

Analysis of long-term performance and reliability of PV modules under tropical climatic conditions in sub-Saharan

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ABSTRACT

Reliability assessment of Photovoltaic (PV) modules is very crucial to increase the service lifetime of PV systems. This study assesses the degradation rate and reliability of PV modules operated for twelve years under the tropical climatic condition in sub-Saharan. For this purpose, various characterization techniques, namely visual inspection, infrared (IR) thermography assessment, and current-voltage (I-V) characterization, have been employed to evaluate the performance of PV modules. Moreover, the functioning of bypass diodes has been tested under partial shading situations. The results demonstrate that after twelve years of outdoor operation, the short-circuit current (I_{sc}) of modules have been degraded up to 16.4% with an average decrease of 11.7% compared to the nameplate values. The open-circuit voltages (V_{oc}) were reduced from 11.4% to 17.1% with a mean of 14.8%. The decline in Fill Factor (FF) of the modules ranges from 11.3% to 24.2%, and the losses of power output were between 34.5% and 41.4%. Moreover, the visual and thermography assessment reveals that the PV modules are severely affected by various failures such as EVA browning, cell interconnects ribbons browning and the corrosion of solder bonds. The results show that averagely, the FF is the most significant factor influencing the loss in the power output of the modules.

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1. Introduction

The global PV plants' capacity is being increased dramatically, and the reliability and performance assessment of PV systems are more crucial in the upcoming years. PV modules as the main component of PV systems are exposed to various environmental and climatic conditions during their lifespan. Therefore, the performance of PV modules should be monitored and evaluated continuously. The number of years given as a warranty by most PV manufacturers is about 25 years for 80% peak power output of PV modules [1]. This warranty provides for 90% of peak power output in the first ten years and 80% peak power output until 25 years [2]. Typically, warranties are begun from the day of installation and range from five years to twenty-five years, depending on the company [3,4]. It is intended that all modules will meet the manufacturers' warranty under the operation conditions.

Authors in Ref. [3] have outlined two types of warranties for PV modules, namely performance warranty which assures output efficiency and product warranty that guarantees for non-failure over the given period. Fig. 1 shows warranty durations for PV modules offered by some leading PV manufacturers as of the year 2018 [1]. The extended warranty given by most manufacturers presupposes the expected high reliability of the PV modules. However, during the lifetime operation of large PV systems, it is unfeasible to determine the output power of a single module, leading to fewer module returns for power output loss [3].

The lifespan and the reliability of PV modules depend on the degradation and failure modes which may be created during PV module production, transportation and installation. However, weather and environmental conditions have the main effects on the performance of PV systems, and different failures can occur in the PV modules during their lifetime. Temperature, solar irradiance, wind, snow, hail, dust, humidity, water and corrosive gases are the main stress factors which degrade the PV modules even in the short period [5,6].

PV systems can become the most cost-effective energy source if

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Nomenclature

Symbol Description Unit

I_{sc}	Short circuit current A
V_{oc}	Open circuit voltage V
P_{mpp}	Maximum power Wp
FF	Fill factor
STC	Standard test condition
α	Temperature coefficient of current %/°C
β	Temperature coefficient of voltage %/°C
δ	Temperature coefficient of power %/°C
GHI	Global horizontal irradiance kWh/m ² /d
DHI	Diffuse horizontal irradiance kWh/m ² /d

G1	Measured irradiation W/m ²
G2	Reference irradiation W/m ²
I_1	Measured current A
V_1	Measured voltage V
I_2	Corrected current A
V_2	Corrected voltage V
$I_{sc,1}$	Measured short circuit current A
$V_{oc,1}$	Measured open circuit voltage V
$I_{sc,2}$	Corrected short circuit current A
T_c	Temperature of module °C
a	Correction factor of irradiance
$\mu_{V_{oc}}$	Temperature coefficient of open-circuit voltage V/°C
c-Si	Crystalline silicon
pc-Si	Polycrystalline silicon

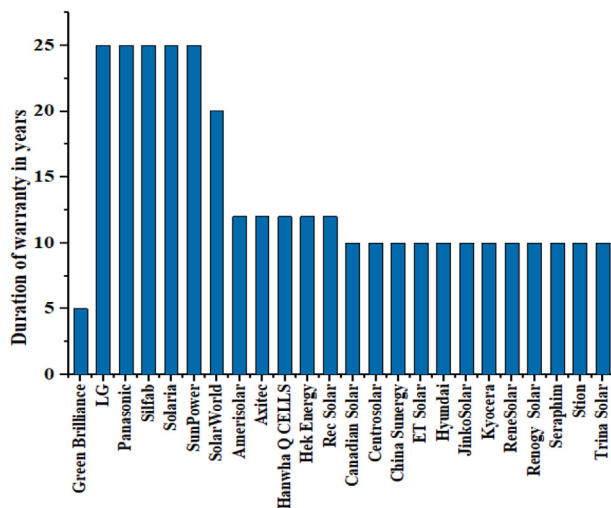


Fig. 1. Warranties given by PV module manufacturers [4].

they reliably generate the expected power output all their lifespan whiles in operation, notwithstanding the location and associated issues [7]. PV modules are tested and certified according to various national and international standards and instructions (e.g. IEC 61215) to guarantee the quality, reliability and durability of PV modules for the period of warranty. These tests aim to unveil any design and manufacturing gaps, which can lead to early malfunction or failure during the first years of operation [8]. However, these standard tests have only been developed based on a set of conditions. Hence, they are not able to verify the quality of the PV modules under various climatic and environmental conditions. Therefore, the PV modules must be monitored and assessed during the operation in order to keep their service life for more extended periods [8]. The IEC 61215 standard of testing for degradation requires only total irradiation of 15 kWh/m² of UV energy [9]. With this requirement, modules pass the test. However, under real operation conditions, some modules have the potential of 5% or more power degradation and browning of encapsulant material just under UV radiation of 150 kWh/m² or more [9].

Much effort has been devoted by scientists to develop different PV modules' technologies which are suited for various geographical regions and climates to reduce the degradation rate [7].

The most common failures like corrosion, light-induced degradation (LID), delamination, discolouration, yellowing, bubbling,

snail trails, hot spots, cell and glass breakage, loss in interlayer adhesion and interconnects micro-cracking and cracking can be created on the PV modules due to the aforementioned weather and environmental conditions. These failures and defects effect on the performance and reliability of PV systems and increase the losses in power output [10].

In the literature, various statistical methods like Linear Regression (LR), Classical Seasonal Decomposition (CSD), Auto Regressive Integrated Moving Average (ARIMA) and, Locally Weighted Scatterplot Smoothing (LOESS) have been reported to determine the degradation rate of PV modules [11,12]. However, these methods have not shown a guaranteed way to assess the degradation precisely, due to uncertainty of the measurement instruments, the data acquisition and translation, the data filtering techniques. Therefore, this issue causes an overestimating or underestimating the actual degradation rate of the PV module [12].

The decline in power output of c-Si PV modules was determined to be around 1.1% per year in the desert region [13].

Carr et al. [14] have evaluated the output of different PV technologies from different manufacturers in Australia after 16 months of operation. The results have shown that c-Si modules have a power degradation up to 2%/year. Moreover, there was an unusually high power reduction in thin film modules, 12% and 8.5% below the rated power for a-Si and CIS, respectively. Dubey et al. (2017) [15] also evaluated the performance of PV modules in six different climatic zones of India. The degradation rate for c-Si was estimated at around 2.46%/year for the modules at the first five years, whereas the PV modules operated for more than five years have been degraded around 1.92%/year. This is because the modules with less operation can be degraded faster due to the excessive stress caused by the high number of expansion-contraction cycles [15].

A review conducted by Jordan and Kurtz, (2011) on installations in India, shows degradation rate of thin film and Si only PV modules reaching to an average of 1.5%/year and 0.7%/year respectively [16]. However, there is still no sufficient studies for tropical climates and harsh environmental conditions which have a negative impact on the performance of PV modules [17,18]. This study assesses the long-term reliability and performance after twelve years operation of monocrystalline PV modules in an off-grid PV system which was exposed under the tropical climatic condition in sub-Saharan of Ghana. The characteristics of the modules have been determined and normalized at standard test conditions using derived translation equations. Results are then compared with various applied procedures whiles the influence of module parameters on the variation of the nominal power is evaluated applying the regression analysis.

2. Experimental setup

In this experimental research, an off-grid PV system has been installed at Koforidua in the Eastern Region of Ghana, which is located in sub-Saharan with hot and humid climate [19]. The climate of Koforidua corresponds to 'Aw', under the Köppen-Geiger classification, which is savanna with dry winter [1,20]. Koforidua has two main seasons, namely, rainy and dry seasons. The rainy season starts from April to November [19]. The average temperature of this location is 25.9 °C, and the annual average precipitation is around 1407 mm approximately, shown in Fig. 2 [21]. Moreover, the average maximum temperature is equal to 30.58 °C, and the average minimum temperature is around 24 °C, depicted in Fig. 3 [21].

The annual average Global Horizontal Irradiance (GHI) and Diffuse Horizontal Irradiance (DHI) for the site are equal to 1,733 kWh/m².day and 1,060 kWh/m².day respectively [22,23]. Monthly meteorological data of the site are summarized in Table 1. Fig. 4 shows the Global Horizontal Irradiation map of Ghana.

2.1. System description

An off-grid PV system has been installed at the Energy House of the Renewable Energy Department at Koforidua Technical University in Ghana for training and education purposes since 2007. This PV system is also used as a backup to supply the electricity requirement for the students' entrepreneurial center. This PV system has been located in the 6.062545 N, -0.266001 W at the elevation of 173 m above sea level. The ground-mounted PV system is made up of Helios H750 PV modules installed on an aluminum structure at an angle of 15°, depicted in Fig. 5. Each PV module is made of tempered front glass, ethylene vinyl acetate (EVA) encapsulant, polymer back sheet and aluminum frame. The Balance of System (BoS) includes a battery bank (LT Solar-Deep Cycle 12 V 100 Ah), charge controller, and an inverter (Meind 3000 W Standalone Power Inverter).

Table 2 summarizes the characteristics of the PV module at standard test conditions (STC) given by the manufacturer. The PV modules have been tested under CEI/IEC 61215 standards and certified by TÜV.

The junction box of each module was opened to have access to the terminals. The modules were electrically isolated from each other and investigated individually while still fixed to their mount structure. PV modules were cleaned before the start of the

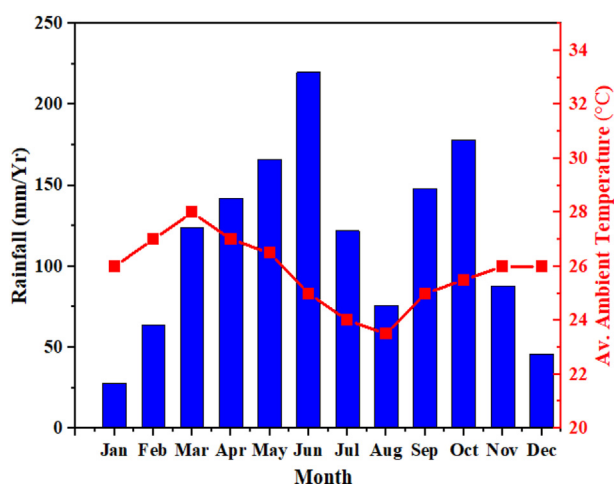


Fig. 2. Rainfall pattern and temperatures.

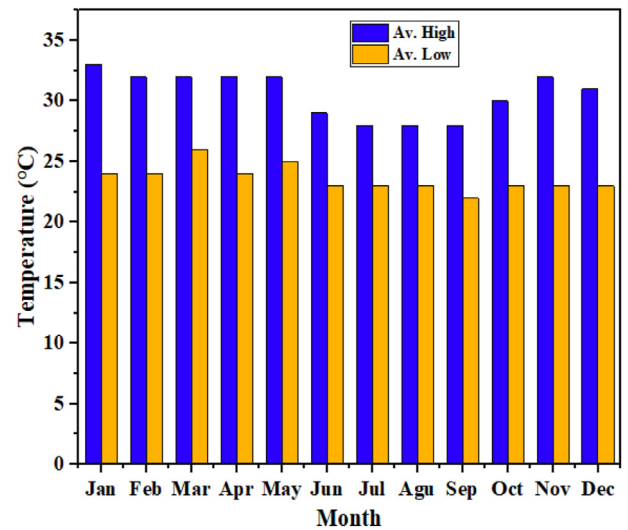


Fig. 3. Average high and low temperatures of Koforidua [21].

experimental measurement process to avoid the effect of accumulated dust on the performance of the modules. The EKO MP-170 I-V curve plotter was employed module characterization with current and voltage measurement ranges of 0.1–10 A ($\pm 1\%$ accuracy) and 10–1000 V ($\pm 1\%$ accuracy) respectively. The measured data was stored in the inbuilt logger of the I-V curve plotter. Measurements of I-V and P-V characteristics were taken simultaneously with irradiation data, and the temperature of modules. Measurements were conducted at mid-day and on a clear day to prevent high deviations that occur when translating low irradiation figures to standard test conditions [26,27]. Plane of Array (PoA) irradiance was measured and stored with the Kimo solarimeter LSL 200 at the level the PV modules. HT-9815 Xintest Pt-100 sensors were attached to the back of the modules according to IEC 61724 to measure the modules' temperature (T_{mod}). In this experimental study, visual inspection has been performed using visual camera (Avio-H2640). Thermography analysis were carried out for the PV modules by infrared (IR) camera (NEC Avio H2640) with properties listed in Table 3. The Avio-H2640 has a very high image resolution and able to achieve faster measurements with a wide area. It also makes use of the multiple emissivity correction functions in real-time and applies the Uncooled Focal Plane Array (microbolometer) as the infrared detector.

Emissivity was, however, set at 0.85 for this measurement. The IR images reveal PV modules affected by hotspot, inhomogeneity in cell temperature, open-circuited bypass diode, potential induced degradation, broken cells, heated bypass diodes and cables [28].

2.2. Correction of experimental data to STC values

Several methods have been mentioned in the literature [11,12,29] for the correction of PV module characteristics at outdoor conditions to the STC values. Joint Research Centre (JRC) in Ispra has developed a uniform correction procedure based on algebraical techniques with an accuracy of 4% and later modified during the German 1000 roofs programme [30,31]. This translation procedure is easily applied even outside specific conditions of constant temperature and irradiation where input data can be deduced during experimental measurements [32]. The default values of temperature and irradiation correction for crystalline silicon modules are summarized in Table 4.

The mathematical expressions for the translation of the current

Table 1
Meteorological data for the location [25].

Month	Global Horizontal Irradiance kWh/m ² ·day	Diffuse Horizontal Irradiance kWh/m ² ·day	Wind Velocity m/s	Relative Humidity %
January	4.20	2.66	2.40	76.5
February	4.79	2.76	3.30	78.5
March	5.21	2.89	3.51	80.2
April	5.37	2.78	3.20	84.2
May	5.15	2.74	2.70	83.9
June	4.65	2.47	2.81	88.3
July	4.48	2.49	3.80	86.0
August	4.34	2.61	4.19	86.4
September	4.85	2.53	3.69	88.1
October	5.05	2.59	2.90	84.2
November	4.76	2.37	2.59	84.0
December	4.19	2.40	2.59	81.6
Year	4.75	2.61	3.1	83.5

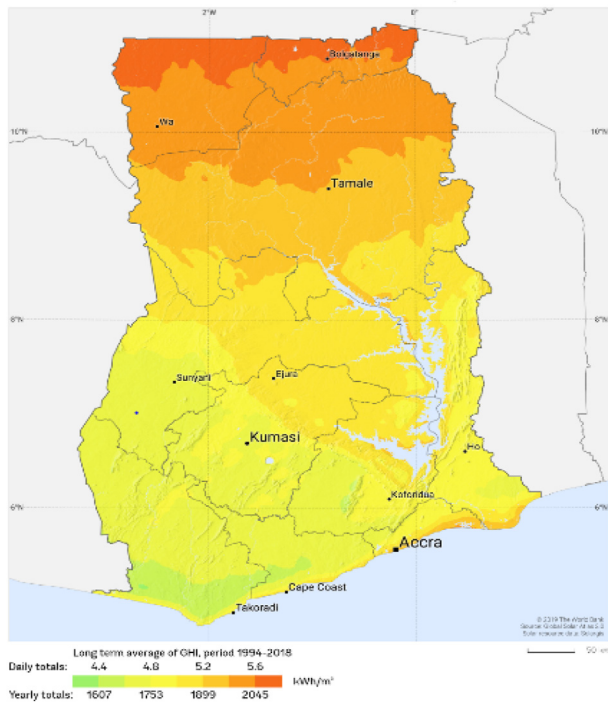


Fig. 4. Global horizontal radiation (GHI) map of Ghana [24].

and voltage are equations (1) – (4). These equations provide a simplified, practicable and accurate procedure for parameters' correction of a PV module without requiring to determine several constants at certain ambient conditions which are not easy to achieve during operation [29].

$$I_{sc,2} = I_{sc,1} [1 + \alpha(T_2 - T_1)] \frac{G_2}{G_1} \quad (1)$$

$$V_{oc,2} = V_{oc,1} \left[1 + a \ln \frac{G_2}{G_1} + b(T_2 - T_1) \right] \quad (2)$$

$$I_2 = I_1 \left(\frac{I_{sc,2}}{I_{sc,1}} \right) \quad (3)$$

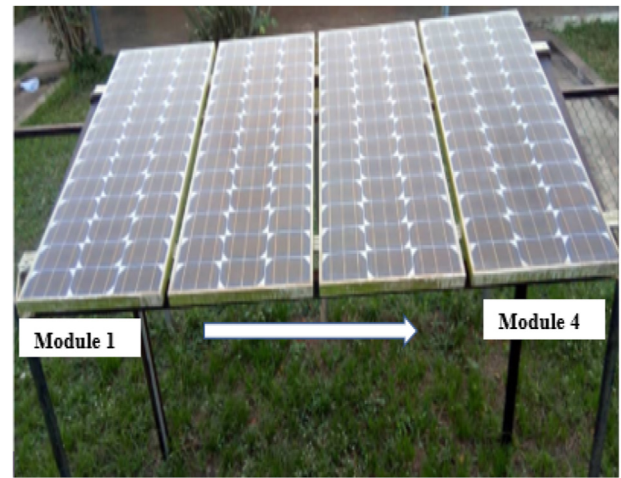


Fig. 5. General view of the installation.

Table 2
Datasheet characteristics of PV module (H750).

Parameters	Value
Maximum power (P_{max})	50 Wp
Short circuit current (I_{sc})	3.16 A
Open circuit voltage (V_{oc})	21.6 V
Voltage at P_{max} (V_{mp})	17.60 V
Current at P_{max} (I_{mp})	2.9 A
NOCT	$43 \pm 2^\circ$
Power tolerance	$\pm 10\%$

Table 3
Features of the (NEC Avio) IR camera.

Parameter	Specification
Type	H2640
Temperature Range	-40 – 500°C
Spectral range	8 – $13\ \mu\text{m}$
Emissivity	0.1 – 1.00
Basic accuracy	$\pm 2\%$ or $\pm 2^\circ\text{C}$
A/D Resolution	14 bits
Response time	150 ms
Detector	Microbolometer
Focusing range	30 cm to infinity

Table 4

Default values for monocrystalline module parameters.

Module parameter	Value
Dimensionless temperature coefficient of I_{sc} (α)	0.0045
Dimensionless temperature coefficient of V_{oc} (b)	0.06
Dimensionless irradiance correction factor (a)	–0.004
Series resistance (R_s)	0

$$V_2 = V_1 + (V_{oc,2} - V_{oc,1}) + R_s (I_1 - I_2) \quad (4)$$

where I_1 (A) and V_1 (V) are the measured current and voltage, I_2 (A) and V_2 (V) are the corrected current and voltage values. G_1 and G_2 (W/m^2) are the measured and reference irradiance, respectively. $I_{sc,1}$ (A) and $V_{oc,1}$ (V) are the measured short-circuit current and open-circuit voltage while $I_{sc,2}$ (A) and $V_{oc,2}$ (V) are the corrected short circuit current and open-circuit voltage, respectively. The temperature coefficients of short-circuit current and open-circuit voltage are α and b respectively while the series resistance is R_s . The correction factor for irradiance is (a) with a default value equal to 0.06, which holds for crystalline silicon modules [29]. The temperature coefficients are dimensionless.

2.3. Translation of experimental data to STC values

Temperature coefficient is defined as the dependency rate of power output, current and voltage of PV modules with temperature [33,34]. The temperature coefficient of the PV modules is obtained from the expressions presented by equations (5) and (6).

$$\delta = \frac{P - P_{STC}}{(T_C - 25)^\circ C} \quad (5)$$

where δ is the temperature coefficient of power, P is the measured maximum power, P_{STC} is the power output of the module at STC and T_C is the temperature of the module. The temperature coefficient of power is also determined by applying the expression provided by Ref. [35] as shown in equation (6).

$$\alpha_p = \frac{\mu_{Voc}}{V_{mp}} \quad (6)$$

where α_p is the temperature coefficient of power, μ_{Voc} is the temperature coefficient of V_{oc} ($V/^\circ C$) and V_{mp} is the voltage at the maximum power point under STC (V) [35]. Equations (5) and (6) are both means of determining the temperature coefficient of power by applying different parameters. However, in Eqn. (6), the temperature coefficient of V_{oc} (μ_{Voc}) which is the determining factor of the module temperature while in operation, cannot be determined by a simple measurement on the module but by further manipulation of measured data to obtain the μ_{Voc} . This procedure may limit the accuracy of the determined value of α_p . Thus, in this study, equation (5) was employed to determine the temperature coefficient of the modules. The implications of a determined high-temperature coefficient of power compared to the nameplate values are evident in the rate of degradation of the PV module. At STC the modules' characteristics are determined at a fixed temperature coefficient, a higher decline in the measured power and high module temperatures increase the negative impact of the temperature coefficient on the power output of the module. Thus, the determined temperature coefficient is an indication of the degradation levels of the module.

2.4. Module degradation factor (MDF)

MDF presents an estimation of the total degradation, which indicates the reduction in I_{sc} as a result of an increase in R_s . MDF can be defined as the degree of degradation in a module which can be determined by equation (7) [36].

$$\%MDF = \left(1 - \frac{I_{sc}(\text{degraded module})}{I_{sc}(\text{ideal module})}\right) \times 100 \quad (7)$$

The reduction in module parameters in comparison with the manufacturer's values is an indication of the module's degradation. However, the major indicators for the extent of degradation of the modules are the enormity of the change in the values of the series resistance (R_s) and shunt resistance (R_{sh}) [35]. Increase in the R_s and a decrease in the R_{sh} cause module degradation by the consequent reduction in the fill factor. As the degradation in modules increases, I_{sc} and V_{oc} values decline because of the effects of the corresponding rise in R_s and decline in R_{sh} . It is found that the I_{sc} is more applicable in the evaluation of protection devices that prevent the failure of PV modules [37]. Module degradation rate is thus, directly related to the I_{sc} of the module. Therefore, the reduction in the I_{sc} as a result of the increase in R_s is an indication of the level of degradation in the performance of the module [35]. Hence, the use of the I_{sc} in the MDF as an index to determine the degradation levels of the modules.

3. Results and discussions

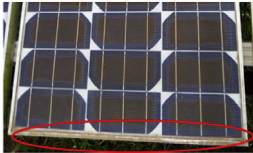
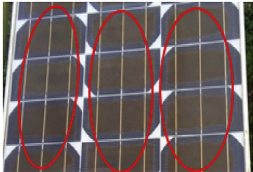
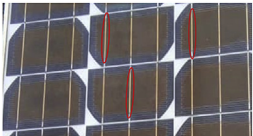
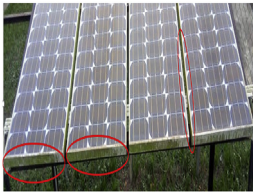
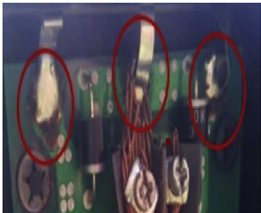
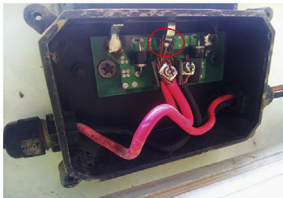
In this study, the PV modules have been evaluated through various methods to assess their performance and degradation rate after twelve years. The monitoring and measurement results are presented, discussed and compared with the results of other locations.

3.1. Visual inspection

Visual inspection is the fastest way and effective method to detect the defects and failures of PV modules [38]. Visual inspection should be performed at above 1000 lux in order to detect the defects and failure better with sight [39]. Table 5 shows the results of the visual inspection of the PV modules.

The yearly average horizontal irradiation for the site is 1,733.75 kWh/m². Thus, the high possibility of browning of the encapsulant. The primary cause of EVA discoloration is the long exposure of modules to UV radiation and very high temperatures beyond 50 °C, as noted by Ref. [38]. Ingressed water vapor combines with UV radiation at high temperatures, to chemically cause the browning of the EVA as observed by Ref. [40]. Table 5 shows the level of browning or discoloration of EVA, covering about 70% of each cell area. EVA browning, which is a commonly reported defect, is thus, directly proportional to the Ultraviolet (UV) light. The excessive stress caused by the high thermal cycle rate resulting from the hot and humid climate also can induce the browning of the EVA. This defect leads to transmittance loss hence reduction in the amount of light energy reaching the cells. Consequently, causing a decrease in I_{sc} and therefore, a drop in the total performance output. The severity of the corrosion observed within the junction boxes of the modules could be a result of moisture ingress combined with the material of the alloy's high sensitivity to moisture. The rate of corrosion observed was the same for all modules and was seen at similar positions of the modules. This infers material failure of the component. This failure mode causes high resistance at the bonds which adversely affects the power output. Corrosion of the interconnect ribbons of the modules was

Table 5
Results of the visual inspection.

PV module component	Observation/ remark	Image
Front of PV module	Shows no sign of delamination, or browning. Glass still feels smooth. Except for accumulated dirt in the lower end and the edges.	
PV cells	All cells uncracked and not broken. Each cell shows some level of discoloration of encapsulant (>70%). EVA discoloration was observed in all the modules.	
Cell metallization	Shows no sign of burns or having been oxidized except for browning or coloration of cell interconnects ribbons.	
Module frame	Well intact with no scratches or broken parts and not askew. Some discoloration observed as a result of the accumulation of dirt and water mostly at the bottom half of the module.	
Back of module	Showed no sign of discoloration or burns and had no scratches.	
Junction box	Intact and all well closed. Corrosion observed at the metallic components when opened. This was observed for the junction boxes of all modules at the same spots. This may be due to moisture ingress. Evidence of bad wiring was observed. (Module wire touching conducting components within the box). This may lead to internal arcing in the box. This was seen for only module 4.	 
Wires/ connectors	Wires not detached, except for discolouration of the insulation of the parts exposed. No sign of brittleness.	

observed for all the modules. This occurs as a result of vapor ingress from the backsheet of the modules resulting in increase in the series resistance.

3.2. Bypass diode test

The aim of bypass diodes in PV modules is to minimize the impact of shading or effects of malfunctioning cell(s) on the performance. Typically, each module has three bypass diodes which are connected in parallel to a set of solar cells. Schottky diodes are most commonly used for the purpose of bypassing in solar modules. In order to check the functionality of the bypass diodes, the PV modules were shaded partially, and the I-V and P-V curves of the modules have been evaluated. In cases where the bypass diodes malfunction, there is a decrease in the flow of current in the shaded string of cells when they are not protected. However, with functioning diodes, the drop is transformed into the inflection points. Fig. 6 shows a sample of the measured I-V and P-V characteristic curves for the modules when partially shaded. The output curves show similar trends for all four modules. The curves exhibit a deviation from the standard I-V and P-V output curves of the modules when not shaded as seen in the same Fig. 6. The curve shows a drastic decline in current with a negligible drop in voltage which indicates a condition of an open circuit performance of the modules. This infers defective bypass diodes, or breaks in the soldering between the bypass diode and the metal contact inside the junction box, which is also mentioned by Ref. [32] as the cause for a similar failure.

3.3. Module temperature

The IR images reveal hotspots, defective bypass diodes, bad fuses and heated cables as well as abnormal module temperature profiles [28]. Also, hidden cracks, internal short circuits, broken cells, delamination, potential induced degradation and open circuits in modules are identified [41,42]. Generally, the temperature on the PV modules is homogenous when the incident irradiance on the modules is uniform. However, if modules are affected by the defects mentioned above, the temperature may be heterogeneous between the affected and non-affected parts. Thermography analysis was performed to detect the failures on the PV modules, see Fig. 7 depicts.

Fig. 8 presents the results of the temperature distribution on the modules' surface. The IR images have shown that the modules were not affected by any significant defects and failures.

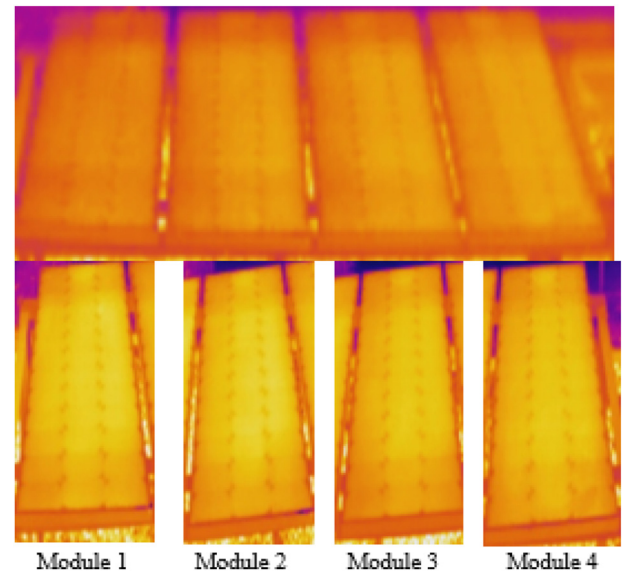


Fig. 7. Captured thermographic images.

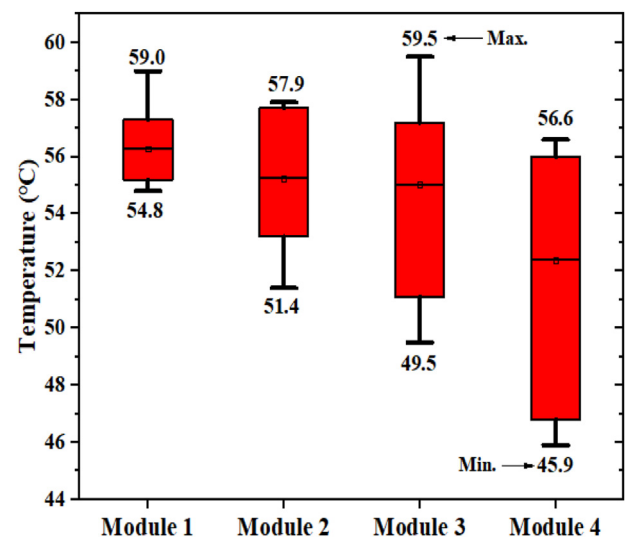


Fig. 8. Temperature distribution of modules.

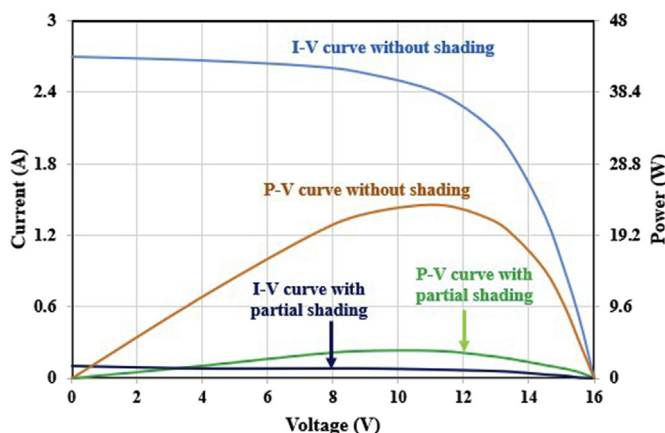


Fig. 6. Measured characteristic I-V, P-V curves (for shaded and partially shaded) modules.

Module 3 had the highest temperature of 59.5 °C, while the lowest temperature of 45.9 °C was measured for module 4 during the thermography analysis. The highest mean temperature of 56.3 °C was obtained by module 1, with module 4 recording the least mean temperature of 52.4 °C. Modules 2 and 3 recorded average temperatures of 55.3 °C and 55.03 °C respectively. Module 4 had the most significant temperature dissimilarity of 10.7 °C, as well as the lowest mean temperature. Modules 3, 2 and 1 respectively recorded temperature dissimilarity of 10.0, 6.5 and 4.2 °C. The standard deviation values of modules are equal to 1.5905, 2.8557, 3.8676, and 4.7545, respectively. The average temperatures were 56.28 °C, 55.25 °C, 55.03 °C and 52.38 °C for modules 1, 2, 3 and 4 respectively. High temperature disparity observed in modules 3 and 4 could negatively impact the performance of the module since there will be an output mismatch among the individual cells. It can be said that, except for module 4, which showed some level of temperature inhomogeneity even though it could not be seen by simple observation of the captured IR images, but through further

analysis, the rest of the modules showed a relatively uniform distribution of module temperature. The non-uniformity in temperature observed in the modules are as a result of the variable absorption rates of solar radiation caused by the non-uniform discoloration of EVA across each module. The uneven discoloration of the modules also causes dissimilar electrical defects which lead to mismatch losses and consequently causing the modules to generate different temperatures over their surfaces.

3.4. Analysis of degradation

The parameters of PV modules were corrected to STC values through the JRC approach. The results show that module 2 has the highest I_{sc} (2.94 A) and closest to the nameplate value. The lowest I_{sc} (2.6 A) was observed for module 1. The average I_{sc} for the array was equal to 2.78 A, whereas a decrease of 11.7% in short-circuit current was measured for the array. Module 1 has the highest degradation rate of 16.4%, and the lowest, 7% reduction was observed for module 2, shown in Fig. 9. The annual loss in short circuit current for the modules was 0.98%.

The average Voc for the array is equal to 18.4 V, which is 14.8% lower than the nameplate value of 21.6 V, shown in Fig. 10. The highest Voc of 19.4 V is recorded for module 2, and the least Voc has been observed for module 3. The highest decrease of 17.1% in Voc was determined for module 3. The average decline in Voc for the modules is equal to 14.8%, which leads to a decline of 1.23%/Yr in Voc.

Fig. 11 shows the fill factor calculated for the PV modules. The fill factor is the ratio of the measured maximum power output of the PV module to the product of the short circuit current and the open-circuit voltage. The squareness of the I-V curve manifests the magnitude of the fill factor; thus, as the squareness is increased by decreasing the saturation current the fill factor increases.

The average fill factor for the array was equal to 60.05. The highest decrease in fill factor of 24.2% was measured for module 3, whereas the least decline of 11.3% was calculated for module 1, illustrated in Fig. 11. The average decline in FF was around 18.0%, which led to the degradation rate of 1.5%/Yr in FF.

Module 2 recorded the highest V_{mpp} of 13.76 V while the lowest V_{mpp} of 12.4 V was measured for module 3. The average value of V_{mpp} for the array was equal to 13.08 V. The decrease in V_{mpp} was around 25.7% with an annual degradation rate of 1.09 V, see Fig. 12. Results from the translation to STC show that the decline

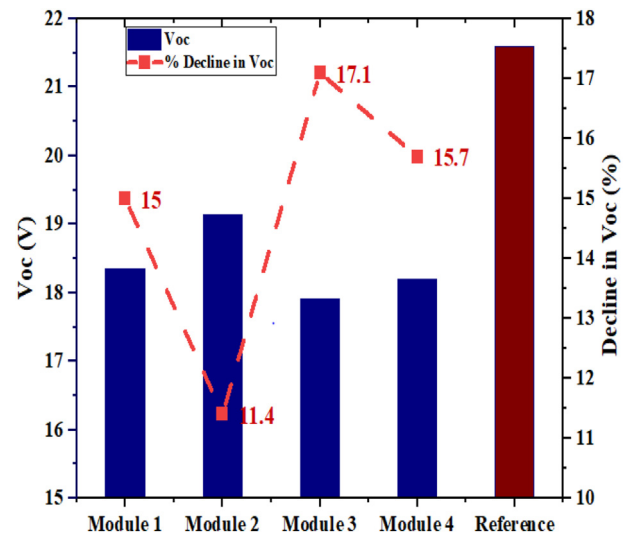


Fig. 10. Open circuit voltage at STC.

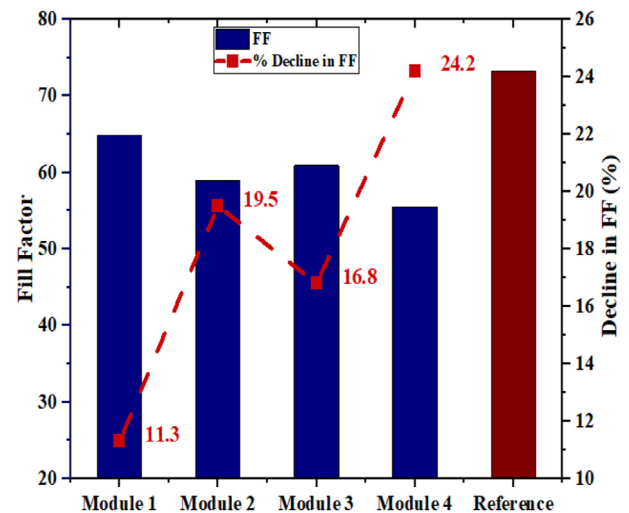


Fig. 11. Fill factor of modules at STC.

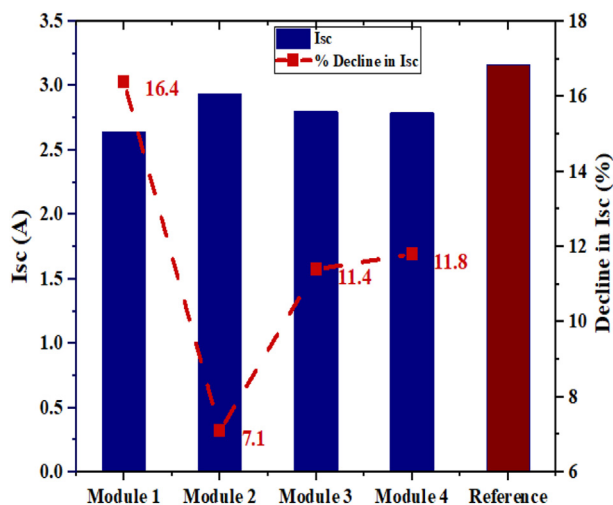


Fig. 9. Short circuit current at STC.

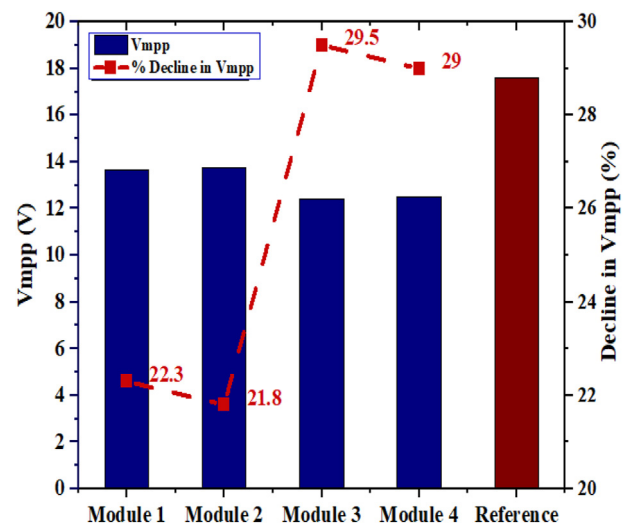


Fig. 12. Maximum power point voltage at STC.

in the module parameters (I_{sc} , V_{oc} , and FF) of the different modules, varies differently for all four modules. For module 1, the highest percentage decline was determined for I_{sc} (16.4%). For module 2, the most significant decline was observed for FF (19.4%). In the case of module 3, the most degraded parameter was V_{oc} (17.1%). An average decline of 24.2% in FF was determined as the most significant loss for module 4. The average percentages decline for I_{sc} , V_{oc} , and FF are 11.7%, 14.8% and 18.0% respectively. This indicates that averagely, the most significantly declined parameter among the three is the FF . Contact resistance which may arise from corrosion at the metal contacts as observed through the visual examination and bulk resistivity increase the R_s affects the FF . The temperature effects on the FF is also evident in the deviation of the temperature coefficients of the modules. Hence the significant impact of FF on the module performance.

The decline in I_{mpp} is relatively lower than the V_{mpp} , which led to a significant decline in V_{oc} . The highest I_{mpp} was equal to 2.40 A for module 4 and the least I_{mpp} of 2.30 A recorded for module 1. The average of I_{mpp} for the PV array is equal to 2.36 A, shown in Fig. 13. The average decrease in I_{mpp} is around 18.6%, with an annual degradation rate of 1.55%.

The average power output measured for the modules was equal to 30.86 Wp. The highest and lowest maximum power output of 32.72 Wp and 29.3 Wp have been observed for modules 2 and 3, respectively. The highest power loss of 41.4% was recorded in module 3, whereas the least power decline was equal to 34.6% for module 2, depicted in Fig. 14. The average decline in the nominal power for the array is 38.3%, which indicates an average annual degradation rate of 3.19%. Studies on the degradation of different PV installations conducted by various authors and the methods applied are presented in Table 6. It is observed that different authors have reported different degradation rates. Results are dependent on the climatic conditions of the site, the PV technology and the duration. Even though the results of the current study present degradation rates that are relatively high, they are comparable to findings in similar climatic conditions.

3.5. Temperature coefficient

The temperature coefficient of maximum power output was determined for the modules, as shown in Table 7. Comparing the results with the reference value of $-0.46\%/^{\circ}\text{C}$, there is a significant deviation of between -2.19 and -2.34 . The negative impact of the

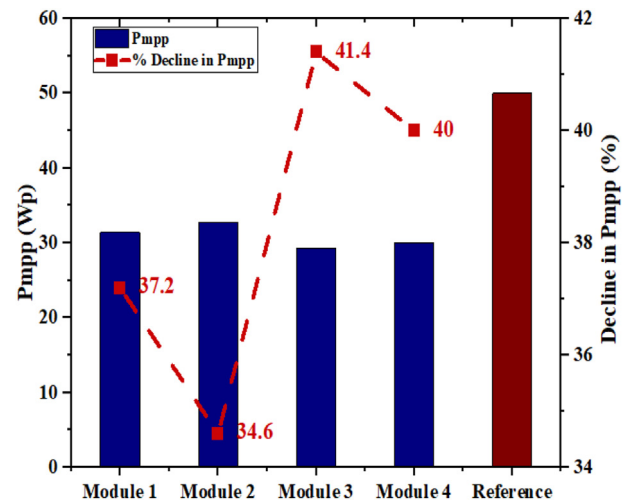


Fig. 14. Nominal power at STC.

high values of the determined temperature coefficient of power of the modules is evident in the steep decline in the measured as well as the translated module characteristics as illustrated in subsection 3.4.

The Root Mean Square Error is 1.212535, which demonstrates the wide disparity between the temperature coefficient of the modules and the reference value.

The estimated MDF of the modules are 16.46%, 6.96%, 11.39% and 11.71% for modules 1, 2, 3 and 4 respectively. The results indicate a wide variation in the degradation of the modules regarding the reduction in I_{sc} , which may be as a result of the increase in R_s . A Regression analysis was performed while modelling the P_{mpp} by two independent variables at each time (I_{sc} - V_{oc} , I_{sc} - FF , and FF - V_{oc}). The results are presented in Tables 8–10. The combinations of the I_{sc} - V_{oc} and FF - V_{oc} had the most influence on the decline of the power output. Their R Square values show a 99% and 98% influence on the P_{mpp} , respectively. However, the P-values for V_{oc} in both cases are 0.057 and 0.099, respectively. Compared with the P values recorded by the I_{sc} and the FF (0.179 and 0.331, respectively), the V_{oc} shows the most significant influence in both combinations. It is inferred that using the regression analysis, V_{oc} showed the most impact on the P_{mpp} . The R square value of the FF - I_{sc} combination was instead low (32%). Thus, the effect of the combination of FF - I_{sc} on the variability of P_{mpp} is comparably negligible. The I_{sc} - V_{oc} combination recorded the highest R square of 99%. Also, it showed the most substantial relationship with P_{mpp} with a Multiple R value of 0.996 compared with the Multiple R values of FF - V_{oc} and I_{sc} - FF (0.977 and 0.569 respectively).

4. Conclusion

The increasing market share of solar PV in the energy sector over the past few years indicates the acceptance of solar PV as one of the main solutions to the world's energy challenges. Performance evaluation of PV modules during operation aims to increase the reliability and service life of PV systems.

This study has assessed the long-term reliability and performance after twelve years operation of monocrystalline PV modules in an off-grid PV system which was exposed under the tropical climatic condition in sub-Saharan of Ghana. The influence of the different module parameters on the decline of the power output has been assessed using statistical analysis. The results are compared with other studies of varying methodologies and

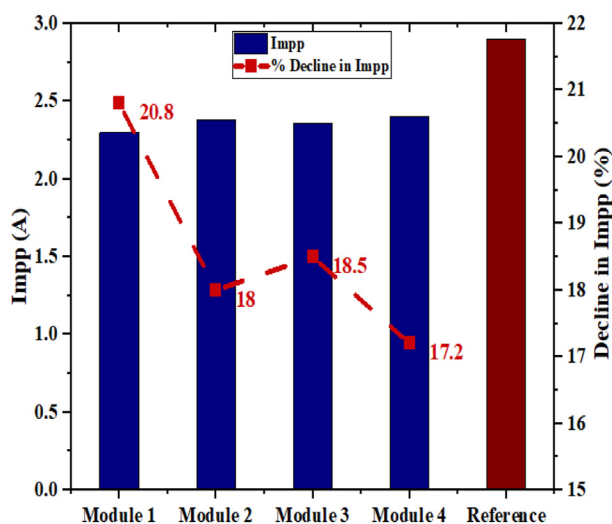


Fig. 13. Maximum power point current at STC.

Table 6

Reported rate of degradation of PV modules for different locations and methodologies.

Location	Duration	Technology	Method applied	Degradation rate (%/year)	Reference
Perth, Australia	19 months	c-Si	MPPTs (continuous measurement)	0.5–2.7	[43]
Perth, Australia	19 months	pc-Si	MPPTs (continuous measurement)	1.0–2.9	[43]
Colorado, USA	8 years	c-Si	Regression model	0.75	[44]
Singapore	3 years	a-Si	Statistical decomposition method (applying the locally weighted scatterplot smoothing)	2	[45]
Japan	10 years	a-Si	Regression analysis	3.51	[46]
Netherlands	44 months	c-Si	Seasonal and Trend decomposition using Locally Weighted Scatterplot Smoothing (Loess) (STL) technique	1.35	[47]
Morocco	3 years	c-Si	IV Tracer and Translation equations	2.6	[48]
Morocco	3 years	pc-Si	IV Tracer and Translation equations by IEC 60891	3.41	[48]
India	22 years	c-Si	IV Tracer and Translation equations by IEC 60891	1.9	[49]
Thailand	4 years	pc-Si	Simple Linear regression model	1.7	[50]
Malaga, Spain	12 years	c-Si	Translation equations	0.7	[51]
Koforidua, Ghana	12 years	c-Si	IV Tracer and Translation equations	3.19	Current study

Table 7

Temperature coefficients of modules.

	Module 1	Module 2	Module 3	Module 4	Reference
T. coeff. (%/°C)	−1.54	−1.51	−1.53	−1.47	−0.46
Deviation	2.34	2.28	2.32	2.19	

Table 8

Regression analysis Results (Pmpp modelled by FF and Isc).

	Coefficients	Standard Error	t Stat	P-value
Intercept	−6.896	54.545	−0.126	0.920
FF	0.231	0.404	0.573	0.669
Isc	8.551	12.936	0.661	0.628

R Square = 0.325, Significance = 0.821.

Table 9

Regression analysis Results (Pmpp modelled by Isc and Voc).

	Coefficients	Standard Error	t Stat	P-value
Intercept	−18.450	4.513	−4.088	0.153
Isc	−4.495	1.296	−3.469	0.179
Voc	3.362	0.302	11.135	0.057

R Square = 0.993, Significance F = 0.085.

Table 10

Regression analysis Results (Pmpp modelled by Voc and FF).

	Coefficients	Standard Error	t Stat	P-value
Intercept	−27.240	9.168	−2.971	0.207
Voc	2.822	0.441	6.398	0.099
FF	0.103	0.059	1.744	0.331

R Square = 0.977, Significance F = 0.152.

locations. Results have demonstrated that the PV modules were degraded and their power output have been declined between 34.6% and 41.4%, with an average loss of 3.19%/year. The decline in Isc of the PV modules were between 7.1% and 16.4%. The Voc of the modules also were in the range of 11.4%–17.1%. The decline in the Fill Factor was between 11.3% and 24.2%. On average, the decline in FF was the most significant, followed by the Voc and then the Isc as the least declined. Furthermore, the visual and thermography

assessment have been performed, and the results reveal PV modules to be severely affected by various failures such as EVA browning, cell interconnects ribbons browning and the corrosion of solder bonds.

CRediT authorship contribution statement

Divine Atsu: Conceptualization, Methodology, Investigation, Data curation, Software, Writing - original draft. **Istvan Seres:** Investigation, Data curation, Supervision. **Mohammadreza Aghaei:** Writing - review & editing. **Istvan Farkas:** Conceptualization, Methodology, Writing - review & editing, Supervision, Funding acquisition.

Declaration of competing 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.

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