Hindawi
International Journal of Energy Research
Volume 2024, Article ID 9919076, 28 pages
https://doi.org/10.1155/2024/9919076

Research Article

Advancing the Adoption of Net Metering: An Economic Assessment of Grid-Tied Solar Photovoltaic Systems in Urban Homes in Ghana

Stephen Afonaa-Mensah,[1] Issah Babatunde Majeed,[2] and Flavio Odoi-Yorke[3]

[1]*Department of Electrical and Electronic Engineering, Takoradi Technical University, Takoradi, Ghana*
[2]*Department of Electrical and Electronic Engineering, Accra Technical University, Accra, Ghana*
[3]*Department of Renewable Energy Technology, Cape Coast Technical University, Cape Coast, Ghana*

Correspondence should be addressed to Flavio Odoi-Yorke; flavio.odoi-yorke@cctu.edu.gh

Received 24 November 2023; Revised 8 March 2024; Accepted 22 March 2024; Published 10 April 2024

Academic Editor: Jiachao Peng

Copyright © 2024 Stephen Afonaa-Mensah et al. This is an open access article distributed under the Creative Commons Attribution License, which permits unrestricted use, distribution, and reproduction in any medium, provided the original work is properly cited.

Net metering schemes are pivotal in advancing grid-tied solar PV systems and promoting renewable energy adoption in developing nations. This study investigates the economic viability of implementing net metering within urban households in Ghana, considering the existing block tariff structure and a proposed time-of-use (ToU) structure for grid-tied PV systems. The study employed PVSOL premium (2023 R3) software for the economic performance assessment of the net metering schemes for simulated grid-tied residential PV systems in selected cities of Ghana's Coastal, Forest, and Savannah climatic zones. The evaluation encompasses key economic metrics, including the levelized cost of electricity, accrued cash flow, annual cash savings, internal rate of return, and payback period. The study findings showed that, in most scenarios, the existing block tariff structure initially proved more economically favourable than the proposed two-tier Time-of-Use (ToU) structure. Consequently, financial investments were recouped within the project's lifespan under net metering schemes based on the existing block tariff structure, whereas investments were not recouped under the ToU-based schemes. Nevertheless, factors such as improved daytime consumption, rising electricity tariffs, and aligning peak demand pricing hours with solar power generation hours emerged as potential drivers that could make ToU-based net metering schemes more attractive than block tariff structures. The study findings have significant implications for policy development related to tariff structures, particularly concerning the implementation of net metering for grid-tied solar PV systems within the residential sector of Ghana and other developing countries in sub-Saharan Africa.

1. Introduction

Africa has high prospects of solar power generation [1–4]. The continent receives insolation levels ranging from 4 to 7 kWh/m^2/day, surpassing those of numerous other regions across the globe [2]. Unfortunately, Africa's solar power remains significantly underutilised [4, 5]. For instance, the International Energy Agency (IEA) reported that, despite being home to 60% of the best solar resources globally, the African continent hosts only 1% of installed solar PV capacity [6].

Nevertheless, the successful implementation of economic incentive policies, such as net metering, has played an essential role in driving the adoption of solar PV in various regions worldwide [7–11]. For example, enforcing net metering policies led to a rapid increase in solar PV adoption in Brazil [12, 13]. Similarly, Germany witnessed a photovoltaic breakthrough by offering economic compensation for rooftop installations that fed electricity into the utility grid [14, 15].

Sarzynski et al. [16] demonstrated that states offering economic incentives experienced faster solar PV technology adoption than those lacking such incentives. An illustrative example of the benefits of economic incentives and net metering can be seen in Romania, where the implementation of net metering played a critical role in helping the country surpass its national target of achieving a 24% share of gross final consumption from renewable sources ahead of schedule [17]. Similarly, in Australia, compensating prosumers for the surplus electricity injected into the grid has been a driving force behind the deployment of residential PV installations [18].

Studies show that financial incentives, like the net metering programmes run by different governments in the European Union (EU), had made renewable energy (RE) projects much more financially viable and appealing to investors when they were first starting [19]. Net metering initiatives have accelerated investments in RE and fostered the widespread adoption of renewable energy sources [1, 11]. Washburn and Pablo-Romero [20] highlight net metering as a vital measure for promoting the penetration of renewable energy. Moreover, IEA has incorporated net metering into its solar technology roadmap, recognising its role in facilitating investments in distributed generation [11].

However, net metering is not universally available in numerous African countries. The absence of net metering has been identified as a key impediment to advance renewable energy in the African residential sector [4]. Addressing this gap in net metering availability is a key step toward unlocking the full potential of RE on the continent.

Like several other countries in sub-Saharan Africa (SSA), Ghana has abundant solar resources yet exhibits low solar energy penetration within its national energy portfolio. Ghana's electricity supply comprises hydro, thermal, RE sources (solar and biogas), and imported sources. Notably, electricity supply from existing large-scale hydropower stations is not classified as RE source under Ghana's energy policy. Thermal power dominates the portfolio with a substantial 64%, followed by hydropower at 35%, while RE technologies account for only 0.6% [21]. Recognising the potential of solar energy, the Ghanaian government has taken significant steps toward scaling up the contribution of RE to its energy mix, with a target of attaining a 10% share by the year 2030 [21].

To achieve this goal, the government has embarked on a critical policy intervention by planning the implementation of net metering in the residential sector. These steps include enacting the renewable energy law, developing net metering, and piloting thirty-three net meters with solar PV systems in some selected residential and commercial facilities [22, 23]. However, it is worth noting that relatively limited attention has been directed toward understanding the impact of the existing electricity tariff structure on the deployment and adoption of grid-tied solar PV systems within the residential sector, particularly as the nation prepares to introduce net metering for residential electricity customers.

Several studies highlight the essential role of electricity tariffs in shaping the economic viability of grid-connected distributed renewable energy sources (DRES) and, consequently, influencing the adoption of net metering within the residential sector [24]. For instance, the study by Avau et al. [25] demonstrated that the tariff structure significantly impacts private incentives for efficiently operating distributed energy resources (DERs) at minimal cost. Oliva et al. [26] further emphasised the critical role of retail electricity tariffs in determining the overall financial returns of contemporary PV investments. Consequently, changes in these tariffs carry implications that warrant careful consideration by policymakers.

Radhi [27] examined the investment viability of integrating solar PV into residential buildings in Gulf Cooperation Council countries. The findings of this study highlighted the crucial influence of electricity tariffs on the cost-effectiveness of building-integrated photovoltaic (BiPV) systems. The study indicated that a substantial upward adjustment of electricity tariffs is necessary to render residential BiPV systems economically viable. Similarly, the investigation in [28] reaffirmed the importance of implementing reasonable electricity tariffs to achieve cost-effective grid-connected residential BiPV solar PV systems in the United Arab Emirates.

Comello et al. [29] assessed the cost-competitiveness of solar PV systems in some regions of the United States. The study findings highlighted a direct correlation between electricity prices and the economic viability of residential solar installations. Ren et al. [30] delved into the analysis of cost-competitiveness concerning distributed photovoltaic generation (DG-PV) from the perspective of residential consumers, considering prevailing cost structures and tariff conditions. It was found that potential cost savings resulting from residential PV systems were contingent upon the specific electricity tariff adopted. In another study, Bustos et al. [31] emphasised the fundamental role of tariff design in establishing a fair and economically efficient distribution system, particularly in the context of high residential DER penetration. Furthermore, Gagnon et al. [32] explored the impact of retail electricity tariffs on the deployment of solar PV systems. The study highlighted how the structure of electricity tariffs significantly influences the financial performance of distributed PV systems and determines the extent of reductions in PV owners' electricity bills.

Samper et al. [33] conducted a comprehensive analysis of grid parity for DG-PV in the province of San Juan, Argentina, considering various tariff policies. Their research highlighted the profound influence of electricity tariffs on investment decisions related to distributed renewable generation, among other determining factors. Similarly, Jacobs et al. [34] emphasised the important role of retail electricity prices in achieving grid parity. Young et al. [35] highlighted the importance of tariff design in ensuring that residential PV systems provide tangible value to households.

Besides, with the ability to consume and generate power, electricity customers owning solar PV systems transform from passive actors to active participants that react to electricity prices and subsequently influence broader energy system transitions [36, 37]. Adopting net metering transforms PV self-consumers into prosumers, necessitating corresponding evolutions in remuneration and regulatory mechanisms concerning electricity tariffs [38].

Moreover, integrating DRES into the utility grid can have adverse effects, including issues related to tariff fairness, wealth transfer, and cost allocation among different customer groups [24, 39, 40]. Thus, penetrating PV into the utility grid necessitates adjustments in electricity tariffs to prevent market distortions and undesirable consequences for electricity providers and consumers [40]. Consequently, the remuneration and regulatory frameworks in the power sector cannot remain static but must evolve in tandem with the increasing PV penetration [35, 38, 41].

In this context, studies suggest that changes in conventional metering and electricity tariff structures are warranted by adopting grid-connected solar PV systems through net metering. For instance, studies in [42, 43] highlight that as DRES becomes more prevalent within the utility grid, the traditional metering approach based on the energy consumed may no longer be suitable for covering electricity costs. Dynamic tariffing is proposed to address the challenges associated with volumetric metering in the context of increasing DRES integration. Time-of-use (ToU) tariffs, as Ansarin et al. [24] suggested, offer a balanced approach between simplicity and cost causality in energy pricing within RE-integrated power systems.

In a recent study, Spiller et al. [44] assessed the impact of various electricity tariffs, including the existing flat volumetric and cost-reflective tariffs, on the performance of residential PV users. The findings revealed that time-variant electricity tariffs promote the adoption of DERs. Mills et al. [45] highlighted the significance of retail rate design for the economics of grid-tied solar PV owners. The study demonstrated that customers with PV systems could significantly reduce their electricity bills by transitioning from a flat rate to a ToU-based electricity rate.

Sepúlveda-Mora and Hegedus [46] conducted a technoeconomic analysis of behind-the-meter photovoltaics under the flat rate and ToU tariff structures. The study concluded that ToU tariffs facilitate rapid and cost-effective adoption of PV systems. Hassan et al. [47] investigated the impact of technical, economic, and environmental factors on grid-supplemented solar PV systems. Their findings indicated that the ToU tariff structure offers a lower energy cost than flat rate tariffs, while the flat rate structure exhibits lower life cycle emissions. The study suggests that the type of electricity tariffs (i.e., flat, step, and time-varying) significantly influences the economic performance of grid-connected solar PV systems. Ren et al. [30] also highlighted that volume-based tariffs do not accurately reflect the cost of electricity for residential PV users, proposing a set of cost-reflective tariffs to mitigate the adverse effects of volume-based tariffs on residential energy consumption patterns.

Carmichael et al. [48] revealed compelling evidence that households assess ToU tariffs positively and report high satisfaction levels. According to the study, from a consumer's perspective, ToU tariffs offer considerable saving potential and serve as an incentive for the adoption of solar PV systems. Say et al. [49] propose that the structure of electricity tariffs should better reflect the actual cost of electricity provision while adapting to changes in customer consumption and generation patterns. ToU tariffs, in this context, encourage customers to reduce their grid demand during peak demand periods.

Oliva et al. [26] also noted that households generally obtain more PV revenue if they are on ToU retail tariffs with a good match between PV generation and high electricity demand times. Also, Fridgen et al. [50] found that volumetric billing encourages shortsighted load management practices, potentially leading to severe absolute peak loads and macrogrid instability. In contrast, time-varying rates offer certain financial advantages for microgrid operators, albeit resulting in more extreme load profiles.

However, it is important to note that other studies suggest no universally ideal tariff structure. Tariff structures contain elements that can be considered contradictory and thus difficult to fulfil simultaneously [35]. In essence, there is no one-size-fits-all solution in tariff design. Consequently, no consensus exists on the perfect pricing mechanism for residential customers with distributed generation systems, especially across regions globally where efforts are ongoing to promote green-distributed generation [50].

As previously mentioned, the Government of Ghana plans to implement net metering to promote the widespread adoption of grid-tied solar PV systems. However, like many other African nations, Ghana has challenges related to its existing electricity tariff structures. These challenges include price distortions, high electricity tariffs, differential tariffing, and cross-subsidisation [51–53]. These difficulties adversely impact the determination of realistic electricity tariffs, resulting in ongoing recoveries and state subsidies that negatively affect the sustainability of energy systems. The evidence of these challenges manifests in the frequent and significant changes in electricity tariffs over the years. Figure 1 shows that there have been 29 tariff adjustments within a mere 10-year period [54].

Since the year 2000, the electricity end-user tariffs in Ghana have shown an average annual growth rate of 9.6% [52]. Recently, Ghana's Public Utility Regulatory Commission (PURC) approved only 27.15% of the 148% upward adjustment in the electricity tariff rate proposed by utilities to survive Ghana's power industry [55]. Moreover, Ghana's electricity tariffs are among the highest in middle-income developing countries [56]. Consequently, the power industries face high utility debt, insufficient power generation, high electricity supply at high cost, and high technical and commercial losses [21, 57]. There is, therefore, a pressing need for structural tariff reforms to encourage private investment in the electricity sector [58].

Meanwhile, high system costs and tariff issues are among the factors that have hampered the deployment of PV systems on the African continent. Studies have emphasised the necessity of investigating the role of renewables in improving tariff designs in African countries [51]. Therefore, research on the influence of existing tariff structures on policy interventions, such as net metering for grid-connected solar PV systems, considering local economic and technical conditions, becomes imperative for Ghana [8, 35].

Nonetheless, as far as the authors are concerned, there is inadequacy in studies focusing on how the current block tariff structure in the country will impact residential consumers who intend to enrol in net metering programmes. As such, this study is aimed at addressing this critical information gap, contributing to the advancement of net metering in the context of grid-tied solar PV in Ghana and other sub-Saharan African countries.

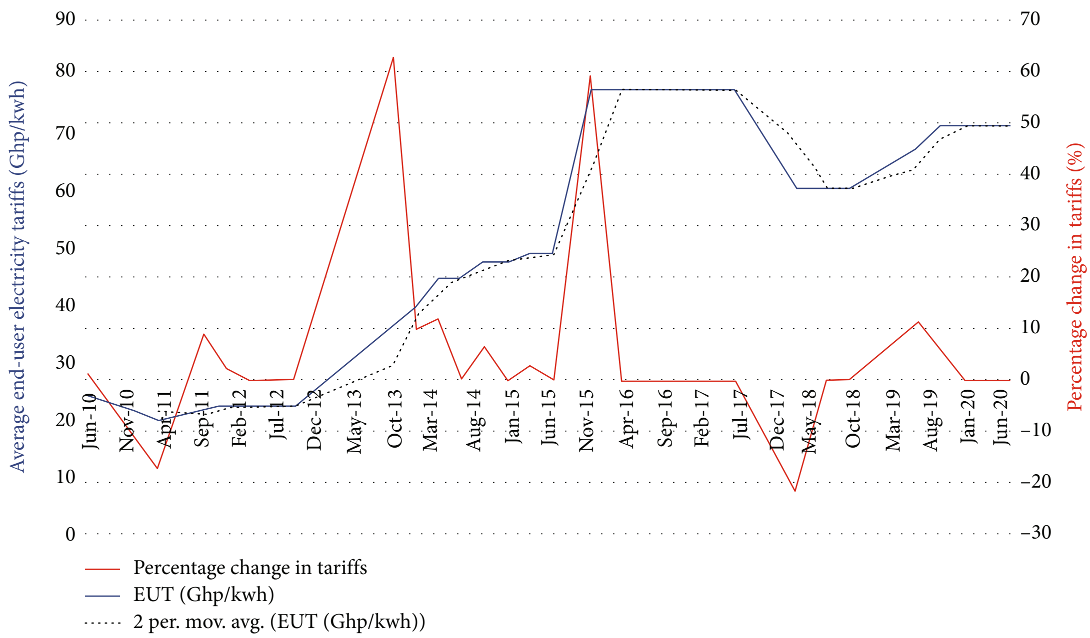

Figure 1: Overall trends in end-user electricity tariffs between 2010 and 2020 [54].

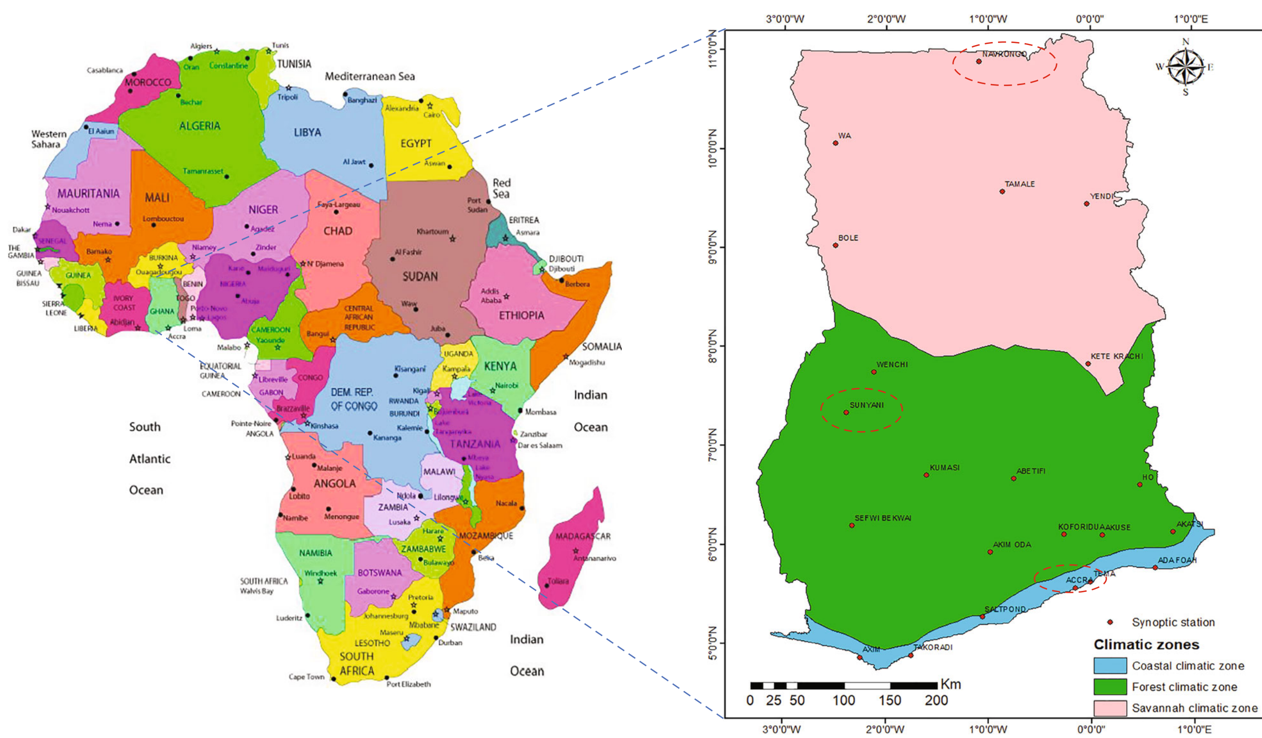

Figure 2: Map of Africa (a) and map of Ghana (b) showing the location of the main climatic zones [60].

Furthermore, this study expands its investigation to include the potential application of ToU tariffing concerning the planned implementation of net metering within Ghana's residential sector. It is important to note that, presently, neither net metering nor ToU tariffs are available to residential electricity customers in Ghana, a situation mirrored in several other African nations. The absence of net metering has been identified as a significant barrier to the widespread adoption of residential PV systems in African countries [4]. The potential of ToU tariffs in Ghana's industrial sector was explored in a prior study [59]. According to the study findings, Ghana's energy sector is conducive to introducing

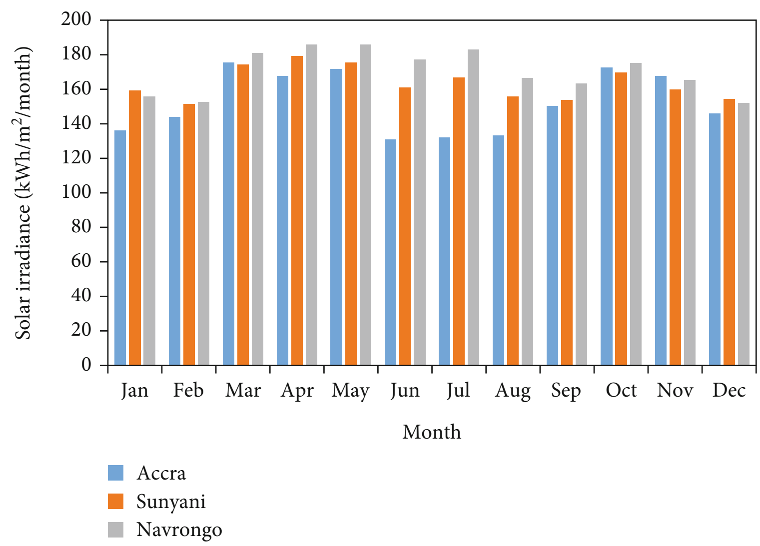

Figure 3: Average monthly solar irradiance of the study area.

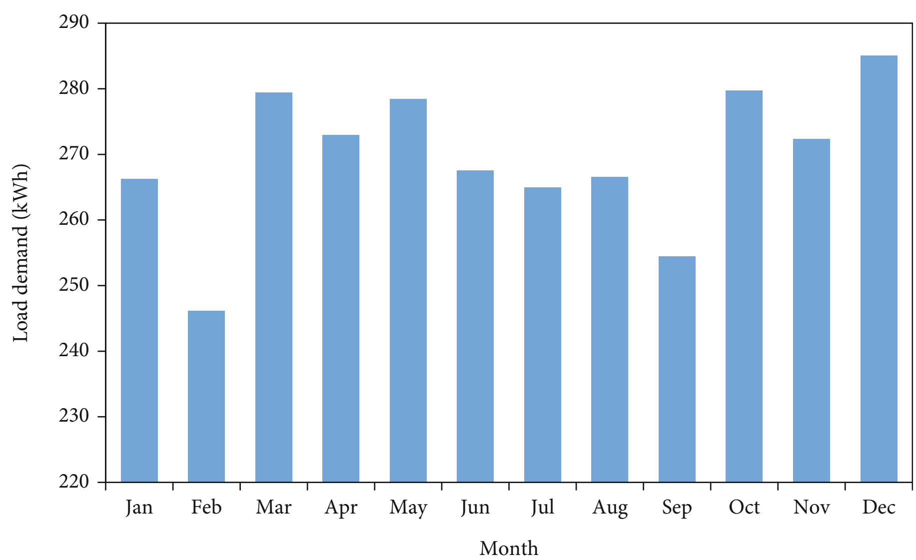

Figure 4: Average monthly load demand of a typical urban home.

ToU tariffs as an initial step in rationalising energy prices, promoting effective load management, and addressing inherent challenges within the power sector. Therefore, the authors chose to explore net metering schemes under block tariff and ToU tariffs because Ghana's residential end-user tariff (EUT) is currently structured on a block tariff. At the same time, ToU tariffing has been recommended as a measure to address key challenges in the power sector [59].

To the best of the authors' knowledge, this study represents a pioneering effort to examine the application of ToU tariffs in the context of grid-connected solar PV and net metering within the residential sector of Ghana. Besides, Ghana's current tariff structure reflects a developing electricity market, similar to other SSA countries [51, 52]. Thus, the study findings are relevant to Ghana and other developing nations, particularly those in sub-Saharan Africa, seeking to advance net metering and deploy grid-tied solar PV systems in the residential sector.

2. Methodology

This section presents a comprehensive overview of the methodology employed in this study. The section delves into key aspects such as the characteristics of the study area, load demand analysis, system modelling and simulation considerations, performance metrics, and a detailed investigation of the diverse electricity tariff structures.

2.1. Study Area. Ghana encompasses three distinct climatic zones: coastal, forest, and savannah [56, 60]. Consequently, this study purposely selected the following specific locations to represent each of these climatic zones: Accra (latitude 5.6°

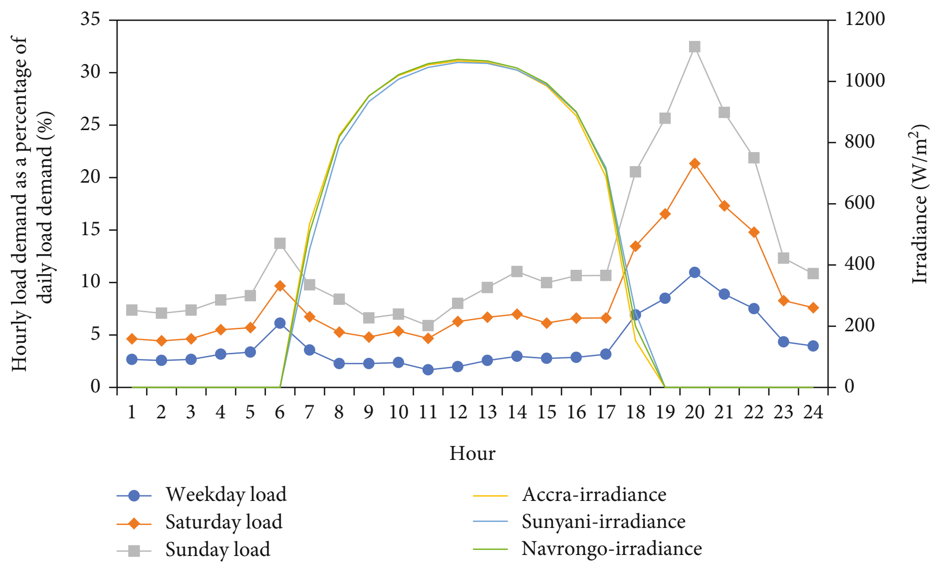

FIGURE 5: Average percentage hourly load demand of typical urban homes against solar irradiance.

TABLE 1: Simulation parameters employed for specific yield estimation using PVGIS®.

Parameter	Value	Remarks/reference
Solar radiation database	PVGIS SARAH2	Readily available in the PVGIS database
PV technology	Crystalline silicon	Crystalline silicon PV technology is common in Ghana
System losses	14%	Authors' assumptions based on typical values considered in related studies [67, 68]
Slope angle	12°	Typical optimal tilt angle due to the study locations [67, 69]
Azimuth angle	180° south	Typical value considered for study location [4, 67]

N, longitude -0.17° E) represents the coastal zone; Sunyani (latitude 7.34° N, longitude -2.27° E) represents the forest zone; and Navrongo (latitude 10.88° N, longitude -1.08° E) represents the savannah zone. Solar resource data was retrieved from the Meteonorm 8.1 climate database integrated into PVSOL premium® and PVGIS® software. Figure 2 illustrates the climatic zones in Ghana in the context of Africa. Meanwhile, Figure 3 displays the average monthly solar irradiations of Accra, Sunyani, and Navrongo. It is evident from Figure 3 that, comparatively, Navrongo has the highest solar irradiation among the three locations, while Accra has the lowest. On an annual basis, these locations have average solar irradiance levels of 1828.2 kW/m^2 for Accra, 1961.9 kW/m^2 for Sunyani, and 2044.1 kW/m^2 for Navrongo.

2.2. Load Demand. This study adopted a Ghanaian estate's average hourly synthetic load profile in PVSOL premium to assess the economic performance of roof-mounted grid-tied solar PV systems for urban residential prosumers. Previous related studies have employed synthetic load profiles [46]. The hourly load profile of the Ghana estate was subsequently adjusted to match the typical weekday, Saturday, and Sunday daily load profile characteristics of urban homes in Ghana, as reported by [61].

In this study, the estimated average annual and daily load demand for urban homes in Ghana is 3234 kWh and 8.9 kWh,

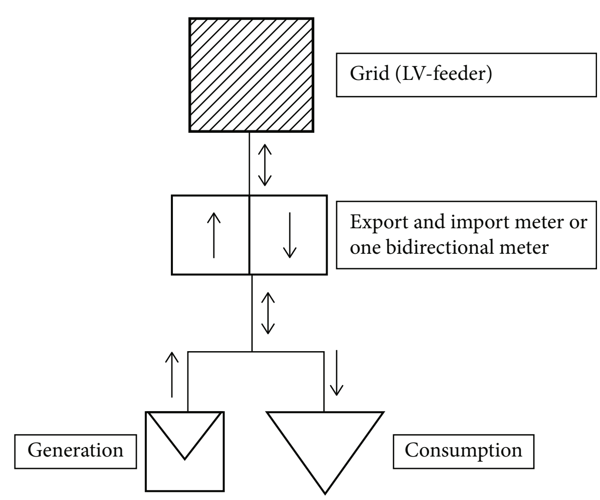

FIGURE 6: Metering configuration for bidirectional net metering [73].

respectively. These figures represent the average electricity consumption for a typical urban household in Ghana with a household size of 4.2, a floor area of 132 m^2, and an income of US$ 906 per month [61]. The average daily energy consumption of 8.9 kWh falls within the range of electricity consumption for middle- to high-class households in many

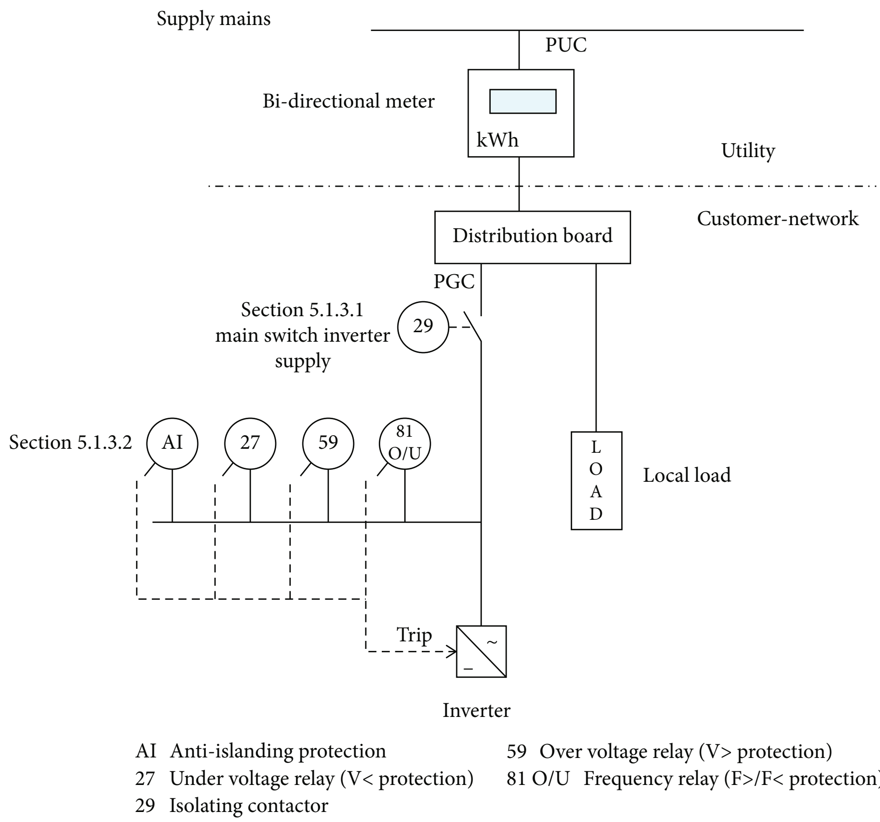

Figure 7: Generation facility connection to the low-voltage distribution network [73].

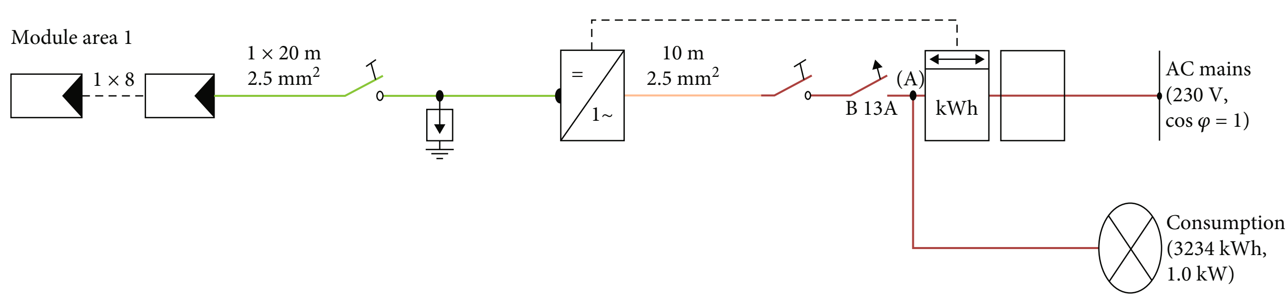

Figure 8: Single-line diagram of the proposed grid-tied PV system under consideration.

developing countries where ventilation fans are used for thermal comfort rather than air-conditioners [4, 61].

Adapting the synthetic load profile characteristics to match those of typical Ghanaian urban homes [61] was necessary because comprehensive national data on residential household energy profiles is not currently publicly available, unlike studies that have accessed and employed such data [62, 63]. Nevertheless, Sakah et al.'s [61] study is the first to comprehensively investigate city-scale hourly electricity consumption patterns in urban Ghanaian homes.

Household electricity demand varies significantly due to various factors, including electrification tariff rates, available household appliances, occupancy patterns, the type of day, available daylight hours, and weather conditions [26, 61, 64, 65]. Therefore, one limitation of using a generalised urban household profile in this study is the inability to account for the heterogeneity in consumer demands [49].

This study focuses on urban households because they are typically close to the national grid, making them potential candidates for net metering systems if implemented for grid-tied solar PV systems in Ghana. Currently, net metering is unavailable to residential urban households in Ghana and many other African countries, leaving solar owners limited to standalone systems even near the national grid. Figure 4 displays the average monthly load consumption of typical urban homes in Ghana.

Figure 5 presents the average percentage hourly load demand for weekdays, Saturdays, and Sundays as utilised in the PVSOL premium® simulation software. The comprehensive load profile details of the Ghanaian urban home

Table 2: Technical specifications of main components of the grid-tied PV system.

Component	Parameter	Value
Solar PV module (JKM265P-60-V)	Manufacturer	JinkoSolar
	Cell type	Si polycrystalline
	Nominal maximum power	265 W
	Maximum power voltage (V_{mp})	31.4 V
	Maximum power current (I_{mp})	8.44 A
	Open circuit voltage (V_{oc})	38.6 V
	Short circuit current (I_{sc})	9.03 A
	Module efficiency	16.19%
	Temperature coefficient of P_{max}	-0.41%/K
	Temperature coefficient of V_{oc}	-0.31%/K
	Temperature coefficient of I_{sc}	5.418 mA/K
	Fill factor	76.03%
	Maximum system voltage	1500 V
Inverter (Fronius Galvo 2.0-1/208 V)	Manufacturer	Fronius USA
	Electrical data—DC	
	DC nominal output power	2.04 kW
	Maximum DC power	2.04 kW
	Nominal DC voltage	260 V
	Maximum input voltage	420 V
	Maximum input current	22.4 A
	Maximum short circuit current DC	22.4 A
	Number of DC inlets	3
	Electrical data—AC	
	AC power rating	1.9 kW
	Maximum AC power in kVA	1.9 kVA
	Number of phases	1
	Number of MPP trackers	1
	Maximum input current per MPP tracker in A	17 A
	Maximum short circuit current per MPP tracker	17 A
	Maximum input power per MPP tracker	2.04 kW
	Minimum MPP voltage	120 V
	Maximum MPP voltage	335 V

considered in this study are accessible in [61]. Notably, these load profiles exhibit similarities to those found in [64, 66].

2.3. System Design and Simulation Considerations

2.3.1. Simulation Software. This study employed PVGIS® (ver. 5.2) and PVSOL premium® (2023 R3) to investigate the economic performance of the proposed net metering systems. PVGIS was utilised to estimate the PV system's annual specific yield in the three selected geographical locations. The simulated specific yield results for Accra, Sunyani, and Navrongo, based on design conditions outlined in Table 1, are as follows: 1626.8 kWh/kWp, 1456.9 kWh/kWp, and 1656.6 kWh/kWp, respectively. Subsequently, the PVSOL premium® (2023 R3) software was used to simulate the grid-tied PV system integrated with a net metering system.

2.3.2. System Modelling and Governing Equations. This section highlights the equations used to size the key components within the grid-tied PV system. Equation (1) is applied to estimate the solar PV power output as follows [70]:

$$P_{\mathrm{PV}} = Y_{\mathrm{PV}} D_{\mathrm{PV}} \left(\frac{R_t}{R_{,t\mathrm{STC}}} \right) [1 + \alpha_{\mathrm{P}} (T_{\mathrm{c}} - T_{\mathrm{c,STC}})], \qquad (1)$$

where Y_{PV} is the rated capacity of the PV array at standard test conditions (kW), D_{PV} is the PV derating factor (%), R_t is the solar radiation incident on the module surface (kW/m^2), $R_{,t\mathrm{STC}}$ is the incident solar radiation at STC (1 kW/m^2), α_{p} denotes temperature coefficient (%/m^2), T_{c} denotes PV cell temperature (°C), and $T_{\mathrm{c,STC}}$ represents PV cell temperature under STC (25°C).

Table 3: Key system design parameters and assumptions for PV system simulation.

Component	Parameter	Value	Source/remarks
Solar PV	Tilt angle	12%	Typical optimal values for Ghana are within 10% to 15%
	Panel azimuth	180 degrees south	Typical value due to the location of the study area
	Derating factor	80%	[75]
	System degradation factor	15%	[75]
Economics	Project lifetime	25 years	Typical project lifespan for similar projects in the literature
	Interest on capital	21.06%	[76]
	Inflation in energy price	9.6%	[52]

The residential PV capacity (C_{PV}) was sized based on the following equation [71, 72]:

$$C_{PV} = \frac{L_a}{Y_a}, \tag{2}$$

where L_a is the annual load demand (kWh) and Y_a is the annual specific yield (kWh/kWp). A solar PV capacity size of 1.98 kWp, 2.2 kWp, and 1.95 kWp is estimated for the residential load in various locations. However, for effective comparison of the PV system in the various locations and available solar panel ratings in simulation software, the same system capacity size of 2.12 kWp is considered for all three locations under consideration.

Equation (3) is used to size the grid-tied PV inverter (P_{inv}) capacity [71]:

$$0.8 \times P_{GEN} < P_{inv} < 1.2 \times P_{GEN}, \tag{3}$$

where P_{GEN} is the capacity of the PV generator (kW). Based on available data, an inverter size of 2.04 kW is selected for the residential grid-tied PV system.

2.4. Net Metering Considerations. This section emphasises the technical requirements outlined in Ghana's net metering code, which have been incorporated into this study's residential grid-tied PV system design [73]. According to Ghana's net metering subcode, the generation capacity for net metering is limited to 200 kW per facility, with a credit rollover of one year. Inverters with a capacity of up to 13.8 kVA can be of single-phase type, while those exceeding 13.8 kVA require special consideration. Additionally, it is mandated that net-metered generating units operate at power factors of 0.98 and unity (1).

Figure 6 displays metering configurations. Likewise, Figure 7 illustrates the facility connection requirements for the low-voltage distribution network (LVDN) stipulated in the net metering subcode. Subsequently, Figure 8 presents the single-line diagram of the residential PV system designed for this study using PVSOL premium®.

Based on Ghana's net metering subcode, each kWh exported to the grid in excess of a customer's consumption attracts a credit of 1 kWh within the billing period. Also, the code stipulates that the distribution utility carry forward any excess kWh to offset the customer's consumption in subsequent billing periods until the end of a calendar year. However, all the unused excess credit expires at the end of a calendar year.

Table 4: Summary of PV component cost data for the 2.12 kWp grid-tied PV system.

Component	Cost ($)
Solar PV	1048
Inverter	637
Cables and accessories	96
Mounting system	115
Switching and protection devices	189
Installation and maintenance cost	742
Total cost of the PV system	2827

2.5. Component Technical Specifications. The technical specifications of the grid-tied PV system components are detailed in Table 2, while Table 3 presents design parameters, assumptions, and relevant considerations. This study considers an interest rate of 21.06%. However, the interest rate trend has been irregular, ranging between 12% and 30% over the past decade [74]. Additionally, Table 4 provides comprehensive data on the system's cost. It is worth mentioning that the cost data in Table 4 has been derived from quotations obtained from Zotch Engineering Services (a major solar PV system vendor in Ghana) and is supplemented by insights from other relevant studies conducted in Ghana [4]. However, it is essential to highlight that the costs of PV system components can exhibit significant variations in developing countries [2, 4].

2.6. System Performance Indicators. The section presents the primary economic indicators to assess the system's performance. These include the levelized cost of energy (LCOE), accrued cash flow, internal rate of return (IRR), payback period, and annual cash savings.

2.6.1. Levelized Cost of Energy (LCOE). The LCOE is a metric that evaluates and compares the cost of generating electricity from different sources or technologies over a power plant's lifespan. It considers upfront capital expenditures, operational and maintenance expenses, financing charges, decommissioning costs, and projected electricity generation. These costs are discounted to their present values and divided by

Table 5: Ghana's approved consumer electricity tariffs [83].

Customer	Measure (kWh)	Tariff charged (GH₵/kWh)	Tariff charged (USD/kWh)[b]
Lifeline residential customers	0–30[a]	0.645 GH₵/kWh	0.059 USD/kWh
Service charge	—	2.130 GH₵/month	0.194 USD/kWh
All other residential	0–300	1.370 GH₵/kWh	0.125 USD/kWh
	301–600	1.778 GH₵/kWh	0.162 USD/kWh
	600+	1.975 GH₵/kWh	0.180 USD/kWh
Service charge	—	10.731 GH₵/month	0.977 USD/kWh

[a]Electricity consumption for lifeline customers. [b]Computed using an exchange rate of 1 GH₵ =0.091 US$, obtained from the Bank of Ghana database using June 2023 as benchmark.

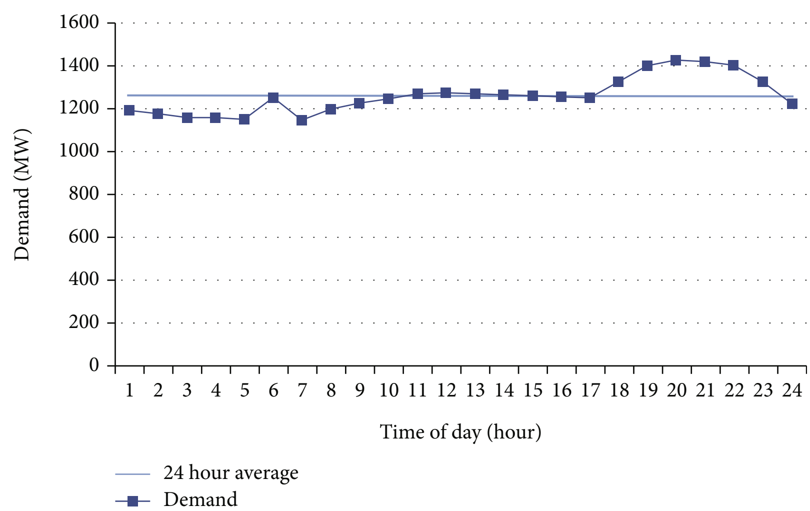

Figure 9: A typical hourly daily load profile of Ghana showing peak demand periods [86].

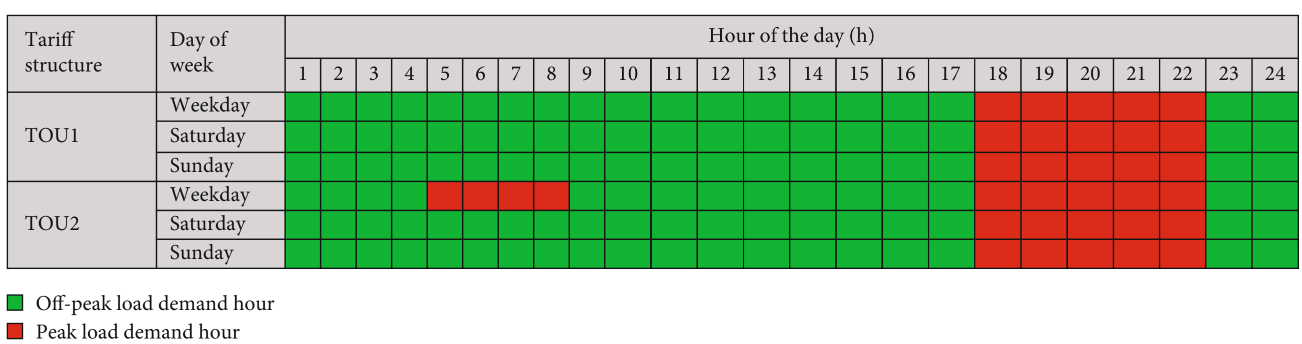

Figure 10: Peak and off-peak load demand hours for the proposed ToU tariff structure.

the anticipated output, yielding the average cost per unit of electricity produced. In view of this, stakeholders such as policymakers, utilities, and investors can compare their economic viability and make informed decisions about energy investments by evaluating the LCOE values of different power generation options. Grid parity is considered attained when LCOE for solar PV systems matches electricity prices from the utility grid [77]. Equation (4) is used to estimate the LCOE [78]:

$$\mathrm{LCOE} = \frac{\sum_{t=0}^{n}\left((\mathrm{CAP}_t + \mathrm{COM}_t)/(1+r)^t\right)}{\sum_{t=0}^{n}\left(\mathrm{EP}_t/(1+r)^t\right)}, \tag{4}$$

where CAP_t is the system's total capital expenditure, COM_t is the system's operation and maintenance expenditure, EP_t represents the system total energy production, r is the discount rate, n represents the project lifetime, and t represents the individual year of lifetime $(0, 1, 2, \ldots n)$.

2.6.2. Accrued Cash Flow. The net present value (NPV) evaluates an investment or project's profitability by calculating the difference between the present values of cash inflows and outflows over its lifetime. It involves estimating future cash flows, determining the time horizon, selecting an appropriate discount rate based on risk, and discounting

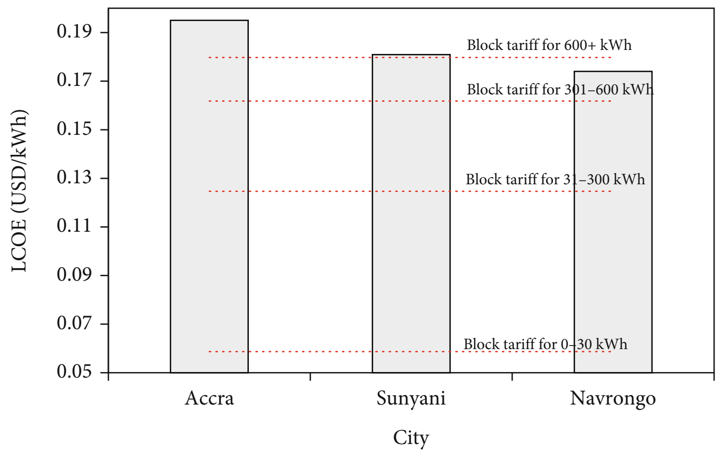

Figure 11: LCOE for residential grid-tied PV systems under various tariff structures.

Table 6: LCOE results from related studies on residential grid-tied solar PV systems.

Authors	Study location	PV system capacity (kWp)	LCOE (USD/kWh)
Present study	Ghana	2	0.174-0.195
Onaolapo et al. [93]	South Africa	—	0.098
Mohammed et al. [80]	Saudi Arabia	10	0.027
Poudyal et al. [94]	Nepal	3	0.06
Enongene et al. [91]	Nigeria	0.2-22	0.398-0.743
Fairuz et al. [79]	Indonesia	2.1–5.4	0.10–0.118
Quansah et al. [92]	Ghana	4	0.32

the cash flows to their present values. The NPV is obtained by subtracting the present value of outflows, including the initial investment, from the present value of inflows. A positive NPV indicates potential profitability, while a negative NPV suggests the investment may not be viable. This metric accounts for the time value of money and allows comparison of investment opportunities. However, NPV relies on accurate cash flow projections and discount rate assumptions. Equation (5) is applied to compute the NPV [79, 80]:

$$\mathrm{NPV} = \sum \left(\frac{\mathrm{CF}_t}{(1+r)^t} \right) - C_0, \tag{5}$$

where CF_t represents the cash flow at the time, r is the discount rate, C_0 represents the initial investment cost, and t is the time period.

2.6.3. Internal Rate of Return (IRR). The IRR assesses the potential profitability of an investment or project. It represents the discount rate at which the project's NPV becomes zero. In other words, it is the rate at which the investment breaks even in terms of cash flows. The IRR must surpass the discount rate to deem an investment financially viable. Conversely, a lower IRR suggests insufficient returns relative to risks. Equation (6) is used to compute the IRR [81]:

$$0 = \sum \left(\frac{\mathrm{CF}_t}{(1+\mathrm{IRR})^t} \right) - C_0. \tag{6}$$

2.6.4. Payback Period. The payback period is the duration within which the anticipated income and other associated benefits recuperate the initial investment, factoring in a predetermined rate of return. Essentially, it signifies the years required for the NPV to reach zero. The payback period is computed as follows [82]:

$$\text{Payback period} = \frac{\text{initial investment}}{\text{annual cash flows}}. \tag{7}$$

2.6.5. Annual Cash Savings. The annual cash savings are the monetary benefits or cost reductions obtained annually from generating electricity through the solar PV system instead of purchasing electricity from the utility grid. The annual cash savings is computed as follows:

$$\mathrm{ACS} = (\mathrm{EGS} * \mathrm{UER}) - \mathrm{AC}_{\mathrm{o\&m}} - \mathrm{FC} - \mathrm{TCI}, \tag{8}$$

where ACS is the annual cash savings, EGS is electricity generated by solar PV systems, UER is the utility electricity rate, $\mathrm{AC}_{\mathrm{o\&m}}$ is the PV system operating and maintenance costs, FC is the financing costs (if applicable) of the PV system, and TCI is the tax credits and incentives (if applicable).

2.7. Electricity Tariff Considerations. This section provides a detailed explanation of the existing electricity tariff structure and the proposed time-of-use (ToU) tariff that has been examined in this study within the context of a net metering

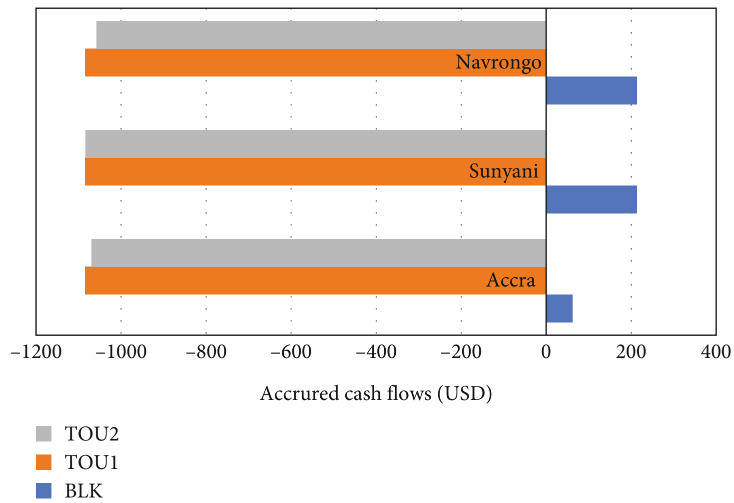

Figure 12: Grid-tied PV systems accrued cash flow under various tariff structures.

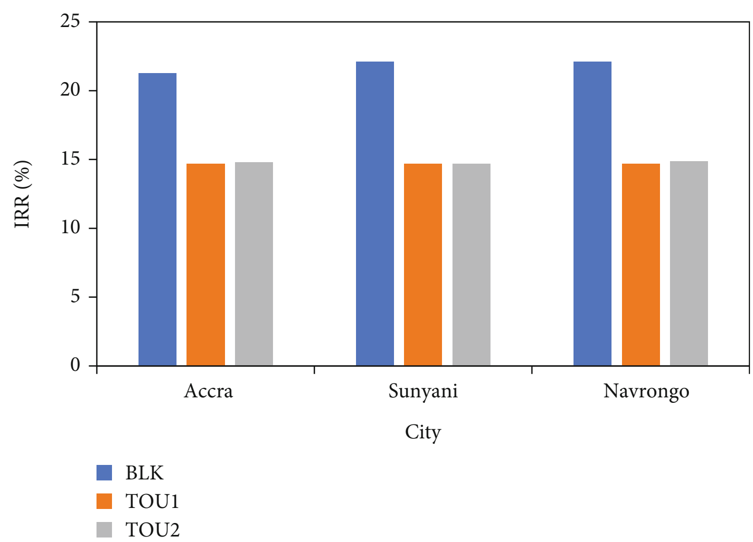

Figure 13: Grid-tried PV system's internal rate of return under various tariff structures.

Table 7: Residential grid-tied PV system payback period under various tariff structures.

City	BLK	ToU1	ToU2
Accra	22.6	>25	>25
Sunyani	18.7	>25	>25
Navrongo	18.7	>25	>25

system for grid-tied solar PV systems in the urban home of Ghana.

2.7.1. Block Tariff. Currently, Ghana uses a block tariff structure for all residential consumer categories. Subsequently, this study evaluates the system performance of grid-connected PV prosumers within the framework of the block tariff structure. Table 5 concisely overviews the energy charges and service fees applicable to different residential consumer categories [83].

2.7.2. Time-of-Use Tariff Structure. While Ghana currently employs a block electricity tariff structure for residential sectors, existing literature suggests the necessity of transitioning to a time-based tariff structure in the context of integrating PV systems into the utility grid [59]. Therefore, this study extends its economic assessment of residential grid-connected solar PV systems from the prevailing block tariff structure to scenarios involving ToU tariff structures. Moreover, Ghana's utility companies have plans to implement smart meters for residential customers, which is a crucial step in enabling ToU tariffs and demand-side management (DSM) programmes [59].

In ToU programmes, key elements include the number of pricing periods and the respective on-peak and off-peak prices. In this regard, the aggregated electricity demand in

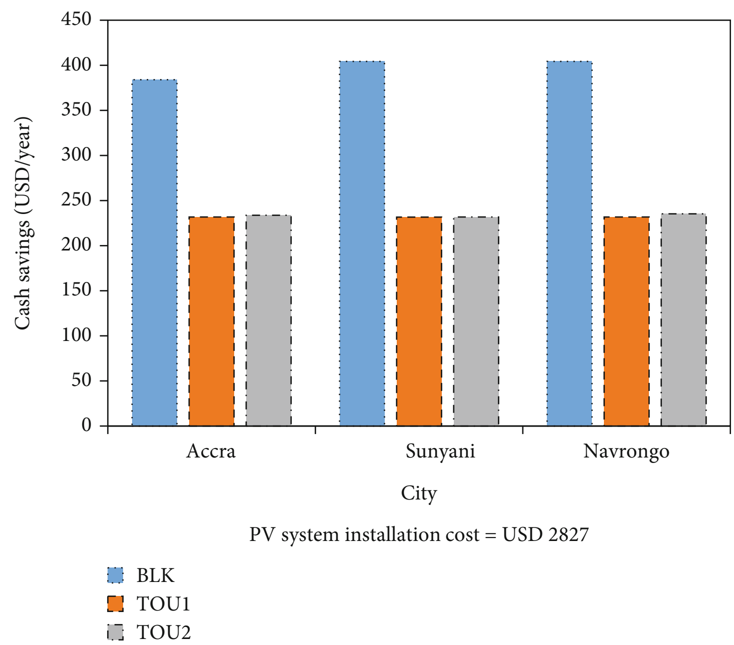

FIGURE 14: Annual cash savings of the residential grid-connected solar PV for various tariff structures.

Ghana typically peaks between 6 p.m. and 10 p.m. Figure 9 illustrates Ghana's typical hourly daily load profile. Meanwhile, the residential sector exhibits two peaks in weekday electricity demand: one during the morning hours (5:00 to 8:00 a.m.) and another during the evening hours (6:00 to 10:00 p.m.) [61]. During weekends, the evening peak demand remains consistent, while the morning peak decreases by approximately 50%. The residential sector significantly contributes to Ghana's aggregated peak demand [84]. Specifically, the residential sector accounts for around 40% of the country's electricity consumption. Also, urban centres contribute about 70% of the residential load demand [85]. These characteristics highlight the potential impact of the residential load profile on Ghana's national electricity consumption patterns.

This study examines a two-tier tariff structure consisting of on-peak and off-peak periods. While some countries employ three-tier ToU programmes with three pricing periods (on-peak, off-peak, and midpeak), research suggests that a two-tier approach is more effective for Ghana [59]. This structure offers administrative simplicity and ease of adoption for electricity consumers. Additionally, due to Ghana's proximity to the equator, energy demand has minimal variation across seasons. For instance, energy demand for residential lighting remains consistent throughout the year, and there is also no correlation between cooling degree days (CDD) and system demand. The minimal variation in energy demand across seasons makes seasonal ToU pricing less relevant for Ghana [59].

Regarding the pricing of off-peak and on-peak demands, literature reveals a wide range of on-peak to off-peak electricity rate ratios. However, for Ghana, it has been proposed that a modest on-peak to off-peak rate ratio of 2 is suitable [59]. This study adopts ToU rates equivalent to the block rate tariffs in Table 5. Consequently, off-peak rates are set at 0.125 USD/kWh, while on-peak rates are set at 0.162 USD/kWh. Aligning off-peak and on-peak rates with block tariff equivalents is expected to facilitate the acceptance of the ToU, especially during its initial stages of implementation. It is also worth noting that the ratio of on-peak to off-peak rates adheres to the modest ratio recommended for Ghana.

Simplicity is a key feature in the ToU structure considered in this study. This is because drastic tariff structural changes may trigger a political backlash and consumer agitation in Ghana [87]. Additionally, overly complex ToU rates can be counterproductive for utility goals, as they may be challenging for customers to understand and act upon. The authors anticipate that adapting this simplified ToU structure could enhance its acceptability among residential consumers, especially since ToU is yet to be implemented in Ghana. However, designing an electricity rate structure is an iterative process that must consider several factors, such as customer response and price elasticity [59]. Therefore, implementing ToU in Ghana will require further investigations to determine appropriate ToU structures mutually beneficial to prosumers, consumers, and power utility companies. Based on a review of related works, Figure 10 displays peak and off-peak load demand hours for weekdays and weekends for various ToU scenarios investigated [61].

In ToU1, peak hours align with the aggregated national load's peak hours. In ToU2, peak hours are exclusively based on the residential sector's peak hours. In the base case scenario for ToU1 and ToU2, the peak load electricity rate is set at 0.162 USD/kWh, corresponding to the electricity rate within the 301–600 kWh consumption block of Ghana's current block tariff structure. Since this study focuses on a two-tier ToU tariff structure, all other hours of the day are considered off-peak, with an electricity rate of 0.125 USD/kWh. This off-peak rate corresponds to the electricity rate

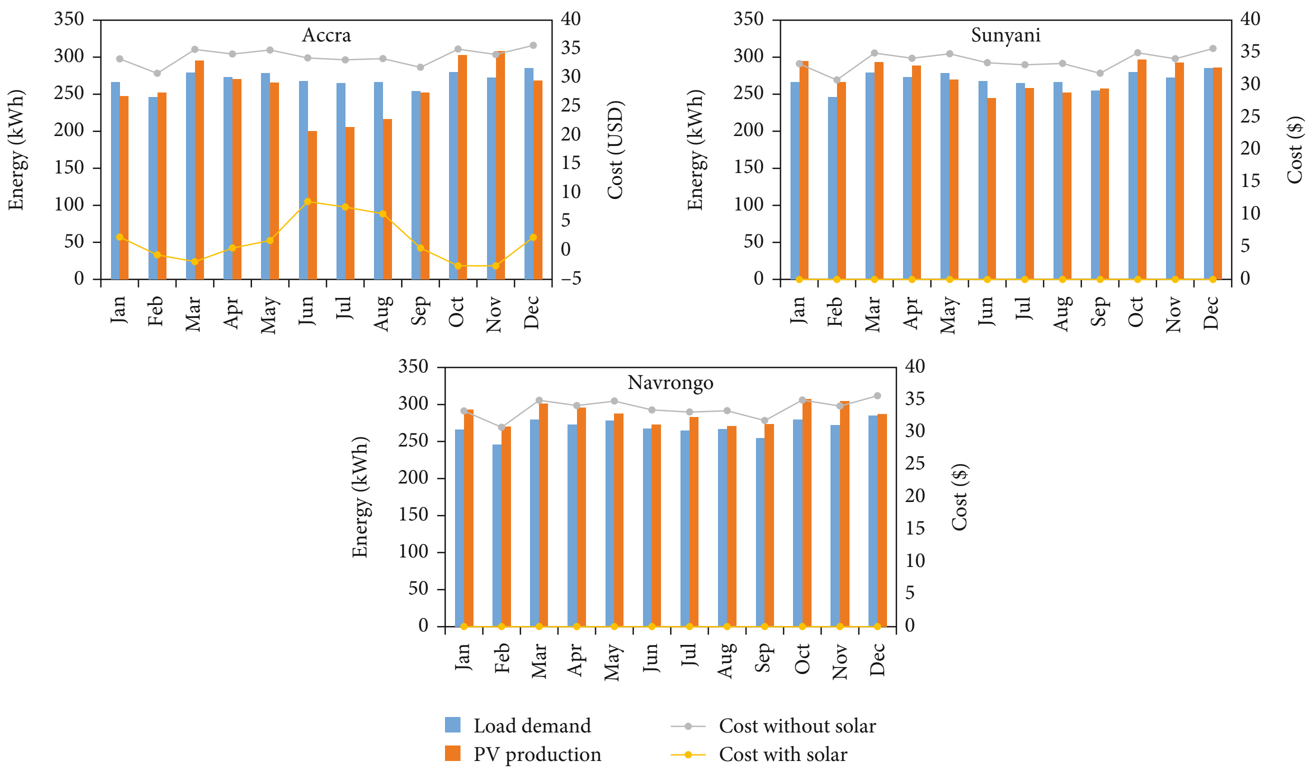

Figure 15: Average monthly load demand, PV production, and electricity costs for consumers with and without solar PV under the block tariff structure.

Table 8: Solar-load correlations between solar power production and load demand.

Location	Pearson coefficient	p value
Accra	-0.463**	≤0.01
Sunyani	-0.476**	≤0.01
Navrongo	-0.486**	≤0.01

**Correlation is significant at the 0.01 level (2-tailed).

for the 0-300 kWh consumption block applicable to residential consumers.

3. Results and Discussion

This section provides an in-depth analysis of simulation results and an economic assessment of net metering schemes for residential grid-tied solar PV systems based on block and ToU tariff structures. The study focuses on three locations in Ghana, Accra, Sunyani, and Navrongo, representing the coastal, forest, and savannah climatic zones, respectively.

3.1. Residential Grid-Tied PV System Economic Performance. In this study, BLK denotes a net metering system based on Ghana's existing block tariff structure. ToU1 represents a net metering system based on a two-tier ToU tariff with peak hours aligned to the national peak load demand hours (i.e., 18 : 00–22 : 00 h). Similarly, ToU2 represents a net metering system based on a two-tier ToU tariff with peak demand hours specific to the Ghanaian residential sector (05 : 00–08 : 00 h and 18 : 00–22 : 00 h). It is important to note that grid-tied PV net metering schemes and ToU options are not accessible to residential consumers in Ghana at present.

Figure 11 displays the LCOE for the simulated residential grid-tied PV systems in Accra, Sunyani, and Navrongo. Additionally, the figure depicts the utility grid electricity rates for different categories of residential consumers under Ghana's existing block tariff structure. It can be observed that the lowest LCOE is achieved in grid-tied PV system installations in Navrongo, while the highest LCOE is observed in Accra. These findings align with the solar resource distribution in Accra, Sunyani, and Navrongo, as shown in Figure 3. This trend supports previous studies highlighting that the PV system's economic performance improves in Ghana's southern to northern regions [56].

It can be deduced from Figure 11 that the LCOE for Navrongo falls below the current retail electricity rates for residential consumers in the third block (i.e., consuming 600+ kWh per month). Sunyani's LCOE aligns with the utility electricity tariff for residential consumers in the same consumption category. However, in Accra, the LCOE for grid-tied PV systems exceeds the electricity tariffs for consumers on the national grid, using over 600 kWh per month. These variations in LCOE across different climatic zones in Ghana suggest the government's need for tailored incentive schemes to promote solar adoption, depending on the local solar potential.

Nevertheless, it is essential to highlight that all LCOE results significantly surpass the retail electricity tariff rates for residential consumer categories with monthly electricity

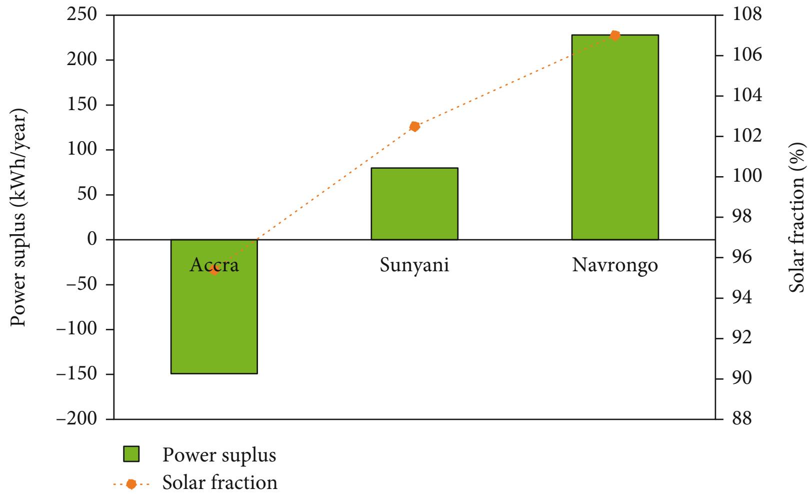

Figure 16: Grid-tied PV system surplus power and solar fraction under various climatic zones.

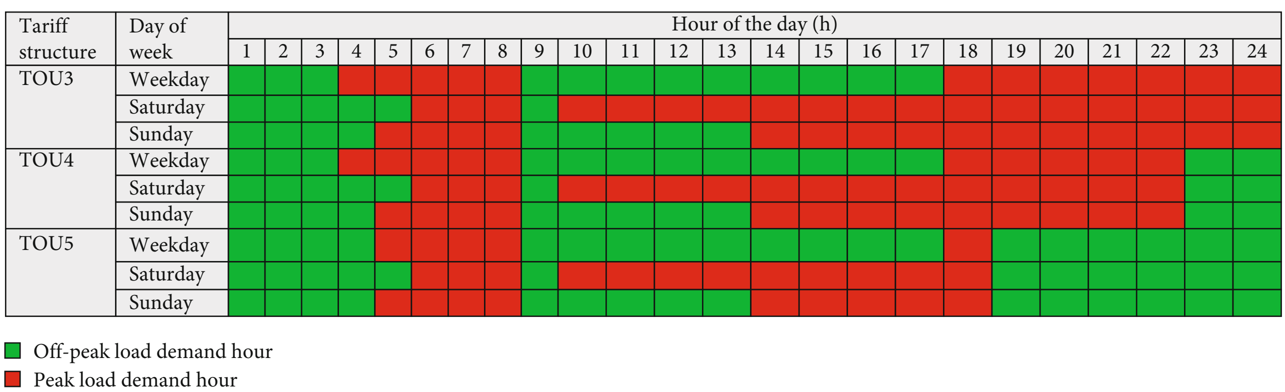

Figure 17: Extended time-of-use (ToU) peak and off-peak load demand hour scenarios.

consumption below 600 kWh. For this result, several studies argue that electricity tariffs in sub-Saharan Africa often do not accurately reflect generation costs [2, 88, 89]. Similarly, Radhi [27] showed that government subsidies make electricity tariffs not reflect the actual cost incurred in generating, transmitting, and distributing electricity at the consumer end. Consequently, government subsidies have been identified as contributing to this discrepancy, discouraging the adoption of alternative energy sources like solar PV. Eduful et al. [90] attributed the relatively higher costs associated with both off-grid and grid-tied solar PV systems in Ghana to the absence of green policies such as carbon taxation.

Meanwhile, the high cost of PV components and other unfavourable economic conditions, including the high cost of financing, adversely impact the economic performance of PV systems [2, 66]. Table 6 compares the LCOE obtained in this study to similar residential grid-tied solar PV system studies. It can be observed that this study's LCOE is within a similar range obtained by Fairuz et al. [79] in Indonesia. Also, it can be seen in Table 6 that this study's LCOE is lower than the LCOE obtained by Enongene et al. [91] in Nigeria and Quansah et al. [92] in Ghana. However, it is higher than Onaolapo et al. [93] in South Africa, Mohammed et al. [80] in Saudi Arabia, and Poudyal et al. [94] in Nepal. It is worth highlighting that the variation in LCOE values in different studies can be attributed to several factors, such as solar resource availability, economies of scale, technological advances, financing costs, currency exchange rates, and local labour costs.

Figure 12 shows the accumulated cash flow for each grid-tied PV system. Also, the IRR from each system is shown in Figure 13. It can be observed in Figure 12 that the BLK scenario consistently yields positive accumulated cash flow across all cases. In contrast, the ToU1 and ToU2 scenarios show negative outcomes. As a result, the payback periods for residential grid-tied PV systems operating under the ToU1 and ToU2 net metering schemes extend beyond the project's anticipated lifespan of 25 years, as detailed in Table 7. These findings suggest that implementing ToU1 and ToU2 tariff structures would not facilitate the recovery of investment costs, rendering them economically unattractive for residential consumers [18, 27]. The study by [27, 66] has previously demonstrated that adjusting electricity rates can positively impact the payback period of residential grid-tied systems. However, under the BLK scheme, prosumers achieve payback within a timeframe shorter than the

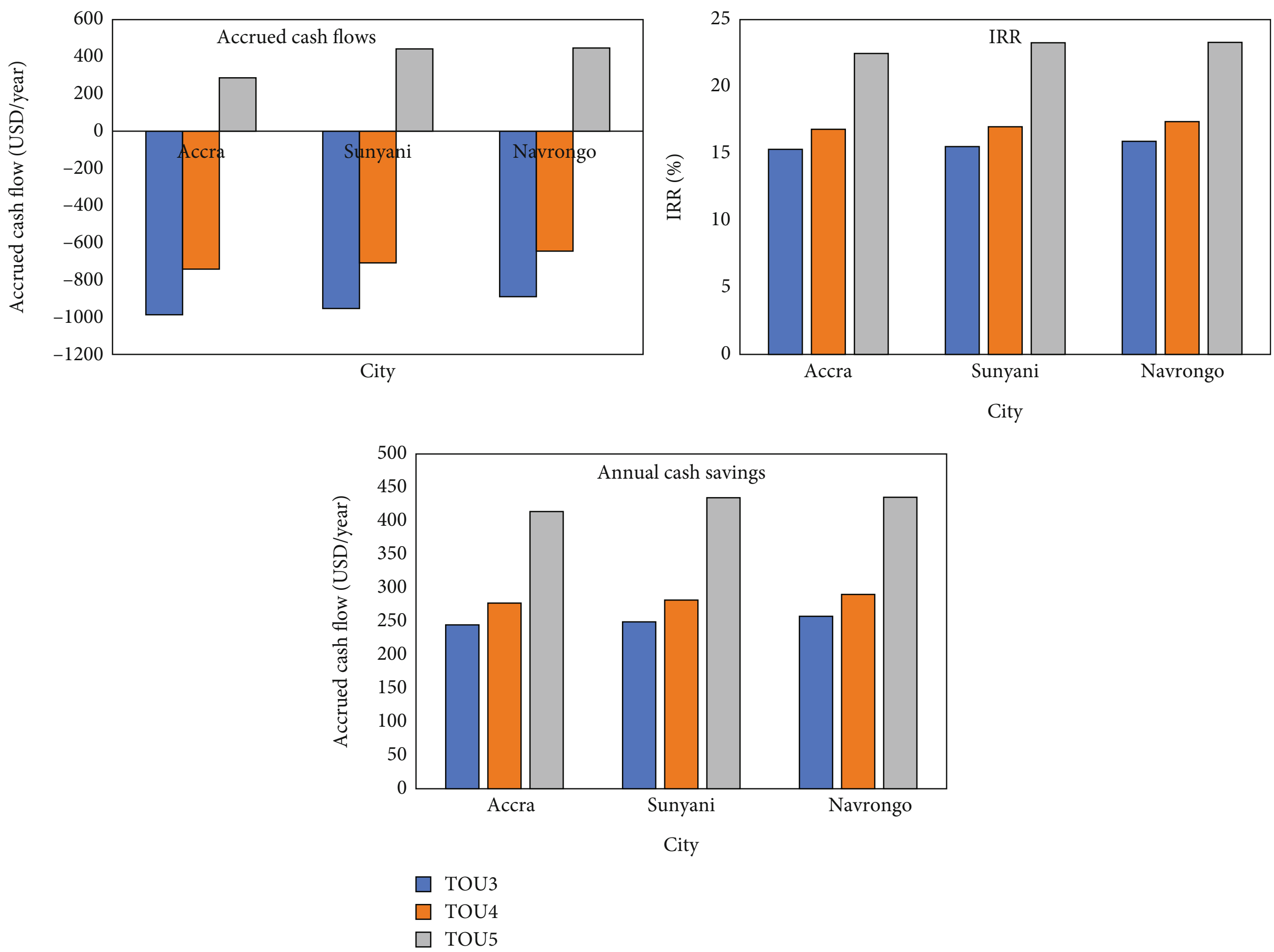

Figure 18: Accrued cash flow, IRR, and annual cash savings of various ToU tariff schemes.

Table 9: Grid-tied PV systems payback period for various ToU tariff structures.

Location	ToU3	ToU4	ToU5
Accra	>25	>25	17.4
Sunyani	>25	>25	15.3
Navrongo	>25	>25	15.2

anticipated 25-year lifespan of on-grid residential PV systems. Specifically, prosumers in Sunyani and Navrongo recoup their investments in just 18.7 years, while those in Accra achieve payback within 22.6 years.

Figure 13 reveals that the IRR results for BLK surpass those of ToU1 and ToU2. This higher IRR in BLK indicates that implementing net metering under a block tariff structure is more economically attractive than the ToU structures under consideration. While ICF International [59] has suggested that ToU could benefit utilities and enhance power stability in Ghana, the results from this study indicate that ToU schemes with off-peak and on-peak rates similar to those in the present block tariff structure may not align with the economic viability of small-scale grid-tied residential PV systems for the average residential consumer.

However, Sakah et al. [61] revealed that Ghana's urban residential load profile exhibits a low load factor, ranging from 36% to 39%, indicating room for improvement through DSM. This improvement could be achieved by rolling out more suitable ToU tariff schemes. Yet, from a financial perspective, the ToU structures investigated here do not appear to incentivise residential solar prosumers to modify their load demands. This finding suggests the need for a more favourable ToU structure.

Without solar, the annual electricity costs for consumers on BLK, ToU1, and ToU2 are 404.25 USD/year, 455.14 USD/year, and 467.68 USD/year, respectively, across all three climatic zones examined. Figure 14 illustrates that the annual potential cash saving solar prosumers could accrue under various tariff schemes in these zones. In line with the results obtained for accumulated cash flow and IRR, Figure 14 shows that consumers on the BLK scheme would achieve higher savings than those on the ToU tariffs.

To elaborate on annual savings, Figure 15 presents the monthly energy demand, solar production, and electricity costs for Accra, Sunyani, and Navrongo consumers, comparing those with and without solar PV systems, all under the block tariff structure (BLK). The significant cash savings observed in the BLK scheme, compared to ToU schemes,

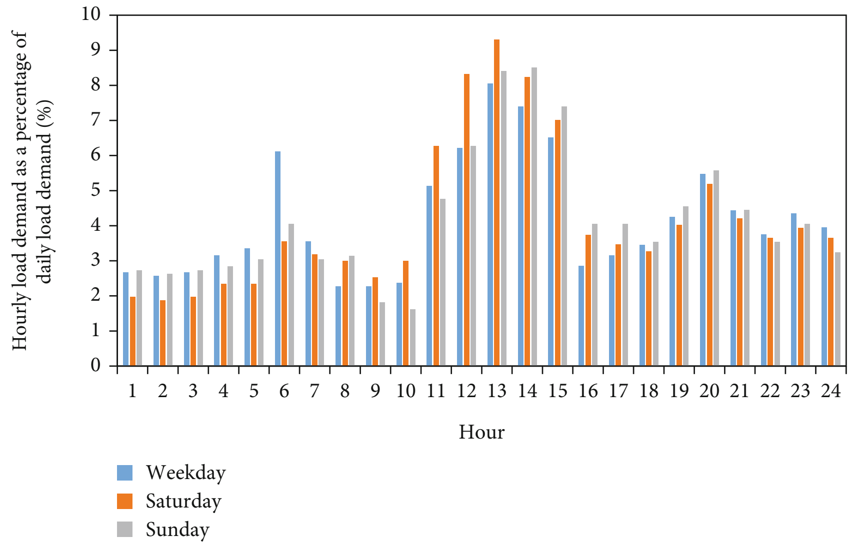

Figure 19: Modified urban residential load profile with enhanced daytime consumption demand.

Table 10: Solar-load correlations between solar power production and load profile with enhanced daytime consumption.

Location	Pearson coefficient	p value
Accra	0.386**	≤0.01
Sunyani	0.407**	≤0.01
Navrongo	0.420**	≤0.01

**Correlation is significant at the 0.01 level (2-tailed).

can be attributed to a mismatch between peak solar power generation and residential load demand in all the cities investigated, as presented in Table 8. Most solar power generated daily is directed back to the grid. However, these high solar power generation hours often coincide with off-peak periods, leading PV owners under ToU tariffs to receive lower compensation for exported energy. Consequently, solar prosumers export a substantial portion of solar energy during off-peak hours, resulting in reduced financial benefits for daytime solar production while purchasing electricity at higher rates during peak demand hours.

According to Oliva et al. [26], households generally achieve greater PV revenue under ToU retail tariffs that align well with the timing of PV generation and periods of high electricity demand. Consequently, it becomes evident that the PV system's economic performance substantially improved across the scenarios investigated in the case of the ToU2 tariff structure, which accounts for both the morning and evening residential peak demand hours. Several related studies have also highlighted the adverse effects of the mismatch between peak power production and residential load demand on the economic performance of residential grid-tied PV systems [66].

The energy balance results in Figure 16 reveal a net energy import for solar prosumers in Accra, contrasting with net energy exports for solar prosumers in Sunyani and Navrongo. The highest net energy export observed in Navrongo is attributed to its higher solar irradiation compared to Accra and Sunyani. With respect to these results, studies show that exporting surplus power to the grid could put unexpected pressure on the grid [95].

A consistently higher economic performance is observed in ToU2 compared to ToU1, coupled with the findings from previous studies suggesting that aligning PV generation with high electricity demand times in ToU retail tariff structures enhances household PV revenues, as indicated in Oliva et al. [26]. In view of this, this study explored additional ToU scenarios to gain deeper insights. These extended scenarios involve extending peak hours into both solar and nonsolar power generation periods. Figure 17 provides an overview of the various peak and off-peak load demand hour scenarios examined in this investigation. In extending the definition of peak demand hours, it was assumed that hourly load demand exceeding 3% of the daily load demand in Figure 5 would be categorised as peak demand.

Specifically, ToU3 considers all load demand hours throughout the day, encompassing solar and nonsolar generation periods where demand exceeds 3%. ToU4 extends peak demand hours beyond the initial ToU structure (i.e., ToU1) to include solar generation hours only. Lastly, ToU5 focuses solely on peak demand periods within the solar power generation hours. These extended ToU scenarios are aimed at providing a more comprehensive understanding of how varying peak demand hour definitions could impact system performance.

Figure 18 displays IRR, cash flows, and savings for the extended ToU tariff structures. The payback period based on the ToU tariff structures is also presented in Table 9. It can be seen that there are significant improvements in IRR, cash savings, and accrued cash flows with the extension of peak pricing periods into solar power production hours (Figure 18). Particularly, ToU5, which exclusively considered peak demand hours within solar power generation windows, displayed the most favourable IRR, cash flows, and cash savings among all the ToU tariff structures. These findings align with prior research indicating that ToU tariff

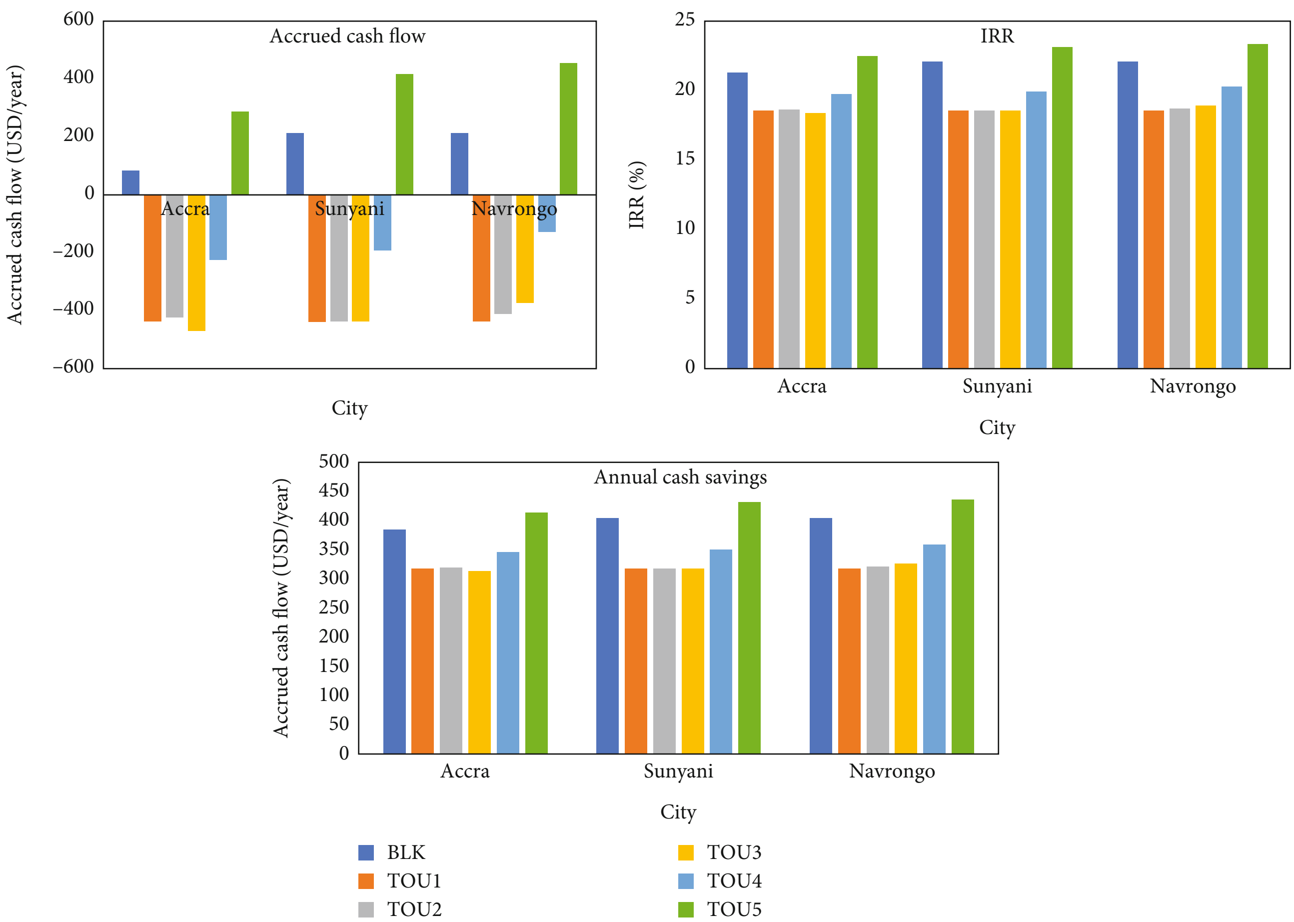

Figure 20: Accrued cash flow, IRR, and annual cash savings for PV systems with enhanced daytime consumption for various tariff structures.

Table 11: Grid-tied PV systems payback period for various tariff structures under enhanced daytime consumption.

City	BLK	ToU1	ToU2	ToU3	ToU4	ToU5
Accra	22.6	>25	>25	>25	>25	17.4
Sunyani	18.7	>25	>25	>25	>25	15.6
Navrongo	18.7	>25	>25	>25	>25	15.1

structures aligning PV generation with periods of high electricity demand can substantially boost household PV revenues, as Oliva et al. [26] suggested. Nevertheless, when compared, the block tariff system still outperformed all ToU tariffs.

Lukuyu et al. [96] and Rose et al. [97] alluded that daytime consumption improvements positively impact solar PV system performance. Additionally, the low load factor of residential demand in Ghana emphasises the importance of implementing DSM techniques to optimise the residential load profile. Thus, this study further explored the economic implications of improving daytime consumption under block and ToU tariff structures. In this scenario, it was assumed that 50% of peak loads would be shifted from the evening peak demand hours (18 : 00–22 : 00 h) to the high solar production daytime hours (11 : 00–15 : 00 h) on weekdays, Saturdays, and Sundays. Figure 19 displays the modified urban residential profile with enhanced daytime load demand. Likewise, Table 10 presents the solar-load correlations between solar power production and the load profile with enhanced daytime consumption. It can be deduced from Table 10 that there are substantial and statistically significant positive solar-load correlations ($p \leq 0.01$) for Accra, Sunyani, and Navrongo.

Figure 20 and Table 11 provide insights into the performance of economic indicators when residential load profiles feature increased daytime consumption for all tariff structures. It is important to clarify that this study does not account for the potential costs associated with modifying consumer load profiles in analysing the economic performance of the residential grid-tied PV system.

Generally, a significant improvement in economic indicators is noticeable when daytime consumption is improved within all ToU-based tariff schemes. However, this improvement had no discernible impact on the economic indicators under the block tariff structure. The ToU5, which operates based on a ToU scheme considering only peak demand hours coinciding with solar generation hours, demonstrated the most robust performance among all tariff structures in the context of improved daytime load demand. This improvement in the residential PV system's performance is

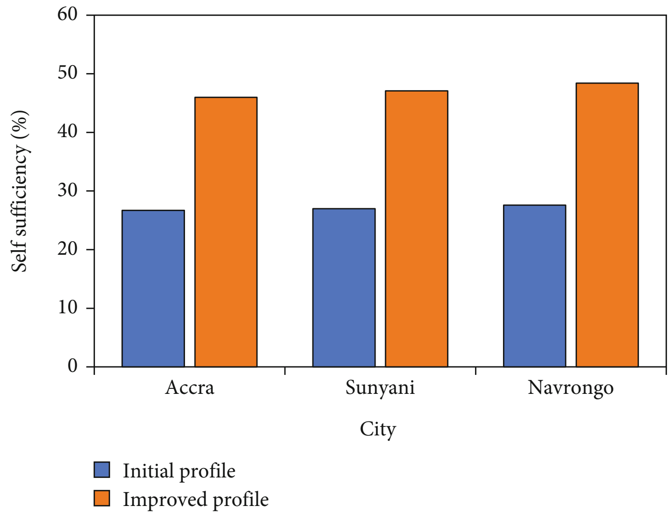

Figure 21: Comparison of self-sufficiency performance of residential grid-tied PV system.

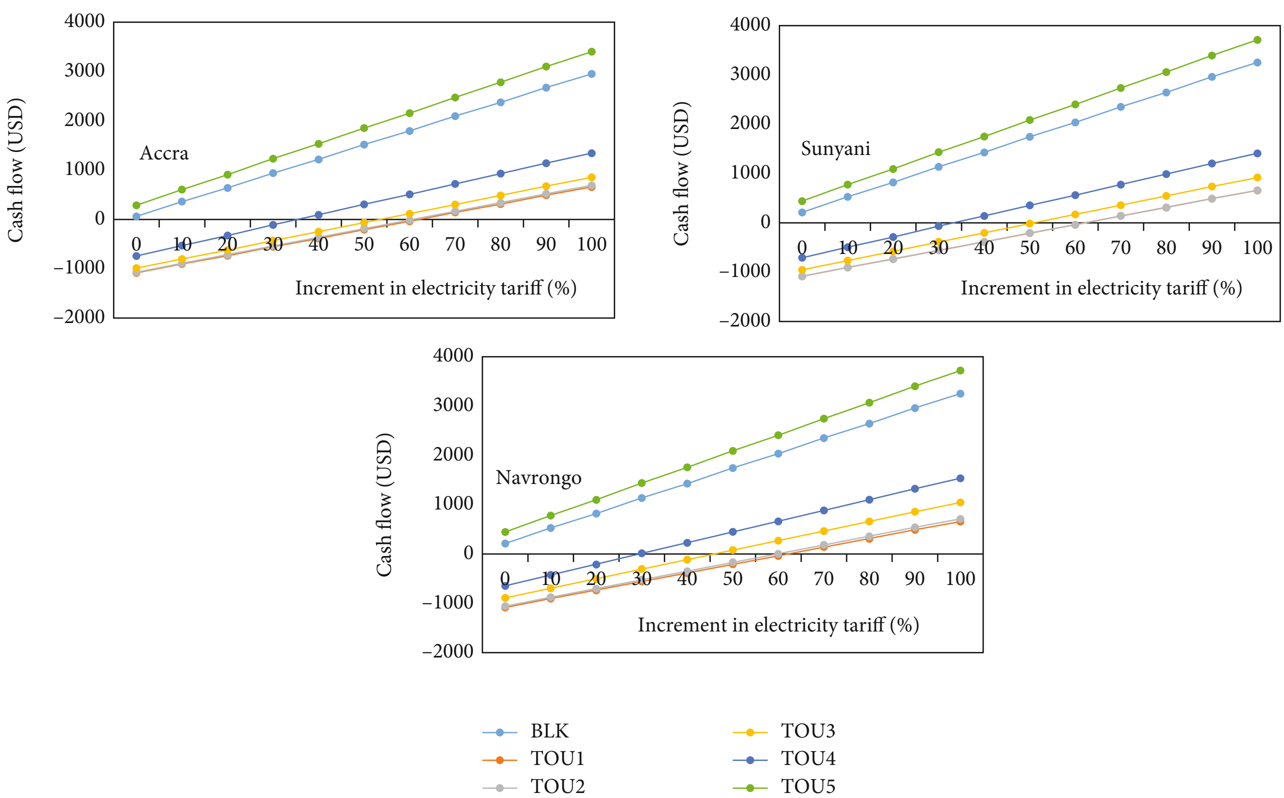

Figure 22: Impact of increasing electricity tariff on accrued cash flows for various tariff structures.

closely tied to the enhanced self-sufficiency of the residential PV system, as depicted in Figure 21.

The lack of responsiveness in the performance of grid-tied PV systems' economic indicators under the BLK tariff structure can be attributed to its foundation on load demand volume. Consequently, there are no adjustments in the per-unit energy charge until the consumer transitions into different consumption blocks, even if there are improvements in profile characteristics. This outcome is consistent with other studies' findings that volumetric tariffs do not incentivise load profile improvement [50]. The performance of economic indicators' unresponsiveness to heightened daytime demand under the BLK structure highlights the importance of suitable tariff schemes with the penetration of DRES within the utility grid [42, 43]. Without such schemes, enhancing daytime consumption may not necessarily translate into improved performance and economic indicators for residential grid-tied PV systems.

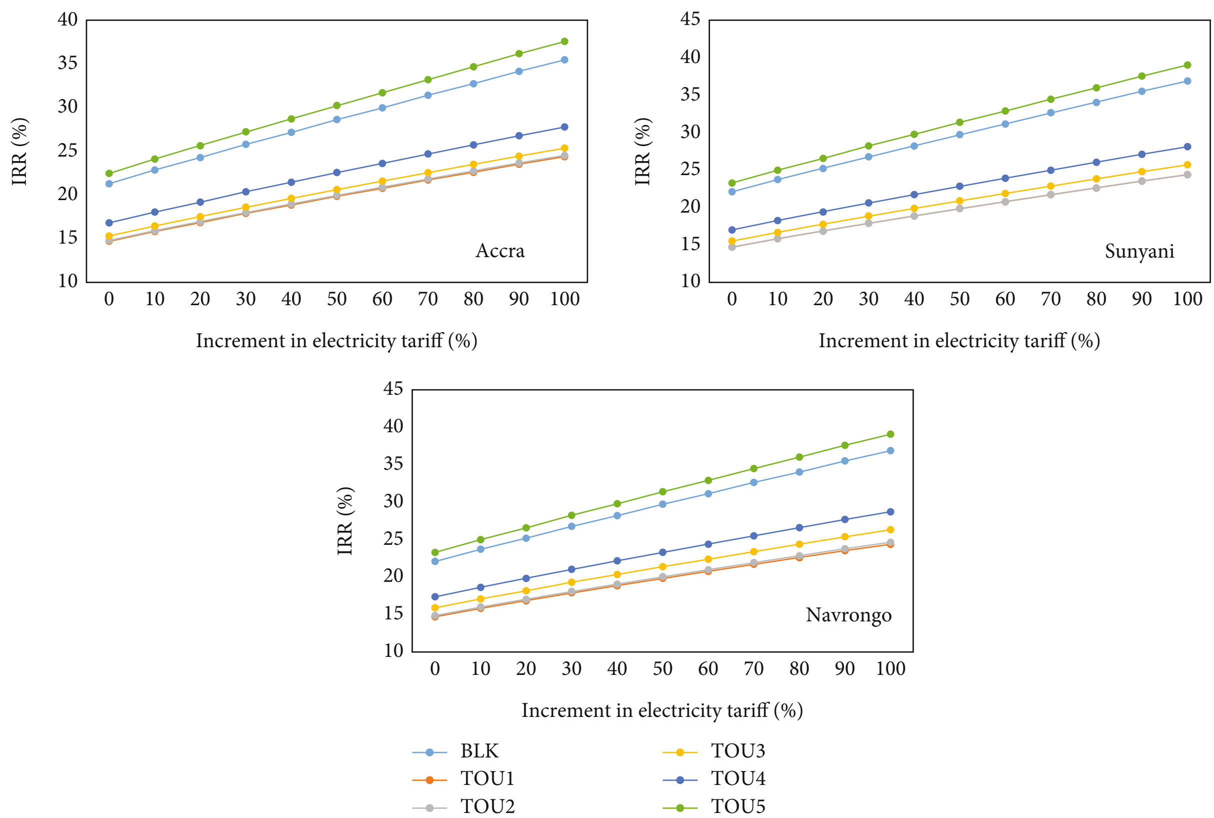

Figure 23: Impact of increasing electricity tariff on IRR for various tariff structures.

Furthermore, the general improvement in grid-tied PV system performance observed across all ToU scenarios aligns with prior research indicating that improvements in daytime consumption positively impact the performance of PV systems' economic indicators [96, 97]. Also, the superior performance of ToU5 highlights the significance of factors such as heightened daytime consumption and aligning peak demand pricing hours with solar power production hours in improving the performance of grid-tied PV system economic indicators operating under ToU structures [26].

3.2. Sensitivity Analysis. Ghana's electricity tariff structures are volatile and susceptible to rapid changes [54] (Figure 1). Therefore, this study investigated the performance of the net metering grid-tied PV systems' economic indicators under varying electricity tariffs. These tariff adjustments were systematically increased by 10%, reaching up to 100%. Figures 22–24 display the economic indicators' performance for various tariff structures under increasing electricity tariffs. The payback period for the various tariff structures under increasing electricity tariffs is presented in Table 12.

The results show that increasing electricity tariffs generally enhances the performance of grid-tied solar PV systems' economic indicators, regardless of whether they operate under block or time-of-use (ToU) tariff structures. For instance, at a 30% upward adjustment in electricity tariffs, the grid-tied PV system under ToU4 became economically viable in Navrongo, with a reduced payback period of 24.3 years. Similarly, other ToU schemes (i.e., ToU3, ToU2, and ToU1) became economically attractive as electricity tariff rates increased by 50%, 60%, and 70%, respectively. Consequently, at a 70% tariff increment, all tariff structure scenarios became economically viable, with the initial investment expected to be recouped within the 25-year lifespan of the project. These findings highlight the impact of tariff adjustments on reducing PV system payback periods, aligning with previous research [66].

Notably, net metering under the BLK and ToU5 tariff structures remained economically viable even at current electricity tariff rates. The ToU5 tariff structure yields the highest IRR, cash flows, payback time, and cash savings among the various tariff structures. With a 100% increase in the initial electricity tariff, accrued cash flow, IRR, and annual cash savings for a grid-tied PV-only system in Navrongo improved significantly, emphasising the potential benefits of increasing tariffs. Specifically, at the 100% increase in the initial electricity tariff, accrued cash flow, IRR, and annual cash savings improved from USD 447.35, 23.3%, and 435.4 USD/year to USD 3721.71, 39.07%, and 870.7 USD/year for the grid-tied PV-only system in Navrongo. A similar trend was observed for a PV system installed in Accra.

However, under the scenario of doubling electricity rates, the shortest payback period of 4.8 years was achieved in the ToU5 structure for grid-tied PV systems in Navrongo and Sunyani. Conversely, the longest payback period of 13.1 years was observed under several tariff structure scenarios, including ToU1 for systems installed in Accra, Sunyani,

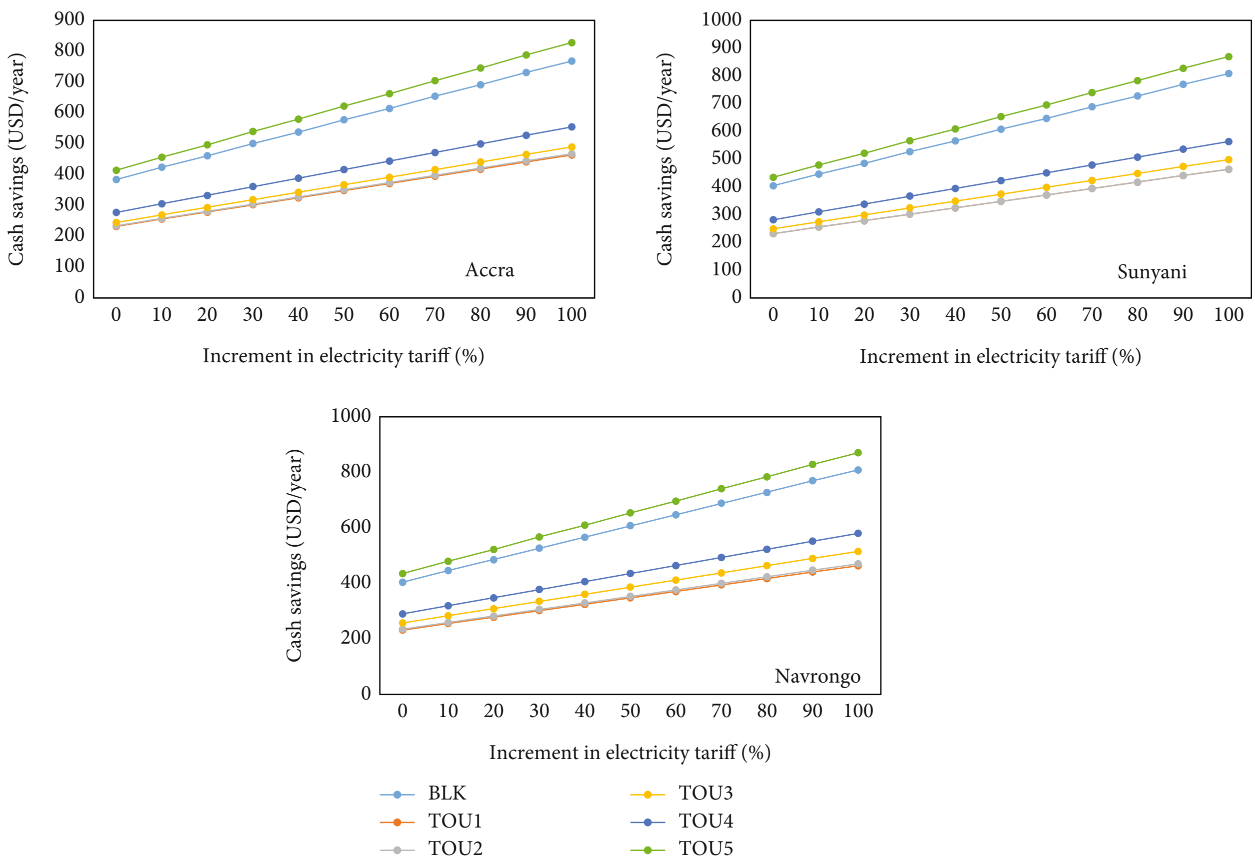

Figure 24: Impact of increasing electricity tariff on cash savings for various tariff structures.

Table 12: Impact of electricity tariff on payback periods under various tariff structures.

City	Tariff	Initial	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Accra	BLK	22.6	16.3	13.3	11.2	9.8	8.7	7.9	7.2	6.6	6.1	5.7
	ToU1	>25	>25	>25	>25	>25	>25	>25	20.3	17.2	14.7	13.1
	ToU2	>25	>25	>25	>25	>25	>25	>25	19.7	16.6	14.4	12.9
	ToU3	>25	>25	>25	>25	>25	>25	21	17.2	14.8	13	11.7
	ToU4	>25	>25	>25	>25	21.6	17.1	14.5	12.7	11.3	10.2	9.3
	ToU5	17.4	13.6	11.4	9.8	8.7	7.7	7	6.4	5.9	5.5	5.2
Sunyani	BLK	18.7	14.3	11.9	10.2	9	8	7.3	6.7	6.2	5.7	5.3
	ToU1	>25	>25	>25	>25	>25	>25	>25	20.3	17	14.7	13.1
	ToU2	>25	>25	>25	>25	>25	>25	>25	20.3	17	14.7	13.1
	ToU3	>25	>25	>25	>25	>25	>25	19.7	16.3	14.1	12.5	11.3
	ToU4	>25	>25	>25	>25	20.4	16.4	14	12.2	10.9	9.9	9.1
	ToU5	15.3	12.2	10.4	9	8	7.2	6.6	6	5.6	5.2	4.8
Navrongo	BLK	18.7	14.3	11.9	10.2	9	8	7.3	6.7	6.2	5.7	5.3
	ToU1	>25	>25	>25	>25	>25	>25	>25	20.3	17	14.7	13.1
	ToU2	>25	>25	>25	>25	>25	>25	24.8	19.3	16.3	14.2	12.7
	ToU3	>25	>25	>25	>25	>25	22	17.7	15	13.1	11.7	10.6
	ToU4	>25	>25	>25	24.3	18.4	15.2	13.1	11.5	10.4	9.4	8.7
	ToU5	15.2	12.2	10.4	9	8	7.2	6.6	6	5.6	5.2	4.8

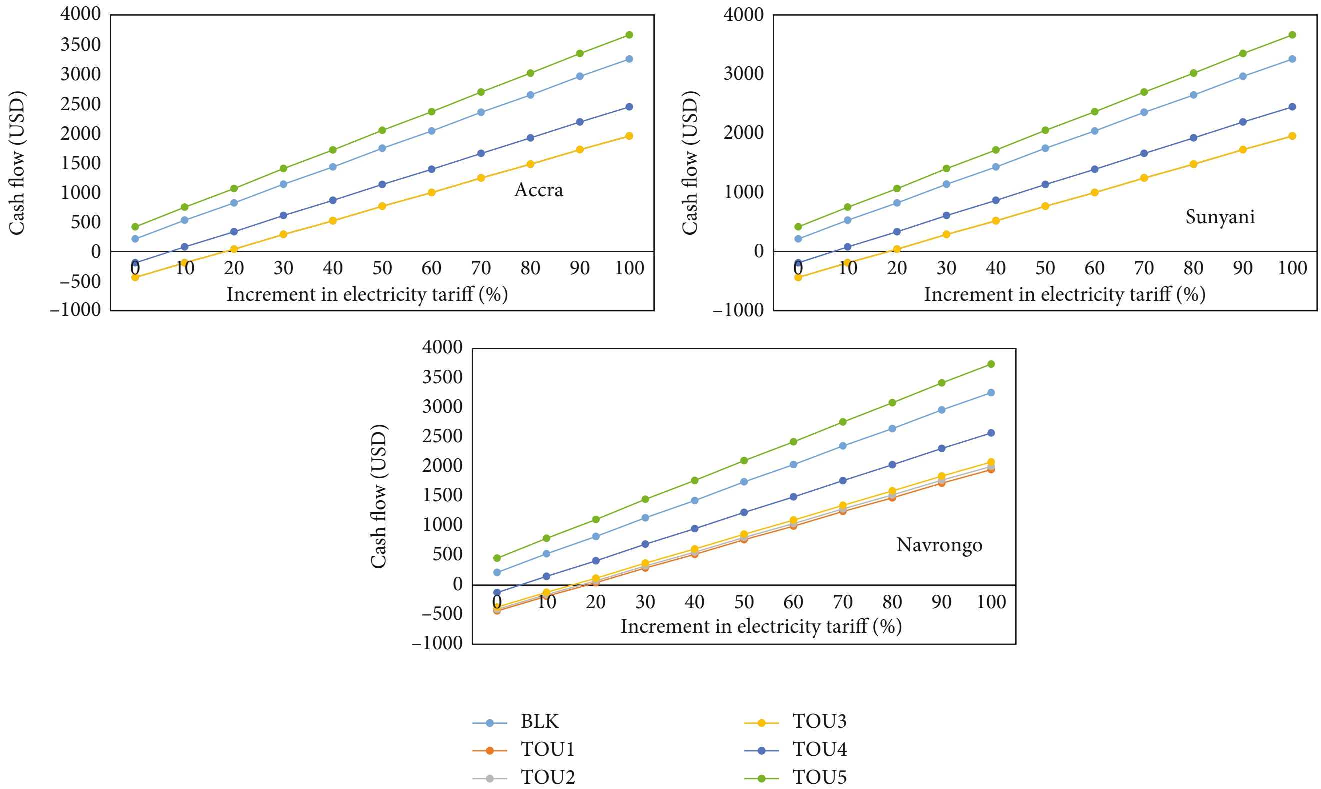

Figure 25: Impact of increasing tariff on accrued cash flows for enhanced daytime consumption scenario.

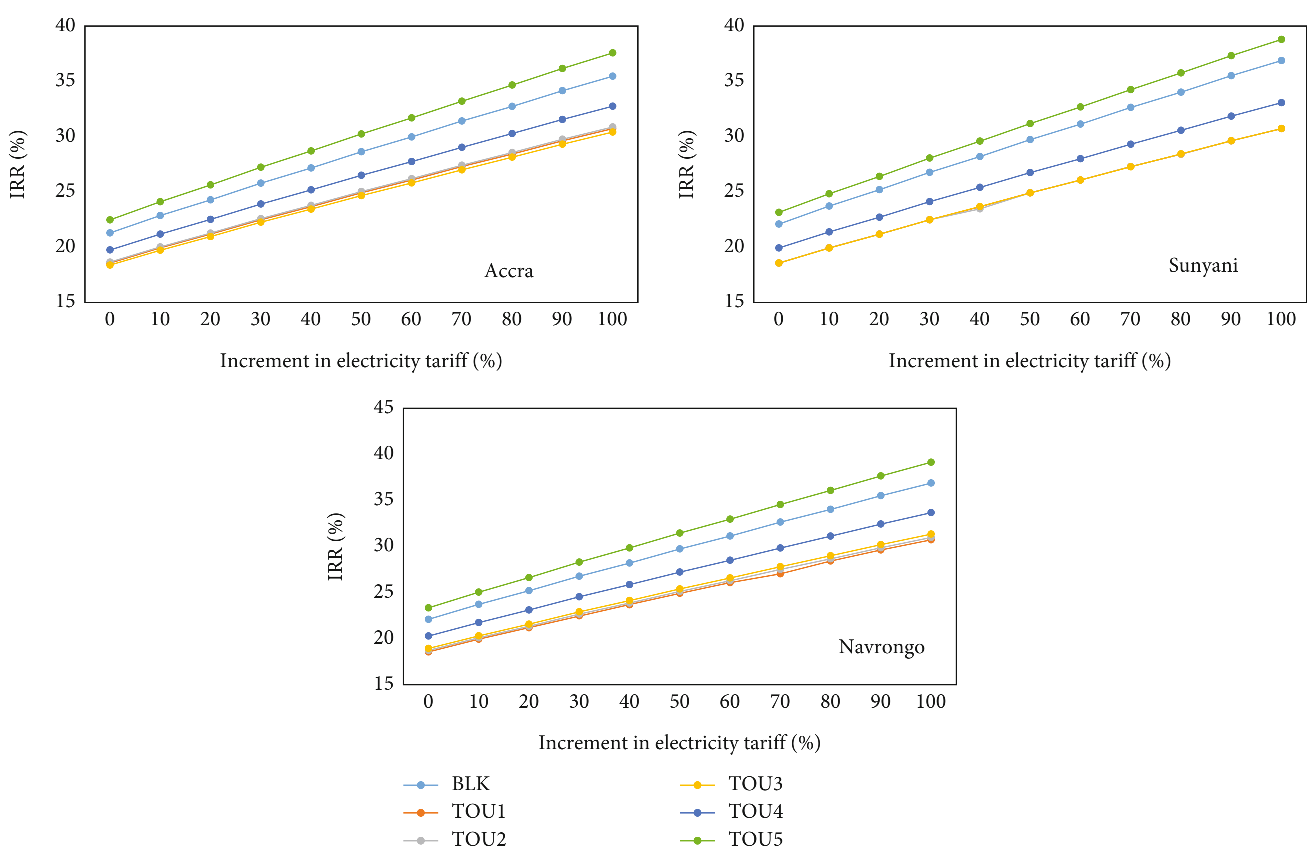

Figure 26: Impact of increasing tariff on IRR for enhanced daytime consumption scenario.

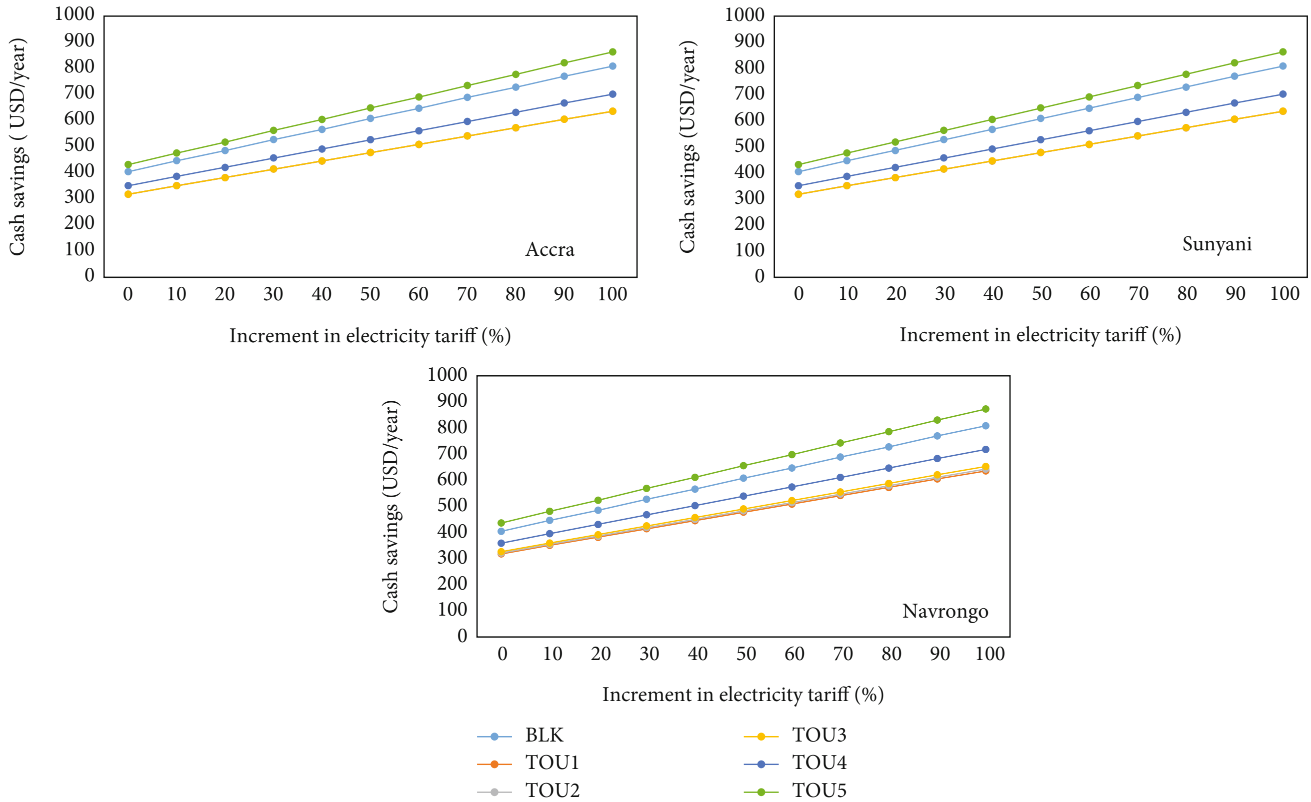

FIGURE 27: Impact of increasing tariff on cash savings for enhanced daytime consumption scenario.

and Navrongo and ToU2 for a grid-tied PV system in Sunyani. The sensitivity study also revealed the similar performance of economic indicators for system installation in Sunyani under the tariff structures ToU1 and ToU2. This similarity in the performance of economic indicators between ToU1 and ToU2 for Sunyani is attributable to the limited solar power generated during the first peak load periods.

Additionally, it is worth noting that, under the ToU2 tariff structure, the system installed in Accra exhibited better economic performance than in Sunyani despite Sunyani's superior solar resource availability. This result may be due to the higher mismatch between residential load demand and solar power generation in Accra compared to Sunyani (Table 8).

Figures 25–27 display the impact of increasing tariff scenarios on IRR, accrued cash flows, and cash savings for various tariff structures under the enhanced daytime consumption scenario. In addition, the impact of varying tariff structures on payback time under enhanced daytime consumption scenarios is shown in Table 13. The results show an improvement in daytime consumption within the initial residential load profile. This improvement significantly enhanced the system's accrued cash flows, IRR, and cash savings under ToU schemes. It can be seen that ToU4 is economically attractive, with a 10% upward adjustment in electricity tariffs for systems installed in Accra, Sunyani, and Navrongo.

Similarly, all electricity tariff structure scenarios under ToU3, ToU2, and ToU1 are economically viable with a 30% tariff increase. Comparatively, ToU4, ToU3, ToU2, and ToU1 are economically attractive with increment rates of 40%, 60%, 70%, and 70%, respectively, for the initial load profile with low daytime consumption. The ToU5 yielded the highest accrued cash flow, IRR, annual cash savings, and least payback periods of USD 3736.44, 39.14%, 872.7 USD/year, and 4.8 years, respectively. This improvement can be attributed to enhanced self-consumption, as shown in Figure 16. Improving self-consumption affects the performance of economic indicators [66].

Interestingly, under the ToU5 tariff structure for Sunyani's grid-tied solar PV system, the initial load profile outperformed the improved load profile with high daytime demand. For example, at a 50% upward tariff adjustment, the accrued cash flow, IRR, annual cash savings, and payback periods were USD 2048.63, 31.18%, 648.3 USD/year, and 7.3 years, respectively. However, the results for the system under the initial load profile were USD 2086.05, 31.36%, 653.3 USD/year, and 7.2 years, respectively. This observation might be attributed to differences in the variations of solar power generation in relation to load demand in Sunyani compared to the other locations under investigation. According to Oliva et al. [26], households benefit more from PV revenue when ToU retail tariffs align with PV generation and high electricity demand times. It could be that the high daytime load demand in Sunyani did not create an ideal match between ToU5 peak power generation and high load demand hours.

Under the high daytime consumption scenario, the longest payback period observed at the 100% upward tariff

Table 13: Impact of increasing tariff on payback period for enhanced daytime consumption scenario.

City	Tariff	Initial	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Accra	BLK	22.6	16.3	13.3	11.2	9.8	8.7	7.9	7.2	6.6	6.1	5.7
	ToU1	>25	>25	23.4	17.4	14.4	12.3	10.9	9.7	8.9	8.1	7.5
	ToU2	>25	>25	22.7	17.1	14.2	12.2	10.8	9.6	8.8	8	7.4
	ToU3	>25	>25	>25	18.1	14.9	12.7	11.2	10	9.1	8.3	7.7
	ToU4	>25	23.3	17.3	14	12	10.5	9.4	8.5	7.7	7.1	6.6
	ToU5	17.4	13.6	11.4	9.8	8.7	7.7	7	6.4	5.9	5.5	5.2
Sunyani	BLK	18.7	14.3	11.9	10.2	9	8	7.3	6.7	6.2	5.7	5.3
	ToU1	>25	>25	23.4	17.4	14.4	12.3	10.9	9.7	8.9	8.1	7.5
	ToU2	>25	>25	23.4	17.4	14.4	12.3	10.9	9.7	8.9	8.1	7.5
	ToU3	>25	>25	23.4	17.4	14.4	12.3	10.9	9.7	8.8	8.1	7.5
	ToU4	>25	22.1	16.7	13.6	11.7	10.2	9.2	8.3	7.6	7	6.5
	ToU5	15.6	12.4	10.6	9.1	8.1	7.3	6.6	6.1	5.6	5.2	4.9
Navrongo	BLK	18.7	14.3	11.9	10.2	9	8	7.3	6.7	6.2	5.7	5.3
	ToU1	>25	>25	23.4	17.4	14.4	12.3	10.9	9.7	8.9	8.1	7.5
	ToU2	>25	>25	22.3	16.8	14	12	10.7	9.6	8.7	7.9	7.4
	ToU3	>25	>25	21	16.2	13.6	11.7	10.4	9.3	8.5	7.8	7.2
	ToU4	>25	20.2	15.7	12.9	11.1	9.8	8.8	8	7.3	6.7	6.3
	ToU5	15.1	12.2	10.3	8.9	8	7.2	6.5	6	5.5	5.1	4.8

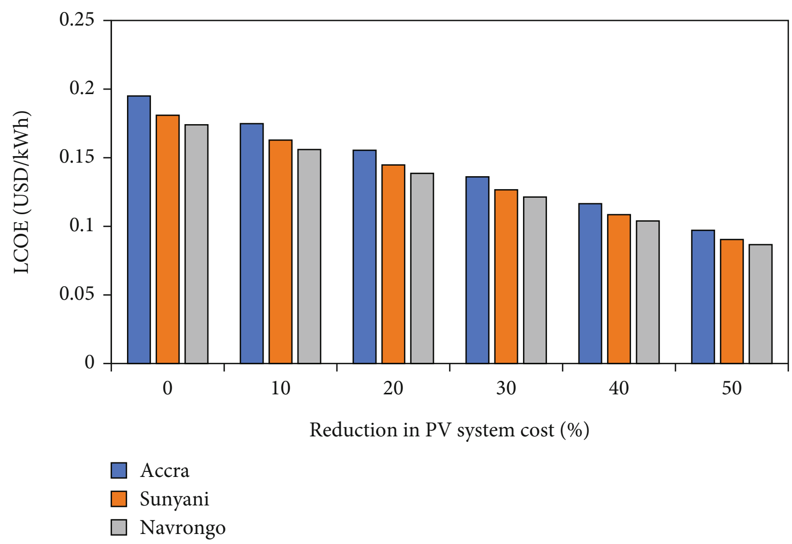

Figure 28: Impact of PV system reduction cost on LCOE.

adjustment was 7.7 years for net metering schemes under Accra's ToU3 electricity tariff structure. It is also evident that high daytime demand had a greater impact on the performance economic indicators for ToU1, ToU2, ToU3, and ToU4 than ToU5. For instance, with a 100% tariff increment for grid-tied PV systems under net metering, the payback periods were reduced from 13.1, 12.9, 11.7, and 9.3 to 7.5, 7.4, 7.7, and 6.6 years for various ToU structures. However, the payback period for the same system under ToU5 remained consistent at 5.2 years. Nevertheless, similar to the results obtained under the initial load profile, the grid-tied PV system was economically feasible even without any upward adjustment for the net metering schemes under the BLK and ToU5 tariff structures.

This study focused on electricity tariffs. However, considering the declining prices of photovoltaic (PV) systems [98, 99], a sensitivity analysis was conducted to examine the impact of these falling PV system prices on the LCOE. The results of this sensitivity analysis are presented in Figure 28. It can be observed that the LCOE of the grid-tied residential PV system reduces proportionally with the reduction in PV prices in all three cities under consideration. Specifically, a 50% reduction in PV system prices reduced LCOE by 50.2%, 50.0%, and 50.2% for PV systems in Accra, Sunyani, and Navrongo, respectively. Accra and Navrongo exhibited the highest and least LCOEs of 0.097 USD/kWh and 0.086 USD/kWh, respectively.

Historically, EUT has been generally characterised by an upward adjustment trend (Figure 1), whereas solar PV systems have generally seen a falling price trend. Further, falling price trends have been projected for solar PV systems due to factors such as technological advancements, manufacturing efficiency, and economies of scale [98]. The results presented in Figure 28, compared to the EUT trend in Figure 1, suggest that a decline in solar PV prices holds significant potential to make grid-tied PV systems competitive with utility-supplied electricity. This could make grid-tied solar PV systems economically attractive to the residential sector in Ghana.

4. Conclusion

This study provides a comprehensive analysis of the economic performance of grid-tied PV-only systems in urban homes, a critical consideration for advancing net metering initiatives in Ghana's residential sector. The study examined the existing block tariff structure and proposed two-tier time-of-use (ToU) schemes. This proposed two-tier tariff aligns off-peak and on-peak rates with the existing block tariff structure of the residential sector, facilitating its acceptance among consumers during implementation. The simulations covered three distinct climatic zones of Ghana, with Accra representing the coastal zone, Sunyani the forest zone, and Navrongo the savannah zone.

The study yielded several important insights. Firstly, results showed that the LCOE for grid-tied PV systems closely matches grid electricity costs in cities with abundant solar resources, such as Navrongo and Sunyani, particularly for consumers with monthly electricity consumption exceeding 600 kWh. However, a notable observation was that the LCOE exceeded the retail electricity tariff rates for residential consumers, with monthly consumption below 600 kWh across all three cities.

When evaluating accrued cash flow, internal rate of return (IRR), annual cash savings, and payback periods, the block tariff structure generally outperformed the proposed two-tier ToU structures in most cases. Under net metering schemes based on the current block tariff structure, financial investments were recovered within the project's lifespan, whereas the ToU-based schemes investigated did not achieve this recovery.

Nevertheless, factors such as improved daytime consumption, rising electricity tariffs, and aligning peak demand pricing hours with solar generation hours emerged as potential drivers enhancing the economic performance of net metering schemes operating under two-tier ToU pricing. The study revealed that these factors could potentially make ToU-based net metering schemes more attractive than block tariff structures in Ghana. Subsequently, the ToU-based scheme, which exclusively considered peak demand hours within solar power generation hours, emerged as the most economically favourable tariff structure for Ghana's residential sector with respect to grid-tied solar photovoltaic systems in urban homes.

It is important to note that this study does not incorporate the financial implications of modifying consumer load profiles to improve daytime consumption in the economic assessment. Additionally, the study analysis focused exclusively on net metering schemes' economic performance from the grid-tied PV prosumers' perspective. Future research should explore the performance of the economic indicators of grid-tied solar PV systems from the utility's perspective, providing a more comprehensive understanding of these systems' impact and feasibility in Ghana's evolving energy sector.

Also, Ghana is yet to implement net metering and grid-interactive solar PV systems. Therefore, this study primarily focused on grid-tied PV-only systems, which are more likely to be adopted by consumers during the early stages of net metering adoption. Further research exploring the role of energy storage systems in enhancing the economic performance of grid-tied solar PV systems could prove valuable in advancing the development of more robust grid-tied PV systems.

Data Availability

Data included in the manuscript.

Conflicts of Interest

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.

References

[1] A. K. Aliyu, B. Modu, and C. W. Tan, "A review of renewable energy development in Africa: a focus in South Africa, Egypt and Nigeria," *Renewable and Sustainable Energy Reviews*, vol. 81, pp. 2502–2518, 2018.

[2] S. Baurzhan and G. P. Jenkins, "Off-grid solar PV: is it an affordable or appropriate solution for rural electrification in sub-Saharan African countries?," *Renewable and Sustainable Energy Reviews*, vol. 60, pp. 1405–1418, 2016.

[3] P. Ortega-Arriaga, O. Babacan, J. Nelson, and A. Gambhir, "Grid versus off-grid electricity access options: a review on the economic and environmental impacts," *Renewable and Sustainable Energy Reviews*, vol. 143, article 110864, 2021.

[4] R. Opoku, G. Y. Obeng, E. A. Adjei, F. Davis, and F. O. Akuffo, "Integrated system efficiency in reducing redundancy and promoting residential renewable energy in countries without net-metering: a case study of a SHS in Ghana," *Renewable Energy*, vol. 155, pp. 65–78, 2020.

[5] J. Amankwah-Amoah and D. Sarpong, "Historical pathways to a green economy: the evolution and scaling-up of solar PV in Ghana, 1980–2010," *Technological Forecasting and Social Change*, vol. 102, pp. 90–101, 2016.

[6] IEA, "Africa energy outlook," January 2024, https://www.iea.org/reports/africa-energy-outlook-2022/key-findings.

[7] A. Afful-Dadzie, A. Mallett, and E. Afful-Dadzie, "The challenge of energy transition in the global south: the case of electricity generation planning in Ghana," *Renewable and Sustainable Energy Reviews*, vol. 126, article 109830, 2020.

[8] E. G. Lara and F. S. García, "Review on viability and implementation of residential PV-battery systems: considering the

case of Dominican Republic," *Energy Reports*, vol. 7, pp. 8868–8899, 2021.

[9] C. O. Okoye and B. C. Oranekwu-Okoye, "Economic feasibility of solar PV system for rural electrification in sub-Sahara Africa," *Renewable and Sustainable Energy Reviews*, vol. 82, pp. 2537–2547, 2018.

[10] K. Mohammadi, M. Naderi, and M. Saghafifar, "Economic feasibility of developing grid-connected photovoltaic plants in the southern coast of Iran," *Energy*, vol. 156, pp. 17–31, 2018.

[11] A. Raturi, A. Singh, and R. D. Prasad, "Grid-connected PV systems in the Pacific Island countries," *Renewable and Sustainable Energy Reviews*, vol. 58, pp. 419–428, 2016.

[12] A. Mejdalani, D. Lopez, and M. Hallack, *The Impact of Net Metering Policy Design on the Adoption Rate of Solar Photovoltaic Systems: A Simulation Using Calibrated Data from Brazil*, Inter-American Development Bank, 2018.

[13] S. Afonaa-Mensah, Q. Wang, and W. Opare, "The impact of the financial incentive levels of demand response programs on the generation cost of solar-integrated power systems," in *2019 International Conference on Power Generation Systems and Renewable Energy Technologies (PGSRET)*, pp. 1–6, Istanbul, Turkey, August 2019.

[14] B. Bayer, P. Matschoss, H. Thomas, and A. Marian, "The German experience with integrating photovoltaic systems into the low-voltage grids," *Renewable Energy*, vol. 119, pp. 129–141, 2018.

[15] E. Bruns, D. Ohlhorst, B. Wenzel, and J. Köppel, *Renewable Energies in Germany's Electricity Market: A Biography of the Innovation Process*, Springer Science & Business Media, 2010.

[16] A. Sarzynski, J. Larrieu, and G. Shrimali, "The impact of state financial incentives on market deployment of solar technology," *Energy Policy*, vol. 46, pp. 550–557, 2012.

[17] C. Cristea, M. Cristea, I. Birou, and R.-A. Tîrnovan, "Economic assessment of grid-connected residential solar photovoltaic systems introduced under Romania's new regulation," *Renewable Energy*, vol. 162, pp. 13–29, 2020.

[18] O. Ellabban and A. Alassi, "Integrated economic adoption model for residential grid-connected photovoltaic systems: an Australian case study," *Energy Reports*, vol. 5, pp. 310–326, 2019.

[19] R. Green and I. Staffell, "Electricity in Europe: exiting fossil fuels?," *Oxford Review of Economic Policy*, vol. 32, no. 2, pp. 282–303, 2016.

[20] C. Washburn and M. Pablo-Romero, "Measures to promote renewable energies for electricity generation in Latin American countries," *Energy Policy*, vol. 128, pp. 212–222, 2019.

[21] Energy Commision-Ghana, "Integrated power sector master plan for Ghana," vol. 2, 2023https://www.energycom.gov.gh/newsite/index.php/planning/ipsmp-data#.

[22] Ghana Energy Commission, "Net metering sub-code for connecting renewable energy generating systems to the distribution network in Ghana," January 2023, http://energycom.gov.gh/files/Net%20Metering%20Sub-Code%2C%202015.pdf.

[23] B. Aboagye, S. Gyamfi, E. A. Ofosu, and S. Djordjevic, "Status of renewable energy resources for electricity supply in Ghana," *Scientific African*, vol. 11, article e00660, 2021.

[24] M. Ansarin, Y. Ghiassi-Farrokhfal, W. Ketter, and J. Collins, "Cross-subsidies among residential electricity prosumers from tariff design and metering infrastructure," *Energy Policy*, vol. 145, article 111736, 2020.

[25] M. Avau, N. Govaerts, and E. Delarue, "Impact of distribution tariffs on prosumer demand response," *Energy Policy*, vol. 151, article 112116, 2021.

[26] H. Sebastian Oliva, I. MacGill, and R. Passey, "Assessing the short-term revenue impacts of residential PV systems on electricity customers, retailers and network service providers," *Renewable and Sustainable Energy Reviews*, vol. 54, pp. 1494–1505, 2016.

[27] H. Radhi, "On the value of decentralised PV systems for the GCC residential sector," *Energy Policy*, vol. 39, no. 4, pp. 2020–2027, 2011.

[28] H. Radhi, "Trade-off between environmental and economic implications of PV systems integrated into the UAE residential sector," *Renewable and Sustainable Energy Reviews*, vol. 16, no. 5, pp. 2468–2474, 2012.

[29] S. Comello, S. Reichelstein, and A. Sahoo, "The road ahead for solar PV power," *Renewable and Sustainable Energy Reviews*, vol. 92, pp. 744–756, 2018.

[30] Z. Ren, G. Grozev, and A. Higgins, "Modelling impact of PV battery systems on energy consumption and bill savings of Australian houses under alternative tariff structures," *Renewable Energy*, vol. 89, pp. 317–330, 2016.

[31] C. Bustos, D. Watts, and D. Olivares, "The evolution over time of distributed energy resource's penetration: a robust framework to assess the future impact of prosumage under different tariff designs," *Applied Energy*, vol. 256, article 113903, 2019.

[32] P. Gagnon, W. J. Cole, B. Frew, and R. Margolis, "The impact of retail electricity tariff evolution on solar photovoltaic deployment," *The Electricity Journal*, vol. 30, no. 9, pp. 22–28, 2017.

[33] M. Samper, G. Coria, and M. Facchini, "Grid parity analysis of distributed PV generation considering tariff policies in Argentina," *Energy Policy*, vol. 157, article 112519, 2021.

[34] D. Jacobs and B. K. Sovacool, "Feed-in tariffs and other support mechanisms for solar PV promotion," *Comprehensive Renewable Energy*, vol. 1, pp. 73–109, 2012.

[35] S. Young, A. Bruce, and I. MacGill, "Potential impacts of residential PV and battery storage on Australia's electricity networks under different tariffs," *Energy Policy*, vol. 128, pp. 616–627, 2019.

[36] M. Klein and M. Deissenroth, "When do households invest in solar photovoltaics? An application of prospect theory," *Energy Policy*, vol. 109, pp. 270–278, 2017.

[37] K. Say and M. John, "Molehills into mountains: transitional pressures from household PV-battery adoption under flat retail and feed-in tariffs," *Energy Policy*, vol. 152, article 112213, 2021.

[38] Á. Ordóñez, E. Sánchez, L. Rozas, R. García, and J. Parra-Domínguez, "Net-metering and net-billing in photovoltaic self-consumption: the cases of Ecuador and Spain," *Sustainable Energy Technologies and Assessments*, vol. 53, article 102434, 2022.

[39] F. Pallonetto, S. Oxizidis, F. Milano, and D. Finn, "The effect of time-of-use tariffs on the demand response flexibility of an all-electric smart-grid-ready dwelling," *Energy and Buildings*, vol. 128, pp. 56–67, 2016.

[40] W. Strielkowski, D. Štreimikienė, and Y. Bilan, "Network charging and residential tariffs: a case of household photovoltaics in the United Kingdom," *Renewable and Sustainable Energy Reviews*, vol. 77, pp. 461–473, 2017.

[41] D. S. Pereira and A. C. Marques, "How should price-responsive electricity tariffs evolve? An analysis of the German net demand case," *Utilities Policy*, vol. 66, article 101079, 2020.

[42] S. Borenstein, “The economics of fixed cost recovery by utilities,” *The Electricity Journal*, vol. 29, no. 7, pp. 5–12, 2016.

[43] A. Picciariello, J. Reneses, P. Frias, and L. Söder, “Distributed generation and distribution pricing: why do we need new tariff design methodologies?,” *Electric Power Systems Research*, vol. 119, pp. 370–376, 2015.

[44] E. Spiller, R. Esparza, K. Mohlin, K. Tapia-Ahumada, and B. Ünel, “The role of electricity tariff design in distributed energy resource deployment,” *Energy Economics*, vol. 120, article 106500, 2023.

[45] A. Mills, R. Wiser, G. Barbose, and W. Golove, “The impact of retail rate structures on the economics of commercial photovoltaic systems in California,” *Energy Policy*, vol. 36, no. 9, pp. 3266–3277, 2008.

[46] S. B. Sepúlveda-Mora and S. Hegedus, “Making the case for time-of-use electric rates to boost the value of battery storage in commercial buildings with grid connected PV systems,” *Energy*, vol. 218, article 119447, 2021.

[47] A. Hassan, Y. M. Al-Abdeli, M. Masek, and O. Bass, “Optimal sizing and energy scheduling of grid-supplemented solar PV systems with battery storage: sensitivity of reliability and financial constraints,” *Energy*, vol. 238, article 121780, 2022.

[48] R. Carmichael, R. Gross, R. Hanna, A. Rhodes, and T. Green, “The demand response technology cluster: accelerating UK residential consumer engagement with time-of-use tariffs, electric vehicles and smart meters via digital comparison tools,” *Renewable and Sustainable Energy Reviews*, vol. 139, article 110701, 2021.

[49] K. Say, M. John, and R. Dargaville, “Power to the people: evolutionary market pressures from residential PV battery investments in Australia,” *Energy Policy*, vol. 134, article 110977, 2019.

[50] G. Fridgen, M. Kahlen, W. Ketter, A. Rieger, and M. Thimmel, “One rate does not fit all: an empirical analysis of electricity tariffs for residential microgrids,” *Applied Energy*, vol. 210, pp. 800–814, 2018.

[51] AfDB and ERERA, “Comparative analysis of electricity tariffs in Ecowas member countries,” January 2023, https://africa-energy-portal.org/sites/default/files/2019-12/Electricity%20Tariffs%20Study%202019.pdf.

[52] T. Acheampong, B. O. Menyeh, and D. E. Agbevivi, “Ghana's changing electricity supply mix and tariff pricing regime: implications for the energy trilemma,” *Oil, Gas and Energy Law*, vol. 19, no. 3, 2021.

[53] E. N. Kumi, *The Electricity Situation in Ghana: Challenges and Opportunities*, Center for Global Development, Washington, DC, 2017.

[54] PURC, *A study on the trends in electricity tariffs in Ghana between 2010 and 2020*, Public Utilities Regulatory Commission of Ghana, 2022, https://www.purc.com.gh/attachment/782680-20211129071159.pdf.

[55] PURC, “2022-2025 multi-year major tariff review for natural gas, electricity and water service,” January 2023, https://www.purc.com.gh/attachment/459725-20220816110856.pdf.

[56] E. B. Agyekum, “Techno-economic comparative analysis of solar photovoltaic power systems with and without storage systems in three different climatic regions, Ghana,” *Sustainable Energy Technologies and Assessments*, vol. 43, article 100906, 2021.

[57] World Bank, *Ghana energy sector transformation initiative project*, PAD2576, 2018, February 2024, https://documents1.worldbank.org/curated/en/293271531711852754/pdf/GHANA-ENERGY-PAD-06252018.pdf.

[58] PURC, “Energy minister calls for a change in Ghana's tariff structure,” May 2023, https://www.purc.com.gh/news-det/681375209#:~:text=Matthew%20Opoku%20Prempeh%20has%20suggested,of%20a%20multi%2Dyear%20tariff.

[59] ICF International, “Partnership for growth, Ghana:TOU Tariff Analysis and Program Development,” 2015, https://pdf.usaid.gov/pdf_docs/PA00SX87.pdf.

[60] E. Bessah, W. Amponsah, S. O. Ansah et al., “Climatic zoning of Ghana using selected meteorological variables for the period 1976–2018,” *Meteorological Applications*, vol. 29, no. 1, article e2049, 2022.

[61] M. Sakah, S. de la Rue du Can, F. A. Diawuo, M. D. Sedzro, and C. Kuhn, “A study of appliance ownership and electricity consumption determinants in urban Ghanaian households,” *Sustainable Cities and Society*, vol. 44, pp. 559–581, 2019.

[62] E. L. Ratnam, S. R. Weller, and C. M. Kellett, “Scheduling residential battery storage with solar PV: assessing the benefits of net metering,” *Applied Energy*, vol. 155, pp. 881–891, 2015.

[63] H. Sebastian Oliva, R. Passey, and M. A. Abdullah, “A semi-empirical financial assessment of combining residential photovoltaics, energy efficiency and battery storage systems,” *Renewable and Sustainable Energy Reviews*, vol. 105, pp. 206–214, 2019.

[64] O. Adeoye and C. Spataru, “Modelling and forecasting hourly electricity demand in West African countries,” *Applied Energy*, vol. 242, pp. 311–333, 2019.

[65] Y. Ye, S. F. Koch, and J. Zhang, “Determinants of household electricity consumption in South Africa,” *Energy Economics*, vol. 75, pp. 120–133, 2018.

[66] S. Sewchurran and I. E. Davidson, “Technical and financial analysis of large-scale solar-PV in eThekwini municipality: residential, business and bulk customers,” *Energy Reports*, vol. 7, pp. 4961–4976, 2021.

[67] M. Z. Jacobson and V. Jadhav, “World estimates of PV optimal tilt angles and ratios of sunlight incident upon tilted and tracked PV panels relative to horizontal panels,” *Solar Energy*, vol. 169, pp. 55–66, 2018.

[68] M. O. Alhassan, R. Opoku, F. Uba, G. Y. Obeng, C. K. K. Sekyere, and P. Nyanor, “Techno-economic and environmental estimation assessment of floating solar PV power generation on Akosombo dam reservoir in Ghana,” *Energy Reports*, vol. 10, pp. 2740–2755, 2023.

[69] M. S. Adaramola, D. A. Quansah, M. Agelin-Chaab, and S. S. Paul, “Multipurpose renewable energy resources based hybrid energy system for remote community in northern Ghana,” *Sustainable Energy Technologies and Assessments*, vol. 22, pp. 161–170, 2017.

[70] D. M. Sackey, M. Amoah, A. B. Jehuri, D. G. Owusu-Manu, and A. Acapkovi, “Techno-economic analysis of a microgrid design for a commercial health facility in Ghana- case study of Zipline Sefwi-Wiawso,” *Scientific African*, vol. 19, article e01552, 2023.

[71] O. Nkuriyingoma, E. Özdemir, and S. Sezen, “Techno-economic analysis of a PV system with a battery energy storage system for small households: a case study in Rwanda,” *Frontiers in Energy Research*, vol. 10, article 957564, 2022.

[72] Natural Resources Canada, *Photovoltaic systems a buyer's guide*, Natural Resources Canada, Ottawa, 2002.

[73] Ghana Energy Commission, *Net metering sub-code for connecting renewable energy generating systems to the distribution*

network in Ghana, Ghana Energy Commission, Accra, Ghana, 2015.

[74] Bank of Ghana, "Policy rate trends," vol. 2024, 2024, https://www.bog.gov.gh/monetary-policy/policy-rate-trends/.

[75] A. K. Awopone, "Feasibility analysis of off-grid hybrid energy system for rural electrification in Northern Ghana," *Cogent Engineering*, vol. 8, no. 1, article 1981523, 2021.

[76] Trading Economics, "Ghana-bank return on equity," October 2023, https://tradingeconomics.com/ghana/bank-return-on-equity-percent-after-tax-wb-data.html.

[77] K. Branker, M. J. M. Pathak, and J. M. Pearce, "A review of solar photovoltaic levelized cost of electricity," *Renewable and Sustainable Energy Reviews*, vol. 15, no. 9, pp. 4470–4482, 2011.

[78] F. Odoi-Yorke, L. K. Osei, E. Gyamfi, and M. S. Adaramola, "Assessment of crop residues for off-grid rural electrification options in Ghana," *Scientific African*, vol. 18, article e01435, 2022.

[79] R. Fairuz, E. A. Setiawan, and I. Hernanda, "Mapping and analysis of initial cost against levelized cost of energy for residential PV rooftoop in Indonesia," *E3S Web of Conferences*, vol. 67, article 01024, 2018.

[80] A. Mohammed, A. Ghaithan, A. Al-Hanbali, A. M. Attia, H. Saleh, and O. Alsawafy, "Performance evaluation and feasibility analysis of 10 kWp PV system for residential buildings in Saudi Arabia," *Sustainable Energy Technologies and Assessments*, vol. 51, article 101920, 2022.

[81] M. M. M. Islam, A. Kowsar, A. K. M. M. Haque et al., "Techno-economic analysis of hybrid renewable energy system for healthcare centre in Northwest Bangladesh," *Process Integration and Optimization for Sustainability*, vol. 7, no. 1-2, pp. 315–328, 2023.

[82] A. Tandon, V. Mohan, and M. Jisma, "Risk adjusted optimal energy asset allocation in residential community with rooftop solar PV," in *2022 22nd National Power Systems Conference (NPSC)*, pp. 47–52, New Delhi, India, December 2022.

[83] PURC, "2023 second quarter tariff review decision for natural gas and electricity," June 2023, https://www.purc.com.gh/attachment/346435-20230517090530.pdf.

[84] S. Gyamfi, F. Amankwah Diawuo, E. Nyarko Kumi, F. Sika, and M. Modjinou, "The energy efficiency situation in Ghana," *Renewable and Sustainable Energy Reviews*, vol. 82, pp. 1415–1423, 2018.

[85] S. Gyamfi, M. Modjinou, and S. Djordjevic, "Improving electricity supply security in Ghana—the potential of renewable energy," *Renewable and Sustainable Energy Reviews*, vol. 43, pp. 1035–1045, 2015.

[86] E. F. Amankwaa, *Water and electricity access for home-based enterprises and poverty reduction in the greater Accra metropolitan area (GAMA)*, PhD Thesis, Geography and Resource Development, University of Ghana, Accra, 2017, http://ugspace.ug.edu.gh/handle/123456789/23605.

[87] B. Dye, *Structural reform and the politics of electricity crises in Ghana: tidying whilst the house is on fire?*, University of Manchester, U.K., 2022, February 2024, https://hummedia.manchester.ac.uk/institutes/gdi/publications/workingpapers/futuredams/futuredams-working-paper-013-dye.pdf.

[88] O. Rosnes and M. Shkaratan, *Africa's Power Infrastructure: Investment, Integration, Efficiency*, World Bank Publications, 2011.

[89] AfDB, "The high cost of electricity generation in Africa," January 2023, https://blogs.afdb.org/blogs/afdb-championing-inclusive-growth-across-africa/post/the-high-cost-of-electricity-generation-in-africa-11496.

[90] G. Eduful, K. Atanga, and D. Pulfrey, "Simulation study of stand-alone and grid-tied photovoltaic systems in Ghana," in *Proceedings of the World Congress on Engineering*, vol. 1p. 184, Newswood Limited, London, U.K., 190 edition, 2021.

[91] K. E. Enongene, F. H. Abanda, I. J. J. Otene, S. I. Obi, and C. Okafor, "The potential of solar photovoltaic systems for residential homes in Lagos city of Nigeria," *Journal of Environmental Management*, vol. 244, pp. 247–256, 2019.

[92] D. A. Quansah, M. S. Adaramola, and E. K. Anto, "Cost-competitiveness of distributed grid-connected solar photovoltaics in Ghana: case study of a 4 kWp polycrystalline system," *Clean Technologies and Environmental Policy*, vol. 19, no. 10, pp. 2431–2442, 2017.

[93] A. K. Onaolapo, G. Sharma, S. Sharma, and T. Adefarati, "The economic feasibility and cost reduction of grid-linked solar PV systems in South Africa," in *2022 2nd International Conference on Innovative Sustainable Computational Technologies (CISCT)*, pp. 1–5, Dehradun, India, December 2022.

[94] R. Poudyal, P. Loskot, and R. Parajuli, "Techno-economic feasibility analysis of a 3-kW PV system installation in Nepal," *Renewables: Wind, Water, and Solar*, vol. 8, no. 1, p. 5, 2021.

[95] Y. Kurdi, B. J. Alkhatatbeh, and S. Asadi, "The influence of electricity transaction models on the optimal design of PV and PV-BESS systems," *Solar Energy*, vol. 259, pp. 437–451, 2023.

[96] J. Lukuyu, M. Shiran, R. Kennedy, J. Urpelainen, and J. Taneja, "Purchasing power: examining customer profiles and patterns for decentralized electricity systems in East Africa," *Energy Policy*, vol. 172, article 113331, 2023.

[97] A. Rose, R. Stoner, and I. Pérez-Arriaga, "Prospects for grid-connected solar PV in Kenya: a systems approach," *Applied Energy*, vol. 161, pp. 583–590, 2016.

[98] International Solar Alliance, "Global trends in solar power," 2023, https://isolaralliance.org/uploads/39193a46a9b21f9a60338100ad85ab.pdf.

[99] International Energy Agency, "Trends in photovoltaic applications," T1-43: 2023, 2023, https://iea-pvps.org/wp-content/uploads/2023/10/PVPS_Trends_Report_2023_WEB.pdf.