Degradation of Crystalline Silicon Photovoltaic Cells/Modules under Heat and Temperature Effect

Original Research Article

ABSTRACT

Temperature is extremely significant to the PV modules degradation process, especially hot spots, encapsulant bleaching, delamination failure on interconnections, corrosion, discoloration, and bubbles on the panel's surface.

We investigated the degradation of crystalline silicon PV cells/modules exposed under heat and temperature effect.

We established a qualitative correlation between the electrical parameters affected and the different modes of PV cells/modules degradation.

We reveal that: the leakage current increase rapidly with increasing number of hot spots. The effect of discoloration causes loss of transmittance of the encapsulant EVA, and reduces the photocurrent density (J_{ph}) owing to a decrease of absorption, and therefore the power loss. Discoloration does not affect the fill factor (***FF***) and (**Voc**) more, but the corrosion causes a decrease of the PV modules maximal power (P_{max}) when the delamination of the PV module reduces the thermal conductivity locally and hence increases the temperature of the cell.

Delamination, bubbles, corrosion, hot pots, EVA discoloration are the predominant modes of the PV cells/ modules degradation.

Keywords: Degradation; temperature and heat effect; leakage current: delamination; EVA discoloration.

1. INTRODUCTION

PV cells/modules know many degradation processes due to their exposure to temperature, atmospheric pressure, humidity, long time ultraviolet (UV) illumination, mechanical shock, precipitations, dust, wind and snow; which reduce the intrinsic lifetime of these cells very short. The limited lifetime is a result of several processes that are in play simultaneously [1, 2].

The yellowing, delamination, bubbles, breakage and cracks in the cells, defects in the anti-reflective coating, burnt cells, discoloration, and corrosion are the visible and dominant factors [1, 3-8]. Besides these direct defects, temperature can accelerate many degradation processes. The temperature plays then an important role in the photovoltaic cells/modules conversion process. The performance of these PV cells/modules decreases with increasing of the temperature, due to increased internal carrier recombination rates, caused by increased carrier concentrations [6]. In addition, combined effects (temperature and humidity; temperature and light; temperature, dust and humidity; light, humidity and dust) are factors of PV cells/modules degradation in almost all identified degradation modes [1-7].

The majority of studies on the crystalline Silicon (c-Si) technology report that the maximum power (P_{max}) degradation has been mainly attributed to short circuit current density (J_{SC}) losses, followed by smaller decreases in the fill factor (FF). (J_{SC}) degradation associated with the reduction of (P_{max}) has been most commonly caused by

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delamination and discoloration [8-13]. [12] Showed that the reduction in J_{SC} was due to discoloration or delamination at the cell/ethylene vinyl acetate (EVA) interface, front glass breakage and increased series resistance (R_S), due to the degradation in electrode soldering. Interconnect degradation in crystalline silicon modules occurs when the joined cell-to-ribbon or ribbon-to-ribbon area changes in structure or in geometry. The characteristics directly attributable to interconnect degradation include increased series resistance (R_S) in the electrical circuit, increased heating in the module, and localized hot spots causing burns at the solder-joints, at the polymer back sheet, and in the encapsulate [13,14].

The identification of the origin of degradation and failure modes and how they affect the photovoltaic cells/modules is necessary to improve the reliability of photovoltaic installations. However, despite the identification of PV modules degradation modes, it is still difficult to study them in real conditions. To overcome the obstacles of the long-term experiences, some analytical models have been elaborated in recent years, in order to study the degradation of the PV cells/modules under real conditions or not, since this depends on the aim at [1, 5, 15].

In this work, crystalline silicon PV cells/modules degradation exposed under heat and temperature effect has been investigated. A qualitative correlation between the electrical parameters affected and the different modes of PV cells degradation has been established.

Moreover, the environmental and climatic conditions in which the modules are exposed significantly influence the performance of these PV cells.

This manuscript is organized as follows. In Section 2, a visual inspection of PV modules degradation observed has been indexed. Subsequently, light-induced degradation, and thermal degradation have been presented. Next, the results are analyzed and discussed in section 3. Finally, in section 4, the conclusions and our perspectives are enumerated.

2. MATERIALS AND METHODS

2.1 Visual Degradation

Delamination is very frequent in hot and humid climates. It causes moisture penetration in the PV module and therefore induces various chemical and physical degradations such as metal corrosion of the module structure most frequently. Delamination is more severe if it occurs in the borders of the module because, a part from the power losses causes electrical risks to the module and the installation. Delamination is also related to a transmittance loss, as materials are not well optically coupled and a part of the light escapes [16-19] (Fig.1).

The corrosion attacks the metallic connections of PV cells causing a loss of performance by increasing leakage currents. Corrosion also degrades the adhesion between cells and metallic frame [3]. [20] Have been found out that corrosion appeared after 1000h of exposure of PV module under 85°C and 85% of relative humidity. Corrosion and discoloration are the predominant modes of photovoltaic modules degradation [3, 5] (Fig.2).
Module discoloration is a change in color of material which turns yellow and sometimes brown. It modifies transmittance of light reaching PV cells and therefore the power generated by the module is reduced. In addition, discoloration degrades the short-circuit current (Isc) of PV module. This degradation may vary from 6% to 8% below the nominal value for a partial discoloration of the PV module surface and from 10% to 13% for complete discoloration [1,4,21,22,23]. The Maximum power (P_{max}) of the PV module is also degraded by module discoloration.

Glass breakage is one of an important degradation factor of PV cells/modules. Breakages and cracks are usually followed by other degradation types such as corrosion, delamination and discoloration [1, 13, 20] (Fig.3). Our investigations shown that, it is generally impossible to detect cracks on the already operational PV module to the naked eye. This detection can be done by using optical methods [24]. This method essentially consists of applying an intense wideband light (1000 suns) and detecting the path where the light passes through the cell or, on the contrary, is blocked due to the reflections that can cause a crack.

Cracks produce a loss in cell consistency and a possible carrier recombination path. They isolate

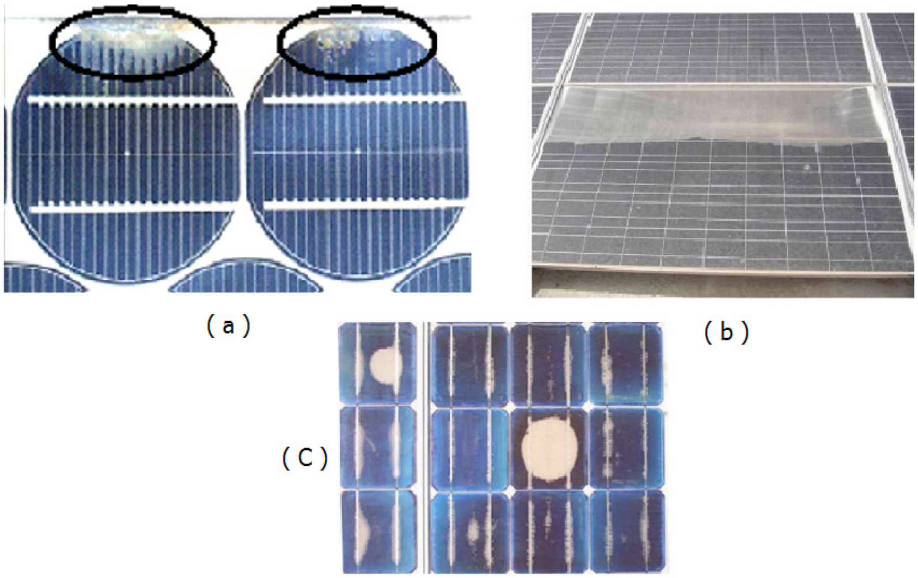

Fig. 1. (a) PV module délamination; (b)-(C) severe delamination (this figure presents an example of how an extreme delamination could destroy a PV module when the defect appeared after barely a year of functioning) [1,16,17]

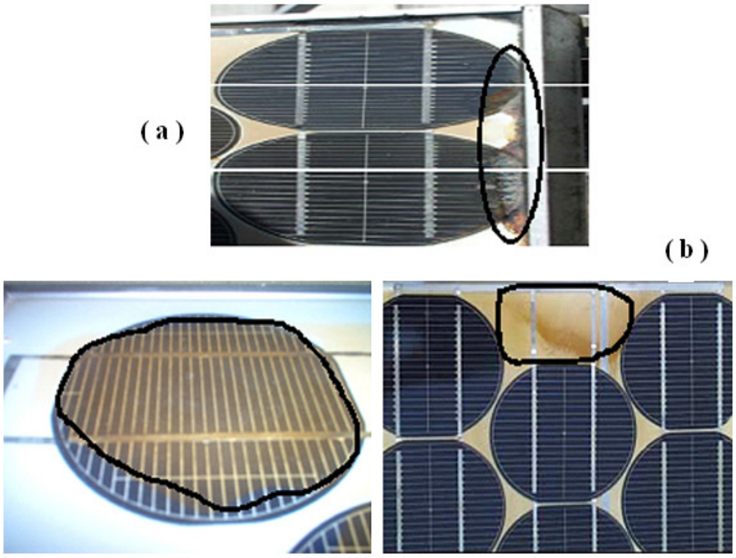

Fig. 2. (a) PV module affected by corrosion at the edge and the junction box [3]; (b) Solar cells discolored [1,19]

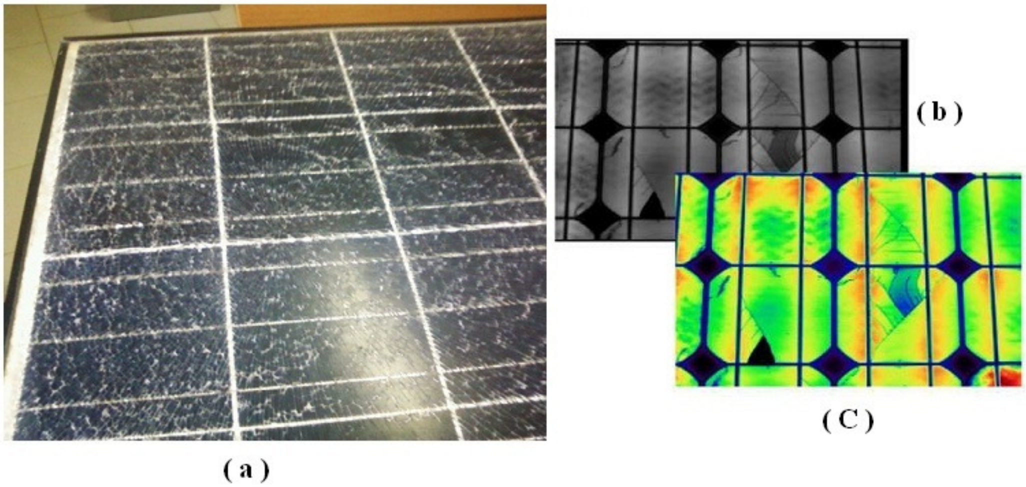

Fig. 3. (a) PV module with broken glass; (b) and (C) Cracks in cells. B &W image a simulated color image [1,24]

parts of the cell avoiding the photocurrent generation. The effect of long-term exposure of the PV modules to a very high temperature, damages the cell or any other elements of the module [1]. This induces hot spots in some areas of the cell. Hot spots cause a variety of cell failures: shadowing, cells mismatch or failures in the interconnection between cells. This defective cell becomes a load for other cells, and a place of a relatively high thermal dissipation constituting thus a hot spot [1, 25].Hot pots can cause damage to the cell or the encapsulant within a short time of operating (Fig. 4).

Thermal analysis has been used to detect a hot spot defect. This analysis could be performed in normal operation. In this case, the PV module could be operating in a solar plant. Another thermal test consists of the operation of the PV module at extreme conditions (short-circuit conditions). In this case, the module should work alone, and the electrical connectors positive and negative of the module are short-circuited [1, 26].

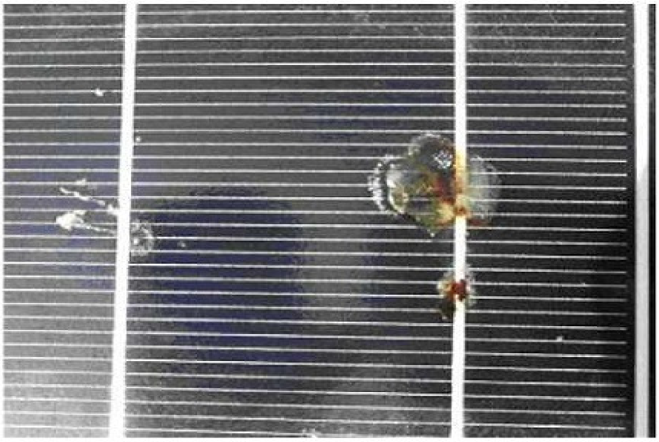

Fig. 4. Hot spot damages the PV cells/modules and reduces their performance [26]

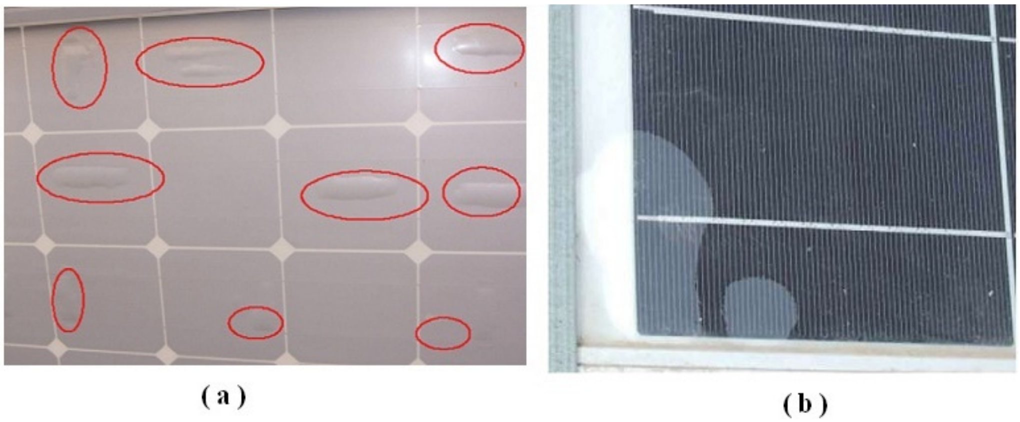

Fig.5. (a) Bubbles on the back side of a PV module [1, 3]; (b) Bubbles on the front side of a PV module [24]

Bubbles are generally due to chemical reactions that emit gases trapped in the PV cell/module (Fig. 5).

Bubbles located on the module front side produce a reduction of the radiation reaching the module. Which cause a decoupling of the light and increase reflection [3].This kind of defect is similar to delamination, but in this case, the lack of adherence of the EVA affects only a small area and is combined with the blowing of areas where this adherence has been lost. These defects appear in the center of the cell and may be due to poor adhesion of the cell caused by the high temperature. [1, 3].When bubbles occur in the back side of the PV module, a bulk appears in the polymeric encapsulant or the back cover, forming a bubble. Bubbles make the heat dissipation of the cells more difficult, overheating them and subsequently reducing the lifetime of these cells. Bubbles have been detected using IR techniques [27], as they are not visible though visual inspection alone but rather cause a temperature change (Fig.5). In addition, the bubble forms an air chamber, and although the air temperature in the chamber appears lower than in the adjacent cells, the cell temperature is actually higher because the heat of the cell is less dissipated [26].Moreover, the yellowing and browning cause a change in the transmittance of the light reaching the solar cells and thus a decrease in the power generated. The main cause of these defects in EVA and in ethylene copolymer films is UV radiation and water exposure combined with temperatures above 50 ℃ that induce a change in the chemical structure of the polymer [21]. In some PV cells/modules, yellowing appears in some areas but not in adjacent areas with a different polymeric encapsulant of a different origin or characteristics. During the life of the PV module, the anti-reflective coating (ARC) receives radiation that could induce a change in the ARC coloring. The anti-reflective properties may suffer changes in this case. The light that reaches the cells may be lower than expected. Nonetheless, this colour change should not cause a decrease in the wavelength radiation that the cell uses, but rather only affect a part of the visible radiation. Anti-reflection coating is one of the light management techniques to reduce reflection loss of solar light. When the light passes through the interface between two media with different refractive index, partial light will be reflected back. In terms of solar cells, reflection will occur at device surface and each interfaces. Such reflected light will not be converted into electricity [28]. A follow-up of the affected modules should be done in order to detect whether this defect leads to another more severe defect [10].Detachment of the frame, lines and blemishes in the cells are the other factors detected.

2.2 Light-Induced Degradation

Possible degradation mechanisms under irradiance are presented in Fig.6. Light induced degradation is one of the main ageing mechanisms. More research is required to understand the mechanisms and kinetics of PV module discoloration as well as the induced power losses. Besides discoloration, bubbles are another concern for encapsulant photo-thermal degradation. In the process of photochemical degradation, gases of different types can be generated with a potential to cause delamination which can enhance water ingress and cause further problems such as decoupling of light transmission and reduction of heat dissipation.

Another problematic reaction product generated during photochemical ageing is acid such as acetic acid and carbon dioxides.

The acidification may form electrolytes leading to metallization corrosion. It may also cause increased conductivity of the encapsulant which can result in increase leakage current. In addition, for the influences of irradiance on encapsulation materials, UV light has the most destructive effects. UV light is a primary initiator for many reactions such as the photodecomposition, photo thermal and photo bleaching. In contrast to discoloration, there is another UV-light induced effect called photo-bleaching as a result of photo-oxidation. With sufficient oxygen and at a high enough temperature, the yellowed polyenes can be oxidized generating products that are more visibly clear. Photo-bleaching can lead to a color changing of EVA from yellow back to clear. Besides the photodegradation of the base material, additives within EVA will decompose under UV light, generating free radicals that accelerate base EVA photodecomposition. The generated products may be chromophores that can worsen EVA discoloration [29-32].

2.3 Thermally-Induced Degradation

The temperature of cells/modules is usually higher than ambient temperature. Moreover, thermal effect acts as an accelerating factor for degradations caused by humidity or irradiance. Thermal cycles can reduce module reliability in a number of ways. For glass, residual strains may exist after lamination which can result breakage or delamination between glass/pottant under thermal strains. For encapsulant, different photo-thermal and thermal reactions can happen together with UV radiation from light. The principal reactions of EVA are what called Norrish I and Norrish II. In Norrish I, the vinyl acetate group can take off from the main chain to form acetaldehyde together with some gases which have potential to further lead to bubbles in the module. In Norrish II, C=C bonds (polyenes) are formed which have been widely considered as the chromophores group for EVA discoloration. Besides that, acetic acid is produced to catalyze discoloration and corrosion reaction.

The polyenes produced in Norrish II can further be oxidized to form α-β unsaturated carbonyl, another product leading to discoloration [6, 33, 34]. Besides chemical reactions, polymer may also undergo morphology changes under high temperature. Cells can also suffer from thermal fatigue with reported cracking and solder joint degradation. With regards to interfaces, the thermal heterogeneity of different materials can induce cracks, bubbles and delamination under daily thermal cycles. Besides these direct defects, temperature can accelerate many degradation processes. The water diffusion through polymers has been reported to be accelerated by temperature in the Arrhenius form [35]. Other procedures like metallization corrosion, leakage current, diffusion of dopants, impurities, occur more rapidly at higher temperature.

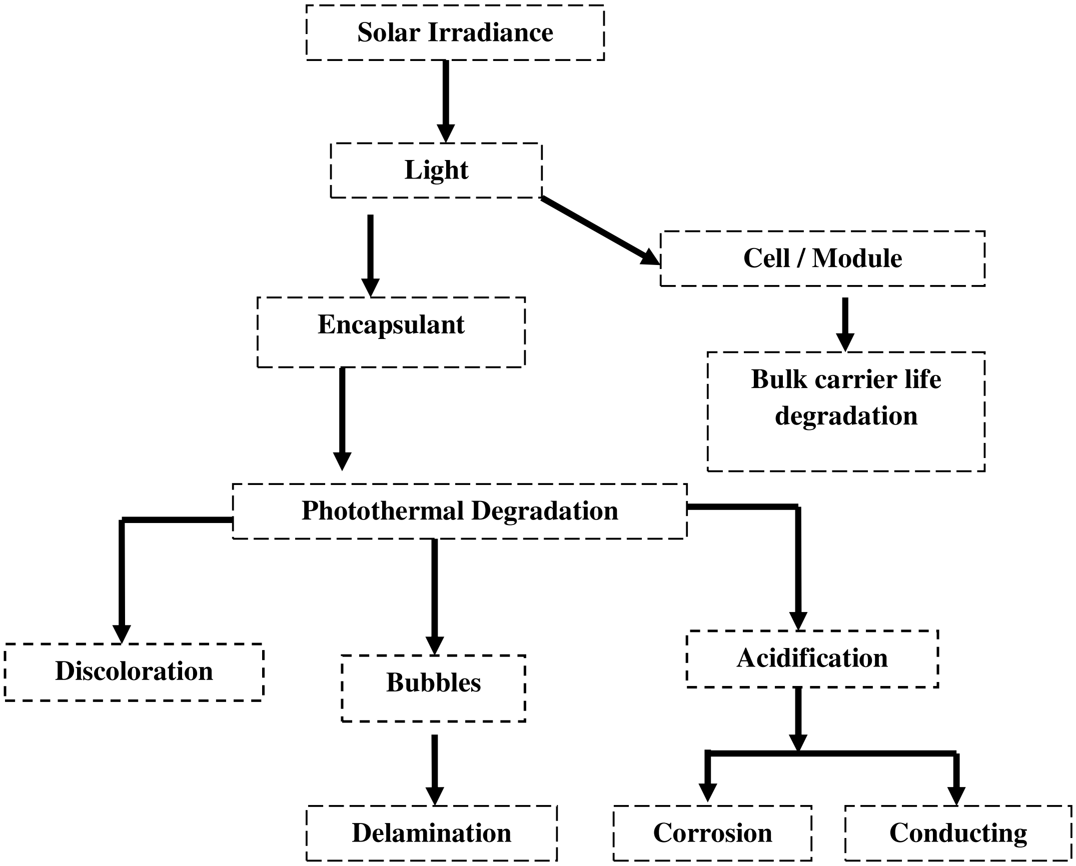

Fig. 6. Light-induced degradation

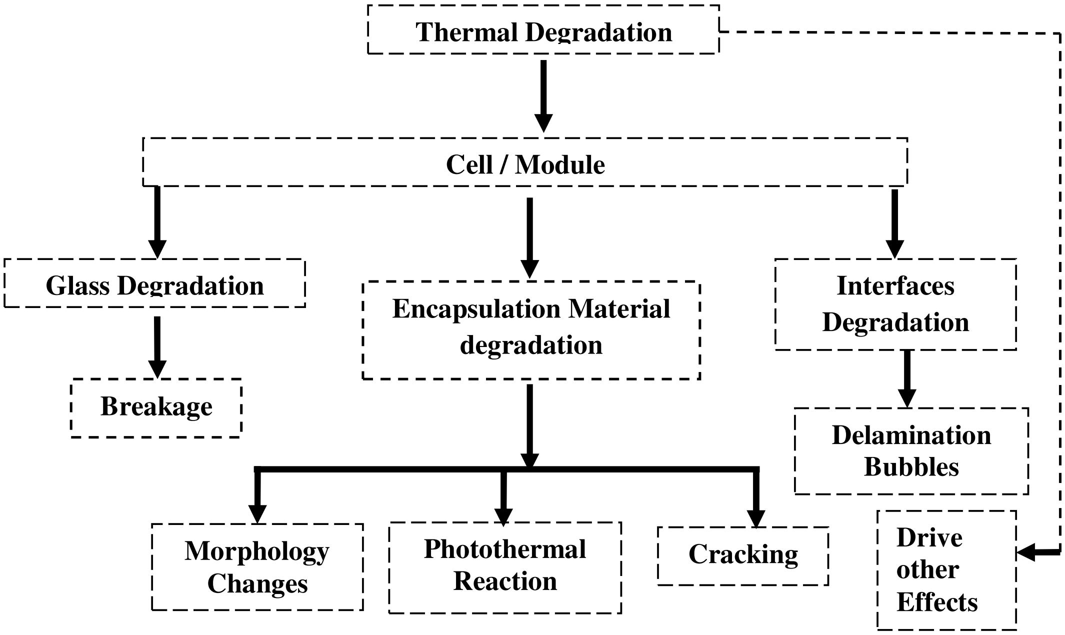

Fig. 7. Thermal-induced degradation

3. RESULTS AND DISCUSSIONS

3.1 Causes and Effects of Degradation (Visual Characteristics)

We indexed the modes of degradation and mechanisms along with cause and effect in association with the encapsulant in photovoltaic cells/modules [36]

3.1.1 Corrosion

❖ **Causes**

- Moisture ingress through or laminate edges
- Presence of higher ambient temperature along with humidity
- High system voltage due to sunlight presence
- Higher ionic conductivity of encapsulant due to moisture
- Higher moisture absorption of encapsulant
- Metallization sensitivity to moisture
- Interconnect sensitivity to moisture

❖ **Effects**

- Hotspot induced backskin burns
- Hotspot induced broken glass
- Power drop beyond warranty limit due to severe series resistance

❖ **Mechanism**

- Chemical corrosion (metallic and semiconducting components during nighttime), electrochemical corrosion (metallic components during daytime), or photoelectrochemical corrosion (semiconducting components during daytime) between cells or between cell and frame.

3.1.2 Encapsulant delamination

❖ **Causes**

- Sensitivity of adhesive bonds to ultraviolet (UV) light at higher temperatures or to humidity in the field
- Poor adhesive bonds at the interfaces during processing (glass/encapsulant; cell/encapsulant; backsheet/encapsulant)
- Contamination from the material (excess in glass or acetic acid from encapsulant)

❖ **Effects**

- Moisture ingress
- Enhanced encapsulant conductivity and interface conductivity (enhanced chemical/ electrochemical/photoelectrochemical corrosion)
- Major transmission loss
- Power drop beyond warranty limit due to optical decoupling and moisture ingress induced corrosion

❖ **Mechanism**

- Photothermal reaction (interface bonds breakage due to UV and temperature)
- Chemical reaction (interface bond breakage because of humidity or contaminants)

3.1.3 Degradation mode slow corrosion

❖ **Causes**

- Moisture ingress through backsheet or laminate edges
- Presence of higher ambient temperature along with humidity
- High system voltage due to sunlight presence
- Higher ionic conductivity of encapsulant due to moisture
- Higher moisture absorption of encapsulant
- Metallization(alloy) sensivity to moisture
- Interconnect (alloy) sensitivity to moisture

❖ **Effects**

- Increase in series resistance and decrease in power but within warranty limit

❖ **Mechanism**

- Chemical corrosion (metallic and semiconducting components during nighttime), electrochemical corrosion (metallic components during daytime) between cells or between cell and frame

3.1.4 Gradual electrochemical corrosion or cation migration to the semiconducteur surface/junction

❖ **Causes**

- Moisture ingress through backsheet or laminate edges
- Higher ionic conductivity of encapsulant due to moisture
- Higher moisture absorption of encapsulant
- Metallization (alloy) sensitivity to moisture
- Interconnect (alloy) sensitivity to moisture

❖ **Effects**

- Series resistance increase and : or shunt resistance decrease depending on bias polarity and climatic conditions
- Potential induced degradation leading to power loss but within warranty limit

❖ **Mechanism**

- Electrochemical corrosion (metallic components during daytime or photoelectrochemical corrosion (semiconducting components during daytime are more sensitive to electrochemical reactions under light) between cell and frame.

3.1.5 Gradual backsheet warping/detaching /cracking/crumbling

- **Cause**
- Poor adhesion between encapsulant and backsheet
- Moisture ingress through backsheet and /or laminate edges
- Polymer disintegration over time

- **Effects**
- Slow power degradation (due to corrosion of cell and circuit components but within warranty limit.

- **Mechanism**
- Chemical reaction weaking interface bonds (due to higher ambient temperature and / or humidity)

3.1.6 Gradual encapsulant discoloration

- **Causes**
- UV exposure at higher operating temperatures
- Reduced breathability
- Higher UV concentration
- Inappropriate additives in EVA

- **Effects**
- Transmission loss Reduced current/power but may not be affecting fill factor or warranty limit Cosmetic/visual change

- **Mechanism**
- Photothermal reaction (in the presence of UV and higher module temperature)

3.2 Electrical Parameters Degradation Correlated with Visual Degradation

In addition, we established a qualitative correlation between the electrical parameters affected and the different modes of degradation listed. However, the effect of discoloration causes loss of transmittance of the encapsulant EVA, reducing the photocurrent density (J_{ph}) of the cell/module thus culminating in decreased absorption of sunlight by the photovoltaic cell/module and power loss [1, 37, 38].

The position of EVA discoloration on solar cell results degradation of (J_{SC}) because it reduces the current flowing through the solar cell. It has been found that the discoloration does not affect the fill factor (FF) and (Voc) more.

However there are significant effect on the (J_{SC}) degradation and hence the power output (P) degradation [38, 39]. The corrosion of the edge, the junction box, bus-bars and interconnects cause the degradation of the PV modules peak power (P_{max}). The rate of power degradation is more in case of high corrosion of string interconnect ribbon. Then, with increase of percentage defects, the rate of power degradation increases. More recently, [39] shown that the power degradation range in Bus-bar is 0-2.1% per year, in cell interconnection ribbon is 0-2.1% per year and in string interconnection ribbon is 1-2.3% per year. The range of power degradation varies from 2.08% to 3.48% per year and the average degradation has been 2.60% per year in the case of EVA discoloration for only seven PV modules analyzed.

Delamination in the back-sheet of the PV module reduces the thermal conductivity locally and hence increases the cells/modules temperature.

Table 1. Electrical parameters influencing on PV cells performance

Parameters	Dependency	Influential factor
Cell density photocurrent	Depend on	Irradiance and wavelength
V_{oc}	Logarithmically dependent on	illumination
Jsc	Dependent on	illunination
Fill factor	Increases by	I1/Is increase
Fill factor	Increases by	Series resistance decrease
Fill factor	Increases by	Shunt resistance increase
V_{oc}	Decreases by	Temperature rise
J_{sc}	Nearly constant by	Temperature rise
Fill factor	Decreases by	Temperature rise

We revealed that the delamination depends on the detachment of the two layers, EVA-glass and EVA-back-sheet. The delamination occurring in back-sheet, the range of power degradation varies from 3.17 to 3.63%/year [38-40]. Hot spot occurs in PV modules due to thermal expansion/contraction of interconnection, shadowing, faulty cell and low resistance cell resulting decrease in (J_{SC}) and power. As the daily average power increases with decrease in number of hot spots, the range of the power degradation has been 0.29%/year for no hot spot and 2.16%/year for four hot spot and total power degradation after 22 years outdoor exposure has been 6.38% for no hot spot and 47.52% for four hot spot [39]. As a result, while a number of hot spot increases the area covered by the hot spot also increases.

In a general way, environmental and climatic conditions in which the modules are exposed significantly influence degradation. PV-module performance in general depends on solar irradiation (intensity, spectrum, especially ultraviolet (UV) radiation), temperature, moisture, mechanical stresses; and electrical operating conditions [41]. Other regional climate factors must be considered: snow, hail, wind, salt, sand, dust, and pollutants/gases, some of which are potentially corrosive.

Temperature is extremely significant to the degradation process, especially hot spots, encapsulant bleaching, delamination failure on interconnections, etc. Temperature is responsible for most of the chemical reactions of the degradation of modules.

Elevated temperatures can drastically change the mechanical, electrical, and optical properties of polymeric materials. Rapid changes in temperature over a short period of time cause thermo-mechanical stress and induce defects that can alter critical properties of polymer [39-41].

The long-term damage to the EVA during its useful life often involves interaction between heating at temperatures above 353K, absorption of moisture, oxygen, and most importantly, ultraviolet (UV) radiation from the solar spectrum. UV radiation has been identified as a critical factor in the degradation of photovoltaic modules by many research groups, and chemical changes in its structure have been identified leading to changes in transmission (discoloration). Thus, photodegradation caused by UV radiation is a major degradation of the material exposed to direct sunlight, and degradation is certainly climate zone dependent since the solar spectrum can change significantly from one geographical area to another [36-41].

4. CONCLUSIONS

Crystalline silicon PV cells/modules degradation exposed under temperature and heat effect has been investigated.

We reveal that:

- Delamination of encapsulant and back sheet,
- Bubble formation, Oxidation of busbars, Yellowing / browning of encapsulants and back sheets with and without power loss,
- Discoloration of busbars,
- Corrosion of connections,
- Cracking of back sheet,
- Hot spots, Cell breakage and micro cracks are the dominant modes of degradation,

Temperature is responsible for most of the chemical reactions, and extremely significant to the PV modules degradation process: especially hot spots, encapsulant bleaching, and delamination failure on interconnections, corrosion, discoloration, and bubbles on the panel's surface.

In perspective, an analytical modeling of electric parameters degradation of crystalline silicon photovoltaic cells will be investigated, using Servant model.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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