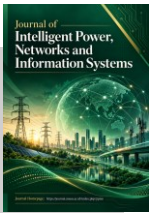
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Simulation-Based Analysis of Solar Irradiance for Photovoltaic Energy Generation

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Abstract*—This paper presents a reproducible, low-complexity simulation framework for characterizing solar irradiation availability and estimating photovoltaic (PV) energy yield under a geographically referenced tropical scenario. Surabaya, Indonesia (7.2575°S, 112.7521°E), is used solely to specify solar geometry; no ground observations, satellite-derived historical irradiation series, or experimental PV measurements are employed. Monthly extraterrestrial horizontal irradiation is calculated from astronomical geometry and multiplied by twelve declared, assumed atmospheric clearness indices. A deterministic set of ten annual multipliers represents illustrative interannual departures rather than actual years. A horizontal 1-kWp PV reference system with a constant performance ratio of 0.78 translates modeled irradiation into electricity. The baseline scenario yields 1,942.68 kWh/m²/year of global horizontal irradiation and 1,515.29 kWh/year of estimated PV electricity, corresponding to a capacity factor of 17.30%. September has the highest modeled monthly irradiation (183.26 kWh/m²), while February has the lowest monthly total (145.29 kWh/m²). A ±20% irradiation sensitivity experiment generates 1,212.23-1,818.35 kWh/year under the fixed-performance-ratio assumption. The work provides a transparent educational and preliminary planning benchmark rather than a site-specific resource assessment; the selected clearness indices, simplified diurnal profiles, and uniform interannual multipliers must not be interpreted as validated climatic patterns.

Keywords*—solar irradiation, photovoltaic energy, clearness index, deterministic simulation, scenario analysis, tropical reference location.

I. INTRODUCTION

Solar photovoltaic technologies convert the available solar resource into electric power without on-site combustion, making resource characterization a prerequisite for preliminary energy planning. In equatorial and near-equatorial settings, yearly changes in solar geometry are often smaller than in temperate latitudes, yet cloud cover, rainfall, aerosol loading, and local shading can alter received irradiation considerably. Site suitability therefore cannot be inferred from latitude alone. Public resource platforms such as PVGIS and NASA POWER provide useful meteorological inputs when a location-specific assessment is required [1], [2].

Several degrees of model complexity can support photovoltaic planning. Advanced workflows couple hourly meteorological inputs, plane-of-array transposition, module temperature, inverter behavior, and electrical losses, whereas simplified engineering approximations can be useful for initial screening and teaching [3], [4]. The latter only remain scientifically interpretable when the origin and uncertainty of input assumptions are explicit. In particular, global horizontal irradiation (GHI) is an energy integral, global horizontal irradiance is an instantaneous flux, and neither quantity should be described as measured if it was generated by a scenario model.

This study does not attempt to reproduce the measured solar climate of Surabaya. Instead, it addresses a narrower methodological question: how do declared monthly clearness-index assumptions propagate through a geometrically based irradiation calculation to a transparent 1-kWp photovoltaic energy estimate? A second question concerns how robust the numerical estimate is to scenario variation when the performance ratio is held fixed. By separating physical geometry from synthetic atmospheric and system-level assumptions, the proposed example provides a reproducible lower-complexity benchmark while making its inferential limitations visible.

The contributions are threefold: (i) a fully specified twelve-month irradiation scenario built from published solar-geometry relationships [5], [6]; (ii) a consistent translation of horizontal irradiation into a reference PV yield using explicitly declared simplifications; and (iii) a sensitivity and structural-identifiability discussion showing which apparent findings follow inevitably from the model rather than from external evidence. The scope is deliberately restricted to resource availability and approximate annual yield; panel efficiency degradation, tilt optimization, and measured day-to-day weather dynamics are excluded.

II. MATERIALS AND METHODS

A. Reference Location and Scenario Architecture

The geographic reference point is Surabaya, Indonesia, at latitude $\varphi = -7.2575°$ and longitude 112.7521°E (Fig. 1). This location parameter affects solar declination and day length in the geometric calculation, but atmospheric clearness indices are not sourced from local

observations. The nominal labels 2015–2024 describe ten synthetic scenario members only and must not be mistaken for historical observations during those years.

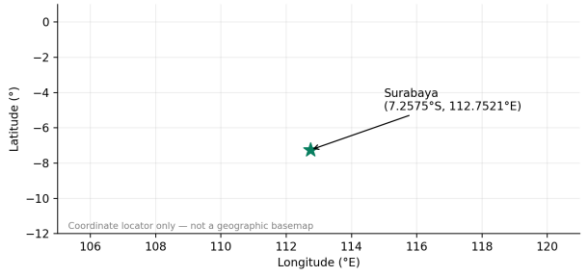


Fig. 1. Geographical coordinates of the reference site. This schematic coordinate locator is not a geographic basemap.

TABLE I. MODEL INPUTS AND DECLARED ASSUMPTIONS

Parameter	Specification
Reference coordinates	7.2575°S; 112.7521°E
Nominal scenario set	10 synthetic year labels
Solar constant	1,367 W/m²
Monthly Kt	0.46–0.62; assumed
PV capacity	1.00 kWp; horizontal
Performance ratio	0.78; constant
Data provenance	Astronomical geometry + assumed scenarios
Validation	No measured or reanalysis observations

B. Extraterrestrial Radiation and Surface GHI

For month m, the daily mean extraterrestrial horizontal irradiation H0,m is evaluated with representative midmonth day number n, Earth–Sun correction dr, solar declination δ, and sunset hour angle ωs using the conventional isotropic astronomical expression [5], [6]:

$$H_{0,m} = (24 \times 3600/\pi) \times G_{sc} \times d_r \times [\cos\varphi \cos\delta \sin\omega_s + \omega_s \sin\varphi \sin\delta] / (3.6 \times 10^6). \quad (1)$$

Here Gsc = 1,367 W/m²; dr = 1 + 0.033 cos(2πn/365); δ = 23.45° sin[2π(284+n)/365]; and ωs = arccos(−tan φ tan δ), with angular terms evaluated consistently in radians. H0,m has units of kWh/m²/day. Modeled mean daily global horizontal irradiation is Hm = Kt,m H0,m, where Kt,m is a selected dimensionless monthly clearness index. Monthly energy is Gm = Hm dm, with dm the representative number of days in the calendar month. February is represented by a mean calendar length of 28.2425 days; consequently the modeled annual sum uses an approximately climatological year rather than a single 365-day calendar.

The January-December Kt values are 0.46, 0.48, 0.51, 0.53, 0.56, 0.59, 0.61, 0.62, 0.60, 0.55, 0.49, and 0.46. They are arbitrary but physically bounded scenario inputs, not inferred observations. Their prescribed late-dry-season maximum influences the modeled monthly peak; the exercise does not establish when irradiance really peaks in Surabaya.

C. Synthetic Annual and Diurnal Scenarios

Ten predetermined multiplicative factors 0.97, 1.03, 0.95, 1.01, 1.04, 0.98, 1.02, 0.96, 1.00, and 1.04 are applied uniformly to all months in corresponding nominal years. The factors have mean 1.00. For scenario year j, Gj,m = fj Gm; their across-scenario sample standard deviation divided by the mean yields CV = 3.33% for every month. Because the same factor applies to each month, the monthly coefficients of variation are necessarily identical and cannot inform real climatological variability.

Two illustrative hourly profiles, January and September, are obtained from a truncated nonnegative sinusoidal curve between 06:00 and 18:00 local solar-time proxy. Each curve is normalized such that its trapezoidal integral equals the corresponding modeled daily GHI; thus the peak shape is assumed and not supported by hourly weather records. A smooth curve should not be interpreted as an observed sunny-day pattern or a prediction of hour-by-hour power.

D. Reference Photovoltaic Model and Evaluation

A horizontal array with nominal capacity P0 = 1 kWp is assumed. Monthly electrical energy is estimated through E_m = (Gm/Gref) P0 PR, where Gref = 1 kW/m² is the standard irradiance reference and PR = 0.78 is a constant aggregate conversion factor. Equivalently, E_m numerically equals 0.78 Gm for this 1-kWp design when Gm is expressed in kWh/m². This simplified method does not explicitly model inverter efficiency, cell temperature, mismatch, soiling, battery storage, or degradation, unlike tools developed for detailed system design [3], [4].

The annual specific yield is Eannual/P0, and nominal capacity factor is CF = Eannual/(P0 × 8760) × 100%. The latter convention uses 8,760 h/year to facilitate comparison, although monthly irradiation was calculated with representative calendar-month durations. Deterministic sensitivity is tested by multiplying annual irradiation by 0.8, 0.9, 1.0, 1.1, and 1.2 while maintaining PR at 0.78. Results are reported as numerical scenario outputs; accuracy indices such as RMSE or MAPE cannot legitimately be calculated without observed reference measurements.

III. RESULTS AND DISCUSSION

A. Monthly Resource Availability

The baseline model produces annual GHI of 1,942.68 kWh/m², equivalent to approximately 5.32 kWh/m²/day over the modeled year. Table II and Fig. 2 show that September reaches the greatest monthly accumulated GHI (183.26 kWh/m²), followed by October (181.53 kWh/m²); February has the smallest monthly total (145.29 kWh/m²). The numerical gap between September and February is 37.97 kWh/m², or 26.1% of February irradiation. Importantly, monthly totals depend on both average daily irradiation and month length: December has the smallest modeled average daily irradiation (4.91 kWh/m²/day), even though February has the smallest monthly total because it is shorter.

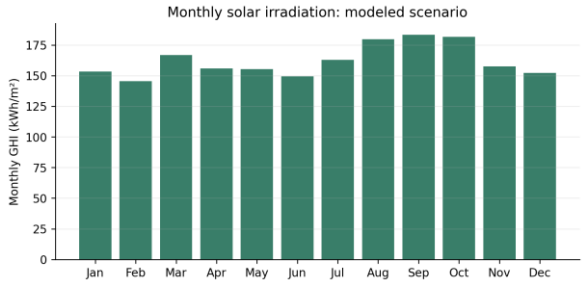


Fig. 2. Simulated monthly global horizontal irradiation (GHI); month-dependent clearness indices are prescribed inputs.

TABLE II. MODELED MONTHLY IRRADIATION (KWH/M² BASIS)

Month	GHI/day	GHI/month	CV (%)
Jan	4.94	153.29	3.33
Feb	5.19	145.29	3.33
Mar	5.38	166.79	3.33
Apr	5.20	155.93	3.33
May	5.01	155.24	3.33
Jun	4.97	149.24	3.33
Jul	5.25	162.70	3.33
Aug	5.79	179.60	3.33
Sep	6.11	183.26	3.33
Oct	5.86	181.53	3.33
Nov	5.25	157.56	3.33
Dec	4.91	152.24	3.33
Year / avg.	5.32	1942.68	3.33*

*Monthly CV values are all 3.33% by construction; the last row is the annual scenario CV. The scenario does not quantify real weather variability.

The monthly differences are dominated by the assumed Kt profile rather than an independently inferred cloud climatology. For example, August and September clearness indices (0.62 and 0.60) are considerably higher than the prescribed January value (0.46). Consequently, the chart demonstrates the propagation of scenario assumptions through solar geometry, not a geographically validated seasonal resource signature. A practical resource assessment would need satellite reanalysis or pyranometer data [1], [2].

B. Synthetic Interannual and Diurnal Structures

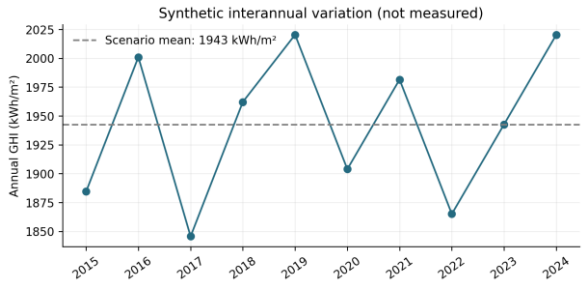


Fig. 3. Synthetic yearly irradiation totals obtained by scaling the same baseline with fixed scenario multipliers; year labels are placeholders.

Figure 3 shows a constrained range from 1,845.54 to 2,020.38 kWh/m²/year. This bounded dispersion corresponds to the chosen annual multipliers; it says nothing about extreme low-irradiance or high-irradiance years in the regional climate. Similarly, the repeated 3.33% monthly CV is a structural feature of the generator, not an independent stability finding. The example highlights why uncertainty analyses should distinguish sampled external variability from investigator-imposed factors.

The illustrative hourly profiles in Fig. 4 reach their maxima near local solar noon because the assumed sine function is symmetric. Actual cloudy or convective conditions can yield irregular intraday changes, and local clock time differs from solar time. Thus the curves are useful solely to visualize how a selected daily energy integral may be distributed across hours. They are not appropriate as input for storage sizing or operational peak-demand claims without replacement by realistic hourly series.

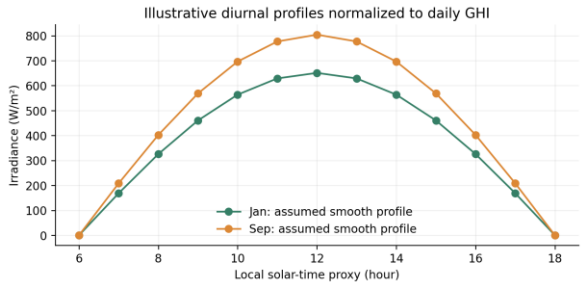


Fig. 4. Illustrative normalized solar-time irradiance curves for January and September, with no observed intraday fluctuations.

C. Estimated Photovoltaic Electricity

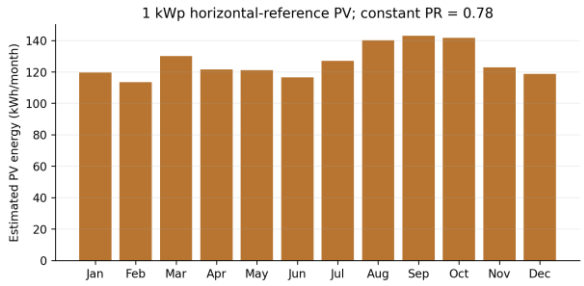


Fig. 5. Reference-model monthly PV generation for a horizontal 1-kWp array under PR = 0.78.

Figure 5 and Table III indicate that the simple reference model converts the annual modeled horizontal irradiation into 1,515.29 kWh of electrical energy. The implied specific yield is 1,515.29 kWh/kWp/year and the nominal annual capacity factor is 17.30%. The monthly modeled maximum is September (142.94 kWh) and the minimum is February (113.32 kWh). These estimates are not independent PV simulation outputs: every monthly value is precisely 78% of the corresponding modeled GHI value because of the fixed-capacity, fixed-PR assumption.

A fixed performance ratio avoids unnecessarily detailed hardware assumptions in a resource-oriented demonstration, but it also suppresses physical effects that matter in tropical settings, including cell-temperature sensitivity, incident-angle losses, shading, and seasonal aerosol loading. The present result therefore should not be presented as a financial yield forecast or evidence of operational system efficiency. PVGIS and PVWatts use more detailed weather and device representations for location-specific energy estimates [3], [4].

TABLE III. BASELINE PV ENERGY ESTIMATES

Indicator	Modeled value
PV nominal rating	1.00 kWp
Annual GHI	1,942.68 kWh/m²
Annual output	1,515.29 kWh
Specific yield	1,515.29 kWh/kWp
Capacity factor	17.30%
Maximum month	Sep: 142.94 kWh
Minimum month	Feb: 113.32 kWh
PV model	Horizontal plane; PR = 0.78

D. Sensitivity and Interpretive Boundaries

When annual GHI is perturbed by −20%, −10%, 0%, +10%, and +20%, the corresponding annual electrical energies are 1,212.23, 1,363.76, 1,515.29, 1,666.82, and 1,818.35 kWh. The absolute spread from the low to high scenario is 606.12 kWh/year. The normalized energy sensitivity $S = (\Delta E/E)/(\Delta G/G)$ equals exactly 1 for any nonzero perturbation because $E = C\,G$ with constant $C = P0\,PR/Gref$. This result is a direct mathematical property of the baseline model, not an empirical confirmation of PV linearity across all real-world conditions.

A second, more meaningful model-uncertainty check can change PR rather than GHI alone. If PR is set to 0.72, 0.78, and 0.84, annual electrical energy changes to 1,398.73, 1,515.29, and 1,631.85 kWh respectively, for unchanged GHI. Thus a plausible modeled PR span of ±0.06 around baseline shifts annual output by ±116.56 kWh. However, without independent characterization of losses even this sensitivity does not represent calibrated prediction intervals. The fundamental uncertainty remains the selected monthly clearness indices and device-loss parameters.

Compared with observation-driven solar resource studies, the principal value of this work is methodological transparency and reproducibility rather than a novel regional climate result. The selected atmospheric inputs and synthetic annual factors are deliberately simple; they facilitate classroom application and auditing of units, but they do not establish regional generalizability. A stronger future empirical study should compare modeled horizontal GHI with archived NASA POWER or PVGIS series, report data coverage, and evaluate errors against a withheld source or ground-based irradiance instrument when available [1], [2], [7].

IV. CONCLUSION

A deterministic framework combining solar geometry, twelve assumed clearness indices, synthetic annual multipliers, and a constant-performance-ratio photovoltaic reference was developed for a tropical coordinate setting. The baseline produces 1,942.68 kWh/m²/year of modeled horizontal solar irradiation and an estimated 1,515.29 kWh/year for a 1-kWp horizontal PV array at PR = 0.78. The model maximum occurs in September (183.26 kWh/m²/month), whereas February has the smallest modeled monthly total (145.29 kWh/m²/month). These seasonal outcomes are conditional on the chosen Kt parameters and must not be generalized to actual Surabaya meteorology.

The ±20% irradiance sensitivity range yields 1,212.23–1,818.35 kWh/year, with unit elasticity imposed by the constant-PR relationship. Its main contribution is a reproducible parameter-to-output demonstration with a clear distinction between mathematical consequences and observational evidence. Future research should replace synthetic clearness indices and normalized hourly profiles with traceable meteorological records, add realistic plane-of-array and cell-temperature models, and validate predicted production against measured PV output. Until that stage, the results are illustrative scenario estimates and not evidence of achieved PV performance.

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