from the analysis of Figure 20.

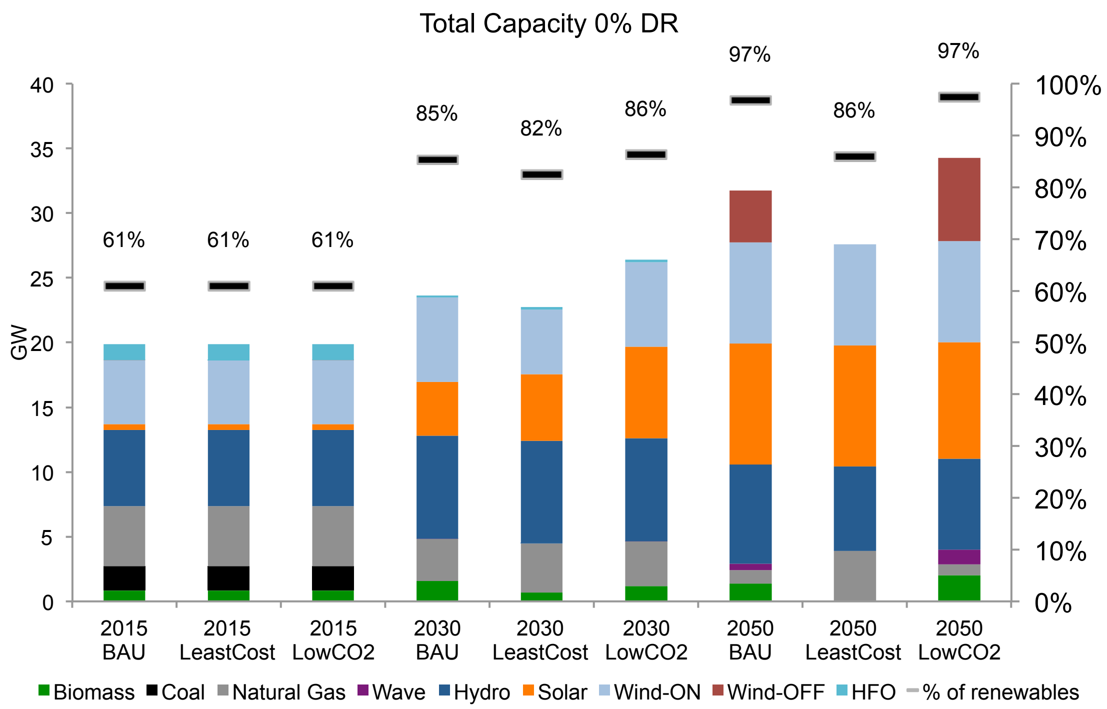

Figure 20: Results: Total Capacity Scenarios 0% DR

The LeastCost scenario reaches 85.9% of renewable capacity in 2050. It needs less 13% (4.5 GW) of total capacity than BAU scenario. In the year 2030 it can already be seen a difference between both scenarios – less total capacity in LeastCost that result from less biomass and onshore wind capacity. In 2050, LeastCost scenario only relies its system in four sources with the disappearance of biomass capacity and no-need for offshore wind, as in BAU. The NG capacity in the LeastCost scenario is constant during the model period, as it provides backup for renewable dispatch.

The LowCO2 scenario has more 7.9% (2.5 GW) of total installed capacity when compared with BAU scenario, for the year 2050. It reaches 97.4% of renewable capacity in the same year – a value that is very close to the one in BAU. The scenario has more renewable capacity than BAU in all the sources, except for hydro. This is due to the faster installation of solar in LowCO2 than in other sources until the solar potential is tapped, and when this happens offshore wind becomes more competitive, and the model installs offshore wind instead of hydro capacity. In the LowCO2 scenario in 2030, the main difference when compared with BAU is the early solar uprising that takes place in the former, with more 3 GW of solar capacity installed.

6.1.2. Generation

Having presented the capacity above, here the generation of electricity will be analysed, in Figure 21 for BAU scenario.

In the first years of the model, and with the decommissioning of the coal capacity, NG starts to have a relevant place in sustaining the system's security of supply. It reaches a maximum of 51% of the total generation in 2022. After that, and with the limit on emissions becoming smaller, the NG generation starts to be substituted by renewable generation. For this, the contributions of solar, biomass and a bit later offshore wind are relevant. Also, in the last year of the model period wave generation starts to feed the system as well from its 0.5 GW of installed capacity.

In the first year of the model, 48% of the generation comes from renewable sources. This number rises to 87% in the last year of the model period. Imports represent steadily around 6% of the total consumption of electricity from the system.

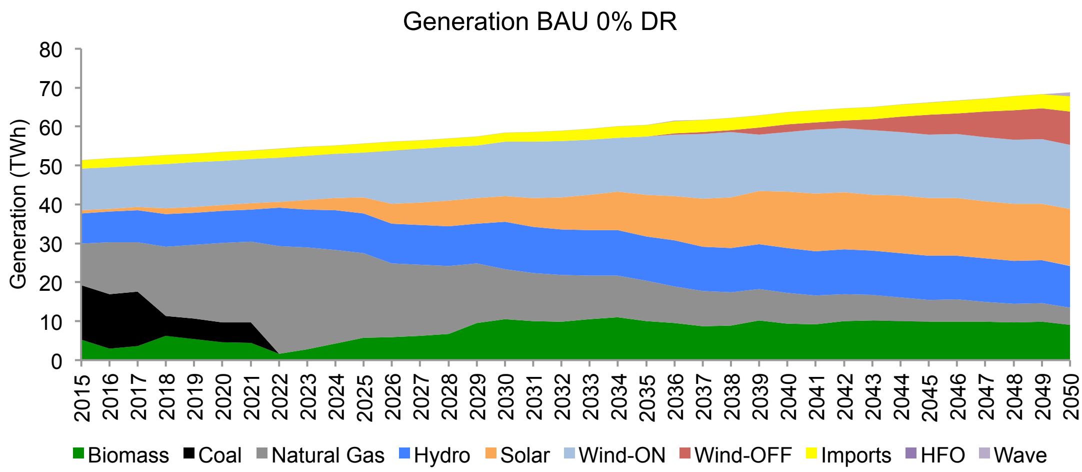

Figure 21: Results: Generation BAU 0% DR

As done in the previous subsection, Figure 22 compares the three scenarios in terms of generation for 0% of demand response implementation.

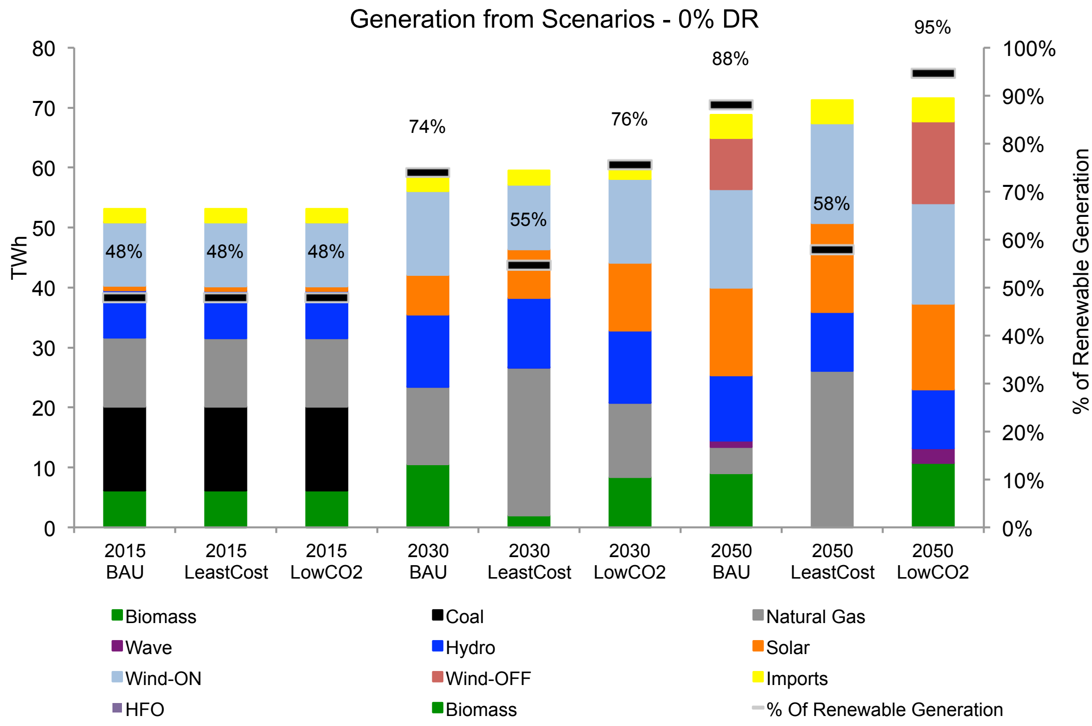

Figure 22: Results: Generation from Scenarios 0% DR

In the LeastCost generation from NG represents 37% of total generation (from only 14% of the total capacity). The NG generation is equivalent to all the generation from biomass, wave and offshore wind in BAU scenario. This results in only 58% of renewable generation in the last year of the model period, which is explained by the competitiveness of NG due to two main factors: 1) low carbon tax that the scenario uses as input; 2) the restriction on emissions that in the LeastCost scenario allows the emissions to be up to 7.5 Mton of CO_2 in 2050.

In the LowCO2 scenario, generation in 2030 differs from BAU mainly on the higher output of solar generation due to higher capacity – a generation that in BAU is coming from biomass. In 2050, with the abolition of NG generation in the LowCO2 scenario, more generation is demanded from wind offshore, wave and biomass – evenly distributed among the three sources. Note that the generation is not 100% renewable, due to the imports of electricity – not considered from renewable sources.

The total generation varies from the three scenarios, due to the assumption of loss of 5% in transportation and distribution per level – see figure 12. This relates to the way the model chooses the sources of electricity – if a source is in the tertiary level it will consume less electricity in transport and distribution than a source that is in the secondary level.

6.1.3. Emissions

In this subsection a closer look is taken into the emissions from the three scenarios. After analysing the generation, the differences within the scenarios and the shape of the emissions curves assume for each of them, can be better explained. Two important assumptions made in the scenarios design contribute to the emissions: the emission targets and the CO_2 cost per ton.

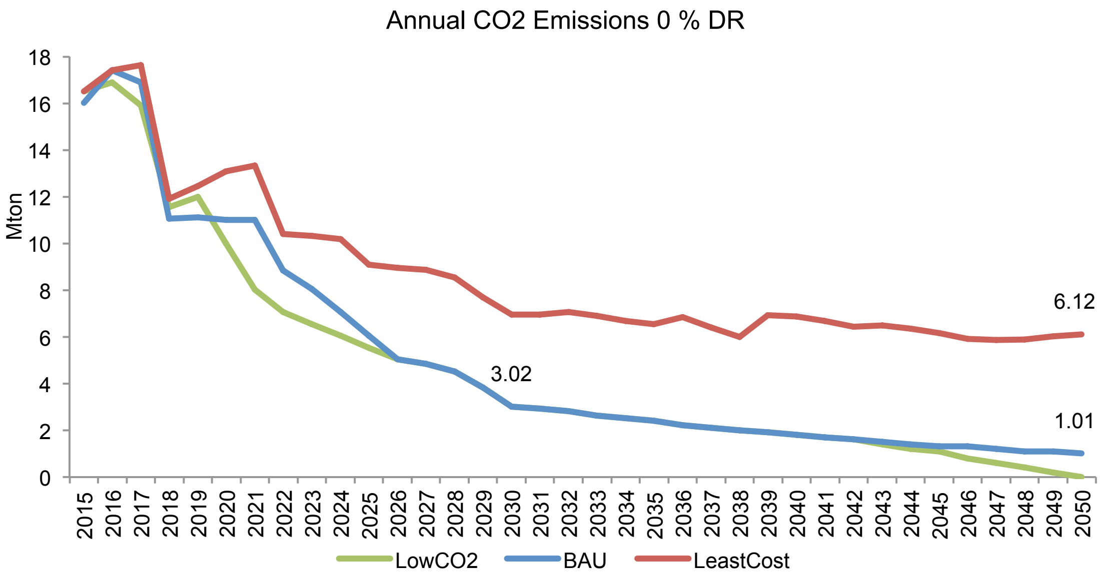

Figure 23: Results: CO2 emissions BAU 0% DR

From the analysis of Figure 23 it can be seen that BAU and LowCO2 scenarios follow the limit of emission in 2030 and 2050. Both scenarios emit the same amount of CO_2 from 2026 until 2044, and after that, BAU evolves to a 1 Mton emission ceiling while LowCO2 evolves to a non-emitting system until 2050. It is important to note that the difference in the cost of CO_2 – in 2050 140$/ton in LowCO2, and 90$/Mton in BAU – is not really reflected in the results. Thus, it can be concluded that the emission ceiling is driving the model to generate from renewables when the CO_2 limit is reached, rather than NG becoming less competitive with a high CO_2 cost.

As for the LeastCost scenario, it doesn't follow the emission ceiling, as it emits always bellow it with some margin. As we've seen in the previous sub-section, NG generates 37% of the total generation. However, with the assumptions in the LeastCost scenario, and with a CO_2 cost lower than in the other two scenarios – 30 $/ton of CO_2 in 2050 – some renewable sources become more competitive than NG: solar, hydro and wind onshore all hit their maximum generation potential in 2050.

In the overall model period, LeastCost scenario is where emissions are higher, with 313 Mton of CO_2, due to the objective of achieving the lower costs. BAU follows with 182 Mton and LowCO2 is the least emitting scenario with 170 Mton of CO_2.

6.1.4. Cost Analysis

In relation to the overall cost of the three scenarios, the LeastCost is the least costly one, performing less 3.4% than the cost of BAU scenario. As for the LowCO2 scenario, it is the scenario with the highest cost, with an overall cost of more 1.9% than BAU scenario.

Using the total costs per technology, an average electricity cost was computed for all scenarios in order to compare the cost of consuming electricity - in EUR/MWh. These results lead in the same tendency as the overall cost, which makes sense due to the same demand in all three scenarios. Therefore the electricity cost in the LeastCost scenario in 2050 was 12.5% lower than in BAU scenario, and in LowCO2 scenario it resulted in a 3.3% higher cost for every MWh delivered to the final demand.

In Figure 24, the overall costs are discriminated for the BAU scenario as well as the curve of the yearly electricity cost calculated in EUR/MWh of demand[6]. Concerning the yearly costs, from year 2015 historical investments in capacity from already installed power plants were considered, and for all the new capacity investments were annualized for the economical lifetime of the power plants.

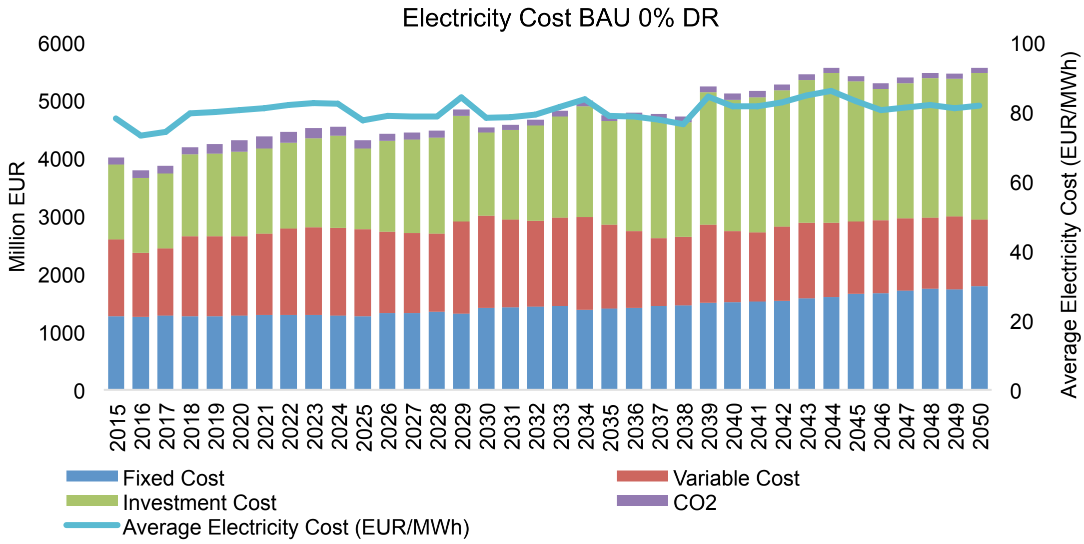

Figure 24: Results: Electricity Cost BAU 0% DR

From the figure, it can be seen that fixed costs rise steadily over the model period due to the increase in the overall capacity. Variable costs – related to operations and maintenance and expenses with fuel for thermal generation – are directly related to the share of generation that originates from renewables that have no variable costs, as is the case of wind, solar and wave. In consequence, variable costs decrease 13% over the entire model period due to the

[6] The cost has to be computed with the electricity demanded rather than the electricity generated. Since there are losses in the transmission of electricity, the cost has to account also for these losses, therefore the final consumer has also to pay for the electricity that is lost in the process of delivery of electricity.

high generation from solar and wind – and less fuel cost expenses. Also, these costs can vary if generation originates from sources with high variable costs that has fluctuating generation over the years, as is the case of biomass: in 2016 reduces its generation and therefore the variable costs also reduce. This tendency inverts when coal generation is reduced in 2018 and biomass substitutes it, increasing the variable costs again. Investment costs are related to new capacity investments and past investments that are still being paid over the economical lifetime of the power plants. For example, in the year 2029 investment costs rise due to the installation of a steam turbine biomass power plant – with high capital investment costs (see annex B for specific investments inputs). Also, in 2039 investment costs rise again due to the new installation of 0.7 GW of offshore wind – that also has a high investment cost.

The electricity cost per MWh follows the annual overall cost fluctuation. Therefore it is understandable that the peaks in the curve are in line with the years with higher costs. However, the curve manages to stay quite steady – cost of electricity rises 4.8% during the model period – due to the 0.8% increase of annual demand. This means that the overall cost increase, but the demand also increases, which leads to a steady value for the average electricity cost.

6.2. Results with active demand response

In this section the impact of active demand response is analysed. As it was done previously, a closer look is taken into the BAU scenario and whenever it seems appropriate, comparison with the other two scenarios are presented. It is important to note that the impact of DR is better understood within each scenario rather than comparing between scenarios, due to the characteristics of the system that results from each scenario.

The installed capacity is analysed in depth. However, the fluctuations of the generation follow the variance in the installed capacity. Therefore, and since no big impact in generation arises due to the implementation of demand response, only total capacity is analysed in depth in this section.

6.2.1. Capacity

BAU scenario

With the implementation of demand response the system changes in the long-term. From the analysis of Figure 25, the impacts of DR start to be seen in 2030, with the substitution of NG capacity for wind offshore capacity – as there are no CO_2 costs of emissions and no variable costs.

Up to the year 2050, the total capacity is reduced with the implementation of demand response. With 50% of DR available, the total capacity of the system decreases 1.5% and with 100% DR available the total capacity is less 2.2% when compared with the BAU scenario without DR. The main factor for this difference is the lower need for backup of thermal power plants – NG and biomass. In fact, in the scenario without DR, the 2.4 GW of thermal capacity is reduced to 1.8 GW in the scenario with full DR implementation. This means that 85% of capacity reduction is due to reduction of thermal capacity. This can be explained by the flexibility provided by DR to exploit the maximum from renewable generation. As a consequence, the percentage of renewables in the system increases with the implementation of DR, from 96.8% without DR to 97.5% with 50% DR implementation, and reaching 97.7% with full DR implementation.

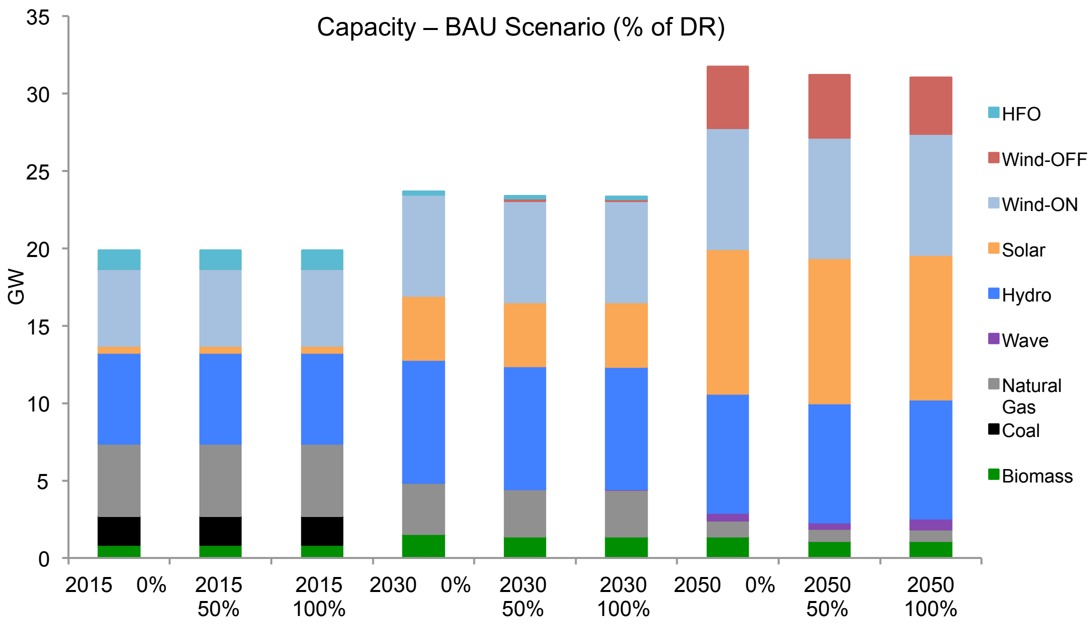

Figure 25: Results: Capacity BAU Scenario (% of DR)

LeastCost scenario

The tendency in LeastCost scenario follows the same as in BAU scenario. The impact of DR results in a 2.1% reduction in the total system capacity in 2050. This reduction is also reached by the reduction of thermal capacity – in this case only NG, due to the non-existence of biomass capacity in 2050 for this scenario (see Figure 20). DR allows for a reduction of 0.6 GW of NG capacity. An interesting fact is that with 50% of DR implementation, 95% of the reduction in the total capacity is reached. This can be explained by an almost exhaustion of the potential of DR reached with only 50% implementation in this scenario. The analysis of the usage of the DR potential is discussed in the next sub-section.

In terms of percentage of renewables, the tendency maintains the BAU scenario as in the previous indicator. DR is responsible for an increase from 85.9% to 87.9% of the total capacity that originates from renewables.

Figure 26 presents the relative total capacity variation, within the three scenarios with different percentages of DR implementation.

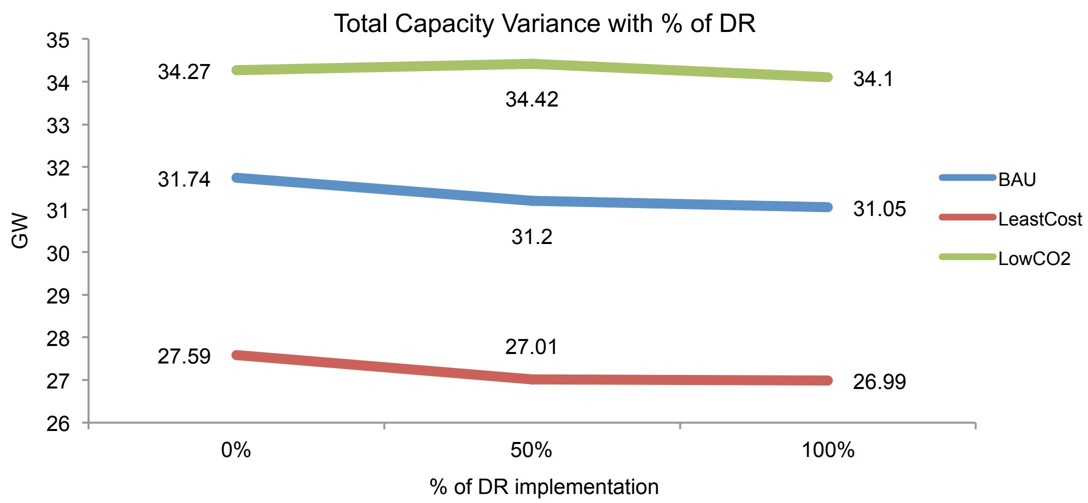

Figure 26: Results: Total Capacity Variance with % of DR

LowCO2 scenario

In the LowCO2 scenario the total capacity is reduced with 100% DR implementation. However, with only half the DR potential, the total capacity increases (see Figure 26). Still, when looking at thermal capacity, the tendency of decreasing remains in the 50% and 100% DR results. In fact, this reduction represents the biggest reduction in thermal capacity from the three scenarios – 1 GW with 50% DR and 1.1 GW reduction with 100% DR. Nevertheless, the increase in the overall installed capacity in the 50% DR case is due to more offshore wind and wave capacity. This is explained by the limited flexibility that 50% DR provides (in comparison with 100%), that allows the system to meet the demand in periods when these technologies can generate instead of having costly thermal plants (due to high CO_2 emission costs from NG and high variable costs from biomass). The consequence is a lower capacity to generation ratio[7] in the overall system that leads to higher total capacity when compared with 0% of DR. The difference with 100% DR, is that the system is able to meet more of the flexible demands in periods where the already installed capacity is capable of generating it.

In terms of the absorption of renewable capacity, in this scenario DR also contributes to increase the share of renewables of the system. From 97.5% renewable capacity without DR, the system is able to have 98.4% with 50% of DR and 98.5% with full DR implementation.

[7] Capacity to generation ratio is an indicator that can inform about the active capacity of the total system. Typically, systems with higher shares of renewables often have lower capacity to generation ratio due to the low capacity factor of its renewable capacity.

6.2.2. Generation and Emissions

In relation to the DR implementation, the electricity generation changes slightly in all three scenarios. As the model optimizes the cost, some of the cost benefits arise by generation electricity from distributed sources, in order to generate less total electricity – due to the avoided losses in the transmissions. As a consequence, in the BAU scenario DR leads to a decrease in 1.2% in total generation in 2050. In the other two scenarios, LeastCost scenario is the one with higher decrease in total generation for the same year - 1.4% decrease. As for the LowCO2 scenario, generation is constant through all the levels of DR implementation. This can be explained by the fact the in the LeastCost scenario, a considerable amount of generation is coming from central power plants (like 37% of NG generation).

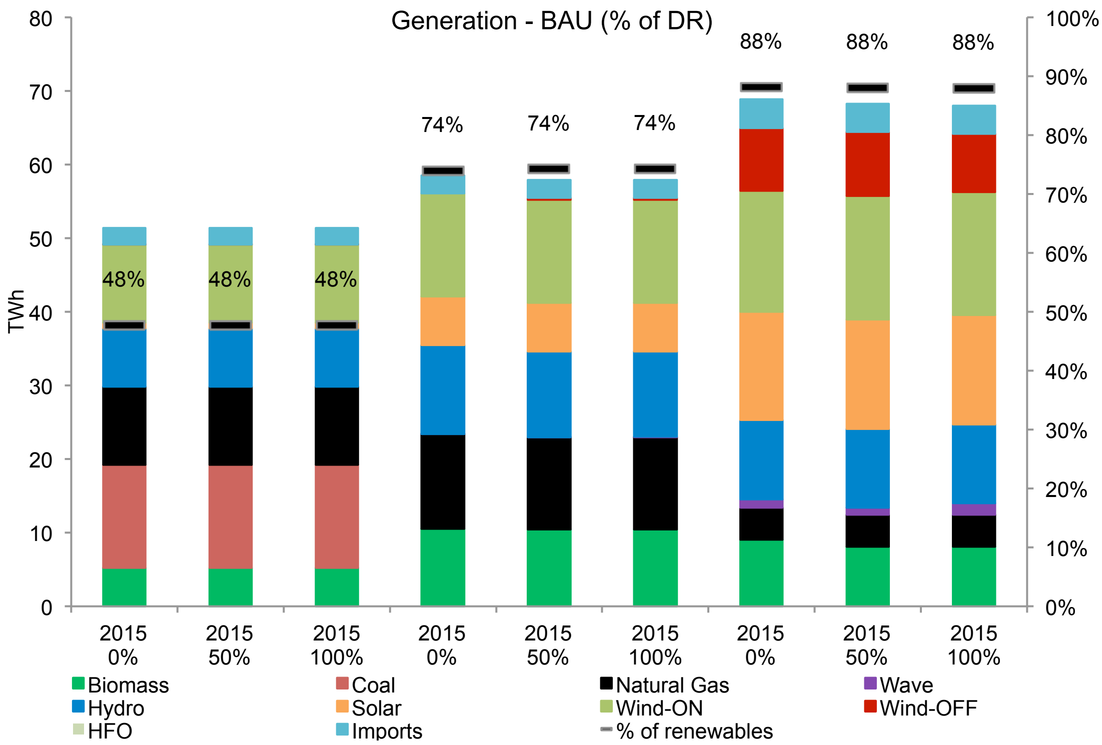

Figure 27: Results: Generation – BAU (% of DR)

In terms of CO_2 emissions, DR has a substantial impact in the LeastCost scenario (Figure 28), but not on the remainder scenarios – due to the low-carbon nature of BAU and LowCO2. This translates in a reduction in 6% of total emissions in LeastCost scenario, but only of 0.5% in LowCO2 and of 0% in BAU. This is related with the percentage of renewable generation of each system. In LeastCost scenario, DR allows for a substitution of generation from fossil fuels with renewables – with DR, the generation in 2030 coming from renewables rises from 55% to 58%. In the other two scenarios, the DR impact only affects which renewable sources generate more electricity. These two scenarios have a strict emission ceiling that restrains the model to always emit the maximum it can in order to become less costly. Therefore, the DR impact on emissions for these two scenarios is small.

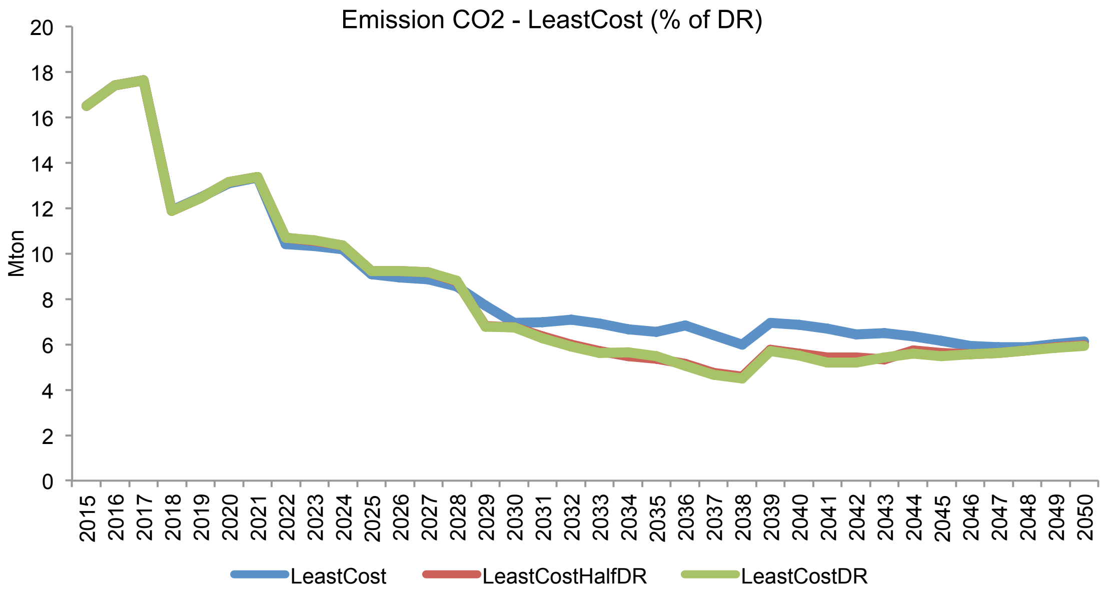

Figure 28: Results: Emissions of CO2 - LeastCost (% of DR)

6.2.3. Load shifting

In this section it is analysed all the loads that were shifted, and the percentage of its potential that was used, both in division of sectors and processes. Here, the BAU scenario is looked at closely in order to understand the technical changes that these flexible loads imply in the system.

This analysis would benefit from an hourly analysis, showing from which time to which time the flexible demands were moved around during the daily period. However, due to the extensive output data file and complex handling of the results, it was not possible to gather this data in an efficient way.

Demand shifted per sector

Analysing the total demand shifted per sector in Figure 29[8], it can be seen that the residential sector is the sector that provides more flexibility to the system (from 4.29 TWh in 2015, to 5.28 TWh in 2050) – and it is also the sector with highest potential available. Despite, its share in the total demand experiences the biggest loss of all three scenarios between the year 2015 and 2050 – from 9% to 8% of the total annual demand. This decrease in the share of the total demand will be addressed in the analysis per process, to better explain this fluctuation.

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[8] The total demand considered refers to the sum of total standard demand and total flexible demand of all the sectors. In Figure 29, the bars refer to the amount of electricity in TWh and the dots to the percentage of total demand

The industrial sector follows the same trend, but with a smaller loss in the total share of demand, remaining its share in 5% (2.4 TWh in 2015 and 2.9 TWh in 2050). This increase in the shifted load is in line with the increase of consumption throughout the model period – around 17% from 2015 to 2050. These values show a constant use of the DR potential, from which it can be inferred that the industrial sector can prove to be more predictable in terms of DR exploitation.

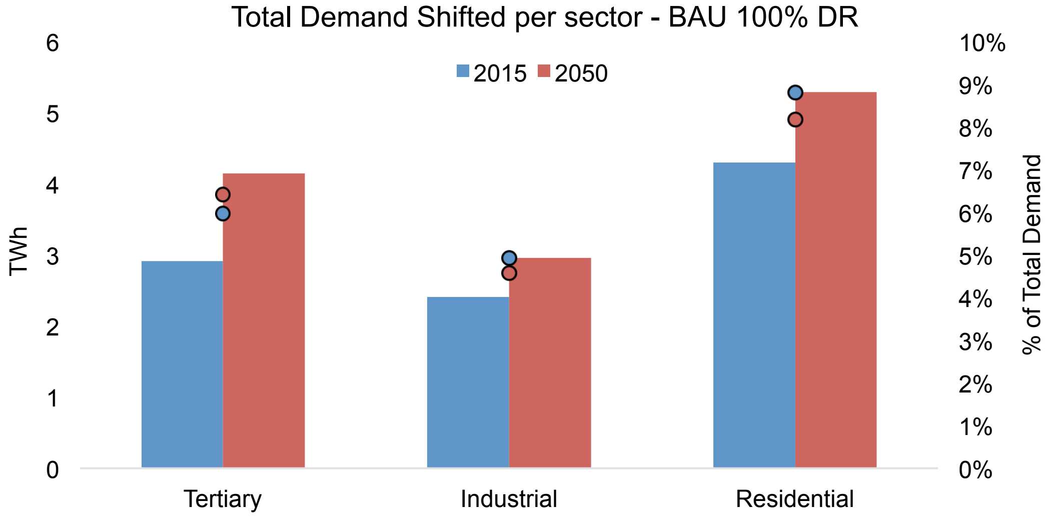

Figure 29: Results: Total Demand Shifted per sector - BAU 100% DR

The tertiary sector is the only sector that is able to increase its share of shiftable demand in the percentage of the total demand in the model period. It increases its total demand shifted in 42% (from 2.91 TWh to 4.14 TWh) - due to the increase in the potential exploited per process. This is analysed in the next sub-section.

Demand shifted per process

In relation to Figure 15, where the total potential per process of DR in Portugal is presented, Figure 30 presents how much of that potential is actually used in providing flexibility from which the system can benefit. It relates to the previous analysis since the tertiary sector processes show a different fluctuation trend from the other two sector processes.

The tertiary sector shows interesting results, where half of the processes decrease their percentage of exploited potential during the model period and the other half increase this same potential. In terms of wastewater treatment and cold storages, the load profiles allow for few flexibility in terms of pushing the demand out of the peak. Therefore, cold storages represent the biggest fall in the tertiary sector – from 58% to 34% used potential.

Concerning industrial processes, all but one (cement) show a decrease in the total potential exploited over the model period. Industry is the sector that can provide more flexibility to the system in terms of number of hours that loads can shift throughout the day. This is true apart from the ventilation of industrial processes – that provides just one daily bracket of flexibility. From Figure 30, it can also be seen that industrial processes provide the highest percentage of potential of exploitation of all the processes considered. This can relate to the simple profile of the industrial processes and to their high temporal flexibility, providing also a good indicator that verifies what was analysed previously.

The cement industry maintains its high potential of exploitation (70%) due to, mostly, its load profile, that is three times higher during the night than during the day period. This means that the installed capacity in the system is sufficient to deal with this demand during the night, and so the model can shift the demand close to the peak demand to periods were the installed capacity could manage more load from this process.

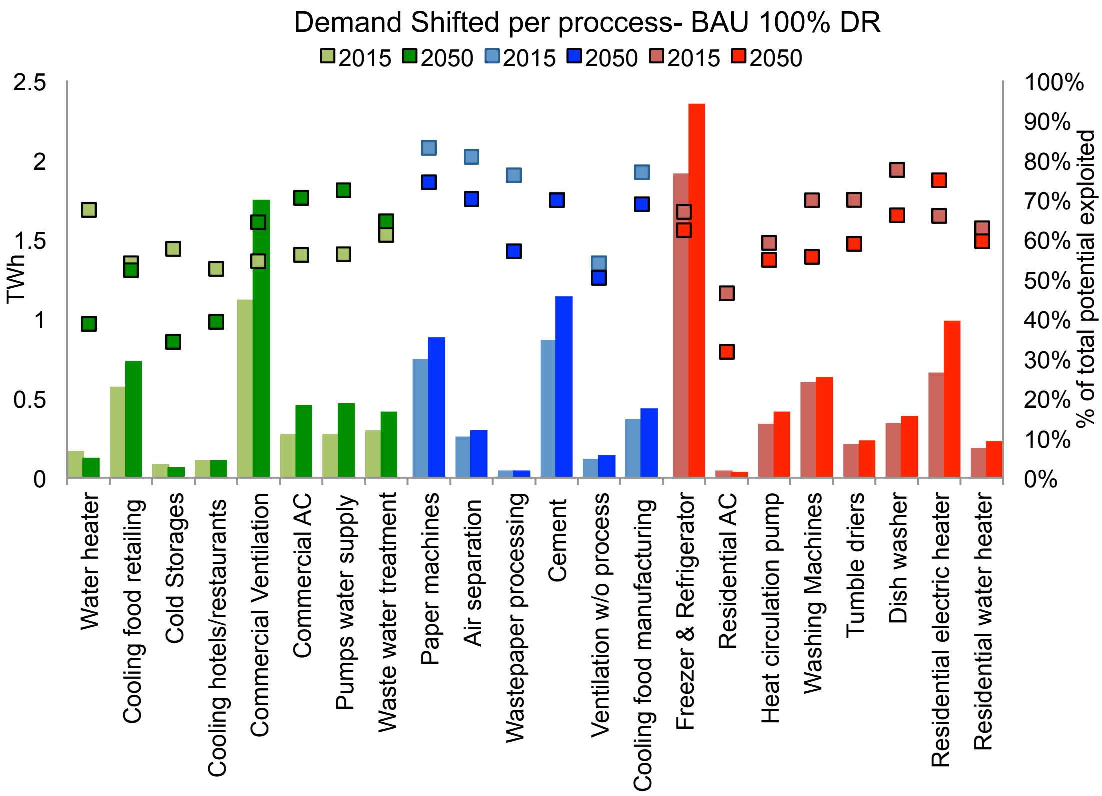

Figure 30: Results: Demand Shifted per process - BAU 100% DR

In relation to processes in the residential sector three processes go against the trend of decrease of the potential exploited: water heaters, heat pumps, and electric space heaters. Due to the fact that the daily brackets of flexibility are different within these processes, this can be explained by the load profile of the processes that can be comparable between the three processes – see Figure 18. From it, we can see that having at least one daily bracket of flexibility is enough to shift the demand away from the daily peaks, either by advancing it in the morning load peak or by delaying it in the night period. In 2050, the electric space heater is the residential process with the highest potential exploited (75%) – way above the average of 62%.

It is relevant to also analyse the role of the refrigerator and freezer – the process with the highest demand potential of all the processes considered. Due to its flat load profile and small flexibility of time its potential is only exploited in 62% in 2050. However, this is a clear approximation to the real system, where instead of one controllable load there are 6 million of households with one small load each. It is questionable, thus, the real potential it can provide to the system, noting that in the model it provides 45% of the total shifted demand in the residential sector. As a consequence, barriers discussed in the literature review arise from huge amount of effort it takes to control 6 million individual appliances in order to exploit flexibility for the electric system.

All the remainder residential processes also increase their total shifted demand, but decrease their percentage of potential exploited. An interesting point of analysis can be deduced from this perspective of reduction of the exploited potential. As the model has perfect foresight into what concerns all the information on the future technology parameters – costs, capacity factors and fuel prices – it can adjust the design of the model to a stabilized load profile (that results from the flexibility), and optimize which loads it will shift until the model is designed to meet the demands in their designated time. However, changing the design of the electric system in a cost optimized way takes a great deal of years. Nevertheless, the model period extends for 35 years, which might make the case for the less use of the DR potential throughout the time. More data will be analysed that relate to this matter in subsection 6.2.4.

50% vs. 100% DR implementation

In the simulations, scenarios with 50% and 100% DR potential available were used to assess its impact in the overall system. Therefore, the difference between these two scenarios can help infer some conclusions about the real DR potential in the Portuguese system.

In Table 11 a comparison between the percentages of potential exploited by the models in each of the scenarios is shown. These values represent which share of the total flexible demand per sector (defined in subsection 5.5) is in fact shifted – or in other words, how much of the potential of each load is important to assure the flexibility.

Table 11: Potential of DR exploitation in BAU scenario

% Of Potential exploited	50%		100%	
	2015	2050	2015	2050
Tertiary	76%	69%	56%	60%
Industrial	83%	78%	75%	70%
Residential	81%	72%	67%	62%

From the results two trends are common and patent in the presented table: industry is the sector that exploits the most of its potential throughout the model period and the residential sector is the sector that reduces more its exploited potential throughout the modeled period.

The first trend can be explained due to the less industrial processes considered, the daily load profile each process has and the number of daily brackets that the industrial processes allow for flexibility (all except for cooling, that allows one full day of flexibility). Also, two of the processes that exploit more of its potential for the industrial sector are the two with more potential load flexibility: cement and air separation, with the latter revealing the exact percentage of potential exploited throughout the modeled period (see Figure 30).

The residential sector reduces sharply its potential exploitation in both scenarios. It is clear that the sector loses some flexibility through the years, mainly due to the new installation of renewables like wind, solar and in a later period wave, which can provide the system electricity during different times in contrast with the year 2015 – due to different capacity factors – where only wind has a relevant capacity share (see Table 5).

Tertiary sector presents the least potential exploitation of all the scenarios, while providing a mix of trends – decreases its usage of flexibility through time in the scenario with 50%, but increases it with 100% DR implementation. The load profiles of the processes of the tertiary sector can explain this increase, as are mainly concentrated during the day period. With the system capable of generating more electricity during the mid-day off peak period due to changes in the installed capacity - high increase of solar that peaks the generation during mid-day – more loads can be shifted throughout the day.

The change in the design of the electric system throughout the modeled period also affects the usage of flexibility of the model. The fact that solar installation rises to the maximum potential in 2050 in BAU scenario can be analysed. From it, the system is able to meet more of its demand during the day. This leads to shifted loads during midday and also less need to shift demands that were needed to be shifted without the solar capacity, hence the reduction of potential. This is true for industry, given that the majority of the loads considered for DR are during the night. Therefore, with the high flexibility provided by the processes these can be shifted to daytime, during the hours when the sun is generating high amounts of electricity.

Finally, it makes sense that with half of the demand response implementation, the potential of the use of flexibility is higher. The curve between the percentage of implementation and the potential exploited is not linear, and it can give important information on the real deployment of DR. For example, DR implementation in the residential sector is extremely complex, but these results show that implementing only 50% of the potential of this technology in the sector can already have a major impact in the system. On the other hand, the industrial sector shows a much more linear and predictable response to DR, maybe verifying the high propensity for DR programs – from the processes considered.

6.2.4. Economic Analysis

In order to do an economic analysis and to better discuss the impact in the cost of the system, it is important to note that the model uses cost optimization to choose how the electricity system is designed. As a consequence, all the scenarios with demand response were less costly than the scenarios without. This tendency also stands for the different levels of implementation of DR, where 100% DR implementation scenarios were less costly than the scenarios with only 50%.

As mentioned before, no associated costs with DR were considered. Therefore, it is not the purpose of this study to conclude whether a system with DR implementation would be less costly than a system without DR, if all the costs were to be considered. However, one can consider that the decrease on the overall costs, from scenarios with 0% DR to 100% DR, can be the investment frontier to implement DR.

Impact in the overall cost

With DR implementation, the overall costs are reduced. For this, the largest contribution arises from avoided capacity investments due to the lower need for installed capacity – mainly from thermal power plants.

In terms of overall system costs for the model period, DR reduces the costs in all the scenarios. In BAU, DR reduces the cost in 1.67% - over 1 billion EUR. For the other two scenarios the trend is traversal. In scenario LeastCost the fall in cost is 0.85% and in the LowCO2 scenario the difference reaches 2.23%.

From these results, it can be noted that the difference in costs is directly related to the installed capacity - discussed in the previous sub-section – and all its associated costs. Moreover, this difference reaches higher values in systems with high share of renewable capacity, as it can be seen from scenario BAU and LowCO2.

Impact in the annual costs

In Figure 31, it is shown the annual fluctuations according to the implementation of DR in the costs of the system for the BAU scenario. In the year 2030, the change in costs related to DR does not have substantial differences. However, in the year 2050, some changes are already perceptible. As mentioned above, avoided capacity investments contribute to these differences, but not alone. Comparing the scenario BAU with BAUHalfDR (50% DR) and BAUDR (100% DR), it is clear that the variable costs shrink in proportion to the implementation of DR. This is due to the flexibility that DR provides to the demand, that the system can shift in order to be met at times when renewable generation is available from sources that don't have associated variable costs – wind, solar and wave.

Costs associated with CO_2 emissions are the same for all the scenarios. This makes sense, as the emissions in the last year of the model period hit the emission ceiling in all the scenarios. In terms of fixed costs, the differences also arise from the different capacity installed between the scenarios. In the scenario without DR, this value is higher because there is more capacity installed, which means that more capacity needs operations and maintenance.

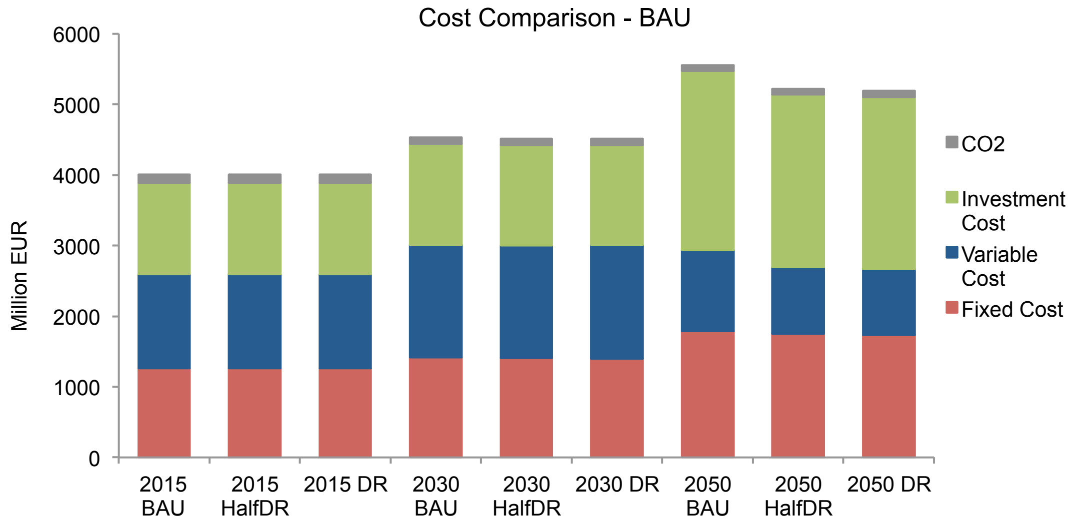

Figure 31: Results: Cost Comparison – BAU

Comparing the scenario 100% DR with standard BAU scenario, the variable costs decrease 18.7%, investment costs decrease 3.7% and fixed costs decrease 3.3%.

Impact in the average electricity cost

Another analysis from an economical point of view can be done according to the electricity cost – and indirectly it can relate to the cost it has in the final electricity consumer. In analogy to Figure 24, in Figure 32 the curve of the electricity cost is compared with the curves of the scenarios with DR.

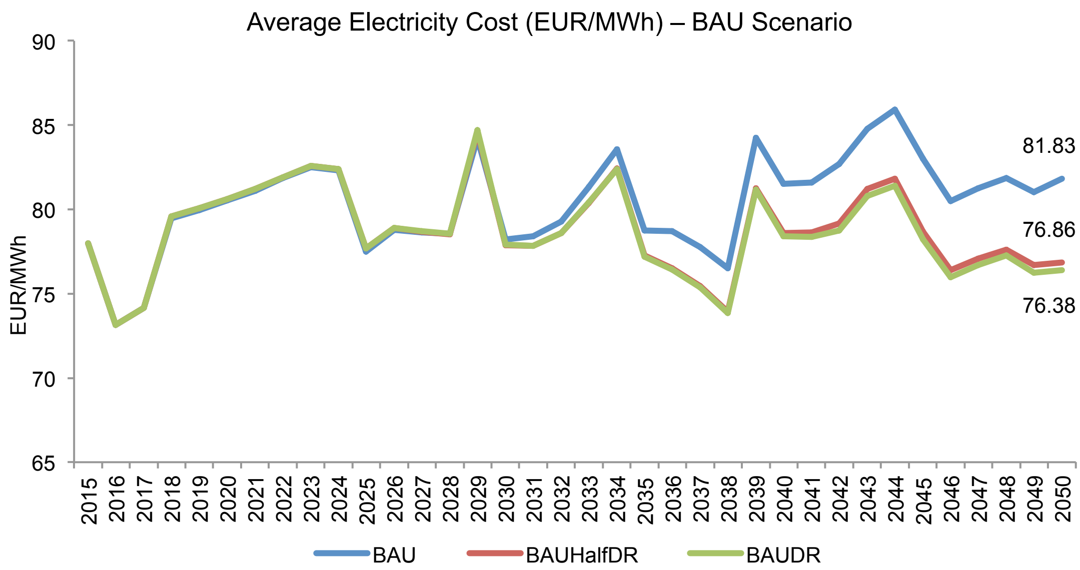

Figure 32: Results Average Electricity Cost (EUR/MWh) – BAU Scenario

Two main conclusions arise from the analysis of the graph. The first conclusion to be taken is that 50% DR implementation provides 95% of the cost benefits of the total benefits available. This is important if we relate this numbers with the potential exploitation discussed in subsection 6.2.3. The impact of adding the 50% of flexibility is even less relevant in scenario LeastCost, were 50% DR can exploit 99% of the available cost benefits. This relates to the share of generation that comes from renewables: in scenario LeastCost, 37% of the generation comes from thermal NG power plants. Therefore, flexibility provided by DR is used to shift smaller quantities of loads, due to the less need for balance in the overall system. However, scenario LowCO2 had the same results as in BAU, showing that flexibility is a key tool for systems with high share of renewables.

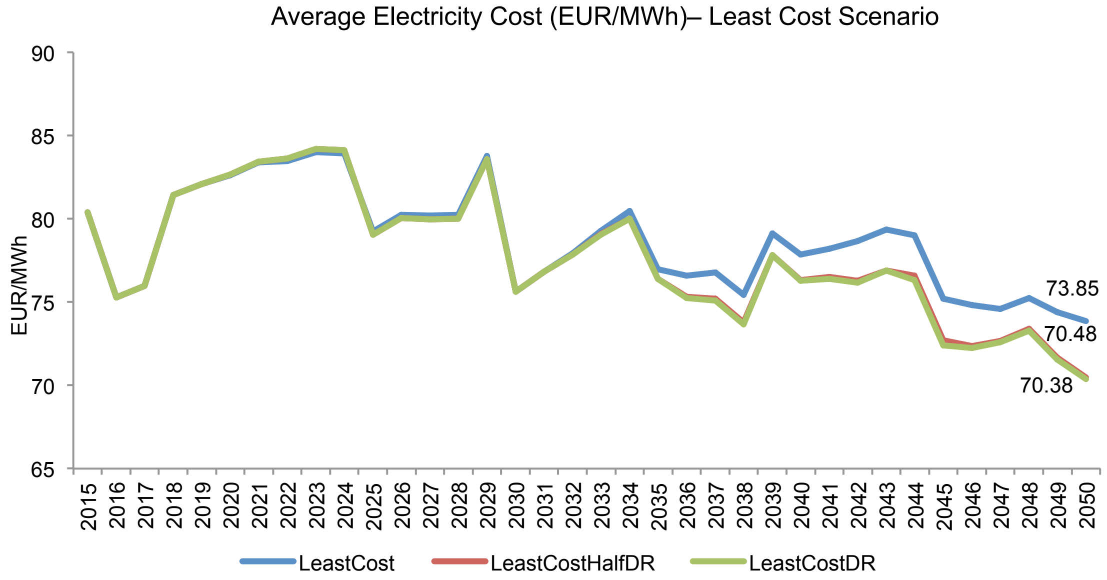

Figure 33: Results Average Electricity Cost (EUR/MWh) – Least Cost Scenario

The second important indicator retrieved from Figure 32 is that the impact that DR implementation has in the average electricity cost is only visible from 2030 on, when the curves of the scenarios start to evolve differently – which also relates to the non-existing differences in Figure 31 for the same year. This means that the implementation of DR takes time to impact on the overall system. In this scenario it took 15 years of the model period. However, in scenario LowCO2 the impacts start to be seen in the year 2027, and interestingly in scenario LeastCost these changes only happen in 2034. This also verifies the matter discussed in the last paragraph.

6.3. Summary of results

Table 12 presents a summary of all the relevant results from the simulations with 0%, 50% and 100% demand response implementation for the three scenarios modelled. Most of the results present in the table were analysed in the previous sections.

Table 12: Summary of results

Scenario Results	BAU			LeastCost			LowCO2		
	0%	50%	100%	0%	50%	100%	0%	50%	100%
Cost (M€)	61080	60122	60063	58980	58507	58479	62272	60887	60883
Total Capacity 2050	31.74	31.20	31.05	27.59	27.01	26.99	34.27	34.42	34.10
Total Capacity 2030	23.66	23.38	23.36	22.74	23.64	23.64	26.40	25.89	25.82
% of renewable capacity 2050	96.81	97.47	97.65	85.92	87.71	87.85	97.45	98.35	98.51
% of renewable capacity 2030	85.34	86.23	86.32	82.45	85.70	85.69	86.28	87.57	87.85
Total generation (TWh) 2050	68.65	68.07	67.98	71.24	70.45	70.21	71.57	71.57	71.57
Total generation (TWh) 2030	58.34	57.75	57.90	59.48	59.32	59.32	60.48	59.55	59.53
Demand (TWh) 2050	64.50								
Demand (TWh) 2030	54.85								
% of Renewable generation 2050	87	87	86	58	58	58	95	95	95
% of Renewable generation 2030	74	74	74	55	58	58	76	75	76
Total emissions	182	182	182	313	295	294	170	169	169
Emissions 2050	1.00			6.12	5.96	5.95	0.00		
Total Emissions Cost (M€)	2204	2203	2204	2089	1992	1986	2349	2338	2333

6.4. Comparison with other Portuguese models

Using studies [42] and [44] (mentioned in the literature review), a comparison is made with the presented thesis. As the studies are also capacity expansions of the Portuguese electricity system, it is interesting to see the changes in the assumptions and inputs, and what consequences these have in the final results. Also, the comparable indicators can be used to verify or put in perspective future projections of the system. Note that the studies mentioned consider the demand as a whole and don't make the distinction between standard and flexible demand.

In [42], the impact of climate change in the hydropower electricity generation is assessed. The main differences in the assumptions used in this study rely on the inexistence of an emission target – which in the presented study is the main driver – and that the Portuguese system is an isolated system (no exchange with Spain). The results show that in 2050 in terms of total installed capacity the scenario without climate change results in 28.7 GW of installed capacity (BAU scenario has 31.74 GW). Generation results show that 91% is due to renewable generation (close to 87% of the BAU scenario presented) and total generation

56.7 TWh of total generation in 2050, which is a big difference compared to our assumption of 64.5 TWh of total demand. As no emission target is considered and less assumed demand, the total installed capacity in the study considered is smaller. Also, the installed capacity that generates electricity from fossil fuels is bigger, due to the no limit on emissions. Therefore, emissions for the year 2050 in all the scenarios in the study are more than double the emissions in BAU scenario. Finally, as no exchanges within the Iberian Peninsula are considered the value for renewable generation is quite high (91%) compared with the BAU scenario - renewable generation in BAU scenario without exports rises to 93%.

In [44], the impact of the rise of the carbon price in the shape of the electric system is studied. Comparing with the study, big differences arise from the assumptions on restraints of new coal capacity (present until 2050) and in the introduction of new technologies of CCS. Also, the hydro potential is considerable higher in the study. The result of these assumptions is that the installed capacity in 2050 is very different from the one presented in this thesis: for example, solar only starts being installed in 2047 in the scenario with 70 €/ton of CO_2, no offshore wind nor wave is installed and CCS technologies account for 30% of total generation. However, comparing the scenario with higher CO_2 cost (300 €/ton) and the LowCO2 scenario, in 2050 the generation share from solar PV is about the same – 20% of total generation.

7. Conclusions and further research

7.1. Main Conclusions

Portugal's electric system has already a high share of both renewable capacity and generation – 58% and 48% respectively [18]. In the electric system, the 2020 emission targets are legally binding, which means that it is compulsory to meet them. In this matter, Portugal will meet all of the targets it proposed. The EU has a vision that lasts until 2050, but this is not a legally binding agreement, meaning that member states can fall short on the targets set in the EU vision without any legitimate loss [86], [88]. In other words, there is no real incentive to achieve these new targets. On the other hand, Portugal has assumed that its individual vision for 2050 is of a total carbon-free electric system, in order to meet its share of contribution to the desired 2ºC of total global warming [8]. Thus, studies like the one presented in this thesis can contribute to understand how this goal may become a reality.

With the implementation of DR, Portugal can take a step closer in achieving a 100% renewable sources system in 2050. The importance of DR reveals itself more relevant in systems with high share of renewables already installed, but still has challenges to achieve the remaining percentages that lead to a complete 100% renewable system. These problems arise mainly from generation, and the balance that DR is able to provide throughout the sectors is a key tool in systems with these characteristics. It is patent in the results of this study that these hypotheses are verified.

From the three scenarios assessed, two of them provide results that are compliant with targets for EU's vision for 2050, and a third one provides results that can project a future with higher uncertainty, less European planning and that is more economically and less environmental driven.

The implementation of DR is transversal in reducing the cost of all three scenarios assessed. This cost reduction is related to the percentage of renewables each scenario presents, increasing in the scenarios with higher renewable capacity and generation. In the carbon free system in 2050 scenario, these cost reductions are over 1 billion EUR. However, since no costs associated with DR implementation were considered, it is senseless to analyse the economic viability of an investment in DR technology for the future.

The impact of DR in the overall system takes, on average, 15 years of the model period to become relevant – in terms of capacity expansion and costs. In the analysis it can be seen that in the scenarios with higher share of renewables this impact is started to become relevant sooner - 12 years for the carbon free system scenario – than in the scenario without emission relevance (18 years).

The complexity of implementation of DR can prove a hard obstacle to energy planers, policy makers and investors. However, the results show that even with just 50% of the potential of DR implemented 95% of the cost benefits could be reach (comparing with 100%

implementation). These costs arise mainly from avoided costs in installed capacity and less variable costs due to more generation from renewables without any marginal cost. This has then all the subsequent benefits in the overall system. Therefore, it can be concluded that with half the potential of DR used, a relevant part of the benefits could be available.

In the processes considered for this study, the demand sectors were divided in tertiary, industrial and residential sector. Although the residential shows the highest total potential of demand that can provide flexibility, it is also by far the most complex. The total demand shifted from this sector diminished significantly within the model period, which can be inferred to be related to the less need for balancing in a system with more capacity from solar and wind sources. The tertiary sector showed the smallest percentage (in relation to the potential) of total demand shifted. An indicator that relates to the fact that load profiles of the tertiary processes are very close to the peak of demand and the majority of the processes have the lowest flexibility considered. Finally, industrial processes showed a constant and steady increase in total demand shifted and due to its profiles and flexibility in terms of time, proved to reach the highest percentage of potential for DR. It can be also considered as the sector with the lowest risk for DR application, due to its constant results and considerable less complexity in relation to the other two sectors.

7.2. Research questions

- Can the implementation of demand response lead to reduction of relevant power reserves that mostly run on fossil fuels?

The implementation of DR proved to reduce the costs in all the scenarios presented. The cost reduction is in great part related to avoided costs in installed capacity, and from the avoided capacity installation a big part of it was of thermal power plants. In the model, the only allowed new thermal power plants were either natural gas or biomass. So it is fair to say that the reduction of thermal capacity of natural gas power plants is influenced by the implementation of DR, since biomass thermal plants are necessary to provide backup to the system (as do NG also), However, with biomass power plants there is no obstacle in reaching a carbon free system – as is patent in the low carbon scenario.

- Can technologies like demand response enable us to increase the percentage of penetration of renewable energy sources?

Using the research question above as base, some scenarios showed the exchange of thermal natural gas and biomass capacity for wind offshore. This fact alone (considering the natural gas plants) proves the increase of the renewable penetration. However, all the scenarios showed an increase in the percentage of renewable capacity. In terms of renewable generation, the biggest increase in the percentage of generation coming from renewables was in the scenario without a big environmental driver. Nevertheless, the more ‘green’ scenario was already limited by the emission target, which meant that it was already generating from renewables its maximum potential.

- How much the percentage of implementation of demand response relate to the impact in the system?

From the three scenarios assessed, in average, 50% of the implementation of demand response led to a 95% of the exploitation of the economical benefits. This is a very useful concluding remark, and its consequences can also help to understand how demand response should be implemented. For example, in the residential sector, if only half of the households is considered for DR programs, its implementation would be half as hard, but it could be exploited almost all the benefits.

7.3. Limitations of the study

The presented study, despite tapping important aspects of real electric systems that can help policy makers project the future of it, has, of course, some limitations that arise from simplifications that keep its complexity manageable. Here, some of these limitations are mentioned. The limitations hereby presented are the ones the author believes have more impact in the results of the model and its improvement could help determine results that might be more according to what happens in the daily evolution of the real system.

Relative to the energy system as a whole no heating, transports or water balance assessment is made in this study. Therefore, it is not possible to evaluate the impact that the electric system evolution would have in the primary energy consumption for Portugal or the evolution of its energy dependence for the future.

Long-term models hardly tap hourly or sub-hourly fluctuations of demand, and come short on modelling market-based electricity exchange. This directly affects the assumption of the interconnection with Spain and the model of the hydro pumped storage capacity – that up to some extent operates in line with market fluctuations. Therefore, the low time resolution of the model can provide low variability of exchange in electricity from the neighboring country Spain and can also affect the impact that pumped storage can have in the overall generation.

Offshore wind interconnections were not differentiated from standard grid connection, which might predict optimistic future installation due to the high costs of subterranean interconnections that span to the ocean.

The low variability of capacity factors, that were assumed to be the same for all the model period years can also affect the results in an optimistic way. Problems also arise with the aggregation of technology capacities, meaning that all the capacity is whether all on-line and generating electricity, or in the other hand is all off-line.

The thermal power plant ramping characteristics were not considered in this study. This relates to the minimum stable operation capacity of individual power plants – considered to be on average 30% of the installed capacity of a thermal power plant. And also, the reserve capacity that is demanded to be on-line to provide backup when renewables are generating electricity was also not considered.

Finally, the fact that DR costs were not considered can also affect the model to provide optimistic results. This is related with the fact that no barriers were considered – apart from the cost – and that the DR potential is freely used in order to optimize the cost of the system. However, with DR costs being taken into account a lower share of shifted demand would be used by the model, changing the presented results.

7.4. Further research

Using this study as a baseline for future studies (as this study did with previous ones), the options are too many to mention them all. Some of the recommendation for future work and research, both concerning the Portuguese electric system and DR implementation, are provided here.

It would be interesting to see the Iberian Peninsula incorporated in one system to assess the interconnection with the rest of Europe, as one of the big concerns of ENTSOE is to incorporate the renewables from Portugal and Spain into the wide European market.

Link the capacity expansion model to a macro-economical model with elasticity of demand from the electricity cost from the end consumers to see the impact it has on the overall system. This would: 1) reduce the optimistic results in installing renewable and more costly capacity due to the fall of demand due to higher average costs of electricity; 2) assess better the impact of societal appropriation of DR, since DR would keep the average electricity cost low as seen in this particular case.

Finally, the capacity expansion model results could be linked to a dispatchable model to see the feasibility of the results for each of the scenarios, and how the geospatial distribution of the power plants would affect the generation and de-centralized dispatch of electricity.

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Annexes

A. Capacity Factors

The following tables and graphs present the input values for the capacity factors of renewable energy sources. For hydro, constant monthly capacity factors are assumed both for pumped storage and for normal hydro. For wind and solar, a day type was calculated for each month and its hourly capacity factor was condensed into four time slices. The time slices period is explained in section 5.3.

1. Hydro

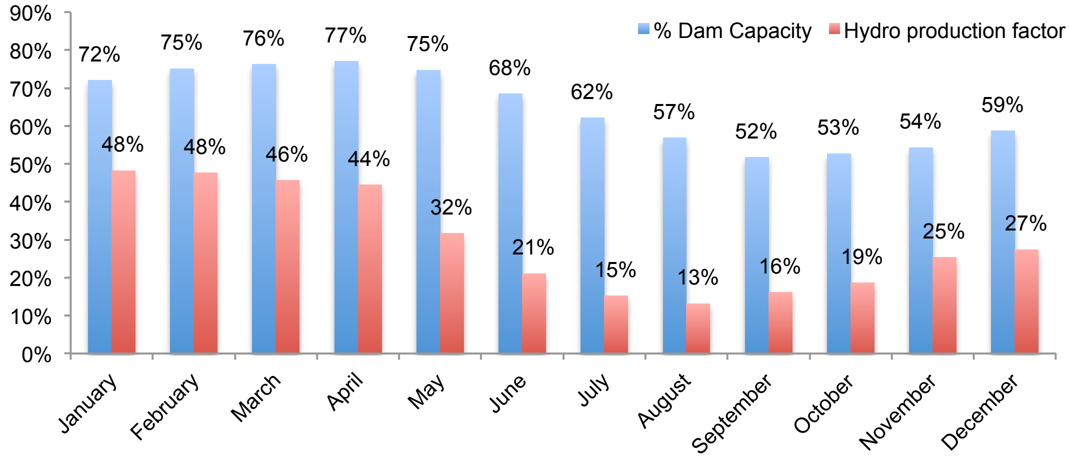

Figure 34: Hydro capacity factors

2. Wind

Here are presented the wind capacity factors. The rows bellow represent each of the four daily brackets considered for both weekday and weekend for each month as explained in section 5.3. The table for solar capacity factors is organized in the same fashion.

Table 13: Wind capacity factors

Jan		Feb		Mar		April		May		June	
B1	0.282	B1	0.361	B1	0.161	B1	0.389	B1	0.216	B1	0.165
B2	0.351	B2	0.359	B2	0.131	B2	0.508	B2	0.282	B2	0.132
B3	0.339	B3	0.345	B3	0.164	B3	0.449	B3	0.334	B3	0.222
B4	0.356	B4	0.314	B4	0.219	B4	0.365	B4	0.252	B4	0.240

July		Aug		Sep		Oct		Nov		Dec	
B1	0.143	B1	0.181	B1	0.153	B1	0.136	B1	0.239	B1	0.384
B2	0.130	B2	0.098	B2	0.258	B2	0.129	B2	0.224	B2	0.307
B3	0.302	B3	0.217	B3	0.317	B3	0.116	B3	0.239	B3	0.249
B4	0.252	B4	0.185	B4	0.265	B4	0.122	B4	0.258	B4	0.275

3. Solar

Table 14: Solar capacity factors

Jan		Feb		Mar		April		May		June	
B1	0.008	B1	0.013	B1	0.041	B1	0.049	B1	0.064	B1	0.075
B2	0.335	B2	0.402	B2	0.598	B2	0.545	B2	0.559	B2	0.613
B3	0.099	B3	0.157	B3	0.283	B3	0.302	B3	0.346	B3	0.361
B4	0.000	B4	0.000	B4	0.002	B4	0.038	B4	0.076	B4	0.106

July		Aug		Sep		Oct		Nov		Dec	
B1	0.075	B1	0.063	B1	0.040	B1	0.023	B1	0.010	B1	0.007
B2	0.635	B2	0.598	B2	0.511	B2	0.471	B2	0.380	B2	0.419
B3	0.393	B3	0.348	B3	0.250	B3	0.197	B3	0.138	B3	0.125
B4	0.114	B4	0.060	B4	0.009	B4	0.000	B4	0.000	B4	0.000

B. Technology detailed parameters

Table 15: Technology inputs

Tech	Availability	Efficiency	CAPEX(M$/GW)			FOM ETRI	VOM ETRI (M$/PJ)	CO2 (Mt/PJ)
			2015	2030	2050			
BMCCDH1	0.85	40%	6,589.04	4,301.37	3,506.85	184.49	3.12	0
BMCHDH2	0.85	30%	5,027.40	4,095.89	3,479.45	150.82	1.26	0
BMCHFH1	0.85	30%	5,027.40	4,095.89	3,479.45	150.82	1.26	0
BMCHPH3	0.85	30%	5,027.40	4,095.89	3,479.45	150.82	1.26	0
BMRCFH1	0.85	65%	5,645.04	5,645.04	5,645.04	395.15	1.33	0
BMSTDH2	0.85	35%	3,958.90	3,246.58	2,945.21	110.85	1.33	0
BMSTPH3	0.85	35%	3,958.90	3,246.58	2,945.21	110.85	1.33	0
COCHDH1	0.85	40%	2,780.82	2,780.82	2,780.82	-	1.94	0.1127
COCHPH2	0.85	40%	2,780.82	2,780.82	2,780.82	-	1.94	0.1127
COCHPH3	0.85	40%	2,780.82	2,780.82	2,780.82	-	1.94	0.1127
COSTDH1	0.8	46%	2,191.78	2,191.78	2,191.78	54.79	1.37	0.2472
COSTPH3	0.8	46%	2,191.78	2,191.78	2,191.78	54.79	1.37	0.2472
HFCCDH2	0.85	58%	1,127.07	-	-	45.08	0.56	0.2083
HFCHDH2	0.91	7%	780.16	-	-	31.21	1.67	0.1130
HFCHPH3	0.91	7%	780.16	-	-	31.21	1.67	0.1130
HFGCDH2	0.15	38%	1,020.99	-	-	40.84	4.17	0.2083
HFGCDN2	0.15	40%	729.28	-	-	29.17	3.33	0.2083
HFGCPH3	0.15	38%	1,020.99	-	-	40.84	4.17	0.2083
HFGCPN3	0.15	40%	729.28	-	-	29.17	3.33	0.2083
HFHPDH2	0.97	42%	1,791.10	-	-	71.64	4.72	0.2083
HFHPFH1	0.97	34%	2,749.76	-	-	109.99	4.72	0.2083
HFRCDH2	0.97	42%	1,791.10	-	-	71.64	4.72	0.2083
HFRCFH1	0.97	34%	2,749.76	-	-	109.99	4.72	0.2083
HFSTDH2	0.8	43%	2,536.66	-	-	101.47	4.72	0.2083
HFSTPH3	0.8	46%	2,789.83	-	-	111.59	4.72	0.2083
HYDMDH1	1		4,520.55	4616,44	4,616.44	135.62	1.90	0
HYDMDH2	1		4,520.55	4616,44	4,616.44	135.62	1.90	0
HYDMFH0	1		6,027.40	6164,38	6,164.38	241.10	1.90	0
HYDMPH3	1		3,013.70	3013,70	3,013.70	105.48	1.14	0
HYDSDH2	1		4,109.59	4109,59	4,109.59	61.64	-	0
HYDSPH3	1		4,109.59	4109,59	4,109.59	61.64	-	0
HYWVDH1	1		12,438.36	6136,99	3,150.68	310.96	-	0
NGCCDH2	0.85	58%	1,164.38	1164,38	1,164.38	29.11	0.76	0.1027
NGCHPH3	0.89	42%	1,205.48	-	-	108.49	0.91	0.0747
NGCHPN3	0.86	60%	1,383.56	1356,16	1,328.77	69.18	1.52	0.0644
NGFCFH1	0.98	53%	1,988.98	1988,98	1,988.98	99.45	0.76	0.1111
NGGCDH2	0.15	38%	1,054.79	-	-	10.5	4.95	0.1763
NGGCDN2	0.15	40%	753.42	753,42	753.42	22.60	4.19	0.1597
NGGCFH1	0.15	38%	1,054.79	-	-	10.55	4.95	0.1763
NGGCFN1	0.15	40%	753.42	753,42	753.42	22.60	4.19	0.1597
NGHPDH2	0.97	42%	1,457.36	1457,36	1,457.36	72.87	0.76	0.1597
NGHPFH1	0.97	34%	2,237.40	2237,40	2,237.40	111.87	0.76	0.1597
NGRCFH1	0.97	34%	2,237.40	2237,40	2,237.40	111.87	0.76	0.1597
NGSTDH2	0.8	43%	2,064.00	2064,00	2,064.00	103.20	0.76	0.1597
SODIFH1	1		1,794.52	1356,16	1,205.48	35.89	-	0
SOUTDH2	1		1,506.85	1109,59	986.30	37.67	-	0
WIOFDH2	1		4,753.42	3534,25	3,123.29	175.88	-	0
WIOFPH3	1		4,753.42	3534,25	3,123.29	175.88	-	0
WIONDH2	1		1,917.81	1780,82	1,506.85	46.03	-	0
WIONPH3	1		1,917.81	1780,82	1,506.85	46.03	-	0
WSCHDH2	0.8	30%	5,027.40	4095,89	3,479.45	150.82	1.26	0.2236
WSCHFH1	0.8	30%	5,027.40	4095,89	3,479.45	150.82	1.26	0.2236
WSSTFH1	0.7	35%	3,958.90	3246,58	2,945.21	110.85	1.33	0.2777

Legend:

Type of nomenclature FUEL-TYPE-SIZE

FUEL: BM- Biomass; CO – Coal; HF- Heavy fuel oil; HY- Hydro; NG – Natural Gas; SO – Solar; WI – Wind; WS – Waste

SIZE: GC – Gas cycle; ST – Steam Turbine; CC – Combined Cycle; CH – Combined heat and power; HP- Heat Recovery; RC – Reciprocating Engines; DM – Dam; DS – Pumped Hydro; WV – Wave; ON- On-shore; OF- Off-shore; DI – Distributed PV; UT – Utility PV;

SIZE: X** P- Primary resource; D: Secondary; F: Final; *X*: H: Existing capacity; N- New capacity; **X: 1-Small Power Plant; 2 - Medium; 3 – Large

C. Shiftable Loads inputs

Table 16: Shiftable loads inputs

Sector	Process	t-shift	Energy (GWh/a)	Profile Ref.
Industrial	Cement mils	24	1243	[5]
Industrial	Recycling paper processing	24	216	[5]
Industrial	Paper machines	24	901	[5]
Industrial	Air separation	24	60	[5]
Cross-sectional Process	Cooling in food manufacturing	24	480	[5]
Cross-sectional Process	Ventilation w/o process relevance	2	217	[5]
Tertiary	Cooling in food retailing	2	1066	[5]
Tertiary	Cold Storages	2	147,6	[5]
Tertiary	Cooling in hotels and restaurants	2	213,2	[5]
Tertiary	Commercial Ventilation	2	2066,4	[5]
Tertiary	Commercial air conditioning	2	492	[90]
Tertiary	Commercial Storage water heater	12	246	[91]
Tertiary	Pumps in water supply	2	492	[5]
Tertiary	Waste water treatment	2	492	[5]
Residential	Freezer/Refrigerator	2	2870	[92]
Residential	Washing Machines, Tumble driers, Dish washer	6	1606	[92]
Residential	Residential AC	2	94,77	[90]
Residential	Residential electric storage water	12	295,2	[93]
Residential	Residential heat circulation pump	2	573,6	[94]
Residential	Residential electric storage heater	12	1004,5	[94]