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PORTUGAL'S ROUTE TO NEUTRALITY: THE CHALLENGE OF HIGH SHARES OF VARIABLE RENEWABLE ENERGY

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Abstract

This project examines the challenge of managing the Portuguese electric power grid, which will experience the installation of large amounts of solar and wind capacity and full coal phasing-out during the next decade. The Irena FlexTool is used to study the flexibility of the power grid in 2030 under different scenarios. We conclude that the variable renewable energy (VRE) expected installed capacity will frequently produce excessive energy supply, leading to high levels of curtailment. Hence, the power baseload price will decrease between 1% and 13% and investments opportunities between 30,1M and 71,3M (€ 2019) will be generated by 2030.

Key Words: decarbonization | VRE | flexibility | curtailment

1. Introduction

Global warming is currently one of the main challenges facing humanity. According to the Intergovernmental Panel on Climate Change (IPCC), there is a 95% certainty that humans are the main cause of the acceleration of global warming. Despite the efforts to counteract it, the problem is still growing. We now live in an era in which the problem is generally recognized and to keep the global average temperature increase below 2ºC relative to pre-industrial levels (target decided on the Paris Agreement, in 2016), a combined effort of all stakeholders will be necessary.

The leading cause of global warming is the increase of greenhouse gases concentration in the atmosphere. Among these gases, those currently responsible for the largest negative impact are carbon dioxide (CO_2) and methane (CH4). These gases are emitted by different human activities, which can be grouped into key sectors, such as: energy, agriculture, transportation and industry.

There is a need to decrease these emissions, or to decarbonize, in all of these sectors. Specifically in the energy sector, there are already solutions available which, if implemented, could significantly reduce these harmful emissions. The transition towards "clean" energy sources is already underway and it will be strengthened in the years to come. The energy sector, being at the basis of the activities of all other sectors, is pivotal to the development of a sustainable future. A relevant trend to consider in this sector is the growth in energy demand. Energy companies face a very challenging endeavor because they need to meet a rising demand and at the same time reduce their carbon emissions (BP, 2019).

Since we all live on the same planet, it should be in the interest of all countries to contribute to this cause, but unfortunately that is not the reality and there are still huge gaps in terms of alignment of climate targets. Currently, Europe is leading the way in terms of political action and social awareness and almost all countries have some kind of climate targets defined, some of them even including deadlines to attain carbon neutrality, including Portugal. Becoming carbon neutral is defined as having net zero CO_2 emissions (CO_2 Emissions – CO_2 Capture = 0).

Portugal's electrical grid is about to experience a structural change during the next decade, with the introduction of large amounts of solar and wind capacity. But how much flexibility will be left in the system after the installation of all the new variable renewable capacity planned and the phasing-out of all coal power plants and how will it affect the system's operational costs?

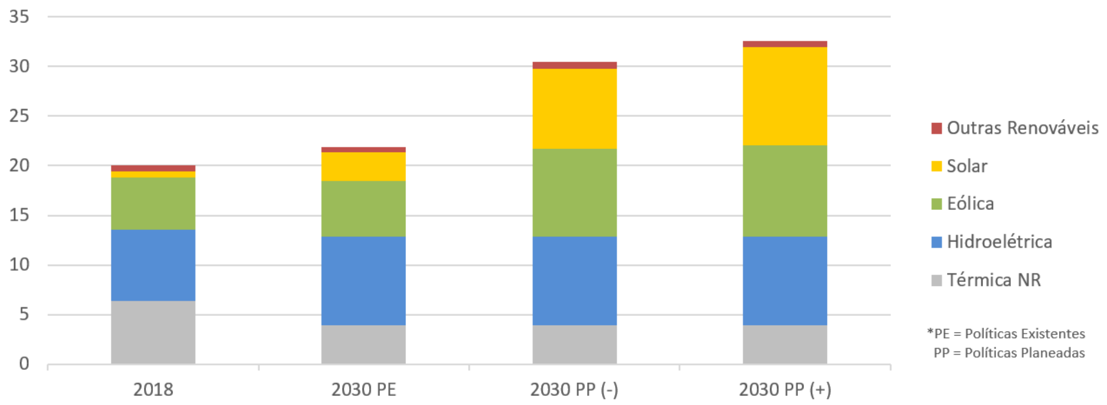
The remainder of this thesis is organized as follows. Section 2 describes the Portuguese context in the transition towards a carbon-neutral economy, section 3 contains the theoretical framework on power systems flexibility, section 4 details how the system was modeled using the Irena Flextool, section 5 discusses the results of the analysis developed in section 4 and section 6 offers the conclusions of the thesis. Ancillary tables and figures and an Appendix containing relevant information on the utilization of the Flextool are included at the end of the thesis.

2. The Context

At the end of 2018, Portugal produced two very significant documents regarding the transition of the Portuguese economy to a low carbon economy: PNEC (Plano Nacional Energia e Clima) and RNC2050 (Roteiro para a Neutralidade Carbónica 2050). RNC2050 defines medium to long-term decarbonization targets for all sectors (energy, industry, buildings, transports, agriculture and residues) so that Portugal can achieve carbon neutrality by 2050. PNEC is more focused on the short and medium-term targets for the energy sector and it is the main political instrument guiding the evolution in this area for the following decade. It was developed by Portugal's Ministry of the Environment and Energetic Transition. A final version of the PNEC is yet to be published, but the version used in this thesis is already very detailed with respect to Portugal's targets. Until now, Portugal had an average performance in terms of compliance with its GHG emissions targets. Considering the Kyoto Protocol, signed in 1997, the country was able to lower its GHG emissions below the 2008-2012 target but it placed quite above the 2013-2020 target, not showing real signs of improvement since 2012, at least until 2016 (Figure 1[1]). During this last period, Portugal went through an economic crisis, which hampered the reduction of GHG emissions. According to the EU goal of reducing 30% of Europe's total GHG emissions by 2030, relative to 2005 levels, Portugal needs to reduce its emissions by, at least, 17% of its 2005 level of approximately 87 Mt of CO_2e (Table 1[1]). Being more ambitious than the minimum requirements, Portugal set a 2030 target of 45% to 55% less GHG emissions relative to 2005, which would drop total emissions to around 39Mt of CO_2e. Specifically in the energy sector, Portugal seeks to have, by 2030, 83% less GHG emissions relative to 2005, making it the sector with the largest emissions reduction. (Table 2[1]). To achieve these targets in the next decade, new renewable capacity is expected to be installed, mainly solar and wind, while coal capacity will be fully phased-out, represented in Figure 2, in the next page.

[1] Page 23.

Figure 2 – Historical and Planned Installed Capacity in Portugal (GW)



Source: Author, using data from PNEC, 2018

In the PNEC, two main scenarios are identified: the Existing Policies Scenario and the Stated Policies Scenario (Table 3 & Table 4[2]). To predict the installed capacity in 2030, the Stated Policies Scenario uses two ranges of values, one more conservative (-) and another less conservative (+), predicting less and more VRE capacity being installed, respectively. Due to the lack of information on the expected installed capacity of non-renewable thermal in the Stated Policies scenario, it is assumed that this value is the same as in the Existing Policies Scenario, 3,9 GW (PNEC, 2018). The increase of renewable capacity would also allow for the better harnessing of endogenous resources, thus reducing Portugal's energy dependence. Portugal performs quite poorly in this area, currently occupying the fourth worst position in European Union in 2017, depending about 80% on imports to fulfill its energy demand (Figure 3[2]). According to PNEC, it aims to reduce this dependency to 65% by 2030 (PNEC, 2018).

3. Brief Comments on the Flexibility of Future Power Grids

Concerning the work already developed on the subject of power systems flexibility, it seems that the PNEC will definitely create disruptions in the system, since "market will

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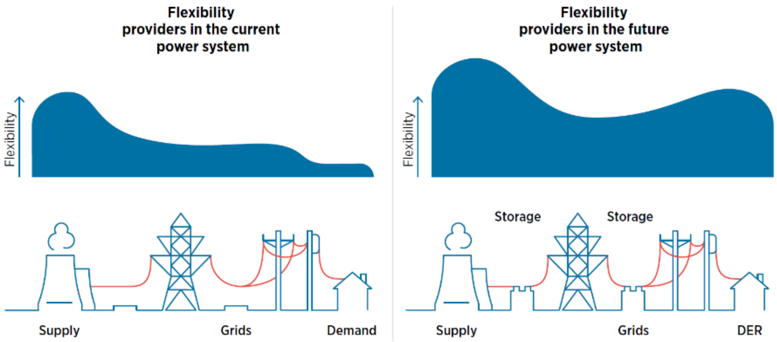
[2] Page 24.

“cope” [with high shares of renewables] to the extent that markets in the electricity supply industry serve the interests of policy rather than drive it.” (Pollitt, Michael & Anaya, Karim, 2016, p. 85). When planning future power systems, economic costs associated with the deployment of power generation coming from variable renewable sources should be fully accounted for, and the increase in the system balancing costs are not negligible, since “the variability and uncertainty associated with VRES-E generation implies real-time deviations in renewable power generation, explained by its non-full predictability, affect daily markets and result in higher balancing costs and greater fluctuation in the reserve requirements.” (Batalla-Bejerano, J. & Trujillo-Baute, E., 2015, p. 8). The efforts to mitigate climate change are pressing governments, which struggle to accommodate high shares of renewables. “In Spain, […] Although the system has more than 25 TW of installed capacity using combined cycle, the fall in electricity demand as well as a growing share of the renewable in the demand means that a very small part of this power is connected to the network when the system requires it.” (Batalla-Bejerano, J. & Trujillo-Baute, E., 2015, p. 8) The difficulty in reallocating production from renewable sources to hours of less availability will eventually result in a decrease in the market value of renewables in systems with high shares of renewables, “thereby upholding high growth rates for renewables. […] Thus, if the target is an energy system that is completely based on renewables, then the most difficult stages of the energy transition may still lie ahead, even if capacity costs of renewables continue to fall sharply.” (Helm, C. & Mier, M., 2019, p. 24).

IRENA is a key institution focused on the study of the flexibility of future power systems and has recently published three reports on this subject: "Solutions to integrate high shares of variable renewable energy" (2019) and "Power System Flexibility for the Energy Transition, Parts 1 & 2" (2019), from which most of the theoretical framework following my thesis in based. The generally accepted solution to reduce GHG emissions in the energy sector involves the substitution of dirty thermal non-renewable technologies by clean renewable ones. In the medium to long term, the main sources for this transition will be solar and wind technologies. Since these are non-dispatchable, it makes it difficult to balance supply and demand. It is expected that by 2050 solar and wind power account for three fifths of the global energy generation (REN21, 2019). There are already some solutions to overcome the unpredictability of this kind of technologies, but none of them is enough by itself, so a combination of different solutions must be used in order to make the system reliable (IRENA, 2019). The whole supply chain needs to become more flexible to fluctuations of supply and demand. Until now, power systems have relied heavily on the ability of ramping up or down production units, very early in the chain, but to accommodate all the unpredictability to come, flexibility in the transmission, distribution and demand phases also needs to be developed.

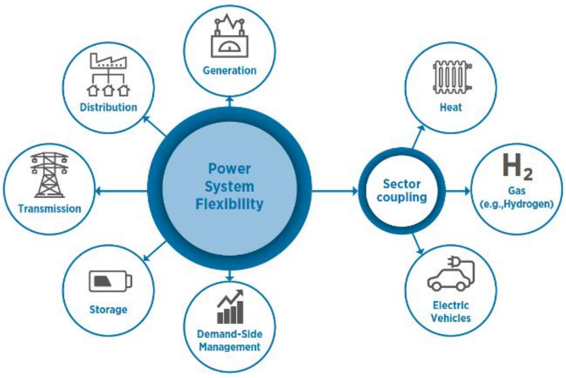
Figure 4 – Flexibility in current and future power systems



Source: IRENA, Solutions to integrate high shares of variable renewable energy*, 2019*

Another very effective way to increase system flexibility is to increase the connection to other sectors that can supply or consume energy, such as the growing hydrogen sector or the electrical vehicles fleet.

Figure 5 – Power system flexibility enablers in the energy sector



Source: IRENA, Solutions to integrate high shares of variable renewable energy, *2019*

Innovation, the key tool behind human evolution, will be key in the process of increasing system flexibility. IRENA identified three main innovation trends in the power sector: Electrification, Decentralization and Digitalization. These can be combined to generate innovations in different dimensions, namely the technological, from which it could be highlighted the utility scale batteries, power-to-X solutions or smart grids. Still in this realm, it is also expected that wind and solar forecasting tools will continue to improve, allowing for a better management of reserves and prediction of power production output. However, this kind of innovation alone will not satisfy the full flexibility needs in the future. There are also new business models opportunities that must be developed, such as the role of an aggregator, who bundles distributed energy resources through enhanced communication, control and automated smart contracts, based on blockchain technology. Even the market design itself needs to be renovated, for example with continuous intra-diary power markets. Portugal is part of the XBID (Cross-Border Intraday Market Project), which aims to achieve that goal[3] (PNEC, 2018). Finally, the system operations too will go through changes and in the near

[3] Another very simple, yet effective solution could be allowing negative prices in the electricity market.

future the concepts of virtual power plants (virtual aggregation of production units) or virtual power lines might become common.

4. IRENA FlexTool Model

To analyze the flexibility of Portugal's power generation matrix, the IRENA FlexTool model was used.

4.1. The Model

The tool was developed by IRENA in 2018 with the objective of identifying flexibility gaps in the short term and to explore optimal investments to support system flexibility in the long run, for energy systems facing increases in shares of VRE (IRENA, 2018). The tool incorporates enough mathematical complexity to address important aspects of system flexibility while at the same time being less complex than advanced commercial packages used for utilities, consulting firms or other institutions (IRENA, 2018). Flextool is a linear programming and deterministic model that runs with the purpose of minimizing its objective function, consisting of all the costs involved in the operations of the power grid (Figure 6[4]). The FlexTool is currently the only publicly and freely available tool that performs capacity expansion and dispatch with a focus on power system flexibility (IRENA, 2018). The model includes two modes that can be used either separately or together: the investment mode and the dispatch mode. The dispatch mode performs the optimal scheduling of power system operations while the investment mode proposes investments in various flexibility sources and other technologies. In this project only the dispatch mode was used because the investments in the electric system studied had to be developed outside the model. The tool can be used in various ways, among which we

[4] Page 25.

find: study of the current electricity system under unexpected events (poor water year, high natural gas prices, etc.) and to identify flexibility shortages in an estimated generation mix in a future scenario and solving for the least cost flexibility options. In this project, we focus on the second, since the goal is to study the flexibility of the Portuguese electrical grid in 2030. The version of the FlexTool used is the 0.64.

4.2. Modeling 2018

In order to check whether the modeling capabilities can serve the purposes of this study, 2018 was modeled first, since it is the most recent year with full data available. For this kind of analysis, the model was run in dispatch mode and then the output data was compared to real data supplied by REN, for validation purposes.

In what concerns the input data, a copy of the template file was created and then modified to match the data from Portugal's grid in 2018. In this input file there is a set of 12 worksheets: *master, gridNode, unit_type, fuel, units, nodeNode, ts_cf, ts_inflow, ts_energy, ts_import, ts_reserves* and *ts_time.* The process of sourcing and inserting the different values required in each of these worksheets is fully detailed in the Appendix.

4.3 Modeling 2030

For the study of the power grid flexibility in 2030, a scenario analysis was developed. Some scenarios analyzed the response of the different electrical systems planned in PNEC under baseline conditions, while others studied the impact of improving or adding elements to the grid. The chosen focus of the analysis is the production and distribution phases of the supply chain. Even though there are other types of solutions to improve flexibility, as mentioned in Section 3, this project focuses on the upstream and midstream phases.

The scenarios modeled were: the Existing Policies Scenario, the two Stated Policies Scenarios (2030(-) and 2030(+)), a dry year scenario, a utility-scale battery scenario and an increased export capacity scenario. A dry-year scenario, simulating a year with low hydro inflows, was developed because hydrologic availability considerably affects the Portuguese power production matrix and because the current trend is for weather to become drier, with more frequent and severe droughts due to climate change. A utility-scale battery scenario was also used, to evaluate the impact and feasibility of using batteries as power storage, at a large scale. Lastly, in order to study what would be the effect of increasing interconnection availability on the system flexibility, the increased export capacity was created. No scenarios were created where the capacity factors[5] of wind or solar technologies were changed, because research on Portuguese and Spanish historical data showed that these were quite stable in previous years. The initial step was to make various copies of the input file for 2018 and update the required data. There were some differences common to all scenarios: CO_2 cost, curtailment penalty, demand, costs of technologies, coal phase-out and the price of natural gas. The cost of CO_2 was updated to 22,30 USD/MWh, based on the price predictions of the Oxford Institute for Energy Studies (Figure 7[6]). According to PNEC, the power demand in 2030 in Portugal is expected to be 4474 ktoe, or 52033 GWh (Table 5[6]), and since in 2018 the power consumption in Portugal was 52485 GWh, the growth rate in this time period is actually negative, at approximately -0,86%. This growth rate was used to estimate power demand, as well as the initial imports and exports in 2030 (further explanations ahead). The costs of the different technologies were mostly the same, with the exception of the fixed costs

[5] Capacity Factor = Average Power Production of a Technology / Capacity Installed of that Technology
[6] Page 25.

of hydro. The coal data were removed from the input files since full coal phase-out is expected in 2022, and no power is expected to be generated from this technology by 2030. The price of natural gas was estimated at 18,87€/MWh, based on natural gas futures currently quoting, CAL 2026 being the product with the longest maturity available (Figure 8[7]). The price of biomass was kept the same as in 2018, due to lack of price forecasts for this fuel. For the purpose of analyzing the flexibility of the grid, it would not make a substantial difference if the wind power was sourced from onshore or offshore plants, so the whole wind capacity was assumed to be onshore. The amount of capacity allocated to hydro reservoir and hydro run-on-river[8] was calculated so that the proportion between the two capacities would be the same as it was in 2018. The amount of hydro storage was also increased so that the share with respect to total capacity installed was maintained. The wind and solar profiles remained the same so the *ts_cf* sheet was not modified. In the *ts_inflow* sheet, the average monthly hydro inflows were inserted (Figure 9[7]). Unfortunately the time range of the data used in the calculation of this inflow average is unknown. In the *ts_energy* and *ts_reserves* sheets, the same time series used for 2018, adjusted by the growth rate of the power consumption in Portugal of -0,86%, were used. Since the import/export values need to be introduced in the model as fixed values (limitation of the tool), they could only be updated after running the model with the different scenarios (initially with import/export values calculated by applying the demand growth rate to imports and exports of 2018), identifying at which time steps curtailment was occurring, and then maximizing the available export capacity in those periods. An export capacity of 3350MW was assumed, since it corresponds to the average of the

[7] Page 26.
[8] Hydro run-on-river is the non-storable hydro capacity.

expected export values for 2030 (Table 7[9]). For this process, data at every time step of the year had to be retrieved, thus all 8760 hours (full year) in the *ts_time* sheet were selected, increasing the average time to run the model to 30 minutes.

Table 8 – Prediction of Power Baseload Prices

	2018	2030EP	2030(+)	2030(-)	2030(-)dry	2030(-) 1600storage	2030(-) increasedexport
Price (€)	57,45	57,15	50,10	52,30	53,77	53,80	53,68
% Decrease (to 2018)	-	-1%	-13%	-9%	-6%	-6%	-7%

Source: Author, 2019

In terms of the specific data for each scenario, different curtailment penalties were assumed, using predictions of the baseload price as proxies. These baseloads were calculated using averages of the hourly prices, where hours with power curtailment were assumed to be priced at 0 €/MWh. Moreover, the capacity of the different technologies had to be adjusted to each scenario: in the dry year scenario, the proxy used was the hydro production in 2017 (REN, 2019), a year markedly dry, resulting in 31% and 46% of the average hydro reservoir and run-on-river production, respectively; in the battery scenario, the 1600MW capacity of the battery was selected so that it would be equivalent to the current coal capacity and the storage capacity was calculated using a proxy for large scale storage from an IRENA report on utility-scale batteries, four times the power of the battery (6400MWh). In the increased export scenario, it was assumed that the export capacity from Portugal to Spain would be increased to 4000MW, which is the maximum planned value for 2040 (Table 7[9]).

[9] Page 27.

5. Discussion of results

Table 9 – Model Results for 2018 VS Reality

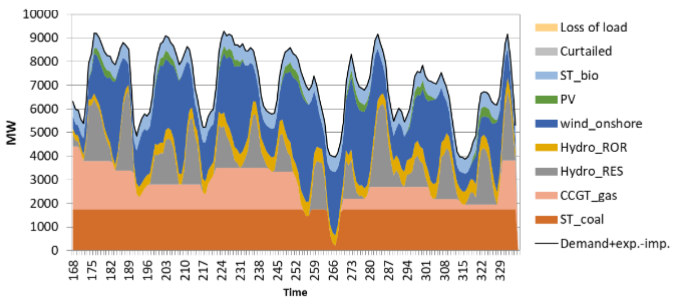
	Irena FlexTool	Reality
Share VRE (%)	35%	37%
Loss of load (GWh)	0	0
Curtailment (GWh)	50	150
Demand (GWh)	52 485	52 485
Wind (GWh)	13 043	12 351
Solar (GWh)	835	827
Hydro_RES (GWh)	6 267	6 092
Hydro_ROR (GWh)	4 684	6 222
Biomass (GWh)	5 377	7 355
Gas (GWh)	10 711	10 188
Coal (GWh)	14 226	11 165
Exports (GWh)	-2 657	-2 657

Source: Author, 2019

Results for 2018: After running the model, the key values from the output file were organized and compared to the "Reality" results, constructed using the 2018 load diagram provided by REN (Table 9). Some similarities, as well as some differences, were found. In terms of similarities, excluding demand and exports, which were inserted, they are the following: the total share of variable renewable energy, as well as the wind, solar, hydro (reservoirs) and gas production. In terms of differences, the curtailment was significantly lower than the real one, as well as the hydro production from run-on-river and from biomass. The lack of production from the previously mentioned technologies was mostly offset by an increase in coal power production. The differences in the hydro run-on-river production could be explained by the maintenance of the infrastructure or by disparities in the hydro inflows, even though these were retrieved from REN's data center. The lack of production from biomass can be due to the real cost of the fuel. Since the objective function of the model is cost minimization the biomass was considered uncompetitive from an economic perspective, when compared to its alternatives, coal and gas.

Figure 10 is one of the plots present in the results file, a load diagram with all the technologies producing power at every time step modeled.

Figure 10 – Load Diagram for 2018



Source: Author, 2019

Despite the differences, the results are considered satisfactory and validate the adequacy of the model to study the 2030 grid. To analyze the grid's flexibility in 2030, the most relevant value is the percentage of VRE used in power generation, the loss of load and the curtailment, for which the model outputs presented differences considered acceptable. Even though the relative differences in curtailment are large, the absolute values are not as significant.

<u>Results for 2030:</u> With the several output files created from running all the scenarios, the most relevant data was organized in Tables 10 and 11. In terms of production, the share of VRE varies within a wide interval, ranging from 56% in the Existing Policies Scenario to 89% in the 2030(+) Scenario. In terms of the CO_2 emissions, the PNEC goal of 1751 kton of CO_2e in 2030 is never attained (Table 12[10]). The loss of load value is always 0, thus demand is always met. In terms of power curtailment, there is always some, even in the Existing Policies Scenario. Biomass is only used as a source for power production in the dry year scenario. The reason why no biomass is used on the other scenarios is probably the same as the one for 2018, that is, related to the cost of the fuel. The costs were converted from USD to Euros and then the present value was calculated for Euros 2019, using an annual real interest rate of 3,92%, that is, the difference between

Table 10 – Model Results for 2030 | Production

	2030EP	2030(+)	2030(-)	2030(-)dry	2030(-) 1600storage	2030(-) increasedexport
Share VRE (%)	56%	89%	84%	74%	85%	85%
CO2 Emissions (kton)	7 265	3 131	3 598	6 354	3 219	3 618
Loss of load (GWh)	0	0	0	0	0	0
Curtailment (GWh)	23	2 521	1 447	993	927	1 037
Demand (GWh)	52 033	52 033	52 033	52 033	52 033	52 033
Wind (GWh)	14 256	22 760	22 137	21 895	22 271	22 251
Solar (GWh)	4 338	14 085	11 921	11 632	12 013	12 002
Hydro_RES (GWh)	6 119	6 119	6 119	1 903	5 830	6 119
Hydro_ROR (GWh)	10 785	9 673	9 823	5 015	10 117	10 037
Biomass (GWh)	0	0	0	570	0	0
Gas (GWh)	20 070	8 651	9 940	17 555	8 894	9 995
Exports (GWh)	-3 536	-9 255	-7 907	-6 537	-6 259	-8 372

Source: Author, 2019

Table 11 – Model Results for 2030 | Costs

1000 €	2030EP	2030(+)	2030(-)	2030(-)dry	2030(-) 1600storage	2030(-) increasedexport
Investment Costs	**0**	**0**	**0**	**0**	**906 370**	**860 000**
Fixed Costs	271 648	392 898	377 053	377 053	668 102	377 053
O&M Costs	34 762	19 550	21 267	27 041	46 779	21 340
Fuel Costs	350 097	150 906	173 391	318 152	274 917	174 348
CO2 Costs	91	39	45	80	72	46
Startups Costs	117	105	110	390	188	111
Curtailment Penalty	734	71 289	42 699	30 141	49 861	31 417
Loss of load Penalty	0	0	0	0	0	0
Operational Costs (with Penalties)	**657 449**	**634 788**	**614 566**	**752 857**	**1 039 918**	**604 314**

Source: Author, 2019

[10] Page 27.

the average of the long term interest rate (OCDE, 2019) and the average inflation rate between 2010 and 2019. The investment costs of new capacity installed in the Existing Policies scenario and both Planned Policies scenarios (2030(-) and 2030(+)) were ignored, as they were considered sunk costs. Looking at the costs of operation of the grid in each scenario, the most expensive year in terms of grid operation is the dry year and the cheapest one is 2030(-) which, relative to 2030EP, produces significant savings from fuel costs, by reducing dependence on thermal units, but at the same time presents higher fixed costs, due to the larger amount of installed capacity (wind and solar, mostly), offsetting the first effect. Curtailment penalties are substantial in all scenarios except for the Existing Policies, representing 4% to 10,8% of the operational costs of the grid, in the dry year and the 2030(+) scenario, respectively. The costs of installing the utility-scale lithium-ion batteries, using the proxy of 250 USD/KWh (Figure 11[11]), was estimated to be around 906M €. The cost of increasing the export capacity to Spain to 4000MW was estimated from the PNI (Plano Nacional de Investimentos). The budget for the development of the power interconnection points of Portugal during the next decade is 860M € euros of what year (PNI, 2019). Since the export capacity expected in 2040 is roughly double the capacity expected in 2030 (Table 7[11]), the value of 860M € was used as the additional investment required at the interconnection point. Given that the increase in interconnection capacity between European countries, namely between Iberian Peninsula and the central Europe, was mentioned in the recent presentation of the objectives of the European Green Deal, some of these costs might end up being subsidized by European funds.

[11] Page 27.

6. Conclusions

This work project is an exercise that uses a flexibility analysis tool (Irena FlexTool) to raise awareness and accountability for challenges and obstacles awaiting Portugal in its way to achieve carbon neutrality.

Given the results of the simulation for the electrical grid in 2030, where there is no loss of load value in all scenarios, it seems that the new wind and solar capacities will be more than enough to compensate for the decrease in thermal capacity, supported by the flat growth rate of demand. That said, the power grid is still inefficient and "dirty", with high shares of electricity being curtailed where the CO_2 emissions goal for 2030 will not be achieved in any of the scenarios. The amount of power curtailed shows a negative correlation with the predicted baseload price, which is higher in the Existing Policies scenario and lower in the less conservative Planned Policies scenario (2030(+)). While in the first it decreases 1% relative to the 2018 average value of 57,45 €/MWh , in the second it is reduced by 13% (Table 8[12]), signaling a noticeable, but not extreme[13], decrease in the power price due to curtailment. Yet, this might be a consequence of the method used to predict the baseload prices,not taking into account which technology was setting the marginal price. It is expected that the number of hours with VRE's as the marginal price-setting technologies[14] increases may lead to further decreases in the baseload price. The results show that curtailment penalties are relevant: including the curtailment penalties in the operational costs, it makes more economic sense to follow the 2030(-) scenario instead of the 2030(+) scenario, but if the curtailment penalties are

[12] Page 14.
[13] This value does not come close to the reference price of 20 MW/h seen in Portugal's latest solar auctions.
[14] The marginal price-setting technology is the most expensive technology injecting power into the grid at a given time period so that demand is met.

disregarded, the opposite conclusion is reached. Based on the results of the utility-scale battery scenario, it is clear that the power storing benefits are hardly high enough to justify the investment costs required for the installation of 1.600MW of utility-scale battery capacity.

There is opportunity for investments that improve system flexibility, by smoothing the energy production, reallocating power produced in peak intervals to the hours when natural gas is still producing significant amounts of power. Such solutions would simultaneously reduce curtailment levels and CO_2 emissions. The estimated cost due to grid inefficiency in 2030, based on the curtailment penalty, is between 30,1M € and 71,3M €, (€ 2019) under baseline conditions, thus representing a significant amount of resources that could be used to pay for investments that produce the effects mentioned above.

Considering the use of IRENA FlexTool, the model completely fulfilled the needs of the analysis, despite some minor bugs found along the way. The way it integrates all the data allowed for a dispatch model that was able to simulate a hypothetical electrical grid and assess how it would react under different circumstances. Even though the use of the FlexTool produced fruitful results, the potential of the tool was not fully exploited. It would be very interesting to split the Portuguese grid into various nodes, which would allow for the study of the electricity flows between the various regions of the country and the impact of investment in new transmission lines. It could also be interesting to separate the pumping demand from the other kinds of demand to better study how this form of storage can be used to manage the excess energy. The production units were modeled as bundles per technology type, but it would also be insightful to model production units separately, allowing for more detailed production data. All of these are beyond the scope of this research. In terms of limitations, there were some issues when running the model with a start and/or finish value for the hydro reservoirs, implying that this feature could not be fully exploited and consequently the reserve levels ended up not matching the real ones. A benchmark with another dispatching model would also be advised. IRENA already compares their model with PLEXOS, thus it would be interesting to compare it with another model.

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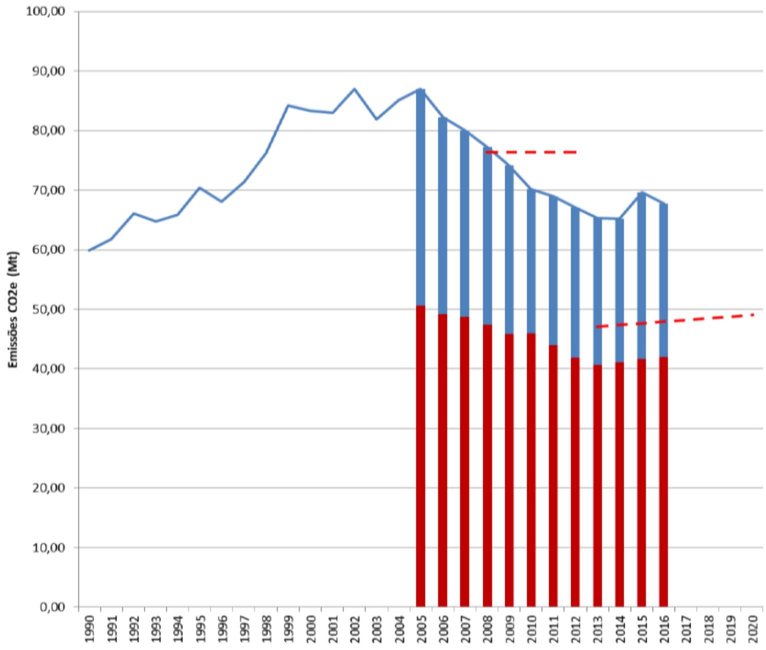
Tables and Figures

Figure 1 – Evolution of the Portuguese GHG emissions from 1990 to 2016



Source: PNEC, 2018

Table 1 – Portugal targets for 2030

Metas 2030	Contributo nacional para as metas da União
Redução de emissões de CO_{2e} (sem LULUCF) (Mt CO_{2e}), face a 2005	-17%[1]
Reforçar o peso das Energias Renováveis (% no consumo final bruto de energia)	47%
Aumentar a Eficiência Energética (% redução no consumo de energia primária[2])	35%
Interligações Elétricas	15%

Source: PNEC, 2018

Table 2 – Potential CO_2 emissions in Stated and Planned Policies Scenarios

	Projeção de redução emissões de GEE face a 2005 (%) – Cenário Políticas Existentes		Projeção de redução emissões de GEE face a 2005 (%) – Cenário Políticas Planeadas	
Setores	**2030**	**2040**	**2030**	**2040**
Energia	73	89	83	93
Indústria	45	45	45	60
Transportes	48	72	53	84
Serviços	64	82	65	100
Residencial	27	29	29	74
Agricultura	19	19	19	20
Resíduos e Águas Residuais	57	69	57	69
Total sem LULUCF	52	64	56	74

Source: PNEC, 2018

Table 3 – Prediction of the evolution of the Portuguese power sector in the Stated Policies Scenario

Tabela 37 – Previsão de evolução da capacidade instalada no sistema electroprodutor nacional para a produção de eletricidade por tipo de fonte em Portugal (GW): Cenário Políticas existentes [Fonte: DGEG]

	2015	2020	2025	2030	2035	2040
Térmica não-renovável	5.7	5.7	5.7	3.9	3.9	3.9
Renovável	11.7	14.7	17.1	18.0	18.0	18.1
Hidroelétrica	6.0	7.0	8.2	9.0	9.0	9.0
Solar	0.4	1.8	2.8	2.9	3.0	3.0
Eólica	5.0	5.4	5.6	5.6	5.6	5.6
Outras Renováveis[1]	0.3	0.5	0.5	0.5	0.5	0.5
TOTAL[2]	17.4	20.4	22.7	21.9	21.9	22.0

[1] Inclui Biomassa, Biogás, Residuos (50% da produção por via dos resíduos não é renovável), Geotermia e Ondas
[2] Não inclui cogeração

Source: PNEC, 2018

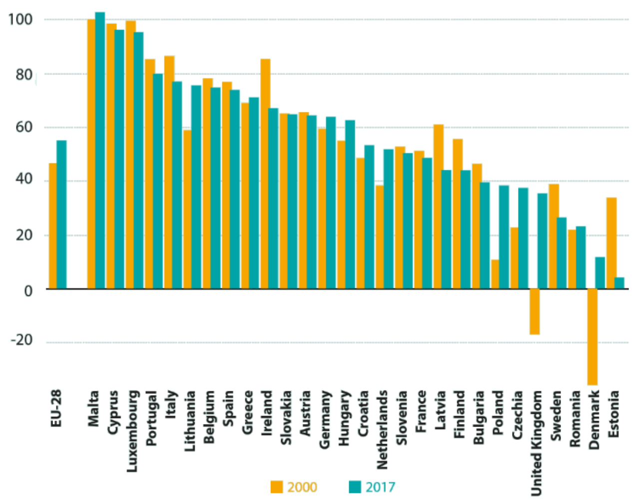
Table 4 – Prediction of the evolution of the Portuguese renewable energy in the power sector in the Planned Policies Scenario

	2015	2020	2025		2030	
Hidroelétrica	6,0	7,0	8,2		9,0	9,0
Eólica	5,0	5,4	6,6	7,8	8,8	9,2
Solar	0,4	1,9	5,5	6,6	8,1	9,9
Outras Renováveis[1]	0,3	0,5	0,5	0,5	0,7	0,6
TOTAL[2]	11,7	14,7	20,8	23,2	26,6	28,6

[1] Inclui Biomassa, Biogás, Residuos (50% da produção por via dos resíduos não é renovável), Geotermia e Ondas
[2] Não inclui cogeração

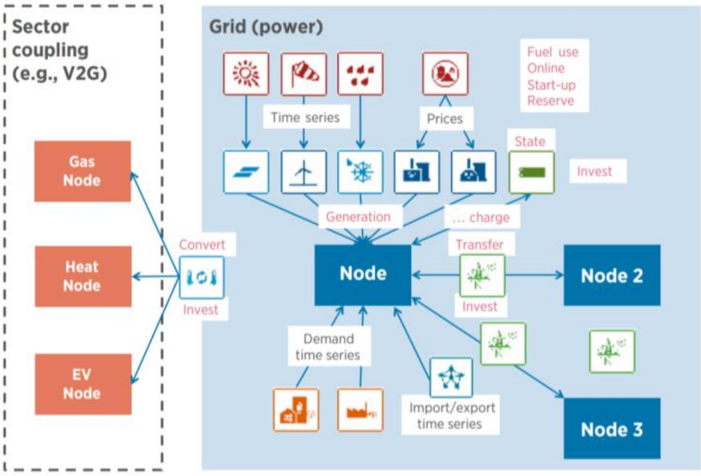
Source: PNEC, 2018

Figure 3 – Comparison of the primary energy dependency rate of EU countries (%)



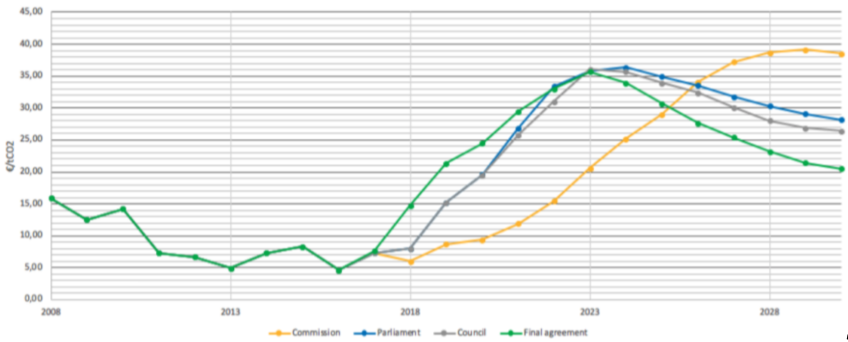
Source: Eurostat, 2017

Figure 6 – Overview of the tool input data (black font) and model outputs (red font)



Source: IRENA, 2019

Figure 7 – Impact of the EU ETS phase IV reform



Source: OIES, 2018

Table 5 – Prediction of final energy consumption in Portugal, per activity sector

	2020	2025	2030	3035	2040
Consumo Total de Energia Final	16 412	17 043	17 385	17 754	17 876
Petróleo	8 103	8 250	8 183	8 075	7 668
Eletricidade	4 172	4 474	4 753	5 083	5 445
Gás Natural	1 712	1 786	1 837	1 892	1 954
Renováveis	1 060	1 123	1 166	1 209	1 255
Calor	1 257	1 299	1 326	1 359	1 395
Outros (inclui hidrogénio)	108	111	120	136	160
Consumo Total de Energia Final sem usos não-energéticos	15 382	15 946	16 246	16 575	16 655
Transportes	5 591				
Transporte Aéreo Nacional	92	102	113	124	137
Transporte Marítimo Nacional	88	92	95	97	99
Transporte Ferroviário	40	39	39	40	40
Transporte Rodoviário	5 371	5 463	5 455	5 459	5 182
Indústria	4 642	4 798	4 899	5 017	5 152
Doméstico	2 707	2 880	2 999	3 116	3 240
Serviços	2 034	2 152	2 218	2 282	2 354
Agricultura e Pescas	407	420	429	439	451

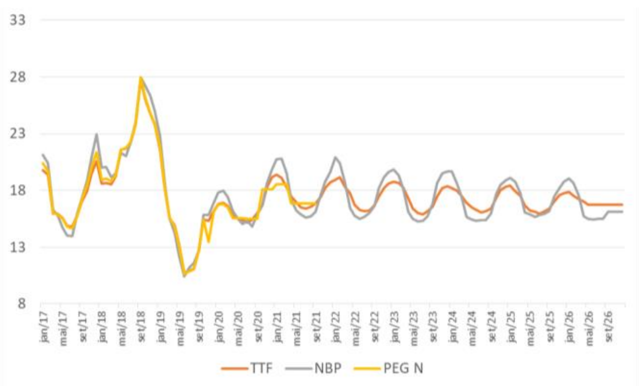
Source: PNEC, 2018

Table 6 – Costs of the technologies considered in the TIMES model

Gás	Custos de Investimento (2015)	Custos de Investimento (2030)	Custos de Investimento (2040)	Custos Fixos (2015)	Custos Fixos (2030)	Custos Fixos (2040)	Custos Variáveis (2015)	Custos Variáveis (2030)	Custos Variáveis (2040)	Referências
	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Gás Ciclo Combinado convencional	759	759	759	18,96	18,96	18,96	0,48	0,48	0,48	JRC (2013)
Gás Ciclo Combinado Avançada	488	488	488	9,01	9,01	9,01	0,52	0,52	0,52	EDP (2017)
Gás Ciclo Combinado com captura de CO2 pos combustão		888	864		31,74	31,05		0,20	0,20	JRC (2013)
Gas Ciclo Aberto (Peaker) Avançada (OGCC)	373	366	364	9,39	9,20	9,16	0,46	0,46	0,46	JRC (2013)
Diesel	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Turbina a vapor a fuel óleo(Supercritica)	1 399	1 113	1 012	17,94	17,86	17,83	0,58	0,58	0,58	JRC (2013)
Turbina a Diesel (Peaker) Avançada	385	377	375	12,20	11,95	11,90	0,52	0,52	0,52	EDP (2017)
Carvão (Antracite)	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Subcritica (Convencional)	1 049	1 049	1 049	20,98	20,98	20,98	0,27	0,27	0,27	JRC (2013)
Supercritica	1 307	1 307	1 307	26,13	26,13	26,13	0,55	0,52	0,49	JRC (2013)
Fluidized Bed	1 927	1 927	1 927	38,54	38,54	38,54	0,26	0,26	0,26	JRC (2013)
Ciclo Combinado com gaseificação integrada (IGCC)	2 014	1 727	1 558	40,28	34,53	31,17	1,23	1,23	1,23	JRC (2013)
IGCC com Captura de CO2 pre combustão		1 880	1 712		30,58	27,60		0,25	0,25	JRC (2013)
Supercritica + Captura CO2 pós combustão		1 732	1 698		31,16	28,12		0,63	0,61	JRC (2013)
Supercritica + Captura CO2 oxy fuel		1 758	1 486		28,70	25,90		0,96	0,91	JRC (2013)
Nuclear	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Nuclear 3ª geração (Light Water reactor)	3 843	3 843	3 843	69,71	69,71	69,71	0,70	0,67	0,65	JRC (2013)
Nuclear 4ª geração (Fast Reactor)			5 019			57,41	0,70	0,67	0,65	JRC (2013)
Hidrica	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Hidroelectrica de fio de água	1 068	970	888	10,68	9,70	8,88				TIMES_PT Database; JRC/EDP
Hidroelectrica Barragem (elevado AF)	771	747	721	7,71	7,47	7,21	0,47	0,47	0,47	TIMES_PT Database; JRC/EDP
Hidroelectrica Barragem (baixo AF)	771	747	721	7,71	7,47	7,21	0,47	0,47	0,47	TIMES_PT Database; JRC/EDP
Hidroelectrica Barragem com bombagem	593	574	554	5,93	5,74	5,54	0,47	0,47	0,47	TIMES_PT Database; JRC/EDP
Geotérmica	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Sistema Geotérmico Enhanced (Hot dry rock)	6 096	4 612	4 612	213,36	161,40	161,40				JRC (2013)
Geotérmica Hidrotermia com flash	1 676	1 537	1 537	58,67	53,80	53,80				JRC (2013)
Vento	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Vento offshore Flutuante	3 596	2 194	1 938	115,07	70,22	62,02				IRENA (2018)
Vento Onshore	826	736	721	30,04	30,04	30,04				EDP (2017)
Micro Eólica	4 291	3 173	2 832	85,82	63,46	56,64	0,10	0,09	0,07	WWEA (2016); Distributed Wind market Report US (2016)

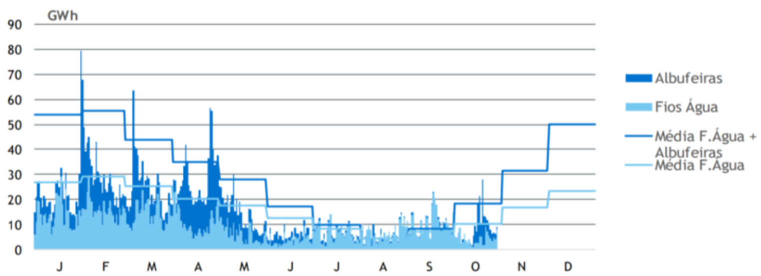
Source: PNEC, 2018

Figure 8 – Forward curve of TTF, NBP and PEGNORD



Source: Galp, 2019

Figure 9 – Annual Portuguese hydro inflows



Source: REN, 2019

Table 7 – Prediction of the interconnection capacity values between Spain and Portugal

	Portugal > Espanha (MW)	Espanha > Portugal (MW)	NOTA
2018	2 600	2 000	-
2022	3 000	3 000	Após concretização da futura linha de interligação a 400 kV Ponte de Lima (PT) – Fontefría (ES)
2027	3 200	3 600	Estimativa com base em análises efetuadas considerando as evoluções previstas no longo prazo ao nível da procura, da oferta, dos fluxos transfronteiriços e da própria estrutura física das redes, nos sistemas português e espanhol.
2030	3 200 – 3 500	3 600 – 4 200	Intervalo estimado com base em análises efetuadas no âmbito do TYNDP 2016 e reconfirmados no TYNDP 2018.
2040	3 500 – 4 000	4 200 – 4 700	Valor estimado com base em análises efetuadas nos cenários *'Sustainable Transition'* e *'Distributed Generation'* do TYNDP 2018, não se encontrando ainda identificados os eventuais reforços de rede necessários para atingir estes valores de capacidade de interligação

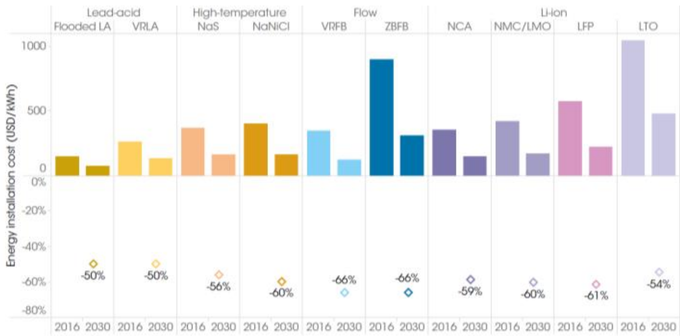
Source: PNEC, 2018

Table 12 – Projetion of GHG emissions in Portugal

	Emissões de GEE (kt CO_{2e})			
Setores	**2005**	**2020**	**2030**	**2040**
Energia	26 167	16 239	4 521	1 832
Produção e transformação de energia	23 039	12 942	1 751	363
Refinação	2 466	2 220	1 861	986
Emissões Fugitivas	662	1 077	909	483
Indústria	18 335	12 448	10 175	7 292
Combustão na Indústria	10 758	7 631	5 886	3 392
Processos Industriais	7 577	4 817	4 289	3 900
Transportes	19 594	16 272	9 286	3 222
Serviços	3 166	1 178	1 114	7
Residencial	2 724	2 427	1 934	717
F-gases	212	2 226	877	606
Agricultura	8 213	7 829	6 615	6 535
Agricultura	6 760	6 728	5 498	5 449
Combustão na Agricultura/Floresta/Pesca	1 453	1 102	1 118	1 087
Resíduos e Águas Residuais	7 701	4 405	3 320	2 362
LULUCF	1 520	-4 642	-6 926	-7 795
Total sem LULUCF	86 112	63 025	37 842	22 573
Total com LULUCF	87 632	58 383	30 916	14 778

Source: PNEC, 2018

Figure 11 – Battery electricity storage system installed energy cost reduction potential, 232016-2030



Note: LA = lead-acid; VRLA = valve-regulated lead-acid; NaS = sodium sulphur; NaNiCl = sodium nickel chloride; VRFB = vanadium redox flow battery; ZBFB = zinc bromine flow battery; NCA = nickel cobalt aluminium; NMC/LMO = nickel manganese cobalt oxide/lithium manganese oxide; LFP = lithium iron phosphate; LTO = lithium titanate.

Source: IRENA, 2019

APPENDIX

Modeling 2018

parameter	value
co2_cost	16,46
loss_of_load_penalty	10000
loss_of_reserves_penalty	20000
curtailment_penalty	63,76
lack_of_capacity_penalty	5000
time_in_years	1
time_period_duration	60
reserve_duration	4,00
use_capacity_margin	1
use_online	1
use_ramps	1
use_non_synchronous	0
mode_invest	0
mode_dispatch	1
print_duration	1
print_durationRamp	1

WS master: In this worksheet the parameters and settings for the whole model were defined. The CO_2 cost was changed to the yearly average cost of the CO_2 allowances (delivery date of December 2018) in USD/MWh. For the whole model, the currency used was USD ($ 2018). The penalties were maintained, except for the exception of the curtailment penalty, that should be the same as the price per MWh of the year considered, which averaged 63,76 USD/MWh according to OMIE data (Iberian power market manager). The variable "time_in_years" was left with a value one, since only the year 2018 would be studied. The variable "time_period_duration" was set to 60, representing the number of minutes between each time step. The "reserves_duration" was not changed from the value of four hours, since it is the minimum time of connection or disconnection to the grid of the thermal groups (ERSE, 2018). The capacity margin value was ignored, since it is not used in dispatch mode. The "use_online" variable was set to 1 so that start-up costs and part-load efficiencies would be considered. The "use_ramps" was also set to 1, to make ramping constraints active (ramping = activation of a production unit). Since no maximum share of non-synchronous (e.g. solar and wind) generation was intended, the variable "use_non_synchronous" was set to 0. The mode variables were defined so that only the dispatch mode was used.

node	demand (MWh)	import (MWh)	capacity_margin (MW)	non_synchronous_share	use_staticReserves	use_dynamicReserves	print_results
node	5,2,E+07	-2,7,E06	50	1,0	0	0	1

WS gridNode: Even though the model allows for various grids (e.g. electrical grid, heating grid) and multiple nodes of a grid to be modeled, for the purpose of this analysis, only the Portuguese electrical grid was considered, as a single node. Thus, in this sheet, the grid node and its respective demand and import/export data are described. The demand value is calculated by the sum of all demand in 2018, including that used for pumping purposes. The import value corresponds to the difference between the total imports (positive values) and exports (negative values). The "capacity_margin "is a variable solely used in investment mode. The fact that the share of variable generation was set to unlimited in the master sheet renders the "non_synchronous_share" meaningless. The "use_staticReserves" variable was set to 1 and the "use_dynamicReserves" variable was set to 0 because the fixed hourly values of the upwards regulation reserves were inserted in the worksheet *ts_reserves*, calculated using monthly data from REN (Table 1[15]). Downwards reserves are ignored in the FlexTool to decrease model complexity (IRENA, 2019). The "print_results" variable was set to 1, so that all information concerning the node was detailed in the output file.

unit type	efficiency	min load	eff at min load	ramp up (p.u. per min)	ramp down (p.u. per min)	unit size (MW)	O&M cost/MWh	availability	max_reserve	fixed cost/kW/year	inv.cost/kW	inv.cost/kWh	fixed kW/kWh ratio	conversion_eff	startup cost	eff charge	self_discharge_loss	lifetime	interest	annuity	*non_synchronous*
ST_coal	0,28	0,40	0,23	0,02	0,02	100	1,46	1,00	1,00	31,71	1586				2,0			40	0,08	0,084	0
Hydro_RES	1,00			0,20	0,20		2,6	1,00	1,00	11,66	1165										0
Hydro_ROR	1,00			0,20	0,20			1,00	0,90	16,15	1615										1
wind_onshore	1,00			1,00	1,00			1,00	0,90	45,41	1249							20	0,08	0,102	1
PV	1,00			1,00	1,00			1,00	0,90	10,00	1000							30	0,08	0,089	1
ST_bio	0,35	0,40	0,30	0,02	0,02	50	4,0	1,00	1,00	50,00	4000				2,0			40	0,08	0,084	0
CCGT_gas	0,55	0,20	0,40	0,10	0,10	100	2,62	1,00	1,00	28,86	1147				0,5			35	0,08	0,086	0

WS unit_type: This is where the characteristics of the power generation technologies used in the model are defined. The following technologies were defined: coal, gas (combined cycle), hydro reservoir, hydro run-on-river, wind onshore, solar photovoltaic and biomass. Other technologies with smaller relevance, such as waves or waste residues were disregarded for simplification purposes. Although Portugal has conventional and combined cycle gas power plants, all of them were considered combined cycle, using the same simplifying rational. All of these technologies were already included in the template file, so only some fine tuning has to be performed. For the variables "efficiency", "min load", "eff at min

[15] Page 36.

load”, “ramp up”, “ramp down” and “unit type”, almost all template values were used with the exception of “efficiency” and “eff at min load” of gas power plants, which were increased to 55% and 40%, respectively (Brenhas, Maria & Machado Rosário & Dinis, Maria, 2008). The variables relative to the costs of the different technologies (“O&M cost/MWh” as variable cost and “fixed cost/kW/year”) used in the analysis were retrieved from PNEC, specifically the 2015 costs used in the TIMES model (Table 2[16]). This was done so that the results of the model can be related to the Portuguese energy plan as much as possible. The costs in Table 2 are monetized using 2000 Euro, so inflation rates from 2000 to 2018 were used to calculate the 2018 costs. Then, the energy units were converted to match the requirements of the input file. The variables “inv.cost/kWh”, “fixed kW/kWh ratio”, “eff charge” and “self_discharge_loss” are relative to storage, so they were left blank. The variable “conversion_eff” is only required when more than one node is used. The variables “startup cost”, “lifetime”, “interest” and “annuity” were template sourced. The variable “non_synchronous” is used to identify the non-synchronous technologies, identified by the value 1.

fuel	fuel (price/MWh)	CO2_content (t/MWh)
coal	8.21	0.34
nat_gas	27.11	0.20
biomass	14.40	0.34

WS fuel: In this worksheet, the prices of the various fuels were inserted. For natural gas, data was retrieved from MIBGAS (Iberia exchange for natural gas) and an average of the spot price in 2018 was calculated. The product used was the PVB (Spanish hub) Day-Ahead. As for coal, a similar approach was used initially for the product API2 (Rotterdam Coal Futures), that is an index based on the price of coal delivered into Amsterdam, Rotterdam and Antwerp region in the Netherlands. Finally, data on biomass was retrieved from an IRENA report, where the commodity used as a proxy was the woody biomass, with neglected

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transportation costs (Figure 1[17]), based on the assumption that it is the main type of biomass used in Portugal. The CO_2 contents of all fuels were left as in the template file. Even though there is emission of GHG emissions during the combustion of biomass, in Europe this technology is considered carbon-neutral, because CO_2 is captured during the trees growth.

grid	node	unit type	capacity (MW)	invested capacity (MW)	max_invest_MW	fuel	cf profile	inflow	grid2	node2	storage (MWh)	invested storage (MWh)	max_invest_MWh	storage start	storage finish	reserve_increase_ratio	inflow_multiplier
elec	node	ST_coal	1756		0	coal											
elec	node	Hydro_RES	4425		2000			node_RES			3,2,E+06		0				1
elec	node	Hydro_ROR	2790		2000			node_ROR									1
elec	node	wind_onshore	5150		2000		wind_A									0,10	
elec	node	PV	559		2000		PV										
elec	node	CCGT_gas	4609		2000	nat_gas											
elec	node	ST_bio	628		2000	biomass											

WS units: In this worksheet, the different power producing units of our 2018 model were defined. These were set so that each unit represents the total production capacity of the technology, meaning that, for example, even though there are four gas powered plants, only one unit of gas is introduced, with a power production capacity equivalent to the sum of all four plants. The inserted units were: coal, gas (combined cycle), hydro reservoir, hydro run-on-river, wind onshore, solar photovoltaic and biomass and their capacities were retrieved from a report on the Portuguese power grid in 2018, by REN, the Portuguese power grid operator. Then, the "fuel" for each thermal unit was selected, as well as the time series that contain the wind and solar profiles and the hydro inflows over the year, through the variables "cf profile" and "inflows", respectively. The maximum capacity of the hydro reservoirs was inserted in the variable "storage" (REN, 2019), while the fullness levels at the start and end of the year were left blank. Even though this information was available, a model bug that occasionally created distorted results whenever one of these fields was not blank. After comparing some good results with and without the start and end levels of the reservoirs and verifying that the hydro production levels did not change considerably, this values

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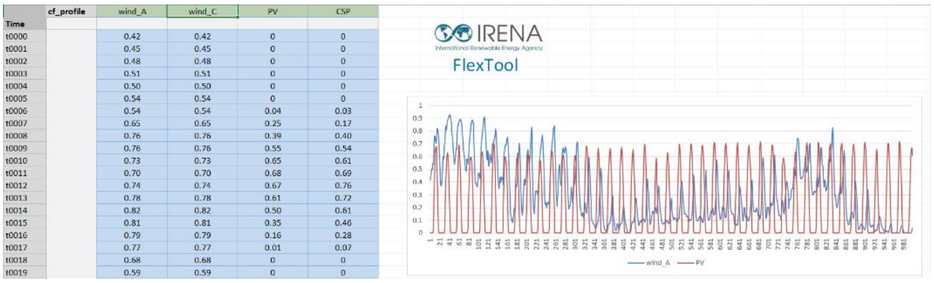
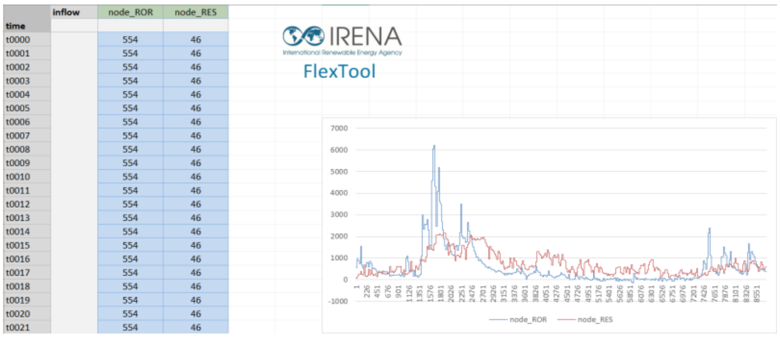
were ignored. The "reserve_increase_ratio" would only be needed for dynamic reserves modeling, a feature that will not be used. The inflow_multiplier was set to 1 because the exact daily inflow values were retrieved from REN website. The variables "maximum_investment_MW" , "invested storage" and "max_invest" do not influence dispatch modeling.

WS nodeNode: This sheet is only needed if we model multiple nodes with interconnection capacities between them. Since that is not the case, the rows present in the template file were deleted, but the sheet was kept.



Time	cf_profile	wind_A	wind_C	PV	CSP
t0000		0.42	0.42	0	0
t0001		0.45	0.45	0	0
t0002		0.48	0.48	0	0
t0003		0.51	0.51	0	0
t0004		0.50	0.50	0	0
t0005		0.54	0.54	0	0
t0006		0.54	0.54	0.04	0.03
t0007		0.65	0.65	0.25	0.17
t0008		0.76	0.76	0.39	0.40
t0009		0.76	0.76	0.55	0.54
t0010		0.73	0.73	0.65	0.61
t0011		0.70	0.70	0.68	0.69
t0012		0.74	0.74	0.67	0.76
t0013		0.78	0.78	0.61	0.72
t0014		0.82	0.82	0.50	0.61
t0015		0.81	0.81	0.35	0.46
t0016		0.79	0.79	0.16	0.28
t0017		0.77	0.77	0.01	0.07
t0018		0.68	0.68	0	0
t0019		0.59	0.59	0	0

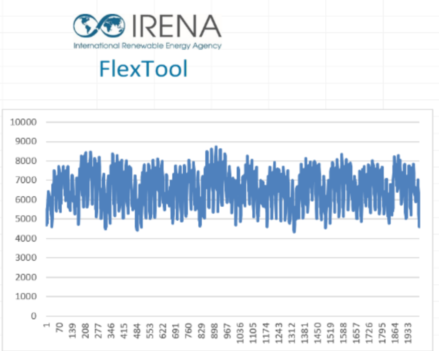
WS ts_cf: This is where the time series for the wind and solar profile are stored. The four profiles that were initially included in the template file were kept. The wind_A profile and the PV were used as capacity factors for wind and solar photovoltaic units of the model, respectively. A validation to this approach was performed, by comparing the total electricity produced by these technologies predicted by the model with the real production values published by REN, after the first model run. The values for both were quite similar, so the profiles were validated.



time	inflow	node_ROR	node_RES
t0000		554	46
t0001		554	46
t0002		554	46
t0003		554	46
t0004		554	46
t0005		554	46
t0006		554	46
t0007		554	46
t0008		554	46
t0009		554	46
t0010		554	46
t0011		554	46
t0012		554	46
t0013		554	46
t0014		554	46
t0015		554	46
t0016		554	46
t0017		554	46
t0018		554	46
t0019		554	46
t0020		554	46
t0021		554	46

WS ts_inflow: The information regarding the hydro inflows of the reservoirs and run-on-river was inserted here. The daily inflow data for 2018, available on REN’s website, was retrieved through a macro and used in the model.

	grid	elec
	node	node
time		
t0000		4701
t0001		4749
t0002		4919
t0003		4798
t0004		4787
t0005		5165
t0006		5496
t0007		5631
t0008		5463
t0009		5701
t0010		6356
t0011		6419
t0012		6426
t0013		6261
t0014		5961
t0015		5847
t0016		5730
t0017		6100



WS ts_energy: In this worksheet the consumption values for each time step (hour) are defined. This time series corresponds to the total power demand, including the one used for hydro pumping purposes. All data provided by REN.

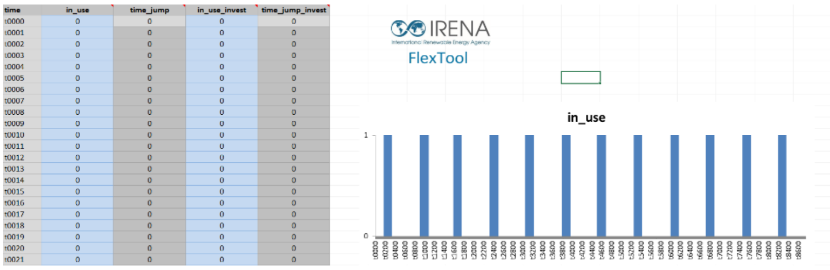
	grid	elec
	node	node
time		
t0000		1373
t0001		1524
t0002		1480
t0003		1497
t0004		1502
t0005		1500

WS ts_import: The time series relative to the import and export activities of the node modeled is depicted here. Positive values represent imports and negative values represent exports. All data provided by REN.

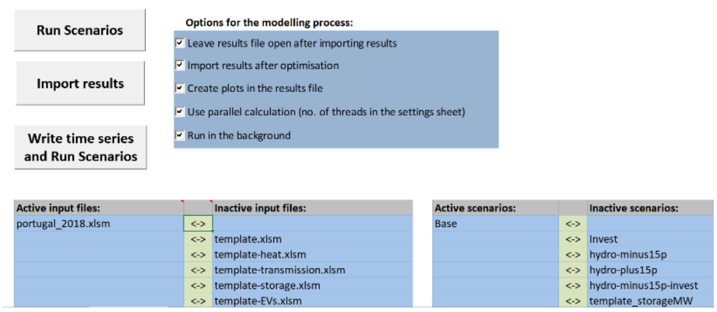
	node	node
Time		
t0000		76
t0001		76
t0002		76
t0003		76
t0004		76
t0005		76

WS ts_reserves: This sheet is used to provide data on the reserve requirements of the grid. There are three kinds of reserves: primary, secondary and tertiary, each one of them serving different purposes, namely frequency correction or to fill a demand gap created by the failure of a production unit. Since the model only requires a single reserve input per time step, only the largest reserves were considered, meaning the tertiary. This type of reserves is yet subdivided in upwards and downwards reserves, where the first are used to correct the grid when it requires more electricity and the latter in the opposite situation. The model only requires inputting the value of upwards reserves. The technologies currently used in Portugal to provide this kind of reserves are hydro and thermal, because of their dispatchable nature (REN, 2019).

The hourly values were calculated by dividing the monthly upward reserves available on REN’s website by the total hours in the month (Table 1[18]).



WS ts_time: The last worksheet is used to define the different time periods of the year that will be modeled. By default, the time intervals are equidistant intervals of 168 hours, or seven days, totaling twelve intervals. The purpose of this selection of intervals is to reduce of complexity of the modelling task. The default layout of time intervals was used because it results in a comprehensive sample of the whole year, while taking less than 5 minutes to run.



After having all inputs included in the model, the master excel file was opened and the iteration phase started. In the *Sensitivity scenarios* worksheet, “portugal_2018.xlsm” was selected as the active input file and “Base” scenario chosen as the only active scenario. Then the button “Write time series and Run Scenarios” was clicked and the model run. The model takes between 2 and 5 minutes to run and it produces an output Excel file that is automatically saved in a folder named Results inside the main folder of the model. After each iteration, the output of the mode

[18] Page 36.

was compared to the actual production data of 2018 and the input errors successively identified and solved.

Table 1 – Portuguese monthly upward and downward tertiary reserves of 2018

Área Bal.	Jan		Fev		Mar		Abr	
	Subir	Descer	Subir	Descer	Subir	Descer	Subir	Descer
HÍDRICAS	47250,1	113760,3	50475,1	78557,5	45843,7	139119,4	32884,6	155797,7
TÉRMICAS	9198,6	50552,0	8846,0	43108,9	19273,1	31758,3	13700,0	12805,7
TOTAL	56448,7	164312,3	59321,1	121666,3	65116,8	170877,7	46584,6	168603,4

Área Bal.	Mai		Jun		Jul		Ago	
	Subir	Descer	Subir	Descer	Subir	Descer	Subir	Descer
HÍDRICAS	28342,7	68344,3	28514,3	52113,5	46131,1	27746,0	36982,5	55019,1
TÉRMICAS	7902,3	31918,2	3919,4	53352,9	7451,0	45192,4	22012,2	66880,2
TOTAL	36245,0	100262,5	32433,7	105466,4	53582,1	72938,4	58994,7	121899,3

Área Bal.	Set		Out		Nov		Dez	
	Subir	Descer	Subir	Descer	Subir	Descer	Subir	Descer
HÍDRICAS	33395,1	49815,8	50548,2	59245,7	64320,3	20299,9	18984,6	56503,7
TÉRMICAS	6254,4	19427,2	6889,2	57015,3	15175,7	33368,4	9921,7	64827,3
TOTAL	39649,5	69243,0	57437,4	116261,0	79496,0	53668,3	28906,3	121330,9

Unidades: MWh

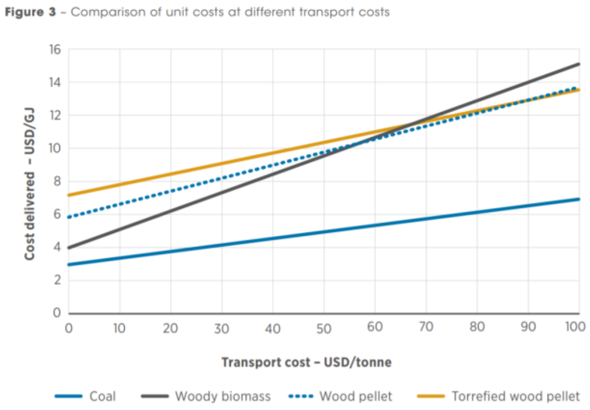
Source: REN, 2019

Table 2 - Costs of the technologies considered in the TIMES model

Gás	Custos de Investimento (2015)	Custos de Investimento (2030)	Custos de Investimento (2040)	Custos Fixos (2015)	Custos Fixos (2030)	Custos Fixos (2040)	Custos Variáveis (2015)	Custos Variáveis (2030)	Custos Variáveis (2040)	Referências
	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Gás Ciclo Combinado convencional	759	759	759	18,96	18,96	18,96	0,48	0,48	0,48	JRC (2013)
Gás Ciclo Combinado Avançada	488	488	488	9,01	9,01	9,01	0,52	0,52	0,52	EDP (2017)
Gás Ciclo Combinado com captura de CO2 pos combustão		888	864		31,74	31,05		0,20	0,20	JRC (2013)
Gas Ciclo Aberto (Peaker) Avançada (OGCC)	373	366	364	9,39	9,20	9,16	0,46	0,46	0,46	JRC (2013)
Diesel	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Turbina a vapor a fuel óleo(Supercritica)	1 399	1 113	1 012	17,94	17,86	17,83	0,58	0,58	0,58	JRC (2013)
Turbina a Diesel (Peaker) Avançada	385	377	375	12,20	11,95	11,90	0,52	0,52	0,52	EDP (2017)
Carvão (Antracite)	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Subcritica (Convencional)	1 049	1 049	1 049	20,98	20,98	20,98	0,27	0,27	0,27	JRC (2013)
Supercritica	1 307	1 307	1 307	26,13	26,13	26,13	0,55	0,52	0,49	JRC (2013)
Fluidized Bed	1 927	1 927	1 927	38,54	38,54	38,54	0,26	0,26	0,26	JRC (2013)
Ciclo Combinado com gaseificação integrada (IGCC)	2 014	1 727	1 558	40,28	34,53	31,17	1,23	1,23	1,23	JRC (2013)
IGCC com Captura de CO2 pre combustão		1 880	1 712		30,58	27,60		0,25	0,25	JRC (2013)
Supercritica + Captura CO2 pós combustão		1 732	1 698		31,16	28,12		0,63	0,61	JRC (2013)
Supercritica + Captura CO2 oxy fuel		1 758	1 486		28,70	25,90		0,96	0,91	JRC (2013)
Nuclear	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Nuclear 3ª geração (Light Water reactor)	3 843	3 843	3 843	69,71	69,71	69,71	0,70	0,67	0,65	JRC (2013)
Nuclear 4ª geração (Fast Reactor)			5 019			57,41	0,70	0,67	0,65	JRC (2013)
Hidrica	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Hidroelectrica de fio de água	1 068	970	888	10,68	9,70	8,88				TIMES_PT Database; JRC/EDP
Hidroelectrica Barragem (elevado AF)	771	747	721	7,71	7,47	7,21	0,47	0,47	0,47	TIMES_PT Database; JRC/EDP
Hidroelectrica Barragem (baixo AF)	771	747	721	7,71	7,47	7,21	0,47	0,47	0,47	TIMES_PT Database; JRC/EDP
Hidroelectrica Barragem com bombagem	593	574	554	5,93	5,74	5,54	0,47	0,47	0,47	TIMES_PT Database; JRC/EDP
Geotérmica	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Sistema Geotérmico Enhanced (Hot dry rock)	6 096	4 612	4 612	213,36	161,40	161,40				JRC (2013)
Geotérmica Hidrotermia com flash	1 676	1 537	1 537	58,67	53,80	53,80				JRC (2013)
Vento	€/KW	€/KW	€/KW	€/KW	€/KW	€/KW	€/GJ	€/GJ	€/GJ	
Vento offshore Flutuante	3 596	2 194	1 938	115,07	70,22	62,02				IRENA (2018)
Vento Onshore	826	736	721	30,04	30,04	30,04				EDP (2017)
Micro Eólica	4 291	3 173	2 832	85,82	63,46	56,64	0,10	0,09	0,07	WWEA (2016); Distributed Wind market Report US (2016)

Source: PNEC, 2018

Figure 1 – Comparison of unit costs at different transport costs



Source: IRENA, 2018