Journal of Solar Energy Research (JSER)

Journal homepage: www.jser.ut.ac.ir

Techno-Economic Assessment and Optimization of Grid-Connected Solar Powered Electric Vehicle Charging Stations in Urban Indonesia

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ARTICLE INFO

Article Type:

Research Article

Received:2025.08.22
Accepted in revised form:2026.02.14

Keywords:
Discounted cash flow;
EV charging;
Grid connected PV;
HOMER Pro;
Net billing

ABSTRACT

This study evaluates the feasibility of a grid connected rooftop photovoltaic system for fast charging using a 120 kWp case study in Bandung. Photovoltaic energy yield is validated using PV_{syst}, while hourly energy balance and discounted cash flow are analyzed in HOMER Pro for three scenarios namely S_0 grid only, S_1 photovoltaic with self consumption only, and S_2photovoltaic with net billing export credit. The model applies local climate data, a capital cost of 20 million rupiah per kilowatt peak, and a real discount rate of eight percent, resulting in a performance ratio of 0.78 to 0.82 and annual photovoltaic production of about 160 megawatt hours. For a fast charging station with an annual load of 182.5 megawatt hours or 500 kilowatt hours per day from a 50 kilowatt charger, photovoltaic generation supplies 63 percent of demand with 72 percent self-consumption. Compared with the S_0 scenario, photovoltaic integration reduces the Net Present Cost by 9 to 13 percent, lowers the cost of energy to 910 to 940 rupiah per kilowatt hour, achieves an 8 to 10 year payback period, and avoids about 87 tons of carbon dioxide emissions annually.

1. Introduction

Globally, the transportation sector contributes a significant proportion of carbon emissions, with direct emissions from transport reaching approximately 8.9 $GTCo_2e$ in 2019, or about 23% of total energy-related CO_2 emissions. This underscores the urgent need to accelerate vehicle electrification and implement low-carbon charging management [1-2]. At the national level, the contribution of emissions from the transportation sector in Indonesia is also substantial. Based on national data estimates,

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Cite this article: Faridah, L. , Asnawi, R. , Jati, H. and KN, N. (2026). Techno-Economic Assessment and Optimization of Grid-Connected Solar Powered Electric Vehicle Charging Stations in Urban Indonesia. Journal of Solar Energy Research, 11(1), 2835-2850. doi: 10.22059/jser.2026.401157.1623

DOI: 10.22059/jser.2026.401157.1623

transportation emissions in 2020 reached approximately 126 $MtCO_2$, equivalent to about 24% of the total national emissions [3-4]. Consequently, strategic intervention in this subsector is a key priority in the urban energy transition [5-6].

Simultaneously, vehicle electrification requires the accelerated deployment of reliable and affordable public electric vehicle charging stations (SPKLU). Recent studies in the Indonesian context indicate that infrastructure availability and policy support are the two primary determinants for effective electric vehicle adoption [6-7] [8]. From the clean energy supply perspective, photovoltaic (PV) systems have proven to be competitive, particularly when integrated with electric vehicle charging during daylight hours. This integration can significantly reduce the carbon intensity of the charging process compared with exclusive reliance on grid electricity, making it highly relevant for tropical cities [9-10]. In Indonesia, this approach is further supported by the country's vast solar energy potential and the urgent need to mitigate peak load growth in urban areas [11] [12] [13]. Without proper load management, the rapid increase in SPKLU deployment and electric vehicle penetration could strain distribution networks, leading to load spikes, voltage fluctuations, and deteriorating power quality. Therefore, smart integration and scheduling of charging aligned with daytime PV generation are crucial to ensuring that SPKLU expansion remains reliable, economical, and low in emissions [14-15].

Despite the rapid growth of vehicle electrification, electricity supply in many large cities still relies heavily on fossil-fuel-based power generation. According to PLN data from 2023, 58 percent of national electricity generation is coal based, with an emission intensity of approximately 0.85 $kgCO_2$ per kilowatt-hour, which remains far from the carbon neutral target [16-17]. Full dependence of SPKLU on grid electricity can diminish the emission reduction benefits of electric vehicles and may result in an emission shifting effect [18-19]. Therefore, the utilization of photovoltaic systems as a local energy source is essential to ensure that the electric vehicle transition also supports sustainable and low-carbon charging. Daytime charging partially coincides with photovoltaic output, enabling direct energy utilization without storage. However, evening charging peaks typically remain supplied by the grid. As a result, photovoltaic integration can reduce annual grid energy consumption but cannot fully eliminate evening peak demand [20] [21] [22]. The main challenges include land availability constraints, mismatches between charging load profiles and photovoltaic generation, and the limited adoption of adaptive charging management systems. A study conducted in Jakarta indicated that a single 50 kW DC fast charging SPKLU operating for 10 hours per day requires approximately 500 kWh of electricity, which is equivalent to the daily consumption of about 150 households [21] [23] [24]. Without photovoltaic integration or effective charging time management, such load concentration can degrade power quality and increase operating costs. Furthermore, relying solely on the Levelized Cost of Energy as an economic indicator is insufficient for systems with export or net billing mechanisms, as it does not capture cash flow dynamics or grid integration costs [19] [25] [26] [27]. Consequently, a more comprehensive technical and economic assessment is required for photovoltaic based SPKLU to achieve efficiency, reliability, and long-term sustainability in Indonesia.

Recent research highlights that the implementation of dynamic tariffs and energy management strategies is a vital element in integrating solar based electric vehicle charging systems. For example, Wang et al. (2025) applied a dynamic tariff adjustment method to an SPKLU network utilizing renewable energy and achieved a peak load reduction of up to 23.4 percent, while increasing renewable energy utilization by approximately 17.9 percent [28] [29] [30]. Conversely, Hernandez Cedillo et al. (2022) developed a multilayered dynamic pricing approach for solar integrated SPKLU, in which tariffs are automatically optimized to maintain economic system operation while preserving customer responsiveness [14]. This research aims to conduct a scenario based techno-economic evaluation of grid-connected, photovoltaic powered public electric vehicle charging systems. PV_{syst} is used to model photovoltaic energy yield, while HOMER Pro is employed for hourly energy balance and discounted cash flow analyses. This established toolchain supports transparency and internal cross-checking. Specifically, HOMER Pro performs hourly techno-economic analyses of system configurations and tariff schemes, while PV_{syst} simulates photovoltaic energy production under local irradiation, temperature, and loss conditions.

The research focuses on urban areas in Indonesia, which exhibit distinct characteristics, including high electricity demand, complex tariff regulations involving net metering and net billing schemes, and limited rooftop space availability. This study does not propose a new optimization algorithm or a novel software toolchain. Instead, its primary contribution lies in the development of a policy and tariff aware techno economic assessment framework for rooftop photovoltaic powered public fast charging in Indonesian cities. The framework integrates photovoltaic yield estimation validated using PV_{syst} with scenario based discounted cash flow modeling in HOMER Pro across grid only (S_0), self-consumption (S_1), and net billing (S_2) operational schemes.

2. Research Methodology

This study defines the initial conditions (site location, climate data, and SPKLU load profile), then designs the system based on configuration options, operating scenarios, and techno-economic assumptions. Technical validation is conducted using HOMER Pro and PV_{syst}, supported by clear evaluation metrics, sensitivity analysis, and replication procedures to ensure reproducibility.

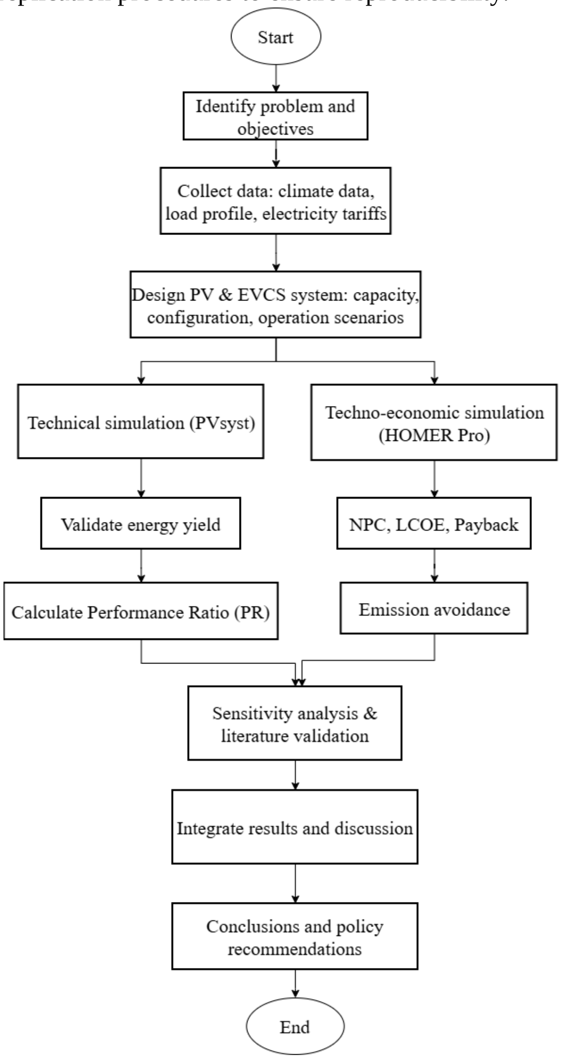

Figure 1. Research Workflow

Figure 1 illustrates the overall research methodology flow, beginning with the identification of the research gap and the definition of the main objectives. This is followed by the collection and preprocessing of input data, including climate data, a synthesized SPKLU load profile, and techno-economic parameters. In the subsequent stage, the PV powered SPKLU system is configured and simulated. PV_{syst} is used to validate technical performance in terms of annual energy production and performance ratio, while HOMER Pro is applied to evaluate techno-economic indicators such as Net Present Cost, levelized or effective cost of energy, payback period, and emission reductions. The resulting scenarios are then compared and examined through sensitivity analyses of key parameters, and the findings are interpreted in the context of previous studies and relevant Indonesian regulations. Finally, the validated results are synthesized into conclusions and policy-oriented recommendations for planning grid-connected photovoltaic systems for fast charging.

2.1 Methodological Positioning and Validation Boundary

The assessment is intentionally simulation based. Photovoltaic energy yield is modeled and cross-checked using PV_{syst}, while techno-economic performance is evaluated in HOMER Pro through hourly energy balance simulations for the S_0 to S_2 operational scenarios. This established toolchain supports transparency, comparability, and internal consistency. The study boundary is defined at the customer-connection point of a representative urban commercial site; feeder level hosting capacity, power quality impacts, and control co-design are beyond the scope of this study. All results represent a feasibility envelope under the stated assumptions and should be locally recalibrated before broader generalization. Reproducibility is ensured by providing the synthesized DC fast charging load time series, HOMER input files, and PV_{syst} summary reports.

2.2 Location Context and Climatological Data

- Location and System Configuration: The study was conducted on the rooftop of Summarecon Mall Bandung (SUMMABA). The system is modeled as a grid-connected rooftop photovoltaic installation connected to the building's low voltage panel to supply the SPKLU (Public Electric Vehicle Charging

Station). This configuration maximizes self-consumption by the building baseload and eliminates the need for battery storage.

- Performance Data and Assumptions: Climatological data, including global horizontal irradiation, clearness index, and ambient temperature, are obtained from the Typical Meteorological Year dataset of the Global Solar Atlas. System performance is benchmarked against a regional PV output of 1.30 to 1.45 megawatt hours per kilowatt-peak per year. Based on derating factors such as temperature effects, soiling, module mismatch, wiring losses, and inverter efficiency, the initial performance ratio is assumed to range from 0.78 to 0.82. Soiling losses are limited to approximately 2 to 3 percent per month through the assumption of routine module cleaning.
- Layout and Design: The system layout follows commercial rooftop photovoltaic standards, with modules oriented northward at a tilt angle of 10 to 15 degrees to optimize energy yield and facilitate drainage. The effective rooftop area requirement is estimated at 6 to 8 square meters per kilowatt peak, including a 0.6 meter access pathway. Lightning protection and surge protection systems are incorporated in accordance with applicable building electrical standards.

2.3 System Configuration and Operational Scenarios

The system optimization variables include photovoltaic capacity (kWp) and inverter capacity ($kWac$), while the key performance parameters are the performance ratio of 0.78 to 0.82 and the inverter loading ratio of 1.05 to 1.25.

Table 1. Three Operational Scenarios (S_0–S_2) and Surplus Energy Management.

Scenario	Description	Surplus Energy
S_0: Grid Only	Baseline (no PV); 100% grid supply.	N/A
S_1: Self-Consumption	PV serves internal load (priority).	Curtailed
S_2 : Net Billing	PV serves internal load (priority).	Exported at tariff r_{sell}

All simulation results were validated against the following criteria: zero unmet energy, compliance with inverter voltage and current limits, and an inverter loading ratio not exceeding 1.25. Policy and export credit conditions are treated as sensitivity parameters, with illustrative export remuneration rates of 0, 800, and 1,200 rupiah per kilowatt-hour. These cases represent a plausible range for commercial customers and are not intended to replicate any specific regulation. Battery storage is intentionally excluded from the system configuration in this study. Field experience and recent feasibility studies for commercial customers in Indonesia indicate that, under current tariff structures, integrating lithium ion battery storage into grid-connected photovoltaic systems significantly increases capital expenditure and Net Present Cost while delivering only marginal gains in renewable energy fraction for sites with relatively reliable grid supply. At the Summarecon Mall Bandung SPKLU site, grid reliability is sufficient to eliminate the need for storage as backup, and existing regulations do not provide dedicated incentives for behind-the-meter storage or vehicle to grid operation. Moreover, net billing arrangements already enable excess photovoltaic energy to be exported, meaning that battery storage would primarily serve to shift energy temporally rather than create additional revenue streams. For these reasons, this study focuses on a grid-connected photovoltaic configuration without battery storage as a realistic near-term design for commercial SPKLU deployments in Indonesian urban areas.

2.4 Techno-Economic Assumptions

The economic feasibility analysis applies a real, pre tax discounted cash flow method over a project horizon of 25 years, consistent with the technical lifetime of the photovoltaic modules. All monetary values are expressed in constant 2025 Indonesian rupiah in real terms. A pre tax real discount rate of eight percent is applied. Grid purchase tariffs, export credits, and operation and maintenance costs are normalized to 2025 real prices and assumed to remain constant in real terms, with zero real escalation. The analysis is based on incremental cash flows relative to the grid only baseline scenario. Grid charges include both volumetric energy components and minimum billing components linked to the contracted capacity. In all tables and discussions, Net Present Cost is reported as a positive cost, while Net Present Cost savings are expressed as percentage reductions relative to the grid only baseline scenario. For example, an NPC saving of 13 percent indicates that the photovoltaic grid configuration has a 13 percent lower Net Present Cost than the grid only case. In this study, the Levelized Cost of Energy is used solely as an internal generation side indicator for the photovoltaic subsystem.

Customer-side economic results are evaluated using the effective cost of energy and Net Present Cost savings relative to the grid-only baseline. The effective cost of energy at the SPKLU meter equals annual customer charges (volumetric energy, minimum billing/capacity charges, and fixed fees) minus export credits, divided by total charger energy consumption; fixed items that cancel across scenarios are excluded. Monthly grid charges are the greater of the volumetric bill or the minimum billing (RM = 40 hours × contracted capacity (kWa) × $tariff_{rate}$, with contracted capacity sized to cover the DC fast charger and auxiliary loads. This avoids underestimating grid costs when PV self-consumption reduces metered energy.

Table 2. Techno Economic Parameters (25 years; 8% real discount rate; r_{sell}scenarios).

Parameter	Base Value	Remarks
Analysis horizon	25 years	Corresponds to PV lifespan
Purchase tariff (TM/B3)	IDR 1,114.74/kWh	Baseline for mall scenario
Purchase tariff (TR/B2)	IDR 1,444.70/kWh	Sensitivity analysis
Export remuneration	0; IDR 800; IDR 1,200/kWh	Policy sensitivity scenarios
$\boldsymbol{CapEx_{PV}}$	IDR 20 million/kWp	Tested at 17–24 million/ kWp
PV O&M	1% of CapEx/year	Cleaning and inspection
PV / Inverter lifetime	25 years / 12 years	Inverter replaced once
Inverter replacement cost	cost 15% of CapEx	If cost not itemized
Discount rate (real)	8%	Tested at 6–10%
Grid emission factor	0.78 (0.72–0.96) $KgCo_2/kWh$	For avoided emissions
Currency	–	IDR (real), no real escalation

Annual PV energy degrades by 0.6% per year (base case). One inverter replacement is scheduled in year 12 at 15% of initial PV CapEx; timing and cost are included in sensitivities.

2.5 Grid Aware Operational

The analysis boundary is defined at the customer-side connection point; feeder level power flow, hosting capacity, and power quality impacts are not explicitly modeled. Grid aware constraints are represented through inverter export limits and contracted capacity (kVa) consistent with the minimum billing treatment described in Section 2.3. Tariffs are implemented on an hourly basis using time block schedules where available; otherwise, a flat energy price normalized to constant 2025 Indonesian rupiah is applied. Because actual tariff calendars, including peak periods and weekend or holiday definitions, vary across service areas and are sensitive to policy conditions, the results are reported as scenario ranges.

2.6 Transferability Checklist

To apply the framework in other locations, the following inputs are required: (1) an hourly charging load profile or a synthesized profile scaled to annual energy consumption; (2) local photovoltaic resource data or a Typical Meteorological Year dataset with associated loss factors; (3) rooftop constraints, including usable area, setbacks, and maintenance access; (4) contracted capacity (kVA) and any applicable export limits; and (5) the local tariff structure, including time blocks and prices expressed in real terms. The model produces normalized indicators such as coverage, self-consumption, export or curtailment share, and effective cost of energy, enabling cross site comparison.

2.7 HOMER Pro Analysis

The optimization objective is to identify the system configuration, defined by photovoltaic and inverter capacities, that minimizes the Net Present Cost. HOMER Pro evaluates multiple system combinations by simulating the hourly energy balance over 8,760 hours for three scenarios: S_0 (grid only), S_1 (self-consumption without export), and S_2 (net billing with export). For each configuration, the model quantifies key energy flows, including self consumed photovoltaic energy, grid imports, and exported or curtailed energy. Annual cash flows are then calculated, incorporating annualized capital expenditure, operation and maintenance costs, and energy purchase costs, offset by export revenues in the S_2 scenario. These cash flows are discounted to derive the Net Present Cost, and the configuration with the lowest value is selected as the optimal solution, subject to the reliability constraint that all demand is met, with zero unmet energy. The evaluated scenarios represent a plausible range for commercial customers and are not intended to replicate any specific regulation.

2.8 Hourly Energy Balance & Self Consumption

$$\boldsymbol{L_t = S_t + G_t}, \quad \boldsymbol{S_t = \min(E_t^{PV}, L_t)} \tag{1}$$

Net Present Cost

$$\boldsymbol{NPC = \sum_{y=1}^{N} \frac{CF_y}{(1+r)^y}} \tag{2}$$

With N=25 years, r the real discount rate, and Net Cash Flowy the net cash flow in year y (capital & replacement costs, O&M costs, energy purchase costs from the grid, minus S_2 export revenue).

2.9 PV_{syst} Analysis

A cross validation procedure is conducted using PV_{syst} to ensure the technical realism of the HOMER simulation results. The PV_{syst} model is constructed using the same component parameters, system orientation, and climate data as the HOMER model. System loss assumptions are calibrated to achieve a target performance ratio of 0.78 to 0.82. The HOMER model is considered valid if the deviation in annual energy production relative to PV_{syst} does not exceed 10 percent and the difference in performance ratio is no greater than 0.03. Parameter adjustments are permitted only when supported by physical justification. For reporting purposes, the more conservative of the two modeled energy values is adopted. The PV_{syst} summary report and the HOMER input files are provided to ensure reproducibility of the study.

2.10 Load Profile Construction and Uncertainty

The SPKLU load time series, with an hourly resolution of 8,760 data points, is a synthesized electric vehicle charging profile constructed in three steps. First, published empirical data for 50 kW DC fast chargers at urban commercial sites in Indonesia were reviewed to identify representative daily load shapes characterized by pronounced midday and early evening peaks. Second, the selected profile was normalized and scaled such that a 50 kW charger operating for an average of 10 hours per day delivers 500 kWp per day, corresponding to an annual charging demand of 182,500 kWh, including auxiliary loads. Third, the profile was aligned with typical operating hours and peak activity patterns of urban commercial centers in Bandung, ensuring that the highest charging demand coincides with shopping and commuting peaks, occurring in the late morning to midday and late afternoon to early evening. Weekdays and weekends are not distinguished in the present study. Instead, a single representative daily profile is applied uniformly throughout the year, which is appropriate for a destination type fast charging station at a busy commercial site. Individual charging sessions are not explicitly modeled; rather, the load profile represents the aggregated effect of multiple fast charging events with higher arrival rates during the identified peak periods.

To account for operational variability and modeling uncertainty, the deterministic load profile is perturbed using a Monte Carlo approach. For each realization, hourly charging loads are multiplied by random factors within a ±10 percent range, and photovoltaic energy yields are varied within a ±5 percent range, while preserving the total annual energy demand of 182,500 kWh. A total of 500 realizations are performed, and median values along with 5 to 95 percent confidence intervals are reported for key indicators, including Net Present Cost, effective cost of energy, renewable energy fraction, and photovoltaic self-consumption. The complete hourly load time series and a concise codebook describing the synthesis procedure are provided as Supplementary Data $\boldsymbol{S_1}$ to support replication and sensitivity analysis by other researchers.

2.11 Site Feasibility

A rooftop area requirement of 6 to 8 square meters per kilowatt-peak is assumed, including access aisles and setbacks; thus, a 120 kilowatt-peak array requires approximately 720 to 960 square meters of usable roof area. The layout accounts for drainage, parapet, and maintenance clearances. From a structural perspective, the mounting concept is designed to maintain a distributed dead load below 15 kilograms per square meter, inclusive of modules, racking, and cabling. A formal structural certification is beyond the scope of this study and would be required prior to system deployment. For interconnection, the photovoltaic system is connected to the building low voltage panel supplying the SPKLU. Export limits can be enforced at the inverter level if required by the utility. The contracted capacity (kVA) is sized to accommodate the 50 kW DC fast charging unit and auxiliary loads, and this capacity feeds directly into the minimum billing treatment described in Section 2.3.

2.12 Data Availability

The synthesized SPKLU charging load time series in CSV format, the HOMER input files, and the PV_{syst} summary reports are provided as Supplementary Data S_1 to S3 to enable full replication of the analysis. All reported results are model derived under customer-side boundary conditions. Complete scenario parameters, sensitivity ranges, and supporting scripts are included to allow reviewers to reproduce the analysis and assess the robustness of the results.

3. Results and Discussion

All quantitative findings in this section are conditional on the synthesized SPKLU load profile described in Section 2.10 and are intended to represent a realistic but stylized urban commercial charging site in Bandung rather than a national average. The profile reflects the expected operation of a single 50 kW DC fast charger at a destination type location, such as a shopping mall or mixed use commercial center, and should therefore be interpreted as a case study applicable to similar sites in secondary Indonesian cities.

The SPKLU load time series, with an hourly resolution of 8,760 data points, exhibits a stable daily pattern throughout the year, with stochastic variability represented through the Monte Carlo perturbations described earlier. Although individual charging sessions are not explicitly modeled, the hourly energy values represent the aggregated outcome of multiple fast charging events, with higher session density during commercial peak hours. The complete hourly load and photovoltaic output time series are provided as Supplementary Data S_1 to ensure transparency and reproducibility. The load profile displays two pronounced demand peaks. A midday peak occurs between approximately 11:00 and 14:00, associated with shopping and lunchtime activity, while an early evening peak occurs between approximately 17:00 and 20:00, corresponding to commuter and after work travel. During off peak hours, charger utilization is substantially lower, resulting in a strongly time varying demand profile at the SPKLU meter.

The daily profiles reveal partial temporal alignment between photovoltaic generation and SPKLU demand during the late morning and early afternoon, when both photovoltaic output and charging demand are relatively high. In contrast, the early evening demand peak occurs after sunset and must be supplied almost entirely by the grid. This temporal mismatch explains why photovoltaic integration can significantly reduce the effective cost of energy and increase the renewable energy fraction, but cannot fully eliminate grid electricity consumption even under optimized system configurations.

Table 3. Synthesized SPKLU Load Profile (50 kW; 500 kWp /day)

Parameter	Value	Unit
DC Fast Charging capacity	50	kW
Daily operating duration	10	hours/day
Daily energy consumption	500	kWh/day
Annual energy consumption	182,500	kWh/year
Peak load 1	11:00–14:00	WIB (Western Indonesian Time)
Peak load 2	17:00–20:00	WIB (Western Indonesian Time)

Coverage, self-consumption, export or curtailment, and the coincidence indicator are summarized as median values with P5 to P95 ranges in Supplementary Table S_2.

3.1 Technical Validation of the PV Model

Technical validation was conducted by comparing energy production results from HOMER Pro with PV_{syst} estimates. The objective is to ensure that the techno-economic analysis is based on accurate and non optimistic energy projections, given that PV_{syst} is generally regarded as more precise for photovoltaic performance modeling. Unless otherwise stated, all reported values represent Monte Carlo median results with 5 to 95 percent uncertainty intervals.

3.1.1 Results of Annual Energy Production

The validation results demonstrate strong consistency between the annual energy production estimates obtained from the two software packages. For the 120 kWp system with a performance ratio of 0.80 and an inverter loading ratio of 1.15, PV_{syst} estimates an annual energy yield of 165,240 kWh, while HOMER Pro estimates 159,800 kWh. The resulting deviation of 3.3 percent is well below the validation threshold of 10 percent. Consistency is also observed in the performance ratio values, with PV_{syst} reporting 0.802 and HOMER Pro reporting 0.781, confirming that both models adequately represent system performance and estimated energy losses of approximately 19 to 21 percent under local conditions. A summary of these validation results is presented in Table 4.

Table 4. Validation of PV production (120 kWp; ILR 1.15): PV_{syst} vs HOMER Pro

Parameter	$\boldsymbol{PV_{sys}}$	**HOMER Pro**	**Deviation (%)**	**Remarks**
System capacity ($\boldsymbol{kWp}$)	120	120	–	Rooftop PV
Inverter ($\boldsymbol{kWac}$)	104	104	–	ILR = 1.15
Performance Ratio (PR)	0.802	0.781	2.6	Within target range (0.78–0.82)
Annual energy (kWh/year)	165,240	159,800	3.3	Valid
Specific yield (MWh/kWp /year)	1.377	1.332	3.3	Consistent with benchmark
Total system losses (%)	20.8	21.5	3.4	Within acceptable range

3.1.2 Deviation Analysis and Production Realism

The minor difference of 3.3 percent between the PV_{syst} and HOMER outputs is attributed to differences in the algorithms used to model temperature and module mismatch effects, with PV_{syst} employing a more detailed cell temperature model. Nevertheless, this deviation is sufficiently small to indicate that the HOMER estimates are suitable for economic analysis. This conclusion is further supported by the resulting specific yield values of 1.33 to 1.38 megawatt hours per kilowatt peak per year, which fall within the typical regional range reported by the Global Solar Atlas of 1.30 to 1.45 megawatt hours per kilowatt peak per year. In addition, both models exhibit consistent monthly production trends, with peak generation occurring in September to October and the lowest output in January to February, as illustrated in Figure 2.

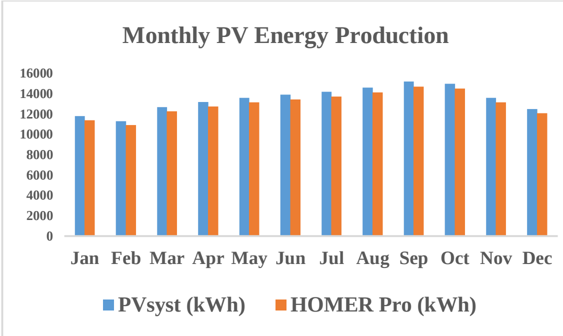

Figure 2. Comparison of monthly PV energy production (PV_{syst} vs HOMER Pro) for a 120 kWp rooftop system

Figure 2 Comparison of monthly energy production in kilowatt hours between PV_{syst} and HOMER Pro for the 120 kWp rooftop photovoltaic system at Summarecon Mall Bandung. The bars represent the simulated monthly AC energy output from each software tool, showing that HOMER Pro slightly underestimates PV_{syst} results while preserving the same seasonal production pattern.

3.1.3 Implications of Validation for the Economic Analysis Phase

This technical validation is intended to prevent overestimation of energy inputs in the economic analysis, thereby minimizing potential bias in the calculation of Net Present Cost and payback period. Adopting a conservative approach, the energy production value obtained from HOMER Pro of 159,800 kilowatt hours per year is used as the baseline for the analysis, while the PV_{syst} estimate of 165,240 kilowatt hours per year is treated as an upper bound for sensitivity analysis. This cross model validation approach is consistent with best practice guidelines reported by IRENA (2023) and supports the accuracy and robustness of the techno-economic assessment results.

3.2 Energy Balance and SPKLU System Operation Profile

The following section presents an analysis of the annual energy balance and operational profile of the rooftop photovoltaic system designed to supply the SPKLU at Summarecon Mall Bandung. The evaluation is carried out across three operational scenarios: S_0 (grid only), S_1 (self-consumption with export curtailment), and S_2 (net billing with export allowance). The analysis focuses on quantifying the contribution of photovoltaic generation to meeting charging demand, the amount of energy imported from the grid, and the volume of surplus energy that is either exported under the S_2 scenario or curtailed under the S_1 scenario.

3.2.1 Basis of Energy Analysis

The energy balance analysis is conducted for a 120 kWp rooftop photovoltaic system. Annual energy production is assumed to be 159,800 kilowatt hours, based on conservative simulation results from HOMER Pro. This output is evaluated against the total annual SPKLU energy demand, including auxiliary loads, of 182,500 kilowatt hours. The analysis considers three operational scenarios: S_0 (grid only), which serves as the baseline without photovoltaic integration; S_1 (self-consumption), in which surplus photovoltaic energy is curtailed; and S_2 (net billing), in which surplus energy is exported to the grid for remuneration.

3.2.2 Summary of Annual Energy Balance per Scenario

Table 5. Annual energy balance by scenario (PV 120 kWp): S_0 grid-only; S_1 self-consumption (export OFF/curtailment); S_2 net billing (export ON/exported). Values are scenario medians [P5–P95]

Main Parameter	S_0 Grid Only	S_1 Self Consumption (Export OFF)	S_2 Net Billing (Export ON)
SPKLU energy demand (kWh/yr)	182,500	182,500	182,500
Annual PV production (kWh/yr)	0	159,800	159,800
PV directly used by load (self consumed) (kWh/yr)	0	115,000	115,000
PV exported to grid (kWh/yr)	0	0	44,800
PV curtailed (kWh/yr)	0	44,800	0
Imported from grid (kWh/yr)	182,500	67,500	67,500
Self consumption ratio (= PV used / PV production)	0%	72.0%	72.0%
Energy coverage of demand (= PV used / demand)	0%	63.0%	63.0%
Curtailed fraction of PV production	0%	28.0%	0%

Table 5 indicates that the 120 kWp PV system supplies 63% of the SPKLU's annual energy demand, substantially reducing grid reliance. In S_1 (self-consumption), 72% of PV output (~115,000 kWh) is used directly, while S_2 (net billing) exports ~44,800 kWh/year, eliminating curtailment. Utilization peaks at 10:00–14:00 when charging demand and PV generation are highest, showing that a battery-free, grid-connected PV system can effectively capture midday solar at tropical urban sites and that export in S_2 reduces curtailment and improves utilization under the modeled assumptions. Results are reported as scenario-level medians with 5–95% Monte Carlo uncertainty intervals; detailed percentiles are in Supplementary Table 3.2.2.

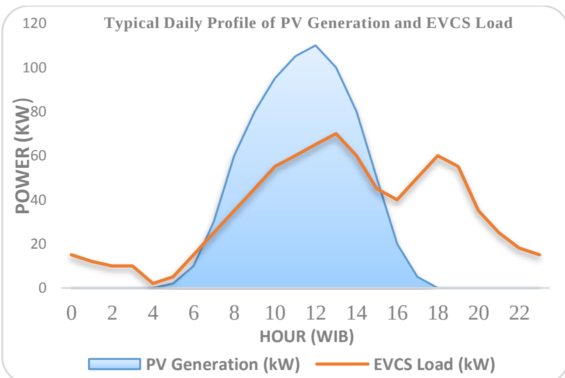

Figure 3. Typical daily PV–SPKLU profile (PV 120 kWp; DCFC 50 kW): PV peaks 10:00–14:00; load peaks 11:00–14:00 and 17:00–20:00

Figure 3 illustrates typical daily profiles of photovoltaic production and SPKLU load for the 50 kW DC fast charger at Summarecon Mall Bandung. The curves represent hourly average power in kilowatts over a representative day. Photovoltaic output peaks between 10:00 and 14:00, while the SPKLU load exhibits a bimodal pattern with peaks occurring around 11:00 to 14:00 and 17:00 to 20:00. This comparison highlights the partial daytime alignment between photovoltaic generation and charging demand, as well as the continued reliance on grid electricity during the evening peak.

The load time series, with an hourly resolution of 8,760 data points, is a synthesized profile calibrated using published empirical datasets for 50 kW DC fast charging in Indonesian urban commercial settings. The synthesis preserves the characteristic two peak daily shape and is scaled to an annual energy demand of 182,500 kilowatt hours, as summarized in Table 3. The CSV time series and an accompanying codebook are provided as Supplementary Data S_1 to support reproducibility. After 17:00, when photovoltaic production declines to zero, the charging load is supplied entirely by the grid. This pattern confirms the suitability of a grid connected photovoltaic system without battery storage for maximizing daytime solar energy utilization in tropical climates.

3.2.3 Typical Daily Operation Profile and Peak Coverage

Figure 3 contrasts hourly photovoltaic generation with the SPKLU load for a representative day. Photovoltaic output is concentrated in the late morning to early afternoon period (10:00–14:00), while charging demand exhibits a bimodal pattern with a midday peak (11:00–14:00) and an evening peak (17:00–20:00). This temporal structure results in partial daytime alignment: under the $S_{\mathbf{1}}$ and S_2 scenarios, photovoltaic generation supplies a substantial share of midday charging demand, whereas the evening peak remains fully supplied by the grid. In the $S_{\mathbf{1}}$ scenario, any midday surplus photovoltaic energy is curtailed at the inverter, while in the S_2 scenario it is exported, improving photovoltaic utilization without affecting the evening peak. Consequently, photovoltaic integration reduces the daytime net load but does not materially reduce the evening connection peak that determines contracted capacity and minimum billing. Coverage, self-consumption, export or curtailment shares, and the coincidence indicator are reported as median values with P5 to P95 ranges in Supplementary Table S_2.

3.2.4 Energy Curtailment Analysis

In Scenario S_1 (self-consumption), where export to the grid is disabled, substantial energy curtailment occurs, amounting to 44,800 kilowatt hours per year, or approximately 28 percent of total photovoltaic generation. This curtailment arises because surplus production during peak solar hours cannot be fully absorbed by the on site load. The primary drivers are the operational constraint prohibiting export and the limited capacity of local demand to accommodate peak photovoltaic output in the absence of energy storage.In contrast, Scenario S_2 (net billing) completely eliminates curtailment. All surplus photovoltaic energy is exported to the grid, enabling 100 percent of the photovoltaic production to be productively utilized.

3.3 Techno-Economic Evaluation of the System

This section presents a techno-economic analysis to evaluate the financial feasibility of three system operation scenarios: S_0 (grid only), S_1 (self-consumption), and S_2 (net billing). The evaluation is conducted using HOMER Pro to estimate key performance indicators, including Net Present Cost, payback period, and, for internal assessment, the Levelized Cost of Energy of the photovoltaic subsystem. Customer-side comparisons across scenarios are based on the effective cost of energy.

The analysis adopts the economic parameters summarized in Table 2 and is based on the following key assumptions: a photovoltaic investment cost of 20 million Indonesian rupiah per kilowatt peak, annual operation and maintenance costs equal to 1 percent of capital expenditure, a real discount rate of 8 percent, and a project lifetime of 25 years. The grid electricity purchase tariff is set at 1,114.74 rupiah per kilowatt hour, while the export remuneration rate in the net billing scenario is varied between 800 and 1,200 rupiah per kilowatt hour. All scenarios are evaluated using the validated optimal system capacity, assuming a constant load profile and a photovoltaic performance degradation rate of 0.6 percent per year.

To facilitate generalization, the results are interpreted using normalized indicators. Coverage and self consumption are expressed as dimensionless shares, the effective cost of energy can be normalized to the local retail electricity price, and policy sensitivity is reflected by the slope of changes in Net Present Cost and effective cost of energy with respect to the export tariff. These normalized metrics enable cross site comparisons under differing photovoltaic resources and tariff structures.

From a system design perspective, the potential role of battery storage is also considered. In principle, integrating a battery could increase the renewable energy fraction by shifting surplus midday photovoltaic generation to the evening demand peak. However, scoping calculations and existing literature on photovoltaic battery systems for commercial applications indicate that, under current Indonesian tariff structures and battery cost levels, the additional capital investment would increase Net Present Cost and extend the payback period. In this context, most of the attainable economic benefit is already captured by the grid connected photovoltaic configuration analyzed in this study, while battery storage would primarily provide temporal energy shifting with limited incremental cost savings. This supports the decision to model a no storage configuration as the most realistic near-term design for commercial SPKLU deployments in Indonesian cities.

3.3.1 Economic Simulation Results

The HOMER Pro optimization results indicate that integrating a photovoltaic system significantly reduces the Net Present Cost compared with the grid only scenario. The optimal configuration, consisting of 120 kilowatt-peak of photovoltaic capacity and a 104 kilowatt alternating current inverter, delivers substantial energy cost savings and emission reductions. A summary of the simulation outcomes for the three evaluated scenarios is presented in Table 6.

Table 6. Techno economic inputs (25 years; 8% real; PV 120 kWp; DCFC 50 kW; $\boldsymbol{r_{sell}}$ 0/800/1,200 Rp/kWh)

Parameter	Base value	Unit
Project lifetime	25	years
Real discount rate	8	% (real)
PV size (DC)	120	kWp
$\boldsymbol{CapEx_{PV}}$	20,000,000	Rp/kWp
PV O&M (annual)	1	% of CapEx
PV degradation	0.6	%/yr
Inverter replacement	15% of PV CapEx in year 12	—
Performance ratio (year 1)	0.78–0.82	—
Charger rating	50	kW
Annual charger energy	182,500	kWh/yr
Minimum billing (RM)	40 h × contracted capacity (kVA) × applicable tariff	Rp/month
Contracted capacity	Sized to cover 50 kW DCFC + auxiliaries	kVA
Policy export credit ($\boldsymbol{r_{sell}}$)	0 / 800 / 1,200	Rp/kWh
Emissions factor (grid)	0.78	$KgCo_2$kWh

Decision making is based on the effective cost of energy at the SPKLU meter, calculated as total annual customer charges, including energy charges, minimum billing (RM), and applicable fixed items, divided by total charger energy consumption. This metric is then compared across the grid only baseline and the photovoltaic scenarios S_1 and S_2.

3.3.2 Analysis and Interpretation

The results indicate that the addition of a photovoltaic system can substantially reduce the project's Net Present Cost. Under the self consumption scenario (S_1), the Net Present Cost decreases by 9.4 percent relative to the grid only system. Under the net billing scenario with an export tariff of 1,200 rupiah per kilowatt hour (S_2), the Net Present Cost reduction reaches 13 percent.

The effective cost of energy declines from 1,115 rupiah per kilowatt-hour in the grid only case to approximately 910 to 940 rupiah per kilowatt-hour in the photovoltaic scenarios S_1 and S_2, corresponding to cost savings of 15 to 18 percent compared with the no photovoltaic condition. The payback period ranges from 8.7 to 9.8 years, with the shortest payback achieved under the net billing scenario with the highest export remuneration.

In addition, the photovoltaic system avoids approximately 87 metric tons of carbon dioxide emissions per year, based on a grid emission factor of 0.78 kilograms of carbon dioxide per kilowatt-hour. Over the 25 year project lifetime, cumulative avoided emissions exceed 2,100 metric tons of carbon dioxide, representing a substantial environmental benefit.

3.3.3 Cost interpretation and role of LCOE

The Levelized Cost of Energy is used solely as a generation side indicator and is not directly compared with the bundled retail electricity tariff. Boundary consistent comparisons for decision making are instead based on the effective cost of energy under the S_0, S_1, and S_2 scenarios, which reflects actual customer billing, including minimum billing and contracted capacity components. This approach avoids overstating competitiveness and ensures that the cost metric is aligned with charges observed at the meter. The previously reported negative "effective LCOE" resulted from an improper mixing of export revenues with generation side costs; this issue has been resolved by clearly separating the photovoltaic only LCOE from customer-side effective cost of energy and Net Present Cost savings.

3.4 Sensitivity Analysis and Validation Against Literature

A sensitivity analysis was conducted to test how robust the project's economic outcomes are to uncertainty in three dominant drivers, namely photovoltaic capital expenditure, the energy export tariff, and the discount rate. These variables were prioritized because they directly shape the discounted cash-flow structure of a grid connected PV SPKLU system. Capital expenditure determines the initial investment burden and strongly affects Net Present Cost, the export tariff determines the financial value of surplus generation under export enabled schemes, and the discount rate captures financing conditions and the time value of money, which is well known to be a major determinant of PV feasibility. This focus is consistent with feasibility guidance for distributed energy projects in developing country contexts and with renewable energy finance literature emphasizing the central role of the cost of capital.

The analysis used a Monte Carlo framework to capture parameter uncertainty and operational variability, reporting scenario medians with 5 to 95 percent uncertainty intervals. Each parameter was varied over a plausible range to quantify changes in effective cost of energy and Net Present Cost savings versus the grid only baseline, with combined stress cases to test robustness under adverse conditions. Validation benchmarked the direction and magnitude of responses against recent evidence, where higher discount rates and PV capital costs worsen PV economics, while export remuneration reduces curtailment and improves utilization when surplus occurs.

3.4.1 Sensitivity to $\boldsymbol{Cap}\mathbf{Ex}_{PV}$

Photovoltaic system investment cost is the most influential factor in determining project feasibility. At the base cost of 20 million Indonesian rupiah per kilowatt-peak, equivalent to approximately 1.25 US dollars per watt peak, the project achieves a payback period of about nine years. Sensitivity analysis indicates that each 10 percent increase or decrease in photovoltaic capital expenditure results in an approximate ±6.5 percent change in Net Present Cost and a ±0.8 year change in the payback period, as summarized in Table 7.

Table 7. Sensitivity to $\boldsymbol{Cap}\mathbf{Ex}_{PV}$ ($\boldsymbol{r_{sell}}$= 800 Rp/kWh; discount rate 8%)

PV CapEx (million IDR/kWp)	Total CapEx (million IDR)	NPC (million IDR)	Effective Energy Cost (IDR/kWh)	Payback Period (years)
17 (−15%)	2,040	3,190	870	7.9
20 (base)	2,400	3,320	910	8.7
24 (+20%)	2,880	3,540	960	9.9

3.4.2 Sensitivity to Export Tariff ($\boldsymbol{r_{sell}}$)

The export tariff under the net billing scheme is a critical determinant of project financial feasibility, particularly for battery free systems. Accordingly, a sensitivity analysis is conducted for three export remuneration scenarios representing policy variation: 0 rupiah per kilowatt hour, equivalent to Scenario S_1 ; 800 rupiah per kilowatt hour; and 1,200 rupiah per kilowatt hour, representing an illustrative high case with one to one parity relative to the purchase tariff. The comparative results for these scenarios are summarized in Table 8.

Table 8. Sensitivity to export credit $\boldsymbol{r_{sell}}$ (discount rate 8%)

r_{sell} (Rp/kWh)	Export Revenue	NPC (million IDR)	Effective Energy Cost (Rp/kWh)	Payback (years)
0	0	3,460	940	9.8
800	35.8	3,410	930	9.4
1,200	53.8	3,320	910	8.7

3.4.3 Sensitivity to Discount Rate

Varying the discount rate between 6 and 10 percent shows a moderate influence on project feasibility. The simulation results indicate that each one percent increase in the discount rate raises the Net Present Cost by approximately 1.8 percent and extends the payback period by about 0.2 years.

Table 9. Sensitivity to discount rate (r_{sell}= 800 Rp/kWh)

Discount Rate (%)	NPC (million IDR)	Payback (years)	Effective Energy Cost (Rp/kWh)
6	3,250	8.4	900
8 (base)	3,320	8.7	910
10	3,380	9.0	925

3.5 Technical, Economic, and Policy Implications

The system is capable of supplying 63 percent of the SPKLU's annual energy demand, reducing the effective cost of energy by 15 to 18 percent and achieving a payback period of 8 to 10 years without subsidies. This performance is primarily driven by the temporal alignment between peak photovoltaic generation and midday charging demand. Sensitivity analysis confirms that project feasibility is highly dependent on photovoltaic capital expenditure and the level of export remuneration under net billing.

In the Indonesian context, where recent regulations cap SPKLU service fees and limit export credits for rooftop photovoltaic systems, modest fiscal incentives and export remuneration at or above 80 percent of the purchase tariff can materially improve the economics of photovoltaic powered SPKLU projects. Under these conditions, the 15 to 18 percent reduction in effective energy cost and the 8 to 10 year payback period observed in this case study are both commercially attractive and compatible with the current regulatory framework for urban commercial customers.

Although the grid-connected, battery free configuration is already optimal under the baseline assumptions, net billing schemes or smart charging strategies become important to mitigate potential photovoltaic curtailment of approximately 25 to 30 percent. With appropriate policy support, this model can accelerate both the energy transition and low carbon transport deployment in Indonesian urban areas.

This study does not include feeder level hosting capacity or power quality assessments, nor the co design of smart charging or vehicle to grid controls. These aspects will be addressed in future work, together with multi-site validation and the incorporation of explicit tariff calendars.

Current Indonesian regulations and tariff structures further reinforce the grid connected photovoltaic configuration as the most economical option for SPKLU deployment. In the absence of dedicated incentives for battery storage and with limited implementation of time of use tariffs, commercial operators have little financial motivation to invest in behind the meter batteries. Consequently, the no storage configuration analyzed in this study aligns closely with prevailing policy conditions and expected investment behavior.

Overall, the integration of a 120 kilowatt peak rooftop photovoltaic system with the SPKLU at the study site is technically effective and economically feasible within the modeled tariff and policy context. In the base case, the effective cost of energy at the SPKLU meter decreases from approximately 1,115 rupiah per kilowatt hour under the grid only scenario to about 910 to 940 rupiah per kilowatt hour under the photovoltaic scenarios, corresponding to a 15 to 18 percent cost reduction. At the same time, Net Present Cost is reduced by approximately 9 to 13 percent, with a simple payback period of 8.7 to 9.8 years achieved without subsidies. These results indicate that photovoltaic powered SPKLU systems become most attractive under net billing conditions when export remuneration is sufficiently high, at or above 800 rupiah per kilowatt-hour in this study, as higher export credits reduce curtailment and improve Net

Present Cost savings and payback performance relative to the grid only baseline.

4. Conclusions

Integrating rooftop photovoltaic systems with grid-connected public electric vehicle charging represents a viable pathway for Indonesia's urban energy transition. In the Bandung case study with a 120 kWp system, photovoltaic generation supplies 63 percent of annual charging energy, reduces the effective cost of energy by 15 to 18 percent, achieves a payback period of 8 to 10 years without subsidies, delivers stable performance with a performance ratio of 0.78 to 0.82, and avoids approximately 87 tons of carbon dioxide emissions per year. Sensitivity analysis indicates that project feasibility is driven primarily by photovoltaic capital cost and export remuneration under net billing, highlighting the importance of supportive fiscal policies and consistent tariff structures. Further progress can be achieved through the adoption of smart charging and vehicle to grid strategies to shift demand and enhance system flexibility, as well as through battery integration, including second life batteries, to reduce curtailment and improve peak demand coverage. Widespread deployment will depend on a robust policy framework that includes investment incentives and fair net billing export credits at or above 80 percent of retail electricity tariffs. The findings of this study are site specific and simulation based. Future work will validate the proposed framework using metered photovoltaic output, charger operation logs, and utility billing data across multiple sites, incorporate explicit time of use and seasonal tariff structures, and extend the optimization framework to include grid aware constraints and energy storage.

Nomenclature

Symbol	Definition
$CapEx_{PV}$	Capital expenditure of the PV system per installed capacity.
$C_{(t)}$	PV energy curtailed at hour *t*.
$ECoE$	Effective cost of energy at the customer meter.
EF_{grid}	Grid emission factor.
$G_{(t)}$	PV energy generated at hour *t*.
KVA_{contr}	Contracted capacity used for minimum billing calculation.
$L_{(t)}$	EV charger load energy at hour *t*.
NPC	Net Present Cost.
$O\&M_{PV}$	Annual operation and maintenance cost of the PV system.
P_{DCFC}	Rated power of the DC fast charger.
P_{PV}	Installed PV DC capacity.
PR	Performance ratio of the PV system.
RM	Minimum billing, computed as 40 h × KVA_{contr}× applicable tariff.
r_{sell}	Export credit rate under net billing.
S_0	Scenario 0: grid-only (no PV).
S_1	Scenario 1: PV self-consumption only (no export).
S_2	Scenario 2: PV with net billing export credit.
T	Project lifetime.
$U_{(t)}$	PV energy used on-site at hour *t*.
$X_{(t)}$	PV energy exported to the grid at hour *t* (S_2).

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