A Work Project, presented as part of the requirements for the Award of a Master's Degree

in Economics from NOVA – School of Business and Economics.

The Economic Value of Photovoltaic Solar Energy in Portugal:

A Cost-Benefit Analysis

Eduardo José Espírito Santo Gonçalves

3685

Work Project carried out under the supervision of:

Maria Antonieta Cunha e Sá

January 2019

The Economic Value of Photovoltaic Solar Energy in Portugal:

A Cost-Benefit Analysis

Abstract

Among renewable energy sources, solar energy has been typically considered to be less competitive in producing electricity. Though, besides having low external costs, solar power benefits from a timing advantage. Despite that these advantages are often recognized, for policy purposes it is crucial to provide evidence of such facts. This project aims at contributing to this goal by using numerical simulation to estimate the short-run economic value of an incremental change in solar PV in five different locations in Portugal. Therefore, it can serve as a stepping-stone for further research on medium- to long-term effects of introducing solar PV in the Portuguese electric system.

Keywords: decarbonisation, electricity**,** solar photovoltaic, carbon emissions, short-run net benefits

1. Introduction

Energy is key to the development of nations, being the engine that feeds their progress. Cheap and abundant energy from conventional resources such as coal, oil and natural gas has allowed countries worldwide to transition from an agriculture-based economy to one grounded on industrial activity. The counterpart of intensive energy usage in its diversity has contributed to the progressive degradation of the environment with negative consequences on living standards. In this context, countries have looked for solutions to transition from high-carbon to low-carbon intensive economies. Increased engagement of the different nations to combat climate change has gained expression with the Paris Agreement.

In a second-best context, incentives to promote alternative energy sources have been granted worldwide. Within the EU, Portugal is no exception. For installations registered until the end of 2012, the most significant instrument of promotion is the feed-in tariff (FiT), which consists of two components: a guaranteed payment for a contracted period plus an amount calculated by a statutorily set formula which varies depending on the energy source. Moreover, while benefiting from the FiT, it is mandatory for all the energy generated under the Special Regime (PRE) to be purchased by the "last resort supplier". This regime has created very favourable conditions to the deployment of renewable energy sources, which currently account for nearly 53% of total electricity generation in the Portuguese electricity sector.[1]

Due to its favourable weather and solar irradiance levels, Portugal is one of the European countries with the highest photovoltaic power potential.[2] Still, photovoltaic (PV)

---

[1] For new small-scale projects, a remuneration regime came into action in 2015. This regime is based on a bidding model, in which producers offer discounts to a reference tariff, currently set at € 95/MWh and received for a period of 15 years. On the other hand, existing concentrated photovoltaics (CPV) receive a much larger feed-in-tariff, around € 380/MWh. Information regarding support schemes, grid issues and policies for renewable energy sources in Portugal was obtained from RES LEGAL Europe, an initiative developed by the European Commission. Special Regime generation (PRE) includes electricity produced from renewable energy sources (RES), "mini-hydro" (less than 30 MW), biomass, co-generation (combined generation of heat and electricity) and distributed generation.

[2] Information regarding photovoltaic power potential and irradiation levels can be obtained from the Global Solar Atlas (GSA), developed by the World Bank Group.

solar energy represents a very small share of total installed capacity in the Portuguese electricity system, even though this is likely to change in the years to come. The Portuguese government has recently developed a Roadmap for Carbon Neutrality in 2050 (RNC2050) defining economically sustainable and socially acceptable paths to ensure a carbon-neutral Portuguese economy by 2050. In particular, one of the government's main goals is to incentivize the installation of solar-based technologies, so that in 2050 solar power represents around 50% of total installed capacity in the electricity system. With that goal in mind there are plans for installing utility-scale projects (large concentration of solar panels) in areas that are not suitable for alternative uses, namely agriculture, while having a high photovoltaic power potential. Such areas are, for example, in the south of Alentejo and in the north of Algarve.

Even though levelized cost estimates are the stepping-stone for cost comparison analysis between energy generating technologies, they do not capture differences in temporal and spatial energy production profiles. Importantly, Solar PV benefits from a timing advantage, producing energy when it is more valuable due to higher electricity demand and consequently higher market prices. These advantages are often recognized by practitioners and policy makers, though seldom evaluated. This project aims at contributing to this literature by estimating the short-run economic value of an incremental change in solar PV for different locations in Portugal.

By accounting for the external benefits associated with avoided emissions and variable costs from the displaced price-setting dispatchable technologies, we obtain "adjusted" cost estimates which are substantially lower than traditional levelized costs. However, since the obtained estimates are conditional both on the current state of technology and the current structure of the market, they may not be effective as breakthroughs in technology or important changes in the market structure occur. Still, the methodology we develop can be applied to the new conditions.

There is evidence of a timing advantage in the production of electricity from solar resources, particularly for installations facing south. However, the magnitude of this effect is not as large as expected, as the "market value" of solar PV is only slightly affected. Compared with other locations of interest, Faro presents the largest photovoltaic power potential, in part explaining why net cost estimates are minimized for this site. Moreover, across all locations and system orientations, residential projects appear to be more expensive than large-scale installations.

The remainder of the thesis is organized as follows. In section 2, the literature review is presented, and in section 3 the methodology is described. In section 4 the framework is applied to the case of five different solar PV installations in Portugal, while in section 5 the main results are highlighted, followed by a discussion in section 6. Finally, in section 7 conclusions are offered. The Annex includes ancillary calculations, tables, and relevant information.

2. Literature Review

Greenstone and Looney (2012) analyse the full costs of conventional energy generation technologies, comparing them with alternative renewable energy sources. That is, in order to make an "apples to apples" comparison between different technologies, the authors emphasize the importance of considering the social cost of energy usage, instead of solely looking at the private cost. For that purpose, the authors provide "adjusted" levelized cost estimates for different types of energy generation technologies, by incorporating the external costs associated with environmental effects such as pollution and climate change, health effects and national security. In addition, given that "intermittent" energy sources are not directly comparable with base-loading technologies, the authors make an additional adjustment by creating hypothetical plants that include intermittent technologies paired with natural gas combustion turbines (a peak-generation technology). As a result, some versions of these combined technologies seem to be competitive with other technologies, when the full costs of energy usage are taken into account.

Besides considering the external costs of energy generating technologies, additional adjustments are needed. In order to properly estimate the short-run benefits of solar PV, it’s important to recognize that the value of electricity varies widely during the day and throughout the course of a given year. Joskow (2011) shows that a typical life-cycle cost metric, known as the Levelized Cost of Electricity (LCOE), is flawed in comparing the economics of conventional and renewable energy generating technologies, since it considers all electricity produced as a homogeneous product governed by the law of one price. However, power generated at different moments in time may not have the same value.

The author distinguishes between dispatchable technologies, which can be adjusted to meet demand at any point in time, and intermittent technologies, which cannot be entirely controlled by the system operator as they depend upon weather characteristics. Solar PV is an intermittent technology that generates electricity during daylight hours and that usually peaks in the middle of the day. Electricity demand and wholesale market prices also tend to peak during this period, meaning that solar PV produces more energy when it’s also more valuable. Wind power typically has the opposite production pattern, as it usually produces more intensely at night, at times when demand and market prices are lower. Comparing these two technologies based only on LCOE estimates would provide us with wrong conclusions, since even if both have the same value based on this metric, solar PV has an additional value that must be accounted for.

According to Borenstein (2012), adjusting for the time variation of production should be straightforward, as we simply have to compare the technology’s levelized cost with the average wholesale value of power it delivers. Moreover, the author claims that residential solar power has an additional value compared with utility-scale installations, since it reduces the need for transmission investment and avoids a small percentage of power that is dissipated when passing through lengthy transmission and distribution lines. The above-mentioned study also highlights the fact that retail rates do not accurately reflect this advantage and therefore an additional adjustment must be made.

Baker et al. (2013) adapt and extend a conceptual framework from Lamont (2008) in order to model the short-run benefits and costs of solar PV. Across all sites of interest and panel orientations, the authors find a timing advantage in solar resource generation. However, the study focuses not only on short-run incremental changes in solar capacity, but also on medium and long-run effects related to structural changes in the electricity system and long-term carbon targets. Even though this Work Project is focused on the short-run, it’s important to keep in mind that over longer time horizons the structure of the electricity system may adjust to accommodate a larger penetration by renewable energy sources. Although learning-by-doing and experience effects are likely, additional costs associated with the intermittent character of solar PV can be significant, as additional backup capacity may be required to avoid temporary mismatches between supply and demand. Finally, considering longer time horizons also implies recognizing the existence of an opportunity cost of using land for solar arrays, which arises when other energy and non-energy uses become restricted due to scarcity of (valuable) land.

3. Conceptual Framework and Methodology

In this section, and following Baker et al. (2013), we describe the methodology used to measure the short run benefits and costs of an incremental increase in photovoltaic (PV) solar energy, which is assumed to displace electricity production from dispatchable generation units by an equivalent amount. This conceptual framework is then used to estimate the short-run net benefits of incremental PV additions at five different sites across Portugal. In addition, since we are interested in comparing the viability of large-scale installations with that of projects of smaller scale (distributed generation), we consider an additional benefit that distributed generation has compared to utility-scale (or central) generation.

Since the analysis is performed for the short-run, all costs and benefits, the infrastructure of the market and the operating characteristics of existing generators are taken as given. Importantly, this exercise allows us to infer about how regional and temporal variation in solar resource interacts with the installed power system operating characteristics to determine the short-run value of incremental increases in PV generation.

3.1. The Short-run Costs: Levelized Cost of Electricity

The LCOE is the typical indicator used to compare the costs of different types of energy producing technologies. It represents the constant price per unit of electricity that a given installation would have to charge in order to equate the net present value of revenues to the net present value of costs over its lifetime, that is,

$$LCOE = \frac{\sum_{t=0}^{T} \frac{C_t}{(1+i)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+i)^t}} \tag{1}$$

where T is the lifespan of the technology, C_t is the cost incurred at t, capturing both installation and operating costs, E_t the energy output at t and i denotes the discount rate. The main components in C_t are the up-front module installation and balance-of-system (BOS) costs at t=0.[3] Importantly, as mentioned before, only incremental changes of solar PV are considered. Since this technology is non-dispatchable, a higher market penetration could result in the

[3]BOS costs are typically defined to include inverters, labour costs, cables, switches or any other type of mounting hardware. However, broader definitions include other costs such as permitting (for example, in Portugal, it’s mandatory to register residential solar PV installations with the DGEG), overhead costs (general and administrative expenses) and installer profit.

acquisition of additional reserve capacity that would substitute for solar PV during unexpected breaks in production. That is, the intermittent character of solar PV may imply larger costs, even though these are not likely to be significant for a low level of market penetration.

Though, to infer about competitiveness of the different technologies by simply comparing the LCOE across them can be misleading, as the economic value of a unit of energy depends on the conditions of the power market when it is generated (Joskow, 2011). Hence, it's crucial to take into account the temporal variation of solar PV as it produces more energy at time periods where the value of electricity is higher due to higher demand and, consequently, the market price is higher.

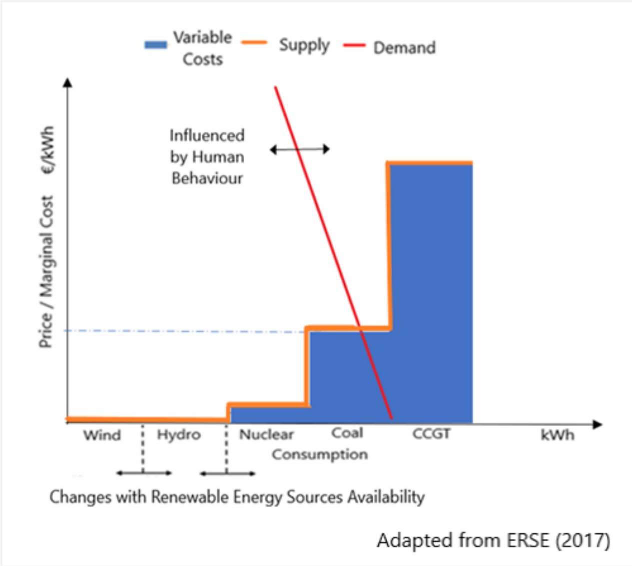
3.2. Short-run Benefits: Displaced Generation and Emissions

In the wholesale spot market of electricity, the clearing price results from the intersection of the electricity demand curve and the supply curve, also called the merit order, that is, the sequence in which generation power plants enter the market going from the least expensive (lowest marginal cost) to the most expensive (highest marginal cost) units. Therefore, the merit order curve is an increasing step function which includes the marginal costs and corresponding capacities of all generators, representing the supply curve in a power market.[4]

Since the price is set by the marginal cost of the marginal dispatchable technology that it is still needed to meet demand, high marginal cost technologies typically set the price when demand is high, and vice-versa when demand is low. Due to negligible marginal costs, renewable energy generation with priority of dispatch enters the supply near the bottom end shifting the merit order curve to the right and, consequently, displacing the energy generated by price-setting dispatchable technologies.

Figure 1: Supply and Demand Curves in the Wholesale Electricity Market

[4] Figure 1 illustrates the merit order curve for Portugal, adapted from ERSE (2017).



Since solar PV does not produce emissions and its variable operating costs are negligible, when introduced in the market its economic value is based on both the estimated avoided emissions and fuel and operation costs of the dispatchable units that are displaced. That is, as in Baker et al. (2013), the short-run value of solar PV is given by the system operating and emission costs that would manifest if there was no installed solar capacity in the system net of the costs that would be incurred for a certain level of installed solar capacity. The resulting short-run marginal economic value includes both market and non-market values of solar PV.

Let the emissions released (EM_h) and the short-run variable costs (VC_h) of the marginal dispatchable generating unit, in a given hour (h), be defined as follows:

$$EM_h(y_h) = \phi_h y_h \quad (2)$$

$$VC_h = \lambda_h y_h \quad (3)$$

where y_h corresponds to the marginal dispatchable technology output, ϕ_h corresponds to the marginal operating emissions rate (grams of CO_2 per unit of energy produced) and λ_h corresponds to its marginal cost. From (2), the monetized damages from emissions released (MD_h) are given by:

$$MD_h = \tau EM_h(y_h) = \tau \phi_h y_h, \quad (4)$$

where τ represents the marginal damage from emissions released (euros per gram of CO_2). For a marginal change in the dispatchable technology output, y_h, the corresponding changes in monetized damages and variable costs are as follows:

$$\frac{dMD_h}{dy_h} = \tau\phi_h \qquad\qquad \frac{dVC_h}{dy_h} = \lambda_h \tag{5}$$

Since the marginal increase in solar generation displaces production at dispatchable units by an equivalent amount, it follows that $dq_h = -dy_h$, where q_h is the output of the solar PV installation at hour h. Therefore, monetized damages and variable costs from dispatchable units decrease by:

$$\frac{dMD_h}{dq_h} = -(\tau\phi_h) \qquad\qquad \frac{dVC_h}{dq_h} = -\lambda_h \tag{6}$$

and the short-run economic value for a given level of q_h is:

$$V_h = \; q_h(\tau\phi_h) + q_h\lambda_h = \; q_h(\lambda_h + \; \tau\phi_h), \tag{7}$$

implying that the resulting short-run marginal value in a given hour can be stated as:

$$MV_h = \frac{dV_h}{dq_h} = \lambda_h + \tau\phi_h. \tag{8}$$

To account for the timing advantage in the production of solar PV, we are interested in the weighted average short-run marginal value over a typical year, that is:

$$MV_{WA} = \frac{\sum_{h=1}^{H} q_h(\,\lambda_h + \tau\phi_h)}{\sum_{h=1}^{H} q_h} = \frac{\sum_{h=1}^{H} q_h\lambda_h + q_h\tau\phi_h}{\sum_{h=1}^{H} q_h} =$$

$$= \frac{\sum_{h=1}^{H} q_h\lambda_h}{\sum_{h=1}^{H} q_h} + \tau\frac{\sum_{h=1}^{H} q_h\phi_h}{\sum_{h=1}^{H} q_h} = \lambda_{WA} + \tau\phi_{WA}, \tag{9}$$

where λ_{WA} and ϕ_{WA} represent the weighted averages of λ_h and ϕ_h, respectively. This measure takes into account the timing advantage of the solar resource by including the correlation between q_h and λ_h, as well as the correlation between q_h and the marginal emissions rate (ϕ_h).

As mentioned in the previous section, periods of high solar output typically match periods of high electricity demand (and high prices). Therefore, by using the solar resource production potentials as weights, smaller weights are associated to hours where the wholesale market price is lower and larger weights to hours where the price is higher. According to Baker et al. (2013), in systems where base load generating units are more emission-intensive than marginal generators in peak hours, the correlation between solar output and the marginal emissions rate will be negative. The typical baseload technology in the Portuguese wholesale market is coal energy generation, the most carbon-intensive fossil fuel, while in peak hours it is typically set by the CCGT (natural gas) power plants, less carbon-intensive. Hence, we should expect the correlation between q_h and ϕ_h to be negative.

In order to assess how large the bias would be if the timing advantage and the correlation between q_h and ϕ_h were ignored, we compare the weighted average marginal value with a simple average over all hours for a given year, that is:

$$MV_{SA} = \lambda_{SA} + \tau\phi_{SA}. \tag{10}$$

As mentioned before, considering the timing advantage in the production of electricity from solar PV is likely to increase the short-run marginal value associated with this technology. However, since in Portugal solar generation is expected to be negatively correlated with the marginal emissions rate, the timing advantage may be offset, and the weighted average marginal value may be actually smaller than the simple average over the course of a typical year.

One of the goals of this research is to compare the viability of utility-scale projects with that of production units of smaller scale, i.e. residential installations. In this context, it's important to consider an additional value that is typically associated to small-scale residential installations when compared to utility scale ones, that is, the avoided transmission and distribution (T&D) losses. Electricity generated in power stations has to pass through complex networks such as transformers, overhead lines and cables before reaching the final consumer. On the other hand, as residential installations usually produce power close to the final consumer, energy does not have to pass through lengthy transmission and distribution lines, thus avoiding losses.[5]

Borenstein (2008) incorporates this additional value by considering a standard engineering approximation to those losses. We follow this author's approach and consider the baseline assumption according to which the losses incurred in the delivery of energy to final consumers are equal to the system's average losses. In particular, they can be approximated by $L_h = \alpha Q_h^2$, where Q_h is the utility-scale generation at time h and α *is* a constant explained in the next section. When one unit of a central (or utility-scale) generation is replaced by one unit of residential production, losses are reduced by $2\alpha Q_h$. Thus, the value of reduced line losses is given by the market price multiplied by $2\alpha Q_h$. Since the price in the wholesale market at hour h is given by the marginal cost of the displaced marginal dispatchable unit, that value is given by $\lambda_h 2\alpha Q_h$. Defining the adjusted "lambda" as $\tilde{\lambda} = \lambda_h(1 + 2\alpha Q_h)$, the resulting weighted average short-run marginal value of residential solar PV is :

$$MV_{WA}^{res} = \frac{\sum_{h=1}^{H} q_h\left(\tilde{\lambda} + \tau\phi_h\right)}{\sum_{h=1}^{H} q_h} = \tilde{\lambda}_{WA} + \tau\phi_{WA}. \qquad (11)$$

4. Estimating the Short-Run Economic Value of PV Solar Energy Production: An Application to the Case of Portugal

In this section, the methodology presented above is applied to different locations in Portugal. We start by describing how the solar resource production potentials are obtained, for each location and hour, and for both utility-scale and residential installations. Then, we explain

[5] According to Borenstein (2008), even though distributed solar energy may result in reduced technical losses, grid engineers argue that the intermittent character of distributed generation and the reverse flow from costumers may increase the stress on distribution transformers, hence increasing the frequency of repairs. However, since there isn't a consensus on this matter, we'll not consider this additional cost.

how the input values were chosen to estimate the LCOE. Finally, we describe how hourly "lambdas" and marginal emission rates for the Portuguese electricity market were obtained. The wholesale prices and marginal price-setting technologies considered are those observed in 2017.

4.1. Estimating Production Solar Resource Potential

First, hourly production potentials for each location and for each type of installation are estimated. Five sites spread across the country were considered: Porto, Coimbra, Lisbon, Évora and Faro. Importantly, each location has different exposure levels to sunshine during the year and, therefore, production profiles may differ substantially. Data on annual average number of sunshine hours was obtained for each of the sites of interest (Table E in Annex 1). Compared with northern regions like Porto and Coimbra, locations in the south of Portugal (as Faro) are exposed to more sunshine hours in a given year.

Ideally, we should measure the production potential by metering actual electricity generation from a solar PV panel installed at each of the locations of interest. However, given that metered hourly data is not available for any of the locations and types of installation, we follow other studies and use simulated data. We use the simulation software provided by the NREL (National Renewable Energy Laboratory) from the US which combined with meteorological data allows us to obtain estimates for the production potential at each hour, site and type of installation (residential and utility-scale).

The System Advisor Model (S.A.M.) is one of the software packages provided by the laboratory and it's the one chosen for our analysis. S.A.M. is straightforward in the sense that it is clear about the inputs needed to estimate both production potentials and the LCOE. In order to estimate solar output, S.A.M. requires information regarding the module and inverter's brand, system design, level of shading, different types of losses, degradation rate and battery storage. A detailed description of these parameters is provided in Annex 1.

According to the database of e2p – Energias Endógenas de Portugal, the average size of utility-scale projects (installations over one megawatt of capacity) located at our sites of interest is around 3 MW.[6] However, excluding outliers such as Cabrela in Évora (12MW), the great majority of installations has a capacity around 2 MW. Regarding residential projects, sizes typically lie between 0 to 20 kW. For this exercise, we'll estimate the production potential for a 2 MW utility-scale system and for a 5kW residential project. Weather files for each of the sites of interest were obtained from EnergyPlus.[7] The optimal panel orientation for systems in the northern hemisphere is typically the south orientation. The western orientation was also considered for comparison purposes. The only type of shading assumed is the standard self-shading to account for row-to-row shading of modules within a subarray caused by shadows from modules in neighbouring rows that block sunlight during certain periods of the day. Project lifetime is 25 years, which is a typical assumption, with a degradation rate of 0.5% per year to account for the decline in energy generation as the panels degrade. Since there is still no cost-effective way to store energy generated from solar PV, no battery storage was considered.

4.2. Estimating Short-Run Costs

To simulate the LCOE for each site and type of installation SAM requires information about direct and indirect capital costs, operation and maintenance costs (O&M) and financial parameters. Direct capital costs incorporate module and inverter costs, balance-of-system equipment, installation labour, installer margin and overhead and a contingency rate to account

[6] Database developed by INEGI (Institute of Science and Innovation in Mechanical and Industrial Engineering) in partnership with APREN (Portuguese Renewable Energy Association).
[7] Weather files for each location of interest were developed by Ricardo Aguiar of INETI (National Institute of Engineering, Technology and Innovation).

for expected uncertainties with respect to direct cost estimates. Indirect capital costs include permitting, engineering costs, grid interconnection costs, land purchase and preparation and the sales tax (VAT). Regarding operation and maintenance (O&M) costs, following Baker et al. (2013) we'll consider exclusively the cost of replacing the inverter every 10 years (typical lifespan of an inverter). The most relevant financial parameters are the investment income tax rate, the sales tax rate, the inflation rate, the real discount rate and the property tax rate. Detailed information regarding these inputs is also available in Annex 1. Most of our cost estimates were provided by ENAT ENERGIAS, a company with large experience in the area of renewable energy, particularly in the installation of solar PV systems.

4.3. Estimating Short-run Benefits

In this section, the estimates of the short-run benefits of solar PV are obtained. As mentioned above, the wholesale price of electricity serves as an indicator for the displaced marginal cost of the marginal dispatchable generating units. The company OMI - Polo Español S.A. (OMIE) is the benchmark system operator in managing wholesale prices in the Iberian Peninsula market. The OMIE price is set according to the EUPHEMIA price algorithm, which solves a welfare constrained maximization problem. OMIE hourly prices for the Portuguese wholesale market are publicly available. Using basic programming skills, we were able to concatenate the 365 daily excel files into a single one.

OMIE's dataset is very detailed. In particular, it is possible to observe which technology is setting the wholesale market price in an hourly basis, for each year since 1998. In addition, data regarding average emission factors over the period of 2013 to 2017 (expressed in grams of CO_2/kWh) for each of the technologies of interest was obtained from the Portuguese Environment Agency (APA).

The EU Emissions Trading System (EU ETS) was set in 2005, currently accounting for over three-quarters of international carbon trading. The clearing price in this market serves as an indicator for the marginal damage from CO_2 released emissions. In the beginning of 2018, the CO_2 European emission allowance price was around 8€ per metric tonne. Since then, it has increased significantly. Currently its value is about 20€ per metric tonne, as adjustments have been introduced to reduce sluggishness. However, if the European Commission aims at complying with the emissions target set by the Paris Agreement, we should expect the emission allowances prices to increase even further.

In this analysis, we focus exclusively on CO_2 emissions in order to estimate the "non-market value" of solar PV. Since the ETS market has been sluggish in the latest years, carbon allowances do not fully reflect the external CO_2 costs of displaced conventional energy generation technologies. Therefore, we propose a sensitivity analysis to the carbon price, by considering two different scenarios. In the first the marginal damage from emissions is set at the current CO_2 European carbon price of 20€/mt (metric tonne). Then, reflecting a tighter future climate policy, the marginal damage is set at a higher price of 30€/mt.

In order to estimate the additional value that residential projects have compared to larger-scale installations, we first need to estimate α. According to EDP Distribuição (2016), estimated losses in the distribution network are approximately 9%. Moreover, based on REN's report on the national transmission network (2018), we conclude that transmission losses in 2017 were about 1.5%. Overall, T&D losses amount to 10.5%. Therefore, α can be obtained as follows:

$$0.105 * \sum_{h=1}^{H} Q_h = \sum_{h=1}^{H} \alpha Q_h^2 \Leftrightarrow \alpha = 0{,}105 * \frac{\sum_{h=1}^{H} Q_h}{\sum_{h=1}^{H} Q_h^2}. \qquad (12)$$

5. Main Results

In this section we present our main results regarding the short-run costs (LCOE), short-run benefits, production potentials and net costs (short-run costs net of short-run benefits) estimates for each location, type of installation and system orientation. We show how accounting for the timing advantage in the production of PV solar energy affects its "market value", and how considering the correlation between the marginal emissions rate and the production potential affects its "non-market value".

5.1. Solar PV Production Potential

Tables A to D (in Annex 1) report the main results for each location, panel orientation and type of project, under the scenario of current carbon prices. Annual energy is presented in the second row. Across all locations and types of project, orienting solar panels south maximizes energy output. Additionally, for each orientation, Faro corresponds to the location with the highest production potential, for both residential and utility scale installations. This may be indicative that the south of Portugal has a more suitable weather for this type of projects. Out of the five locations, Porto and Coimbra present the lowest annual production potentials. Compared with these two locations, Lisbon and Évora present a higher potential, though smaller than that obtained for Faro.

5.2. Levelized Cost of Electricity (LCOE)

The LCOE for each location, type of installation, and system orientation is provided in the third row of each table.[8] Orienting panels south minimizes the LCOE for each location and type of installation. Given that Faro's annual output exceeds that of the remaining locations by a significant amount, it's no surprise that the LCOE is minimized for projects installed in this

[8] S.A.M. provides LCOE estimates in $/kWh. Hereinafter, in order to convert dollar estimates into €/kWh, the annual average dollar-to-euro exchange rate of 2017 is considered.

site. Considering larger scale projects, the location with the second smallest LCOE corresponds to Évora, being around 11% higher than in Faro. Likewise, for residential projects, the second smallest LCOE is still around 10% higher than the one for Faro. Moreover, estimates obtained for residential projects are significantly larger than those obtained for utility-scale installations. However, as mentioned before, simply looking at LCOE estimates can be misleading.

5.3. Short-Run Marginal Value

The short-run marginal value of photovoltaic solar energy is presented in rows 10-11. Considering the current price of carbon, we obtain a simple average marginal value of 0.059 €/kWh. However, this estimate does not consider the timing advantage mentioned before nor the correlation between production potentials and marginal emissions rates. Across all sites of interest, we observe a timing advantage in the production of energy for systems oriented south. However, this effect is modest, as it only increases the “market value” of solar PV by 0.4% to 1.4% (across all types of projects and sites of interest). On the other hand, the negative correlation between production potentials and the marginal emissions rate is significant, reducing the “non-market” value of photovoltaic solar power by approximately 30% for systems facing south. Given that the timing advantage is offset by this negative correlation, the weighted average marginal value estimate is slightly smaller than the simple average one.

Across all sites of interest and types of project orienting panels south maximizes the weighted average short-run marginal value of solar PV. Moreover, while Faro possesses the highest annual energy potential, incremental changes in solar generation are slightly more valuable for Lisbon when considering residential projects. Likewise, for utility-scale systems Lisbon has the highest weighted average short-run marginal value, yet by a very small margin.

5.4. Net Costs

The last two rows of each table are obtained by subtracting the short-run marginal value from the corresponding levelized cost of electricity to come up with an estimate for the net cost (€/kWh). For all sites of interest and types of project, orienting the system south minimizes the net cost. For utility-scale projects and the current price of carbon, installations located in Faro present the lowest net cost estimates, when considering both simple and weighted averages (0,013€/kWh and 0,014€/kWh, respectively). Even though net cost estimates constructed with simple averages are smaller, they may lead to wrong conclusions for the reasons mentioned in the previous sections.

For residential projects, conclusions are similar: installations located in Faro present the lowest net cost estimates, when considering both simple and weighted averages. Furthermore, across all sites of interest, residential projects present higher net cost estimates than larger scale installations, even when considering the additional value associated with avoided transmission and distribution losses. In fact, this additional effect seems to be non-significant as the "market-value" of residential projects is barely affected.

Finally, we estimated the net cost under a more stringent scenario by assuming that the marginal damage from emissions is set at 30€/mt. As expected, considering a higher carbon price yields higher short-run marginal value estimates for each location and type of installation. As a result, net cost estimates under this scenario are smaller, even though the difference is not significant (less than half cent per kWh).

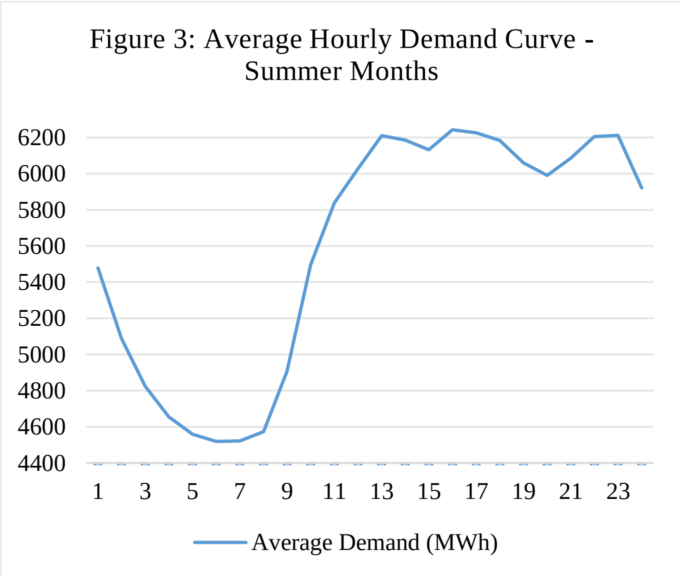
6. Discussion

In this study, we used simulated data in order to estimate the timing advantage in the production of photovoltaic solar energy and the correlation between production potentials and the marginal emissions rate in five different locations in Portugal. Therefore, the estimates obtained for these effects may not correspond to what would be observed if we had access to real data. According to Borenstein (2008), using simulated data tends to undervalue solar PV generation, since we fail to account for the unobserved correlation between production potentials and market prices. However, the author concludes that this bias is likely to be small.

Figure 2 illustrates the timing advantage, when using simulated data. Considering only summer months, we compare the average hourly production potential with the average hourly wholesale price for a south oriented utility-scale project in Porto. During daylight hours, the correlation between production potentials and market prices seems to be significant. In fact, when considering the period between 7am to 7pm, the obtained correlation between these two variables is approximately 91%. However, for the remaining time periods there is no evidence of correlation (wholesale market prices are high even though solar generation is null), dampening the above-mentioned effect. Overall, the obtained correlation between q_h and λ_h is approximately 55%.

Figure 2: Average PP and Wholesale Price - Summer Months

As stated in ERSE's tariff structure report (2017), the daily cycle is divided into four periods: peak, half-peak, normal off-peak and super off-peak. However, peak and half-peak periods don't necessarily correspond to daylight hours. In fact, during summer months, typical half-peak periods go until midnight. Based on REN's database, we were able to obtain the summer average hourly demand curve for 2017 (Figure 3). There is a clear resemblance between both curves. High demand during the night explains why we obtain a weak correlation between solar output and market prices. If prices were lower during the night period, the estimated timing advantage might have been significantly larger. Nonetheless, it's still true that solar PV generates more energy when the value of electricity is high, due to high demand and market prices.



For utility-scale projects oriented south, our levelized cost estimates are between 0.072€/kWh for Faro and 0.086€/kWh for Porto (approximately). Considering smaller-scale installations, our estimates lie between 0.089€/kWh and 0.106€/kWh. According to the International Renewable Energy Agency (IRENA, 2017), since 2010 there has been a remarkable fall of 73% in the global weighted average LCOE of utility-scale solar PV, to 0.10$/kWh in 2017 (or approximately 0,089€/kWh). Regarding residential projects, the agency's estimates are between 0.10$/kWh and 0.2$/kWh (around 0.177€/kWh), depending on the country. We can therefore conclude that the estimates we obtained are realistic and in line with current trends.

This study is intended to inform policy and decision makers about the economics of photovoltaic solar energy in Portugal, for a given market structure and state of technology. Importantly, we are interested in the social value of solar generation. Therefore, as recommended for this type of analysis, we excluded the impact of government incentives such as feed-in-tariffs, as they represent a transfer between consumers and producers. If these incentives were included, our net cost estimates would have been much smaller. On the other hand, we considered a real social discount rate, which is lower than the private one. If a higher discount rate was considered, our levelized cost estimates would be higher. Nonetheless, the social discount rate is the appropriate one for public policy analysis.

As mentioned above, this research paper focuses on short-run incremental changes in solar PV capacity. In the medium- to long-run, and, in contrast to what was currently developed, higher levels of solar penetration may occur, meaning that the structure of the power system will adjust to accommodate a larger share of renewables. Additional costs related to the intermittent character of solar PV were not considered in this analysis, as they will only become significant in the medium- or long- terms. Nevertheless, it's important to acknowledge that those costs may be substantial, as there is still no cost-effective way to store energy generated by solar PV installations. On the other hand, the increased adoption of this technology may result in learning by-doing effects that can reduce costs, although distinguishing them from economies of scale may be challenging in practice. Moreover, while learning by doing effects can justify government intervention if they are not entirely appropriable by one firm, the same cannot be claimed for economies of scale.

7. Conclusion

In this Work Project, we compare the short-run net benefits across five different solar PV installations in Portugal. Building upon recent research, the additional benefits associated with renewable energy sources that are typically overlooked are considered. Such benefits include the avoided emissions and variable costs from displaced price-setting dispatchable units, and the existence of a timing advantage in the production of electricity from solar PV. Moreover, we compare the viability of large-scale projects with that of installations of smaller scale. For that purpose, we complement our analysis by accounting for an additional value that distributed generation has compared to utility-scale generation.

Our main results indicate that Faro corresponds to the most suitable location for installing photovoltaic solar energy in Portugal. This location has the highest potential in terms of annual output, exceeding by far that estimated for the remaining sites of interest. Moreover, incremental changes in solar generation located at this site have a high economic value. The combination of these two factors explains the low net cost estimates we obtained. Furthermore, within each location, residential projects appear to be costlier, even when considering the additional value associated with avoided transmission and distribution losses.

Using simulated data, we were able to estimate the timing advantage of photovoltaic solar energy for each location, type of installation and system orientation. We concluded that for systems oriented south, the correlation between production potentials and wholesale market prices is positive, but minor. Half-peak demand periods during the night explain why there are high market prices when solar generation is null, weakening the above-mentioned effect. On the other hand, the negative correlation between solar output and the marginal emissions rate strongly affects the "non-market value" of solar PV and, consequently, its net cost estimates.

The costs of photovoltaic solar energy have been decreasing significantly. In addition, by considering the benefits associated with avoided emissions and variable costs from the displaced price-setting dispatchable technologies, we obtain net cost estimates that are substantially smaller than the levelized costs. The increasing competitiveness of solar PV may be indicative that in the near future this technology will represent a larger share of total electricity generation in the Portuguese electricity system. However, it should not be ignored that larger levels of penetration may imply additional costs related with the intermittent character of this technology. Therefore, additional research is essential to better understand the full benefits and costs of photovoltaic solar energy, not only in the short-run, but also in the medium- and long-run. This will be left for future research.

References

Baker, E., Fowlie, M., Lemoine, D., and Reynolds, SS. 2013. The Economics of Solar Electricity. Annual Review of Resource Economics 5.

Borenstein, Severin. 2008. The Market Value and Cost of Solar Photovoltaic Electricity Production. Center for the Study of Energy Markets Working Paper 176, University of California Energy Institute.

Borenstein, Severin. 2012. The Private and Public Economics of Renewable Electricity Generation. Journal of Economic Perspectives, American Economic Association, vol. 26(1), pages 67-92, Winter.

EDP Distribuição. 2016. Plano de Desenvolvimento e Investimento da Rede de Distribuição 2017-2021, PDIRD-E 2016 Proposta final.

Entidade Reguladora dos Serviços Energéticos (ERSE). 2017. Estrutura Tarifária do Setor Elétrico em 2018.

Greenstone, M. and Looney, A. 2012. Paying Too Much for Energy? The True Costs of Our Energy Choices. MIT Department of Economics Working Paper No. 12-05.

IRENA. 2018. Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi.

Joskow, Paul. 2011. Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies. Review, Vol. 101, No. 3, pp. 238-241.

Lamont, Alan D. 2008. Assessing the long-term system value of intermittent electric generation technologies. Energy Economics 30:1208–1231

Redes Energéticas Nacionais. 2018. Caracterização da Rede Nacional de Transporte para Efeitos de Acesso à Rede.

Annex 1: S.A.M. inputs and Main Results

1. General Assumptions

- **Sites of interest**: Porto, Coimbra, Lisbon, Évora and Faro. Weather files were obtained from EnergyPlus, developed by Ricardo Aguiar of Instituto Nacional de Engenharia, Tecnologia e Inovação (INETI).

- **Azimuth (system orientation):** The LCOE and production potentials were simulated for north, south, east and west orientations; the short-run marginal value and net-cost estimates were obtained for south and west orientations. For countries in the north hemisphere, solar arrays are typically oriented south. We also considered the west orientation for comparison purposes (north and east were not considered as they provided much smaller production potentials and substantially larger LCOE estimates).

- **Tilt**: a fixed panel axis was assumed, just as in Baker et al. (2013). However, instead of setting the panel tilt equal to the latitude (as it's typically recommended), we considered an alternative that according to Landau (2017) produces better results. According to the author the optimal tilt to be considered (given Portugal's latitude) is equal to the latitude, times 0.76, plus 3.1 degrees.

- **Direct-to-Alternating Current ratio**: The DC/AC ratio is an important factor to consider when designing a solar project. For example, if a 5 kW solar array (DC) was combined with a 4 kW Inverter (AC), then the DC/AC ratio would be 1.25. The main concern here is to avoid what is called "clipping losses", which occurs when power being fed to an inverter exceeds the amount it can handle. According to Bhesaniya (2016), design values of 1.2 often result in minimal losses. Therefore, this is the value considered in our analysis.

- **Shading and soiling losses**: The only type of shading assumed was the standard self-shading, to account for row-to-row shading of modules within a subarray, caused by shadows from modules in neighbouring rows that block sunlight during certain periods of the day. I assume higher soiling loss rates for less rainy months (summer) and smaller soiling rates for months that are usually rainier.

- **Other losses**: AURORA (an electric modelling and forecasting software), presents multiple suggestions based on NREL studies: Module mismatch set at 2%, Connection losses at 0.5%, DC wiring losses at 2%, resulting in a total DC power loss of 4.5%. AC wiring losses are set at 1%.

-**Lifetime** is 25 years with a **degradation rate** of 0.5% (Pereira et al. (2016), Skoczek et al. (2008), Baker et.al (2013)). Given that there is still no cost-effective way to store energy generated by solar PV, no battery storage was assumed.

2. System Costs - Utility Scale Projects (2 MW)

The System Advisor Model (S.A.M.) requires inputs given in dollars per kWh. Resulting levelized cost estimates are then converted into euros per kWh, using the annual average dollar-to-euro exchange rate of 2017.

-**Module cost**: Importantly, there is a link between module's efficiency and cost. In the photovoltaic plant of Amareleja (the largest in Portugal) the YingLi brand was the one chosen, having a low efficiency and therefore a low cost[9]. However, many other brands are available in the market, some of them much more efficient and of course, more expensive. FF Solar presents multiple examples for utility scale, commercial size and residential size solar PV installations in Portugal. As a reference case, we considered the 2,2 MW Utility scale project in Seixal, where the Brand Trina Solar was used (250W). We consider the model TSM-255PEG5, which has a relatively high efficiency given its cost. Consulting several wholesale shopping platforms

[9] Module efficiency refers to the percentage of sunlight that is converted into usable electricity. The higher the efficiency of a module, the smaller will be the number of panels needed to make up a system. Therefore, high efficiency modules typically present a higher cost.

(freecleansolar, Alibaba, Solaris, etc.) the price-per-watt for this module is estimated to be around 0.3$/Wp.

-**Inverter cost**: We considered the model AE 500TX-400 480V from Advanced Energy Industries, which has a maximum AC power of 500 kW and an efficiency of around 97%, which is relatively high. The cost found for this inverter is 0.24$/Wp.

The three following costs were suggested by ENAT ENERGIAS, a company with large experience in the area of renewable energy, particularly in the installation of solar PV systems:

- **Balance-of-System equipment**: for a 2 MW system, the cost to be considered is approximately 0.31$/Wp.

- **Installation labour, permitting and engineering overhead**: Labour costs are estimated at 200€ per day or approximately 225$; Permitting costs are estimated to be around 11,285$; Engineering costs: for a 2 MW system, the cost to be considered is approximately 5643$.

- **Installer margin and overhead**: these include general and administrative expenses. The value considered is 40,500$, including costs related with accommodation and food.

- **Contingency rate**: To account for expected uncertainties in direct cost estimates, a contingency rate 3% was assumed (NREL, 2016).

- **Land requirements** are automatically calculated by S.A.M: 50,000 m2 or around 5 hectares. The cost of land varies substantially across districts and within each district (for 50,000 m2 land prices can be either below 100,000€ or reaching 1M€). For simplicity reasons, the land purchase cost was assumed to be 250.000$ for Porto and Lisbon and 200.000$ for the remaining cities. Land preparation and transmission costs correspond to around 2/3 of the land purchasing cost.

- **O&M costs**: Inverter will be replaced every 10 years (typical lifespan).

Installation Cost: Considering the above-mentioned inputs, the installation cost for utility-scale projects corresponds to 1.31$/Wp for Porto and Lisbon and 1.28$/Wp for the remaining sites. Our results are in accordance with IRENA's report on Renewable energy costs (2018), where the global weighted average installation cost of utility scale solar PV was estimated to be around $ 1.4/Wp in 2017.

3. System Costs - Residential Projects (5 kW)

- **Module cost**: Consulting FF solar, one of the most common brands used in residential projects appears to be SolarWorld, model SW290 mono. SolarWorld is an 'American-made' brand, which has a high efficiency (17.5%) and consequently higher cost. The average price found for this model appears to be around 220$ per module, yielding a cost of 0.76$/Wp, which is quite high. We could, for comparison purposes, see how much a low efficiency 290Wp module would cost. In large wholesale platforms such as Alibaba we can find several 290W modules at a much smaller price. Of course, we can expect a much smaller efficiency. For example, YingLi 290W panels are in the range of 0.35-0.45$/Wp but having an efficiency of 14-15%. On the other hand, the Trina brand (from Taiwan) appears to be a very good option, having a high efficiency and a smaller cost than SolarWorld. The model Trina Solar Panel Mono TSM-290DD05A.05 has a very high efficiency of 17.8% and a cost of 160$ per module, equivalent to 0.55$/Wp. Given the good price-quality relationship, this model will be the one chosen.

- **Inverter cost**: The most common brand for inverters used by FF Solar is SMA America. This brand provides us with several models for their 5kW inverters. A good choice would be the model SMA Sunny Boy 5.0-US Inverter, which costs around $1,425.00 (wholesale), equivalent to 0.285$/Wp.

- **Balance-of-System equipment**: for a 5kW system, the cost to be considered is approximately 0.4$/Wp.

- **Installation Labour, Permitting and Engineering Overhead**: Labour costs amount to 200€ per day, which is approximately 225$. A 5KW project usually takes around 2 days to be built, resulting in a total cost of 450$; For a 5kW project, costs regarding the acquisition of permits or registering the installation amount to 250€ or 282$; Engineering costs amount to one day of work, so I'll consider the cost of 225$.

- **Installer margin and Overhead**: A cost of 0.5$/Wp is assumed.

- **Contingency rate**: The contingency was assumed to be 4% of total direct costs (NREL, 2016).

- **O&M costs**: Inverter will be replaced every 10 years (very common assumption).

Installation Cost: Considering the above-mentioned inputs, the installation cost for residential projects corresponds to 3.10$/Wp. According to Pereira et al. (2016), reference (global) installation costs for residential projects corresponded to 3.3$/Wp in 2015. Given that solar PV costs have been gradually decreasing, it should be safe to assume that this value is now lower.

4. Financial Parameters:

- **Discount rate**: Following Baker et al. (2013) and Borenstein (2008) we considered a real social discount rate of 3%, which is lower than the rates most buyers would actually face. Nonetheless, it's the appropriate rate for public policy analysis.

- **Inflation Rate**: 1.37% (The average inflation of Portugal in 2017).

- **Investment Income Tax rate** of 28%.

- **Sales Tax**: According to the European Commission (2014), the reference sales tax to be considered in unsubsidized solar PV projects is the Portuguese VAT of 23%.

- The **Property Tax rate** (“IMI – Imposto Municipal sobre Imóveis”) will be different for each location. Additionally, urban property exclusively intended for the production of energy from renewable sources benefits from a 50% reduction of the IMI rate.

- The **debt level** is assumed to be zero for simplicity reasons;

References

Baker, E., Fowlie, M., Lemoine, D., and Reynolds, SS. 2013. The Economics of Solar Electricity. Annual Review of Resource Economics 5.

Bhesaniya, Hardik. 2016. What should be my DC/AC Ratio for Solar PV Power Plant? https://www.linkedin.com/pulse/what-should-my-dcac-ratio-solar-pv-power-plant-hardik-bhesaniya/

Borenstein, Severin. 2008. The Market Value and Cost of Solar Photovoltaic Electricity Production. Center for the Study of Energy Markets Working Paper 176, University of California Energy Institute.

Landau, Charles R. 2017. Optimum Tilt of Solar Panels. http://www.solarpaneltilt.com/

Fu, R., Feldman, D., Margolis, R., Woodhouse, M., Ardani, K. 2017. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017. NREL/TP-6A20-68925. Golden, CO: National Renewable Energy Laboratory (NREL). https://www.nrel.gov/docs/fy17osti/68925.pdf

IRENA (2018), Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi.

Pereira, M., Joyce, A., and Reis, P. 2016. O Valor e o Custo da Electricidade Produzida por Sistemas Solares (Fotovoltaicos). Instituto Português de Energia Solar.

Skoczek, A., Sample, T., Dunlop, E. 2008. The results of performance measurements of field-aged crystalline silicon photovoltaic modules. Progress in photovoltaics: Research and Applications 17:227–240

Huld, T., Jäger Waldau, A., Ossenbrink, H., Szabo, S., Dunlop, E., Taylor, N. 2014. Cost Maps for Unsubsidised Photovoltaic Electricity. European Commission JRC Scientific and Policy Reports. Report JRC 91937.

Appendices

Table A –Main Results: Porto and Coimbra (Utility-Scale Projects)

Utility-Scale Projects	**Porto**		**Coimbra**	
Panel Orientation	South	West	South	West
Annual Energy - kWh	3,597,302	3,059,939	3,543,283	3,011,985
Levelized Cost (€/kWh)	0,0860	0,1011	0,085931	0,1011
Average λ (€/kWh)	0,0526		0,0526	
Weighted average λ (€/kWh)	0,0529	0,0516	0,0532	0,0519
% increase in the "market value"	0,6%	-1,9%	1,1%	-1,4%
Average ϕ (g/kWh)	319		319	
Weighted average ϕ (g/kWh)	216	239	221	241
% decrease in the "non-market value"	-32,1%	-25,0%	-30,7%	-24,5%
SRMV - Simple Averages	0,0590		0,0590	
SRMV - Weighted Averages	0,0572	0,0564	0,0576	0,0567
Net Cost - Simple Averages	0,0271	0,0421	0,0270	0,0421
Net Cost - Weighted Averages	0,0288	0,0447	0,0283	0,0444

Table B – Main Results: Lisbon, Évora and Faro (Utility-Scale Projects)

Utility-Scale Projects	**Lisbon**		**Évora**		**Faro**	
Panel Orientation	South	West	South	West	South	West
Annual Energy - kWh	3,855,915	3,014,632	3,845,672	3,286,828	4,244,703	3,609,305
Levelized Cost (€/kWh)	0,08017	0,10251	0,07963	0,09311	0,07192	0,08460
Average λ (€/kWh)	0,0526		0,0526		0,0526	
Weighted average λ (€/kWh)	0,0533	0,0520	0,0528	0,0517	0,0532	0,0519
% increase in the "market value"	1,4%	-1,2%	0,4%	-1,6%	1,1%	-1,2%
Average ϕ (g/kWh)	319		319		319	
Weighted average ϕ (g/kWh)	221	238	222	240	220	239
% decrease in the "non-market value"	-30,6%	-25,3%	-30,4%	-24,5%	-31,0%	-25,0%
SRMV - Simple Averages	0,0590		0,0590		0,0590	
SRMV - Weighted Averages	0,0578	0,0567	0,0572	0,0565	0,0576	0,0567
Net Cost - Simple Averages	0,0212	0,0436	0,0207	0,0342	0,0130	0,0256
Net Cost - Weighted Averages	0,0224	0,0458	0,0224	0,0366	0,0143	0,0279

Table C –Main Results: Porto and Coimbra (Residential Projects)

Residential Projects	Porto		Coimbra	
Panel Orientation	South	West	South	West
Annual Energy - kWh	8,439	7,176	8,366	7,122
Levelized Cost (€/kWh)	0,10517	0,12371	0,10580	0,12433
Average (adjusted) λ (€/kWh)	0,0525880	0,0525880	0,0525880	0,0525880
Weighted average (adjusted) λ (€/kWh)	0,05287	0,05158	0,05319	0,05185
% increase in the "market value"	0,5%	-1,9%	1,1%	-1,4%
Average ϕ (g/kWh)	319		319	
Weighted average ϕ (g/kWh)	215	239	220	240
% decrease in the "non-market value"	-32,4%	-25,1%	-31,0%	-24,6%
SRMV - Simple Averages	0,0590		0,0590	
SRMV - Weighted Averages	0,0572	0,0564	0,0576	0,0567
Net Cost - Simple Average	0,0462	0,0647	0,0468	0,0654
Net Cost - Weighted Average	0,0480	0,0674	0,0482	0,0677

Table D – Main Results: Lisbon, Évora and Faro (Residential Projects)

Residential Projects	Lisbon		Évora		Faro	
Panel Orientation	South	West	South	West	South	West
Annual Energy - kWh	9,047	7,057	9,071	7,765	10,026	8,531
Levelized Cost (€/kWh)	0,09764	0,12513	0,09826	0,11484	0,08868	0,10420
Average (adjusted) λ (€/kWh)	0,0525880	0,0525880	0,0525873	0,0525873	0,0525873	0,0525873
Weighted average (adjusted) λ (€/kWh)	0,05333	0,05195	0,05278	0,05169	0,05317	0,05191
% increase in the "market value"	1,4%	-1,2%	0,4%	-1,7%	1,1%	-1,3%
Average ϕ (g/kWh)	319		319		319	
Weighted average ϕ (g/kWh)	220	238	221	240	219	239
% decrease in the "non-market value"	-30,8%	-25,3%	-30,7%	-24,6%	-31,3%	-25,0%
SRMV - Simple Averages	0,0590		0,0590		0,0590	
SRMV - Weighted Average	0,0577	0,0567	0,0572	0,0565	0,0576	0,0567
Net Cost - Simple Average	0,0387	0,0662	0,0393	0,0559	0,0297	0,0452
Net Cost - Weighted Average	0,0399	0,0684	0,0411	0,0583	0,0311	0,0475

Table E – Annual Average Number of Sunshine Hours

Location	Annual
Lisbon	2799.0
Porto	2468.0
Coimbra	2480.0
Faro	3036.0
Évora	2771.0

Source: UNdata

Figure 1 - Summary

Summary Data tables Losses Graphs Cash flow Time series Profiles Statistics Heat map PDF / CDF

Metric	Value
Annual energy (year 1)	3,286,828 kWh
Capacity factor (year 1)	15.0%
Energy yield (year 1)	1,316 kWh/kW
Performance ratio (year 1)	0.79
PPA price (year 1)	17.08 ¢/kWh
PPA price escalation	1.00 %/year
Levelized PPA price (nominal)	18.83 ¢/kWh
Levelized PPA price (real)	16.24 ¢/kWh
Levelized COE (nominal)	12.18 ¢/kWh
Levelized COE (real)	10.50 ¢/kWh
Net present value	$3,117,466
Internal rate of return (IRR)	15.00 %
Year IRR is achieved	20
IRR at end of project	15.58 %
Net capital cost	$3,281,881
Equity	$3,281,881
Size of debt	$0
Minimum DSCR	Inf

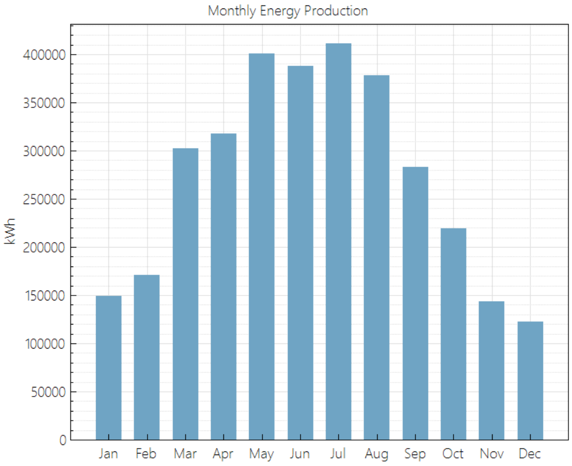


Figure 2 – Data Tables

Summary Data tables Losses Graphs Cash flow Time series Profiles Statistics Heat map

Copy to clipboard Save as CSV... Send to Excel Clear all

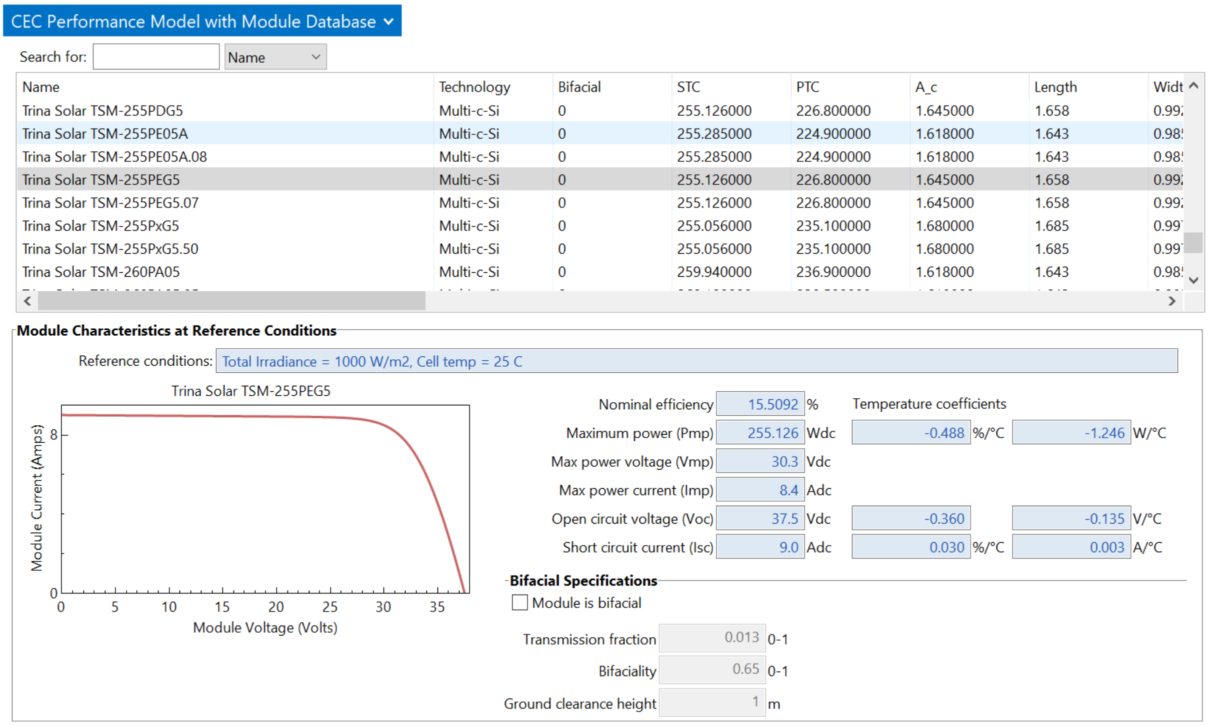
Search

Hourly Data

⊕ Single Values
⊕ Monthly Data
⊕ Annual Data
⊖ Hourly Data
- ■ AC wiring loss (kW)
- ☐ Absolute air mass
- ☐ Array DC power (kW)
- ☐ Array DC power loss due to snov
- ☐ Array POA beam radiation after s
- ☐ Array POA front-side beam radia
- ☐ Array POA front-side total radiati
- ☐ Array POA front-side total radiati
- ☐ Array POA front-side total radiati
- ☐ Array POA front-side total radiati
- ☐ Array POA radiation total after cc
- ☐ Array POA rear-side total radiatic
- ☐ Inverter DC input voltage at MPP
- ☐ Inverter clipping loss AC power li
- ☐ Inverter clipping loss DC MPPT vc
- ☐ Inverter efficiency (%)
- ■ Inverter night time loss (kW)
- ■ Inverter power consumption loss
- ☐ Inverter thermal derate loss (kW)
- ☐ Inverter total power loss (kW)
- ☐ Irradiance DHI from weather file (
- ☐ Irradiance DNI from weather file (

	System power generated (kW)	AC wiring loss (kW)	Inverter night time loss (kW)	Inverter power consumption loss (kW)
Jan 1, 12:00 am	-0.23432	0.00232	0.232	0
Jan 1, 01:00 am	-0.23432	0.00232	0.232	0
Jan 1, 02:00 am	-0.23432	0.00232	0.232	0
Jan 1, 03:00 am	-0.23432	0.00232	0.232	0
Jan 1, 04:00 am	-0.23432	0.00232	0.232	0
Jan 1, 05:00 am	-0.23432	0.00232	0.232	0
Jan 1, 06:00 am	-0.23432	0.00232	0.232	0
Jan 1, 07:00 am	-0.23432	0.00232	0.232	0
Jan 1, 08:00 am	62.3074	0.629368	0	4.14209
Jan 1, 09:00 am	174.544	1.76307	0	3.9695
Jan 1, 10:00 am	343.945	3.47419	0	3.63516
Jan 1, 11:00 am	443.136	4.47612	0	3.42487
Jan 1, 12:00 pm	534.823	5.40225	0	3.22735
Jan 1, 01:00 pm	553.469	5.59059	0	3.18569
Jan 1, 02:00 pm	496.139	5.01151	0	3.3072
Jan 1, 03:00 pm	262.85	2.65505	0	3.79485
Jan 1, 04:00 pm	50.8412	0.513547	0	4.14279
Jan 1, 05:00 pm	-0.23432	0.00232	0.232	0
Jan 1, 06:00 pm	-0.23432	0.00232	0.232	0
Jan 1, 07:00 pm	-0.23432	0.00232	0.232	0
Jan 1, 08:00 pm	-0.23432	0.00232	0.232	0
Jan 1, 09:00 pm	-0.23432	0.00232	0.232	0
Jan 1, 10:00 pm	-0.23432	0.00232	0.232	0

Figure 3 – Module and Inverter Brands



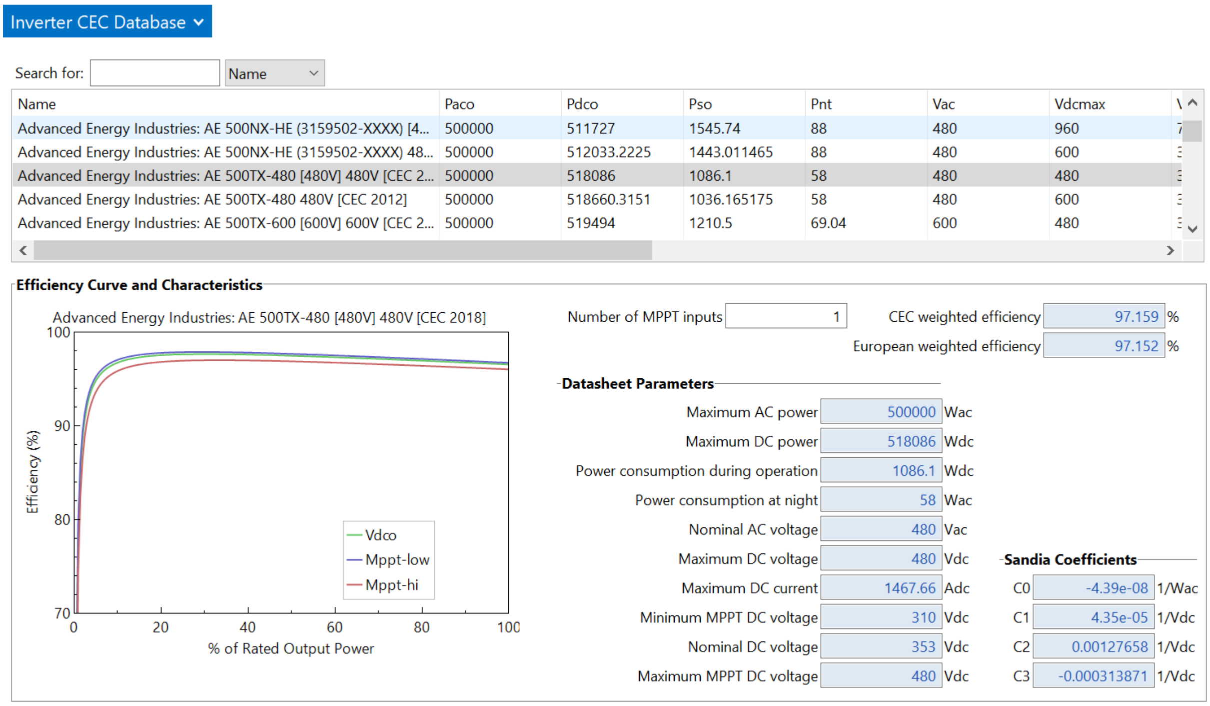
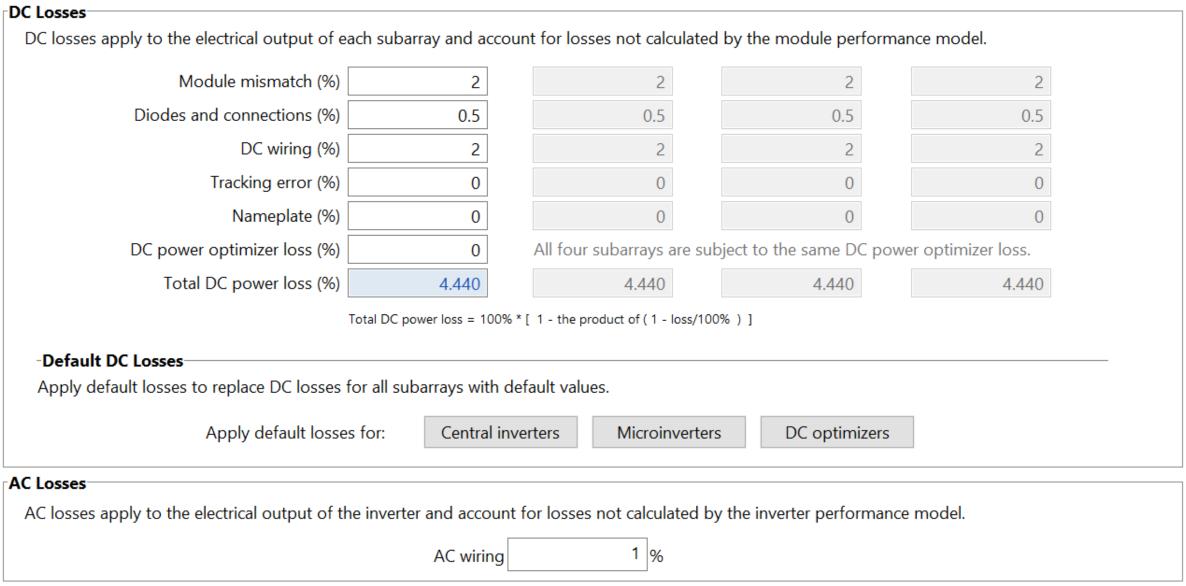


Figure 4 – DC and AC losses



DC Losses

DC losses apply to the electrical output of each subarray and account for losses not calculated by the module performance model.

Module mismatch (%)	2	2	2	2
Diodes and connections (%)	0.5	0.5	0.5	0.5
DC wiring (%)	2	2	2	2
Tracking error (%)	0	0	0	0
Nameplate (%)	0	0	0	0
DC power optimizer loss (%)	0	All four subarrays are subject to the same DC power optimizer loss.		
Total DC power loss (%)	4.440	4.440	4.440	4.440

Total DC power loss = 100% * [1 - the product of (1 - loss/100%)]

Default DC Losses

Apply default losses to replace DC losses for all subarrays with default values.

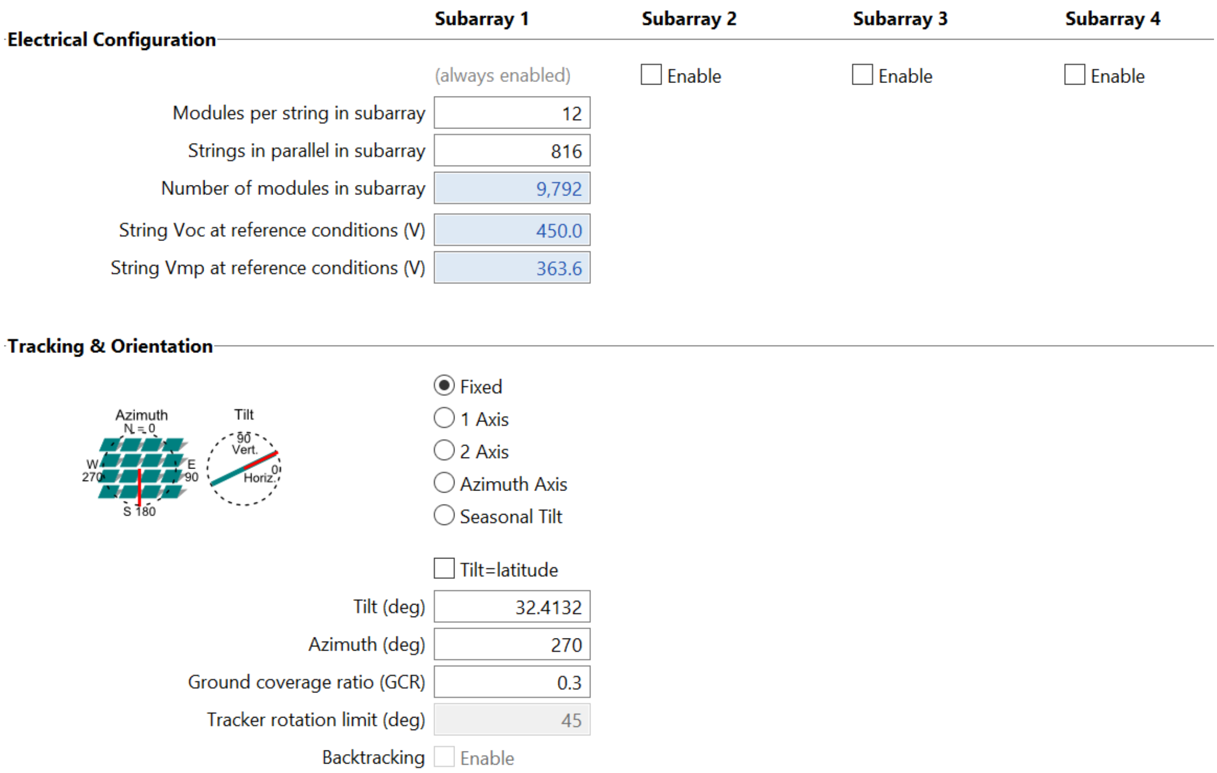
Apply default losses for: Central inverters | Microinverters | DC optimizers

AC Losses

AC losses apply to the electrical output of the inverter and account for losses not calculated by the inverter performance model.

AC wiring 1 %

Figure 5 – System Design



Electrical Configuration

	Subarray 1	Subarray 2	Subarray 3	Subarray 4
	(always enabled)	Enable	Enable	Enable
Modules per string in subarray	12			
Strings in parallel in subarray	816			
Number of modules in subarray	9,792			
String Voc at reference conditions (V)	450.0			
String Vmp at reference conditions (V)	363.6			

Tracking & Orientation

Fixed
1 Axis
2 Axis
Azimuth Axis
Seasonal Tilt

Tilt=latitude

Tilt (deg)	32.4132
Azimuth (deg)	270
Ground coverage ratio (GCR)	0.3
Tracker rotation limit (deg)	45
Backtracking	Enable

Figure 6 – System Costs

Direct Capital Costs

Module	9,792 units	0.3 kWdc/unit	2,498.2 kWdc	0.30 $/Wdc	$ 749,458.19
Inverter	4 units	500.0 kWac/unit	2,000.0 kWac	0.24 $/Wdc	$ 599,566.50
		Battery pack	0.0 kWh	300.00 $/kWh dc	
		Battery power	0.0 kW	600.00 $/kW dc	$ 0.00

	$		$/Wdc		$/m²		
Balance of system equipment	0.00		0.30		0.00		$ 749,458.19
Installation labor	81,000.00	+	0.00	+	0.00	=	$ 81,000.00
Installer margin and overhead	40,500.00		0.00		0.00		$ 40,500.00
						Subtotal	$ 2,219,983.00

Contingency

Contingency	3 % of subtotal	$ 66,599.48
	Total direct cost	$ 2,286,582.25

Indirect Capital Costs

	% of direct cost		$/Wdc		$		
Permitting and environmental studies	0		0.00		11,285.00		$ 11,285.00
Engineering and developer overhead	0	+	0.00	+	5,643.00	=	$ 5,643.00
Grid interconnection	0		0.00		33,855.00		$ 33,855.00

Land Costs

Land area	13.3 acres							
Land purchase	$ 0/acre	+	0	+	0.00	+	200,000.00	= $ 200,000.00
Land prep. & transmission	$ 0/acre		0		0.00		142,857.00	$ 142,857.00

Sales Tax

Sales tax basis, percent of direct cost	100 %	Sales tax rate 23.0 %	$ 525,913.94
		Total indirect cost	$ 919,553.94

Total Installed Cost

Total installed cost	$ 3,206,136.25
Total installed cost per capacity	$ 1.28/Wdc

Figure 7 – Financial Parameters

Analysis Parameters

Analysis period	25 years	Inflation rate	1.37 %/year
		Real discount rate	3 %/year
		Nominal discount rate	4.41 %/year

Project Tax and Insurance Rates

		Property Tax	
Federal income tax rate (Value / Sched)	0 %/year	Assessed percentage	100 % of installed cost
State income tax rate (Value / Sched)	28 %/year	Assessed value	$ 3,206,136.25
Sales tax	23 % of total direct cost	Annual decline	0 %/year
Insurance rate (annual)	0.5 % of installed cost	Property tax rate	0.225 %/year