Failures of the Photovoltaic Module Components

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With the global increase in the deployment of photovoltaic (PV) modules, the need to explore and understand their reported failure mechanisms has become crucial. Despite PV modules being considered reliable devices, failures and extreme degradations often occur. Some degradations and failures within the normal range may be minor and not cause significant harm. Others may initially be mild but can rapidly deteriorate, leading to catastrophic accidents, particularly in harsh environments.

photovoltaic (PV)   failure mechanisms   PV components failures

1. Introduction

Among different renewable energy sources, solar energy is the most prevalent renewable source in most regions of the world due to its cost-effective implementation and simple installation [1]. The cost of photovoltaic (PV) systems has declined rapidly over time [2]. Between 1990 and 2020, Germany's PV investment for a 10 kW system dropped by nearly 92.6% from EUR 14,000 to EUR 1036 per kW [3]. In the U.S., the decline in the wholesale price for multi-crystalline modules was roughly 95% between 2008 and 2018.

The conversion efficiency of the solar cell has progressed rapidly [4]; nowadays, it converts nearly 26% of the solar spectrum within the wavelength range from 350 nmnm to 1150 nmnm into electrical energy [5]. PV cells are serially connected to maximise energy production. Then, they are packaged into modules using a polymer coating, the encapsulant, and covered by a protective layer, predominantly made from glass [6][7]. After being encapsulated, the PV module is ready to use and guaranteed by manufacturers to have a 25-year lifetime with an expected degradation rate of 0.8% of power per annum [8][9][10]. This degradation rate was derived following extensive experimental studies and assessments that have been conducted. That is, failures found in previously deployed PV modules, such as encapsulant and solar cell defects, prompted the development of these studies. For instance, the National Renewable Energy Laboratory (NREL) developed accelerated stress tests to examine degradation rates, validating the superior quality and long-term reliability of PV modules [11]. However, despite these measures, there are still reports of abnormal degradation rates in PV modules due to a variety of failures. Abnormal degradation rates dramatically reduce reliability and increase the cost of PV operation. Harsh weather conditions and manufacturing defects are among the major factors influencing degradation rates. Consequently, higher degradation rates pose a barrier to favouring PV applications over other energy sources [12][13].

The need to review PV failures and degradation has encouraged researchers to engage in comprehensive research investigating and analysing experiments and real-world industry studies available in the literature. Köntges et al. [14] reviewed PV failures based on their emergence in the operational life cycle. Jordan and Kurtz [15] reviewed PV failures based on a severity scale, where Scale 1 referred to no effect on the PV system and Scale 10 referred to destructive effects on PV power that pose safety risks. Madeti and Singh [16] differentiated between reversible PV failures (temporary) such as shading from snow covering or dust accumulation and irreversible failures (permanent) such as encapsulant discolouration, reviewing applicable detection techniques on the DC and AC sides of the PV system. Pillai and Rajasekar [17] focused on detection techniques for PV failures and segregated failures based on their occurrence due to environmental stress factors and electrical (e.g., line to line, line to ground) and physical appearance, whether damaging the PV module or the connected devices and accessories. A recent review by Osmani et al. [18] followed a similar direction as Pillai and Rajasekar [17], focusing more on detection techniques with limited exposure to the failure mechanisms occurring on the PV module. Despite the solid analysis in the aforementioned published reviews [14][15][16][17][18], the literature still lacks an in-depth state-of-the-art review that provides detailed information on failures encountered in the PV module itself and its components (from protective glass to backsheet), exploring their mechanisms and root causes.

2. Failures of the PV Module Components: Discussion and Observations

A PV module consists of solar cells, solder, an encapsulant, protective glass, and a backsheet, see **Figure 1**. The most common raw material for the PV cell is silicon. Although silicon is not the ideal element for power conversion efficiency, its properties have been extensively studied and well understood by the market before the development of solar cells [4][19].
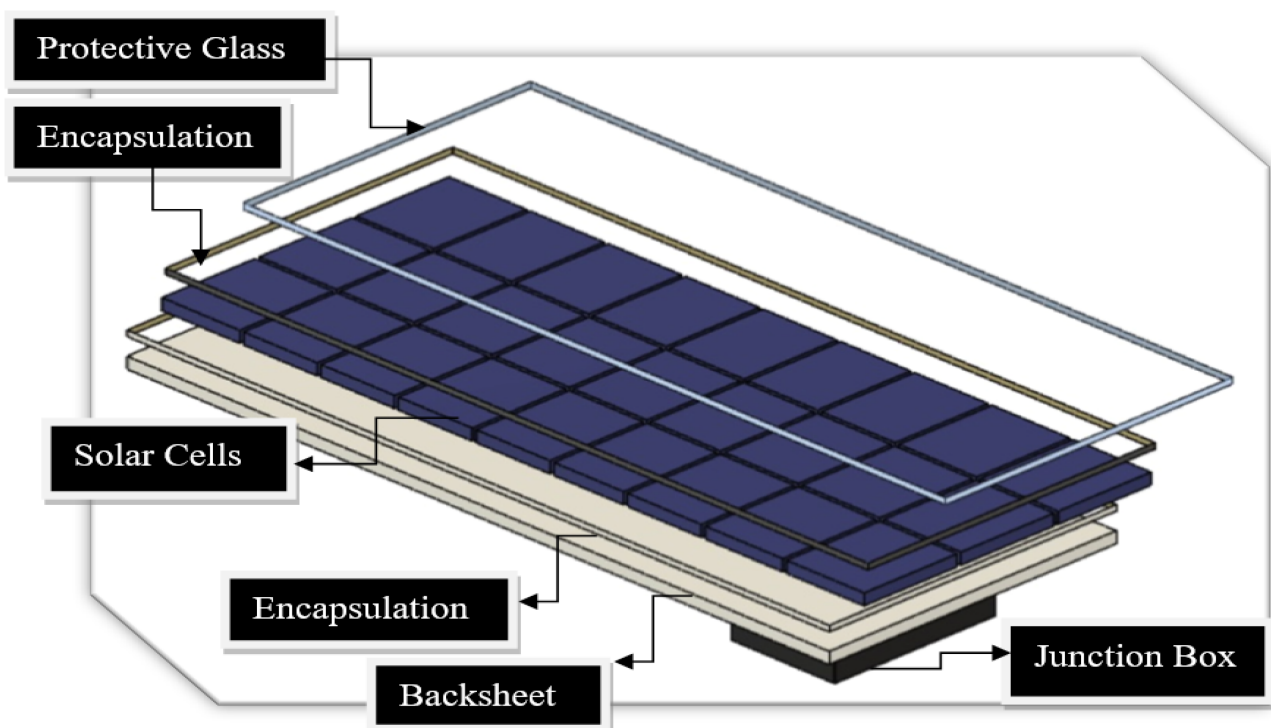
Figure 1. PV module components designed using Fusion 360 software. (The software is from Autodesk and is called Fusion 360. The version is 2.0 and Autodesk are located in San Francisco, CA, USA).

Silicon is highly purified and drawn into single crystal ingots before being sliced into wafers ranging between 0.2 to 0.5 mm thick. Residuals of crystalline silicon created during the slicing process vary based on the slicing technology. They are frequently used as crystalline ribbons to reduce manufacturing costs [4]. Once the wafer is connected to the ribbon, the solar cell is ready for testing.

2.1. Protective Glass

The protective glass in the PV module is made from tempered glass that contains a small proportion of iron oxide, not exceeding 0.05%, to allow for the transmission of sun light [20]. It is manufactured and designed to resist environmental stress factors such as a drastic change in temperature.

Gürtürk et al. [21] validated glass properties by measuring its optical transmittance and energy efficiency. They investigated two types of PV glass, one of which was rated to have a 1% higher solar transmittance. One in each type was used as a control glass and tested at a constant temperature. The others were tested at an elevated temperature that reached 120 °C. Their results showed no significant impact on energy efficiency, only a slight variation, not exceeding 2.06% at most. Afridi et al. [22] artificially formed a hotspot via shading with temperature rising to 200 °C in glass/glass and backsheet/glass PV modules and proved that the front glass of those two types was not broken or shattered despite the occurrence of severe damage like burn marks, specifically in the glass/glass PV module type. Belhaouas et al. [23] inspected twenty PV modules equipped with two different types of glass after 11 years of deployment in Bouzareah, Algeria: eight with float glass and the other twelve with textured glass. Their visual inspection showed more optical failures such as delamination in the float glass types, albeit all PV modules suffered from discolouration. Moreover, the electrical parameters of PV modules with float glass type displayed reduced values compared to those with textured glass, except for the open-circuit voltage. Nonetheless, all twenty PV modules experienced nearly the same degradation rate, at 1.04% per year.

A reduction in light transmittance is the primary failure that occurs in PV glass and is potentially caused by glass breaking or shattering or by harsh weather conditions like ultraviolet exposure and dust accumulation [24][25]. A lab experiment by Tagawa et al. [26] explored dust accumulation on glass and its effect on transmittance. Their results revealed a dramatic coarseness increment that resulted in a 32% reduction in glass transmittance after 44 min of accumulation. To protect against harmful UV wavelengths, some PV glass is doped with cerium as an additive [27]. However, King et al. [28] discovered, in a laboratory experiment, that doping cerium reduces optical transmission by up to 2%. Kempe et al. [29] conducted further experiments on the impact of removing cerium from protective glass and found that excluding cerium can raise optical transmittance by approximately 1.8% [17], which drives some manufacturers to abandon cerium in the production of PV glass. However, excluding cerium from PV glass is extremely risky; it can cause a substantial rise in the rate of delamination failure by a factor of three [29]. Consequently, when it comes to cerium, Kempe et al. [29] determined that excluding cerium will not boost electrical

efficiency, and if excluded, there is a need to coat the glass with anti-reflective substances to filter out damaging ultraviolet wavelengths, predominantly below 350 nmnm.

Glass shattering can be the result of poor PV module transportation or incorrect manufacturing processes involving excessive clamping force [30][31][32][33]. Some weather conditions also contribute to PV glass degradation and failures. A study by Bora et al. [34] analysed the failure modes of PV modules in different weather conditions in India. They showed that PV modules deployed in hot areas were vulnerable to glass breakage within five years of operation. Shattering or breakage of the module's glass allows water vapor to enter the solar cells, creating short circuits and safety risks like electrical shock [35]. This is why glass breakage failure ranked 9 out of 10 in terms of severity as it affects safety severely [35].

In addition, the temperature at the glass's breaking point increases, which may cause hotspot failure [14]. In an investigation study by Chandel et al. [36], a PV module with glass breakage had developed hotspot failures with resulting significant power loss, which was also identified by Băjenescu and Titu-Marius [37]. Typically, a hotspot forms in a PV module when some cells receive less illumination than others, resulting in those cells dissipating energy rather than producing energy, i.e., the energy produced by the fully illuminated solar cells is dissipated by the less illuminated ones, increasing the latter cells' temperature and causing them to operate in reverse bias [38]. Hotspot failures are not only driven by broken glass failures but also driven by shading and mismatch failures [39]. Shading failure is a common PV failure that is strongly linked with hotspot formation [40][41]. When hotspots occur, they cause permanent damage to the solar cells or other module parts, such as metal connection, EVA encapsulation, or protective glass [42][43]. Jordan et al. [15] rated PV failures based on their severity, where one is low, and ten is considered the most severe; they listed hotspots to have the highest severity rate among all PV failures.

However, Ndiaye et al. [30] investigated a PV module with broken glass operating for five years and found no hotspot that led to significant power loss. This may indicate that glass breakage was not the cause of the failure, but a subsequent consequence due to weak protection. Bansal et al. [35] investigated a PV module operating for 10 years in a mega-plant and found that glass breakage was almost certainly combined with solar cell cracking and significant power loss as a result of weak protection.

2.2. Encapsulant

Various encapsulating substances have been used in photovoltaic modules, such as polydimethylsiloxane (PDMS) and thermoplastic polyurethane (TPU) [7][44][45][46]. Manufacturers evaluate their advantages and disadvantages in terms of properties including reliability and cost before selection. For instance, PDMS demonstrates better immunity to environmental stress factors, which favoured it in the early trials of PV encapsulation [47]. Recently, manufacturers such as DuPont developed a PV encapsulant classified as an ionomer which offers 25 times more protection against potential-induced degradation (PID) failure than the typical encapsulant, ethylene-vinyl acetate (EVA). Dow Chemicals, another manufacturer, developed polyolefin-based encapsulants and has claimed they have greater electrical resistance as well as moisture protection when compared to EVA and ionomers [48][49].

Azam et al. [50] explored the degradation rate of four modules, two of which were laminated with polyvinyl butyral (PVB) encapsulant, under an accelerated ultraviolet test and found they had a 50% lower degradation rate compared to EVA.

Despite the superior protection features against environmental stress factors in more advanced encapsulating materials, EVA is still used in more than 75% of all PV modules due to its cost effectiveness [51][52]. The cost of PVB material, for instance, is about 50% more per m^2 than its competitor, EVA [50]. The majority of EVA composition is vinyl acetate, with the remainder being a combination of ethylene, antioxidants, and curing agents [53][54].

However, from the historical research carried out in 1981 by Lathrop et al. [55] at Clemson University until recent literature reviews, e.g., [56][57], EVA encapsulant is the primary cause of PV degradation mechanisms. Aboagye et al. [58] recently inspected polycrystalline and monocrystalline PV modules deployed in three locations in Ghana with different weather conditions, all of which showed defects in EVA encapsulants. The same findings were noted for 43 monocrystalline PV modules mounted for ten years in Nordic weather conditions, specifically in Grimstad, Norway [59]. Nearly all 43 modules suffered from encapsulant defects, namely delamination or discolouration. In Florida, United States, 156 PV modules were inspected after 10 years of deployment and also revealed the same results as [58][59]: all 156 modules exhibited encapsulant delamination failure.

Encapsulant wear-out can result in low optical performance in PV modules, which causes a reduction in the electrical output owing to decreased light absorption and extreme light reflection [60]. The encapsulant discolouration effect begins with a drop in the short-circuit current (I_{SC}). The drop in I_{SC} can be as much as 40%, albeit it is not regarded as a PV failure, as it may not pose a safety hazard [61]. Still, discolouration leads to more severe failures like delamination and corrosion as a result of the release of acetic acid. The released acetic acid in turn is characteristically found responsible for the corrosion of contacts that frequently occurs after the initiation of discolouration failure [62].

With that in context, delamination can cause a substantial decrease in the amount of light absorbed, thereby leading to a significant drop in I_{SC}. Bubble formation is one of the primary triggers of encapsulant delamination; it is formed initially during the lamination process of encapsulation due to a higher localised ratio of released volatile organic compounds [63][64]. The area affected by bubbles in the PV module operates at hotter temperatures and potentially leads to burn marks [65]. A study by Rajput et al. [66] analysed the degradation mechanism of 90 monocrystalline PV modules operated for 22 years in India; it was found that the PV modules affected by more bubbles had more power loss.

Despite ultraviolet radiation occupying a relatively small percentage in the solar spectrum, less than 4%, it is considered a major reason for the degradation of PV encapsulant material [67][68]. Due to its shorter wavelength, ultraviolet radiation possesses greater energy that can gradually degrade the encapsulant, decomposing its polymeric bonds [69]. The UV spectrum is divided into three types: UV-A, UV-B, and UV-C. In deployments, PV modules are not exposed to ultraviolet type-C but ultraviolet type-B radiation. Hence, the latter is regarded as the primary trigger of the degradation mechanism in EVA [70][71][72]. Even with the implementation of UV-blocking glass,

the degradation of EVA remains significant when exposed heavily to UV-B, particularly in conjunction with other stressors such as high temperatures and humidity [29][73]. Consequently, a chemical process is instigated, resulting in the creation of acetic acid and aldehyde, which leads to a gradual darkening of the EVA material from clear to dark brown in severe instances [73][74].

Miller et al. [45] examined five types of encapsulants, exploring the degradation process after exposing them to an artificial ultraviolet source and different combination levels of humidity and temperature. Their experiments revealed that encapsulants had higher degradation rates when they were exposed to lower humidity and higher temperatures, displaying faster yellowing. Experiments for exposing PV encapsulant to ultraviolet sources with stressors were also conducted by Arularasu [75] and showed similar results to Miller et al. [45].

To account for the degree of encapsulant yellowing, a "yellowing-index" terminology, published by the International Organization for Standardization (ISO) [76], is used. Yellowing index is defined as the alteration of polymer colour toward yellow [76]. Nevertheless, Oliveira et al. [77] discovered that early degradation of EVA cannot be spotted as it may start before its colour turns yellow, i.e., the yellowing index has not experienced any modifications. This ambiguity has driven more investigations, for example [27][78][79], to explore the initial stage of EVA degradation.

The latter might be the one of reasons for Ferrara and Philipp [80] stating there is no distinct correlation between the shift in EVA's colour and the solar cell's electrical performance. However, Rosillo and Alonso-Garcia [81] demonstrated through experimentation that an increase in the yellowness index reduces the major electrical parameter maximum power output. The results of their study are consistent with the well-known research conducted by Pern et al. [82], which examined the electrical performance of solar cells for five different colours of EVA (clear, yellow-brown 1, yellow-brown 2, brown, and dark brown). The researchers concluded that as the EVA colour darkened, there was a gradual decrease in maximum power output, with the greatest reduction observed in the dark brown colour [71].

In addition, Dechthummarong et al. [83] took measurements of PV modules before and after they were mounted for 15 years to ascertain whether the insulation resistance still complied with the IEC 61215 standard [84]. The researchers categorised EVA discolouration into four colours: light yellow, yellow, brown, and dark brown. Their findings revealed that the modules with light yellow and yellow discolouration exhibited healthier performance with superior efficiency when compared to the brown and dark brown EVA modules. Surprisingly, the insulation resistance of all PV modules met the IEC 61215 standard, even though modules with brown and dark brown discolouration were more vulnerable to failure from corrosion, delamination, and EVA bubble formation. An investigation conducted by Diniz et al. [85] also found that modules with brown discolouration were associated with more severe and safety-related failures, including corrosion.

2.3. Solar Cells

Solar cells are connected in series and then encapsulated, typically with EVA, to provide adhesion between the solar cells and the protective glass. Failure of the solar cell mainly occurs due to the very thin profile of the silicon

wafer. These thin wafers are very brittle and are prone to cracking easily during manufacturing or transportation.

Generally, microcracks of the cell cannot be detected by the naked eye. Consequently, they may spread and distribute to other cells in the module [14]. When the cracks prevent more than 8% of the cell from functioning, it may lead to a hotspot [14][86]. The active area of the cracked cell may be forced to operate in reverse bias, eventually causing a hotspot failure. Moreover, cracks are subject to expansion and seeding more cracks, especially under environmental and mechanical stress factors like hot, cold, and windy climate conditions [87][88][89][90]. Consequently, they accelerate the ageing process, showing a higher degradation rate [14]. Buerhop et al. [91] reported that PV modules with cracked cells had a greater than 10% power loss after six years of operation when compared to healthy ones. A study by Siruvuri et al. [92] developed a deep learning model based on four attributes —crack type (edge or centre), size, orientation angle (angle in degrees of the crack: horizontal vs. vertical cracks), and ambient temperature—to forecast the impact of crack severity on power loss. The outcome results were analysed and evaluated, revealing that power loss increased with increasing crack size and temperature but decreased with increasing orientation angle. However, with regards to angle orientation, their results contradicted the results of Dhimish et al. [93], where horizontal cracks were more gentle than vertical cracks or so-called parallel to busbar [94].

Conversely, snail track failure can be detected by the naked eye; this failure is so named because it is shaped like a snail's trail. Dolara et al. [95] indicated that most snail track failures are linked to the existence of cracked cells. They also compared four PV modules with a snail track against a healthy one. In their findings, maximum power output dropped in all PV modules with a snail track, one of which had a power loss of 40% of rated power. This reduction in maximum power was caused primarily by a significant reduction in I_{SC}, despite a slight increment in open-circuit voltage (V_{OC}). This association between cracked cells and snail tracks was also stressed in a recent investigation conducted in Indonesia [96]. Duerr et al. [97] found that four degradation mechanisms trigger snail track failures, depending on the combination of the encapsulant materials, and on that basis, snail tracks should be described and categorised under PV failures rather than a single degradation mechanism.

Potential-induced degradation (PID) is another PV failure mode. First observed in Germany in 2005 [98], it degrades PV wafers and leads to the development of hotspots [12][13]. It is formed owing to polarisation differences between the PV module frame and the module's cells. Thus, it mostly occurs in PV plants and farms where PV frames are grounded as a protective technique against fire ignition [99]. If undetected, it may lead to 100% power loss within a few years [24]. A report based in Germany stated that PID failure progresses rapidly with the release of acetic acid due to EVA discolouration [100]. Moreover, in a lab experiment by Pingel et al. [101], the PV module was found unlikely to recover from PID when operated at higher temperatures. With the rise of bifacial PV module deployment in the last decade, Molto et al. [102], reviewed the PID failure displayed in these module types. Although bifacial modules joined the PV market recently, over 30 scientific papers on such failures have been published in the literature. The review analysis of Molto et al. [102] came up with four classifications of PID failures: PID-s, Na-penetration-PID, PID-p and PID-c. Both PID-s and Na-penetration were caused by the leaning and movement of Na- Na-positive ions to the polarised cells. Involvement of Na$^+$ ions were also found in PID-c type, which was also classified into three categories, whereas PID-p was related to the deterioration of the PV surface. Recovery of all

types was found to be possible either fully or partially via dark storage or ultraviolet lighting, particularly for PID-p, but was found to be irreparable for the PID-c type [102].

Another failure that solar cells might experience is through disconnection of solar cell busbars or ribbons. This type of failure occurs because of a manufacturing defect; it is also driven by excessive heat due to long partial shading and can produce excessive leakage current. When undetected, it increases cell temperature and forms a hotspot [103]. Such failures can be detected by an infrared (IR) camera or by monitoring the output I–V curve. When this failure occurs, the output power typically decreases by ~35%. With progression, the power will decrease by ~46% [104]. Consequently, the solder bond will become extremely hot, leading to burn marks and discolouration of the EVA encapsulant [105]. In the worst-case scenario, the protective glass will be broken, with visible burn marks on the PV module's backsheet blocking the current path and initiating an electrical arc and fire, causing irreversible damage [14].

Colvin et al. [106] explored interconnection failures depending on cut location in the PV module and irradiance. They investigated cuts in busbars that connect cells in the centre of the PV module and cuts in outer busbars (at the edge). Results showed that outer busbar cuts are more severe and reduce module power output by nearly double compared to cuts in centred busbars. Their findings were justified by the fact that alternative busbars that can carry the captured photocurrents are limited to one when cuts occur at the outer busbar, whereas in inner cuts, there is more than one alternative busbar that can act in place. Majd et al. [107] explored failure immunity in three common interconnection types in PV modules through FEM simulation: the first one is the conventional interconnection known as front-to-back interconnection; the second type is the light-capturing type, which is named due to the recapturing of lost photons via reflection; the third type is the multi-busbar, which uses its rounder shape to reflect the lost light to the cell. Among the three, the multi-busbar type showed 15 per cent higher immunity against ribbon and busbar failures.

Thus, as with most PV failures, early detection is essential to assure a reliable and safe operation of the PV system.

2.4. Backsheet

The backsheet is the last protection layer of the PV module that provides construction support to the PV module. It shields the module's electrical parts from short-circuit failure, ensuring perfect electrical insulation from various environmental stress factors such as water ingress from high relative humidity [108]. Failures and degradation in the backsheet can appear as cracks, discolouration, delamination, bubbles, and burn marks [100].

The major cause of burn mark failures are hotspots, and this may lead the PV module to catch fire. For this purpose, a study conducted by Cancelliere and Liciotti [67] investigated fire reactions with four material arrangements on the basis of a PET (polyethylene terephthalate) backsheet: three layers (PET/PET/primer), four layers (PET/aluminium/PET/primer), three layers (fluoro-coating/PET/EVA), and PET layer with an outside and inside coating. Two backsheets—PET monolayer with an inside and outside coating and the four-layer backsheet

(PET/aluminium/PET/primer)—reacted slower to fire and had fewer damaged areas with no or less harm to the EVA encapsulant. However, the monolayer with an inside and outside coating backsheet is favoured over the other as aluminium is electrically conductive and may result in less power production. PET backsheets were also compared for cracking against backsheets made of PP (polypropylene) by Oreski et al. [109]. That comparative study employed an accelerated stress test to explore if PP backsheets have the same immunity as PET backsheets. They found that PP exhibited cracking after the same exposure time as PET, which makes it a reliable substitution for PV backsheets. Further to this, Elfaqih et al. [110] suggested mixing PP backsheets with 5% carbon fibre to provide greater strength and longer reliability against failure. They came up with their proposal after they investigated PP and PPCF (PP supported with carbon fibre) and found that the PPCF backsheet has higher tensile strength.

Investigations of PV module backsheets deployed in outdoor conditions were also conducted by Pascual et al. [111]. In their study, PV modules were deployed in an 8 MW plant. All of them were from the same manufacturer but with two backsheet types: PVF (fluorinated) and polyamide. The PV modules were deployed in 2011 and investigated after six years of operation. Visual inspection revealed that 14% of modules with polyamide backsheets suffered from cracks. Furthermore, polyamide backsheets were susceptible to chalking, which is the decomposition of backsheet material into white powder and is considered a warning sign of abnormal degradation [112]. More than 90% of inspected PV modules with polyamide backsheets degraded by chalking, while none of the PVF backsheets did. The strength of the PVF backsheet might be one of the reasons that has driven research efforts, e.g., [113][114], to search for effective ingredients to be used in accelerated stress tests.

Regarding cracking, Mühleisen [115] developed a solution based on polyurethane paint to be coated at the early onset of backsheet cracking. The coating was examined for nearly two years in outdoor conditions and was also tested under accelerated stress tests. Their results showed a significant reduction in crack progression in coated backsheets compared to uncoated ones. The study of Mühleisen [115] is not the first of its kind, as Beaucarne et al. [116] also fabricated a coated solution of a flowable silicone sealant that can act in place to avoid early replacement of PV modules. They applied the solution on PV modules operated for less than 8 years with heavy backsheet cracks. These modules included four types of backsheet: co-extruded polyamide, PVF, PVDF, and PET. The cracked backsheet modules were tested for insulation resistance and none of them passed the required standard level. After applying the coating, all of them were restored to a healthy level of insulation resistance even after applying accelerated stress tests for a thousand hours.

2.5. Junction Box and Bypass Diodes

A junction box (J-box) is attached to the PV module through adhesive material to regulate and provide a safe flow of the collected photocurrents into the PV module [117]. To guarantee the correct flow path of the current, bypass diodes are also installed inside the J-box in different configurations: overlap and non-overlap [118]. Failures in the J-box are mainly caused by low wiring quality, blown bypass diodes, corrosion, and poor bonding to the PV module (delamination), caused primarily by high humidity [56]. Failure of the J-box may result in zero output of electricity, as was found by Bakir [119] in a recent assessment of a 23 MW PV plant mounted in Turkey. Many studies, e.g., [120]

[121], have come up with novel techniques to monitor and protect J-boxes from failures. Most J-box failures allow for the ingress of water vapor, causing serious safety issues, such as initiating an electrical arc or causing hotspots [14]. Ong et al. [122] listed J-box failures among the root causes of fire ignition in PV modules. Han et al. [123] investigated the condition of 177 monocrystalline PV modules that operated for 22 years in a humid climate with an average temperature of 27.5 °C. Most of the junction boxes of the modules had been seriously damaged and needed replacing.

Furthermore, junction boxes can degrade at a faster rate when exposed to large variations in ambient temperature during the year. Daher et al. [124] evaluated the reliability of a 9-year PV system (270 modules) installed off-grid that was expected to produce 62 kW in Ali Adde town, Djibouti. The PV system was exposed to the town's high temperatures with dramatic variation from winter (average temperature is 26.7 °C) to summer with an average of 38 °C. Out of 270 modules, 39% were diagnosed with adhesive junction box failure.

On the other hand, cold climates with high relative humidity like that of Grimstad, Norway, led to the corrosion of junction boxes [59]. J-boxes and metal parts of PV modules operating in so-called floatovoltaics structures, such as PV systems deployed on the water in a floating construction, are also at higher risk of corrosion [125]. This urged Ghosh [126] to recommend that J-boxes should have a protection rating of IP67 when attached to PV modules mounted in a water-based environment. Unsurprisingly, dust has also been found to corrode the PV module's junction box. Tabet et al. [127] inspected a module operating in a dusty environment for six years, finding that the J-box failed because of corrosion. This is in agreement with the finding of Lin and Zhan [128] that water-dissolvable salts represent more than 59% of dust composition, in which, whenever stuck to metal, they react and cause corrosion, primarily in humid environments.

Several PV failures were found to form hotspots, making it necessary to protect the PV module. One means of protection is to use a bypass diode, although it has been criticised for being neither safe nor effective [42][129][130]. The existence of a bypass diode enables the current to flow over the defective solar cells, thereby protecting the PV module from thermal increases and hotspots. This is one of the main explanations why some PV manufacturers, such as AE-Solar, a German PV manufacturer, attach a bypass diode to each PV cell [131]. One of the recurrent reasons for blown bypass diodes is the increase in their temperature due to long-term shading [132][133]. Also, it was indicated by Bansal et al. [56] that those bypass diodes that were exposed to overirradiance, in particular over 1400 Wm^{-2}, Wm^{-2}, are expected to be blown due to excessive currents.

Failure to detect poor bypass diodes may lead to serious safety issues [133][134]. Since bypass diodes are used to avoid PV failures that lead to hotspotting, whenever they fail, the module loses its means of protection, becomes vulnerable, and, in the worst scenario, initiates fire [135][136]. Bakir [137] used an infrared imaging detection technique where he attached thermal cameras to a drone to be flown over three solar plants that ranged between 2 and 3.5 MW. One of the plants had three PV modules with failed bypass diodes and as a result, their operating temperature increased by an average of 19.7 C. It was shown by Ghosh et al. [138] that the operating temperature of PV cells undergoing shading failure decreases by nearly 50% when bypass diodes are functioning. Their experimental study aimed to explore if total cross-tied (TCT) array configurations were effective in preventing hotspots by

allowing the bypass diodes to respond promptly in cases of shading. The study also showed that bypass diodes were only functioning if more than one cell was affected by shading and, therefore, further investigations are required to pinpoint the optimal configuration of PV arrays that is able to activate bypass diodes even in the case of one shaded cell, such as situations of fouling by bird droppings.

PV failures can be classified based on the components affected. The same PV failure mechanism can be seen or experienced in more than one component due to the similarity of the materials; e.g., EVA is present in encapsulants and also in backsheets. Furthermore, EVA defects are usually considered an early sign of PV module degradation and failure as EVA, alongside PV glass, represents the first defence line against weather stressors. Unlike snail tracks in PV cells, corrosion is another failure mechanism that can attack more than one component, such as solar cell solders, bypasses, and junction boxes, especially in humid environments.

The hotspot failure mechanism is considered the most severe failure and leads to catastrophic consequences. It deteriorates all PV module components if undetected, and a PV module affected by an elevated level of hotspots cannot reverse the degradation and often requires replacement. Thus, identifying the initial stages of PV degradation can prevent potential hazards through proactive maintenance. Sometimes, it is even more effective to substitute a PV module that displays the early onset of deterioration as it will guarantee all deployed modules in PV plants continue generating the healthier (expected) power, regardless if their condition complies with the IEC 61215 standard [84].

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