Value of bifacial photovoltaics used with highly reflective ground materials on single-axis trackers and fixed-tilt systems: a Danish case study

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Abstract: The energy produced by bifacial photovoltaic (PV) arrays can be augmented via albedo enhancements. However, the value of the additional energy must outweigh the costs for such modifications to be economically viable. In this work, the electrical performance and economic value of six 13 kWp crystalline-silicon (c-Si) PV arrays with distinct configurations are evaluated. The system designs include horizontal single axis trackers (HSAT) and 25˚ fixed-tilt structures, monofacial and bifacial PV panels, and low and high ground albedo. The value of the system designs is assessed using onsite electrical measurements and spot prices from the Nord Pool electricity market. We find that HSAT systems increase the annual value factor (VF) by 4% and decrease levelized cost of energy (LCOE) by 3.5 EUR/MWh relative to fixed-tilt systems. The use of bifacial panels can increase the VF by 1% and decrease LCOE by 4.0 EUR/MWh. However, a negligible VF increase and modest LCOE decrease was found in systems with bifacial panels and ground albedo enhancements. Although our results show that albedo enhancements result in lower LCOE than designs without, the uncertainty in upfront and ongoing costs of altering the ground in utility-scale PV parks makes the solution presently unadvisable.

1 Introduction

Recent years have shown a steady increase in bifacial photovoltaic (PV) installations because the light that impinges on the backside of a bifacial PV array can be converted into useable photocurrent. Historically, PV cells based on crystalline silicon (c-Si) have featured a rear side electrical contact fully covered in aluminium, which inhibits rear side light absorption. In contrast, the rear side of bifacial PV cells is only partially covered with metallisation [1]. When such bifacial cells are assembled into a module with a transparent rear cover (such as glass or a transparent back sheet) there is potential for considerable energy gains compared to monofacial (single-sided) modules that are deployed in the same conditions. The growth of bifacial PV implementation in large-scale systems is driven by the continuous reductions in PV module prices [2, 3] to the extent that the ITRPV forecasts that bifacial PV cells will account for 70% of the market share by 2030 [4].

The increased energy produced by a bifacial PV system over a monofacial PV system with equivalent front side power operating in the same conditions is known as the bifacial energy gain (BEG). The BEG is attributed to light reaching the backside of a PV system, which typically consists of diffuse (scattered) light from the ground, sky, or neighbouring PV rows, but the contributions of direct beam light are possible when the sun is behind a fixed-tilt system. In utility-scale PV parks, BEG is typically between 5 and 12%, depending on the configuration and the ground albedo [5–8]. Bifacial PV has potential to reach the lowest levelised cost of energy (LCOE) of any commercially available PV technology because such bifacial energy gains are achievable using the same land area that is used for monofacial PV designs while maintaining comparable upfront costs [9, 10]. A study by Rodriguez-Gallegos et al. [11] assessed the economics of different PV designs and found that bifacial PV on single-axis trackers achieves the lowest LCOE for >90% of the world’s land area.

In 2018 (the time of this work’s inception) the state-of-the-art bifacial PV simulation software lacked wide-scale validation [12], but according to a 2020 PV technology roadmap, bifacial PV model validation remains an urgent task [13]. Recent efforts have been made by the authors in [14–17] to close this gap. Still, bifacial PV installations do not have the decades of field experience that conventional monofacial PV technology has [18, 19]. The uncertainty surrounding bifacial PV performance results in perceived risk by investors, and consequently, an increase in project soft costs such as interest rates and cost of capital. Therefore, in 2018 the Danish-based renewable energy developer European Energy A/S constructed a 420 kWp pilot project to test bifacial PV technology against monofacial counterparts on large-scale fixed tilt (FT) structures and horizontal single-axis trackers (HSAT) [20]. The site was constructed to observe real-world bifacial gains under different conditions, to benchmark those gains against estimates made by reduced-order bifacial PV performance tools such as PVsyst and SAM, and ultimately to determine the economic value of bifacial PV on trackers within the Danish context.

The literature contains several studies that experimentally demonstrate the annual energy production gain of real HSAT systems versus equator facing FT systems. For example, a three-year study performed by Kinsey et al. [21] showed that the utility-scale HSAT systems in Andhra Pradesh, India produced a 14% higher yield than the latitude tilted static systems collocated at the same site. Another field study performed in Boca Raton, Florida showed that a 7.5 kWp HSAT system produced about 15% more energy on an annual basis than a latitude tilted static reference system [22]. Meanwhile, simulations indicate that the advantage of HSAT over static systems with optimally aligned fixed-tilt structures is between 10 and 25% depending on the ground cover ratio (GCR) and site latitude [23, 24]. It has been demonstrated that the BEG is mostly additive to the tracker gain [25].

Although PV power plants are commonly designed to maximise annual generation, when the business model is based on power markets the interesting parameter is not the total production or even the average cost of the energy, but the market value of the
electricity PV generated relative to the capital and ongoing costs within the investment horizon, which is typically 10 years. As shown in Fig. 1, the hourly power prices of the Nordic Nord Pool spot market [26] (also known as the ‘day-ahead’ market) are dynamic on hourly, daily, seasonal and yearly timescales. This price variability is driven considerably by the intermittent nature of renewable resources (e.g. hydro, wind and solar). Such price variability occurs not only in Scandinavia but in all Northern Europe [27, 28].

The profiles in Fig. 1 consistently show a midday drop in pricing due to high supply and low demand. This is consequently the same time that equator facing fixed-tilt PV systems have their peak production on clear sky days. Bifacial PV and HSAT technologies – whether used individually or together – offer the possibility to shift peak production to match times of peak demand. Investigations to this end have been conducted for vertically mounted east-west facing bifacial systems (VBPV), and their potential to match supply and demand profiles, stabilise the grid and increase self-consumption [29–31]. Simulations performed by Van Aken [32] have shown that bifacial on HSATs can generate more revenue per watt peak than VBPV in climates with both low and high fractions of diffuse irradiance.

We presented a preliminary version of this work in [33], but expand on it here by presenting nearly 1 year of energy production from six different systems installed at the test site. The six systems include bifacial and monofacial PV arrays mounted on a south-facing 25° tilt static structures and HSATs wherein the bifacial systems are above either natural grass or a highly reflective white tarp. The use of reflective materials to enhance bifacial gain has been studied by several authors [34–37], but the validation in these studies has only been made on small systems consisting of an individual bifacial cell or panel. Furthermore, according to a recent bifacial PV review paper [38], there is still an open question as to whether the cost of increasing the albedo is worth the additional energy yield. The present study investigates the extent to which large-scale bifacial PV on HSATs above highly reflective ground can optimise not only the annual generation but also the value of generation compared to monofacial static tilt designs. Additionally, the paper explores the potential for bifacial PV systems over highly reflective materials to create value-driven PV designs, wherein the bifacial boost may be exploited to load shift towards periods of high grid demand. This is achieved with measurements and simulations of large-scale bifacial PV systems that have structural dimensions analogous to those found in utility-scale installations.

2 Methods
2.1 Bifacial test site

Fig. 2 shows an aerial view of the test site and highlights the six systems investigated in this work. The balance of system (BoS) is identical in all systems investigated with the exception of the following differences: the orientation of the PV panels (static or tracked), the cell type (monofacial or bifacial), and the ground albedo (low or high). A description of the systems is given in Table 1. The natural grass vegetation is used to represent a low albedo scenario. Ground view images of the FT structures investigated in this work. The balance of system (BoS) is identical in all systems investigated with the exception of the albedo (low or high). A description of the systems is given in Table 1. The natural grass vegetation is used to represent a low albedo scenario. Ground view images of the FT and the HSAT systems above the white tarp are shown in Fig. 3.

Fig. 4 summarises the measured albedo of the two ground surfaces during a nine-month measurement campaign. Both surfaces exhibit a slight reduction in reflectance during winter, which is likely due to low sun angles but could also be attributed to an increase in the dew and moisture on the ground during that period. Also notable is that the white tarp's reflectance gradually degrades over time – about 0.07 (0.7%) per month. This degradation is expected, and the material's integrity is not expected to last longer than five years. Please note that the white tarp beneath the PV structures in Fig. 3 only extend about ± 2.0 m from the torque tube axis and, therefore, are not representative of uniform ground coverage.

We have used view factor calculations to estimate the effective reflectance along the vertical chord of the backside array for the white tarp scenarios. In the case of the FT structure, the percentage of reflected light originating from the white tarp out of the total ground reflected light is 65% for the bottom cells in the array. In other words, 35% of the ground reflected light received by bottom
Table 1  Technical descriptions of the six PV systems studied in this work. Note that ground clearance for tracker (HSAT) systems refers to the torque tube height while for FT systems it refers to the height from the lowest module edge to the ground

| System description (structure-PV array-ground) | PV Array | Average ground Albedo | Row-to-row pitch, m | GCR Ground clearance, m |
|------------------------------------------------|----------|-----------------------|--------------------|------------------------|
| FT-monomacial-grass                            | 44 × 305 Wp p-PERC (13.4 kWp) | 0.22 | 7.6 | 0.40 | 1.56 |
| FT-bifacial-grass                              | 44 × 295 Wp p-PERC (13.0 kWp) | 0.22 | 7.6 | 0.40 | 1.56 |
| FT-bifacial-white tarp                         | 44 × 295 Wp p-PERC (13.0 kWp) | 0.6 | 7.6 | 0.40 | 1.56 |
| HSAT-monomacial-grass                          | 44 × 305 Wp p-PERC (13.4 kWp) | 0.22 | 12 | 0.28 | 2.10 |
| HSAT-bifacial-grass                            | 44 × 295 Wp p-PERC (13.0 kWp) | 0.22 | 15 | 0.22 | 2.10 |
| HSAT-bifacial-white tarp                       | 44 × 295 Wp p-PERC (13.0 kWp) | 0.6 | 15 | 0.22 | 2.10 |

white tarp. In the case of the HSAT, the calculation is dynamic. At the extreme angle of 60° we find that for cells at the bottom, ~96% of the ground reflected light received originates from the white tarp, with a reduction to just 35% for cells at the top of the array. We demonstrated in [39] that the electrical mismatch losses induced by such gradients amount to <1%. Finally, ray-trace simulations performed by Rhazi et al. [40] have shown that increases in the coverage area (m²) of highly reflective materials below bifacial systems do not correspond with linear increases in bifacial energy gain. This indicates that adding additional white material is not likely to improve project economics beyond what is achievable with the modest amount of white material shown here.

The FT arrays are adjustable but are oriented with a 25° tilt angle during the period studied here. This tilt angle was chosen to reduce the mechanical stress on the structure compared to a more optimal tilt angle of 45°, which in an unshaded installation, could increase the annual generation by about 3% according to our PVsyst simulation. The horizontal single-axis tracker (HSAT) is mounted on a north-south oriented axis, where the rotation is varied from −60° in the morning (facing east) to +60° in the evening (facing west) by an algorithm that uses astronomical equations to track the sun in azimuth. The angular position is monitored by inclinometer sensors mounted on the back of the trackers. These data are within 2° of the tracker algorithm described by Marion and Dobos [41] for 50% of timestamps, and within 8° for 95% of the timestamps presented here when backtracking is not active.

Production data are recorded every minute from all installations on the DC and AC sides independently of their respective inverters. However, in some cases, there are systems with unique configurations (e.g. natural grass and white tarp) connected to the same inverter. Although such systems are connected to dedicated maximum power point trackers (MPPTs), it is not possible to distinguish between their performance on the AC side. Therefore, only maximum power ($P_{MAX}$) measurements from the DC side are used in this work and the partial load efficiency curve from the inverter manufacturer is used to model AC power. The monofacial and bifacial system have the same cell type (p-PERC) and are from the same manufacturer, but the front side rating of the bifacial modules is 10 W lower than the monofacial ones. Therefore, the AC power is normalised by the ratio of two front side power ratings to make their performance comparable.

The analysis presented here is limited to the period where the polymeric white tarps were installed underneath the HSAT and FT systems, which spans from August 2019 to June 2020 (11 months). Unfortunately, the inverter connected to the bifacial FT system above the white tarp experienced a failure during Denmark’s COVID-19 lockdown, which resulted in three months of lost data. Therefore, the results from this system are excluded from the analysis in some cases.

2.2 Economic analysis

The real-time hourly spot price of electricity at the back-feed location is used to determine the economic value generated by the six systems. However, as explained by Hirth [42] it is often more meaningful to study the relative, rather than the absolute market value. Therefore, the value of the energy generated by the six systems is not estimated and compared solely based on hourly Nord Pool Spot power market prices and income. We additionally

Fig. 3  Ground level views of the test site
(a) South facing FT rows with bifacial PV and white tarp, (b) HSAT with a bifacial and white tarp. The white tarp coverage in both systems is ~2 m from the torque tube

Fig. 4  Box plots of monthly albedo measured onsite during a nine-month campaign. The connecting lines show the monthly means. The white tarp measurements are made with upward and downward facing EKO ML-02 sensors. The grass measurements are made with upward and downward facing Kipp & Zonen CMP10 sensors. Both measurements are made in unshaded areas of the park

cells comes from surfaces other than the white tarp. The percentage is lower for cells at the top of the FT array: ~43% of the total ground reflected light received by these cells originates from the
use the value factor (VF) as used in [31, 43], which is the ratio of the income generated by a specific PV system relative to the average spot price during the period analysed the following equation:

\[ VF = \frac{P_{PV}}{P} \]  

(1)

Derivations of the VF numerator and denominator are shown in (2) and (3) respectively. In (2), \( P_{PV} \) is the calculated hourly spot price \( (P_t) \) weighted according to the hourly electricity \( (E_t) \) generated by a given PV system. And in (3) \( P \) is the base price calculated simply as the arithmetic mean of all spot prices during the period \( T \). The \( VF \) calculations only consider times when PV generation is greater than zero (i.e. night data is excluded).

\[ P_{PV} = \sum_{t=1}^{T} E_t \cdot P_t \sum_{t=1}^{T} E_t \]  

(2)

\[ P = \frac{1}{T} \sum_{t=1}^{T} P_t \]  

(3)

The \( VF \) would equal one if a PV system generated a flat (i.e. time-invariant) production curve during the analysed period. A \( VF \) of less than one means that the value of electricity produced is less than what a constant production profile would earn. When comparing the production curves of two or more generating technologies, increasing \( VF \) simply indicates that the power production curve is better aligned with high spot prices.

Additionally, we use the \( LCOE \) to compare the different system types in terms of their upfront and ongoing (i.e. lifecycle) costs and the electricity generated during a 30-year project period. The full \( LCOE \) model we use here is described in Annex 2 of [44], but the basic form of the \( LCOE \) calculation is shown in the following equation:

\[ LCOE = \frac{\sum_{r=1}^{N} C_r / (1 + d)^r}{\sum_{t=1}^{T} E_t / (1 + d)^t} \]  

where \( C_r \) is the total expenditures (capital, operation and maintenance, debt and equity service etc.) in year \( r \) and \( E_t \) is the energy generated in year \( t \). All cashflows are discounted by the discount rate \( d \). Many input values within the \( LCOE \) equation are highly project-specific (e.g. cost of capital and debt, land costs, local taxes etc.) and as such, the absolute \( LCOE \) values published here will vary for PV projects in different regions. However, the \( LCOE \) remains a practical and intuitive tool for assessing the costs and economic benefits of different energy generation technologies relative to each other.

2.3 Simulation

Since the specific installation conditions of this test site are not likely to yield the optimum annual generation, revenue, or value factor achievable with bifacial PV, we have performed simulations where the installation parameters known to affect bifacial PV performance were varied (e.g. row spacing, module height, tilt angle etc.). These simulations have been performed on an hourly basis using the System Advisor Model (SAM), free software from the US National Renewable Energy Laboratory [45]. The model parameters, coefficients and settings have been estimated in a parallel work [17], and are also used here. The site-specific meteorological data have been measured at DTU Fotonik’s Solar Radiation Station located ~400 m from the PV test field.

3 Results

3.1 Electrical performance and economics

Fig. 5 shows specific yields of the six PV systems and a statistical display of daily spot prices at the test site location. The average production profiles are illustrated for each month. Compared to the FT systems, the performance of HSAT systems generally have longer generation periods over the day, especially in summer months when the sun’s path is higher in the sky and spans a wider range of azimuth angles. The HSAT systems show higher generation in the morning/evening, but lower generation during midday when the tracker is oriented horizontally, and the sun’s angle incidence is higher relative to the FT plane than to the HSAT plane. Nevertheless, the HSAT production profile corresponds well to the typical variation of the power market prices over the day – wherein relatively high prices are observed in the morning/evening and relatively low prices observed during midday. Little difference is observed in FT versus HSAT production on cloudy days when 100% of the solar irradiance comes from diffuse light. Under such conditions, similar income is expected among all PV systems. The income from each system is calculated by simply multiplying the energy generation (MWh) by the spot price (DKK/MWh) at the time the energy was generated.

The Danish Kroner is part of the European Exchange Rate Mechanism, and as such, it is tied to the Euro within ±2.25%.

As expected, the income from each system shows a strong correlation with the energy generated \( (R^2 = 0.995) \). Fig. 6 shows the total income plotted as a function of the total energy generated during the entire 11-month test period. The data on the x-axis and the y-axis are normalised to the maximum energy and income, which in both cases is the bifacial HSAT system above the high reflectance white tarp.

Similar to the tracker gain, the bifacial gain can be inferred as the difference in normalised energy between the HSAT and FT systems that use the same module type. In the case of the monofacial arrays, the tracker gain is 12.8% and for the bifacial arrays, the tracker gain is 16.0%. The tracker gain for the bifacial arrays is larger because bifacial HSAT and monofacial HSAT have a different row to row pitches. The bifacial HSAT has a 15 m pitch while the monofacial HSAT has a 12 m pitch; the wider pitch of the bifacial HSAT leads to fewer hours backtracking from the ideal roll angle.

The difference in bifacial gains observed between the systems with differing GCR is consistent with the simulations performed by [7], which showed about a 3% reduction in bifacial gain when GCR is increased from 0.25 to 0.5.

The bifacial boost due to use of the high reflectance white tarp can be inferred from Fig. 6 by the difference between two bifacial systems on the same structure. In this case, the only comparison on the HSAT is possible because the FT bifacial system above the white tarp experienced 3 months of downtime. The bifacial boost from the white tarp below the HSAT is 2.8%, which is on top of the bifacial gain on grass (10.5%), and the monofacial tracker gain (12.8%), resulting in a total energy gain of 26.1% relative to the monofacial FT system.

The relative income delivered by the different PV systems mostly corresponds to the relative energy gains previously mentioned. However, there are deviations from a linear trend. These differences can be inferred from Fig. 6 by the difference between that 45° black unity line and the symbols representing the various systems. The largest differences from unity are on the order of 4%, which occur for both FT system types. This suggests that the additional economic value is mostly due to the single-axis
tracking gain rather than due to the bifacial gains. This will be discussed further in the Value Factor Analysis section.

Fig. 7 gives insight into the electrical generation and cumulative income on two select days. In the first case, (Fig. 7a) a clear sky day near the equinox is shown. This day shows the classic price profile with morning/afternoon prices that are higher than midday prices. The measured electrical performance of six PV systems is shown in the middle of the figure. The benefit of the HSAT's twin-peak profile is captured in the cumulative income plot shown in the bottom frame.

Fig. 7b depicts a day with high cloud variability and negative pricing for most of the day. When the spot price goes below zero, power producers are charged for electricity they put onto the grid. On a day such as the one shown here, PV operators would be penalised most heavily for the production of the bifacial systems. This is a scenario where bifaciality can indeed harm project financials unless actions like placing the PV systems in the open-circuit state are taken. The lowest (i.e. most negative) prices are observed in the middle of the day and therefore penalise the bifacial FT systems greatest of all.

3.2 Value factor analysis

Fig. 8 shows value factors (VFs) calculated according to (1). Recall that systems with a higher VF have a generation profile that is better aligned with high hourly spot prices than systems with lower VFs. The historic variability in VF is calculated using the electrical data measured during the period studied (Fig. 5a) and scaled according to the solar radiation and temperature measured onsite between 2015 and 2019. Each box plot is constructed using the historic hourly Nord Pool prices (Fig. 1) within each respective period to demonstrate the interannual variability in VF. There is a downward trend in the last five years, which makes sense because the market value of electricity from renewables drops with increasing grid penetration rates [42]. As Denmark’s capacity of
solar-generated electricity increased from 2% in 2015 to 4% at the end of 2020 [48], the historical VFs show a corresponding reduction. In most years, the HSAT systems yield about 1–2% higher VF than the FT systems. Interestingly, the largest spread in VF occurs in the 11-month period of data collection performed in this work (Aug 2019–Jun 2020). During this period there is about a 4% difference in VF between HSAT and FT systems, wherein about an additional 1% in VF is observed for bifacial over monofacial systems. The notable differences in VF during the period studied here (Aug 2019 – Jun 2020) are likely due to the occasional – but sometimes significant – negative pricing observed midday during March to June 2020. Negative midday pricing will always penalise the economics of the 25° FT system more severely than HSAT systems due to the higher midday electrical production at this latitude.

Fig. 9 shows the internal rate of return (IRR) plotted as a function of LCOE. The IRR is shown in conjunction with LCOE because the IRR is oftentimes a more meaningful metric for investors while the LCOE is mostly used by technical experts to compare different technologies. A clear negative correlation is observed, wherein the IRR decreases as the LCOE increases. Notably, whether the VF or LCOE is used as a figure of merit, the relative ranking of the six system types is largely the same.

In Fig. 9, the missing energy production data from the FT bifacial white tarp system have been imputed from months with a similar solar resource (e.g. missing April data is filled in with measured August data). Cost assumptions for all cases are based on discussions with suppliers. We have multiplied the expected capital cost of the white tarp by a factor of four to account for installation costs, which makes the white tarp ~15% of the total hard capital costs. This capital cost of the white tarp recurs every five years to include a 20-year mortgage with 0.5% interest that covers 80% of the total (i.e. soft and hard) capital expenditures, spot prices from 2018 as a baseline with inflation of 1.3%/year, linear depreciation over 30 years, a tax rate of 22%, system degradation of 0.5%/year and unavailability of 0.5%/year.

The results show that there are similar decreases in LCOE (and thus increases in IRR) between FT and HSAT systems and between monofacial and bifacial systems (3.5–4.0 EUR/MWh). There is a small, but a notable decrease in LCOE between bifacial above grass and bifacial above white tarp cases. In the FT bifacial grass versus FT bifacial white tarp case, there is a 0.6 EUR/MWh LCOE decrease and a 0.4% IRR increase. While the comparison of the HSAT bifacial grass and HSAT bifacial white tarp systems shows a smaller difference: a 0.1 EUR/MWh decrease in LCOE and a 0.1% increase in IRR. The larger LCOE and IRR differences in the FT case could be due to the use of data imputation.

For both the bifacial FT and bifacial HSAT system, the extra cost of the white tarp does appear to be compensated by the additional energy production. The LCOE and IRR differences between bifacial grass and bifacial white tarp are, however, small. Therefore, the uncertainty in the capital expenditure and O&M parameters leads to the prudent conclusion that the white tarp is not advisable until O&M and/or CAPEX of such an albedo enhancement solution comes down. For example, an O&M increase of just 10% in the bifacial white tarp cases increases the LCOE and decreases IRR to levels less favourable than bifacial cases without ground albedo enhancement.

### 3.3 Simulations with varying GCR

It is worth repeating that the measurements and simulations of the FT and HSAT systems presented here have been made for one specific set of installation conditions (i.e. GCR of the FT = 0.4, and GCR of the HSAT = 0.28). In practice, the net benefit of HSAT over FT systems is highly dependent on the GCR [49]. The net increase both in the energy yield and revenue achieved by HSAT systems will be higher for low GCR sites (i.e. wide PV row spacing) than for low GCR sites. This is large because in low GCR sites, HSAT systems can spend more hours in the early morning and late evenings oriented at an ideal angle without shading.
neighbouring rows. In other words, the trackers must backtrack less at low GCR sites.

Fig. 10 shows the specific yield (kWh/kWp) results from simulations where the GCR is varied. The measured yields are shown as individual markers. The measured and modelled results shown in Fig. 6 indicate that income is correlated with energy gain between the same two system types, which suggests that modifying the ground with high reflectance material has the greatest benefit for PV installations with a wide row-to-row pitch.

4 Conclusions

We have assessed the relative energy gains and prospective economic advantages of six different PV array designs installed in Denmark. The design variations tested were FT versus single-axis tracker designs, monofacial versus bifacial PV array designs, and designs that have low versus high ground reflectance. Nearly one year of measurements showed that the relative energy gains between the different PV systems are as high as 26.1%. Specifically, it was found that the tracker gain using monofacial panels is 12.8%, the bifacial energy gain on grass is 10.5% using trackers and is 7.2% using FT systems, and finally, the bifacial boost from using a polymeric white tarp below the tracker is 2.8%.

We have assessed the economic advantage of each system by analysing $V_F$ and $LCOE$ values of the system designs. For the system designs studied here, we found that the largest economic advantage due to daily energy generation profiles is obtained with single-axis tracking designs. Specifically, single-axis tracker designs can improve the relative economic benefit achieved by single-axis trackers, on the order of 1%. We found a negligible increase in $V_F$ when a highly reflective white tarp was mounted below the bifacial PV arrays. The $V_F$ results dovetail with the $LCOE$ findings. The $LCOE$ of bifacial systems with the white tarp is between 0.1 and 0.4 EUR/MWh lower than bifacial systems without it. However, we found that small variations in the capital and/or O&M cost of the white tarp could easily reverse the financial allure of this albedo modification if the power loss in such scenarios is complex and thus inaccuracies in the shading model or any modest misrepresentation of the physical system geometry in the model are suspected to cause the larger errors in these months.

The largest difference in energy gains is observed for the 0.2 GCR case. In this case, there is a 24% energy gain of the ‘HSAT-Bifacial-White Tarp’ system compared to the ‘Fixed Tilt-Monofacial-Grass’. As for the 0.8 GCR case, there is only an 8% energy gain between the same two system types, which suggests that modifying the ground with high reflectance material has the greatest benefit for PV installations with a wide row-to-row pitch.
augmentation solution. Therefore, it is our prudent recommendation to not recommend such ground albedo enhancements until definite cost reductions are achieved.

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