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Integration of Multiple Simulation Tools for Photovoltaic System Design and Analysis

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Abstract

This research aims to develop a photovoltaic (PV) project assessment method by integrating four simulation tools to maximize potential benefits from multidimensional scopes of projects. The proposed method combines output parameters and the cost databases of selected tools to overcome individual limitations by facilitating complementary strengths. Most simulations require more analytical results while using single or multiple tools separately. Also, it combines HelioScope, RETScreen, HOMER, and PVsyst software to simulate entire generation export, self-consumption, and impact of load shedding with sensitivity analysis. The method employs the capability of HelioScope to find maximum installation capacity based on available space, the carbon-trading feature of RETScreen, HOMER's optimization, and PVsyst's viability analysis. The results demonstrate that carbon trading shortens the project's payback period while maximizing installation capacity and performance improvement by energy export with a stable capacity factor and performance ratio. The method proffers a promising technique for PV system assessment.

Keywords: PV assessment, HelioScope, HOMER, PVsyst, RETScreen

1. Introduction

Renewable energy (RE) sources render impactful solutions to effectuate the sufficiency of energy and the sustainability of the environment. Solar photovoltaic (PV) systems mechanistically utilize sunlight to produce electricity cleanly and sustainably. The capacity of PV systems varies from a few watts to a mega-watt scale. It requires larger installation space than conventional power plants for the same amount of electricity [1]. Therefore, capacity determination based on available space and subjected load, mode of operation, and economic benefits are crucial for a successful PV project. Technically, PV system simulation shows system performance, economics, cash flow, and profitability before implementation and identifies constraints and advantages based on different scenarios [2]. Consequently, users can find the best solution by analyzing the results. Therefore, simulation is essential in PV project assessments.

Undeniably, however, each simulation tool has its strengths and limitations [3]. As a result, the ideal and intuitive solution to conquer the limitations is eclectically using multiple tools to provide diversified information for analysis [4]. Umar et al. [5] compared ten tools, concluding that PVsyst, HOMER, and RETScreen are the best simulators. They identified that HelioScope has an interactive design facility that empowers users to use a web-based graphical interface to design efficiently and maximize the installation capacity. The central gap in this study lies in the practical exclusion of financial analysis and the ineffectiveness of maximizing the benefits of energy business or carbon credit.

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Khan et al. [6] performed a field survey to find the maximum installation capacity for a PV project. Concerning the study, the survey data in system advisor mode (SAM) and RETScreen were utilized to compare the software results. RETScreen provides cost data on PV installations, operations and maintenance (O&M). Moreover, it has an emission and carbon trading analysis option, whereas this option was not further adopted. Another issue with this approach is that a field survey involving the workforce consumes valuable time and costs. An interactive design suite like HelioScope can minimize the field survey efforts and cost [7]. The comparison of results of different software only reflects limited quantitative differences and deviations. The study also overlooks opportunities to accelerate the payback time and impacts of the change in economic conditions.

De Souza et al. [8] compared HOMER and PVsyst results with practical data from a PV project site, indicating that PVsyst produces accurate results, and HOMER renders system optimization. Users can use inverter cost data from the HOMER database, and PV cost from the PVsyst database. None of these tools provides both data. Limiting the analysis to component configuration and electricity production suffers from the inability to provide information on the payback period, power export opportunity, emission analysis, and carbon trading [9-11]. Notwithstanding acknowledging load shedding as a common phenomenon in underdeveloped countries, most simulation tools fail to produce practical system configurations for load-shedding situations [12].

Baqir and Channi [13] analyzed a grid-connected PV system using PVsyst. The study indicates that grid-connected systems could benefit from total or excess energy export situations. Moreover, PVsyst can analyze both total and excess energy export situations, whereas it lacks carbon trading accounting. The study deficits the exploration of carbon trade benefits. However, it deals with system performance without sensitivity and risk analysis. Islam et al. [14] explored PV installation prospects on existing infrastructure using HOMER and PVsyst. The main shortcoming of this work is the absence of shading analysis since the subjected infrastructures are prone to shading impact [15]. PVsyst performs shading analysis but requires actual landscape drawings, which implies difficulties. The study might have used the HelioScope for shading analysis [16]. The plant's installation size is a few MW, indicating that it could benefit from a carbon trading analysis.

Bangladesh aims to increase RE share in its national energy mix from 4.67% to 40% of renewable electricity. The country targets 30% by 2030 and 40% by 2041 [17]. The government has initiated several MW-scale PV power projects throughout the country. Given that there are 179 public and private universities with increasing electricity demands in Bangladesh, the government recommends using PV power to reduce dependency on the national grid and facilitate the fed-in-tariff (FIT) once the installed site exports energy to the grid [18]. Therefore, the grid export scenario becomes essential in Bangladesh. Four assessment studies examined grid-connected rooftop PV systems on university campuses [19-22]. Two of these studies used a field survey and mathematical approach to estimate installation capacity; two used simulation tools. The studies indicate that excess electricity export is profitable for grid-connected PV systems. However, these studies lack the entire export scenario and do not cover emission analysis, shading loss, carbon trading, export profits and shortfalls optimization, sensitivity analysis, and standardized cost data [23].

The objective of this research is to prepare a PV-project analysis method to synthesize results by integrating complementing features provided by the selected tools. The purpose of the study is to exploit interactive design options, utilize a standard cost database, provide system optimization, find loss variants, perform economic analysis, evaluate system performance, explore carbon trading and its impact on the payback, observe risk and sensitivity impacts, and identify benefits from different scenarios. The method integrates HelioScope, RETScreen, HOMER, and PVsyst in four stages, connecting the results from the preceding stages.

2. Site Selection and System Constraints

The selected site name is American International University-Bangladesh, situated in Dhaka. Bangladesh has a 1.3 MW electricity demand. Holistically, it consumes grid electricity and generates power from 2,575 kVA diesel generators during load shedding to support the loads. The campus has eight suitable rooftops for installing PV. A 194,471.80 square foot area is open to the sun for 4 hours, with a solar irradiation of 4.65 kWh/m^2/day. This research proposes a PV system comprising existing diesel generators and grid electricity, preparing three scenarios exploring the best mode of operation, as listed as follows.

Scenario A: Grid with full export implies the total export of produced electricity using the FIT to look for the impact on payback. Furthermore, it examines emission reduction and carbon trading.

Scenario B: Having a Grid-PV system without load shedding considers self-consumption from both the PV and the grid power. This scenario can predict energy savings, grid purchases, and own generation.

Scenario C: Grid with outage covered by diesel generator and PV. This scenario considers yearly schedules for load shedding and estimates the impact of diesel emissions and electricity costs.

In brief, Scenario A emphasizes business prospects, Scenario B looks for energy savings, and Scenario C looks for costs and environmental impact. Fig. 1 shows the aerial view of the site.

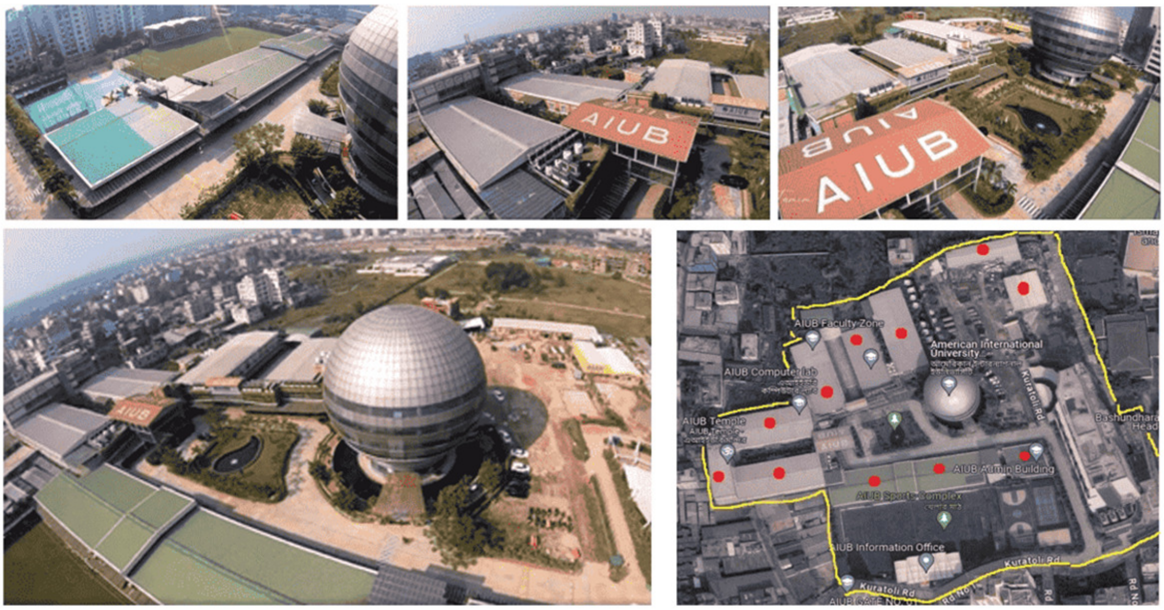


Fig. 1 Arial view and map images of subjected campus rooftops

3. Methodology

This research investigates and integrates prominent options, features, and the cost database of selected tools. Determining installation capacity based on available usable space enables users to identify the maximum PV size, shading, and losses. The analysis's vital aspects are the cost database, scenario-based system design, emission analysis, optimization, performance analysis, economic assessment, risks, and sensitivity.

3.1. Selection of tools

The total simulation comprises four stages where each tool complements each other. HelioScope provides installation capacity but does not address load-specific system performance, carbon emission, or simulation of different scenarios. At this gap, RETScreen offers the cost database, complete export scenario, profitability, carbon trading, and risk analysis. However, none of these tools handle load, optimization, and electricity production costs. Here, HOMER, as a notable exception, furnishes these features and the cost data for the inverter but lacks PV cost. Meanwhile, RETScreen complements the PV cost data. RETScreen and HOMER yield risk and sensitivity analysis. HOMER facilitates grid purchase, PV generation, and excess electricity, simulating the self-consumption scenario. HOMER cannot provide the entire export scenario. At this point, PVsyst provides grid export and consumption scenarios.

3.2. Simulation stages

The process commences with the HelioScope at stage one. HelioScope empowers users to compute the maximum usable space by a graphical interface. Specifically, users can select the installation area, panel models, input shading, row spacing, and tilt angles. HelioScope yields result on solar access, shading, electricity production, system loss, and installation capacity.

At stage two, the simulation uses RETScreen since it requires a predetermined installation capacity of PV and inverter. HelioScope provides these values. RETScreen utilizes its own cost and emission factor database. It calculates the energy exported to the grid using emission estimations.

At stage three, HOMER optimizes the system based on load. HOMER database proffers costs for inverters but lacks PV and O&M costs. Here, RETScreen gives these values. HOMER uses RE fractions to estimate the optimal PV size. The method deploys this option to match the HOMER input, and HelioScope results on PV capacity.

At stage four, the PVsyst simulates the load profiles, resource data, energy exchange, electricity rate, and economic evaluation with emission analysis and paucity of optimization or outage scenarios. However, it estimates system losses, payback, return on investment (ROI), profitability, and performance. Its database contains PV, inverter, and installation costs but lacks O&M costs; therefore, the method uses the RETScreen database for O&M costs.

Fig. 2 depicts the variables and parameters inside the elliptical shapes. Solid black circles give a particular parameter's flow to the input of a tool. Full circles show the position of a tool in the process, starting from the left. The dotted lined boxes present the results from a tool.

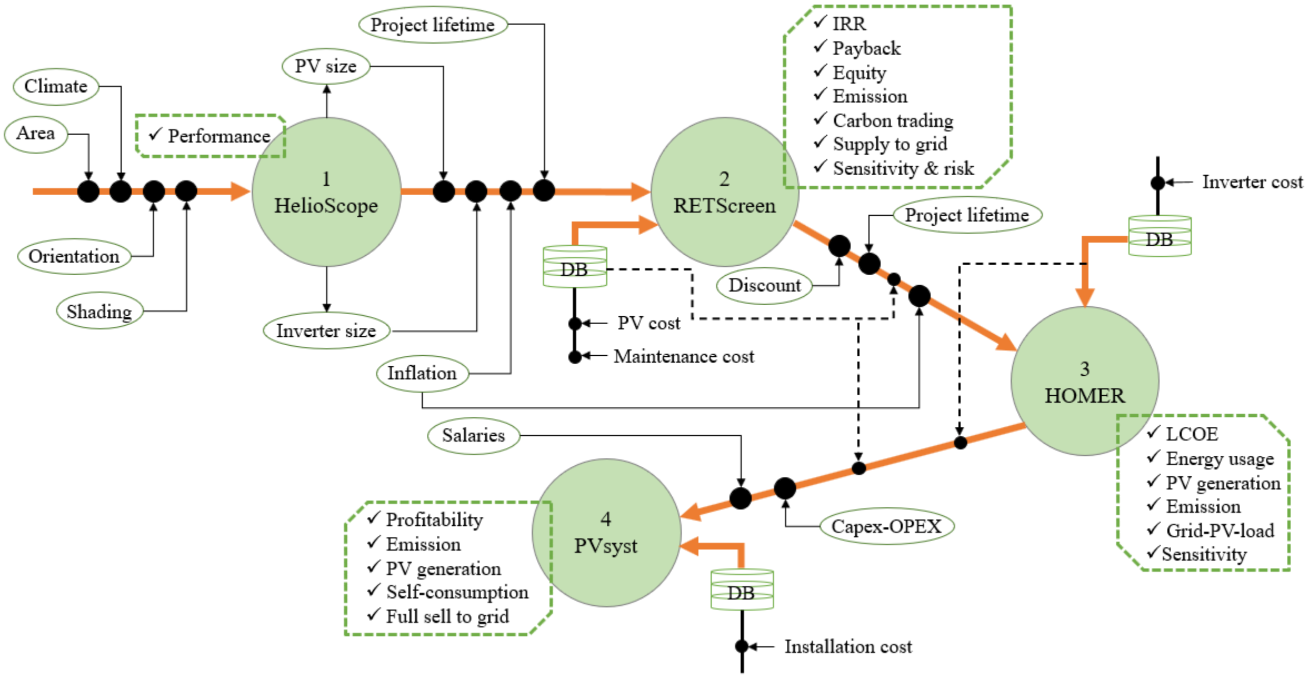


Fig. 2 Design flow of the proposed method

4. Results and Discussions

The result combines different outputs from each tool. The HelioScope gives the PV installation size. RETScreen renders a complete export scenario, including emissions, carbon trading, and risk analysis. HOMER presents cash flow, electricity cost, emission analysis, and sensitivity. Lastly, PVsyst introduces performance ratio (PR), payback, emission analysis, and profitability results. Fig. 3 is the high-level presentation of the process. It evinces the stage position of each tool and the compilation of results by dotted lines. The solid line presents the estimation of the power outage scenario based on HOMER and PVsyst results.

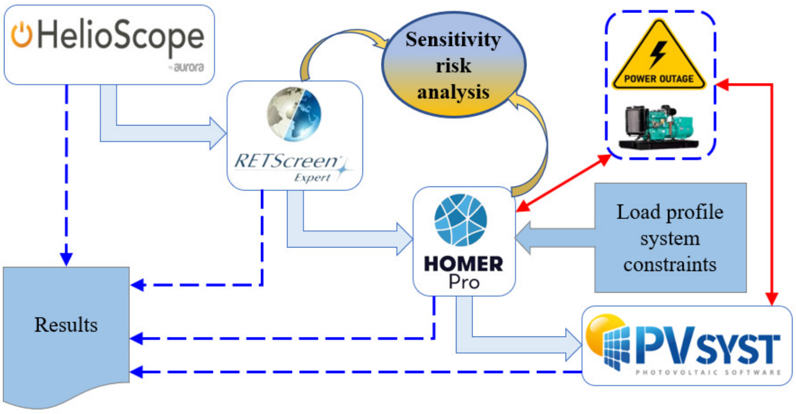
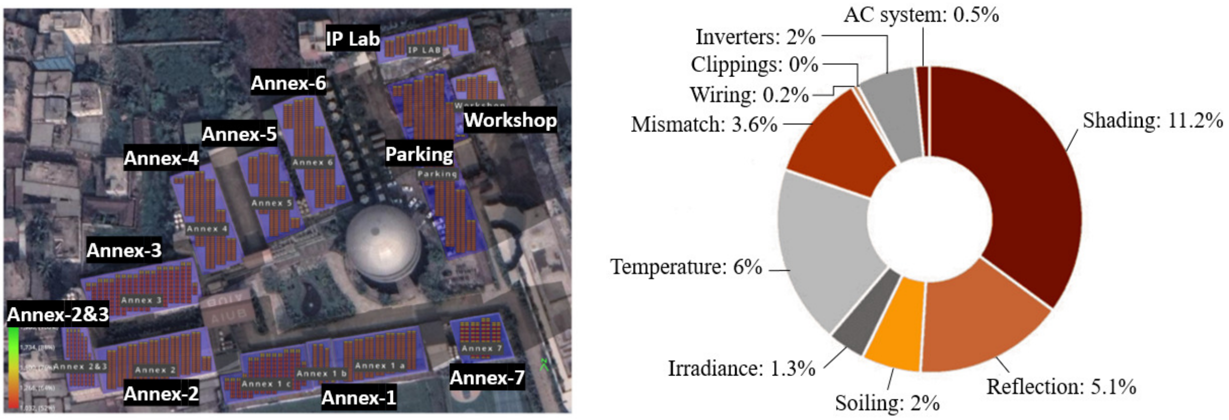


Fig. 3 Flow of analysis using multiple simulation tools

4.1. HelioScope results

The HelioScope returns the nameplate capacity as 1.09 MWp, using 3,163 Trina Solar, model TSM-PE15H-345 (345W). The usable rooftop is 87,000 ft^2 and 18,781 ft^2 from the parking space. This site has 89% solar access, 72% tilt and orientation factor (TOF), and 63.5% total solar resource fraction (TSRF).



(a) Annex-wise PV installation capacity

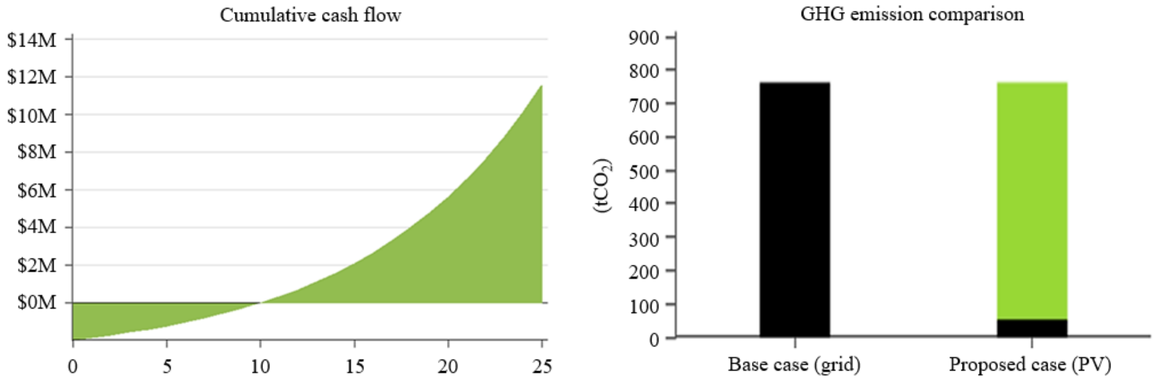
(b) Various system losses

Fig. 4 HelioScope results on estimation

The optimal plane of array (POA) irradiance is 1,967.5 kWh/m^2 at 28.40° tilt and 179.70° azimuth. The PR is 71.8%. Fig. 4(a) shows the usable rooftops and the maximum installation on available space. Fig. 4(b) shows that the highest loss is due to shading and indicates the reason for performance reduction. The system requires 37 Sunny-Tripower-24000TL-US (SMA) inverters, giving 890.2 kW capacity. There are 185 strings of 17,288.20 ft American Wire Gauge (AWG) 10 (copper) wire.

4.2. RETScreen results

Considering 1.09 MWp returning 3,164 numbers of TSM-PE15H-345 (345W) PV modules, the fixed-track module efficiency is 17.74%. The loss input is 28.2% with 98% inverter efficiency. The electricity export is 1,261 MWh/yr. The electricity export rate is \$0.1/kWh, resulting in a revenue of \$126,128/yr. The capacity factor (CF) is 13.2%. The installation cost is \$1,800/kW for 1,000 kWp. The operating cost is \$18/kW/yr. It uses an inflation rate (11%) and project life (25 years). The total initial cost is \$1,964,844, along with \$19,648 of O&M. The result shows the internal rate of return (IRR) value is 13.8% with a payback of 10-18.5 years. RETScreen reflects a reduction of 710.8 tCO$_2$, and the proposed case would emit only 53.5 tCO$_2$/yr. Considering the certified emission reduction (CER) rate (\$300/tCO$_2$), the carbon reduction revenue is \$213,225. Apropos the verified emission reduction (VER) rate (\$100/tCO$_2$), the revenue is \$71,075 [24]. The payback is 11.1 years for VER and 6.1 years for CER. Fig. 5(a) shows that the cash flow increases after ten years because of component replacements. Fig. 5(b) represents the emission reduction performance of the PV system compared to the grid.



(a) Cumulative cash flow (b) Emission reduction

Fig. 5 RETScreen results

4.3. *Homer results*

HOMER returns the system comprising 1027 kWp PV with an 824 kW inverter having a 32% renewable fraction. Fig. 6 shows the PV, load, inverter, and grid connections. The PV provides DC electricity to the DC bus. The inverter converts DC power into AC and supplies it to the AC bus. The grid injects electricity into the AC bus. The load is AC type and fed by an AC bus.

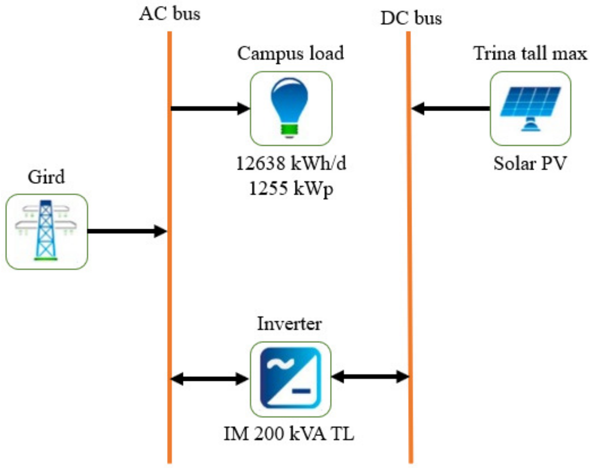
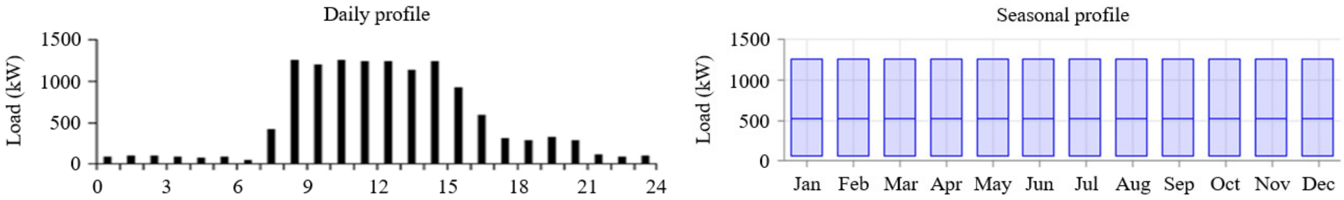


Fig. 6 Optimized system configuration by HOMER

Fig. 7(a) illustrates the hourly load demands, which steeply rise from 8:00 AM and remain consistent until 3:00 PM. They fall gradually from 4:00 PM. The load is 150 kW from 12:00 AM to 8:00 AM, and 350 kW from 4:00 PM to 9:00 PM. Fig. 7(b) is a box plot with three quartiles. The median is between 500 kW and 1000 kW. The lower quartile lies between 0 kW and 500 kW. The top quartile is above 1200 kW.



(a) Daily load profile (b) Seasonal load profile

Fig. 7 HOMER configuration

Fig. 8 presents the hours of the day (left axis) and the output (right axis). The brighter shades regions represent the mean inverter output, ranging from 800 to 1000 kW, with the highest output (1000 kW) mostly occurring between 8:00 AM and 4:00 PM. The darker shades regions indicate periods of low consumption, while the unshaded (or darkest) areas represent times with no generation.

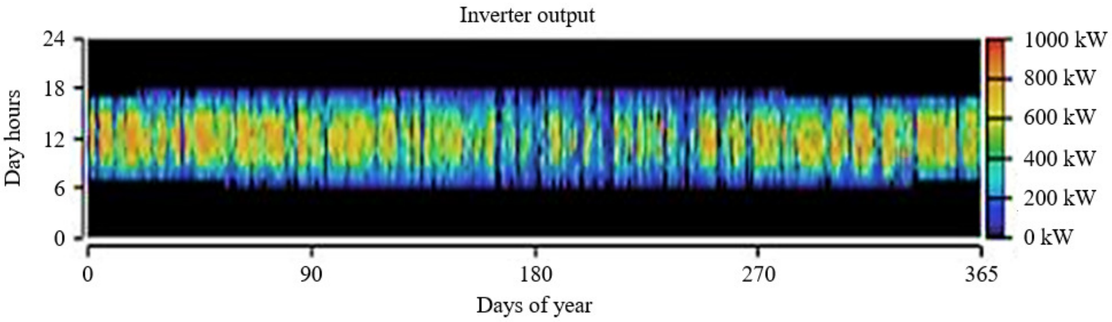


Fig. 8 HOMER results on Inverter output

Fig. 9 shows the generation equivalent to 800-1000 kW in the bright regions within the graph, mostly between 10:00 AM and 4:00 PM, indicating higher PV outputs. The comparatively darker regions from 400-600 kW represent lower power output, mostly distributed in the early morning and late afternoon. The unshaded or darkest areas from 0-200 kW indicate times of no generation.

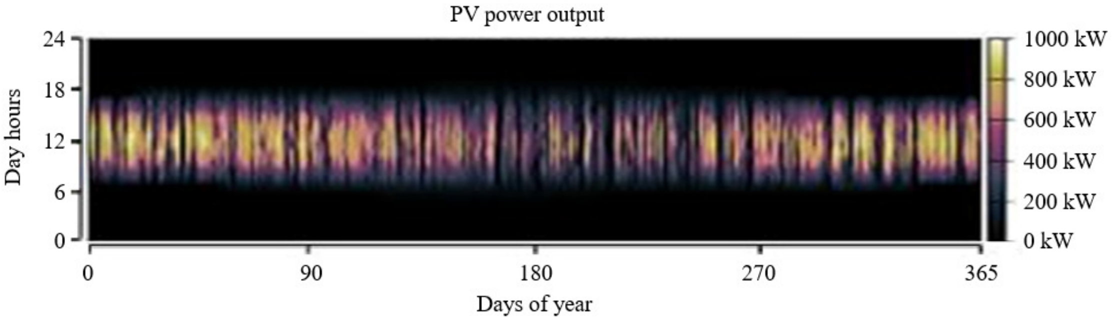
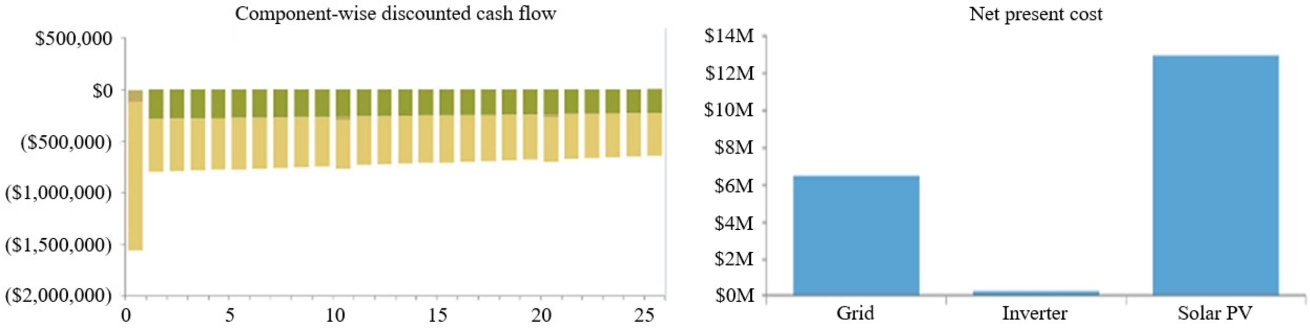


Fig. 9 HOMER results on PV power output

Fig. 10(a) shows discounted cash flow using brown bars (lighter shade) for the investment and green bars (darker shade) for the revenue from excess electricity. The revenue is steady, and the cash flow decreases over the lifetime. The first-year investment is high due to the system installation. Fig. 10(b) depicts the costs of components, with PV taking the highest investment. The inverter has the smallest share of the cost.



(a) Discounted cash flow (b) Net present cost

Fig. 10 HOMER result on economics

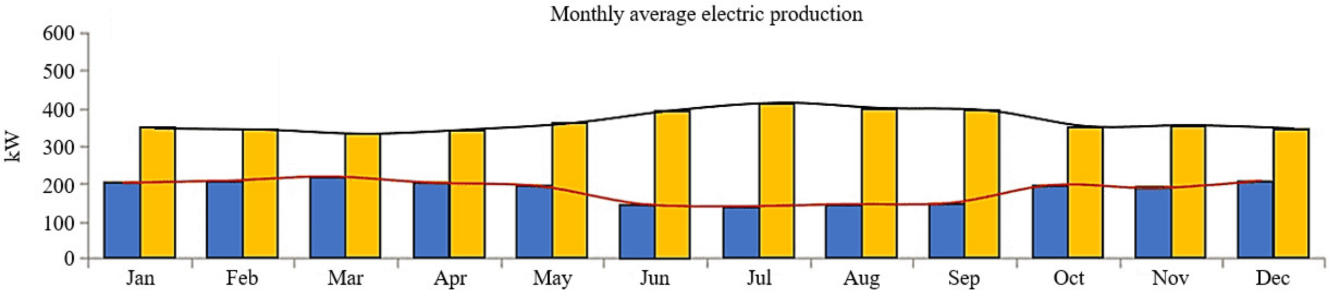
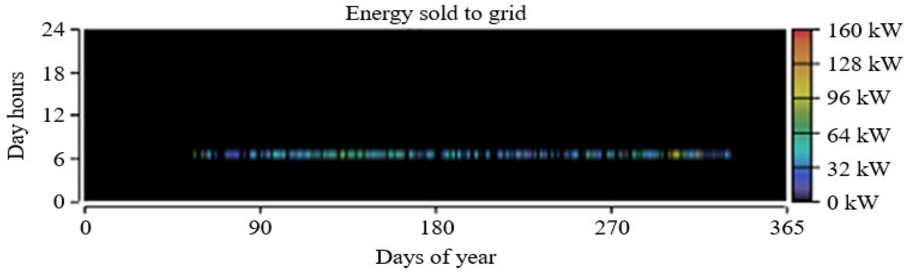
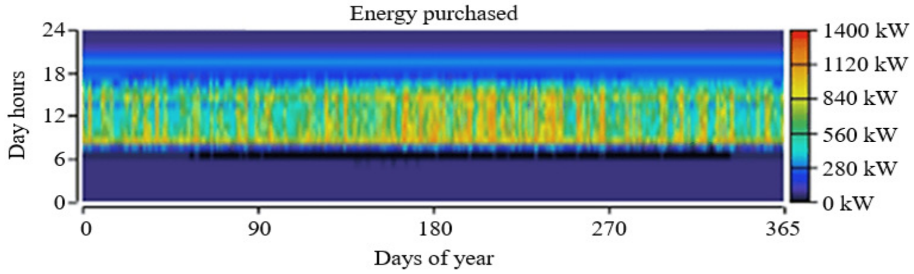


Fig. 11 Electricity supply by Solar PV and grid

Fig. 11 shows the electricity share by the grid and PV. The bars on the left indicate the electricity supply from TrinaTallMax, with their height representing PV generation. Meanwhile, the bars on the right indicate the grid electricity supply. The highest grid dependency occurs from June to September due to the clouds during these months, and the lower grid consumption occurs from October to May. Fig. 12(a) reflects the electricity sold to the grid, with the export time spanning from 6:00 AM to 8:00 AM. The distribution of equivalent energy is categorized into 2 types to represent the extent of energy, i.e., 96-160 kW and 32-64 kW, respectively. Fig. 12(b) depicts the electricity purchased from the grid. Higher-intensity dots represent purchases in the 840-1400 kW range, while lower-intensity dots represent lower imports of electricity.



(a) Energy sold to grid



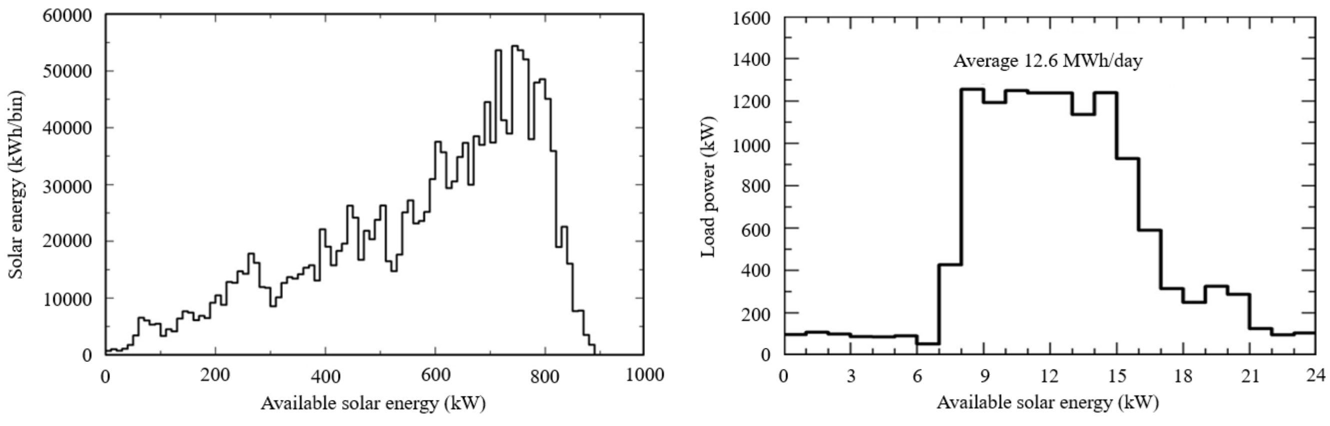
(b) Energy purchase

Fig. 12 HOMER results on power exchange

The levelized cost of electricity (LCOE) is \$0.190/kWh, with an initial capital of \$19.6M. Electricity production is 4,665,568 kWh/yr, consumption is 4,621,306 kWh/yr, and excess electricity is 7,349 kWh/yr. Total purchase from the grid is 3,120,206 kWh, and export to the grid is 8,437 kWh. The greenhouse gas (GHG) emissions are 1,971 tCO_2/yr, 8.5 tSO_2/yr, and 4.2 tNO/yr while using grid power.

4.4. PVsyst results

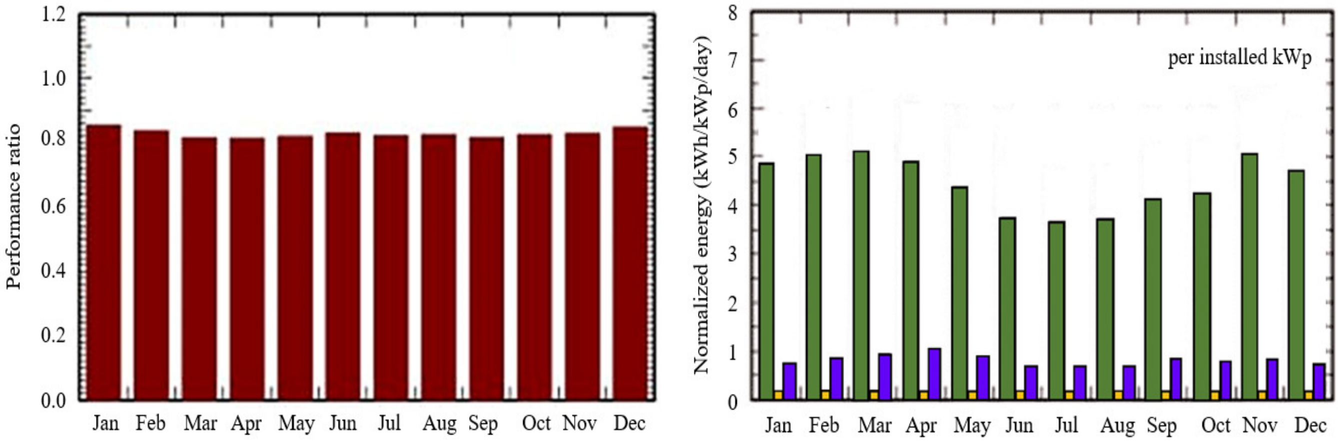
PVsyst analysis considers \$21,868.40/yr for salary. The payback for self-consumption mode is 15.4 years, considering the \$0.1/kWh FIT rate and \$0.088/kWh grid electricity purchase rate. The payback is 11.6 years for the entire export scenario. The LCOE is \$0.13/kWh, ROI is 13.3%, and PR is 82%. The PV can save 21,109.3 tCO_2.



(a) Output power distribution (b) Daily load profile

Fig. 13 PVsyst results on output power distribution and configuration on daily load profile

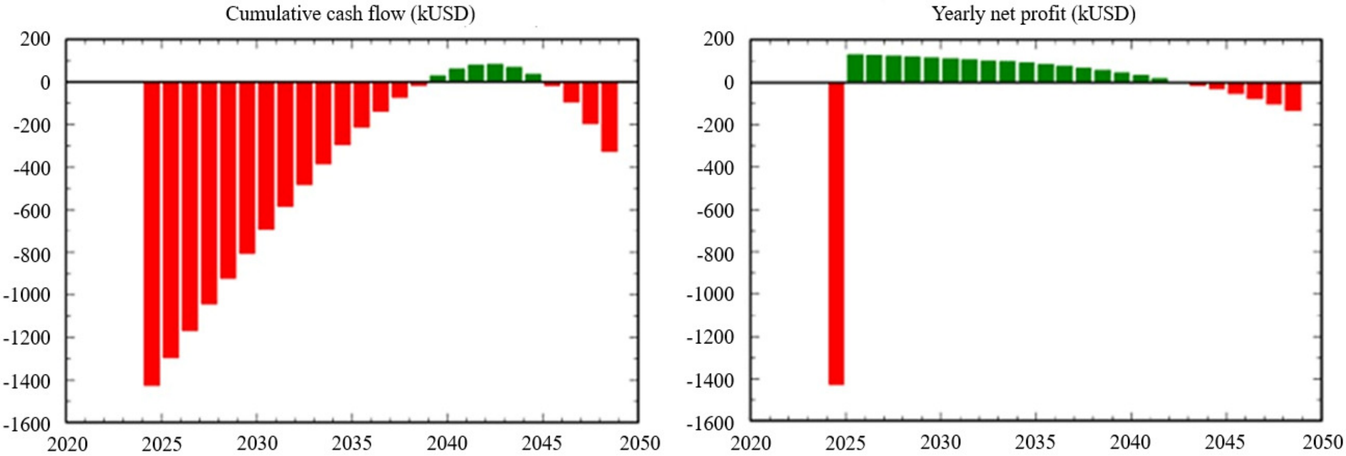
The self-consumption is approximately 1,777 MWh/year, and the export is 4.0 MWh/yr. Fig. 13(a) depicts the solar energy output for the available irradiation. The 700-780 kW bin evinces a significant output of 55,000 kWh of energy. Fig. 13(b) illustrates the load profile, where demand increases from 7:00 AM to 8:00 AM, remains stable until 3:00 PM, and declines until 6:00 PM. Fig. 14(a) renders a stable PR throughout the year. The highest value occurs in January. Fig. 14(b) exhibits the system's normalized energy production. The highest value occurs in March. In Fig. 14(a), bars indicate usable energy. Meanwhile, in Fig. 14 (b), each month's longest bars represent useful energy, the intermediate-highest bars indicate PV-array loss, and the shortest bars denote system losses.



(a) Month-wise performance ratio (b) Normalized productions

Fig. 14 PVsyst results on monthly performance ratio and normalized production

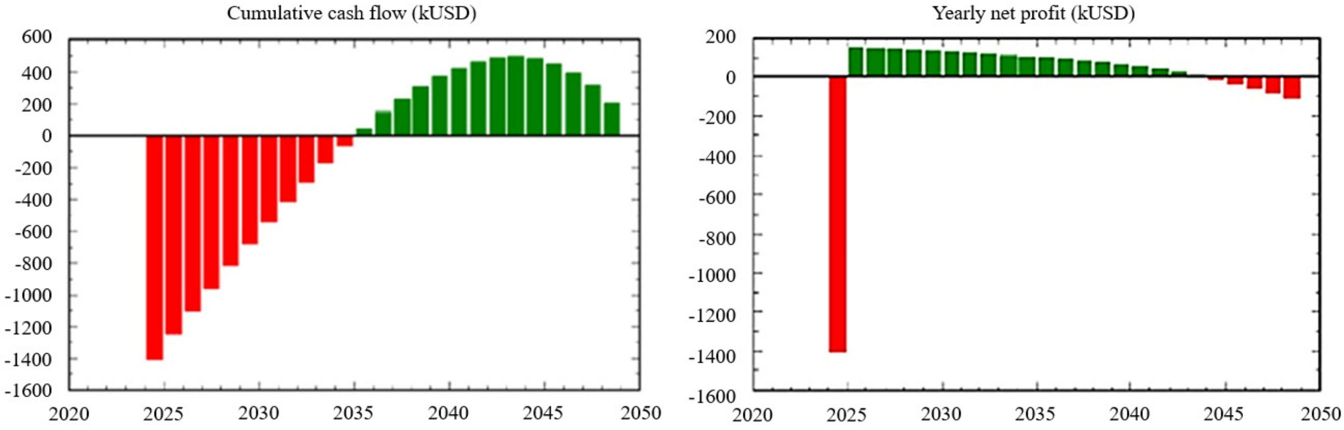
Fig. 15(a) presents the cumulative cash flow in the self-consumption scenario. The individual bars account for all cash inflow and revenues in a specific year. The bars above zero indicate that the revenue exceeds the expenses. After 2045, there will be an increase in the number of bars underneath zero, indicating new investments. Fig. 15(b) presents the net profit where bars below zero present investment and the bars above zero show the profit. The net profit gradually decreases until 2042. After 2043, net profit becomes negative, presenting the new cash investment.



(a) Year-wise cash flow (b) Year-wise net profit

Fig. 15 PVsyst results on the self-consumption scenario

Fig. 16(a) shows the cumulative cash flow in the grid injection scenario. The cash flow will decline until 2035. In this scenario, the zero crossing is four years earlier than the self-consumption scenario. Fig. 16(b) shows the net profit where zero crossing is one year longer than the self-consumption. Fig. 17 shows the project's life cycle emissions and carbon savings. The net balance is 21,109.3 tCO_2. The system produces an emission amount of 1,993.20 tCO_2. The system replaces 25,995.4 tCO_2 concerning the grid. The yearly balance is about 844 tCO_2/yr.



(a) Year-wise cash flow (b) Year-wise net profit

Fig. 16 PVsyst results on complete injection scenario

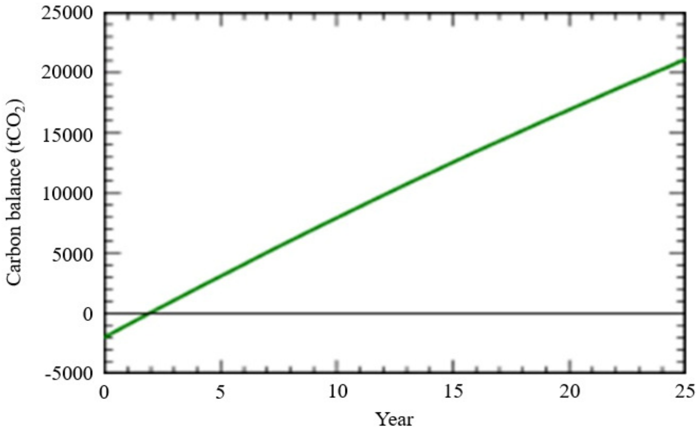


Fig. 17 Year-wise carbon balance

4.5. *Load shedding estimation*

The site becomes a PV-diesel system during outages. Table 1 presents the load-shedding schedules where the peak hour outage is 1 hour. The total off-peak outage is for 2 hours. Generators support a 1,250 kW load during peak time. Regarding off-peak 1, it is 150 kW and 350 kW for off-peak 2. The diesel expenditure is $600/hr. There are 3 hours of load shedding for 85 days/year, resulting in 255 hours of outage, which costs $260,038.24/year. The electricity generation is approximately 238,000 kWh/year. The LCOE for diesel is $1.09/kWh. The PV could reduce diesel usage by 32%. The diesel will cause 6.5 tCO_2/yr.

Table 1 Load shedding and diesel generator profiling

Campus hours	Load shedding hour	Duration (hour)	Avg load (kW)	Fuel cost ($)
Off-peak 1	02:00 AM to 03:00 AM	1	150	163.89
Peak	11:00 AM to 12:00 AM	1	1250	1365.75
Off-peak 2	08:00 PM to 09:00 PM	1	350	382.41
			Per day cost	1912.05
			Per hour average cost	637.35
			Yearly cost	162523.90

4.6. *Sensitivity and risk analysis by RETScreen*

The analysis investigates the sensitivity and risks on payback due to the changes in initial cost, O&M, export to the grid, export rate, and GHG credit rate on the payback period, as shown in Fig. 18. A 30% sensitivity and ten-year threshold evinces a 15% decrease in electricity export. This results in an unachievable payback even if the initial cost is 30% less. Similarly, a 15% increase in initial cost makes longer paybacks.

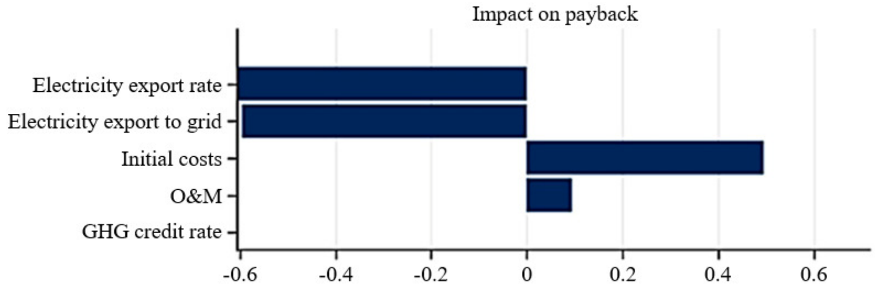


Fig. 18 Monte Carlo simulation on equity payback impact by components

Fig. 19 introduces results on 20% risk, examining the payback with 90% (P90) confidence. It excludes the lowest and highest 10% of data. At 20% risk, the payback stays within 8.4-11.4 years. Fig. 20 shows the payback remains inside the 6.6-14.5 years range for 0% risk. The export income and the electricity rate have opposite impacts on payback.

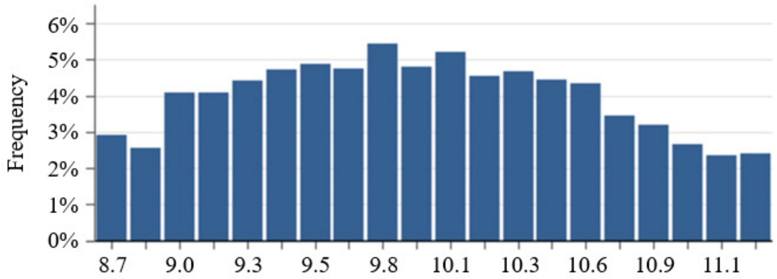


Fig. 19 Equity payback distribution for 20% risk level

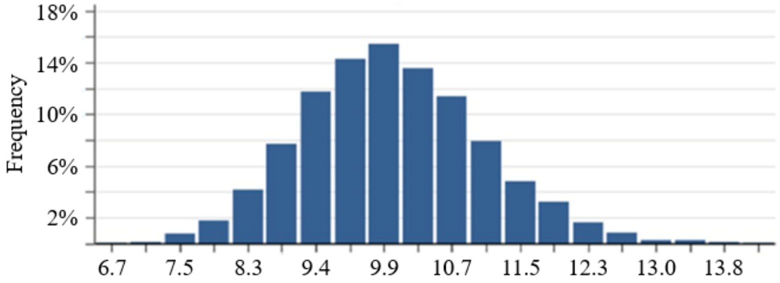


Fig. 20 Equity payback distribution for 0% risk level

4.7. Sensitivity analysis by HOMER

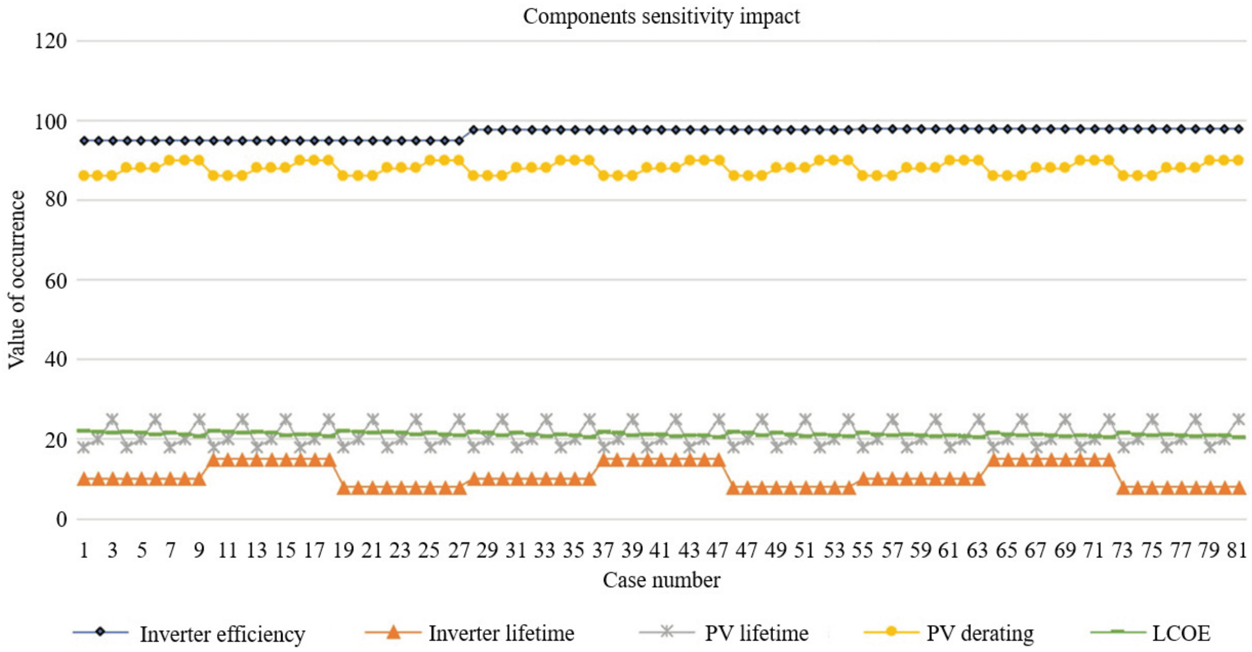


Fig. 21 Sensitivity impact on LCOE by system components

HOMER investigates the sensitivity of economic conditions and component performance. Once the HOMER sensitivity module yields the values of different parameters, the simulation picks and generates different LCOEs based on the values. Table 2 illustrates the values for the component sensitivity. Here, PV lifetime ranges between 18 and 25 years. The panel-derating factor is 86%-90%, and the inverter efficiency is between 95% and 98%. Fig. 21 gives the linked sensitivity results. The lines presented in Fig. 21 represent the value of a sensitivity parameter and its impact on LCOE. HOMER generates 81 sensitivity cases. The LCOE ranges between \$0.19 and \$0.21. Here, the USD conversion rate is 110 BDT/\$.

Table 2 Sensitivity parameters of system components

PV panel lifetime (Years)	PV panel derating (%)	Inverter lifetime (Years)	Inverter efficiency (%)
25	88	10	97.6
20	90	15	98
18	86	8	95

Table 3 exhibits the economic sensitivity parameter values. The increment of the discount rate elevates the LCOE. The input values are 10%-14%. The impact of inflation can be known by analogy with the discount rate. The value for the inflation rate is 9%-13%. It takes a project lifetime of 18-25 years. The lifetime shows an inverse effect on LCOE. Fig. 22 shows the fluctuations in LCOE due to economic sensitivity in 75 cases. Due to sensitivity, the estimated electricity cost varies between \$0.19 and \$0.21.

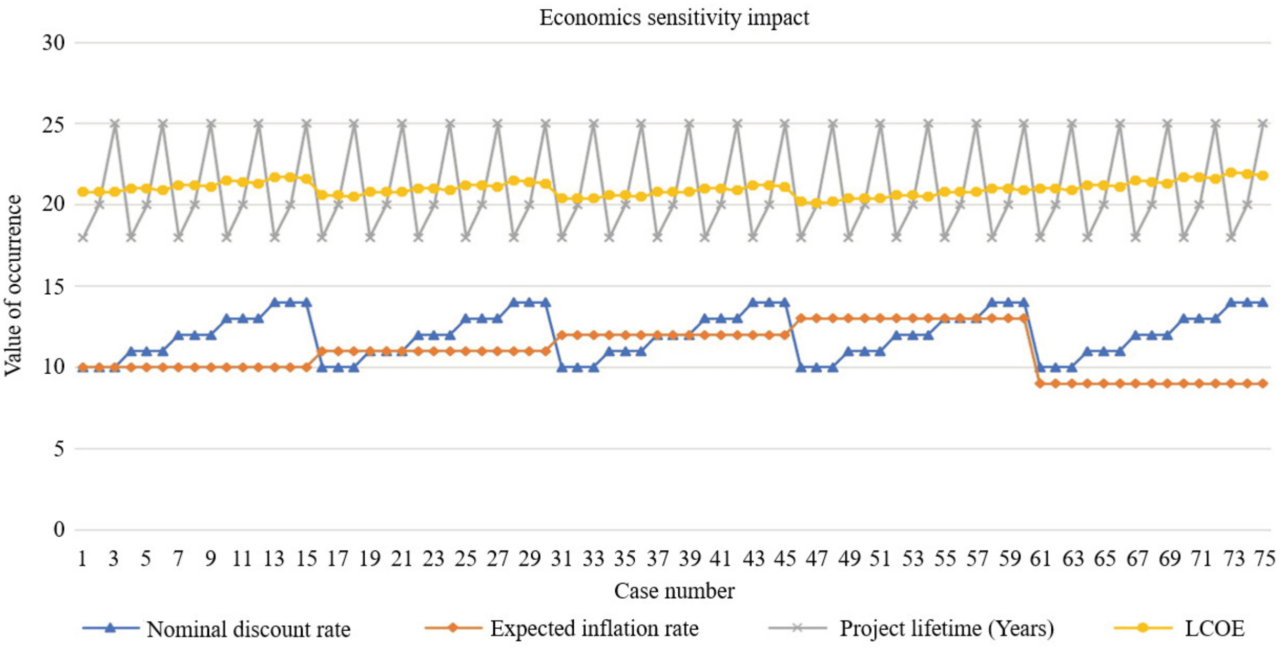


Fig. 22 Sensitivity impact on LCOE by economic factors

Table 3 Sensitivity parameters of economics

Nominal discount rate (%)	Inflation rate (%)	Project lifetime (Years)
10	9	18
11	10	20
12	11	25
13	12	-
14	13	-

Table 4 compiles 12 critical input and output parameters. ‘User-defined’ means that the value is a user input. The term ‘Own database (ODB)’ refers to the value from the database of that tool. If the values are yielded from different tools, the table mentions the tool’s name. Table 4 gives the relationships between inputs and outputs from different tools and presents the mode of simulations.

Table 4 List of input and output parameters of all used software

Type	HelioScope	RETScreen	HOMER	PVsyst
Input	Rooftop area	System size (HelioScope)	Project time (user-defined)	Install cost (ODB)
Input	Panel orientation	Inflation rate (user-defined)	Discount rate (user-defined)	Salaries
Input	Climate data	Project lifetime (user-defined)	Inflation rate (user-defined)	Meteonorm
Input	Shading	Inverter size (HelioScope)	Cost (RETScreen, ODB)	PV (ODB)
Input	PV module	PV cost (ODB)	System size (HelioScope)	Inverter (ODB)
Input	Inverter module	Maintenance cost (ODB)	Maintenance cost (RETScreen)	O&M (RETScreen)
Output	System size	IRR	LCOE	Profitability
Output	Inverter size	Simple payback	Cash flow	Payback period
Output	Performance ratio	Equity payback	Grid purchase	ROI
Output	Shading loss	Emission analysis	Emission for grid	LCOE
Output	Other system loss	Carbon trading outlook	PV generation	Performance ratio
Output	Energy production	Risk analysis	Sensitivity analysis	Losses
Mode	-	Full export	Self-consumption	Both

4.8. Comparison of results

The performance ratio is a crucial index of PV power plants. It is a ratio between the actual and theoretical output. An 80% PR indicates an efficient PV plant [25]. In addition, shading loss is an important variable that can reduce power production, which occurs when buildings or trees create a shadow on the PV panel surface. Therefore, selecting the proper landscape, orientation, and position is essential [26]. The CF represents the ratio between the actual and theoretical energy production at the highest rate throughout the year. A 10-25% CF indicates a sound PV system [27]. The LCOE by PVsyst is \$0.13, and HOMER gives \$0.19. The difference is \$0.06 due to the renewable fractions. In HOMER, the CF is 32.5%, and in PVsyst, it is 38.63%. HOMER produces the energy production of 4.7 GWh/yr, PVsyst yields 1.8 GWh/yr, and the HelioScope presents 1.1 GWh/yr. The PR is 71.8% by HelioScope and 82% by PVsyst. The HelioScope results are the lowest due to the inclusion of losses like irradiance, shading, temperature, soiling, array, and wiring loss. PVsyst does not consider shading loss but takes other types, whereas HOMER does not consider these loss parameters.

In the self-consumption scenario, PVsyst generates 2,823 MWh of grid electricity usage, and HOMER produces 3,120 MWh. This scenario causes an emission of 1,359-1,971 tCO_2/yr. The electricity export is about 4.0-8.4 MWh. The grid injection is 1,261-1,781 MWh for the complete export scenario. The difference in climate data also induces these deviations. HOMER also considers a higher cell efficiency (17.8%) than PVsyst (16.99%). PVsyst's total cost is \$15.6M, with a salvage of \$0.1M. HOMER yields the net present cost (NPC) of \$19.6M, operating cost of \$0.8M/yr, initial capital of \$1.56M, and O&M of \$0.8M/yr. The difference is due to the individual database values.

PVsyst returns the ROI to be 13.3% and RETScreen IRR to be 13.8%. PVsyst offers a payback of 15.4 years. RETScreen evinces 11.4 years of payback, rendering 90% confidence and 0 to 20% risk. It returns a carbon saving of 710.7 tCO_2/yr. The carbon balance result by PVsyst is 844 tCO_2/yr. The difference between RETScreen and PVsyst is 134 tCO_2/yr. The deviation is due to the different meteorological data, losses, and differences in emission factors. The GHG reduction revenue is \$213,225 (CER) and \$71,075 (VER). The lowest payback is 6.1 years, exploiting grid export and carbon trading.

4.9. Recommendations and improvements for further studies

The study recommends the practical implementation of this project. The site should use the international carbon trading opportunity. There might be a comparative study between the estimated and practical data. The actual cost data from the implementation may benefit the study. Future research may consider this project for the hybrid microgrids model with a reliability and resilience study concerning the environmental impacts of storage mechanisms. Further research may consider an automated load-shedding analysis. The software developers might include this scenario as a feature.

5. Conclusions

The research integrates four distinct PV system simulation software, identifying the best features from a rigorous literature review. It utilizes different parameters from one tool to another in different stages, and each stage produces several results as the output. The study employs the developed process to analyze a university campus PV system. Based on the simulation of different scenarios, the conclusions are as follows:

(1) The integration produces an extended result set that covers the multidimensional analysis of a project.

(2) The method eliminates the necessity of field-based surveys using HelioScope, which reduces the workforce and associated costs.

(3) Some key results are LCOE (\$0.13), ROI (13%), CF (13%), performance ratio (82%), shading and different losses (32%), Payback period (11 to 15 years), energy export (4 MWh/yr), carbon trading revenue (\$71,075-213,225), emission reductions (710.7 to 844 tCO_2/yr).

(4) Carbon trading reduces the payback period by gathering revenue from international markets. In this case, the payback is six years instead of 11 years. This venture may help popularize the larger PV project in underdeveloped countries.

(5) Standard database values on costs enable users to utilize international standardized values for estimation.

(6) Self-consumption and a 100% export scenario empower users to decide on profitability using the feed-in tariff. The comparison finds the plant’s suitability for self-use or a total power export business.

(7) Such a method proffers the financial analysis for the ‘only PV’, ‘grid-PV’, and ‘grid-PV-diesel’ scenarios, considering load shedding as a fact in underdeveloped countries.

(8) The study suggests including a real-life load-shedding scenario in the existing software.

The above findings highlight the various aspects of a PV project determined by the developed method and attest to its potential applicability as a promising PV System assessment process.

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Conflicts of Interest

The authors declare no conflict of interest.

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