REVISITING BIFACIAL MODULE TECHNOLOGY

1. INTRODUCTION

Bifacial products have long been commercially available in the solar industry. In North America, Sanyo was the first to commercialize bifacial technology with the introduction of their HIT Double bifacial module in 2006. Due to cost and lack of industry infrastructure such as standards and modeling tools, the technology did not receive much interest. However, with recent reductions in module pricing and the ability to produce bifacial products at costs only incrementally higher than standard PV modules, the industry is giving bifacial modules renewed attention.

In very basic terms, bifacial modules contain active PV cell circuitry on the rear sides of the cell surfaces in addition to the front side. Compared to a standard (or monofacial) PV module which typically utilizes an opaque covering to protect the back side, a bifacial module must incorporate a transparent backsheet or second sheet of glass to expose the rearside cell surfaces to light. In this manner, a bifacial module captures reflected light from the ground surface and surrounding structures and converts this to usable energy, which is additive to the front side. Energy gains for bifacial systems can be on the order of 5-25%, compared to monofacial systems, depending on the system configuration and ground surface reflectance. The basic concept is shown in Figure 1.1 below:

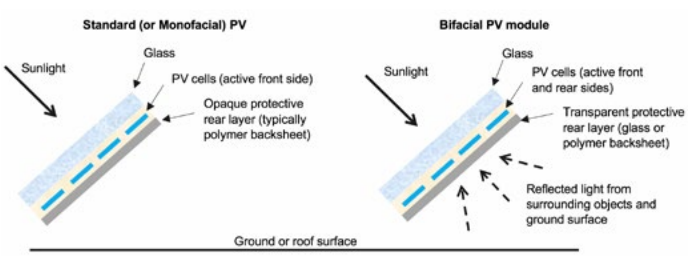

Figure 1.1: Schematic showing basic differences between monofacial and bifacial modules

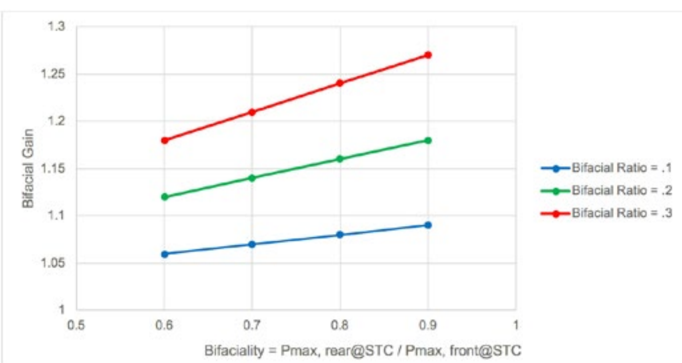

Figure 1.2: Impact of Bifaciality and Bifacial Ratio on Bifacial Gain

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The intent of this paper is to summarize the start of the art relating to bifacial products, and to clarify for system developers and investors the complexities involved in system design, modeling approaches, technology selection and reliability considerations. It will also provide guidance on best practices in each of these areas.

This paper will begin with an overview of important bifacial terminology, followed by an overview of modeling approaches and areas of uncertainty. Next a review of available field data and best practices for optimum energy generation will be presented, and will conclude with an overview of commercially available products with special issues related to long term reliability.

1.1 DEFINITIONS

Bifacial Gain is the measure of bifacial performance compared to a monofacial or single-sided comparable PV plant. It is defined as follows:

$$\text{Bifacial Gain} = \frac{\text{Energy}_{\text{bifacial}}}{\text{Energy}_{\text{monofacial}}} = 1 + \text{Bifacial Ratio} \times \text{Bifaciality}$$

where:
Energy$_{bifacial}$ = Energy produced from a bifacial system
Energy$_{monofacial}$ = Energy produced from a comparable monofacial, or single-sided, system
Bifacial Ratio = Irradiance or irradiation received on the rear side divided by the front side = Irradiance$_{rear}$ / Irradiance$_{front}$
Bifaciality = The relative efficiency at Standard Test Conditions (STC) of the module backside divided by the front side = Pmax$_{rear@STC}$ / Pmax$_{front@STC}$

There are two parameters which influence the Bifacial Gain: the Bifacial Ratio and the Bifaciality. The biggest factor in increasing bifacial energy production is increasing the solar irradiance received by the rear side of the module, or increasing the Bifacial Ratio. As the graph in Figure 1.2 shows, as the Bifacial Ratio increases from 0.1 to 0.3, or 20% absolute (the range typically seen in field applications), the Bifacial Gain will increase by almost the same magnitude. Some of the parameters influencing Bifacial Ratios will be discussed in further detail below.
Bifaciality is a property of the PV module, and while it plays a role in impacting bifacial energy production, the effect is secondary to the Bifacial Gain (as shown in Figure 1.2). Increasing the Bifaciality from 0.6 to 0.9, the approximate range seen in commercially available products, will increase the bifacial gain by less than 10%.

2. MODELING

2.1 MODELS AVAILABLE FOR BIFACIAL SYSTEMS

The main challenge in modeling the performance of bifacial PV arrays is the prediction of irradiance hitting the backside of the PV modules. Backside irradiance varies significantly with the array geometry, the presence of near field objects which influence reflected light, and the albedo of the ground and nearby surfaces.

There are two primary approaches to modeling backside irradiance: Ray Tracing models and View Factor models.

Ray Tracing models follow light from the source of interest (forward ray tracing) or from the surface of interest back to the source (backward ray tracing). These models simulate hundreds of thousands of different rays and use optical physics to predict how each ray interacts at each surface. (Sandia, n.d.)

View factor models, in contrast, are built on radiative transfer calculations which calculate the amount of radiation leaving one surface and reaching a second surface. In the case of bifacial modules, the second surface is the back side of the bifacial module and the first surface is a collection of surfaces near the array such as the ground and the front of the PV modules behind the module of interest. View factors may also be referred to as shape factors, configuration factors or angle factors. (Sandia, n.d.)

Specific models often cited in the literature for modeling bifacial systems include NREL's View Factor model and PVsyst (which are both View Factor models) and NREL's Radiance model which is based on backwards ray tracing. A short description of each is included here below:

NREL Radiance: Radiance is a reverse ray tracing model which has been used for lighting design of buildings due to its ability to provide realistic illuminance mapping. The model calculates reflections from surfaces of defined albedo and surface roughness (C. Deline, 2017), however due to the complexity of the analysis, the execution time is considered to be too long for routine use in modeling the performance of bifacial systems. (B. Marion, 2017). Validation of this simulation method against field-measured irradiance values in bifacial systems has been previously conducted (C. Deline, 2016).

NREL View Factor (VF): In order to facilitate reasonable execution times, NREL introduced the View Factor model which assumes that edge effects are not significant with respect to the overall energy generation of the bifacial array. It is applicable for a row or multiple rows of PV modules. The model can estimate variation of back surface irradiance along the vertical dimension (slant height) of the module, but not along the row length. This permits faster execution times because the backside irradiance is not determined for every PV module in the system. The model is open sourced, and can produce an annual energy generation simulation along with hourly time steps. (B. Marion, 2017) The model will be integrated into the System Advisor Model (SAM), the PV system performance model available from NREL, in September, 2018.

PVsyst: PVsyst (version 6.64 and higher) utilizes a view factor methodology for computing irradiance on the rear side. As with the NREL View Factor model, it can only handle unlimited shed models for which no edge effects are considered. PVsyst only takes into account reflected light from the ground surface and does not consider reflections from adjacent rows of modules. (PVsyst) Further discussion on PVsyst's modeling approach is described below.

2.1.1 MODELING WITH PVsyst

PVsyst is the most widely used software to carry out solar energy yield calculations for utility scale projects. A more detailed explanation of the bifacial modeling approach used in PVsyst is therefore described here. To calculate energy production from a bifacial system, PVsyst computes a rear side irradiance, weighted by the bifaciality factor, and adds it to the front side irradiance to compute total PV array energy generation.

The approach used to model the irradiance on the rear side of bifacial modules is briefly summarized below (PVsyst):

Irradiance reaching the ground between the rows of the PV array is multiplied by the albedo factor (see section 2.3 below for albedos of common surfaces), which is equal to the fraction of light reflected. Highly reflective surfaces have a high albedo, and non-reflective surfaces have low albedo values.

In PVsyst, the light reaching a point on the ground surface is assumed to have an isotropic distribution, meaning that the light is reflected with the same intensity in the half-sphere above this point.

Finally, to calculate the amount light received by the modules, the model uses the View Factor approach. The View Factor is defined as the fraction of light reaching the backside surfaces of the PV modules. The View Factor is solely dependent on the geometry of the system. For each point on the ground surface, PVsyst calculates an average View Factor (or fraction of light received) for the module backside surfaces.

The View Factor concept is illustrated in Figure 2.1 below. Regardless of the time of day or time of year, light reflecting from a given point below the modules will produce a specific View Factor unique to that point. Examples from different times of day in April and June are shown in the figure below. The View Factor, or portion of light received on the module back surfaces, is the same for the ground surface point shown below in April and in June, however the intensity of the light will be different. A plot showing the average backside View Factor for each ground point is also shown below in Figure 2.2. This View Factor is used along with the intensity of the light throughout the day and year to calculate the total backside irradiance.

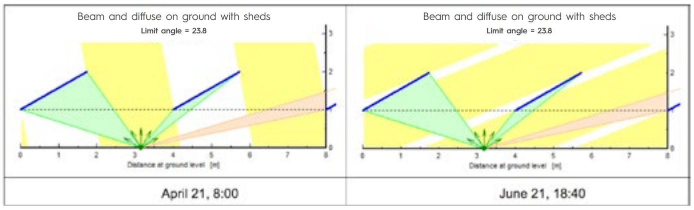

Figure 2.1: The View Factor (fraction of light received on the module back surfacees) is the same for each ground surface point regardless of time of day or time of year (PVsyst)

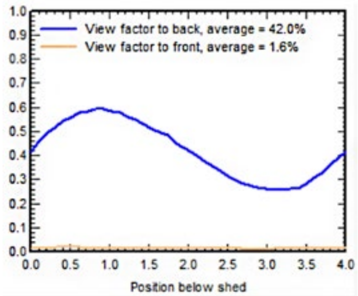

Figure 2.2: Average View Factor for the entire back surface of the PV module, for each ground surface point. Simulation run with PVsyst 6.7.2, Tilt 30°, Pitch 4m, Shed width 2m, Height 1m, albedo 30%, Raleigh, NC.

2.2 MODEL COMPARISON AND VALIDATION WITH FIELD DATA

In general, the performance of a bifacial system is increased by getting more light to the module back surfaces. This can be accomplished in several ways: by increasing the height of the modules, reducing the collector width, increasing the row spacing (pitch), increasing the module tilt angle, and increasing the ground albedo (see Figure 2.3).

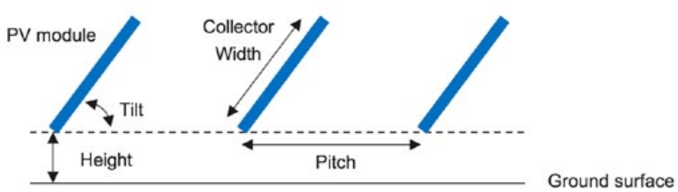

Figure 2.3: Geometrical factors impacting amount of light to module back surfaces

In this section, the models described above are compared under various scenarios as a function of these variables.

Prior work conducted (Palaez, 2018) shows comparisons between the three models discussed above, along with two additional empirical models. The Solarworld and Prism models were developed to model the bifacial gains of their respective products (Solarworld, n.d.) (J. Stein, 2017). Yearly backside bifacial gains were calculated for a Richmond, VA location for varying row spacings, clearances (height/collector width), tilt angles and albedos.

The NREL VF and Radiance models show reasonably good agreement with each other (typically within 1%), with higher variations seen for low GCR (GCR = Collector Width / Pitch) and higher clearance configurations. Compared to Radiance, View Factor tends to underpredict backside irradiance gains at higher ground clearances and low GCRs, where the assumptions in the model begin to become less applicable and edge effects are more prominent. PVsyst is generally observed to run up to 3% higher than NREL VF, with the larger deviations occurring under those same edge effect conditions (low GCR and high clearances).

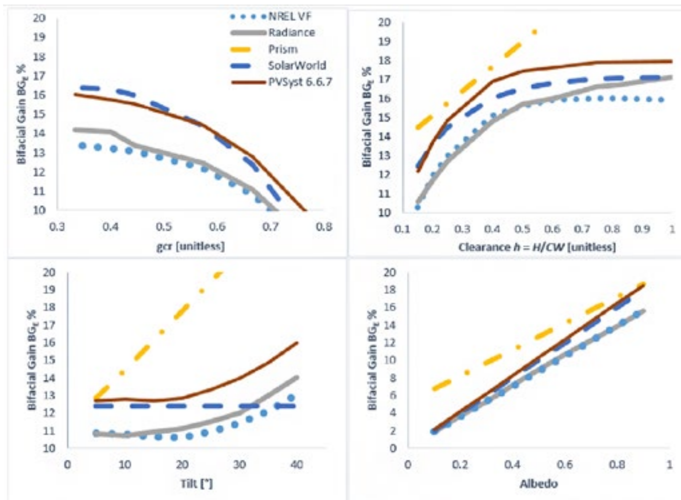

Figure 2.4: Yearly Bifacial Gain comparison for five bifacial models for Richmond, VA (Palaez, 2018)

Additional studies conducted for single axis trackers (gtm Webinar, 2018) show roughly 2% agreement between the NREL VF, Radiance and PVsyst models. Simulations in this study were conducted for 2X portrait trackers, at 0.35 GCR and 0.3 albedo. In this scenario, PVsyst simulated results fall between the two NREL models and only approximately 1% higher than the NREL VF model.

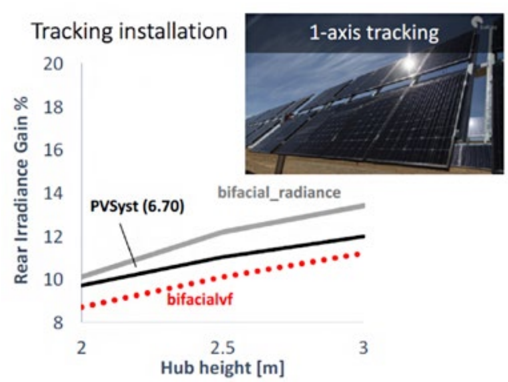

Figure 2.5: Single axis tracking simulations for 2x portrait configuration, 0.35 GCR, 0.3 albedo (gtm Webinar, 2018)

Work to date has been limited in regards to model validation against field data. Work conducted by (Palaez, 2018) showed model agreement within 2-3% of experimental data for the NREL VF and Radiance models for a 3-row test array constructed in Golden, Colorado. At higher ground clearances, edge effects become more significant and therefore model prediction is not as accurate for the VF model which does not take into account impacts around the array edge.

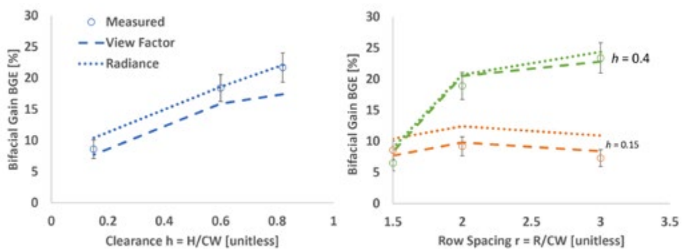

Figure 2.6: Fixed tilt simulations compared against a 3-row test bed in Golden, Colorado (Palaez, 2018)

Work conducted by (Deline, 2017) has also compared NREL's VF and Radiance models to measured field data for the same 3-row mock array used in the previous study. Deviations between the VF model and measured data emerge at higher ground clearances when edge effects become more prominent (see Figure 2.7).

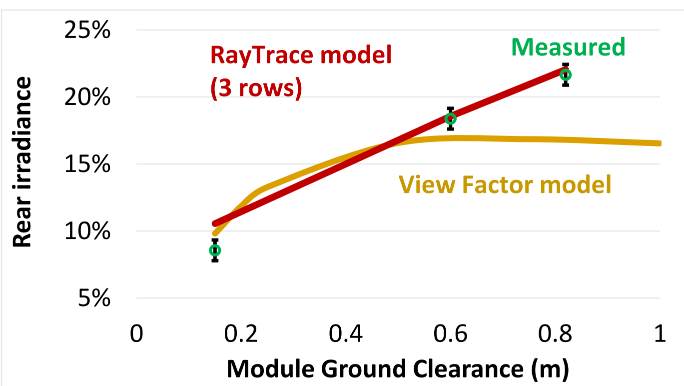

Figure 2.7: Comparison of RayTrace (Radiance) and VF models for 3-row mock array, using 2 months of field data (Deline, 2017)

Edge effects are further illustrated by (Deline, 2017), where it shows that for a module height of 1m off the ground, at least 5 landscape oriented modules are needed per row, with at least 6 rows, before edge effects are minimized. At 3m off the ground, at least 10 landscape oriented modules are needed per row with at least 12 rows. Two dimensional modeling tools such as VF and PVsyst would be expected to show larger deviations with field data below this threshold (backside irradiance will be under predicted).

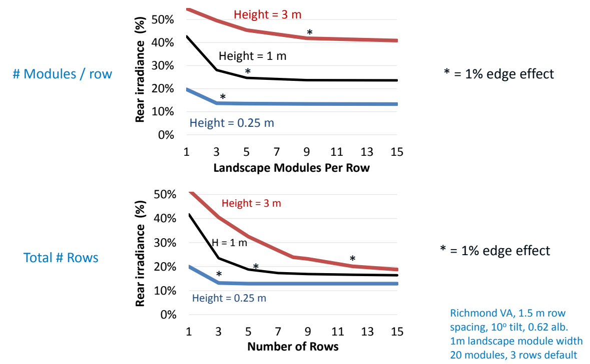

Figure 2.8: Illustration of edge effects in bifacial system modeling (Deline, 2017)

In conclusion, while limited field validation data is available, the modeling approaches discussed above appear to show reasonably good agreement with measurements. The inability of current modeling tools to accurately describe edge effects will not materially influence energy yield predictions for commercial-scale PV farms, but may be significant for smaller rooftop installations.

2.3 REAR SIDE IRRADIANCE VARIATION

Variation in back side irradiance as well as irradiance throughout the PV array is one of the key complexities associated with bifacial systems. Several studies have demonstrated that non-uniformity in irradiance across the backside of the module (in the 2D plane) is a function of installation height divided by collector width (Palaez, 2018), (gtm webinar, 2018)). As installation heights decrease and/or collector widths increase, the variation in backside irradiance is expected to increase. Similarly, at higher installation heights and/or smaller collector widths, the backside irradiance will be more uniform. This is shown below comparing computed backside irradiance in 1x portrait versus 2x portrait configurations (gtm webinar, 2018):

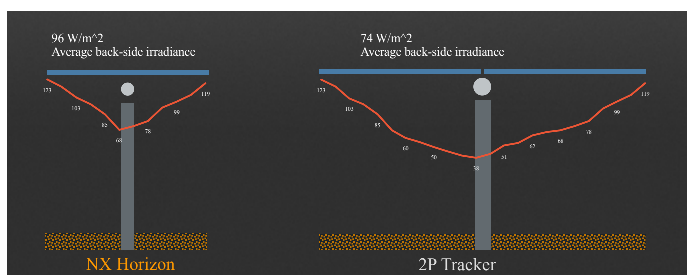

Figure 2.9: Backside irradiance for Nextracker's NX Horizon (1X portrait) versus a 2X portrait tracker at the same height. (gtm webinar, 2018)

This was also shown by (J. Libal, 2017), where backside irradiance uniformity was simulated for a location in Egypt with a ground albedo of 0.5. In this case, backside uniformity is significantly improved at a height of 1m compared to a height of 10cm. The same study also illustrated the potential for deviation in energy production across an entire array, where modules positioned around the edges can produce as much as 4% more energy compared to interior modules.

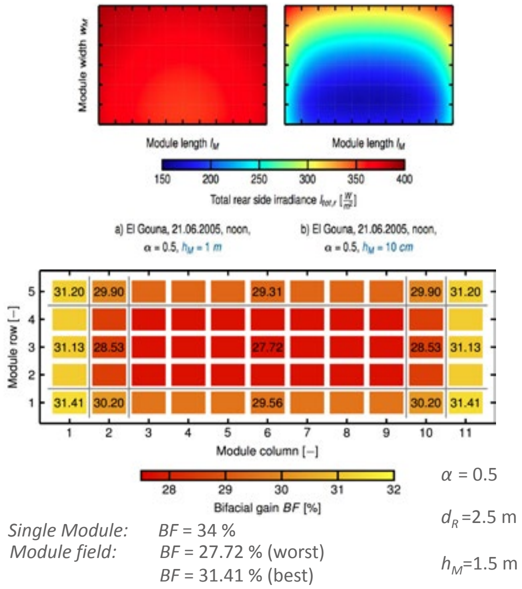

Figure 2.10: Simulations showing variation in irradiance across a single module, and variations in Bifacial Gain across an entire array (J. Libal, 2017)

PVsyst's view factor model does not take into account the variation in rear side irradiance. Since the cell with the lowest current will dictate the current in the whole string, PVsyst uses a bifacial mismatch loss factor to take this additional energy loss into account. At the present time, PVsyst does not offer any guidance in estimating this loss factor, so this is left to the user to determine. For most commercial and utility scale ground-mounted PV plants, backside irradiance variation is likely to be small since installation heights are likely large enough to minimize this effect. For smaller rooftop installations, this will likely play a larger role and will need to be addressed by increasing the modeling uncertainty (see section 2.5 for further discussion)

Rearside irradiance variation is also important to consider when multiple modules are used across the collector width. There may be significant variation in irradiance from module to module along the two-dimensional collector width of the rows. While it is typically common practice in monofacial systems to contain all the modules in a given row to the same string, this is more critical in bifacial systems for this reason.

One would expect module and/or string level power electronics to be increasingly used with bifacial systems as a means of reducing mismatch, particularly when installation heights are low (larger backside irradiance variation) and arrays are small (edge effects become more significant).

2.4 QUANTIFYING ALBEDO

As shown in Figure 2.4, the ground albedo has a direct linear impact on the Bifacial Gain of PV project, and therefore determining the correct albedo to be used for modeling purposes will be critical in generating accurate energy assessments. Because of the high potential for variability, it is generally advised that this factor be measured for the particular project site in question. Albedo values measured for various ground surfaces are shown in Figure 2.11 below, which illustrates the high degree of variability:

SURFACE TYPE	ALBEDO
Green field (Grass)	23 %
Concrete	16 %
White painted concrete	60-80 %
White gravel	27 %
White roofing metal	56 %
Light grey roofing foil	62 %
White roofing foil (for solar applications)	> 80 %

Figure 2.11: Measured albedo values for common ground surfaces (SolarWorld)

Added to the complexity is the fact that the albedo may change over time due to aging of the surface or soiling. One study (H. Akbari) evaluated the albedo of roofing membrane materials after field exposure for 5-8 years, and then again after cleaning. The graph in Figure 2.12 summarizing the results shows a high variation in the albedo of the uncleaned values, ranging from 0.3 to 0.7, compared to 0.8 for the un-weathered values. In most cases, the original surface albedo could be mostly restored after cleaning.

The albedo has a direct linear impact on the Bifacial Gain, so a gain of 20% for example on a highly reflective roofing surface could easily be reduced to 10% if the membrane becomes soiled and is not cleaned. Therefore a regular cleaning schedule for the roofing material should be included in the project O&M for bifacial projects for optimum gains.

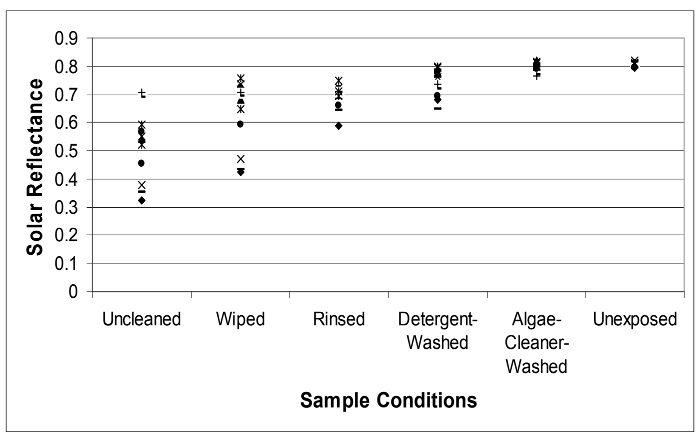

Figure 2.12: Effect of soiling on roofing surface albedo values. Cleaning process was cumulative: dry wiping, rinsing with water, washing with detergent, and washing with algae cleaners. (H. Akbari)

There are two main ways of measuring the site albedo: with a pyranometer or with a PV module. If measuring with a pyranometer, the ground albedo is calculated by measuring the irradiance reflected from the ground and dividing it by the irradiance measured from the sky. With a PV module, the albedo is calculated by measuring the module Isc while facing the ground, and dividing it by the module Isc when facing the sky.

In either case, measuring on a cloudless day during midday hours is recommended, and at least 3 to 5 measurements should be taken across the site area. Additionally, for fixed tilt plants, if the tilt angle is known, the sky and ground facing measurements may be done at the installation tilt angle for greater accuracy. (SolarWorld).

2.5 MODELING UNCERTAINTY

There is currently no standard industry practice for estimating the uncertainty associated with the modeling of bifacial modules. Based on the review conducted above, these are the likely additional sources of modeling uncertainty for bifacial PV projects:

Model uncertainty: based on the review conducted above; there should first be an additional source of uncertainty applied for inherent modeling inaccuracies. The limited prior work done in this area has shown a roughly 3% variance between PVsyst and the NREL VF and Radiance models. A base requirement for any modeling is that the system must be large enough such that edge effects are minimized, however this would normally be the case for any large commercial or utility scale installation. For projects where applicable field data has been collected for the design and geometry planned, model uncertainties should be reduced since any bias between the model and specific project configuration could be understood and accounted for.

Nameplate uncertainty: specifications for bifacial models have an inherent source of error since measurement procedures to determine nameplate power have not yet been fully implemented (see Section 4.1). Some manufacturers are further advanced in their measurement processes compared to others. Applying an additional uncertainty factor here may be warranted depending on the specific product used.

Albedo: Whether the ground albedo is assumed or measured would have a large effect on the uncertainty. If a measurement campaign was conducted for a specific project, modeling uncertainties should be lower compared to a situation where ground albedos were estimated. Methodology used for measuring could also have an impact, and should be included in the evaluation. In addition, an assessment will need to be made regarding seasonal changes in albedo or whether the albedo will change over time, since this will also add to the uncertainty.

Mismatch Factor: PVsyst's view factor model does not take into account the variation in rear side irradiance. Since the cell with the lowest current will dictate the current in the whole string, PVsyst uses a bifacial mismatch loss factor to take this additional energy loss into account. This is another source of uncertainty which must be estimated. At higher installation heights and/or smaller collector widths, the backside irradiance will be more uniform, so one would expect uncertainty due to mismatch to be reduced (see Section 3.3 for further discussion).

3. MAXIMIZING ENERGY YIELD

3.1 BIFACIAL ENERGY GAINS EXPERIENCED IN THE FIELD TO DATE

Bifacial Gain values reported in the literature for small fixed-tilt test systems on commercial white rooftops range from 15% - 25%. In their own test facility, Fraunhofer ISE reports Bifacial Gains of 22% over 235 days in 2009 for a roof-top test installation (roof albedo of 0.64, module height 0.2m, 15 degree tilt). (Reise, 2015)

Field experience with tracking systems are described in detail in Table 3.1 on the next page. As reported below, Bifacial Gains generally fall into the 12-14% range for single axis trackers installed over natural ground surfaces.

Table 3.1: Field Experience with Tracking Systems

14 MW NELLIS AIRBASE IN LAS VEGAS, NV

- Installed in 2007 included 2 MW Sanyo bifacial
- Powerlight T-20 tracker with 2 portrait design and 20 degree tilt
- Measured bifacial gains of 12%+ due to low GCR and high albedo

Source: (gtm webinar, 2018)

SPRINGS PRESERVE BIFACIAL PROJECT IN LAS VEGAS, NV

- Installed in 2008
- Powerlight horizontal tracker with tilted PV, installed over white reflective fabric doubling as shade for cars
- Bifacial gains up to 17% reported

Source: (gtm webinar, 2018)

NEXTRACKER HEADQUARTERS, FREMONT, CA

- 4 years of field testing
- NX Horizon tracker with framed bifacial modules, ground albedo reported 0.18, GCR 42%
- Bifacial gains of 14% for 90% bifacial modules, and 6% for 70% bifacial modules reported

Source: (gtm webinar, 2018)

LA SILLA OBSERVATORY, CHILE

- 575kW Megacell bifacial modules, 9 months of testing, system installed in 2016
- Soltec single axis trackers, 2x in portrait
- Bifacial gain of 13% reported

Source: (A.D. Stefano, 2017)

3.2 OPTIMUM CONFIGURATIONS FOR TRACKERS VS FIXED TILT SYSTEMS

3.2.1 FIXED TILT SYSTEMS

For fixed tilt systems, modeling work conducted by (Xingshu Sun) has demonstrated that an albedo of 0.25 (typical for natural groundcover, such as vegetation and soil) will produce a Bifacial Gain of less than 10% globally for modules mounted at ground (or roof) level, regardless of azimuth and tilt. Increasing the ground albedo to 0.5 can boost the Bifacial Gain of ground (or roof) level mounted modules to ~20% globally. Elevating the module 1 m above the ground (measured from ground to lower edge) can further increase the bifacial gain to ~30%, combined with a 0.5 ground albedo. These values appear to be line with observed values from the literature showing 15% - 25% gains in bifacial systems installed on commercial rooftops (see Section 3.1).

Specifically, (Xingshu Sun) has calculated optimum heights and tilt angles for bifacial systems installed globally. The figure below shows the average minimum elevation (E95), or height, to achieve 95% of the maximum energy production as a function of latitude at a fixed ground albedo. Note that the E95 values decreases almost linearly with latitude. At a latitude of 35 degrees (southern US), optimum heights would range from about 0.75m for ground albedos of 0.25 (natural groundcover) to 1.5m for albedos of 0.5 (reflective roof surfaces, for example).

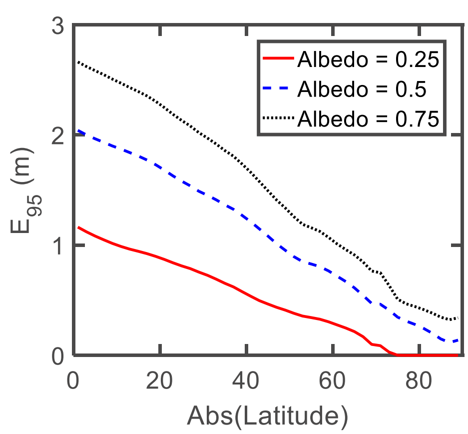

Figure 3.1: Average minimum elevation (E95), or height, to achieve 95% of the maximum energy production as a function of latitude at a fixed ground albedo (Xingshu Sun)

Optimum tilt angles were also generated for a range of albedos and latitudes (shown compared to optimum tilt angles for monofacial modules). In general, optimum bifacial tilt angles are higher than for monofacial modules in all cases. Using again a latitude of 35 degrees as a baseline and an elevation of 1m, the optimum tilt angle is approximately 40 degrees for an albedo of 0.5 (in figure (b) below), compared to an optimum tilt of 25 degrees for monofacial. Optimum tilt angles are expected to decrease for lower albedo values, however this scenario was not specifically calculated for an elevation of 1m.

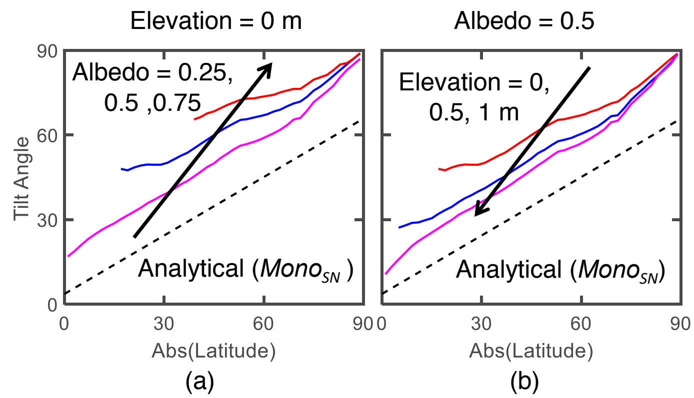

Figure 3.2: Optimum tilt angles for a range of albedos and latitudes (Xingshu Sun)

3.2.2 TRACKING SYSTEMS

There has been much focus on optimization in single axis tracker design and installation for bifacial systems. Projected single axis tracking bifacial gain over natural ground cover is projected to be 5-15% globally (gtm Webinar, 2018). This is in line with observed field performance of tracker installations where bifacial gains have generally ranged from 12-14% (see Section 3.1). Modeled irradiance gains expected by area are shown in Figure 3.3 below, with higher potentials generally observed in areas closest to the equator and in regions with high anticipated albedo:

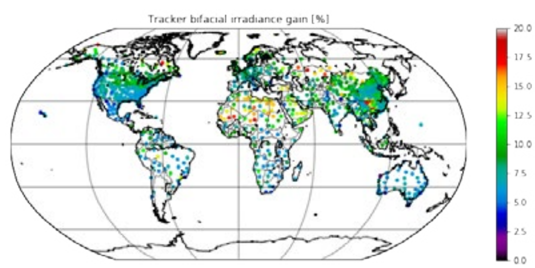

Figure 3.3: Modeled bifacial irradiance gains: 1-axis tracking, 2x portrait, 0.35 GCR, 0% shading and mismatch, natural ground cover albedo from NASA, h = 3 m (local albedo may be under-reported by satellite imagery) (gtm Webinar, 2018)

Nextracker's bifacial tracking design utilizes a 1.5m tracker tube height on the NX Horizon with a 1X module in portrait configuration. This puts the lower module edge at approximately .6m above the ground at maximum rotation [1], which is close to the optimum height of .75m calculated for fixed tilt systems discussed previously for natural groundcover. Soltec SF7 bifacial single axis trackers utilize a 2X portrait configuration with a tube height of 2.35m. As with the Nextracker design, this puts the lower module edge also at 0.6m at maximum rotation (gtm Webinar, 2018) [1].
For optimum bifacial tracker gains, Nextracker advises 30-40% GCR with a 1.25 DC/AC ratio to limit clipping losses. (gtm webinar, 2018).

[1] Assumes 2m length module, +/- 60 rotation

4. BIFACIAL PRODUCTS

4.1 COMMERCIALLY AVAILABLE BIFACIAL MODULES

Below is a list of select commercially available bifacial modules based on currently available product datasheets. (Note that manufacturer product specifications change regularly, so it is advised to check with the manufacturer for any updates to product specifications.)

There are a few issues related to bifacial module specifications which the user should be aware of. First and foremost, there is currently no measurement standard for factory testing of bifacial products to determine nameplate rating. The front side and back side must be separately flash-tested to be able to provide bifacial specifications. However, bifacial devices are more sensitive to deviations in environmental conditions. For example, reflections on the rear side of the device under test can increase significantly the measurement uncertainty and possibly over-inflate stated electrical specifications for the front side being tested. Sandia and NREL are currently developing a draft measurement standard, IEC 60904 Part 1-2 (Bifacial PV Characterization and Rating Standards, n.d.)

Additionally, there is no standard for reporting of bifacial specifications. Some manufacturers provide values for Bifaciality, however others avoid reporting this information and only supply backside power at certain percentages of energy gain, which does not inform the user how much power the backside will produce at specific irradiance levels.

With those caveats stated, a summary of reported information from product specification sheets is provided in Table 4.1 below. Cell types generally fall into two classifications: Monocrystalline PERC and N-type Silicon. Reported Bifaciality values range from 70% to 90%, with N-type cells tending to fall on the higher end of that range compared to Monocrystalline PERC cells. Construction varies between dual glass products, some of which are framed and some of which are not, to glass/transparent backsheet construction (see section 4.2 for further discussion). Warranties are also quite variable, however most manufacturers offer 30 year power warranties (see section 4.4 for further discussion).

Table 4.1: Bifacial module specifications

MODULE	CELL TYPE, № OF CELLS	FRONTSIDE NAMEPLATE / EFFICIENCY	CONSTRUCTION	BIFACIALITY	WARRANTY
JA Solar JAM72D00 350-370/ BP	Mono PERC, 72	350-370 / 17.8-18.8%	Frameless Glass/Glass, thickness not provided	70%	12 year product / 30 yr linear power @ 0.5%/yr
LG Neon 2 LG395N2T-A5, LG390N2T-A5	Mono N-type, 72	390-395 / 18.5-18.7%	Framed Glass/Backsheet	76%	25 year product / 25 yr linear power @ 0.5%/yr
Prism Solar Bi72	Mono N-type, 72	345-360 / 17.5-18.3%	Frameless Glass/Glass, 3.2mm/3.2mm	90%	10 year product / 30 yr power (no add'l info available)
Silfab SLG-X	Mono N-type, 72	360 / 18.5%	Framed Glass/Backsheet	85%	12 year product / 30 yr linear power @ 0.4%/yr
Solarworld Bisun	Mono PERC, 60	290 / 17.3%	Framed Glass/Glass, thickness not provided	Not provided	20 year product / 30 yr linear power @ 0.35%/yr
Sunpreme Maxima GxB	Hybrid Cell Technology, 72	360-380 / 18.5-19.5%	Frameless Glass/Glass, 2.9mm/2.9mm	Not provided	15 year product / 30 yr linear power @ 0.5%/yr*
Yingli Panda Bifacial 72CF	Mono N-type, 72	~340-360 / 17.2-18.2% (calculated from datasheet)	Framed Glass/Glass, 2.5mm/2.5mm	82%	10 year product / 30 yr linear power @ 0.5%/yr
Trina Duomax Twin	Mono PERC, 72	345-365 / 17.4-18.4%	Frameless Glass/Glass, 2.5mm/2.5mm	Not provided	10 year product / 30 yr linear power @ 0.5%/yr

Source: Manufacturer's data sheets
*97.5% power warranty first 5 years

4.2 RELIABILITY CONSIDERATIONS

4.2.1 MOISTURE RESISTANCE

As shown in the table above, bifacial module construction can be quite variable. One major difference between the module types is use of a dual glass construction versus a transparent backsheet. In a dual glass construction, the polymer backsheet film typically used on the backside is replaced with a second sheet of glass. Dual glass modules are generally considered to be relatively robust since the glass is considered impermeable to moisture transmission, and therefore the cells and interconnects are less vulnerable to corrosion over years of exposure in the field. However, manufacturers do need to ensure that the edges around the module are properly sealed to ensure expected lifetimes. (M.D. Kempe, 2010) Transparent polymer backsheets are relatively new to the industry, and resistance to premature weathering and degradation may vary widely with the particular construction. Care should be taken that the backsheet material will meet the demands of the environment at the project site.

Resistance of the construction to the damaging effects of moisture can be evaluated with Damp Heat testing and Humidity/Freeze cycling. IEC 61215/61730, which are the required international standards, require 1000 hours of Damp Heat and 10 cycles of Humidity/Freeze testing. However, it is increasingly common for manufacturers to test their products beyond the basic requirements in the IEC standards. Good performance to at least 2-3X the standard test lengths are increasingly viewed as the minimum validation of product durability. Independent 3rd party test results should be reviewed as part of product diligence.

4.2.2 MECHANICAL STRENGTH

Another major difference in construction within the dual glass module types is the thickness of the glass used and whether a frame or frameless construction is used. Glass thickness if not always specified, but in the sampling of products in the above table, thickness ranges from 2.5mm to 3.2mm. Particularly for the frameless modules, this can have a significant impact on mechanical strength and ability of the module to resist cell and module interconnect breakage over years of field exposure. Many 3rd party laboratories offer dynamic mechanical load testing, which is meant to simulate the mechanical stresses experienced by the module in the field. This is not a test which is required for IEC certification, but is one which is generally considered a good indicator of mechanical integrity, and is typically done as part of an extended length test program.

4.3 LID

Monocrystalline PERC cells are thought to be more susceptible to Light Induced Degradation (LID) compared to traditional aluminum back surface field (AL-BSF) cells. Degradation occurs due to activation of boron-oxygen (BO) defects in boron-doped p-type monocrystalline silicon (referred to as BO-LID). The degradation is more severe for high-performance technologies such as PERC. While LID power loss for Al-BSF is typically 2–3%, for PERC cells it can be as high as 3–6%. (Sraisth, 2018)

One approach to solving the problem is regeneration processes, where a cell is treated with light intensity at an elevated temperature. However, all cells need to be treated and results can be quite variable since there is a distribution of defects and therefore LID across the cell population. One report states that even with this treatment, 50% of installed modules may still exhibit LID to some degree. (Lin, 2018) Another approach is to replace Boron with Gallium as the dopant in the silicon crystals. Replacing Boron with Gallium has been shown to significantly reduce LID in monocrystalline PERC cells, however the approach is not yet widely adopted. (J. Lindroos, 2016)

N-type Silicon is known to exhibit minimum LID, and therefore the risk of LID will be much lower with bifacial products based on these technologies.

As part of overall product diligence, reviewing third party test data and understanding manufacturing production procedures is best practice in assessing expected levels of LID. Since LID can be variable by batch, best practice is to receive data representative of the project modules to be used.

4.4 LONG TERM DEGRADATION

All products listed in Table 4.1 offer 30 year warranties, with the exception of the LG Neon 2, which has a polymer backsheet and offers a standard 25 warranty. Warranty specifications, based on high level descriptions in product datasheets, are graphed in Figure 4.1. Note that manufacturers' warranty documents should be reviewed carefully to determine warranted power levels of backside as well as front side power, as well as additional details including the initial power used as the warranty starting point. The power warranties with the highest year-1 warranted percentages include Silfab and Yingli, both of which are based on N-type Silicon and would therefore expect to have reduced susceptibility to LID which occurs within the first year. Silfab offers the most competitive warranty overall, with a warranted power percentage of 99.3% in year-1, followed by a warranted degradation rate of 0.4% per year out to year 30.

As part of overall product due diligence, warranted power degradation should be validated by supporting test data. Test data supporting both initial LID (see section 4.3), since this influences year-1 warranted percentages, as well as longer term data such as extended length Thermal Cycling (600 or more thermal cycles) combined with available field data should be reviewed to provide comfort in 30+ year lifetimes.

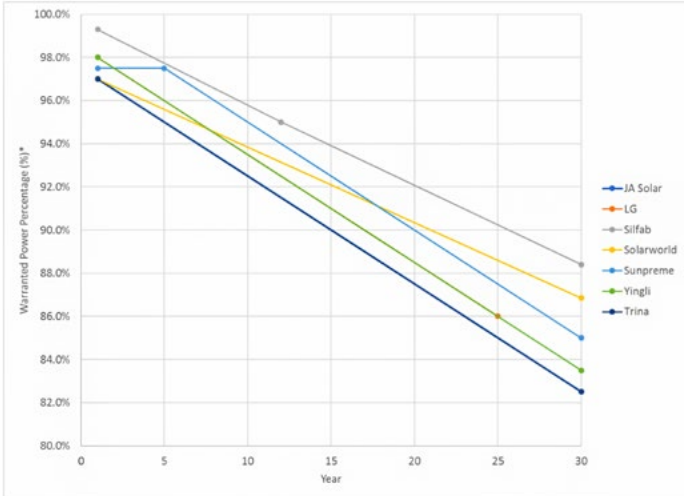

Figure 4.1: Bifacial manufacturer power warranties
* Refer to manufacturer's warranty document for details

5. SUMMARY AND CONCLUSIONS

Interest in bifacial technology is rapidly increasing due to the prevalence of modules now available, and the commercial infrastructure, including mounting systems and trackers, that are now designed to capitalize on potential energy gains. Additionally, field studies showing quantifiable energy gains have now been completed and commercially available energy models that predict generation and support financing of bifacial systems are now available.

The literature reviewed here has shown general agreement in expected Bifacial Gains for various system configurations. The modeling work completed as well as the field data for ground-mounted single axis tracking systems has supported anticipated Bifacial Gains in the range of 5-15%, with the higher end of that range more likely for higher ground albedos and regions closer to the equator. Based on the work reviewed here, fixed-tilt ground mounted systems are expected to show a Bifacial Gain of less than 10%. In comparison, this range could increase to 15-25% for fixed-tilt commercial roof mounted systems with higher albedos. This is intended as general guidance, and of course actuals gains will depend on a number of variables including technology selection, system geometry, location and ground (or roof) albedo.

There will be challenges in the adoption of bifacial products, however these are all manageable and will be addressed as the market matures. Energy models for yield prediction of bifacial systems show reasonable agreement with each other and with field measurements. Modeling uncertainties can be calculated knowing the various factors and scenarios which are likely to lead to less accurate predictions. Sandia and NREL are currently developing a draft measurement standard for factory testing and nameplate rating of bifacial models, and this will enable greater transparency in reporting bifacial model specifications. Reliability concerns can be mitigated with diligence and review of supporting test documentation as outlined here in this paper.

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