Lessons learned from simulating the energy yield of an agrivoltaic project with vertical bifacial photovoltaic modules in France

Conference Paper · September 2021

Lessons learned from simulating the energy yield of an agrivoltaic project with vertical bifacial photovoltaic modules in France

Jesús Robledo[1,*], Jonathan Leloux[1], Babacar Sarr[1], Christian A. Gueymard[1,2], Anton Driesse[3], Pierre-François Drouin[4], Sébastien Ortega[5], Damien André[5]
[1] LuciSun, Rue Saint-Jean, 29, 1495 Sart-Dames-Avelines, Belgium
[2] Solar Consulting Services, P.O. Box 392, Colebrook, NH 03576, USA
[3] PV Performance Labs, Emmy-Noether-Str. 2, 79110 Freiburg, Germany
[4] Syneria, 5 Rue Taitbout, 75009 Paris, France
[5] Amarenco, Château de Touny Les Roses, Chemin de Touny, 81150 Lagrave, France
*Phone: +34 656 37 59 74; E-mail: jesus.robledo@lucisun.com

ABSTRACT: Agrivoltaics is a novel application of solar (PV) photovoltaic power generation where the PV modules are installed in the same field as where crops are also cultivated. This is advantageous because this combines land use while keeping attractive productions for both agricultural crops and power generation. Several configurations currently exist for these agrivoltaic installations, including rooftop PV generators, ground-mounted agrivoltaic plants, and PV installations on greenhouses. One particularly innovative kind of agrivoltaic application uses rows of vertical bifacial PV modules. In recent years, bifacial technology has experienced a swift increase in its share of the PV market, which opens the door to performance improvements and even new kinds of solutions. However, in the current state-of-the-art PV simulation tools, the added complexity introduced by bifacial technology is still not fully covered. This is even more true for agrivoltaic PV plants with vertical bifacial modules. Here, we present a summary of our most relevant findings while assessing the energy yield of an agrivoltaics plant planned with vertical bifacial PV modules in the south of France. The evaluation of the bifacial energy gain (BEG) has been carried out with a novel simulation tool based on the use of the latest 3D evaluation libraries incorporated into the Graphic Processor Units (GPU) of modern computers. These were developed for the video game industry, and they offer many interesting advantages for such bifacial PV applications. We also discuss the main challenges that still lie ahead in the path to a better design optimization and assessment of the energy yield of such vertical PV installations.
Keywords: Bifacial, Agrivoltaics, PV, simulation, BEG, GPU, photovoltaic plants

1 INTRODUCTION

Agrivoltaics is a novel application of solar photovoltaic (PV) power generation where the PV modules are installed in the same field as where crops are also cultivated. This is advantageous because this arrangement combines land use while keeping attractive productions for both agricultural crops and power generation. Several configurations currently exist for such agrivoltaic installations, including rooftop PV generators, ground-mounted agrivoltaic plants, and PV installations on greenhouses. One particularly innovative kind of agrivoltaic application uses rows of vertical bifacial PV modules. In recent years, bifacial technology has experienced a swift increase in its share of the PV market, which opens the door to performance improvements, and even to new kinds of solutions. However, in the current state-of-the-art PV simulation tools, the added complexity introduced by bifacial technology and intricate geometries is still not fully covered. This is even more true for agrivoltaic PV plants with vertical bifacial modules. Some particularities of this specific case are:

The notion of "front and rear" side of the modules is not so straightforward because the total irradiation received on both sides can be similar in various situations, such as an east/west orientation. This means that (i) the bifacial contribution cannot be seen as a simple "gain" over the main front contribution but as a comparable one, and that (ii) the sensitivity of the whole energy yield evaluation to the bifacial energy gain (BEG) may be large.

Traditionally, the geometry of agrivoltaic installations introduces complex shading effects (both for direct sunlight and for the sky and ground-reflected diffuse components), thus requiring a detailed 3D shading analysis. In that context, the total diffuse irradiance (emanating from the sky and from ground reflections) becomes a key variable. This implies that the directional reflection properties of the ground are important. Hence, a Bidirectional Reflectance Distribution Function (BRDF) should be considered instead of an ideal Lambertian response. Moreover, seasonal variations in ground albedo (caused by vegetation cycles) can be noticeable, and thus need to be accounted for.

This study presents the lessons learned from an innovative agrivoltaic project located in France with vertical bifacial modules.

The evaluation of the bifacial energy gain (BEG) has been carried out with a novel simulation tool based on the use of the latest 3D evaluation libraries incorporated into the Graphic Processor Units (GPU) of modern computers. These were developed for the video game industry, and they offer many interesting advantages for such bifacial PV applications.

2 PV INSTALLATION LOCATION AND LAYOUT

The project under scrutiny here is located in the Occitany Region (southern France), in a rural area where the land is mainly dedicated to agriculture. A PV plant was projected on a parcel (shown in Figure 1). The promoter of this project planned to install a PV plant whose nameplate peak power was slightly below 4 MW_p.

Figure 1: Satellite view of the site selected for the agrivoltaic PV plant project.

The promoter chose to use vertically mounted bifacial PV modules to keep a mixed use of the land between agriculture and photovoltaic energy generation. To facilitate mechanized agriculture, the vertical structures were projected to be installed in rows that only deviate from the north-south direction by ≈26º, following the natural orientation of the main edge of the field. As a consequence, the PV modules were oriented so that one face deviates 64º from due south towards the east, while the other face deviates 116º from due south towards the west. The PV modules have a bifaciality ratio of 70%, which is currently very common. To maximize the energy yield of this PV plant, the front (or main) side of the PV modules were installed towards the eastern direction, which receives more solar irradiation over the year, and the other side was installed towards the western orientation. The design of the mounting system is such that the ground clearance, the minimum distance between the PV modules and the ground, is exactly 1 m. This makes it possible to grow crops close to the PV modules while minimizing the impact on the crops of any potential shading caused by the installation Two rows of PV modules in landscape mode are installed on these structures. The width of the modules is of approximately 1 m. Therefore, the total height of the structure is ≈3 m. This is a good compromise between installation costs, mechanical stress induced with the wind, shelter from the wind offered to the cultures, and visual impact on the landscape. A pitch separation distance of 15 m was chosen between the rows of PV modules because it corresponds to a good tradeoff between installed PV area density and energy losses caused by shading. Figure 2 shows a 3D representation of the resulting PV plant layout that was proposed as the result of the optimization exercises.

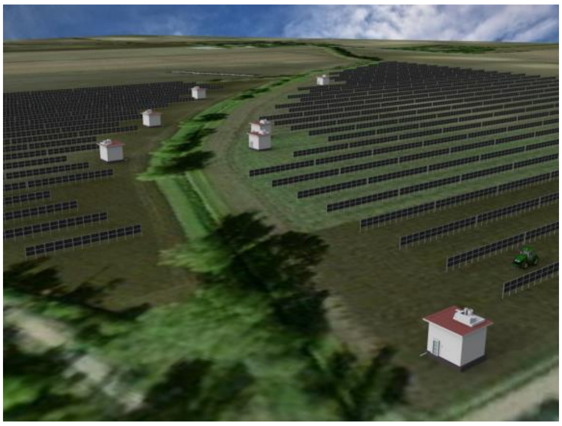

Figure 2: 3D representation of the PV plant layout.

3 SOLAR RESOURCE AND WEATHER DATA

Several sources of solar irradiation and weather data have been consulted to assess the long-term solar resource available on the site described above. As a result of the comparison between different solar irradiation databases, an hourly TMY Global Horizontal Irradiation (GHI) time series was generated by combining 4 different sources of data (CMSAF [1], SARAH [2], Meteonorm [3] and Solargis Prospect [4]) and was eventually used to simulate the energy yield of the PV plant. The specific method used for the combination of these data sources is out of the scope of this work, but it respects relatively common practice, and in any case the exact method followed has little influence on the rest of the considerations that are presented in this article. A long-term annual value of GHI of 1,423 kWh/m^2 was retained for this project.

Several particularities arise in the case of vertically mounted bifacial PV modules when assessing the Global Tilted Irradiation (GTI) on both faces of the modules. The first critical aspect is the choice of the transposition model that has to be used to evaluate GTI on a vertical surface from the knowledge of GHI. Among other considerations, the selection of the most appropriate transposition model is of critical importance. The well-known Perez model is frequently used for typical ground-mounted PV plants, facing the equator with a low fixed tilt or with trackers. Several other models are also used by solar engineers and PV simulation software developers for such installations, with similar uncertainty levels. For vertical surfaces, however, the uncertainty associated with the transposition is generally higher, and the Perez model might not be the most suitable choice [5]. Other "anisotropic" models, such as the Hay model [6], might actually be more suited to the case of vertical surfaces [7]. One reason why the predictions of transposition models differ significantly more for vertical surfaces than for low-tilt surfaces is that, in the former case, the diffuse radiation reflected by the foreground amounts to a significant fraction (if not a preponderant fraction) of the total (sky + reflected) diffuse radiation incident on the surface. So far, transposition models have not attempted to evaluate the diffuse reflected irradiance in sufficient detail, with some exceptions, e.g. [8]. This discussion indicates that, for agrivoltaic installations (and more generally for all projects involving vertical PV modules), there is certainly room for improvement in the calculation of GTI and the overall assessment of the irradiation incident on vertical surfaces. The present study uses the Hay model for its modeling simplicity and efficiency, and because of its recognized performance in a wide variety of situations [9].

Another important challenge arises from the necessity of accurately determining the reflected component of GTI on both sides of the PV modules. As mentioned above, this contribution is very significant for vertical surfaces in general, particularly for non-equatorial orientations. This is discussed further in Section 5.

4 ALBEDO ASSESSMENT

Several methods exist to assess the albedo of the ground. For this kind of project in a rural area, several key questions arise. First, for most PV projects, reliable on-site measurements of the ground albedo are not available, for reasons of costs, manpower, available time, etc. Second, the nature of the ground under the PV plants might change after completion of the project, and even during the lifetime of the project. In the case of a vertical PV installation mixed with agriculture, the crops that are cultivated between the rows of PV modules typically changes every year, hence the albedo also changes. Moreover, the state of vegetation changes seasonally, also inducing significant albedo variations. Because of all these difficulties, some general assumptions need to be made, and the higher associated uncertainty needs to be fully acknowledged when estimating the energy yield.

For this project, the assessment of the ground albedo was carried out with the help of three widely different databases: MERRA2 [10] and GLDAS [11] (both based on reanalysis models) and Solargis Prospect [4] (based on MODIS [12] satellite observations). Their precision is however limited, in particular by the nature of their processing, as well as by their spatial resolution. The spatial resolution of MERRA2 is 0.5º x 0.625º, and that of GLDAS is 0.25º x 0.25º. Solargis offers a much better spatial resolution of 1 km x 1 km. Fortunately, it is often the case in rural regions dedicated to agriculture that the overall albedo is relatively homogeneous over large areas. Figure 3 shows a satellite view of an area of approximately 20 km x 20 km surrounding the PV project, where a typical vegetation color, varying from green to yellow, is visible. The albedo is not homogeneous on one pixel of the satellite data, but it is nevertheless relatively representative of the cultures.

Figure 3: Satellite view of the overall area of the PV project.

At the time of the study, monthly values were available from MERRA2 and GLDAS, and an average annual value was available from Solargis Prospect. It is generally accepted that MERRA2 data is of better quality, but of lower spatial resolution, than GLDAS, and that the satellite-based data from Solargis are of the highest quality. It is fortunate that, for the case of this project, the three databases provide very similar results. Figure 4 shows a comparison of the monthly albedo data from MERRA2 and GLDAS. The annual average albedo is ≈17%, with very slight seasonal variations of only ≈1%. The albedo is slightly higher in summer, which in rural areas is usually caused by the change in color of the vegetation from dark green (or dark, wet bare soil) to lighter tones. The opposite could obviously be true in cold areas impacted by snow in winter [13].

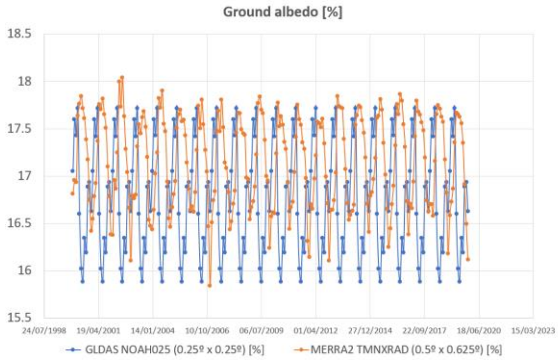

Figure 4: Monthly-average albedo during the 20 last years, from MERRA2 and GLDAS.

A detailed analysis of the most reliable albedo data obtained for homogenous parcels shows that the albedo of green grass is typically ≈14%, and that of most crops encountered in the region of southern France under scrutiny is in the range 10–25%. The albedo of the vegetation is also highly spectrally selective, mainly due to photosynthesis in plants. This translates into a very low albedo (≈0.05) in the visible and a high albedo (≈0.8) in the near infrared. This can impact the calculation of spectral effects and their impacts on PV performance, but this development is beyond the scope of this study.

In addition to spectral variations, the albedo of bare soil and vegetation has an anisotropic angular distribution. The reflectance pattern of each reflective material can be conveniently modeled by a bidirectional reflectance distribution function (BRDF). These BRDF functions are particularly important to consider for light-reflecting materials whose albedo deviates significantly from Lambertian behavior, and whose spectral reflectance is very selective, as is the case with vegetation in general.

Taking all these considerations into account led to choosing a somewhat conservative albedo value of 14%, constant over the whole year and associated with an anisotropic angular distribution represented by the BRDF of a typical green grass [14]. The BRDF used here is represented in Figure 5.

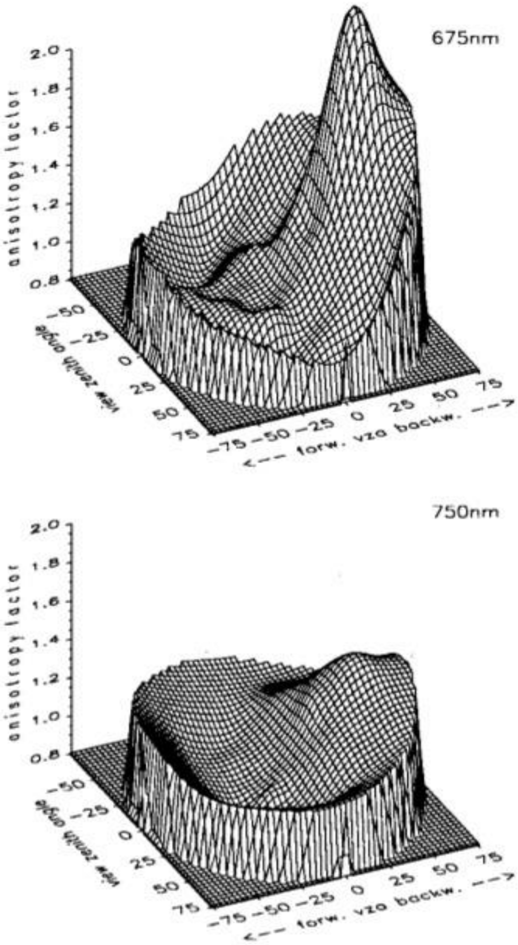

Figure 5: Directional (BRDF) of a typical green grass and its effects on the incident irradiance.

5 IRRADIANCE REFLECTION AND BIFACIAL IRRADIANCE GAIN

The evaluation of the bifacial energy gain (BEG) has been carried out with a novel simulation tool based on the use of the latest 3D evaluation libraries incorporated into the Graphic Processor Units (GPU) of modern computers. These were developed for the video game industry. The achievable spatial resolution is similar to what is possible with backward ray-tracing techniques, but only necessitates a tiny fraction of the latter's required simulation time. The method behind the use of GPUs for solar energy application has been described elsewhere, e.g., for the evaluation of complex shading problems [15] and for the evaluation of bifacial irradiance [16]. Overall, the novel approach proposed here provides a detailed and accurate simulation of the energy yield of agrivoltaic PV plants for small or large commercial projects.

In the present case, the irradiance profiles have been evaluated with high spatial resolution (i.e., at the PV cell level), and with a relatively high temporal resolution of 10 minutes. With this GPU-based approach, the simulations generate a hemispherical view of the front and back sides of each PV module, thus allowing a comprehensive representation of the environment. Figure 1 illustrates the use of this method for the evaluation of the irradiance incident on a part of the PV plant. The GPU-generated image is divided into key areas: the directly-lit part, the background sky, and the shaded areas. The contributions of the different areas are evaluated by transforming each field of view into a specific view factor. These view factors are then weighted by the amount of solar irradiance received from each component of the solar irradiance (diffuse irradiance received from the sky, reflected diffuse irradiance, and reflected direct irradiance). The total reflected irradiance incident on each PV element is simply obtained as the sum of these three components. The process is divided into five main steps.

The first step is to apply a mesh over the terrain, as illustrated in Figure 6.

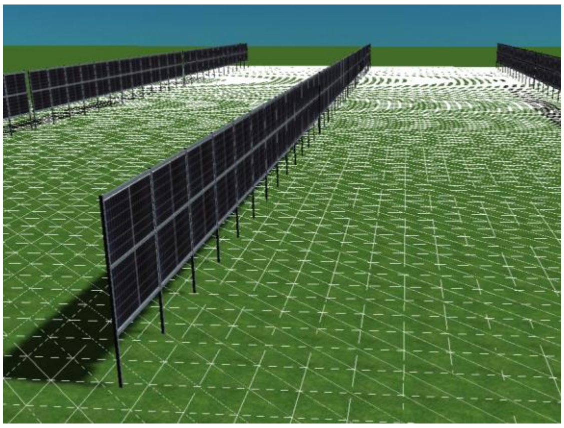

Figure 6: Definition of a geometric mesh over the terrain.

The second step is to evaluate, for each on the terrain's nodes, the visibility of the sky (sky view factor, between 0 and 1) to define the potential diffuse irradiance that could be reflected. This is illustrated in Figure 7.

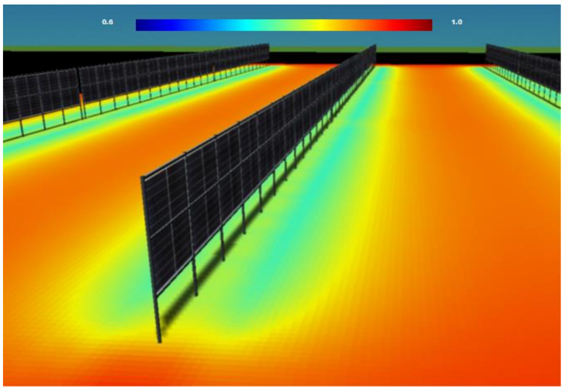

Figure 7: View factor of the ground to the sky.

The third step is, from different points on the PV modules, to generate the spherical view of what is seen from it; then split the areas on the different view factors that will be applied to the irradiance components (direct, isotropic diffuse, and circumsolar diffuse; the separation of the sky diffuse irradiance into the latter two components is generated by the Hay transposition model) [9]. Some results from this step are shown in Figure 8.

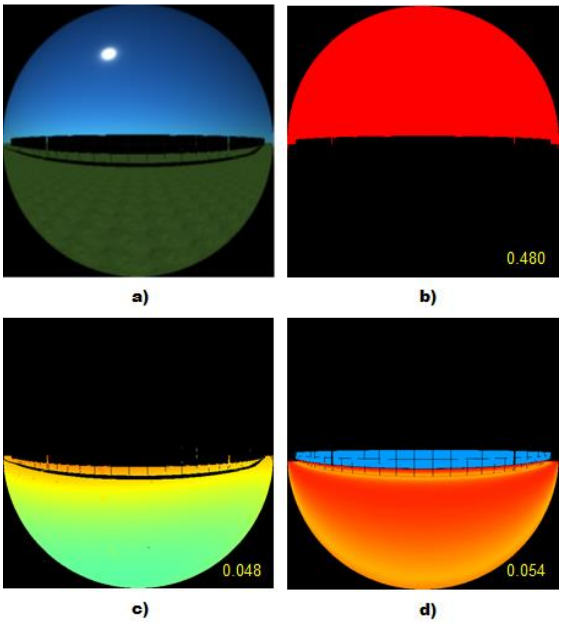

Figure 8: (a) Realistic view of the sky from one point of view on the PV array, (b) Raw sky view factor, (c) Field of view multiplied by the directional reflectance for the direct component, (d) Field of view multiplied by the effective albedo for the isotropic diffuse component.

The fourth step is, as described in [17], to multiply each view factor by the corresponding irradiance component [see Figure 8, (b) and (d) by DFIiso and (c) by (DNI + DFI_{circ}) cosθ to obtain the breakdown of each contribution.

The fifth step is to represent the result for the different points over the full PV modules to create a detailed spatial map of the magnitude of the different irradiance components.

The irradiance incident on the PV arrays can be visualized with heatmaps. They are useful to rapidly compare the effective components as a fraction of their original (unaltered) value. In summary, the value that is thus obtained quantifies the relative contribution of the incident irradiance component relative to the total irradiance.

As an illustration of this procedure, Figure 9 shows an example of heatmap quantifying the magnitude of the isotropic diffuse irradiance that is directly incident from the sky, as calculated for one specific moment. The normalized values vary here between 0.43 and 0.50. This represents the fraction of the sky that is visible by any point of the PV array. The highest values (≈0.50) occur at the top of the PV array, representing half of the whole isotropic irradiance from the sky. This also corresponds to the maximum potentially visible fraction of the sky that is visible by a vertical structure. As could be expected, this value decreases when the point of observation gets closer to the ground, because of mutual shading between the rows of PV modules (one row hides parts of the sky from the surrounding PV modules).

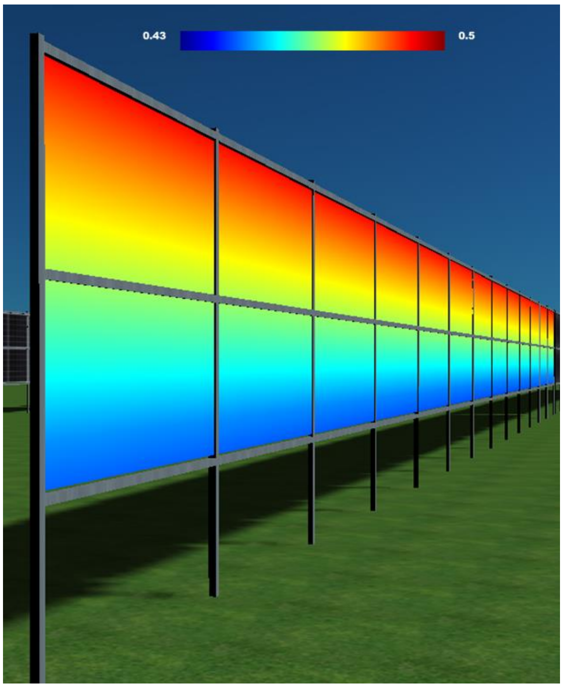

Figure 9: Fraction of the sky that is seen by each point on the PV array, indicating the fraction of diffuse isotropic irradiance that is incident on the vertical surface.

Figure 10 represents the contribution of the reflected isotropic diffuse irradiance as a fraction of the total isotropic diffuse incident irradiance. This ratio provides an estimate of the irradiance gain created by ground reflections for that specific component. The vertical gradient of this irradiance profile follows an opposite pattern than was shown in Figure 9 because more irradiance is reflected to the points that are closer to the ground. However, the variation of this contributir is not so high (between 0.052 and 0.056) and is consequently quite uniform.

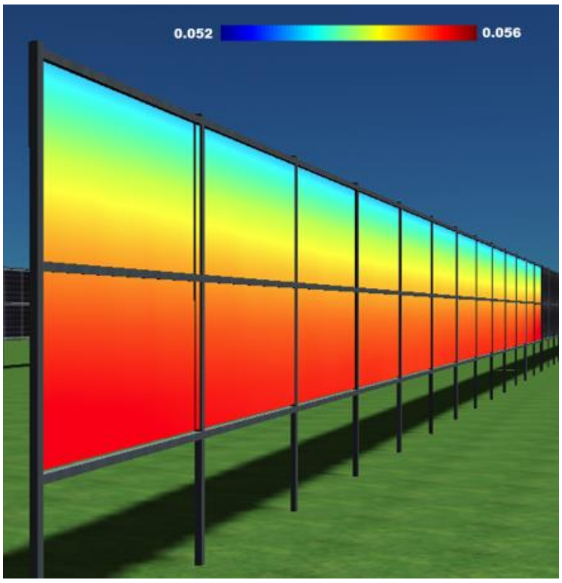

Figure 10: Contribution of the reflected isotropic diffuse irradiance to the total isotropic diffuse incident irradiance.

Figure 11 represents the contribution of the reflected direct irradiance to the total direct irradiance. The picture on the left shows the irradiance map for the side of the module that is away from sunlight at that moment, while the sun shines on the other side. For the sun-facing side, the vertical irradiance gradient indicates an increase from top to bottom, because more light is reflected to the area that is closer to the ground. For the opposite side, the lowest solar cells of the PV array receive less reflected irradiance because the shaded area on the ground occupies a greater part of their field of view. Additionally, this component is the one mainly impacted by the directionality of the BRDF function for the reflectance.

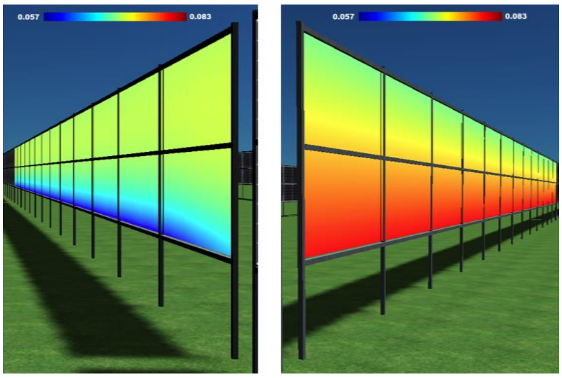

Figure 11: Contribution of the reflected direct irradiance to the total incident direct irradiance. Left: side of the module that does not receive sunlight; right: sun-facing side.

These irradiance heatmaps illustrate the relatively high degree of spatial inhomogeneity of the solar irradiance incident on the PV modules. This is an important specificity of bifacial PV module—particularly if installed vertically. This inhomeneity changes dynamically over the day becuase of the varying solar geometry and BRDF angular effects. Since spatial irradiance inhomogeneities induce mismatch losses in practice (see Section 6), all these intricate effects needs to be described in detail and taken into account in PV yield simulations, as explained in Section 6.

Figure 12 shows the resulting estimated incident irradiance for a typical clear day. The irradiance reaches higher values in the morning on the front side of this specific PV module because it is oriented towards the east (64º from south).

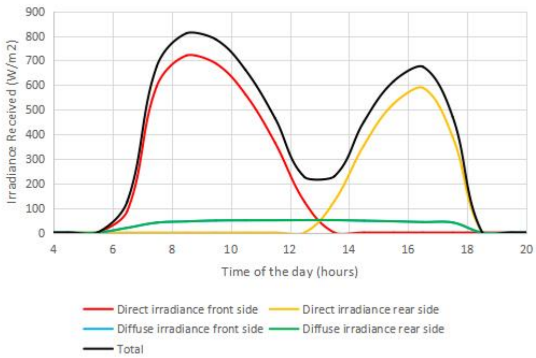

Figure 12: Estimated irradiance and its components for a typical clear day.

Finally, Figure 13 shows the corresponding estimated effective irradiance of the module, defined as the previous irradiances per side as shown in the figure 12, but with the bifaciality factor (70% for this example) applied on the rear side, as the modules are less efficient on that side.

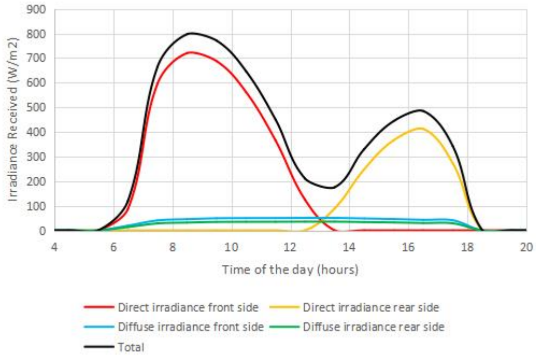

Figure 13: Direct and diffuse irradiance (from the sky and ground reflections) incident on the front and rear sides of a vertical module during a clear day and considering the bifaciality factor of the module.

6 FROM IRRADIANCE TO ENERGY

Once the incident irradiance profile has been obtained for each PV cell composing the PV plant, and for each 10-min time interval of the year, the irradiance is converted into PV power using a PV simulation model that accounts for the PV conversion losses in the whole system. For most of these energy losses, standard simulation routines can be used, because several of them are available and widely used (PVlib [17], PVsyst [18], SISIFO [19], [20], SAM [21]). The differences between these alternative models are beyond the scope of this study and are not relevant toits central topic.

Among the energy losses that need particular attention, the additional mismatch losses that are caused by the spatially inhomogeneous irradiance distribution on the PV modules need to be cautiously addressed. Several possibilities exist to simulate the impact of uneven irradiance distributions on the electrical mismatch losses. The most accurate method is to generate I-V curves for the whole PV system, considering the mapping of the irradiance down to cell level. This, however, is a very demanding exercise in terms of computing power. Other alternatives have been developed in the literature. One of them is selected here: it consists of a parametric model that estimates the mismatch losses as a function of the overall degree of inhomogeneity of the irradiance incident on the PV array [22]. This model has produced annual losses values in the range of 0.3% to 1%, depending on the specificities of each PV project.

Once the PV power is obtained for each time interval, the energy yield is calculated by summation over the time period considered.

For the test case exemplified here, the annual energy yield is estimated to be 1,093 kWh/kWp, which is approximately 10% lower than the typical PV yield of a ground-mounted monofacial PV plant facing south and with optimal tilt that would be installed at the same location. In some cases, project promoters might be willing to sacrifice a small fraction of the potential energy yield to keep an appropriate mix between agriculture and electricity generation over the available land area. The yield value just mentioned is representative of the southern France only and can greatly vary as a function of climate and latitude, with typically higher yield losses for sunnier locations at lower latitudes, and lower yield losses (or even gains) for higher latitudes or cloudier locations [23].

The Performance Ratio (PR) is often used to analyze the overall performance of PV plants. It is defined as:

$$PR = \frac{Y_f}{Y_r}$$

where the final yield Y_f is equal to the ratio E_{pv}/P^{STC}, and the reference yield Y_r is equal to the ratio GTI/G^{STC}, where: E_{pv} is the net electrical energy produced by the installation during a given period, P^{STC} is the rated power of the PV generator under Standard Test Conditions (STC), G^{STC} is the global solar irradiance under STC (i.e., 1000 W/m^2), and GTI is the Global Tilted Irradiance received by the PV generator.

There is currently a lack of agreement on the definition of the reference GTI value required to define the yield for bifacial PV modules. One part of the PV community still uses the GTI incident on the front side of the PV modules for that purpose, because the backside irradiation is more difficult to evaluate with accuracy. Nevertheless, this mechanically leads to an overestimated PR by an amount that is close to the bifacial energy gain. This definition often represents a PR increase of typically several percent for most bifacial PV plants relatively to their equivalent monofacial configuration. Nevertheless, this is particularly problematic in the case of vertical PV modules, for which the front side and backside can receive a similar irradiance. This can lead to annual PR values that are much higher than the PR values of monofacial PV modules, and also much higher than 100%, which is very confusing. For these reasons, a different reference GTI is selected here. It is defined as the sum of the GTI received on the front side and of the backside GTI multiplied by the bifaciality factor. This constitutes the *effective bifacial irradiation*. With this definition, the estimated PR amounts here to a reasonable value of 82.6%.

7 DISCUSSION AND CONCLUSION

The use of bifacial PV modules for agrivoltaics presents interesting advantages, in particular regarding the combined use of the land between agriculture and photovoltaic energy generation. However, this is still a rather new kind of application, and many challenges still lie ahead towards a more accurate assessment of the energy yield of these PV plants.

Among the most challenging topics that were encountered during the course of this project, we have identified the need for accurate albedo values and reflectance profiles, including angular and spectral considerations.

The uncertainty surrounding the assessment of the inclined solar irradiance on these vertical surfaces is also particularly challenging because most of the commonly used irradiance translation models have mainly be developed and validated for south facing and optimally tilted surfaces, or for tracking surfaces. Therefore, new research is needed to improve our knowledge and develop more accurate and robust translation methods that are more suitable for vertical surfaces, in particular for vertical surfaces facing east or west.

We have also identified that, because the contribution of the reflected components of the reflected irradiance has relatively large weight in these kinds of PV installations, the energy yield of these configurations is particularly sensitive to the value and nature of the albedo, as well as to the accuracy of the simulation of the multiple light reflection processes that take plan in the PV plant. We have presented a novel simulation tool that provides a good compromise between results accuracy and computation speed. The application of that simulation tool has been illustrated on the case study of the PV plant projected in the south of France.

The use of the front side GTI for the calculation of the PR leads to important overestimations of its value. Therefore, we suggest that the PR for bifacial PV modules is calculated using the effective bifacial irradiation as a reference. This is particularly important in the case of vertically oriented PV arrays where both sides receive similar amounts of solar irradiation.

The GPU-based method presented here has already been used to assess the bifacial energy gain of many large bifacial PV plants totaling more than 1 GW since 2017, with a large diversity of applications, including large PV plants with fixed structures or trackers, carports, canopies in rural areas, greenhouses, or vertical agrivoltaic structures. Several application cases have been illustrated in this article. The further development and scientific validation of this method is currently ongoing in the context of two European R&D projects: the H2020 project SERENDI-PV, and the COST project Pearl-PV. However, given the increasing diversity of bifacial PV installations, and the scarcity of reliable monitored operation data that are currently available, more effort and more collaboration will be needed in the future in order to incorporate and validate new functionalities in the tool. In this context, collaboration proposals are welcome, on the research effort as well as on the analysis of the operation data of bifacial PV installations.

ACKNOWLEDGMENTS

The research activities behind the simulation tool that was used in this project were partially funded by European Commission through the Horizon 2020 project SERENDI-PV (https://serendipv.eu/), which belongs to the Research and Innovation Programme, under Grant Agreement 953016. This publication is also partially based upon work from COST Action CA16235 PEARL PV (https://www.pearlpvcost.eu), supported by COST (European Cooperation in Science and Technology).

REFERENCES

[1] https://www.cmsaf.eu/EN/Home/home_node.html
[2]https://ec.europa.eu/jrc/en/PVGIS/downloads/SARAH
[3] https://meteonorm.com/en/
[4] https://solargis.com/
[5] C.A. Gueymard, Direct and indirect uncertainties in the prediction of tilted irradiance for solar engineering applications, http://dx.doi.org/10.1016/j.solener.2008.11.004
[6]J.E. Hay, J.A. Davies, 1980. Calculation of the solar

irradiance incident on an inclined surface, in:
J.E. Hay, T.K. Won, (Eds.), First Canadian Solar Radiation Data Workshop, Toronto, Ontario,
Canada. pp. 59–72.
[7] C.A. Gueymard, Solar Radiation Resource: Measurement, Modeling, and Methods, https://doi.org/10.1016/B978-0-12-819727-1.00101-1, 2021, in press.
[8] C.A. Gueymard, C.A., 1987. An anisotropic solar irradiance model for tilted surfaces and its comparison with selected engineering algorithms. Solar Energy 38, 367–386, Erratum, Solar Energy 40, 175 (1988).
[9] C.A. Gueymard, 1987. An anisotropic solar irradiance model for tilted surfaces and its comparison with selected engineering algorithms. Solar Energy 38, 367-386.
[10] https://gmao.gsfc.nasa.gov/reanalysis/MERRA-2/
[11] https://ldas.gsfc.nasa.gov/gldas/.
[12] https://modis.gsfc.nasa.gov/data/.
[13] C.A. Gueymard, Surface albedo spatial variability in North America: Gridded data vs. local measurements, 2021, https://doi.org/10.1016/j.solener.2021.05.012.
[14] J.-L. Roujean, M. Leroy and P.Y. Deschamps, 1992, A bidirectional reflectance model of the Earth's surface for the correction of remote sensing data, J. Geophys. Res., 97(D18), 20455– 20468, doi:10.1029/92JD01411.
[15] J. Robledo, J. Leloux, E. Lorenzo, C.A. Gueymard,
From video games to solar energy: 3D shading simulation for PV using GPU, Solar Energy, 2019, https://doi.org/10.1016/j.solener.2019.09.041.
[16] J. Robledo, J. Leloux, B. Sarr, C.A. Gueymard, A. Driesse,
Dynamic and visual simulation of bifacial energy gain for photovoltaic plants, European Photovoltaic Solar Energy Conference and Exhibition (EU PVSEC), 2021.
[17] https://pvpmc.sandia.gov/applications/pv_lib-toolbox/.
[18] https://www.pvsyst.com/.
[19] https://www.sisifo.info/es/default.
[20] J. Muñoz, O. Perpiñán, A simple model for the prediction of yearly energy yields for grid-connected PV systems starting from monthly meteorological data, Renewable Energy, 2016, https://doi.org/10.1016/j.renene.2016.06.023.
[21] https://sam.nrel.gov/.
[22] C. Deline, S. Ayala Pelaez, S. MacAlpine, C. Olalla, Estimating and parameterizing mismatch power loss in bifacial photovoltaic systems. Prog Photovolt Res Appl. 2020; 28: 691–703. https://doi.org/10.1002/pip.3259.
[23] https://pvpmc.sandia.gov/modeling-steps/5-ac-system-output/pv-performance-metrics/annual-yield/.