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Advanced UV-fluorescence image analysis for early detection of PV-power degradation

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Abstract. Reliability and durability of photovoltaic modules are a key factor for the development of emerging PV markets worldwide. Reliability is directly dependent on the chemical and physical stability of the polymeric encapsulation materials. One method capable of detecting ageing effects of the polymeric encapsulant directly on-site is UltraViolet Fluorescence (UVF) imaging. This work deals with advanced imaging analysis of UVF images and the subsequent correlation to electrical parameters of PV modules, which were exposed to climate-specific, long-term, accelerated aging procedures. For establishing a correlation, a so called UVF area ratio was established, resulting from the typical fluorescence patterns of the encapsulant material, which arise due to stress impact (e.g., water vapor ingress, elevated temperature, irradiation) and aging/degradation processes. Results of the data analysis show a clear correlation of the UVF area ratios and the electrical parameters with increasing aging time. In particular, the relationship between power and series resistance could be confirmed by extensive long-term test series with different climate-specific aging processes. Assuming the same type of polymeric encapsulation and backsheet and a comparable climate, determining the UVF area ratio can be used to estimate the service life and electrical power dissipation of each module installed in a PV array.

Keywords: Reliability / imaging / operation / maintenance / non-invasive

1 Introduction

Reliability and durability of photovoltaic (PV) modules are a key factor for the development of emerging PV markets worldwide [1]. Reliability is directly dependent on the chemical and physical stability of the polymeric encapsulation materials [2,3]. The predominant material for the encapsulation of the active solar cells is ethylene vinyl acetate (EVA), a copolymer of ethylene and vinyl acetate (vinyl-acetat content 25–33%) that is chemically cross-linked in the lamination process (@140–150 °C) of the PV module production [3,4]. Due to the crosslinking with an peroxidic crosslinker a 3-dimensional network is formed which gives the encapsulant good thermal and thermo-mechanical stability. A high degree of crosslinking and a low concentration of residual crosslinker (reactive peroxides) in the encapsulant are favouarable for high stability of the EVA over time [5]. It was found, that EVA foils with different degrees of crosslinking revealed that the photoluminescence intensity is proportional to the degree of crosslinking directly after processing and, thus, this method can be used for an non-destructive determination of the degree of crosslinking [6–9]. Furthermore it was also demonstrated that photoluminescence – or in specific fluorescence – measurements can be used to characterize aging effects in EVA encapsulants [10–13]. Ultraviolet fluorescence (UVF) imaging is a method that can be used to demonstrate aging effects of the polymeric potting material in the laboratory after exposure to stress in accelerated aging tests, but also directly in the field [14–18]. A comprehensive overview of the potential and possibilities of UV fluorescence methodology (imaging and spectroscopy) as an evaluation tool for PV modules can be found in [15].

UVF can give information on the extent of stress-induced changes of the encapsulant (includes the polymer itself and special constituents e.g., impurities, additives or fragments of a cross linker). With increasing lifetime (natural weathering) or storage time in a climate chamber (accelerated aging), the encapsulant material changes/ages due to the impact of climatic stresses – mainly temperature, irradiation and water vapour. Besides the architecture and

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bill of material of the PV-module e.g., permeability of the backside (glass, polymeric backsheets) and type of encapsulant [19], the resulting UVF pattern is mainly dependent on the exposure time and the stress factors applied [11,15,20,21].

This work describes an advanced imaging analysis of UVF images and the subsequent correlation to the performance and selected electrical parameters of PV mini-modules, which were exposed to climate-specific, accelerated aging procedures. In order to exclude material effects in the presented study, only modules with identical bill of material and module design were used to develop the advanced UVF image analysis method and establish a correlation to the electrical performance. Since the formed UVF (which is mainly triggered by high temperatures and irradiation) can be partially quenched by oxygen permeating into the encapsulant via the polymer backsheet, very distinctive UVF patterns were detected depending of the parameters chosen for the artificial aging tests [12,15,22,23]. These effects develop with increasing (accelerated) aging time and thus, changes in fluorescence intensity and spread can be converted into a scalar quantity (ratio).

In the following it will be investigated to which extent aging induced changes of the encapsulant material (visualized by its UVF pattern) can be set in relation with changes in the electrical performance/electrical parameters.

2 Experimental approach

The data taken for the analysis was generated/measured within the Austrian (flagship) project INFINTY, and is currently processed within the follow-up project ADVANCE!. Identical 6-cell test modules with EVA encapsulant and PET-based backsheets were manufactured and exposed to climate-specific, long-term, accelerated aging procedures (up to 6000 h) [12]. For the data evaluation approach presented in this paper, the characterization data of the modules in the original state, several intermediate and the final state, after five specific accelerated aging procedures (Tab. 1) were used. While in 4 of the test procedures (so called Tropical 1 & 2, Arid 1 and Moderate 1) the application of stress was continuous, test “Alpine 1” comprised 3 consecutively applied stress procedures, which were repeated 5 times [24]. Beginning with 250 h of humidity and temperature (DH) storage, followed by 250 h temperature, humidity and irradiation aging and then by 1000 cycles of dynamic mechanical stress testing (DML).

For comparison to the artificially aged modules, a set of the test modules was “naturally aged” and exhibited to sunlight in a outdoor test site in Vienna/Austria (climate zone Cfb) for 1.5 years.

2.1 UV-fluorescence Imaging

UVF imaging is an established inspection tool for PV modules, especially when a rapid, non-destructive on-site characterization method for aging effects in encapsulants [10–12,17,25–27] and/or cell-breakage-detection is needed [28–32]. In general, the polymeric encapsulant

Table 1. Test sequences for climate specific accelerated aging procedures.

	Duration	Temperature	Humidity	Irradiation	Effective module temperature*	Effective module humidity*	DML	Time-Steps	Interval
Tropical 1 (=DH85/85°)	6000 h	85°C	85%	–	–	–	–	9	500 h / 1000 h
Tropical 2	3000 h	90°C	90%	–	–	–	–	7	500 h
Arid 1	1000 h	95°C	50%	1200 W/m^2	129%	16%	–	5	250 h
Moderate 1	1250 h	85°C	85%	1000 W/m^2	113%	30%	–	6	250 h
Alpine1	2000 h	85°C	85%	1200 W/m^2	119%	25%	1000 cycles	5	500 h

*Formula for calculation according to IEC TS 62804-2:2022 (Ed.1).

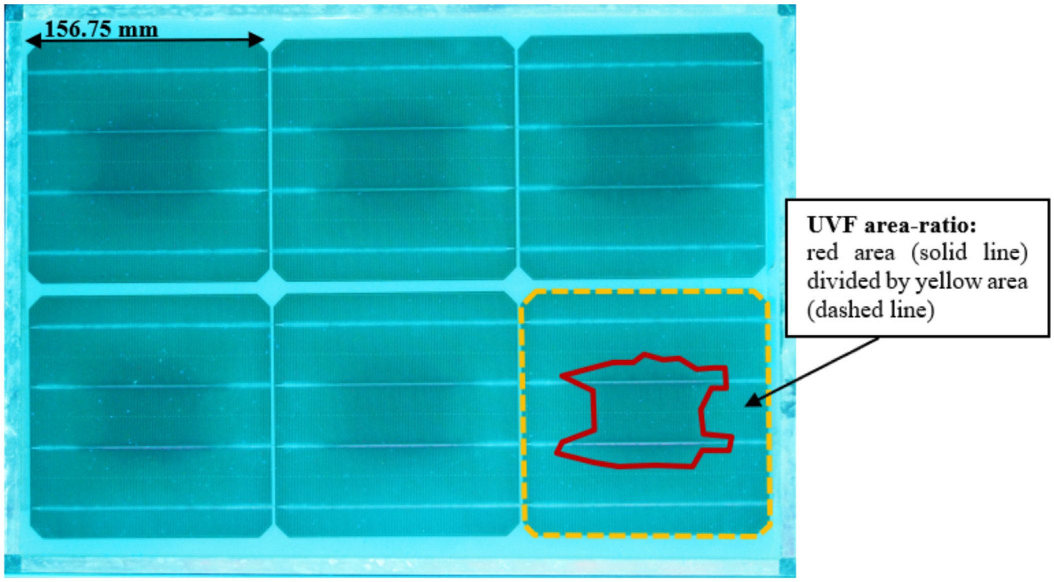

Fig. 1. Typical UVF pattern after 6000 h of (accelerated) aging (Tropical 1).

(polymer + additives) of PV modules does not show distinctive fluorescence effects in the original state. With increasing lifetime, the encapsulant material ages due to the interaction with climatic stress factors (mainly irradiation by sunlight, elevated temperature and humidity) by forming fluorophores. It was found that the UVF image patterns obtained for the naturally and/or artificially aged modules depend on the composition/design of the PV-module; in particular (i) if gas-tight (glass, backsheets with Al-barrier layers) or breathable (polymeric backsheets) backsides are used (determines the impact of oxygen quenching), (ii) if cell-cracks, pinholes in the cell or hot cells are present and (iii) on the stress factors applied at the installation site and/or in the climatic chamber in accelerated ageing tests [33]. Additionally we can state, that there is no evidence for a specific additive in the EVA, which causes UVF. Studies demonstrated UVF imaging to be a suitable tool for e.g. (micro-) crack detection [28–32], or short circuit current (Isc) reduction correlation on site, due to degradation processes and discoloration of the encapsulation material [25,27,34].

UV-fluorescence images were recorded in dark environment by UV light illumination (self-made UV-lamp with three power-tunable LED-arrays as light source; emission maximum at 365 nm, 50 W each, tunable) and a low pass filter to cut off visible light. The detection of the UVF occurs with a digital photographic camera (Olympus OM D, equipped with high pass filter to cut-off the UV-irradiation).

From the obtained UVF-patterns, a so called UVF area ratio was derived. This scalar quantity was defined as a ratio between the darker spot in the middle (so called "non-fluorescing" part) of each cell and the total cell area (Fig. 1). The ratio is set to 1 when no pattern was detected.

The UVF area ratio was manually extracted from the UVF images using an image manipulation software (GIMP 2.10.30). Due to slight brightness/contrast differences in the recorded UVF images and therefore hardly detectable UVF area ratios, an automated approach for extracting the UVF area ratio was not possible. Hence contrast and brightness values were adjusted to increase the visibility of these areas and the sharpness of the edges. For this, a grey value analyis was conducted across the cell (defined area reaching from fluorescent to non-fluorescent part) with a subsequent adjustment of the brightness/contrast values in order to obtain the position of the maximum gradient (interface between fluorescent and non-fluorescent part). In a next step, for each individual solar cell on the respective PV module a mask was drawn to encircle the non-fluorescing part.

For calculating the ratio, the masked area was divided by the total cell area of the six solar cells. Intermediate and edge areas were excluded from the calculation. Finally a mean UVF area ratio was calculated from the six cells to extract one correlation parameter per mini-module (Fig. 2). This procedure was repeated for all aging steps to obtain time resolved UVF area ratios (Fig. 3).

2.2 Electrical characterization

The electrical performance was measured under laboratory standard test conditions (STC; 25 °C; 1000 W/m^2 with AM 1.5 spectral distribution) by using a PASAN HighLIGHT VLMT A+A+A+ flash tester (IEC60904-1 and IEC60904-9). These time-resolved characterization parameters represent relevant electrical properties of PV modules, which were recorded at every intermediate step of the specific accelerated aging procedures (Tab. 2).

In addition to these data, also electroluminescence (EL) images were recorded for all modules and aging iterations (Fig. 4). For this, the full six cell modules were captured at one shot using a ATIK 16200 B/W cooled Si-CCD-Camera under both low current (10% of I_{SC}) and high current (100 % of I_{sc}) settings. The exposure time was set to 60 s and the aperture was set to 2.8/f.

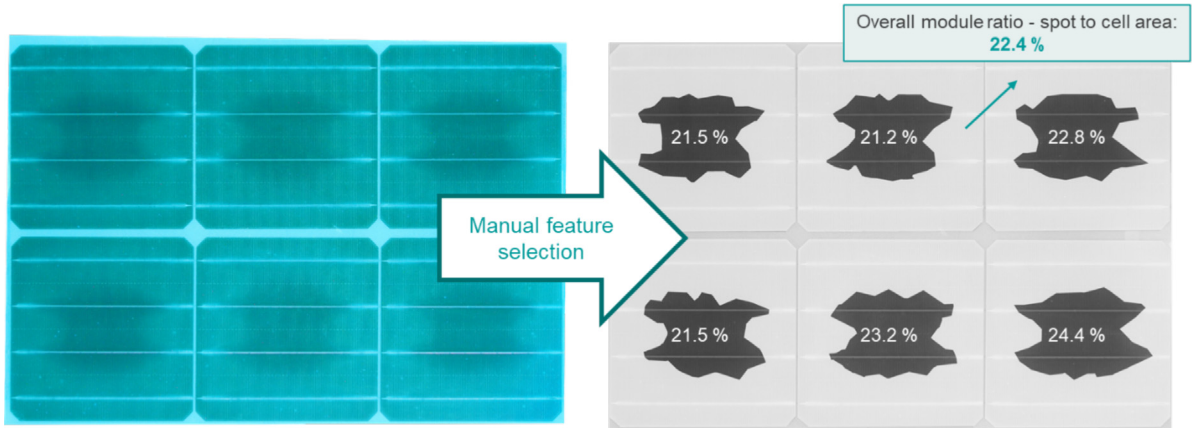

Fig. 2. Manual extraction of UVF patterns on cell/module level.

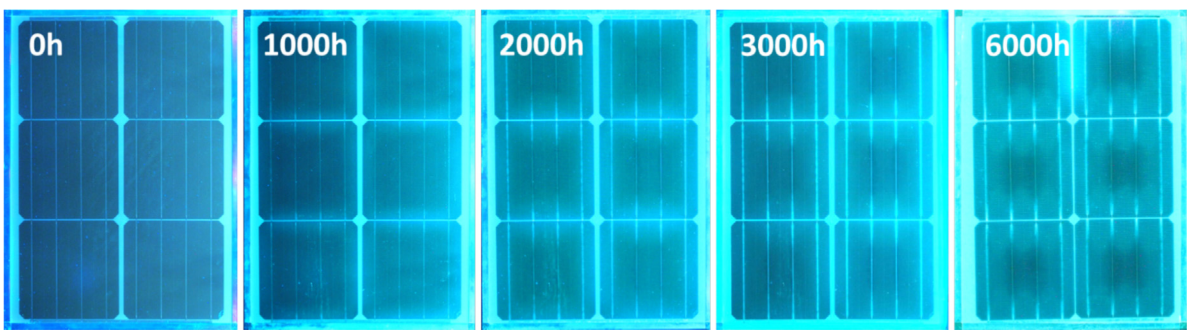

Fig. 3. UVF-images of the Tropical 1 time series.

Table 2. Overview of electrical measurement parameters.

Electrical Parameter	Abbreviation
Open circuit voltage	U_{OC}
Short circuit current	I_{SC}
Serial resistance	R_S
Parallel resistance	R_P
Power at maximum power point	P_{MPP}
Current at maximum power point	I_{MPP}
Voltage at maximum power point	V_{MPP}
Fill factor	FF

3 Results

First the methodology of deriving the UVF ratio and correlating the results with changes in the electrical performance is shown for a series of modules having been exposed to elevated temperature and high humidity (Tropical 1 and 2). Then, in a second step, the procedure is applied to accelerated aged modules that faced 3-fold stress-impact: irradiation, high temperature and humidity (Alpine 1, Arid 1 and Moderate 1). Finally, examples of UVF-images of naturally aged PV-modules are shown.

3.1 Accelerated aging tests: temperature and humidity stress impact (damp heat)

Clear correlation of UVF area ratios (Fig. 5) and electrical module parameters (Fig. 6) with aging time was found. Analyzing the results in detail revealed an increase in the series resistance (R_S) and a concomitant decrease in the output power (P_{MPP}) while the short-circuit current (I_{SC}) stays unchanged. The UVF area ratio also significantly declined with aging duration. Increasing moisture penetration through the backsheet with exposure time was found to be responsible for (i) grid finger/busbar corrosion effects, reflected in changes in R_S and P_{MPP} and [24] (ii) changes in UVF area ratio [30] (Fig. 7). These effects of the prolonged damp-heat exposure, i.e. cell corrosion effects (especially above the ribbons), are also clearly visible in the EL image, displayed in Figure 4. The yellowness index and transparency of the encapsulant (measured in the centre of the cell) showed no significant changes with age, consistent with the negligible reduction in I_{SC}.

3.2 Accelerated ageing tests including irradiation

In addition to the accelerated aging procedures based on temperature and humidity stress impact (Tropical 1 and 2) as described in Section 3.1, also aging processes with additional irradiation stress were investigated (accelerated aging: Arid 1, Alpine 1 and Moderate 1). The UVF-images

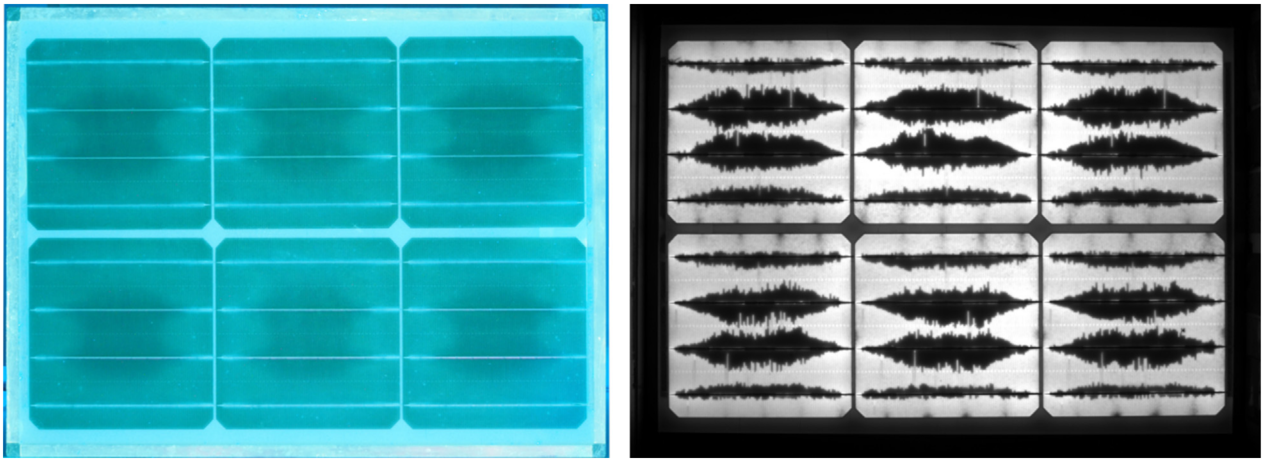

Fig. 4. Comparison of EL and UVF image after 3000 h of Tropical 2 accelerated aging.

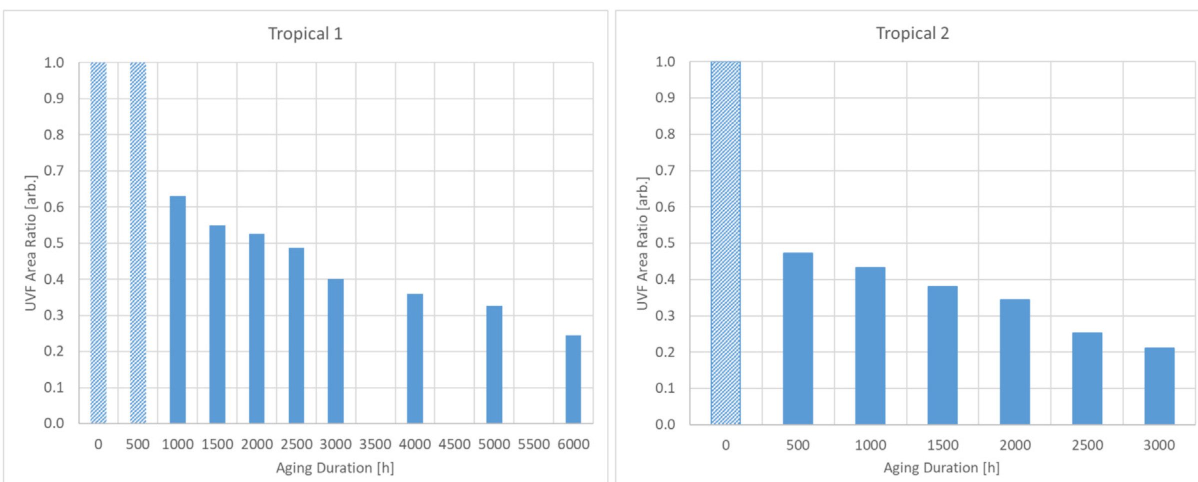

Fig. 5. UVF area ratio analysis for accelerated aging procedures Tropical 1 & Tropical 2.

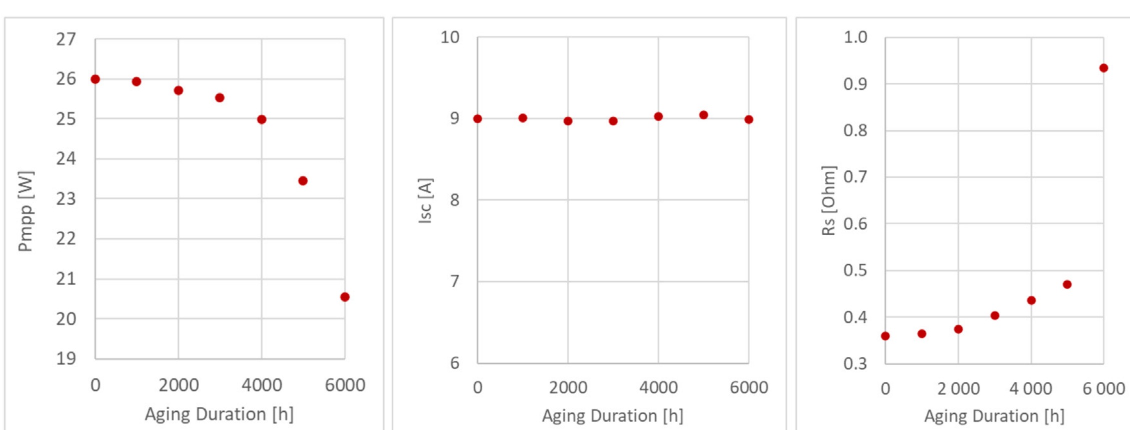

Fig. 6. Electrical parameter evalutation for an exemplary test module during 6000 h of Tropical 1 storage.

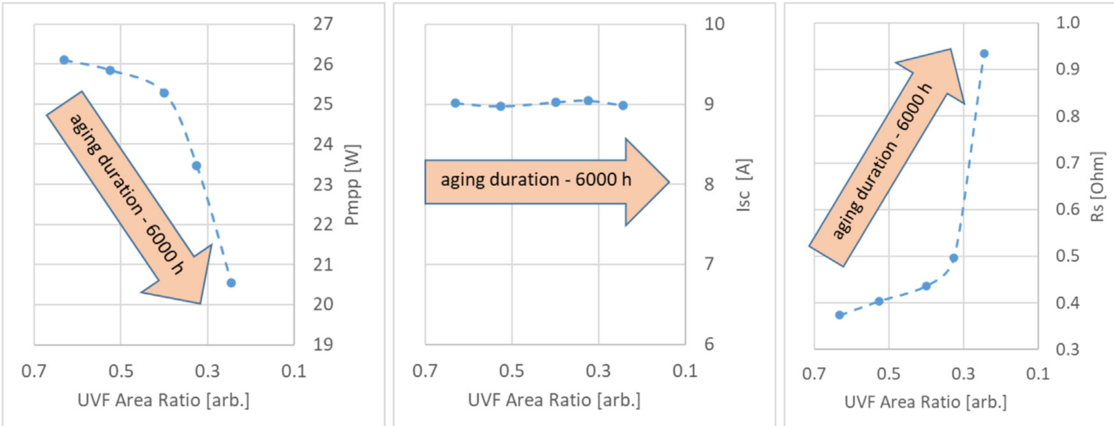

Fig. 7. Correlation of electrical parameters and UVF area ratio for Tropical 1 (85 °C, 85% r.H.).

Fig. 8. Comparison of UVF-images of test modules after 1000 h of accelerated aging (procedures with and without additional irradiation); exemplarly specific UVF pattern is highlighted in yellow for each module [9].

after 1000 h artifical aging time for 4 different aging procedures are compiled in Figure 8. Also for the test modules exposed to artificial sunlight (Metal-Halid lamps) a decrease of the UVF area ratio with increasing accelerated aging time (up to 2000 h) can be observed (see Figs. 9 and 10). Nevertheless, the trend is much less visible compared to the results after sole temperature and humidity storage (up tp 6000 h) as shown in Section 3.1. The main reason for this seems to be the shorter aging duration of these specific accelerated stress tests (2000 h for Alpine 1, 1250 h for Moderate 1 and 1000 h for Arid 1). Thus, prolonged aging times would be needed to detect more pronounced trends.

3.3 Natural weathering

In order to establish a correlation of the UVF area ratios obtained in the accelerated aging tests (as described in Sects. 3.1 and 3.2) and the UVF effects observed with naturally aged PV-modules, a set of the test modules was also stored in a outdoor test site in middle Europe (Austria, Vienna) for 1.5 years. The comparison of one typical UVF-image of the naturally aged testmodule with one after 1000 h of artifical irradiation (1000 W/m^2) and 2000 h of temperature-humidity (Tropical 1) storage is given in Figure 11. It is obvious that the UVF- image of the naturally aged module (Fig. 11b) appears as a superposition of that of the irradiatiated (Fig. 11c) and the temperature-humidity stressed (Fig. 11a) module. In accelerated aging tests in a climatic chamber, e.g. damp-heat testing, UVF is caused by hydrolysis. In contrast to that, outdoors, under natural weathering conditions, UVF is created by irradiation (photooxidative formation of radicals in EVA and quenching ("canceling") of UVF due to oxygen ingress). For extracting the UVF area ratios from naturally aged modules, the same procedure as for modules which were stored under accelerated aging conditions was applied.

By comparing the P_{MPP} of the lightstabilized modules in the original state and of the naturally aged modules, it was nearly unchanged, after 1000 h and 2000 h DH, and after 1000 h irradiation P_{MPP} slightly decreased by <1%.

In a next step, the UVF area ratio of the naturally aged module was calculated to be 0.7 (after 1.5 years of outdoor exposure). Compared to the artificially aged modules, this value would correspond to ~750 h (Tropical 1) DH storage and ~900 h of Moderate 1 exposure. It seems most reliable to compare the naturally aged module in Vienna (climate zone Cfb) with the "moderate" climate having an average yearly

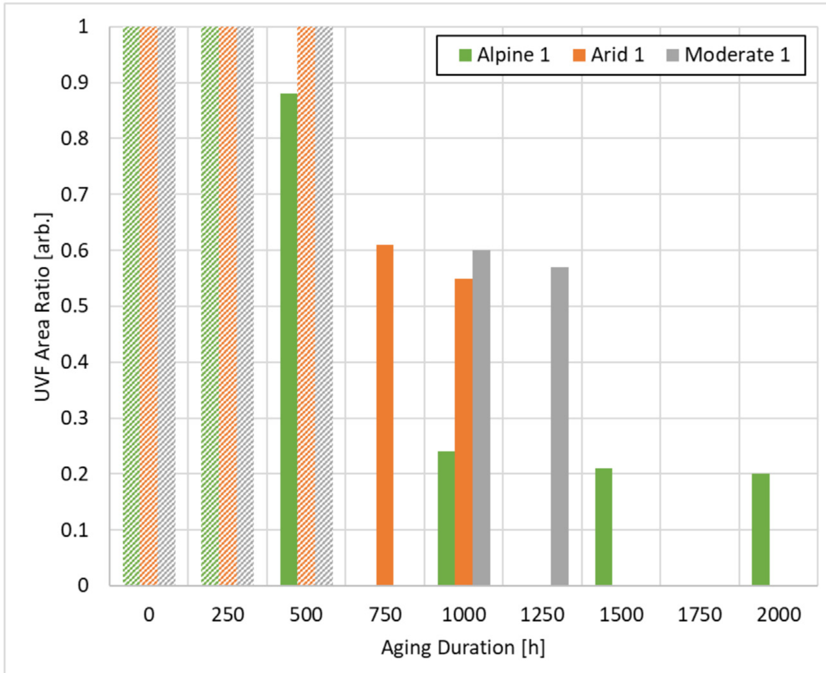

Fig. 9. UVF area ratio analysis for accelerated aging procedures of Alpine 1, Arid 1 & Moderate 1.

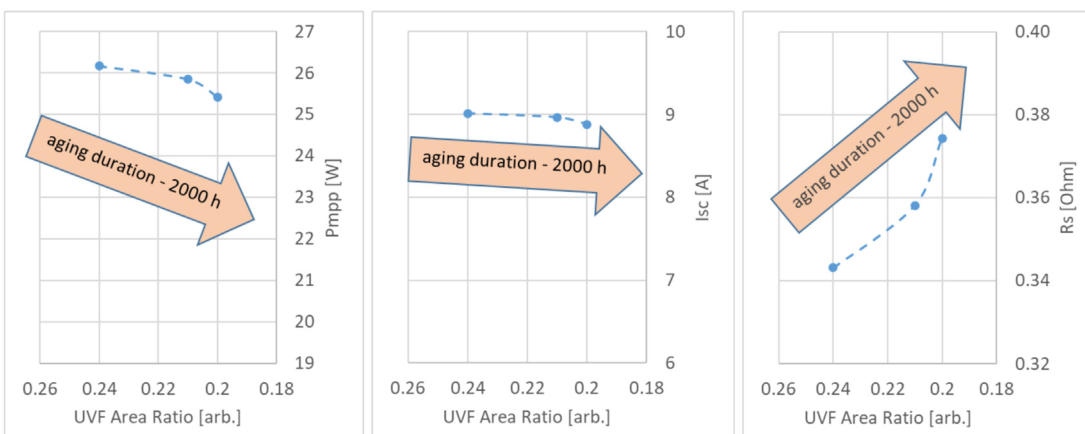

Fig. 10. Correlation of electrical parameters and UVF area ratio for Alpine 1 (85 °C, 85% r.H., 1200 W/m^2, 1000 cyles DML).

sunshine duration of 2100 h (1460 kWh/m^2 module surface) and monthly average temperatures between 0 and 20 °C.

Finally, a naturally aged, full sized 60-cell PV module was analyzed (Fig. 12). As it is known that the water vapor transmission rates (WVTR) and oxygen transmission rates (OTR) of the backsheet core material have a great influence on the rate of formation and extent of the formed UVF patterns [31], a module with the same type of PET-based backsheet, utilized also for the test modules, was selected.

The PV module was installed at a PV plant located in Villach (Austria, climate zone Cfb; 2350 h average yearly sunshine duration, 1530 kWh/m^2 module surface). UVF-images were taken after 3 years and 3.8 years operational time. The UVF area ratios were calculated to be 0.58 and 0.52, respectively. By comparing the UVF area ratios with the ones from modules of the accelerated aging (Moderate 1), the full-size PV module corresponds to accelerated aging durations of ~1100 h (3.0 years) and ~1500 h (3.8 years), respectively (Fig. 13).

By approximating an annual degradation rate of 0.5–0.6% [35], the naturally added module is expected to have about 2% power loss after 3.8 years which would correspond to the characterization results of the test modules after 1500 h Moderate 1 exposure (ΔP_{MPP} 1.8% after 1250 h). Measurement data of the respective module, utilizing an IV curve tracer (HT Instruments, I-V400w), resulted in a power degradation of ~4%. This fits to the

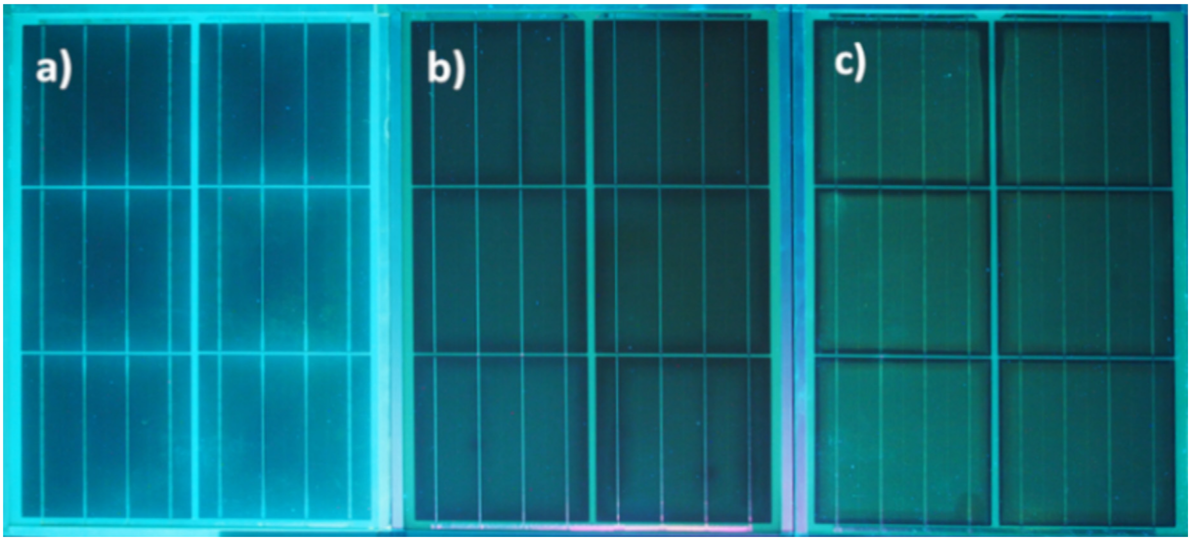

Fig. 11. UVF images of test modules; (a) after DH storage (Tropical 1) for 2000 h, (b) after natural weathering (outdoors) for 1.5 years and (c) after exposition to artificial sunlight (climate chamber; 1000 W/m^2) for 1000 h.

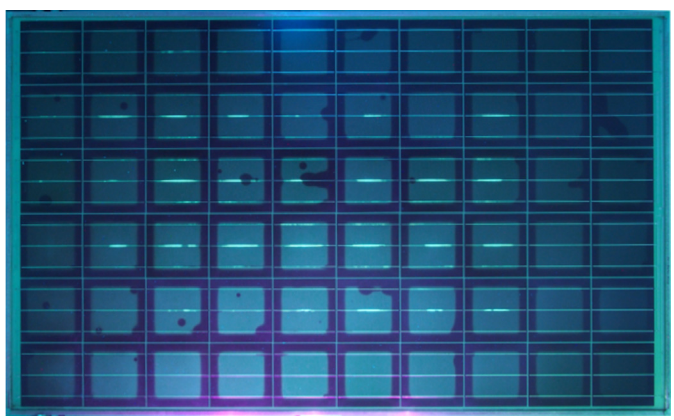

Fig. 12. UVF-image, taken 3.8 years after installation, of a naturally aged PV Module.

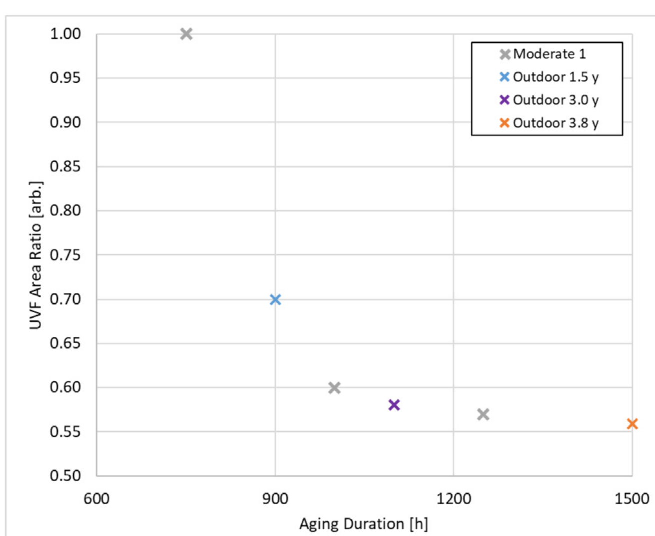

Fig. 13. Analysis of aging duration and UVF area ratio of a naturally aged PV module in combination with artificially aged test modules.

approximated values of the UVF analysis, considering small measurement errors, non-ideal measurement conditions and slightly higher yearly degradation rates within the first years of the module's lifetime.

Hence, determining the UVF ratio of naturally aged modules in a PV plant can allow for an estimation of the operating time of a specific module and also the loss in P_{MPP} (the same type of backsheet core material and EVA encapsulant provided).

4 Conclusion and outlook

In summary, it can be stated that there is a clear correlation between the UVF area ratio and the electrical parameters of PV modules; In particular, with the power P_{MPP} and the series resistance R_{S}, a connection could be confirmed by extensive long-term test series from different climate-specific accelerated aging processes [12,15,16,30].

In order to be able to explain the shape of the formed UVF patterns, it is necessary to understand the processes of fluorophore formation and quenching under the influence of temperature, humidity and irradiation [10,15]. Different types of fluorophores are formed upon exposure to moisture (hydrolytic activation of the polymer) and upon irradiation (photothermal activation)—both rates of formation are strongly influenced by temperature. Fluorescence quenching in the encapsulation materials is driven by oxygen penetration and diffusion into the PV modules through the backsheets. The OTR is also greatly increased by temperature.

In accelerated aging tests, one can replicate the influence of water vapor/temperature in the presence and absence of irradiation on the formation of UV patterns and separate their individual effects [11]. In the present work, the influence of moisture on the UVF pattern was tracked over time and correlated with corrosive degradation processes, which can be measured in a degradation of the electrical power P_{MPP} and R_{S}.

Under natural weathering conditions, however, the influence of irradiation/temperature on the formation of UVF in the encapsulation is dominant [15].

Therefore, the additional impact of the irradiation under 3 different temperature-humidity irradiation scenarios was also simulated in the climate chamber. Here too, a connection between the formation of UVF patterns and electrical degradation can be demonstrated. It must again be emphasized that all of these artificial tests were carried out on modules with the same type of polymeric PV encapsulation and backsheet.

Assuming comparable climatic conditions and bill of materials, it could be shown [30,36] that by determining the UVF area ratio, an estimate of the operational service life and the resulting electrical power loss (annual degradation) can be made.

Therefore, quantifying and investigating the temporal evolution of the UVF pattern in outdoor conditions can be an approach to the development of a new on-site O&M procedure. The results presented in this work can be the basis for the development of such a tool showing clearly the correlation of UVF-pattern formation and operational lifetime and power deterioration. The performance evaluation/approximation based on UVF images can be performed without affecting the operation of the PV array.

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Author contribution statement

The authors confirm contribution to the paper as follows: study, conception, design, data analysis, interpretation and writing: L. Neumaier and G.C. Eder; data acquisition and electrical measurements: G. Újvári; data acquisition of UVF images: Y. Voronko; data interpretation and database management: K. Knöbl; data interpretation and electrical analysis: K.A. Berger. All authors reviewed the results and approved the final version of the manuscript.

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