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Accuracy investigation in the modeling of partially shaded photovoltaic systems

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ABSTRACT

Software for simulation of photovoltaic (PV) systems is widely used for dimensioning and forecasting electrical production. A factor of losses in PV installations is the partial shading caused by surrounding elements, and these software allow the user to estimate this effect. However, the accuracy of these simulated results for shaded PV systems is not widely studied. The purpose of this article is to investigate the accuracy and quantify the differences between simulated and measured data of partially shaded PV systems, obtained with the widely used tools SAM and PVSyst. Measured data from a PV installation were compared to results from simulations performed using the different shading calculation options available in both tools. The simulated outputs were both underestimated and overestimated in the shading situations. This variation was related to the use of an hourly fraction of shading and, in the case of SAM, due to the limitations of the 3D tools available for representation. Another source of differences between simulated and measured values was the use of uniform shading factors for diffuse and albedo. In addition, the simplification of the 3D model had a significant impact on the predicted energy, mainly on cloudy days. Both software overestimated the electricity production for the entire measurement period, reaching differences between the predicted and the measured energy varying from 9% to 24%. Shaded PV systems must be carefully analyzed, and the simulated results may differ from the measured values, which may even influence the decision on the feasibility of an installation.

1. Introduction

Photovoltaic (PV) conversion from solar energy has become increasingly used worldwide (Jäger-Waldau, 2020). Technological improvements, mainly related to the increase in efficiency, and the reduction in costs have driven this growth in recent years, a behavior that is expected to continue (Victoria et al., 2021). Others advantages that favor expansion are the PV modularity and shorter installation times compared to other sources (Victoria et al., 2021). In addition to these advantages, PV energy is a fundamental source for the transition to a 100% renewable electricity system (Bogdanov et al., 2019; Jacobson et al., 2017).

In this scenario of PV expansion, a good estimate of the available solar radiation and the electric energy produced by PV systems allows better use of this source. Thus, accurate models for estimating radiation and PV system performance considering loss factors are essential. Partial shading is a common loss factor mainly in PV systems installed in urban areas, and these losses should be considered when forecasting electrical production (Trzmiel et al., 2020). Therefore, the accuracy of shaded PV systems modeling for forecasting electricity production should be known.

The purpose of this article is to investigate the accuracy and quantify the differences between simulated and measured data of a partially shaded PV system. Detailed simulations were carried out to analyze a PV system's performance under partial shading. Electrical and climatic data as well measured I-V curves were employed to adjust the input parameters for the simulations and check the simulation accuracy. The software called Crearray (Chepp and Krenzinger, 2021) was used to perform the simulations with greater control of variables and for comparison with the results of the analyzed tools. Simulations with SAM and PVSyst were performed using a weather file with measured data and adjusted input parameters, allowing the comparison between the simulated and measured results.

The literature is reviewed in Section 2 of this article. Section 3 briefly describes how shading losses are estimated in the tools used, and the methodology used for the analysis is described in Section 4. I-V curves

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were measured over a day to better analyze the PV system behavior and adjust the input parameters, as described in Section 5. The results of the simulations were compared to the measured data in Section 6. Finally, the conclusions are presented in Section 7.

2. Literature review

Simulation software for PV systems is widely used by designers to assist the step of dimensioning and estimating electrical production (Wijeratne et al., 2019). Among the most used tools, PVSyst has been used for solar potential assessment (Belmahdi and Bouardi, 2020), PV system performance analysis (Kumar et al., 2017), design and simulation (Kumar et al., 2020), and economic evaluation (Dey and Subudhi, 2020). Other tools such as PV*Sol (Sharma and Gidwani, 2017) and SAM (Shukla et al., 2016) have also been used for these analyzes. As in any simulation, the quality of the results depends on the input parameters used, so the greater the number of parameters provided by the user, the greater the complexity of the simulations and the results (Freeman et al., 2014).

The accuracy analysis of the results obtained by simulation from widely used tools is extremely important (Mondol et al., 2007), and some uncertainties in PV systems design have been verified by Quesada et al. (2011). Axaopoulos et al. (2014) compared experimental data from a 19.8 kW PV installation with simulated data using TRNSYS, Archelios, Polysun, PVSyst, PV*Sol and PVGIS software. They found that all tools underestimated the electricity generation for every month of the year, except PVGIS, which did not allow an input file with measured data; however, all investigated tools overestimated the radiation on the tilted plane. The results generated by the TRNSYS software were the closest to the measured ones. The biggest error was associated with the PV cell model. Freeman et al. (2014) also validated multiple tools (SAM, PVWatts, PVSyst and PV*Sol) for modeling PV systems, and all tools showed annual errors within ±8%. Palmero-marrero and Matos (2015) concluded that PVSyst and TRNSYS are accurate tools for forecasting annual production based on the comparison of measured data from a 124.2 kWp plant and software simulation. All accuracy analyzes mentioned above were performed considering PV systems under uniform radiation only. The work reported here focuses on the accuracy of shaded PV systems modeling. In addition to analyzing differences in the accumulated energy between measured and simulated results, the research reported in this article analyzes the input parameters and compares measured and simulated I-V curves from a partially shaded PV system.

PV systems partially shaded or installed in locations with many elements that obstruct the horizon are the ones that require greater attention for performance simulation (Trzmiel et al., 2020). The effects of partial shading on PV systems are widely known and investigated; however, the accuracy of the input variables involved in the simulation can lead to significant differences, which is the scope of this article. Some previous studies have focused on proposing simplified methods to simulate the I-V curve in shading situations (Bai et al., 2015; Deline et al., 2013; Kermadi et al., 2020), while others verify the impact of different shading patterns (Ahmad et al., 2017; Alonso-García et al., 2006; Gallardo-Saavedra and Karlsson, 2018). These shading effects can be reduced through different configurations of the PV module (Baka et al., 2019; Daliento et al., 2016; Ghosh et al., 2019) or the PV array (Karatepe et al., 2007; Mohammadnejad et al., 2016; Saiprakash et al., 2020). Sai Krishna and Moger (2019) reviewed the state of the art of techniques to reduce the effect of partial shading, which are the bypass diode, different configurations of PV array interconnections, distributed maximum power point tracking (MPPT) techniques, multilevel inverters and reconfiguration strategies. In addition, the power curve as a function of voltage has multiple peaks (local maximum and global maximum) during partial shading conditions. This situation can lead to failure in the MPPT, following a local maximum instead of the global maximum. Therefore, different methods for MPPT for partial shading situations have been proposed in the literature (da Rocha et al., 2020; Mohapatra et al., 2017; Verma et al., 2020). Ram et al. (2017) reviewed the state of the art of techniques for MPPT and compared conventional and unconventional (soft computing) methods.

To enable faster simulations, some commercial tools offer simplified models, and sometimes they have different options for shading calculation, which can affect the simulation accuracy. Previous studies on the accuracy of simulations comparing simulated and measured results rarely focus on shaded PV systems. Therefore, the simulation accuracy of partially shaded PV systems performed in widely used software packages and the quantitative effect of different options for shading calculation are not sufficiently investigated or reported. The knowledge gap discussed above is the purpose of the investigation reported here.

3. Estimation of shading losses

When a PV system is partially shaded, the shaded region receives less radiation than the non-shaded one, therefore the photogenerated current is less in the shaded cells. In addition to the loss of incident beam solar radiation in a shaded region, there are also diffuse radiation losses due to elements that obstruct the horizon and reduce the sky view factor. Therefore, the 3D representation of a system and its surroundings is an indispensable step in the simulation, and failure to consider one of these surrounding elements can result in an overestimated value of electrical production (Trzmiel et al., 2020). There are also electrical effects related to the configuration of PV cells which, because are usually in series, increase the losses (Mermoud and Lejeune, 2010).

The vast majority of crystalline silicon PV modules are composed of series-connected cells and bypass diodes connected in antiparallel to a set of cells. Dividing a PV module into submodules, with each submodule corresponding to a group of cells connected in series and a bypass diode, is effective to assess the impact of partial shading (Daliento et al., 2016; Mermoud and Lejeune, 2010; Mohammed et al., 2020). The electric current of the most shaded cell (lowest current) limits the current of all PV cells that are in series in the same submodule. Performing in cell level simulations is significantly wearing, so it is common for simulation tools to simplify the estimation of shading effects by submodule (Mikofski et al., 2018).

The PVSyst software version 7.1 (PVSyst, 2021) has three different methods for estimating the shading effects available for the user. To perform the shading analysis, it is necessary to build the 3D representation using the available tools or to import a 3D model generated in another software. The method called linear shading considers that the shading losses of the PV system are proportional to the shaded area. In this first model, only irradiance losses in the module plane are considered and it has two options: calculation through shading tables (faster) or simulation (slower). The second method assesses losses according to the strings and it considers that as soon as the shadow reaches a string of modules, all modules become unproductive; the user can determine the fraction of the electrical effect. According to the software manual, this model represents the maximum loss limit. In the detailed model (third option), the modules are divided into submodules according to the bypass diodes. The fraction of linear shading for each submodule is calculated, and the I-V curve is generated. The resulting curve is obtained by adding the voltages of the curves of the submodules in series and adding the currents of the curves of the submodules in parallel.

The System Advisor Model (SAM) software version 2020.2.29 was developed by NREL (National Renewable Energy Laboratory) and has two options for shading losses (SAM, 2020). The first option considers a linear loss (irradiance loss), and the second, called partial shading model, consists of dividing the module into submodules. SAM has the option to perform 3D representation; however, the tools are limited and it is not possible to import files generated in another software. Nevertheless, it allows the user to import shading tables that can be generated in PVSyst, SunEye or Solar Pathfinder software. Macalpine and Deline (2015) described the shading calculation method.

It is expected that the methods that divide the PV modules into submodules are more accurate than the others for crystalline silicon PV modules. However, it is important to analyze the simulated results for the other calculation options, considering that, although there is an explanation about the methods in the software manuals, a user can choose any of the options to perform the simulation. Therefore, simulated results for each calculation option of both software are compared to measured data in this work to evaluate the differences expected according to the available options.

4. Methodology

The studied PV system is located in Porto Alegre (southern Brazil, coordinates 30°S 51°W) and consists of a string with 10 multicrystalline silicon PV modules of 245 Wp connected to a grid-connected inverter with 2500 W. The array is tilted at 50° and facing north. The PV modules dimensions are 1650 mm × 990 mm, they have 60 cells and one bypass diode for every 20 cells, which makes a submodule. The PV modules were installed in a plane respecting the architectural characteristics of the building, and the tilt is not ideal for maximizing annual electricity production considering the site latitude. The system was installed for analysis and testing under non-ideal conditions, such as high tilt and partial shading.

A pyranometer (EKO, MS60) was used to measure the global horizontal solar irradiance. Another pyranometer (Kipp & Zonen, CM-11) installed under a shadow ring was used to measure the diffuse horizontal solar irradiance. A crystalline silicon reference cell measures the solar irradiance on the plane of the PV modules. The ambient temperature and the central PV module temperature were measured with Pt100 temperature sensors. Data acquisition and recording equipment (SMA, Sunny Boy SBCOP02) register 20 min average values from each variable. Fig. 1 shows the PV system and some details of the positioning of instruments and sensors.

Simulated results of the PV system were performed using the Crearray software, developed at LABSOL (Solar Energy Laboratory at UFRGS), which generates I-V curves for given temperature and irradiance conditions. The software also calculates the maximum power point (MPP) from an input file with irradiance and temperature data. The PV modeling based on the single diode model and the operation of Crearray were described by Chepp and Krenzinger (2021). This software allows a detailed analysis of the I-V curve for any condition, making possible a better adjustment of input variables that are shared with the simulations performed in PVSyst and SAM later on.

Fig. 2 shows the system surroundings which consist of trees, a wall

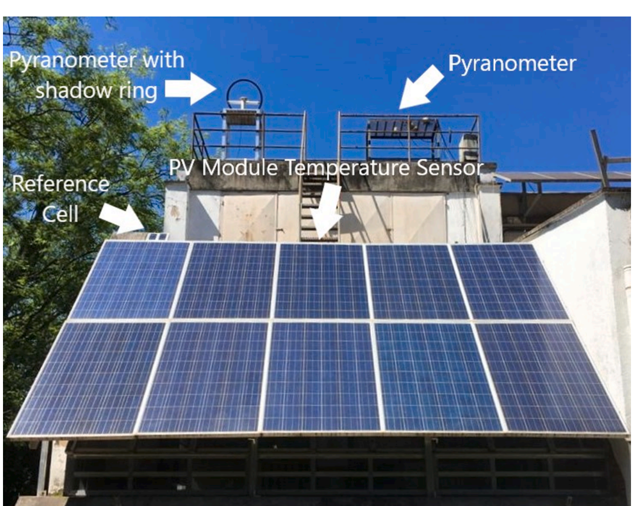

Fig. 1. Studied PV system.

(the white wall on the right of Fig. 1), and another PV system. The PV array with each PV module divided into submodules, the wall, the neighboring PV modules and some trees were modeled in the SketchUp software. The shading fraction for each submodule was obtained with the EnergyPlus software. The shading fraction of the submodule when the shadow reaches a complete cell was determined, which is the same effect as if the entire submodule to which it belongs were shaded.

The effective incident irradiance on a PV module on the tilted plane ($G_{T,eff}$) was calculated according to Eq. (1), by adding beam (G_B), diffuse (G_D) and the reflected radiation on the ground, considering the global horizontal radiation (G), albedo (ρ), angle of incidence (θ), zenith angle (θ_Z) and slope (β) (Duffie and Beckman, 2013). Moreover, the losses due to the shading fraction (F_S), effective view factor (EVF), soiling (L_S), angular reflection of the glass ($K\tau\alpha$) and air mass modifier (M_{am}) were considered. F_S is 0 for completely shaded and 1 for non-shaded. The effective irradiance is the input for the Crearray software, while SAM and PVSyst apply their methods to calculate the effective irradiance on a PV module. Snell's law, Eq. (2), relates the refractive index of medium 1 (n_1) and medium 2 (n_2) to the incidence (θ_1) and refraction (θ_2) angles. Eq. (3) gives the reflection of the glass as a function of the angle of incidence, $r(\theta_1)$, and Eq. (4) gives the angular reflection coefficient of the glass (De Soto et al., 2006; Duffie and Beckman, 2013). The air mass (AM_a) was calculated from Eq. (5) and depends on the altitude (h) and solar zenith (θ_Z) (King et al., 1998). Eq. (6) gives the air mass modifier, in which the polynomial coefficients used are: $a_0 = 0.918093$; $a_1 = 0.086257$; $a_2 = -0.024459$; $a_3 = 0.002816$; $a_4 = -0.000126$ (Fanney et al., 2003).

$$G_{T,eff} = G_B\left(\frac{\cos\theta}{\cos\theta_z}\right)K_{\tau\alpha}M_{am}F_sL_S + \left[G_D\left(\frac{1+\cos\beta}{2}\right) + G\rho\left(\frac{1-\cos\beta}{2}\right)\right]L_SEVF \tag{1}$$

$$n_1\sin\theta_1 = n_2 sin\theta_2 \tag{2}$$

$$r(\theta_1) = \frac{1}{2}\left(\frac{sin^2(\theta_2-\theta_1)}{sin^2(\theta_2+\theta_1)} + \frac{tan^2(\theta_2-\theta_1)}{tan^2(\theta_2+\theta_1)}\right) \tag{3}$$

$$K_{\tau\alpha} = \frac{1-r(\theta_1)}{1-r(0^\circ)} \tag{4}$$

$$AMa = \frac{\exp(-0.0001184h)}{cos\theta_z + 0.5057(96.080-\theta_z)^{-1.634}} \tag{5}$$

$$M_{am} = a_0 + a_1AMa + a_2AMa^2 + a_3AMa^3 + a_4AMa^4 \tag{6}$$

Several I-V curves of the PV system were measured (using an I-V curve tracer PVE, PVPM 1100C) over a clear day and they were compared to the I-V curves simulated in Crearray for the same conditions. The I-V curves are essential for an extensive analysis of the system behavior, checking the pattern of shadows, and for a better adjustment of input parameters for the simulations. After adjusting the input parameters, the system performance in direct current (DC) was obtained for the entire measurement period (approximately 2 months) from Crearray, SAM and PVSyst. The simulated results were analyzed and compared with the measured ones.

The hourly average values of the measured irradiance from the pyranometers and ambient temperature data were used for simulations in PVSyst and SAM as parameters of the input weather file. PVSyst allows the user to make a geometric model using drawing tools or import a model (the model created in SketchUp was imported), and average values for diffuse and albedo shading factors are calculated. Two simulations were done with SAM: one using a shading table exported from PVSyst and another with the simplified 3D model generated in SAM, which has quite simple and limited drawing tools.

Fig. 2. PV System surroundings.

5. Analysis of the PV system over a clear day and adjustment of the input parameters

Some variables are difficult to estimate due to the complexity of the PV installation surrounding, such as the albedo and therefore, the reflected radiation incident on the PV plane, which can vary over time, and the effective view factor (EVF) of the PV modules. In addition, the PV system performance simulations used hourly averages, and the shadows vary significantly within that time interval. In order to verify the behavior of the PV system and to better adjust the input parameters for the simulation, I-V curves were measured over a clear day with a time interval of 20 min.

Several I-V curves of the PV system were simulated in Crearray using the effective irradiance on the PV array calculated from measured global and diffuse solar irradiance and measured PV module temperature. Shading fractions in the submodule level were visually determined by inspecting photos taken at the same time that the I-V curve was measured. An albedo of 0.4 was considered to estimate the radiation reflected by the ground and surroundings and 5% of radiation losses due to soiling on the PV modules. The simulated I-V curves were compared with the measured ones.

Initially, uniform diffuse and albedo shading factors calculated by PVSyst were used for all PV modules. However, the measured I-V curve showed visible differences compared to the simulated one. Fig. 3 (a) shows that the measured curve has a higher current and a larger slope in the short circuit region. The measured current of the I-V curve around higher voltages (~300 V) has a slightly lower current than the simulated curve. These results indicate that the shaded modules have a lower EVF since the wall causes shade and also reduces the EVF for the diffuse radiation. Because of this behavior, different EVF were estimated for the modules, considering lower for the modules closer to the wall and increasing as they move away from the wall. The curve was simulated again considering non-uniform EVF. The comparison with the measured curve is in Fig. 3 (b), showing that a non-uniform EVF improves the accuracy of the simulated I-V curve.

The system is partially shaded by the neighboring trees in the morning, as shown in Fig. 4 (a). This type of shadow is difficult to reproduce with models as seen in Fig. 4 (b) because it is irregular and changes fast. Another visible issue in the I-V curve is the effect of the white wall reflection indicated in Fig. 4 (b), where the measured array short circuit current is higher than the simulated one. The variable characteristic of this non-uniform shading and the high radiation reflection in the early morning introduces extra complexity to the modeling.

During the moments without shading, the simulated and measured curves are considerably close, as shown in Fig. 5 (a) and (b). The short-circuit current of the measured curve is greater than that simulated one at 10 am, as indicated in Fig. 5 (a), and also at 9:20 am as indicated in Fig. 4 (b). This effect occurs because part of the solar radiation is being reflected by the white wall (which has an albedo greater than 0.4), increasing the current of the modules closer to the wall. Although this reflection increases the short circuit current, it does not affect the array's maximum power. This reflection effect does not happen at solar noon (12:10 pm), and both curves overlap as shown in Fig. 5 (b).

The wall and PV modules of the neighboring PV system begin to shade the studied PV system at 12:20 pm. Fig. 6 shows the PV system with two shaded submodules and the corresponding I-V curves at 1 pm. From this time on, a voltage difference between the curves is also verified, related to the temperature difference between the shaded modules and those that are not shaded, which was not considered in the simulation. This effect is also reported previously by Mohammed et al. (2020).

From 3 pm, the measured curve has a higher current than the simulated one, as shown in Fig. 7, as a result of the solar radiation that is reflected by the tree leaves located to the east of the PV system and affects the modules that are not shaded. Moreover, the MPP of the curve moves to voltages below 224 V (minimum voltage of the inverter MPPT) between 3 pm and 4 pm as indicated in Fig. 7. Therefore, the PV system

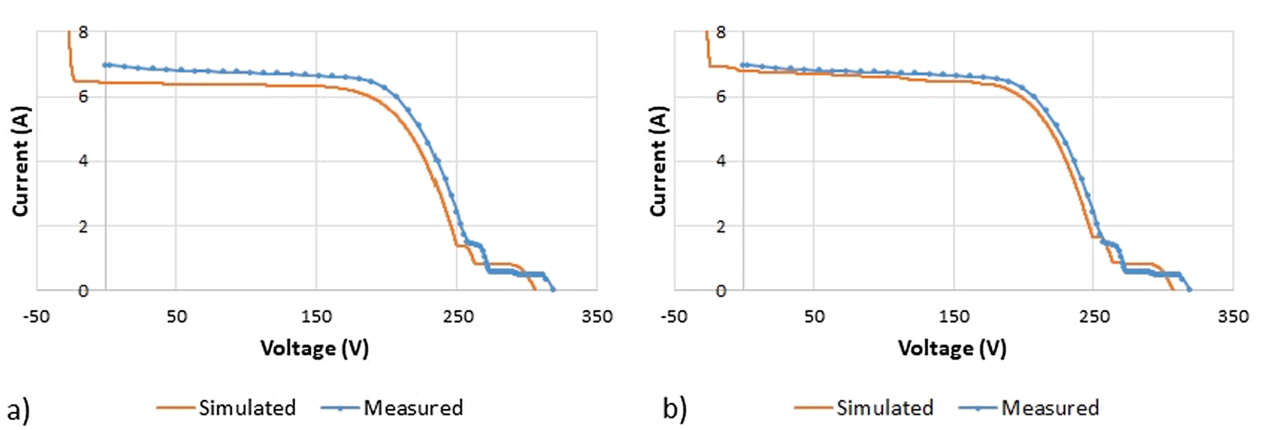

Fig. 3. I-V curves measured and simulated at 2 pm; (a) using uniform diffuse and albedo shading factors; (b) using non-uniform EVF for the PV modules.

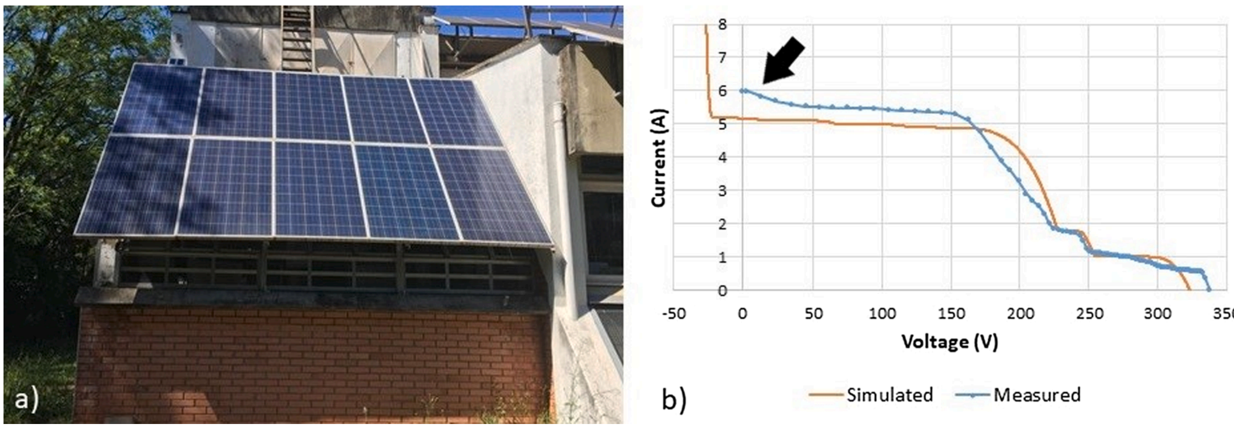

Fig. 4. (a) The PV system at 9:20 am showing irregular shadows; (b) The I-V curves where the white wall reflection effect is indicated.

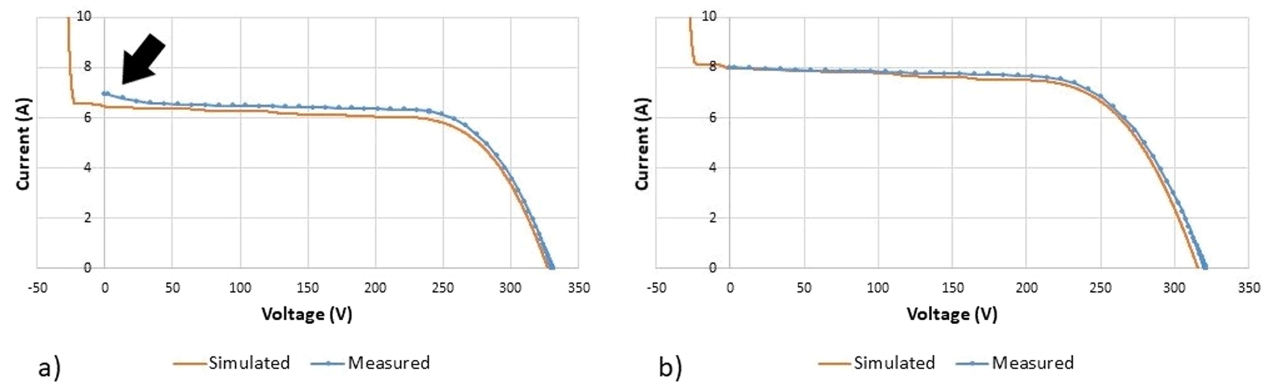

Fig. 5. (a) I-V curves at 10 am with the white wall reflection effect indicated. (b) Overlapping I-V curves at 12:10 pm.

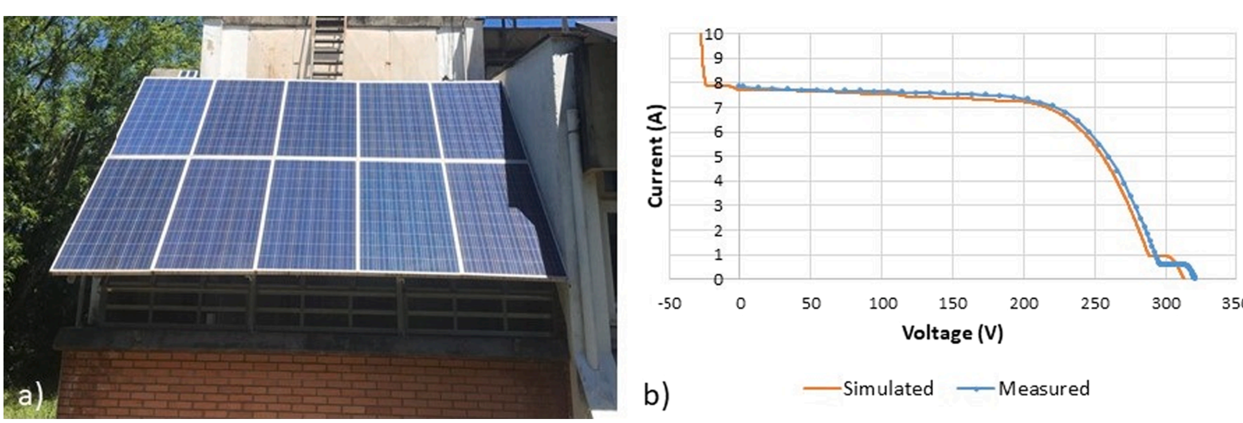

Fig. 6. (a) Partially shaded system photo at 1 pm; (b) corresponding I-V curves at 1 pm.

does not operate at maximum power during these shading periods.

The effect of the reference cell shading in the morning and the leaves reflection in the afternoon can be confirmed in Fig. 8, which compares the hourly average values of the irradiance measured by the reference cell and the effective one calculated from the pyranometers measurements (without shading and soiling effects). The effective irradiance is greater than that of the reference cell in the early morning, between 7 am and 9 am, due to the reference cell being shaded sometimes. The solar irradiance measured by the reference cell and the calculated one is very close from 10 am to 12 pm. The reflection effect of the leaves of the trees begins to occur from 1 pm, when the difference between both radiation values begins to increase.

From this analysis, the reflection caused by the wall in the early morning and by the trees in the afternoon contributes to the measured current being greater than the simulated one. The temperature difference between the PV modules leads to voltage differences between the simulated and measured curves. The use of non-uniform EVF for the PV modules leads to a simulation closer to measurement results. The shadows caused by the trees in the early morning are irregular, making it difficult to reproduce both the shadows and the effect on the I-V curve. Therefore, the non-uniform EVF was employed and the albedo of 0.4 and 5% of soiling loss was set for the simulations in Crearray, since the curves overlapped at times close to the solar noon (without shadow and reflection of the wall and trees).

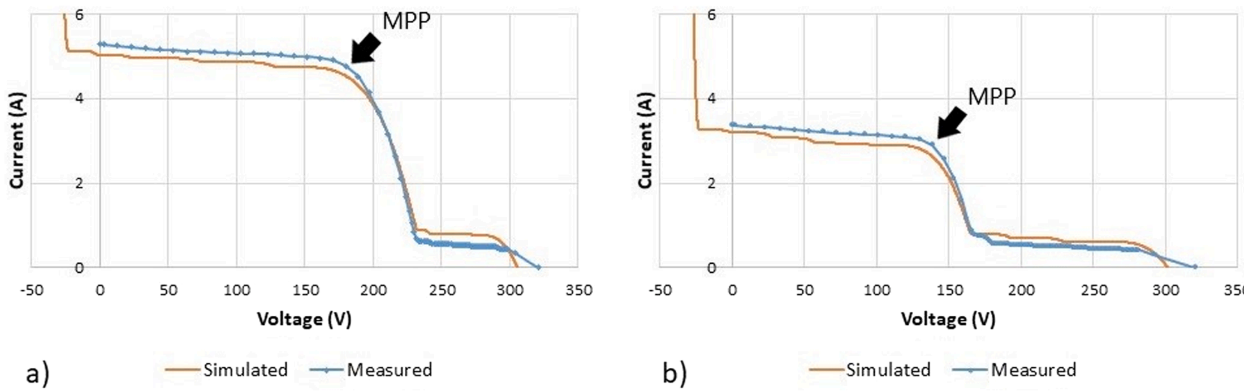

Fig. 7. I-V curves measured and simulated with the MPP indicated (a) at 3 pm; and (b) at 4 pm.

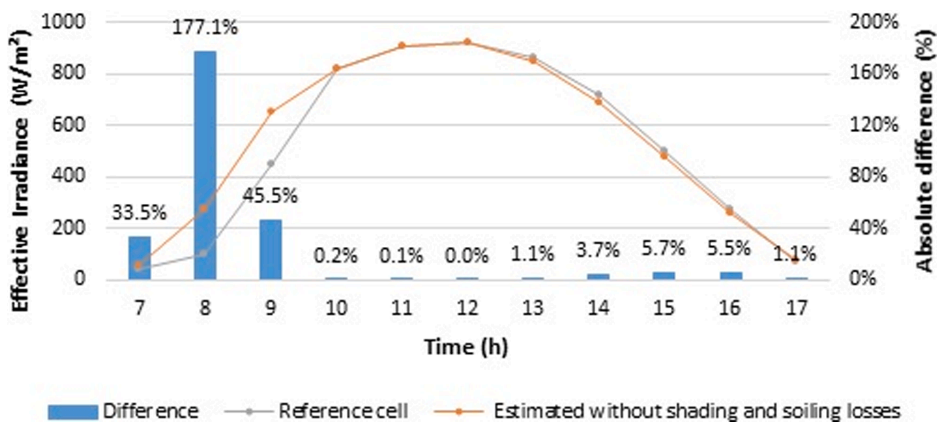

Fig. 8. Solar irradiance measured by the reference cell, the effective solar irradiance calculated from pyranometers measurements without shading and soiling effects and the absolute difference between them.

6. Comparison between simulated and measured values

The data measured between August 27 and October 31, 2020, were compared with the results simulated by Crearray, PVSyst and SAM. In PVSyst, the 3D model generated in SketchUp was imported and the following shading options were considered: detailed, linear (table), linear (simulation) and losses according to string (with fractions of electrical effect set to 60% and 100%). A simplified geometric model was made in SAM, considering the studied PV system, the wall and the trees, with the partial shading option selected. The neighboring PV system was not considered, as SAM has limited set tools for accurate 3D modeling. Another simulation was performed using a shading loss table generated by PVSyst (linear loss) for beam solar radiation considering the sun path over a day. It is expected that the partial shading models of PVSyst (detailed calculation option) and SAM (3D shade calculator) will show results closer to those measured, but all available options were analyzed.

All PV modules used in the system had their I-V curves measured

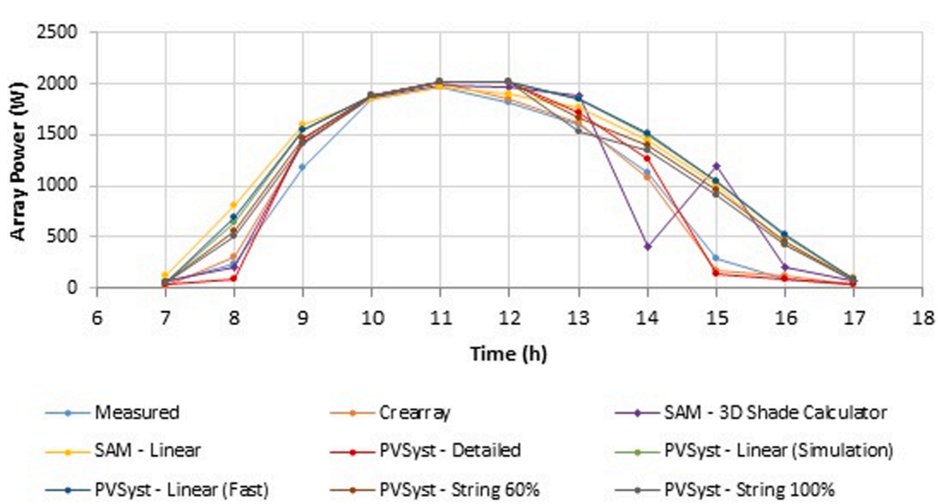

Fig. 9. PV system power (DC) measured and simulated by all tools over a clear day.

with a solar simulator (PASAN, Sunsim 3C), and the mismatch was estimated in the Crearray software. In the simulations, soiling losses of 5%, mismatch losses of 0.7% and ohmic losses of 0.21% were considered. The albedo was considered constant over the period with a value set to 0.4. All analyzes were performed using DC values.

6.1. Comparison of results on a clear day and a cloudy day

Fig. 9 shows the measured and simulated hourly average power over a clear day. On this day, Crearray, PVSyst with detailed model and SAM with 3D model reproduce the effect of tree shadows in the early morning, approaching the measured power, while the other models showed higher average power. In the afternoon, SAM with the geometric model shows a power reduction in the shadow hours but does not coincide with the measured values, while the detailed model of PVSyst and Crearray had results closer to the measured values. The difference showed by SAM with the 3D model is related to the geometric modeling difficulties, where some details were not considered. The other models showed fewer shading effects and greater differences compared to the measured values.

Fig. 10 shows the hourly differences for Crearray, PVSyst (detailed) and SAM (3D shade calculator) in comparison to measured values. The differences between 10 am and 1 pm are lower than the others, times when the system is not shaded (at 10 am and 11 am) or is poorly shaded (at 12 am and 1 pm). The differences vary at other times when there is shading, with both overestimated and underestimated average hourly power. Moreover, the simulated daily energy production is greater than the measured by 5% for PVSyst (detailed) and 10% for SAM (3D shade calculation) for this specific day.

Fig. 11 shows that the shadows predicted by SketchUp and PVSyst are similar to the shadow observed on the PV system. The differences are related to inaccuracies in the 3D representation. However, the software performs hourly calculations, and, as shown in Section 5, shadows vary significantly over an hour. Therefore, although the shadow prediction is close to that visually verified, the use of an hourly shading value may affect the results. The power estimated by Crearray, SAM (3D shade calculator) and PVSyst (detailed) are lower than the measured at some times and higher at other times under shading conditions.

Fig. 12 shows the measured and simulated hourly average power over a cloudy day. Crearray results are considerably close to those measured since it was employed a non-uniform EVF. The EVF varies significantly according to the PV module position in the PV system for this case study. SAM and PVSyst use average values for shading losses in diffuse radiation and albedo. The difference is more significant on cloudy days since they have a greater fraction of diffuse solar radiation. This effect was evident with the influence of the EVF in the analysis of the curves performed in Section 5 and with the similarity between the results obtained by Crearray and those measured. Throughout the day, the electricity simulated by PVSyst (detailed) and SAM (3D shade calculator) was about 7% and 35% higher than the measure one, respectively. All PVSyst models had the same results and the plots overlapped.

6.2. Analysis of the results over the entire measurement period

Fig. 13 shows the difference between the simulated and measured results for 11 am (non-shaded PV system) every day as a function of effective solar irradiance on PV modules. It is verified that the greater the irradiance, the lower the differences calculated for all software. The differences are larger and vary more when the solar irradiance is less than 500 W/m^2. Except for cases of low irradiance (<200 W/m^2), PVSyst and SAM tend to estimate greater production than the measured in situations without shading. However, the hourly differences were less than 10% for solar irradiance above 700 W/m^2 (clear days). Unlike the results of PVSyst, the simulated results in SAM vary with the chosen shading model, the difference that can be related to the surrounding elements not considered in the 3D model.

Table. 1 shows the DC electric energy (kWh) produced over the entire period, which shows that the electricity generated was less than that simulated by all software. Crearray results have the least difference between simulated and measured outputs, as it was used as a comparison standard and to adjust the input parameters. The detailed model of PVSyst had the lowest difference (9%) compared to the other models of PVSyst and SAM. The SAM partial shading calculation had a significant difference between simulated and measured values of 20%, a value close to the difference obtained with the linear loss option. This result for SAM can be associated with the limitations of the 3D modeling.

PVSyst and SAM have different options to perform the simulations that lead to significant differences in the results obtained, reaching a difference of up to 15% between the linear and detailed shading models in PVSyst. These significant differences show that an inappropriate choice of the model by the user can lead to results that are far from those obtained experimentally.

The clear days produced the largest part of the accumulated energy. Among 62 measurement days, 22 were cloudy days (irradiance does not exceed 400 W / m^2 over the day) that produced about 10% of the energy accumulated during the entire measurement period. Table. 2 shows the impact of the difference between the simulated ($E_{S,\ Clear\ day}$) and measured ($E_{M,\ Clear\ day}$) accumulated energy on clear days on the total energy accumulated over the entire measurement period ($E_{M,\ total}$), calculated according to Eq. (7).

$$Difference\ in\ weight = \frac{(E_{S,Clear\ \ day} - E_{M,Clear\ \ day})}{E_{M,total}} \times 100\% \tag{7}$$

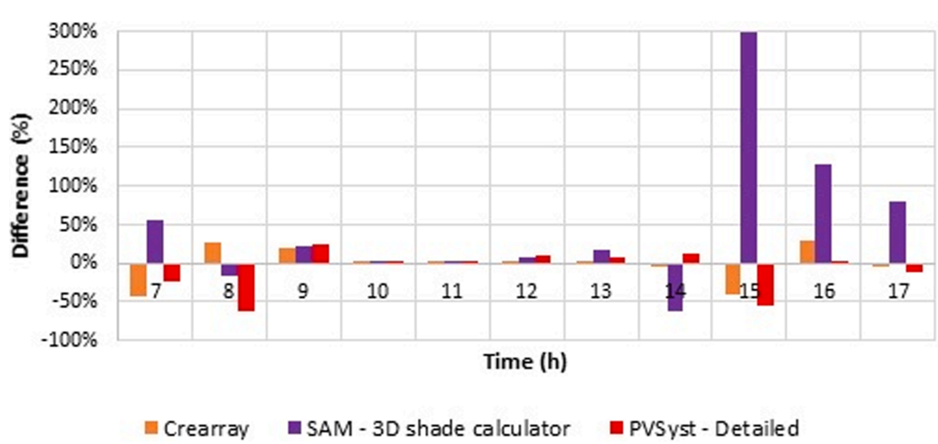

Fig. 10. Differences between simulated and measured hourly average power over a clear day.

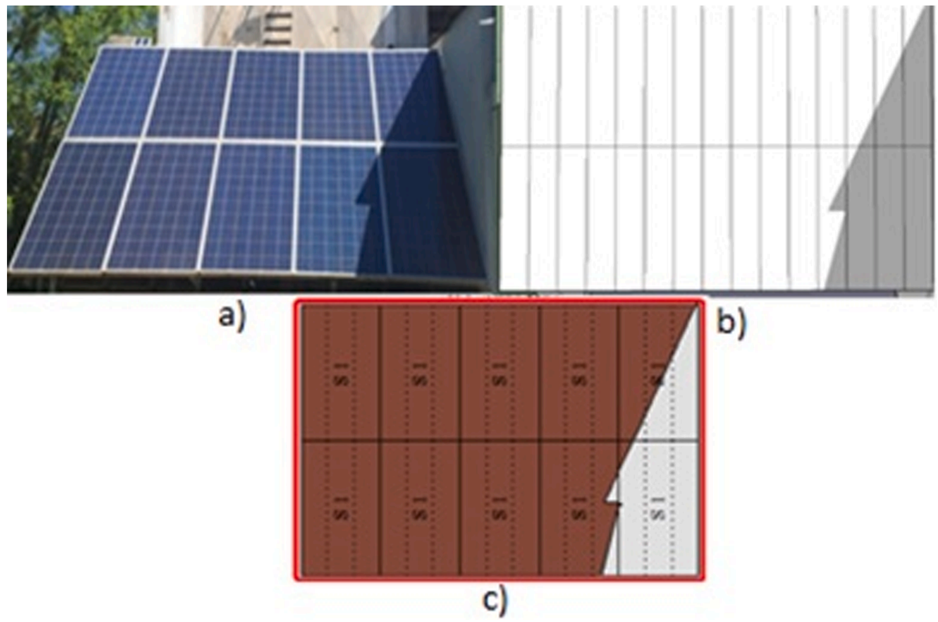

Fig. 11. Comparison between shadow patterns for October 19 at 2:46 pm. (a) system photo; (b) prediction by SketchUp where the lines represent submodules; (c) prediction by PVSyst showing module and submodule divisions.

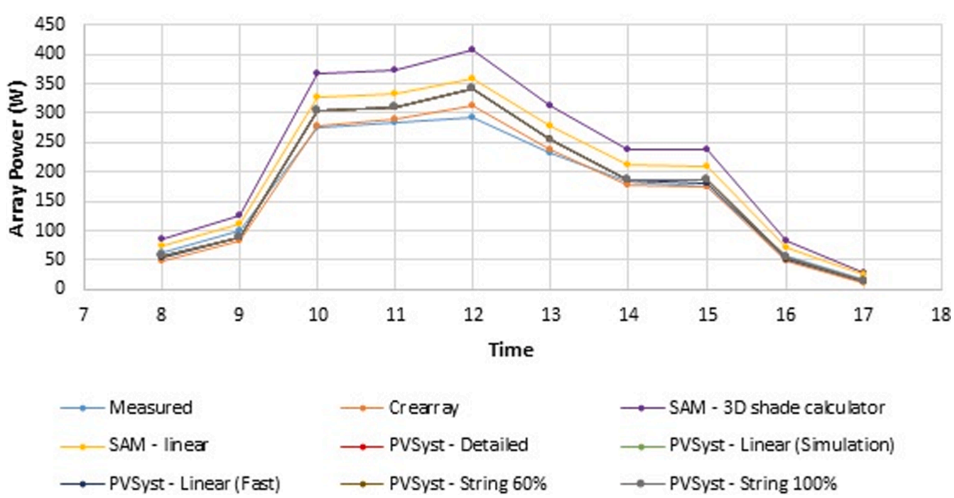

Fig. 12. Simulated and measured PV system power (DC) by all tools over a cloudy day.

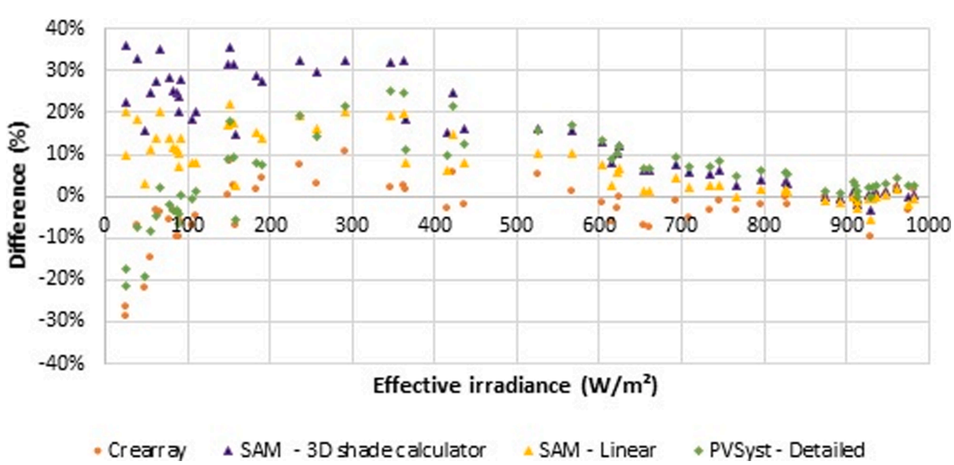

Fig. 13. Difference between simulated and measured results as a function of solar irradiance at 11 am of every measured day.

Table 1
Simulated and measured electricity generated (DC) throughout the entire measurement period.

	Energy (kWh)	Difference (kWh)	Difference %
Measured	309.5	–	–
Crearray	313.7	4.2	1%
SAM - 3D shade calculator	371.3	61.8	20%
SAM - Linear	379.5	70.0	23%
PVSyst - Detailed	338.4	28.9	9%
PVSyst - Linear (Slow)	384.4	74.8	24%
PVSyst - Linear (Fast)	384.1	74.6	24%
PVSyst - String 60%	371.7	62.2	20%
PVSyst - String 100%	363.2	53.7	17%

Table 2
Ratio of the difference between simulated and measured energy for clear days by the energy measured over the entire measurement period.

Model	Simulated energy (kWh)	Difference from the measured value (kWh)	Difference in weight (%)
Crearray	282.6	4.7	2%
SAM - 3D shade calculator	329.3	51.4	17%
SAM - Linear	341.8	63.9	21%
PVSyst - Detailed	305.4	27.5	9%
PVSyst - Linear (Slow)	350.2	72.3	23%
PVSyst - Linear (Fast)	350.1	72.2	23%
PVSyst - String 60%	337.6	59.8	19%
PVSyst - String 100%	329.3	51.4	17%

Table 3 shows these values for cloudy days, showing the impact of the measured ($E_{M,\ Cloudy}$) accumulated energy and the simulated ($E_{S,\ Cloudy}$) one for cloudy days on the total accumulated energy, calculated according to Eq. (8). These values show that the differences between simulated and measured values for cloudy days have a lower effect on accumulated energy, although the daily differences are greater than those obtained for clear days. The lower influence of cloudy days is related to less solar irradiance and less production on these days.

$$Difference\ \ in\ \ weight = \frac{\left(E_{S,Cloudy\ \ day} - E_{M,Cloudy\ \ day}\right)}{E_{M,total}} \times 100\% \tag{8}$$

Table 3
Ratio of the difference between simulated and measured energy for cloudy days by the energy measured over the entire measurement period.

Model	Simulated energy (kWh)	Difference from the measured value (kWh)	Difference in weight (%)
Crearray	31.1	−0.5	0%
SAM - 3D shade calculator	42.0	10.4	3%
SAM - Linear	37.7	6.0	2%
PVSyst - Detailed	33.0	1.4	0%
PVSyst - Linear (Slow)	34.2	2.6	1%
PVSyst - Linear (Fast)	34.1	2.4	1%
PVSyst - String 60%	34.1	2.4	1%
PVSyst - String 100%	34.0	2.3	1%

6.3. *Effect of the surrounding elements on the 3D representation*

Considering that the detailed geometric representation with all the surrounding elements is a wearing step, some simulations were made using a more simplified geometric representation. Considering only two trees that shade the system in the morning (the other trees that influence the EVF were not considered), the differences between the simulated and measured accumulated energy were around 22% (for the detailed model) and 35% (linear model) in the PVSyst and around 24% (partial shading) and 32% (linear) in SAM for the entire period considered. In addition, differences would vary between 26% and 37% in PVSyst and between 28% and 33% in SAM if no trees were considered in the 3D model. Therefore, the fewer elements of the surroundings are considered, the greater the difference between the forecasted and measured energy.

Fig. 14 shows the simulated power over a cloudy day considering the detailed model (PVSyst) and partial shading (SAM) for the three surrounding scenarios. It is confirmed that the more detailed the 3D representation is, the closer to accurate the simulations will be, and the elements that do not cause a shadow, but obstruct the horizon, can significantly affect the results.

7. Conclusions

This article analyzed the accuracy and the differences between measured and forecasted power when modeling partially shaded PV systems. Measured DC power was compared to simulations performed using the Crearray, SAM and PVSyst software. Crearray was used to better adjust the input parameters of the simulation to match the measured results. Although the differences between simulated and measured values obtained by the detailed calculation option of PVSyst and the partial shading option of SAM (with 3D representation) were expected to be the smallest, the other options were simulated to analyze the differences for all options available to the user.

Over a clear day, the simulated power was overestimated and underestimated in shading situations, which can be related to the use of hourly shading fractions. The accuracy of the shadow prediction in SketchUp and PVSyst was confirmed. In uniform irradiance conditions, the tools tend to overestimate the power of the PV system.

When performing an analysis of a cloudy day, the surrounding elements that do not cause shadow significantly influence the diffuse solar radiation, since they reduce the effective view factor. The more elements that were considered in the 3D model, the closer to the experimental results was the simulation. Both software use average and uniform shading factors for diffuse radiation (from sky and albedo), which was verified as a possible source of differences between simulated and measured energy values, mainly in cloudy days.

In terms of electricity produced in the entire measurement period, the results obtained by PVSyst with the detailed calculation differ 9% from measured values, which was the smallest difference, as expected. The other options available in PVSyst showed differences of around 20%. The difficulty found in SAM is related to the limited drawing tools, influencing the accuracy of the 3D model, which led to errors in predicting shadows. Although there is an option to import a shading table from PVSyst, this one also showed significant differences. Both the partial shading model and the linear model in SAM had differences of around 20%.

Therefore, partially shaded PV systems should be simulated carefully, and the results can substantially differ from the measured values. In addition, the different options for shading losses calculation lead to significant differences in results, and a wrong choice of the calculation option can lead to results that are far from those obtained experimentally. The differences can also affect the decision of the viability of a given PV system.

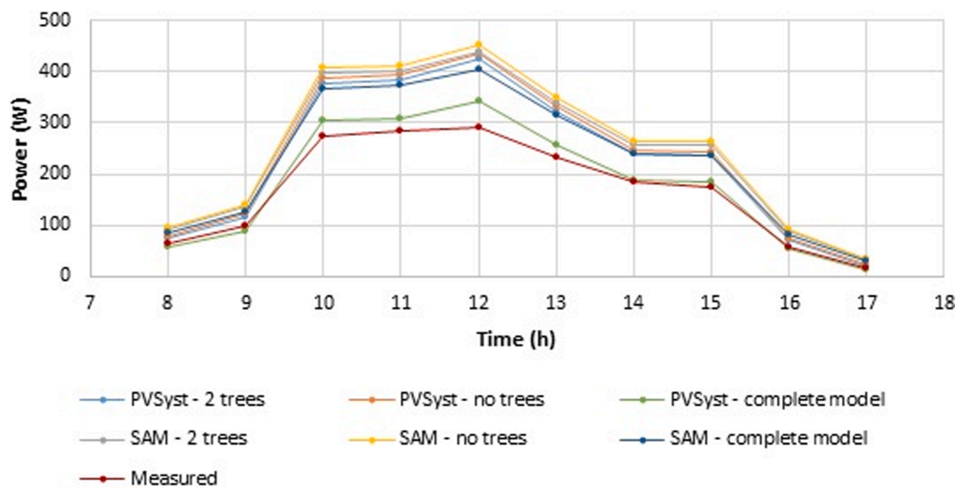

Fig. 14. Simulated power (DC) over a cloudy day for different elements of surroundings.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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