Assessment of PV Modules Degradation based on Performances and Visual Inspection in Algerian Sahara

Sadok Mohammed*, Benyoucef Boumediene**, Benmedjahed Miloud*‡

*Unité de Recherche en Energies Renouvelables en Milieu Saharien (URER/MS), Centre de Développement des Energies Renouvelables, B.P 478, (01000), Adrar, Algeria

**URMER Laboratory, Aboubakr Belkaid University – Tlemcen – Algeria

(sadokmohammed@hotmail.com, benyoucef_boumediene@yahoo.fr, benmedjahed_78@yahoo.fr)

‡ Corresponding Author; Benmedjahed Miloud, Po B.P 478, (01000), Adrar, Algeria, Tel: +213 49 362 247,

Fax: +213 49 362 249,benmedjahed_78@yahoo.fr

Received: 09.12.2015 Accepted:22.01.2016

Abstract- On-site measurement is a useful mean of diagnostic value and an important key for the assessment of electrical performances and the study of degradation of photovoltaic modules. This paper presents some findings of PV modules behaviour in Adrar (southern Algeria). The study allowed assessing the long-term degradation of modules and detecting possibly defects by visual inspection method. The average annual power degradation rate of PV modules is around 1,5%. Such value tallies with several studies. The visual inspection helps us detecting many types of failures in PV modules like delamination, burn marks, cracking while discoloration of encapsulant was the predominant modes of degradation. This study will in the other hand provide useful information to the manufacturers and owners and helps to better understanding the degradation mechanisms and, therefore, improving the long-term reliability of photovoltaic modules in the Algerian Sahara.

Keywords PV module, I-V characteristic, parameter, performance, degradation.

1. Introduction

Use of photovoltaic energy systems keep on increasing throughout the world. The world's cumulative installed PV capacity is rising steadily. From less than 1GW in 1998, it exceeded 23GW at the end of 2009 and by 2013, almost 138.9 GW of PV had been installed [1,2,3,4]

However, the long-term reliability of photovoltaic panels is essential for progress of photovoltaic field and allows guaranteeing technical and economic viability of PV systems as a reliable energy source. The consumers are becoming more and more sensitive to power losses [5]. Therefore, it is of the utmost importance that behaviours of PV devices should be understood. Reliability and lifetime of a PV system depend mainly on the modules performance and their different degradation modes [6,7,8].

On-site measurement of I-V characteristics of a PV module is a mean of diagnostic value and an important key for identifying its quality (weak modules, possible defects, degradation,...) [9,10,11,12].

This work is aiming at assessing the performances of about thirty photovoltaic modules after long period of outdoor exposure in the Algerian Sahara. The analysis was conducted by electrical performance evaluation and visual inspection of photovoltaic modules. Thus, the study allowed analysing long term field aged modules by estimating annual degradation rates and checking possible defects in modules. It will also provide useful information, helps manufacturers to understand outdoor degradation mechanisms and improve long-term reliability of photovoltaic modules in the Algerian Sahara.

2. Experimentation

In order to plot I-V curves of modules, we have used an electronic load and a scope meter (fig.1). The modules are of the same type (UDTS-50) and consist of 36 cells, an encapsulant (ethylene vinyl acetate), two bypass diodes, two junction boxes (one for each polarity), a protective glass on the front face and a polymer film (Tedlar) [13]. The assembly of these components can protect cells against different external agents and environmental conditions such as humidity (fig.2).

Experiments took place at Adrar in the south-west part of Algeria. This region of the Algerian Sahara has one of the greatest solar deposits in the world. The number of sunshine hours amounts almost 3500 hours/year [14]. The mean annual of the daily global irradiance measured on tilted surface exceeds the value of 7kWh/m.sq/day [15]. Curves of fig.3 give some examples of the diurnal global horizontal irradiance measured at Adrar (data source: New Energy Algeria meteorological station). However, this Saharan region is characterized by important differences in temperature over the year. In summer, the daily average of ambient temperature exceeds 42°C (the maximum almost reaches 50°) while in winter the daily average is around 7°C (the minimum is nearly 0°C) (see fig.4). The annual average measured relative humidity in year 2014 is near 19% (Source: New Energy Algeria meteorological station). In Adrar, sandstorms are more frequent, particularly in March and April.

3. Equivalent circuit of the module

In general a photovoltaic module is characterized by the equivalent circuit of the single diode model (fig.5).

Fig.1. Experimental setup

Fig.2. UDTS-50 PV modules

Within the normal operating range, this model has shown a high concordance with experimental data. The load voltage (V) and the load current (I) of the photovoltaic module are usually given by [16,17]:

$$I = I_{ph} - I_d - I_{sh} \tag{1}$$

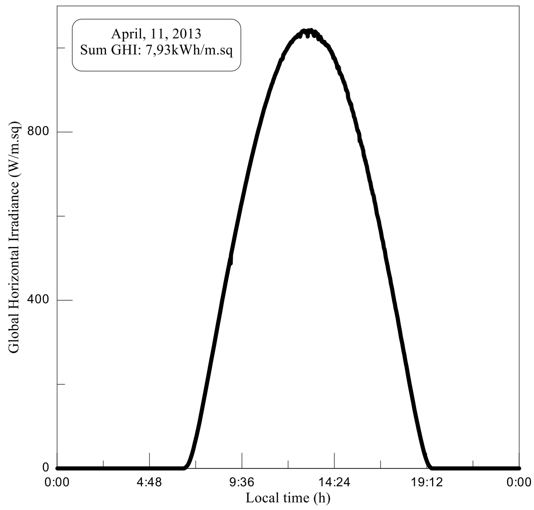

Fig.3(a). Global horizontal irradiance at Adrar (Source: NEAL meteorological station)

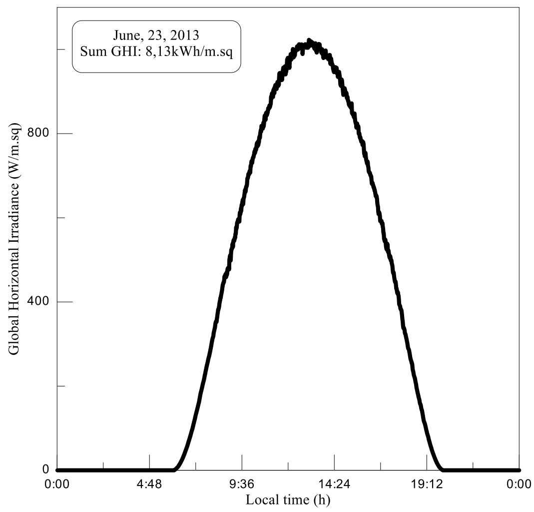

Fig.3(b). Global horizontal irradiance at Adrar (Source: NEAL meteorological station)

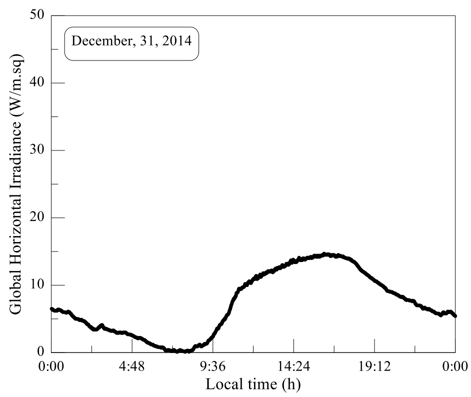

Fig.4(a) Ambient temperature at Adrar (Source: NEAL meteorological station) where I_{ph}, I_d and I_{sh} represent the light-generated current, the diode current and the leakage current due to shunt resistance, respectively.

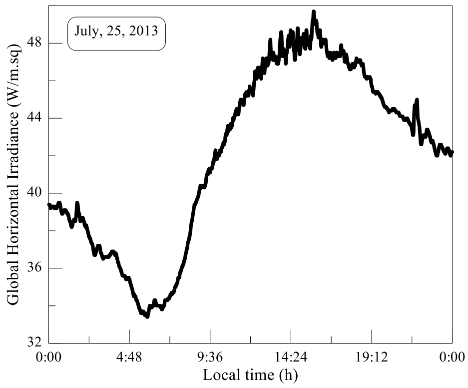

Fig.4(b) Ambient temperature at Adrar (Source: NEAL meteorological station)

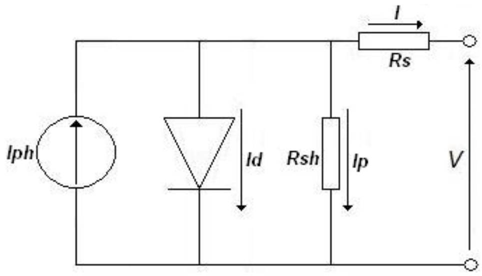

Fig.5. Equivalent circuit of single diode model of photovoltaic module

The currents I_d and I_{sh} are given by the following expressions:

$$I_d = I_0 \left\{ \exp \frac{q(V + I.R_s)}{A.k.T_c} - 1 \right\} \tag{2}$$

$$I_{sh} = (V + I.R_s)/R_{sh} \tag{3}$$

where I_o, R_s and R_{sh} are respectively the reverse saturation current of the p-n diode (A), the series and shunt resistance of the module (Ω). A is the ideality factor, k is the Boltzman's constant (J.K-1), T_c is the module temperature (K) and q is the charge of the electron (C).

Eq. (1) is implicit and non linear. The parameters are, by themselves, dependent on working conditions (solar radiation, temperature...) [3].

4. Analysis of experimental I-V curves

4.1. Experimental data fitting

The methodology we adopted consists in fitting the experimental I-V characteristics, translating them to standard test conditions, determining the modules performances and evaluating the degradation rates.

In order to make an estimation of modules parameters, we used the least square method for the single diode model (eq.1). However, the precision of the fitted curves is strongly affected by the choice of parameters initial values. The difficulties are increased when it's about of implicit and non linear type equation and parameters which depend on environmental conditions.

In fig.6, we have represented some fitted I-V characteristics. Similar characteristics which have been obtained in a previous work are also represented for comparison. We can see notable improvements with respect to the previous work [18]. The discrepancies between experimental and fitted curves are mainly due to the distribution of I-V data and then affect estimation of modules performances.

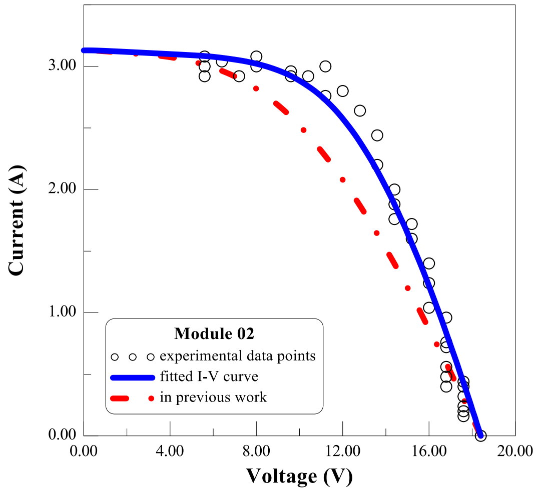

Fig.6(a). Some experimental and fitted I-V curves

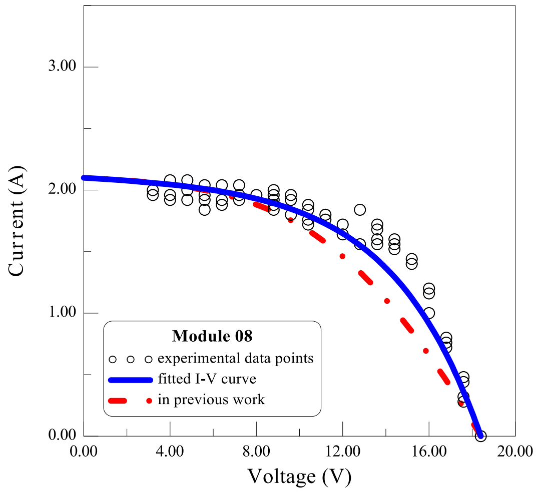

Fig.6(b). Some experimental and fitted I-V curves

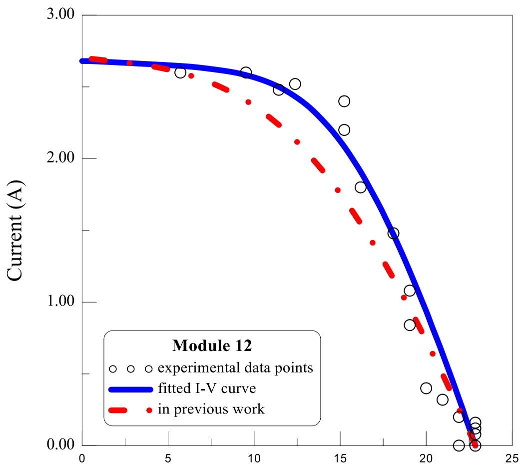

Fig.6(c). Some experimental and fitted I-V curves

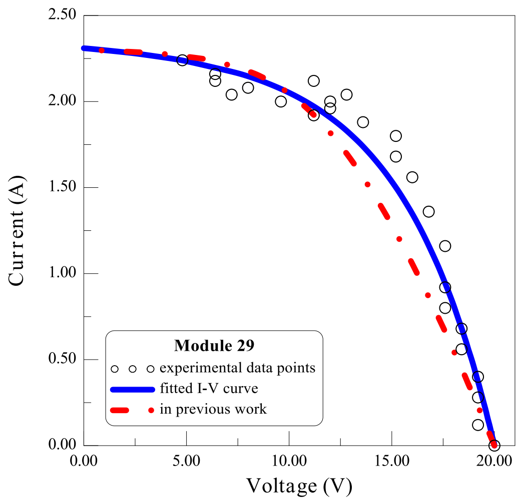

Fig.6(d). Some experimental and fitted I-V curves

4.2. Modules parameters

The graphical fitting has then enabled the estimation of the main parameters of one diode model (R_s, R_{sh}, I_0...) which provide the best possible precision. In table 1, we have represented some values of these parameters. These values have been used in the extrapolation to standard test conditions of fitted characteristics in order to determine the normalized performances of modules and eventually analyse degradation mechanisms [18].

Table 1. Main parameters of some tested photovoltaic modules

Module	$R_{sh}(\Omega)$	$R_s(\Omega)$	λ(V^{-1})	I_o(mA)	I_{ph}(A)	σ_{exp}(%)
01	269	0,002	0,27	11,94	2,124	1,92
02	200	1,246	0,57	0,085	3,150	1,12
08	211	0,084	0,25	19,23	2,102	1,75
09	240	0,005	0,24	25,25	2,060	1,38
11	201	0,152	0,31	6,85	1,992	1,62
16	201	0,878	0,35	2,32	2,061	1,68
24	203	0,764	0,37	2,79	2,723	0,69
29	222	0,888	0,35	4,33	2,696	1,48
30	202	2,111	0,52	0,14	2,883	0,75
32	203	1,302	0,48	0,30	3,021	0,97

5. STC extrapolation

In real functioning, the ambient conditions, under which a PV module can operate, don't necessarily match with laboratory tests [19]. Thus, it is more appropriate to present the modules performances in normalized format in order to make further comparison. Such normalization is made by carrying out a point by point extrapolation of measured data for reference conditions [19,20]. The procedure of the extrapolation of measured I-V characteristic necessitate to make punctual correspondence between measured and translated characteristic including the corrections due to subsequent deviation against standard test conditions and which are owed to simultaneous effects of irradiance (1000W/m^2) and module temperature (25°C) [21,22].

5.1. Operating module temperature

Estimation of operating module temperature presents a challenge because of the complexity of the thermal balance influenced by some factors such as wind direction, module design, orientation and mounting structure... [21,23]. The measuring temperature of a photovoltaic device is difficult because the contact with individual cells is impossible. In practice, it's the temperature of the rear module surface which is recorded, but this alternative leads to some discrepancies [23,24,25].

Another approach considers the nominal operating cell temperature (NOCT). This parameter allows bypassing the complexity of the thermal behaviour of photovoltaic modules [21,26]. Thus, a simplification is adopted by supposing that the difference cell temperature/ambient temperature increase linearly with irradiation. The linearity coefficient depends on module installation, wind speed, ambient humidity and so on. For different values of irradiation, a simplified expression of the module temperature is given by [21,26]:

$$T_c = T_a + \frac{H}{800}\left(NOCT - 20\right) \tag{4}$$

with T_a and H are respectively the ambient temperature and incident solar irradiation. The parameter NOCT is the nominal operating cell temperature.

5.2. STC I-V characteristics of PV modules

With their previous form, the fitted characteristics of modules seem to be not convenient for a subsequent use because they have been recorded for ambient conditions which are not necessarily identical. They must then be presented for the same ambient conditions in order to make possible any comparison [18]. Within the framework of this study, outdoor modules characteristics have been translated to standard test conditions by using the well-known formulas found in several references and given by [27,28]:

$$I_{STC} = I_{meas}\left(\frac{H_{STC}}{H_{meas}}\right) + \alpha\left(T_{c,\mathrm{mod}} - T_{STC}\right) \tag{5}$$

$$V_{STC} = V_{meas} - \beta.\Delta T - R_s.\Delta I + V_t.Ln\left(\frac{H_{STC}}{H_{meas}}\right) \tag{6}$$

with I_{STC} is the current module at STC (A), V_{STC} the voltage module at STC (V). H_{STC} and H_{meas} are respectively the reference and the measured irradiance (W/m^2), T_{STC} the reference module temperature (°C), Tc the measured (or computed) module temperature (°C), α the temperature coefficient of the current (A/°C), β the temperature coefficient of the voltage (V/°C), R_s the series resistance, I_{meas} the measured current.

ΔT and ΔI are given by the following expresions:

$$\Delta T = T_{STC} - T_{c,\mathrm{mod}} \tag{7}$$

$$\Delta I = I_{STC} - I_{meas} \tag{8}$$

The parameter T_c corresponds to the junction temperature of module cells. It's computed by using the formula of equation 4 [21,29]. An equivalent temperature is then supposed representing the thermal behaviour of all device cells [18].

When we applied the translation expressions, we obtained new characteristics which refer to standard test conditions. In fig.7, we have represented together the translated characteristics of some tested photovoltaic modules. So, it would be easier to compare between the performances of these modules. The examination of these graphs allows noting that the translated characteristics are relatively close to each other. This could be logical because all tested modules are of the same type [18]. The noted differences can nevertheless be ascribed to different factors [18]:

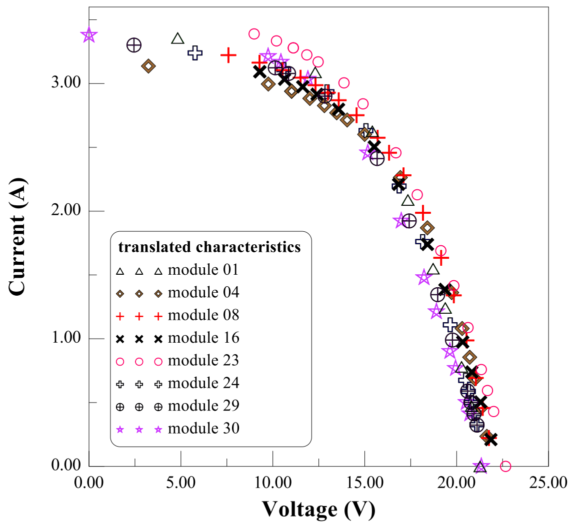

Fig.7(a). STC I-V characteristics of some modules

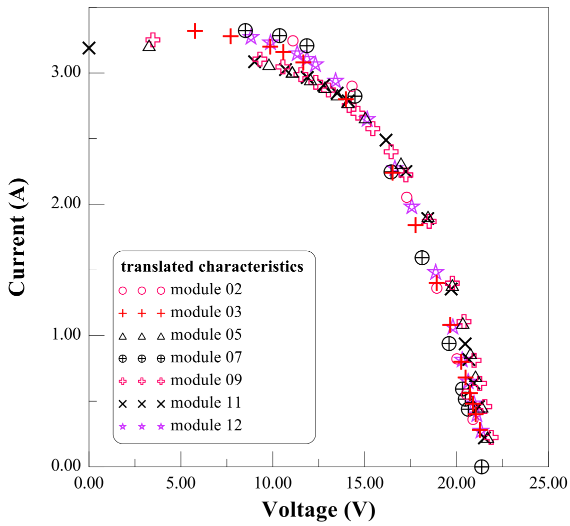

Fig.7(b). STC I-V characteristics of some modules

- sources of errors due to experimentation ;
- both coefficients α and β (used in STC equations) were supposed to have the same values for all the modules under test. Besides, the values of these coefficients can change with time. On the other hand, some measurements confirmed that the assumption of only two coefficients for the entire characteristic is not valid. This is one of reasons for which translation methods are less accurate [23,25,30];
- possible degradation or failures in modules ;

➢ errors relevant to the estimation of the equivalent module temperature (temperature model).

6. Performances and degradation assessment

6.1. PV modules performances

The analysis of STC I-V characteristics resulted in the determination of modules performances, namely the maximum powers, fill factors and efficiencies. Such parameters are presented in table 2. The values of modules parameters allowed deducing marked drops in maximum powers and fill factors with regards to initial values of a same-type module, so we can confirm that the modules have sustained performance degradation.

6.2. Assessment of PV modules degradation

In order to assess the degradation rate of modules, it's necessary to have information about their initial characteristics. In this study, we have chosen the same type module tested in the same site (before degradation). Then, we proposed using this module as a reference for the degradation study. The STC characteristic and the main parameters of this module are presented in figure 8.

Table 2. Some PV modules performances

Module	$P_{max,STC}$ *(W)*	FF_{STC} *(%)*	η *(%)*
02	40,98	56,77	9,55
04	38,99	56,29	9,09
08	40,45	55,05	9,43
09	39,80	54,88	9,28
12	40,31	54,61	9,40
16	38,86	53,98	9,06
24	40,10	57,74	9,35
27	34,49	47,05	8,04
30	38,21	52,80	8,91
31	31,76	46,39	7,40

In order to make a comparison between the modules performances, we intended to represent their characteristics in a dimensionless form [19]. In principle for a same module, the dimensionless function $i = f(v)$ defined for different values of environmental conditions leads to reduced characteristics which are close to each other. [19]. The examination of curves of figure 9 allows noting considerable deviations against the reference module, in particular in the maximum power region. Consequently, the modules fill factors will be dropped.

In order to assess the degradation of the modules, we defined a degradation factor for each parameter of the module (P_{max}, FF, R_s,...). This factor has been used in order to make a theoretical estimation of the change in these parameters compared to reference module ones. In table 3, we have given values of degradation factors for some tested modules. As first observation, we can report a decrease in the maximum power. The values of ΔI_m and ΔV_m let to conclude that the maximum power points were moved away from the reference module knee. Certainly, the increase in Rs and decrease in R_{sh} have principally contributed in the performances degradation of tested photovoltaic modules. The outdoor testing of the 32 photovoltaic modules revealed that the power degradation rate is ranged between 33% and 7% in 11 years of operating (3%/year and 0,64%/year). The yearly average rate is around 1,5%.

6.3. Discussions about the degradation rate

There is no consensus number for the annual degradation rates of conventional crystalline modules; however, it

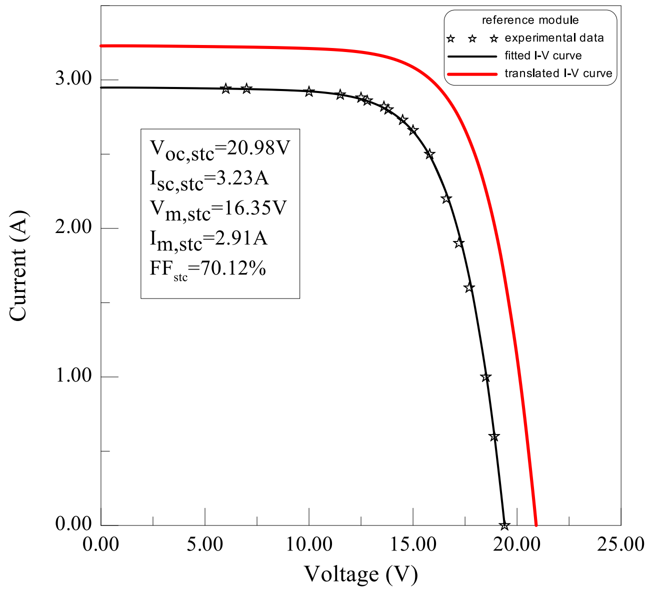

Fig.8. Experimental and STC characteristics of reference module

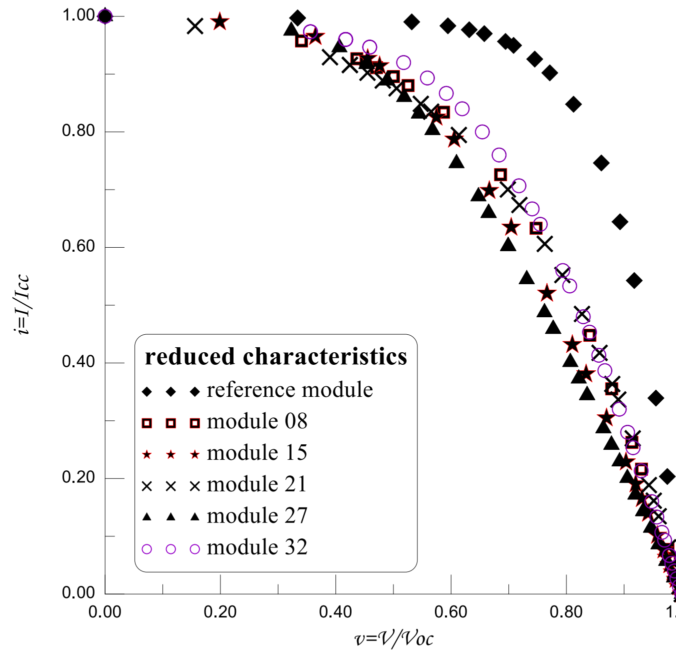

Fig.9. Reduced I-V characteristics of reference and tested modules

became a focus for researchers [31]. Various field studies have measured the yearly degradation rates of crystalline modules and indicate a value of approximately 1.0% per year

[31,32,33,34]. In recent studies, it has been reported a value of 0,8%/year of the mean degradation rate deduced from more than 2000 degradation rates measured on modules after long periods of exposure field. Nevertheless, 22% of these reported rates are greater than 1%/year [35]. In reference [36], the degradation rate of 12-13 years old modules is ranged between 0,6%/year and 2,5%/year depending on the manufacturer. Other study showed a mean degradation rate over 14% after 11 years (1,27%/year) [9].

The degradation rate found in the present study seems to be in good concordance with studies. It's nearly identical to others quoted for modules fielded in desert climatic conditions [31,33]. Higher degradation rate (1,75%/year) has been found after 20 years of field exposure of a same type module tested in other site of Algerian Sahara [37].

Table 3. Degradation Factor values of some modules

Module	*ΔVm*	*ΔIm*	*ΔPm*	*ΔFF*	*Δη*
M01	-8,63	-5,74	-13,75	-19,03	-13,71
M02	-10,91	-2,50	-13,01	-18,90	-12,98
M03	-10,96	-7,59	-17,61	-24,14	-17,57
M04	-4,65	-14,05	-17,94	-19,73	-17,90
M05	-4,76	-11,90	-15,97	-19,83	-15,93
M07	-12,15	-1,87	-13,67	-18,67	-13,63
M08	-5,01	-10,50	-14,86	-21,50	-14,82
M09	-5,02	-11,92	-16,22	-21,74	-16,18
M11	-4,22	-11,78	-15,39	-18,60	-15,35
M12	-9,25	-6,64	-15,15	-22,12	-15,11
M16	-7,30	-11,90	-18,21	-23,01	-18,18
M23	-6,99	-4,30	-10,86	-24,65	-10,82
M24	-7,50	-8,88	-15,59	-17,65	-15,55
M29	-10,52	-9,57	-18,96	-23,84	-18,93
M30	-13,60	-7,04	-19,57	-24,70	-19,53
M31	-22,05	-14,36	-33,15	-33,84	-33,12

We shouldn't rule out that degradation rate can increase under influence of intense ambient temperature [38]. Furthermore, other studies confirmed that modules, incorporating EVA encapsulant and a Tedlar aluminium back sheet, showed higher degradation than silicone encapsulated ones [35,39]. We should point out that the number of modules under test is relatively insufficient with respect to other studies. In reference [36], the number of modules reached 4000. Obviously, the fitting errors of experimental characteristics have no negligible influence on the estimation of modules degradation rates.

6.4. Detection of defects by visual inspection

Fielded photovoltaic modules are subjected to several environmental stresses which cause the performance losses affecting the electrical and financial performance of the system and the consumer fulfilment. [6]. Theses environmental stresses are due to several factors such as: temperature, humidity, irradiation, mechanical shock, etc [6,8,36]. According to several studies, the degradation of photovoltaic modules can be due to some mechanisms which are brought about to design failure or defects that can emerge when the modules are in operation [4,40]. Environmental parameters such as temperature, humidity and UV radiation are the main factors of PV module degradation [8,41]. In the case of crystalline silicon PV modules, the degradation of the semiconductor is not important because of the stability of the semiconductor material. Field experience indicates that the primary causes of performance losses are associated with mechanisms external to the cell itself such as corrosion, discoloration, delamination, breakage and cracking cells… [8,42].

In order to detect photovoltaic module degradation modes, scientists use various methods such as visual inspection, infrared images, electroluminescence and photoluminescence imaging techniques…[4,12,43]. However, the visual inspection is a powerful tool and is the most effective and quickest method to identify causes of failures in a PV module. In addition, the vast majority of the returns were associated with mechanisms that can be observed visually by customers [43,44].

Generally, power degradation of PV modules appears to be primarily due to current drop (discolouration and/or delamination of the encapsulant) and fill factor drop (series resistance increase due to thermo-mechanical fatigue of solders bonds) [36,43]. The factors affecting the durability of the interfaces within a PV module may include UV radiation, temperature, and/or moisture [43].

In this study, we just carried out visual inspection for detecting defects in photovoltaic modules. The observed defects are thus highlighted as follows:

6.4.1. Browning of the EVA encapsulant

Under irradiance, encapsulant becomes too vulnerable. In fact, UV light is the primary stressful factor for polymers as its high energy content. Some authors determined that this degradation is mainly due to change in chemical structure of the polymer provoked by UV radiation and water exposure combined with temperatures above 50°C. This degradation is accompanied by a discoloration of the encapsulant. This causes a change in the transmittance of the light reaching the solar cells and therefore the power generated by the module is reduced [4,6,7]. Some studies showed that EVA discoloration degrades the short-circuit current (I_{sc}) of PV module; this degradation of I_{sc} 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 [8]. In our study, most of tested modules showed light discoloration over centre of cells Fig.10 shows an example of the discoloration of EVA.

6.4.2. Delamination

The loss of adherence between the encapsulating polymer and the cells or between cells and the front glass and

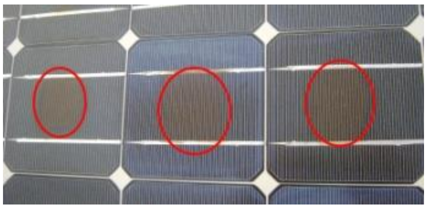

Fig.10. Discoloration of EVA

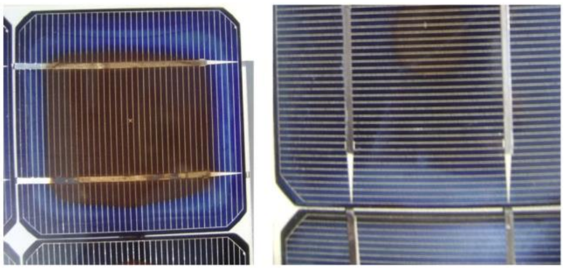

Fig.11. Some delaminated cells

the subsequent detachment of these layers is called delamination. It represents a serious problem for photovoltaic module lifetime because it can cause severe performance degradations. It can lead to two effects: an increase of the light reflection as well as water penetration inside the module structure (chemical reactions and degradation of different parts of the module). It can also weaken and even interrupt heat dissipation within the module to cause hot spot and thermal fatigue. Delamination often results in the corrosion of metals involved in the module structure and then the resistance could increase. Delamination can also lead to a transmittance loss [4,6,8,43]. This defect type is not frequently encountered in tested modules. Fig.11 illustrates such defect seen in UDTS-50 PV modules.

6.4.3. Snail trail

Snail trails are a widespread phenomenon affecting crystalline silicon modules at outdoor exposure and arouse an enormous concern to the solar industry. The formation of silver carbonate nanoparticles discolours the silver paste of the front metallization solar cells (at the edge of the solar cell and along usually invisible cell cracks) [43,45,46,47]. During the summer and in hot climates snail tracks seem to occur faster [43,45,46]. It seems that moisture is a key factor in the phenomenon [45]. There is a little sign that snail trails cause significant decrease in module power [45,47]. The origin of the discoloration of the silver paste has not been clarified [43,46]. Fig.12 shows such defect in a photovoltaic module.

6.4.4. Bubbles

A bubble is a sort of an air chamber that is usually due to a chemical reaction releasing some gasses. This kind of defect can result in increase in temperature of adjacent cells because the heat is less dissipated [4]. We have not seen this kind of defect (in back or front side of photovoltaic modules). However, the stains in the photo of fig.13 look like bubbles. Sometimes a bubble can be only detected using IR techniques, as it is not visible though visual inspection alone but rather causes a temperature change [4,8].

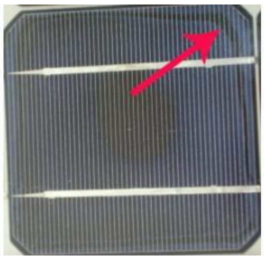

Fig.12. Discoloration due to snail trails

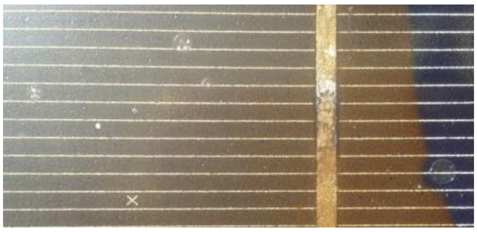

Fig.13. Bubbles in UDTS-50 module

6.4.5. Burn marks

Burn marks are one of the most common failures sometimes observed in silicon modules. They are associated with parts of the module that become very hot because of a variety of cell failures (partial shadowing, solder bond failure, failures in the interconnection between cells, cells mismatch or other hot spots) [43,48]. Solder bond failures can be caused by thermal fatigue. As the temperature increases, the resistance may also increase until the temperature is hot enough to discolour the encapsulant [43]. Most of inspected modules didn’t show visible burn marks. Nevertheless, hot spot defects can’t be detected by sight but by performing a thermal analysis [4]. The photos of fig.14 show some examples of burn marks in cell-interconnect busbar.

6.4.6. Other defects

Visual inspection, carried out in photovoltaic modules, revealed some other defects which we summarize as follows:

- Cracks, lines and blemishes: the small thickness of silicon solar cells makes them more vulnerable to cracks. Some cracks are very small and thus they aren’t visible to the naked eye (micro-cracks). A crack could probably lead to chemical reaction or a migration that affected the anti-reflective coating and upper layers and result in a visible line [4,49]. There is always a potential risk that micro-crack can develop into longer and wider cracks leading to a cell fraction with a performance lost [6,49]. Cracks are due to mechanical stress caused by wind and thermo mechanical stress on the solar modules due to temperature variations [43]. The thermal heterogeneity of different materials can induce cracks, bubbles and delamination under daily thermal cycles [6].The photos of fig.15 show cell in module with lines and some blemishes.

- Defects in anti-reflective coating: in operating conditions, the radiation could induce a change in the anti-reflective coating colouring and their properties as well. Then the light that reaches the cell may be lower than expected [4]. A follow-up of affected modules showed that this defect is related to an oxidation of this coating. Such oxidation can severely affect adherence between the cells and the glass [4] (fig.16).

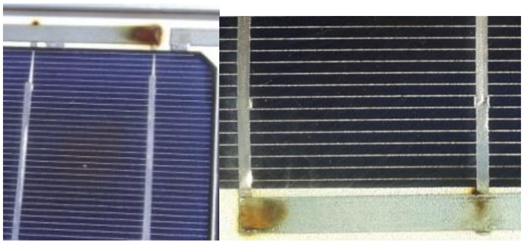

Fig.14 Somme detected burn marks

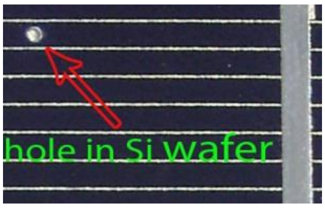

Fig.15a Cracks, lines and blemishes in some modules

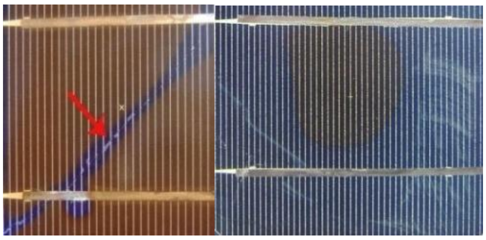

Fig.15b Cracks, lines and blemishes in some modules

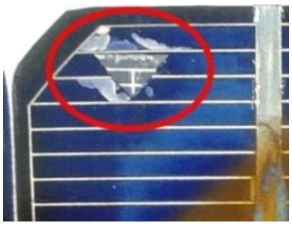

Fig.15c Cracks, lines and blemishes in some modules

Fig.16. Defects in anti-reflecting coating in some modules

Other defects (stain, imperfection, scratches, abnormalities,…) were also observed in some modules and can cause risk of power degradation or breakdown or hotspots (fig 17).

In general, we have not observed visible signs of defect or damage in junction boxes of modules. Nevertheless, we have to care about two major problems with electrical connections:

- due to the thermal differences, the module wiring connectors may slacken off (connections must be regularly inspected and tightened if necessary);

- penetration of dust in the electrical connection boxes can weaken the electrical contacts (periodical cleaning and inspection are necessary).

7. Conclusion

The aim of this work was to provide an assessment of the performance degradation of UDTS-50 photovoltaic modules, made up of monocrystalline silicon solar cells, after long period of exposure in Algerian Sahara.

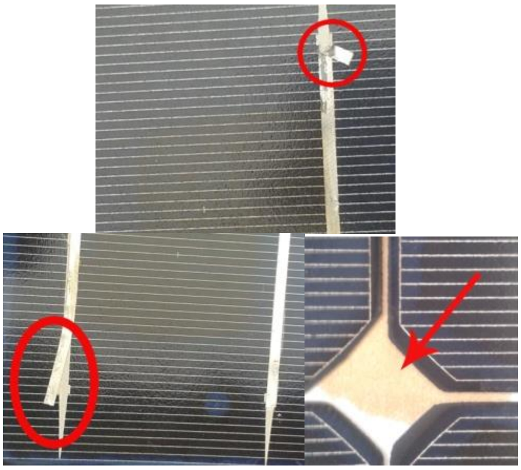

Fig 17. Some other defects in PV modules

The parameters of the photovoltaic modules have been determined by using the graphical fitting approach (least squares method). Then the translation procedure has been used in order to extrapolate the fitted I-V characteristics to standard test conditions. The comparison of these characteristics with a reference module revealed a drop in performances namely the maximum power. This means that the modules have sustained degradation in their performances. The average annual power degradation rate of modules is around 1,5%. This rate seems to be in good concordance with several studies and it is identical to others quoted for modules fielded in desert climatic. Higher degradation rate (1,75%/year) has been reported for the same type module after 20 years of field exposure in similar site of Algerian Sahara.

Visual inspection has been carried out in order to detect defects in fielded photovoltaic modules. Several types of defects have been observed (discoloration, delamination, burn marks…) but discoloration of encapsulant was the predominant modes of degradation.

References

[1] Global market outlook for photovoltaics 2014-2018. Available from http://www.cleanenergybusinesscouncil.com

[2] PVPS Report Snapshot of Global PV 1992-2013. Available from www.iea-pvps.org.

[3] Renewables 2011 Global Status Report. Available from: http ://www.ren21.net/Portals/97/documents/GSR/REN21 GSR2011.pdf.

[4] Munoz MA, Alonso-Garci MC, Vela N, Chenlo F, “Early degradation of silicon PV modules and guaranty conditions”, Solar energy; vol. 85, pp. 2264-2274, 2011.

[5] A. Chaurey, T. C. Kandpal, “Assessment and evaluation of PV based decentralized rural electrification: An overview”, Renewable and Sustainable Energy Reviews, vol. 14, pp. 2266–2278, 2010.

[6] Dan Wu, Jiang Zhu, Thomas R. Betts, Ralph Gottschalg, “PV Module Degradation Mechanisms under Different Environmental Stress Factors”, 8th Photovoltaic Science Application and Technology Conference (PVSAT-8), Newcastle, 177-180, 2-4 April 2012.

[7] E. Hasselbrink, M. Anderson, Z. Defreitas, M. Mikofski, Y.-C. Shen, S. Caldwell, A. Terao, D. Kavulak, Z. Campeau, D. DeGraaff, “Site Data Validation of the PVLife Model Using 3 Million Module-Years of Live”, 39th IEEE PVSC Tampa, FL, pp. 0007-0012, 16-21 June 2013.

[8] A. Ndiaye, A. Charki, A. Kobi, C. M. F. Kébé, P. A. Ndiaye, V. Sambou, “Degradations of silicon photovoltaic modules: A literature review”, Solar Energy, vol. 96, pp. 140-151, 2013.

[9] Reis AM, Coleman NT, Marshall MW, Lehman PA, Chamberlin CE, “Comparison of PV module performance before and after 11-years of field exposure”. 29th IEEE Photovoltaic Specialists Conference - PVSC, New Orleans; pp. 1432-1435, 2002.

[10] Blaesser G, “PV system measurements and monitoring the European experience”, Solar Energy Materials and Solar Cells, vol. 47, pp. 167-176, 1997.

[11] Marwan M.M, “Transient analysis of a PV power generator charging a capacitor for measurement of the I-V characteristics”, Renewable Energy, vol. 31, pp. 2198-2206, 2006.

[12] Petr Mastny, Jan Moravek and Jiri Drapela, “Practical Experience of Operational Diagnostics and Defectoscopy on Photovoltaic Installations in the Czech Republic”, Energies, vol 8, pp. 11234-11253, 2015, doi:10.3390/en81011234

[13] A. El Amrani, A. Mahrane, F.Y. Moussa et Y. Boukennous, “Procédé d’encapsulation des modules photovoltaïques type mono-verre”, Revue.des Energies. Renouvelables, vol. 9, pp. 37-42, 2006.

[14] Hadj Belkacemi M, “Modélisation et Etude Expérimentale d’un Capteur Solaire non Vitré et Perforé”, master’s thesis, University of Tlemcen Algeria, 2011.

[15] Capderou M, “Atlas Solaire de l’Algérie”, vol. 2. Office des Publications Universitaires; Alger, 1985.

[16] K. Ishibashi, Y. Kimura, M. Niwano, “. An extensively valid and stable method for derivation of all parameters of a solar cell from a single current-voltage characteristic”, Journal of Applied Physics, vol. 103, 094507, 2008.

[17] Carrero C, Ramírez D, Rodríguez J, Platero CA, “Accurate and fast convergence method for parameter estimation of PV generators based on three main points of the I-V curve”, Renewable Energy, vol. 36, pp. 2972-2977, 2011.

[18] Sadok M, Mehdaoui A, “Outdoor testing of photovoltaic arrays in the Saharan region”, Renewable Energy, vol. 33, pp. 2516-2524, 2008.

[19] Blaesser G, “The reduced current-voltage characteristics of PV arrays and its quasi- independence of ambient conditions”, 14th European photovoltaic solar energy conference, Barcelona, pp. 1520-1523, 30 June - 4 July 1997.

[20] Kurtz SR, Myers D, Townsend T, Whitaker C, Maish A, Hulstrom R, Emery K, “Outdoor rating conditions for photovoltaic modules and systems”, Solar Energy Materials & Solar Cells, vol. 62, pp. 379-391, 2010.

[21] Luque A, Hegedus S, “Photovoltaic science and engineering”, Chichester: John Wiley & Sons Ltd.; 2003.

[22] Leboeuf C, Ossenbrink H, “PV module power output : sensitivity and uncertainty in non-STC measurements”, 22th IEEE Photovoltaic Specialists Conference, Las Vegas; pp. 614-619, 7-11 Oct. 1991.

[23] King DL, Kratochvil JA, Boyson WE, Bower WI, “Field experience with a new performance characterization procedure for photovoltaic arrays”, 2nd World Conference and Exhibition on Photovoltaic Solar Energy Conversion, Vienna, pp. 1947-1952, 6-10 July 1998.

[24] Markvart T, Castaner L, “Practical Handbook of Phtotovoltaics: Fundamentals and Applications”, Elsevier Ltd, Kidlington, 2003.

[25] King DL, “Photovoltaic module and array performance characterization methods for all system operating conditions”. Proceeding of NREL/SNL Photovoltaics Program Review Meeting, pp. 347-368, November 18-22, 1996, Lakewood, CO, AIP Press, New York, 1997.

[26] E.A. de la Breteque EA, “Thermal aspects of c-Si photovoltaic module energy rating”, Solar Energy, vol. 83, pp. 1425-1433, 2009.

[27] Leboeuf C., Ossenbrink H, “PV module power output: sensitivity and uncertainty in non-STC measurements”, 22th IEEE Photovoltaic Specialists Conference, pp. 614-619, 7-11 Oct. 1991.

[28] Knaup, W, “Power rating of photovoltaic modules from outdoor measurements”, 22th IEEE Photovoltaic Specialists Conference, pp. 620-624, 7-11 Oct. 1991.

[29] Coakley JF, Kallis JM, Jones IR, Cuddihy EF, Garcia A, “Cell temperatures in terrestrial photovoltaic modules effect of design factors”, 17th IEEE Photovoltaic Specialists Conference, Orlando, pp. 496-501, May, 1-4 1984.

[30] King DL, Kratochvil JA, Boyson WE, “Temperature coefficients for PV modules and arrays : measurement methods, difficulties, and results”, 26th IEEE Photovoltaic Specialists Conference, Anaheim, pp. 1183-1186, 29 September–3 October 1997.

[31] SunPower® Module Degradation Rate. Available at http://us.sunpower.com

[32] Sample, T. (2011). Failure Modes and Degradation Rates from Field-Aged Crystalline Silicon Modules. In PV Module NREL Reliability Workshop, Golden, pp. 611-641, CO., February 16-17, 2011.

[33] Suleske A. A, “Performance Degradation of Grid-Tied Photovoltaic Modules in a Desert Climatic Condition”, Thesis of Master of Science in Technology, Arizona State University, 2010.

[34] Jennifer E Granata, William E Boyson, Jay A Kratochvil,and Michael A Quintana, “Long-term performance and reliability assessment of 8 PV arrays at Sandia National Laboratories”, 34th IEEE Photovoltaic Specialists Conference (PVSC), Philadelphia, PA, pp. 001486 – 001491, 7-12 June 2009.

[35] Dirk C. Jordan and Sarah R. Kurtz Photovoltaic. Degradation Rates - An Analytical Review. Progress in Photovoltaic Research and Applications, vol. 21(1), pp. 12-29, 2013.

[36] Mani G. Tamizh-Mani, Joseph Kuitche and Research Students of ASU-PRL, “Failure and Degradation Modes of PV modules in a Hot Dry climate: Results after 12 to 26 years of field exposure”, PV Module Reliability Workshop 2013, Golden, Colorado, February 26–27, 2013.

[37] K.Agroui, “Contribution au Développement des Techniques de Contrôle de Qualité des Modules PV de Diverses Technologies”, Doctorate Thesis, Université de Bechar, Algeria, 2010.

[38] A.W.Czanderna and F.J.Pern, “Encapsulation of PV modules using ethylene vinyl acetate copolymer as pottant: critical review”, Solar Energy Materials and Solar Cells, vol. 43, pp. 101-118, 1996.

[39] Manuel Vázquez, and Ignacio Rey-Stolle. Photovoltaic Module Reliability Model Based on Field Degradation Studies. Progress in photovoltaics: Research and Applications, 16, pp. 419-433, 2008.

[40] F. Iberraken, R. Medjoudj, D. Aissani, “Competing Risk of Degradation Processes of a Photovoltaic System under Several Conditions”, International Journal of Electrical Energy, vol. 2, No. 4, pp. 295-299, 2014.

[41] M. Makenzi, N. Timonah, M. Benedict, I. Abisai, “Degradation Prevalence Study of Field-Aged Photovoltaic Modules Operating Under Kenyan Climatic Conditions”, Science Journal of Energy Engineering, vol. 3, No. 1, pp. 1-5, 2015.

[42] Quintana MA, King DL, McMahon TJ, Osterwald RC, “Commonly observed degradation in field-aged photovoltaic modules”, 29th IEEE Photovoltaic Specialists Conference, pp. 1436–1439, New Orleans , 2002.

[43] Performance and Reliability of Photovoltaic Systems. International Energy Agency Photovoltaic Power Systems Programme, March 2014. Available from: http://www iea-pvps.org

[44] S.S. Chandel, M. Nagaraju Naik, Vikrant Sharma, Rahul Chandel, “Degradation analysis of 28 year field exposed mono-c-Si photovoltaic modules of a direct coupled solar water pumping system in western Himalayan region of India”, Renewable Energy, 78 (2015) 193-202.

[45] S. Meyer, S.Timmel, S.Richter, M.Werner, M.Gläser, S.Swatek, U.Braun, C. Hagendorf, “Silver nanoparticles cause snail trails in photovoltaic modules”, Solar Energy Materials & Solar Cells, vol. 121, pp. 171–175, 2014.

[46] S.,Richter,M.,Werner,S.,Swatek,C. Hagendorf, “Understanding the snail trail effect in silicon solar modules on microstructural scale”, 27th European Photovoltaic Solar Energy Conference and Exhibition, Frankfurt, pp.3439–3441, 24-28 September 2012.

[47] P Peng, A.Hu, W.Zheng, P.Su, D.He, K.D. Oakes, A.Fu, R.Han, S.L. Lee, J.Tang, Y.N. Zhou, “Microscopy study of snail trail phenomenon on photovoltaic modules”, RSC Advances, 2, pp. 11359-11365, 2012.

[48] Molenbroek, E., Waddington, D.W., Emery, K.A, “Hot spot susceptibility and testing of PV modules”, 22th IEEE Photovoltaic Specialists Conference, Las Vegas, pp. 547–552, 1991.

[49] Damages at Solar Panels Available from: http://www.europe-solar.de.