Full-spectrum economic optimization of a solar PV park

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Abstract

Optimization of a solar PV park is usually performed with a view to maximize the annual energy yield. However, the main goal of power plant owners is maximizing the profit of the investment. This dissertation aimed at using simulation data based on the real-case scenario of a large-scale PV park under development to conduct and link the above-mentioned approaches, analysing the problem and developing tools/instruments that directly relate input parameters with economic variables. Conducted works cover tracking systems deployment, DC/AC ratio definition, string length sizing and the usage of bifacial modules. Results show that the strongly adopted configuration of horizontal single-axis tracking underperforms a fixed-tilt configuration, with a decrease in IRR and NPV from 7.56% to 4.03% and from 4.64 M€ to -8.83 M€. DC/AC Ratio optimum point was found for ratio values in the 1.30 to 1.35 range, translating in a 6% increase on NPV compared to the 1.24 base-case. String length extension from 25 to 28 modules resulted in a 11.80% Energy Yield increase, and IRR and NPV grew from 6.71% to 7.56%, and from 1.96 M€ to 4.64 M€, respectively. Fixed-tilt bifacial was found to improve project IRR from 7.56% to 7.66% if a 10% bifacial cost premium is considered.

Keywords: Utility-scale solar PV park, optimization, technical parameters, economic variables

1. Introduction

Over the last ten years, solar energy industry has assumed a central role in the energy scene, being recognized as one of the greatest weapons against climate change [1]. Since 2015, the cost of the elements required for producing solar energy has been declining significantly [2]. In 2020, the Levelized Cost of Energy (LCOE) of large-scale solar production technologies dropped, for the first time, below the LCOE for Combined Cycle Power Plants. Along with wind power, solar energy is now the cheapest energy generating technology [3].

According to IRENA [1] data, collected from +17,000 projects in 2019, solar production costs have fallen by 82% since 2010. In what regards to photovoltaic (PV) modules, the cost has fallen by 90% since the same year, accompanied by a decrease in the set of costs associated with wiring, mounting racks, solar inverters, among other necessary elements [4].

The profitability of a solar energy park is closely linked to its Energy Yield. However, most literature focus on increasing energy production at any cost. This study aims at analysing the sensitivity of economic parameters to the variation of the most important technical parameters in the design phase of a large-scale photovoltaic park. For this, PVSyst software is used to carry out multiple simulations using data provided or validated by Galp Energia[2] for the Alcoutim Solar Photovoltaic Park. The project decisions discussed consist of the use of single-axis or dual-axis solar trackers, the definition the of DC/AC Ratio, the definition of the number of modules in series in each string, and the use of bifacial modules. For each, a financial model is used in parallel with PVSyst simulations for Annual Energy Yield (in MWh), to analyse the Net Present Value (NPV) and Internal Return Rate (IRR).

2. Literature Review

Literature on solar energy does not provide enough relevant insights into the economic impacts of technical optimizations. Also, applications to practical cases of utility-scale plants are scarce, given that their proliferation is a recent advent. Another factor for this lack of information is the aggressive change in PV costs - a 90% drop since 2010 which makes economic permissions obsolete.

Miguel Silva [5] conducts an optimization study similar to the one here proposed, but considering less parameters, such as the DC/AC ratio, and the variation on expenditure values with the different technologies was directly supplied by the partner company without an industry benchmark. In another study, Hayat Ullah *et al*. [6] evaluate possible sites for projects from a technical and economic point of view, a component that this study did not consider as the land was already leased. Some studies have tried to include an even broader approach, but in different directions: Lisa Ryan *et al*. [7] propose an approach that considers the maximization of social welfare in addition to traditional parameters like LCOE. Regarding the DC/AC ratio, Mondol *et al*. [8] explored the optimization of PV/inverter sizing ratios concluding that the optimum ratio varied from 1.1 to 1.3. In what the maximum number of modules in series is concerned, Karin *et al*. [9] present a new methodology to develop longer strings using weather data, resulting in 10% longer strings that still maintain voltage within the electrical limits. Regarding the optimization of systems using bifacial

[1] IRENA – International Renewable Energy Agency.
[2] All economic data in this dissertation was based on literature and market values validated as applicable by Galp Energia and do not necessarily imply real project data.

modules, M. Tahir *et al*. [10] explored different combinations of monofacial and bifacial modules with fixed-tilt and tracking configurations, considering the effect of latitude on the gains. For latitudes lower than 50º, an East/West horizontal single-axis tracking (HSAT) bifacial system is the best in terms of Energy Yield, but the study misses the opportunity of including a fixed-tilt monofacial option, and only computes LCOE in a module to land perspective, not considering the impact of tracking or bifacial technologies on the costs. Rodriguez-Gallegos *et al.* [11] computed single-axis tracking bifacial LCOE in multiple locations, comparing it to dual-axis tracking bifacial. The LCOE was lower for single-axis given the initial investment and operation and maintenance (O&M) costs. Talavera *et al.* conducted a similar study to conclude that all targeted five projects registered a lower or equal LCOE for the fixed-tilt solution. The higher cost of tracking systems is also addressed in a study from NREL, by Lars Lisell *et al.* [12], that emphasizes the difference in OPEX between fixed and tracking systems. The work concludes that moving parts and higher rate of demanded maintenance can result in a 100% increase in tracking systems OPEX when compared to fixed ones.

Complete approaches that include multiple parameters of the wide range of technical decisions available are scarce. By proposing four different variations to the base-case of a project under development, this work aims at merging scattered techno-economical optimizations and industry knowledge.

3. Simulation Conditions

3.1 Technical and Economic Assumptions

To study the impact of technical variations in terms of energy production and economic impacts, this work evaluates the Energy Yield value over the 30-year project lifetime. To accomplish this, the key component PV Degradation Rate of PVSyst is used, which allows the simulation of equipment aging, considering a progressive loss of efficiency.

The range of values predicted in literature for the annual degradation factor is wide. Given the absence of a paradigm establishing an accurate value to be considered, this dissertation keeps in line with the industry-standard value of 0.5% per year. There is also a value of 1% considered for light-induced degradation losses - the loss of performance in the first operation hours, derived from the initial exposure to the sun that affects the functioning of the crystalline modules.

To analyse the economic performance a model was developed with Microsoft Excel tools. The economic assumptions for the project were literature and market values validated as applicable by Galp: a discount rate of 6%, project lifetime of 30 years and a pool price of 38 €/MWh. The energy pool value is the price at which the project sponsor believes energy will be sold once operation begins and it is assumed that a Power Purchase Agreement (PPA) contract will be negotiated during the construction phase, which satisfies this initial assumption of 38 €/MWh.

3.2 Project Costs

CAPEX values were based on market and a literature review validated as applicable by Galp, while OPEX values were calculated based on a literature review. These values are then determined in each section, considering the proposed variations to the base-case previously described.

The value for the initial investment considered in the calculations is obtained by multiplying the number of peak watts (Wp) installed by the cost per Wp. This cost totals 0.5985 € and includes the components described in **Table 1**.

Table 1 - Breakdown of CAPEX costs

PV Costs Breakdown		
Category	**Value [€/Wp]**	**Value [%]**
PV Modules	0.18	30.1%
Support for PV Modules	0.095	15.9%
Grid Connection	0.08	13.4%
Settings and Others	0.055	9.2%
Electrical components	0.05	8.4%
Inverters	0.045	7.5%
Civil Works	0.045	7.5%
Mechanical Assembly	0.03	5.0%
Insurance	0.013	2.2%
Studies and Analysis	0.0055	0.9%
Transport, Accessories	Included	n/a

Table 2 presents a summary of the literature reviewed, and from which was determined the average value to be considered for fixed-tilt systems, of 17.039 €/kWp/year.

Table 2 - Literature Review: O&M costs for fixed-tilt systems

O&M Costs [€/kWp/year]	
Source	**Fixed-Tilt**
[13]	20.000
[12]	8.500
[14]	14.195
[15]	2.250
[16]	21.250
Average Value	17.039

CAPEX and OPEX costs mentioned previously are then used as a starting point to latter reflect the impacts resulting from each technical variation considered in the study. New configurations as HSAT systems and bifacial modules, among other changes, naturally have a great impact on these values as it will later be seen.

4. Optimization: Result Analysis

Fixed vs. Tracking systems

A common optimization strategy for photovoltaic modules involves their installation in solar trackers that follow the sun's movement throughout the day. They can be split into two categories: one axis (single-axis) and two axis (dual-axis) trackers. Constituting by far the most adopted group of trackers [17], single-axis trackers are the current trend being implemented industry wise [17]. In the single-axis trackers category, the Horizontal Single-Axis Tracking (HSAT) system is the most implemented. Therefore, an HSAT system was simulated and compared to a fixed-tilt and dual-axis structure.

Simulations conducted on PVSyst show the impact of trackers in the Energy Yield of PV projects. **Table 3** summarizes these results, allowing one to compare Energy Yield for the different technologies proposed, all for the total installed capacity of the park of 48 MWp.

Table 3 – Simulation Results: HSAT vs. Dual-Axis

	Fixed-Tilt (Base-case)	HSAT	Dual-Axis Tracking
Energy Yield (1st year of operation) [MWh]	91,309	99,586	126,668

These results suggest that a HSAT system would generate 9.06% more energy than the fixed-tilt system. A dual-axis system would be the most beneficial approach from an Energy Yield perspective, with an increase of almost 40%, when compared to the base-case scenario.

The critical item to be examined besides Energy Yield, is the impact of technology on both CAPEX and OPEX values. For the fixed-tilt scenario, CAPEX values are obtained by multiplying installed capacity in kWp per the total unitary PV cost in €/kWp. For the other two scenarios, reviewed literature data [11], [15], [16], [18]–[20] shows an average necessary additional initial investment of 360.33 €/kWp associated with the deployment of single-axis tracking systems, and of 1015.42 €/kWp for dual-axis tracking systems. The average value of the additional initial investment, for each system, is multiplied by the total amount of installed capacity in kWp and the result is added up to the original fixed-tilt CAPEX costs to find the new CAPEX values with single-axis and dual-axis installation premiums.

Regarding OPEX costs, a similar approach is used, but a total O&M cost in terms of EUR per installed kWp per year is reviewed and compared to the base-case. Given the recent progresses and cost decreases in O&M associated with a greater adoption of tracking systems [21], and to fully understand their economic potential, best-case scenarios of 17.85€/kWp/year for single-axis and 29.75€/kWp for dual-axis will be considered as inputs in the economic model.

Higher values of O&M in single-axis systems are associated with a more frequent need for servicing moving parts, alignment and calibration, among other periodical activities, an effect that has even greater impacts on dual-axis trackers. Similar procedure as for CAPEX is followed for OPEX values, multiplying installed capacity by total unitary O&M costs to find the new annual OPEX.

For both CAPEX and OPEX, results are summarized on **Table 4**, with It meaning Initial Investment. These are the CAPEX and OPEX values to be used in the economic model for HSAT and dual-axis analysis. The results of the economic model are summarized in **Table 5**.

Conclusions point that the increased amount of energy production is not enough to cover the higher installation and operation costs. The additional gain from an HSAT system appears to be not effective. The situation is even more significant with dual-axis systems. In the case of single-axis systems, given the adoption rates previously mentioned, the conclusions obtained may be questionable since the industry trend is trusting single-axis tracking as the option to follow when terrain conditions allow. However, these conclusions are supported by a BloombergNEF report that gathers data from +700 recently financed projects and 13,000 modelled LCOE forecasts across 25 technologies and 54 countries around the world [22]. Within the Iberian Peninsula, conclusions differ. In Portugal, fixed-tilt projects end up being less expensive to install in terms of LCOE, while in Spain, tracking systems are the most cost-effective solution.

Table 4 - New CAPEX and OPEX values for tracking technologies

	Fixed-Tilt	HSAT	Dual-Axis
Total Capacity [kWp]	47,992	47,992	47,992
O&M [k€/yr]	817.736	856,657.2	1,427,762
Added It [k€]	-	17,292.957	48,732.0374
Total It [k€]	28,723.212	46,016.169	77,455.249

Table 5 – Fixed-Tilt and tracking systems economic model results: IRR and NPV values for a 30-year period obtained with PVSyst

Configuration	Fixed-Tilt	HSAT	Dual-Axis
IRR [%]	7.56%	4.028%	0.9%
NPV [€]	4,642,188	-8,830,924	-34,322,340

DC/AC Ratio

DC/AC Ratio is determined as per equation (1),

$$DC/AC\ Ratio = \frac{Installed\ DC\ Capacity}{Installed\ AC\ Capacity} \quad (1)$$

where *Installed DC Capacity* accounts for the maximum rated module power output at STC, and *Installed AC Capacity* is the sum of all inverter rated capacity.

When the oversized PV array is at its maximum production, the injection is above the inverter's faceplate power rating. The additional power is limited by the inverter, in an event referred to as clipping that guarantees the safe operation within inverter specifications. The analysis of the daily production profile for PV technology, as illustrated in **Figure 1**, supports a possible optimization which consists of oversizing the system in order to maximize the average value of solar production. In **Figure 1**, the advantages of oversizing a PV-array are illustrated by the area in blue, and clipping losses in orange.

This oversizing advantage is related to two main characteristics of solar production: producing at rated capacity only happens during a reduced number of hours a day, and the rated capacity of the solar modules is measured under STC conditions, which in practical situations hardly happens. To measure these advantages, distinct DC/AC Ratio scenarios are proposed, and compared with the 1.24 original DC/AC Ratio of the base-case, as included in **Table 6**

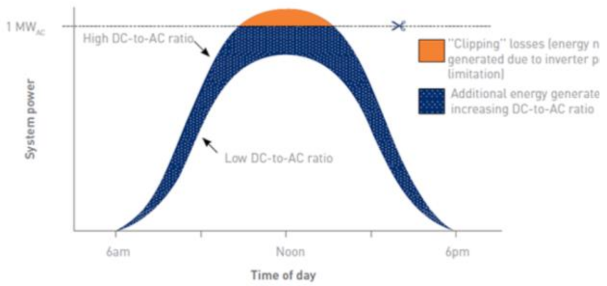

Figure 1 - Oversizing scenarios: differences between low and high DC/AC ratios [31]

Table 5 Following the technical optimization, these results are now included in the economic model, with Energy Yield values being directly exported from PVSyst. OPEX values are calculated assuming that the base-case did not change, as adding more modules will always result in an increasing necessity of conducting maintenance. In the case of CAPEX, **Table 6** proposes a new optimized scenario that considers adding or removing new modules to already installed inverters, which results in a correlated impact on CAPEX costs. For DC/AC ratios higher than the base-case, the lower cost results from removing the inverter cost from the original CAPEX costs breakdown, originating a new value of 0.5535 €/Wp, which is applied to the difference in the installed capacity when compared to the base-case. For DC/AC ratios lower than the base-case, the inverter cost is added to the original CAPEX, to account for the same number of inverters being kept, although installed capacity is diminishing.

These new starting points are then used in the economic model to evaluate the IRR and NPV associated to each configuration.

Table 7 summarizes these results. As shown, the best configuration in terms of IRR is a DC/AC Ratio of 1.30, and in terms of NPV is a DC/AC Ratio of 1.35

These conclusions represent an increase to the industry-standard of 1.20. This analysis shows that the cost decline in the photovoltaic module chain might have an impact on the optimal configuration of module to inverter distribution, questioning the one-size fits all approach for defining the DC/AC ratio as 1.20.

A report by IRENA [2] has collected DC/AC Ratio data from 2010 to 2020 comprising 202 GW of capacity from 6,836 projects, showing that in the USA the median DC/AC Ratio grew 9% between 2010 and 2019, to reach 1.31 in 2019. The same growing trend is illustrated in **Figure 2**.

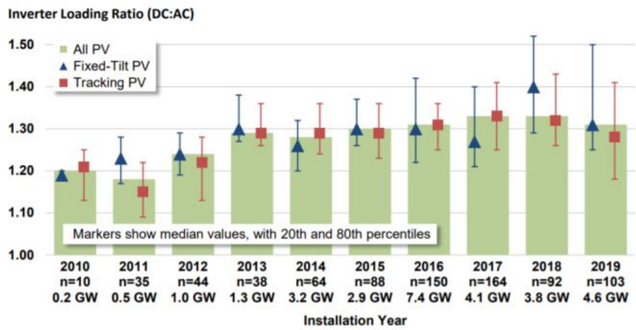

Figure 2 - Inverter loading ratio by mounting type and installation year [17]

Table 6 - Simulation results: Optimized Initial Investment for distinct DC/AC Ratios

DC/AC Ratio – Cost Variation									
DC/AC Ratio	1.00	1.10	1.15	1.20	1.24 (base-case)	1.30	1.40	1.50	2.00
Total Installed Capacity $[kWp]$	38.304	42.581	44.560	46.412	48.008	50.434	54.200	58.094	77.725
O&M Costs $[k€/year]$	537.329	597.326	625.088	651.068	673.456	707.488	760.318	814.943	1,090.327
New It value $[k€]$	23,361.624	25,728.944	26,824.320	27,849.402	-	30,075.579	32,160.060	34,315.389	45,181.148

Table 7 - Simulation results: IRR and NPV values for distinct DC/AC Ratios

Economic Analysis									
Configuration	**Fixed-Tilt**								
DC/AC Ratio	1.00	1.10	1.15	1.20	1.24 (bas-case)	1.30	1.35	1.40	1.50
IRR [%]	7.40%	7.48%	7.48%	7.54%	7.56%	7.56%	7.52%	7.46%	7.27%
NPV $[M€]$	3.38	3.96	4.22	4.46	4.64	4.83	4.92	4.89	4.58

Number of modules in series

The number of modules in series in each string is limited by the solar module open-circuit voltage (V_{oc}), which translates the maximum voltage measured at the module level with no current flowing through it. This happens since in a series connection the maximum operating module voltage adds up as represented in **Figure 3**.

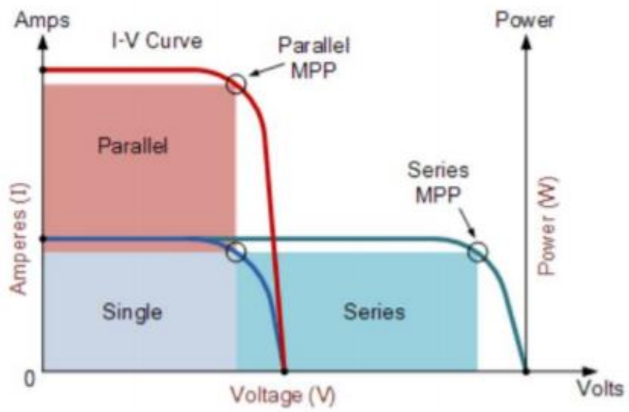

Figure 3 - Influence of Modules Series and Parallel Connections in the IV curve [32]

The maximum voltage corresponds to the referred V_{oc}, and is inversely proportional to temperature, and directly proportional to irradiance. The maximum system V_{oc} will, therefore, be registered at the minimum expected ambient temperature, also depending on the irradiance. The maximum value for V_{oc} is usually determined based on the values of the module data sheet temperature coefficients, as given by equation (2),

$$Module\ V_{OC_{max}} = V_{OC} \times \left[1 + (T_{min} - T_{STC}) \times \left(\frac{Tk_{V_{OC}}}{100}\right)\right] \quad (2)$$

where $V_{OC_{max}}$ is the maximum value for V_{oc}, to which the module is subjected, V_{oc} is the open circuit voltage specified by the manufacturer at STC, T_{min} is the minimum ambient temperature that is expected to be recorded at the site location, T_{STC} is the temperature under STC conditions and $Tk_{V_{OC}}$ is the open circuit voltage temperature coefficient.

This value obtained for $V_{OC_{max}}$ is then used to divide the maximum inverter input voltage, flooring the result to the greatest integer less than or equal to it, obtaining the number of modules to be associated in series.

As can be inferred, equation (2) represents an unnecessarily conservative approach as it considers an extreme value for the minimum temperature (T_{min}). Also, the mentioned irradiance influence in V_{oc} is not included. From a statistical point of view, this approach is therefore conservative since the minimum value recorded for ambient temperature may never again be observed. Furthermore, it does not consider that the minimum temperatures are registered during the night, when the irradiance is null. Thus, it results in an extreme value of $Module\ V_{OC_{max}}$, that is never reached nor approached. The influence of both temperature and irradiance simultaneously is explored in **Figure 4**, in which it is possible to verify that, even with an ambient temperature of 0ºC, V_{oc} do not reach an extreme value when the irradiance decreases.

The alternative proposed in this work entails using equation (3) to calculate V_{OC}, now considering site temperature and irradiance,

$$Module\ V_{OC}\ (G,T) = V_{OC}^{\mathrm{Ref}} + \left(Tk_{V_{OC}} \times V_{OC}^{\mathrm{Ref}} \times (\mathrm{T} - T_{STC})\right) + \mathrm{m} \times V_T \times \ln\left(\frac{\mathrm{G}}{G_{STC}}\right) \quad (3)$$

where m is the diode's ideality factor, V_T is the thermal voltage, G_{STC} is the Irradiance on STC conditions equal to 1000W, and G, T are respectively the irradiance and temperature registered at any point in time at the specific site. Applying both methodologies described above, two different values for the maximum number of modules in series are obtained. The difference has a significant impact on production values. The conservative method is firstly used to determine the standard number of modules in series. Considering a V_{oc} of 53.32 V, an open circuit voltage temperature coefficient of -0.28%/ºC, a value of 58.545 V

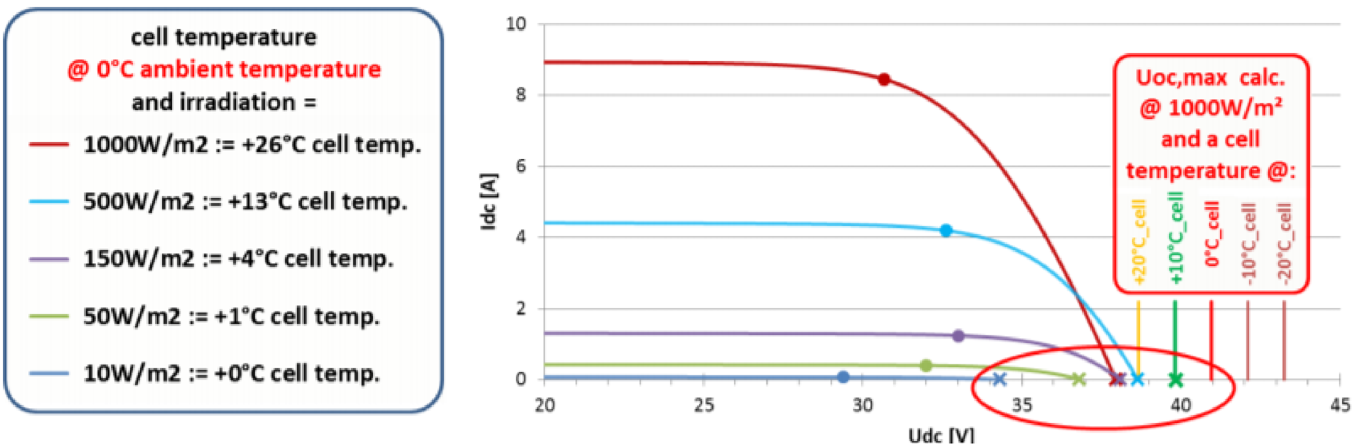

Figure 4 - Resulting cell temperatures at a constant room temperature (0 ºC) at different irradiation levels (left); Realistic open circuit voltages vs. calculation with simple formula (right) [33]

according to equation (2) is obtained for $Module\ V_{OC_{max}}$. With these values dividing the Sungrow inverter input voltage of 1500 V, a maximum number of modules in series of 25 units is obtained. In PVSyst, only the minimum temperature value registered in the project site can be modified, and the system will not allow one to perform simulations with a different value of modules in series than the one calculated based on this method. PVSyst default value also considers the minimum temperature as -10 °C.

The meteorological data provided by Galp in the form of a Typical Meteorological Year (TMY) shows that the minimum value ever registered in the TMY was 1 ºC, a temperature calculated for March 22nd at 04:30 AM. To assess the viability of an extension on original string length based on meteorological data, a value of 28 modules is now proposed. The second method is applied to every temperature and irradiance value available on the dataset for every given hour of the TMY according to equation (3). At this point, it is important to state that, according to Galp, manufacturers are now certifying operation at a voltage level residually higher than the rated 1500 V, a difference that provides an extra warranty-security buffer that may accommodate sporadic situations where a dramatically low temperature can occur simultaneously with a considerable irradiation. As such, scenarios where the proposed 28 modules V_{OC} exceed in more than 5% the rated voltage are evaluated. This means, finding the occurrences that fulfil the condition $Module\ V_{OC}\ (G,T) > 56.339\ V$, for an inverter input voltage of 1577.5 V. Situations that verify this condition only occur in 8 out of 8760 hours in the virtual year. All the 8 occur at periods between 06:30 AM and 07:30 AM at low temperatures and the maximum inverter input value for voltage never exceeds 1584.31 V.

Comparatively, to acknowledge that this is the best scenario, a further extension from 28 to 29 modules in series using the same processes would result in more than 1000 hours filling the condition from the inequation mentioned. Energy Yield simulations were conducted for both configurations of 25 and 28 modules in series, with all other parameters defined according to the base-case specifications. Results are available on **Table 8**.

Table 88 - Economic parameters variation with string lenght

String length	NPV [€]	IRR
25 modules	1,961,320.61	6.71%
28 modules	4,642,188.34	7.56%

The advantages of the optimized scenario are mainly related with BoS costs per module. That economic benefit would translate in a slight increase in the unitary value for CAPEX in terms of €/kWp in the case of 25 modules. This is because the original considered CAPEX unitary value was calculated based on the assumption of having 28 modules installed. Diminishing this value would mean a higher value for inverters, among other BoS components. **Table 9** presents a summary of these techno-economic parameters. The economic model is then applied to the 30 years of project lifetime. **Table 10** summarizes these results.

Table 9 - Energy Yield simulations for baseline scenario (-10 ºC) and optimized scenario (30 ºC)

Energy Yield Simulations		
Scenario	Standard (-10 ºC) Without Irradiance Effect	Optimized (30 ºC) With Irradiance Effect
Modules in series	25	28
Energy Yield – 1st Year $[MWh]$	81,646	91,309
Specif. Prod. - 1st Year $[kWh/kWp]$	1,905	1,902
Performance Ratio [%]	87.62	87.47

Table 10 - String length optimization parameters

Technical and Economic parameters of string length optimization		
Modules in Series	25	28
Number of Modules	75,175	84,196
Total Installed Capacity $[kWp]$	45,437	47,992
Total O&M Costs $[k€/year]$	774.201	817,736
Initial Investment $[k€]$	27,194.045	28,723.212

The impact of this optimization on the IRR is an increase of 0.85%. The 11.8% increase in the Energy Yield, when compared to the cost increase, reinforces the assumption that the industry-standard calculation hides the possibility of greater economic benefit.

Bifacial Modules

Bifacial photovoltaic technology consists of PV modules that convert light to electricity both in the traditional front side, but also on the back side of the modules. The main difference of bifacial modules is taking advantage of the radiation reflected in the ground and other adjacent modules, and also the diffuse radiation which originate from separation processes in the atmosphere and after being reflected on the ground. As a result, more energy is produced per area unit, as represented in **Figure 5**.

The extra energy produced by the bifacial module is often referred to as the Bifacial Gain (BG) and is defined as the ratio between the energy produced by the newly included rear side of the module, and the energy produced on the normal front side. The System Bifacial Gain (BG_{sys}) differs from the traditional module BG by proposing a comparison between two simulations: one with bifacial modules and one with

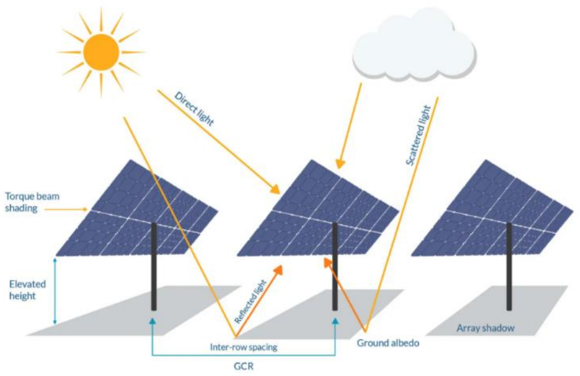

Figure 5 - Key factors that affect bifacial efficiency [34]

monofacial modules, with identical properties, as per equation (4),

$$BG_{sys} = \frac{E_{bif} - E_{mono}}{E_{mono}} \qquad (4)$$

where BG_{sys} is the system Bifacial Gain, E_{bif} is the Energy Yield simulated or measured on the bifacial solution, and E_{mono} is the Energy simulated or measured on the monofacial solution.

The parameter that most influences the BG is the albedo, which represents the percentage of radiation that reaches the ground and is reflected to the atmosphere and is heavily dependent on typology and ground cover.

To compare monofacial and bifacial module deployment, the equivalent bifacial model from the same manufacturer was created and the electrical specifications imported to PVSyst according to the manufacturer datasheet for Jinko Solar TR JKM570M-7RL4-TV-D4 module, with modifications to mirror the PAN file provided by Galp for the equivalent monofacial module. To obtain monofacial values to calculate BG_{sys}, two strategies are used. In the first, the same bifacial module is used but the rear-face contribution to the production is ignored on PVSyst. In the second, the equivalent monofacial module used in previous sections is used. Final BG_{sys} is the average value of these two calculations. Simulations were also conducted using the same procedure for a bifacial system deployed on a horizontal single-axis configuration.

Simulations result in average values for BG_{sys} of 2.77% for fixed-tilt option and 1.99% for the HSAT system. Results for BG are aligned with reviewed literature [23]–[26].

Economic considerations

To correctly compare bifacial systems with their monofacial counterparts BG_{sys} is now used accordingly with a variation of the method suggested by the IEA [27], where the economic impacts of a bifacial system deployment are adapted according to two methods:

Method A: Keeping the number of modules in the bifacial system as it was on the base-case with monofacial modules. Associated economic impacts are measured in terms of a variation in cabling, inverters and transformers directly proportional to Δ, which is roughly equivalent to the percentage of BG_{sys}.

Method B: Reducing the number of bifacial modules to keep the same annual yield as produced by the monofacial system, with associated economic impacts being translated via the reduced installed capacity.

Regarding the PV module component on the cost breakdown, module prices are the most important factor to be incorporated. **Figure 6** illustrates the trend in bifacial module costs when compared to monofacial ones.

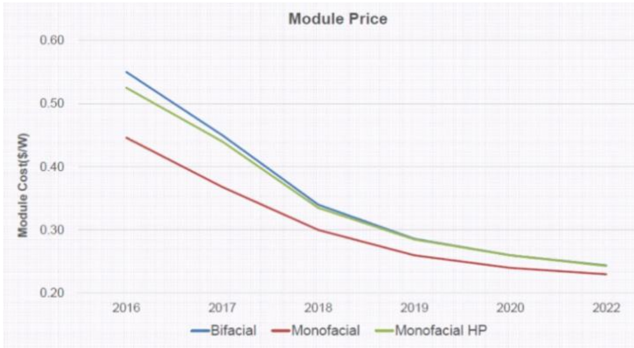

Figure 6 - Cost gap between bifacial and monofacial modules based on manufacturer data (HP stands for High Power) [28]

IRENA annual Renewable Power Generation Cost report from 2019 states that bifacial module costs were 56% higher than monofacial modules' on that year. The same report from 2020 mentions that bifacial crystalline modules sold 21% higher than high efficiency monofacial modules during December 2019. It also adds that this cost premium fell to 6% during December 2020. **Figure 6** and other reports [28] point in the same direction, although in a more conservative way with a bifacial premium between 10 and 40%. To include this range, two pricings of 10% and 30% are used in this work

Table 9 summarize the changes implemented on PV unitary cost breakdown, explained in the paragraphs above. Cells coloured green show the bifacial module premium variation, while cells coloured yellow show the variations included in Method A, depending on the previously calculated values for the BG_{sys}.

Considering this new cost distribution, new values for initial investment are obtained. **Table 12** shows these results, including the new installed capacity in the case of Method B columns, which was calculated to result in the same energy yield originally produced by the monofacial base-case system, as explained on Method B above. New values for Initial Investment derive from the application of changes in the unitary PV cost breakdown as previously mentioned.

The economic model results with these new values are presented in **Table 13** and **Table 14**, for fixed-tilt and tracking systems, respectively. As seen on the case of monofacial modules, horizontal single-axis trackers do not show enough Energy Yield increase to justify the added value in terms of both CAPEX and OPEX, resulting in worst

Table 9 - Changes implemented on PV unitary cost breakdown as per Method A and Method B

Case	Base-case	Method A (BG_{Sys} = 2.77 and 1.99)				Method B	
Category	Base Value [$€/Wp$]	BG_{Sys} = 1.99% 10% Scenario	BG_{Sys} = 1.99% 30% Scenario	BG_{Sys} = 2.77% 10% Scenario	BG_{Sys} = 2.77% 30% Scenario	10% Scenario	30% Scenario
PV Modules	0.1800	0.1980	0.2340	0.1980	0.2340	0.1980	0.2340
Support for PV Module	0.0950	0.0950	0.0950	0.0950	0.0950	0.0950	0.0950
Inverter price	0.0450	0.0459	0.0459	0.0462	0.0462	0.0450	0.0450
Studies and analysis	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055
Electrical components	0.0500	0.0510	0.0510	0.0514	0.0514	0.0500	0.0500
Mechanical assembly	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300	0.0300
Transport, accessories	Included	Included	Included	Included	Included	Included	Included
Settings and others	0.0550	0.0550	0.0550	0.0550	0.0550	0.0550	0.0550
Grid connection	0.0800	0.0816	0.0816	0.0822	0.0822	0.0800	0.0800
Civil Works	0.0450	0.0450	0.0450	0.0450	0.0450	0.0450	0.0450
Insurance	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130
TOTAL	0.5985	0.6254	0.6614	0.6226	0.6586	0.6165	0.6525

Table 10 - Initial investment for a Fixed-Tilt system with Albedo as 0.2 and a HSAT system with Albedo as 0.2

	Fixed-Tilt – Albedo 0.2				HSAT – Albedo 0.2			
System Bifacial Gain	2.77%				1.99%			
Method	A		B		A		B	
Bifacial Premium [%]	10.00	30.00	10.00	30.00	10.00	30.00	10.00	30.00
Total It [kWp]	47,992		45,662		47,992		45,821	
O&M Costs [k€/year]	817.736		778.035		856.657		817.904	
Adapted It [k€]	29,819.709	31,547.421	28,150.623	29,794.455	47,047.158	48,774.869	44,759.327	46,408.883

Table 11 - IRR and NPV values for a Fixed-Tilt system with Albedo as 0.2

	Fixed-Tilt – Albedo 0.2				
	Base-Case (Fixed-tilt)	Method A		Method B	
		Premium 10%	Premium 30%	Premium 10%	Premium 30%
IRR	7.56%	7.50%	6.91%	7.66%	7.05%
NPV	4,642,188	4,676,294	2,948,582	4,877,182	3,233,350

Table 12 - IRR and NPV values for a HSAT system with Albedo as 0.2

	HSAT– Albedo 0.2				
	HSAT Simulations	Method A		Method B	
		Premium 10%	Premium 30%	Premium 10%	Premium 30%
IRR	4.03%	4.65%	4.44%	4.89%	4.56%
NPV	-8,830,923	-6,257,247	-7,984,959	-5,557,276	-7,206,832

performances in terms of IRR and NPV. Once again, in this type of system the minimum required return rate of 6% is not achieved.

Fixed-tilt results reiterate the importance of considering a range of values for the bifacial module premium. The system achieves a better IRR and NPV when compared to the base-case if the additional price paid for bifacial modules is only 10% higher, but the conclusion differs if one considers a 30% increase on this cost. This happens for both Method A and Method B, which point to similar conclusions and contribute to the robustness of the model, with two different approaches. This conclusion makes clear the fact that an effective bifacial adoption is highly dependent on the type of procurement deal that companies close with manufacturers.

5. Link to the Portuguese case

Table 13 lists the projects subjected to the Environmental Impact Assessment (EIA) procedure by the Portuguese Environment Agency during the first half of 2021. The procedure is mandatory for projects with installed power greater than 50 MWp. Through the analysis of the environmental impact study, it is possible to obtain information on some technical decisions taken during the licensing phase. It is useful for understanding the projects being currently developed in Portugal, allowing to get a grasp of the formulated engineering choices.

Table 13 - Large-scale projects subject to EIA between January 2020 and May 2021 [35]

Year	Project	AIA Id. Number	Promoter	Installed Capacity [MWp]
2021	CSF do Cercal	3388	Aquila Capital	282.00
2021	CSF do Fundão	3385	Dos Grados Capital	126.50
2021	CSF Douro Solar	3382	Blowing Glow LDA.	126.40
2021	CSF de Montechoro I + II	3375	Iberdrola	36.53
2021	CSF da Cerca	3374	EDP Renováveis	200.00
2021	CSF de Lupina	3373	Lightsource BP	265.00
2021	CSF do Carregado	3371	Enfinity	63.50
2021	CSF da Falagueira	3369	Total Portugal	128.00
2021	CSF Adomingueiros e Nave	3367	Glennmont Partners	98.00
2021	CSF de Rio Maior e Torre Bela	3363	Neoen + Aura Power	284.00
2021	CSF THSiS	3362	Prosolia	1,008.50
2020	CSF dos Arrochais	3352	SunArrochais	240.70
2020	CSF de Margalha	3351	Akuo Energy	144.00
2020	CSF de Polvorão	3346	Akuo Energy	100.00
2020	CSF de Santas	3345	Akuo Energy	150.00
2020	CSF de Pinhal Novo	3340	SmartEnergy	63.50
2020	Parque Solar Escalabis	3311	Energi Innovation	189.00
2020	CSF de São Miguel do Pinheiro	3305	Fermesolar	558.00

Fixed vs. Tracking systems

Horizontal single-axis trackers (HSAT) are a common choice in Portuguese PV projects, usually combined with bifacial modules. One third of the projects use fixed-tilt technology, while all the others opt for a HSAT tracking strategy. The use of trackers is heavily dependent on the slopes of the terrain where the project is located. A flat terrain is more suitable for installing trackers since manufacturers generally require a maximum slope up to 15% [29], [30], depending on the tracker model. In terrains with uneven topography, earthmoving may be a solution, but this type of terrain changes would greatly increase the project costs, and maybe prevent the use of such technology.

Results obtained in this work indicated that HSAT adoption is not cost-effective, but it is important to understand that economic modelling considered a specific discount rate and energy price, which may vary on the projects addressed in the table. Further ahead, projects that use bifacial modules are in all the studied cases except one installed using HSAT.

DC/AC Ratio

Regarding the ratio between installed peak power and grid injection power, the values recorded oscillate between 1.11 and 1.41. The average value of 1.24 is close to the optimal range calculated with the economic model in this work and it is exactly the base-case value. The reasons for such a wide range of values can be varied. At the lower limit, with a ratio of just 1.11, the cause may be related to the lack of usable area that prevents the placement of a greater number of photovoltaic modules for a given licensed power of injection into the grid. As an example, if the terrain topography does not technically allow the installation of structures in a certain area, the maximum value for the installed peak power would therefore be limited. At the upper limit, the involved variables would need to be further analysed to understand the reasons behind such an oversizing, but low irradiance locations could be one of the factors that impact this type of configuration. A higher DC/AC Ratio can help mitigating this site problem.

Number of modules in series

Of the 10 projects in which environmental impact studies publish information which allows for calculating the V_{oc} value, it was found that only two propose a string length with more modules than the conservative -10ºC scenario.

A thoroughly analysis considering meteorological studies for each site location would have to be conducted to acquire values for temperature and irradiance and consequently calculate new thresholds for number of modules in series. Instead, projects most likely rely on the normal fixed irradiance approach. These studies, thus, follow an ultra-conservative perspective of the maximum assumed value for the voltage in the inverter, which represents a potential loss in the order of 12% of the annual Energy Yield. The reason for this lack of optimization may be related to outdated industry practices, but the number of modules in series might also be calculated exclusively using an automatic calculation software such as PVSyst, which, as discussed, assumes an unnecessarily conservative scenario as well. An additional point may be related with the bankability of the projects – if not done properly, the calculation might not be certified and end up representing an obstacle for strict project financing rules, which is why a conservative and by-the-book approach might be used.

Bifacial Modules

Regarding the use of bifacial modules, although only a few projects are already built and in operation, the adhesion to this recent technology is surprisingly high, with 50% of the projects incorporating this technology. As seen on this work, it is now possible to get a better economic performance using this type of technology and some sources already mention an increase in costs of 10% or less, so project promoters should shoot for the objective of closing procurement deals with manufacturers that allow then to meet lower price premiums. Contracts signed for several projects simultaneously might be an important strategy to capitalize scale economies and influence the cost of technologies such as bifacial modules.

6. Conclusions

Conducted work sustains the thesis that after a technical analysis and optimization, it is essential that the associated economic impact is also addressed to opt for the most viable option. Alternatives that increase energy yield are not always translated in greater economic benefits and a failure to incorporate this component might endanger project viability. The strongly adopted configuration of including horizontal single-axis trackers was shown to underperform in terms of economic behaviour when compared to the original fixed-tilt base-case. HSAT represented a 9.06% increase in Energy Yield, but the trade-off meant a reduction in the IRR and NPV from 7.56% to 4.03% and from 4.64 M€ to -8.83 M€. Dual-axis technology usage was shown to be totally unfeasible with an IRR of 0.7% and an NPV of -35.4 5M€ and justifies the fact that this technology is not being deployed at utility-scale projects in Portugal. In terms of DC/AC Ratio, simulations show that Energy Yield is maximized with an increasing DC array oversizing, but the optimum point in terms of IRR and NPV was found for ratio values of 1.30 and 1.35, respectively, with subsequent drops in this indicators for further increased values of DC/AC ratio. The optimized system configurations represented a surge in NPV when compared to the base-case, improving from 4.64 M€ to 4.92 M€, while calculated IRR was similar. String length extension was also proven to be an effective way of better using the available resources to harvested additional energy without significant additional economic effort. Overriding outdate conservative project methods translated in 11.80% Energy Yield increase, with the corresponding reflection on the economic model, increasing IRR and NPV from 6.71% to 7.56%, and from 1.96 M€ to 4.64 M€. Regarding Bifacial modules, simulations were conducted for both fixed-tilt and HSAT configurations. Fixed-tilt bifacial shown an average IRR of 7.28% and NPV of 3.93 M€ against 4.54% and -6.75 M€ on the case of HSAT bifacial. In the fixed-tilt case, a premium of only 10% when compared to the monofacial counterpart resulted on an average IRR of 7.58% and an average NPV of 4.78 M€, while a 30% increase resulted on an average IRR of 6.98% and an average NPV of 3.09 M€. All considered results observe the available room for improvement when it comes to the overall quality of deployed projects.

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