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Research Article

Contribution to the Study of the Degradation of Modules PV in the Tropical Latitudes: Case of Senegal

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Abstract: A major problem remains in the photovoltaic sector; the performances are rarely achieved because the solar panels do not work almost never under standard test conditions. This is added the degradation problems caused by exposure to UV radiation, temperature, humidity and aerosols for Sahelian environments. A contribution to the study of the degradation of the production of photovoltaic modules exposed to the real conditions in the tropical latitudes precisely coastal Senegal. The availability of environmental data and electrical parameters measured from a display unit for a year. The exploitation of the data allowed us first to show that the conditions according to actual site on modules are far from standard conditions (STC, T = 25°C, E = 1000 W/m^2). Thus, actual site, the modules operate at sunshine values 800 W/m^2 and temperatures between 40°C and 60°C. The damage on the production of associated modules could be calculated over the year and by season. This is the ratio between the maximum power measured under real conditions (Pmax) and rated power (P0) module measured under standard conditions. The impact of environmental parameters on this degradation was evaluated. The results show that this degradation is more affected by temperature followed by sunshine. The two parameters varying in the same direction, the results were used to evaluate the degradation of the production of PV modules.

Keywords: Degradation, degradation parameter, environmental parameters, PV module, standard condition

INTRODUCTION

In the photovoltaic industry, design, optimization and implementation of PV systems are current problems for better use of solar energy.

This energy now plays an important role in the renewable energy market; it is used for both industrial needs, communities and individuals. Furthermore, the installed PV power annually throughout the world is continuously growing, it has increased from less than 1 GW in 2003 to more than 7.2 GW in 2009 (EPIA, 2010).

The performance of a photovoltaic system depends on the orientation of the solar panels and insulation zones where you are.

A photovoltaic generator is composed of photovoltaic modules themselves compounds of photovoltaic cells connected together.

Senegal has an interesting solar potential for various applications, with an average of 5, 5 kWh/m²/day of raw ground solar energy is an annual global irradiation 2.000 kWh/ approximately 3000 h of sunshine. Enough to supply the energy needs of the entire population throughout the country. Solar energy has enormous potential for development in Africa.

Photovoltaic solar energy comes from the conversion of light into electricity sun within semiconductor materials like silicon or covered with a thin metal layer.

The proliferation of solar PV projects gives rise to problems with system performance under real exposure conditions away from testing standard set at 25°C of temperature, sunshine 1000 W/m^2 and under a mass of 1.5 atmospheres. Add to this the problems of degradation associated with climatic conditions and particularly in Africa with dust. This significantly reduces the service life and plays on the reliability of photovoltaic solar panels.

These photosensitive materials have the property of releasing their electrons under the influence of external energy. This is the photovoltaic effect.

Currently the PV modules are certified to moderate open-air climates not taking into account the specificities of the tropics;

However, operation of the PV panels includes a complex combination of factors (wind, rain, heat, light ...) that causes damage over time that is manifested by a reduction of its power.

Furthermore, experience has shown that the deterioration is due to a reduction of the life of the

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module. It is thus one of the four factors that define the cost of solar electricity (safety, economic cost, reliability and aesthetics) (Dunlop, 2003; Dunlop *et al*., 2005).

LITERATURE REVIEW

Equivalent plan of a photovoltaic cell:

Ideal cells: The operation of a solar cell can be modeled by considering the equivalent circuit diagram (Fig. 1). We can consider the case of an ideal cell comprising a current source and a diode in parallel. The source of the current Iph represents the current photo-(generated) and the diode branch of a current ID.

The current delivered by the illuminated photovoltaic cell on a load R is:

$$I = I_{ph} - I_D \tag{1}$$

$$I_D = I_S\left[e^{\left(\frac{V_D}{V_T}\right)} - 1\right] \tag{2}$$

$$V_T = \frac{KT}{q} \tag{3}$$

$$I = I_{ph} - I_S\left[e^{\left(\frac{V_D}{V_T}\right)} - 1\right] \tag{4}$$

Module real: In the case of an actual solar cell, other parameters into account Resistive effects recombination, leakages towards the edges must be taken-in Consideration. The mathematical model of the photovoltaic generator is based on the equivalent circuit. This circuit is shown in Fig. 2 by a current generator, a diode and three resistors (Shunt resistance, load resistance and the series resistance).

According to the equivalent circuit diagram of a solar cell in then:

$$I = I_{ph} - I_D - I_p \tag{5}$$

$$I_p = \frac{V_D}{R_{Sh}} = \frac{V + I.R_S}{R_{Sh}} \tag{6}$$

$$I = I_{ph} - I_s\left[\exp\left(\frac{V + I.Rs}{AV_T}\right) - 1\right] - \frac{V + I.R_S}{R_{Sh}} \tag{7}$$

The maximum power output of the modules is the most important test of whether the photovoltaic module has failed (Skoczek *et al*., 2008).

To measure the energy efficiency of a photovoltaic module, a current-voltage curve (IV curve), which shows the current versus the voltage of the module is determined.

Thus, the short circuit current Isc of the PV module can be simply calculated by the following relationship:

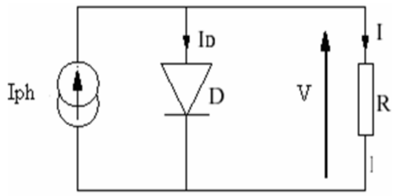

Fig. 1: Circuit diagram of an ideal solar cell

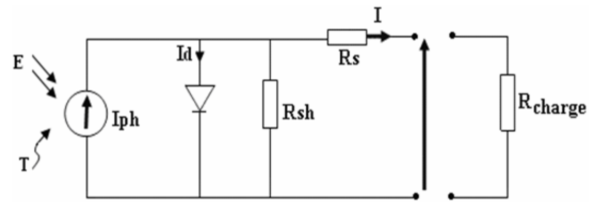

Fig. 2: Diagram of a real electric photovoltaic cell

$$I_{cc} = I_{cco}\left(\frac{G}{G_o}\right)^{\alpha} \tag{8}$$

Moreover, additional conditions where some correction parameters should be introduced to take account of the shunt resistor, the series resistor and the non-ideality of the diode.

Based on the model in Van Dyk *et al*. (2002) and taking into account the temperature effect, the open circuit voltage Voc, for a given sunshine and temperature, can be expressed as:

$$V_{co} = \frac{V_{co}}{1 + b\ln\left(\frac{G_o}{G}\right)}\left(\frac{T_o}{T}\right)^{\gamma} \tag{9}$$

The expression of the form factor is given by the following equation (Green, 1992):

$$FF = FF_o\left(1 - \frac{R_S}{V_{co}/I_{cc}}\right) \tag{10}$$

$$FF = \frac{V_{con} - \ln(V_{con} + 0.72)}{1 + V_{con}} \tag{11}$$

$$V_{con} = \frac{V_{co}}{nKT/q} \tag{12}$$

The form factor is a dimensionless parameter to judge the quality of a photovoltaic module. It can also be defined as the ratio between the maximum output power and the product of the short-circuit current and open circuit voltage of the module (Ricaud, 1997):

$$FF = \frac{P_{max}}{V_{co}.I_{cc}} \tag{13}$$

(a) (b)

Fig. 3: PV module affected by corrosion of the edge (a) and the junction box (b)

The short circuit current and open circuit voltage of a photovoltaic solar module at time t can be given by expressions and Eq. (14) and (15) (Koutroulis *et al*., 2006):

$$I_{cc}(t) = \left[I_{cc,ste} + K_i (Tm(t) - 25) \right] \frac{G(t)}{1000} \tag{14}$$

$$V_{co}(t) = V_{co,stc} - K_v . T_m(t) \tag{15}$$

The voltage temperature coefficient of open circuit, Tm (t) is the average temperature of a module. It is given by the expression:

$$T_m(t) = T_{amb}(t) + \left(\frac{T_{NOCT} - 20}{800} \right) G(t) \tag{16}$$

The power output of a photovoltaic module at time t can be given by Eq. (17):

$$P_{pv}(t) = V_{co}(t) . I_{cc}(t) . FF \tag{17}$$

Furthermore, experience has shown that the deterioration is due to a reduction of the life of the module. It is thus one of the four factors that define the cost of solar electricity (safety, economic cost, reliability and aesthetics) (Dunlop, 2003; Dunlop *et al*., 2005).

Modes and causes of the photovoltaic degradation modules: Degradation mechanisms include either a gradual reduction in the power output of a PV module with time, a decrease in power due to a defect in a cell. A photovoltaic module may have its effective power decrease for reasons which may be temporary or reversible.

The causes identified above are at the origin of the degradation of the modules, which is manifested in several forms.

The corrosion is due to the presence of oxidizing agents such as oxygen, moisture or acid in the atmosphere. The metal connectors are particularly vulnerable to corrosion. Thus, moisture penetrating into the module through the back sheets or layered edges causes corrosion (Quintana *et al*., 2002).

Corrosion also degrades the adhesion between the cells and the metal frame. Figure 3 shows a PV module reached by corrosion along and at the junction box (Munoz *et al*., 2011).

Wohlgemuth and Kurtz (2011) studied the impact of humidity and temperature on the degradation of PV modules. They conducted accelerated 85/85 according to IEC 61215 (CIS, 2005).

They found that the corrosion appeared after 1000 h exposure module at a temperature of 85°C and a relative humidity of 85%.

We also see that (Wohlgemuth *et al*., 2005) also conducted in 2005 tests on BP Solar modules from the feedback that allowed him to assert that corrosion was the most common mode of degradation.

He exploited the commercial database BP Solar which collects all the information from the technical monitoring of their crystalline modules installed since 1994. Other studies (Quintana *et al*., 2002; Realini, 2003; Vazquez and Ignacio, 2008) also claim that corrosion and discoloration are the predominant modes of degradation of PV modules.

Carlson *et al*. (2003) in collaboration with NREL, showed at the end of tests on BP Solar modules as sodium contained in the glass reacts with moisture is a major factor in corrosion the edges of the PV modules.

Osterwald *et al*. (2002) states that the first and faster degradation of silicon PV module due to oxygen which is the first corrosion factor junctions in silicon.

Kempe (2005) showed that the moisture in the PV module is correlated to the rate of degradation, particularly in hot and humid geographical areas such as Miami, Florida.

Due to the relatively high rate of diffusion of water into the Ethylene Vinyl Acetate (EVA), the infiltration of moisture into the module remains high during its life even if the module consists of a double glass structure.

By Kempe (2005), the only way to prevent moisture infiltration is to use well-sealed joints or edge joints low diffusivity containing a large amount of desiccant. Therefore, it may be more economical to focus on ways to reduce the corrosion processes which are accelerated by the penetration of moisture.

Discoloration usually results in a degradation of the encapsulating module, EVA (Ethylene Vinyl Acetate) or the adhesive material between the glass and the cells. This is a color change of the material sometimes turns yellow and which turns brown. It causes a change in the transmittance of the light reaching the solar cell and therefore the power generated by the module is reduced.

Oreski and Wallner (2005) and Wallner and Oreski (2009) argue that the main causes of the degradation of the EVA are UV rays combined with water under exposure to temperatures above 50°C.

Fig. 4: Solar cells discolored

All these factors cause a change in the chemical structure of the polymer.

The discoloration can appear in different zones and not adjacent module; this may be the result of original encapsulating polymers or different characteristics. This could mean that the discoloration comes from the encapsulating polymer instead of adhering element, EVA generally; but also as EVA is not deployed in the same areas in the same manner to the modules using the same polymers.

Kojima and Yanagisawa (2004) looked at the yellowing of the EVA is in the PV modules. For this, they are subject PV modules to an artificial solar sunshine. They are only interested in the contribution by UV (wavelengths between 280 and 380 nm).

However, for UV radiation 1000 W/m^2, no change occurred in the region 280-380 nm after 500 h.

Wohlgemuth *et al*. (2011) conducted tests on UV PV modules at a temperature of 60°C, it was found that the encapsulant discoloration occurs when UV irradiation total reached 15 kWh/m^2 in the wavelength range between 280 nm and 385 nm without exceeding an exhibition of 250 W/m^2 (Fig. 4).

Osterwald *et al*. (2002) argues that slow long-term damage is linearly correlated to the exposure of UV modules.

In recent years, most publications on the degradation of PV modules crystalline silicon focused on the degradation of the EVA (Kempe, 2006, 2010; Kempe *et al*., 2007).

Realini (2003) conducted an experiment between 1982 and 2003 that allowed him to make the correlation between the electrical characteristics and discoloration of the encapsulated.

Fading module degrades the short-circuit current (Isc). This degradation of Isc can vary from 6 to 8% below face value for partial discoloration of the module surface and from 10 to 13% for total discoloration.

METHODOLOGY OF THE ESTIMATION OF THE PHOTOVOLTAIC DEGRADATION MODULES

Model de pan: In Pan *et al*. (2011), Pan (Jet Propulsion Laboratory) proposed a degradation model for PV modules:

$$D(t) = 1 - \exp(1 - bt^{a}) \tag{18}$$

We in our case we will try to determine experimentally using two PV modules to initial power P0.

First the module is placed in a chamber under suitable conditions for a time t in order to determine a power at time t and to the relation between this power and the initial power.

In the second step we will do the same and measure another power at a time t ' and make the connection between this power and the initial power.

The value of these two D (t) allows us to have two equations with two unknowns and from there we can easily determine these two parameters.

For discoloration of the encapsulant and corrosion, the probability of failure is studied by following the degradation of the delivered energy power. The degradation due to corrosion is determined by Pan *et al*. (2011):

$$D_{\mathrm{mod}ulecorrosion}(t) = \left[1 - \exp\left(-b_{corrosion}.t_{corrosion}{}^{2}\right)\right] \tag{19}$$

At least two wet heat tests such as 85/85 (Oreski and Wallner, 2005) are performed to determine and a corrosion b corrosion.

Temperatures taken during the tests shall not exceed the technological limit temperature of PV modules equal to 120°C according to Kern (1999).

Wohlgemuth *et al*. (2005) studied the degradation of a polycrystalline PV module with the model of Pan, he determined the parameters a and b from 85/85 humid heat tests.

This degradation can be considered that due to corrosion with factors of temperature and humidity which are the exposure settings in these tests.

And the degradation due to discoloration of the encapsulant is determined by:

$$D_{décoloration}(t) = \left[1 - \exp\left(-b_{décoloration}.t_{décoloration}{}^{2}\right)\right] \tag{20}$$

The degradation parameter describing the degradation modes of a photovoltaic module is determined:

$$D_{dégradation\,\mathrm{mod}\,ule}(t) = 1 - \Pi^{5}{}_{k=1}\left[1 - D_{k}(t)\right] \tag{21}$$

Degradation is reached when the supplied power is equal to 80% of the original power. Let D (t) = 20%. In the literature, we can meet different degradation rates were observed in different conditions of operation of photovoltaic modules.

However, studies conducted have concluded that this rate may increase because of high ambient temperatures, since the modules, subject to high operating temperatures, showed faster degradation (Czanderna and Pern, 1996).

However, in our study we considered the parameter Pmax/P0 comme being the model for determining the degradation.

To determine the degradation parameter, we used the ratio Pmax/P0, which defines the relationship between the instantaneous maximum power considered (Pmax) according to the rated power of the photovoltaic module before first use (P0 = 30W).

This is determined in the STC (Standard Test conditions: T = 25°C, Sunning = 1000 W/m^2, AM = 1.5).

MATERIALS

The experimental platform is composed PV conversion of two channels, module temperature sensors, a thermo-hygrometer, a pyranometer a datalogger, a shunt resistor and a computer.
The platform is shown in Fig. 5.

RESULTS AND DISCUSSION

Presentation of the measures: The environmental parameters are measured sunlight, ambient temperature and relative humidity. Measurements on modules cover the module operating temperature, short-circuit current and open circuit voltage.

Moreover, for sunshine, ambient temperature and relative humidity, measurements are taken every minute.

While the short-circuit current and the open circuit voltage of the modules are measured every ten seconds.

Presentation of the annual and daily variation of temperature, relative humidity and power panel studied: We will study the changes in humidity, temperature and power over time, by considering a typical day in the month and for every season (Fig. 6).

Analysis of the curve in Fig. 7, we can confirm that the relative humidity varies inversely with temperature.

This is due to the fact that the relative humidity is higher during the rainy season with a minimum of 50% against a minimum of 13.8% during the dry season while the graph of temperature is higher during the dry season with a maximum of 60°C and a minimum of 49°C during the rainy season.

Furthermore, as regards the annual variation, it is observed in Fig. 7 that the production reaches its maximum for the month.

April (4th month) and July (month 7) respectively with a power ranging from 30 W to 30, 7 W where temperatures are at their minimum and humidifies to their maximums.

These different values of humidity and temperature represent constraints in relation to the modules operating conditions.

Percent of yield per additional degree above 25°C so that a panel would have a surface temperature of 85°C would have a 30% loss.

This is why the cooling system must be present in the design of the experimental device, to maintain the temperature of the modules to an acceptable level, a guarantee of obtaining a good output power of the system.

Contrary to what one can imagine a PV panel with a surface temperature exceeds 25°C loses half a.

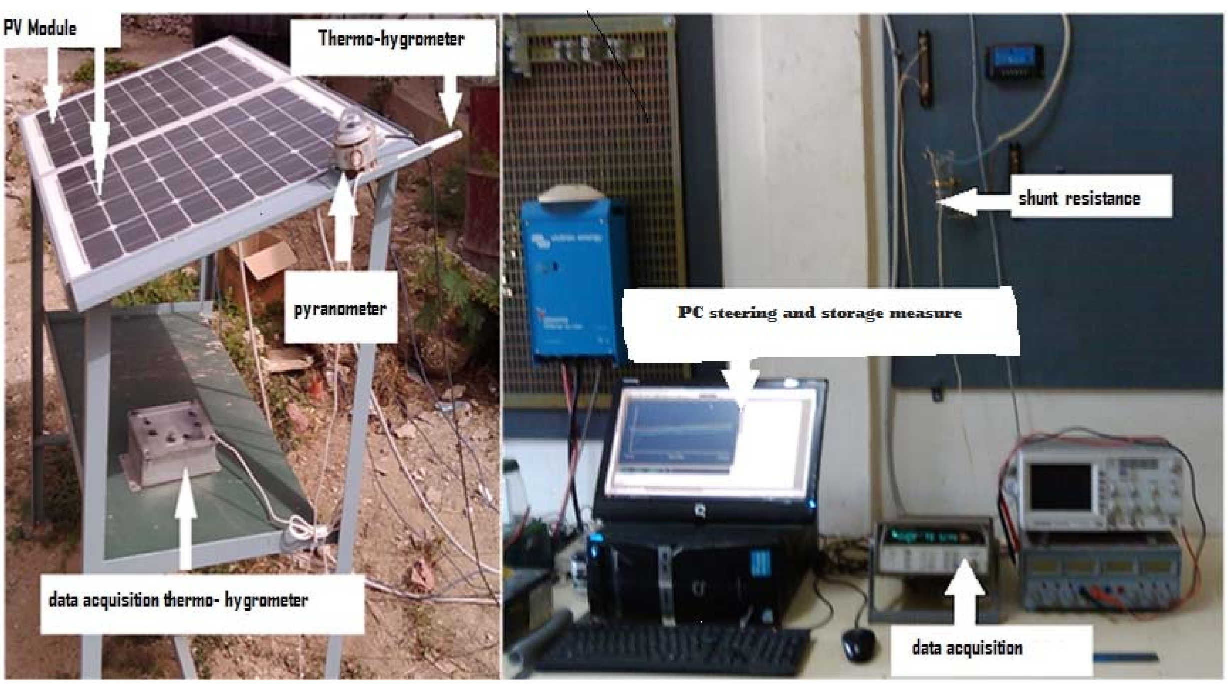

Fig. 5: Working platform

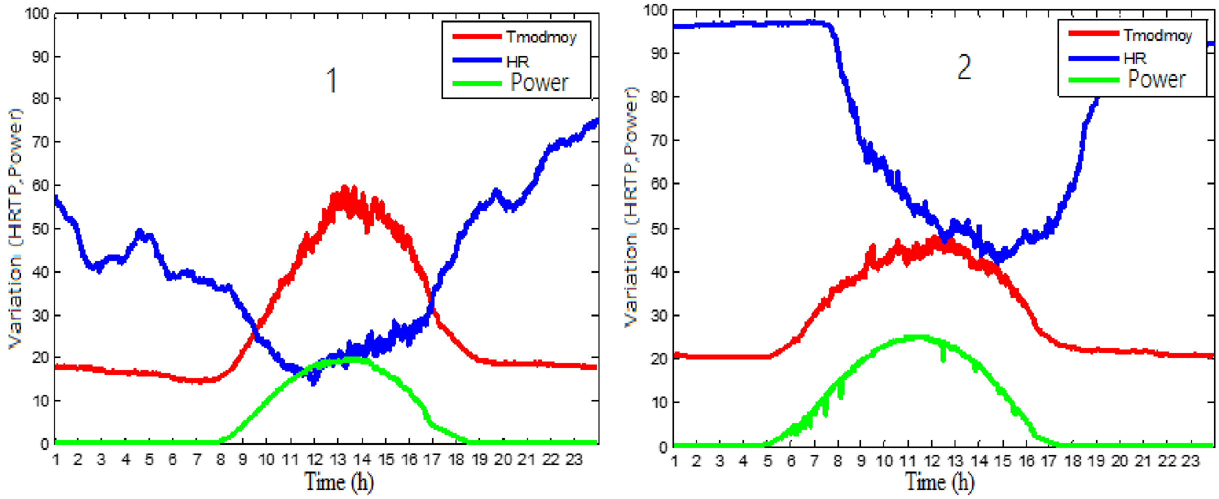

Fig. 6: Daily variation of temperature, relative humidity and power during a typical day during the dry season (1) and the rainy season (2)

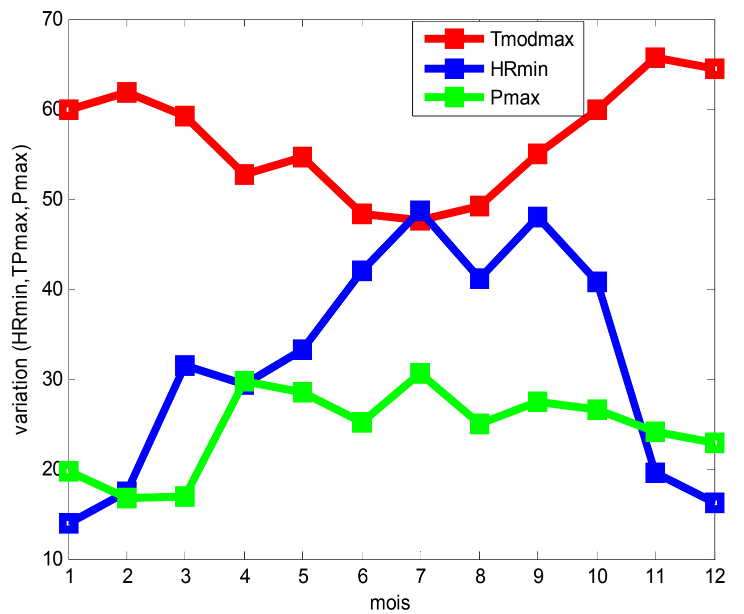

Fig. 7: Annual change in humidity, temperature and power

Presentation of the daily change in radiation and power: We will study the changes in radiation and power over time, by considering a typical day in the month and for every season.

Thus, the analysis of the curves in Fig. 8 shows that sunlight varies with the power during a day.

During the rainy season, the power has slightly increased while the changes reflect sunlight passing clouds that are more frequent and more important during this period.

During the dry season, the power decreases and deformation observed on the end of the day curve may be due to a shadowing effect.

Comparative study of ambient temperature and real simulated on the modules: Before, we used our measurements to validate the model Kenny *et al*. (2006) connecting the room temperature module temperature.

This temperature (Tmodule) will be expressed by retaining the phrase Kenny *et al*. (2006), defined by the relationship:

$$T_{module} = T_{amb} + \frac{G}{800}\left(T_{NOCT} - 20\right) \tag{22}$$

T_{NOCT} varies between 45°C and 48°C but it can take 47°C. The G sunshine and ambient temperature Tamb are stochastic parameters.

The ambient temperature is the temperature of the environment, that is to say the whole universe except the system considered.

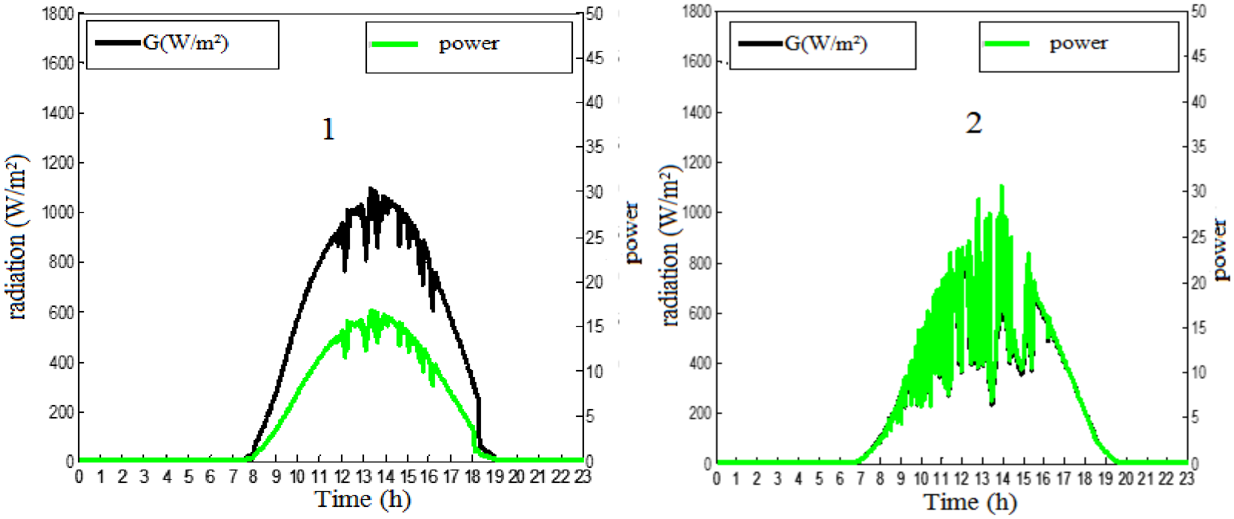

Fig. 8: Change in sunshine and power during a typical day during the dry season (1) and the rainy season (2)

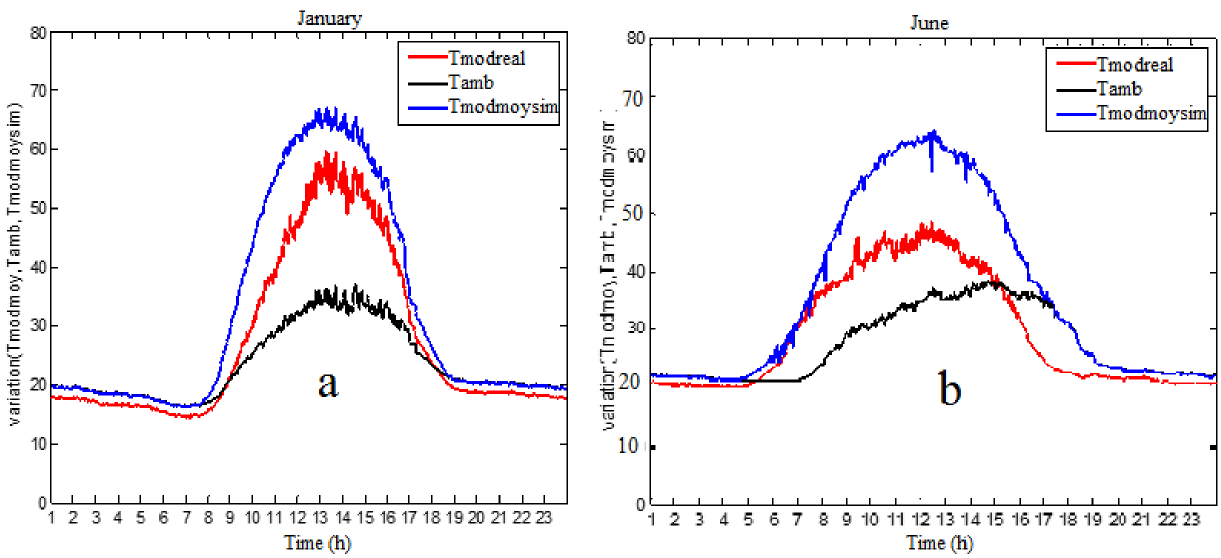

Fig. 9: Daily temperature variation of real and simulated modules and ambient temperature during the dry season (January-a) left and the rainy season (June-b) to right

The analysis of the curves in Fig. 9 shows that the ambient temperature of the site increases progressively in going from 20°C to 33°C in the interval [7 h-14 h].

It reached its peak at 14 h and then decreases on the interval [14 am-18 pm] starting from 37°C to 22°C for January (dry season) and 39°C to 24°C for June (rainy season).

The increase in the ambient temperature during the first hours of the day due to the increase in solar radiation. This aspect is best illustrated in Fig. 9.

Another remarkable feature is that the observed value of the ambient temperature to 18 h situated slightly above the temperature for 8 h.

This phenomenon is related to the fact that the earth stores during the day a fraction of the heat energy from the sun and the evening returns: This is the greenhouse effect.

Photovoltaic energy is an energy category primarily resulting from the sun.

The ambient temperature is closely linked to the light irradiation, it is therefore appropriate to take into account the ambient temperature parameter in the study of PV systems.

For module temperature profile of evolution depending on the time of day is modeled on that of room temperature.

It increases during the first hours of the day (7 h-14 h) ranging from 19°C to 55°C during the dry season (January) and 20°C to 45°C during the rainy season (June). The maximum temperature is reached at 14 h and it follows a progressive decrease. Then we deduce that the temperature of the modules is linked to the sunlight.

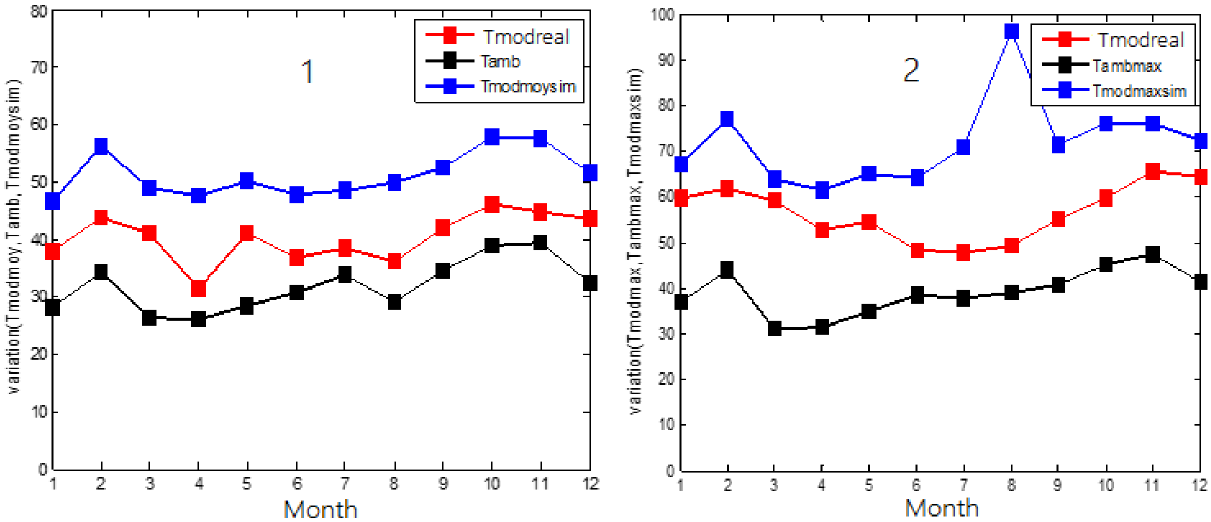

Fig. 10: Average monthly change (1) to left and up (2) to the right of the actual temperature modules

Table 1: Determination coefficient

Month	Determination coefficient
January	0.97
February	0.99
March	0.98
April	0.96
May	0.97
June	0.96
July	0.64
August	0.55
September	0.98
October	0.99
November	0.98
Dcember	0.98

The analysis of the curves in Fig. 10, shows that the module temperature is greater than room temperature, which varies around 38°C in general.

The latter peaked at 47°C for only one month of the year, the month of November.

Nevertheless, we find that the module temperature is between 48°C and 65°C and values.

Temperatures in the actual conditions are very different from those observed in the STC.

This difference in temperature can lead to constraints on production modules.

According to the determination coefficients obtained, it is possible to admit that the gap between the simulated temperature and the actual temperature on a day is high during almost every month except for the months from June to August corresponding to the season characterized by rain showers affecting the sunlight received by the module (Table 1).

Thus, we note that sunshine is a parameter of the relationship Kenny Eq. (22).

In addition, it is possible to admit that the gap between the simulated temperature and the actual temperature on one day is higher during the dry season than rainy season.

This difference is due to the fact that the simulated temperature values sunshine use a clear sky day.

Study on the degradation: The parameter degradation of the power is determined by comparing the maximum instantaneous power to the initial power (P_{max}/P_0). This parameter is determined by considering a typical day of each month.

The results obtained are illustrated in Fig. 11.

The study of module power degradation parameter allows us to see the months for which a significant degradation is observed.

It is recalled that in the case of a breakdown, the module produces less electricity than at the beginning of his life but continues to produce.

The module is also said that when his power is degraded at time t reaches 80% of its original power.

Indeed, the power being the main parameter characterizing the performance of photovoltaic modules remains a determining factor in the assessment of degradation.

The parameter degradation of the power thus established is the ratio between the instantaneous maximum power and rated power of the module (P_{max}/P_0).

From the curve in Fig. 11 it is clear that it is from April until November where we observe the dominant degradation parameters of operation of the modules in other words, it is the month where there is less degradation compared to January, February, March and December where the degradation is greater.

In the following, we will study the impact of sunlight, temperature and relative humidity on the degradation.

The analysis of the curves in Fig. 12 shows that when the sun is greater than 1000 W/m^2, we also observe a significant degradation of power. Similarly,

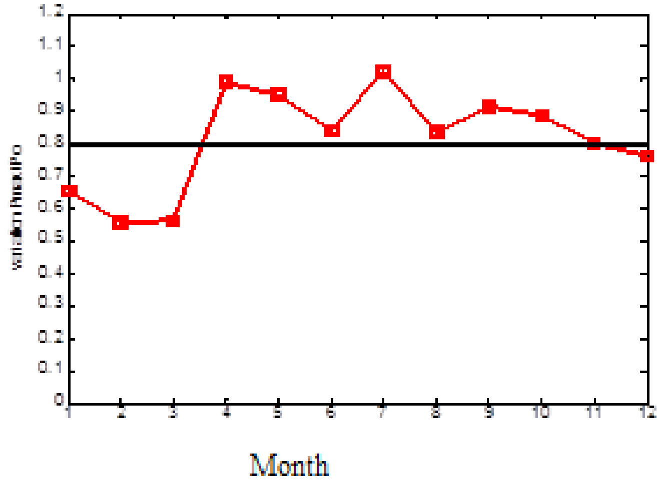

Fig. 11: Annual degradation change

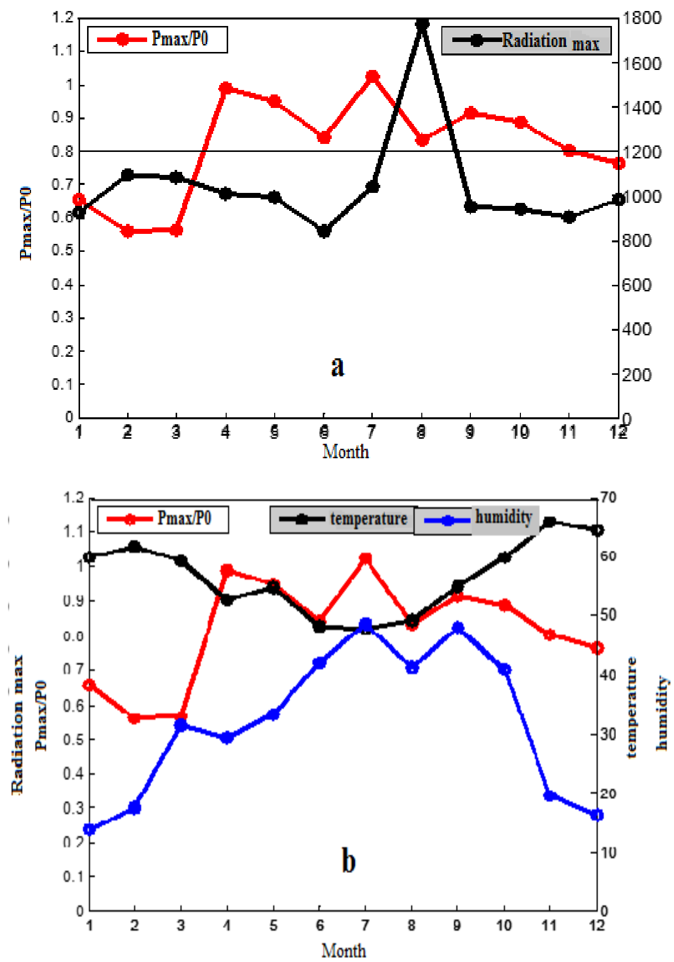

Fig. 12: Change in sunshine and degradation (a) Change in moisture and temperature and degradation (b)

degradation is observed also when the temperature becomes high in the order of 60°C and the humidity varies little between 14 to 30%.

Finally we conclude here that the module degradation depends heavily on sunlight, humidity and temperature. However, a significant increase in the sunshine at a given temperature would normally cause a reduction in degradation but the results show that more sunlight increases with temperature more degradation is important.

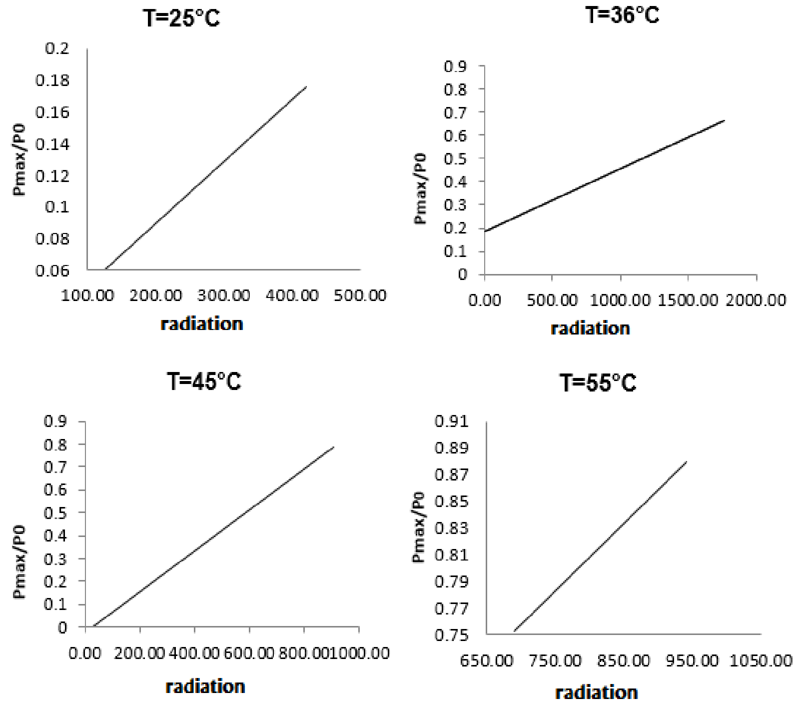

Fig. 13: Influence of radiation on the degradation at constant temperature

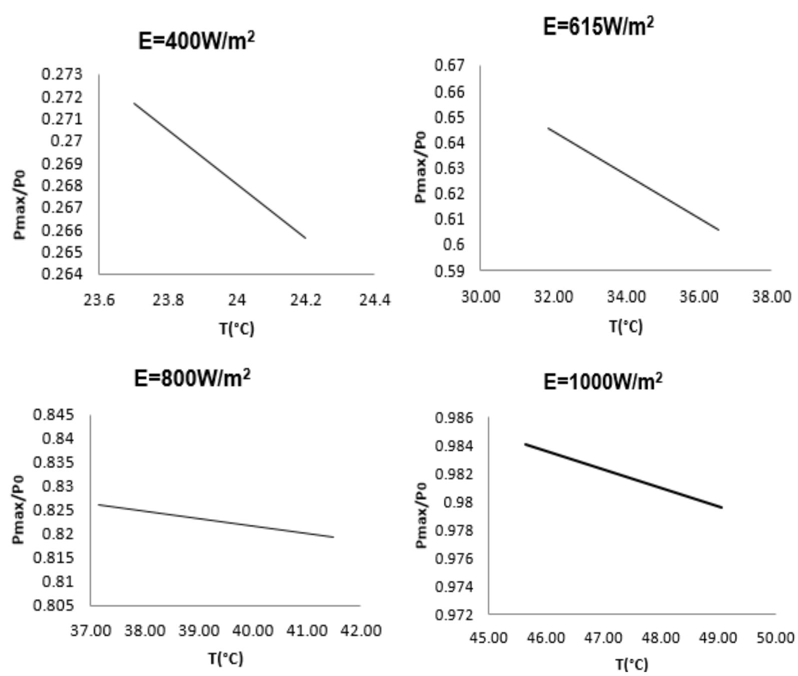

Fig. 14: Influence of temperature on the degradation at constant radiation

Study of the influence of environmental parameters: On the degradation firstly, to better see the impact of environmental parameters on the degradation, we will set the temperature and study the variation of the parameter degradation Pmax/P_0 depending on the sunlight.

On the other hand we will try to fix the sunshine and study the variation of degradation parameter (P max/P_0) of the PV module depending on the temperature.

Influence of radiation on the degradation at constant temperature: We will fix the temperature and watch the influence of UV radiation on the Pmax/P_0 parameter.

In Fig. 13, the degradation parameter Pmax/P0 changes with radiation. Indeed, when the sunlight increases, the degradation parameter also increases and the degradation of the power becomes less important. In other words, the instantaneous maximum power (Pmax) is close to the rated power (P_0) and the ratio (P max/P_0) is close to 1.

However, we note that for a temperature of 25°C, sunlight does not reach the 1000 W/m² which explains the impossibility to reach the STC (T = 25°C, E = 1000 W/m^2 and AM = 1.5) in real conditions.

Influence of temperature on the degradation at constant radiation: They are looking at the influence of temperature on the parameter Pmax/P_0 to constant radiation.

We observe in Fig. 14 that the degradation parameter Pmax/P0 changes with the temperature. Indeed, when the temperature increases, the degradation parameter progressively decreases and the deterioration of the power becomes large. In other words, the instantaneous maximum power (Pmax) is much lower than the nominal power (P0) and the ratio (P max/P0) is also much lower to1.

The results showed that for an irradiation of 1000 W/m^2, the temperature exceeds 25°C STC conditions.

CONCLUSION

Of the measuring platform the data were used to characterize a part of the environmental parameters of the exposure site, but also to measure the maximum power delivered by the modules in this manner.

The deterioration of production has been determined as the ratio between the power and the power rating measured under STC conditions provided by the manufacturers.

The results showed that the modules operating in almost of the time, far from the STC (temperature = 25°C, Sunning = 1000 W/m^2, AM = 1.5).

Moreover, in the actual conditions, the modules are characterized by temperatures ranging from 42°C to 65°C and an average radiation around 800 W/m^2.

This which has an effect on production and therefore degradation.

The values of this degradation were assessed on all months of the year showing a variation. Finally we studied the influence of temperature and sunlight degradation. The results show that the impact of temperature is more predominant.

These results show the importance to be given to the evaluation of the production of PV solar modules under real operating conditions. This is possible by instrumenting the study sites to ensure monitoring of the electrical parameters as the environmental parameters.

The results are characteristics of our study area located on the coast; it would be interesting to make this study on all the climatic zones of Senegal and to a regional study in other countries in West Africa. All these are interesting for manufacturers experience feedback on the actual production of their technology but also their reliability, which is related to the life span.

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