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Long-term reliability of photovoltaic c-Si modules – A detailed assessment based on the first Italian BIPV project

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ABSTRACT

Assessing the long-term reliability of PV systems is important for understanding their energy and cost efficiency. Typically, estimates and predictions are based on indoor tests and accelerated ageing. However, fluctuating and differently interacting outdoor factors such as solar radiation, dust, and shadowing in real environment can impact the actual performance. This paper examines alterations related to ageing of c-Si PV modules, firstly by classifying the main factors that affect aged c-Si PV modules and then assessing the impact on their performance degradation by analysing a pilot BIPV system at Politecnico di Milano after 20 years of actual operation. Such system, which is highly representative since is the first public BIPV plant funded in Italy, was carefully and continuously monitored during its operating life. In particular, according to the visual/IR inspection carried out after the 20th year of operation, the main observed alteration in the modules were discoloration of the encapsulant, delamination, and chalking of the backsheet. The I-V characterization shown that all sampled modules had an overall degradation rate of less than 20 %, which is within the warranty limit, although in many cases the degradation rate over time shows a non-linear trend. Only one module experienced a severe fault that caused the complete loss of functionality. Obtained results confirm the reliability of c-Si technology, stressing the importance of a careful monitoring especially after the 15th year, when an increase of the degradation rate might occur.

1. Introduction

In the last 30 years Solar Photovoltaic (PV) technology has made significant progresses in terms both of efficiency and cost-effectiveness, increasing its competitiveness respect to conventional fuels, and representing one of the main technologies for a quick reduction of CO_2 emissions [37].

According to the data elaborated by the International Renewable Energy Agency (IRENA) [12,24,25], in 2022 the photovoltaic cumulative capacity worldwide accounted for 1046 GW, with Asia representing around 57 % of this market and Europe covering 21% of the total cumulative PV capacity.

An increasing fraction of this capacity, i.e., more than 11 GW worldwide in 2020, almost 50 % of which installed in EU, can be categorized as Building Integrated Photovoltaic (BIPV), confirming the importance of the combination of photovoltaic technology and buildings [43].

Worldwide, the share of solar energy on global energy production has grown from negligible percentages of the beginning of the current century to almost 4 % of 2021 [12]. Among the various reasons for this growth, besides the undeniable environmental benefits, is the fact that the current LCOE (Levelized Cost of Energy) of PV technology is much more competitive than that of fossil fuel, with a range between 3 and 10 c€/kWh [47]. Although the highest LCOE is usually that of BIPV, such type of installation typically allows to save the cost of traditional construction materials, such as tiles or façade panels, thus ensuring cost-effectiveness and an excellent aesthetic impact.

Looking ahead, the global installed PV capacity is projected to further increase to over 3300 GW by 2030 and 8500 GW by 2050 [29].

In such a context, nowadays and in the near future, a great fraction of the currently installed PV plants will exceed 20 years of operation; for instance, the expected number of photovoltaic modules that will have exceeded 20 years of service life is estimated to overcome 100,000,000 units in 2030 [52].

As a consequence, it is pivotal to precisely assess the actual reliability of the PV technology, by analyzing problems/defects related to ageing of main components (e.g., modules, inverters, etc.), which could lead to productivity reduction/interruption.

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In such a framework, the object of this study is to assess the long-term reliability of c-Si PV modules, with a specific focus on the different types of alterations that can appear during operating life, and that can cause their power degradation. The final scope is thus to investigate how long, and under which conditions, such PV modules can maintain functionality.

In fact, it must be noted that during the last 5 years crystalline silicon strengthened its leading role, with a market share at the end of 2021 of about 95 % of the total worldwide production [47], thus assessments on such technology are particularly relevant.

To achieve this aim, studies have been carried out on highly representative plant, which is the 20 years aged BIPV system installed at Politecnico di Milano in December 2001, a pioneering installation under the Italian incentive program "PV Roofs", started in 2001. The present research study focuses on the analyses of the key features and performances of the PV modules of the abovementioned system after 20 years of operation, in order to outline the main effects resulting from long-term operating conditions that could directly impact on modules' efficiency and reliability.

The work, thus, can be considered the prosecution and the updates of the previous research [8] in which the same BIPV plant was analyzed.

2. PV modules lifetime and degradation: state-of-art

Both the economic viability and the environmental impact of PV systems are mainly related to the degradation (i.e., the decrease of the power output) and operating life of their PV modules and other key components such as DC/AC inverters. However, while for the latter the degradation can be considered negligible in presence of a proper system design (e.g., avoiding thermal stress and direct solar exposure) and a regular maintenance [48,45], the power decrement of PV modules in operative conditions is affected by several factors, hereafter discussed.

So, knowing the remaining useful operating life of photovoltaic modules and systems is of primary value to orient financial decisions, as well as planning and maintenance activities. Commonly, the end of the operating life of PV modules in commercial systems can be set when the power output is 50 % or less of the nominal value. [15]. Reached this threshold, in fact, typically the O&M expenditure could exceed the benefit related to the power production and thus the asset is no longer profitable [15].

Such a yield degradation is mainly related to the PV modules power degradation, which shows a typical average rate between 0.5 %/y and 0.8 %/y but can rise over 1 %/y in particular operating conditions [7]. In many cases, as stated by several manufacturers [1] and also some research with a specific reference to PV performance modelling [38], this degradation is assumed linear during the whole lifespan of the module, thus directly proportional to operational time. In this regard, in fact, several PV modules manufacturers offer a linear warranty, which means that the amount of guaranteed power output decreases by a constant rate year-over-year, with a degradation usually within 0,8%/y [26].

In fact, as the manufacturing process of PV modules has improved in the last decades, the performance warranty period has considerably changed over time [3,5]. As already introduced, such period in the past has commonly been assumed to be 20 years, but different studies published in the last ten years have shown that solar modules can overcome this target and aim a for longer operating period with an overall degradation lower than 20 % compared to nominal peak power. For example, a survey of U.S. Solar Industry Professionals shows that solar stakeholders (e.g., project developers, consultants, long-term owners, etc.) have increased the expected operating life from an average of $\sim$21.5 years in 2007 to $\sim$32.5 years in 2019, reaching 35 years nowadays [56]. Moreover, a study [54] shows that, considering a two-step power warranty for the products (e.g., 90 % of the nominal peak power after 10 years and 80 % power after 25 years), only 35 modules out of 204 tested (17.6 %) failed. Another study [55], instead, reports that less than 45 % of tested modules showed a power degradation greater than 10 % after 15 years of operation. Also, the researchers in [5] conclude that, in a temperate climate, approximatively 60 % (around 70 % if considering a $\pm$3 % measurement uncertainty) of the modules would still fulfil the performance warranty threshold set at 80 % of initial performances after 35 years of operation. This motivates the fact that, recently, commercial module warranties provide for periods of at least 25 or 30 years.

2.1. Degradation processes due to weathering factors

Generally speaking, power degradation of PV modules is influenced by multiple factors, among which climate is the most influencing one [7,27]. More in detail, three main degradation processes can be described as the combination of weathering factors, as follows.

- *Hydrolysis-degradation*, related to the effect of temperature and humidity. It can cause the infiltration of moisture, triggering the delamination of polymers or corrosion of solder bonds [35]. This phenomenon presents the minor influence in almost all the Köppen-Geiger-Photovoltaic climate zones [6] but is noticeably more relevant in tropical climates (AH and AK), due to high precipitation levels (thus high relative humidity) and temperature levels.
- *Photo-degradation*, which depends on temperature, humidity and UV component, is analogous to hydrolysis-degradation but the process triggered by UV irradiation. The latter could also cause a degradation of the encapsulant (primarily EVA): additives in the EVA can lead to the production of acetic acid under UV radiation and the encapsulant darkens [36]. For hot and dry climates, even though the high irradiance level, the low relative humidity limits its influence, which on reverses is remarkable in hot and humid areas (AH and AK) because of the relevant climatic stress of all variables (temperature, humidity, and UV irradiation).
- *Thermo-mechanical degradation* is mainly related to daily and seasonal temperature variations. Temperature gradient, frequency and amplitude of thermal cycles, in fact, induce thermo-mechanical stress/fatigue which frequently leads to solder interconnections breakage, cell cracks, and deterioration of polymeric components [53]. It typically exhibits a high contribution to the overall degradation rate in all climates excluding in the tropical areas, which are characterized by limited temperature fluctuations [27].

The total climate degradation rate is thus the consequence of the combination of the above-mentioned degradation mechanisms. Predicted values resulting from validated degradation models [7] typically show good agreement with the conventional values established by manufacturer warranties. Under the experimental point of view, monitoring data [7] show that in Europe, which is predominately characterized by temperate climates, the average yearly degradation rate stands between 0.4 % and 0.6 %, except for the hottest areas of the South Spain and Portugal where the total degradation rate could reach 0.8 %. Another study [32] showed how degradation rates could change depending on the PV technology and production's year, however no significant difference was recorded between mono-Si and multi-Si technologies, resulting in an average degradation rate around 0.5 %/year.

2.2. Degradation categories

For sake of simplification, in the present paper the *degradation* is divided into two categories:

A. Expected degradation. It includes the initial degradation (i.e., the light-induced degradation) and the operational degradation due to standard weather exposure.

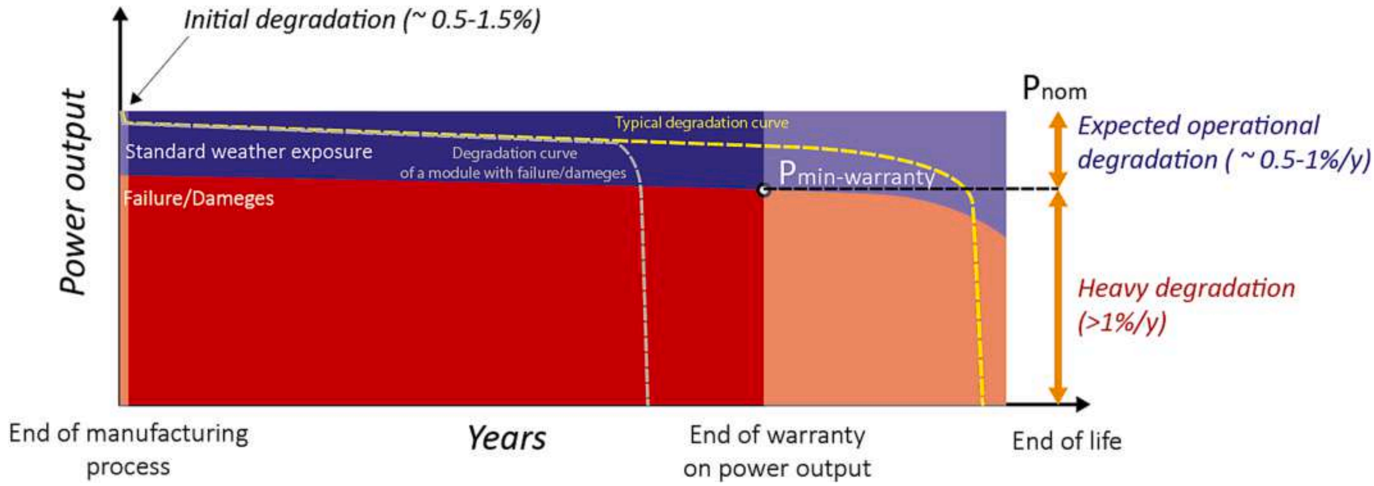

Fig. 1. Typical degradation scenarios for Si-based crystalline photovoltaic modules.

B. Heavy degradation, i.e., greater than performance warranty rate. It may be symptoms of specific problems such as failures and damages, as described hereafter.

Failures can be classified as effects, not related to normal operational stress, which seriously compromise the module functionality and/or create a safety issue [49], such as moisture infiltration or electric circuit brakeage.

Damages are, instead, alterations to appearance, performance and safety level, not attributable to manufacturing defects or standard weather exposure but caused by external events such as natural disruptive phenomena (e.g., large hail damaging front glass) or design/installation/O&M errors at PV system level (e.g., cells crack due to wrong installation techniques, bad wiring causing overtemperature or overvoltage, etc.).

The resulting degradation mechanisms for Si-based crystalline photovoltaic modules is summarized in the figure below, which considers the different trends of power degradation depending on the possible causes (Fig. 1).

2.3. Main types of alterations

Generally speaking, the above-mentioned phenomena (i.e., consequences of standard weathering factors, failures and damages) can be generally identified as alterations, since they refer to everything in a PV module that differ from its status at the end of a flawless manufacturing process [59,2,57]. The most common ones in a Silicon based PV module, which is the technology that is analyzed in the case study, are described hereafter.

Delamination: it is an alteration where the different layers loss their adhesive properties. It must be noted that the most used encapsulation materials in dated modules are the EVA (Ethylene-Vinyl Acetate) copolymers [46]. The reduction of adhesion is typically caused by UV irradiation, heat and humidity but also to manufacturing inaccuracies during lamination stages/other treatments. Frontside delamination mainly causes an increase of the solar radiation reflection and of transmission losses. Backside delamination occurs when the back encapsulant sheet is not well adhered and bubbles may be formed [13,49]. On average, delamination appears on modules older than ten years and more frequently in hot and humid zones [4,13,41,49].

Light-induced degradation (LID). It occurs when the module is exposed for the first time to a first quantity of tens of kWh/m^2. It is principally caused by carrier recombination due to the deeper energy-level defects, created by the substitutional boron and interstitial oxygen in P-type silicon under solar radiation. For c-Si cells typical losses are between 0.5 and 1.5 %, recorded in the very first exposure to solar radiation and it interests all types of PV modules [11].

Encapsulant discoloration: It consists in the change of its transparency from clear to yellow or brown, under the action of UV radiation and high temperature, causing the reduction of transmission of solar radiation to solar cells, which directly reduces the current, decreasing PV module performances [4,16,23,38]. As verified by [13], this kind of alteration can be found even in the youngest modules located in all climatic zones, but mostly appear in hot and dry zones, since high temperature and UV radiation are the main causes of discoloration.

Hotspot: It describes a localized heating phenomena of a single solar cell or a cell part, interested by a lower current flow compared to the surrounding cells, so that all the power produced by the functioning cells is dissipated by the affected cell. Light hotspots simply cause a reduction of conversion efficiency due to higher operative temperature, while serious hotspots can cause failures (e.g., breakage of the cell and burning of the backsheet) [20]. The problem can be caused both by external causes (e.g., localized dirt, shadows) or by solar cell defects, such as cracking or weak solder, which lead to a local current reduction, in some cases also forcing the affected cell to work in reverse bias, dissipating power with a consequent temperature increase [38]. When the phenomena are highly localized and small (e.g., due to solder bond failure, ribbon breakage, etc.) they are classified as burn marks and are usually visible from dark spots on the backsheet [49].

Cell cracking: it consists in cracks formation due to brittle silicon cells, which can lead to inactive electric regions, and thus reduced current [44,49]. Vibrations and static/dynamic mechanical loads can induce micro-cracks in the cells and/or enhance manufacturing imperfections. It appears that, depending on the size and position, some cracks could have a more deleterious impact on the module power performance than others [31]. In some cases, cell cracking can be consequence of an uncontrolled manufacturing process (e.g., cells handling or soldering phases), of a bad installation procedure (e.g., trampling of modules), or of high mechanical stress on the module surface (e.g., heavy snow) [10]. Under the performance point of view, cracks cause a reduction of the current and, in the most severe cases, the complete inactivity of the cell.

As a side effect of vibrations and mechanical loads or thermo-mechanical stress, a disconnection of cell's fingers can occur.

Potential Induced Degradation (PID): it is one of the main causes of module degradation and is a consequence of leakage current between the modules' aluminium frame and the solar cells. The leakage current develops due to elevated potential difference between the string voltage and the ground, and it causes current losses flowing through the module, leading to a potential loss of efficiency of the PV cells [39,42]. PID becomes more prevailing as the module ages, and it normally does not

Fig. 2. Picture of the building 11 with the BIPV sheds.

affect all the solar cells in the module, thus this performance difference can be detected via an electroluminescence test. It was also found that cracks in solar cells can accelerate PID due to the localized heat caused by the cracks [17].

Snail tracks: they are a discoloration of silver pastes of the front metallization of screen-printed solar cells, visible by the human eye and similar to a snail track on the front side of the PV cell [22,49]. Previous works found that the snail trails are silver nanoparticle, silver oxide or silver carbonate nanoparticles and the silver element is from the corrosion of the silver grid of solar cells [58]. The influence on the power performance is typically negligible, since in their initial state these alterations can be classified as visual and surface related; however, it was also observed that they are often correlated with cell micro cracks, which instead can lead to a power degradation [18].

Corrosion/oxidation: it can be caused by air relative humidity alone or in combination with gases, which penetrate the laminate due to poor quality of materials/manufacturing process or delamination; higher temperatures usually accelerate the reaction. Usually, corrosion in solder joints and metal contacts is generally a long-term degradation. Corrosion can be also a consequence of hydrolysis within EVA encapsulant in the presence of moisture, heat and UV [13,23]. Corroded electrical elements inside the laminate typically decrease their conductivity and thus negatively affect the conversion efficiency, leading also to heavy performance degradation [51].

Chalking: it refers to the formation of white powder on the outer backside layer, due to the photothermal degradation of the backsheet polymer [13]. Chalking alone doesn't affect module's performance, however, in advanced stages, the phenomenon may be accompanied by the presence of cracks in the backsheet and, in general, by a reduction in the level of insulation of the protective layer, and thus give rise to issues that can seriously degrade the performances [19].

Junction box failure: main failure modes are contributed by burnt bypass diode or burnt junction box, as a consequence of low manufacturing quality or bed installation [14], but in other cases the failure can be also caused by a loss of the waterproof rating, which allows the penetration of moisture or water that causes short circuit or corrosion of electric contacts.

Mechanical alteration of the laminate: it is a damage usually caused by the impact of objects (e.g., large hail, stones, etc.) that normally crack or break the glass, causing its optical properties to change or even moisture/water infiltration. In limited cases the phenomenon can also be a consequence of a bad manufacturing process of the glass. In desertic areas, the presence of wind and sand can lead to abrasion of the glass, altering its optical properties and increasing the performance degradation rate [50]. In some events, the mechanical alteration (e.g., static or dynamic pressure of a heavy load like snow or weight) can interest the whole laminate, causing its complete fault.

As a consequence, a precise identification of aged PV modules alterations and the subsequent correlation with actual power degradation is particularly interesting to the scope of the research, as described in the following sections.

3. PV system description

The case-study assessed in the present work is the 20 years aged BIPV plant installed at Politecnico di Milano University, which has been constantly monitored during its operational life [8]. As previously introduced, the system represents a milestone for the PV sector, because it is the first BIPV plant which received public fundings in Italy and also since it was carefully designed, installed and monitored during its lifetime; thus, obtained results can be considered highly representative for the reliability analysis of the PV technology.

More in detail, the 11 kW_p pilot BIPV system has been installed on the roof of the so-called Building 11A at Politecnico di Milano in Leonardo Da Vinci (Latitude 45°27′, Longitude 9°11′) in December 2001.

The singular shed structure of Building 11A roof allow to exploit the solar potential, making it an ideal site for installing a photovoltaic system. Originally, the roof consisted in 30 skylights with a triangular shape (in section), organized in three parallel rows of 10 elements each, able to provide daylighting to the classroom below. However, due to waterproof issues, which caused water infiltration, the glass surfaces on the north side of the skylights were covered and sealed with a waterproofing membrane, resulting in the loss of their original purpose (Fig. 2).

Some years later, the PV system has been specifically designed to be placed over the obscured side of the sheds (oriented towards South). To achieve this, 150 poly-Si photovoltaic panels with anodized aluminum frames were installed. The modules were placed in groups of 5 on each skylight, tilted at 65°, and oriented towards the south. L- and Ω-shaped clamps were designed and used to connect the PV modules to the shed slabs made in concrete. Chemical expansion bolts were used to secure the aluminium frame of the module to the shed structure, allowing an

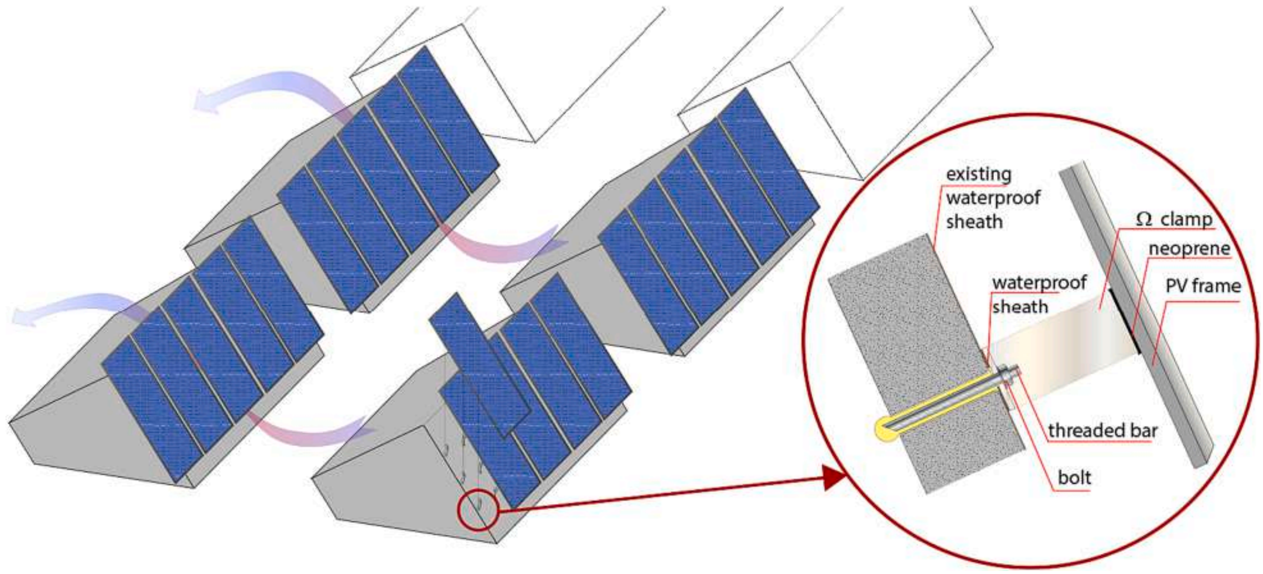

Fig. 3. Axonometric scheme and detail of the BIPV system.

Table 1
Main alterations on 5 representative modules based on 2014 analysis.

Module ID	150	140	138	51	31
Alterations	- Snail tracks - Delamination near JB	- Hotspot - Heavy discoloration	- Delamination along busbars - Delamination near JB - Heavy discoloration	- Low visual defects	- Delamination along busbars -

easy installation and maintenance. Moreover, it should be noted that a ventilated gap 10 cm thick between the modules and the underlying waterproof surfaces was created in order to reduce potential overheating phenomena (Fig. 3).

It must be noted that the system is a particular type of ventilated BIPV that could be also classified as BAPV (Building Applied Photovoltaic), even if the presence of the ventilated cavity was a peculiarity of the design to ensure better performances and not just a technical simplification as usually happens in BAPV.

Regarding PV modules' type, the Shell Solar RSM75 product was selected due to its size (1220 × 580 mm), which perfectly fit with the shed's dimensions. In this respect 5 modules for each shed have been installed, for an overall amount of 150 modules. Each of them consists in a laminate composed by a Tedlar-aluminium-polyester foil by Dupont used as a backsheet, 36 multicrystalline cells (with a surface of 12.5 × 12.5 mm), an ultraviolet-stabilised ethyl vinyl acetate layer used as the encapsulant, and a front glass composed by a 4 mm tempered texturized glass (structured pyramid-shape).

Each module has a peak power of 73 W and an efficiency of 10.6 % at Standard Test Condition (STC).

Overall, the poly-Si modules form a 10.95 kW_p PV plant which is connected to five inverters: three of 3 kW-and two of 1.1 kW.

As already introduced, within its 20 years of operation, the PV plant has been continuously subjected to an assessment for the identification of all the effects caused by long-term operating conditions. For example, at the end of 2014, after 13 operating years, all modules were subjected to a visual inspection and five representative modules underwent to I-V characterization test to evaluate their actual performances and thus the degradation rate.

At the same time, a visual inspection, as well as an IR analysis were carried out on the entire array, using a thermal camera, to identify possible failures or over heating phenomena. The overall results are discussed in detail in previous publications [8]; a summary of the main alterations of 5 representative modules, which will be further analyzed in the present paper, is reported in Table 1.

It should be noted that, although analysing a small sample of PV modules can introduce limitations and potential biases errors, it allows a constant monitoring of the sample along the time ensuring higher data quality and more precise insights [9,40,21].

4. Experimental assessment of PV modules degradation

According to literature review, the stages where most of the failures emerge, after exposure to mechanical load cycles (e.g., wind, snow loads, etc.), solar radiation and thermal stress, is the so called "wear-out phase", which typically occurs in the first 12 years after the installation [30]. As a consequence, the adopted monitoring strategy planned the first detailed inspection and test of the system at the end of the wear-out phase (2014). The inspection was constituted by a punctual visual inspection/IR imaging on all modules and laboratory test (I-V characterization and electroluminescence imaging analysis) on representative modules, as described in detail below.

The second detailed inspection was then planned at the end of the power warranty period (2021), to check the status of the modules in this key moment. Considering the observed worsening of some alterations and the nonlinear degradation trend measured in the sample modules, the testing frequency has been now set every 3 years. This methodology allows a good compromise between the amount of obtainable information and the testing effort.

As already mentioned, in the first monitoring milestone (2014) the PV plant did not experience a significant decrease in performance. The average measured performance decay was lower than 0.5 % per year, without highlighting particular criticalities. Additionally, visual inspection and infrared (IR) analysis showed that none of the PV modules was seriously damaged. During the same assessment, one of the PV modules (Module 32) was also back insulated, to test if an operating condition with higher temperatures could determine in the long-term different alterations compared to other back-ventilated modules.

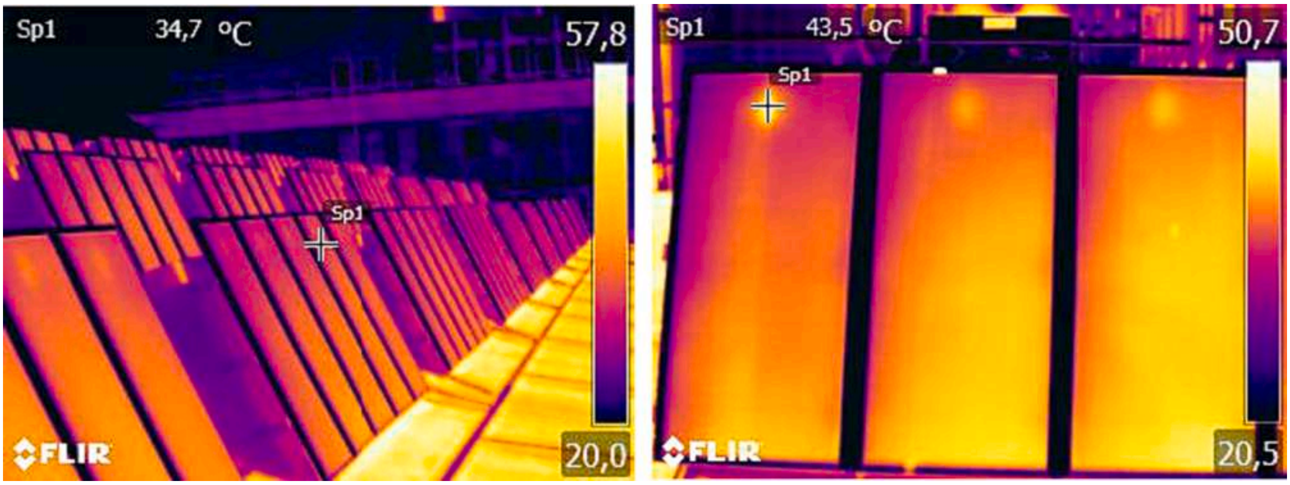

Fig. 4. IR overview of the BIPV array (left) and frontal picture of 3 modules (right).

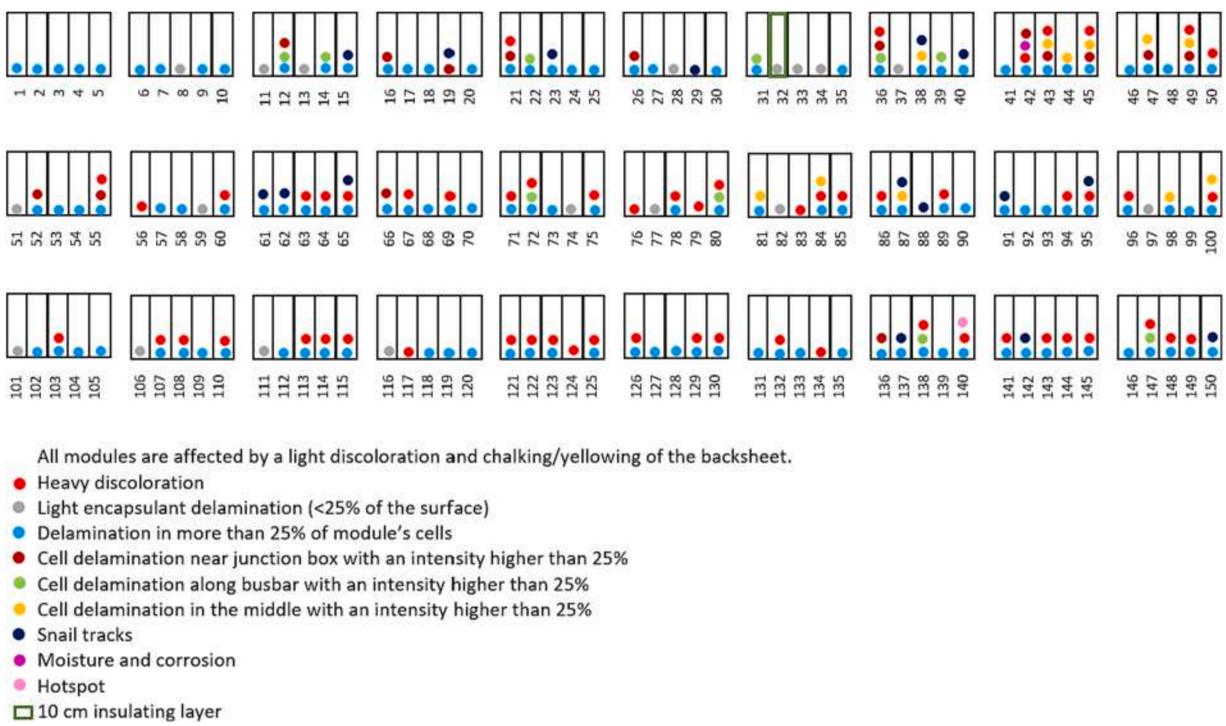

Fig. 5. Main alterations identified in the visual inspection on Politecnico di Milano BIPV Plant.

In this section, an update of the assessment and performance evaluation of the PV modules after 20 operating years is reported. The analysis is divided in two main parts: the on-field inspection, carried out on all the modules with visual and infrared method at the end of 2021, and a detailed laboratory testing, carried out on some representative modules at the beginning of 2022, which allow to correlate the results of the visual/IR inspection with the actual performance degradation.

More in detail, laboratory testing was carried out at the at the PV Laboratory of the University of Applied Sciences and Arts of Southern Switzerland (SUPSI).

A summary of the type of climate to which the modules have been subjected from their installation is provided below.

4.1. Visual/IR inspection

Firstly, on-field visual inspections have been carried out during sunny days in November 2021, after 20 years of outdoor exposure.

In particular, an inspection checklist for the evaluation of visually observable alterations in PV modules has been used, according to that proposed by IEA in Jordan et al. [34]. So, taking such checklist as a reference, a summary table for each module has been produced.

After the visual inspection, in order to identify possible failures or overheating phenomena due to cells defects, also an infrared (IR) analysis was carried out with a Flir T640b IR camera (Fig. 4).

More in detail, the entire array was examined, checking the possibiity of hot spots or other thermal anomalies. The images were taken from the front side, setting the emissivity of the module to 0.85, which is a typical value for the glass.

The main alterations detected by the visual/IR inspection are summarized in the scheme reported below, which also represent the displacement and numbering of the 150 modules within the array (Fig. 5).

(a) (b) (c)

Fig. 6. A new RSM75 PV module (a), one affected by light (b) and heavy (b) discoloration.

(a) (b) (c)

Fig. 7. Examples of delamination along busbars (a), near junction box area (b) and in the middle of the cell (c).

As, already observed in previous works [8], all the modules are interested by a discoloration of the encapsulant. It has been decided to distinguish discoloration phenomenon between light and heavy discoloration, depending on its intensity compared to the module's color when it was new (Fig. 6).

As showed, approximately 40 % of modules are affected by heavy discoloration, while 60 % are characterized by a weaker phenomenon.

The other frequent alteration is the delamination: it appears in all modules, but its intensity and extension are heterogeneous. In particular, considering all modules affected by delamination, 81 % of them present a potentially critical situation, since they are characterized by delamination in more than one quarter of the total surface, while in the remaining 19 % the phenomenon interests just very limited parts (Fig. 7).

Regarding the backsheet instead, it was found that 100 % of the modules is affected by chalking and yellowing. However, it must be noted that previous studies have already proved that weak chalking doesn't necessarily lead to severe degradation of its properties. Moreover, in some cases modules are also affected by further slight backsheet impairments such as small bubbles, which, however, are not associated with fractures that can cause moisture infiltration.

Fig. 8. Moisture infiltration and corrosion in module 42.

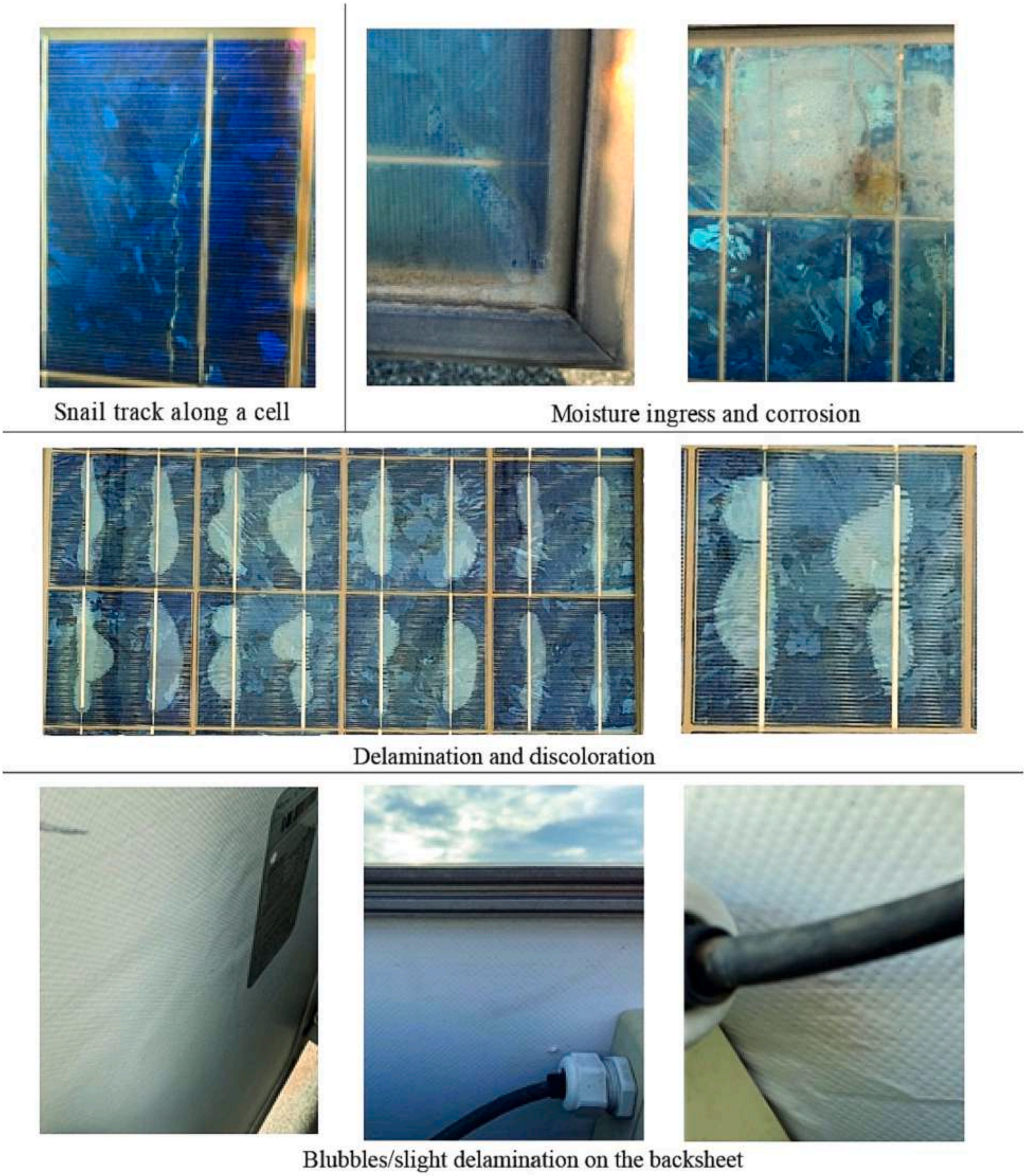

Fig. 9. Overview of the main detected alterations.

On one module (Module 140) a slight hotspot was found during the IR analysis, with a local increase of the surface temperature of about 10 °C compared to other cells (i.e., around 40 °C versus an average of 30 °C). It's important to note that the same phenomenon was observed during the 2014 assessment and no changes can be highlighted.

Just one module (Module 42) presented a fault during the visual inspection; more in detail, it was characterized by moisture/rainwater infiltration in the junction box and subsequent corrosion of electric contacts. The phenomenon was clearly detectable from the presence of moisture in the laminate, which probably caused hydrolysis within EVA with the consequent production of acetic acid; the latter acts as a catalyst in the corrosion of finger electrodes and solder ribbon, causing the formation of dark areas in solar cells, as shown in the following picture (Fig. 8).

A visual summary of other mentioned alterations is reported in the following figure (Fig. 9).

4.2. Detailed laboratory testing

As introduced, to relate the results of the visual/IR inspection with the actual performance degradation, some representative modules were selected for the laboratory testing.

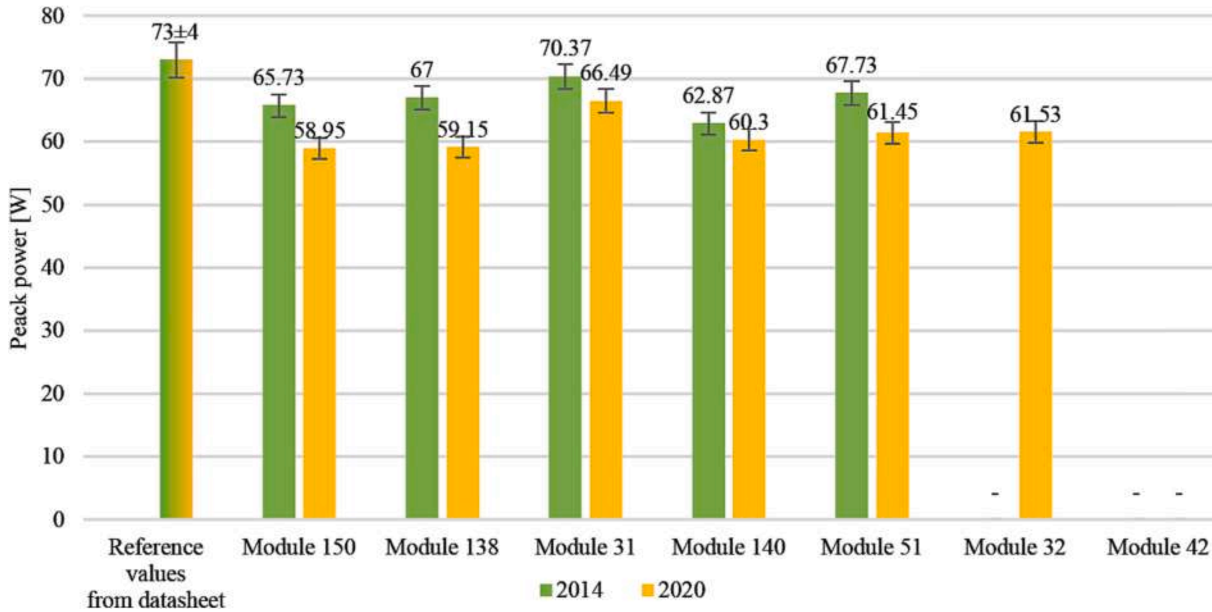

Fig. 10. Power variation after 13 and 20 years compared to reference power from datasheet.

Table 2
Weather parameters in Milan from 2002 to 2021.

	Average Temperature [°C]	Min. Average Temperature [°C]	Max. Average Temperature [°C]	Average Relative Humidity [%]	Global yearly irradiation [kWh/m^2]
2002	14.17	11.13	17.45	65.2	1241
2003	15.28	11.96	18.88	60.1	1426
2004	14.45	11.39	17.83	64.4	1304
2005	14.02	10.90	17.46	62.5	1323
2006	14.88	11.63	18.52	61.5	1313
2007	14.75	10.26	16.73	59.4	1270
2008	15.18	11.80	18.30	64.5	1301
2009	15.42	11.89	18.46	62.8	1330
2010	13.93	10.84	17.32	66.7	1232
2011	16.39	12.17	18.47	59.4	1408
2012	16.02	11.82	18.32	65.8	1345
2013	14.51	11.12	17.92	68.4	1237
2014	16.29	11.43	17.08	69.0	1246
2015	16.24	12.85	20.08	63.9	1323
2016	15.70	12.37	19.28	66.3	1235
2017	14.01	12.37	19.68	59.1	1401
2018	14.54	12.20	18.68	66.6	1392
2019	14.62	11.91	18.87	63.3	1412
2020	14.40	12.19	19.11	65.0	1443
2021	14.11	12.10	18.91	63.8	1427

In particular, it has been decided to select:

- five PV modules that already were subjected to laboratory tests in 2014 (see Table 1);
- Module 32, which operated from 2014 with the insulation layer on the backside;
- Module 42, which is characterized by a severe corrosion.

The first test implemented was a flash test for I-V characterization, which was carried out on in February 2022 at the SUPSI PV Lab in standard test conditions (STC) following the procedure defined by the IEC 61215 [28], using an AAA class Pasan Flasher, with a 2.7 % accuracy and a 0.2 % repeatability. A sun simulator supplies the I-V characteristic curve of solar modules, providing information about Maximum Power Point.

Current I-V characterization has been compared to reference values

Table 3
Power variation after 20 years of operation respect to nominal values and variation respect to the 13th years of working (accuracy on the measurement equal to 2.7 %, repeatability equal to 0.2 %).

	Module 150	Module 138	Module 31	Module 140	Module 51	Module 32	Module 42
Respect to nominal power (73 W_p)	19.2 %	19.0 %	11.0 %	17.4 %	15.8 %	15.5 %	No output
Respect to min. guaranteed nominal power (70.08 W_p)	15.87 %	15.58 %	7.25 %	15.06 %	12.16 %	12.19 %	No output
Respect to the 13th year	10.31 %	11.72 %	5.51 %	5.33 %	9.12 %	Not tested	Not tested

Table 4
I-V characterization of PV modules after 20 years (accuracy on the measurement equal to 2.7 %, repeatability equal to 0.2 %).

	Module 150	Module 138	Module 31	Module 140	Module 51	Module 32	Module 42
V_{OC} [V]	21.11	21.15	21.32	21.24	21.14	21.04	N. A.
I_{SC} [A]	3.94	3.98	4.19	3.96	3.97	3.98	N.A.
FF [%]	70.81	70.34	72.71	71.64	72.66	73.48	N. A.

Table 5
Annual degradation rate comparison (accuracy on the measurement equal to 2.7%, repeatability equal to 0.2%).

	Module 150	Module 138	Module 31	Module 140	Module 51	Module 32	Module 42
Annual degradation rate 2002–2014 (13 years) -P_{nom} (73 W_p)	0.77 %	0.63 %	0.28 %	1.07 %	0.56 %	–	–
Annual degradation rate 2002–2014 (13 years) - P_{min} (70.08 W_p)	0.48 %	0.34 %	−0.03 %	0.79 %	0.26 %	–	–
Annual degradation rate 2015 – 2021 (7 years)	1.47 %	1.67 %	0.77 %	0.76 %	1.29 %	–	–
Average annual degradation rate 2002–2021 (20 years) – P_{nom} (73 W_p)	0.96 %	0.94 %	0.44 %	0.86 %	0.79 %	0.77 %	–
Average annual degradation rate 2002–2021 (20 years) – P_{min} (70.08 W_p)	0.79 %	0.77 %	0.26 %	0.70 %	0.61 %	0.61 %	–
Variations compared to 2014	Enlarged delamination	Enlarged delamination	Limited spot delamination	No visible variations	Enlarged delamination	–	–

from datasheet and the I-V characterization evaluated in 2014 after 13 years, as reported below. It must be noted that all values ae referred to cleaned PV modules (Fig. 10).

Table 2 reports power degradation compared to nominal power (73 W_p), to minimum guaranteed power (70.08 W_p) and to the value measured in the 2014 assessment (Table 3).

For the sake of the facts, the detailed data obtained in terms of V_{OC}, I_{SC} and FF are also provided hereafter. The same data obtained in the test carried out in 2014 as well as the reference value from the datasheet are reported in the previous publication [8] (Table 4).

In Module 42, the junction box presented a so dreadful state, caused by corrosion, which precluded the possibility to carry out both flash and electroluminescence tests, since connection was impossible and power supply in that conditions would be dangerous.

Among other modules, it is evidently noticeable that Module 150 presents the worst power degradation respect to datasheet values, and this is probably due to the presence of snail trails identified along two cells. Module 138 instead, was characterized by a strong delamination along busbar and near junction box and by a strong discoloration especially along cell's edges, which probably have worsened during the last five years, since it presents the highest degradation respect to 2014 values. Regarding module 140, slight hotspots could explain the quite high power-degradation respect to 73 W. For this reason, module's power was already low in 2014 and therefore the variation respect to previous I-V characterization is the lowest. Module 51 instead, didn't present any visual defects to naked eyes, but it presents higher degradation rates compared to module 31 characterized by spot delamination along busbar and near junction box. Module 32, instead, characterized by a 10 cm insulation layer arranged in 2014, although it is within the reasonable range for expected degradation, it is close to the 0.8 %/y threshold, so a probable slight negative influence due to the higher operating temperature is conceivable.

In the following table the annual degradation rate has been calculated, by comparing the one referred to the first 13 years of operation and that related to the 20th year, to understand if the trend has changed during the last years (Table 5).

As reported below, annual degradation has worsened in mostly of the cases, except from module 140 which has a degradation rate in the last 7

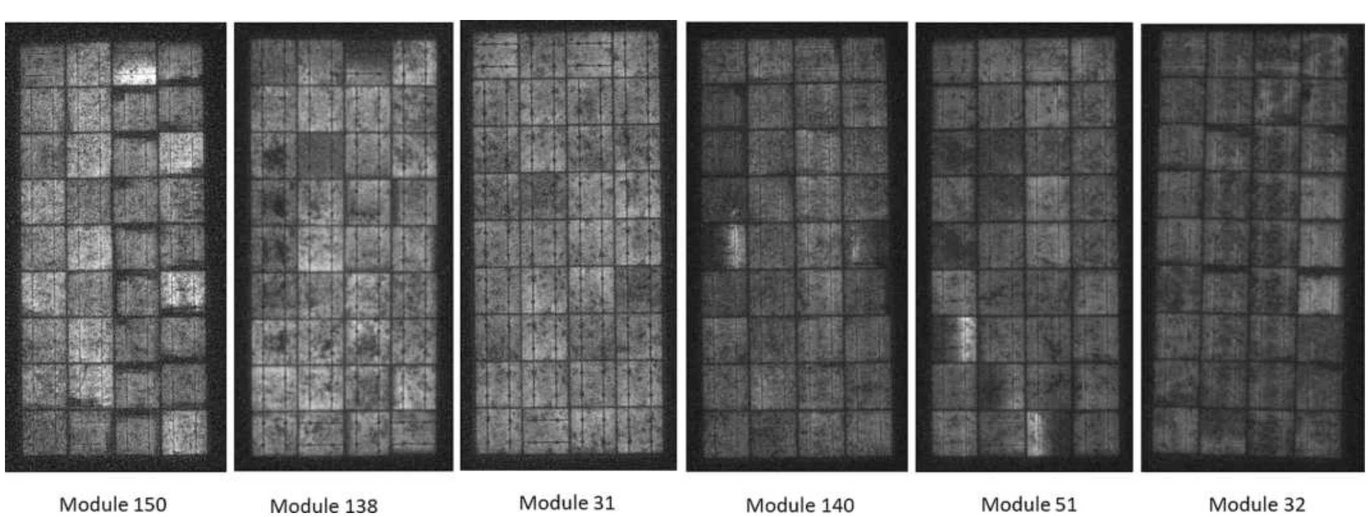

Fig. 11. Electroluminescence image of tested PV modules.

Table 6
Outcomes of EL analysis.

Module ID	EL outcomes	Comments
150	EL confirmed the extance of a cross crack line nearby snail tracks, already detected in 2014 assessment. Moreover, darker sections attributable to a mismatch of the cells, probably caused by a factory defect or poor assembly during wafer construction, are present along the lower edges of all the cells belonging to the right two columns.	The presence of the crack justifies the highest overall degradation rate among tested modules.
138	EL reports darker spots along cells belonging to the first column, which probably correspond to slight moisture ingress, since there the delamination is more intensive. Moreover, along the right edges of two cells and along the upper edge of one cell, we have identified darker sections similar to the ones previously explained, which could be attributed to a mismatch of the cells.	The extended delamination with slight moisture ingress and the heavy discoloration explains the significantly increased degradation rate in the 2015–2021 period.
31	EL image doesn't highlight relevant problems, except for some darker spots near delamination zones	The module is an optimal conservation status, just some spot delamination appeared in the 2015–2021 period. This justifies the lowest degradation rate among tested modules.
140	EL shows the existence a light hotspot (i.e. brighter sections along busbars' joints), which were not visible by the IR images.	The problem is the same highlighted in 2014 and no changes are recorded. Thus, it could be related to a manufacturing imperfection which didn't change during operation.
51	EL revealed two brighter sections along cells' joints, which could be classified as hot spots	The problem was not present in 2014, thus it could be caused by the disconnection of cells electrical contacts occurred in the 2015–2021 period. This justifies the increased degradation rate.
32	EL image didn't relevant issues, except for a few darker sections along the lower edges of the cells, attributable to a mismatch of the cells	The degradation rate, although it is within the reasonable range for expected degradation, it is close to the 0.8 %/y threshold, so a probable slight negative influence due to the higher operating temperature is conceivable. Additional tests will be performed in the future on the same module.

years that is on average lower than that of the first 13 years of operation.

As a consequence, all tested PV modules except Module 140 have a nonlinear degradation rate i.e., the mean degradation rate in the last 7 years is higher than the average value recorded in the first 13 years. At this regard, it was demonstrated [33] that some factors (e.g., encapsulant discoloration) typically lead to an approximately linear degradation, since they are substantially dependent on the time of exposure to weather conditions. Differently, other factors (e.g., delamination, cracked cells or solder bond failures and corrosion) cause a non-linear degradation trend, which is proportionally increasing during the module's lifetime [33]. In detail, modules 51, 150 and 138 are characterized by an enlarged delamination compared to 2014 inspection. Normally, delamination leads to a loss because of the formation of an extra optical interface, thus the larger the area, the higher the loss. Furthermore, if the phenomenon becomes more severe, it could cause moisture infiltration [33].

Module 140, instead, has a degradation rate that is roughly linear: the mean rate recorded in the last 7 years is even slightly lower than the average value of the first 13 years. However, when comparing the value referred to the minimum guaranteed nominal power (70.08 W_p) in the first 13 years with that of the most recent period, it can be observed that the 2 numbers are substantially equal.

For module 31 and 51 no visible variations are detected compared to the 2014 assessment, however their mean annual degradation rate increased significatively.

Thus, in order to investigate in a deeper way the status of the modules and justify obtained results, an electroluminescence imaging analysis has been carried using an IR camera sensitive to the emission spectra. This test has been done in February 2022 in a dark test chamber at SUPSI PV Lab at standard test conditions (STC), following the procedure defined in IEC 61215 [28]. In this case PV test module is supplied by a DC current in forward bias conditions to stimulate radiative recombination and measure photoemission using a silicon charged coupled device (CCD) camera (Fig. 11).

Obtained results are described in the following table (Table 6).

5. Conclusions

The present work analyzed the 20 year old BIPV plant installed at Politecnico di Milano. The results of a visual and infrared inspection of all modules, as well as laboratory testing of representative modules, were analyzed to understand the performance trend over the years and the main parameters that affect power reduction.

In summary, the following observations can be derived from the overall analysis:

- Delamination and chalking are the most widespread alterations, since they interest all modules of the plant. In 12 % of the modules, delamination is limited to less than 25 % of the surface while for the remaining 88 % it is above this threshold, but never exceeding 50 % of the surface and/or presenting particularly serious decoupling of the layers. In addition, chalking is never associated with cracks in the backsheet. Module 31, 32 and 51, which are those affected just by delamination and chalking among the tested modules, all show an average annual degradation rate over 20 years lower than 0.8 %/y, demonstrating that those alterations are not currently determining heavy degradation and are typical effect of weathering exposure and operational stress.
- Delamination increased relevantly in the last 7 years of operation, thus with a nonlinear trend, causing an increase over time of the degradation, as demonstrated for instance by results obtained for Module 31, 32 and 51. In particular, Module 138 is one of those showing the most serious alteration, which is probably leading to a moisture ingress in some perimetral areas of the module. Its average annual degradation rate raised from 0.63 %/y in the first 13 years to 1.67 %/y in the last 7 years. This increase is also due to a heavy discoloration, as described in the subsequent point.
- Heavy discoloration affects around 40 % of the modules, and, as expected, determine an additional performance loss. Module 138, which in addition to delamination presents also heavy discoloration, has the second highest average annual degradation rate over 20 years, equal to 0.95 %/y.
- The slightly higher degradation rate of module 51 and 32, compared to the top performing module (31), could be correlated to the probable partial disconnection of cells electrical contacts for the first one and by the higher operating thermal stress in the second one. However, the latter phenomenon will be further investigated in the future.
- Snail tracks interest around 10 % of the modules. In the tested sample (Module 150), it is associated to a microcracks, in good agreement with literature findings. This alteration, which was already observed in the 13th year assessment, justifies the highest annual average

degradation rate of the module (0.96 %/y), with a nonlinear trend; in fact, usually microcracks tends to expand and worsen performance loss during time due to vibrations and thermal stress.

- Module 140, which is affected by a slight hotspot, probably due to a manufacturing imperfection, didn't show an appreciable worsening of its status in the last 7 years, and thus its degradation rate over time can be considered substantially linear.
- All representative modules subjected to testing reported an overall degradation rate in the first 20 years of operation lower than 20 %, thus within the warranty limit.
- Just one module over 150 (less than 1 % of the total) show an alteration that can be classified as a severe fault (i.e., impairment of water tightness of junction box, with consequence serious corrosion), which causes the complete loss of functionality.

Overall, the study confirms the high reliability of PV technology over the time. In a well-designed and maintained PV system in EU climates, modules' degradation typically stays lower than 1 %/y in the first 20 years. Most widespread alterations, such as backsheet chalking, discoloration or light delamination usually determine limited losses, typically with a linear and homogeneous trend over the time. However, some phenomena could become more serious when the end of the performance warranty period approaches. This is the case of heavy delamination or microcracks, which could lead to a growing non-linear degradation, rapidly decreasing the power output. Modules affected by such alterations must be carefully monitored, especially after the 15th year of operation, to avoid that the deteriorating performance of a single module will not affect that of an entire string. Similarly, typical causes of potential faults such as junction box failures, corrosion or mechanical alteration must be periodically monitored, since a timely detection could prevent the complete fault of the module and extend its useful lifetime.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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