6.2 Review of failures found in silicon wafer-based PV modules

The most common PV modules are made of wafer-based silicon solar cells. Therefore a large knowledge base has been accumulated for the most PV module failures of this type. However even for this type of PV modules some effects like potential induced degradation and snail tracks have been studied in detail in the last 3 years for the first time. Therefore their description shows the current state and is not a final presentation. Even the other module failure descriptions arise from older PV modules which may differentiate them from current module and material designs.

6.2.1 EVA discolouration

One of the most overt degradation mechanisms for PV modules is the discolouration of the ethylene vinyl acetate (EVA) or other encapsulation materials. This type of degradation is predominantly considered to be an aesthetic issue. Discolouration may become apparent to an observer before module current (therefore power production) can be confirmed to decrease, but EVA discolouration is expected to contribute < 0.5%/a of the ~0.8%/a degradation that is commonly seen for Si modules [Jordan11]. Examples of the discolouration of EVA are shown in Tab. 5.1.3.

EVA is usually formulated with additives, including UV and thermal stabilizers. But if the choice of additives and/or their concentrations are inadequate, the EVA may discolor as shown in Tab. 5.1.3. To explain, interaction between incompatible additives in the field may produce discolouring chromophore species [Holley98] or the depletion of additives (such as the UV absorber) over time [Shioda11] may render the EVA vulnerable to damage. The patterns of discolouration observed in the field can be very complex because of the diffusion of oxygen or the products of reaction, such as acetic acid [Pern97], generated when heat and UV light interact with EVA. The presence of oxygen photobleach chromophores, creating a ring of transparent EVA where no discolouring chromophore species are present, around the perimeter of a wafer-based cell. It is quite common to see symmetric patterns and sometimes multiple rings based on the effects of limited chemical diffusion, both into and out of EVA and the existence of multiple chemical pathways that produce similar chromophore species. A photo in Tab. 5.1.3 shows an example where a single cell is far darker than any of the adjacent cells. This typically implies that the most discolored cell was at higher temperature than the surrounding cells, perhaps because of a lower photocurrent of the cell compared to the other cells in the module or the cell being located above the junction box.

Unless discolouration is very severe and localized at a single cell, where it could cause a substring bypass-diode to turn on, the discolouration of EVA does not present any safety issues (safety class A). While it is uncommon for EVA discolouration to induce other failures within the cell, discolouration may correlate to: significant thermal history (high temperature in the field), the generation of acetic acid [Pern98] and concomitant corrosion [Weber12], and the embrittlement of the EVA [Dhere98].
There is some evidence that discolouration of EVA may be a contributor to the slow degradation that is seen in the majority of silicon modules. The median degradation rate of ~0.5%/a was reported for a summary of ~1800 studies of silicon module degradation [Jordan11]. This degradation was found to be dominated by loss of short-circuit current. Of these, ~60% reported observation of discolouration. A total loss of ~10% in the module performance appears as a severe discolouration, implying that EVA discolouration is unlikely to account for the full decrease in performance observed for the majority of silicon modules. To conclude, the EVA discolouration is classified into the power loss category \( D(t, uv) \) with a slow saturating time dependence depending on UV radiation and temperature.

References


6.2.2 Cell cracks

Photovoltaic cells are made of silicon. This makes photovoltaic cells very brittle. Cell cracks are cracks in the silicon substrate of the photovoltaic cells that often cannot be seen by the naked eye. Cell cracks can form in different lengths and orientation in a solar cell. In the manufacturing process for solar modules a number of photovoltaic cells are embedded into a solar module. In today’s PV modules most often 60 photovoltaic cells are built in per module. In the following the number of cell cracks considered to be normal and what this means in terms of expected cell crack rate for the product are discussed. The wafer slicing, cell production [Pingel09], stringing and the embedding process during the production of the solar cell and module
causes cell cracks in the photovoltaic cells. Intrinsic manufacturing process variation causes cell cracks during solar module manufacturing. Especially the stringing process of the solar cells has a high risk for introducing cell cracks to the cells [Gabor06]. After finishing the production, a great source for cell cracks is the packaging/transport and reloading of PV modules [Reil10]. At last the installation of PV modules is a great source for cell cracking if the module e.g. drops or someone steps on the module [Olschok12]. A mean cracking distribution over all modules from various manufactures analysed at the ISFH and TÜV Rheinland is shown in Fig. 6.2.1 [Koentges11]. However all these cell cracking is not necessarily a module failure, because the reason for the failure is an external source, see Chapter 4.3.2.

But there are also cell cracks introduced during production. These are discussed in the following. For each production line under constant conditions it is possible to specify the probability $p$ to have a cell crack in a solar cell. If one takes $n=60$ cells of the produced cells to make a PV module, the probability $p_k$ to have a certain number $k$ of cells with cell cracks in the PV module is given by the binominal distribution:

$$p_k = \binom{n}{k} \cdot (1 - p)^{(n-k)}$$  \hspace{1cm} (6.2.1)

In other words Eq. (6.2.1) gives the probability ($p_k$) for a PV module (with $n$ cells) to have $k$ cracked cells if one knows the probability ($p$) of cell cracks during production. Therefore the best way to assess a quality criterion for PV modules is to use the binomial distribution to describe the number of cracks per module directly after production. An example for a distribution of cell cracks in production is given in Fig. 6.2.1. The binomial distribution describes this production-caused cell crack distribution well.

There are three different sources of cell cracks during production; each has its own occurrence probability $p$:

1. Cracks starting from the cell interconnect ribbon are caused by the residual stress induced by the soldering process. These cracks are frequently located at the end or starting-point of the connector, because there is the highest residual stress [Sander11]. This crack type is the most frequent.
2. The so called cross crack, which is caused by needles pressing on the wafer during production.
3. Cracks starting from the edge of the cell are caused by bouncing the cell against a hard object.

Once cell cracks are present in a solar module, there is an increased risk that during operation of the solar module short cell cracks can develop into longer and wider cracks. This is because of mechanical stress [Kajari11] caused by wind or snow load and thermo mechanical stress [Sander11] on the solar modules due to temperature variations caused by passing clouds and variations in weather.

Furthermore there are some typical crack patterns in a PV module detectable by electroluminescence imaging which can be assigned to a certain cause. Examples of these crack patterns are shown in Tab. 5.4.1. A repetitive crack pattern which appearance is turned by 180° from one string to the neighbour string is caused by a production failure (typically caused by the stringer) before the lamination of the PV module. This repetitive crack pattern can not be created after the lamination.
Fig. 6.2.1: Logarithmic histogram of 60 cell PV modules showing a specific number of cracks per PV module. The red squares show the crack distribution of PV modules (#80) directly after production from one manufacturer. The blue diamonds show the crack distribution (#574) of PV modules found in the field [Koentges2012]. The straight line depicts the binomial distribution of equation (6.2.1) for $p=5\%$.

Cracks beyond the cell interconnect ribbons appear as a finger failure type C, compare Tab. 5.4.1. This failure type typically indicates a high strain at the solder joint. PV modules with this kind of failure typically show more of this failure after thermomechanical stress and lead e.g. to a higher power loss in the TC200 test than PV modules without this failure type [Wendt09].

PV modules showing dendritic like solar cell crack patterns have been exposed to a heavy mechanical load [Koentges11] or a high acceleration. Typical reasons for the heavy mechanical loads are wrong packaging during transport, dropping of a PV module parallel to the ground, tilting over of a PV module or very heavy snow load. This crack pattern indicates that the crack has occurred after the lamination process. A cell with a dendritic crack pattern is not possible to be machined in a production line. In our experience PV modules with a dendritic crack pattern in the cells show higher power loss in humidity freeze tests than modules with cells with other crack patterns.

Depending on the crack pattern of the larger cracks, the thermal, mechanical stress, and humidity may lead to “dead” or “inactive” cell parts that cause a loss of power output from the affected photovoltaic cell. A dead or inactive cell part means that this particular part of the photovoltaic cell no longer contributes to the total power output of the solar module. When this dead or inactive part of the photovoltaic cell is greater than 8% of the total cell area, it will lead to a power loss roughly linearly increasing with the inactive cell area [Koentges10]. This rule holds for PV modules with 230 Wp with 60 cells, 156 mm edge length, and 3 bypass diodes. Finally an inactive area of 50% or more will lead to a power loss of one third of the solar module power as the bypass diode is activated and shortcuts this part of the solar module. This happens because of the failure of one cell in one of the three sub strings in the solar module.
For PV module strings, the power loss is much more dramatically depending on the inactive area. The dependency between inactive cell area and power loss is compared in Fig. 6.2.2 for a single PV module and a string of 20 PV modules simulated for PV modules [Koentges08]. The Fig. 6.2.2 shows, that for a high but typical string length of solar modules the power loss due to inactive cell areas raises much steeper at 8% inactive cell area than it does for a single PV module. Therefore an inactive cell area of more than 8% is not acceptable. Besides the risk of power loss there is a chance of hot spots due to inactive cell parts greater than 8%. This happens if the cracked cell has a localised reverse current path in the still active cell part. Due to the missing cell area the cell is driven into reverse bias and the full current can flow along the localised path. This may cause hot spots and therewith burn marks (chapter 6.2.4).

![Simulation of the power loss of a single 230 Wp PV module with a single solar cell having a varying inactive cell area. The simulated power loss of a 20 PV modules array containing this defective module is also shown. More than 8% of inactive cell area in the 20s module array leads to a much higher power loss compared to the stand-alone PV module. These simulations depend on the reverse bias characteristics assumed for the silicon modules.](image)

Fig. 6.2.2: Simulation of the power loss of a single 230 Wp PV module with a single solar cell having a varying inactive cell area. The simulated power loss of a 20 PV modules array containing this defective module is also shown. More than 8% of inactive cell area in the 20s module array leads to a much higher power loss compared to the stand-alone PV module. These simulations depend on the reverse bias characteristics assumed for the silicon modules.

The higher the number of cell cracks in a solar module, the higher the chance that a PV module will develop longer and wider cracks in the course of its service life. A humidity freeze accelerated aging test being a combination of test procedure 10.11 and 10.13 defined in the standard IEC 61215 shows a correlation between the number of cracks and power loss (Fig. 6.2.3). A higher number of cracked cells per module show a higher power loss after the accelerated aging test [Koentges10]. Due to the dependence of the power loss on the orientation of the cell crack in a solar cell, the correlation between the number of cell cracks and power loss is very noisy. However for greater statistics the mean power loss risk should be linear with the number of cells with cell cracks as can be assumed from Fig.6.2.3.
Fig. 6.2.3: The power loss after a test sequence of mechanical load and 200 humidity freeze cycles correlates with the number of cells cracked in the mechanical load test. Each point represents a single PV module. A bias power loss of about 3% is caused by glass corrosion.

The crack development and speed of isolation of cracked cell parts in PV modules being in service live is not known, yet. There have been seen PV modules with plenty of cracked cells, but there was even after two years in the field no significant power loss detectable. However there are examples in the literature showing that cell cracks can have a dramatic impact on the output of PV modules. In a solarpark with 159 PV modules with 165 Wp nearly 50% of the PV modules show a power loss of ~10% or more after 6 years of operation [Buerhop11]. Even 3.8% of the modules show cell cracks that force the bypass diode to bypass the cracked sub-module.

References


6.2.3 Snail tracks

Figure 6.2.4 shows typical images of “snail tracks” found in the field. A snail track is visible by the human eye. A snail track is a grey/black discolouration of the silver paste of the front metallisation of screen printed solar cells. In the PV module the effect looks like a snail track on the front glass of the module. The discolouration occurs at the edge of the solar cell and along usually invisible cell cracks. The discolouring typically occurs 3 month to 1 year after installation of the PV modules. The initial discolouring speed depends on the season and the environmental conditions. During the summer and in hot climates snail tracks seem to occur faster.
The origin of the discolouration of the silver paste is not clear. However in the region of the snail track discolouration along the silver finger of the front side cell metallisation shows nanometer sized silver particles in the EVA above the silver finger. These silver particles cause the discolouration. The silver particles are compounds of sulfur, phosphorus or carbon, depending on the module looked at [Richter12, YI-Hung12, Richter13]. So there may be different causes for snail tracks. Furthermore the discolored silver finger is more porous than normal silver fingers [Richter13]. This may reduce the conductivity of the silver finger especially along the crack line of the cells.

Common IEC 61215 testing will not show up snail tracks reliably [Philipp13]. To create snail tracks cell cracks should be present in the module of interest. Therefore a mechanical test should be included in a snail track test. Furthermore the combination of UV radiation and temperature seem to play an important role [Berghold12]. Berghold suggested a combined mechanical load, UV, and humidity freeze test to test for snail tracks [Berghold12] as shown in Fig. 6.2.5a.
On the material side the choice of the EVA and the back sheet material seems to be important for the snail track occurrence. The snail track does not depend on the kind of silver paste used for the cell production. Snail tracks have been found in a great variety of solar modules and manufacturers. PV modules being affected by snail tracks show a tendency to high leakage currents as can be seen in Fig.6.2.5b.

The growth speed of the snail track discolouration must be very slow or it saturates directly after the first occurrence. We know no case where the discolouration itself leads to a measurable power loss of the PV module. However the snail tracks make cell cracks in the solar cell visible which can reduce the PV module power, see chapter 6.2.2. Due to the observed porous silver finger in snail track affected modules the isolation of cracked cell parts may be accelerated more than it would be without snail tracks.
Fig. 6.2.5b: Histogram of leakage current measured in wet leakage testing for snail track affected panels. Given percentage values are relative to the number of all tested PV modules [Berghold12].

References


6.2.4 Burn marks

One of the most common failures sometimes observed in silicon modules is associated with parts of the module that become very hot because of solder bond failure, ribbon breakage (chapter 6.2.6), localized heating from application of reverse current flow (chapter 6.2.2) or other hot spots [Degraaff11].

Solder bond and ribbon failures can be caused by thermal fatigue. The failures may be hastened because of the increased resistance and associated heating as the joint begins to fail and current still flows through it. As the temperature increases, the resistance may also increase until the temperature is hot enough to discolor both the front and/or back encapsulation. Examples are shown in Table 5.1.3. Such failures may occur at any metal-semiconductor or metal-metal interconnection including within a ribbon or other metallic conductor.

A second type of burn mark occurs because a cell or part of a cell is forced into reverse bias. Sometimes this occurs because part of the module is shaded; it can also occur because of nonuniformities within the module including cracked cells (chapter 6.2.2) or defects that cause shunting. In some cases, the reverse current flow causes heating that further localizes the current flow, leading to a thermal runaway effect and the associated burn mark.

Burn marks are often associated with power loss, but if redundant electrical interconnections are provided, a failed solder bond may have negligible effect on the power output. If all solder bonds for one cell break, then the current flow in that string is completely blocked and an electric arc can result if the current cannot be bypassed by the bypass diode and the system operates at high voltage. Such an arc can cause a fire.

An electric arc is a so-called thermal plasma discharge with the particles temperature high enough to dissociate and ionize the medium to an extent that it is electrically conductive (plasma state). In the case of DC fault arcs in PV systems the arc is burning in an air plasma, modified by evaporated material from conductors and insulating material components. The minimum arc temperature is above 6000 K to keep the matter of a free burning arc in the plasma state and a minimum voltage (depending on electrode material and current) exists allowing for a stable burning dc arc, see Fig. 6.2.6. For a brief introduction into the matter of electrical contacts, related material, and arc plasma issues see [Rieder00, Rieder01].

With the PV generator characteristics depicted in Fig. 6.2.6 it would be possible to operate a serial arc with 200 mm maximum length resulting in 6 kW of dissipated power. By means of the power of a single 60 cell 240 Wp standard module a maximum arc length approx. 2-5 mm may be reached. The I-V characteristic of PV systems (stabilized current source) fits perfectly to generate stable arcing conditions. If the arc and PV characteristics intersect in 2 points, the point with the higher current is the stable operating point. Because of its high temperature an arc evaporates adjacent material resulting in fluid dynamic forces. Additionally the electromagnetic Lorentz-force acts onto the arc plasma. Therefore the arc length
and its voltage are not completely constant, causing a high frequency noise pattern that may be used for detection of arc faults [Bieniek11].

![I-V characteristic curve](image)

**Fig. 6.2.6:** I-V characteristics of free burning DC arcs in air on copper electrodes depending on arc length (in orange, from [Rieder55]) in comparison with typical PV system characteristics (blue curve).

Burn marks can usually be identified as such visually. If there is a question about whether the existence of the burn mark requires replacement of the module, an infrared image under illuminated and/or partially shaded conditions will quickly identify whether the area is continuing to be hot and/or whether current flow has stopped in that part of the circuit.

**References**


