

Performance Assessment of a Standalone Residential Solar PV System for a 19.8 kWh/day Load: A Comparative Study of Abuja, Beijing, and Washington DC

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ABSTRACT

This study presents a comparative techno-economic assessment of a standalone residential solar photovoltaic (PV) system with LiFePO₄ lithium-ion battery storage designed to meet a relatively high household electricity demand of 19.8 kWh/day across Abuja (Nigeria), Beijing (China), and Washington DC (USA). PV system simulations were performed using PVsyst, while economic analysis was conducted over a 25-year project lifetime. Independent validation was additionally carried out using HOMER Pro. The results show significant variation in solar resource availability, with Abuja recording the highest global horizontal irradiation (2,042 kWh/m²/year), followed by Beijing (1,564 kWh/m²/year) and Washington DC (1,503 kWh/m²/year). The standalone PV systems demonstrated strong technical performance in all locations, achieving solar fraction values above 0.93, indicating reliable operation for high-demand residential applications. Beijing achieved the lowest levelized cost of electricity (LCOE) of 0.176 USD/kWh and the lowest net present cost (NPC), while Washington DC exhibited the weakest overall techno-economic performance. Despite the favorable technical performance, all locations produced negative net present value (NPV) results, indicating that the standalone PV systems were not economically competitive with prevailing grid electricity tariffs under the adopted assumptions. Sensitivity analysis identified discount rate and battery storage cost as the most influential economic parameters. The HOMER Pro validation showed good agreement with the PVsyst results for annual energy production, LCOE, and NPC, confirming the robustness of the adopted simulation methodology. The findings demonstrate that both solar resource availability and local economic conditions strongly influence the feasibility of standalone PV systems for high-demand residential applications.

1. Introduction

Off-grid solar photovoltaic (PV) systems integrated with battery energy storage have gained considerable attention as sustainable solutions for decentralized electricity supply, particularly in regions experiencing unreliable grid infrastructure or limited electricity access. Declining PV module prices, improvements in power electronics, and advances in battery technologies have significantly enhanced the economic competitiveness of solar PV systems worldwide [1–5]. Consequently, off-grid PV systems are increasingly being deployed for residential electrification, especially in developing countries where grid expansion remains slow and costly [6, 7].

Battery storage plays a critical role in ensuring the reliability of off-grid PV systems by storing excess solar energy during the daytime and supplying electricity during nighttime or periods of low solar irradiation [8, 9]. Among the various battery technologies available, lithium-ion batteries have emerged as the preferred option for modern residential PV systems due to their higher energy density, longer cycle life, higher round-trip efficiency, and deeper allowable depth of discharge compared to conventional lead-acid batteries [10–14].

In particular, lithium iron phosphate (LiFePO₄ or LFP) batteries have gained increasing attention in residential and off-grid applications because of their improved thermal stability, enhanced safety characteristics, long service life, and declining market cost [15–18]. These advantages have significantly improved the long-term technical and economic performance of standalone PV systems, making lithium-ion storage increasingly attractive for high-demand residential applications.

In recent years, increasing residential electricity demand arising from greater appliance ownership, air-conditioning usage, and digital equipment has created the need for larger and more reliable off-grid PV systems. Designing standalone PV systems for high-demand residential applications requires larger PV arrays and increased battery storage capacity, which significantly influence system cost, reliability, and long-term economic feasibility. As a result, comprehensive techno-economic evaluation has become increasingly important for assessing the practicality of standalone PV systems under different climatic and economic conditions.

2. Review of related works

Several studies have investigated the techno-economic feasibility of off-grid solar PV systems in different geographic and socioeconomic contexts. Sharma and Tiwari demonstrated that the techno-economic feasibility of residential solar PV systems with battery storage is strongly dependent on system sizing, solar irradiance, and local economic conditions [19]. Similarly, Mandelli et al. evaluated off-grid PV systems for rural electrification and showed that PV-battery systems can provide reliable electricity supply at competitive costs in regions with high solar resources [20]. Other studies have emphasized that solar resource availability significantly influences PV system productivity and economic viability [21–26].

Comparative techno-economic analyses across multiple locations have also attracted increasing attention because they provide insights into how climatic conditions and economic parameters affect PV system performance. Previous studies have shown that PV systems deployed in regions with higher solar irradiance generally achieve higher specific energy production and lower levelized cost of electricity (LCOE) values than systems installed in lower-irradiance regions [27–32]. These studies further highlight the importance of considering local electricity tariffs, financing conditions, and component costs when evaluating system feasibility.

Recent literature has also shown increasing interest in lithium-ion battery integration in standalone PV systems due to improvements in battery lifespan, depth of discharge, and declining storage costs [13–18]. Lithium iron phosphate (LiFePO₄) batteries, in particular, have been widely recognized for their suitability in residential renewable energy applications because of their operational safety, long cycle life, and reduced maintenance requirements [16]. Several studies have further demonstrated that declining lithium-ion battery prices are improving the economic competitiveness of off-grid PV systems globally [14, 18].

Despite the growing body of literature on standalone PV systems, several important research gaps remain. First, most previous studies focus on relatively low residential electricity demand levels, typically below 10 kWh/day, which may not adequately represent the growing energy demand of modern large residential buildings. Second, many comparative studies primarily investigate grid-connected PV systems rather than standalone configurations requiring substantial battery storage capacity. Third, limited studies have examined high-demand residential standalone PV systems across multiple global electricity markets characterized by different solar resources, economic conditions, and electricity pricing structures.

These limitations indicate the need for further studies that integrate high-demand residential load modeling with comparative multi-location techno-economic analysis of standalone PV systems using modern battery storage technologies.

3. Research objective and contributions

In response to these identified gaps, this study investigates the techno-economic feasibility of a high-demand standalone residential solar PV system with LiFePO₄ lithium-ion battery storage based on an estimated electricity demand of 19.8 kWh/day for a five-bedroom residential building. Using PVsyst simulation and life-cycle economic analysis, system performance is evaluated across three geographically and economically distinct locations: Abuja (Nigeria), Beijing (China), and Washington DC (USA).

The main contributions of this study are summarized as follows:

(1) High-demand residential load assessment:

Unlike many previous studies focusing on relatively low household electricity demand, this study evaluates a standalone PV system designed for a comparatively high residential load of 19.8 kWh/day representative of large modern households.

(2) Multi-location comparative analysis:

The study performs a comparative techno-economic assessment across three global cities characterized by different climatic conditions, solar resources, and electricity market structures, thereby providing insights into the influence of geographic and economic factors on PV system feasibility.

(3) LiFePO₄ lithium-ion battery-based system evaluation:

Unlike many earlier studies based on conventional lead-acid storage, this study investigates the application of LiFePO₄ lithium-ion battery technology, which offers higher efficiency, longer cycle life, deeper discharge capability, and improved operational reliability for standalone residential PV systems.

(4) Comprehensive techno-economic evaluation:

The study integrates technical performance indicators, including system energy production, performance ratio, and solar fraction, with economic indicators such as levelized cost of electricity (LCOE), net present value (NPV), net present cost (NPC), and payback period, thereby providing a comprehensive assessment of system feasibility.

By combining high-demand residential load modeling with comparative multi-location techno-economic analysis, this study contributes to the growing body of knowledge on decentralized renewable energy systems and provides useful insights for policymakers, researchers, and homeowners considering standalone solar PV solutions across different global electricity markets.

4. Methodology

4.1 Study locations

This study evaluates the techno-economic performance of an off-grid solar photovoltaic (PV) system with LiFePO₄ lithium-ion battery storage across three geographically diverse locations: Abuja (Nigeria), Beijing (China), and Washington DC (USA). These locations were selected to represent different climatic conditions, solar resource availability, and electricity market characteristics.

Abuja is located in the tropical region of West Africa and is characterized by relatively high solar irradiation throughout the year. Beijing, located in northern China, experiences moderate solar resources with significant seasonal variation. Washington DC, located in the eastern United States, represents a temperate climate with relatively lower solar irradiance compared to Abuja.

Solar resource data for each location were obtained from the PVsyst meteorological database (PVGIS TMY 5.3), which provides long-term average solar radiation and climatic parameters required for PV system simulation. Key solar resource indicators include global horizontal irradiation (GHI) and global irradiation on tilted plane (GTI). The study locations are illustrated on a global map in Fig. 1, while the corresponding site-specific data are summarized in Table 1.



Fig. 1 Global map showing the geographic locations of the study sites: Abuja (Nigeria), Beijing (China), and Washington, DC (USA).

Table 1 Location-specific parameters of the study sites including available solar resource characteristics.

S/N	Location	Coordinates	PV optimal azimuth & tilt	GHI (kWh/m ² /yr)	GTI (kWh/m ² /yr)
1	Abuja, Nigeria	9.0643° N, 7.4893° E	180°/15°	2,042	1,902
2	Beijing, China	39.9078° N, 116.3980° E	0°/22°	1,564	1,874
3	Washington DC, USA	38.8866° N, -77.0327° E	0°/58°	1,503	1,683

4.2 Residential load assessment and hourly load profile

The PV system was designed to supply electricity to a five-bedroom residential building with multiple household appliances. The estimated load profile includes electric fans, lighting systems, refrigerator, air conditioner, computers/televisions, and other domestic appliances.

The daily energy consumption was calculated based on the rated power of each appliance, the number of units, and the estimated daily operating hours. The total daily energy demand E_d was obtained by summing the energy consumption of all appliances according to equation (1):

$$E_d = \sum_{i=1}^n P_i \times N_i \times t_i \quad (1)$$

where: P_i = rated power of appliance i (W), N_i = number of appliances, and t_i = daily operating time (hours/day).

The estimated household energy demand for the load profile is 19.8 kWh/day, corresponding to an annual electricity demand, E_a of approximately 7,227 kWh/year. Although this demand level is higher than that typically reported for conventional low-income residential electrification studies, it is considered representative of large modern residential buildings with multiple occupants, extensive appliance usage, refrigeration, entertainment systems, computing

devices, and significant air-conditioning demand. Similar increases in residential electricity consumption associated with urbanization, improved living standards, and increased cooling requirements have been reported in previous residential energy studies [33–35].

Furthermore, the selected load profile was intentionally adopted to evaluate the capability of standalone PV systems to reliably supply relatively high residential electricity demand under different climatic and economic conditions. This enables a more rigorous assessment of PV array sizing, battery storage requirements, system reliability, and long-term economic feasibility than studies based on relatively small household loads.

The appliances and estimated energy demand for the residential five-bedroom duplex are presented in Table 2, while the daily energy demand distribution of the appliances and the adopted hourly load profile are shown in Figs. 2 and 3, respectively. The hourly load profile indicates that electricity demand is generally higher during evening periods due to increased lighting, cooling, entertainment, and household appliance usage, thereby significantly influencing battery storage requirements and overall system sizing.

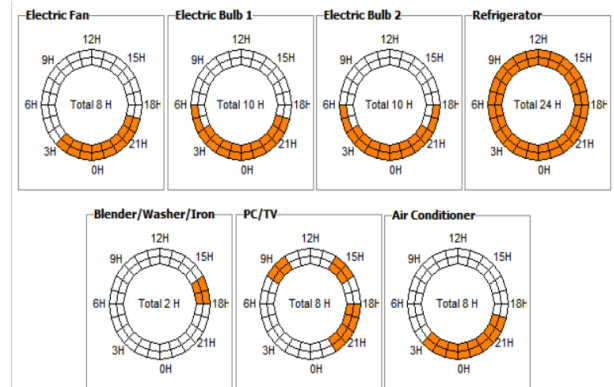


Fig. 2 Daily household appliance energy demand distribution.

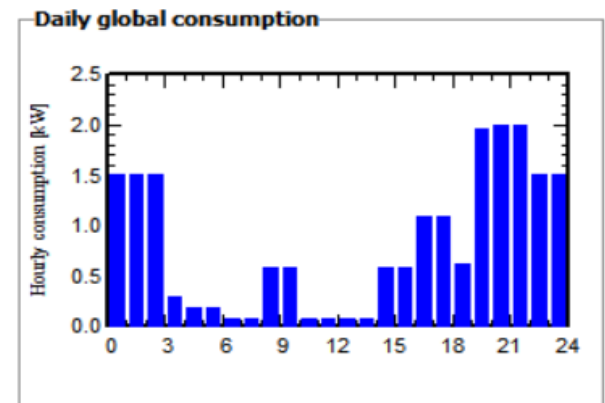


Fig. 3 The hourly load profile.

Table 2 Appliances and estimated energy demand for a residential 5-bedroom duplex.

S/N	Appliance	Wattage/App.	No. of App.	Total Wattage/App.	Daily usage (hours/day)	Daily energy demand (Wh)
1	Electric Fan	60 W	7	420 W	08	3,360
2	Electric Bulb 1	12 W	10	120 W	10	1,200
3	Electric Bulb 2	6 W	14	84 W	10	840
4	Refrigerator	2,000 Wh/d	1	2,000 Wh/d	24	2,000
5	Blender/Washer/Iron	1,000 W	1	1,000 W	02	2,000
6	PC/TV	100 W	5	500 W	08	4,000
7	Air Conditioner	800 W	1	800 W	08	6,400
Total E_d						19.8 kWh

4.3 PV system configuration

The off-grid solar PV system was designed and simulated using PVsyst 8 software, which is widely used for PV system performance analysis and system sizing. The system consists of the following major components: Solar PV array, Battery energy storage system (LFP batteries), Hybrid inverter, and Electrical loads.

The PV array capacity was optimized in PVsyst to ensure reliable energy supply while minimizing energy deficits. The nominal PV power for the system was 5.9 kWp, which was determined to be sufficient to meet the annual energy demand while maintaining a high solar fraction.

The PV modules were assumed to be installed at an optimal tilt angle and azimuth appropriate for each location (as determined with the help of PVsyst orientation optimization guide and presented in Table 1) in order to maximize annual solar energy capture. System losses such as inverter losses, wiring losses, temperature effects, and battery charging/discharging losses were considered within the PVsyst simulation environment.

4.4 Battery storage system design and sizing

Battery energy storage was incorporated into the standalone PV system to ensure continuous electricity supply during nighttime periods and intervals of low solar irradiation. A lithium iron phosphate (LiFePO₄ or LFP) battery technology was adopted in this study due to its high round-trip efficiency, long cycle life, improved thermal stability, deeper allowable depth of discharge, and growing suitability for modern residential off-grid PV applications.

The battery bank was sized based on the daily household energy demand, the required days of autonomy (DoA), the allowable maximum depth of discharge (DoD), and the system DC voltage. A design autonomy of 1.5 days was selected to ensure reliable operation during short periods of insufficient solar energy generation. In addition, a maximum battery depth of discharge of 80% was adopted in order to reduce excessive battery cycling and improve long-term battery lifespan.

The required battery storage capacity, C_b (Ah) and number of batteries, N_b were estimated according to equations (2) and (3):

$$C_b = \frac{E_d \times DoA}{V_{dc} \times DoD_{max} \times \eta_b} \quad (2)$$

$$N_b = \frac{C_b}{C_{1b}} \quad (3)$$

where: E_d = daily energy demand (Wh/day), DoA = days of autonomy, V_{dc} = system DC voltage (V), DoD_{max} = allowable battery depth of discharge, η_b = battery efficiency, and C_{1b} is the capacity of one battery.

The selected battery bank consists of four 48 V/200 Ah LiFePO₄ batteries connected in parallel (1S×4P), giving a total bank capacity of 48 V/800 Ah, equivalent to 38.4 kWh of nominal storage. At the adopted maximum depth of discharge of 80%, the usable storage capacity is approximately 30.72 kWh. This satisfies the design autonomy requirement of 1.5 days for a daily load of 19.8 kWh/day, corresponding to an autonomy energy requirement of 29.7 kWh. The configuration therefore meets the storage sizing criterion while maintaining the system DC bus voltage at 48 V.

Battery lifetime was evaluated using the battery aging and cycling models available in PVsyst. The simulated battery service lifetimes were approximately 11.1 years for Abuja and 10.5 years for both Beijing and Washington DC. The slightly longer simulated lifetime observed for Abuja is associated with differences in battery cycling behavior and operational conditions arising from local solar resource characteristics and system operating profiles.

The selected LiFePO₄ battery technology offers important advantages for standalone residential PV systems, including reduced maintenance requirements, improved operational safety, higher usable storage capacity, and longer service life compared to conventional lead-acid battery systems. These characteristics contribute to improved long-term system reliability and economic performance over the project lifetime.

4.5 PV System performance indicators

Several technical performance indicators were used to evaluate the PV system performance across the three locations. They include System Production, Specific Production, Performance Ratio (PR), and Solar Fraction. These were determined by PVsyst using equations 4 to 6:

$$E_{pv} = P_{nom} \times Y_f \quad (4a)$$

$$E_{pv} = G_{poa} \times A \times \eta_{pv} \times PR \quad (4b)$$

$$Y_f = PR \times Y_r \quad (5)$$

$$SF = \frac{E_{pv}}{E_a} \quad (6)$$

where: E_{pv} = annual energy produced by the PV system (kWh/year), P_{nom} = nominal installed PV capacity (kWp), Y_f = final yield or specific production (kWh/kWp/year), G_{poa} = annual irradiation on the plane of array (kWh/m²/year), A = total PV array area (m²), η_{pv} = module efficiency, PR = performance ratio, Y_r = reference yield which corresponds to the equivalent number of full-sun hours received by the PV array, SF = Solar Fraction, and E_a = total annual load demand.

4.6 Economic evaluation

The economic performance of the off-grid PV system with LFP battery storage was assessed using key techno-economic indicators, including capital expenditure (CAPEX), operational expenditure (OPEX), levelized cost of electricity (LCOE), and net present value (NPV).

A project lifetime of 25 years and country-specific discount rates were employed in the economic analysis to account for differences in financing conditions, inflation, and investment risk across the study locations. Discount rates of 12%, 7%, and 6% were adopted for Nigeria, China, and the United States, respectively. The relatively higher discount rate for Nigeria reflects the elevated cost of capital and macroeconomic uncertainty commonly associated with developing economies, whereas lower values for China and the United States represent more stable financing environments and lower borrowing costs. The use of location-specific discount rates is consistent with established techno-economic assessment methodologies for renewable energy systems [36–40].

Site-specific annual PV module degradation rates of 0.8%, 0.7%, and 0.5% were adopted for Abuja, Beijing, and Washington DC, respectively, to reflect differences in operating climate and thermal stress. The highest degradation rate was assigned to Abuja because tropical locations generally expose PV modules to higher

ambient temperature and humidity, which can accelerate long-term performance loss. Beijing was assigned an intermediate value due to its continental climate and seasonal temperature variation, while Washington DC was assigned the lowest value, reflecting comparatively milder operating conditions. These values fall within the commonly reported PV degradation range of approximately 0.5–0.8% per year for crystalline silicon modules [41–44].

The annual degraded PV energy yield in year t was estimated in PVsyst according to equation (7):

$$E_t = E_1(1 - D_r)^{t-1} \quad (7)$$

where: E_t is the PV energy output in year t , E_1 is the first-year PV energy output, and D_r is the annual degradation rate.

The degraded annual energy output was used in the LCOE and NPV calculations over the 25-year project lifetime.

Capital Expenditure (CAPEX): The total initial investment cost of the system was estimated as the sum of the major system components using equation (8):

$$CAPEX = C_{PV} + C_{inv} + C_{batt} + C_{other} \quad (8)$$

where: C_{PV} = cost of PV modules, C_{inv} = cost of inverter, C_{batt} = cost of battery storage, and C_{other} = accessories, installation, and logistics costs.

The “other costs” category includes mounting structures, cabling, protection devices, installation labor, transportation, and contractor overheads. Previous studies (e.g., IRENA, NREL, and Fraunhofer ISE) indicate that these costs typically represent 30–60% of the PV module cost in residential systems [45–47]. In this study, a base value of 50% of the module cost was adopted, while a range of 40–60% was considered during sensitivity analysis.

Component cost benchmarks for the U.S. system were adapted from the NREL Q1 2023 PV and Energy Storage Cost Benchmark Report [46]. The benchmark values were adjusted for Beijing and Abuja to reflect regional market conditions, including domestic manufacturing advantages in China, lower import tariff exposure, lower labor costs, and reduced soft costs relative to the United States. Abuja component prices were assumed to remain slightly higher than Beijing due to importation and logistics costs but lower than U.S. benchmark prices because Nigeria imports PV components primarily from China without the higher tariff structures applicable in the United States. The benchmark specific costs adopted for PV system components are presented in Table 3.

Table 3 Benchmark specific costs adopted for PV system components.

Component	Abuja	Beijing	Washington DC
PV module (\$/kW)	300	260	372
inverter (\$/kW)	180	160	227
LFP battery (\$/kWh)	170	150	219

Operational Expenditure (OPEX): The annual operational expenditure consists of routine operation and maintenance (O&M) costs and provisions for battery replacement over the project lifetime. The O&M cost was assumed to be 1.5% of the initial CAPEX per year, which is consistent with reported values for residential PV systems in the literature [48].

Electricity Tariffs: To evaluate the economic benefits of PV-generated electricity, location-specific electricity tariffs were considered. The unit cost of electricity was obtained from national regulatory

and international energy databases. For Nigeria, tariff data were sourced from the Nigerian Electricity Regulatory Commission (NERC), while data for China and the United States were obtained from international energy statistics and national databases such as the International Energy Agency (IEA) and the U.S. Energy Information Administration (EIA) [49–51]. The assumed average electricity prices were: 0.150 USD/kWh for Abuja, 0.113 USD/kWh for Beijing, and 0.160 USD/kWh for Washington DC. China has different tariff for different levels of residential electricity consumption. The residential tiered rates include: Tier 1 with consumption of ≤ 240 kWh/month and tariff of ~ 0.070 USD/kWh; Tier 2 with consumption of 241 – 400 kWh/month and tariff of ~ 0.077 USD/kWh; and Tier 3 with consumption of > 400 kWh/month and tariff of ~ 0.113 USD/kWh. The electricity demand for this study is ~ 600 kWh/month and therefore falls within Tier 3 of China’s tiered electricity rates.

Levelized Cost of Electricity (LCOE): The levelized cost of electricity represents the average cost of electricity generated over the system lifetime and was calculated using equation (9):

$$LCOE = \frac{\sum_{t=0}^N \frac{C_t}{(1+r)^t}}{\sum_{t=0}^N \frac{E_t}{(1+r)^t}} \quad (9)$$

where: C_t = system cost in year t , E_t = energy generated in year t , r = discount rate, and N = project lifetime.

Net Present Value (NPV): The net present value was used to assess investment profitability and was calculated from equation (10):

$$NPV = \sum_{t=0}^N \frac{B_t - C_t}{(1+r)^t} \quad (10)$$

where: B_t is the benefits from electricity savings, and C_t is the costs in year t . A positive NPV indicates that the investment is economically viable.

Net Present Cost (NPC): The net present cost was used to estimate the total discounted life-cycle cost of the standalone PV system over the project lifetime and was calculated using equation (11):

$$NPC = \sum_{t=0}^N \frac{C_t}{(1+r)^t} \quad (11)$$

where: C_t represents all system-related expenditures in year t (including initial capital investment, operation and maintenance cost, and component replacement cost), r is the discount rate, and N is the project lifetime. Lower NPC values indicate lower overall lifetime system cost and improved economic performance.

4.7 Weighted techno-economic performance index

To enable an integrated comparison of PV system performance across the three locations, a Weighted Techno-Economic Performance Index (WTPI) was developed. The index combines three key indicators representing: Technical performance – specific PV production (SP), Energy reliability – solar fraction (SF), and Economic efficiency – levelized cost of electricity (LCOE). Because these indicators have different units and magnitudes, they were first normalized.

For **benefit indicators** (higher values are desirable), normalization was performed using equation (12a):

$$X_{norm} = \frac{X_i}{X_{max}} \quad (12a)$$

while for cost indicators (lower values are desirable), normalization was performed using equation (12b):

$$X_{norm} = \frac{X_{min}}{X_i} \quad (12b)$$

where: X_i = value of the indicator for location i , and X_{max} , X_{min} = maximum and minimum observed values.

The WTPI was then computed from equation (13) as a weighted sum of the normalized indicators:

$$WTPI = w_1 SP_{norm} + w_2 SF_{norm} + w_3 LCOE_{norm} \quad (13)$$

where: w_1, w_2, w_3 = weighting factors, and $w_1 + w_2 + w_3 = 1$.

In this study, weights of 0.30, 0.30, and 0.40 were assigned to SP, SF, and LCOE, respectively, with greater emphasis placed on economic performance due to its importance in investment decision-making.

To validate the robustness of the weighting criteria, a sensitivity analysis was performed by varying the weights assigned to the technical, economic, and reliability indicators.

4.8 LCOE sensitivity analysis

A sensitivity analysis was conducted to evaluate the impact of key parameters on the economic performance of the PV system. The analysis was performed for all the locations to assess how variations in system parameters influence economic outcomes.

The parameters considered include PV module cost, Battery cost, Inverter cost, Discount rate, Operation and maintenance cost, and other system costs.

The sensitivity analysis focused on the effect of these parameters on the levelized cost of electricity (LCOE), which serves as a primary indicator of system economic viability.

4.9 HOMER Pro validation of PVsyst results

To improve the reliability and credibility of the simulation results, the PV system performance obtained from PVsyst was independently validated using HOMER Pro software. HOMER Pro is a widely used techno-economic optimization and energy system simulation platform for evaluating hybrid and standalone renewable energy systems under different operating and economic conditions. The validation was performed by modeling the same standalone PV system configuration in HOMER Pro using identical load demand, solar resource data, component specifications, battery storage configuration, project lifetime, and location-specific economic assumptions adopted in the PVsyst simulations.

The validation focused on three key techno-economic performance indicators: annual system energy production, levelized cost of electricity (LCOE), and net present cost (NPC). These parameters were selected because they directly reflect the technical performance and long-term economic viability of the standalone PV systems. The HOMER Pro simulations incorporated the same LiFePO₄ battery characteristics, PV module degradation assumptions, discount rates, and component cost inputs used in the PVsyst-based analysis to ensure consistency between the two simulation platforms.

The annual PV energy production obtained from HOMER Pro was compared with the annual system production predicted by PVsyst in order to evaluate the consistency of the energy yield estimation between the two software platforms. Similarly, the LCOE and NPC values generated by HOMER Pro were compared with the corresponding values estimated from the PVsyst-based economic analysis. The percentage difference between the two software outputs was calculated using equation (14):

$$\% \text{ Difference} = \frac{|X_{HOMER} - X_{PVsyst}|}{X_{PVsyst}} \times 100 \quad (14)$$

where: X_{HOMER} and X_{PVsyst} represent the corresponding techno-economic parameter obtained from HOMER Pro and PVsyst, respectively.

The comparative validation using HOMER Pro provides an additional level of confidence in the robustness of the simulation methodology and helps reduce uncertainty associated with dependence on a single software platform. Similar cross-validation approaches have been adopted in previous renewable energy system studies to improve the reliability of techno-economic assessments and verify simulation consistency across different modeling tools [52–54].

5. Results and discussion

5.1 Solar resource characteristics across the study locations

The solar resource availability across Abuja, Beijing, and Washington DC plays a fundamental role in determining the performance of the off-grid PV system. Fig. 4 presents the comparison of global horizontal irradiation (GHI) and global tilted irradiation (GTI) for the three locations.

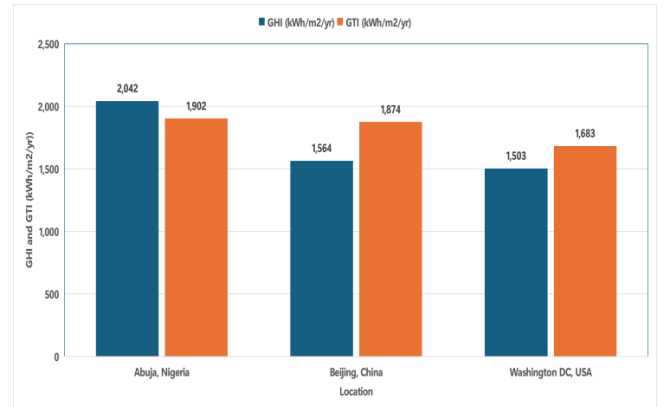


Fig. 4 Solar resource comparison across the locations.

The results indicate that Abuja exhibits the highest solar resource, with an annual GHI of 2,042 kWh/m²/year, followed by Beijing (1,564 kWh/m²/year) and Washington DC (1,503 kWh/m²/year). This trend reflects the geographic and climatic differences among the locations, with Abuja's tropical climate providing more consistent and intense solar radiation compared to the temperate climates of Beijing and Washington DC.

A similar pattern is observed for the global irradiation on the plane of array (GTI). Abuja records the highest GTI value of 1,902 kWh/m²/year, while Beijing and Washington DC have GTI values of 1,874 kWh/m²/year and 1,683 kWh/m²/year, respectively. The relatively small difference between GHI and GTI in Beijing suggests effective optimization of panel tilt, whereas the lower GTI in Washington DC reflects reduced solar availability due to climatic conditions such as higher cloud cover and seasonal variability.

Comparing GHI and GTI for the different locations shows that GHI is higher than GTI in Abuja whereas the reverse is the case for Beijing and Washington DC. The relationship between GHI and GTI is strongly influenced by solar geometry, latitude, and surface orientation. In low-latitude regions, where solar altitude angles are high, horizontal surfaces receive near-optimal solar radiation, resulting in GHI values comparable to or exceeding GTI. Conversely, in mid-latitude regions, tilted surfaces intercept solar radiation more effectively due to lower solar elevation angles, leading to higher GTI values. This behavior has been extensively documented in solar radiation modeling and photovoltaic system design literature [55–58].

The higher solar irradiation in Abuja implies a greater potential for PV electricity generation and improved system productivity. However, it is important to note that solar resource alone does not fully determine system performance, as other factors such as system design, temperature effects, and economic conditions also play significant roles.

5.2 PV energy production relative to household demand

The ability of the PV system to meet the household electricity demand is a key indicator of system adequacy in off-grid applications. Fig. 5 compares the annual PV system energy production with the household electricity demand of 7,227 kWh/year, corresponding to the daily load of 19.8 kWh/day.

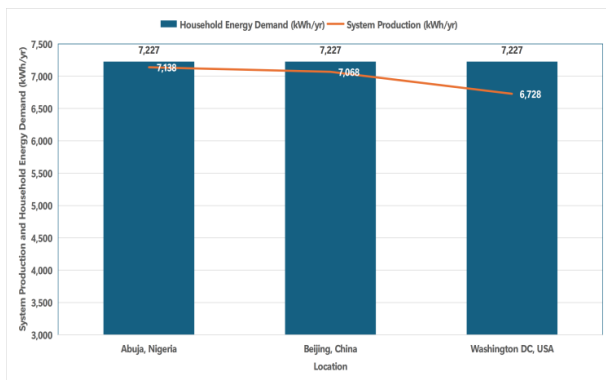


Fig. 5 PV production vs household demand across Abuja, Beijing, and Washington DC.

The results show that the PV system generates approximately 7,138 kWh/year in Abuja, 7,068 kWh/year in Beijing, and 6,728 kWh/year in Washington DC. These values indicate that the system is capable of meeting a substantial portion of the household electricity demand across all three locations, although the degree of load coverage varies.

In Abuja and Beijing, the annual PV production is very close to the household demand, resulting in minimal energy deficit and indicating that the system is well-sized for the load. In contrast, Washington DC exhibits a more noticeable shortfall between energy production and demand, reflecting the lower solar resource availability in this location.

The observed differences in PV production are consistent with the variation in solar irradiation discussed in Section 3.1. Higher solar resource in Abuja leads to slightly higher energy output, while the lower irradiation in Washington DC results in reduced PV generation. However, the relatively small difference between Abuja and Beijing suggests that factors such as system configuration and module performance also contribute to the final energy output.

From a system design perspective, these results demonstrate that a 5.9 kWp off-grid PV system can adequately support a high residential load of 19.8 kWh/day, particularly in regions with moderate to

high solar resource availability. The results also highlight the importance of location-specific design considerations, as systems deployed in lower irradiation regions may require larger PV capacities or additional storage to fully meet the load demand.

5.3 System performance: solar fraction and performance ratio

The overall performance of the off-grid PV system was evaluated using two key indicators: solar fraction (SF) and performance ratio (PR). These parameters provide insight into the system's ability to meet the load demand and its operational efficiency under real conditions. Fig. 6 presents the variation of solar fraction and performance ratio across Abuja, Beijing, and Washington DC.

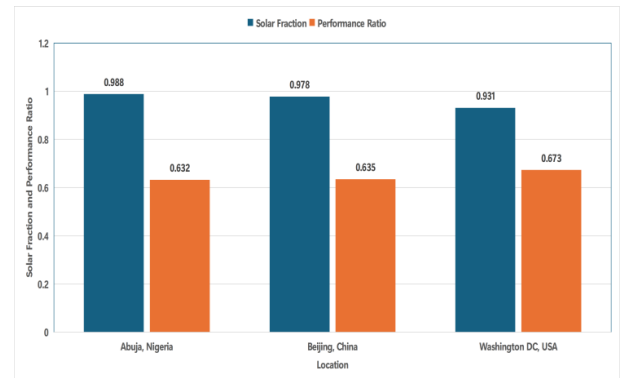


Fig. 6 Solar fraction and performance ratio across the locations.

The results show that the solar fraction is highest in Abuja (0.988), followed by Beijing (0.978) and Washington DC (0.931). These values indicate that the PV system is capable of supplying nearly all the household electricity demand in Abuja and Beijing, while a slightly larger fraction of unmet demand exists in Washington DC. The lower solar fraction in Washington DC is consistent with its reduced solar resource availability, as discussed in Section 5.1.

The high solar fraction values obtained across all locations demonstrate that the system is appropriately sized and capable of reliably meeting a high residential load. In particular, the near-unity solar fraction in Abuja and Beijing suggests minimal reliance on backup energy sources, which is desirable for standalone systems.

The performance ratio (PR), which reflects the overall system efficiency by accounting for various losses, shows a different trend. Washington DC exhibits the highest PR, while Abuja and Beijing show slightly lower values. This observation can be attributed primarily to temperature effects, as PV modules generally operate more efficiently under cooler climatic conditions. The relatively lower temperatures in Washington DC reduce thermal losses, thereby improving system efficiency despite the lower solar resource.

In contrast, higher ambient temperatures in Abuja contribute to increased thermal losses, which slightly reduce the performance ratio. This highlights an important trade-off in PV system performance: regions with higher solar irradiation may not necessarily achieve the highest system efficiency due to temperature-related losses.

5.4 Battery storage performance

The performance of the battery storage system is critical to the reliability of off-grid PV systems, as it determines the ability to supply electricity during periods of low solar generation. Table 4 presents the monthly variation of average battery voltage (U_{Batt}) and mean state of charge (SOC_{mean}) for Abuja, Beijing, and Washington DC.

Table 4 Storage battery operation and performances.

	Abuja		Beijing		Washington DC	
	U_Batt (V)	SOCmean	U_Batt (V)	SOCmean	U_Batt (V)	SOCmean
Jan	49.3	0.65	49.2	0.59	49.1	0.52
Feb	49.3	0.65	49.2	0.57	49.1	0.51
Mar	49.3	0.64	49.3	0.63	49.2	0.57
Apr	49.3	0.64	49.2	0.61	49.1	0.55
May	49.2	0.61	49.3	0.62	49.1	0.54
Jun	49.3	0.62	49.2	0.59	49.2	0.60
Jul	49.2	0.57	49.2	0.59	49.2	0.56
Aug	49.0	0.47	49.3	0.61	49.3	0.62
Sep	49.1	0.55	49.2	0.59	49.1	0.55
Oct	49.3	0.63	49.1	0.55	49.1	0.53
Nov	49.3	0.65	49.2	0.56	49.0	0.50
Dec	49.3	0.65	49.1	0.52	49.1	0.51
Yr	49.2	0.61	49.2	0.59	49.1	0.55

Note: U_Batt = Average Battery Voltage (V), SOCmean = Mean State of Charge, SOC_End = End-of-period State of Charge, Mgass (liter) = Battery gassing losses, EffBatI = Battery Charge Efficiency, EffBatE = Battery Discharge Efficiency.

The results show that the battery operation remains stable across all locations, with average voltages of approximately 49.1–49.2 V and annual mean state of charge (SOC) values of 0.61 (Abuja), 0.59 (Beijing), and 0.55 (Washington DC). Higher SOC values in Abuja and Beijing indicate favorable operating conditions and reduced depth of discharge.

Seasonal variations are more pronounced in Washington DC, where lower winter irradiation leads to reduced SOC and increased battery cycling. This suggests higher battery stress and potential implications for long-term battery life. Overall, battery performance is more favorable in regions with higher and more stable solar resources.

5.5 Location-based variation in component prices and system cost structure

The cost of PV system components varies across different regions, and this variation plays a crucial role in determining the overall economic performance of off-grid PV systems. Table 5 presents the estimated unit prices of key system components—PV modules, LFP batteries, and hybrid inverters—in Nigeria, China, and the United States.

The results show differences in component costs across the three locations. China exhibits the lowest prices for all major components, with PV module cost at approximately \$80 per 330 Wp unit, battery cost at \$1400 per 48 V/200 Ah unit, and hybrid inverter cost at \$700. Nigeria shows slightly higher costs, with PV modules priced at \$100, batteries at \$1600, and inverter at \$800. The United States has higher component prices than other locations, with PV modules costing about \$120, batteries \$2000, and inverter \$1000.

Table 5 Estimated unit price of major components.

Component	Abuja	Beijing	Washington DC
330 Wp mono Si solar panel price (\$)	100	80	120
4.5 kW/48 Vdc hybrid inverter price (\$)	800	700	1000
48 V/200 Ah LFP battery (\$)	1600	1400	2000

These differences can be attributed to several factors, including manufacturing scale, local supply chains, import duties, transportation costs, and market structure. China's lower component costs reflect its position as a global manufacturing hub for PV modules and batteries, benefiting from economies of scale and

well-established production infrastructure. Nigeria, on the other hand, relies largely on imported components, leading to moderately higher prices due to logistics and currency exchange factors. The higher costs in the United States are influenced by higher labor costs, market pricing structures, and import duties.

5.6 Capital and operating cost comparison of the PV system

The capital and operating costs of the PV systems were evaluated to assess their economic implications across the three locations. Tables 6 and 7 present the breakdown of capital expenditure (CAPEX) and annual operational expenditure (OPEX) for Abuja, Beijing, and Washington DC.

The results show significant variation in total system investment cost across the locations. The estimated CAPEX is \$9,900 for Abuja, \$8,460 for Beijing, and \$12,240 for Washington DC. Among the three locations, Beijing exhibits the lowest capital cost, primarily due to lower prices of PV modules and battery storage, as discussed in Section 5.5. In contrast, Washington DC has the highest CAPEX, driven by significantly higher component and installation costs.

Table 6 CAPEX estimation for the solar PV systems.

Component	Specification	Qty & config.	Abuja Total Cost (\$)	Beijing Total Cost (\$)	Washington DC Total Cost (\$)
PV Module	330 Wp mono-crystalline Si	18 (2x9)	1,800	1,440	2,160
Battery	48 V/200 Ah LFP battery	4 (1x4)	6,400	5,600	8,000
Hybrid Inverter	4.5 kW, 48 Vdc / 220 Vac, MPPT	1	800	700	1,000
Other Costs	Accessories, Installation, & Logistics	1	900	720	1,080
Total			9,900	8,460	12,240

Table 7 OPEX estimation for the solar PV systems.

System Services	Abuja Yearly Cost (\$/year)	Beijing Yearly Cost (\$/year)	Washington DC Yearly Cost (\$/year)
Provision for battery replacement	320.58	309.33	441.90
Repairs and Maintenance	148.50	126.90	183.60
Total	469.08	436.23	625.50

A closer examination of the cost breakdown reveals that battery storage constitutes the largest share of the total system cost in all locations. This highlights the critical role of energy storage in off-grid PV systems and underscores the importance of battery cost in determining overall system affordability. PV modules also represent a substantial portion of the capital cost.

The operational expenditure (OPEX) also varies across the locations, with annual values of approximately \$469 for Abuja, \$436 for Beijing, and \$626 for Washington DC. These costs include provisions for battery replacement and routine repair and maintenance. Similar to CAPEX, Beijing exhibits the lowest OPEX, while Washington DC has the highest.

5.7 Economic viability: LCOE vs electricity tariffs, NPV, and NPC

The economic viability of the off-grid PV system was assessed by comparing the levelized cost of electricity (LCOE) with the corresponding local electricity tariffs in Abuja, Beijing, and Washington DC, and by evaluating the Net Present Value (NPV) and Net Present Cost (NPC) across the three locations. Figures 7 to 9 present the comparative economic results.

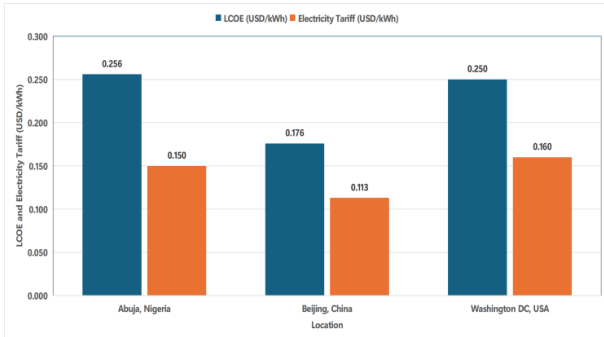


Fig. 7 LCOE versus electricity tariff across the different locations.

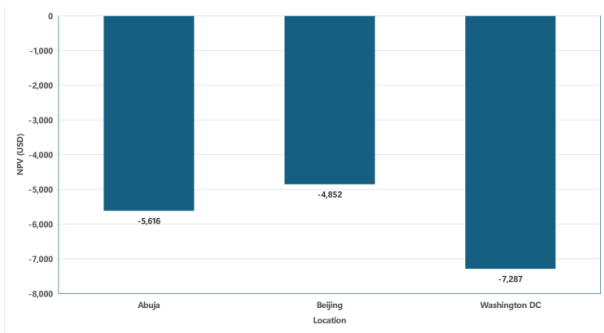


Fig. 8 Economic viability (NPV) comparison.

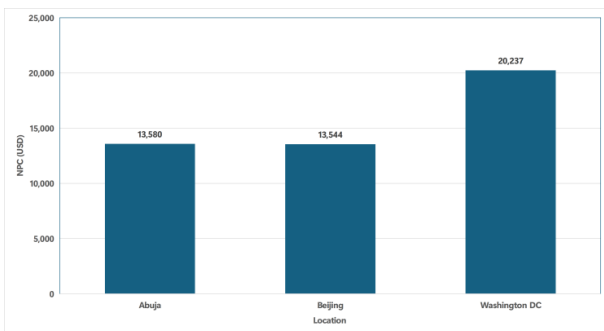


Fig. 9 Economic viability (NPC) comparison.

The results show that Beijing achieved the lowest LCOE of approximately 0.176 USD/kWh, followed by Washington DC at 0.250 USD/kWh and Abuja at 0.256 USD/kWh. These variations reflect the combined influence of solar resource availability, component cost structure, financing conditions, and system configuration, which are widely recognized as major determinants of PV system cost-effectiveness and long-term economic performance [27, 29, 30]. The comparatively lower LCOE obtained for Beijing is primarily associated with lower component procurement costs and favorable financing assumptions, whereas the relatively higher values obtained for Abuja and Washington DC are linked to higher financing costs and increased overall system expenditure.

However, LCOE alone does not fully determine economic viability. A more realistic assessment is obtained by comparing the LCOE with the prevailing local electricity tariff, which represents the avoided cost of electricity. This approach is consistent with established techno-

economic evaluation frameworks, where the financial attractiveness of a PV investment depends on whether the generated electricity can compete economically with the existing electricity supply alternative [19, 20, 48]. Similar studies have emphasized that standalone PV systems with battery storage often exhibit higher electricity costs than grid-connected systems because battery storage substantially increases the total life-cycle cost of electricity generation [14, 18, 29].

In Abuja, the electricity tariff (0.150 USD/kWh) is lower than the calculated LCOE (0.256 USD/kWh), indicating that the PV system would generate electricity at a higher cost than grid electricity. Consequently, the avoided electricity savings are insufficient to offset the high capital and storage-related costs over the project lifetime, resulting in a negative NPV value of -5,616 USD. In addition, the NPC result for Abuja indicates that the system requires substantial long-term expenditure despite the favorable solar resource conditions observed in the location. This finding demonstrates that strong solar irradiation alone does not necessarily translate to economic viability when financing conditions and storage costs remain significant. Similar observations have been reported in previous standalone PV studies, where high discount rates and battery costs were identified as major barriers to investment profitability [29, 32, 48].

Beijing, despite exhibiting the lowest LCOE (0.176 USD/kWh) and the lowest NPC among the studied locations, also produced a negative NPV value of -4,852 USD because the prevailing electricity tariff (0.113 USD/kWh) remained lower than the system generation cost. The relatively lower NPC observed for Beijing confirms the economic advantage associated with reduced component costs and favorable financing conditions. Nevertheless, the tariff-LCOE gap prevented the recovery of the initial investment within the project lifetime. This outcome highlights an important limitation of relying solely on LCOE as a measure of economic feasibility, since lower generation cost does not automatically guarantee positive financial returns [30, 32].

Similarly, in Washington DC, the LCOE (0.250 USD/kWh) exceeded the local electricity tariff (0.160 USD/kWh), resulting in the least favorable economic performance among the studied locations. The system produced a highly negative NPV value of -7,287 USD together with the highest NPC, indicating the largest overall lifetime system expenditure. The higher NPC obtained for Washington DC reflects the combined effect of higher system costs and comparatively lower solar resource availability relative to Abuja. This observation agrees with previous studies showing that standalone PV systems may struggle to achieve financial competitiveness in regions characterized by relatively low electricity tariffs and high system installation costs unless supported by policy incentives, subsidies, or significant reductions in storage cost [21, 31].

The NPC results provide additional insight into the long-term economic burden associated with standalone PV systems. While Beijing achieved the lowest NPC and Washington DC recorded the highest NPC, all three locations exhibited relatively high discounted lifetime system costs due largely to battery storage requirements, replacement costs, and financing assumptions. The NPC trends obtained in this study are also consistent with previous techno-economic investigations reporting that battery storage remains one of the dominant contributors to the life-cycle cost of standalone PV systems [14, 18].

Overall, these findings highlight a critical insight: low LCOE alone does not necessarily guarantee economic viability. Although Beijing achieved the lowest LCOE and NPC among the studied locations, all three systems produced negative NPV results under the adopted assumptions. This indicates that the generated electricity

was not sufficiently cost-competitive relative to prevailing grid electricity tariffs to recover the total discounted life-cycle investment cost over the project lifetime. The results therefore demonstrate that the economic feasibility of standalone PV systems depends not only on minimizing LCOE and NPC, but also on local electricity tariff structures, financing conditions, battery storage costs, and capital investment requirements. These observations are consistent with established energy economics literature emphasizing that avoided electricity cost, financing conditions, and cost of capital are critical determinants of renewable energy investment feasibility [19, 48].

5.8 Integrated techno-economic ranking using WTPI

To provide an integrated assessment of system performance across the three locations, a Weighted Techno-Economic Performance Index (WTPI) was developed by combining normalized indicators of specific PV production, solar fraction, and levelized cost of electricity (LCOE). Figure 10 presents the WTPI values for Abuja, Beijing, and Washington DC.

The results indicate that Beijing exhibits the highest overall techno-economic performance, followed by Abuja, while Washington DC shows the lowest performance. The superior ranking of Beijing is primarily attributed to its lowest system cost and lowest LCOE, which outweigh the slightly lower solar resource and energy production compared to Abuja.

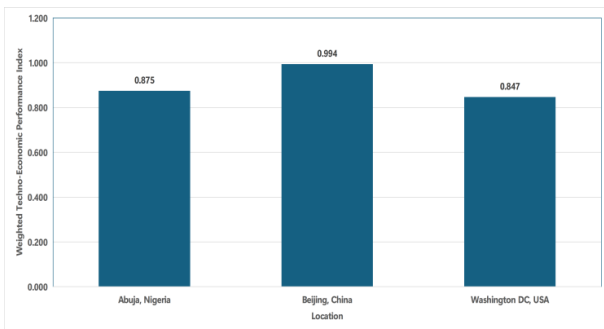


Fig. 10 Weighted Techno-Economic Performance Index (WTPI) across the locations.

Although Abuja benefits from the highest solar irradiation and marginally higher PV energy output, its overall ranking is slightly lower than Beijing due to relatively higher system costs and LCOE. This highlights the importance of economic factors in determining overall system performance. In contrast, Washington DC records the lowest WTPI value due to its combination of lower solar resource and higher system costs, which result in poor economic performance despite relatively favorable operating temperatures.

The WTPI results clearly demonstrate that technical performance alone is insufficient for evaluating PV system feasibility. While Abuja shows strong technical indicators such as higher solar fraction and energy production, Beijing achieves superior overall performance when economic factors are taken into account. This underscores the importance of adopting a multi-criteria evaluation approach when comparing PV systems across different locations. Such an approach is widely supported in the literature, where integrated techno-economic frameworks have been shown to provide a more realistic assessment of renewable energy systems than purely technical metrics [5, 19, 30]. In particular, studies have emphasized that optimal system selection must account for both performance indicators and economic constraints, as variations in local cost structures, resource availability, and market conditions can significantly influence overall system viability [27, 29].

Consequently, multi-criteria decision-making and composite performance indices, such as the WTPI used in this study, are increasingly recommended for comprehensive evaluation of PV systems across diverse geographic contexts [24, 31].

5.9 WTPI sensitivity analysis

To evaluate the robustness of the weighted techno-economic performance index (WTPI), a sensitivity analysis was performed by varying the weighting factors assigned to the technical, economic, and reliability indicators. In addition to the base-case weighting configuration (0.30, 0.30, 0.40), alternative weighting scenarios emphasizing economic performance, technical performance, and equal weighting were examined. The results are presented in Table 8. In this Table, A, B, and W are used to represent Abuja, Beijing, and Washington DC, respectively.

The WTPI values varied slightly under different weighting configurations; however, the overall ranking of the study locations remained unchanged, with Beijing consistently exhibiting the highest WTPI, followed by Abuja and Washington DC. This indicates that the comparative performance ranking is relatively insensitive to moderate variations in weighting assumptions and therefore demonstrates the robustness of the proposed WTPI evaluation framework.

Table 8 Sensitivity of WTPI ranking to weighting variations.

Weight Scenario	W ₁	W ₂	W ₃	A WTPI	B WTPI	W WTPI	Ranking
Base case	0.30	0.30	0.40	0.875	0.994	0.847	B > A > W
Scenario 1	0.25	0.35	0.40	0.875	0.994	0.847	B > A > W
Scenario 2	0.40	0.30	0.30	0.906	0.993	0.871	B > A > W
Scenario 3	0.33	0.33	0.33	0.887	0.983	0.854	B > A > W

The stability of the ranking further confirms that Beijing's superior overall performance is not solely a consequence of subjective weighting selection but results from its balanced technical and economic characteristics. Similarly, Washington DC consistently recorded the lowest WTPI because of its comparatively weaker economic performance despite acceptable technical performance indicators.

The limited variation in ranking under different weighting scenarios suggests that the WTPI framework provides a stable basis for comparative PV system assessment.

5.10 LCOE sensitivity analysis

A sensitivity analysis was conducted to evaluate the influence of key economic parameters on the levelized cost of electricity (LCOE) of the PV system. The analysis was performed for the three locations. Figures 11 to 13 present the results in the form of a tornado diagram for Abuja, Beijing, and Washington DC, respectively

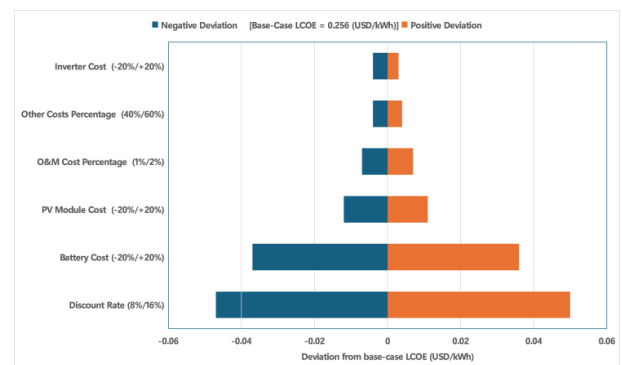


Fig. 11 Tornado diagrams showing the sensitivity of LCOE for Abuja to key economic parameters.

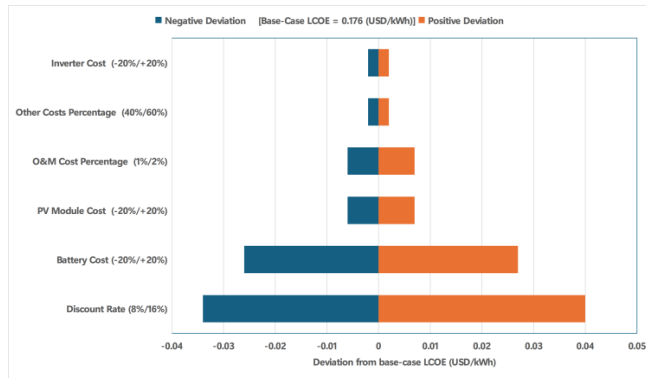


Fig. 12 Tornado diagrams showing the sensitivity of LCOE for Beijing to key economic parameters.

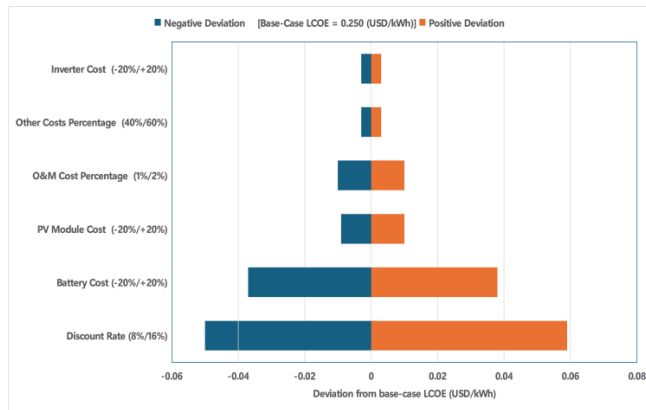


Fig. 13 Tornado diagrams showing the sensitivity of LCOE for Washington DC to key economic parameters.

The results indicate that the discount rate is the most influential parameter affecting LCOE, followed by battery cost and PV module cost. Variations in the discount rate produce the largest change in LCOE, highlighting the strong impact of financing conditions and investment risk on the economic performance of PV systems. Higher discount rates significantly increase LCOE due to the reduced present value of future energy generation.

Battery cost is identified as the second most sensitive parameter, reflecting the substantial contribution of energy storage to the overall system cost. Given that battery storage constitutes a large portion of CAPEX in off-grid systems, reductions in battery cost can significantly improve economic viability. Similarly, PV module cost also has a notable impact on LCOE, although its influence is slightly lower than that of battery cost.

Other parameters, including inverter cost, operation and maintenance cost, and other system costs, show comparatively smaller effects on LCOE. This suggests that while these factors contribute to total system cost, their influence on overall economic performance is less critical.

The sensitivity results highlight that economic feasibility can be significantly improved through cost reductions in key components, particularly battery storage, as well as through favorable financing conditions such as lower discount rates. This is consistent with established techno-economic analyses, which show that capital-intensive components—especially batteries—are among the most influential parameters affecting system cost and viability [14, 18, 29]. In addition, the discount rate has been widely identified as a critical determinant of project economics, as it directly influences life-cycle cost metrics such as LCOE and net present value [20, 48].

These findings are further supported by global trends indicating that declining battery and photovoltaic module costs are key drivers for improving the competitiveness of off-grid solar systems. Recent studies have documented substantial reductions in lithium-ion battery costs and continued cost declines in PV modules, leading to enhanced affordability and wider deployment of decentralized energy systems [18, 27, 32]. Consequently, cost reductions and improved financing conditions are expected to play a pivotal role in accelerating the economic viability and adoption of standalone PV systems, particularly in regions with growing energy demand and limited grid access [19, 31].

5.11 Validation of PVsyst results using HOMER Pro

To verify the reliability of the PVsyst simulation results, the standalone PV systems were independently modeled in HOMER Pro using the same load demand, solar resource data, component specifications, battery configuration, and economic assumptions adopted in the PVsyst analysis. The validation focused on three key techno-economic indicators: annual system energy production, levelized cost of electricity (LCOE), and net present cost (NPC). The comparative results obtained from both simulation platforms are presented in Table 9.

Table 9 (a) Validation of PVsyst results for Abuja.

Parameter	Abuja		
Modeling Software/ Variation	PVsyst	HOMER	Variation
System Production (kWh/yr)	7,138	7,821	10%
LCOE (USD/kWh)	0.256	0.258	1%
NPC (USD)	13,580	14,101	4%

Table 9 (b) Validation of PVsyst results for Beijing.

Parameter	Beijing		
Modeling Software/ Variation	PVsyst	HOMER	Variation
System Production (kWh/yr)	7,068	7,693	9%
LCOE (USD/kWh)	0.176	0.185	5%
NPC (USD)	13,544	13,994	3%

Table 9 (c) Validation of PVsyst results for Washington DC.

Parameter	Washington DC		
Modeling Software/ Variation	PVsyst	HOMER	Variation
System Production (kWh/yr)	6,728	7,387	10%
LCOE (USD/kWh)	0.250	0.255	2%
NPC (USD)	20,237	22,159	9%

The results show good agreement between the PVsyst and HOMER Pro simulations across all three locations. For annual system production, the percentage variation between the two software platforms ranged from approximately 9% to 10%. HOMER Pro generally predicted slightly higher annual energy production values than PVsyst for all locations. For example, the annual system production for Abuja increased from 7,138 kWh/yr in PVsyst to 7,821 kWh/yr in HOMER Pro, while corresponding variations of approximately 9% and 10% were observed for Beijing and Washington DC, respectively.

The observed differences in energy production can be attributed primarily to variations in the modeling approaches and loss assumptions implemented by the two software platforms. PVsyst employs a highly detailed physical modeling framework that explicitly incorporates thermal losses, wiring losses, mismatch losses, battery charging behavior, and other system-specific operating effects.

In contrast, HOMER Pro uses a more simplified techno-economic energy balance approach with aggregated derating assumptions. Similar differences between PVsyst and HOMER Pro energy yield predictions have been reported in previous comparative renewable energy system studies [52–54].

The LCOE results obtained from HOMER Pro also showed strong agreement with the PVsyst-based estimates. The variation in LCOE values ranged from approximately 1% for Abuja to about 5% for Beijing, indicating good consistency in the long-term economic assessment of the systems. The relatively small differences observed further confirm the robustness of the adopted economic assumptions and cost modeling methodology.

Similarly, the NPC results obtained from the two simulation platforms showed reasonably close agreement, with percentage variations ranging from approximately 3% to 9%. The lowest NPC variation was observed for Beijing, while Washington DC exhibited the highest variation. Despite these differences, both software platforms consistently identified Washington DC as the location with the highest lifetime system cost and Beijing as the location with the lowest overall economic burden.

The relatively small variations observed between PVsyst and HOMER Pro confirm the reliability and consistency of the simulation methodology adopted in this study. The close agreement between the two independent software platforms provides additional confidence in the technical and economic results presented for the standalone residential PV systems across the studied locations.

6. Conclusion

This study evaluated the techno-economic performance of a standalone residential solar PV system with LiFePO_4 lithium-ion battery storage designed to meet a relatively high residential electricity demand of 19.8 kWh/day across three geographically and economically distinct locations: Abuja (Nigeria), Beijing (China), and Washington DC (USA). The results demonstrate that the standalone PV systems are capable of supplying a substantial portion of the household electricity demand in all locations, with solar fraction values exceeding 0.93, indicating strong operational reliability for high-demand residential applications.

The analysis further revealed that solar resource availability significantly influences PV energy production, with Abuja exhibiting the highest solar irradiation and annual PV energy yield among the studied locations. However, the overall techno-economic performance of the systems was strongly affected by component costs, financing conditions, electricity tariffs, and local economic parameters. Beijing achieved the lowest levelized cost of electricity (LCOE) and the lowest net present cost (NPC), primarily due to lower component costs and favorable financing conditions, resulting in the highest weighted techno-economic performance index (WTPI). In contrast, Washington DC exhibited the weakest overall techno-economic performance because of comparatively higher system costs and lower solar resource availability.

Despite the relatively strong technical performance observed across all locations, the economic analysis showed negative net present value (NPV) results for all three systems under the adopted assumptions. This indicates that the standalone PV systems were unable to achieve sufficient financial returns relative to prevailing grid electricity tariffs and financing conditions over the project lifetime.

The results therefore demonstrate that favorable solar resources alone do not guarantee economic viability, as financing conditions, battery storage costs, component prices, and electricity tariff structures play equally important roles in determining investment feasibility.

The WTPI sensitivity analysis further confirmed that the comparative ranking of the locations remained stable under different weighting scenarios, demonstrating the robustness of the adopted evaluation framework. In addition, the economic sensitivity analysis identified the discount rate and battery storage cost as the most influential parameters affecting LCOE, NPC, and NPV. These findings suggest that reductions in battery prices, improved financing conditions, and lower cost of capital could significantly improve the long-term economic competitiveness of standalone residential PV systems.

Furthermore, independent validation of the PVsyst results using HOMER Pro demonstrated good agreement between the two simulation platforms for annual system production, LCOE, and NPC, with relatively small variations observed across the evaluated parameters. This consistency provides additional confidence in the reliability and robustness of the adopted simulation and economic assessment methodology.

Overall, this study demonstrates that standalone PV systems with lithium-ion battery storage can reliably support high residential electricity demand across diverse climatic conditions. However, their financial viability remains highly location-dependent and strongly influenced by economic and policy-related factors. The findings provide useful insights for policymakers, researchers, and system designers involved in the planning and deployment of decentralized renewable energy systems in different global electricity markets.

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Author Contributions

Anthony Ohajanya: Conceptualization, Methodology, Software, Investigation, Formal analysis, Writing – original draft, Visualization; **Obinna Duru:** Methodology, Validation, Writing – review & editing; **Benjamin Okereke:** Validation, Writing – review & editing; **Emmanuel Agbo:** Validation, Writing – review & editing; **Muhammad Abdurrahman:** Validation, Writing – review & editing; **Mustapha Shehu:** Validation, Writing – review & editing.

Declaration of Interest Statement

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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