

Article

Rooftop Bifacial Photovoltaics Under Site-Specific Roof-Albedo and Geometry Scenarios: Energy, Emission, and Economic Assessment

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Abstract

Rooftop bifacial photovoltaic (PV) performance depends on both the optical properties of the roof surface and the installation geometry. This simulation-based study assessed a planned rooftop PV installation on a school building in Brno, Czech Republic, using PV*SOL simulations and statistical post-processing in R. The principal dataset comprised 238 bifacial scenarios combining seven spatially distinct roof zones assigned nominal albedo values from 8% to 80%, 17 module tilts from 0° to 80°, and row spacings of 1.00 and 2.10 m. Because each nominal albedo was associated with a different physical roof zone, the results represent combined roof-zone, reflectance and geometry responses rather than the isolated causal effect of albedo. The highest annual specific yield was obtained in the roof-zone scenario assigned 70% nominal albedo. The maximum was 1296.60 kWh/kWp at 1.00 m spacing and 35° tilt and 1359.34 kWh/kWp at 2.10 m spacing and 50° tilt. Under the fixed 25° reference configuration, the bifacial system outperformed the matched monofacial reference in all seven scenarios, with bifacial gain ranging from 7.57% to 11.23%. An empirical response-surface model reproduced the complete simulation grid with adjusted $R^2 = 0.980$ and RMSE of 13.94 kWh/kWp. For the representative 6.0 kWp subarray, the maximum lifetime incremental avoided-emission difference relative to the matched 8% reference was 10.35 t CO₂. Within the predefined Monte Carlo ranges, the highest-ranked scenarios produced positive incremental net present value in all 5000 sampled combinations. The findings show that roof reflectance should be evaluated together with tilt, spacing and spatial roof context. They do not establish a universally optimal albedo or rooftop configuration.

Keywords: bifacial photovoltaics; rooftop PV; roof-zone reflectance; roof albedo; module tilt; row spacing; PV*SOL; response-surface model; avoided CO₂ emissions; net present value



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1. Introduction

Photovoltaic electricity generation is one of the principal technologies supporting the transition towards low-carbon energy systems. Rooftop PV installations are particularly relevant in urban and industrial environments because they enable renewable electricity production without additional land occupation. As usable roof areas are often limited, improving energy production per unit of installed capacity is an important objective in sustainable PV-system design.

Bifacial PV modules can increase energy production by converting the irradiance incident on both the front and rear sides. Compared with monofacial systems, however, their performance is more sensitive to installation geometry and to the optical properties of the surrounding surfaces. Rear-side irradiance depends on roof reflectance, module tilt, mounting height, row spacing, shading and the fraction of the reflective surface visible from the module rear side. These parameters are, therefore, closely related to roof material, surface colour, spatial position and mounting configuration.

Increasing roof-surface albedo is generally expected to increase bifacial yield because a more reflective surface can provide additional rear-side irradiance. In practical rooftop installations, however, reflectance cannot be considered independently of geometry and spatial context. The useful rear-side contribution may be affected by self-shading, horizon obstruction, row-to-row interactions, finite reflective areas and the angular distribution of reflected irradiance. Consequently, a set of site-specific roof-zone and geometric scenarios may exhibit a non-monotonic yield response, and the scenario with the highest nominal albedo does not necessarily have to produce the highest annual yield.

This study evaluates the performance of a planned rooftop bifacial PV installation using a site-specific scenario grid combining nominal roof-surface albedo, module tilt and row spacing. The analysis considers annual specific yield, bifacial gain, avoided CO₂ emissions and economic indicators, particularly net present value under uncertainty. A monofacial configuration at the predefined base tilt is used as a fixed reference rather than as an independently optimised competing design.

Because the nominal albedo values were assigned to spatially distinct roof zones, the results are interpreted as combined roof-zone, reflectance and installation-geometry responses. Furthermore, the number of modules and installed capacity were held constant, so the study compares specific yield rather than total electricity production or economic value per unit of available roof area. The identified best-performing configurations, therefore, apply only to the tested scenario grid and are not presented as universally optimal design values.

2. Literature Review

Rooftop PV installations contribute to renewable electricity generation while using surfaces that are already part of the built environment. They are, therefore, relevant not only for energy production but also for sustainable spatial planning, building operation and regional energy transition [1–5]. Bifacial modules are particularly attractive because they can use irradiance incident on the rear side, although the practical value of this contribution depends strongly on the installation environment.

Early studies established that rear-side energy production is controlled by the amount and angular distribution of reflected irradiance reaching the module [6–15]. Bifacial gain is, therefore, not a fixed module characteristic, but a system-level indicator determined by module properties, surface reflectance, geometry, shading and irradiance distribution. Experimental measurements and yield models have further shown that the same bifacial module may produce different gains under different albedo, mounting-height and tilt conditions [16–22].

Installation geometry is consequently a central aspect of bifacial-system design. Module tilt influences front-side irradiance and rear-side visibility of the reflective surface. Mounting height affects the fraction of the roof or ground contributing to rear irradiance, while row spacing influences mutual shading, horizon obstruction and the distribution of reflected radiation. Previous sensitivity studies show that these parameters interact with surface reflectance and can either enhance or limit the benefit of a high-albedo surface [23–30].

Response-surface and optimisation studies, therefore, recommend treating bifacial-system design as a multivariable problem [31–37].

Surface reflectance is another important external driver of bifacial PV performance. Previous studies have investigated sand, concrete, soil, artificial reflectors, white membranes, cool roofs, green roofs and other natural or engineered surfaces [38–49]. More reflective surfaces generally increase rear-side irradiance, but the resulting energy gain varies because it also depends on the distance between the surface and the module, the visible reflective area, material optics and the local irradiance regime. Reflectance should, therefore, be treated as a geometry-dependent design variable rather than as an isolated guarantee of higher yield.

Rooftop applications introduce additional constraints. White roofs and cool-roof coatings can increase reflectance and may also reduce roof-surface temperature [50–53]. Green roofs and other urban surfaces may additionally influence thermal conditions, evapotranspiration and reflectance [54–59]. However, the energy benefit of a reflective surface depends on the PV layout. Closely spaced rows, unsuitable tilt or limited rear-side visibility may reduce the value of a high-reflectance treatment.

Reliable albedo data are also important for simulation accuracy. Albedo is commonly represented by a single scalar value, although actual reflectance varies with wavelength, angle of incidence, ageing, soiling, moisture, season and spatial heterogeneity [60–65]. Model-comparison studies have shown that different rear-side irradiance assumptions may produce different predictions for the same installation [66–74]. This uncertainty is particularly relevant on roofs, where the reflective area is finite and may be spatially heterogeneous.

The importance of installation context is also evident in floating PV, agrivoltaic, high-latitude, desert and hybrid-energy applications [75–86]. These studies confirm that bifacial performance should not be generalised without considering local geometry and reflective conditions. Advanced module concepts and tandem technologies do not remove this dependence on rear-side irradiance availability [87–97].

Economic performance is equally context-dependent. Bifacial systems can be economically attractive when their additional energy production compensates for higher module, mounting or design costs [4,5,98–101]. Reflective roof treatments may introduce additional investment and maintenance costs, while their economic value depends on electricity prices, discount rates, project lifetimes, degradation and the magnitude of the incremental yield. Energy analysis should, therefore, be complemented by financial indicators such as NPV and by environmental indicators, such as avoided CO₂ emissions.

The reviewed studies demonstrate the importance of reflectance, tilt, mounting height and row spacing, but relatively few combine spatially heterogeneous rooftop scenarios, systematic tilt and spacing variation, and subsequent environmental and economic assessment in one framework. This gap is relevant to practical design because reflective roof treatments must be evaluated within the geometric and spatial constraints of a specific building.

The principal literature findings and their implications for the present study are summarised in Table 1.

Based on this review, the present study addresses the need for an integrated, site-specific assessment of rooftop bifacial PV performance. PV*SOL simulations are combined with statistical post-processing in R to evaluate energy, emission and financial indicators across roof-zone, tilt and spacing scenarios. The outputs are interpreted as responses of the tested scenario grid rather than as evidence of an isolated or universally applicable albedo optimum.

The study is guided by the following research questions:

1. How does annual specific yield vary across the tested roof-zone, nominal-reflectance and module-tilt scenarios?

2. How does row spacing modify the observed relationship between roof-zone scenarios, module tilt and bifacial yield?
3. Which tested combinations of roof zone, nominal reflectance, tilt and spacing are associated with the highest annual specific yield?
4. Under the fixed 25° base configuration, how does the bifacial system perform relative to the monofacial reference?
5. How do scenario-dependent energy differences translate into avoided CO₂ emissions and economic indicators, particularly incremental NPV under the stated assumptions?

Table 1. Main literature findings and their implications for the present study.

Research Stream	Main Finding	Implication for This Study	Representative References
Bifacial PV fundamentals	Bifacial gain depends on rear-side irradiance and installation conditions and is, therefore, a system-level indicator.	Compare bifacial and monofacial systems under matched reference conditions.	[10,14,22]
System geometry	Tilt, mounting height and row spacing interact with surface reflectance and determine how much reflected irradiance can reach the rear side.	Evaluate nominal reflectance, together with tilt and row spacing using scenario analysis and empirical response surfaces.	[24,31,32,37]
Roof surfaces and coatings	White, cool and reflective roofs can increase PV output, but the effect is site- and layout-dependent.	Treat roof reflectance as a configuration-dependent design variable.	[50–52]
Albedo data and modelling	Albedo varies with material, incidence angle, spectrum, ageing, soiling, moisture and season.	Interpret PV*SOL outputs through site-specific scenario comparison rather than as universal albedo effects.	[60,61,64,66]
Economic and environmental value	Additional bifacial yield is relevant when it improves emission reduction and investment performance.	Extend the energy analysis to avoided CO ₂ emissions and NPV.	[1,3,4,98]

3. Materials and Methods

This study presents a simulation-based, site-specific assessment of a planned rooftop photovoltaic (PV) installation on a school building in Brno, Czech Republic. The supporting roof surfaces were represented as horizontal planes, while the PV modules were installed on tilted mounting structures. Energy simulations were performed using PV*SOL premium 2026 (R6) (Valentin Software GmbH, Berlin, Germany) [102], and the exported outputs were processed in R version 4.5.2 (R Foundation for Statistical Computing, Vienna, Austria) [103].

The simulation design combined nominal roof-surface albedo, module tilt and row spacing. Because each nominal albedo value was assigned to a spatially distinct roof zone, the resulting differences represent combined roof-zone, reflectance and installation-geometry responses rather than isolated causal effects of albedo.

3.1. PV System Configuration

The complete PV*SOL model represented a 42.0 kWp grid-connected rooftop system comprising 84 JA Solar JAM60D41-500/LB bifacial modules (JA Solar Technology Co., Ltd., Beijing, China), each rated at 500 Wp. The total module area was approximately 186.0 m². The system was divided into seven roof-zone subarrays, denoted A–G. Each subarray contained 12 modules, had a nominal capacity of 6.0 kWp and covered approximately 26.6 m² of module area.

Each subarray was connected to one Huawei SUN2000MA-6KTL-M1 inverter (Huawei Technologies Co., Ltd., Shenzhen, China). Each inverter used two maximum-power-point trackers, with six modules connected to each tracker. The approximate module dimensions recorded in PV*SOL were 1.95 m × 1.13 m. Rear-side electrical properties, including the bifacial response, were taken from the PV*SOL database record for the JAM60D41-500/LB module and were not modified manually.

The principal technical parameters are summarised in Table 2.

Table 2. Principal parameters of the PV*SOL system model.

Parameter	Value or Treatment
Location	Brno, Czech Republic
PV*SOL version	PV*SOL premium 2026 (R6)
Climatic dataset	Meteonorm 8.2 (Meteotest AG, Bern, Switzerland) typical meteorological year for Brno, generated from the 2001–2020 reference period, hourly resolution
Bifacial module	JA Solar JAM60D41-500/LB, 500 Wp
Monofacial reference	Matched 6.0 kWp simulation dataset at 25°; the exact module designation was not retained in the archived analytical exports
Approximate module dimensions	1.95 m × 1.13 m
Complete system capacity	42.0 kWp
Number of modules	84
Roof-zone subarray	12 modules, 6.0 kWp
Inverter	Huawei SUN2000MA-6KTL-M1
Number of inverters	7
MPP configuration	Two trackers per inverter, six modules per tracker
Module azimuth	197°
Supporting roof surfaces	Horizontal
Base module tilt	25°
Principal tilt range	0–80° in 5° increments
Diagnostic tilt cases	85° and 90°
Row-separation variants	1.00 and 2.10 m
Mounting height	Part of the original PV*SOL 3D geometry; not varied as an analytical factor and not reported numerically in the archived standard outputs
Automatic layout optimisation	Not used

The module azimuth was fixed at 197°, corresponding to an orientation approximately 17° west of geographical south. Module number, nominal capacity, inverter configuration, azimuth, climatic dataset and electrical layout were retained within each simulation series.

The base configuration used a module tilt of 25°. This angle represented the predefined engineering layout of the planned installation and was not identified as an energy optimum. It was selected as the technology-comparison reference because matched bifacial and monofacial outputs were available for this configuration.

The monofacial dataset represented a matched reference with the same nominal subarray capacity, roof-zone assignment and tilt. It was used to quantify the difference relative to bifacial operation and was not independently optimised over the complete tilt–spacing range. The exact monofacial-module database designation was not preserved in the archived analytical exports; this comparison is, therefore, interpreted as a fixed simulation reference rather than as a fully reproducible optimised monofacial design.

For the extended bifacial assessment, tilt was varied from 0° to 90° in 5° increments. The principal analysis was restricted to 0–80°. The 85° and 90° configurations were retained only for diagnostic inspection because they exhibited discontinuous near-vertical simulation outputs and were excluded from the main response-surface analysis.

Two row-separation variants, 1.00 and 2.10 m, were evaluated. These values correspond to the dimensioned horizontal clear separation between adjacent module rows in plan view in the PV*SOL installation plans. They do not represent centre-to-centre row pitch, because total pitch also depends on module dimensions and tilt.

Mounting height was not included in the exported analytical dataset and was not treated as an independent study variable. It remained part of the underlying PV*SOL 3D mounting geometry, but its numerical value was not included in the archived standard reports. Consequently, the independent effect of mounting height cannot be quantified from the present dataset.

The module number and installed capacity were fixed for all tilt and spacing scenarios. The study, therefore, compares the annual specific yield for fixed-capacity layouts. It does

not optimise the number of module rows, total installed capacity, total building-level electricity production or NPV per unit of available roof area.

Annual specific yield was calculated as

$$Y = \frac{E_{AC}}{P_{STC}}, \quad (1)$$

where E_{AC} is annual AC electricity production and P_{STC} is the nominal DC capacity under standard test conditions.

3.2. Roof-Zone and Albedo Scenarios

The rooftop layout used to define the seven spatial zones is shown in Figure 1. The figure documents the spatial context in which the nominal albedo values were assigned.



Figure 1. Rooftop layout and spatial zones used for assigning the nominal albedo scenarios in the PV*SOL model. Letters A–G denote the seven spatial roof zones used in the scenario analysis.

The assignment of nominal albedo values to roof zones A–G is reported in Table 3.

Table 3. Assignment of nominal albedo values to the PV*SOL roof zones.

Roof Zone	A	B	C	D	E	F	G
Nominal Albedo (%)	8	80	70	60	50	40	30

The albedo values were defined as comparative design scenarios and were not obtained from an in-situ reflectance measurement campaign. The 8% case represented a dark, low-reflectance reference surface, while the higher values represented progressively more reflective roof conditions. The selected range spans low- to high-reflectance conditions commonly considered in bifacial-PV and reflective-roof studies [50,51,61].

The spatial zones A–G were inherited from the original PV*SOL roof partition. The albedo-to-zone mapping was neither randomised nor optimised and was not designed to form a monotonic spatial sequence. Because each nominal albedo value was associated with one physical roof zone, albedo and spatial position were not statistically separable. Differences related to roof edges, neighbouring surfaces, visible reflective area and surrounding geometry, therefore, remained part of the comparison.

Each zone contained the same bifacial module model, module number, nominal capacity, inverter configuration and azimuth. Incremental energy, emission and economic indicators were calculated relative to the 8% scenario at the same tilt and row spacing. These indicators consequently represent differences between matched site-specific scenarios rather than isolated albedo effects.

3.3. Energy-Yield Modelling

The simulations used an hourly Meteonorm 8.2 typical meteorological year for Brno generated from the 2001–2020 reference period [104]. The PV*SOL reports identify the Hofmann model for diffuse irradiance on the horizontal plane and the Hay–Davies model for transposition to the inclined module plane.

The hourly Meteonorm weather file supplied the global, direct and diffuse irradiance components required by PV*SOL. Annual global horizontal irradiance and direct normal irradiance totals were not separately exported in the archived standard reports and were, therefore, not included as independent variables in the subsequent statistical analysis.

The 3D model included the roof and surrounding geometry. However, the standard PV*SOL reports identified the aggregate annual shading-loss value as “not calculated”. No separate annual shading-loss percentage was, therefore, exported to R or interpreted as an independent explanatory variable. The post-processing used the annual AC outputs generated by the complete PV*SOL model.

PV*SOL did not automatically optimise tilt, row separation, mounting height or module number. Each tilt-spacing configuration was defined explicitly, while the remaining documented technical parameters were retained.

The principal bifacial dataset contained

$$7 \text{ roof-zone scenarios} \times 17 \text{ tilts} \times 2 \text{ spacing levels} = 238 \text{ scenarios.} \quad (2)$$

The 17 principal tilt values covered 0–80° in 5° increments. The analytical dataset contained the roof-zone identifier, nominal albedo, module tilt, row spacing, annual AC production and annual specific yield. Duplicate combinations were checked before analysis, and no duplicate combinations remained in the final dataset.

Because nominal albedo and roof-zone position were linked, the scenario response was expressed conceptually as

$$Y = f(\alpha, \theta, s, z), \quad (3)$$

where α is nominal albedo, θ is module tilt, s is row spacing and z represents the spatial roof-zone context.

Separate annual front- and rear-side energy components were not available in the exported analytical dataset. The analysis, therefore, evaluates total annual AC output and does not attribute individual yield differences exclusively to front-side irradiance, rear-side irradiance or shading.

For the technology comparison at 25°, bifacial gain in energy was calculated as

$$\text{BGE} = \frac{Y_{\text{bifacial}} - Y_{\text{monofacial}}}{Y_{\text{monofacial}}} \times 100\%. \quad (4)$$

The highest-yield scenarios were identified by sorting all 238 principal cases in descending order according to their unnormalised annual specific yield. No within-spacing normalisation or composite ranking score was applied. The ranking used annual specific yield only; no economic weighting, roof-area normalisation, spacing penalty or composite design score was included.

3.4. Emission-Impact Assessment

Avoided CO₂ emissions were calculated for a representative 6.0 kWp roof-zone subarray as

$$\text{CO}_{2,\text{year}} = E_{\text{AC}} \text{ EF}, \quad (5)$$

where EF is the electricity-emission conversion factor.

A constant value of

$$EF = 0.25 \text{ kg CO}_2 \text{ kWh}^{-1} \quad (6)$$

was retained to maintain consistency with the original environmental calculations. This value is treated as a comparative scenario coefficient and is not presented as the official Czech national emission factor.

For context, the Czech Ministry of Industry and Trade reported a 2025 gross-generation emission factor of 0.33 kg CO₂/kWh and a residual-mix factor of 0.45 kg CO₂/kWh [105]. The reported results scale linearly with the selected factor and can, therefore, be recalculated using another national, regional or time-dependent factor without repeating the PV*SOL simulations.

Lifetime electricity production and avoided emissions were calculated as

$$E_{\text{life}} = \sum_{t=1}^n E_{\text{AC}}(1-d)^{t-1}, \quad \text{CO}_{2,\text{life}} = E_{\text{life}} EF, \quad (7)$$

where $n = 25$ years and $d = 0.005$ is the annual degradation rate. Incremental emission differences were calculated relative to the matched 8% reference scenario.

Because the same constant emission factor was applied to every scenario, the absolute avoided-emission patterns are direct linear transformations of the annual energy-yield results rather than independent physical response surfaces.

3.5. Economic and Monte Carlo Analysis

The economic and Monte Carlo analyses used the same representative 6.0 kWp subarray and an assumed treated roof area of 40 m². The analyses evaluated fixed-capacity scenarios and did not optimise total building-level capacity or NPV per unit of available roof area.

For scenario i , project NPV for the representative subarray was calculated as

$$\text{NPV}_i = -I_{\text{PV}} - C_{\alpha,i} + \sum_{t=1}^n \frac{E_{i,t}p_t - C_{\text{O\&M},t}}{(1+r)^t}, \quad (8)$$

where I_{PV} is the PV investment, $C_{\alpha,i}$ is the assumed surface-treatment cost, $E_{i,t}$ is annual electricity production, p_t is the electricity price, $C_{\text{O\&M},t}$ is the annual operation and maintenance cost and r is the discount rate.

Incremental NPV relative to the matched 8% scenario was calculated as

$$\Delta\text{NPV}_i = -C_{\alpha,i} + \sum_{t=1}^n \frac{\Delta E_{i,t}p_t}{(1+r)^t}, \quad (9)$$

where $\Delta E_{i,t}$ is the annual production difference relative to the 8% reference at the same tilt and spacing.

The deterministic analysis used the most-likely parameter values. The Monte Carlo analysis used 5000 iterations and triangular distributions over the ranges listed in Table 4.

The principal robustness indicator was the probability that incremental NPV was positive. All economic results are conditional on the specified parameter ranges, the 25-year project lifetime, the assumed treated area and the fixed-capacity layout.

Table 4. Assumptions used in the deterministic and Monte Carlo analyses.

Parameter	Minimum	Most Likely	Maximum	Unit
Electricity price	0.10	0.18	0.30	EUR/kWh
Discount rate	2	5	9	%
PV CAPEX	700	1000	1400	EUR/kWp
O&M cost	10	18	30	EUR/kWp/year
Annual degradation	0.20	0.50	0.80	%/year
Surface-treatment cost	0	5	20	EUR/m ²

3.6. Statistical and Regression Analysis

The seven paired bifacial and monofacial outputs at 25° were summarised using the mean paired difference, a paired *t*-test and Cohen's *d*. Because the observations were deterministic simulation scenarios rather than a random sample of operating installations, these statistics were used as supplementary indicators of consistency and effect magnitude rather than as population-level inference.

For diagnostic purposes, separate albedo-only models were fitted to the seven bifacial and seven monofacial roof-zone scenarios at 25°. The linear diagnostic model was

$$Y = \beta_0 + \beta_1\alpha + \varepsilon, \quad (10)$$

and the quadratic diagnostic model was

$$Y = \beta_0 + \beta_1\alpha + \beta_2\alpha^2 + \varepsilon. \quad (11)$$

These models were retained only to document the limitations of one-variable descriptions. They were not used for physical optimisation or causal interpretation because nominal albedo was linked with spatial roof-zone position. Their detailed results are reported in Appendix A.

For the complete 238-scenario bifacial dataset, three nested empirical models were compared. The linear benchmark was

$$Y = \beta_0 + \beta_1\alpha + \beta_2\theta + \beta_3I_s + \varepsilon. \quad (12)$$

The additive quadratic benchmark was

$$Y = \beta_0 + \beta_1\alpha + \beta_2\theta + \beta_3I_s + \beta_4\alpha^2 + \beta_5\theta^2 + \varepsilon. \quad (13)$$

The principal empirical response-surface model additionally included the tested two-way interactions:

$$Y = \beta_0 + \beta_1\alpha + \beta_2\theta + \beta_3I_s + \beta_4\alpha\theta + \beta_5\alpha^2 + \beta_6\theta^2 + \beta_7\alpha I_s + \beta_8\theta I_s + \varepsilon, \quad (14)$$

where α is nominal albedo expressed as a percentage, θ is module tilt in degrees, and $I_s = 0$ for 1.00 m spacing and $I_s = 1$ for 2.10 m spacing.

The models were used as empirical surrogates for the PV*SOL scenario grid. Model performance was evaluated using R^2 , adjusted R^2 , root mean square error, leave-one-out cross-validation RMSE, Akaike information criterion and residual inspection. A high goodness of fit indicates accurate reproduction of the tested simulation grid but does not establish a universal causal relationship between albedo and yield.

3.7. Methodological Limitations

Nominal albedo and spatial roof-zone position were not independently varied. The observed responses, therefore, include both reflectance and spatial effects. The simulations have not yet been validated using measured operating data, and measured albedo, separate front- and rear-side annual energy and an aggregate annual shading-loss value were unavailable.

The numerical mounting height and exact monofacial-module designation were not retained in the archived standard outputs. Mounting height was not analysed as an independent variable, and the monofacial configuration was not independently optimised.

Module number and installed capacity were retained across all spacing scenarios. The study consequently evaluates specific yield for fixed-capacity layouts rather than total roof-area utilisation. The emission and economic outputs depend on scenario assumptions, and the response-surface model should not be extrapolated beyond the tested parameter ranges.

3.8. Research Hypotheses

The following hypotheses were evaluated within the site-specific scenario grid:

H1. *Annual specific yield differs across the tested roof-zone and nominal-reflectance scenarios.*

H2. *The response within the tested grid is non-monotonic, and the highest nominal albedo is not necessarily associated with the highest annual yield.*

H3. *Module tilt and row spacing modify the observed scenario response.*

H4. *Under the fixed 25° reference configuration, the bifacial system produces more energy than the matched monofacial reference.*

H5. *Scenario-dependent energy differences produce proportional emission differences and may generate positive incremental NPV under the stated economic assumptions.*

These hypotheses apply to the analysed rooftop model and are not intended as universal causal claims for all bifacial PV installations.

4. Results

The results describe the performance of the rooftop bifacial PV system across the tested roof-zone, nominal-reflectance and installation-geometry scenarios. Because each nominal albedo value was assigned to a spatially distinct roof zone, the observed responses represent the combined influence of surface reflectance, roof-zone position, module tilt and row spacing rather than the isolated causal effect of albedo.

The principal bifacial dataset contained 238 scenarios after excluding the diagnostic configurations above 80°. It comprised 119 scenarios for 1.00 m spacing and 119 scenarios for 2.10 m spacing. Module type, installed capacity, module number, inverter configuration, azimuth, climatic data and mounting configuration were retained within each simulation series. The bifacial–monofacial comparison was evaluated separately under the fixed 25° base configuration.

4.1. Effect of Roof-Zone Reflectance, Tilt and Spacing on Bifacial Yield

The rooftop layout and the assignment of nominal albedo values to areas A–G are presented in Figure 1. The roof planes were modelled as horizontal surfaces, while the modules were installed on tilted mounting structures.

Within the tested scenario grid, the highest annual yield was associated with the roof zone assigned a nominal albedo of 70%, rather than with the zone assigned 80%. This difference should not be interpreted as evidence that increasing albedo from 70% to 80% independently reduces PV yield. The two nominal values represented different spatial roof zones, and differences in position, visible reflective area, roof edges and surrounding geometry remained part of the comparison.

The complete annual-yield response for both row-spacing configurations is shown in Figure 2. The response surfaces illustrate the combined variation with nominal albedo and tilt, while the heatmaps provide a direct comparison of the high- and low-yield regions.

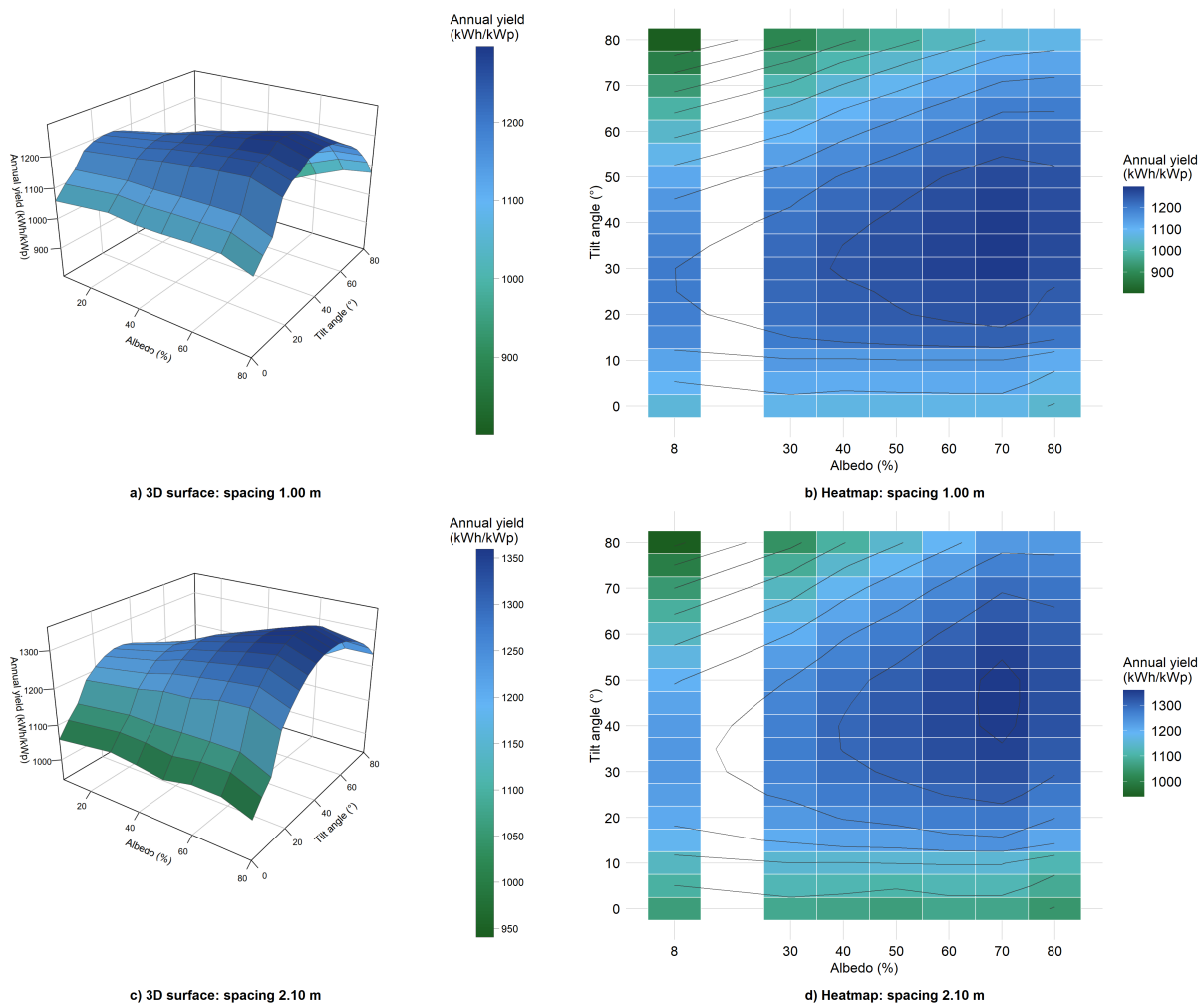


Figure 2. Annual bifacial yield across the tested nominal-albedo, tilt and row-spacing scenarios. Each nominal albedo was assigned to a spatially distinct roof zone; the surfaces, therefore, represent combined reflectance, roof-zone and installation-geometry responses.

The descriptive statistics corresponding to Figure 2 are reported in Table 5. At 1.00 m spacing, the mean annual specific yield was 1161.92 kWh/kWp and the maximum was 1296.60 kWh/kWp. At 2.10 m spacing, the mean and maximum increased to 1225.99 and 1359.34 kWh/kWp, respectively.

The tilt associated with the highest yield shifted from 35° at 1.00 m spacing to 50° at 2.10 m spacing. Wider spacing can reduce row-to-row obstruction and increase the roof area visible from the module rear side. However, separate annual front- and rear-side energy components were not available in the exported dataset. The results, therefore, describe the net annual AC response and do not quantify the contribution of individual irradiance components.

Table 5. Summary of annual bifacial yield by row spacing.

Row Spacing (m)	Mean Yield (kWh/kWp)	Minimum Yield (kWh/kWp)	Maximum Yield (kWh/kWp)	Best Tested Albedo (%)	Associated Tilt (°)
1.00	1161.92	801.63	1296.60	70	35
2.10	1225.99	940.71	1359.34	70	50

The spacing comparison used a fixed number of modules and a fixed nominal capacity. It consequently evaluates specific yield and does not account for the number of module rows or the total installed capacity that could be accommodated on a roof of fixed dimensions.

To clarify the scenario ranking, all 238 cases were sorted according to their unnormalised annual specific yield. The resulting ten highest-yield scenarios are listed in Table 6. The ranking used annual specific yield only; no within-spacing normalisation, economic weighting, roof-area normalisation, spacing penalty or composite score was used.

Table 6. Ten highest annual bifacial specific-yield scenarios in the complete dataset.

Rank	Spacing (m)	Nominal Albedo (%)	Tilt (°)	Annual Yield (kWh/kWp)
1	2.10	70	50	1359.34
2	2.10	70	45	1359.22
3	2.10	70	40	1357.18
4	2.10	70	55	1348.79
5	2.10	70	35	1347.51
6	2.10	60	40	1340.03
7	2.10	60	45	1339.38
8	2.10	60	50	1336.95
9	2.10	70	60	1335.81
10	2.10	60	35	1333.59

All ten globally highest-yield scenarios used 2.10 m spacing. The best overall scenario combined 70% nominal albedo with a tilt of 50° and produced 1359.34 kWh/kWp. The best 1.00 m configuration reached 1296.60 kWh/kWp at 70% nominal albedo and 35° tilt, but did not belong to the global top ten.

The largest positive and negative differences between the two spacing configurations are presented in Table 7. These comparisons further demonstrate that the effect of spacing was dependent on tilt and roof-zone scenario.

Table 7. Selected indicators of the row-spacing effect on annual bifacial yield.

Indicator	Nominal Albedo (%)	Tilt (°)	Yield at 1.00 m (kWh/kWp)	Yield at 2.10 m (kWh/kWp)
Maximum positive spacing difference	70	80	1062.65	1233.31
Maximum negative spacing difference	50	0	1073.46	1060.75
Best tested 1.00 m configuration	70	35	1296.60	1347.51
Best tested 2.10 m configuration	70	50	1280.50	1359.34

The largest positive spacing difference occurred in the 70% scenario at 80°, where yield increased from 1062.65 to 1233.31 kWh/kWp. A small negative difference occurred in the 50% scenario at 0°. The 70% roof-zone scenario was, therefore, the best-performing case within the analysed model, but this does not establish 70% as a universally optimal physical albedo.

4.2. Bifacial Versus Monofacial Performance

The direct comparison was performed under the fixed 25° base configuration. The monofacial system served as a matched reference and was not independently optimised over the complete tilt–spacing range.

The comparison of annual bifacial and monofacial yields is presented in Figure 3. The bifacial configuration produced more energy in all seven matched scenarios. Both technologies, however, exhibited a decline between the 70% and 80% roof-zone scenarios, indicating that the change cannot be attributed exclusively to a bifacial rear-side albedo mechanism.

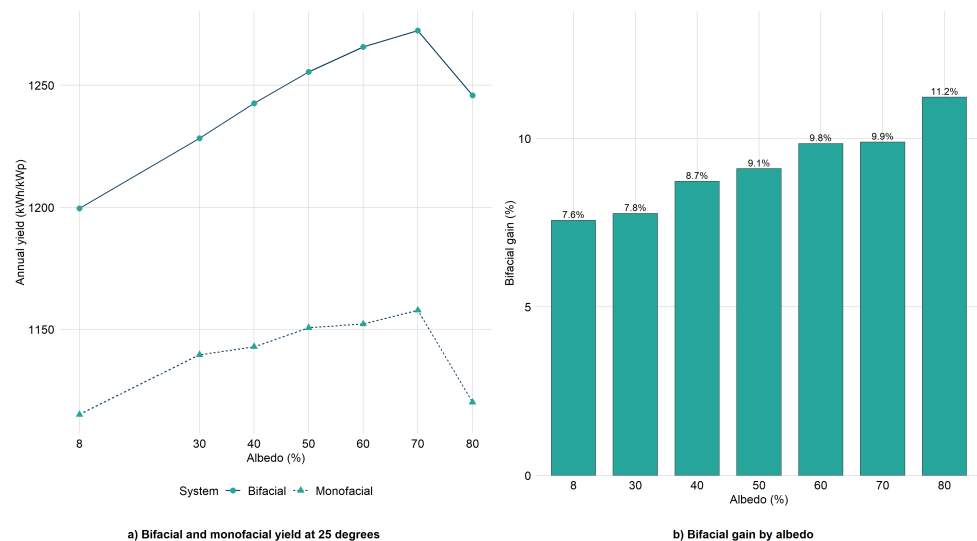


Figure 3. Comparison of bifacial and monofacial annual yield under the fixed 25° base configuration. Nominal albedo values correspond to spatially distinct roof-zone scenarios.

The numerical results underlying Figure 3 are reported in Table 8. The highest absolute bifacial production, 7634.35 kWh/year, occurred in the 70% scenario. The highest relative bifacial gain, 11.23%, occurred in the 80% scenario, partly because the corresponding monofacial reference value was lower.

The mean bifacial production advantage was 626.85 kWh/year, and all seven paired differences were positive. A paired *t*-test produced $t = 18.70$ and $p = 1.51 \times 10^{-6}$, while the standardised paired effect size was Cohen's $d = 7.07$. Because the observations were deterministic simulation scenarios rather than a random sample of operating systems, both statistics are interpreted descriptively and not as population-level inferential estimates.

Table 8. Bifacial and monofacial performance under the fixed 25° base configuration.

Nominal Albedo (%)	Bifacial Production (kWh/y)	Bifacial Yield (kWh/kWp)	Monofacial Production (kWh/y)	Monofacial Yield (kWh/kWp)	Production Difference (kWh/y)	BGE (%)
8	7197.19	1199.53	6690.74	1115.12	506.45	7.57
30	7369.36	1228.23	6837.62	1139.60	531.74	7.78
40	7455.72	1242.62	6857.13	1142.86	598.59	8.73
50	7532.61	1255.43	6904.08	1150.68	628.53	9.10
60	7593.99	1265.67	6913.11	1152.19	680.88	9.85
70	7634.35	1272.39	6947.03	1157.84	687.32	9.89
80	7475.20	1245.87	6720.77	1120.13	754.43	11.23

4.3. Empirical Response-Surface Modelling

The albedo-only linear and quadratic regressions are retained in Appendix A to document why simple one-variable descriptions were not used for physical optimisation.

The principal analysis was based on the complete 238-scenario bifacial dataset and the nested empirical models defined in Section 3.6.

The model-performance indicators are compared in Table 9.

Table 9. Empirical model comparison for the complete bifacial scenario grid.

Model	R^2	Adj. R^2	RMSE (kWh/kWp)	LOOCV-RMSE (kWh/kWp)	AIC	n
Response surface	0.981	0.980	13.94	14.51	1949.59	238
Quadratic model	0.919	0.917	28.82	29.86	2291.23	238
Linear model	0.268	0.258	86.62	88.36	2809.08	238

The response-surface model provided the closest empirical approximation, with adjusted $R^2 = 0.980$, RMSE of 13.94 kWh/kWp and LOOCV-RMSE of 14.51 kWh/kWp. These results show that the multivariable model accurately reproduces the tested PV*SOL grid within the analysed ranges. They do not independently validate a universal causal relationship between albedo and yield.

4.4. CO₂ Emission Reduction Potential

The environmental assessment converted annual electricity production from the representative 6.0 kWp subarray into avoided CO₂ emissions using a constant factor of 0.25 kg CO₂/kWh, a 25-year lifetime and annual degradation of 0.5%. Because the same emission factor was applied to every scenario, the avoided-emission patterns are direct transformations of the energy-yield results rather than independent physical response surfaces.

The derived avoided-emission maps for both spacing variants are retained in Appendix B. A numerical summary of the annual results is provided in Table 10. The values refer to the representative 6.0 kWp subarray rather than to the complete 42.0 kWp installation.

Table 10. Summary of avoided CO₂ emissions for the representative 6.0 kWp subarray.

Spacing (m)	Mean Avoided (t CO ₂ /y)	Maximum Avoided (t CO ₂ /y)	Mean Incremental (t CO ₂ /y)	Maximum Incremental (t CO ₂ /y)	Scenarios
1.00	1.743	1.945	0.119	0.413	119
2.10	1.839	2.039	0.126	0.439	119

The largest incremental annual and lifetime emission differences are reported in Table 11. Both maxima occurred in the 80% scenario at 80° because the corresponding 8% reference scenario performed relatively poorly at the same steep tilt.

Table 11. Maximum incremental CO₂ differences relative to the matched 8% reference scenario.

Spacing (m)	Nominal Albedo (%)	Tilt (°)	Annual Difference (t CO ₂ /y)	Lifetime Difference (t CO ₂)
1.00	80	80	0.413	9.73
2.10	80	80	0.439	10.35

These values represent the largest baseline-relative differences and not the configurations with the highest absolute annual energy production. The emission results should, therefore, be interpreted together with the selected reference scenario and conversion factor.

4.5. Economic Robustness Under Uncertainty

The economic results below report the conditional performance of the representative 6.0 kWp subarray under the assumptions defined in Table 4. The methodological setup is described in the Materials and Methods section and is not repeated here.

The resulting probabilities are conditional on the parameter ranges in Table 4. The largest deterministic incremental NPV occurred at 80° in both spacing groups. These cases should not be interpreted as recommended installation tilts because incremental NPV was calculated relative to the comparatively weak 8% reference scenario at the same inclination.

The conditional robustness results for 1.00 m spacing are shown in Figure 4. The left panel presents the probability of positive incremental NPV, while the right panel ranks the scenarios with the highest median incremental NPV.

The corresponding results for 2.10 m spacing are presented in Figure 5. Under the specified assumptions, the largest median incremental NPV was obtained for the 70% roof-zone scenario at 80°.

A numerical comparison of the highest-ranked scenario for each spacing configuration is provided in Table 12. This table is intentionally placed after both robustness maps so that the graphical results are presented first and the numerical summary follows in the same order.

Table 12. Highest conditional Monte Carlo results by row spacing.

Spacing (m)	Nominal Albedo (%)	Tilt (°)	P(Δ NPV > 0) (%)	Median Δ NPV (EUR)	P05 Δ NPV (EUR)	P95 Δ NPV (EUR)
1.00	80	80	100.0	3782.47	2295.12	5844.66
2.10	70	80	100.0	4086.31	2515.64	6267.42

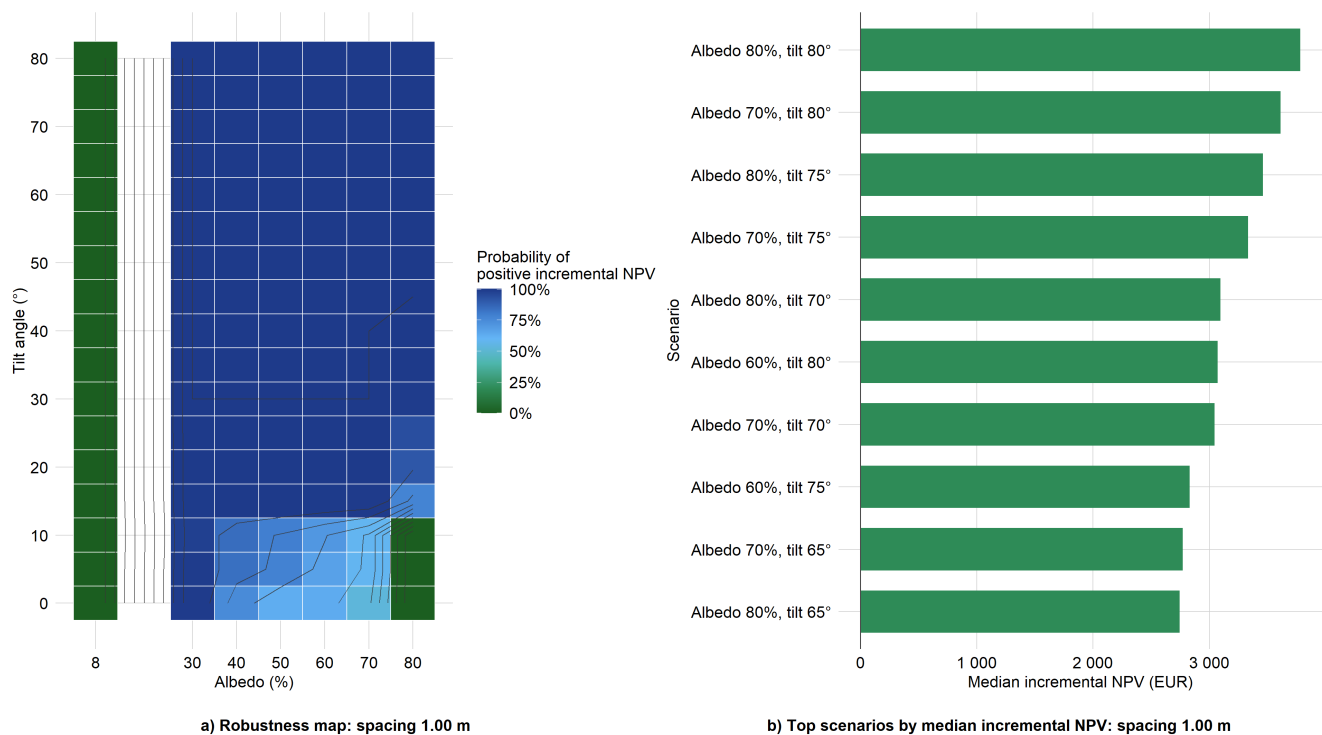


Figure 4. Conditional probability of positive incremental NPV and highest median incremental-NPV scenarios for 1.00 m spacing.

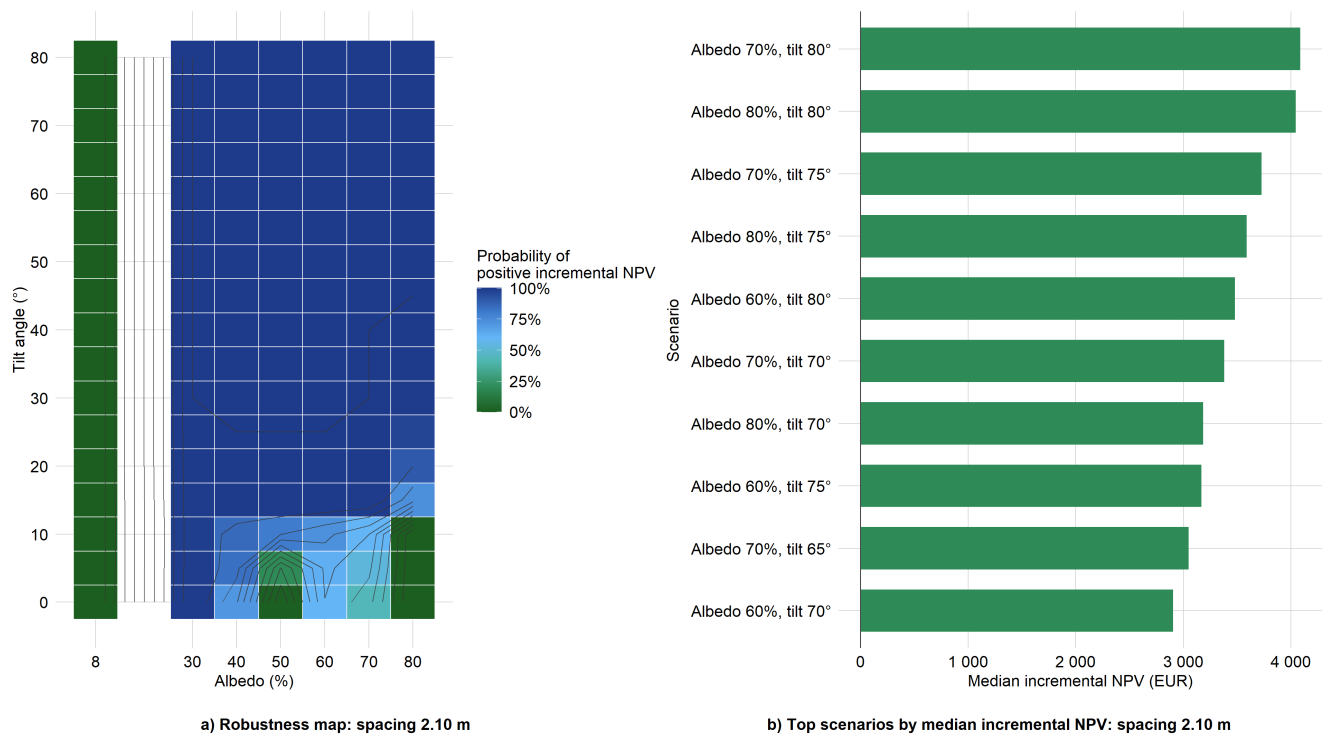


Figure 5. Conditional probability of positive incremental NPV and highest median incremental-NPV scenarios for 2.10 m spacing.

For both spacing configurations, every one of the 5000 sampled combinations produced a positive incremental NPV for the highest-ranked scenario. The reported probability of 100%, therefore, applies only to the predefined uncertainty ranges and does not imply that the investment is risk-free under different project conditions.

The full distribution and parameter-sensitivity results for the highest-ranked 2.10 m scenario are shown in Figure 6. The distribution remained positive within the selected ranges, while electricity price and discount rate produced the strongest positive and negative associations with NPV, respectively.

The Spearman sensitivity coefficients associated with Figure 6 are reported in Table 13. PV CAPEX had little influence on incremental NPV because the same underlying PV investment was used for the enhanced-surface and reference scenarios.

Electricity price was the strongest positive driver of both full and incremental NPV, whereas discount rate was the strongest negative driver. Surface-treatment cost had a weaker negative association within the tested cost range.

The configuration with the highest absolute annual yield was not identical to the configuration with the highest incremental NPV. This difference results from the baseline-relative economic calculation and should not be interpreted as evidence that an 80° installation is the preferred building-level design.

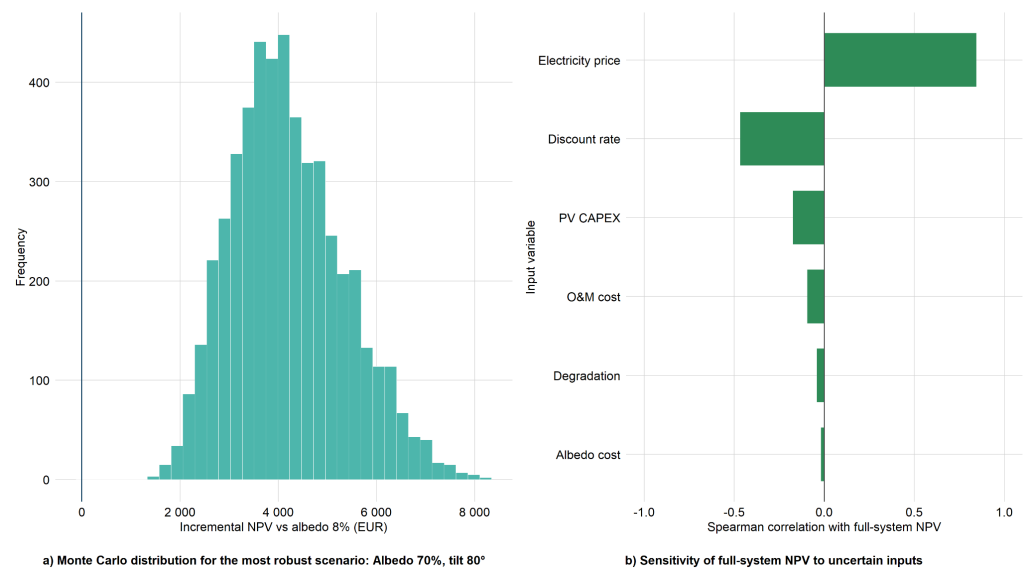


Figure 6. Monte Carlo distribution and sensitivity analysis for the highest-ranked conditional scenario at 2.10 m spacing.

Table 13. Sensitivity of NPV to uncertain economic inputs.

Input Variable	Spacing 1.00 m		Spacing 2.10 m	
	Full NPV	Incremental NPV	Full NPV	Incremental NPV
Electricity price	0.842	0.828	0.845	0.832
Discount rate	−0.458	−0.506	−0.466	−0.508
PV CAPEX	−0.199	0.001	−0.174	0.001
O&M cost	−0.104	−0.025	−0.095	−0.025
Degradation	−0.041	−0.039	−0.041	−0.039
Surface cost	−0.027	−0.141	−0.017	−0.112

5. Discussion

The results show that rooftop bifacial PV performance depends on the combined effect of roof-zone characteristics and installation geometry. Bifacial gain is a system-level response governed by surface reflectance, module tilt, mounting height, row spacing, shading and the visible reflective area rather than by module technology alone [10,11,14,22].

Under the fixed 25° reference configuration, the bifacial system outperformed the monofacial system in all seven matched scenarios, with bifacial gain ranging from 7.57% to 11.23%. However, the scenario with the largest relative bifacial gain was not the scenario with the largest absolute annual production. The highest absolute bifacial yield occurred in the roof zone assigned a nominal albedo of 70%, whereas the largest relative gain occurred in the 80% scenario. This distinction confirms that percentage gain and total electricity production represent different design criteria.

The decline between the 70% and 80% scenarios must be interpreted cautiously. A similar decline was also observed in the monofacial results. Because the nominal albedo values were assigned to different spatial roof zones, the result cannot be attributed exclusively to a change in rear-side irradiance. Roof-zone position, finite reflective area, roof edges and surrounding geometry remained part of the comparison. The 70% case should, therefore, be described as the best-performing tested roof-zone scenario, not as a universally optimal albedo value.

This interpretation is consistent with studies showing that the effect of reflective surfaces depends on module elevation, tilt, row spacing and surrounding geometry [23–27].

Reflective roofs can improve bifacial performance, but the magnitude of the benefit remains site- and layout-dependent [50–53].

5.1. Influence of Tilt and Row Spacing

Increasing row spacing from 1.00 m to 2.10 m increased the mean specific yield from 1161.92 to 1225.99 kWh/kWp and increased the maximum yield from 1296.60 to 1359.34 kWh/kWp. The tilt associated with the highest yield shifted from 35° at 1.00 m spacing to 50° at 2.10 m spacing.

This response is consistent with the expected geometric influence of wider spacing, which can reduce row-to-row obstruction and increase the roof area visible from the rear side of the modules. Nevertheless, separate annual front-side and rear-side energy components were not available in the exported dataset. The present study, therefore, evaluates net annual AC output and does not quantify the individual contribution of each optical mechanism.

The spacing comparison was performed at a fixed module number and fixed installed capacity. It consequently evaluates specific yield, not the maximum electricity production obtainable from the available roof area. A smaller spacing may permit more module rows and a higher total installed capacity, while a larger spacing may improve production per installed kWp. These objectives require a separate roof-density and building-level NPV optimisation and were outside the scope of this study.

5.2. Interpretation of the Regression Models

The diagnostic albedo-only regressions retained in Appendix A showed that quadratic curves reproduced the seven simulated points more closely than linear models. However, these regressions included only seven roof-zone scenarios in which nominal albedo and spatial position were linked. Their stationary points are mathematical properties of the fitted curves and are not interpreted as independent physical albedo optima.

For the complete bifacial dataset, the response-surface model achieved adjusted $R^2 = 0.980$ and RMSE of 13.94 kWh/kWp. Its high goodness of fit shows that the model provides an accurate empirical representation of the tested PV*SOL grid. It does not independently validate a universal causal relationship between albedo and yield.

The principal contribution of the regression analysis is, therefore, descriptive. It demonstrates that a multivariable model including tilt, spacing and interaction terms reproduces the simulated dataset more accurately than a simple linear model. This is consistent with previous studies recommending multivariable sensitivity and response-surface approaches for bifacial PV assessment [31–33,37].

5.3. Environmental and Economic Interpretation

The avoided-emission results are a direct linear transformation of annual electricity production because the same emission factor was applied to all scenarios. The emission heatmaps, therefore, reproduce the energy-yield patterns by construction and should not be interpreted as independent physical results.

For the representative 6.0 kWp subarray, the largest lifetime incremental difference relative to the matched 8% reference scenario was 10.35 t CO₂ over 25 years. This value occurred at 2.10 m spacing, 80% nominal albedo and 80° tilt. It does not represent the configuration with the highest absolute yield; it represents the largest difference relative to a low-performing reference at the same tilt.

The economic results require the same distinction. The highest incremental NPV scenarios occurred at steep tilt angles because the corresponding 8% reference cases produced relatively low energy. These scenarios should not be interpreted as recommended building-level layouts.

Within the assumed uncertainty ranges, the best scenarios achieved a calculated 100% probability of positive incremental NPV. This means that all 5000 sampled combinations within the defined parameter ranges produced positive results. It does not imply that the investment is risk-free under different electricity prices, coating costs, maintenance requirements or project conditions.

Electricity price was the strongest positive driver of incremental NPV, while the discount rate was the strongest negative driver. Surface-treatment cost had a smaller influence within the assumed range of 0–20 EUR/m². Project-specific quotations, durability information and maintenance costs would be required before an actual investment decision.

5.4. Verification of the Research Hypotheses

The hypotheses were evaluated within the limits of the site-specific simulation design. Their assessment is summarised in Table 14.

Table 14. Verification of the research hypotheses within the tested scenario grid.

Hyp.	Hypothesis	Evidence	Assessment
H1	Annual yield differs across the tested roof-zone and nominal-reflectance scenarios.	Substantial yield differences were observed across the seven scenarios and tilt-spacing combinations.	Supported within the tested grid
H2	The response within the tested grid is non-monotonic, and the highest nominal albedo is not necessarily associated with the highest yield.	The 70% scenario produced a higher absolute yield than the 80% scenario. The difference also occurred in the monofacial data and is, therefore, interpreted as a combined roof-zone response.	Supported with qualification
H3	Tilt and row spacing modify the scenario response.	The best-performing tilt shifted from 35° at 1.00 m spacing to 50° at 2.10 m spacing, and spacing effects increased at steep tilts.	Supported within the tested grid
H4	The bifacial configuration produces more energy than the fixed monofacial reference at 25°.	Bifacial yield was higher in all seven matched scenarios.	Supported for the reference configuration
H5	Scenario-dependent energy differences translate into environmental and economic differences.	Avoided emissions changed proportionally with energy output, and selected scenarios produced positive incremental NPV under the assumed ranges.	Supported conditionally

5.5. Practical Implications

The results indicate that roof reflectance should be considered together with module tilt, row spacing, mounting height and available roof area. Reflectance should not be maximised without considering the complete installation layout.

For the analysed building, the zone assigned a nominal albedo of 70% was associated with the highest specific yield. This result can support preliminary design screening, but it should not be transferred directly to other buildings. Different roof dimensions, obstructions, orientations, mounting systems and climates may produce different preferred configurations.

For public buildings, reflective roof treatment may be attractive when it is already being considered for waterproofing, thermal management or maintenance. In such cases, its optical properties can be included in the PV design process. The final decision should consider specific yield, total installable capacity, roof-area utilisation, structural constraints, maintenance and project-specific economics.

5.6. Limitations and Future Work

The principal limitation is that nominal albedo and spatial roof-zone position were not independently varied. The observed non-monotonic response, therefore, represents a combined roof-zone, reflectance and geometry effect.

The results are based on PV*SOL simulations and have not yet been validated using measured operation. Real performance may differ because of weather variability, module temperature, soiling, ageing, shading and maintenance. Actual roof reflectance may also vary with wavelength, incidence angle, moisture and season [60,61,64,65].

The mounting height was fixed rather than optimised, and the monofacial reference was evaluated only at the base 25° configuration. In addition, the module number and installed capacity were held constant, so the study did not optimise total electricity production or NPV per unit of roof area.

The environmental and economic results depend on assumed emission and financial parameters. They should, therefore, be treated as conditional scenario indicators rather than final project forecasts.

Future work should include measured roof albedo, front- and rear-side irradiance, module temperature, shading losses and annual energy production from the planned installation. A further extension should compare alternative layouts using total installed capacity and NPV per unit of available roof area.

6. Conclusions

This study assessed the energy, environmental and economic performance of a planned rooftop bifacial PV installation in Brno using PV*SOL simulations and statistical post-processing in R. The analysis considered seven nominal roof-surface reflectance scenarios, two row spacings and multiple tilt angles. Because the nominal albedo values were assigned to spatially distinct roof zones, the results represent combined roof-zone, reflectance and installation-geometry effects rather than the isolated causal effect of albedo.

Within the tested scenario grid, the highest annual specific yield was associated with the roof zone assigned a nominal albedo of 70%. The maximum yield was 1296.60 kWh/kWp at 1.00 m spacing and 35° tilt, and 1359.34 kWh/kWp at 2.10 m spacing and 50° tilt. The lower yield observed in the 80% scenario should not be interpreted as evidence that increasing albedo alone reduces PV performance, because a similar decline was also present in the monofacial results. The finding instead confirms that the best-performing configuration depends on the complete rooftop geometry and spatial context.

Under the fixed 25° reference configuration, the bifacial system produced more electricity than the monofacial reference in all seven matched scenarios, with bifacial gain ranging from 7.57% to 11.23%. The highest relative bifacial gain did not coincide with the highest absolute annual yield, demonstrating that percentage gain and total energy production are different design criteria. The monofacial configuration was used as a fixed benchmark and was not independently optimised across the complete tilt-spacing range.

The empirical response-surface model reproduced the full simulation dataset with adjusted $R^2 = 0.980$ and RMSE of 13.94 kWh/kWp. This confirms the usefulness of a multivariable representation including tilt, spacing and interaction terms. The model should, however, be interpreted as a surrogate of the tested PV*SOL scenario grid rather than as proof of a universal nonlinear albedo relationship or a universally optimal albedo value.

For the representative 6.0 kWp subarray, the environmental and economic analyses translated the simulated energy differences into conditional sustainability indicators. The maximum lifetime incremental emission difference relative to the matched 8% reference scenario was 10.35 t CO₂ over 25 years. Selected scenarios also achieved a calculated 100% probability of positive incremental NPV within the predefined Monte Carlo ranges. These results are conditional on the assumed grid-emission factor, electricity prices, discount rates, treatment costs, project lifetime and treated roof area; they should, therefore, be considered scenario-screening outcomes rather than guaranteed project forecasts.

The principal practical conclusion is that roof reflectance should be evaluated together with module tilt, row spacing, mounting height and roof-area utilisation. The present study compares fixed-capacity layouts and does not optimise the number of module rows, total installed capacity or NPV per unit of available roof area. Consequently, the identified best-performing scenarios apply only to the analysed rooftop model.

Future work should validate the simulations using measured annual production, front- and rear-side irradiance, roof-surface reflectance, module temperature, soiling and shading data from the planned installation. A further extension should compare alternative layouts using total energy production and economic value per unit of available roof area.

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Data Availability Statement: The processed datasets, archived PV*SOL output reports and R scripts used for the energy, emission, economic and regression analyses are available from the corresponding author upon reasonable request. The original PV*SOL project files were not part of the archived analytical package; consequently, the exact monofacial-module designation and numerical mounting-height setting cannot be reconstructed from the shared outputs. An interactive article-derived scenario calculator is available at the following URL: <https://maksym.mykhei.website.tuke.sk/Monografie%20a%20u%C4%8Debnice/Calcul.%20Albedo.html> (accessed on 21 July 2026). The calculator reproduces direct article values where available and otherwise interpolates only within the embedded article-derived ranges of nominal albedo, module tilt and row spacing. Its economic module uses the same units and baseline uncertainty ranges as the manuscript, including O&M in EUR/kWp/year and surface-treatment cost in EUR/m² for a user-defined treated area. All calculations are performed locally in the browser; the tool does not transmit entered data. It is intended for exploratory scenario screening and is not a substitute for project-specific PV*SOL modelling, engineering design, quotations or selection of an official grid-emission factor.

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Abbreviations

AC	Alternating current
AIC	Akaike information criterion
BGE	Bifacial gain in energy
CAPEX	Capital expenditure
CO ₂	Carbon dioxide

DC	Direct current
EF	Emission factor
LOOCV	Leave-one-out cross-validation
MPP	Maximum power point
NPV	Net present value
O&M	Operation and maintenance
PV	Photovoltaic
PV*SOL	Photovoltaic system simulation software
RMSE	Root mean square error
STC	Standard test conditions

Appendix A. Diagnostic Albedo-Only Regressions

The diagnostic regressions in this appendix are retained to demonstrate the limitations of modelling the seven roof-zone scenarios using nominal albedo as the only explanatory variable. Because nominal albedo and spatial roof position were not independently varied, these models are descriptive and are not used to determine a physical optimum.

The fitted curves and residual patterns are shown in Figure A1.

The corresponding model-quality indicators are reported in Table A1. Quadratic models reproduced the seven points more closely than linear models, but their stationary points are mathematical characteristics of the fitted curves and are not interpreted as physically optimal albedo values.

Table A1. Diagnostic regression comparison for the seven roof-zone scenarios at 25°.

System	Model	R^2	Adjusted R^2	RMSE (kWh/kWp)	Stationary Point (%)
Bifacial	Linear	0.698	0.637	12.54	–
Bifacial	Quadratic	0.892	0.838	7.49	65.9
Monofacial	Linear	0.140	−0.032	14.03	–
Monofacial	Quadratic	0.733	0.599	7.82	49.9

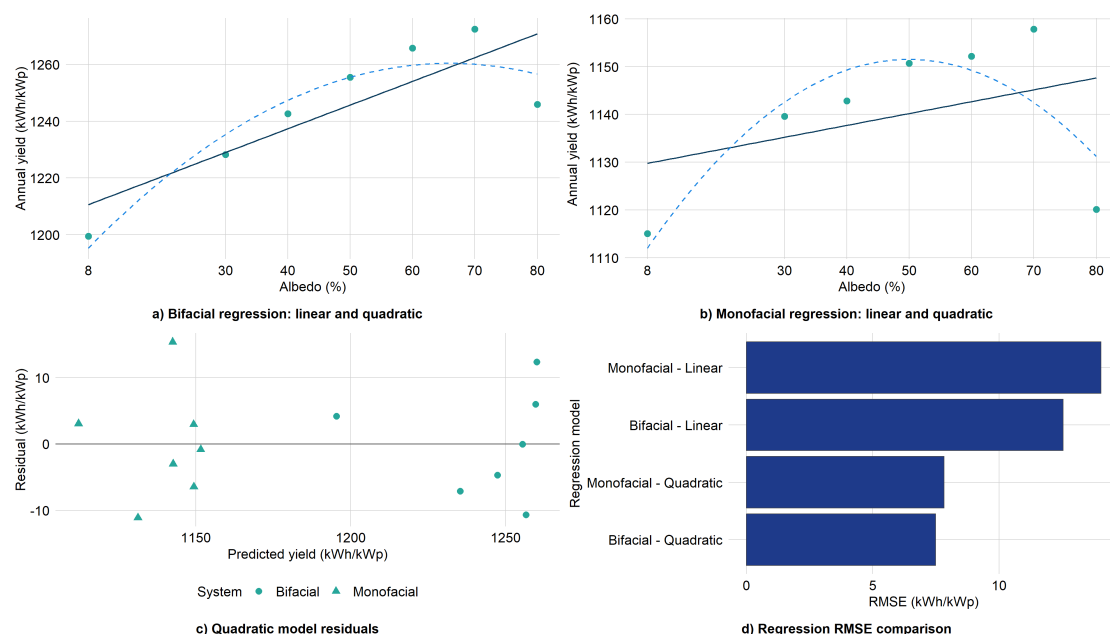


Figure A1. Diagnostic linear and quadratic regressions for the bifacial and monofacial roof-zone scenarios at 25°. Solid lines represent the fitted linear models, whereas dashed curves represent the fitted quadratic models. The models do not separate nominal albedo from spatial roof-zone effects.

Appendix B. Derived Avoided-Emission Maps

The maps in this appendix convert the energy-yield results into avoided-emission units using the constant scenario factor of 0.25 kg CO₂/kWh. They are retained for transparent reporting of the environmental post-processing, but their spatial patterns do not constitute independent physical evidence.

The derived results for 1.00 m spacing are shown in Figure A2.

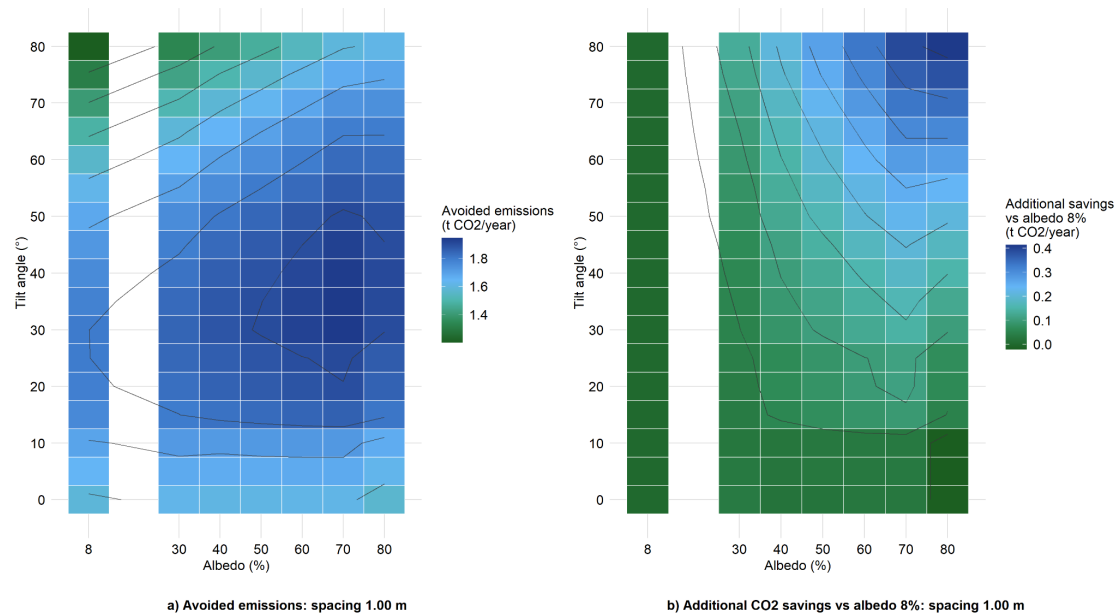


Figure A2. Conversion of the simulated energy-yield results into avoided CO₂ emissions and incremental differences relative to the matched 8% reference scenario for 1.00 m spacing. A constant conversion factor was applied, so the spatial pattern follows the energy-yield response.

The corresponding derived results for 2.10 m spacing are shown in Figure A3.

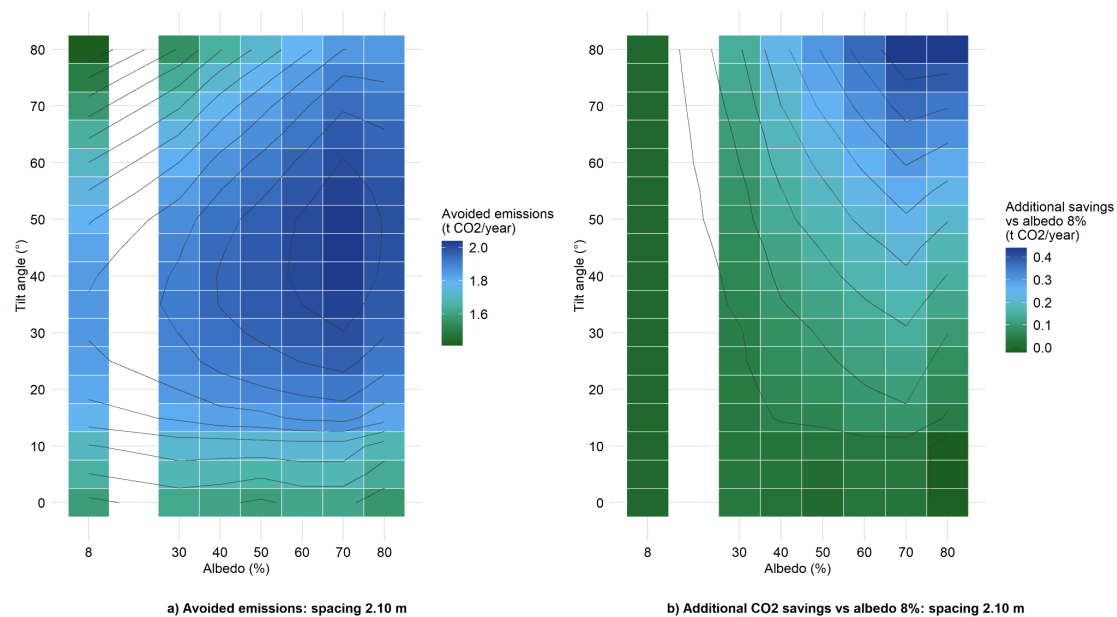


Figure A3. Conversion of the simulated energy-yield results into avoided CO₂ emissions and incremental differences relative to the matched 8% reference scenario for 2.10 m spacing. A constant conversion factor was applied, so the spatial pattern follows the energy-yield response.

Appendix C. Detailed Monte Carlo Input Interpretation

Table A2 provides the detailed interpretation of the fixed values and triangular distributions used in the 5000-iteration economic robustness analysis. The numerical ranges are identical to those reported in Table 4.

Table A2. Monte Carlo assumptions used in the economic robustness analysis.

Input Parameter	Distribution	Interval/Fixed Value	Interpretation
Number of simulations	Fixed	5000	Number of sampled parameter combinations.
Representative PV capacity	Fixed	6 kWp	One 12-module roof-zone subarray.
Project lifetime	Fixed	25 years	Discounted cash-flow evaluation period.
Reference scenario	Fixed	8%	Matched low-reflectance roof-zone scenario.
Assumed treatment area	Fixed	40 m ²	Scenario assumption, not a measured project quantity.
Electricity price	Triangular	0.10/0.18/ 0.30 EUR/kWh	Value of generated electricity.
Discount rate	Triangular	0.02/0.05/0.09	Discounted cash-flow assumption.
PV CAPEX	Triangular	700/1000/ 1400 EUR/kWp	Rooftop PV investment-cost range.
O&M cost	Triangular	10/18/ 30 EUR/kWp/y	Annual operating-cost range.
Annual degradation	Triangular	0.20/0.50/ 0.80%/year	Long-term output-degradation range.
Surface-treatment cost	Triangular	0/5/ 20 EUR/m ²	Hypothetical treatment-cost range.

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