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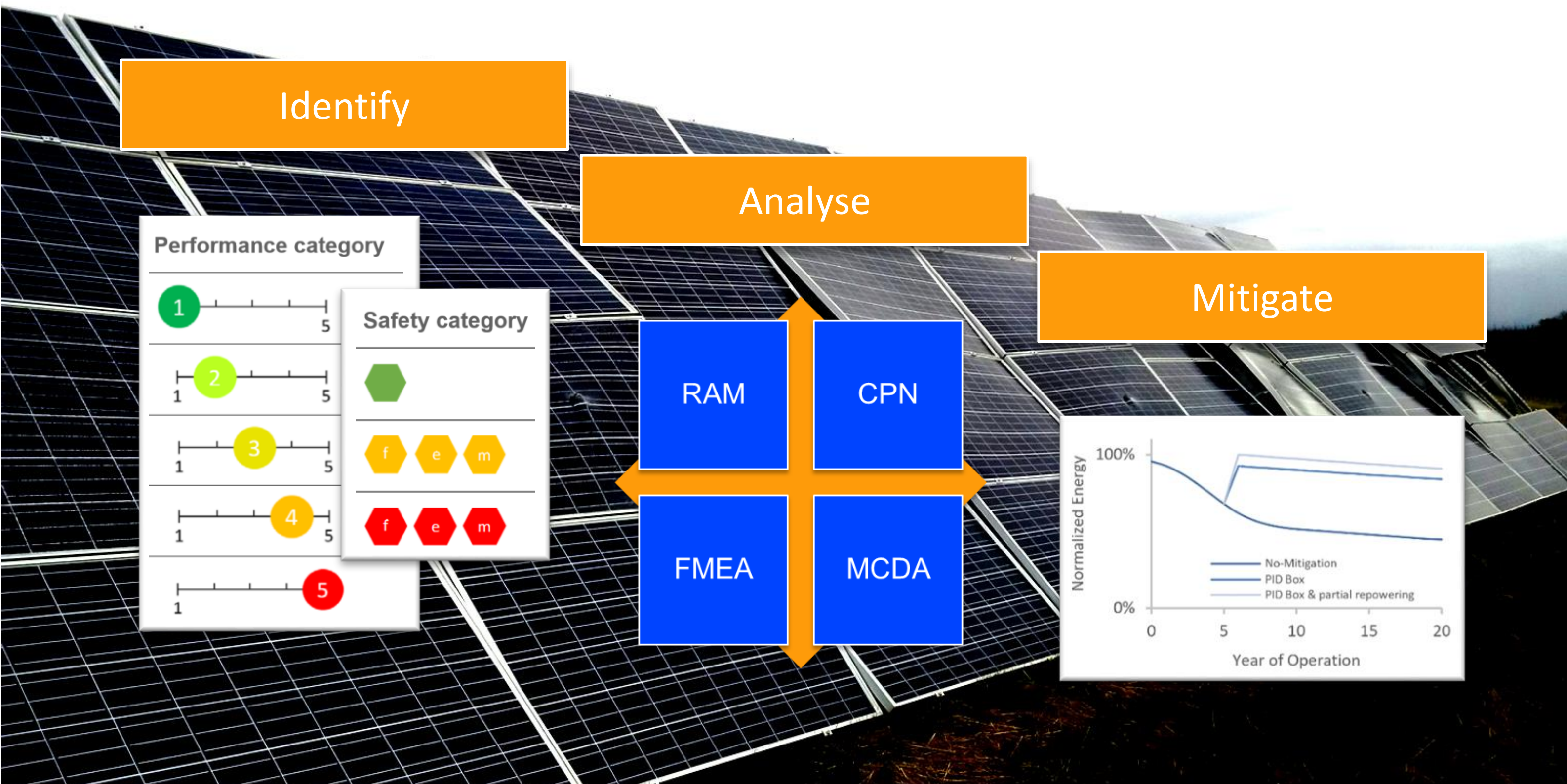

Task 13 Performance, Operation and Reliability of Photovoltaic Systems

PVPS

Quantification of Technical Risks in PV Power Systems 2021

Report IEA-PVPS T13-23:2021

What is IEA PVPS TCP?

The International Energy Agency (IEA), founded in 1974, is an autonomous body within the framework of the Organization for Economic Cooperation and Development (OECD). The Technology Collaboration Programme (TCP) was created with a belief that the future of energy security and sustainability starts with global collaboration. The programme is made up of 6.000 experts across government, academia, and industry dedicated to advancing common research and the application of specific energy technologies.

The IEA Photovoltaic Power Systems Programme (IEA PVPS) is one of the TCP's within the IEA and was established in 1993. The mission of the programme is to "enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems." In order to achieve this, the Programme's participants have undertaken a variety of joint research projects in PV power systems applications. The overall programme is headed by an Executive Committee, comprised of one delegate from each country or organisation member, which designates distinct 'Tasks,' that may be research projects or activity areas.

The IEA PVPS participating countries are Australia, Austria, Belgium, Canada, Chile, China, Denmark, Finland, France, Germany, Israel, Italy, Japan, Korea, Malaysia, Mexico, Morocco, the Netherlands, Norway, Portugal, South Africa, Spain, Sweden, Switzerland, Thailand, Turkey, and the United States of America. The European Commission, Solar Power Europe, the Smart Electric Power Alliance (SEPA), the Solar Energy Industries Association and the Cop- per Alliance are also members.

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What is IEA PVPS Task 13?

Within the framework of IEA PVPS, Task 13 aims to provide support to market actors working to improve the operation, the reliability and the quality of PV components and systems. Operational data from PV systems in different climate zones compiled within the project will help provide the basis for estimates of the current situation regarding PV reliability and performance.

The general setting of Task 13 provides a common platform to summarize and report on technical aspects affecting the quality, performance, reliability and lifetime of PV systems in a wide variety of environments and applications. By working together across national boundaries we can all take advantage of research and experience from each member country and combine and integrate this knowledge into valuable summaries of best practices and methods for ensuring PV systems perform at their optimum and continue to provide competitive return on investment.

Task 13 has so far managed to create the right framework for the calculations of various parameters that can give an indication of the quality of PV components and systems. The framework is now there and can be used by the industry who has expressed appreciation towards the results included in the high-quality reports.

The IEA PVPS countries participating in Task 13 are Australia, Austria, Belgium, Canada, Chile, China, Denmark, Finland, France, Germany, Israel, Italy, Japan, the Netherlands, Norway, Spain, Sweden, Switzerland, Thailand, and the United States of America.

COVER PICTURE

In the back, inspection of a PV power plant after a severe storm. Photo curtesy of TÜV Rheinland.

In the front, practices of risk quantification divided into an adapted rating system by SUPSI/Sinclair, analysis methods and mitigation by TÜV Rheinland.

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INTERNATIONAL ENERGY AGENCY

PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

IEA PVPS Task 13

Performance, Operation and Reliability of Photovoltaic Systems

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AUTHORS

Main Authors

Magnus Herz, TÜV Rheinland, Cologne, Germany
Gabi Friesen, SUPSI-PVLab, Mendrisio, Switzerland
Ulrike Jahn, VDE Renewables, Alzenau, Germany
Marc Köntges, ISFH, Emmerthal, Germany
Sascha Lindig, EURAC Research, Bolzano, Italy
David Moser, EURAC Research, Bolzano, Italy

Contributing Authors

Stefan Bordihn, ISFH, Emmerthal, Germany
Gabriele Eder, OFI, Vienna, Austria
Uwe Hupach, TÜV Rheinland, Cologne, Germany
Guillermo Oviedo Hernández, BayWa r.e., Rome, Italy
Bert Herteleer, KU Leuven, Gent, Belgium
Werner Herrmann, TÜV Rheinland, Cologne, Germany
Jay Lin, PV Guider Consultancy, Taipei, Taiwan
Christian Schill, Fraunhofer ISE, Freiburg, Germany

Editors

Magnus Herz, TÜV Rheinland, Cologne, Germany
Ulrike Jahn, VDE Renewables, Alzenau, Germany

TABLE OF CONTENTS

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LIST OF ABBREVIATIONS

AC	Alternating Current
AHP	Analytic Hierarchy Process
BYT	Bypass Diode testing
CAPEX	Capital Expenditures
CPL	Component Power Loss
CPN	Cost Priority Number
D	Detectability
DC	Direct Current
dIV	Dark I-V Measurement
EL	Electroluminescence
EPC	Engineering, Procurement, Construction
FMEA	Failure Modes and Effects Analysis
FTA	Fault Tree Analysis
IEA	International Energy Agency
INS	Insulation Testing
IRT	Infrared Thermography
I-V	Current-Voltage
KPI	Key Performance Indicator
LCOE	Levelised Cost of Electricity
LeTID	Light and elevated temperature induced degradation
LID	Light induced degradation
MCDA	Multi Criteria Decision Analysis
MDT	Mean Down Time
MM	Mitigation Measure
MON	Data Monitoring
MTTF	Mean Time To Failure
NPV	Net Present Value
O	Occurrence
O&M	Operation and Maintenance
OPEX	Operational Expenditures
PDF	Probability Density Function
PID	Potential Induced Degradation
PMBOK	Project Management Body of Knowledge
PLR	Performance Loss Rate
PR	Performance Ratio
PV	Photovoltaic

PVDS	PV Failure Degradation Sheet
PVFS	PV Failure Fact Sheet
PVPS	PV Power Systems
RAM	Reliability, Availability, and Maintainability
RBD	Reliability Block Diagram
RDB	Risk Database
RPN	Risk Priority Number
S	Severity
SRD	Statistical Risk Data
STL	Seasonal-Trend Decomposition using LOESS
STM	Signal Transmission Method
UV	Ultra Violet
VI	Visual Inspection
VOC	Voc Measurement

EXECUTIVE SUMMARY

Photovoltaic (PV) risk analysis serves to identify and reduce the risks associated with investments in PV projects. The key challenge in reacting to failures or avoiding them at a reasonable cost is the ability to quantify and manage the various risks. There are several interpretations of the concept of risk, but in general risk can be defined as the probability of failure multiplied by the consequences of its failure.

Best practice guidelines to improve the operation of PV power systems are often only applied as long as the recommended actions have advantages for the executors, the Engineering, Procurement, Construction (EPC) and Operation and Maintenance (O&M) companies and for the investors whose main interests focus on low risks and maximum profit from an economic point of view. This leads to the key question: How can you demonstrate the effectiveness of measures and justify their application? Because the technical best solution is not always the economic best solution. And before you are able to evaluate the cost-benefit ratio, the following question arises: How to quantify the basic impact of technical risks on performance and reliability?

In a first approach we reviewed scientific literature and technical reports to compare and assess the common practices for quantifying the impact of technical risks. Limitations and challenges were compiled and selection criteria defined for the four methods:

a) Failure Modes and Effects Analysis (FMEA)
b) Multi Criteria Decision Analysis (MCDA)
c) Reliability, Availability, and Maintainability (RAM) analysis
d) Cost Priority Number (CPN) method

The advantages and disadvantages of these methods are demonstrated considering the factors maturity level and data availability, and as well an overview of common risk mitigation measures is given.

The second part deals with 30 PV Failure Fact Sheets (PVFS) annexed to this report which summarise some of the most important aspects to know about single failures. The target audience for these PVFSs are PV planners, installers, investors, independent experts and insurance companies or anyone interested in a brief description of failures with examples, an estimation of risks and suggestions of how to intervene or prevent these failures. Besides the PVFS collection we used a PV Failure Degradation Sheet (PVDS) as introduced in [1]. These requires much more detailed measured input data but are able to provide statistics on degradation rates and power loss of PV systems based on failure types. Compared to the survey structure in [1] we added two new failure categories for PV modules: Light and elevated temperature induced degradation (LeTID) and potential induced delamination.

These statistics serve as a basis for risk models, such as the CPN method [2] [3], which are used to assess the associated risk and the economic impact over the project-lifetime of a PV plant. In addition to the knowledge of the individual risks, the economic impact of these risks are driving factors for further analysis and decisions. In a final step the costs of mitigation measures are included in a cost-benefit analysis in order to derive the best strategy from a technical and financial perspective.

The revised CPN approach is presented through an exemplary calculation of individual CPN values. The CPN approach was applied to 191 maintenance tickets of a PV plant located in

central Italy which is in operation since 2013. The maintenance tickets were analysed manually, corresponding to all the planned and corrective activities carried out in 2018 for the example plant. The improved CPN methodology has been applied manually to this case study, which led to important improvements, especially in terms of the structure and standardisation of the CPN table. We conclude that the development of an automated, and therefore time-efficient, solution for extracting key parameters from maintenance tickets is of vital importance for the implementation of this methodology at the portfolio level, and thus, to gain statistical insights from a large number of PV plants.

In a second case study the CPN method was also applied to a 10 MWp PV plant. As one of the main risks for the PV modules, potential induced degradation (PID) was selected. Taking Capital Expenditures (CAPEX), Operational Expenditures (OPEX) and annual revenues into account, the project's financial profit after 20 years of operation was 48% below original expectations. Considering the additional costs of mitigation measures, the loss on the cumulated financial income after 20 years of operation could be kept at only 5% - 6% below the originally expected profit.

Cleaning routines for PV power systems in desert regions are a typical corrective measure to reduce energy yield losses due to soiling. The impact of different cleaning procedures on the soiling losses over one year are calculated and shown for a 10 MWp PV plant near Abu Dhabi. In the case of periodic (monthly) cleaning, annual energy losses due to soiling are reduced from 30% to 4% including the costs of 12 cleaning routines. The best economic results are achieved with "triggered cleaning" at a soiling loss of 5%, even if 20 cleaning routines per year are required. The calculations showed how it is possible to determine the best economic solution for a specific PV plant, loss scenario and mitigation approach.

With the provided overview of quantification methods, we draw the conclusion that more standardisation is required. Risk definitions are not fully structured and event databases (solar logbooks) are not harmonised. The development of a software tool for field technicians is recommended that would allow the precise and error-free recording of standardised parameters for the calculation of the O&M contractor's Key Performance Indicators (KPI) necessary for efficient implementation of the methodology [4]. In summary the O&M field practices must certainly move away from the manual input of tickets in text format and adopt a more standardised approach where human intervention is limited.

All things considered, we believe that the data-driven evaluation and modelling of techno-economic performance indicators is a significant key to take decision support on Levelised Cost of Electricity (LCOE) to the next level.

1 INTRODUCTION

Technical risks are important criteria to be considered when investing in new and existing PV installations. Quantitative knowledge of these risks is one of the key factors for the multiple types of stakeholders, such as asset managers, banks or project developers, to define reliable business decisions before and during the operation of their PV assets.

While multiple interpretations of the concept of risk exist, it is generally agreed that risk can be defined as the probability of failures multiplied by the consequences of these failures. The common approach in evaluating technical risks is to apply a classical FMEA [5]. It is widely used in the automotive, aerospace, and electronics industries to identify, rank, and mitigate potential failures. Root cause and impact of a failure can be analysed. The disadvantage of this approach is that the risk is evaluated in a qualitative way and cannot provide a framework for the calculation of the economic impact. Thus, a cost-based FMEA was proposed in 1993 [6] and enhanced in 2003 [5]. Several applications of cost-based FMEA can be found in the literature [7], often related to automotive or wind energy [8].

In 2017, a cost-based FMEA was presented within the Solar Bankability Project [9] as a first attempt to implement a cost-based FMEA to the PV sector. The metric CPN was applied as one KPI for the risk assessment of PV investments. In [4], the CPN method was further developed with the focus on the needs of large O&M operators. Other publications [10] [11] discussed the topic from a reliability perspective. As by definition, if you enhance the reliability of the system's components, the overall system risk is reduced.

The aim of this report is to increase the knowledge of methodologies to assess technical risks and mitigation measures in terms of their economic impact and effectiveness during operation & maintenance and to investigate the most important risks by collecting case studies and updating the database with the acquired information. Based on results from previous work yield assessments for new projects [12], monitored loss rates for existing power plants [13] [14] and the relevant financial parameters [15] decisively determine the impact of technical risks on Net Present Value and the Levelised Cost of Electricity.

In Chapter 2, common practices for quantifying the impact of technical risks were compared and a list of recommended mitigation measures tailored to the identified risks and the status of the PV plant is developed. After a first review of the scientific literature and technical reports, the limitations and challenges are compiled, and selection criteria defined.

Chapter 3 deals with the systematical approach to identify the main technical risks and collect these failure, loss and occurrence data from previous IEA PVPS Task 13 reports [16] [1]. These statistics can then serve as the basis for risk models which are used to assess the associated risk and the economic impact over the project-lifetime of a PV plant. In addition to the knowledge of the individual risks, the economic impact of these risks are the driving factors for further analysis and decisions.

In Chapter 4, real case studies are introduced. The costs of mitigation measures are included in a cost-benefit analysis in order to derive the best strategy from a technical and financial perspective.

2 COMMON PRACTICE FOR QUANTIFYING THE IMPACT OF TECHNICAL RISKS

According to the Project Management Body of Knowledge (PMBOK) guide, a set of standard terminology and guidelines for project management [17], "Risk quantification is a process to evaluate identified risks to produce data that can be used in deciding a response to corresponding risks". This implies that the first step is to identify the technical risks and subsequently determine the probability of occurrence and the impact on the energy yield. Previous works within IEA PVPS Task 13 [16] [1], Moser et al. [2] and the PV failures fact sheet in Chapter 3.1 have identified and described the most common technical failures that could impact the performance of a PV power plant. In addition to failures, there are also other technical risks during operation caused by varying performance loss rates as analysed in [18] [14]. How to respond to these risks with preventive or corrective actions is discussed by Jahn et al. in [3] and [19]. In the following, these evaluation processes are classified into semi-quantitative and quantitative methods with a focus on photovoltaics. This chapter gives an insight into common methods used, how technical risks in PV plants can be evaluated and minimised, and provides recommendations for best practices.

2.1 Key Definitions

While there are specific parameters for each quantification method, this chapter presents the recurring indicators typically used in contracts in the PV sector (s. Figure 1). Further definitions can be found in the Task 13 report [12] or [20].

Technical risk: The probability of problems multiplied by the consequences of its failure.

Reliability: The probability that a component performs its intended function

Energy Yield: The electrical energy generated by a power plant.

Yield Loss: Not-generated energy caused by a problem.

Failure rate: It indicates how many objects fail on average in a period of time.

Detection time: How long a problem exists before it is noticed.

Response time: Time between when the problem is detected and the corrective action starts.

Resolution time (repair time): time to resolve the fault from the moment of reaching the plant.

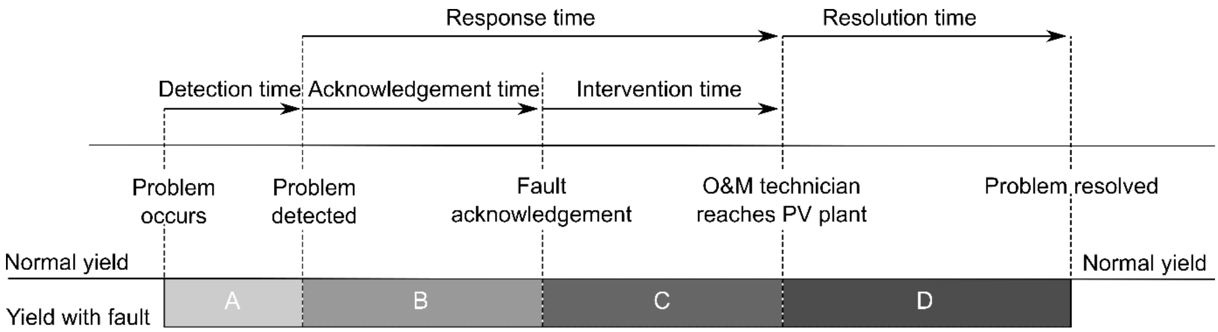

Figure 1: Parameters to calculate the O&M contractor KPIs, extracted from the monitoring and ticketing system [19].

2.2 Semi-Quantitative Methods (FMEA, MCDA)

These semi-quantitative methods use human problem-solving strategies, based on expert knowledge and expert opinion. The best ways to use such a knowledge-based method is to conduct on- or offline workshops where experts can discuss and consequently assign values to the risks identified. They can prioritise the identified risks using a pre-defined rating scale. Risks will be scored based on their probability or likelihood of occurrence and their impact.

2.2.1 FMEA

One typical approach is a classic Failure Modes and Effects Analysis [21]. In the FMEA, each identified risk is evaluated for its Severity (S), Occurrence (O) and Detectability (D).

$$RPN = S \cdot O \cdot D \tag{1}$$

With the resulting Risk Priority Number (RPN) the evaluated risk can be ranked and compared with other risks. Figure 2 gives an example of FMEA rating of PV module failures. The disadvantage of this approach is that further usage, i.e. within a financial model, is limited [2].

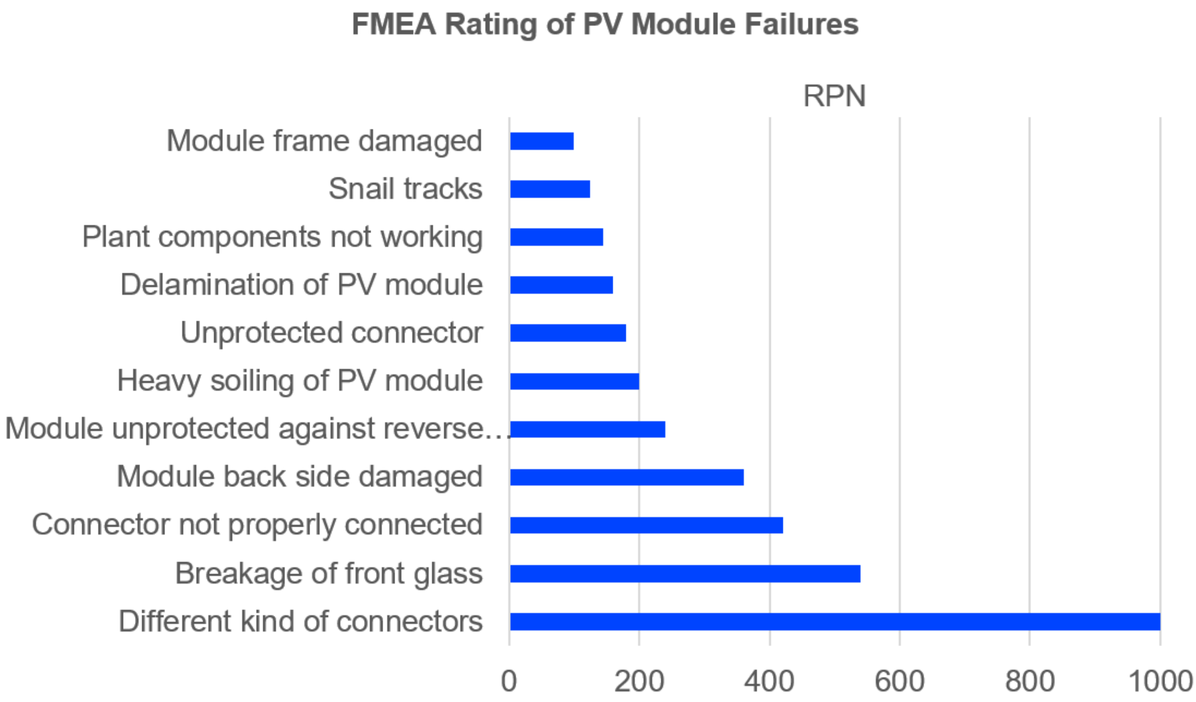

Figure 2: Example of rating of PV module failures based on classic FMEA. The rating of the technical risks was based on the statistics of failure reports from TÜV Rheinland. RPN is the product of S, O and D where each factor is an integer between 0 and 10 [2].

2.2.2 MCDA

Another class of methods is the Multi Criteria Decision Analysis [22]. MCDA methods use relationships such as priority, outranking and distance between the criteria. It is similar to FMEA; however, it solves the biased subjective ranking within FMEA, as each single variable is additionally weighted.

One MCDA known for robustness is the Analytic Hierarchy Process (AHP) method developed by Saaty [23]. It is based on three principles: building hierarchies, priority and logical consistency. Priorities are absolute numbers between 0 and 1 and always add up to 1. Figure 3 shows the calculated priorities to determine the optimal location for a large PV plant in southern Iran [24].

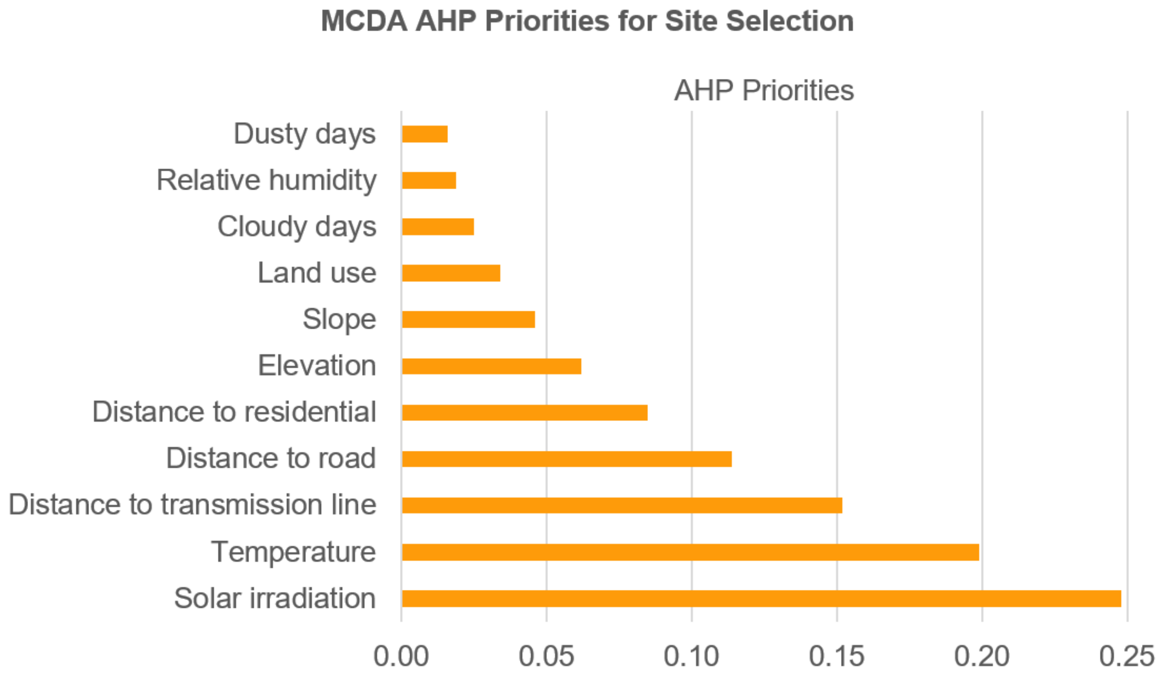

Figure 3: Example of AHP priorities to determine the optimal PV plant location in southern Iran. The sum of all priorities is equal to 1. Adapted from [24].

2.3 Quantitative Methods (CPN, RAM)

Quantitative Methods involve assessing the probability and impact of risks using numerically based techniques, such as simulation and fault tree analysis. The results provide information about the effects of the identified risks and represent a given reality in the form of a numerical value that can be utilized in economic and financial models for quantitative decision making.

2.3.1 Cost Priority Number (CPN)

In this sub-section, the CPN methodology, a method originally developed for PV systems in the H2020 project Solar Bankability [9], is discussed.

CPN was developed in the early 2000’s to address the fact that FMEA was unable to be used for quantitative financial assessments. Therefore Cost-based FMEA was proposed. The FMEA community had already developed the Risk Priority Number (RPN). When full lifecycle analysis [25] of large projects such as the “Next Linear Collider” were being designed and priced, full lifecycle costs, considering not just construction, but O&M, repairs and loss of production time, and FMEA needed to be taken into account [26]. In 2003 [27] this was formalized as Cost-based FMEA [5], as an extension of the RPN used previously [7]. And in the ensuing years the utility of connecting FMEA to lifecycle costs and financial decision making was introduced in many engineering fields [8] [28], with Kahrobaee et al. [29] introducing CPN in a lifecycle and FMEA analysis of wind turbine systems.

For PV systems CPN enables accurate economic quantification of PV degradation modes and other performance impairing effects of operating PV plants. It therefore has enabled risk assessments of investments in PV power plant projects [2]. The CPN methodology used assessed the economic impact of PV projects based on factors such as performance loss and downtime. Thereby, a cost-based Failure Mode and Effect Analysis methodology for the PV sector has been developed in form of the CPN. In its initial form, it was developed using theoretical scenarios to calculate extreme values for the CPN metric, expressed in €/kWp/year (see Figure 4). Thereby, all phases of a PV power plant's life cycle (from product testing to decommissioning) have been included. The methodology helps to identify and classify technical risks and their economic impact by assigning a cost metric that, based on collected statistics, supports preventive and corrective measures, which would then lower the impact of failures on the availability and performance of a PV plant. Thereby, it was possible to create a database which gives indicators of failure appearance likeliness and severity. Such results could then be used to improve O&M activities.

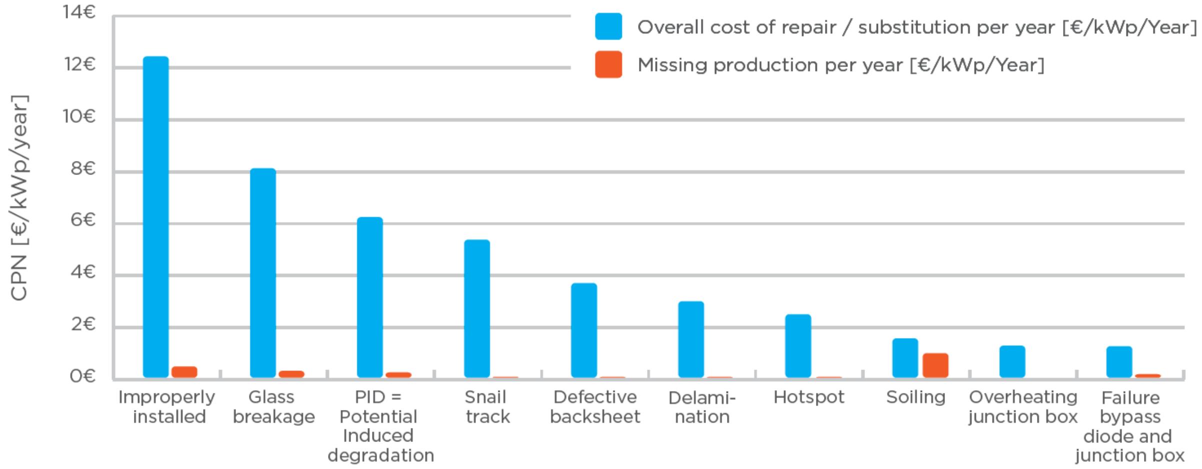

Figure 4: CPN, repair costs and performance losses for top 10 risks for PV modules [30].

An important improvement of the methodology was the integration of monitoring data to calculate realistic CPN values for individual PV system performance impairments [4]. Thereby, the focus is on the operation and maintenance (O&M) phase which is by far the longest one in the life cycle of a PV plant (20-25 years). Real monitoring data were used, and information was extracted from maintenance tickets to improve the accuracy of the methodology by stepping away from theoretical assumptions. In order to calculate the cost due to the performance impairment arising from a system failure, the downtime is divided into time intervals defined in Chapter 2.1 [20]. According to the CPN methodology, costs related to the appearance of specific failures can be calculated as:

$$\boldsymbol{CPN}\ [€/kWp/year] = C_{down} + C_{fix} \tag{2}$$

$$PR_{fail}[\%] = PR_{start,mon} - PLR * (year_{fail} - year_{start,mon}) \tag{3}$$

$$Y_{loss}\ [\mathrm{kWh/kW_p}] = H_{loss} \cdot PR_{fail} \tag{4}$$

$$E_{loss\_detection} = Y_{loss\_detection} \cdot P_0 \cdot \left(\frac{n_{fail}}{n_{total}}\right) \cdot CPL \cdot M_1 \tag{5}$$

$$E_{loss\_response} = Y_{loss\_response} \cdot P_0 \cdot \left(\frac{n_{fail}}{n_{total}}\right) \cdot CPL \cdot M_1 \tag{6}$$

$$E_{loss\_repair} = (Y_{loss\_repair} - Y_{loss\_shutdown}) \cdot P_0 \cdot \left(\frac{n_{fail}}{n_{total}}\right) \cdot CPL \cdot M_1 \tag{7}$$

$$E_{loss\_shutdown} = Y_{loss\_shutdown} \cdot P_0 \cdot \left(\frac{n_{fail}}{n_{total}}\right) \cdot M_2 \quad \textbf{(8)}$$

$$E_{loss_{TOTAL}}[\mathrm{kWh}] = E_{loss\_detection} + E_{loss\_response} + E_{loss\_repair} + E_{loss\_shutdown} \quad \textbf{(9)}$$

$$C_{down}[€/\mathrm{kW_p}/\mathrm{year}] = \frac{E_{loss_{TOTAL}} * FIT}{P_0} \quad \textbf{(10)}$$

$$C_{fix}\,[€/\mathrm{kW_p}/\mathrm{year}] = \frac{(C_{det} + C_{rep/sub} + C_{trans} + C_{lab})n_{fail}}{P_0} \quad \textbf{(11)}$$

Where

Table 1: Parameter definition for calculating CPN.

PR_{fail}	Performance Ratio when failure occurs [%]	n_{fail}	Number of components affected
$PR_{start,mon}$	Annual average PR calculated with the first available complete year of monitoring data [%]	n_{total}	Total number of components
PLR	Performance Loss Rate calculated using at least two years of historical data [%/year]	CPL	Component Power Loss [%]
$year_{fail}$	Year when failure occurs	M_1	Multiplier to consider failures that cause problems at higher component level during *detection*, *response* and *repair times* (excluding *shutdown time*) [--]
$year_{start,mon}$	Year from which monitoring data is available	M_2	Multiplier to consider failures that cause problems at higher component level during the *shutdown time* [--]
Y_{loss}	Specific Yield Loss, energy per kW_p that the plat would have produced if unaffected by the failure [kWh/kW_p]	FIT	Feed in tariff [€/kWh]
H_{loss}	Irradiation loss, calculated as the sum of Plane of Array (POA) irradiation [kWh/m^2]	C_{labour}	Cost of labour [€]
$E_{loss\_detection}$	Energy loss during detection [kWh]	t_{repair}	Repair time [h]
$E_{loss\_response}$	Energy loss during response [kWh]	n_{ST}	Number of site technicians involved in the repair activity
E_{loss_repair}	Energy loss during repair [kWh]	C_{ST}	Internal cost (rate per hour) of the site technician [€/h]
$E_{loss\_shutdown}$	Energy loss during shutdown [kWh] considerers CPL=100%	C_{detect}	Cost of detection [€/component] To account for various techniques (visual inspection, IR for thermal anomalies, I-V curve tracing for power deviations, EL for cracked cells, etc.)
$E_{loss_{TOTAL}}$	Total energy loss [kWh]	C_{repair}	Cost of repair/substitution [€/component]
P_0	Total installed capacity of the PV plant [kW_p]	C_{transp}	Cost of transportation [€/component]

The CPN assesses the economic impact based on two factors: lost production during downtime (C_{down}) and costs related to fixing the issue at hand (C_{fix}).

C_{down} is accurately determined by evaluating the Performance Ratio (PR) at the time of the failure's appearance through the inclusion of the Performance Loss Rate (PLR). The PLR is calculated using *seasonal-trend decomposition using LOESS* (STL) [31], which was selected based on a comparative study of available algorithms [32]. This method decomposes a time-series into its subparts and extracts a long-term trend of PR values. This trend is then subject to linear regression and the PLR is given in percentage per year. By including the PLR, the PR was derived for the time each failure occurred, instead of assuming a fixed PR value for all the tickets for the whole period analysed.

For the calculation of the initial PR, it might be desirable to use as a starting point the PR calculated right after the commissioning of the plant or even better, some months later, when the modules' output power has stabilised.

The Component Power Loss (CPL) defines the power loss for the affected components of the PV plant. The multipliers M_1 and M_2 ensure that components at higher component level, are considered if needed. For example, a broken or stolen module affects the performance of the whole string. The division into shutdown M_2 and excluding shutdown time M_1 is important as a shutdown will affect not only one string but all strings which are connected to a combiner box which is turned off, for instance to replace a module.

This development is a cornerstone for automating the CPN methodology for use with system monitoring and maintenance ticket data of fleets of PV systems to gain qualitative as well as quantitative insights into common performance issues of PV systems. An application example follows in Chapter 4.1.1

2.3.2 Reliability, Availability and Maintainability (RAM) analysis

Technical risk and the reliability of a component are complements of each other, as long as they cover the same sample space. In this context another widely used quantification method is the Reliability, Availability and Maintainability analysis. RAM analysis aims to identify any significant performance losses and then recommend improvements to the maintenance strategy. In this bottom-up approach a Reliability Block Diagram (RBD) or the Fault Tree Analysis (FTA) is recommended to determine the effects of the failure of individual components (Figure 5).

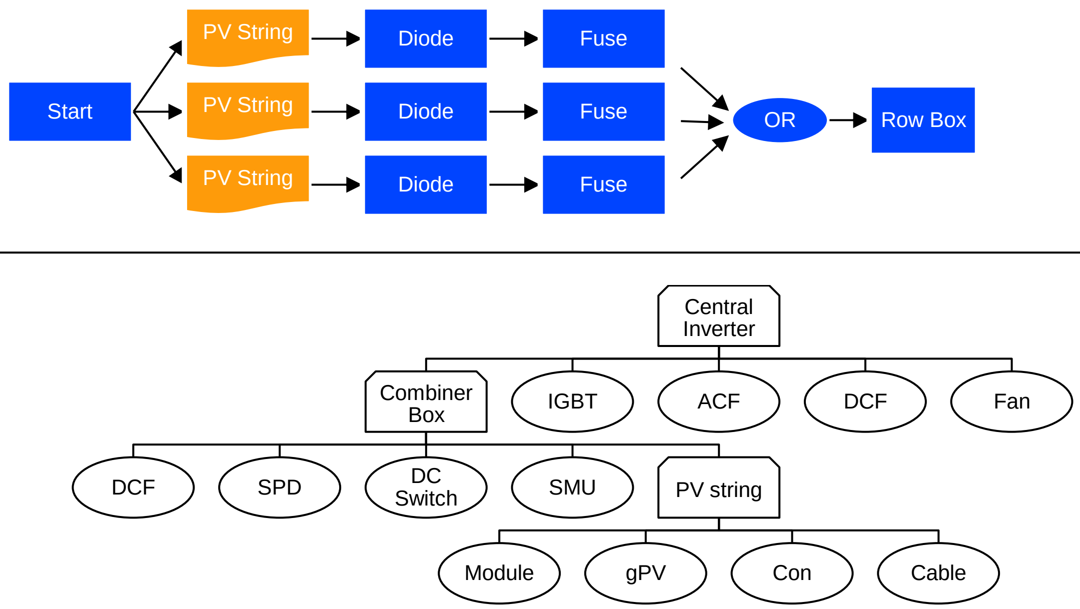

Figure 5: Examples of Reliability Block Diagram (TOP) and Fault Tree (BOTTOM). Adapted from [11].

In RAM modelling, the reliability R is defined as the probability that a system or component performs adequately within a given time.

$$R(t) = \int_{t}^{\infty} f(t)dt \tag{12}$$

The probability density function PDF of failures f(t) with increasing lifetime is expressed by an exponential, normal, Weibull or lognormal distribution. Weibull distributions are applicable to a broad range of failure modes and mechanisms. The normal distribution is preferred for items that have a wear out mechanism such as bearing or motors. Derived from [33] the best-fit PDFs for the different components are shown in Table 2.

Table 2: Best-fit PDFs for the components of a PV plant adapted from [33].

Component	PDF
PV modules	Exponential
Bypass diode	Weibull
DC switch	Lognormal
AC switch	Weibull
AC circuit breaker	Weibull
Connector	Exponential
Inverter	Lognormal

The failure rate λ is the frequency of component failure. The mean time to failure (MTTF) of a component defines the expected life of non-repairable items.

$$\lambda = \frac{f(t)}{R(t)} \tag{13}$$

$$MTTF = \int_{0}^{\infty} R(t)dt \tag{14}$$

Availability (A) is defined as the percentage of time that the plant was successfully operating. A is MTTF divided by the total operating time and can be calculated with MTTF and Mean Down time (MDT), as follows:

$$A = \frac{MTTF}{MTTF + MDT} \tag{15}$$

In [33], [11] and [34] the RAM analysis was performed based on failure rates taken from the literature along with real data from PV systems' operations over a 25 year period. The reliability analysis has proven, that the expected lifetime of the PV modules records 44 years, whereas the expected lifetime of the balance of system and inverter are 19 and 8 years respectively [33]. In [11], the reliability of a string inverter is given between 8 (older devices) and 25 years (state-of-the-art inverters). The associated reliability (after 20 years), availabilities and energy losses are presented in Table 3.

Table 3: Results of RAM analysis of a 15.3 MW PV plant adapted from [11].

Component	Reliability (after 20 years)	Availability	Energy Losses [MWh]
PV string	88.7%	99.85%	805
Combiner Box	14.4%	99.69%	1656
Inverter	0.1%	99.42%	2842
Transformer	55.6%	99.50%	2601

2.4 Risk Mitigation Measures

Once technical risk, reliability and availability have been determined, mitigation measures (MM) can be assigned to reduce the associated energy losses. Jahn et al. [3] identified eight generic mitigation measures for PV technical risk management:

- **Component testing** of important plant components such as PV modules or inverters. The testing can be performed by the manufacturer in the factory, or independent testing at certified laboratory, or on-site at the PV plant;
- **Design review** and construction monitoring serve to catch issues caused by bad PV plant design and poor PV construction workmanship;
- **EPC qualification** focuses on ensuring the competencies of the field workers, e.g, by requiring certain technical qualification prerequisites or regular training of the field workers;
- **Implementing advanced monitoring system** for early detection and diagnosis of faults;
- **Use of basic monitoring system** to monitor plant level alarms and notifications;
- **Advanced inspection** (e. g., infrared thermographic or electroluminescence imaging) to detect defects not usually visible to the naked eye;
- **Visual inspection** to establish any visible changes in PV plant components;
- **Spare parts management** to minimize the costs of downtime during repair or substitution of components.

These MMs can be grouped into two main categories. Preventive measures are applied before the failure occurs to prevent it from happening. The MMs under this category are component testing, design review, construction monitoring, and EPC qualification. Corrective measures are MMs that aim to reduce higher losses and costs if the failure has already occurred. Cleaning strategies to minimize soiling losses on the PV modules are described in [18]. The following advanced inspection methods are presented in detail in [35].

- Drone-mounted electroluminescence & thermal infrared imaging of PV arrays
- Daylight I-V measurement of PV strings and PV modules
- PV module characterization with mobile PV test centre
- Dark I-V measurement of PV strings and PV modules
- PV plant testing vehicle for PV strings
- Electrical impedance spectroscopy of PV strings
- Daylight electroluminescence imaging
- UV fluorescence imaging
- Advanced outdoor photoluminescence imaging of PV modules
- Spectroscopic methods for polymeric materials

2.5 Best Practice, Limitations and Challenges

Choosing the best method for the individual purpose is rarely trivial. The advantages, and disadvantages of the presented methods are demonstrated considering the factors maturity level and data availability and are illustrated in Figure 6.

FMEA is based on the opinions of experts defining occurrence and severity of events. The ranking within an FMEA is subjective and further use of RPNs, e.g. within a financial model, is limited. It is usually applied during the early phase of the project, when new products or strategies are implemented. It is best suited for immature technologies when operational data is limited and no sufficient previous experience is available.

MCDA evaluates the performance of alternative courses of action. Its strong advantage is its ability to capture both subjective and objective information, however weights and values are difficult to estimate and it can results into skewness of results due to extreme values. It is best suited for technologies at a relatively low maturity level where operational data and sufficient previous experience is available.

CPN assesses the economic impact based on factors such as performance reduction and down-time. It is based on statistical analysis and real-time data and can be applied to a single PV plant or to a large portfolio of PV plants. It is best suited for technologies at a high level of maturity where operational data and sufficient previous experience is available.

RAM analysis identifies significant causes of loss of availability or issues that limit the energy yield. It starts during the early phase of the project and can be reviewed and updated as the project progresses. It is best suited for mature technologies but in the case where operational data is limited and insufficient previous experience is available, such as for young PV power plants.

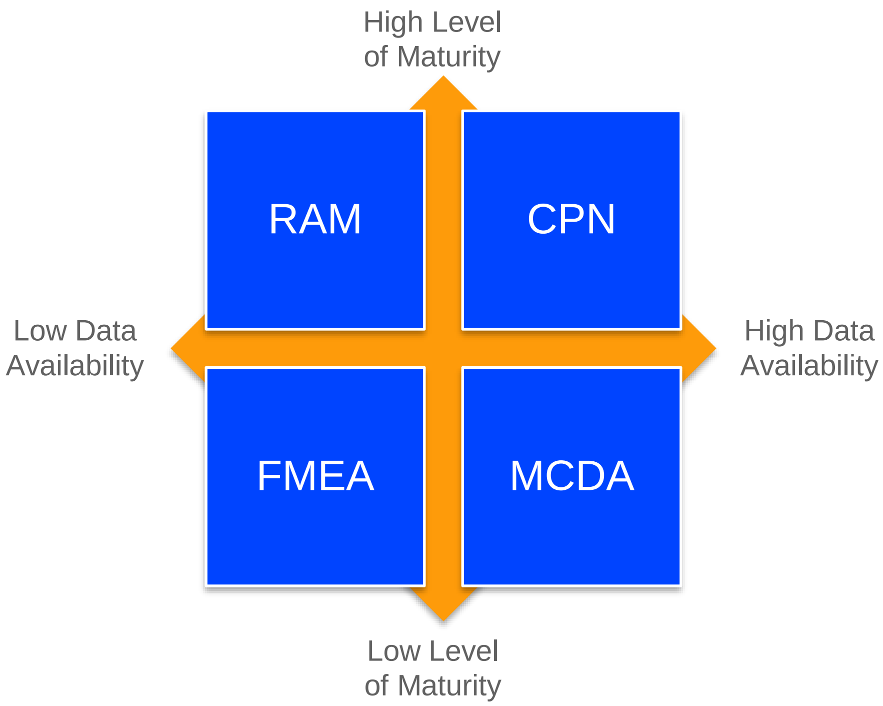

Figure 6: Selection guide of methods presented based on the driving-factors: data availability and level of technology maturity.

3 RISK DATABASE

According to the PMBOK guide [17], the Risk Database (RDB) is the central repository for all information regarding the identified risks. In terms of technical risks the RDB provides the range of affected components the description with causes and consequences, failure rates, the probability of occurrence, the impact on KPIs and the recommended control and mitigation actions. It should be updated and maintained as a growing data hub through all phases of the project. In this chapter we present a systematic approach to identify the main technical risks, define the most important risk parameters and collect these failure, loss and occurrence data.

3.1 PV Failure Fact Sheets (PVFS)

The PV failure fact sheets (PVFS, Annex 1) summarise some of the most important aspects of single failures. The target audience of these PVFSs are PV planners, installers, investors, independent experts and insurance companies, and anyone interested in a brief description of failures with examples, an estimation of risks and suggestions of how to intervene or prevent these failures.

The failure sheets do not aim to deepen the theoretical background of the failures and its detection, but they aim to summarise the key aspects described in the numerous IEA PVPS Task 13 technical reports [1] [16] [18] [36] [35] and reference documents [37] [38] [39] [40] [41] [42] [43] [44] [45] [46] [47] used for the preparation of the PVFSs shown in Table 4. The failure sheets are specific to the component in which they occur.

3.1.1 PVFS structure

The format of the PVFS is based on the failure description presented within the H2020 Solar Bankability project [9]. A rating system for the estimation of the severity of a failure is used here which simplifies the approach proposed within the IEA PVPS Task 13 [16] by implementing the rating system proposed by the Sinclairs [37]. The correlation between the different failures is highlighted in the text by using bold characters. Each PVFS is structured into 1 to 3 pages. The first page is a descriptive page, whereas the remaining pages contain examples composed of a picture, a legend and an estimation about its severity. The first page is structured as follows:

Component

The PV system components are divided into:

(1) PV module (including junction box)

(2) Cables and interconnectors (at module, string and combiner box level)

(3) Mounting (structure, clamps and screws)

(4) Inverter

Defect

Short name describing the failure/defect.

Appearance

Description of how the defect looks like.

Table 4: List of PV Failure Fact Sheets.

No	Component	Failure name
1-1	PV module	Cell cracks
1-2	PV module	Discolouration of encapsulant or backsheet
1-3	PV module	Front delamination
1-4	PV module	Backsheet delamination
1-5	PV module	Backsheet cracking
1-6	PV module	Backsheet chalking (whitening)
1-7	PV module	Burn marks
1-8	PV module	Glass breakage
1-9	PV module	Cell interconnection failure
1-10	PV module	Potential induced degradation
1-11	PV module	Metallisation discolouration/corrosion
1-12	PV module	Glass corrosion or abrasion
1-13	PV module	Defect or detached junction box
1-14	PV module	Junction box interconnection failure
1-15	PV module	Missing or insufficient bypass diode protection
1-16	PV module	Not conform power rating
1-17	PV module	Light induced degradation in c-Si modules
1-18	PV module	Insulation failure
1-19	PV module	Hot spot (thermal patterns)
1-20	PV module	Soiling
2-1	Cable and Interconnector	DC connector mismatch
2-2	Cable and Interconnector	Defect DC connector/cable
2-3	Cable and Interconnector	Insulation failure
2-4	Cable and Interconnector	Thermal damage in combiner box
3-1	Mounting	Bad module clamping
3-2	Mounting	Inappropriate/defect mounting structure
3-3	Mounting	Module shading
4-1	Inverter	Overheating (temperature derating)
4-2	Inverter	Incorrect installation
4-3	Inverter	Complete failure (not operating)

The list does not pretend to be exhaustive or updated. The complete list with all PVFS can be downloaded under [48]

Detection

Description of methods which can be used to detect the failure. Detection methods in brackets lists secondary methods, which do not detect the failure with absolute certainty or which can be used in addition to other methods. Following abbreviations are used:

Table 5: Abbreviations of Detection Methods.

Abbreviation	Detection Methods
VI	Visual inspection
IRT	Infrared thermography
EL	Electroluminescence
IV	Daylight I-V measurement
UV	UV fluorescence
STM	Signal transmission method
MON	Data monitoring
dIV	Dark I-V measurement
BYT	Bypass diode testing
VOC	V_{oc} measurement
INS	Insulation testing

Origin

Description of the failure and its main causes and origin (1. Material and production, 2. Transport and installation, 3. Operation and maintenance).

Impact

Description of the impact on the safety, performance and reliability of the component and system and its severity. For every failure, a range of possible ratings is given, one for the safety and one for the performance.

A failure is defined as a safety failure when it endangers somebody who is applying or working with PV modules or simply passing the PV modules. Three categories are defined in Figure 7.

Safety category	Description
	Failure has no effect on safety.
f e m	Failure may cause a fire (f), electrical shock (e) or a physical danger (m) if a follow-up failure and/or a second failure occurs.
f e m	Failure can directly cause a fire (f), electrical shock (e) or a physical danger (m).

Figure 7: Safety category

A failure is defined as a performance failure when it impacts the performance and/or reliability of a system. Five categories are defined in Figure 8. They go from 1 (low severity) to 5 (high severity).

Performance category	Description
1	The defect has no direct effect on performance.
2	The defect has a minor impact on performance.
3	The defect has a moderate impact on performance.
4	The defect has a high impact on performance.
5	The defect has a catastrophic impact on performance.

Figure 8: Performance category

For each category, the expected loss is estimated on the component level and if no mitigation measure is implemented. It can range from no power degradation (0%) over power degradation below detection limit (<2-3%), power degradation within warranty (<0.7-1%/year) and power degradation out warranty (>0.7-1%/year) to catastrophic power degradation (>3%/year).

Mitigation

Description of the corrective actions to be done on a short and medium term when detecting a failure and preventive actions to be implemented to avoid the failure from the beginning. Preventive actions are separated into recommended actions, representing the minimum requirement for small residential systems and optional actions for large scale systems.

The general rule for intervention in case of a failure is: All components with a direct safety risk or a performance severity of 5, highlighted in red, should be replaced or repaired. Regular inspections should be performed to monitor the status of the not replaced or repaired components.

3.1.2 Example PVFS: Front delamination

The delamination of the encapsulant **FS1-3: Front delamination** is here taken as example to further explain the FS structure and rating system.

Component Defect	**Module** **Front delamination**		**PVFS 1-3**
Appearance	Any local separation of the layers between (i) the front glass and the encapsulant or (ii) the cell and the encapsulant, visible as bubbles or as bright, milky area/s. It may appear continuous or in spots. The position and size of the delamination or bubble depends on the origin and progress of the failure.		
Detection	VI, (INS)		
Origin	The adhesion between the glass, encapsulant, active layers, and back layers can be compromised for many reasons. Typically, it is caused by the manufacturing process (e.g. poor cross linking of EVA, too short lamination times, too high pressure in the laminator, contaminations, improper cleaning of the glass, incompatibility of EVA with soldering flux, inadequate storage of the raw material) or environmental factors (e.g. thermal stresses, external mechanical stresses, UV). Delamination is generally followed by moisture ingress and **corrosion**. It is therefore more frequent and severe under hot and humid conditions.		
	Production ■	Installation ☐	Operation ■
Impact	Delamination or bubbles do not automatically pose a safety issue, but they can result in **reduced insulation** of the component and increased safety risk when they form a continuous path between electric circuit and the edge due to possible water ingress. Moisture in the module will decrease performance due to an increase of series resistance, affect long term reliability and in some cases also the structural integrity of the module. Moreover, delamination at interfaces in the optical path will result in additional optical reflection and subsequent decrease in current. This can be the origin of current mismatch. If the mismatch is significant, it will trigger the bypass diode and cause further power loss. The inverter might also shut down due to leakage current's leading to a further performance loss. Manufacturing related delamination issues often affects a relevant percentage of modules within the same production batch and consequentially has a big impact on system performance.		
	Safety: f e e	Performance: 1 2 3 4 5	
Mitigation	Corrective actions	Preventive actions (recommended)	Preventive actions (optional)
	Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules. In case of individual module testing all modules which failed the insulation and/or wet-leakage test should be replaced.	Check validity of IEC 61215 certification and BOM, ground fault detection by inverter or other devices at all time.	Extended testing (e.g. damp heat), pre-shipment inspections (e.g. cross linking level of EVA) regular visual system inspections.

Figure 9: First page of PVFS example with general information

Figure 10: Remaining pages of a PVFS contain examples composed of a picture, a legend and an estimation about its severity.

The first section of the sheet describes the **appearance** or how to recognise a specific failure and which **detection** methods are available. Delamination is generally easily detectable by visual inspection (VI) of the modules from the front. Insulation measurements (INS) can give a hint of a severe delamination, but it is not the first method to detect an early delamination, reason why it is put in brackets.

The second section describes the **origin** or in which phase of the lifetime of a PV system the failure occurs and what the main causes are. Delamination problems have its origin mainly in the quality of the raw material, the manufacturing process and/or the environmental factors to which the modules are exposed during its operational lifetime. Transport and installation do not generate any delamination problems.

The third section describes the **impact** the failure has on the safety and performance of the component and PV system. Below the general description the severity rating accord. Figure 7 and Figure 8 is given. The severity rating in the first page gives the full range of possible ratings observable in the field and how the failure can evolve over the whole lifetime of a PV system. The rating in the examples gives instead a snapshot of the gravity of the failure for a specific case at a certain time. The pictures are taken from literature or case studies and give only a partial picture of the situation and are here used to explain the potential levels of impact.

The delamination of the potting material does not automatically pose a **safety risk.** It is therefore often rated as not critical (see example 1.3.1-1.3.7, 1.3.10 and 13.11 in Annex 1), but depending on the propagation of the failure it can develop into a more severe safety failure.

When creating a continuous path between the electric circuit and the edge of the module (see example 1.3.13-1.3.15), delamination can lead to electric leakage currents with a direct risk of electrical shock or the risk can occur later, due to the progress of the delamination and/or the ingress of moisture. This is particularly the case when the original delamination is close to the edge of the module or the junction box, or if it is going over a very extended area (see example 1.3.8-1.3.12). The **performance loss risk** for modules with delamination problems ranges from 1 to 5. Very small delamination areas on top of a cell or outside the cell area and not combined with other failures, are classified as having no impact (1) or a minor power loss typically below the detection limit (2), if the failure is not increasing over time (see example 1.3.1-1.3.4, 1.3.8, 1.3.10 and 1.3.11). The severity is in the range of (2-4) when the delamination area is getting larger (see example 1.3.7 and 1.3.9) or if it is occurring in combination with follow-up failures like moisture ingress (see example 1.3.14) or an insulation failure (see example 1.3.13). It increases also when occurring in combination with a second failure like discoloration (yellowing or browning) of the encapsulant or backsheet (see example 1.3.6, 1.3.7, 1.3.13), or cell cracking (see example 1.3.5). A catastrophic performance loss of (5) is reached when the cell mismatch is so large that one or more bypass diodes could be activated (see example 1.3.13 and 1.3.14).

The last section describes the **mitigation** measures. In case of delamination, all modules which do not guarantee anymore the electrical safety or insulation resistance or have an active bypass diode, have to be replaced. Not replaced modules with minor delamination have to be monitored by regular visual inspections and ground fault detection. Basic preventive measures consist in selecting certified and tested products only. In case of large-scale systems regular system inspection is recommended.

3.2 PV Failure Degradation Sheets (PVDS)

Besides the PVFS collection we provide an update on the statistical risk data of the PV Failure Degradation Sheet (PVDS) survey developed in Koentges et al. [1]. It requires much more detailed measured input data but it is able to generate statistical data on degradation rates and power loss of PV systems based on failure types. Due to the high requirements on the PVDS much less input data can be collected. In the following, we introduce the collected data, the way of analysing the data and the analysis results.

3.2.1 Introduction of PVDS

The failure data is collected in an excel sheet which is sent to system owner, experts installer or manufacturer. Some data is also collected by scientific publications or an Australian internet survey. The survey structure is first presented in the IEA PVPS TASK 13 report “Assessment of Photovoltaic Module Failures in the Field” [1], see also Figure 11. The plain survey and the survey explanation can be downloaded here [49] [47]. The survey is structured into system components, as described in Chapter 3.1. All system components may have various predefined failures. For each failure, a power loss and a safety failure may be given. Furthermore, for each system a Koeppen-Geiger climate zone must be selected. The Koeppen-Geiger climate zones shift during the ongoing climate change. We used the Koeppen-Geiger map calculated by Rubel [50] for the time period 1976-2000 as classification classes.

Compared to the first presented survey structure in [1], we added two new failure categories for PV modules: LID/LeTID degradation and potential induced delamination [51]. Furthermore, it is now possible to add all three letters of the Koeppen-Geiger classification to the survey compared to one in the first version. The translation tool for “geo data” to “Koeppen-Geiger climate zones” [52] helps to find the correct classification for each position in the world.

PV system basics		Goal of this survey	How to start ?	Other questions
System ID:	iterator i counts System IDs	PV module type		
Source of data		Inverter type		
Country		Mounting system type		
Climate zone		Grounding of substructure & module frames/conductor		
Special stress		Other system component		
Kind of system		Nominal system power	[kW]	P_i
Orientation		Date of system start	[MM/YYYY]	$T_{a,i}$
Inclination		Date of failure documented here	[MM/YYYY]	$T_{b,i}$
Comment if a field is orange				

Integral data	Following failure specifications are based on investigated percentage of					
Total system power loss [%]	Inverter [%]	Cable and interconnector [%]	PV module [%]	Mounting [%]	Other [%]	Comment
			y_i			

Failure specification for	$z_{i,x,1}$	% of the system				k=1
Failed system part	Failure 1 specification	Power loss 1 [%]	Failure 2 specification	Power loss 2 [%]	Safety failure 1	Safety failure 2
Inverter	No failure	No detectable loss	No failure	No detectable loss	No failure	No failure
Cable and interconnector	No failure	No detectable loss	No failure	No detectable loss	No failure	No failure
PV module	x	$\Delta P_{i,x,1}$	No failure	No detectable loss	No failure	No failure
Mounting	No failure	No detectable loss	No failure	No detectable loss	No failure	No failure
Other system component						
Comment if a field is orange						

Figure 11: Top rows of the PVDS excel sheet for the failure collection. The symbols in the fields illustrate the source of the data for the calculation of degradation values. For the sake of clarity, only indicated here for the evaluation of module failures.

3.2.2 Introduction of statistical evaluation

The calculation of basic degradation values is done as described in [15]. Table 6 lists all calculated basic degradation values and input variables. Figure 11 shows the corresponding value sources of the data in the excel sheet.

Table 6: Description and calculation of degradation values from input values of the PVDS survey.

Description of value	Symbol	Unit	Calculation or source of value
Data number	i		Anonymized iteration number of data “System ID”
Failure specification for system part k in system i	k		There are 5 sections in the data sheet were a failure can be specified. “k” is the iteration number of the section.
Failure type	x		Data “Failure specification”
Nominal power of a system i	P_i	kW_p	Data “Nominal system power”
By failure x affected system part of system i for part k of the system	$z_{i,x,k}$	% of the total nominal system power	Data “Failure specification for ” _% “of the system” for part k of the system i
By failure x affected system part of system i	$z_{i,x}$	% of the total nominal system power	$z_{i,x} = \sum z_{i,x,k}$ Sum over all sections k having an entry for failure x

System part of system i being analysed for failures. System parts are given for the system components: Inverter, Cable and interconnector, PV modules, mounting and other system components	y_i	% of the total nominal system power	Data given in “Following failure specifications are based on investigated percentage of” for each system component
Power loss for a specified failure x in system I for part k of the system	$\Delta P_{i,x,k}$	% of the nominal component power	Data given in “Power loss 1” or “Power loss 2“ for a failure x in system I for part k in the system
Date of the failure documentation	$T_{b,i}$	date	Data “Date of failure documented here”
Commissioning date of system	$T_{a,i}$	data	Data “Date of system start”
Number of x type failures in the survey.	n_x		n_x amount of systems in the survey with the failure x
Mean power loss for a specified failure x in system i.	$\Delta_{i,x}$	% of the nominal power of the investigated system part	$\Delta_{i,x}=\sum \Delta P_{i,x,k} * z_{i,x,k} / z_{i,x}$ Sum over all sections k in data set i having an entry for failure x
Degradation rate of a specific module failure type x of dataset i.	$d_{i,x}$	% of the nominal power of the investigated system part	$d_{i,x}= \Delta_{i,x} / (\tau_{b,i}-\tau_{a,i})$
Degradation rate of the whole system for the failure type x for dataset i. It is expected that the investigated part of the system is representative for the whole system.	$\delta_{i,x}$	% of the nominal power of the investigated system	$\delta_{i,x}= d_{i,x} z_{i,x} / y_i$
Mean degradation rate of a specific module failure type x.	$\overline{d_x}$	% of the nominal power of the investigated system part	$\overline{d_x}=\sum d_{i,x}/n_x$
Number of datasets i with the failure type x in the whole dataset or in a specific part of the data set (e.g., restricted to a climate zone).	n_x		$n_x=\sum f(i,x)$ with f(i,x)=1 if dataset has an documented failure x, otherwise, f(i,x)=0
Mean degradation rate of the whole system for the failure type x.	$\overline{\delta_x}$	% of the nominal power of the investigated system	$\overline{\delta_x}=\sum \delta_{i,x}/n_x$

Percent of the investigated system power $p_{i,x}$ affected by a power loss after a sudden event x for system i. It is expected that the investigated part of the system is representative for the whole system.	$p_{i,x}$	% of the investigated system equivalent to % of the total system	$p_{i,x}=z_{i,x}/y_i$
Power loss relative to the investigated system power. It is expected that the investigated part of the system is representative for the whole system.	$\pi_{i,x}$	% of the power of the investigated system equivalent to % of the power of the total system	$\pi_{i,x}=\Delta_{i,x}\,p_{i,x}$

The evaluation of the failure date is based on several assumptions. It is assumed that the person who documented a failure in the database analysed a representative part of the PV system. Therefore, we assume that we can extrapolate the failure impact x of the investigate system part (y_i) to the total system (P_i). The data are stored in monthly resolution in the database. The analysis is done on a yearly resolution. Failures occurring in the first year of system power production are categorised into year 1 and so on for the following years of operation. We do not know the progress of most of the failures with time. However, many studies show that especially module-based failures proceed somewhat linearly. Therefore, we calculate degradation rates from the database with the assumption that the power degrades linearly ($d_{i,x}$,$\delta_{i,x}$ and the respective mean values) with time. Furthermore, there are failures which are expected to be sudden events. In this case we calculate the system part which is affected by the failure ($p_{i,\ x}$) and the resulting power loss relative to the total system power ($\pi_{i,x,\ x}$) and their corresponding mean values. The following listings shows to which power loss categories the failure types are assigned.

Linear degradation profile: Delamination, defect backsheet, defect junction box, junction box detached, frame breakage/bown/defect, discolouring of pottant, cell cracks, burn marks, potential induced shunts (often named PID), potential induced corrosion (often with thin-film modules), potential induced delamination, LID/LeTID degradation, disconnected cell or string interconnect ribbon, defective bypass diode/wrong dimensioned, corrosion/abrasion of AR coating, isolation failure, CdTe: back contact degradation

Sudden power loss: Glass breakage, hail -> glass breakage/cell breakage, snow load -> deformed frame/glass- /cell-breakage, Storm -> deformed frame/glass-/cell-breakage, direct lightning stroke -> defect glass/frame and defect bypass diodes, animal -> bite/corrosion/dirt, biofilm soiling, dust soiling

3.2.3 Results of new failure data evaluation

Unfortunately, many datasets were not complete so that we had to exclude a lot of data. Since the last failure data evaluation [1], we added 76 new complete PVDSs to the PV system data collection. The data collection consists of 226 PVDSs in total. An overview of the distribution of the PV systems and the analysed PV module technologies is given in Figure 12. Most data is from Europe. In total, data from all 6 continents are available. Although the market share of mono- and multi-crystalline silicon solar wafers has switched from the multi market domination to a mono market domination, the main analysed technologies are still multi-crystalline silicon wafer based solar cells. In the data collection, PV systems are include with installation year beginning from 1982 to 2018. Over 90% of the data are from PV systems installed in the range of 2005 to 2018.

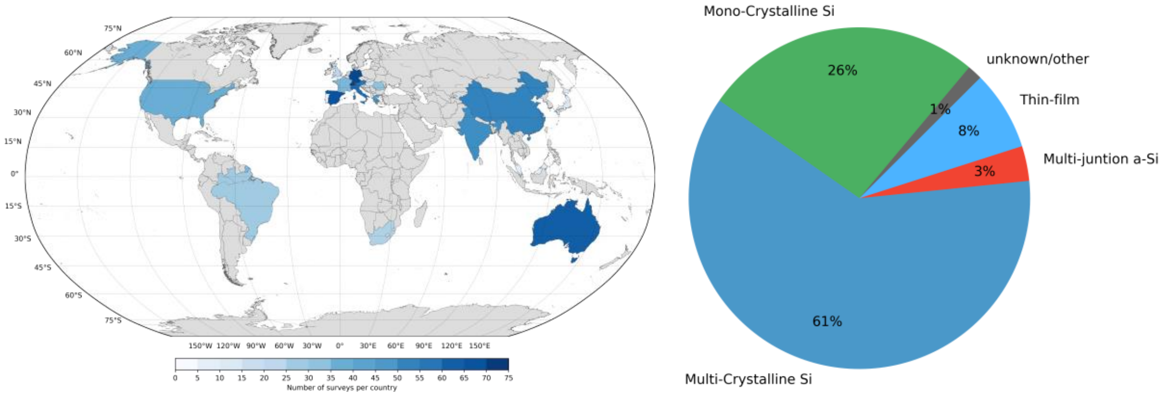

Figure 12: Left - Distribution of PV system locations in the data collection.
Right - Distribution of PV module technologies in the data collection.

Figure 12 shows the frequency distribution for PV module failures with an impact on the power generation of the PV systems. The distribution is split into failures which lead to a degradation and sudden occurring failures. Most reports on failures with power loss are given in the first 10 years of operating time. This is to be expected as it is often too expensive to repair PV systems older than 10 years. Therefore, no detailed analysis is made. The main results of the last report "Assessment of Photovoltaic Module Failures in the Field" remain true. PID effects, cell cracks and defective bypass diode failures seem to dominate the failure statistic in the first seven years. This dominance now becomes even more pronounced in comparison with the statistics presented in [1]. Additionally, the failure type "burn marks" have been detected more frequently. For sudden events, also shown in Figure 13, the failure glass breakage and dust soiling fully dominate the failure statistic.

Figure 14 shows the power loss impact of sudden events on PV system performance. Documented glass breakage events lead in temperate climates to a loss of 1% to 2% of a system's power, with one exception in the dataset. These events seem to occur everywhere but appear to be not so severe for the whole system. Dust soiling appears everywhere except for tropical climates. In temperate climates, the impact is at a maximum 7% of the total system power whereas up to 15% power loss occurs in dry climates and over 25% for continental climates. As expected, the deformed PV module frame due to snow load occurs only in the continental and polar climate.

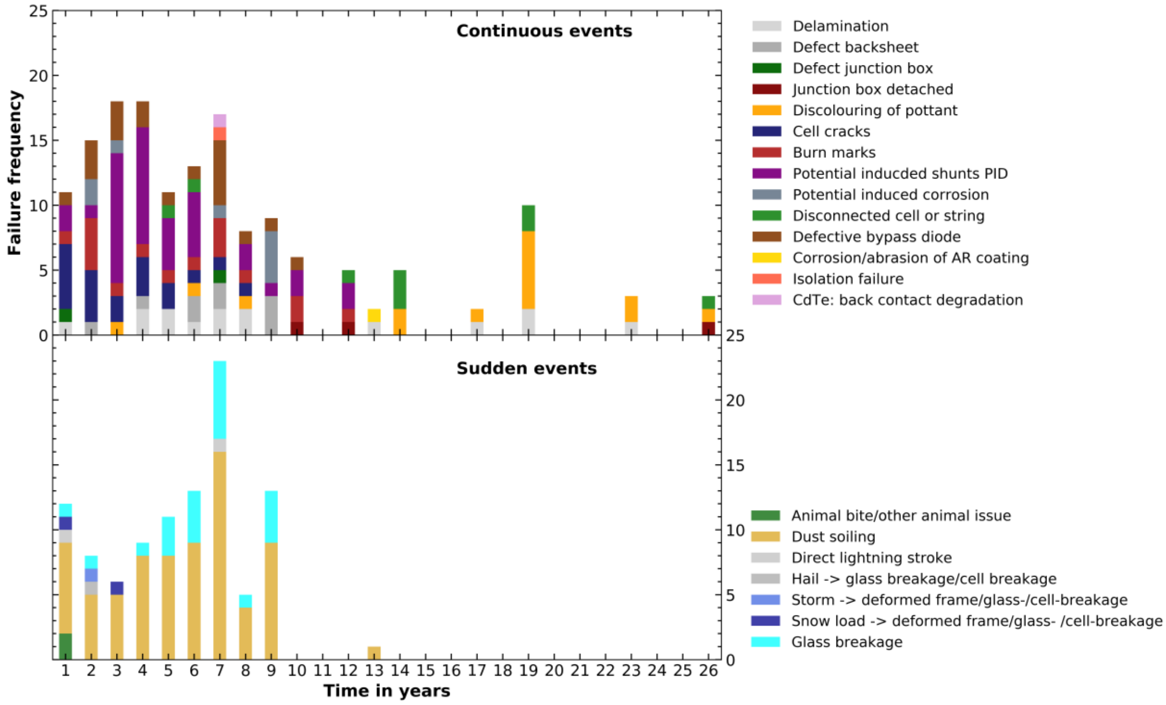

Figure 13: Failure frequency for PV module defects with an impact on the system power. The upper graph is showing PV module failure frequency with a slow degradation over time and the lower graph failure frequency for sudden events.

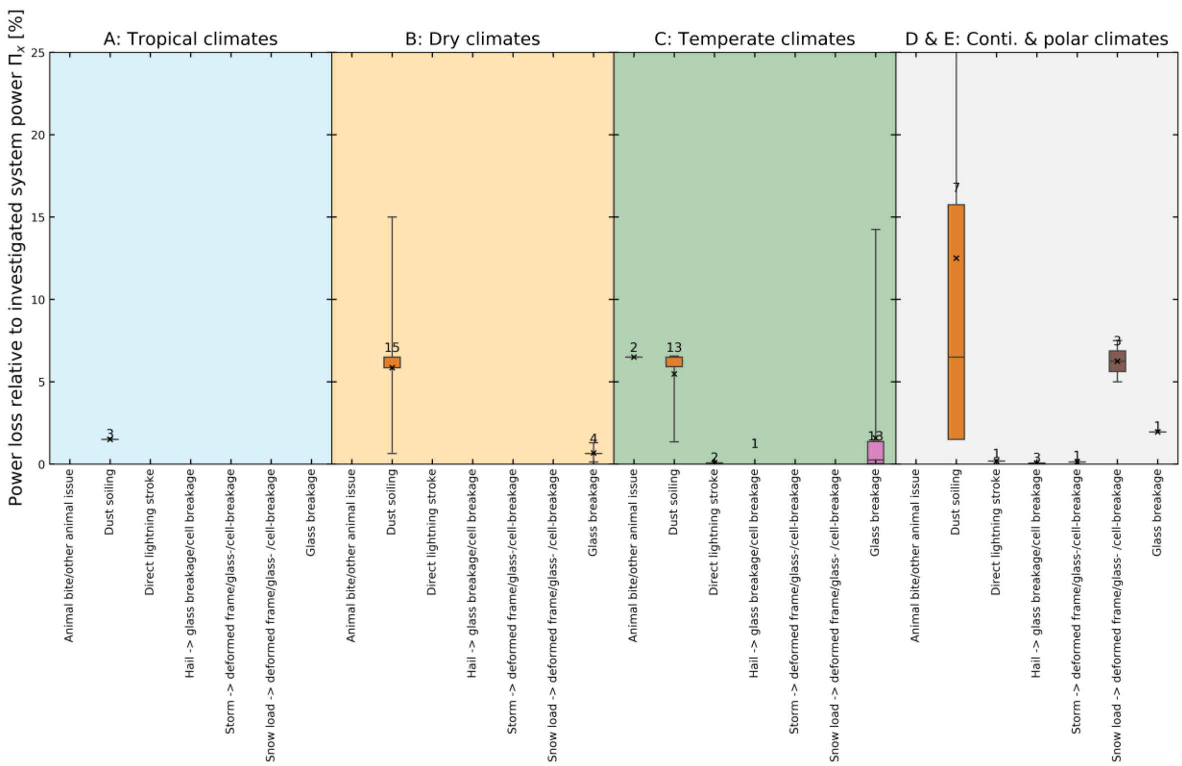

Figure 14: Power loss of sudden failure events on the total power of the PV system.

Figure 15 and Figure 16 show the degradation rate for the affected system parts and the whole system for various failures sorted by climatic zones. The additional data supports the former statements for the degradation rates of the failure types in [1].

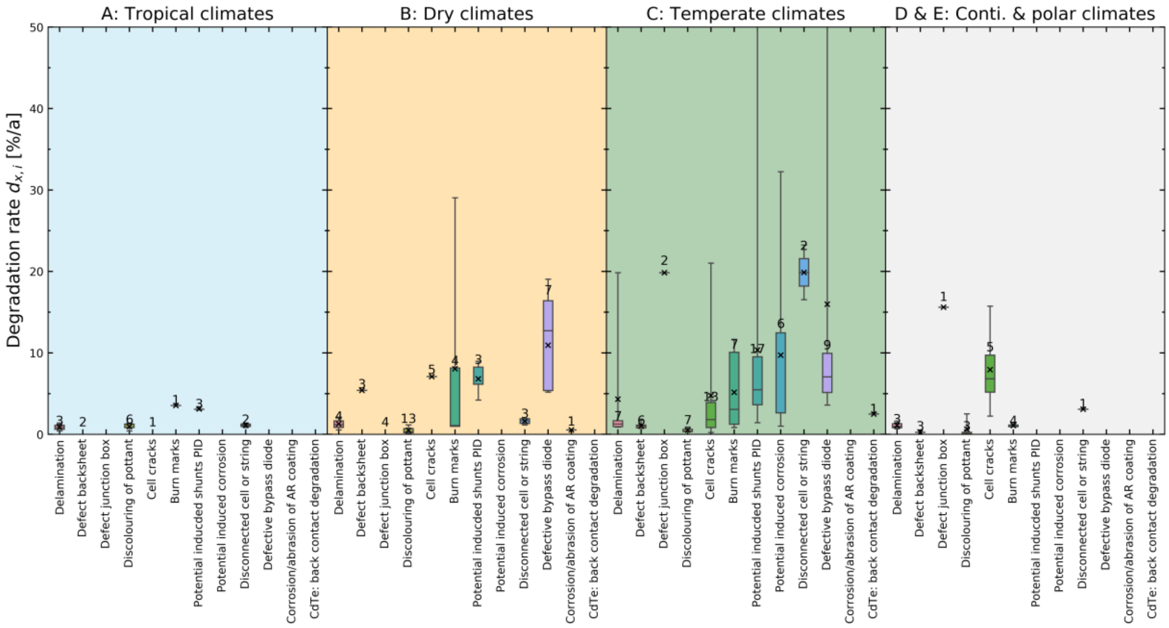

Figure 15: Box plot of degradation rates d_x of PV module affected by failures x sorted by climatic zones. The numbers show the quantity of data per failure in the database. The cross shows the mean degradation rate. The boxes include 50% of all values, the whisker show the full range of existing values. The middle line in the box shows the median.

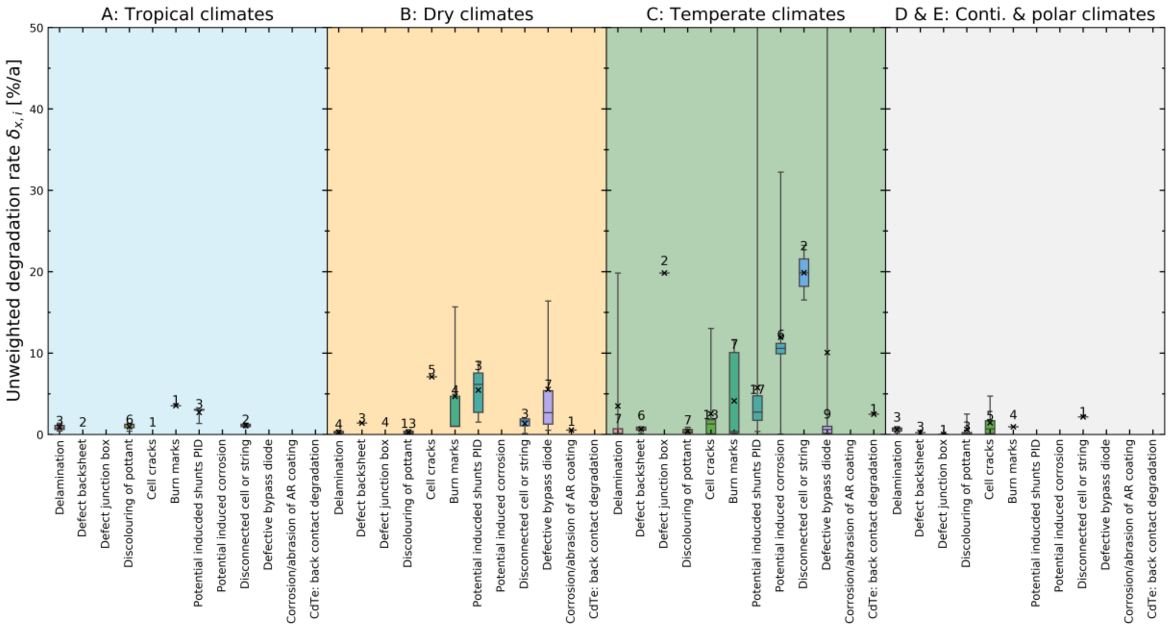

Figure 16: Degradation rates of the whole PV system sorted by climatic zones. The numbers show the quantity of data per failure in the database. The boxplot and the whisker have the same meaning as in Figure 15.

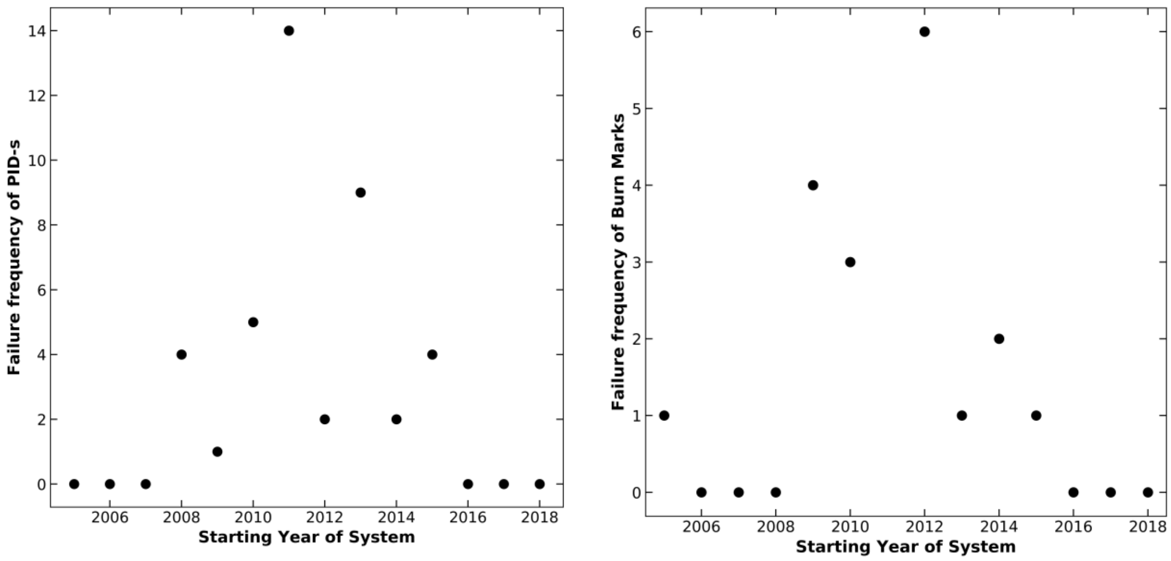

Figure 17: Left - Failure frequency of PID-s. Right – Burn mark cases in the base data as function of the installation time of the system.

A common effect is that new and unexpected failures types occur in the field. After they are recognised, understood and tests are developed, the failure type vanishes in the field because the manufacture can develop their products defect free. The PID-s and burn mark effect, shown in Figure 17, are good example for such a cycle. The first PID-s reports are for PV systems installed in 2008. In 2016, after 8 years, we have no more reports on PID-s failures in the field in the data collection. The burn mark defects show a similar trend.

However, for new PV modules similar failure types may reappear in the field. A potential induced polarization (PID-p) effect is found for PERC solar modules with bifacial cell design (PERC+) [53]. However, this effect was found before large systems have been installed. Similarly, we have observed hot cell effects in PV modules with high power (>400 Wp) [54]. Perfectly blocked cells in high power modules, when locally shaded, may become as hot as about 180°C in the full unshaded cell area. However, this effect is found in an early stage to develop mitigation strategies before these modules were installed in the field.

There are some substantial types of PV module failures missing in the PVDS which have a major impact on power loss for PV systems if they appear. We could not manage to fit the available data into the data collection as always, some important data is missing, there are reports on acetic acid corrosion focussing on tropical climates [55] which led to power losses between 30% to 70% of the PV modules in 8 years of exposure. This defect type does not occur in the same time span with the same module type in moderate climates. Furthermore, there are reports on back sheet failure causing some isolation failures up to corrosion and power loss in the solar cell matrix of the modules [56], [57] up to a total loss of mechanical module integrity with a following disintegration of the modules.

3.3 PV Cost Data

Besides the power of the PV system, occurring costs are essential to make the best decisions from a cost-benefit perspective. O&M costs are costs required to operate and maintain PV plants. The scope of O&M works comprises of tasks such as IR scans of the plant as introduced in Chapter 2.4, and supports the identification of performance losses. Therefore, these costs are part of the quantitative risk assessment. For the most important measures the cost ranges were collected from [19] and are shown in Table 7.

Table 7: Collection of typical costs for individual O&M services [19].

PM Task	Costs	Remarks
Base O&M scope	6 - 14 €/kWp/year	Includes: full preventive maintenance scope, regular module cleanings, security (remote or on-site); excl. IR and EL scans. Varying highly with the site characteristics, labour and frequency of activity.
Cleaning/washing of PV modules	0.5 - 2.5 €/kWp/year	Varying with the module technology, labour, cleaning solution and method, climatic conditions (affecting the frequency), etc.
IR scans	0.5 – 3.0 €/module	Includes drone inspections, analysis and reporting
EL scans	3.0 – 10.0 €/module	

4 CASE STUDIES

Having the methods presented and data collected, the following chapter demonstrates risk and cost-benefit analysis using three case studies that show techniques for prioritising decisions from an economic perspective and provide important results for risk managing strategies.

4.1 Risk Analysis

Risk analysis enables users with statistical and reliability data to develop and run scenarios in which PV performance and costs are affected by components that can fail.

4.1.1 Case 1: Inverter complete failure (not operating)

In this chapter the revised CPN approach, introduced in Chapter 2.3.1 is presented through an exemplary calculation of individual CPN values [4] [58].

The PV plant under consideration is in operation since 2013 and is located in central Italy. Table 8 summarizes the metadata of the system.

Table 8: Metadata of investigated PV plant in Case 1.

Parameter	
Type of plant	Ground-mounted fixed tilt
Installed capacity	9,019.531 kWp
Country	Italy
Commissioning data	25-08-2013
Feed in tariff	0.119 €/kWh
Number of modules	69,381
Module nominal power	130 Wp
Number of inverters	17
Inverter nominal power	500 kW

Overall, 191 maintenance tickets were analysed manually, corresponding to all the planned and corrective activities carried out in 2018 for the example plant. Time-series of monitoring data are available since November 2016, including on-site irradiance (pyranometer measurements) and power (inverter measurements). A detailed metadata table was created containing all the relevant parameters useful for our purpose, mapping all the components of the plant whose failure could cause a power loss. This metadata table was populated using as source the available as-built documentation, the O&M contract and other CAPEX and OPEX related documents.

The improved CPN methodology has been applied manually to the introduced case study, which led to important improvements, especially in terms of the structure and standardisation of the CPN table (see Table 9). The analysis of real maintenance tickets has mainly led to the optimization of the number and format of the input parameters. Instead of using the methodology to create scenarios based on assumptions that would cover a wide spectrum of O&M approaches, real data from a specific O&M contractor were used. Parameters such as costs of interventions and spare parts, failure, acknowledgement, response and repair times were directly extracted from the monitoring and ticketing system. This task proved to be very time-consuming because, although the description of failure and corrective measures is common practice in the field of O&M, it is not often carried out with the sufficient level of detail to derive meaningful statistical analyses due to the lack of a standardized approach in the assignment, wording and categorization of failures.

Table 9: Extract of the CPN table related to the Case 1.

Ticket name	$t_{detection}$	$t_{response}$	t_{repair}	$E_{lossTOTAL}$	C_{fix}		C_{down}		CPN
	[h]	[h]	[h]	[kWh]	[€]	[€/kWp]	[€]	[€/kWp]	[€/kWp]
Inverter 3D off	0.40	0.10	1.33	424	50.44	0.01	46.67	0.005	0.011
Meter 1 connect error	18.20	1.00	95.5	0	0.0	0.00	255.00	0.028	0.028
Inverter 1B off	2.60	126.15	502.83	27,956	3,326.7	0.37	1,066.00	0.118	0.487
Inverter 1B off	1.18	0.40	0.58	76	9.09	0.00	20.42	0.002	0.003
Inverters cabin 3 off	8.70	16.30	0.83	4,704	559.83	0.06	29.17	0.003	0.065
Inverter 1B off	1.58	1.00	8.17	2,326	276.73	0.03	285.83	0.032	0.062
Plant off	0.17	0.17	19.83	11,360	1,351.86	0.15	35.00	0.004	0.154

The results presented in Table 9 are examples of how the CPN methodology can be used to accurately calculate the cost of individual entries in the ticketing system of a PV plant. The automation of calculating the CPN for a great number of tickets and plants will enhance our understanding of the appearance likeliness and severity of PV plant performance impairing issues in order to improve the operation of existing plants and the design of future PV systems. It is concluded that the development of an automated and therefore, time-efficient solution for extracting key parameters from maintenance tickets is of vital importance for the implementation of the methodology at portfolio level, and thus, to gain statistical insights from the large number of PV plants.

It became apparent that the O&M field practices must move away from the manual input of tickets in text format and adopt a more standardised approach where human intervention is limited to choosing the category and failure type from a pre-defined selection list.

4.1.2 Case 2: PV Module PID

How the risk quantification method can be also applied in practice is demonstrated using a 10 MW PV plant with PID affected PV modules. The assumptions in Table 10 serve as input for this case study. Not considered are financial parameter as depreciation, interest or taxes.

Table 10: Metadata of investigated PV plant in Case 2.

Parameter	
Risk	Potential induced degradation (PID)
Detection time	4 years
Response time	1 year
Repair time	1 year
Size of plant	10 MW
Module tilted/ orientation	20°, 0° south oriented, 2 portraits
Type of installation	Free Field Installation

Base frame	Fixed Installation
Modules	40000 x 250 Wp
Inverters	20 x 500 kVA
PPA	0.25 €/kWh
CAPEX	20 Mio€
OPEX	50 k€/a
Inverter nominal power	500 kW

Taking the behaviour of the identified root cause into account, the potential future PLR is expected to increase further with an expected saturation of 50%. After this value is reached, the PLR is expected to stagnate at a constant level of 0.7% per year. This prediction of performance development for 20 years of operation is shown together with the exceedance probability P10 and P90 for a confidence level of 68.2% in Figure 18. Taking CAPEX, OPEX and annual revenues into account, the project's financial profit after 20 years of operation is 48% below original expectations for the defined scenario without mitigating actions.

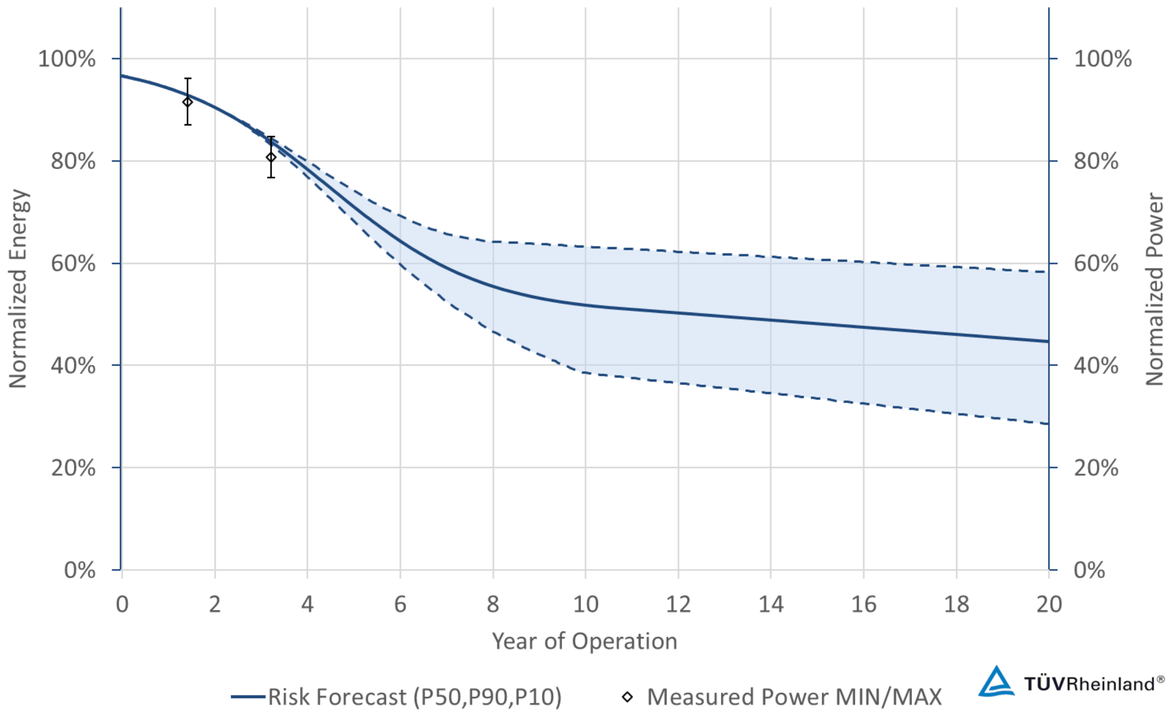

Figure 18: Energy forecast of No-Mitigation Scenario.

4.2 Cost-Benefit Analysis

The CPN methodology allows the estimation of the economic impact of failures on the LCOE and on business models of PV projects and has been developed not only to determine the economic impact of technical risks, but also to be able to assess the effectiveness of mitigation measures. Specific failures have to be examined in order to draw recommendations on how to mitigate the economic impact for, e.g. soiling, or potential induced degradation (PID). Some failures can be prevented or mitigated through specific actions at different project phases (e.g. for PID); others (e.g. soiling) can be prevented or mitigated through a more generic action. For example, the monitoring of performance or visual inspection can be considered as generic mitigation measures that can have a positive impact on the reduction of the CPN of many failures. In practice, it is important to understand how mitigation measures can be considered as a whole to be able to calculate their impact and thus assess their effectiveness.

4.2.1 Case 2: PV Module PID

The cost-benefit analysis is also a tool to determine whether the benefit of one option will justify its costs. It can point out the best mitigation options from an economical point of view. The analysis continues the case study presented in Chapter 4.1.2. Three mitigation scenarios are defined:

- **No-Mitigation** option without intervening into the current status of plant operation
- **PID Box**: Installing PID-boxes and allowing the performance of the PV modules to re-cover to a certain level
- **PID Box & partial repowering**: Installing PID-boxes and replacing very low perform-ing PV modules by high-power-modules.

The expected annual production of energy yields for the three scenarios is illustrated in in Figure 19. After the mitigation measures were applied in year 5 of the operation, the energy yields show a steep rise. The expected PV plant output after 20 years of operation is calculated at 45% rated energy output for the no-mitigation scenario and at 84% and 91% for mitigation options 1 and 2, respectively.

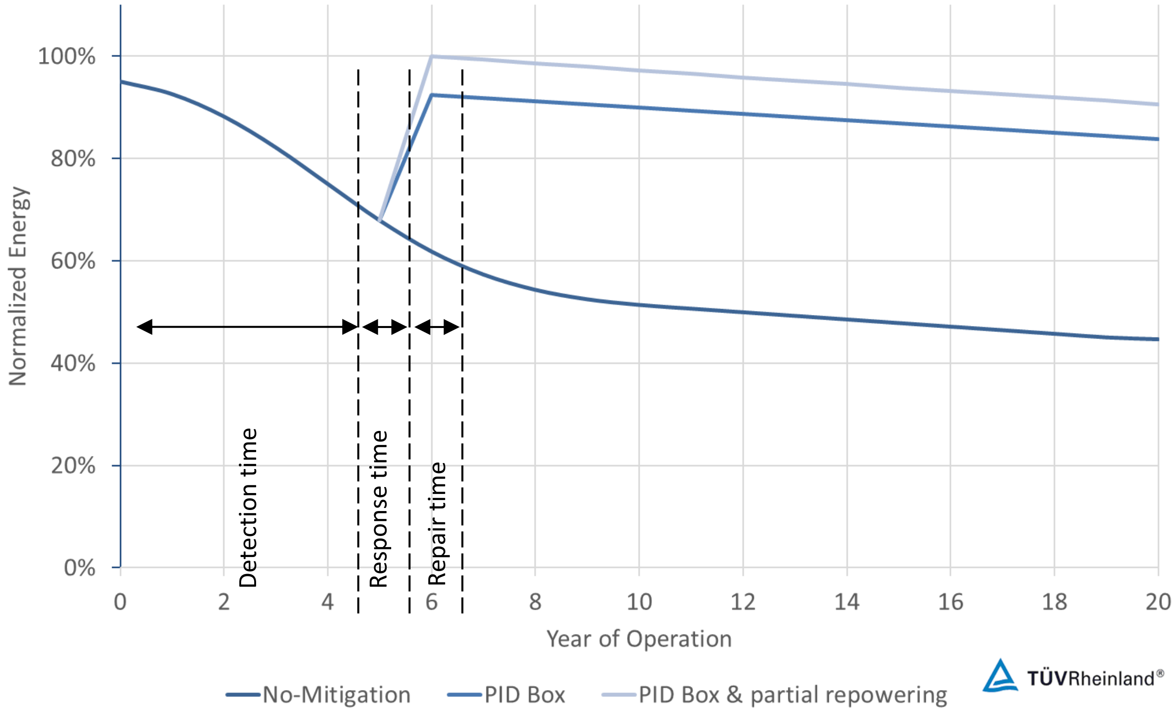

Figure 19: 20-year forecast for three mitigation scenarios; the repowering is carried out with a higher module power class.

Table 11: Costs of mitigation scenarios.

	No-Mitigation	PID Box	PID Box & partial repowering
Cost [k€]	15	238	3233

The cost-benefit analysis also takes the associated costs of the available options into account, as described in Table 14. The impact on the annual cash flow is demonstrated in Figure 20. In the reference scenario, the monetary yield of the PV project after 20 years is expected to be around 225% of the CAPEX (dashed line). If no mitigation measures are taken, the lowest result of around 115% of CAPEX is forecasted. Mitigation options 1 and 2 result in 6.0%, respectively 4.6% below expectations, which both represent successful projects results. It can be concluded that both mitigation options should be considered and taken as a solution compared to non-action. However, the additional investments in year 5 of operation for option 2 are significantly higher by a factor of 8.

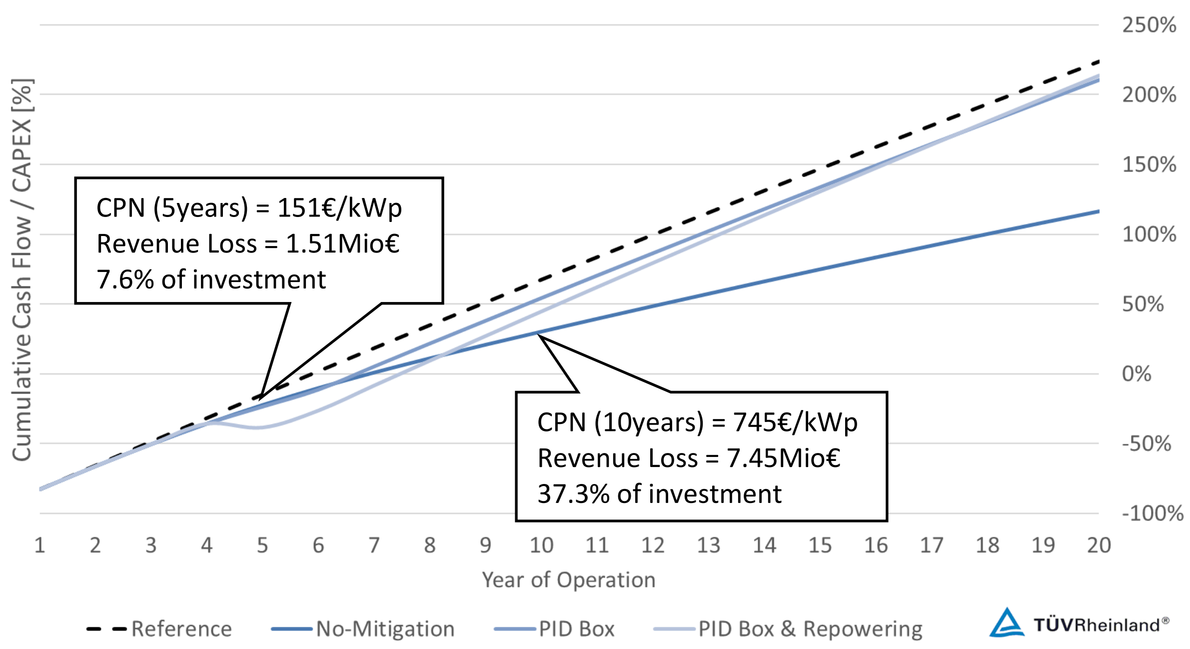

Figure 20: Annual cumulative cash flow of the mitigation scenarios with CPN and loss of revenue after 5 and 10 year of operation if no action is taken.

4.2.2 Case 3: PV Module Soiling

Cleaning routines for PV power systems in desert regions are a typical corrective measure to reduce energy yield losses due to soiling. The impact of different cleaning procedures on the soiling losses over one year are calculated and shown in Figure 21 for a 10 MWp PV plant near Abu Dhabi [59]. The soiling rate is 0.3%/day and only two significant precipitation events are recorded during one year. If no cleaning (natural cleaning) is performed, soiling losses (brown bars) may reach up to 30% per year and result in annual costs of 2614 k$ (Table 12).

Table 12: Impact of cleaning routines on soiling losses of a 10 MWp plant in Abu Dhabi.

Index	Soiling Loss [%]	Precipitation Events [-]	Cleaning Events [-]
Natural Cleaning	28.4	2	0
Periodic Cleaning	4.1	2	12
Triggered Cleaning	2.3	2	20

In case of periodic cleaning (monthly cleaning), energy losses due to soiling are reduced to 4% (green bars) resulting in reduced yield losses (377 k$) and an annual cost of 497 k$, which includes the costs of the 12 cleaning routines (Table 12). Best economic cleaning measure is achieved when performing “triggered cleaning” at a soiling loss of 5%, which results in further reduced yield losses (212 k$) and an annual cost of only 412 k$, which includes the costs of 20 required cleaning routines (Table 12). The calculations show that it is possible to determine the best economic solution for a specific PV plant (10 MWp), location (Abu Dhabi), loss scenario (0.3%/day soiling loss rate) and mitigation concept (three types of cleaning).

Table 13: Impact of cleaning routines on monetarized yield losses of a 10 MWp plant in Abu Dhabi.

Index	Yield Loss [k$]	Cleaning Cost [k$]	Total Cost [k$]
Natural Cleaning	2614	0	2614
Periodic Cleaning	377	120	497
Triggered Cleaning	212	200	412

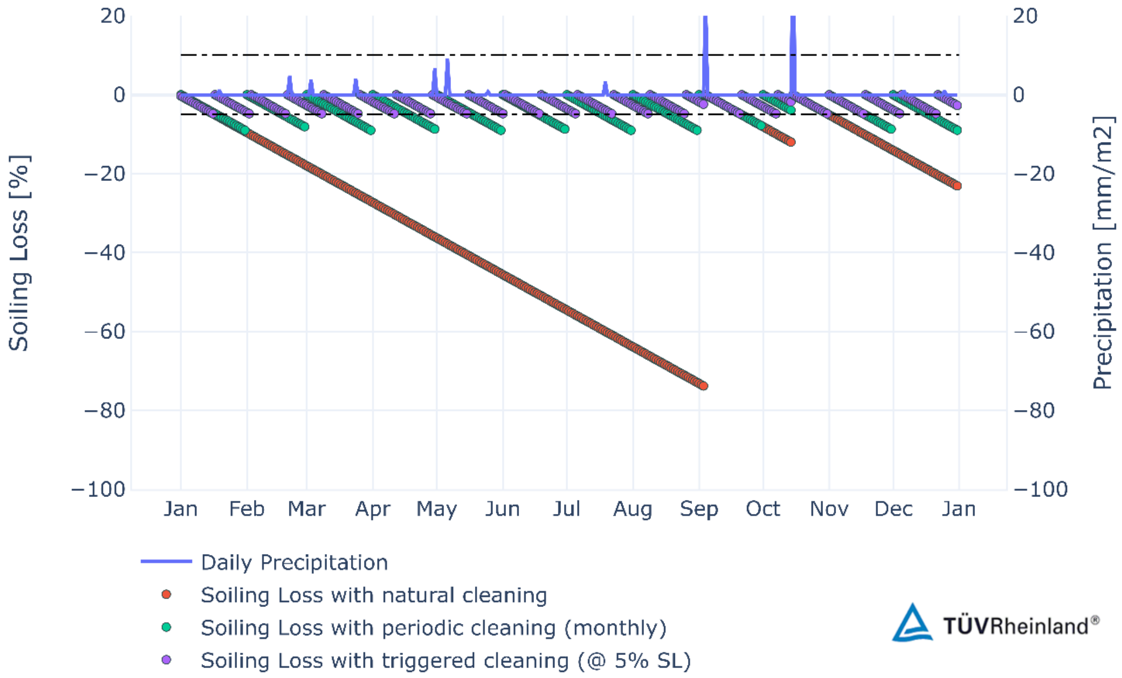

Figure 21: Impact of cleaning routines on soiling losses of a 10 MWp plant in Abu Dhabi.

5 CONCLUSIONS

Best practice guidelines to improve the operation of PV power systems are often only applied as long as recommended actions have advantages for the executors, the EPCs and O&M companies and for the investors whose main focus is on low risks and maximum profit from an economic point of view. This leads to the key challenge: How can you demonstrate the effectiveness of the measures and justify their application? The technical best solution is not always the economically best one. Before you are able to evaluate the cost-benefit, the following question arises: How to quantify the basic impact of technical risks?

In order to answer these questions, we introduced semi-quantitative and quantitative methodologies to assess technical risks in PV power systems and provided 30 examples of common technical risks described and rated in the new created PV failure fact sheets (PVFS). Besides the PVFSs based on expert knowledge and expert opinion, an update on the statistics of the PV failure degradation survey developed in Koentges et al. [1], was given. With the knowledge acquired and data collected, the risk and cost-benefit analysis were demonstrated in three case studies that showed methods for prioritising decisions from an economic perspective and provided important results for risk managing strategies.

However, providing the overview of quantification methods, we draw the conclusion that more standardisation is required. Risk definitions are not fully structured and event databases (solar logbooks) are not harmonised. Data analysis would benefit from the use of a standardised language and metadata formats. Development of an automated and therefore time-efficient solution for extracting key parameters from maintenance tickets is required to gain statistical insights from a large number of PV plants. Also, the development of a software tool for field technicians is recommended that would allow the precise and error-free recording of standardised parameters for the calculation of the O&M contractors KPIs necessary for an efficient implementation of the methodology [4]. In summary, the O&M field practices must certainly move away from a manual input of tickets in text format and adopt a more standardised approach where human intervention is limited.

In the 2020 launched H2020 project TRUST-PV [60], the improved Cost Priority Number approach is the basis for the creation of a large database including PV system data, coming from several major O&M companies and asset managers across Europe, for failure rates calculation. It is thereby a direct continuation where the improved Cost Priority Number methodology will be automatised in terms of acquiring failure data, power loss calculations and related cost determination. The output will later be integrated in the PV plant design of newly commissioned PV plants and in a decision support system platform for operating plants.

Technical risks from a reliability perspective, as introduced in the RAM analysis, are addressed in IEC TS 63265 – "*Reliability practices for the operation of photovoltaic power systems",* coordinated by Roger Hill with the planned publication in the first half of 2022. Its motivation is to provide a toolkit description of many methods of how different stakeholders can demonstrate the effective of reliability increasing measures from technical and economic point of view.

All things considered, we believe that data-driven evaluation of techno-economic performance indicators is a significant key to take decision support on LCOE to the next level.

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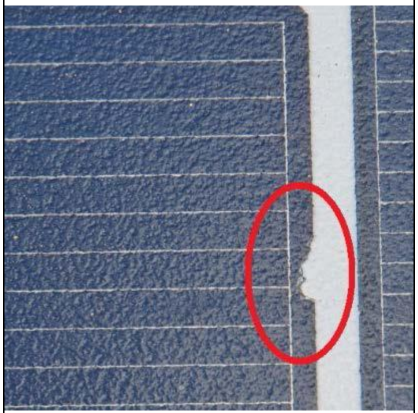
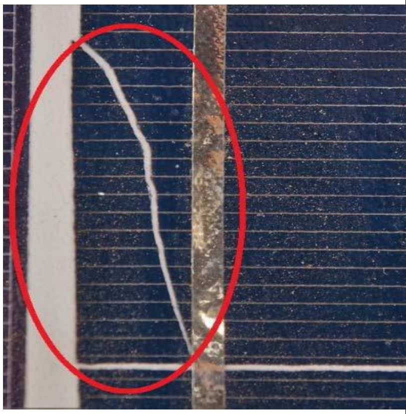
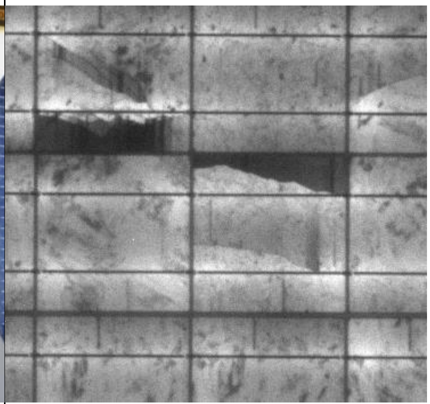
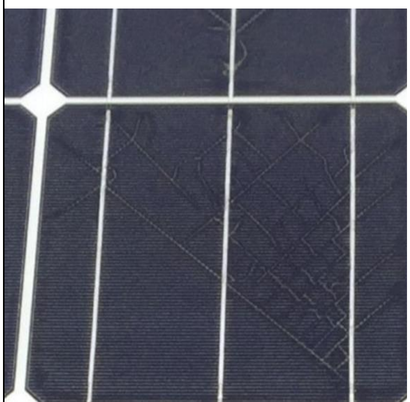
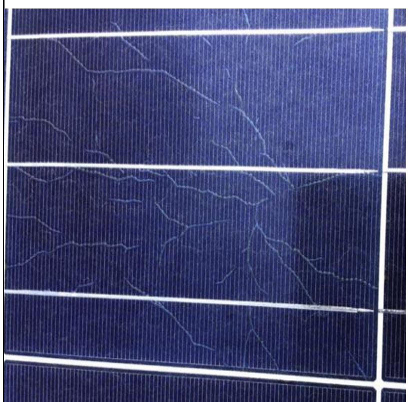
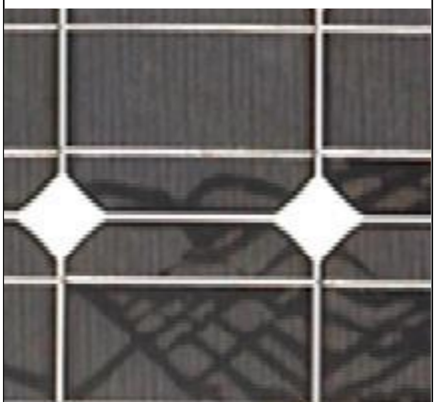
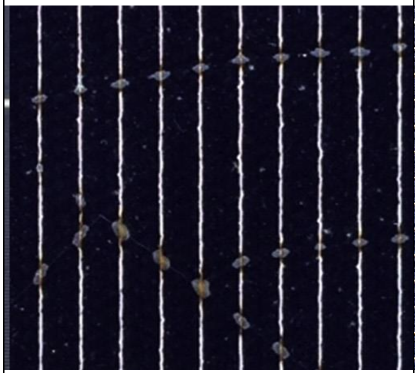
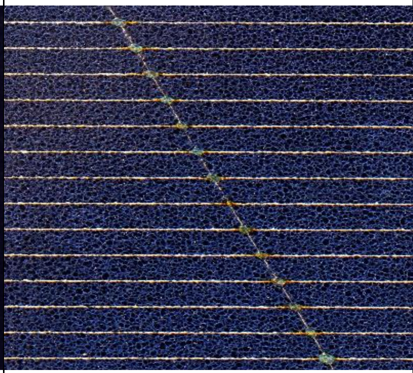
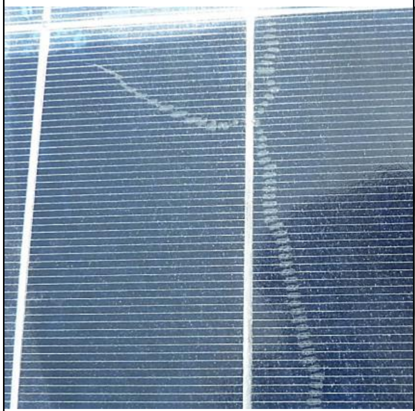
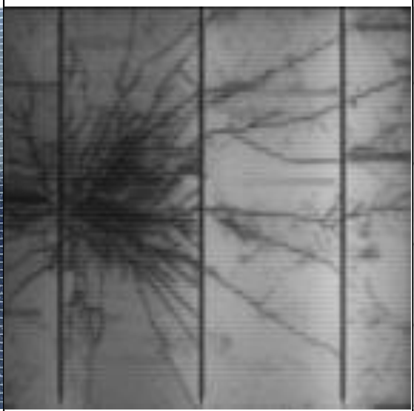
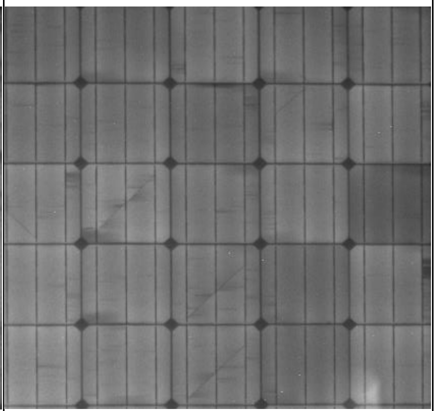
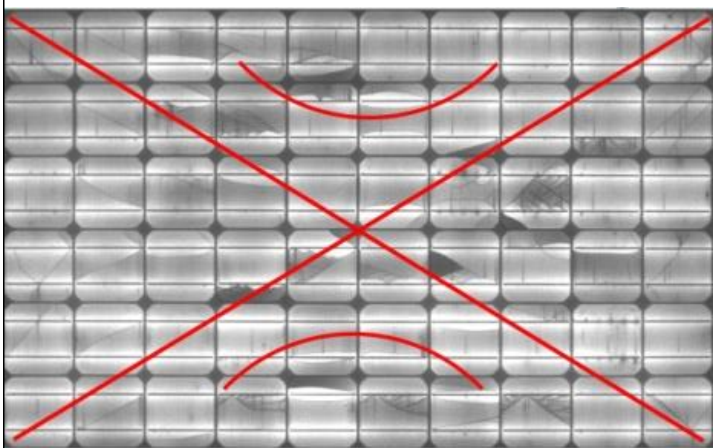
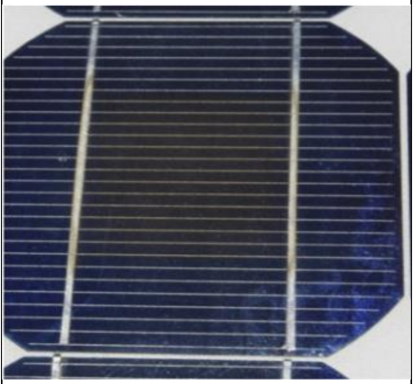
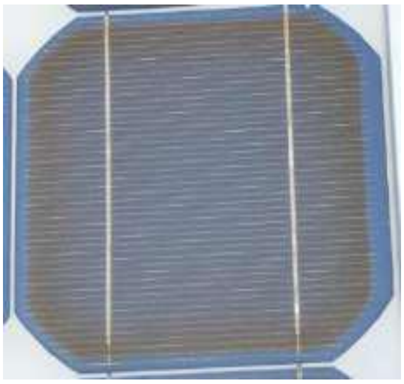
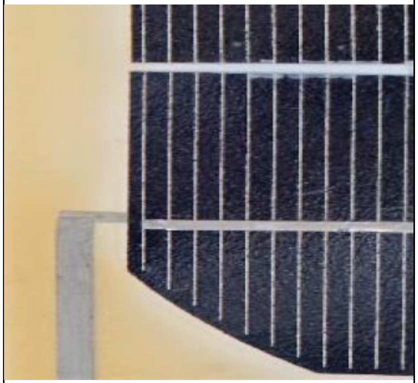
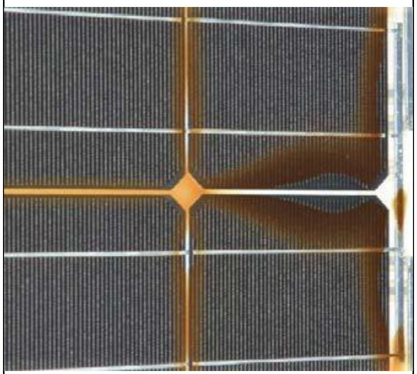
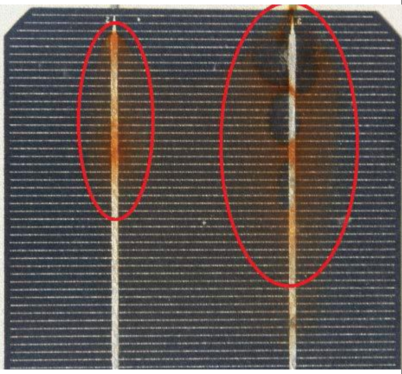
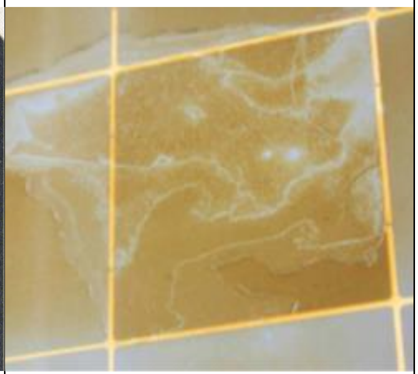
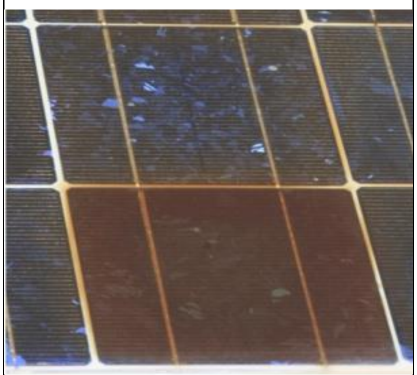
ANNEX 1

<table>
<tr><td>Component
Defect</td><td colspan="3">Module
Cell cracks</td><td>PVFS 1-1vs.01</td></tr>
<tr><td>Appearance</td><td colspan="4">Cell cracks are cracks in the silicon substrate of the photovoltaic cells. Most of the cell cracks cannot be seen by the naked eye. Only large cracks or where the backsheet is visible through the cracks can be seen. Cell cracks can be easily detected through imaging techniques like electroluminescence, UV fluorescence or lock-in thermography. Cell cracks can have different lengths and orientations (crack patterns). Small cell cracks (micro-cracks) become visible by eye when they form snail tracks or when photobleaching or delamination takes place along the cracks. A snail track is a discoloration of the silver paste of the front metallisation of solar cells which occurs typically 3 months to 1 year after installation of the PV modules. Affected metal fingers on cells may be silver, yellow or brown in appearance, this effect can also be seen on cell edges. Photobleaching is a counteracting effect to the yellowing of the encapsulant and it occurs along the cracks and the borders of the cells. Delamination along cracks is visible as small bubbles.</td></tr>
<tr><td>Detection</td><td colspan="4">EL, UV (IRT, VI ,IV)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="4">Cell cracks can have origin in all lifetime phases of a PV module: production, installation and operation. In production, cell cracks can occur during wafer, cell and module manufacturing. Especially the stringing and soldering process of the solar cells can damage the cells. After production, major sources for cell cracks are the packaging and transport of the modules, and the installation. After installation, external forces like hail, heavy snow weight or strong wind may result in cell cracks. Once cell cracks are present, further mechanical and thermomechanical stresses can lead to the propagation of the cracks into longer and wider cracks. Some crack patterns can give indications on the origin of the failure, but the final cause of cell breakage is not always easy to identify. A repetitive crack pattern can be for example caused by a production failure, whereas PV modules showing dendritic crack patterns have been probably exposed to heavy mechanical loads. Snail tracks can be found in a great variety of solar modules, but not in all. The combination of different materials (encapsulant and back sheets) with UV radiation and temperature plays an important role in the creation of snail tracks.</td></tr>
<tr><td>Production ■</td><td colspan="2">Installation ■</td><td>Operation ■</td></tr>
<tr><td>Impact</td><td colspan="4">Cell cracking does not necessarily lead to a failure of the module. The presence of a crack of any size that does not, or likely will not through its propagation, remove more than 10% of that cell's area from the electrical circuit can be considered to have limited to no impact on the performance. Even if each cell in a 60 cell module is cracked, but do not lead to a separated cell area, the power loss of the module is typically below 2.5 % of the nominal power. In cold and snow climate zones cell cracks seem to have a more pronounced impact. Here relatively high mean degradation rates of up to 7%/y can be found. Besides the risk of power loss there is a risk of hot spots and burn marks due to inactive cell parts. Snail tracks are reported to have no influence on the performance of the PV module, but due to the observed porous silver fingers the isolation of cracked cell parts may be accelerated more than it would be without snail tracks.</td></tr>
<tr><td></td><td>Safety:</td><td>f e</td><td>Performance:</td><td>1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td>Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules.</td><td colspan="2">Adequate transport procedures, installation and cleaning by trained personal, in case of higher snow or hail risk use of therefore certified modules.</td><td>Request EL pictures from production, pre-shipment or warehouse inspection, EL images with mobile laboratory before or during installation, regular EL inspection or after sever weather conditions.</td></tr>
</table>

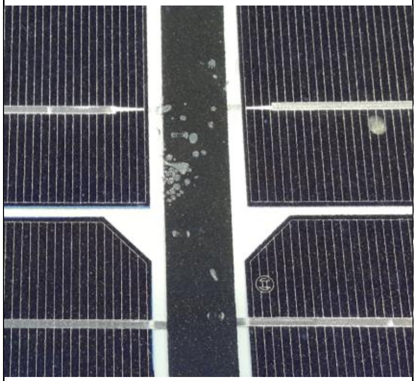
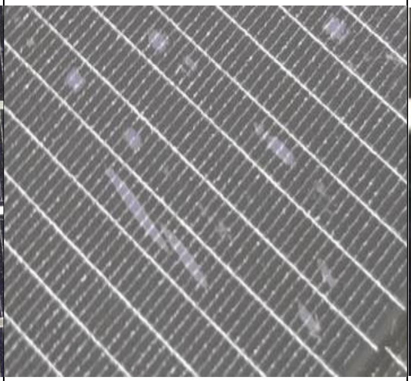
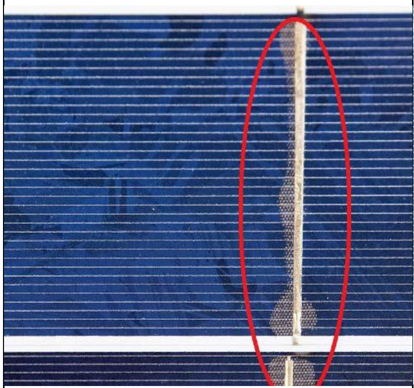
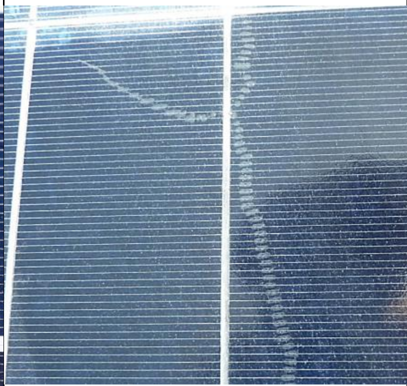
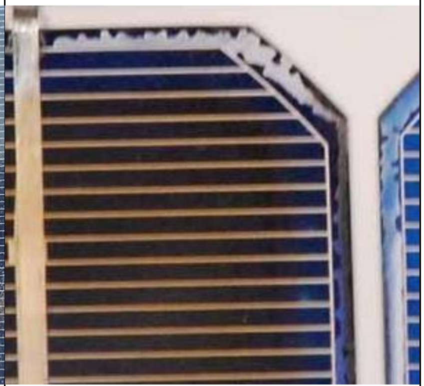
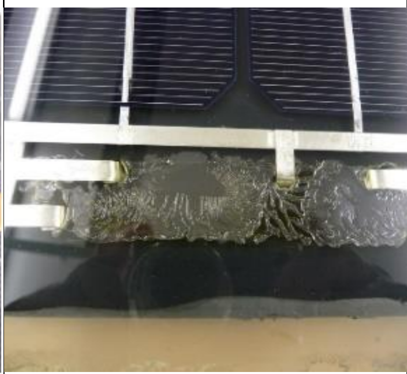
EXAMPLES (page1)			**PVFS 1-1vs.01**
Examples 1-3			
	Cell chipping. A very small region is missing from the edge of the cell, but does not enter metallized region. [16]	Large crack at cell corner visible by eye - small portion of the cell (<10%) is no longer electrically connected. [16]	Cell crack with snail track. No isolation of any cell part. The propagation could isolate a cell area >10%. [16]
Severity	1	2	2
Examples 4-6			
	Cell cracks visible by the photo-bleaching effect. This may not be mistaken for snail tracks. [16]	Two cell cracks with extensive delamination, EVA browning and photo bleaching. [41]	EL image of 2 cell cracks which isolates more than 10% of the cell area. [TUV Rheinland]
Severity	f e 2 3 4	f e 2 3 4 5	f e 2 3 4
Examples 7-9			
	Snail track example. [41]	Snail track example. [41]	EL of cell cracks with snail tracks. [16]
Severity	f e 2 3 4	f e 2 3 4	f e 2 3 4

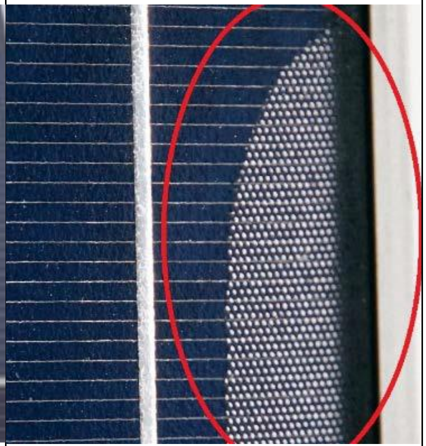
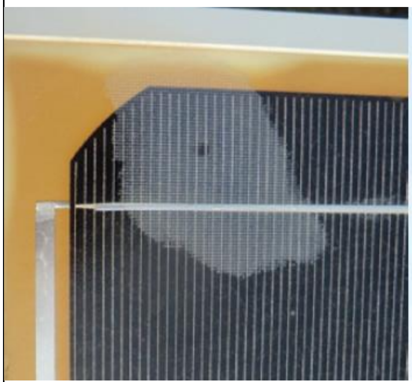
Examples 10-12			
	Zoom of snail track with delamination. [41]	Zoom of snail track with browned fingers. [37]	Zoom of snail track with delamination. [SUPSI]
Severity	f e — 2 3 4	f e — 2 3 4	f e — 2 3 4
Examples 13-15			
	Cell crack with EVA delamination. [TUV Rheinland] (see also PVFS 1-3)	Typical EL picture of a cell crack caused by hail. [TUV Rheinland]	Repetitive crack pattern due to impact of soldering machine. [SUPSI]
Severity	f e — 2 3 4	f e — 2 3 4	2
Examples 16			
	Typical EL picture of cell cracks caused by a heavy homogeneous mechanical load (X-crack pattern) also without glass breakage. [16]		
Severity	f e	3 4	

<table>
<tr><td>Component
Defect</td><td colspan="3">Module
Discolouration of encapsulant or backsheet</td><td>PVFS 1-2vs.01</td></tr>
<tr><td>Appearance</td><td colspan="4">The degradation of the encapsulation or backsheet materials is getting visible as a light yellow to dark brown discolouration. Colour can be next to or above the cells, along the busbars or cell interconnects or on the back or front side of the backsheet. Often discolouration is inhomogeneous and follows spatial patterns depending on the type of module construction. Typically, for glass/backsheet modules the browning occurs in the central region of the cells with wide clear encapsulant areas, or “frames” around the cell edges. Discolouration can also be observed in the encapsulant between neighbouring solar cells when the front side of the backsheet (layer behind the cells) is degrading. For glass/glass module constructions the encapsulant discolouration is mostly spatially uniform, but can also show patterns of clearer areas over some cells. In glass/backsheet modules the location of these patterns generally correlates with cell cracks. In some cases, the discolouration is more pronounced in one or more cells of the module.</td></tr>
<tr><td>Detection</td><td colspan="4">VI, (IV, IRT)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="4">In the past, yellowing or browning was mostly associated with the degradation of the mostly used encapsulant ethylene vinyl acetate (EVA) but this problem was greatly solved by improved stabilisation of the polymer with additives, including UV absorbers and thermal stabilizers. If the choice of additives and/or their concentrations are inadequate, or the lamination process is inadequate or incomplete, the encapsulation material may discolour over time. The patterns of discolouration observed in the field can be very complex because of the diffusion of oxygen or the products of reaction, such as acetic acid, generated when heat and UV light interact with EVA. The presence of oxygen leads to the so called photobleaching effect which creates a ring of transparent EVA around the perimeter of a cell or a cell crack. The case of single cells which are far darker than the adjacent cells, implies that the most discoloured cell was at higher temperature than the surrounding cells, perhaps because of differences between the cells or the cell being located above the junction box.</td></tr>
<tr><td>Production ■</td><td>Installation □</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="4">Discoloration is a sign that the polymeric compounds within the module started to degrade. This type of degradation is predominantly considered to be first an aesthetic issue before a decrease of module current and power production is detected. Typically, mean yearly degradation rates due to yellowing are about 0.5%/a and may reach up to 1%/a in hot and humid or moderate climates. While it is uncommon for EVA discolouration to induce other failures within the cell, it may correlate to: high temperatures in the field, the generation of acetic acid and concomitant corrosion and embrittlement. Unless discolouration is very severe and localized at a single cell, where it could cause a substring bypass-diode to turn on, the discolouration of EVA does not present any direct safety issues. More critical is the discolouration of UV sensitive backsheets that can result in a loss of mechanical properties (elastic behaviour) and cracking of backsheet due to thermomechanical stresses.</td></tr>
<tr><td>Safety:</td><td>f e</td><td>Performance:</td><td>1 2 3</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td>Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td>Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules.</td><td>Check validity of IEC 61215 certification and BOM.</td><td colspan="2">Regular system inspections
For areas with harsh climate, request modules pass higher test standards, like double or triple IEC 61215 test condition.</td></tr>
</table>

EXAMPLES (page1)			PVFS 1-2vs.01
Examples 1-3			
	Slightly browned EVA in the centre of the cell with photobleaching at the edges. [16]	Slightly browned EVA in the centre of the cell with photobleaching at the edges. [44]	Yellowed backsheet from the inside. [37]
Severity	2	2 3	1 2
Examples 4-6			
	Dark discolouration at cell edges, between cells and over gridlines and busbars. [37]	Dark discolouration over metalization. [37]	Backsheet air side yellowing. [37]
Severity	2 3	2 3	e 1 2
Examples 7			
	Single cell browned much faster than the others due to local heating. [16]		
Severity	f e 2 3		

<table>
<tr><td>Component
Defect</td><td colspan="4">Module
Front delamination</td><td>PVFS 1-3vs.01</td></tr>
<tr><td>Appearance</td><td colspan="5">Any local separation of the layers between (i) the front glass and the encapsulant or (ii) the cell and the encapsulant, visible as bubbles or as bright, milky area/s. It may appear continuous or in spots. The position and size of the delamination or bubble depends on the origin and progress of the failure.</td></tr>
<tr><td>Detection</td><td colspan="5">VI, (INS)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="5">The adhesion between the glass, encapsulant, active layers, and back layers can be compromised for many reasons. Typically, it is caused by the manufacturing process (e.g. poor cross linking of EVA, too short lamination times, too high pressure in the laminator, contaminations, improper cleaning of the glass, incompatibility of EVA with soldering flux, inadequate storage of the raw material) or environmental factors (e.g. thermal stresses, external mechanical stresses, UV). Delamination is generally followed by moisture ingress and corrosion. It is therefore more frequent and severe under hot and humid conditions.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation □</td><td>Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="5">Delamination or bubbles do not automatically pose a safety issue, but they can result in reduced insulation of the component and increased safety risk when they form a continuous path between electric circuit and the edge due to possible water ingress. Moisture in the module will decrease performance due to an increase of series resistance, affect long term reliability and in some cases also the structural integrity of the module. Moreover, delamination at interfaces in the optical path will result in additional optical reflection and subsequent decrease in current. This can be the origin of current mismatch. If the mismatch is significant, it will trigger the bypass diode and cause further power loss. The inverter might also shut down due to leakage current’s leading to a further performance loss. Manufacturing related delamination issues often affects a relevant percentage of modules within the same production batch and consequentially has a big impact on system performance.</td></tr>
<tr><td>Safety:</td><td>f e e</td><td>Performance:</td><td colspan="2">1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules. In case of individual module testing all modules which failed the insulation and/or wet-leakage test should be replaced.</td><td colspan="2">Check validity of IEC 61215 certification and BOM, ground fault detection by inverter or other devices at all time.</td><td>Extended testing (e.g. damp heat), pre-shipment inspections (e.g. cross linking level of EVA) regular visual system inspections.</td></tr>
</table>

EXAMPLES (page1)			PVFS 1-3vs.01
Examples 1-3	 Encapsulant delamination in un-critical position. [SUPSI]	 Encapsulant delamination from cell caused by production process. [SUPSI]	 Encapsulant delamination from cell along grid fingers and bus bar. [38]
Severity	1	1 2	1 2
Examples 4-6	 Encapsulant delamination from glass (spotted due to glass texture) along the bus bars. [37]	 Encapsulant delamination along a cell crack. [46] (see also PVFS 1-1)	 Encapsulant delamination near cell edges in combination with cell browning. [38]
Severity	1 2	f e 2 3 4	2 3
Examples 7-9	 Delamination in front of cell in the centre of the module. [40] (see also FS 1-2)	 Delamination at module insert connections of a glass/glass module (junction box). [SUPSI]	 Delamination at cell edges. [16]
Severity	2 3 4	e 1 2	e 2 3 4

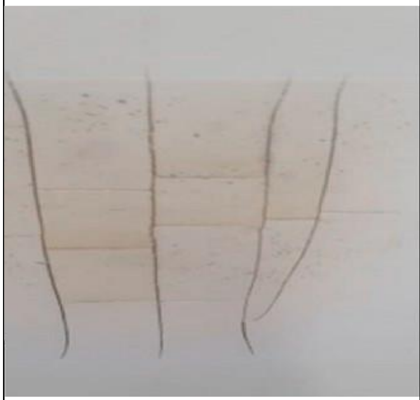
EXAMPLES (page2)			PVFS 1-3vs.01
Examples 10-12			
	Encapsulant delamination at borders. [37]	Encapsulant delamination along a bus-bar in a cell close to the module edge. [40]	Encapsulant delamination of from glass (spotted due to glass texture) at the edge of the cell. [37]
Severity	1	1 2	2 3
Examples 13-15			
	Delamination creating a continuous path between electric circuit and the edge. [40]	Delamination with corrosion. [1] (see also FS1-11)	Delamination caused by detachment of backsheet with exposure of encapsulant from the back. [SUPSI]
Severity	3 4 5	3 4 5	3 4 5

<table>
<tr><td>Component
Defect</td><td colspan="3">Module
Backsheet delamination</td><td>PVFS 1-4vs.01</td></tr>
<tr><td>Appearance</td><td colspan="4">Any local separation of the polymeric back sheet layers leading to an air gap between the backsheet and the rest of the module, or within the multilayer backsheet (=internal delamination). The backsheet may appear wavy, with locally limited bumps, bubbles or ripples. In the worst case, one or more layers may peel off. The position and extent of the delamination will depend on the cause and progression of the failure.</td></tr>
<tr><td>Detection</td><td colspan="4">VI, (INS)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="4">There are many different forms and compositions of polymeric multilayer backsheets on the market. With laminated backsheets (polymeric layers adhered to each other by a thin adhesive layer) internal delamination can appear: the multiple layers may delaminate upon adhesive degradation, which may lead to local delamination of two subsequent layers or a peel-off of one or more layers. Co-extruded backsheet are prone to internal lamination. Delamination of the backsheet from the encapsulant can appear with all types of backsheets and originates from a lack of adhesion between the backsheet and the encapsulation. The major drivers for the delamination of or within the the backsheet are (i) thermo-mechanical stress originating from differing CTE of the individual polymeric layers, (ii) chemical reactions at the interfaces (material incompatibility) or deteriorated interfacial bonding as a result of the attack from heat, UV and moisture or (iii) external mechanical stress applied on the module. Therefore, it is more frequent and severe under hot and humid conditions. Delamination can be also caused by an insufficient lamination process e.g. too short lamination times.</td></tr>
<tr><td>Production ■</td><td>Installation □</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="4">If delamination occurs forming bubbles in a central, open area of the back, it will not present an immediate safety issue. That area would likely operate at slightly higher temperatures as the heat conduction/dissipation through the backsheet is disturbed. But as long as the bubble is not further mechanically cracked or expanded, the performance and safety concerns are minimal. However, if delamination of the backsheet occurs near a junction box, or near the edge of a module there would be more serious safety concerns. Delamination at the edge may provide a direct pathway for liquid water to enter the module during a rainstorm, or in response to the presence of dew. That can provide a direct electrical pathway to ground creating a very serious safety concern. Similarly, delamination near a junction box can cause its loosening, putting mechanical stress on live components with the danger of breakage. A break might cause a connection failure to a bypass diode and possibly result in an unmitigated arc at full system voltage. In multilayer backsheets the severity depends also on which layer is affected.</td></tr>
<tr><td>Safety:</td><td>f e e</td><td>Performance:</td><td>1 2 3 4</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td>Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td>Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules. In case of individual module testing all modules which failed the insulation and/or wet-leakage test should be replaced.</td><td>Check validity of IEC 61215 certification and BOM.

Ground fault detection by inverter or other devices at all time.</td><td colspan="2">Regular system inspections.</td></tr>
</table>

EXAMPLES (page1)			PVFS 1-4vs.01
Examples 1-3			
	Multiple bubbles in the centre and edge of the backsheet. [46]	Blisters because of vapour barrier, such as aluminium foil. [1]	Big central bubble + wavy delamination. [16]
Severity	e / 2 3 4	e e / 1 2 3 4	e / 1
Examples 4-5			
	Backsheet delamination with direct exposure of encapsulant. [SUPSI]	Delamination of top layer without exposure of encapsulant. [SUPSI]	
Severity	f e / 2 3 4	f e / 1 2 3	

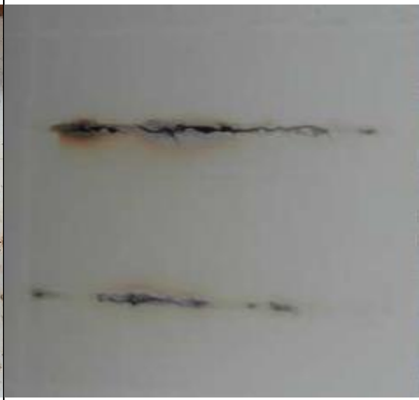
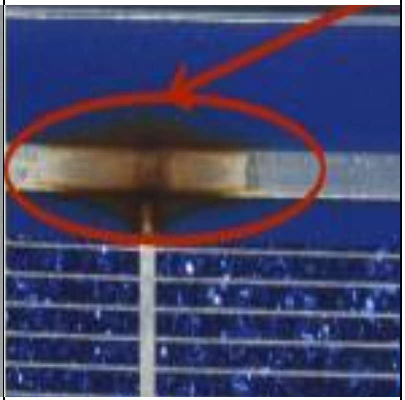
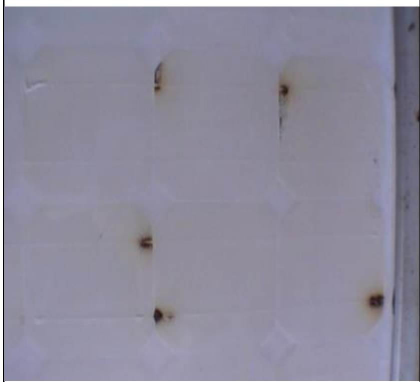
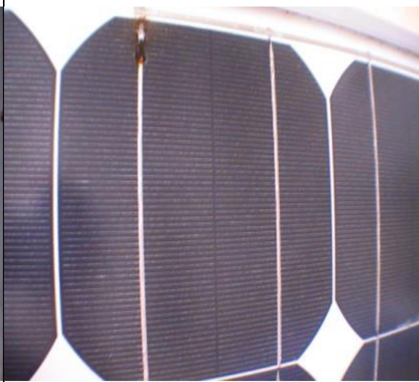
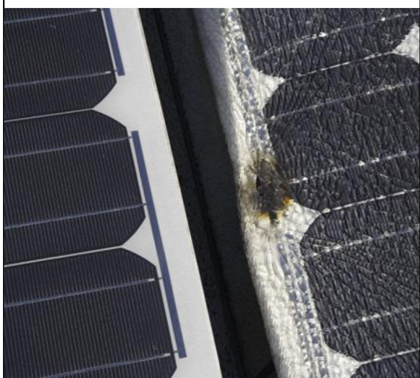
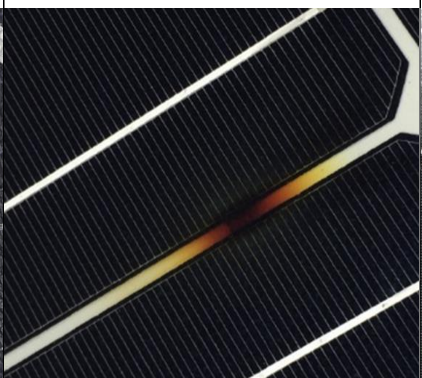
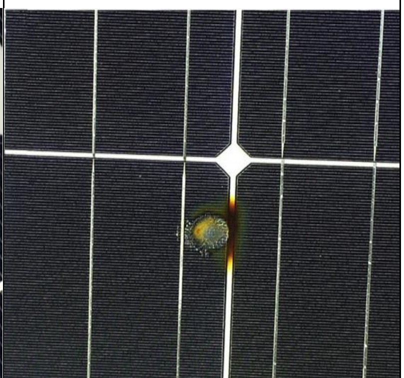
<table>
<tr><td>Component
Defect</td><td colspan="4">Module
Backsheet cracking</td><td colspan="2">PVFS 1-5vs.01</td></tr>
<tr><td>Appearance</td><td colspan="6">Any damage of the backsheet (surface or whole stack) that is visible as crack, burst or scratch. The location and extent of the cracks depend on the cause and progression of the failure. The cracked area may be localized (e.g bursted bubble, scratch), extend along specific module areas (e.g. long or between the cells, along the busbars) or extend over large or the full area of the module (e.g embrittled surface). The crack can be very deep and affect the back sheet stack.</td></tr>
<tr><td>Detection</td><td colspan="6">VI, (INS)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="6">The degradation of the backsheet can be caused by environmental factors like UV-irradiation, thermal stress, external mechanical stress or by internal stress (e.g. thermomechanical stress with the multimaterial composite PV-module) or incorrect handling during transport and installation (local cuts, scratches). Deep backsheet cracking (whole backsheet stack split) is often followed by moisture ingress and corrosion. This is more frequent and severe under hot and humid conditions. The use of low quality material (e.g. low UV resistance) or incompatible material combinations (backsheet ↔ encapsulant) causes most of the premature degradation failures. Discolouration and or strong chalking can be precursors for backsheet cracking. Deep cracks or bursted bubbles can be the result of local hotspots/burn marks that split or break the backsheet.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="6">A broken backsheet can cause electrical insulation failure, posing a safety hazard and a potential ground fault. On the long-term, power degradation due to the penetration of moisture into the module which induces further failures (e.g. corrosion, delamination) can occur. In the case of deep cracks reaching the active part of the cells, the insulation is immediately compromised and safety is not anymore fulfilled.</td></tr>
<tr><td>Safety:</td><td colspan="2">f e m e</td><td>Performance:</td><td colspan="2">1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules. In case of individual module testing all modules which failed the insulation and/or wet-leakage test should be replaced.</td><td colspan="2">Ground fault detection by inverter or other devices at all time, check validity of IEC 61215 certification and BOM, visual inspection before installation.</td><td colspan="2">Regular system inspections.</td></tr>
</table>

EXAMPLES (page1)			PVFS 1-5vs.01
Examples 1-3			
	Cracked backsheet in combination with yellowing under a hot cell. [39]	Squared cracks beneath cell interspaces. [39]	Cracking between cells. [38]
Severity	f m e | 2 3 4 5	f m e | 2 3 4 5	f m e | 2 3 4 5
Examples 4-6			
	Longitudinal cracks located under bus bars. [39]	Backsheet cracking. [57]	Backsheet cracking. [57]
Severity	f m e | 2 3 4 5	f m e | 2 3 4 5	f m e | 2 3 4 5
Examples 7-8			
	Localized superficial damage. [1]	Deep scratch on backsheet. [TUV Rheinland]	
Severity	f e m | 1	f m e | 1 2	

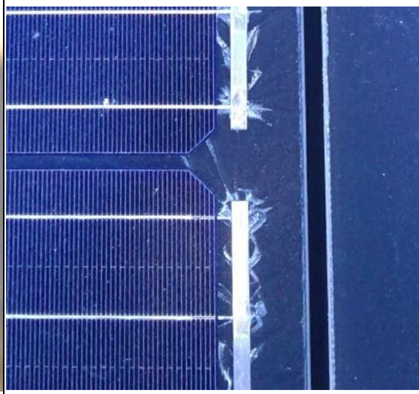
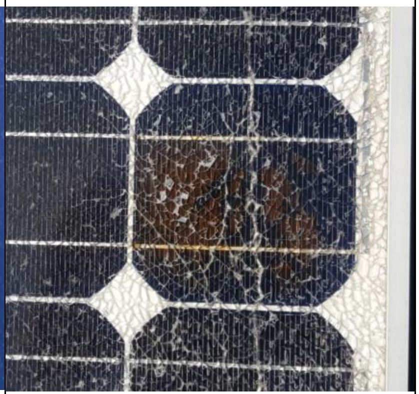
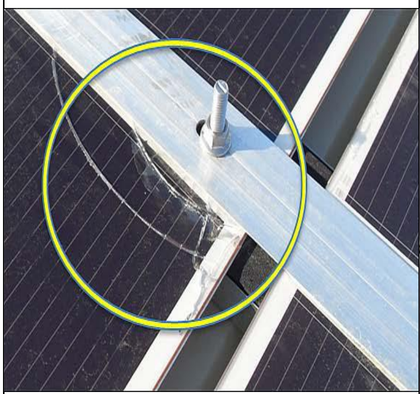
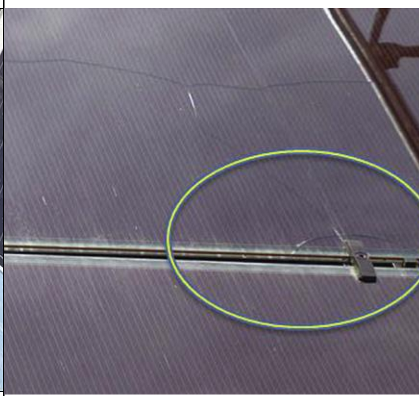
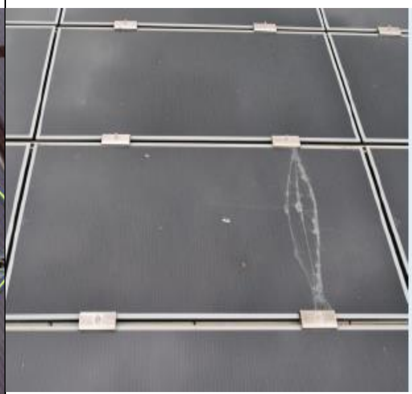
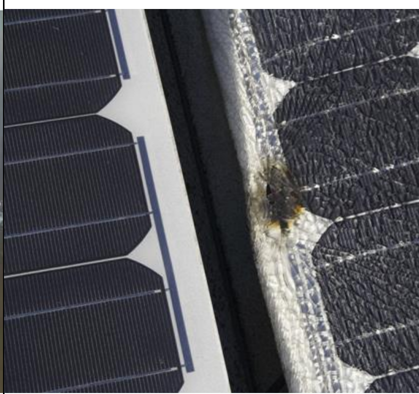
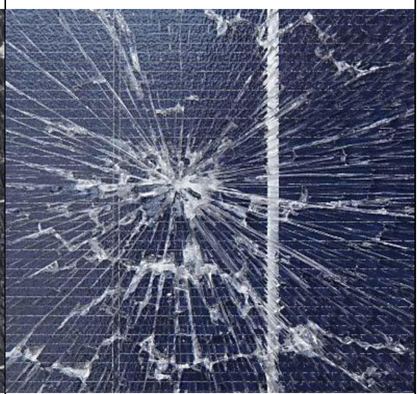
<table>
<tr><td>Component
Defect</td><td colspan="4">Module
Backsheet chalking (whitening)</td><td>PVFS 1-6vs.01</td></tr>
<tr><td>Appearance</td><td colspan="5">White powder is detectable on the external surface of the backsheet. It can be seen by passing a finger over the backsheet. It can be removed. The backsheet has usually a rough or dull appearance.</td></tr>
<tr><td>Detection</td><td colspan="5">VI</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="5">Chalking is caused by the photothermal degradation of the polymers in the outer backsheet layer containing inorganic pigments. For example, TiO_2 pigments are often used in the outer layers as UV blocker.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation □</td><td>Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="5">Chalking does not affect module safety or performance on first sight, but it can be a sign for an ongoing degradation of the backsheet and a precursor for severe backsheet cracking. Due to the degradation-induced reduction of UV protection, more serious failures, such as back-sheet cracking and insulation failures can occur. Enhanced moisture diffusion into the en-capsulant/active PV-parts can lead to corrosion of cells and connectors, having a negative impact also on the performance.</td></tr>
<tr><td>Safety:</td><td>e</td><td>Performance:</td><td colspan="2">1</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td colspan="2">Regular inspections should be done to monitor the pro-gress of the observed failure. Ground fault detection by in-verter or other devices at all time.</td><td colspan="2">Check validity of IEC 61215 certification and BOM.</td><td>Regular system inspections.</td></tr>
</table>

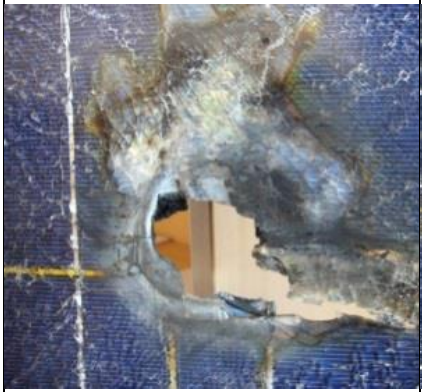
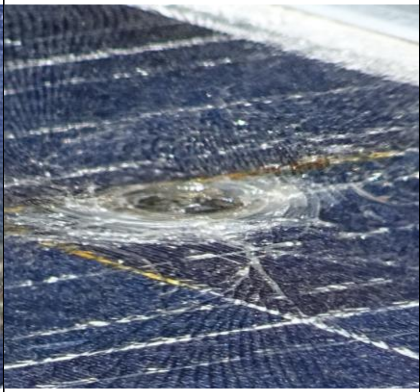
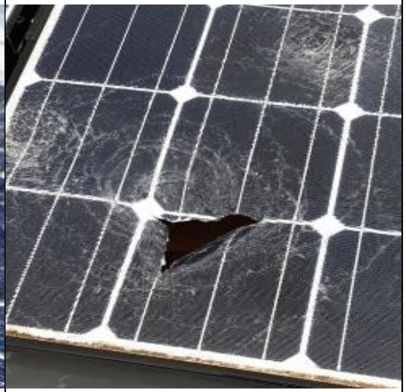
EXAMPLES (page1)			**PVFS 1-6vs.01**
Examples 1-2			
	Finger with white powder. [TUV Rheinland]	Fingerprint on a module with chalking. [TUV Rheinland]	
Severity	e 1	e 1	

<table>
<tr><td>Component
Defect</td><td colspan="5">Module
Burn marks</td><td>PVFS 1-7vs.01</td></tr>
<tr><td>Appearance</td><td colspan="6">Burn marks are visible with the naked eye as burnt, blackened area/s. The burn mark may lead to bubbling or melting of the polymeric encapsulant, and/or glass breakage or a hole in the backsheet. Burn marks on the backheet may be not visible from the front requiring an inspection with an IR camera if the back of the module is not accessible. They may however not be visible by IR inspection in case no further or ongoing heating occurs.</td></tr>
<tr><td>Detection</td><td colspan="6">VI, IRT, (EL)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="6">The defect is associated with parts of the module that became very hot because of production errors (e.g weak solder bonds, ribbon breakage, incomplete cell edge isolation, alignment errors, metal particles) and/or transportation/handling errors (e.g, cracked cells, damaged back-sheet) in combination with one or more operational factors (e.g. shadowing, open circuited bypass diodes, reverse current flows). Physical stress during PV module transportation, heavy snow loads, a lightning strike, thermal cycling, and/or hot spots by partial cell shading during long-term PV system operation forces mechanical weak(ended) cell/connection parts to break. Burn marks occur for example when a reverse current flow causes heating that further localizes the current flow, leading to a thermal runaway effect and the associated burn mark.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="6">Burn marks on interconnections are often associated with power loss, but if redundant electrical interconnections are provided, a failed solder bond may have negligible effect on the power output. If all solder bonds for one cell break, then the current flow in that string is completely blocked and an electric arc can result if the current cannot be bypassed by the bypass diode and the system operates at high voltage. Performance, reliability and safety are likely to be severely compromised. Such an arc can cause a fire if there happen to be flammable material around. If there is a question about whether the existence of the burn mark requires replacement of the module, an infrared image under illuminated and/or partially shaded conditions will quickly identify whether the area is continuing to be hot and/or whether current flow has stopped in that part of the circuit. Temperature difference between neighbouring cells should not be over 30 K. At this stage safety risk may still be not so high because the temperature of this hot spot cell does not increase to more than around 100 °C. Also edge isolation faults on the solar cell level are under normal conditions not problematic, but when the bypass diode is in open-circuit, the current is driven in reverse through the shunts of the solar cells and burns the encapsulation.</td></tr>
<tr><td>Safety:</td><td colspan="2">f e m f e m</td><td>Performance:</td><td colspan="2">1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules.</td><td colspan="2">Visual inspection before installation, commissioning of system with IRT.</td><td colspan="2">Regular system inspections.</td></tr>
</table>

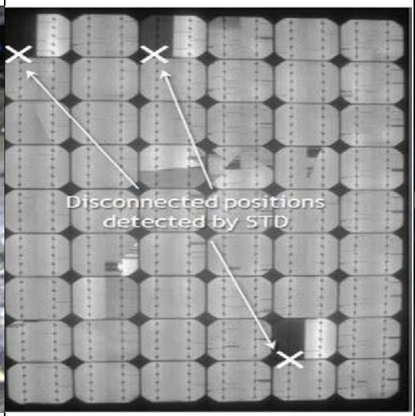
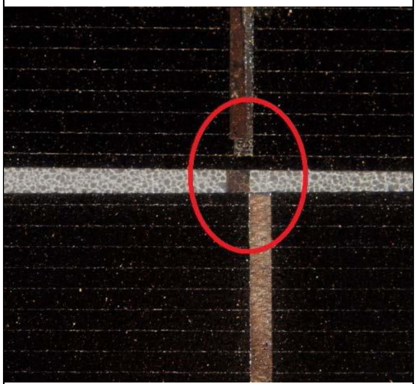
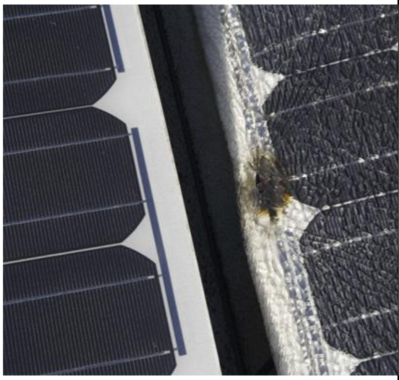
Examples 1-3			
	Burn mark at the backsheet with cracked backsheet. [37]	Burn marks at the backsheet due to heating along a busbar. [16]	Burn mark associated with overheating along the metallic interconnection (without backsheet damage). [16]
Severity	f e m | 5	f e m | 3 4 5	f e m | 2 3
Examples 4-6			
	Front and back side view of burn marks caused by open-circuited bypass diodes and current mismatch conditions (due to shading or cracked cells). [16]		Burn marks caused by defect bypass diodes or an interconnect failure in the junc. box. [16]
Severity	f e m	3 4 5	f e m | 3 4 5
Examples 7-9			
	Burn mark with broken glass caused by poor bussing ribbon soldering. [41] (s. also PVFS 1-8 and PVFS 1-8)	Burn mark due to intrinsic shunting caused by error in manufacturing process. [41]	Burn mark due to intrinsic shunting caused by error in manufacturing process. [41]
Severity	f e m | 3 4 5	f e m | 1 2 3	f e m | 1 2 3

<table>
<tr><td>Component
Defect</td><td colspan="3">Module
Glass breakage</td><td>PVFS 1-8vs.01</td></tr>
<tr><td>Appearance</td><td colspan="4">Glass is cracked locally or over the full area of the module. Glass breakage looks different depending on the type of glass and the origin of the glass breakage. Tempered glass or heat-treated float glass will shatter into small pieces, whereas annealed glass breaks into big pieces. Heat-treated glass stays in between.</td></tr>
<tr><td>Detection</td><td colspan="4">VI, IRT</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="4">Glass breakages of the front glass can be caused by heavy impacts such as hail or stones or other extreme mechanical stress onto the module frame due to external stresses or bad mounting. High temperatures (hot-spot or arc) can also break the glass. Annealed glass breaks also due thermal gradients or stress induced by the lamination process or cleaning of the modules. A relatively often seen failure in the field is glass breakage of frameless PV modules caused by the clamps. Glass/glass modules are more sensitive to glass breakage. The origin of the failure is, on the one hand, at the planning and installation stage either (a) poor clamp geometry for the module, e.g. sharp edges, (b) too short and too narrow clamps or (c) the positions, kind or number of the clamps on the module not being chosen in accordance with the manufacturer’s manual. The second origin which induces glass breakage could be excessively-tightened screws during the mounting phase or badly-positioned clamps. The glass of some PV modules may also break due to vibrations and shocks occurring during transportation or handling. Another reason for glass breakage comes from impact stresses on the glass edge. Sometimes vandalism or animal damage happens, the animals like goats like to climb on the PV modules, and birds may drop stone or other objects from the sky.</td></tr>
<tr><td>Production ■</td><td>Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="4">Module mechanical integrity is compromised when the glass is broken. Over time glass breakage leads to loss of performance due to cell and electrical circuit corrosion caused by the penetration of oxygen and water vapour into the PV module. Shattering of tempered glass usually also breaks the cells reducing the power of the module and increasing the risk of hot spots. Mechanical and electrical safety is thus compromised. Firstly, the insulation of the modules is no longer guaranteed, in particular in wet conditions. Secondly, glass breakage causes hot spots, which lead to overheating of the module. A module with a completely broken glass lead to current and power reductions in the whole string.</td></tr>
<tr><td>Safety:</td><td>f e m f e m</td><td>Performance:</td><td>1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td>Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td>All damaged modules have to be replaced.</td><td>Adequate transport procedures, installation and cleaning by trained personal, in case of higher snow or hail loads use of certified modules.</td><td colspan="2">Regular system inspections.</td></tr>
</table>

EXAMPLES (page1)			PVFS 1-8vs.01
Examples 1-3			
	Chipped glass at the corner. [38]	Glass breakage along the string interconnect ribbons due to weak manufacturing process. [SUPSI]	Glass breakage of tempered glass induced by a hot-spot. [SUPSI]
Severity	m 1	f m e m 2 3	f e m 3 4 5
Examples 4-6			
	Glass breakage caused by too tight screws. [16] (see also PVFS 3-1)	Glass breakage caused due to poor clamp design. [16]	Glass breakage caused due to poor clamp design. [1] (see also PVFS 3-1)
Severity	f m e m 2 3 4	f m e m 2 3 4	f m e m 2 3 4
Examples 7-9			
	Glass breakage through high temperature gradient and not tempered glass. [16]	Glass breakage of tempered glass induced by burn mark. [1] (see also PVFS 1-7 and PVFS 1-9)	Breakage of tempered glass. [1]
Severity	f e m 3 4 5	f e m 3 4 5	f e m 3 4 5

EXAMPLES (page2)			PVFS 1-8vs.01
Examples 10-12			
	Direct lightning stroke. [46]	Impact damage caused by a heavy object. [SUPSI]	Hail damage. [SUPSI]
Severity	f e m — 5	f e m — 5	f e m — 5

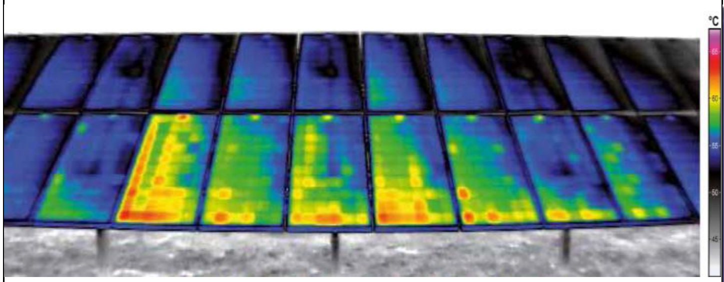
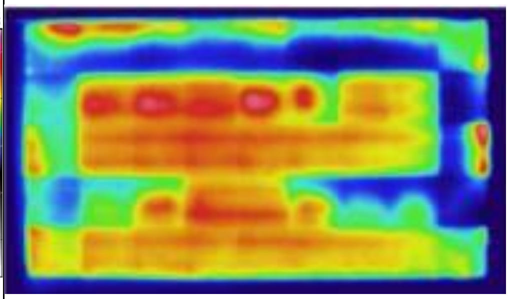
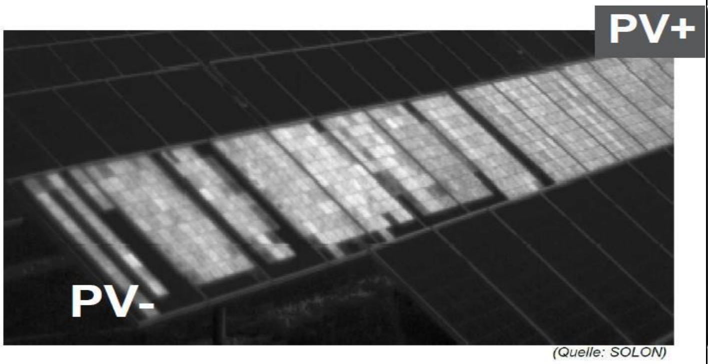
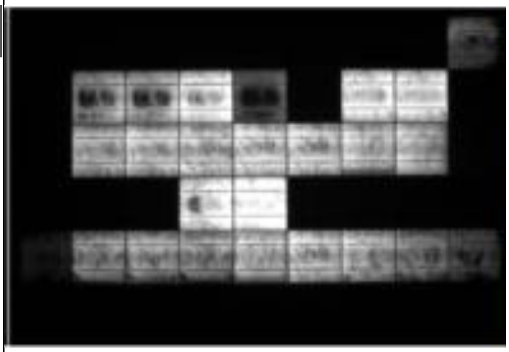
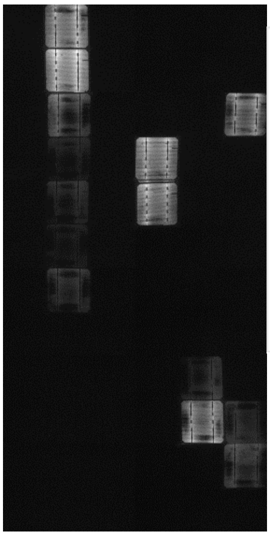
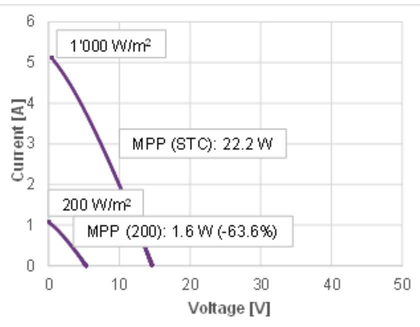
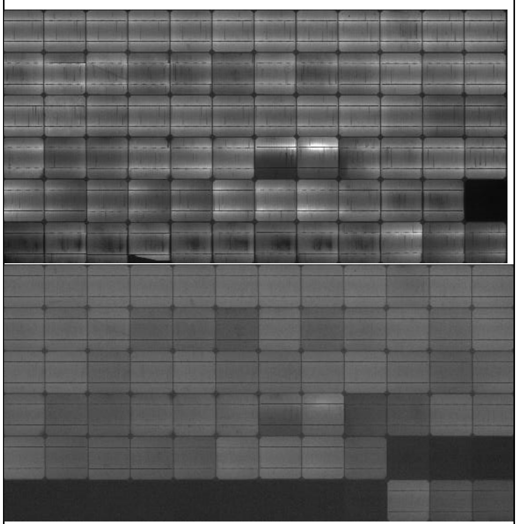
<table>
<tr><td>Component
Defect</td><td colspan="5">Module
Cell interconnection failure</td><td>PVFS 1-9vs.01</td></tr>
<tr><td>Appearance</td><td colspan="6">Weak or broken cell or string interconnection are not easy to see by the naked eye. The failure can be identified as dark region in the electroluminescence image where the failed interconnect would otherwise be collecting carriers or as a hot spot in the infrared image. In a progressed stage burn marks and glass breakage can occur.</td></tr>
<tr><td>Detection</td><td colspan="6">EL, IRT, STM, (VI)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="6">Typically, it is caused by the manufacturing process (e.g. poor soldering, misplacement of ribbons, too intense deformation of the ribbon kink, narrow distance between the cells) followed by thermomechanical stress or repetitive wind load caused by the outdoor operating environment. Electrochemical corrosion can be another cause for the degradation of interconnections.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation □</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="6">Poor interconnections (soldering bonds) lead to an increase of contact resistance, higher power dissipation and localized heating. Broken connections are often associated with power loss, but if redundant electrical interconnections are available, a failed connection may have negligible effect on the power output. Safety risk may be not so high until the temperature of the induced hot spot does not increase to more than around 100 °C. If all busbars of a cell are interrupted, then the current flow in that string is completely blocked and an electric arc can result if the current is not bypassed by the bypass diode and the system operates at high voltage. The safety risk depends on the durability of this bypass diode. A bypass diode, which is continuously active over days can be damaged and pass into open-circuit or short circuit state. As a result of an open circuited diode, the current goes through the failed cell string and generates heat at the disconnected position. Very high temperatures or an electric arc and may cause fire, open electrical conducting parts to the user and destroy the mechanical integrity of the module.</td></tr>
<tr><td>Safety:</td><td colspan="2">f e m f e m</td><td>Performance:</td><td colspan="2">1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules.</td><td colspan="2">Check validity of IEC 61215 certification and BOM.</td><td colspan="2">Regular system inspections.</td></tr>
</table>

EXAMPLES (page1)			PVFS 1-9vs.01
Examples 1-3			
	Zoom of a broken cell interconnect. [41]	EL image of a module with 3 cells with disconnected interconnect ribbons. [16]	Disconnected cell interconnect with delamination. [1]
Severity	f e — 2 3 4	f e — 2 3 4	f e — 2 3 4
Examples 4-6			
	Dislocation of interconnection ribbon. [37]	Poor soldering of string interconnect leading to burn mark and broken glass. [41] (see also PVFS 1-7 and PVFS 1-8)	Mirco arc which occur if the conductive glue on the string interconnect has an insufficient contact. [16]
Severity	f e — 1 2	f e m — 3 4 5	f e — 2 3 4

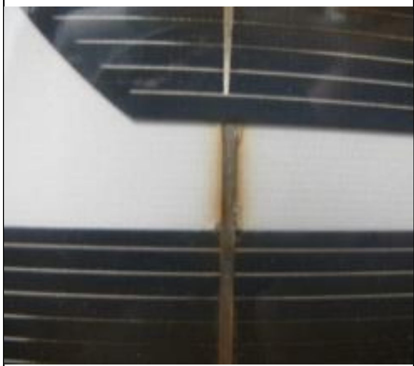
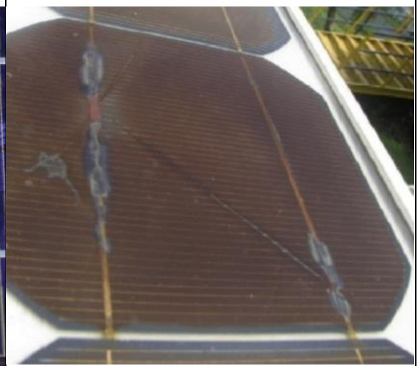
Component Defect	**Module** **Potential induced degradation (PID) (page1)**	**PVFS 1-10vs.01**
Appearance	A potential induced degradation (PID) is not directly visible by eye. It is recognisable as an overtime increasing power loss, which is easily observable only a few years after installation. Infrared thermography (IRT) imaging of operational PV modules in the direct sunlight is the most straightforward method for getting the evidence of PID degradation. Typical PID IRT patterns (warmer cells close to the bottom frame or patchwork patterns) and PV modules positioned close to one of the poles of the module string are strong indications for PID. The most efficient, but more complex and expensive detection method for PID is to take EL images. When taken at 1/10 of the rated current it can detect PID also in an early stage, before a power loss can be noticed. It's because in the early stage, the PID degradation is more pronounced at low light conditions. To quantify the performance loss, I-V measurements have to be performed on the affected string and/or modules. In an advanced stage secondary induced failures like **hot-spot's**, **yellowing** and/or **corrosion** can be sometimes observed.	
Detection	IV, EL, IRT, (MON)	
Origin	PID is a degradation mode induced by a high voltage stress with respect to ground. The occurrence of this failure depends on the magnitude of the voltage (number of serially connected PV modules per string) and the polarity of the electrical field build-up between the framing/glass surface and the solar cells. The last depends on the inverter typology (transformer), the grounding concept and cell technology. Modules with p-type cells degrade in negative polarity strings whereas modules with n-type cells in strings with positive polarity. PID degradation is more pronounced the higher the potential to which a single cell within a module or string is subjected. The PID effect is therefore stronger in cells that are located at the edges of the module (close to frame) and to the bottom of a string with an increase towards one end of the string. The degradation is further accelerated by temperature, humidity, rain (surface wetting), condensation and soiling. Two different types of PID are known for crystalline silicon modules: PID-p (**p**olarization) and PID-s (**s**hunting). The PID-p was observed for the first time in back contact cells within Sunpower modules. PID-p is caused by the build-up of negative surface charges on the cells, which results in a current loss. The PID-s is induced by leakage currents through the module's front glass and the encapsulation material. The flow of Na+ ions mainly from the glass into the cell leads to the creations of shunts. For both PID types, module and cell design has a fundamental influence if and how much a module is affected by PID. There are modules on the market which are designed to be PID resistant.	
	Production ■ | Installation ■ | Operation ■	
Impact	Yield losses of 20 percent and more within 1 year were observed in the past. The PID-s effect causes a reduction of I-V curve fill factor and output power. Short circuit is affected only in a very progressed state. Due to its catastrophic performance loss PID-s bears a high economic risk. PID-s is to some extent a reversible polarization effect and can therefore 'repaired' or omitted when detected in time. If detected too late the PV system can't be repaired and non-reversible damages has to be taken into account. The PID-p effect causes instead a significant reduction of short circuit current, open circuit voltage and power. PID-p can be fully regenerated by reversing the polarity of the bias potential. Up to now safety problems directly related to the PID are not reported, but hot spots and corrosion caused by the strong cell mismatch may cause later safety issues. The PID sensitivity of PV modules can be tested in the laboratory. Anti-PID insurance can be obtained, although many insurers need to be educated about the phenomenon for correct risk estimation and pricing.	
	Safety: | Performance: 2 3 4 5	

Component Defect	**Module** **Potential induced degradation (PID) (page2)**		**PVFS 1-10vs.01**
Mitigation	Corrective actions	Preventive actions (recommended)	Preventive actions (optional)
	How to proceed depends very much on the stage on which PID is detected. If detected in an early stage recovery is possible by applying a reverse voltage during night-time. Specific anti PID kits are available on the market promising a recovery of the lost power. As there is not a full guarantee that the recovery will be effective for the specific situation, it should be monitored or measured to see if the problem has been sufficiently solved. In the case of progressed PID without visible module damages, the recovery could need several months or even years suggesting in any case a replacement of all modules with modules tested to be PID resistant.	Modules tested for PID accord. IEC 62804-1 should be less prone to PID (verify that BOM corresponds!)	PID prevention at system level: The installation of an inverter with transformer can be considered as mitigation measure for the PID phenomenon. On the other hand, the trade-off with the inverter efficiency and the cost of the inverter must be taken into account. Anti-PID insurance.

EXAMPLES (page1) — PVFS 1-10vs.01

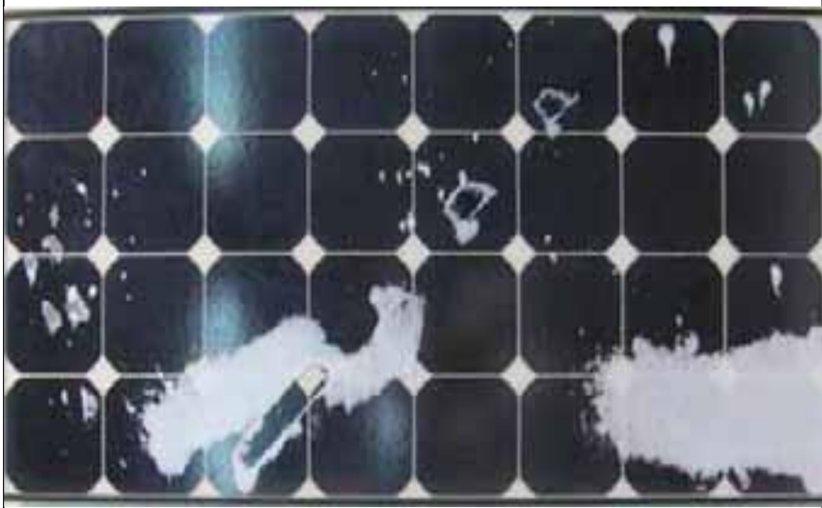
Examples 1-2				
	Strings with PID, detected with IR thermography. [16]		Dark IR thermography at I_{sc} for a module affected by PID. [16]	
Severity		2 3 4 5		2 3 4 5
Examples 3-4				
	Strings with PID, detected with EL imaging.		Electroluminescence image made at I_{sc} for a module affected by PID. [16]	
Severity		2 3 4 5		2 3 4 5
Examples 5-6	 			
	PID affected module with power loss of 89%, left: EL at 1.5 x I_{sc}, right: I-V curve of the same module at 1000 and 200 W/m2. [35]		PID affected module with power loss of 14%. top: EL at 1.5 x I_{sc}. bottom: EL of the same module at 0.2 x I_{sc}. [35]	
Severity		5		3

<table>
<tr><td>Component
Defect</td><td colspan="4">Module
Metallisation discolouration/corrosion</td><td>PVFS 1-11vs.01</td></tr>
<tr><td>Appearance</td><td colspan="5">The discolouration and/or corrosion of the cell metallisation and the interconnections is getting visible as a light yellow to dark brown to black discolouration of the electrical parts. Depending on the material combinations corrosion is furthermore noticeable by the presence of galvanic products that may appear powdery, white, light gray, and/or have a yellow, blue, or green tinge. The defect occurs typically at the solder bonds, on the cell gridlines/fingers or the cell/string interconnect ribbons. It is very often observed together with other failures like delamination and discolouration of the encapsulant and sometimes with burn marks. Under certain circumstances corrosion is more visible near cell edges. Dark areas at the cell borders of the EL images can here highlight the diffusion of moisture through the rear side of the module and the gaps between the cells and the subsequent front side cell corrosion starting from the edges.</td></tr>
<tr><td>Detection</td><td colspan="5">VI, (EL, IV)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="5">The corrosion/oxidation of the metallisation is caused by the presence of moisture and acidity in the encapsulant, as e.g. acetic acid, a degradation product of the mostly used encapsulant EVA or remaining crosslinker (peroxides). Acetic acid has a corrosive effect on the cell metallisation and the cell interconnect. The ingress of moisture caused by an ongoing delamination process leads together with the oxygen to a further acceleration of the corrosion. Corrosion can be caused by a poor manufacturing process (e.g residual crosslinker due to a too short lamination process; imperfections in cell soldering) or the choice of poor materials (low corrosion resistance of tin-based coating of copper ribbons, high water permeability of back sheet and/or encapsulant materials). Environmental factors can accelerate the corrosion (e.g ammonia, salt, humidity, temperature). For these reasons, corrosion is more frequent and severe under hot and humid climates or in agriculture or maritime environments. Discolouration can be also related to non-corrosive processes like a discolouration due to light-sensitive solder flux residues on the ribbon.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation □</td><td>Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="5">The metallisation, and/or interconnect, corrosion leads to an increased series resistance and therefore losses in module performance. The power loss is less pronounced for modules with metallisation discolouration without corrosion. The defect does not automatically pose a safety issue. Locally increased series resistance leads to current mismatch. If the mismatch is getting significant, it can trigger the bypass diode and cause further power loss of the PV module.</td></tr>
<tr><td>Safety:</td><td colspan="2"></td><td>Performance:</td><td>1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective action</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules.</td><td colspan="2">Check validity of IEC 61215 certification and BOM.</td><td>Regular system inspections.</td></tr>
</table>

EXAMPLES (page1)			PVFS 1-11vs.01
Examples 1-3			
	Discolouration due to corrosion or to light-sensitive flux residues on the ribbon.	Discolouration due to corrosion on the ribbon. [SUPSI]	String interconnect corrosion. [1]
Severity	1	1	1 2
Examples 4-6			
	Cell interconnect corrosion. [1]	Modules with light Ag finger oxidation after 5 years in the field. [41]	Severe oxidation/corrosion and burn marks on the Ag fingers, busbars, and interconnects of modules after 25 years. [41]
Severity	1 2	2	e 2 3 4
Examples 7-9			
	Corrosion seen as red, green and black discolouration in the string interconnect. [41]	Busbar corrosion and delamination at the edge. [SUPSI]	Glass/glass module showing delamination and subsequent corrosion. [1]
Severity	e e 2 3 4 5	e 3 4 5	e e 3 4 5

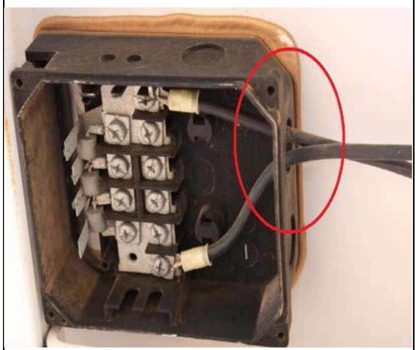
<table>
<tr><td>Component
Defect</td><td colspan="3">Module
Glass corrosion or abrasion</td><td>PVFS 1-12vs.01</td></tr>
<tr><td>Appearance</td><td colspan="4">The degradation of the glass front layer is getting visible as a homogenous or heterogeneous change in colour and transparency of the glass. The affected glass surface can appear hazy or milky and in some cases also rougher compared to the non-degraded module/module area. Increased susceptibility to soling could be observed.</td></tr>
<tr><td>Detection</td><td colspan="4">VI, (IV)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="4">To optimise the efficiency and appearance of a PV module most manufacturers apply some anti-reflective coatings (ARC), anti-soiling coatings (ASC) or multilayer coatings on the front of their modules. 1-3% more power can be obtained by these techniques respect to module with uncoated glass. Corrosion or abrasion of these layers can however, reduce or vanish the effectiveness of these coatings. Glass corrosion is caused by atmospheric humidity in combination with gases or particles present in the atmosphere (e.g. pollutants, salt, ammonia) and the glass. It happens for example when water (dew) dissolves some of the sodium ions from the top of the soda lime glass, leading to the production of an alkali base that can then corrode the glass silicate. Glass abrasion or corrosion can be also caused by inappropriate cleaning techniques (mechanical removal techniques, inappropriate cleaning agents) which damage or removes the coatings. Abrasion occurs mostly in the desert, due to the combination of wind, sand and dust which causes abrasion and frosting of the glass surface.

UV or voltage induced degradation effects can further accelerate the degradation of the coatings.</td></tr>
<tr><td>Production ■</td><td colspan="2">Installation ☐</td><td>Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="4">Corrosion or abrasion of the glass front layer lowers the transmission of the glass, leading to a power loss. The power loss is generally limited to a few percent and is saturating over time except in the case where the soiling susceptibility is significantly increased and larger losses can be observed. Operating and Maintenance (O&M) costs can be affected by this.</td></tr>
<tr><td>Safety:</td><td></td><td>Performance:</td><td>2 3 4</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td>Modules with a direct safety risk or a severity of 5 should be replaced. Depends on the level of performance loss. For extreme environments (e.g. near to mines, cement factories), evaluate cost-effectiveness of replacing modules with lost yield.</td><td colspan="2">Check validity of IEC 61215 certification and BOM, appropriate component selection in function of intended application.</td><td>Regular system inspections.</td></tr>
</table>

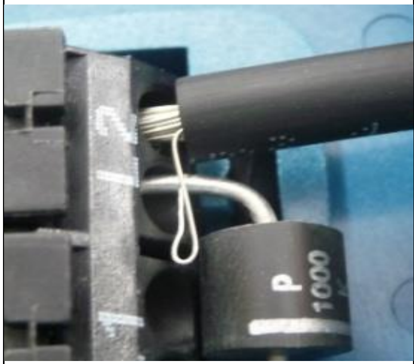
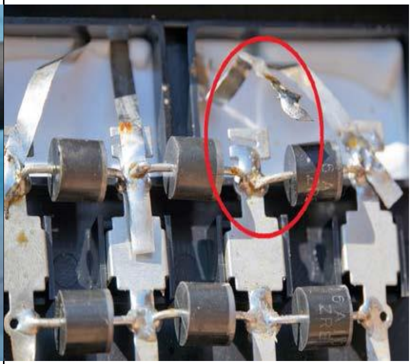
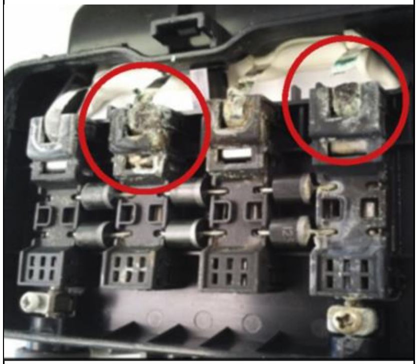
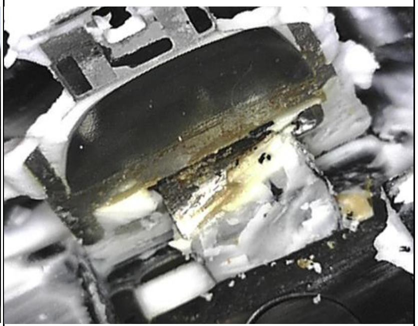
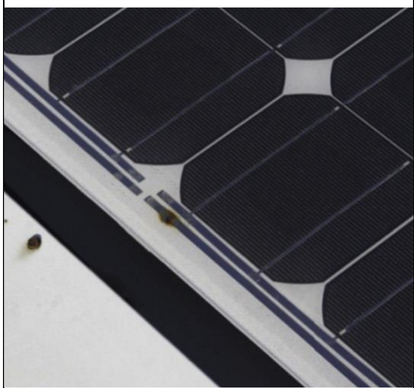
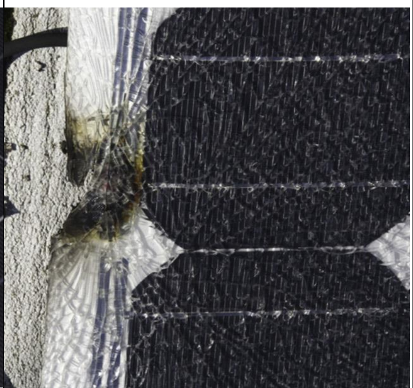
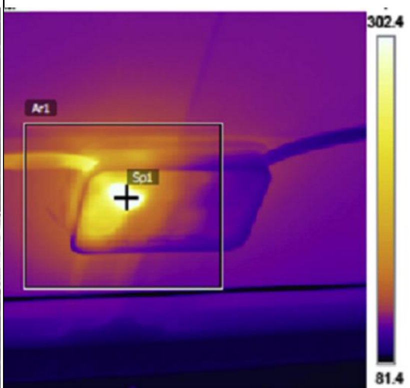
EXAMPLES (page1)			PVFS 1-12vs.01
Examples 1-3			
	Zoom of module with hazy glass (homogenous discoloration) due to surface corrosion. [45]	Zoom of module with hazy glass (heterogenous discoloration) due to surface corrosion. [43]	Hazy glass due to glass corrosion close to frame. [44]
Severity	2	2 3	2
Examples 4-5			
	Glass corrosion on the front of a mono-Si back-contact module after damp heat 90/90 testing. [42]		Glass corrosion. [46]
Severity	3		3 4

<table>
<tr><td>Component
Defect</td><td colspan="5">Module
Defect or detached junction box</td><td>PVFS 1-13vs.01</td></tr>
<tr><td>Appearance</td><td colspan="6">The junction box housing and lid appears either defect (weathered, brittle, cracked, warped, melted or burned) and/or detached (open or loose lid, shifted or detached junction box from backsheet). The sealant/adhesive material with which the junction box is attached to the back-sheet can be weathered or appear as yellowed. The sealing components/material around the wire entrance or the lid can be damaged (squeezed, broken, brittle) or completely missing.</td></tr>
<tr><td>Detection</td><td colspan="6">VI</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="6">Junction box detachment results from poor fixing of the junction box to the backsheet or use of low quality adhesive. Acrylic or PE Foam tapes were used as junction box attachment material in early years, but they frequently loss stickiness at low temperature and result in detachment. Use of inadequate IP rating junction box may cause water intrusion and subsequent failure. Opened or badly closed j-boxes may due to poor manufacturing process or air pressure caused by high temperature for boxes with no exhaust path. Delamination near a junction box can cause it to become loose. Improper handling or mounting of the modules can be also the cause of damages the j-box, like pulling modules up on the cables before mounting, or missing cable fixing or usage of too short cabling to interconnect modules to a string, causing frequent or permanent mechanical stress on the j-boxes.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="6">A defect or detached junction box is causing humidity ingress with corrosion of the interconnections, leading to performance losses and increasing risk of electrical arcing and subsequent initiation of fire. Furthermore, a loose junction box is putting mechanical stress on the contacts within the junction box, with the risk of breaking them and exposing persons to active electrical components.</td></tr>
<tr><td>Safety:</td><td colspan="2">f e f e</td><td colspan="2">Performance:</td><td>1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced or repaired. Regular inspections should be done to monitor the status of the not replaced modules.</td><td colspan="2">Check validity of IEC 61215 certification and BOM.

Ground fault detection by inverter or other devices at all time.</td><td colspan="2">Regular system inspections.</td></tr>
</table>

Examples 1-3			
	Poorly bonded junction box on the backsheet. [16]	Open junction box in the field. [41]	Detached junction box from backsheet. [SUPSI]
Severity	f e — 1	f e — 1 2 3 4 5	f e — 1 2 3 4 5
Examples 4-5			
	Left: Missing junction box lid sealing with corrosion of contacts. Right: Good junction box sealing. [45]		Missing seal or strain relive of module cables, improper cable inlet. [37]
Severity	f e	1 2 3 4 5	f e — 1 2 3 4 5
Examples 6-7			
	Melted junction box. [TUV Rheinland]	Burned junction box caused by corroded contacts within the junction box. [TUV Rheinland]	
Severity	f e — 5	f e — 5	

Component Defect	**Module** **Junction box interconnection failure**		**PVFS 1-14vs.01**
Appearance	Not connected, broken, burned, corroded or short circuited parts within the junction box. It can involve solder joints, wires, bypass diodes or tabbing ribbons. The interconnection failure itself could be hidden by the potting material in the junction box and be visible only by removing the potting material. The material can appear as degraded (yellowed, browned, burned or bubbled) due to the heat or arcing occurring in the junction box.		
Detection	IRT, (VI, IV, VOC)		
Origin	Bad contacts or moisture ingress may be the cause of interconnection failures in the junction box. Contacts are either soldered, screwed or inserted (mechanical spring clamping). Bad soldering contacts are caused by low soldering temperature (cold solder point) or chemical residuals of the previous production process on the solder joints. Bad mechanical contacts are caused by loose clamping or screws. Mechanical contacts can get loose due to the thermal cycling of day and night and seasonal changes. Moisture ingress in bad or damaged junction boxes (e.g. adhesion loss, brittled, cracked, missing seal at wire entrance or junction box housing) leads to corrosion of the contacts. Delamination near the junction box can cause it to become loose, putting mechanical stress on the contacts within the junction box and breaking them.		
	Production ■	Installation □	Operation ■
Impact	Bad contacts or **corrosion** can cause a high resistance and consequent heating in the junction box. Resistive heating can moreover result in **discolouration** and **burn marks** in the encpasulant/backsheet behind and around the junction box and to **glass breakage**. In the worst case interconnection failures causes a short circuit or internal **arcing** within the j-box. The heat can be detected with a IR camera. In addition to the visual defects, interconnect failures can also lead to significant power losses, which can be detected by measuring the V_{oc} of a module or a string. The measurement can be affected by changing mechanical or thermal stress conditions. Interconnect failures are particularly dangerous because the arcing can initiate fire.		
	Safety: f f e m	Performance:	1 2 3 4 5
Mitigation	Corrective actions	Preventive actions (recommended)	Preventive actions (optional)
	Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules.	Check validity of IEC 61215 certification and BOM. Ground fault detection by inverter or other devices at all time.	Testing of modules with mobile test centre before installation, regular system inspection, installation of arc detection tool.

Examples 1-3						
	Junction box with poor wiring. [16]		Detached tabbing ribbon due to bad soldering. [16]		Corrosion failure due to water soaking of the IP65 rated Jbox. [41]	
Severity	f	5	f	5	f	2 3 4 5
Examples 4-6						
	Jbox failure due to poor electric connection. [41]		Evidence of loose screw connection inside Jbox with browning of pottant. [41]		Cold soldering of module bussing ribbon to the Jbox connection terminal pad with minor browning of pottant. [41]	
Severity	f e m	3 4 5	f	2 3 4 5	f	2 3 4 5
Examples 7-9						
	Overheating due to the poor Jbox interconnect leading to light discoloration and burn mark on front and back side. [41]		Overheating due to the poor Jbox interconnect leading to burn mark and glass breakage. [41]		IR imaging of a hotspot Jbox due to loose electric connection inside. [41]	
Severity	f e m	3 4 5	f e m	3 4 5	f e m	3 4 5

<table>
<tr><td>Component
Defect</td><td colspan="4">Module
Missing or insufficient bypass diode protection</td><td>PVFS 1-15vs.01</td></tr>
<tr><td>Appearance</td><td colspan="5">Missing, disconnected, inverted, damaged, open circuited or short circuited bypass diode.</td></tr>
<tr><td>Detection</td><td colspan="5">BYT, (IV, IRT, EL, STM)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="5">Bypass diodes fail either because they are undersized or because they are exposed to high voltages due to lightning strikes or other high voltage events. In addition to these two reasons, the diodes have a certain ppm of failure rate, that is the nature of the component. For diodes working constantly at high temperatures this failure rate increases. Typically, Schottky diodes are used as bypass diodes in PV modules, but they are very susceptible to static high voltage discharges and mechanical stress. Two main failure modes are observed with bypass diodes: open circuit or short circuit. Short circuit condition occurs when the bypass diode is physical shortened in the junction box, it is mounted the wrong way around or when it has been exposed to high voltages like lightning strikes or static electricity. Open circuit condition occurs when a diode is simply missing, it is not properly connected, a strong current damaged the diode, or it is undersized and not resisting to a continuous current flow.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation □</td><td>Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="5">Bypass diodes are mainly used to reduce the power loss caused by partial shading on the PV module and to avoid the reverse biasing of single solar cells higher than the allowed cell reverse bias voltage of the solar cells. In the case of an open circuited diode no current is flowing through the bypass diode and a cell can be reversed with a higher voltage than it is designed for the cell and may evolve hotspots that may cause browning, burn marks or, in the worst case, fire. The problem is that the failure will be not detected until the module is not exposed to these risks. A short circuited bypass diode will continuously lower the power production of the module but also of other modules within its string by causing a shift off of their maximum power point. Bypass diode failures sometimes cause the junction box to deform or even burnt due to heat dissipated in the junction box. When the junction box or backsheet are burnt through, the safety issues like leakage current may follow.</td></tr>
<tr><td>Safety:</td><td>f</td><td colspan="2">Performance:</td><td>1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules.</td><td colspan="2">Check bypass diode dimensioning, commissioning of system with IRT.</td><td>Testing of module bypass diodes with mobile test centre before installation. Regular IRT inspections.</td></tr>
</table>

<table>
<tr><td>Component
Defect</td><td colspan="2">Module
Not conform power rating</td><td>PVFS 1-16vs.01</td></tr>
<tr><td>Appearance</td><td colspan="3">The STC output power of a brand new module is below a specified tolerance limit or the minimum nameplate output power is not clearly specified by the manufacturer.</td></tr>
<tr><td>Detection</td><td colspan="3">IV, (MON)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="3">Deviations of the measured power of a single module respect to the name plate power depends on the product variability, manufacturing quality, the labelling policy and the measurement uncertainty. The quality of cells (e.g. LID susceptibility) together with the binning method applied in production for the reduction of mismatch losses, has a significant impact on the product variability. The deviations in the measurement in the factory comes from several sources of uncertainty, for example the environment temperature, measured module temperature, calibration of the solar simulation, maintenance of the reference module, measurement equipment, connectors and cables. According to the international standards, the power rating has to take into account any technology related initial degradation effects (for c-Si see FS 1-17). This means that after a first exposure to light the output power of a new module has still to be within the rated power tolerance. The measurement uncertainty of the test laboratory performing the STC performance test has therefore to be taken into account. The modules have to be stabilised according the procedure described in IEC 61215-2:2021. Technology specific test requirements are described in IEC 61215-1-1:2021 to IEC 61215-1-4:2021. Depending on the technology, a maximum allowable measurement uncertainty is defined for the verification of power ratings. For c-Si modules it is specified as 3%. A PV module is considered to be conform to the IEC61215 standard, when following criterion (gate 1) is fulfilled:

$$P_{max}(Lab)\cdot\left(1+\frac{\frac{1.65}{2}|m_1|[\%]}{100}\right)\geq P_{max}(NP)\cdot\left(1-\frac{|t_1|[\%]}{100}\right)$$

P_{max} (Lab): measured maximum STC power of each module in stabilized condition
P_{max} (NP): minimum rated nameplate power of each module without rated production tolerances
m_1: measurement uncertainty in % of laboratory for P_{max} (expanded combined uncertainty (k = 2)
t_1: manufacturer's rated lower production tolerance in % for P_{max}

The minimum nameplate power rating, $P_{max}(NP)$ and tolerance t_1 has to be derived from the nameplate or data sheet values. If the $P_{max}(NP)$ derived from the datasheet is different from the nameplate value, the module can be considered to be not conform. If the tolerance is not stated on the nameplate or the datasheet, then t_1 = 0. If the tolerance is not reduced to a single value on the nameplate or data sheet (for example, if multiple tolerances or measurement uncertainty components are specified) the smallest number shall be utilized.</td></tr>
<tr><td>Production ■</td><td>Installation ☐</td><td>Operation ☐</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="3">A non-conform STC power rating is not a real module failure, as it causes no degradation or safety issue, but it has a negative impact on the lifetime energy yield and financial return. An incorrect estimation of the installed STC power has a direct impact on the energy yield predictions and investor expectations.</td></tr>
<tr><td>Safety:</td><td colspan="2">Performance: 1 2 3</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td>Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td>Confirm underperformance through an accredited PV test laboratory. Claim for missing power.</td><td>Verify power warranties and data sheet conformity, purchase modules from trusted manufacturers.</td><td>Independent third party testing of samples at factory gate and/or arrival on site. Signature of a contractual agreements.</td></tr>
</table>

Examples 1

a)

Product Z300W

Maximum power (P_{max})	300 W ±3 %
Maximum power voltage (V_{mp})	37 V
Maximum power current (I_{mp})	8,1 A
Open circuit voltage[a] (V_{oc})	45,9 V
Short circuit current[a] (I_{sc})	8,9 A
Maximum DC system voltage	1 000 V

[a] +5 % / –0 % tolerance

Product Z series
Electrical Data at STC

Peak power watts ±3 % - P_{max} (W)	300	305	310
Maximum power voltage - V_{mp} (V)	37	37,2	37,5
Maximum power current (I_{mp}) (A)	8,1	8,2	8,27
Open circuit voltage[a] - V_{oc} (V)	45,9	45,9	45,9
Short circuit current[a] - I_{sc} (A)	8,9	8,92	8,98
Module efficiency - η_m (%)	14	14,2	14,4

[a] ±5 % / –0 % tolerance on I_{sc} and V_{oc}

P_{max} (NP) = 300 W; t_1 = 3 %
V_{oc} (NP) = 45,9 V; t_2 = 5 %
I_{sc} (NP) = 8,9 A; t_3 = 5 %

b)

Product X300W

Maximum power (P_{max})	296 to 300 W
Maximum power voltage (V_{mp})	37 V
Maximum power current (I_{mp})	8,1 A
Open circuit voltage[a] (V_{oc})	45,9 V
Short circuit current[a] (I_{sc})	8,9 A
Maximum DC system voltage	1 000 V

[a] ±4 % production tolerance

Product X series
Electrical Data at STC

Peak power watts[a] - P_{max} (W)	296 to 300	301 to 305	306 to 310
Maximum power voltage - V_{mp} (V)	37	37,2	37,5
Maximum power current (I_{mp}) (A)	8,1	8,2	8,27
Open circuit voltage[a] - V_{oc} (V)	45,9	45,9	45,9
Short circuit current[a] - I_{sc} (A)	8,9	8,92	8,98
Module efficiency - η_m (%)	14	14,2	14,4

[a] ±4 % production tolerance

P_{max} (NP) = 296 W; t_1 = 0 %
V_{oc} (NP) = 45,9 V; t_2 = 4 %
I_{sc} (NP) = 8,9 A; t_3 = 4 %

If t_1 is not specified, it is taken to be 0.

c)

Product Y300W

Maximum power (P_{max})	300 W ±3 % / -0
Maximum power voltage (V_{mp})	37 V
Maximum power current (I_{mp})	8,1 A
Open circuit voltage[a,b] (V_{oc})	45,9 V
Short circuit current[a,b] (I_{sc})	8,9 A
Maximum DC system voltage	1 000 V

[a] ±2 % measurement uncertainty
[b] ±10 % tolerance on I_{sc} and V_{oc}

Product Y series
Electrical Data at STC

Peak power watts - P_{max} (W)	300	305	310
Power output tolerance (%)	-0 / +3	-0 / +3	-0 / +3
Maximum power voltage - V_{mp} (V)	37	37,2	37,5
Maximum power current (I_{mp}) (A)	8,1	8,2	8,27
Open circuit voltage[a,b] - V_{oc} (V)	45,9	45,9	45,9
Short circuit current[a,b] - I_{sc} (A)	8,9	8,92	8,98
Module efficiency - η_m (%)	14	14,2	14,4

[a] ±2 % measurement uncertainty
[b] ±10 % tolerance on I_{sc} and V_{oc}

P_{max} (NP) = 300 W; t_1 = 0 %
V_{oc} (NP) = 45,9 V; t_2 = 2 %
I_{sc} (NP) = 8,9 A; t_3 = 2 %

t_2 is not reduced to a single value. Thus, the smaller value is chosen. The same situation exists for t_3.

d)

Product T300W

Maximum power (P_{max}) Power selection (±5 W)	300 W
Maximum power voltage (V_{mp})	37 V
Maximum power current (I_{mp})	8,1 A
Open circuit voltage (V_{oc})	45,9 V
Short circuit current (I_{sc})	8,9 A
Maximum DC system voltage	1 000 V

±3 % tolerance on P_{max}, I_{sc}, V_{oc}

Product T series
Electrical Data at STC

Peak power watts[a] - P_{max} (W)	300	310
Maximum power voltage - V_{mp} (V)	37	37,5
Maximum power current (I_{mp}) (A)	8,1	8,27
Open circuit voltage[a] - V_{oc} (V)	45,9	45,9
Short circuit current[a] - I_{sc} (A)	8,9	8,98
Module efficiency - η_m (%)	14	14,4

[a] ±3 % tolerance on P_{max}, I_{sc}, V_{oc}

Fails to meet requirements of IEC 61215-1 5.2.2. Lower edge of power bin is 295 W on nameplate, but is 300 W on datasheet.

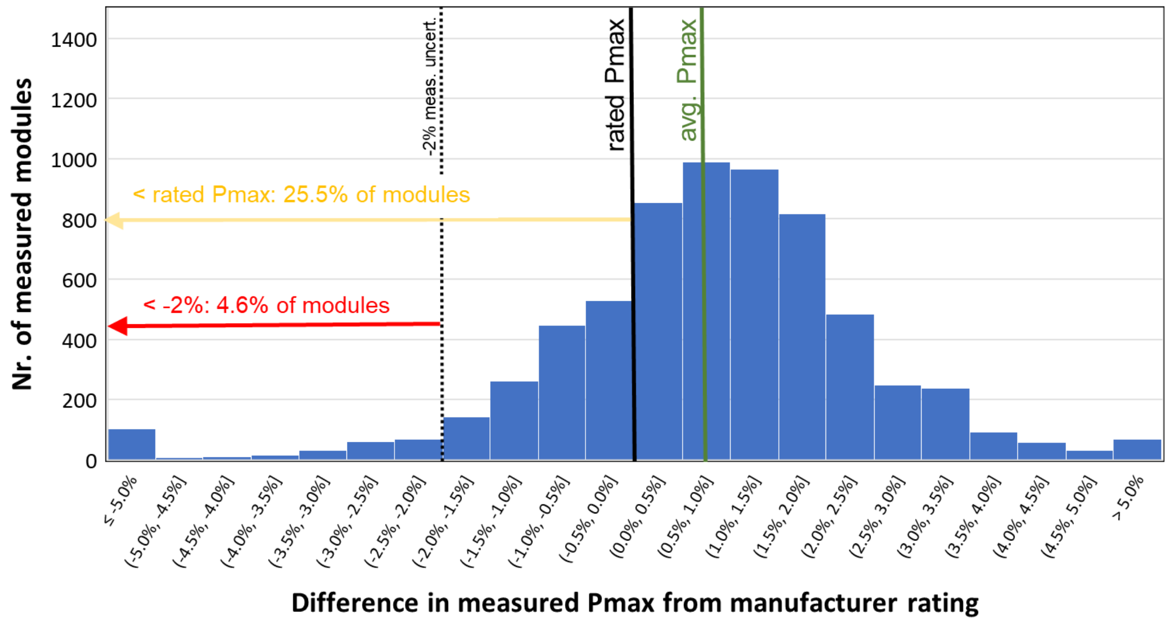
Example of a hypothetical conform (a-c) name plate and datasheet values with on the right the accord. IEC 61215-1:2021 derived rated values and tolerances in comparison to a hypothetical example of a not conform STC rating (d). [IEC 61215-1:2021]

Severity		NA

EXAMPLES (page2)	PVFS 1-16vs.01

Examples

2



Statistical analysis done by Eternalsun on around 6500 new modules with 96 different PV module types from 29 different manufacturers. [35] Considering the measurement uncertainty of +/-2% a total of 4.6% of the modules are below the gate 1 limit defined by the IEC 61215 standard. [IEC 61215-1:2021]

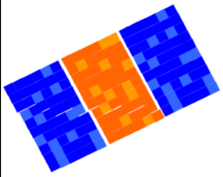
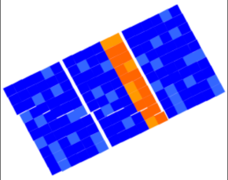
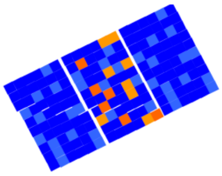
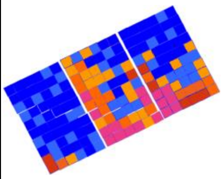
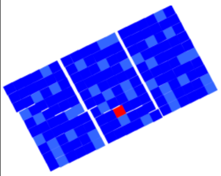
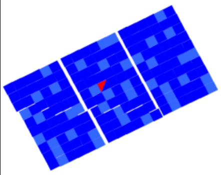
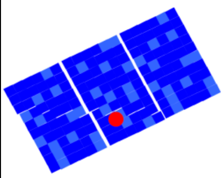
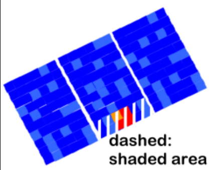
Note: In case of a measurement uncertainty of +/-5% none of the PV modules would fail, but it would be not conform to the IEC 61215 standard prescribing a maximum measurement uncertainty for c-Si modules of +/-3%.

Severity		1 2

<table>
<tr><td>Component
Defect</td><td colspan="3">Module
Light induced degradation in c-Si modules (LID/LeTID)</td><td>PVFS 1-17vs.01</td></tr>
<tr><td>Appearance</td><td colspan="4">Light induced degradation in crystalline silicon modules is recognisable mainly as a drop in STC output power, but also short circuit current and open circuit voltage, within the initial lifetime of a PV system. It isn't correlated with any visual defect or other failure modes. Increasing non-uniformity of electroluminescence images (patchwork pattern) can in some cases highlight an ongoing degradation process.</td></tr>
<tr><td>Detection</td><td colspan="4">IV, (EL, IRT)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="4">Two different light induced degradation effects are known: LID (light induced degradation) and LeTID (light and elevated temperature induced degradation). Both degradation modes occur at cell level, but the physical mechanism staying behind them are different. The first is related to the concentration of boron and oxygen in the cells, whereas the second one is probably correlated to the concentration of hydrogen in the cell, but the mechanisms are still not fully understood. Mainly p-type multi and mono crystalline silicon modules are affected. High-efficiency cell technologies that use n-type wafers, such as n-type PERC, HJT, or n-PERT seem to be much less or not at all concerned by these two degradation effects. LID occurs only within the first days of exposure to the sun and is limited to 1-3%, whereas LeTID is in a more severe and long-term light induced degradation mechanism. LeTID was observed for the first time with the introduction of PERC modules on the market. The degradation can reach up to 10% and sum-up with the LID loss. It occurs only at elevated temperatures above 50 °C. The speed with which the degradation occurs depends on the average module temperature and is therefore strongly site dependent. The time frame in which it occurs is in the order of magnitude of years. Once the full degradation is reached the modules can regenerate, recovering the lost power. This process is however very slow and also climate dependent. The lost power may even not recover over the typically expected 25-year lifetime of a module. There exist approaches of accelerated regeneration of LeTID-sensitive modules in the field, but they are not very user-friendly. Over the last years always more manufacturers adapted their cell production process to stabilise the cells in-line. Different industrial approaches exist for the mitigation of LeTID and depending on the methodology the degradation rates, even if reduced, can differ from one manufacturer to the other and range from 1-4%.</td></tr>
<tr><td>Production ■</td><td>Installation □</td><td colspan="2">Operation □</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="4">LID or LETID causes no safety problems, but it has a negative impact on the lifetime energy yield and financial return. An under-estimation of the initial degradation has a direct impact on the energy yield predictions and investor expectations. LID is less critical for the investors, because it is generally less severe and it is taken into account by the manufacturers when labelling the modules and defining the first year warranty, whereas a high LeTID degradation rate and the difficulty to predict the trend over time is much more critical for manufacturers' warranties and system owners. The sensitivity of PV modules to LeTID can be tested in the laboratory. Serious LID above 10% degradation may result in hotspot and can be detected by IR camera, it happened mainly to the cells produced when PERC were just commercialized and no mitigation of LID in the manufacturing process was available.</td></tr>
<tr><td>Safety:</td><td></td><td>Performance:</td><td>2 3</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td>Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td>Confirm underperformance through an accredited PV test laboratory. Claim for missing power.</td><td>Verify power warranties. Verify the use of LeTID stable cells by module manufacturer.</td><td colspan="2">Request test reports with % power loss for realistic estimations. Stipulate a contractual agreement on tolerated loss. Test individual modules. Verify BOM (cell type).</td></tr>
</table>

<table>
<tr><td>Component
Defect</td><td colspan="4">Module
Insulation failure</td><td>PVFS 1-18vs.01</td></tr>
<tr><td>Appearance</td><td colspan="5">A module with bad insulation between its current carrying parts and the frame (or the outside world) are not directly visible by eye. An unequivocally detection is only possible through a measurement of the insulation resistance of the module under dry (≥40 Mohm/m²) or better humid/wet conditions. It can be sometimes deduced by the presence of visual defects which can potentially lead to insulation problems. Under certain circumstances like after a rain fall or in the early morning when the PV modules are covered by dew, this kind of defect is detected by the inverter (low insulation fault) or the inverter is switching off when the resistance value falls below a certain limit.</td></tr>
<tr><td>Detection</td><td colspan="5">INS, (MON)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="5">Insulation failures can have different causes. It can occur in the design/production phase of a module, due to solar cells too closely positioned to the frame or to material weaknesses like the use of inadequate encapsulation or backsheet materials or a poor lamination process. In the installation phase it can be caused by mechanical damages of the module, whereas in the operational phase it is generally caused by catastrophic events or due to a delamination process close to the edge of the module or water ingress or condensation in the junction box. Modules with failed or skipped insulation test in production due to an insufficient quality assurance could be also the origin of the problem. Various module failures are at the origin of an insulation failure: backsheet and encapsulant delamination, backsheet damages, burn marks, glass breakage.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation ■</td><td>Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="5">A low insulation resistance at module level itself does not lead to a performance loss, until an inverter failure occurs. The presence of an electrical leakage current to the frame can become a safety hazard exposing persons to a potential electric shock hazard. Touching non-insulated parts of the string or frame can cause severe injury, without the use of safety gear and safe measuring instruments.</td></tr>
<tr><td>Safety:</td><td>e</td><td>Performance:</td><td colspan="2">1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced. Regular inspections should be done to monitor the status of the not replaced modules. In case of individual module testing all modules which failed the insulation and/or wet-leakage test should be replaced.</td><td colspan="2">Check validity of IEC 61215 certification and BOM, commissioning of system with IRT, ground fault detection by inverter or other devices at all time.</td><td>Regular system inspections, Insulation testing of modules with mobile test centre before installation.</td></tr>
</table>

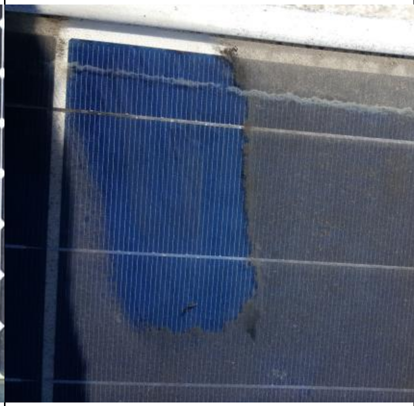
<table>
<tr><td>Component
Defect</td><td colspan="4">Module
Hot-spot (thermal patterns)</td><td colspan="2">PVFS 1-19vs.01</td></tr>
<tr><td>Appearance</td><td colspan="6">A hot-spot is a thermal abnormality such as a local overheating or a thermal pattern which deviates from the normal behaviour of a module. It can be detected only by imaging techniques such as e.g. infrared thermography. Hot spots are not visible by the naked eye until they lead to irreversible hot-spot damages like e.g. local yellowing, burn marks, glass or cell breakage. The position, size, intensity and pattern of the hot-spot/s depends on the origin and progress of the failure, but also under which conditions the module is operating (shading, load and irradiance level). A temperature gradient of smaller than 10 K is considered as normal and is not a hot spot or thermal abnormality.</td></tr>
<tr><td>Detection</td><td colspan="6">IRT, (VI)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="6">A hot spot may be caused by shading, soiling, severe cell mismatch, damaged cells (e.g. cell crack and shunted cells), glass breakage, poor electrical connections (e.g. bad or broken solder joints, short circuits, cell interconnect ribbon failures), or low quality solar cell or module production. When such a condition occurs, the affected cell or group of cells is forced into reverse bias and will dissipate power, which can cause overheating. If the power dissipation is high enough or localised enough, the reverse biased cell(s) can overheat resulting in melting of solder, deterioration of the encapsulant and/or backsheet and glass breakage. To reduce the effects of hot spots bypass diodes are connected in parallel to the cells. Well-dimensioned and correctly working bypass diodes helps in reducing hot spot damages from occurring.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="6">Hot-spots do not always lead to a power loss. Due to normal tolerances in cell sorting and module production, thermal abnormalities of less than 10% of the recorded modules usually do not indicate a special quality issue. Most of the times modules with a single hot cell have an insignificant power loss. Power reduction becomes significant when a permanently activated bypass diode leads to a minimized power output of the affected solar cell string and thus to a reduction of the total module power output. The impact on system level is only visible when more modules are affected. Very high losses can occur when PID is the origin of the warmer cells. Module safety is affected when the overheating causes critical module damages or when it leads to a fire. A temperature gradient in a range of 10 K to 20 K is considered as unproblematic if it is not increasing during the operation of the PV power plant. Temperature gradients above 20 K are expected to cause power losses; in extreme cases, the material compound may even degrade, resulting in a safety issue during maintenance work. Further increase in temperature gradient are expected during the operation phase of the PV power plant if the modules are not replaced. If PV modules of a system are not cleaned and maintained at a suitable frequency, high temperatures of some cells or modules may occur due to bird droppings or power mismatch for a long time which may lead to module damage. At a later stage it might be difficult to evaluate whether the damage was caused by quality problems or by missing cleaning or maintenance procedures.</td></tr>
<tr><td>Safety:</td><td colspan="2">f</td><td>Performance:</td><td colspan="2">1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td colspan="2">Modules with a direct safety risk or a severity of 5 should be replaced or repaired. If more than 10% modules show thermal abnormalities, the reason for that behaviour should be evaluated and respective corrective actions should be implemented.</td><td colspan="2">Commissioning of system with IRT.</td><td colspan="2">Regular system inspections.</td></tr>
</table>

Pattern	Description	Origin	Performance	Remarks	Safety	Power
	One module warmer than others	Module is open circuited - not connected to the system	Module normally fully functional	Check wiring		5
	One row (sub-string) is warmer than other rows in the module	Short circuited (SC) or open sub-string - Bypass diode SC, or - Internal SC	Sub-strings power lost, reduction of V_{oc}	May have burned spot at the module	f	5
	Single cells are warmer, not any pattern (patchwork pattern) is recognized	Whole module is short circuited - All bypass diodes SC or - Wrong Connection	Module power drastically reduced, (almost zero) strong reduction of V_{oc}	Check wiring	f	5 (see PVFS 1-15)
	Single cells are warmer, lower parts and close to frame hotter than upper and middle parts.	Massive shunts caused by potential induced degradation (PID) and/or polarization	Module power and *FF* reduced. Low light performance more affected than at STC	- Change array grounding conditions - recovery by reverse voltage		2 3 4 5 (see PVFS 1-10)
	One cell clearly warmer than the others	- Shadowing effects - Defect cell - Delaminated cell	Power decrease not necessarily permanent, e.g. shadowing leaf or lichen	Visual inspection needed, cleaning (cell mismatch) or shunted cell	f	1 2 3 4 5 (see also PVFS 1-1, 1-3, 3-3)
	Part of a cell is warmer	- Broken cell - Disconnected string interconnect	Drastic power reduction, *FF* reduction		f	2 3 4 5 (see also PVFS 1-1, 1-7, 1-9)
	Pointed heating	- Artifact - Partly shadowed, e.g. bird dropping, lightning protection rod	Power reduction, dependent on form and size of the cracked part	Crack detection after detailed visual inspection of the cell possible	f	2 3 4 5 (see also PVFS 1-1, 1-7, 1-9)
	Sub-string part remarkably hotter than others when equally shaded	Sub-string with missing or open-circuit bypass diode	Massive *Isc* and power reduction when part of this sub-string is shaded	May cause severe fire hazard when hot spot is in this sub-string	f	2 3 4 5 (see also PVFS 1-15, 3-3)

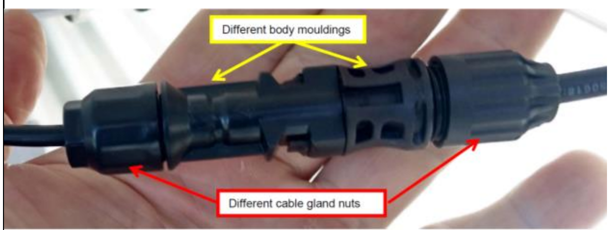
Overview of typical IR image patterns observed in outdoor measuerments. [16]

<table>
<tr><td>Component
Defect</td><td colspan="3">Module
Soiling</td><td>PVFS 1-20vs.01</td></tr>
<tr><td>Appearance</td><td colspan="4">Soiling is visible as a deposition of dust, dirt or other contaminants on the surface of a PV module. The deposition can be uniform or non-uniform and vary in thickness. Due to the presence of hot-spots caused by non-uniform soiling, it can be also seen through IRT imaging.</td></tr>
<tr><td>Detection</td><td colspan="4">VI, (IRT, MON)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="4">Soiling of PV modules can have various origins such as dust accumulation, air pollution, bird droppings or growth of moss, lichens or algae. It can be due to natural sources, as sand in desert areas, seasonal pollen or volcanic emissions, or due to human activities, as near mining, industry, high ways, railways, urban or agricultural surroundings. The soiling level and its persistence over time depends on the exposure time, the chemical composition and particle size as well as the local climate conditions. Whereas rainfalls and wind can lead to a natural cleaning of modules, humidity can have a contrary effect by increasing adhesion and cementation of dust on the module. The module design (e.g glass coating, frame, distance of cells from the edge), the orientation (e.g tilt angle, azimuth, landscape/portrait) and mounting conditions (e.g clamps, height above ground, stringing) of the modules plays an important role. Typically soiling increases as tilt angles decreases. The direction of the wind or obstacles can influence the soiling process, leading to non-uniform patterns on system and module level.</td></tr>
<tr><td>Production ☐</td><td>Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="4">The deposited soiling layer causes optical losses, reducing the amount of light that reaches the solar cells, with a consequential performance drop. Soiling is not a real module failure, as it is reversible when the module is cleaned, but it has a negative impact on the lifetime energy yield and financial return. Soiling is a site-specific issue. In arid regions with seasonal dry periods and dust, extreme soiling losses of up to 25%/a are reported, if modules are not cleaned. In temperate regions with year-round rain, the annual soiling losses typically ranges between 0% to 4%. In case of specific soiling sources (e.g. railway, farming, etc.) and/or constraints of the natural cleaning effect due to unfavourable mounting conditions (e.g low tilt angle) much higher losses can be observed. Non-uniform soiling leads to current mismatch losses which further increases the power loss and to hot-spots which in extreme cases can permanently damage a PV module. In modules affected by potential induced degradation (PID), soiling can further accelerate the ongoing degradation effect. Soiling can be mitigated by cleaning the modules or preventing excessive soiling. The cleaning approach has to be appropriate to the type of soiling and site specific conditions (e.g. accessibility and water availability). The cleaning schedule should take into account that natural agents, such as rain-falls, wind or dew can have a natural cleaning effect at no cost. Anti-soiling coatings (ASC) can help in reducing soiling and stretch the cleaning frequency, but only if the coating is adequate for the type of soiling present on the system and if adequate cleaning processes are followed, which do not damage the coating. Moreover, it has to be considered that some ASC can also increase transmission losses by themselves.</td></tr>
<tr><td>Safety:</td><td>e</td><td>Performance:</td><td>2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td>Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td>Cleaning by qualified persons is recommended when the revenue lost because of the missed energy production is higher than the cleaning cost. A best time to clean should be defined.</td><td>Preliminary site inspections for the assessment of the soiling risk. Cost estimation for the implementation of mitigation measures. Regular visual inspections to control the soiling level.</td><td colspan="2">Estimation or measurement of soiling losses prior to installation. Installation of soiling sensors to determine the most profitable time to clean.</td></tr>
</table>

EXAMPLES (page1) — PVFS 1-20vs.01

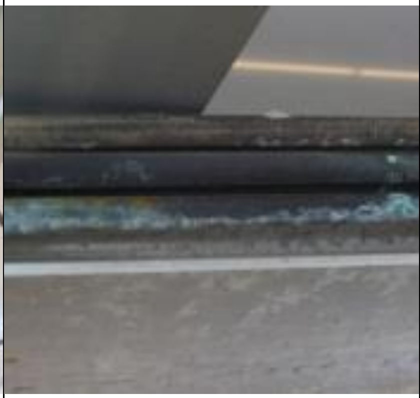
Examples 1-3						
	Uniform light soiling, which in ideal conditions is self-cleaning when raining.		Uniform heavy soiling caused by rail way station. [SUPSI]		Non-uniform soiling caused by low inclination and close mounting to roof. [SUPSI]	
Severity		2		3 4		2 3
Examples 4-6						
	Moss growing on the edge of a module combined with edge soiling. [1]		Soiling pattern on a system in the Atacama desert. [ISE]		Soiling pattern demonstrating dominant wind direction on a test site in Atacama desert. [ISE]	
Severity	e	2 3		3 4		3 4
Examples 7						
	Heavy biofilm soiling. [46]					
Severity		4 5				

<table>
<tr><td>Component
Defect</td><td colspan="3">Cables and Interconnectors
DC connector mismatch</td><td>PVFS 2-1vs.01</td></tr>
<tr><td>Appearance</td><td colspan="4">Combination of male and female DC-connectors of two different manufacturers or types (cross-mating) between modules, strings, arrays or to the inverter.</td></tr>
<tr><td>Detection</td><td colspan="4">VI, (IRT)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="4">There is yet no standard for PV connectors prescribing dimensions and tolerances. Therefore, it is possible to find very similar-looking and even apparently fitting connectors on the market, advertised as ‘compatible’. Slight differences in the design of the connector can lead to reduced water and vapour tightness. Problems may also occur due to incompatibilities of materials (chemical incompatibility or different thermal expansion parameters) of the metal contact, gaskets or sealings. Most of the time the mismatch of connectors occurs at the string end where extension cables are used or when connecting an inverter or a string combiner box, which has been delivered with incompatible connectors.</td></tr>
<tr><td>Production ■</td><td>Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="4">The interconnection of connectors from different manufacturers may significantly increase the risk of loss of performance and defects which cause hazards for human and environment [IEC TR 63225:2019]. The consequences are e.g. contact corrosion, burnt connectors, electrical arcing and in the worth case a fire. One of the most common failures is that no current will flow through the connection at all. The problems do not manifest themselves right away, but only over time with increasing contact resistance and/or degradation of the connector/s. At humid weather conditions mismatching connectors can also lead to a partial failure of the inverter or a ground fault. The fire risk is further increased when the connectors are not properly positioned and are close to flammable material such as wooden roof beams or heat-insulation materials. Often connectors are at least partly installed at position where they cannot be inspected during normal visual inspections (e.g. within profiles, underneath roof parallel modules or even in BIPV). In combination with the unclear compatibility issue, the interconnection of different brand or type of connectors may result in high risks.</td></tr>
<tr><td>Safety:</td><td>f e</td><td>Performance:</td><td>1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td>Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td>All not matching connectors should be replaced.</td><td>Ask supplier or check module/inverter spec sheets for the type/manufacturer of connector, only connectors from the same manufacturer and certified as compatible should be mated together.</td><td colspan="2">Verify that both modules and inverters are delivered with the same connectors. Provision of spare connectors and string cables with connectors of the same type as the module connectors.</td></tr>
</table>

Examples 1-2			
	Connectors (male of female) are of different brand or type and obviously do not match. **[40]**	Connectors (male of female) are of different brand or type and obviously do not match. [40]	
Severity	f e — 1 2 3 4 5	f e — 1	
Examples 3-5			
	Corroded connector due to cross-mating. [Stäubli]	Melted connector due to cross-mating. [Stäubli]	Burned connector due to cross-mating. [Stäubli]
Severity	f e — 3 4 5	f e — 5	f e — 5
Examples 6-7			
	Different types of connectors recognisable by different body mouldings and cable gland nuts. [ESV guide]	Different types of connectors recognisable by different 'O' rings or logos. [ESV guide]	
Severity	f e — 1	f e — 1	

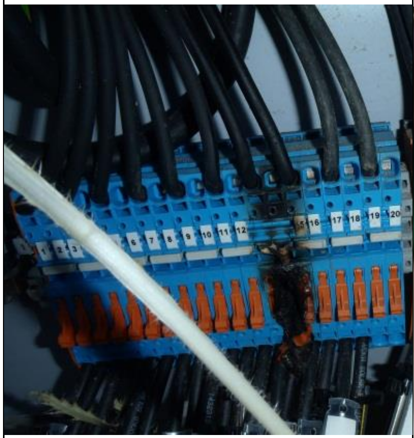
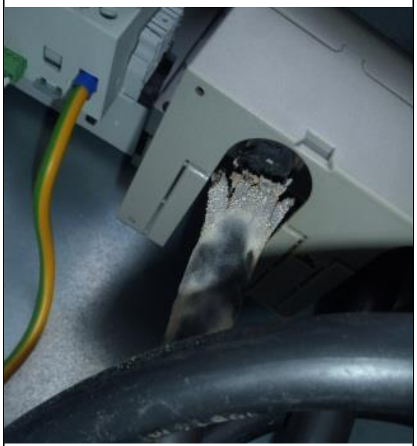
<table>
<tr><td>Component
Defect</td><td colspan="2">Cables and Interconnectors
Defect DC connector/cable</td><td>PVFS 2-2vs.01</td></tr>
<tr><td>Appearance</td><td colspan="3">A damaged connector or cable appear as melted, burned, brittle, broken, cracked or whitened. Opened connectors can demonstrate corrosion. Affected connectors show very often overheating or hot spots in an early state if a thermography check is performed.</td></tr>
<tr><td>Detection</td><td colspan="3">VI, (IRT)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="3">One of the major causes of damaged connectors are the combination of incompatible components (DC connector mismatch), a low quality connector or a bad installation. In the last case the connectors are either not installed according the instructions (e.g. bad crimping or connection, exposure to rain or polluted before installation, installation of damaged connectors) or the connectors are not fixed correctly exposing them over longer times to humidity or dirt without allowing the connector to dry completely. In case of damaged cables the major causes are the use of low quality material in production (e.g. insulation material or cupper wires), an inadequate selection of components within the design phase (e.g. undersized cables, too large cable glands, inadequate IP classification or UV protection) or an improper handling or fixing of the cables in the installation phase (e.g. cable routing over sharp or abrading edges, hanging cables close to connections, overly tight bending, missing or not correctly installed cable glands or exposure to direct UV radiation).</td></tr>
<tr><td>Production ■</td><td>Installation ■</td><td>Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="3">Damaged connectors or cables constitute a high safety risk and may lead to the power loss of the whole string. The continuity of the circuit isn't any more guaranteed and inverter failures can occur (low insulation faults or inverter switch off), leading to partial or complete power losses. In the worst case damaged cables or not well-connected connectors may cause electric arcs. In many cases, the connectors and cables are much closer to flammable material such as wooden roof beams or heat-insulation materials than the PV module laminate, increasing the risk of fire.</td></tr>
<tr><td>Safety: f e f e</td><td colspan="2">Performance: 1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td>Corrective actions</td><td>Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td>Components constituting a direct safety risk should be replaced. Regular inspections should be done to monitor the status of the not replaced components.</td><td>Protection of connectors and cables from humidity during installation. Use of adequate crimping tools. Installation should be done by trained personal.</td><td>Signature of a contractual agreement for maintenance of the warranty when connectors are substituted by the installer, perform regular system inspections.</td></tr>
</table>

EXAMPLES (page1)						PVFS 2-2vs.01
Examples 1-3						
	Weathered connector. [1]		Cracked connector. [1]		Corroded connector. [1]	
Severity	f e	2 3	f e	5	f f e	3 4
Examples 4-6						
	Not fully inserted or interlocked connecter. [41]		Melted connector. [1]		Cracked/disintegrated cable insulation. [1]	
Severity	f e	2 3	f e	4 5	f f e	3 4 5
Examples 7						
	Incorrect crimping (right) versus correct crimping (left). [47]					
Severity	f e		2 3			

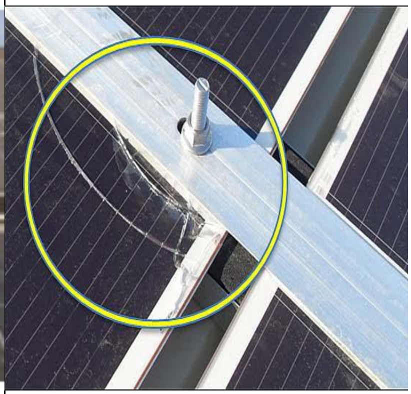
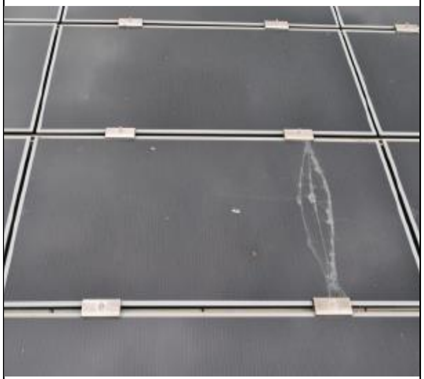
<table>
<tr><th colspan="6">EXAMPLES (page2)</th><th>PVFS 2-2vs.01</th></tr>
<tr><td rowspan="2">Examples
8-10</td><td colspan="2"></td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td colspan="2">Burned connector. [1]</td><td colspan="2">Corroded Cable. [1]</td><td colspan="2">Animal bite on cable. [1]</td></tr>
<tr><td>Severity</td><td>f e</td><td>5</td><td>f e</td><td>1 2 3</td><td>f f e</td><td>3 4 5</td></tr>
</table>

<table>
<tr><td>Component
Defect</td><td colspan="4">Cables and Interconnectors
Insulation failure</td><td colspan="2">PVFS 2-3vs.01</td></tr>
<tr><td>Appearance</td><td colspan="6">A bad isolation of cables is not always visible by eye. An unequivocally detection is only possible through the measurement of the insulation resistance under dry or humid/wet conditions. It can be sometimes deduced by the presence of degraded or damaged cables and/or connectors. Under certain circumstances like after a rain fall or in the early morning when the cables or connectors are exposed to humidity, this kind of defect can lead to inverter failures (low insulation fault or inverter switch off).</td></tr>
<tr><td>Detection</td><td colspan="6">VI, (INS, MON)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="6">Isolation failures occurs as a result of a short-circuit. It is usually the result of a combination of humidity and damaged or degraded DC cables or connectors.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="6">A low insulation resistance due to the cables or a connector does not lead to a performance loss itself, until an inverter failure occurs. An isolation fault can however cause potentially fatal voltages in the conducting parts of the system potentially exposing persons to an electric shock hazard. Touching of non-insulated parts may cause severe injury, without the use of safety gear and safe measuring instruments. In the worst case damaged cables or connectors may cause electric arcs and initiate a fire.</td></tr>
<tr><td>Safety:</td><td colspan="2">f e f e</td><td>Performance:</td><td colspan="2">2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td colspan="2">Cables or connectors constituting a direct safety risk should be replaced. Regular inspections should be done to monitor the status of the not replaced components.</td><td colspan="2">Ground fault detection by inverter or other devices at all time.</td><td colspan="2">Regular system inspections.</td></tr>
</table>

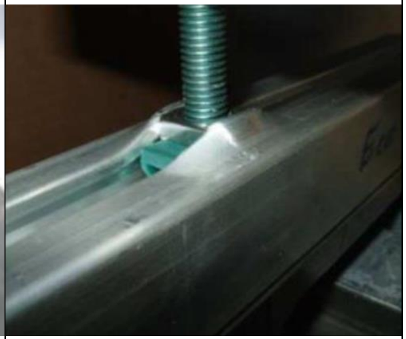
<table>
<tr><td>Component
Defect</td><td colspan="5">Cables and Interconnectors
Thermal damage in combiner box</td><td>FS 2-4vs.01</td></tr>
<tr><td>Appearance</td><td colspan="6">Defects appearing in the combiner box as discoloured or burned cable interconnections or fuses. Damaged parts can be found by visual inspection or infrared thermography (IRT).</td></tr>
<tr><td>Detection</td><td colspan="6">VI, IRT, (MON)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="6">Thermal damages in the combiner box can be due to the selection of inadequate components (e.g underrated fuses or fuse holders), a not proper connection of DC cables (e.g improper wire torqueing, missing fuses) or a wrong wiring of the modules/strings in the field or on-roof.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="6">This damage is caused by the excess heat generated in fuse holder and defect DC connect-ors/cables. The partial or complete thermal damage of the combiner box leads to performance losses, electrical shock hazards and risk of fire. Actions must be taken immediately by qualified personnel to prevent further damage.</td></tr>
<tr><td>Safety:</td><td colspan="2">f e m f e m</td><td>Performance:</td><td colspan="2">1 2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td colspan="2">Replace the components with defect or abnormal tempera-ture.</td><td colspan="2">Use IRT to check the compo-nents and connection to find poor connection or defect components.</td><td colspan="2"></td></tr>
</table>

EXAMPLES (page1)			FS 2-4vs.01
Examples 1-3			
	Burned terminal block of the combiner box. [TUV Rheinland]	Improper wire torqueing causes a fire. [46]	Connection show signs of corrosion. [TUV Rheinland]
Severity	f e m — 5	f e m — 5	f e m — 1 2
Examples 4			
	Connecting terminals show signs of burning, have melted or charred. [TUV Rheinland]		
Severity	f e m — 5		

Component Defect	**Mounting** **Bad module clamping**		**PVFS 3-1vs.01**
Appearance	Inadequate fastening or damage of the module or frame by the clamp.		
Detection	VI		
Origin	The installation instructions of the module and mounting structure from the manufacturer are not followed. Typical errors at the planning and installation stage are: (a) use of inadequate clamps for the selected module and/or mounting structure, e.g. sharp edges damaging glass/glass modules, wrong combination of clamps and modules or mounting structure (b) too short and too narrow clamps or (c) the positions, kind or number of the clamps on the module not being chosen in accordance with the manufacturer's manual. Other errors are too excessively or insufficiently tightened screws during the mounting phase.		
	Production ■	Installation ■	Operation ■
Impact	An improperly installed clamp compromises the integrity of the mounting system and the ability of the module to stay in place under high wind or load conditions. The detachment of modules can happen as series effect because the modules share the clamps with the module next to it. Once one module is detached, the clamp immediately loses fixing force on the next module and result in series detachment. The detachment of the module/s from the mounting structure is posing a serious hazard to persons and the risk of damaging the rest of the system and/or the property in the vicinity of the installation site. Problems such as frame damage, **glass breakage** or **cell cracks** can occur compromising on the long term the performance and the electrical safety.		
	Safety: f e m e m	Performance:	1 2 3 4 5
Mitigation	Corrective actions	Preventive actions (recommended)	Preventive actions (optional)
	Modules with a safety risk or a severity of 5 should be replaced.	Use only compatible clamps (mounting structure/ modules/ clamps) and follow manufacturer mounting instructions. Check local wind and snow loads.	Testing of non-standard mounting configurations by an accredited test laboratory (eg. facade mounting), perform regular system inspections

EXAMPLES (page1)			PVFS 3-1vs.01
Examples 1-3			
	Improper installation of clamp. [?]	Wrong combination of clamps and modules. [40]	Glass breakage caused by too tight screws. [35] (see also PVFS 1-8)
Severity	f e e 1	f e e 1	f m e m 2 3 4
Examples 4			
	Glass breakage caused by poor clamp design. [40] (see also PVFS 1-8)		
Severity	f m e m 2 3 4		

Component Defect	**Mounting** **Inappropriate/defect mounting structure**		**PVFS 3-2vs.01**
Appearance	Mechanical damages (e.g cracking, bending) or other visual defects (e.g. corrosion of frame or mounting holes) observable on the mounting structure.		
Detection	VI		
Origin	Typically, this failure occurs when the mounting structure is not designed to withstand the wind or snow loads which are typical for the site in which the system is installed (e.g. mounting structure does not comply with static calculations, underestimation of the environmental conditions), or if the anchorage of the mounting structure to the ground or roof is weak (e.g. ground conditions are not considered sufficiently when choosing the mounting structure). The roof strength, to withstand the added load of the PV system and include allowance for O&M activities, is not verified. Another reason for the failure of a mounting structure is the use of inappropriate materials (e.g use of corrosive materials in a corrosive environment, insufficient galvanisation, poor quality material due to a bad or missing quality assurance in production), leading to a premature degradation or mechanical failure of the mounting structure. Installation errors (e.g. missing/non-original components, excessively or insufficiently tightened screws) can be the origin of a failure of the mounting structure.		
	Production ■	Installation ■	Operation ■
Impact	An inappropriate or damaged mounting structure compromises the integrity of the modules mounted on it and in some cases also the substructure (e.g roof insulation). In the worst case this leads to the detachment of single modules or the whole mounting structure from the roof or ground, or roof collapses, posing a serious hazard to persons and the risk of damaging the rest of the system and/or the property in the vicinity of the installation site. Performance losses are to be expected, depending on the damage on module level (number of disconnected modules/strings, **glass breakage, cell cracks**, **back sheet damages**, **damaged or detached junction box**) and the time and labour needed to repair the system. Galvanic corrosion is important for the installation with two different metals in contact, for example aluminium frame fixed on steel structure, especially in humid or costal area. Direct contact of different metals generates galvanic corrosion which frequently happens around the fastening screws. Therefore insulation between two different metals is required in humid and costal area.		
	Safety: f e m	Performance:	1 2 3 4 5
Mitigation	Corrective actions	Preventive actions (recommended)	Preventive actions (optional)
	Mounting structures with a direct safety risk should be replaced or repaired.	Use only compatible mounting structures (ground/mounting structure/modules) and follow manufacturer mounting instructions. Check local load (conditions (wind, snow, other).	Regular system inspections. Testing of non-standard mounting configurations by an accredited test laboratory (e.g. facade mounting), perform regular system inspections.

EXAMPLES (page1)			PVFS 3-2vs.01
Examples 1-3			
	Corrosion due to salt water. [46]	Cracks in mounting structure due to mechanical stress. [46]	Screw canal bends due to mechanical stress. [46]
Severity	f e m — 1 2	m — 1	m — 1
Examples 4-6			
	Bracket fractured due to mechanical stress. [46]	Undersized mounting structure for local snow load conditions. [46]	Undersized mounting structure for local wind conditions. [15]
Severity	m — 1	m — 5	m — 5

<table>
<tr><td>Component
Defect</td><td colspan="4">Mounting
Module shading</td><td colspan="2">PVFS 3-3vs.01</td></tr>
<tr><td>Appearance</td><td colspan="6">Depending on the position of the sun (day and time), shading can be seen either by eye when performing a visual inspection, or by comparing monitoring data of unshaded and shaded strings or by running shading simulations. The shade can have different patterns and change/move over the day and season.</td></tr>
<tr><td>Detection</td><td colspan="6">VI, (MON, IRT)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="6">The choice of the mounting structure and the position in which the modules are mounted influences the shading conditions. Shading can be caused by different factors or obstacles e.g trees, antennas, poles, chimneys, satellite dishes, roof or façade protrusions, near buildings, cables, or by self-shading (inter array or row-to-row shading) or soiling. Shading conditions can change over the lifetime of a PV system due to growing vegetation, new constructions or construction elements. It can be distinguished between different types of shades: direct shades hindering the direct light to reach the module or diffuse shades.</td></tr>
<tr><td colspan="2">Production ☐</td><td colspan="2">Installation ■</td><td colspan="2">Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="6">A cell or module which does not receives or receives less sunlight due to a shading obstacle, lowers the performance of a PV system. Typically, the cumulative annual shading loss of PV systems is between 1-5%, but energy losses up to 20-30% can be observed for roof top or façade systems. Due to series connection of cells and modules, the power loss is significantly higher than the shaded area. The final loss depends on the on-site implementation or shading mitigation measures like optimised string and module arrangements (landscape mounting), use of module-level power electronics (MLPEs), inverter characteristics (MPPT search algorithms, string control) or the use of shading tolerant module technologies (e.g half-cut cells, back contact cells). Shading itself does not pose a safety issue, but the hot-spots caused by prolonged shading can lead to follow-up failures (e.g burn marks, bypass diode failures, glass breakage, arcing or fire). It further can result in an acceleration of the aging process resulting into higher degradation rates. The right time to consider the impact of shading is at the system planning phase, later it is usually too late. The use of MLPEs such as micro-inverters and DC optimizers for individual modules can potentially increase performance under shading conditions, but the gain achieved by these devices do not always exceeds the loss caused by the MPLE device itself (lower efficiency), and the shading still activates the bypass diode and result in hot spot on the shaded cell, which increases the risk of reliability issues. The choice of using them only in the area where shading occurs should be considered an alternative to install them for all modules. A cost benefit analysis should be done in any case.</td></tr>
<tr><td>Safety:</td><td colspan="2">f e m</td><td>Performance:</td><td colspan="2">2 3 4 5</td></tr>
<tr><td rowspan="2">Mitigation</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td colspan="2">Preventive actions (optional)</td></tr>
<tr><td colspan="2">Indirectly damaged modules with a safety or severity risk of 5 should be replaced or repaired. Eventual trees or vegetation responsible for the increased shading loss should be cut.</td><td colspan="2">A basic shading analysis (full year solar/shade data) is recommended to identify areas and periods of major shading. Areas exposed to shading within the central part of the day or sunny season should be avoided or appropriate/cost-effective shading mitigation measure should be implemented.</td><td colspan="2">A detailed shading loss analysis should be done which estimates and compares different system configurations and shading mitigation measures. Perform regular system inspections.</td></tr>
</table>

EXAMPLES (page1)			PVFS 3-3vs.01
Examples 1-3			
	Shading by pole-and-wire (poor design: too close to nearby shading objects). [36]	Shading due to bad planning or coverage by afterwards build construction element. [40]	Shading by tree with seasonal changes due to foliage. [40]
Severity	2 3 4	5	3 4
Examples 4-6			
	Missing maintenance on flat green roof. [SUPSI]	Vertical shading of a standard module with 3 bypass diodes. [J.Lin]	Shading by balustrade. [J.Lin]
Severity	f e m 5	3 4 5	2 3 4
Examples 7			
	Continuous shading caused by chimney. [SUPSI]		
Severity	f e m 3 4 5		

Component Defect	**Inverter** **Overheating**		**PVFS 4-1vs.01**
Appearance	The inverter reduces its power or switches off to protect components from overheating (temperature derating). Inverters do not always deliver a corresponding status message "power reduction" or "derating". For this reason, it is recommend to check the inverter behaviour by determining and analysing performance curves (Power vs Irradiance).		
Detection	MON, (IV, IRT)		
Origin	Temperature derating of the inverter can occur for various reasons, e.g. improper installation of the inverter, fan failure, dust blocking heat dissipation or an incorrect programming of the inverters.		
	Production	Installation	Operation
Impact	When the monitored components in the inverter reach the maximum operating temperature, the inverter shifts its operating point to a lower power. During this process, power is reduced step-by-step. In the extreme case, the inverter switches off completely. As soon as the temperature of the threatened components falls below the critical value, the inverter returns to the optimal operating point. The partial or complete failure of the inverter leads to performance losses, which will get worth if the problem is not solved. In the worth case inverter will switch off. Inverter overheating do not affect module safety.		
	Safety:	Performance:	3 4 5
Action	Corrective actions	Preventive actions (recommended)	Preventive actions (optional)
	Once identified the origin of the temperature derating the failure should be repaired. The filters and in general heat dissipation path should be cleared of obstruction.	Follow the given installation procedure, use of adequate cooling technology, perform regular inspections of the ventilation units.	Monitoring of inverter temperature

EXAMPLES (page1)						**PVFS 4-1vs.01**
Examples 1-3						
	Dust blocking heat dissipation [TUV Rheinland]		A soiled air filter causes overheating [TUV Rheinland]		Installation not appropriate (direct exposition to sun) [TUV Rheinland]	
Severity		3		3		3

<table>
<tr><td>Component
Defect</td><td colspan="4">Inverter
Incorrect installation</td><td>PVFS 4-2vs.01</td></tr>
<tr><td>Appearance</td><td colspan="5">The inverter must be installed according to the installation instruction. A common failures is the installation near flammable, explosive, corrosive or humid sources. Also the minimum distances to bottom, top or to the sides are not always fulfilled. If the input cables are not fixed properly, increased temperatures can occur at the loose contact point which lead to lower performance or risk of fire. Inverters must always be accessible for operation and maintenance and properly secured to an appropriate base.</td></tr>
<tr><td>Detection</td><td colspan="5">VI (MON)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="5">Violating instruction manual, e.g. installed nearby flammable materials as wood or in direct sun light.
Minimum distance to adjacent components not maintained.</td></tr>
<tr><td colspan="2">Production ☐</td><td colspan="2">Installation ■</td><td>Operation ☐</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="5">Incorrect installation of the inverter can cause danger to users and hazardous conditions and can result in overheating of the inverter. The use of the inverter in the presence of flammable vapours or gases can lead to explosions. The inverter housing can become very hot under operation. Follow the instruction to provide gaps from both sides and top for adequate cooling. Direct sunlight on the inverters must be avoided. The inverter must be safely accessible to avoid accidents during maintenance work.</td></tr>
<tr><td>Safety:</td><td>f e m</td><td>Performance:</td><td colspan="2">1 2 3 4 5</td></tr>
<tr><td rowspan="2">Action</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td colspan="2">Dismount the component and follow the installation procedure.</td><td colspan="2">Follow the given installation procedure, use of adequate cooling technology, perform regular inspections of the ventilation units.</td><td>Monitoring of inverter temperature.</td></tr>
</table>

Examples 1-3						
	Installation in direct sun light. [TUV Rheinland]		Inverters are not or difficult accessible for operation and maintenance. [TUV Rheinland]		Distance to bottom, top or to the sides too low. [TUV Rheinland]	
Severity		3	e m	2	f	3
Examples 4-5						
	Housing not appropriate. [TUV Rheinland]		Presence of inflammable material. [SUPSI]			
Severity		1	f	1		

<table>
<tr><td>Component
Defect</td><td colspan="4">Inverter
Not operating (complete failure)</td><td>PVFS 4-3vs.01</td></tr>
<tr><td>Appearance</td><td colspan="5">If the inverter does not work despite good production conditions, common problems are the lack of restart after grid faults or isolation faults. The inverter may show fault codes to help understanding the problem. This can be observed by checking the display or the data log of the monitoring system. Examples for hardware defects in the inverter are discoloured or burned cable interconnections or fuses. Damaged parts can be found by visual inspection or infrared thermography (IRT).</td></tr>
<tr><td>Detection</td><td colspan="5">MON, (VI, I-V, VOC)</td></tr>
<tr><td rowspan="2">Origin</td><td colspan="5">A complete failure of the inverter occurs due one or more malfunctions of single hardware or software component of the inverter or faults due to grounding issues, e.g. high humidity inside the inverter, or a firmware issue.</td></tr>
<tr><td colspan="2">Production ■</td><td colspan="2">Installation ■</td><td>Operation ■</td></tr>
<tr><td rowspan="2">Impact</td><td colspan="5">The complete failure of the inverter leads to significant performance losses and immediate actions must be taken. When the restart does not work or the fault occurs recurrently the origin must be identified in most cases by a service team. Software issues can be solved by updating the firmware for technical reasons or to update the system to new standards/grid technical requirements. While damaged hardware components of central inverters are usually repaired, string inverter are replaced more often for economic reasons. Damaged hardware can cause fire and electric shock hazards and must be repaired by qualified personnel.</td></tr>
<tr><td>Safety:</td><td>f e f e</td><td>Performance:</td><td colspan="2">3 4 5</td></tr>
<tr><td rowspan="2">Action</td><td colspan="2">Corrective actions</td><td colspan="2">Preventive actions (recommended)</td><td>Preventive actions (optional)</td></tr>
<tr><td colspan="2">Restart the inverter. Replace the components with defect or abnormal temperature. Update the software.</td><td colspan="2">Use IRT and VOC to check the components and connection to find poor connection or defect components.</td><td></td></tr>
</table>

EXAMPLES (page1)						PVFS 4-3vs.01
Examples 1-3						
	Insulation failure. [TUV Rheinland]		Not operating inverter. [TUV Rheinland]		Damaged hardware component. [37]	
Severity	e	3 4 5		3	f e	5

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