Available online at www.asric.org
ASRIC Journal on Engineering Sciences 1 (2023) 58-71

Solar PV Electricity Supply for a Bank Office: Techno-economic and GHG Emissions Analyses

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Received 29 July 2022; revised 21 August 2022; accepted 31 August 2022

Abstract

Persisting power supply issues in Nigeria have recently stimulated reliance on hybrid renewable energy systems, especially considering their environmental benefits. Analyses of the power generation, economic and greenhouse gas (GHG) emissions reduction potentials of solar photovoltaic (PV) systems for electricity supply to a bank branch were undertaken in this study, relying on the RETScreen energy analysis tool. A prior evaluation of energy use in the branch revealed that close to 38% of existing energy loads could be avoided by implementing energy efficiency measures. Subsequent analyses investigated the techno-economic implications of deploying solar PV systems to supply either the existing branch energy loads or the energy loads after energy efficiency measures had been implemented. PV supply of between 50% to 100% of the energy loads were considered. The costs of solar PV systems needed to supply current energy loads to the branch: NGN 60 to 80 million (USD 167,000 to 222,000), reduced considerably with the energy efficiency measures – NGN 48 to 57 million (USD 133,000 to 158,000). These were also reflected in the assessments of assets IRR, equity IRR, equity payback, net benefit–cost ratio (BCR) and debt service coverage. Specifically, maximum pay back periods of roughly ten years, positive BCRs greater than 10, and generally positive debt service coverages were obtained in the analysis. The GHG emission analysis showed that the deployment of solar PV systems could provide considerable GHG emission reductions (up to 116 t CO2eq per anuum) by displacing the electricity supplied by fossil fueled grid supply and diesel generators. These results strongly suggest the economic viability of running commercial bank branches on solar PV power supply, and thus greater official focus and support for the adoption of solar PV by the commercial sector is elicited to encourage such deployments.

Keywords: GHG mitigation; Renewable energy; RETScreen; Solar photovoltaics; Technoeconomic analysis

1.0 INTRODUCTION

Reasonably priced electricity is a crucial factor in the industrialization of nations, and the attendant social upliftment and reduction of poverty [1]. Despite a population of about 180 million, the installed electric power generation capacity in Nigeria is less than 12,232 MW. Power generation hovers around 4,000 MW compared with an estimated demand of 10,000 MW [2, 3]. While Nigeria's energy generation per capita has increased from 74.13KWh in 2000 to 178.38KWh in 2013 [2], this increase of about 140.6%, compares poorly with those of contemporary nations like Cameroon (280.67%), Ghana (354.71%) or South-Africa (4,198.40%). The central grid has thus been unable to meet Nigeria's electricity demand, stunting industrial growth and compelling many homes and businesses to resort to self-energy-generation.

Nigeria is practically an energy store house, abounding with resources such as coal and lignite, natural gas, crude oil, solar, hydro etc. The availability of these vast resources notwithstanding, only four sources (coal, crude oil, natural gas and hydro) are currently utilized in processed forms while fuel wood is used unprocessed for heating, cooking and lighting [4]. Presently energy supply in Nigeria is heavily dependent on fossil fuel, providing the basis for increased attention to the development of suitable, sustainable alternative sources of energy to overhaul the energy mix of the nation.

Solar energy has become widely accepted as the energy solution for the future, based on environmental and economic sustainability considerations [5]. It is readily available and is becoming cost effective in the long run. The use of solar photovoltaics (PV) is gaining increasing acceptance in Nigeria as an energy source. To sustain this, the technical and economical implications of utilizing alternative power sources ought to be thoroughly considered, including equipment sizing, financial costs and environmental implications, since the cost of electricity generation, distribution and hence electricity supply are key determinants of technology penetration. The banking sector is a major component of the Nigerian economy and energy is required for the smooth operation of banking halls – for cooling indoor spaces for customers and staff comfort, 24-7 operation of ATMs, security systems, communication, computing, etc. Whereas most banking concerns resort to diesel generators as alternative sources of power supply, there is an obvious need for cost effective and environmentally benign alternatives to enable optimal and profitable operations.

2.0 BACKGROUND

Locations in Nigeria receive abundant insolation, as indicated by many studies [5–8], and numerous studies have been undertaken to assess potentials for solar PV power generation [6], [8–12]. The study of Njoku, [5] established that all locations in Nigeria had huge potentials for solar PV generation being capable of producing above 1000 kWh per kWp nominal capacity annually, while Adeyemo [9] estimated that a full exploitation of Nigeria's solar energy resources will yield up to 120,000 times the current grid-tied electricity produced in the country.

While availability of the solar energy resource is not in doubt, most studies have reached negative conclusions on the economics of solar PV deployments in Africa. The study of Akpan and Udoakah [13] on electricity access in the north of Nigeria, where the highest average monthly solar irradiation levels are experienced – Maiduguri experiencing 5.90kWh/m2/day, Nguru 6.12kWh/m2/day, Bauchi and Gombe 5.77kWh/m2/day, Damaturu 5.96kWh/m2/day, and Gashua 6.11kWh/m2/day – found that solar PV projects will not be economically viable at the prevailing commercial lending rates, which yielded negative net present value (NPV). The authors judged that government support through reduced lending rates and provision of start-up grants was needed to change this.

Kumi and Brew-Hammond [14] studied a 1 MW grid-connected solar PV system for the Kwame Nkrumah University of Science and Technology (KNUST), Ghana. The system was projected to annually yield about 1,159 MWh of electricity, which is about 12% of KNUST's annual electricity consumption. However, under the tariff conditions prevailing in the country, the project will only be financially viable if incentives such as grants and feed-in tariffs are provided. In Kebede's [15] study on the viability of grid-connected solar PV systems in Ethiopia, 35 locations were assessed for their technical potentials, considering a 5 MW PV power plant in each site. Whereas proposed solar PV systems had positive financial indicators that suggested their economic viability, incentive mechanisms were still needed to create sufficient attraction for commercial investors.

The seemingly weak economics of solar PV systems is hugely offset by the benefits of greenhouse gas (GHG) and air pollutant emissions mitigation, which they offer. Kumi and Brew-Hammond's study

[14] showed that electricity generation from the 1 MW solar PV plant would save about 792 tons of CO2. Khalid and Junaidi [1] also demonstrated a CO2 avoidance of 17,938 tons/year by a 10 MW PV power plant in Quetta – Pakistan. Mondal and Islam [16] showed that a minimum of 1,423 tons of greenhouse gas emissions can be avoided annually by deploying 1 MW PV plants in any part of Bangladesh. Harder and Gibson [17] showed that using solar PV to generate 24 GWh saves over 10,000 tons of GHG emissions annually in Abu Dhabi, United Arab Emirates, while Kebede [15] stated that in Ethiopia, it is possible to reduce the annual GHG emissions by at least 1,089 tons if 7658 MWh electricity were to be generated using solar PV systems.

These studies were performed with the RETScreen Clean Energy Project Analysis Software, the world's leading clean energy decision-making software, which is freely distributed by the Government of Canada [18]. This free software facilitates the identification, tabulation and analysis of all costs and life cycle of Renewable Energy Technologies (RETs) [19]. It is composed of a number of spreadsheets selected by the user depending on the selected method of analysis. Different sections of the simulation have up to two or three methods that offer the user the choice of best suited tools for any analysis [20]. RETScreen predictions of the energy production of off-grid PV systems can be used to estimate the amount by which energy production by PV would decrease the GHG emissions from traditional energy sources. When assuming that a facility is powered by non-solar PV power system, the tool uses the annual emission data obtained to estimate the air pollutant emissions that would be avoided when replaced with the PV off-grid system. Thereafter, selected economic indices obtained alongside the RETScreen emissions factors for base-case scenarios can be used to estimate the benefits of the avoided air pollutants and GHG emissions.

In the absence of studies focused particularly on PV supply to bank buildings, this study analyzed potentials for PV power supply to a bank branch. A financial analysis was carried out to estimate the economic viability of the proposed PV power supply considering two scenarios – the first in which the power requirement was based on the existing load situation in the bank branch, and the second in which energy efficiency measures have been applied to minimize the branch's power requirement. For both scenarios, six cases were further analyzed in which proposed PV systems provided between 50% and 100% of branch power requirements. Finally, the potentials for GHG emissions avoidance by all the scenarios and cases were analyzed to provide an assessment of the environmental benefits of the proposed solar PV systems.

3.0 RETSCREEN ANALYSIS

The branch of a popular commercial bank serving the University of Nigeria, Nsukka campus (latitude 6.86oN, longitude 7.33oE) was considered in this study and analyses were performed with the RETScreen energy analysis software. About thirty officials work in the case study bank branch. Power supply to the bank building is received from the local utility (Enugu Electricity Distribution Company, EEDC). However this supply is unsteady and the bank branch resorts to a diesel generator (DG) for backup supply when the grid supply fails.

Current bank branch energy use

An energy audit of the bank branch was undertaken to determine the energy consumption of different electrical appliances used within the branch. Where available, appliance power ratings were obtained from manufacturer name plates. Alternatively, they were measured with a non-contact device. The audit also reviewed records of DG fuel purchases, maintenance costs and utility payments by the branch during a one year period (March 2018 to February 2019), to determine the baseline energy expenditures of the bank branch.

Using the daily usage duration of each appliance, t_d (hours), and its energy consumption, l_i, provided by the energy audit, the weekly averaged daily electricity requirement of the branch L was calculated using Eq. 1, viz.,

$$L = \frac{1}{l}\sum l_i t_d n_d \quad (1)$$

where n_d is the number of days that appliance i operates in a 7 day week.

Electricity Production Analysis

The potential for solar PV energy production at the branch location was analyzed using the Energy Model worksheet of RETScreen software. The input data required for this analysis were the project location (latitude and longitude), solar tracking mode/mechanism, type of PV module, miscellaneous losses of array and inverters, etc.

Financial Feasibility Assessment

Next, the financial and economic viability of utilizing solar PV supplied electricity by the bank branch were analyzed. The financial analysis considered overall investment costs of the required solar PV system, including initial costs such as feasibility and design studies, development and engineering (civil, electrical and mechanical), power system costs, balance of system and miscellaneous costs, and associated periodic and maintenance costs, which included the cost of periodic change of inverters and batteries (every five and ten years, respectively). A breakdown of the PV project costs is provided in Table 1.

Table 1. Breakdown of solar pv project cost components

Cost component	**Cost description**
Feasibility study	Permits and approvals, project management, travel and accommodation
Development	Permits and approvals, project management, travel and accommodation
Engineering	PV system design, electrical design, tenders and contracting, construction and supervision
Renewable energy equipment	PV module(s), inverters, transportation.
Balance of plant:	Module support structure (batteries, tracking system), electrical equipments, system installation, construction of mini-grid, transportation
Miscellaneous:	Training, contingencies
Operation and maintenance	Property taxes/insurances, others contingencies

Prevailing economic indicators in Nigeria during the period were the needed inputs to the financial analysis, including the fuel cost escalation rate, inflation rate, discount rate, incentives and grants. Other inputs were the project life-span, debt ratio, debt interest rate and debt term. With these inputs, vital decision making financial statistics were determined, including energy payback time, debt payments, pre-tax cash flows, net present value (NPV), internal rate of return (IRR), simple payback period (SPP), annual life cycle savings, benefit-cost (B-C) ratio, debt service coverage (DSC), energy production cost and GHG emission reduction cost. The input economic parameter for the RETScreen financial analysis are given in Table 2.

Table 2. Breakdown of solar pv project cost components

Parameter	**Values**
Fuel cost escalation	11.0%
Inflation rate	11.0%
Discount rate	5.0%
Project life-span	30 years
Debt ratio	50%
Debt interest rate	15%
Debt term	10 years
Incentives and grants	0

Assessment of GHG Emissions Reduction

Finally, the GHG emissions that would be avoided by solar PV electricity supply to the branch was estimated based on the air pollutant emissions from both grid and DG electricity supply to the branch. These were used with the economic indicators for the PV supply case to determine the benefits of the avoidable air pollutants and GHG emissions.

4.0 RESULTS AND DISCUSSION

Energy Use in the Branch

The summary of appliances and their associated power consumption ratings are shown in Table 3. The weekly averaged daily amount of electricity required by the branch was obtained as 474.40 kWh using Eq. (1). Energy efficiency measures were identified for all appliances, such as the use of less-energy consuming replacements, regular servicing, behavioral changes, etc. The levels of achievable reduction in energy requirements and the power ratings estimated for the energy efficient appliances are also given in Table 3. The weekly averaged daily load required for the proposed case was obtained to be 294.46 kWh using Eq. (1). Comparing the total energy requirement of the base and energy efficient scenarios, we find that a 37.9% reduction in energy requirements could be achieved in the bank branch by just implementing energy efficiency measures.

Table 3. Branch load specifications used as inputs to the energy model worksheet

Description	**No. of units**	**Hours of use per day**	**Base load (W)**	**Days of use per week**	**Achievable load reduction**	**Energy Efficiency load (W)**	**Load reduction (W)**
Light bulbs	116	11.00	4640	5	63%	1716.8	2923.2
Security lights	10	12.00	1200	7	75%	300	900
Air Conditioners	21	11.00	33517	5	40%	20,110.2	13406.8
Micro-Wave Oven	1	2.00	1100	5	15%	935	165
Fridge	1	11.00	100	5	30%	70	30
Computers	21	11.00	2325	5	15%	1976.25	348.75
Cable TV	1	14.00	160	5	60%	64	96
ATMs	5	20.00	2850	7	15%	2422.5	427.5
Hand Driers	3	2.00	2160	5	35%	1404	756
Systems Room	1	20.00	120	7	30%	84	36
Scanners,copiers & printers	1each	11.00	1265	5	30%	1227.5	379.5
Man-Trap-Doors	2	11.00	556	5	20%	444.8	111.2
Water Dispensers	1	11.00	1265	5	20%	1012	253
Total			51,258				19,832.95

Energy Costs of the Branch

The costs of energy provision for the branch (utility bills and diesel purchases) are shown in Table 4, as determined from the energy survey. The unit price of diesel was USD0.67 (₦240) per liter. Besides these are the cost of the diesel generator (USD 19,450 or ₦7,000,000.00) with a maximum live span of ten years (hence, USD1,945 or ₦700,000.00 per year) and the cost of generator maintenance: USD1,670 (₦600,000.00) annually. Thus the total annual operation and maintenance cost of the DG alternative power supply was USD9,630 (₦3,476,080.00), resulting in a total sum of USD16,720 (₦6,019,535.25), as the annual cost of electricity supply to the branch.

For the project site at latitude 6.3^{o}N and longitude 7.5^{o}E, the annual average daily insolation received was about 4.92kWh/m2/day on horizontal surface and 4.96kWh/m^{2}/day if PV modules are tilted to the local latitude angle. While one axis and two axes tracking surfaces receive about 5.97kWh/m^{2}/d and 6.13kWh/m^{2}/d insolation, respectively. From the insolation data provided for this location by the RETScreen tool (Table 5), the highest average global daily radiation on the horizontal is experienced in February, and the least value in August [28]. Of the solar tracking options available in the RETScreen Energy Model, fixed tilt PV arrays are less costly, due to the absence of the associated cost of sun tracking mechanisms incurred with the other systems [1]. The fixed tilt array with a south-facing orientation was therefore chosen.

Table 4: Annual branch expenditure on energy bills for mar., 2018-feb., 2019

Months	E.E.D.C Bills (₦)	Diesel Consumption (Litres)	Diesel Costs (₦)	Total Monthly Energy Costs (₦)
March	269,896.00	547	131,280.00	401,176.00
April	250,039.49	686	164,640.00	414,679.00
May	180,803.64	1148	275,520.00	456,323.64
June	145,804.78	563	135,120.00	280,924.78
July	136,947.93	1243	298,320.00	435,267.93
August	203,326.72	1024	245,760.00	449,086.72
September	188,422.44	490	117,600.00	306,022.44
October	188,422.44	898	215,520.00	403,942.44
November	199,484.35	1067	256,080.00	455,564.35
December	230,897.25	748	179,520.00	410,417.25
January	274,705.35	552	132,480.00	407,185.35
February	274,705.35	101	24,240.00	298,945.35
Total	2,543,455.74	9,067	2,176,080	4,719,535.25

Photovoltaic Modules and Inverters

Table 5: Average Monthly Solar Irradiation and Ambient Temperature for the Study Location [28]

Months	Daily solar radiation – horizontal (kWh/m²/d)	Daily solar radiation – tilted (at the latitude angle)	Earth temperature (°C)
January	5.68	5.94	27.9
February	5.74	5.90	28.4
March	5.57	5.61	27.5
April	5.25	5.19	27.1
May	4.94	4.82	26.8
June	4.54	4.40	25.6
July	4.14	4.04	24.8
August	3.91	3.86	24.8
September	4.19	4.18	24.9
October	4.57	4.65	25.2
November	5.11	5.30	25.3
December	5.46	5.74	26.2
Annual	4.92	4.96	26.2

Commercial crystalline PV modules were selected because of their superior age derating proporties [1]. The Sanyo mono-Si-HIP-205BA3 module model, with characteristics given in Table 6, was selected. The peak power demands obtained from the RETScreen analysis of the base and the energy efficient load scenarios were 192,290 W and 119,310 W, respectively. The number of PV modules required for both load scenarios was obtained by dividing the peak power demands by the PV module peak rated output (205 Wp). These are presented in Table 6, alongside the numbers of panels required for cases in which 50%, 60%, 70%, 80%, 90% and 100% of the power supply to the branch was supplied by solar PV.

Table 6: Selected Module Specifications

Module model	Sanyo model of mono-Si-HIP-205BA3			
Nominal capacity	$205W_p$			
Area size	$1.18m^2$			
Module efficiency	17.4%			
Unit price	USD 125 (NGN45,000.00)			
Life Span	30 years			
Nominal cell operating temperature	45 °C			
Temperature coefficient	0.40 % / °C			
	Total area covered		**Number of modules**	
Percentage solar PV coverage	**Base load**	**EnEff load**	**Base load**	**EnEff load**
100%	1106	686	938	582
90%	366	538	735	456
80%	756	467	639	396
70%	651	403	552	342
60%	549	341	466	289
50%	449	278	381	236

The capacity of the inverters considered was chosen in accordance with the peak load required, hence, an inverter with rated capacity of 48.33kW is required. For this reason, 50kW MPPT inverters with 95% conversion efficiency were selected. Though inverters having higher efficiencies are commercially available, the efficiency chosen in this study was to ensure high reliability. The occasional replacement of the inverters was reflected as periodic costs in the subsequent financial analysis..

The system's battery bank was selected to consist of 48V, 250Ah capacity batteries, connected in a parallel arrangement, giving a 48V battery string of 1250Ah storage capacity. Considering the electrical load of the branch, the battery efficiency (85%), maximum depth of discharge (80%), and for two days of autonomy, the battery storage capacity determined for the base load and the energy efficient load scenarios are given in Table 7. In the subsequent financial analysis, a unit battery cost of USD315 (₦113,280.00) was used, based on the survey of prevailing commercial prices.

Losses in the PV power systems, which affect system energy outputs were fixed at 5%. These losses may occur as a result of module mismatch, system operating temperatures, dust/dirt deposition on modules (soiling), DC to AC conversion losses in the inverter, etc.

Table 7: Configuration of Battery Storage for the Analyzed PV Systems

Case	**Load**	**Battery storage capacity**	**No of batteries strings**	**Total number of batteries required**
Base	474.40 kWh	28,246 Ah	$\frac{28{,}246\,Ah}{1{,}250\,Ah} = 22.5968 \approx 23$	115
Energy efficient	294.46 kWh	17,527 Ah	$\frac{17{,}527\,Ah}{1{,}250\,Ah} = 14.0216 \approx 15$	75

The energy delivered to the branch by the solar PV system is shown in Fig. 1 for all the solar PV coverage cases considered. The plot shows that the system designed for the based load will deliver more energy to the branch than the system designed for the energy efficient load. Whereas the energy delivered for both scenarios increases with the solar PV coverage, the increase is steeper for the base load scenario.

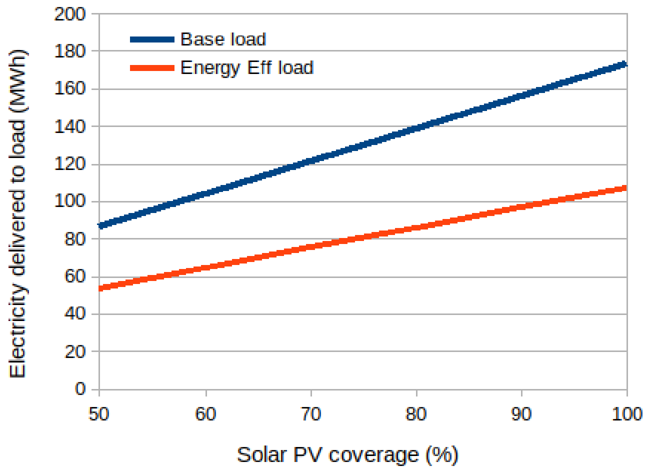

Figure 1. Annual Electricity delivered to load for different levels of solar coverage for the two scenarios

Financial Analysis

The 38% reduction in the branch energy load due to the introduction of energy efficiency measures (see Table 3) led to power system cost savings of USD58,930 (₦21,215,286.00). Under the energy efficient load scenario, for the case of 100% solar PV coverage, total system costs were estimated to be USD157,440 (₦56,678,612.00), while periodic costs of batteries, inverters and charge controllers amounted to USD71,505 (₦25,742,000) (for the system's life-span). These summed up to a total system cost USD228,950 (₦82,420,612.00) over the entire system lifespan. Dividing this by the 30 year system life span gave an estimated annual cost of USD7,631 (₦2,747,353.73) which was significantly less than the USD16,720 (₦6,019,535.74) presently being spent annually to provide the energy to the bank. Thus annual savings of USD9,090 (₦3,272,182.01) could be achieved by the branch by using the solar PV power system – a total of USD272,680 (₦98,165,460.20) over the 30 years life span of the project. If similar savings are replicated for other branches of the bank, the reduction in energy expenditure by the bank nationally can then be appreciated. Considering prevailing energy escalation rate, inflation rate, and the current global downward trend in PV system costs, these savings can only increase going forward.

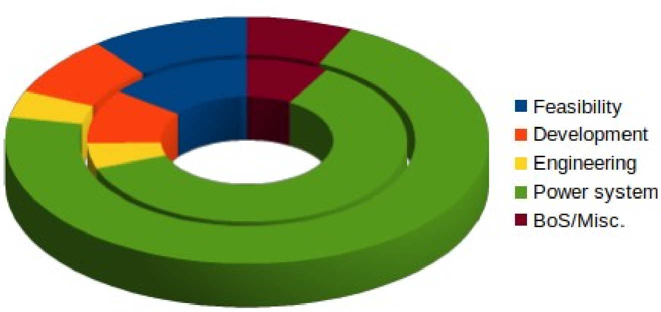

Figure 2. Initial and periodic costs of different levels of PV power plant coverage for Cases 1 and 2

The breakdown of the total cost into feasibility, development, engineering, power system and balance-of-system / miscellaneous costs are shown in Fig. 2. The ratios of the cost components are similar for both load scenarios – the feasibility, development, engineering costs are identical for both scenarios, while the major cost components are the power system (PV module) costs.

Total energy provision and total power system costs for the branch at different levels of solar PV coverage are shown in Fig. 3; both costs increased with increase in the solar PV coverage. However, for the energy efficient load scenario, both the power system and total costs showed a slight reduction as the solar PV coverage* increased from 90% to 100%. Diesel generators of different capacities (and hence costs) are required for both scenarios when the solar PV coverage is less than 100%. As the PV coverage increases from 90% to 100%, power system costs are reduced due to the exclusion of the diesel generators. In the base load scenario, this reduction is completely offset by the cost of the extra solar PV modules required. However, because of the reduced load for the energy efficient scenario, the cost of the additional PV modules needed for 100% solar coverage is much less than the diesel generator cost, hence the drop in the total costs.

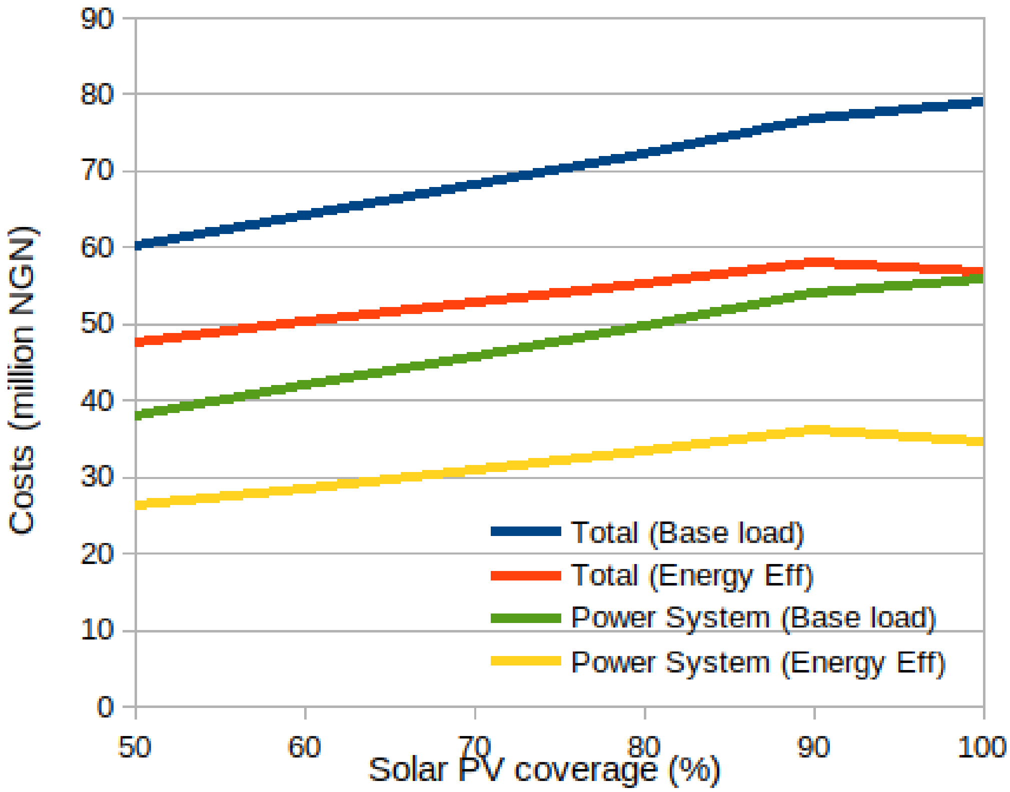

Figure 3. Total energy provision and total power system costs

Positive cash flows were predicted to be four years earlier for energy efficient scenario than for the base load scenario as shown in Figs. 4(a) and (b). The cumulative cash flow plot for the base load scenario in Fig. 4(a) indicates that roughly 10 years will be required before cash inflows become positive, whereas only 6 years will be required for the energy efficient case (Fig. 4 (b)). The periodic depressions in the cash inflows observed in both CCF plots (every 10 years) were due to the periodic costs of replacing batteries and inverters.

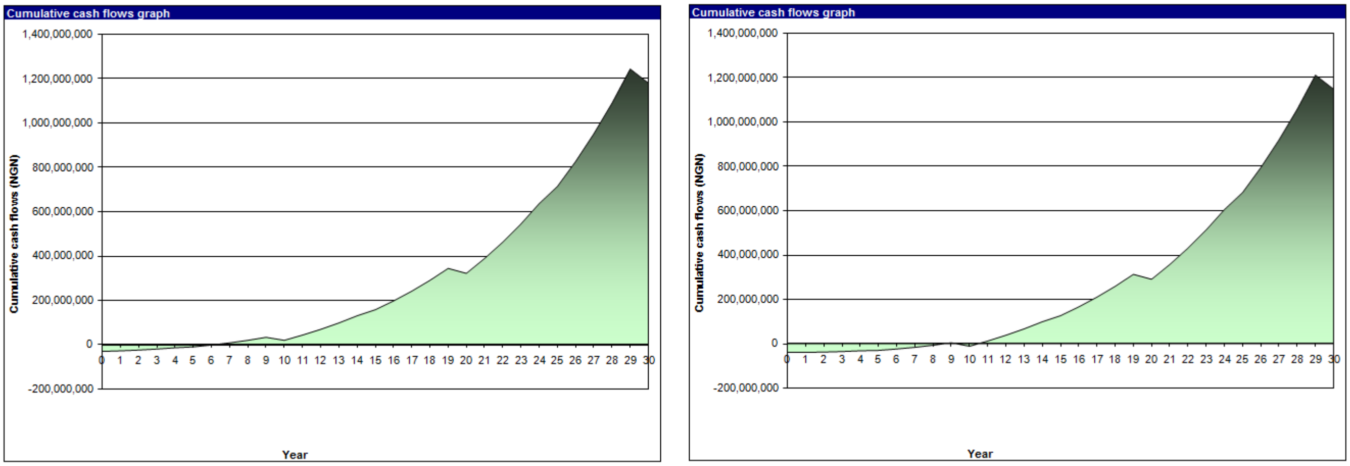

Figure 4. Cumulative cash flows for 100% solar PV power coverage, (a) case1 with 10yrs positive cash flow; (b) case2 with 6yrs positive cash flows

The estimated internal rates of return (IRR) on both equity and asset are shown in Fig. 5. For both base and energy efficient scenarios, Fig. 5 shows that the IRRs increase as the contributions of solar coverage increase. For the base case, the highest IRRs – 20.3% (equity IRR) and 14.9% (assets IRR), were obtained for the 100% solar PV coverage. These were lower than the equity and assets IRRs for the energy efficient scenario, which was estimated as 26.5% and 18.8%, respectively.

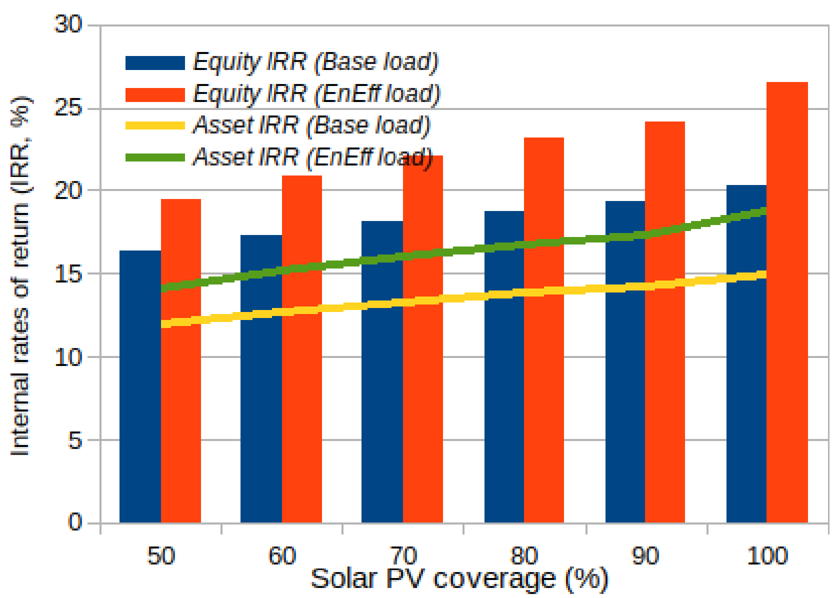

Figure 5. IRR ON EQUITY for different levels of solar coverage of the two scenarios

The payback periods, which shows how quickly the capital invested on the project is recovered, are shown in Fig. 6. The shortest payback periods were for the 100% solar PV coverage case of the energy efficient load scenario, which had just

7.6 and 5.9 year simple and equity payback periods, respectively. The payback periods increased with decreasing solar PV coverage up to that for the 50% coverage with payback periods of 10.2 years (simple) and 8.4 years (equity).

This trend, which was unexpected since the total system costs increased with solar PV coverage (Fig. 3), was similarly displayed by the pay back periods for the base load scenario. It was caused by the fact that some costs associated with grid/DG power supply do not change even when the contribution of grid/DG power supply is decreasing. E.g., cost of DG plant and periodic maintenance. Hence though the total cost of the PV systems increase as solar PV coverage increases, the reduction in grid/DG power costs is not corresponding, leading to decreasing payback periods.

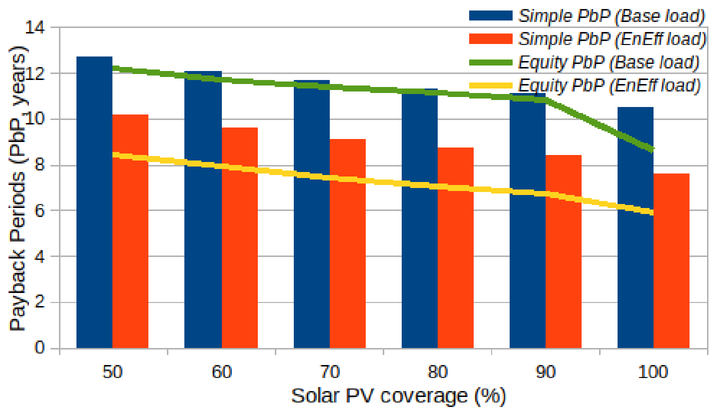

Figure 6. Simple Payback periods for different levels of solar coverage of the two scenarios

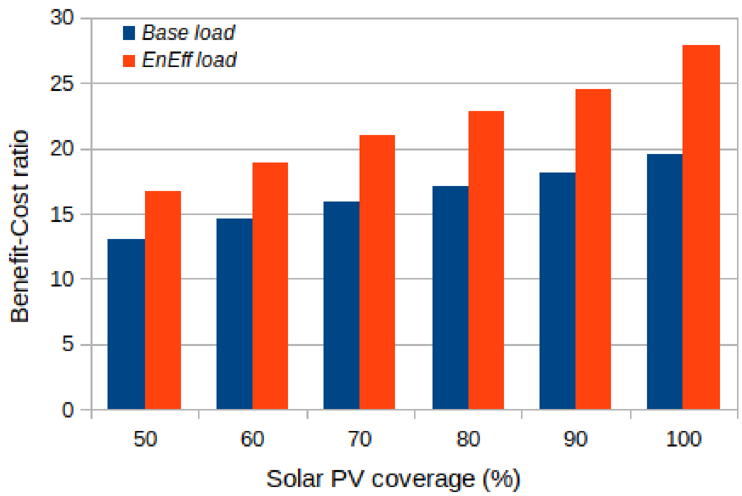

Figure 7. Benefit-Cost ratio for different levels of solar coverage, of the two scenarios

Ideally, any value of the Benefit-Cost ratio greater than unity, is considered to be good and indicates a worthwhile investment. Thus Fig. 7 shows that all solar PV coverage cases for the two scenarios considered were capable of generating the required cash flows needed to service their costs. The values are particularly interesting considering the significant systems costs estimated by the financial analysis. The debt service coverage (Fig. 8) was also found to be generally positive and very strong for the two scenarios considered, though higher for the energy efficient load scenario. (Any positive value is generally considered as acceptable.) This established the project viability of all the cases except the 50% solar coverage case of the base load scenario. This case had a negative debt service coverage, indicating that the cost savings obtainable with the case will not sufficient to offset the credit payments under the credit conditions specified for the study (see Table 2). Comparing the two scenarios, even the worst case for the energy efficient scenario (1.09 at 50% solar coverage) was stronger than the best base load scenario case with a debt service coverage of 1.06.

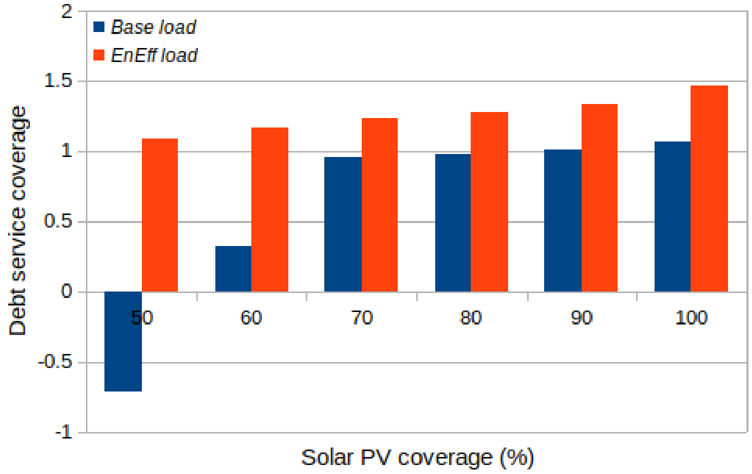

Figure 8. Debt service coverage for different levels of solar coverage, for the two scenarios

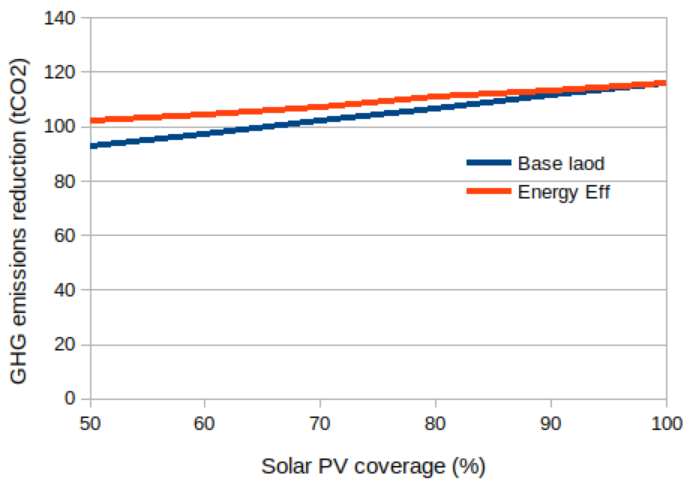

Figure 9. GHG emission reductions for different levels of solar PV coverage for case 2

Greenhouse Gas Emission Analysis

The amount of green house gas (GHG) that could be avoided as a result of solar PV power was calculated, with diesel specified as the base fuel source. The GHG emission reductions that were obtained for the different cases are Fig. 9. As with the previous results, the GHG reductions increased monotonically with increasing solar PV coverage. This was highly anticipated since any situation short of 100 percent solar electricity generation will be characterized by the introduction of diesel generated electricity with the associated associated GHG emissions. The highest avoided GHG emissions were estimated for the 100% solar PV coverage cases – 116 tons of CO_2 for the energy efficient load scenario and 116.1 tons for the base load scenario. This is equivalent to not using 21.2 car and light trucks or 3480 tons of CO_2 for the entire project life-span. When aggregated for branches of the bank nationwide, the GHG emission reductions will represent a significant greening of Nigeria's financial sector.

5.0 CONCLUSION

In order to aid investors and decision makers and to show the feasibility of running a bank branch on solar PV power supply, a project viability analysis has been performed using the RETScreen energy analysis software. Electricity production, financial and GHG emission reduction estimates were obtained. The results of the financial analysis showed that solar PV electric power supply to a bank branch will be profitable. This is concluded based on evaluations of energy production costs, assets IRR, equity IRR, equity payback, net benefit–cost ratio (BCR) and debt service coverage. Specifically, maximum pay back periods of roughly ten years, positive BCRs greater than 10 and generally positive debt service coverages were obtained in the analysis. In addition to profitability, the environmental impact of the proposed PV power were also evaluated through a GHG emission analysis, which showed that large amounts of GHG emissions would be avoided with the implementation of the proposed systems. The new insights provided by this study strongly suggest the possibility of running commercial bank branches on solar PV power supply. Further scenarios, including branch sizes and location are recommended for further studies to firmly establish the use of solar PV power systems for electricity supply to bank branches.

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