# Influence of thermal plants cycling costs in the economic balance of renewables in Portugal


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***Abstract* — The main focus of this work is to evaluate if the cycling costs of the Portuguese thermal plants increased with the escalation of electricity produced from renewable energy sources, particularly variable sources, in the power system over the years, and to frame these costs in the total renewable overcosts. Then, these are compared with the total economic benefits from renewables. The work is important since there is still an argument used in disproval of renewable energies based on the cycling costs, which claims that these are unsupportable. It adds value since there are no previous works evaluating the cycling costs of each thermal plant in the Portuguese power system, and also by doing a quantification of the economic benefits of the renewable energy. Two models were developed for this, one in which evaluation of the cycling costs is done, and another to quantify the economic benefits. The results of these illustrated that the cycling costs represented less than 1% of the total renewable overcosts in the year analyzed. It is concluded that the cycling costs did rose between the years analyzed but are insignificant when compared both with the total overcosts and economic benefits.**



***Keywords – Renewable energies, electricity price, LCOE, MIBEL, intermittent renewable energy, cycling costs***


## I. INTRODUCTION

The world is changing. It is impossible to deny that the pollution and the utilization of natural resources at a fast pace are some of the causes. Portugal, to fulfil the European Commission guidelines for 2030, agreed to commit to ambitious targets. One of these targets is a weight of 31% on final energy consumption in 2020 and 40% in 2030 from renewable energy sources (RES). To do so, it is expected to have 80% of electricity produced by renewable energy sources in 2030. Big investments in technologies have been made to improve the generation of electricity by renewable energy sources. Additionally, and due to its favorable climacteric conditions, Portugal is in a good position to make the transition to a power system less dependent on fossil fuels. It is not by chance that in 2016, Portugal was the sixth country in the European Union, ninth in Europe, with more electricity produced from renewable energy sources (57%) [1].
However, there are still arguments used to discredit these technologies, in favor of more conventional generation units. An argument used to discredit the use of electricity generated by renewable energy sources is that they will involve additional costs which arise in conventional thermal plants due to the intermittence of the wind and photovoltaic technologies. It is claimed that, some years ago, when there were only dispatchable generation units in the system, it was easier to plan the electricity that needed to be produced by each thermal unit. Having this in mind, the planning of a thermal unit could be more precise, reducing some costs. Nowadays, with the inclusion of intermittent technologies, it might become harder to do this planning. On the other hand, the intermittence has always been present in the system, due to the consumption, which varies during each day.
The purpose of this thesis is to evaluate the growth of the cycling costs in the Portuguese thermal units due to the increase of electricity in the power system produced by intermittent technologies, namely wind and photovoltaic, and to frame these extra costs in the economic benefits from these sources. To do so, the thesis will focus on the following objectives:

- Describe and explain the functioning of the Portuguese wholesale electricity market;
- Analyze the evolution of the levelized cost of energy of the different technologies, focusing on renewable energy sources;
- Detail and explain the different cycling costs that thermal plants have;
- Quantify the impact of these costs in the Portuguese power plants;
- Calculate the monetary influence in the electricity wholesale market caused by renewable energies;
- Frame the cycling costs in the economic benefits of the renewable energies;
- Compare these benefits with the total renewable overcosts;
- Calculate a final balance between the costs and profits.

The paper is organised as follows: Section I – Introduction; Section II – Portuguese Electricity System; Section III – Power System Costs; Section IV – Models Overview; Section V – Results and Analysis; Section VI – Conclusions.

## II. PORTUGUESE ELECTRICITY SYSTEM

In the last decades, a shift to more electricity produced from RES has been happening in the electricity consumption in Europe, as well as in Portugal. In 2016, 57% of the electricity consumed was produced by RES. Just like the consumption of electricity, the Portuguese electric sector has also been changing. After several changes throughout the years, the electric sector is currently divided in six different areas, production, transport, distribution, commercialization, electric market operations and logistics operations, whose function is to intermediate an exchange between sellers by a consumer. Each of these activities usually function independently and must respect the competition principles, in order to maintain and impulse a fair wholesale electricity market.

The production can be divided in two regimes. Ordinary Status Generation (OSG), which includes all the classic non-renewable thermal plants, as well as the big hydro plants, and Special Status Generators (SSG), which are all the producers which use renewable energy sources, except big hydro, and the cogeneration producers. OSG producers sell their energy in a free market regime. As for SSG producers, a special feed-in tariff is paid for the most of these projects, to make them economically interesting, so that Portugal continues its transition to a more environmentally sustainable production of energy. The current SSG are all the small hydro (until 10 MW), biomass and biogas, wind, solar and waves, urban and industrial waste and cogeneration, both renewable and non-renewable. [2].

The transport is done exclusively by REN, the Portuguese Transmission System Operator (TSO). REN is responsible for the construction, well-functioning and maintenance of all the transmission lines, which are mostly lines of 400 kV, 220 kV and 150 kV. It is also responsible by the overall well-functioning of the Portuguese electrical system, coordinating all the production and distribution, to secure a reliable and safe system. These activities are sustained by tariffs which are paid by all the consumers. [3].

The distribution can be divided into two categories: high and medium voltage, which have lines of 60/130 kV and 6/10/15/30 kV respectively, and the distribution is in charge of by EDP Distribuição; low voltage is responsibility of the cities, however, a big portion of these attributes the concession to EDP Distribuição as well. To maintain the quality, security and reliability of these lines, a tariff is paid by the consumers [4].

The commercialization sector, in charge of selling the energy to the consumers, functions mostly as a free market. The agents which sell energy will be named suppliers. The consumers in Portugal are free to change their energy supplier at any time. When a supplier operates in the Liberalized Market is considered a Free Supplier, e.g. Endesa, Iberdrola, EDP Comercial. On the other hand, when a supplier functions in the Regulated Market is considered a Last Resource Supplier. These sell their energy at a regulated price, by ERSE, and are obliged to provide service to the following clients [5]: financially vulnerable clients; Clients with a contract under the terms of regulated tariffs or transitory tariffs, defined by ERSE; Clients whose energy supplier is no longer allowed to provide their services; Clients located in regions where there is no offer from free suppliers.

The feed-in-tariffs, paid to SSG, are also supported by Last Resource Suppliers. Rules are being applied to promote the migration from all the clients to the Free Market by applying a transitory tariff to the clients which are still on the Regulated Market. This migration started in 2013, however some delays have occurred during the process. Current legislation expects the transition to be made until the end of 2020 [6].

The wholesale electricity market, in which the suppliers acquire the electricity which is then sold, is named Iberian Electricity Market (MIBEL). The electric market operations are controlled by the two poles, responsible by the control of the Iberian Electricity Market (MIBEL). The Portuguese pole, OMIP, and the Spanish pole, OMIE. Each has specific tasks, which include the management of day and intraday operations, by OMIE, and the management of the forward market, by OMIP.

For the well-functioning of the spot-market, it is necessary to ensure that the grid interconnections between both countries are enough to support the energy flow, which is dictated by the market. If the connections are not enough, there is a market split between both countries and new energy prices are calculated. However, with the constant upgrades to the grid, this situation is not very frequent, nowadays. Regarding the market price, MIBEL functions with a marginal system, meaning that, theoretically each energy producer sells their energy with the price that cost to produce one extra megawatt of energy (supply curve). This is known as the marginal cost. The offers of all the producers are organised in a price ascending curve. On the other hand, each agent who wants to buy energy also presents a price offer which is the maximum price that the agent is willing to pay for the energy (demand curve). These offers are organised in a descending curve. After this, the market price is defined by the point in which both curves intersect each other, which is the lowest price that guarantees that all the supply is satisfied by the demand. Figure 1 shows the aggregate supply and demand curves for the first hour of 2017, as well as the price of energy for that hour. As it is possible to understand by the image, the sales (orange line) and purchases (blue line) proposals are ordered by their prices with opposite criteria, the sales in an ascending price ordering, and the purchases with a descending ordering. The point where they match will be the price of energy in that hour. The proposals which were matched are represented in the figure by the red (sales) and beige (purchases) lines. This is a merit order organization.

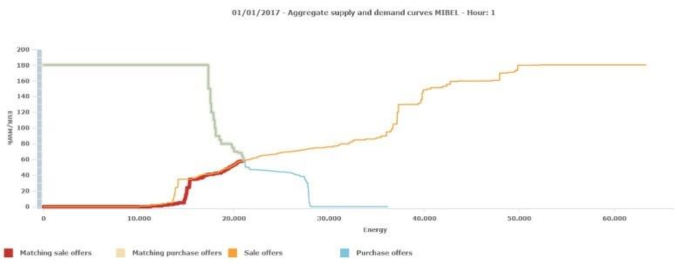


Figure 1. Aggregate supply and demand curves 1/1/2017 (Adapted from [7])

The curve of the available sources, supply curve, is organized based on the ascending marginal costs. The integration of RES production in the market has shifted this supply curve to the right, due to the near zero marginal costs associated with these technologies. This characteristic is what makes RES so attractive, making them economically viable.

## III. Power System Costs

### A. Levelized Costs of Energy

This chapter starts by giving a description of the Levelized Costs of Energy (LCOE), and the evolution of the LCOE of the different technologies. Then, the different cycling costs are presented, focusing on start-up costs and ramping costs.

The increase in the installed capacity of wind and most recently photovoltaic solutions is related with different factors, like the government incentives and the increased concern about the environment sustainability. However, one of the most decisive factors was the decrease in price of these technologies. The most common metric to compare the costs of the different technologies will be approached.

Due to the increase on RES in the system, it is important to do a correct economical assessment of the different technologies. Despite the many social benefits that the RES bring to a country, and to the environment, they will only be used if it is economically valuable. The Levelized Costs of Energy (LCOE) are a metric that is usually used to assess the economic value of a power generating technology and compare between technologies. LCOE can be described as the full life cycle costs, both fixed and variable, of a power generation technology per unit of electricity, €/MWh [8] and can be calculated as presented in equation (1).

$$LCOE = \frac{\sum(CAPEX_t + O\&M_t + FC_t + EC_t)\ (1+r)^{-t}}{\sum MWh_t\ \ (1+r)^{-t}} \quad (1)$$

$CAPEX_t$ = Capital expenditures in year t
$O\&M_t$ = Fixed operation and maintenance costs in year t
$FC_t$ = Fuel costs in year t, when applied
$EC_t$ = Environmental costs in year t, when applied
$MWh_t$ = Electricity produced in MWh in year t
$(1+r)^{-t}$ = Discount factor for year t

Fundamental inputs to calculate LCOE usually include all the financial and capital costs on the fixed costs hand, and variable operation and maintenance costs (O&M) and fuel and environmental costs on the variable costs side. It is in photovoltaic (PV) technology where the biggest decrease of LCOE is verified. In the past eight years, the LCOE of PV panels has decreased more than 700%, representing an average annual decrease of 89%. Also, wind LCOE has had a decrease of 300% during this period. These two technologies represent the lower LCOE currently, according to [9]. On the other hand, thermal plants did not have any big changes in their respective LCOE during these years. Coal technology had a decrease of 9% in the period of analysis, while Combined Cycle Gas Turbine (CCGT) decreased 38%.

However, this measurement has some failures, particularly when evaluating RES type of plants. Some conditionings are not taken into consideration, such as [9]:

- Capacity value vs system value: the capacity of RES production to meet the demand reliably vs the non-assessed benefits that installing a plant in a particular location can bring;
- Permitting or other development costs;
- The costs required to integrate the energy produced by a new plant, named integration costs;
- Environmental regulation costs;
- Environmental externalities, such as long-term residual consequences of thermal plants, like the environmental impacts;
- System value. LCOE does not allow one to assess the system value of a RES plant, like the environmental benefits, or the benefits for the society where it is installed;

The integration costs are frequently mentioned when the LCOE failures are addressed. Decomposing these, usually three components stand out:

- Grid costs arise from the location-specific characteristic of RES, meaning that it is costly to create conditions for the power transmission, in case the plant is located far from a load center. The best locations for VRE are usually in places without a lot of demand, meaning that the system grid in these locations is not prepared to big injections of power;
- The uncertainty of RES can create balancing costs, due to forecast errors and intra-day adjustments, since energy produced by these, specially VRE sources, cannot be dispatchable. Overall, solar predictions are accurate during the day, due to the well understanding of the sun movement. However, sudden clouds can appear, and create some changes, and consequently costs. Wind, on the other hand, is less predictable, but it is still possible to identify daily and season patterns;
- The VRE sources create the need to have back-ups, due to its low capacity value, creating adequacy costs. System operators need to ensure the capacity of the grid to absorb any quick changes that might occur. More than this, in times of high VRE production, it might be necessary to shut down fossil-fueled thermal plants. This creates cycling costs in these plants.

Different metrics have been developed to improve LCOE. However, this is still the most consensual metric in the scientific community.

Another technology frequently mentioned to reduce the variability induced on the grid by wind and solar technologies is the electrical energy storage (EES). There are many possible applications for this technology. EES can be the solution for some of the major problems of the grids. It would allow a lower dependency on fossil fuels, and consequently not being exposed to their price volatility. It would also allow the thermal plants to not need to function as peak-demand units. This would reduce their costs. Storage near VRE production would allow the decongestion of the grid in times of high production of these units, and at the same time it would provide a constant source of back-up electricity, improving the grid security. All these would help the improving of the power quality at the customer-side. The increase of VRE in the systems only reinforces the impact that EES could have on an energy system.

### *B. Cycling costs*

Adding more variability and unpredictability to a power system causes thermal units to have more start-ups, ramping and periods of operation at low load levels. These are considered cycling costs, and these will now be defined.

Due to the non-dispatchable properties of wind and photovoltaic technologies, these have priority in MIBEL, since this functions as a merit-order effect market. With the development of these technologies, their integration in the Portuguese energy system has been increasing throughout the years. This is one of the factors which has been forcing base-load units to operate in ways which they were not planned to work, having to deliver high variable outputs to meet the load at every instant. For instance, when wind power becomes available, the most expensive thermal units available need to slow down their production, and eventually be turned off. The deregulation of the electricity market is another factor which contributes for the cycling of the thermal units. The units were forced to be more flexible to remain profitable. In a competitive environment, a unit with more flexibility has more opportunities to increase profits. Therefore, fossil fueled power plants, which were designed to be baseload units, must work more as load following units.

The biggest portion of cycling costs in thermal units are the start-up costs. In some analysis on the matter, other costs are even despicable, accounting only start-up costs. Generally, older thermal plants were designed to have non-cyclical baseload operations, with few start-ups per year. In Portugal, the same happened. The coal plant located in Sines dates from 1985, while the one in Pego dates from 1998. When these were installed, there was almost no power from VRE sources in the grid. With the appearance of new sources of energy, the system had to be adapted. To start-up a thermal plant, it is necessary to heat all its components, therefore all the energy spent until the components are in the proper conditions is only for internal usage, with no production for the grid. In the boiler, the fuel is burned, to provide thermal energy. Then, this energy (usually gas or steam at high temperature and pressure) converts to mechanical energy by torque on a shaft. The mechanical energy is then converted into electricity by electromagnetic induction, with the remaining thermal energy being released to the atmosphere through a cooling tower [10]. More than this, usually, when a power plant is started, it needs to be started until producing a minimum load, which differs between plants and technologies.

Also due to this, the start-ups of coal thermal plants can be defined in three different categories, which slightly vary between different authors [10]: hot start-up, when a plant has been without functioning at eight or less hours; warm start-up, when a plant has not been working between eight and forty-eight hours; cold start-up, when a plant has not been working over forty-eight hours. When comparing the costs of start-up, a coal unit and a CCGT unit the second tend to be higher, due to the high costs of natural gas, even though these can start-up faster.

The start-up costs occupy the biggest porting of the cycling costs. However, these are not the only costs that should be taken into consideration. The bigger variability on the load due to the integration of VRE leads the thermal plants to have to do quicker adjustments the follow the load. The ramp rate describes how fast a power plant can change its net power during the operation. The integration of power injected from VRE sources has forced thermal plants to haver faster ramp rates, to maintain the well-functioning of the grid, incurring in ramping costs. The variation of production leads to a quicker wear and tear of the components of the plants. Likewise, the operation and maintenance costs increase, to maintain the components of the thermal plants functional.

Despite the two costs presented being the most consensual among the bibliography analyzed, there are others which need to be accounted. Both the start-ups and the ramping of the units lead to the quicker fatigue of the plants' components, as well as in their lifetime. The lifetime of a power plant depends upon other factors, but high load changes (above 50% of nominal power, e.g. passing from 40% to 100%) and cold start-ups are considered to put a lot of stress in some components of the thermal plants, decreasing their lifetimes. In the same way, this leads to a decrease in their efficiency. The plants are planned for a certain utilisation rate, and, with extra start-ups and load following cycles, these components decrease their efficiency in ways which were not predicted when the units were projected. This is another cost which needs to be taken into consideration, although it is again hard to evaluate financially the decrease in efficiency of a component in a unit.

## IV. MODEL OVERVIEW

This section describes the models created to do the simulations. Two models were created, to evaluate different aspects. On the one hand, it was necessary to evaluate how much would the energy cost if no energy from renewable sources was integrated into the system; on the other hand, it was needed to have a model to identify the cycling costs which arise in thermal plants due to the volatility of some technologies, namely wind and photovoltaic RES. Finally, the official Portuguese calculation of all the costs due to renewable energy is presented. These are used to frame the cycling costs in the total renewable overcosts.

### *A. RES production influence on the wholesale electricity price*

To evaluate the electricity wholesale price without RES, the model developed simulates the electricity wholesale prices of the Portuguese system without the presence of wind and PV technologies. The whole process to the development of this model will now be explained, from the beginning, where hydro technologies were also considered, until the final model, where only wind and PV technologies were considered. Thermal SSG were excluded since the beginning since it was not possible to distinguish between biomass generation and cogeneration.

The load diagrams of the different technologies are presented in fifteen minutes periods. To do a match with price data regarding the electricity prices negotiated at MIBEL, available by OMIE

[11], it was necessary to do the hourly averages of the production, since these electricity prices are presented on an hourly basis. Figure 1 presents the total hourly production of electricity from the Portuguese RES during the year of 2016 (hydro, solar and wind, further referred as RES).

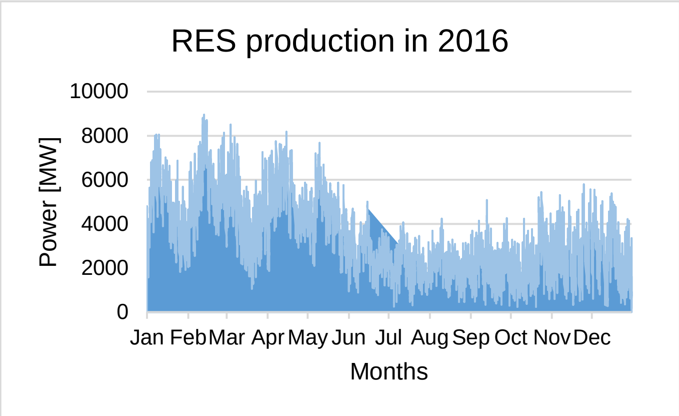


Figure 1. RES production in 2016

As it is possible to infer from the contour of Figure 1 (light blue), there were big variations in the production of electricity by RES in 2016. In this year, the hour with more RES production had 8954 MW of power injected into the system by RES, in 13th of February. On the other hand, the hour with least power injected into the system by RES had only 167,6 MW injected, in the 31st of December.

To do a better analysis of this information, the production was organized in a different perspective. The hourly production was organized as an accumulated diagram, starting in the hour with more RES production in 2016, until the hour with less production, as presented in Figure 2. It is important to mention that this was a leap year, so there were 8784 hours during the year. As it was predictable, the hour with more power from RES on the system (X=1), had 8 954 MW of power, and the hour with least power (X=8784) had only 167 MW.

After organizing the production in an accumulated load diagram, the hour referring to each of the power productions was identified, i.e., X=1 corresponds to a production of 8954 MW, X=2 corresponds to a production of 8950 W and so on. To know the hours in which the values of production were obtained, a match was done in Excel. After knowing the hour in which the production occurred, the electricity price in this hour was used.

Doing this matching for all the hours, it was necessary to decide how many hours were necessary to analyze so that a good simulation of the electricity price with and without RES was done. To do so, it was decided to approach this problem using hour percentages, i.e., if it is referred that 10% of the hours were used, it means that the 878 hours with more and less RES on the system were analyzed.

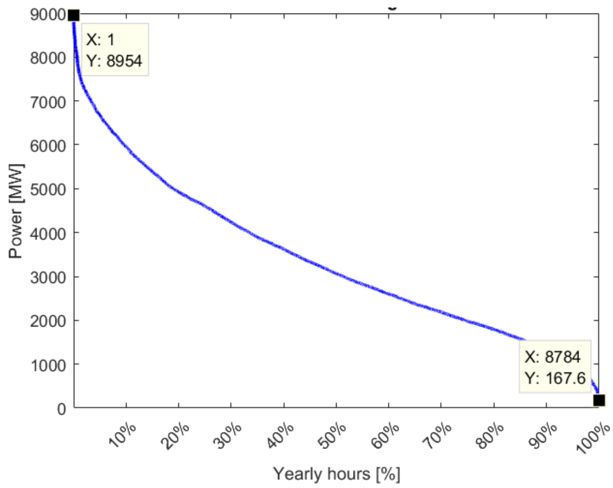


Figure 2. Load Duration Diagram 2016

After some initial simulations, it was noted that the percentages of hours studied had a big difference in the savings, i.e. the electricity price difference between the hours with more and less power from RES in the system. More than this, the influence of each technology in the savings also differed a lot. For this reason, it was necessary to do specific simulations for each technology, and groups of technology, as well as for different hour percentages. This way, it was achieved a solid method to understand the influence of each technology in the electricity price.

It was noted that there is a direct relation between non-dispatchable renewable energy production and the reduction of electricity price, but there is no relation between the higher production of hydroelectricity and the reduction of the price. Frequently, the bigger power output of hydro plants occurred when there was no production from wind and PV technologies, and the electricity price was high. This, together with the fact that hydro plants exist on the Portuguese system for many years now, were the reasons for this technology to not be considered in the model. Moreover, although only reservoirs are considered a dispatchable energy source, both run-of-river and small hydro technologies might have the capacity to hold water for hours/days, meaning that, although they are not considered dispatchable sources of energy, it is possible to have some control over when the energy is produced, so these were not considered as well. For the final simulations, only wind and PV productions were considered.

To try to have a better perspective of the influence of these technologies in the price of energy, it was done a sensibility analysis with the data. Simulations were done with 5%, 10% and 15% of the hours with most and least energy from RES on the system, and then for the hours with most and least wind and photovoltaic. To understand how the hydro technology as a different behavior, the same simulation was done for this technology. These simulations were done for 2014, 2015 and 2016, although only the data of 2016 was used in the analysis.

To validate the results from this model, which will be presented later, APREN made available the results from their model. To calculate how much the price of energy would be if no renewable energy existed in the system, APREN developed a model in which they organize all the offers in one hour of selling energy from the lower price to the higher one. For the same hour, they do the same with all the offers from the buyers of energy, organizing these from the highest price to the lowest. This is the normal market organization, where the intersection between these two lines gives us the energy price in that hour. Afterwards, to calculate the energy price if no power had been injected by SSG, all the offers made by these are removed to this diagram. This means that the new price will have only in account the selling offers from non-SSG.

### *B. Cycling Costs Model*

Besides a good evaluation of savings due to renewable energies, a model to know the extra costs due to cycling effects was necessary. To evaluate this increase, the year of 2010 was used as the reference year with less VRE, and then compared with 2016. Although there was already a lot of wind capacity installed in 2010, this was the oldest year in which was possible to gather information about the production of electricity by each thermal plant, which is available in [12]. In 2010, there was still a small production of electricity by the thermal plant located in Carregado, which functioned by fuel-oil. However, this thermal plant was decommissioned during that year, having a very small production of energy. This way, it was not considered. Different perspectives of the cycling costs will be presented. Different papers on the matter will be analyzed.

The integration of renewable energies in the grid causes a big variability in the production of thermal plants. [13] evaluates how the various parameters influence a generation portfolio and defines 5 types of cycling costs due to this variability:

- Direct start costs, which are the costs of fuel, CO2 emissions, and auxiliary services during a start-up of a thermal plant;
- Operation and maintenance (O&M) costs created by a start-up, referred to as indirect start costs;
- The cost of forced outages due to cycling, which is the opportunity cost of not generating during an outage;
- Operation and maintenance (O&M) costs due to load following, referred to as ramping costs;
- The cost of having a less efficient plant due to cycling;

Direct, indirect and load-following costs have a direct application. Regarding forced outage costs, these are about 5% of total cycling costs. As for the decrease of the thermal units' efficiency, it can be expressed in the cycling costs as the difference between the generation costs of a system with all generation at decreased efficiency and a system with the original efficiency. Since these generation costs are not available, the decrease in the efficiency of the units is not accounted for. It concludes that a good unit commitment scheduling can reduce cycling costs up to 40%. More than this, it is concluded that cycling costs increase with increasing technologies. However, the total system costs reduce with the increase of renewable generation.

In a similar perspective, the implications of incorporating short-term dispatch into the planning of energy generation are studied in [14], doing a case study of a system with multiple technologies. To evaluate cycling costs, the value of the start-up fuel cost is presented. Then, to considerate other cycling costs, this value can be multiplied by a factor between 2 and 5. The authors of the paper calculate the higher possible costs, multiplying the start-up fuel costs by 5, for the coal plant, and by 3 for the CCGT unit. This represents other costs associated with the cycling of a unit, such as O&M, forced outages, the unit heat rate, meaning the decrease in efficiency of a power plant that happens when more cycling occurs, and manpower. The conclusions of the paper point for the fact that the costs associated with cycling are highly dependent on the portfolio studied.

In [15], the costs due to wind penetration in a base-load unit are assessed. It simulates the 2020 Irish system, because of its unique characteristics. It presents the characteristics of a CCGT and Coal units simulated on that system, including start-up costs. Simulations with different wind percentage penetrations are done, and it is concluded that CCGT units have the highest increase in costs, since they are displaced to mid-merit operation. It is also stated that, at very high wind penetration (6000 MW), the storage of energy can decrease start-up costs. However, although it is mentioned that the increase in cycling operation will lead to increased outages and plant depreciation, these costs are not included in the simulation.

In a similar context, the Irish electric system is simulated to evaluate the impact of increasing wind generation in [16], with the purpose of evaluating the extra start-up costs incurred in base-load generators by the variability that wind causes in the system. It presents the start-up costs of base-load units, both coal and CCGT. It is mentioned that, with the increase of the wind penetration, some of these units start functioning as mid-merit units, presenting the characteristics, including start-up costs, of the units used in the simulation. It concludes that the cycling of base-load units is increased with the growth of wind penetration.

As for the Portuguese system specific values, [17] addresses the implications of the increase of RES in the Portuguese energy system. In the analysis done, the start-up costs of the Portuguese thermal units were assessed. It is assumed that, when a start-up occurs, the unit must start functioning at least at a minimum power, 1/3 for coal plants and 2/9 for CCGT plants. The start-up costs are divided into three categories: abrasion costs, which are the costs resulting from the corrosion of the units due to start-ups; fuel consumption costs, referring to the costs of fuel necessary to start a plant until minimum power; CO2 emissions costs, the costs regarding the CO2 emissions.

To assess the cycling costs of the Portuguese thermal plants, an analysis was done based on the characteristics of the units presented in the papers above. A model was developed to allow a quicker analysis of the data, returning the extra-costs due to the cycling of a thermal plant. It makes the distinction between start-ups and load-following of a plant, counting the number of start-ups.

For that model, the data from each individual Portuguese thermal was extracted from the Excel files into MATLAB. It analyses the hourly production of a thermal plant, calculates the costs of each start-up that occurs during the year, and returns the total cost value. When applicable, it also adds the load-following costs. This program was run for each coal and natural gas thermal plant in function for the years of 2010 and 2016.

Regarding the two papers which include load-following costs, [13] and [14], the total cost values between both differ a lot. This is partly due to the methodology used in the papers. Although both take into consideration different cycling costs, according to [14], these are all calculated based on the number of start-ups and depending on start-up fuel costs. This way, as it is considered that coal plants have high start-up fuel costs, due to the emission costs, as well as the power needed to start-up all the auxiliary components., this emphasizes the rest of the costs in these type of plants, since the start-up costs are multiplied by a factor 5 to calculate them, whereas the CCGT units have lower costs. Hence, although the number of CCGT start-ups is much higher, it is possible to infer that, in 2010, the coal costs represent 68,5% of the total cycling costs. In 2016, even with the increase of CCGT start-ups, the reduction of start-ups in coal plants reduces the total cycling significantly, though they are still higher in comparison with [13] costs. In regards of [13] methodology, analyzing both years, it is clear that cycling costs were higher in 2016, due to the increase of cycling costs in CCGT units. This indicates that, alongside with the increase in the number of start-ups, the small variations due to load-following were more intense, increasing the cycling costs.

After this analysis, and considering the characteristics of each paper, two have better approaches than the rest regarding the total cycling costs. Within the papers which only consider start-up costs, [17] has a specific approach for the Portuguese units, which is exactly what is being discussed. As for [13] and [14], which have more detailed approaches, since more than start-up costs are accounted in these studies, [13] is more complete, due to the extensive cover of different costs and to the fact that the paper's values are framed within all the papers The coal start-up costs presented in [14] are too disrupting when compared with the other papers, with no justification.

Therefore, even considering the specific Portuguese units' costs in [17], the values adopted in this thesis were the ones presented by [13].

### *C. Renewables Overcosts*

There are other costs which influence the renewable overcosts. The most relevant one is the price paid by the electricity produced by RESs. Renewable energy producers get paid a special tariff to produce renewable energy, which is usually higher than the wholesale market price of the electricity. This tariff was created to encourage the investment in renewable energy producers. These tariffs vary, according with the year in which the plant started producing electricity. So, if the energy in 2016 was sold at, on average, 68,76€/MWh but the producers got paid a tariff higher than that price, this creates a big cost for the consumers. The methodology applied by the Portuguese Regulator, ERSE, will be applied, according with formula 2.

$$\mathrm{EC} = \mathrm{C} - \mathrm{R} + \mathrm{FC} + \mathrm{OC} \tag{1}$$

In this equation: EC corresponds to the extra costs, i.e. all the costs but the costs of acquiring the energy from SSG; C are the costs of acquiring the energy from SSG and R are the revenues from selling it in the wholesale market; FC represents functioning costs, such as the costs regarding the well-functioning of the structure which carries the buying of energy from SSG; C represents the other costs which need to be considered in this calculation, like the costs which are paid to REN for the usage of Portuguese system grid by SSG.

## V. Results and Analysis

In this section, the results and analysis of the models showed in Section IV are presented. The electricity price without the presence of PV and wind in the system is calculated. Following this, the cycling costs of the Portuguese system are presented and analyzed. An official methodology is used to calculate the renewables overcosts, and the chapter finalizes with a closing balance.

### *A. Electricity Price with and without VRE in the System*

The results from the procedure previously explained will now be presented. Firstly, simulations were performed for 2014, 2015 and 2016 using the wholesale prices of electricity of the 10% of the hours of the year with more electricity produced by RES, including hydro, and the 10% of the hours of the year with less production. The difference of the electricity prices in both scenarios are named of savings.

After analyzing the results, it was clear that this approach was not enough to give a good value for the potential cost of the electricity without renewable on the system, due to the dispatchable technologies. In 2015, the price of electricity with the most and least renewable energy on the system was almost the same. Therefore, the same 10% of the hours with more and less production of electricity from hydro were analysed alone, as well as the 10% of the hours with more and less production from VRE technologies, wind and PV.

These results showed that as hydro is a dispatchable source of energy, a high production of energy from these does not mean that the energy is cheap during these times. On the contrary, these are used often when there is no electricity being produced from PV and wind, therefore the electricity price is high. Due to the reasons before explained, only wind and PV technologies were taken into consideration for the model developed. Finally, a sensibility analysis was done, for different percentages of hours. After comparing these results with APREN's, it was chosen that the 5% of the hours should be used in the simulation, as presented in Table 1.

Concluding, in 2016 the integration of the RES in the Portuguese

system created a saving of 18,01 €/MWh. There were 49 501 GWh traded in 2016, which means that the total savings of this year were 891 513 010 €.

Table 1. Savings

| 2016 | APREN | Model |
|---|---|---|
| **Price with Wind and PV supply** | 39.4 €/MWh | 36.52 €/MWh |
| **Price without Wind and PV supply** | 61.3 €/MWh | 54.53 €/MWh |
| **Savings** | **21.9 €/MWh** | **18.01 €/MWh** |
| **Total Savings** | **1 084 071 900€** | **891 513 010 €** |

### *B. Cycling Costs Analysis*

In this section, the results from the model developed based on [13] will be analyzed. In Table 2, the values of the different costs assessed are described for the year of 2010 and 2016. The cycling costs of CCGT plants in 2016 are much higher when compared to 2010, 277%. Coal cycling costs have a small increase of 13% in 2016. In this year, more 137 start-ups occurred, despite the fewer start-ups in coal thermal plants, only 38 compared with the 52 in 2010. The thermal plant of Outeiro has the biggest variation in of costs, more than tripling its costs in 2016. Overall, all the thermal plants increase their costs in 2016, with Pego coal thermal plant being the exception, since it had a small reduction in total costs between the two years of analysis.

It is relevant to compare the cycling costs by technology. Firstly, it is interesting to present the influence of each one of these technologies in total cycling costs. It is perceptible that, in 2016, the cycling costs related with coal are a smaller portion of total cycling costs when compared with 2010. However, the more important information that is gathered from this comparison is the discrepancy between both technologies. The functioning as base-load units from coal thermal plants leads to less cycling costs. More than this, there are more CCGT capacity installed in Portugal than coal. This, together with the functioning of coal plants as base-load units is sufficient to create the percentages in where CCGT units have responsibility for around 70% in 2010 and 80% in 2016 of total cycling costs.

One more reason to explain the differences in both years is the cost of the fuel. This cost plays the biggest role for the usage planning of the power plants, since it corresponds to its biggest cost. In 2010, the cost of the coal was more expensive when compared with 2016. This led to a bigger search for alternative energy sources, with special focus on natural gas, since the installed capacity of renewable energies was not enough for the needs. In 2016, with lower coal costs, the usage of these plants was pushed to the limits, which is confirmed by the energy produced in each of these years by these plants. Simultaneously, the installed capacity of wind and PV increased. All this contributed for the increase of start-ups of natural gas plants.

### *C. Renewables Overcost and Final Balance*

In this section, the costs generated by SSG will be calculated. The methodology applied to calculate the costs due to SSG was the same that is used by ERSE as official values. In Table 3, it is represented the information that is available by ERSE [10], for the year of 2016. Only the data important for the calculation of the costs due to SSG is presented. Applying equation 2 with the values [10]:

$$\mathrm{EC} = 1\,560\,121\,000 - 581\,339\,000 + 5\,221\,000 + 4\,267\,000 = 969\,294\,000\ €$$

Therefore, in 2016, the costs due to the SSG were around 1 370 M€.

There are two different considerations which need to be done to frame the results of this thesis. On one hand, the cycling costs in 2016 were higher than in 2010, with an increase of 92%. However, the plants do not program their usage based on start-up costs, but mainly based on fuel costs. This means that the extra costs due to cycling costs is only partly related with the intermittence provoked by wind and PV on the grid, and it can be misguiding to analyze these values without having this in mind.

On the other hand, it is imperative to contextualize these costs in the total costs of the system due to SSG, according with ERSE, as well as in the benefits. Table 3 summarizes the savings and costs due to renewable energy production.

Table 3. Costs and savings in 2016

| Total Overcosts [€] | Total Savings [€] | Cycling Costs [€] |
|---|---|---|
| **988 270 000** | 891 513 010 | 10 092 280 |

Different conclusions can be reached from this table. Regarding the main focus of the thesis, the cycling costs, it becomes obvious that the magnitude of these is insignificant. When compared with the total overcosts of the renewables, it represents only 1.021% of these. When compared with the total savings, it represents 1,13%, which indicates that it is totally worth it.

Another conclusion is the fact that the total costs are bigger than the total savings. This can be explained by several reasons, such as the high tariffs which are being paid to older plants and are much higher than what the market dictates, or the investments made on the grid which are still being paid, or the social measures.

## VI. Conclusions

The main objective of this thesis was to evaluate the extra costs that conventional thermal plants had due to the growth of electricity produced by renewable energy sources in the system. In order to do that, the year of 2010, the reference year, was compared to 2016. To do so, different papers, where the cycling are described, were analyzed. The methodology and results from the more reliable paper were chosen, [13], to be used in the Portuguese system, once it contains more details on cycling costs. The ideal scenario would have been to use information from an older year, since in 2010 there were already 3 705 MW of wind capacity installed; however, there is no detailed information about the production of each coal and CCGT plant available before that year.

The results exposed an increase of the cycling costs when comparing both years, from 5 244 151 € to 10 092 280 €. Additionally, more 137 start-ups occurred in 2016. The reason for this increase can be justified by different arguments. First, the fuel costs, which are the most influent parameter when deciding when a thermal plant in turned on, were different in both years, with coal being much cheaper in 2016. This resulted in coal thermal plants producing 5 154 GWh (78 %) more in 2016. Second, at the same time, one more CCGT thermal plant became functional in this period, in Pego, in 2011, increasing the number of start-ups of natural gas thermal plants, even though these produced less 2 829 GWh in 2016 than in 2010, when they produced 14 400 GWh. It was also noticed that the main share of the cycling costs are the indirect costs, i.e. the maintenance costs due to a start-up, representing around 80% (77% in 2010 and 82% in 2016) of the total costs.

Considering these results, it was necessary to recognize how relevant the costs were when compared to the economic impact that the RES have on the wholesale electricity price. To understand this, a model was developed. The price of the 5% of hours with more and less electricity produced from non-dispatchable RES was evaluated, simulating a system in which no electricity is produced from these sources (less production). Only PV and wind, the two non-dispatchable technologies, were used in the simulation, because it was proved that hydro peaks of production and low electricity price during those peaks do not have a direct relation.

It was concluded that, in 2016, the 5 % of the hours with less electricity produced from wind and PV had a price of 54.53 €/MWh, 18.01 €/MWh higher than the hours with more electricity generated (from these sources). When considering the electricity produced in the whole year, this difference reflects in savings of 891.5 M€. To verify the results, APREN made available the outcomes of their model, which simulates MIBEL without the production of electricity from wind and solar. The system without electricity from wind and PV would be 21.9 €/MWh more expensive than electricity price in the year of 2016. This corresponds to total savings of 1 084 M€.

Considering the purpose of this thesis - to evaluate the growth of the cycling costs in the Portuguese thermal units due to the increase of electricity in the power system produced by intermittent technologies, and to frame these extra costs in the economic benefits from these sources -, with these results, it is possible to state that the extra cycling costs are irrelevant when compared with the economic benefits from the RES. In 2016, these represent less than 2 % of the total economic benefits. Also, this outcome discredits the argument that claims that renewable energies provoke unsustainable cycling costs in the thermal units.

Another evaluation needed to be done is the comparison between the cycling costs and the total overcosts. To do so, ERSE methodology to calculate the total renewables overcost was used, in what concerns the year of 2016. The result presented overcosts of 969.3 M€, which were 96.7 M€ more than the savings in this year. An analysis presented in [18] also shows that the overcosts were higher in 2016 when compared to the savings, but, since 2010, the benefits have largely surpassed the overcosts. Therefore, this does not discredit the use of RES. The overcosts are driven by different reasons. When the wind and PV technologies appeared, they were not economically viable. Additionally, these entered in a market dominated by conventional thermal plants, which already had their investments paid, and only have operational costs. This led to high tariffs being paid to the RES producers to attract investment for the implementation of these solutions. As the years go by, these overcosts will tend to disappear.

Table 2 – Cycling Costs in 2010 and 2016

| | Thermal plant | No. of Starts | Direct costs [€] | Indirect costs [€] | Ramping costs [€] | Forced outages [€] | Total costs [€] |
|---|---|---|---|---|---|---|---|
| **2010** | | | | | | | |
| **CCGT** | **Lares** | 34 | 25 450 | 203 600 | 58 913 | 14 398 | 287 963 |
| | **Outeiro** | 66 | 136 873 | 1 094 984 | 145 385 | 68 862 | 1 377 242 |
| | **Ribatejo** | 106 | 209 524 | 1 676 196 | 98 906 | 99 231 | 1 984 626 |
| | **Total** | **206** | **371 847** | **2 974 780** | **303 204** | **182 491** | **3 649 831** |
| **Coal** | **Pego** | 38 | 193 567 | 425 848 | 212 207 | 41 581 | 831 622 |
| | **Sines** | 14 | 94 000 | 206 800 | 461 898 | 38 134 | 762 698 |
| | **Total** | **52** | **287 567** | **632 648** | **674 105** | **79 716** | **1 594 320** |
| **Total (CCGT + Coal)** | | **258** | **659 414** | **3 607 428** | **977 309** | **262 207** | **5 244 151** |
| **2016** | | | | | | | |
| **CCGT** | **Lares** | 32 | 72 038 | 576 300 | 83 062 | 36 570 | 767 970 |
| | **Outeiro** | 145 | 404 810 | 3 238 500 | 92 155 | 186 773 | 3 922 238 |
| | **Ribatejo** | 96 | 226 518 | 1 812 148 | 56 861 | 104 776 | 2 200 303 |
| | **Pego** | 87 | 144 415 | 1 155 320 | 31 727 | 66 573 | 1 398 035 |
| **Coal** | **Total** | **360** | **847 781** | **6 782 268** | **263 805** | **394 692** | **8 288 546** |
| | **Pego** | 19 | 145 450 | 319 990 | 113 464 | 28 945 | 607 849 |
| | **Sines** | 16 | 285 625 | 628 375 | 224 938 | 56 946 | 1 195 884 |
| **Total (CCGT + Coal)** | | **395** | **1 278 856** | **7 730 633** | **602 207** | **480 584** | **10 092 280** |

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