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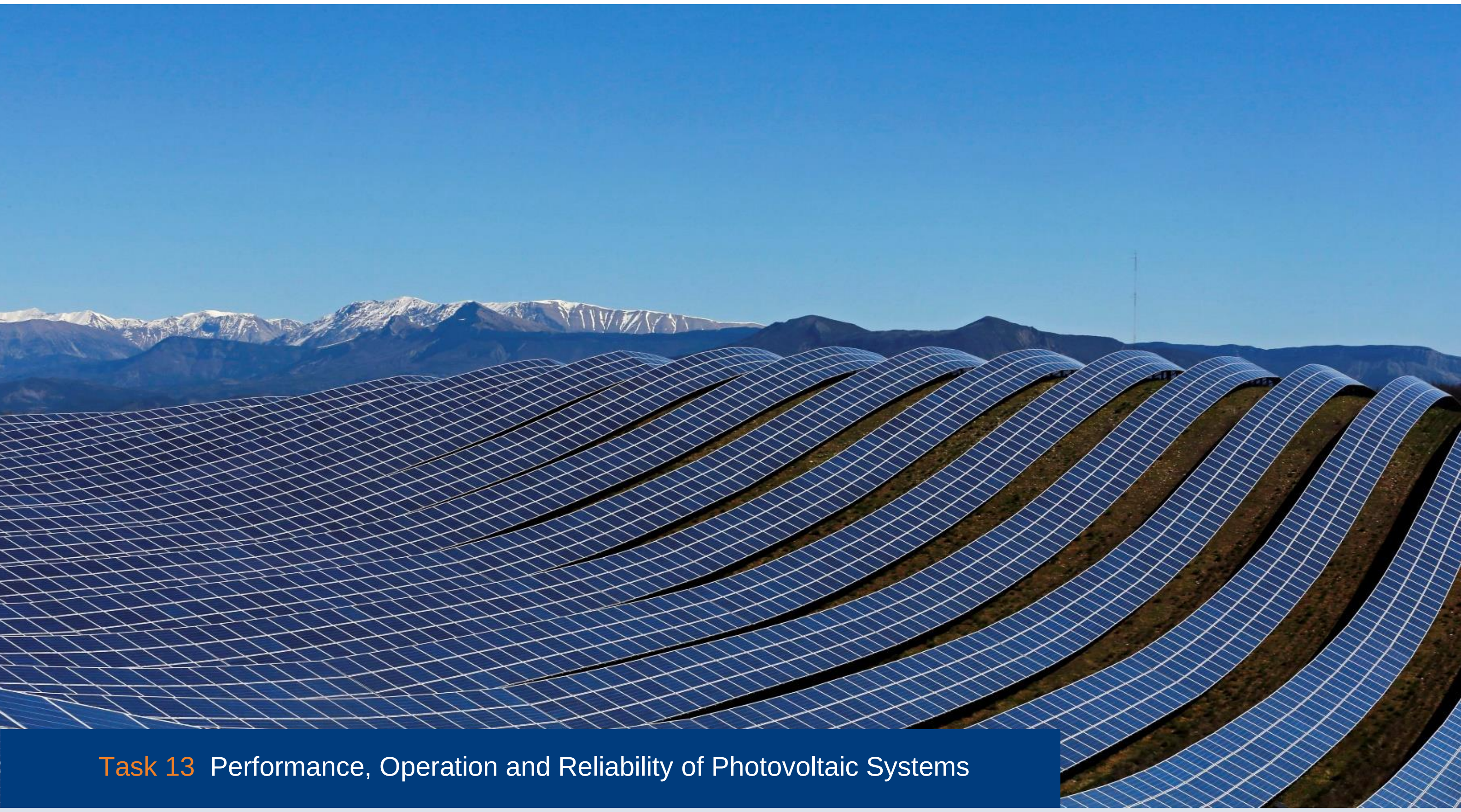

Task 13 Performance, Operation and Reliability of Photovoltaic Systems

PVPS

Guidelines for Operation and Maintenance of Photovoltaic Power Plants in Different Climates

2022

Report IEA-PVPS T13-25:2022

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 the 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 TCPs 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 goal, the programme’s participants have undertaken a variety of joint research projects in photovoltaic (PV) power systems applications. The overall programme is headed by an Executive Committee, comprising one delegate from each country or organizational member, which designates distinct ‘Tasks’ that may be research projects or activity areas.

The IEA PVPS participating countries are Australia, Austria, 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, Smart Electric Power Alliance (SEPA), and Solar Energy Industries Association are also members.

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What is IEA PVPS Task 13?

Within the framework of IEA PVPS, Task 13 aims to support 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 reliability and performance of the current PV systems.

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 that PV systems perform at their optimum and continue to provide competitive return on investment.

Task 13 has established a framework for calculations of various parameters that provide an indication of the quality of PV components and systems. The framework, along with the results included in the high-quality reports, is useful to and appreciated by the solar PV industry.

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.

This report addresses climate-specific guidelines for operation and maintenance of PV systems with the aim to serve different functions to various stakeholders depending on their roles in the entire value chain of PV. Further information and results of Task 13 can be found at: https://iea-pvps.org/research-tasks/performance-operation-and-reliability-of-photovoltaic-systems/.

* Belgium is no longer participating in IEA PVPS, effective from 01 July, 2022.

COVER PICTURE

The solar PV farm of Les Mées is located in the hills of the plateau de la Colle des Mées, in the Alpes-de-Haute-Provence department in the south of France. Covering an area of 200 hectares with a total of 112,780 PV panels, located at 800 metres above sea level, the installation is the largest in France. It generates a total electrical power of 100 MWp and supplies nearly 12,000 homes with sustainable energy. Photo Courtesy of AvaxNews.

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LIST OF ABBREVIATIONS

AI	Artificial Intelligence
AMR	Automatic Meter Reading
ANNs	Artificial Neural Networks
AR	Auto-Regressive
BAPV	Building Applied Photovoltaics
BIPV	Building Integrated Photovoltaics
BoS	Balance of Systems
CAPEX	Capital Expenditure
CCD	Charge Coupled Device
CM	Corrective Maintenance
DSOs	Distribution System Operators
EL	Electroluminescence
EPC	Engineering, Procurement and Construction
EPI	Energy Performance Index
ERP	Enterprise Resource Planning
GFS	Global Forecast System
GRP	Guaranteed Performance Ratio
HMM	Hidden Markov Models
IEA	International Energy Agency
IML	Inhomogeneous Mechanical Loading
IR	Infrared
KPI	Key Performance Indicator
LCOE	Levelized Cost of Energy
LD	Liquidated Damage
LOTO	Lockout-Tagout
MAE	Mean Absolute Error
ML	Machine Learning
MPPT	Maximum Power Point Tracking
MRA	Maintenance Reserve Account
NAM	North American Mesoscale
NIR	Near Infrared

NWP	Numerical Weather Prediction
OEM(s)	Original Equipment Manufacturer(s)
OHS	Operational Health and Safety
O&M	Operation & Maintenance
OPEX	Operational Expenditures
PF	Power Factor
PID	Potential Induced Degradation
PM	Preventive (or proactive) Maintenance
PPC	Power Plant Controller
PPE	Personal Protective Equipment
PR	Performance Ratio
RMSE	Root Mean Square Error
SCADA	Supervision control and data acquisition
SCB	String Combiner Box
SL	Soiling Loss
SR	Soiling Ratio
SVM	Support Vector Machine
TMY	Typical Meteorological Year
TSOs	Transmission System Operators
UAV	Unmanned Aerial Vehicles
WHO	World Health Organization
WRF	Weather Research and Forecasting

EXECUTIVE SUMMARY

The increasing adoption of PV systems in different climate zones and conditions worldwide has indicated that stress factors such as temperature, humidity, exposure to UV light, rain, and wind could contribute to the occurrence of module failures. Knowing of this fact, operation & maintenance (O&M) operators have looked to customize O&M services to the climate zone where particular plants are located.

At present, comprehensive guidelines for climate-specific O&M programs have yet to be developed. With this gap in mind, this report aims to provide comprehensive guidance for customized O&M service in seven different climate zones. The first four are for conditions which broadly prevail in large parts of the world (moderate, hot and dry, hot and humid, desert at high elevation), while the latter three are for extreme conditions (flood-prone regions, cyclonic regions, snowy regions). These guidelines can assist PV plant engineers and designers, financing parties, and investors in designing and maintaining PV plants, as well as in determining operational risk related to investment decisions.

The report presents these guidelines according to the following topics: O&M performance indicators and standard O&M operator services (Chapter 2), guidelines for monitoring, forecasting, and analysis of PV plant performance and safety (Chapter 3), the different types of maintenance services and advanced inspections (Chapter 4), and finally the recommendations for climate-specific O&M along with a report of field experiences that affected reliability, performance and safety (Chapter 5).

The key highlights from each chapter are the following:

- Chapter 2: An O&M contract should clearly describe the scope of the services and responsibilities of the operator to prevent any ambiguities in their respective responsibilities, as well as acceptable compensation if operators fail to fulfil their obligations. Key to this is including at least one of the O&M operator KPIs (key performance indicators) such as Guaranteed Performance Ratio, Guaranteed Plant Availability, and Response Time in the contract to allow for straightforward standards in measuring contract compliance. The choice of which of these KPIs to select is based on negotiations in the O&M contracting phase. Finally, O&M contracts should take into account regional differences, such as national or local legislation that affects the availability of staff on-site, as well as variations in the capabilities of key stakeholders that affect project cost.

- Chapter 3: Performance monitoring systems should allow for a ´follow-up´ of the energy flows within a PV system. The scale and complexity of plants determine the level of monitoring: the larger and more complex the plant, the more intensive the monitoring. Minimum requirements are detailed in international standards such as IEC61724-1, as well as best practice guidelines such as the SunSpec Alliance. To gather insights on specific failures and underperformances, predictive maintenance services with data collection devices on-site should be put in place to create an “intelligent” monitoring system. O&M operators need to be ready to comply with applicable grid codes and regulations, allowing for the re-evaluation of the scope of operations for contracts if grid codes change, especially in contexts where more RE plants replace thermal sources of power.

- This could particularly apply to PV power forecasting services, which are increasingly critical but could be offered either by O&M contractors or by external service providers. Asset owners may find it convenient to choose a PV forecasting service s/he is already working with, as these may impact contract agreements with other partners who may depend on the performance of the plant, such as trading service providers. Finally, to ensure safety, O&M operators must guarantee plant and worker safety by ensuring that staff is well-trained and qualified to implement safety procedures, equip them with PPE, tools and consumables, and take into account site-specific risks such as heights, presence of water, increased fire risks, or weather conditions.
- Chapter 4: Preventive maintenance (PM) action plans that exclude redundant activities can bring costs down. The preventive maintenance plan should seek to optimize the overall PV plant and O&M budgeting, depending on the plant´s size, design, complexity, and environment. The most important actions here include periodic sampling of individual electrical measurements at module level, soiling and snow mitigation, site and vegetation management, and keeping balance of systems and SCADA (supervision control and data acquisition) monitoring systems operational.
- Aerial infrared (IR) and visual imagery are powerful tools for diagnosing faults, especially for power losses. As of present, turnkey solutions for aerial imagery diagnostic solutions for large-scale PV does not yet exist, as current wireless communication and camera control technology limit the operational range. Typical costs for base O&M scope, including soiling mitigation, range from 6.5 up to 16.5 €/kWp*year. Additional costs for advanced diagnostics/analytics based on aerial IR scans (on bi-annual basis), range from 0.5 to 3 € per PV module or array. In corrective maintenance/spare parts action plans, maintenance reserve accounts are recommended to be set aside by the plant owner, to foresee possible replacement costs.
- Chapter 5: The essential practical guidelines for the climate zones studied are:
    - **Temperate –** An on-site evaluation of vegetation, wildlife and farm animals should be conducted. Grass cutting should be combined with an inspection of the status of solar PV modules to decide if cleaning and/or corrective maintenance actions are required. In industrial environments, solar PV modules can develop unexpected deterioration. Special attention must be paid to selecting cleaning products. It is advised to follow expert recommendations on suitable products.
    - **Hot and Dry –** Assessments must be made of wildlife risks, appropriate planning for visits to typically remote sites (hydration, anti-venom procedures, PPE, travel to and from sites). Wildlife risks cover poisonous animals and insects that can harm humans directly, whereas nesting insects and animals can cause short-circuits or arc flashes. The typically remote nature of PV sites in hot and dry climates entails significant travel and preparation requirements, due to logistical risks in terms of supplying these facilities as well as access to emergency medical care. Temperature extremes and salt exposure also increase material degradation in modules, frames, junction boxes and transmission cables.
    - **Hot and Humid –** Wildlife intrusion in ground-mounted systems, particularly from rodents, snakes, and termites can cause failures in PV components and electrical systems. Rapidly growing plants can also have a soiling impact (dust

accumulation). Cleaning schemes can decrease production losses of PV modules by as much as 6-8% during summer months. Fire risks can also be posed by agricultural activities such as field clearing. Adequate ventilation during hot months is crucial for good operating conditions of inverters.

- **Flood-prone –** It is important to note that PV systems are not typically designed with flood endurance in mind. However, climate change and extreme weather events, combined with limited availability of land in certain parts of the world, mean that some plants are built in areas that flood 2-3 times a year. Actions to prevent damage include switching off the plant in anticipation of flooding and only switching it back on after technical inspection. Floods can damage module mounting clips, PV modules, the lamination on panels, and even uproot foundations. Soiling damage is particularly difficult to repair when water has been standing on the PV modules for a long time. Submerged inverters can also short circuit and cause burn/fire risks. Fast flowing water can also cause debris impact because most PV mounting systems present a high resistance to flowing water.
- **Cyclonic Regions –** Damage from typhoons and cyclones typically affect PV modules and mounting racks. Glass breakage is also a particular issue in cyclonic regions. The breakage of fixing parts was also observed due to uplifts in air pressure. Cell cracks caused by deflection with strong wind load can also occur. While national standards for wind loads are present in the USA, Japan, and the EU, non-uniform mechanical load testing has not yet been launched due to a lack of experts and countries which are needed to form a project team. It is thus recommended to estimate the effects of winds using wind tunnel tests, ensuring that structural connectors are of sufficient strength and that PV modules have sufficient uplift resistance. It is also recommended to assess the compliance with standards during construction, to conduct periodic maintenance of all bolted connections, to store sufficient repair parts, and to remove loose debris around the plant.
- **Snowy Regions –** Snow accumulation affects PV performance, as heavy snow loads hinder the transmission of light to the cells and could damage modules. A suggested limit for snow accumulation on panels is 0.7m. PV racking systems can also be damaged by extremes between winter and summer temperatures. In this case steel racking is preferred over aluminium racking. If active cleaning measures are implemented, such as brushing, care must be taken not to scratch the glass as well. Experiments have been conducted to heat PV modules by applying a controlled forward voltage to melt the snow. This would require careful load control and the use of weather forecasts.

In conclusion, a combination of well-designed O&M specifications, proactive monitoring systems and a flexible and tailored O&M regime that considers both climactic impact on systems as well as possible changes to grid requirements are good practices to ensure that PV systems reach or even exceed the expected lifetime. Reducing risks by ensuring that personnel are trained and equipped for O&M operations, as well as using PV forecasting to reduce possible downtimes, also helps to maintain PV plant performance to specifications.

1 INTRODUCTION

Solar photovoltaic (PV) plant equipment is composed of a variety of different materials. The final products, such as solar PV modules, power conversion equipment (inverters, transformers, combiner boxes, etc.), module mounting structure, etc., are put together (i.e. installed) at the site of the PV installation. The PV plant, together with all the equipment, are then commissioned into operation with a typical lifetime of 25 to 30 years.

The performance and durability of PV plant equipment are expected to change over the lifetime of a PV plant. The climatic environment in which the equipment is operating will influence the equipment's aging defects, the occurrence of failures and the equipment's degradation; this is because different materials (and how they are processed and assembled) respond differently to different climatic stress factors such as temperature, humidity, UV light, rain, wind, etc. A combination of these climatic parameters will also create second-order stressors (mechanical load from snow, soiling from dust) to PV plants. In a study conducted by Köntges et al. [1] whereby a database of PV module failures in the field were analysed in different climate zones, the authors reported that despite the lack of strong correlation between module failure occurrences and impacts with the Köppen and Geiger climate zones [2], certain failures (e.g. soiling losses in hot and dry climate) tend to occur more in certain climates.

The world of PV plant operation and maintenance (O&M) is increasingly competitive, reflected clearly by a significant drop in the O&M service fee over the last decade; e.g. Bloomberg New Energy Finance has reported a drop of 73% of average full-scope O&M price in Europe between 2011 and 2017. Typically, PV plant operators typically offer a standard O&M scope of services that could be replicated easily across to reach an optimal point (i.e. minimizing operation and maintenance efforts (thus expenditures) while maximizing PV plant uptime, performance and durability). However, a shift from the one-size-fits-all approach to a customized O&M approach could offer as advantage that the O&M activities are adapted to the needs of the PV plant, focusing on the maintenance activities that are necessary. Such customization could be setting an O&M service based on the climate zone in which a PV plant is located.

One of the main challenges in customization of an O&M programme for a specific climate zone is the present lack of comprehensive guidelines to guide the users to do so. Existing guidelines and standards do not fill the gaps or only clarify the minimum requirements of climate-specific O&M and their implementation. In this context, this report seeks to provide a comprehensive guidance on setting up a customized O&M practice for PV plants in seven different climate zones, four of which are general (moderate, hot and dry, hot and humid, desert in high elevation), and three which are more specific to extreme conditions (flood-prone region, cyclonic region, snowy region). The recommendations are built based on field experiences of the contributing experts from various countries representing the climate zones addressed.

The climate-specific O&M guidelines presented in this report aim to serve different functions to various stakeholders depending on their roles in the entire value chain of PV. The most direct application is for PV plant operators and owners by setting up an optimal and appropriate O&M programme for their PV plants, taking into account the specific climate conditions. PV plant engineers and designers would also benefit from relevant O&M measures and recommendations to use as inputs or design criteria during the design and engineering of the plants. At the other end of the spectrum, financing parties and investors could use these guidelines as a benchmark for PV plant operational risk assessment, inputs which are used in the decision-making process of project finance/investment.

With these in mind, this report consolidates and discusses key recommendations, guidelines, and best practices towards optimized O&M for PV plants. Task 13 puts an emphasis on best practices through the different chapters on the site-/climate-specific aspects of PV O&M, ranging from the regulatory, risk/safety and asset management level, up to the operational level (notably the monitoring/inspections, data analytics, maintenance, and optimization). Figure 1 gives an overview of exactly all these different, yet interrelated, “components” that assemble the overall O&M agenda throughout the technical lifecycle of PV plants.

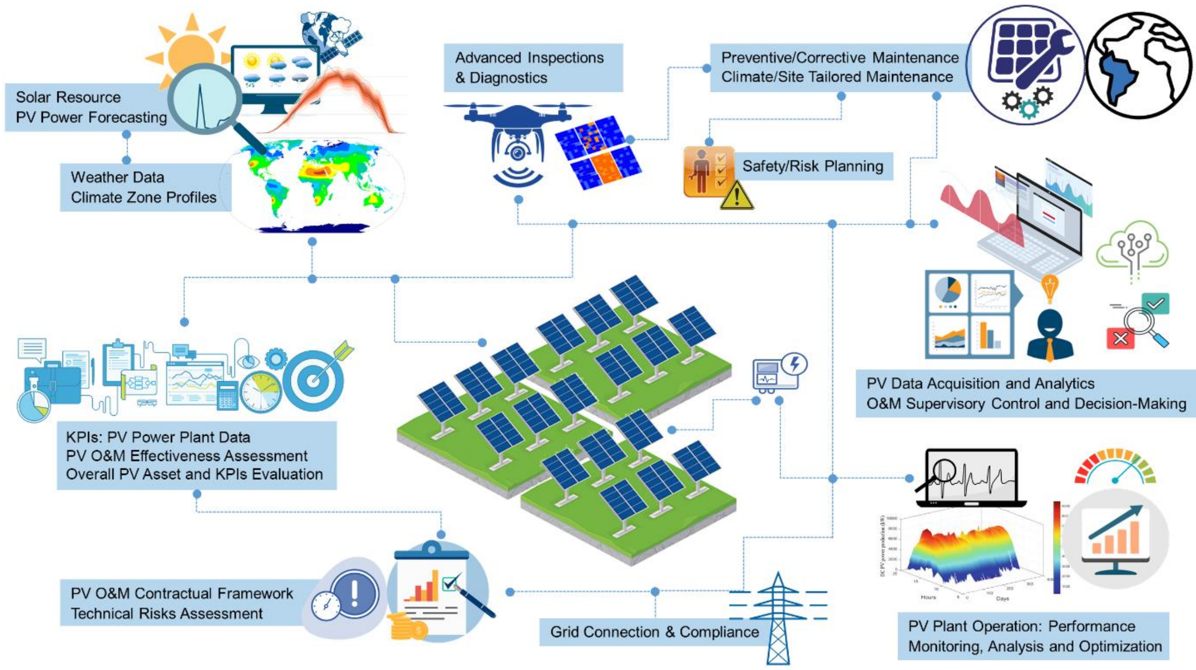

Figure 1: Overview of O&M aspects and services for PV power systems (source: CEA-INES).

Chapter 2, **chapter 3** and **chapter 4** touch on various aspects of PV plant operation and maintenance which are applicable to installations across different climate zones:

- Chapter 2 discusses the topic of O&M performance indicators, namely ways to assess how the PV plant itself is performing, and O&M service provider services and obligations. Parameters to measure the performance of these two aspects are discussed in the chapter;
- Chapter 3 elaborates on the guidelines for monitoring, analysis and forecasting of PV plant performance and safety;
- Chapter 4 presents the different types of maintenance services and important trends (advanced inspections);
- Chapter 5 presents the guidelines for O&M in the seven different climate zones. This chapter is comprehensive and includes not only recommendations for the climate-specific O&M, but also shares examples of field experiences in regard to PV plant reliability, performance and safety issues in these various climate zones.

2 PERFORMANCE INDICATORS

2.1 PV Power Plant Data (Key Performance Indicators)

2.1.1 Defining the Testing Boundary

Understanding of the intended testing boundary is critical to the construction of appropriate PV power plant KPIs. Factors of performance that lie within the testing boundary should be captured by one or more of the KPIs, while factors of performance that lie outside of the testing boundary should be explicitly excluded. The following examples demonstrate the importance of a well-defined testing boundary in the determination of a) which KPIs are most appropriate and b) the particular corrections and exclusions that should be applied to each KPI.

Example 1. Electricity network downtime can have a considerable impact on the total yield of a power station, but these impacts are not typically within the control or responsibility of an O&M contractor, and therefore lie outside of the testing boundary. Periods of network downtime are typically excluded when assessing the plant performance.

Example 2. If the ambient temperature at the PV power plant is higher than anticipated during modelling and design, the PV modules may exhibit decreased efficiency. Since the O&M contractor has no control over the ambient temperature, this behaviour is typically deemed to be outside of the testing boundary and should be corrected for when calculating KPIs.

Example 3. Both the size of the PV array and the available solar resource during the period under consideration have a direct bearing on the total yield generated. However, these factors are not within the testing boundary when assessing plant performance, and therefore must be corrected. Correcting the plant yield for these considerations results in the standard definition of the performance ratio (PR).

2.1.2 Performance Ratio

The most ubiquitous measure of PV plant performance is the performance ratio (PR). The PR is a measure of the efficiency of the entire plant as a converter of solar irradiation to AC energy and can be considered as a measure of yield, normalised to account for both the size of the array and the available solar resource. The PR therefore captures the combined effect of all losses occurring within the plant, including modules, inverters, transformers, electrical cabling, and system or network downtime.

To correct for the available solar resource, the measured plane of array insolation (H_i, typically written as H_{POA}) is expressed in terms of equivalent full-sun hours by dividing by the assumed reference irradiance level, or standard testing conditions ($G_{i,ref}$, typically written as G_{STC}). This measure is known as the *reference yield* (Y_r) [3] and is given in Eq (1).

$$Y_r = \frac{H_i}{G_{i,ref}} = \frac{H_{POA}}{G_{STC}} \qquad (1)$$

To correct for the plant size, the measured AC energy production (E_{out}) is divided by the plant peak DC power (P_0 or P_{STC}), to produce the *specific (final) yield* (Y_f) as given in Eq (2).

$$Y_f = \frac{E_{out}}{P_0} = \frac{E_{out}}{P_{STC}} \qquad (2)$$

The performance ratio can then be expressed as the ratio of the specific yield and the reference yield.

$$PR = \frac{Y_f}{Y_r} = \frac{E_{out}/P_{STC}}{H_{STC}/G_{STC}} \tag{3}$$

An advantage of the performance ratio is its adaptability. Factors affecting plant performance that are deemed to be outside of the testing boundary can be accounted for by making appropriate adjustments to either the numerator or denominator of Eq (3). Common corrections are presented in the following sections.

A. Module temperature correction for the performance ratio

In the calculation of a temperature corrected performance ratio, the specific yield is adjusted to reflect the level of yield that would be achieved had the modules been operating at an agreed-upon reference temperature. This reference temperature is often the annual (weighted) module temperature from a standard model, or the standard testing temperature of 25°C. The temperature-corrected PR ($PR_{TC,ref}$) gives better insights into a PV plant's operation, as it reduces or removes temperature effects from consideration. To estimate this correction, the effect of temperature on module efficiency is modelled as a single-coefficient linear model, using the module temperature coefficient of power (γ), as per Eq (4).

$$PR_{TC,ref} = \frac{\frac{E_{out}}{1+\gamma * \left(T_{mod} - T_{mod,ref}\right)}/P_{STC}}{H_{STC}/G_{STC}} = \frac{PR}{1+\gamma * \left(T_{mod} - T_{mod,ref}\right)} \tag{4}$$

Note that Eq (4) is sometimes written in the form shown in Eq (5). While Eq (5) is mathematically accurate (if implemented correctly), it is still recommended to use Eq (4), as this is more intuitive, and is the form presented in IEC 61724-1 [3].

$$PR_{TC,ref,alternative} = \frac{PR}{1-\gamma * \left(T_{mod,ref} - T_{mod}\right)} \tag{5}$$

The module temperature correction factor, resulting in de-rating for temperatures above the reference temperature, gives an uprating for lower temperatures. When using aggregated values for a time period to calculate PR, the mean module temperature shall be calculated as an irradiance-weighted average.

B. Corrections for curtailment for the performance ratio

Curtailment of a PV plant's power output may occur due to a variety of reasons, ranging from a lack of flexibility of other generating technologies on the grid, to (local) oversupply of PV power, or grid stability events where the system operator directs plants to reduce output [3] [4].

In such cases, the typical approach is to exclude the periods where curtailment was applied, and then calculate the non-curtailed PR. This approach generally provides valid results, yet careful analysis is required, especially for cases where curtailment occurs for more than 50% of the time. As per IEC 61724-1, data exclusions must be recorded.

C. Soiling corrections for the performance ratio

Soiling of PV plants lowers the yield that can be generated by PV modules, compared to un-soiled (clean) conditions. The PV industry has transitioned from using (only) an all-encompassing PR where soiling is seen as part of the complete PR, to seeing soiling as an external factor that can be measured and, with the appropriate cost-benefit analyses, result in decisions to clean modules or not.

The soiling ratio (SR) is defined as per Eq (6), with the soiling loss (SL) defined in Eq (7) [3]:

$$SR = \begin{cases} \dfrac{P_{soiled}}{P_{clean}} \; preferably \\ \dfrac{I_{sc,soiled}}{I_{sc,clean}} \; alternatively \end{cases} \tag{6}$$

$$SL = 1 - SR \tag{7}$$

Note that the usually defined soiling ratio SR is a measure of "cleanliness", because SR = 1 denotes zero soiling losses, while low SR values represent high losses due to soiling.

The ratio of the soiled module power to the clean module power is used as the preferred calculation method, as this better reflects soiling impacts on power losses. However, if this method suffers from issues (e.g. jitter in the voltage measurement which would then also show up presents as jitter in the power data), then the short-circuit current is used as the alternative method to determine the soiling ratio. The reader is referred to [3] for the complete methodology to determine the soiling ratio.

The soiling-corrected PR is then the PR divided by SR, as per Eq (8).

$$PR_{soiling\ corrected} = \frac{PR}{SR} \tag{8}$$

D. Power factor correction for the performance ratio

With increasing renewable energy fractions and renewable power fractions on grids, changes to the output power of PV plants have become standard: no longer are these allowed to inject active power without also providing reactive power. The consequence of this is that less active power is injected, compared to the situation where the power factor (PF) is equal to one [5] [6]. The power factor PF is defined as the active power divided by the apparent power. Depending on the contractual framework, a correction to the PR is made to account for the deviation in delivered active energy, and therefore the performance ratio, as given in Eq (9).

$$PR_{PF\ corrected} = PR * \left(\frac{PF_{ref}}{PF_{measured}}\right) \tag{9}$$

2.1.3 Energy Performance Index

The energy performance index is an alternative approach to evaluating the whole-of-system performance of a PV power plant. While the performance ratio is concerned with direct assessment of the efficiency of the plant as a converter of solar insolation (i.e. resource) into AC electrical energy (i.e. yield), the energy performance index (EPI) instead compares the measured yield to an expected yield (Y_{exp}), typically obtained from an agreed-upon contractual model as given in Eq (10).

The EPI is expressed as the ratio of the measured yield (Y_{meas}) and the expected yield Y_{exp}.

$$EPI = \frac{Y_{meas}}{Y_{exp}} \tag{10}$$

In practice, a key difference between these two approaches (PR or EPI) lies in their respective suitability towards different types of corrections and exclusions. For example, weather corrections to the performance ratio calculation can be provided through explicit modifications to the formula, such as those described in section 2.1.2, and these may be negotiated by the contract parties. On the other hand, equivalent corrections to the EPI require that a pre-built simulation is run against measured weather data, otherwise known as a digital twin. In this case, the corrected EPI may be simpler to produce than the corrected PR, but the calculation is less transparent to the contract parties.

In [7] a lack of field measurement data for state estimation and PF optimization was compensated by a real-time simulation. The concept of a PV system digital twin, reflecting actual operating and boundary conditions is helpful in automated failure detection supporting O&M procedures [8].

2.1.4 Availability

Availability KPIs measure the extent to which the plant was generating electricity throughout the period of examination. Unlike the performance ratio and energy performance index, the performance of the plant during times of successful generation is not considered in the calculation of these KPIs.

A. Technical Availability, or Uptime

IEC TS 63019 [9] provides a framework from which the availability metrics of a PV power system can be derived and reported. Technical availability measures the portion of time in the period examined that the plant was successfully operating and its definition is given in Eq (11).

$$A_{technical} = T_{useful} - T_{down,useful} \tag{11}$$

B. Contractual Availability

Contractual availability draws upon the definition of technical availability, but excludes periods of downtime, such as network downtime, that are deemed not considered to be within the contractor's control or responsibility, and therefore lie outside of the testing boundary. Typical exclusion for O&M contracts are network downtime, and asset owner mandated actions as defined in Eq (12).

$$A_{contract} = \frac{T_{useful} - T_{down} + T_{excluded}}{T_{useful}} \tag{12}$$

C. Energy Availability

IEC 61724-3 [10] provides a method to determine the energy availability, where it is defined as the ratio of the expected energy during availability periods to the total expected energy. It therefore considers that periods of high irradiance are of greater value than periods of low irradiance: for example, missing three days of energy generation in winter has less of a financial impact than missing an equal duration of time in summer. On the other hand, the lower energy loss in winter, when PV plants participate in market prices, can be economically more serious than in summer during the hours when energy prices are low (on the spot market or in advance) because PV plants supply large amounts of electricity. Eq (13) and (14) show two alternative approaches to calculating the energy availability [10] [11].

$$A_{energy} = \frac{Y_{exp} - Y_{unavailable}}{Y_{exp}} = \frac{Y_{exp,available}}{Y_{exp,total}} \tag{13}$$

$$A_{energy} = \frac{Y_{exp}}{Y_{exp} + Y_{exp,loss}} \tag{14}$$

More, commonly used availability metrics in contracts are discussed in [12].

2.2 O&M Contractor Key Performance Indicators

It is universally understood that the quality of a solar PV power plant is primarily driven by the selected technologies and how well the PV plant itself is designed and constructed. These factors are primarily under the responsibilities of the EPC contractor. It is, however, equally important to operate and maintain a well-constructed PV installation to ensure that it is operating according to its safety and functional requirements and that the PV system is producing the amount of solar energy as targeted in the project business book. The latter falls under the responsibilities of the operation and maintenance (O&M) service provider (operator). Just as having a good EPC contract is important to ensuring high quality in the implementation of a PV system, it is no less important to have a proper O&M framework for the PV plant to ensure its proper functioning throughout its designated lifetime. The last is achieved by an O&M contract which typically starts on the PV plant's commercial operation date and lasts until the end of the O&M contractual term.

A good O&M contract should have all necessary aspects covered under properly set terms that could legally bind the party carrying out the O&M services, namely the PV plant's operator. The principal objective is to clearly describe the scope of the services and the responsibilities of the operator to prevent avoidance of responsibilities, and to set an acceptable level of compensation (usually in terms of financial penalties) in the event the operator fails to fulfil its obligations under the contractual agreement. It is therefore highly recommended that the terms and conditions in the O&M contract should leave minimal room for ambiguities and misinterpretations. One key is to include O&M operator key performance indicators (KPIs) in the O&M contract which are clearly defined and could be measured quantitatively.

2.2.1 Different Types of O&M Key Performance Indicators

There are different key performance indicators which are typically used in the O&M contracts in the PV sector, and they are tied directly to the performance of the PV plant (commonly used KPIs are the performance ratio (PR) and the plant availability, as discussed in section 2.1 above.), or the maintenance services performed (response time, plant outage time, etc.).

In this section, how these three KPIs should be arranged in the O&M contract is presented.

A good O&M contract should have at minimum one of these KPIs used to be respected by the operator. Failure to meet the agreed upon KPIs will lead to the application of financial penalties. As PV plant lifetime spans over many years, the KPI(s) should be set for each operational year of the PV plant, and thus is/are assessed on an annual basis.

Although having comprehensive guarantees in an O&M contract is a must, there is to-date no one standard way on how the contractual guarantees should be set; nevertheless, there are plenty of best-practice O&M contracting guidelines publicly available for use and reference [13]. One main reason is that O&M guarantees are directly tied to risk and liability allocation/ownership which is dictated by commercial objectives. The guarantees are therefore arranged on a project-by-project basis as part of commercial negotiation during the O&M contracting phase.

The world of solar PV O&M is extremely competitive; in addition to using more effective ways to achieve the same scope of O&M services (e.g. via intelligent plant monitoring or automated maintenance), reducing operator guarantees is another (but not advisable) way to keep the O&M cost to minimum. A survey done in the Solar Bankability project [14] on O&M contracts for large-scale PV plants developed in Europe has illustrated this case. From the study, the authors have found that the O&M prices could range between 30 to 70% of the total operational expenditures (OPEX) and there are quite some differences among the surveyed contracts in the types of guarantees set, with the stronger guarantees resulting in higher costs.

In the next few paragraphs, the different types of guaranteed KPIs for O&M contracts are discussed. They correspond to the PV plant performance indicators discussed in section 2.1 and the intention here is to give certain guidelines on how to employ these parameters to contractually bind the O&M operator in fulfilling their obligations.

A. Guaranteed Performance Ratio

Guaranteed Performance Ratio (GPR) is one of the most important and commonly used KPI in the O&M contract. It is related directly to the energy output of the PV plant. Expressed in relative form (percentage, %), it represents the ratio between the actual and theoretical energy output of the PV plant. The theoretical initial plant performance ratio is calculated at the contracting phase of the PV project, utilizing typical meteorological year (TMY) solar resource datasets. With the information of the theoretical PR, the guaranteed PR should then be set in the O&M contract.

Two different approaches have been observed in the industry practice: either setting the theoretical PR as the guaranteed PR, or setting a minimum GPR with a slightly lower value than the theoretical PR. For example, a PV plant’s theoretical PR is estimated to be 85%, the O&M contract could either set the guaranteed PR to be 85%, or set a minimum GPR at, e.g. 2% lower, to 83%. Although both approaches are deemed acceptable, the former could be considered stricter as it leaves no buffer between the GPR and what the plant could theoretically achieve in its production.

Once the initial GPR is set, the annual guaranteed PRs after the initial period is calculated taking into account the annual PV system degradation rate (also referred to as performance loss rate).

The assessment of the actual performance of a PV plant in operation is done by comparing the actual energy produced over a given monitoring period (i.e. annual), to the energy yield that the plant should deliver calculated using the actual solar irradiation over the study period. Some key factors to achieve a proper assessment of PV plant performance ratio are therefore:

- Agreeing on a correct formula to use to calculate the PR: There are different ways a PR formula could be set and it is important that the formula accounts for all necessary parameters such as the effect of temperature, the availability of the PV plant, etc. This topic is discussed in section 2.1 above.
- Using correct input data: The correct actual plant energy output and the correct actual solar irradiation and temperature over the period of monitoring should be used. This implies the importance of (1) having a plant monitoring system that could properly/reliably measure/collect the necessary plant parameters with good data availability, and (2) proper data processing (quality check, inclusion, and exclusion procedures). This topic is discussed in section 2.2.3 below.

B. Guaranteed Plant Availability

Guaranteed (plant) availability (GAV) of the PV plant (percentage, %) is the second most common guarantee used in the O&M contracts for solar power plants. When discussing the variable 'availability', it is important to distinguish the availability at the PV plant level from the overall availability which includes the grid availability. From the O&M operator's perspective, the plant level availability is the KPI of interest as the grid functioning is beyond their control.

Most good practice guidelines recommend setting the guaranteed PV plant availability to at least 99%. In fact, it is almost unheard of to have GAV less than 99% in PV O&M contracts nowadays, except for very special cases.

The plant availability could be assessed either using a time-based approach or an energy production-based approach:

- A time-based availability indicates the percentage of time during which the PV plant is producing power. It is expressed as the ratio between the duration of production activity and the recording period (both expressed in hours). To calculate the availability, inverter-level data should be used. For the calculation, it is important to set a time window which defines the period at which the PV plant is to be considered in production mode. This could be achieved by using either (1) an irradiance threshold (minimum 30 W/m^2 is usually a good approach) or (2) an hour range (from hh:mm in the morning to hh:mm in the afternoon or evening). Beyond this window, the measured data could be excluded in the availability calculation. In principle, the time window should be set using threshold values which are realistic, as well as considering the geographical location and seasonal conditions of the PV plant. The first approach is recommended as it is not affected by seasonality or weather variation, i.e., as long as the minimum irradiance threshold is achieved, the plant is considered capable of producing power. While relatively easy to calculate, the drawback of the time-based indicator is that it does not allow for the calculation of the impact of unavailability on the overall system yield.

- An energy-based availability takes into account the reference yield, and therefore indicates the energy lost during times of unavailability. The energy-based availability is calculated as the ratio between the reference yield that has been converted to electricity and the total reference yield.

Similar to performance ratio, the two important factors to properly assess the plant availability are using a correct formula and input data. The various topics related to this are discussed in section 2.1 and section 2.2.3.

After the guaranteed performance ratio, the guaranteed plant availability is most commonly used for setting up the guarantees of an O&M contract. The time-based availability is more often employed than the energy-based availability, mainly because the input data is straightforward and directly collected from the inverter monitoring system.

Best practice recommendations call for using both GPR and GAV together in the O&M contracts to strongly bind the O&M operator contractually. For stand-alone systems, the guaranteed PR is usually preferred because the impact of unavailability can be accounted for by including the plant availability parameter in the PR calculation, unless the energy-based availability guarantee is used.

C. Response Time

Some O&M Operators, on occasion, may opt to guarantee a minimum maintenance response time to faults/alarm events. This is usually expressed in minimum time lapse (in time units such as minutes or hours) to trigger an intervention and is timed from the moment the event or fault occurs. In this approach, the response time should be defined in responses to critical, major, and non-critical events. Faults or events with immediate impacts on the safety operation of the PV plant are critical and require immediate intervention (e.g., fire event). Faults or events with major impacts on the plant production should be considered major and responded within a day or two from the alarm trigger. Any non-critical events or faults should be responded to in the next periodic maintenance cycle.

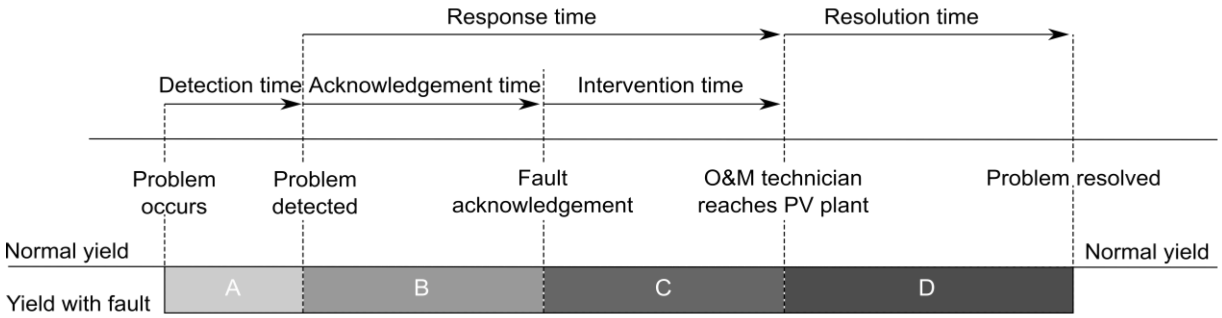

Figure 2: Timeline from fault to resolution, showing the O&M KPIs related to response and resolution time, and the associated yield losses for each phase. In many cases, the detection time will be very short, although this depends on the nature of the SCADA system and the type of fault. Depending on the contractual framework, the yield loss

(the areas indicated by the letters A to D) may be excluded or not from KPI short falls and the agreed penalties. Figure adapted from [11].

The minimum response time guarantee is straight forward. Nevertheless, the O&M contract should include clear definitions of the different response time categories and guaranteed associated time lapse, as well as the response time that is to be measured. Having said this, it is important to note that minimum response time guarantees should not be considered as adequate to contractually bind the O&M operator to its obligations. The response time guarantees should be used as an additional guarantee to one of the more important KPIs discussed above (guaranteed PR, availability, or yield). The overview of the different time values is shown in Figure 2, which also shows the detection time, for which monitoring systems are crucial.

2.2.2 Key Performance Indicator Shortfalls and Penalties

The consequences of not meeting the guaranteed values of key performance indicators in O&M contracts are typically realized in the form of monetary compensation called liquidated damage (LD) or performance shortfall penalty. Beyond a certain maximum limit of LD or penalty (so called LD or penalty cap), the owner of the PV plant could opt to terminate the O&M contract. The definition of and under which conditions (not only inclusions but also exclusions) the LDs will be applied should be clearly defined in the O&M contract. Of equal importance, the associated LDs and how to size them are also a must in the O&M contract.

Two most common LDs are penalties associated with PR and availability shortfalls. The PV plant performance should be calculated every year over the duration of the O&M contract term, and the actual PR and availability should be compared against their corresponding contractual guaranteed values for the relevant monitoring year.

The amount of the LDs to be paid by the O&M Operator should be sized correctly. From the perspective of the plant owner, the amount should at minimum compensate the loss of electricity sales revenue associated with the MWh production loss. On the other hand, the O&M operator would like to minimize the penalty amount as this will work against their account book. A higher penalty could lead to a higher annual O&M fee as the operator is likely to consider the extra risk factor in order to optimise the revenue/costs. The key in O&M contract negotiation is to find a sweet spot for both sides of the negotiating parties.

There are two approaches to size/calculate the number of LDs. The first is straight-forward and the LDs are determined through the loss of electricity sales revenue associated with the MWh non-production. In the formula, the difference (in MWh) (delta from actual measured, say at the energy meter, vs guaranteed) is multiplied with the unit electricity sales price (e.g., €/MWh).

The second calculation is tiered based (for each percentage point below the guaranteed values), and the penalty is also tiered with respect to the annual O&M fee. A typical set-up in O&M contracts translate along the line of, e.g., for every 1% PR or availability shortfall, the O&M operator shall pay X% of the annual O&M fee. This approach is acceptable, but care must be taken to ensure that the LD amount as calculated relative to the annual O&M is capable of covering the equivalent loss in electricity sales revenue associated with 1% of PR or availability of the PV plant.

Regarding the maximum LDs or penalties cap to be set, the best-practice recommendation is to set it at 100% of the annual O&M fee. More importantly, these penalties and LDs should be reset at the beginning of every O&M service year.

2.2.3 Data Acceptance and Classification

Advanced monitoring platforms apply a set of criteria for data acceptance and classification following e.g., IEC 61724 [3] standard recommendations. This crucial step ensures the quality of the data to be used for KPIs calculation and reporting as well as for advanced data analytics for the early detection of failures and underperformances during the operational lifetime of a PV plant. An overview of the most common data processing and quality checks is presented below. Further details can be found on dedicated standards such as the IEC 61724 [3].

Daylight hours are considered for the calculation of KPIs and alarm functionalities. This is typically calculated based on minimum irradiance thresholds. Depending on the application this specific value can differ but typically ≥30 W/m² is accepted as a common minimum threshold. This ensures eliminating night-time values and some outliers that can negatively impact the calculation of KPIs and data analytics.

The main quality checks consist often of removing invalid readings and dealing with missing data. Correctly labelling the raw monitoring data for further processing is crucial for an advanced monitoring platform. Several checks and filters are applied to ensure data consistency, plausibility, and availability. These checks are typically executed automatically in monitoring platforms and can allow certain flexibility to adjust to different stakeholder needs. For example, among the most common checks for invalid data are: minimum and maximum physically reasonable limits, outlier identification, timestamp checks, parsing of error codes, duplicates, etc. These checks are performed at the component level and can vary depending on the component and monitoring level.

The correct identification, labelling and reporting of missing data is crucial to enable further analysis. The specific methodology applied must always be clearly documented in all reports and monitoring portals. Once the missing data has been correctly labelled, different approaches can be used for its treatment. For example, the invalid or missing data can be replaced by data from other valid sensors, or this can be modelled using other valid data sources. The use of digital twin models to fill in the missing data is gaining popularity as a result of the latest improvements in artificial intelligence (AI) techniques. However, it is important to always respect and treat the missing data in accordance with contract specifications. As recommended by IEC 61724, the treatment of missing or invalid data will ultimately depend on the goal of the measurement and the analysis. Further details and recommendations for treatment of missing or invalid data are included in IEC 61724 [3].

2.3 Contractual Framework

In the preceding section, the key performance indicators that can be used to contractually bind the O&M service providers to their obligations and responsibilities were discussed. In addition to these, the framework of the O&M contract is equally important as it defines all the necessary aspects together with the terms and conditions and serves to avoid any avoidance of or ambiguities in the responsibilities of the contracting parties.

2.3.1 O&M Contract Framework

Typically, an O&M contract is drafted and prepared by a PV plant owner with the involvement of legal expertise, and by taking inputs from technical and/or financial advisors. Different parties usually prepare their own template based on contracts used in the PV market. There are also publicly available templates for download (some free, others at a cost). Among the common templates used in the O&M contracting is the one of the International Federation of Consulting Engineers (so called FIDIC template) adapted for solar PV power plant O&M. There is also an O&M contract template prepared from the joint effort between the Terawatt Initiative and the International Renewable Energy Agency (IRENA) [13]; this template is specific to solar power plants.

Regardless of the types of templates used, the O&M contract should include at the minimum elements discussed hereafter; focuses are placed on elements that are directly or somewhat related to technical aspects of PV plant.

1. Parties Involved

The legal identification and registered location of the contracting parties should be clearly defined.

2. Contract Term and Commencement

The duration of the service should be clearly stated. Whether the term could be extended (how long and how) should also be specified.

The effective date of service commencement, including any conditions precedent, should be defined.

3. O&M Fee / Contract Price

The O&M service fee (expressed in kWp per year, or for total installed plant capacity to be maintained) should be presented.

Any indexation of the fee should be clearly specified.

Any specific exclusions of the O&M service fee should be outlined clearly.

4. Scope of Services

The O&M contract should clearly specify which activities should be executed as part of the O&M service provided. To be noted, it is not enough to mention only the scope of the works, but also to clearly specify if the activities performed are covered by the contract fee.

The following scopes are common to O&M contracts:

Plant operation around-the-clock monitoring and supervision, including but not limited to:

- Daily performance monitoring, maintenance program execution supervision, alarm/fault detection to trigger appropriate maintenance).
- Operation documentation management.
- Equipment warranty and claim management.
- Representing the plant owner with the grid operator.
- Support in management of change.
- Support in maintaining plant operation permit and permit of evacuation whenever applicable.
- Security and surveillance.

PV plant maintenance: The O&M contract should clearly define (as well as distinguish) the types of maintenance (preventive, corrective, predictive) to be performed. Equally important, the maintenance programme should be adapted to the climate the PV plant is operating under. For the latter, refer to the subsequent chapters of this report for climate specific maintenance guidelines.

- Preventive maintenance (discussed further in Chapter 4.1):
  - The frequency and procedure should be adapted specific to the equipment to be maintained.
  - Site maintenance should be included.
  - Waste management (temporary storage, disposal and removal) should be the responsibility of the O&M Operator.
- Corrective maintenance (discussed further in section 4.2):
  - Clear definition of what is included in the service scope and if the activities are also covered under the O&M fee.
  - Response time for different types of alarm, fault events. In general, faults which will impact the safety operation of the PV plant, or 100% plant outage should be treated as critical and responded to within four to eight hours. Faults impacting major production loss should be treated as major and should be addressed within 24-48 hours.
  - Notification procedure to plant owner.
- Predictive maintenance (optional). The progress in the field of data analytics and artificial intelligence/ machine learning has led to the development of predictive maintenance of solar plants. Predictive maintenance utilizes historical operational data of PV plant mined from the monitoring system and parameters perceived from the environment (weather condition such as irradiance, temperature, rainfall, etc.), with the goal to learn the behaviour or performance pattern of the PV plant and using this to anticipate and plan for maintenance interventions before an event or fault occurs. An example is using predictive maintenance to anticipate and plan for a PV module cleaning cycle. Predictive maintenance is not a standard feature yet in the O&M scope of service.
- Spare parts and consumables management, including storage, replenishment, management of stocks.

Any other services should be specified including reporting to asset management, for example.

Like guarantees to O&M key performance indicators, the scope of works of the O&M operator drives the price of the O&M service. The fuller the scope, the more expensive the service is likely to be. In some cases, the plant owner would exclude certain scopes to minimize the O&M costs; this is usually a commercial decision. In the latter approach, the plant owner is recommended arranging for the excluded service scopes elsewhere, which could make it more difficult to hold one contractor responsible for underperformance.

5. Contractor’s Responsibilities

In addition to specific activities to be carried out under the scope of services, the responsibilities of the O&M service provided should be specified. Among the commonly included items are:

- The O&M services should comply with requirements prescribed in the technical specification's documentation of the PV plant and equipment suppliers' requirements.
- The O&M services should be carried out according to good industry practice, and comply with all applicable laws, consents, and permits.
- The O&M service provider is responsible for providing all other material, equipment, tools and consumables necessary to perform the O&M services.
- The O&M service provider is responsible for ensuring the health and safety of all maintenance activities performed at the project site and is responsible for the safety of its and any approved subcontractor personnel in performing the services.
- The O&M service provider shall carry out the services so that the PV plant achieves the performance requirements and guaranteed key performance indicators.
- The O&M service provider shall ensure it has all the necessary permits and insurances for it to carry out the services, including maintaining the validity of such permits and insurances.
- Provide to the plant owner, in a timely and expeditious manner, all reasonable assistance and information to allow for the plant owner to obtain the permits for which the plant owner is responsible to obtain.

6. Owner Responsibilities

A good O&M contract should also clearly define the responsibilities of the plant owner to facilitate the O&M service provider to carry out its services. Among these obligations are:

- Obtaining all required permits and consents to operate the PV plant, as well as to produce and inject electricity (whenever applicable).
- Making sure to give the O&M operator the right of access to the project site to carry out the O&M services.
- Providing to the O&M operator, in a timely and expeditious manner, all reasonable assistance and information for the operator to obtain the permits needed for by the operator to perform its services.
- Paying to the O&M operator the contracted O&M fee according to the agreed payment schedule.

7. Subcontracting

The contract should clearly mention if the O&M service provider is allowed to subcontract. If this is the case, it is recommended that all subcontracting should be reviewed and approved by the plant owner prior to the start of the services. If there are major parts of the services subcontracted, this should be mentioned during the O&M contract negotiations.

Moreover, if subcontracting is agreed upon, it should be clearly specified that the O&M service provider is responsible for its subcontractor(s).

8. Spare Parts and Consumables

Spare parts could be categorized into spare parts of plant equipment (such as PV modules, inverters, low and medium voltage fuses, tracker motors, structures, etc.), and general consumable small items such as fasteners (screws, bolts, nuts etc.), cables etc. Having a good level of available spare parts of plant equipment will help to avoid prolonged plant downtime/outage due to equipment malfunctioning or damage.

Three main aspects of spare parts management should be clarified in the O&M contract: the storage, the replenishment of used spare parts, and the management of stocks. For consumables, best practise recommendation usually calls for the O&M service provider to be responsible for all the storage, replenishment, and management of consumables.

For the plant equipment however, as discussed in section 4.2, the plant owner and the O&M operator must agree on who is responsible for the storage, replenishment, and management of stocks of spares. In general, keeping inventory of spare parts falls under the responsibility of the O&M operator. However, storage and replenishment of spares could be arranged differently. However, it is important to have this clearly specified in the O&M contract. In the case spare parts replenishment is not foreseen in the O&M service scope, the plant owner should arrange for a separate spare part replenishment set-up, or foresee future maintenance expenses on key equipment replacements (usually in the form of maintenance contingency or reserve account, as discussed in section 4.2).

In addition to defining the responsible parties to spare parts management, it is important to have in the O&M contract two other aspects on spares:

- Warranty periods of replaced defective plant components, and
- Transfer of title: in general, since the plant owner pays for the spare parts, the spares should be the sole property of the owner, and they shall be returned to the owner at the end of the O&M contract term.

9. Key Performance Indicators (KPIs) / Performance Guarantees

Please refer to section 4.2 for detail on recommended KPIs and the corresponding liquidated damages.

10. Dispute, Arbitration

The applicable law for dispute and arbitration should be clearly defined.

Best practice recommendation also includes an allowance in the O&M contract for the involvement of an independent third-party expertise in case of technical disputes.

2.3.2 Influence of Region on O&M Framework

Despite the significant efforts by all stakeholders in the PV industry to increase the standardisation in design and O&M of PV systems, there are still differences that will result in the O&M framework varying, in some cases even within a country or region. Examples of differences:

- Legislative requirements for O&M personnel to be permanently on-site, such as in Mexico [11], which enables the possibility for higher minimum guaranteed availability values to be negotiated.
- The proposed [15] (and subsequently declared invalid [16]) legislation in Queensland, Australia, which would have mandated that only qualified electricians could work with PV modules, inclusive of physical mounting.
- Variances in the maturity of PV market stakeholders (policymakers, developers, EPCs, O&M providers) and the impact of the PV system location can strongly affect O&M costs and the ability to maintain response times [12], [17], [18].

- As discussed in **[17]**, it protects PV stakeholders, especially asset managers and O&M providers with a multinational or multi-regional footprint to fully acquaint themselves with the specific aspects of the PV system in question, as not all practices and assumptions can be fully replicated everywhere.

2.3.3 Other Influences

Given that PV systems have expected lifetimes of 25 years or more, it is highly likely that regulatory or legislative changes will affect these during their lifetimes. In particular, the redesign and repowering of PV systems may occur during an O&M contract.

As defined in [11], revamping involves replacing components, mainly inverters and modules, without substantially changing the plant's nominal power, while repowering (or upgrading) involves replacing components, which may substantially change the plant's nominal power.

Depending on the scope of the revamping or repowering activities undertaken (whether it affects a portion or the whole PV plant), it may be useful to redefine or renegotiate O&M KPIs, or even have a new O&M contract start once the revamping/repowering has been achieved.

3 POWER PLANT OPERATION

3.1 Plant Performance Monitoring Guidelines

In order to obtain operational excellence – next to the use of best value-for-money materials and high-quality installation competencies – performance monitoring, analysis and reporting tools are key for PV plant stakeholders to differentiate. This is to be compared to industrial automation and enterprise resource planning (ERP) systems for a production facility.

However, monitoring capacities should be aligned with the type of installation to monitor; therefore, an initial classification of those is needed before starting monitoring strategies.

A monitoring system allows to follow the energy flows within a PV system. In principle, it reports on the parameters that determine the energy conversion chain. These parameters, along with the most important energy measures in terms of yields and losses, are illustrated in Figure 3 below.

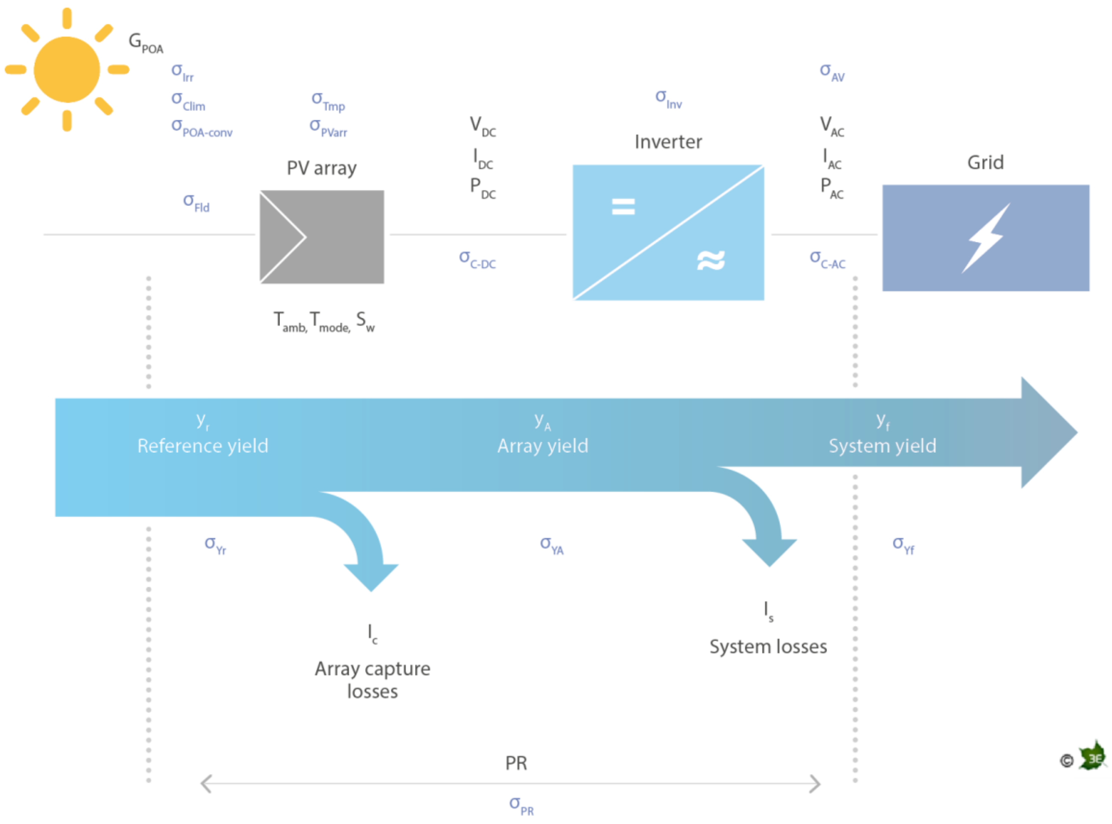

Figure 3: Energy flow diagram in a grid-connected photovoltaic system (source: 3E [19]).

Utility-scale PV plants use complex highly customized monitoring systems, comparable to those used in industrial automation projects. On the other hand, monitoring of residential and commercial systems is typically performed by inverter and data logger manufacturers providing in most cases free or semi-free access to web-portals collecting the data from the local hardware.

As stated in the IEC61724-1 [3], the required accuracy and complexity of the monitoring system depends on the PV system size and user needs. A proposed classification for monitoring systems and suggested applications is given in the Table 1 below.

Table 1: Monitoring system classifications and suggested applications as per IEC61724-1 [3].

Typical applications	Class A High accuracy	Class B Medium accuracy	Class C Basic accuracy
Basic system performance assessment	X	X	X
Documentation of a performance guarantee	X	X	
System losses analysis	X	X	
Electricity network interaction assessment	X		
Fault localization	X		
PV technology assessment	X		
Precise PV system degradation measurement	X		

	Class A High accuracy	Class B Medium accuracy	Class C Basic accuracy
Recommendations on measurement's accuracy requirements			
Uncertainty on irradiance measurements	< 3%	< 8%	n/a
Irradiance sensor inclination angle alignment accuracy	1º	1.5º	2º
Irradiance sensor azimuthal angle alignment accuracy	2º	3º	4º
Inverter-level measurement of input (DC) voltage and current	± 2%	n/a	n/a
Inverter-level measurement of output (AC) voltage and current	± 2%	± 3%	n/a
Plant-level AC electrical output active power and energy	Class 0.2 S as per IEC 62053-2 [20]	Class 0.5 S as per IEC 62053-22 [20]	Class 2 as per IEC 62053-21 [21]
Power factor	Class 1 as per IEC 61557-12 [22]	Class 1 as per IEC 61557-12 [22]	n/a

3.1.1 Analysis of Monitored Data

Several "standard" PV monitoring solutions, enabling data collection and data provision under a given service level agreement, do exist in the market. Smart PV performance monitoring going beyond these standard solutions is indispensable, especially for large utility-scale PV plants. Today, such smart PV monitoring systems should have at minimum the following features:

- Extended monitoring on the plant level including device alarm collection and external equipment monitoring (AC cabinet, security, etc.)
- Complex aggregation functionality up to portfolio level for all analysis and contractually required KPIs
- Notifications based on device alarms and on functional alarms calculated from complex analysis functions
- Advanced aggregation and prioritization functionality of device and functional alarms on portfolio level
- Inclusion of accurate and independent irradiation references, e.g. based on satellite data

- Expected behaviour calculation based on validated simulation models
- Intervention management system integrated with alarm handling and analysis functionality on component level
- Business intelligence enabled for advanced reporting from intervention up to portfolio level.

Further insights on state-of-the-art smart PV performance monitoring systems are provided in section 3.2 “Performance Analysis and Optimization”.

The strategy for monitoring data depends usually on contractual agreements and it is directly related to the scale of the PV plant (e.g., utility-scale PV plant in contrast with an industrial rooftop PV system). Class B and Class C monitoring systems usually will only take care of basic performance parameters with a simple sampling plan. However, Class A plants deserve smart performance monitoring and the same happens with the alternatives for analysis of monitored data.

A typical example for the Class A installation is the case of multi-MW PV plants built under strict contractual conditions and LCOE targets. Both the parameters to be monitored and the analysis strategy to follow their evolution should be clearly defined at PV plant design level ensuring that adequate sensors will be considered for integration in the PV plant. Not only physical parameters (e.g., irradiation, temperature, voltage, current, DC power, AC power, etc.) but also synthetic parameters as defined depending on plant characteristics, can then be tracked. Specific attention should also be given to solar forecasting in order to estimate the PV energy yield to be achieved on e.g., a daily or even intra-daily basis.

For the analysis of monitoring data, statistical data control and evaluation of tendencies on the parameters, more than individual values, are taken into consideration. This strategy allows having as soon as possible an “a priori” identification of unwanted evolution, thus avoiding potential faults and/or (excessive) performance degradation. Artificial intelligence and big data techniques are usually applied for the analysis and interpretation of the monitored data in this case. A detailed explanation of the application of these methodologies from small industrial systems up to commercial utility-scale ones, can be found in “Report IEA PVPS T13-07:2017 Improving Efficiency of PV Systems Using Statistical Performance Monitoring” [23].

Reporting of monitoring analysis is done in line with contractual agreements and is usually accessible via web application. Depending on the intelligence of the monitoring system, and the interest of the customers in knowing about the performance of their installations, the evolution of the parameters, and proposals for actions to be taken can be presented in a detailed way.

3.1.2 Best Practice Guidelines

As introduced in the previous section, different PV plant monitoring solutions are available in the market for different PV plant sizes and stakeholder needs. In all cases it is recommended to always follow standards and best practice recommendations to ensure the correct calculation of all KPIs such as, for example, PR and availability calculated from the monitored data. These minimum requirements are detailed in international standards such as IEC61724-1 [3], covering different aspects ranging from data quality checks to remove invalid data points up to the correct identification, labelling and reporting of missing data as summarized in section 2.2.3 “Data acceptance and classification”. Furthermore, consistency checks to ensure that the correct PV plant configuration is selected as input into the PV monitoring software is key to enable further analysis of the data through the application of PV digital twin models. Finally, best practice guidelines such as, for example, SunSpec Alliance [24] should be followed carefully to ensure open data accessibility for optimized transition between monitoring platforms during the operational lifetime of the PV plants.

A non-exhaustive summary of best practice guidelines for PV plant performance monitoring is presented in the table below. These guidelines reflect the current state-of-the-art in monitoring and PV plant performance assessment, as represented in various standards and research results including those from the PerformancePlus project [25], among others, as well as the SolarPower Europe Operation & Maintenance Best Practice Guidelines [11].

Table 2: Best practice guidelines for PV plant performance monitoring.

Measurement	Recommendations	Explanation
Irradiance measurements	Solar irradiance in the plane of the array (POA) is measured on-site by means of at least one irradiance measurement device according to ISO 9060:2018.	The pyranometer class (e.g., Class A, Class B, or Class C) according to ISO 9060-2018 will define the final uncertainty. Furthermore, best practice is to apply at least one pyranometer in the horizontal plane and two pyranometers in the plane of the PV array. In case of different array orientations within the plant, at least one pyranometer is required for each orientation. Use of satellite-based irradiance data is strongly recommended as back-up in case of sensor's unavailability and for regular data accuracy checks.
Module temperature measurements	The temperature of the modules should be measured with a temperature sensor attached directly to the backside of the module. The use of an appropriate device with an accuracy < ±1 °C is recommended.	The temperature sensor should be glued with appropriate and stable thermally conductive glue to the middle of the backside of the module (in the centre of the cell) in the middle of the array table.
Local meteorological data	It is best practice to measure ambient temperature and wind speed on-site. Ambient temperature should be measured with a shielded thermometer and wind speed is measured with an anemometer, at 10 m height above ground level.	Wind and ambient temperature data are normally not required for calculating PR unless this is a contractual requirement/agreement (e.g., according to specific recommendations such as for calculating the weather corrected PR as proposed by NREL [26]). However, they are required when the PV plant is to be modelled in operation or in retrospect.
String measurements	Individual string current measurements should be considered when not supported by the inverters.	String level monitoring, as compared with inverter level, allows for more precise trouble-shooting procedures and advanced data analytics at higher spatial granularity. Measuring current and voltage of every string with at least 15 minutes resolution is recommended. To reduce costs, the current sensor can potentially measure more than one string (depending on the sensor's measurement range and the number of modules per string), but it is not recommended to parallel more than two of them.

Measurement	Recommendations	Explanation
Inverter measurements	It is recommended to collect data from all measured variables at the highest possible resolution, including inverter alarms being a valuable source of information for fault diagnosis. Best practice for measuring inverter-based variables is a <1 min sampling and a temporal granularity of up to 15 minutes.	Although the precision of inverter integrated measurements may not be very high and this is often not documented by the manufacturers, these measurements become a valuable source of information when performing fault diagnosis and root cause identification.
Energy meter	A high accuracy energy meter to measure energy produced and consumed by the plant is normally required by the utility. When this is not the case it is a best practice to install a meter with a maximum uncertainty of ± 0.5%, especially for plants >100 kWp. When providing reactive energy, it is necessary to have metering not only for active power P, but also reactive power Q, and/or power factor PF in place.	Gathering energy meter data is required for invoicing purposes but it is also the best reference for measuring energy and calculating plant PR and yield and is much more accurate than using inverter data. It is recommended to have a meter with two communication bus ports as well as automatic meter reading (AMR) service from the utility or meter operator. For meters that can store historical data it is a best practice to have a monitoring system capable of retrieving the historical data to avoid any production data loss in case of monitoring system outages.
Control settings	It is recommended to monitor all control settings of the plant at inverter level (DC side) as well as grid injection level (AC side) if available.	Monitoring all control settings of the plant is important for contractual reporting or performance assessment. Many plants apply control settings for local grid regulation (injection management) or optimization of the market value of the PV generation portfolio (remote control).
Alarms	As a minimum requirement, the monitoring system must have the following alarms: • Loss of communication • Plant shutdowns • Inverter stops • Plant with low PR • Inverter with low PR (e.g., due to overheating)	As best practice, the following alarms should also be sent by the monitoring system: • String without current • Plant under UPS • Discretion alarm (or alarm aggregation) • Intrusion detection • Fire alarm detection

Measurement	Recommendations	Explanation
AC circuit / protection relay	It is recommended to monitor the position of all AC switches through digital inputs.	Whenever possible, it can also be useful to read and register the alarms generated by the protection relay control unit via the communication bus.
Infrared thermography (IRT)	When performing IRT measurements, global POA irradiance must be at least 600 W/m^2 and should be continuously measured on-site. It is recommended to use infrared cameras with a minimum optical resolution of 320 x 240 pixels and a thermal sensitivity (resolution) of at least 0.1 K. Measurements must be taken at a distance which ensures that the resolution of the infrared image allows each solar cell to be depicted by at least 5 x 5 pixels. IEC TS 62446-3 [27] provides a complete list of such recommendations.	IRT imagery provides clear and concise information about the exact location (i.e., detection) and type of a large range of failure modes (i.e., diagnosis, classification) [28]. As such, IRT is broadly used in both preventive and corrective maintenance. However, the use of IR thermography alone might be insufficient to reach a conclusive diagnosis on the root cause and its impact in quantitative terms (power output losses). Therefore, it is recommended to combine this with data analytics and complementary field tests [29].
IV curve tracing	In prior point current and voltage measurements at string level have been already described. However, the I-V curve trace gives valuable information concerning certain degrees of degradation on the PV modules performance that not in all cases can be found by just I_{sc} and V_{oc} values at string level. Measurement is quite fast so not big loss of production is expected and should be done in line with the procedures established by IEC-61289:2016. For the individual module IV curve measurements, it is also necessary to disconnect full string and time to measure might be longer per module, with the expected loss of production.	The shape of the string I-V curve allows identifying the origin of the loss of power by giving information on the potential cause of the failure. The theoretical addition of individual I-V curves of PV modules can be considered reference and differences with respect to it in power or field factor can be interpreted in order to find the problem and later go to the string to identify the malfunction on individual modules, unwanted shadowing or any other problem to be solved at O&M level. The necessity of performing individual module I-V curve measurements should be carefully assessed, as it results in a costly activity in terms of production loss and labour time. Other inspection tools (visual inspection, IRT imagery) should be tested before deciding on using it.

Measurement	Recommendations	Explanation
Electrolumines-cence	Electroluminescence (EL) imaging is another tool for on-site quality control and fault diagnosis at PV module and solar cell level. It is recommended to perform EL measurements to a certain sample of PV modules upon their arrival to the PV plant's site and prior to their installation/commission, in order to detect unwanted problems due to transport and/or handling. Moreover, additional EL inspections of PV modules right after their installation and during plant operation, are typically recommended for scrutinous quality control and detailed fault diagnosis. EL measurements are usually carried out in dark conditions (late evening, night, or early morning times). However, new solutions allow for performing these EL measurements also at day light [29].	EL is an image technique that allows identifying important damages in the PV modules (as cracks and micro cracks) that in some cases do not provoke a significant impact on the performance at initial level, but over time could evolve with outdoor exposure into important performance degradation. Detecting the potential presence of defects in this first stage of degradation is the key for preventing their future propagation or extension when the electrical performance may be already compromised. Concerning another type of defects, EL can also detect damage due to impacts on the module, not only in the front side but also in the back side, or other kinds of problems due to stress produced when they were installed in the field. Finally, EL technique is also capable of detecting possible degradation related to electrical problems as PID (potential induced degradation) [30].
Soiling measurements	It is recommended to measure dust or dirt accumulation (soiling) locally in order to optimize cleaning schedules and thus revenues particularly in areas where soiling represents an important risk [31].	Several methodologies exist for soiling monitoring, the most basic being human inspections. A widely used soiling measurement method is using ground-based soiling reference modules consisting of a module that remains soiled, a cleaned reference cell, an automatic cleaning station and measurement electronics. Upcoming digital solutions for soiling monitoring include the analysis of satellite imagery with remote sensing techniques, machine intelligence algorithms and statistical methods.

3.2 Performance Analysis and Optimization

Asset managers and operators need to analyse the monitoring data at different levels, going from large scale portfolios down to plant level and even components analysis. Smart alarming systems based on user specific thresholds such as, for example, business plan data or real-time deviations between on-site assets are crucial to enable fast reaction times and performance optimization [11].

As introduced in section 3.1 above, smart PV performance monitoring systems go beyond simple analytics and alarm systems by providing fault detection and diagnosis capabilities giving actionable recommendations and insights for the operator and asset manager. The value and related complexity of big data analytics changes depending on different O&M objectives as represented in Figure 4 below.

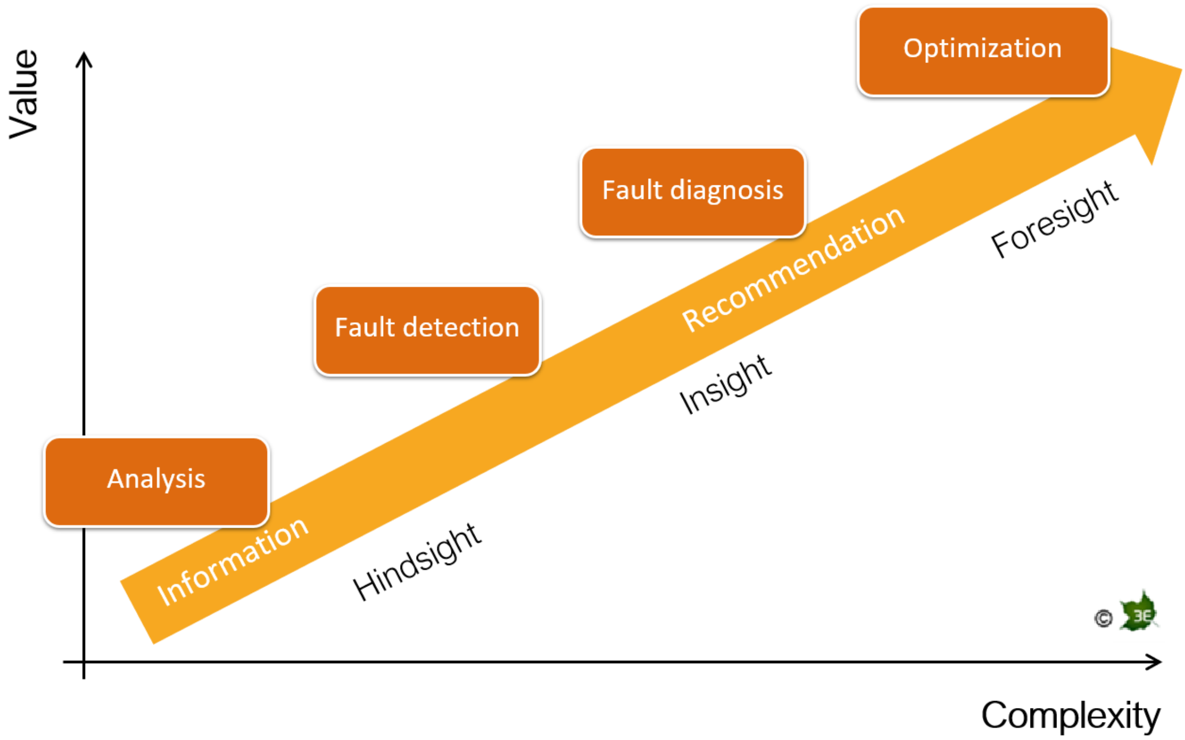

Figure 4: Big data analytics - Value and complexity for different operation and maintenance objectives (source: 3E).

For example, a simple analysis based on monitoring data provides limited value, but it is not complex to execute and therefore all monitoring platforms today offer such basic functionality. However, this typically provides limited information and will still require the operator or asset manager to take further actions based on the information, i.e. no actionable recommendations are provided at this stage. Subtle trends that would otherwise go unnoticed until the next site inspection and that indicate underperformance or upcoming component or even system failures, can in most cases, be identified remotely through regular performance data analysis of the PV plant by using a smart solar performance monitoring system.

Today, however, users (especially O&M managers/engineers) require further insights on specific failures and underperformances and therefore, smart monitoring systems start providing additional functionalities around fault detection and fault diagnosis with insights and particularly, with actionable recommendations. A PV performance monitoring system today provides not only analysis features but also fault detection and diagnosis capabilities providing insight on the failure or underperformance root cause(s) and generating clear and actionable recommendations for performance optimization.

A “predictive” smart solar monitoring would in theory provide foresight capabilities towards optimization of O&M activities. For example, providing insights on the optimal replacement cycle including cost per time unit under the optimal age-based replacement policy information would be highly valuable information for an operator towards predictive maintenance activities. However, given the high complexity of this type of analysis, and the limitations in terms of lack of communication between devices and lack of standardization, this technology has not been deployed yet at full industrial scale and has not been sufficiently validated and demonstrated.

A prerequisite for a good predictive maintenance service is that the devices on-site can provide information about their state, in such a way that the O&M contractor can evaluate trends or events that signal deterioration of the device [11]. The asset owner or operator that wants to benefit from predictive maintenance should, as a best practice, select “intelligent” equipment set with enough sensors, and opt for a smart monitoring service. Furthermore, a standardization of status and error codes through inverters and data loggers within the same brand should be followed and, in the future, this standardization should become common to all manufacturers.

3.3 Power Plant Controller and Requirements for Grid Compliance

Continuous grid compliance is a requirement for all generators connected to the electrical grid. The evolving knowledge about PV systems and improvements in their capabilities, coupled with their increased uptake on grids (and therefore larger relative and absolute impacts on grids) [32], have resulted in increased requirements for grid compliance. This has evolved from “simple” anti-islanding protection functions of PV inverters [33] in the early 2000s, to additional grid support by these by the 2010s, such as reactive power control, (power) drop control, power factor control and the ability to remotely set values (i.e. enable curtailment) [34]. Updates to inverter standards over time also increase grid compliance requirements [35] which in some cases can be resolved through software (firmware) upgrades, and in other cases require hardware replacements or retrofits. The specific context where the PV plant operates can also affect grid connection or compliance requirements, for example where PV systems operate in high Renewable Energy Fraction (REF) environments [36].

For larger, possibly less solicited grids with lower REF values, grid compliance requirements are currently not as stringent, nor are the requirements homogeneous over similar geographic regions (albeit in different jurisdictions), with Distribution System Operators (DSOs) and Transmission System Operators (TSOs). For example, PV inverters in Belgium must have reactive fault current support deactivated [37], whereas just across the border in Germany, PV systems must provide reactive current support during faults [38], [39]. Homogenisation and adoption of more stringent connection requirements for neighbouring countries is expected over time, with a significant step taken having been in the EU, with the Commission Regulation (EU) 2016/631

[40], which established a network code on requirements for grid connection of generators, which is then combined with the appropriate standard according to the PV plant size, either EN 50549-1 (PV connected to LV networks) [41] or EN 50549-2 (MV networks) [42]. In the USA and associated jurisdictions, IEEE 1547 [43] sets the requirements for distributed energy resources, which includes PV systems. Some countries or geographical regions have their location-dependent challenges or characteristics, such as found in Australia's National Electricity Market with its extensive and sparse high-voltage grid which is seeing large amounts of renewable power coming online while thermal generators (mainly coal-fired stations) are decommissioned [44], posing challenges to the traditional power system operation paradigm. Given the different physical characteristics of inverter-based generation compared to synchronous generators, PV systems typically apply for negotiated generator performance standards [45] to connect and remain connected to the grid.

While compliance with grid requirements can be expected to last as an inherited trait from the design, construction and commissioning phases, changing requirements for grid compliance are very likely to occur over the plant's lifetime, given the technical and financial lifetimes of PV plants and the rapid deployment of renewable power and changes to the grid. The period to implement changes to the plants (repowering, retrofits) will likely be excluded from O&M KPIs, yet the O&M operator will have to adapt its processes to ensure that the PV plant continues to operate within the updated compliance framework.

PV plants of larger size are often required to be ready for dispatch by the grid manager, requiring added capex for installing the control and communication functionalities between the dispatcher and the plant. The dispatched plant can be curtailed, and the power factor changed by the dispatcher as the grid requires, at the cost of lost energy generation to the PV plant.

As PV plants increase in size to many tens of megawatts, the implementation of enabling control by the grid manager becomes more challenging due to the modular distributed nature of a PV power plant. The solution for this is a power plant controller (PPC), which centralises control over the plant so that it behaves as a single entity, in line with the applicable regulations. Depending on the jurisdiction and PV plant power rating, a certified PPC is obligatory for ensuring grid compliance, e.g., with [38], [39].

Given the above, it is the responsibility of the O&M operator to ensure compliance with all applicable regulations and grid codes, knowing that if and when these codes change, the O&M contractor's scope of operation and the KPIs originally defined may have to be re-evaluated.

3.4 Power Generation Forecast

3.4.1 Importance within PV O&M

More than 80% of the PV plants installed worldwide today have been commissioned only within the last 5 years. This reflects a constantly and significantly growing share of solar PV electricity in the global energy mix and, of course, an impressive increase rate of PV deployment and feed-in of electricity to the power grid. The growing PV penetration could also trigger the need for new regulations, in order to guarantee grid stability and correct balancing of electricity supply/consumption at all times, inevitably resulting in curtailment and losses to plant owners.

The two main challenges towards addressing such high penetration rates of PV systems are variability and uncertainty; in other words, the fact that PV power output exhibits variability at all timescales – from a few seconds to daily, seasonal or (multi)annual degree – and the fact that predicting such variability (PV power forecasting) is a task of high intrinsic uncertainty.

Within a PV asset management and O&M plan, PV plant power forecasting is an important element of the PV operations, which refers to the adoption of forecasting tools to calculate the expected PV power production for a certain timeframe, based on weather forecasts, satellite data, or measured irradiance and PV power. PV power forecasts depend on country/climate and plant/site. They can serve different stakeholders related to a PV plant, from PV asset owners up to grid operators and energy traders.

PV power forecasting services are generally offered by PV monitoring service providers and/or O&M contractors; however, other external service providers can also provide this function, based on proprietary or publicly available meteorological forecasts, satellite data, statistical methods, and site observations/measurements. Requesting such kinds of (optional) services, particularly from the O&M contractor, implies different service level agreement(s); which, in turn, may have an influence on the contract agreement for electricity dispatching, between the asset owner and the trading service provider.

From PV plant financing, project development and O&M perspective, the importance of PV power forecasting is multifold [46]:

PV power forecasting is the basis for trading PV-power on day-ahead or intra-day electricity markets. To ensure grid stability, deviations of forecasts from the actual PV power must be compensated with costly balancing power. Depending on the specific regulations for grid- integration of PV power in different markets, there are different models to cover these costs. With feed-in tariff models, plant owners receive a fixed price per kWh, and grid operations are in charge of balancing costs. For direct marketing of PV power, in some markets, PV power marketers directly must cover balancing costs (e.g., in Germany). In other markets contract agreements come with an associated level of reliability or performance “fidelity”, implying financial penalties for underperformance (e.g., China). Therefore, accurate PV power forecasting is indispensable for the bankability of PV plant projects not receiving a fixed feed-in tariff.

PV power forecasting allows for commitment and dispatch of conventional resources (e.g., diesel generator) with their given ramp-up time. This is particularly crucial in cases of remote systems (energy islands, geographical islands) or in micro grid applications.

PV power forecasting is a basis to optimize energy management for PV plants combined with storage in order to e.g., avoid curtailment or to compensate for forecast errors in short-term market.

When benchmarked with PV monitoring data, PV power forecasts can facilitate cross-checking and quantitative assessment of underperformance issues. Here especially satellite based now-casting can give valuable information.

PV power forecasts can be used as an additional input to maintenance schedules.

3.4.2 Requirements, Methodologies and Recommended Practices

Essential characteristics of PV power forecasts include the forecast horizon, the spatial and temporal resolution, and the update frequency. The requirements with respect to these characteristics vary with the envisaged application, the data availability, etc. For applications relevant to PV power systems or the power market in general, forecast horizons are typically up to 48 hours, the time resolution is 15 minutes to one hour (depending on the power system or the market). Forecasts are provided either for single PV power plants, for the overall PV power in control areas or for grid nodes. In this sense, common commercial services provide day-ahead and intraday power forecasts.

Typically, day-ahead forecasts are delivered in the morning hours (for the next day) and updated once or twice during the same day; whereas intraday forecasts are delivered and updated automatically every 15 minutes or every hour by the forecast provider. PV forecasts with longer time horizons (typically one week or more) comprise a more relevant practice when long-term planning, dispatching, unit commitment or maintenance schedules are to be addressed.

In terms of implementation methodology, we can distinguish three segments of solar PV power forecasting, namely: i) physical methods, ii) statistical and artificial intelligence (AI) based methods and iii) hybrid models. Most PV forecasting products and services combine several of these methods, often in a case-by-case context. An overview of PV power forecasting methods and associated accuracies is given by Lorenz et al. [47], where also limits and benefits of the different methods are discussed.

Irradiance prediction is an essential step in solar power prediction. PV power predictions are derived from irradiance predictions with PV simulation models and/or statistical methods (Figure 5), except time-series approaches for very short-term forecast horizons that are solely based on PV measurements. As Figure 5 depicts, irradiance prediction can be implemented based on different forecasting models for different forecast horizons (cloud-motion sky imager and satellite data, numerical weather prediction) and in combination with statistical learning approaches for optimized site-specific predictions. Next, PV power prediction steps refer to the conversion of irradiance to PV power with parametric PV simulation models and/or statistical learning approaches. A last step refers to the upscaling requirement of the regional PV power prediction [48].

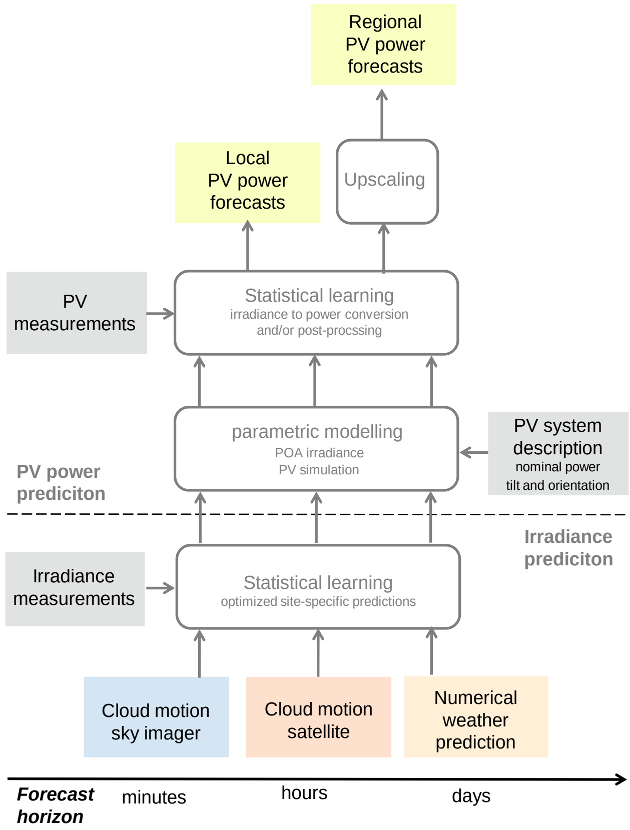

Figure 5: Overview of basic modelling steps in PV power prediction. Adapted from [49].

In the **physical methods** segment, PV power forecasting is implemented by analysing atmospheric data (e.g., cloud cover, temperature, pressure, or humidity), numerical weather prediction (NWP) tools or cloud observations (i.e., sky and satellite imagery).

Numerical weather prediction (NWP) models, routinely operated by meteorological services, are employed for forecast horizons from several hours up to 15 days- ahead several days. NWP models describe and predict the physical and dynamic processes in the atmosphere, employing current weather state observations as a basis to forecast weather patterns. Predicting dynamic changes of the atmosphere, including formation and dissipation of clouds as well as advection, essentially relies on this physical modelling. NWP-based modelling is highly computing-intensive. It is used for predicting the atmospheric characteristics on either a worldwide (global) scale or a continental/regional scale (mesoscale). Broadly used and validated NWP global models are the Integrated Forecast System (IFS) operated by the European Centre for Medium-Range Weather Forecasts (ECMWF) and the Global Forecast System (GFS) by the US National Oceanic and Atmospheric Administration (NOAA).

Examples of mesoscale models are the North American Mesoscale (NAM) model and the Weather Research and Forecasting (WRF) model. Generally, NPW models are differentiated mainly in terms of their employed physical models, their spatial resolution and the input parameters. Typical resolutions for Global NWP models are ten kilometres to 50 kilometres and temporal resolutions of one, three or six hours. Mesoscale models have finer grids of typically three kilometres to 10 kilometres with hourly resolution.

For intra-day horizons of several hours ahead, forecast with higher spatial and temporal resolution and higher accuracy can be inferred from satellite data. In the *satellite-imaging* domain, the cloud pattern is determined through the analysis of images (in both the visible and the infrared spectrum), generated with the use of satellite-based sensors and imaging systems. Multiple, consecutive satellite images are combined to determine cloud structures during earlier recorded time steps and to generate cloud-motion vector fields, which, in turn, can be utilized to forecast future locations of clouds and their variability. As such, these methods are used effectively in predicting irradiance (particularly GHI) with a temporal resolution of 5 minutes to one hour with a spatial resolution of one kilometer to five kilometres up to several hours ahead. For intra-hour PV power forecasting sky-imagers offer the potential to forecast irradiance with a temporal resolution down to minutes or even less and a spatial resolution in the range of several meters to 100 m.

Sky-imagery can be effectively employed for sub-kilometer observations of cloud shadows, e.g., over a utility-scale PV power plant, suited thus for PV power forecasting of high spatial resolution. Sky imaging systems employ digital – typically, charge coupled device (CCD) type – cameras and refer to the ground-based identification of clouds, cloud motion determination and measurement of cloud height above ground. PV power forecasting via sky imagery analysis comprises of four steps:

1. Image acquisition near the forecast site, using the sky imager.
2. Sky image data analysis for cloud pattern recognition.
3. Cloud-motion vector estimation.
4. Short-term probabilistic and deterministic forecasts of cloud cover, irradiance, and PV power.

Overall, the detailed cloud cover (structure, extent, and motion) analysis achieved by sky imagery renders this method a very suitable tool, for very short-term PV power forecasts or a so-called nowcasting, for certain PV installations. Maximum forecast horizons of sky imager forecasts depend on the extent of the monitored cloud scenes and cloud velocities. They typically range between ten minutes and 30 minutes ahead.

PV power forecasting based on **statistical and artificial intelligence (AI) methods** – also mentioned as time-series and machine learning methods respectively – refers to the implementation of advanced analytics on historical data of solar irradiance, for a given PV installation site. Statistical and AI methods maybe employed as pure ‘time-series approaches” solely based on local measurements. They also may be employed for statistical post-processing and to infer PV power from NWP or satellite-based forecasts, which are described as hybrid models below. The user community for statistical methods and artificial intelligence refers to the former as “statistical models without exogenous input” and to the latter as “statistical models with exogenous input”.

Common examples of statistical and AI methods applied for PV power forecasting, include the use of artificial neural networks (ANNs), neuro-fuzzy models, the support vector machine (SVM), hidden Markov models (HMM), regression analysis and auto-regressive (AR) models. AI or machine learning algorithms are well suited for PV forecasting, all being based on the same principle, i.e., of utilizing existing data for modelling parameters and creating (self) learning patterns towards classification, regression, and prediction.

Today, ANNs represent the most common machine learning technique, accounting to nearly a quarter of all methods used for PV power forecasting, notably due to their ability in resolving complex and non-linear forecasting models. The accuracy and robustness of machine learning (ML) based PV power forecasting depend on both the training method and the evaluation metric for the quality of the forecasts. Also, the access to quality-controlled PV power measurements is crucial.

Pure time-series approaches benefit from the high accuracy of on-site measurements of irradiance and PV power and the high autocorrelation for short time lags in time-series of solar irradiance. However, changes in cloud conditions, such as approaching clouds, can hardly be predicted based on local measurements alone.

Hybrid models in PV forecasting combine two or more of the aforementioned methodologies, thus aiming to leverage their individual benefits and/or overcome certain limitations, in terms of accuracy, forecast horizon or temporal and spectral granularity. A common case is the fusion of NWP models with ANNs (i.e., hybrid-physical models), where the outputs of the former are used as inputs for the latter, for training the latter, in a self-learning loop.

In practice, integrated approaches can be implemented in nearly any form and combination, i.e., linear-linear, nonlinear-nonlinear, or nonlinear-linear models, whereas all can be classified into either competitive or cooperative approaches [50]. In this sense, it is also particularly common to utilize multiple predictors, e.g., by coupling statistical and learning machine techniques (i.e., hybrid-statistical models), to obtain aggregated decisions for improved PV forecasting accuracy or to further self-training. In their review study, Diagne et al. [50] discuss in detail how integrated PV forecasting methods outperform individual ones in multiple aspects.

On the basis of reported literature and today’s research status in the field [50], [51], [52], [53], Table 3 summarizes typical spatial and temporal resolution as well as forecast horizons for the PV forecasting methodologies that have been discussed.

Summarizing, good forecasting practice for PV power plants requires numerical weather predictions as input for day-ahead forecasting and a combination with satellite data and/or online PV power measurements for intra-day forecasting. Further, statistical post-processing is a recommended practice in all cases, which requires measured PV power data as a basis to adapt the forecasts.

Here, near-real time data feeds from PV monitoring systems towards PV forecast providers are beneficial, as input for shortest term forecasting and for continuously updating the training of machine learning models with recent data. Finally, it is highly recommended as best practice to warn and communicate (when applicable) all scheduled outages and the expected duration of forced outages to the forecast provider.

Table 3: Typical forecast horizons and typical temporal and spatial resolutions for different PV power forecasting methods. Statistical/AI tool for post-processing can be applied to all models and forecast horizons.

	Forecast Horizon	Temporal Resolution	Spatial Resolution
NWP	2 – 15 days	1 - 6 hours	1 km - 50 km
Satellite based cloud motion	2 – 6 hours	5 – 30 minutes	500 m – 5 km
Sky Imager cloud motion	10 - 30 minutes	1 second – 1 minute	2.5 m – 500 m
Statistical / AI tools (no exogenous input)	10 minutes – 2 days	1 second – 1 day	PV plant

3.4.3 KPIs/Accuracy Metrics and Uncertainties

Introducing and understanding key metrics and considerations in PV forecasting, allows to better assess and compare the performance and accuracy of the different PV forecasting models, as well as to weigh the impact of different parameters on them.

In their work, Zhang et al. [54] point out that classical KPIs may not fully address the different requirements of grid operators, O&M managers, or investors in relation to real-case PV power plants. Indeed, for the latter, certain metrics that "penalize" large errors are indispensable, considering that such forecasting errors also have highly negative impact, in both finiancial and operational stability/reliability terms. From this perspective, PV forecasting KPIs, or metrics can be classified into four categories:

1. Statistical metrics for different time and geographic scales.
2. Uncertainty quantification and propagation metrics.
3. Ramp characterization.
4. Economic metrics.

The most common statistical KPIs for PV forecasting quality are the root mean square error (RMSE) and the mean absolute error (MAE), which are defined in Eq (15) and Eq (16).

$$RMSE = \sqrt{\frac{1}{N}\sum_{i=1}^{N}\left(P_{for} - P_{act}\right)^2} \tag{15}$$

$$MAE = \frac{1}{N}\sum_{i=1}^{N}\left|P_{for} - P_{act}\right| \tag{16}$$

where P_{for} and P_{act} are the forecasted and actual (measured) power output and N refers to the sampling count (size). In other words, RMSE points out and "penalizes" large errors in a square error; while MAE shows the average difference between the actual and modelled (forecasted) values, thus being suitable for evaluating uniform forecast errors. Typically, RMSE and MAE of PV power forecasts are evaluated using day-time values only and normalized to installed PV power.

Yet, both RMSE and MAE are only unbiased for cases of Gaussian distributions. Besides, when used stand-alone, they present certain limitations such as in the case of over forecasting tendency, as highlighted by Zhang et al. For this reason, other statistical parameters, particularly skewness and kurtosis are also used. Further, with respect to uncertainty quantification and ramp characterization in PV forecasting, other metrics such as the Rényi entropy, the standard deviation of the power forecast errors, and the "swinging door" algorithm are proposed. Recently, Yang et al. [55] proposed to apply the well-established Murphy–Winkler framework for distribution-oriented forecast verification as a standard practice to analyse and compare solar forecasts.

Furthermore, the comparison to simple reference models, quantified by "skill scores" is a frequently applied check to assess forecast quality. A forecasting tool has skill if it is able to outperform trivial models. In solar irradiance forecasting, the simplest and widely used reference model is persistence, i.e., the assumption that cloud conditions stay the same ("persist") in the future.

In addition to the computation of KPIs, at least basic visual analysis is recommended. A direct comparison of measurements and forecasts in scatter plots or two-dimensional histograms and time-series is very helpful to develop a better understanding of forecast performance.

From the economic metrics' perspective, as explained by Antonanzas et al. [51], the way grid operators address irradiance (thus solar and PV yield) variability is through reserves. Practically, the greater the penetration of solar energy, the bigger the energy reserves (and their associated costs) must be, to mitigate potential variations. On this basis, the number of operating reserves and, consequently, the operating costs can be significantly reduced when accurate PV power forecasts are achieved and leveraged. Perez et al. [56] propose the concept of firm power forecast to evaluate the economic value of forecasts and as an operational strategy to integrate increasing amounts of intermittent solar generation on power grids. The costs incurred in transforming imperfect into firm predictions define the new metric: these include the costs of energy storage and output curtailment necessary to make-up for any over/under prediction situations.

Finally, specifying the expected uncertainty of PV power predictions gives valuable additional information to forecast users and helps them to assess the risk associated to using the forecast as a basis for decisions. Probabilistic forecasts or confidence intervals provide situation-specific uncertainty information, e.g., as a function of the cloud conditions and the time of the day. As reported in the literature [54], using the 95th percentile of forecast errors is a simple and frequently used option to e.g., quantify the minimum required operating reserves.

3.4.4 State of Play

With the increasing contribution of PV power to the electricity supply in many countries, a strong need for reliable PV power predictions arose during the past decades. Reacting to this new and rapidly evolving situation on the energy market, with great need for reliable solar power predictions, increasing effort has been spent on developing and enhancing solar irradiance and power prediction models. Today, PV power prediction systems are an essential part of electric grid management in countries that have substantial shares of solar power generation, as e.g., Germany or Spain. Several companies offer good quality worldwide PV power forecasting services.

PV power forecasting is offered for different temporal and spatial scales depending on the needs of different stakeholders. Many forecast providers address different applications and stakeholders, but most of them have a specific focus and/or specific strengths, depending on their key customers and/or their background.

As described above, PV power forecasting integrates different models and data: Meteorological models for irradiance forecasting for the different temporal and spatial scales, PV simulation for irradiance to PV power conversion, statistical or machine learning approaches to improve forecasts or infer PV power predictions, and PV power measurements as a basis to train ML forecast algorithms. A good PV power forecasting service integrates all these elements, but not necessarily all of them must be operated by a PV power prediction services provider.

Companies offering PV Power forecasts often have a strong background in one of these elements. Private weather forecasting companies extend their meteorological services to additionally offering PV power forecasts, providers of long-term satellite data also offer satellite based short term predictions, experts in machine learning set up PV power prediction services using data from other companies, and PV monitoring service providers exploit their access to PV power measurements for PV power forecasting.

Also, several forecasting services have been developed to specifically address the requirements of grid-operators, partly by companies also offering wind power predictions. Grid operators typically require forecasting services for aggregated PV power in their control areas as a basis for allowing PV power on the grid and for congestion management rather than forecasts for single PV power plants. Mostly these companies have extended their portfolio to also provide forecasts for single PV power plants and direct marketing.

Any PV power forecasting service offering day-ahead predictions - be it for control areas, grid nodes, or single PV plants - requires NWP irradiance forecast as essential input. Here, it is good and common practice to employ NWP forecasts from public or private weather services. IFS forecasts provided by ECMFW are a popular choice because of their high accuracy [57] as well as freely available GFS forecast, or meso-scale models forecasts of national weather services. Some forecast providers also run their own weather models, with the freely available

WRF model often used. Top forecast providers do not rely on one single NWP model but integrate several models. Simple averaging is beneficial here, because forecast errors of different models are not fully correlated and therefore partly cancel each other. More advanced forecast combinations exploit strength and weaknesses of different models for different weather situations.

Intra-day PV power prediction services mostly combine NWP predictions with online-PV power measurements as additional input for very short-term horizons of five minutes up to several hours ahead. Here, the access to these online measurements is of critical importance. Therefore, PV power prediction services are frequently offered by PV monitoring service providers and/or O&M contractors. Another option is that access to online PV power measurements is directly given to the trading service provider, e.g., a direct marketer, or a PV power prediction service provider. Direct marketers often run their own PV power forecasting tools or cooperate with PV power prediction service companies.

A valuable additional data source for improving PV power forecasts for several hours ahead are satellite-based cloud motion forecasts. Only a comparatively small number of companies worldwide operate satellite based short term predictions with good quality. Mostly, these companies offer their own PV power prediction services with the satellite-based forecasts being a special feature. Some also deliver the satellite-based irradiance forecast to other PV power prediction providers.

For very high-resolution intra-hour forecasting, few specialised companies offer sky-imager based PV forecasting, which is a comparatively new field, with respect to model and application development.

PV power forecasts in principle may be offered based on irradiance predictions in combination with PV power simulation. However, forecasts for all forecast horizons benefit from high quality PV power measurements as a basis for improved forecasts with statistical or ML algorithms. For single plant forecasts, they may be used to adapt the forecasts to the specifics of a PV plant, including e.g., shading or adaptation of orientation which is often not correctly specified. All high-quality PV power services providers adapt their forecasts to PV power measurements in some form, which makes access to these data crucial.

Finally, for customers of PV power forecasting services, besides the used models, data, and accuracy of a service, also the form of implementation as well as general considerations with respect to contracting service partners are of importance. Most PV power service providers offer to deliver forecasted PV power data to their customers, e.g., using a web-service or by providing the data for download on a web-platform. Though, also the implementation of PV power forecasting tools on-site is offered by some providers for customers who prefer this option, e.g., because confidential data is involved. With respect to deciding for a service partner, it may be convenient for an asset owner to choose a partner he is already working with, e.g., a monitoring and/or O&M service provider or a trading service provider. Such kinds of additional, optional services imply different service level agreement(s) and may also impact contract agreements with other partners, e.g., using a forecasting service from the O&M contractor, may have an influence on the contract agreement for electricity dispatching, between the asset owner and the trading service provider.

3.5 Power Plant Safety Considerations

3.5.1 Overview

Grid connected PV power plants are expected to have a technical lifetime of decades, with maintenance, repairs or modifications required to ensure continued power production. Several PV plants have already demonstrated their ability to operate over time spans of decades [58]. Maintenance activities of PV plants expose personnel to safety risks which must be known, understood, and mitigated appropriately. Legislation and standards such as ISO 45001 [59], ANSI Z10 [60] have been put in place to ensure general workplace safety, often in conjunction with ISO 9001:2015 [61] which aims to ensure that risk-based thinking is applied into the management system; in this case, the operation and maintenance of PV plants. Since 2017, the IEC 63049 [62] standard is available for the PV industry which provides guidelines for effective quality assurance in PV systems operation and maintenance. Here, quality is taken as an encompassing term that also covers risks and risk-based thinking.

Asset owners have the legal responsibility to warrant the health and safety[1] of the people inside and around a PV power plant. By having an O&M company under contract the responsibility of safety is internally transferred to the service contractor.

The commissioning of a PV power plant is usually executed by the engineering, procurement, and construction (EPC) company engaged by the owner. It must confirm a regular commissioning and that the plant can safely be operated, in line with local laws and regulations, and any other project-specific requirements. After the proof of such procedure having been successfully passed, is delivered, the plant (and associated risks) is handed over to the principal, who in turn may engage an O&M contractor.

The safe and reliable operation of PV power plants is essential to ensuring that the asset can deliver power as expected. Among the best practices applied is the use of specialised and qualified staff to deal with special components such as power conditioning units/inverters, who are sourced either from the manufacturer itself or from a qualified and authorized service partner of the manufacturer, where the use of quality management and risk management systems such as IEC 63049 and ISO 9001:2015 are essential.

A key tool to minimise or eliminate risks is the hierarchy of controls methodology, as shown in Figure 6. At the O&M stage the ability to eliminate risks is limited compared to the design and construction phases (where safety can be designed into (or omitted in the design of the PV plant) unless additional investments are performed.

[1] Safety as the state of being safe as person; freedom from the occurrence or risk of injury, danger, or loss.

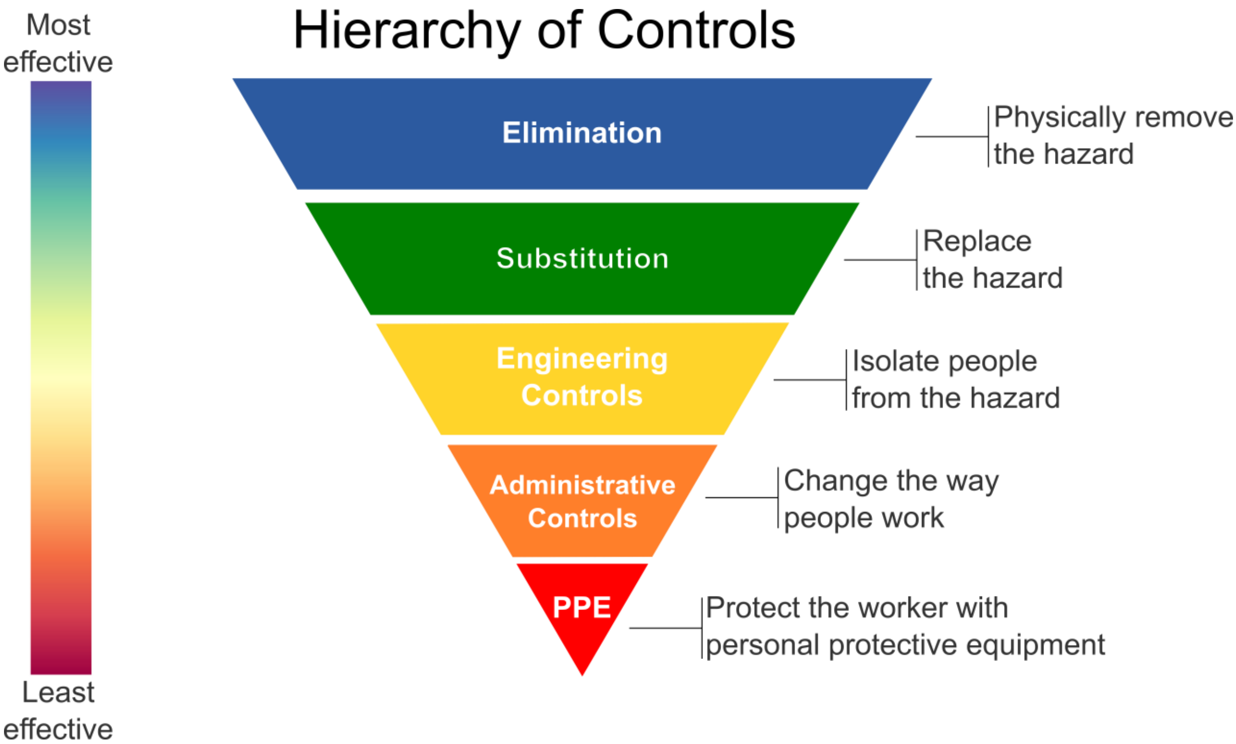

Figure 6: Hierarchy of controls, adapted from [63].

Consequently, the focus of this section is more on best practices around known and typical safety issues that can be encountered during the operation and maintenance of PV plants.

3.5.2 Qualification of PV Maintenance Staff

Assuring a safety power plant operation presumes skilled and experienced service staff. Moreover, the attitudes of staff and systems in place can mitigate or exacerbate risks that are present. To keep the plant in electrical safe conditions the maintenance staff should have expertise and knowledge related to the construction and operation of the electrical equipment and installations of the PV power plant. It also should have been given special safety instructions for high power and/or high voltage DC systems, with central inverter PV plants operating with 1000 Vdc or 1500 Vdc, whereas internal AC ring mains for larger utility-scale power plants or distributed over large areas can operate anywhere between 12 kV and 36 kV. Typically, general work on electrical components is restricted to qualified or registered electricians, while work on inverters or transformers require additional training and/or certifications.

Skilled maintenance personnel should have the following qualifications to maintain PV power plants safely and successfully:

- Qualification as certified electricians or equivalent trained persons
- Current first-aid training certification with qualification for emergency first aid for electric shock
- Training in how to deal with hazards and risks associated with operation and maintaining electrical devices and plants
- Familiarity with the special high power DC application of the PV plant

- Knowledge of how the PV power plant works and is operated
- Skilled or instructed according to valid electrical safety standards and the use and care of a referring safety equipment
- Selecting and using personal protection equipment
- Knowledge and understanding of technical plant documents and component manuals with all described safety precautions
- Authorisation to connect and disconnect medium-voltage sources if maintenance activities are required for medium-voltage components or other parts of the power plant.
- Beside electro-technical knowledge, knowledge of relevant PV standards and directives is desirable

The execution of different maintenance works typically require different qualifications and safety equipment.

To ensure the health and safety of workers at a PV power plant, a tailored system of main theoretical PV basics, safety training and procedures must be established, where IEC 63049:2017 [62] and ISO 9001:2015 [61] can inform the course design and the subsequent implementation and monitoring on an organisational basis. The training then also serves as proof of the special qualification required to confront any incidents occurring.

A. Personal Protective Equipment

Authorized service staff / personnel must be equipped with appropriate personal protective equipment (PPE) including the following:

- Safety glasses
- Ear protection
- Steel-toed safety boots
- Safety hard hats
- Padlocks and barriers
- Double-insulated tools
- Appropriate qualified measuring instruments, regularly checked and re-calibrated. For instance: appropriate LV meter to verify that the circuits are de-energized (1 000 V AC and 1 000 V rated, or 1 500 V DC rated, dependent on max. DC system voltage)

B. Special maintenance safety instructions

- Cleaning of PV modules
- Replacement of defective PV modules
- Safely changing a DC fuse link in a field connection / combiner box and in the DC inlet of a PV inverter

- A strict smoking ban inside the PV power plant: fire risk due to increased/rapid vegetation growth in and around PV arrays

For a change of DC fuse links during plant operation, a verification with a meter is a must to confirm that the DC circuit is de-energized. Opening a module string is only allowed after measuring and confirming that there is no current on the circuit. Some DC switches used in the field of a PV plant (e.g., field combiner boxes) may not be designed for load-break operation (disconnect switch). Disconnect switches shall be labelled as non-load-disconnecting. These must never be opened while the system is operating. Before opening such a DC switch that is not rated for load break, the referring sub-system should in any case be switched off respectively by disconnection of the inverter in question.

3.5.3 Electrical Safety Considerations

In this section we describe relevant safety considerations regarding electrical safety in general, with requirements regarding qualification of maintenance staff, training of the staff, personal safety equipment, and PV special instructions. While the overall hierarchy of controls methodology remains valid and applicable, it is advisable to consult more specific sources such as those discussed by [64].

PV power plant operation should take place under safe, continuous, and trouble-free conditions. Planned service routines should keep the plant in an up-to-standard condition, be well scheduled and executed and result in minimum energy losses. Extraordinary plant or sub-plant shut offs are often considered in the yield expectations or considered by an availability factor. In practice, when such availability factor of a PV power plant is considered in the initial financial calculations, a clear definition is indispensable. The same applies for O&M contracts which include an availability clause.

The electrical safety of a PV power plant in general presumes a consequent electrical safety concept in design, by selection of high-quality products, for PV applications certified components and the strictly conducted concept in practice [65]. Among others, health, and safety rules, referring regulations, relevant national and valid international photovoltaic standards / codes are considered. Knowledge of manuals of main components ensures that professional maintenance directives will be executed, and special safety precautions applied.

A. General electrical safety of PV power plants

The electrical design of PV arrays of large PV power plants is typically classified as ground-free, Safety Class II and designated as IT grid (insulated earth). This classification refers to all electrical components such as PV modules, DC cabling, field connection boxes must have double isolation. Safety Class II or double insulated electrical appliances is designed in such a way that it does not require (and must not have) a safety connection to electrical earth/ground.

At the international level, according to the EU standard [66], the operator of the electric facility (the PV plant) is responsible to indicate which testing period is suitable for the facility. This procedure leads to a self-responsibility and self-certification situation, which is mitigated by the incentive for the principal: the operator must ensure the reliable (and therefore safe) operation of the plant, partly also to be able to claim insurance in the event of an incident.

However, there are national norms and regulations or even contractual agreements with grid operators that reverse the above argument, as these require all (PV) power plants connected to the (medium or high voltage) grid to be always operated at a safe operational level.

B. Electrical safety from the viewpoint of maintenance

As in any facility generating electric power, electrical safety in a PV power plant is of the highest priority. One major difference with other types of power generation plants is that the primary on-site electrical system is associated with the production of DC power. In cases of DC short-circuits in the field, hazardous arcs may occur. Such a case may affect persons and cause damages of material to a certain extent by fire, as well as follow-up repair efforts and costs, depletion of spare parts and finally, energy production losses.

In large PV power plants nearly all types of maintenance work bear safety risks. A well-organized maintenance strategy applies a special maintenance risk management to provide an as safe as possible working environment. It covers and presents all relevant hazards and presents adequate solutions for mitigation. Since each PV power plant has unique characteristics, the risk management must be adjusted individually. However, most PV power plants share many features, and organizations that perform O&M on multiple plants typically have procedural documents which have common sections, combined with specific sections for the individual plants.

For servicing and maintaining PV power equipment, a team of minimum two people is required. In case of any accident on site or weakness of one person the other can immediately initiate help actions. An emergency list with addresses and phone numbers to be contacted and informed must be available for personnel at short notice, which typically must be carried with the person or in the vehicle.

C. General Safety Precautions

As in any other electrical installation, basic safety precautions must be strictly adhered to in PV power plants' operation. Plant owners are legally liable for the asset, and, among others, they are responsible for safety issues. Risks are covered by an indemnity insurance. In case of an accident inside the PV plant the asset owners and operators are obliged to give evidence to have taken all preventive measures for protection of people against accidents. Even visitors of a PV plant, before entering the site, must undergo safety instructions and act in accordance with precaution guidelines. Similarly, a list of emergency contact numbers should be made available for easy access by staff and visitors, which can reduce the time between an issue occurring and a call for help being made.

To ensure safety at the place of work whilst e.g., interventions, maintenance or repairs are taking place, it is necessary to respect the following internationally accepted five rules. These ensure proper lockout-tagout (LOTO), so that work is performed on de-energised systems as shown in Table 4.

Table 4: Safety Rules for Works in Electrical Facilities [11], [12], [67].

Rule	Action	Special conditions / Remarks specific for PV plants
Rule 1	**Isolate** / **separate** completely (isolate the installation from all possible sources of electrical power)	
Rule 2	**Protect against reconnection**, fix (protect against reconnection) in the open position all the breaker components or switching device in the on position, or adopt preventative measures when that is not feasible	
Rule 3	**Check that voltage is not present**, verify there is no electrical power, after having previous identified the place of work and the installation which has been placed without electrical power	⚠ Caution, PV special 1: at daylight PV modules / module strings are voltage-carrying. For getting real voltage-free conditions covering modules / module strings with opaque material is required. ⚠ Caution, PV special 2: works at an opened PV inverter cabin requires verification of absolute de-energized inverters: internal capacitors must be de-energized! The time to be considered must be provided by the inverter manufacturer. It may e.g., last 5-15 minutes!
Rule 4	**Ground** and **connect in a short circuit**	
Rule 5	**Protect** against nearby power sources and cordoned off the working zone	

The above-mentioned rules are especially valid for MV/HV switching equipment and disconnecting devices in transformer stations or in medium stations of large PV power plants. When switching operations are carried out at such points, only authorised specialists are allowed to perform such operations, wearing protective equipment if necessary.

3.5.4 Weather Conditions Increasing Risk during and Post Events

A. Thunderstorms

Due to massive wide-spread metallic structures and cabling PV power plants are more likely to be affected by thunderstorms than other structures in the area. Even though a lightning protection system is typically installed following best practices and according to local regulations – which should protect the investment - it does not guarantee a protection of people inside the plant. Thus, during a thunderstorm the complete plant site must be vacated by maintenance personnel for safety reasons. Best practices in this area include proactive weather monitoring (e.g., "push" notifications on smartphones to warn of approaching storms) by O&M personnel to prevent any personnel being on-site if a thunderstorm is likely to appear.

B. Heavy rain

PV power plants often cover a large area. Heavy rain falls may turn the terrain to mud, and areas may be inundated. Walking around the site by maintenance crews in such conditions will see increased risks to personnel such as sprains or dislocations, the potential for vehicles to become bogged, as well as increased risk of electrocution due to reduced electrical insulation compared to dry conditions. In some areas, heavy rains can even result in flash flooding occurring. Given the increased risk of electrocution due to the lowered resistivity of the area, proactive de-energisation (ideally, remotely operated) of inverters or strings prior to movement among arrays is recommended.

C. Damaging winds

In the event of high winds (above 50 km/h sustained, or wind gusts above 80 km/h) being forecast for the area of the PV plant, it is recommended to reschedule maintenance activities to another time. This reduces the risk of elements (in the worst case, modules) becoming airborne while the maintenance crew is onsite. After such an event has occurred, staff should exert special care, as modules may have come loose, or the presence of debris within the power plant may increase risks, such as the likely presence of broken glass and potentially exposed or frayed electrical wiring.

D. Natural hazards

The presence of insects or venomous animals in PV plants may be a risk throughout the year, or peak in certain periods. In the case of poisonous snakes or arachnids, rapid response procedures must be known and adhered to; in some cases, this requires having anti-venom on site if bites occur. In other cases, having a wildlife catcher on speed dial can help in safely catching the insect or animal. Note also that killing such animals is often illegal according to local legislation, and significantly increases the likelihood of bites occurring. Works in mosquito areas require special protection such as mosquito nets and repellent, and in specific cases additional prophylactic actions, such as taking anti-malaria pills.

E. Fire safety ground-mounted

Fire constitutes a major risk and hazard to the safe operation of a PV plant and its surroundings. To reduce the risk of fire spreading over large areas, ground-mounted PV plants are typically designed with fire breaks, such as roads or areas where vegetation is kept to a minimum. Moreover, local rules and regulations often require site visits and consultations with local fire brigades for development approvals, aiming at ensuring that fire risks are eliminated or minimised at the design stage. The visit should include the information on how the fire brigade is embedded in the PV plant's emergency plan and the communication strategy. An appropriate firefighting strategy must be developed [68]. Guidelines for fire-fighters to operate in or near PV plants have already been published in multiple countries such as Japan, the United States, Germany, and Australia. On the other hand, the British BRE National Solar Centre released some recommendations for photovoltaic industry with the input of British fire brigades [69] and a detailed literature and standard review [70].

Vegetation management such as clearing of weeds and cutting the grass on site is a key component of fire risk reduction. Additional fire risks stemming from PV components (modules, inverters, transformers) require on-site inspections combined with monitoring software and/or the use of SCADA to rapidly shut off parts of the plant in the event of fire, or the detection of indicative parameters [23], [71].

3.5.5 Building-Mounted PV Safety Considerations

Building-mounted PV systems have specific safety risks and considerations in addition to ground-mounted ones. These risks stem from the fact that the PV installation is mounted on a building, and the PV installation is at a height where there is a risk of falls.

Building-mounted PV can be either applied (BAPV) on or physically integrated (BIPV) in the building skin. BAPV systems include all the PV installations added to flat or inclined roofs. BIPV elements can be part of the roof, façade or part of a balustrade or another integral part of the building (envelope). Such elements have both structural and electricity production functions. Apart from "pure" building applications, PV can be applied or integrated in individual infrastructure, such as noise barriers, railway station shelter roofs, and carports, which typically have different or additional security requirements, compared to BIPV or BAPV.

Typically, building mounted PV installations are electrically connected via the power connection of the building to the grid. As such, the electric low-voltage installation standard IEC 60364 is applied, particularly Part 4 ([72], [73], [74], [75]) and Part 7-712 [76] for safety and PV installation aspects respectively.

In practice, constructors, and O&M managers of BAPV or BIPV installations must ensure compliance with certain additional norms, technical specifications and directives that regulate:

- Requirements for non-flammability and fire load for modules and underlying construction elements, particularly thermal insulation, or roof membranes, but also cables and installation tubes
- The distance of the array from firewalls or roof edges
- Fall protection related to working at heights
- Fire protection depending on the buildings height and use, which can have consequences for the PV system installation
- Dimensioning and routing of cables in the building, and their allowed load with regards to fire protection
- Glass safety and construction of modules for overhead glazing or balconies
- Periodic controls of the electrical installations, in particular of building mounted PV installations

Furthermore, a PV installation must be integrated into existing protection elements of the building, such as lightning and surge protection or the equipotential bonding, as well as preventive fire protection measures. These elements should be verified with all involved parties and the insurer.

Many of such regulations depend on the use of the building, as well as on national and local regulations. Also, in general, BAPV has less stringent requirements because in its case the PV array is clearly separated from the building envelope, whereas in the BIPV case the array consists of multi-functional BIPV elements or are even construction products, with dedicated standards [77], [78]. An overview of the existing regulations for building-mounted PV, including guidelines for prevention of losses can be found in existing literature [79], [80].

Some of the additional requirements for building mounted PV stem from the fact that in and around the building persons are present and not only in the case of maintenance of the PV installation, as is often the case for ground-mounted systems.

For example, in case of an inclined roof in snowy regions, persons passing by may be in danger because of a sudden roof snow avalanche. Depending on the situation, temporary measures that eliminate the risk – cordoning off the affected area, clearing off the roof from ice and snow - or constructive measures such as a snow retention system must be previewed.

In building-mounted PV installations, which are connected via the power connection of the building, self-consumption of the PV electricity in the building and net metering are also considered, depending on the local legislation. In addition, batteries or an uninterruptible power supply can be integrated to enhance auto-consumption or to ensure electric power supply for critical usage in case of grid failure, but it must also then be an integral part of the security concept.

A. Maintenance

Maintenance of BAPV or BIPV systems can be done according to a maintenance plan that has been already developed at the planning phase of the PV installation. With this, it is ensured that visual inspection and maintenance can be done safely and efficiently, at predefined time intervals. On flat roofs that normally include fall protection measures such as lifelines at anchor points, sufficient spacing should be considered between the PV rows, so that the modules can be cleaned, and any unwanted vegetation or other shading obstacles can be safely removed. It is necessary to facilitate maintenance interventions to building-mounted PV installations while avoiding damage to building components such as tiles, skylights, or roof membranes and that their function is not compromised. Similarly, safe access to other technical equipment installed on flat-roofs, e.g., thermal PV collectors or ventilation mono-blocks, must be ensured, for trained technical personnel. Typically, the O&M plan of the building-mounted PV system should be an integral part of the O&M plan of the building.

B. Working at height: risk of falls

This risk stems from working at heights and on the (roof) structure onto which a PV system is installed, where there is a risk of falls. For these reasons, staff that perform maintenance on building-mounted PV systems often require additional training, which may or may not be mandatory per jurisdiction. Examples of such requirements range from “working at heights” certifications, to the need to use climbing harnesses (and sometimes to have climbing certifications) to enable safe access to PV equipment in exposed areas (façades, close to roof edges). Examples of poor workmanship or system design have resulted in loss of life e.g., as the roof could carry the weight of the PV equipment, but not the additional weight of the O&M personnel, resulting in the roof collapsing.

Potential risks can also arise from roof windows and smoke/heat extraction installations, which must either be breakthrough-proof or have a sufficiently indicated location and large safety distance from the PV elements, to prevent accidental falls.

C. Fire safety for building-mounted PV systems

For building-mounted PV systems, the installation must not only be “fireproof”, but also "fire brigade friendly". Hence, it is recommended that fire brigade experts inspect such PV systems in advance, particularly for systems of installed capacity >30 kWp (corresponding to approximately 200 m² solar module area). Ideally, the installer or owner should carry out an inspection with the fire brigade upon commissioning, which also assumes that the fire brigade has been involved in pre-installation or design stakeholder meetings.

For this, according to existing example cases [81], the technical documentation with all plans and electrical diagrams, as well as the components of the PV system must be available. A copy of the documentation must be located with the 230 V/400 V electrical panel (AC) or with the inverters. This document must contain the following information that is important for the local fire brigade:

1. Location of the AC switch-disconnector
2. Location of the 230 V/400 V electrical panel (AC) with FI circuit breaker
3. Location of the DC load break switches and inverters
4. Location of PV fireman's switch, if available
5. Location of the generator connection boxes, if available.
6. Information on whether the array boxes have DC load break switches or not; and if these can be operated manually or by means of PV fireman's switches
7. A guarantee that the operable safety components are accessible
8. Location of the solar modules
9. Information on roof access/paths without stepping onto solar modules
10. Information on where the roof skin can be opened without damaging the solar modules
11. Warning and information signs on the PV system and its components. The operable safety components can be quickly identifiable during operation
12. Telephone numbers of the operating personnel, safety managers and/or contact persons

For systems with a minimum size of 30 kWp, a fire brigade deployment plan with the most important mission-relevant information must be drawn up. Yet, it must be noted that firefighters' practices and requirements can differ [68]. Analyses of the causes of fires in PV installations and on the firefighters’ interventions have been made and recommendations are given in the BRE recommendations [70].

D. Special Safety Aspects of BIPV

In addition to the above considerations, special safety, and reliability aspects for BIPV systems can also include:

- Compared to free-standing modules, the rear sides of modules in BIPV and BAPV installations are often not easily accessible for visual control. Therefore, adapted inspection methods may be required
- Higher module operation temperatures are to be anticipated, also for the junction boxes and bypass diodes, because of limited ventilation conditions, in cases of confined BIPV modules

- Higher requirements of non-flammability of the underlying construction elements, particularly regarding thermal insulation or roof membrane materials
- In the built environment, shading of a part of the installations during several days of the year by neighbouring buildings, trees, or building details such as balconies (for BIPV façades) or technical infrastructure elements such as ventilation outlets and/or HVAC systems may cause hot spot effects. As a mitigating measure today, DC optimizers are often used for modules in BIPV systems where shading is inevitable, eliminating hot spots (and with-it further hazards, such as melting or fire), while maximizing the PV energy yield. Yet, particularly in the case of BIPV systems, with their higher operational temperatures, there is no sufficiently long-time experience with respect to the durability of the DC-DC-transformation components

3.5.6 Conclusion

One of the factors for PV's success has been its reduced O&M requirements compared to other types of electricity generation. However, low maintenance does not mean no maintenance. Whereas the PV industry has made great strides in detecting faults and even permitting some faults to be corrected remotely, the safe and reliable operation of PV plants still entails scheduled and unscheduled maintenance work, for which personnel will have to be onsite. While the bulk of safety issues are designed out (or in) during the design and construction phases of PV plants, there are elements which need to be considered, most of which can be planned or mitigated:

- The safety systems and procedures in place
- The training of staff with the appropriate qualifications for the tasks to be undertaken
- The presence of appropriate equipment to perform maintenance tasks: PPE, consumable as well as durable maintenance tools
- Site-specific risks to be considered, such as heights (PV on buildings), presence of water (PV on water), or increased fire risks
- Weather and site conditions for onsite visits

While many of PV systems and plants are becoming more standardised, each PV power plant has its individual characteristics, and therefore the safety briefing and procedures should address those specific aspects together with general safety considerations.

The various methods and systems described in this chapter address risks and their mitigation for the safe operation of PV power plants. The human and organisational aspects, such as implementing the hierarchy of controls (Figure 6) and developing PV systems in keeping with ISO 45001, IEC 63049, ISO 9001, or ANSI Z10 are key issues to ensure that the PV power plant and the staff who maintain it can operate safely.

4 POWER PLANT MAINTENANCE

4.1 Preventive Maintenance Actions

Preventive (or proactive) Maintenance (PM) represents the foundation of an O&M plan applied to a PV power plant, comprising a wide range of "per-schedule" activities and services of maintenance in PV plant components. Typically, PM actions refer to all routine screening (e.g., physical, and visual inspections), onsite or remote testing and servicing/intervention at (pre)determined frequencies and time intervals. The latter can be determined on a case-by-case basis, considering the equipment type and original equipment manufacturers (OEMs) requirements, system size and complexity, environmental/site conditions, historical data and, of course, certain PV O&M agreement terms and conditions (warranty, financing, insurance).

Ultimately, PM is aiming to maximize the long-term energy yield and operational lifetime of a PV plant, by preventing the occurrence of costly or catastrophic failures and breakdowns at both PV system level and at individual “key” components, in compliance with the OEMs operating manuals and recommendations. As such, PM actions also ensure that PV equipment and component warranties are in place, while reducing the risk of failures or (performance and physical) degradation. On this basis, PM approaches are well-established and standard practices in PV O&M, particularly for their perceived effect in lowering the risk of unplanned PV system downtime.

Yet, a PM action plan – due to its inherent “per-schedule” nature – can have a considerable financial cost within the overall PV O&M agenda, often inducing excessive or redundant activities, thus labour (and costs), especially if not optimally planned and/or implemented. Therefore, PM must be well balanced against the overall PV plant and O&M budgeting. Such balance is pursued considering mainly direct costs of scheduled PM interventions and services, as well as yield and cash flow through the life of the system. Balancing and optimizing PM protocols and “best practices” will also depend on PV system size, design, complexity, and environment. In addition, for PV systems and O&M plans where support by predictive maintenance (based on highly granular PV data) is technically and economically applicable, PM scheduling can be greatly improved both at the manufacturing level (better lifetime predictions for the PV components) and at the O&M level (inspection of PV components at more realistic time intervals). Lastly, technical experience and relevant track records can also be leveraged to further optimize PM action plans.

In practice, though, it must be noted that PM action should generally comply with prescribed OEM and O&M manuals as well as respective legislative and regulations, e.g. (inter)national standards for periodic inspections of certain electrical components in PV installations. Besides, the O&M contract should include this scope of PM services and the frequency of each task. It is then under the responsibility of the O&M contractor to draft and implement the PM task plan and report all activities to the PV asset owner/manager. Reporting of PM activity is important to record tracking and follow up the plan according to the conditions in the contractual PV O&M agreement, as well as to justify any deviations, if required. Typical exemplary PM “manuals”, annual O&M plans and best practices have been recently compiled by NREL and SolarPower Europe task forces [11].

Independent of the PV plant's size, the most common PM actions in PV O&M include:

- Periodic "sampling" of individual electrical (I-V) measurements at module level
- Periodic inspections of PV modules or strings: mainly IR and/or (auxiliary) EL imaging
- Cleaning of PV modules (including soiling and/or snow removal)
- Site maintenance including vegetation management, removal of loose objects
- Upkeep of BOS (inspection, inverter servicing, tracker maintenance)
- Upkeep of SCADA/monitoring systems (including weather stations, data acquisition units, sensors, etc.)
- Other actions related to site management (water drainage, isolation from wildlife, fence/road repairs, environmental compliance, and security)

During PV operational years, it is important to consider vegetation growing on adjacent PV assets (e.g., growth of grass/plants in the short term, growth of trees in the long term), especially if these will cause shading on PV arrays, which can then result in hot spots, which are shown in the small inserted IR images (Figure 7). Site and **vegetation management**, depending on the site/climatic conditions and the size of the PV plant, can be both challenging and labour/cost intensive. In arid areas, mowing may be unnecessary with proper soil stabilization. On the other hand, for areas where mowing is required, there is the added risk of projectiles damaging modules. In the latter case, vegetation management "strategies" that have gained increasing popularity in the last years include the collaboration with local farmers in using certain species of grazing animals.

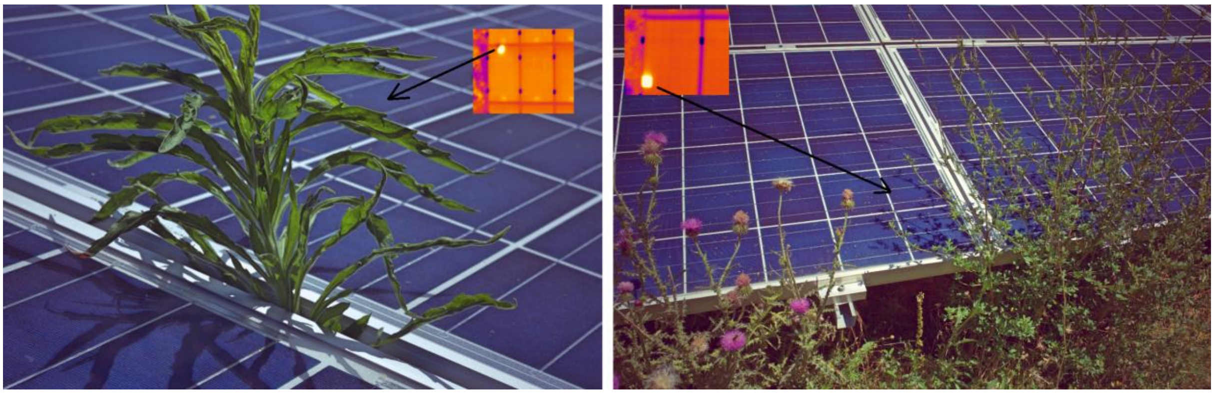

Figure 7: Examples of shading caused by non-managed vegetation at a utility-scale PV plant © CEA-INES.

Similarly, regular **cleaning** of modules from dust (soiling) or snow is an imperative PM action in PV plants installed in certain geographical locations and climates. As well known, soiling can result in considerable losses in the PV energy yield on both seasonal and annual scale. Also, as in the case of unwanted shading from vegetation, cases of uneven, localized soiling (dirt e.g. from bird droppings) can lead to hot-spot effects on PV modules and risks of follow-up failures (glass/cell fractures, melting of the backsheet) or even fire hazards (Figure 8). Upon cleaning of PV arrays, care should be taken, in compliance with the OEM's recommendations, to avoid damaging the different PV components. For instance, cleaning solutions shall be based on plain demineralized water and mild detergents.

Figure 8: Aerial view of a rooftop commercial PV plant installed at a coastal site, presenting severe issues of localized soiling due to dirt (bird droppings) © CEA-INES.

At **PV inspection-level**, PM practices concentrate on primarily two categories of onsite inspections: 1) manual electrical (I-V) tests at module or string level and 2) visual and IR/EL imagery. Today, such inspections are indispensable not only in PM but in the overall PV O&M context, since data from PV SCADA/monitoring systems present certain inherent limitations in terms of both accuracy and spatial resolution, especially considering the rapidly increasing sizes of utility-scale PV plants.

Manual electrical testing such as open-circuit voltage, operating current, or field I-V curve tracing can be used to detect faults on the DC side of PV systems, at submodule, module, or string level. Such faults, which often remain undetected or are misdiagnosed by monitoring systems, can result in follow-up failures, physical degradation of PV modules, constantly underperforming PV plants and, ultimately, in significant energy yield (thus financial) losses. Since such electrical measurements are carried out in real field conditions, the accuracy of the testing equipment is limited by the combined accuracy of the necessary irradiance, temperature, and electrical sensor inputs; and in the case of a standard I-V tracing set-up, it is limited to around 5%. In practice, electrical testing can only reveal existing defects and failures at string, module, or submodule level that at MPPT and field conditions result in measurable power output losses. However, when correlated with the IR/EL image patterns, electrical signatures can also yield valuable insights into underlying module-quality issues, thus often enabling the timely prevention of more severe, follow-up failures, e.g., fire hazards.

4.1.1 Thermal Imagery PV Plant Inspection

Thermal imagery-based inspections refer to the collection and processing of IR images at PV system, string, module or even submodule/cell level, to diagnose and classify certain thermal patterns of PV failures (small inserted IR images in Figure 7 and Figure 9). As a widespread best practice today, IR imagery of PV plants is performed in the form of aerial inspection. By analysing abnormal thermal variations and thermal patterns across the inspected PV arrays, nearly any critical defect or failure that is causing even a minor performance loss can be located and diagnosed, in addition to the proactive detection of hot spots and potential fire risks, as aforementioned. IR imagery scans can be performed in addition to or instead of manual electrical testing, as an integral part of the annual PM plan in PV O&M, while they can also be deployed in cases such as PV system commissioning, site-management related checks (e.g., vegetation, soiling mitigation), insurance claims and end-of-warranty inspections, as well as for IR inspections of AC substations. (Figure 10).

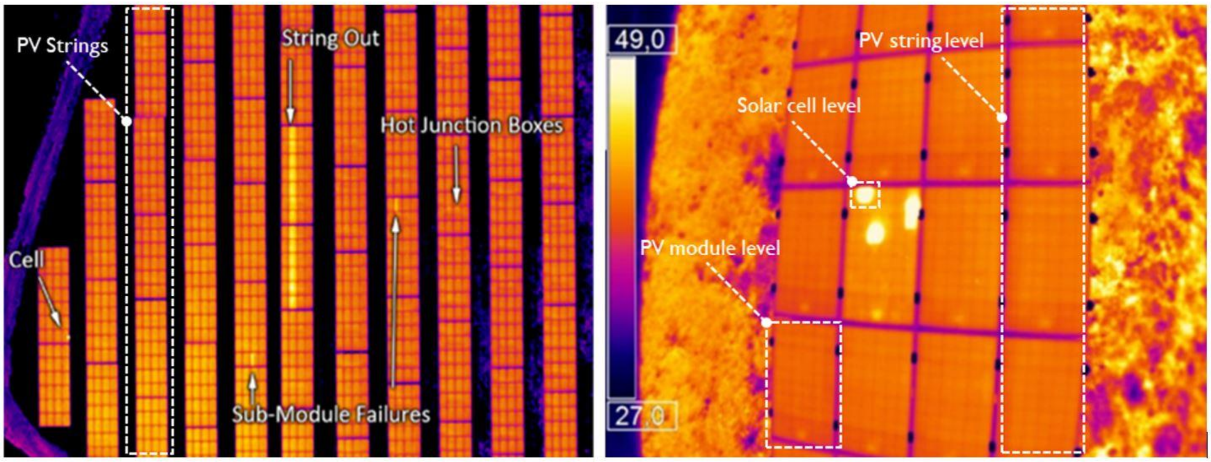

Figure 9: Aerial IR imaging by aircraft (left) and drone (right), revealing different failure modes at cell, submodule, module, and string level © Heliolytics Inc. (left image), © CEA-INES (right image).

Figure 10: Aerial visual imagery for general inspection in general site management of a PV plant © CEA-INES.

Today, aerial thermal imaging of PV plants can be performed using manned survey-type aircraft or unmanned aerial vehicles (UAVs, drones). The diagnostic and quality of the assessment depends largely on the aerial imagery sensors, the measurement conditions (and their compliance to best practices and technical specifications, e.g., the IEC TS 62446-3:2017), as well as the employed post-processing systems and algorithms that are used.

The resulting imagery should be processed by a validated processing routine to correctly identify thermal "signatures" of PV failures/defects and their exact physical location in the field. Such PV failure data, in the form of thermal patterns, are typically of very high spatial granularity from system up to cell level; and their labelling allows O&M engineers and field technicians to quickly diagnose, classify and remediate PV faults and their root cause. When properly applied, aerial IR/visual imagery is a powerful tool for diagnosing:

- PV module faults and solar cell defects:
    - Electrical mismatches and hot spots
    - Bypass diode and junction box failures
    - Glass fracture and/or cell cracks
    - Snail trails
    - EVA delamination and discoloration
    - Localized soiling (bird droppings, debris, vegetation)
    - Broken interconnections
- PV string and system faults:
    - Burnt fuses
    - Inverter failures
    - Cabling/connector failures
    - Open- or short-circuited PV modules or strings
    - MPPT faults
- Racking and BOS faults:
    - Major racking shifts
    - Systemic shading
    - Major erosion
    - Tracking systems' mismatch

The use of proper post-processing and image data analytics is critical to accurately localize, diagnose, classify all these different PV failure modes, or even quantify them in terms of associated power loss. Further cross-validation against ground data and auxiliary measurements (I-V tracing, EL imaging) is often recommended, to allow proper root cause analysis, limit false-positives and optimize decision-making on corrective interventions.

At present days, there are quite a number of suppliers active in aerial IR/visual imaging services. Many of these players provide not only the inspection of PV plant but also solutions for

PV diagnostics. This full turnkey aerial-IR inspection services typically include artificial intelligence (AI)-based data analytics, fault diagnostics and reporting as well as consulting, i.e., recommendations for corrective maintenance actions to PV asset owners and O&M engineers. In the general PV O&M context, such services typically include scans for both regular inspection as part of preventative maintenance, and for reactive troubleshooting during corrective maintenance, as well as for commissioning or asset transfer.

Furthermore, market leaders in aerial PV inspections can leverage large and consistently increasing portfolios (already beyond the GW-scale) of inspected PV plants, to offer comparisons of different PV underperformance issues and anomalies against extensive fault libraries, utilizing proprietary imagery analysis and IR/RGB mapping software. As such, the offered solutions commonly identify a large range of PV plant anomalies, from extensive string, combiner or array-level outages to module-, submodule- and cell- level failures and subtle defects, e.g. PID, electrical mismatches and concomitant hot spots. In addition, fast return of investments (ROIs) for aerial inspections is justified by most service providers, based on both a decrease of preventative O&M costs by over 10% (compared to those employing manual and ground-based inspections) and recovery of an average 1-2% PV power capacity losses.

In principle, the data acquisition equipment and approaches employed for aerial PV inspections can vary among the different downstream service providers. For instance, in contrast to UAV/drone-based aerial IR imaging scans, some suppliers opt to employ IR imagers mounted on aircrafts, offering flyovers at much higher altitude and speed; thus, allowing for very high inspection rates (e.g., 100 MW per hour), multiple times faster compared to competitors' drone-based inspections. However, such approach can considerably limit the spatial granularity, being rather impractical to fully comply with the minimum recommended diagnostic resolution, for correct identification of certain failure modes at PV submodule and cell level.

Yet, all services face certain operational limitations. In particular, their current high reliance on (semi-)manual image data processing, represents a major drawback as human error drives down the diagnostic accuracy (and its consistence) of IR imaging for PV. In addition, such solutions are typically "restricted" to a qualitative diagnosis of PV failures, being inefficient (until today) in providing reliable, quantitative, and real-time assessments on the PV yield losses associated to the detection of failures. It should also be noted that shifting from today's "per schedule" aerial IR inspections towards data-driven ones, will have a significant impact on the technical bankability, financial feasibility, and consequent long-term competitiveness of these commercial services.

4.1.2 Electroluminescence Imagery PV Plant Inspection

Electroluminescence (EL) imagery inspection is becoming quite popular to inspect defects or flaws in PV cells and modules. EL imagery has many advantages as it shows the details of the defects, so it is helpful to identify most of cell and module defects [1].

Electroluminescence screening in the beginning of a PV plant's lifetime is a concept that ensures the quality of cell material during constructions and gives the security to all stakeholders that, at the handover, the plant's power generating surface is not only operational but of flawless quality. Workers and constructor must operate more carefully knowing that the result is screened. The investor/operator has a warranty that there are no construction errors such as cracked and damaged modules. Insurance companies have an initial footprint of the plant to which they can reference, and damage can be more easily tracked to single events such as hail and wind loads, maltreatment during cleaning or maintenance work during operation. In fact, legal problems are likely to arise due to a lack of initial reference when screening is performed only after damage becomes apparent. Insurers are reluctant to accept the screening results as proof that the damage was done during operation or by an insurable event. Thus, knowing the initial quality ensures that legal problems will not add up to financial problems caused by underperformance.

A. Electroluminescence Test Procedure

For electroluminescence imaging, the PV cells and the modules need to be fed with reverse current to generate near infrared (NIR) light, which is captured using a special camera. Moreover, the environment needs to be dark, and thus EL inspection is best done at night because the daylight contains a lot of NIR which is stronger than the NIR irradiated from the PV modules. If the inspection is carried out during daytime, a dark environment (such as a dark enclosure or a darkroom) needs to be set up around the PV modules which are to be inspected.

Like IR inspection, unmanned aerial vehicles (UAV) or drone inspection is favoured to quickly cover a large amount of inspection surface. A recording of the EL imagery would be the most comfortable solution considering the number of frames per second and hardware limitations.

There are several difficulties which are still hindering a wide adoption of drone EL inspection. First, as previously explained, PV plant inspection is best done at night, but flying at night for EL field inspection increases the difficulty and risk of loss of UAV control. A technique for daylight EL drone inspection is explained in [29]; in this case, the drone stability plays a very important role (wind conditions should be optimal).

The second challenges in EL inspection, the PV module strings to be inspected must be energized, i.e., the module strings need to be connected to a DC power supply to feed in current to the PV cells. It requires more work than the IR inspection. If the module strings are connected to DC combiner boxes which are located at a distance to each other, the DC power supply needs to be moved from box to box connecting the strings at night, an added complexity. The requirements for an EL inspection make the UAV option less efficient.

The third difficulty is the limit of the camera capability. Most of the silicon sensor commercial cameras are not sensitive in the NIR wavelength range, so the exposure time needed is usually long (from a few seconds up to minutes). However, the long exposure time might result in blurry images taken by UAV.

With much lower resolution sensors, some of the InGaAs cameras have very good sensitivity for NIR getting the luminescence signal of the PV modules in some few milliseconds. The capability of video recording is the biggest added value in these kinds of cameras, making things easier to the O&M operator. Depending on the type of analysis, a compromise between UAV panel distance and lenses should be found in order to obtain the desired image quality for the proposed analysis. From micro-cracks to submodule or string functioning analysis, the solution combinations can be several. The UAV-panel distances for IR and EL are not comparable due to the resolution constraints of the latter.

There are still no turnkey solutions in the market to do EL from UAVs. Wireless communication and camera control is now the biggest challenge. Fortunately, the camera technology and the inspection devices are improving, and a complete inspection device shall become commercially available in the near future. However, inspection service companies and research centres are developing their own solutions with increasing success. In the Report IEA-PVPS T13-24 on mobile devices for PV inspections by Herrmann et al. [29], details on the detectable failure types for PV modules and arrays are given as well as measurement uncertainties and cost considerations for EL inspections.

B. Electroluminescence Test Sampling

For EL test sampling, the screening can be done in different ways and 100% screening is not always necessary. Experience has shown that a 1% scan is sufficient in most cases to monitor the main performance related issues. Inspectors and designers have identified a number of critical points, such as:

- Racks near the transformer/inverter stations, combiner boxes, meteorology stations
- Points with high traffic during construction near the fence, and close to roads

Screening these points makes detection of common construction problems feasible. These points in the plant are exposed to additional stresses during the construction and the maintenance operation. From experience in the field, these points are prone to more damage than other parts of the plant. Further screening of several modules in zones with high wind loads (corners and edges of the plant) is important to be able to proof that damage was caused by an extreme weather event and not during construction. The bottom rows of freestanding installations need to be checked before commissioning. In practice, damages due to leaning on the lower module rows during installation, is often reported.

When a purely statistical screening is done, it is important to be able to track the screened modules over time for later inspection. As the modules should not be obviously marked (constructors might take extra care with only these) the utilization of hidden transponders in the frame is useful to mark the modules that are selected for statistical screening. This makes especially sense if these modules were tested at earlier points in the supply chain. In this fashion, the gap between incoming goods inspection and commissioning is bridged. If the first test is performed in the field, recording of GPS position or relative position in the park of the respective modules is sufficient. Both ways, the sample modules are easily findable and identifiable in the plant.

Ideally, the selected modules should be screened before and after installation and periodically during O&M measures. By establishing a routine screening, prior to commissioning and after certain O&M measures, the cause of the fault is more easily identified.

4.1.3 Preventive Maintenance Scope vs O&M Costs

Regarding cost aspects, obviously, costs associated with individual PM tasks (and the overall PV O&M budgeting) cannot be determined in a simple “one-size-fits-all” approach. Multiple and interrelated parameters, such as the PV plant’s size/use (residential or small-scale; commercial/industrial; utility-scale), its characteristics in both design/layout and PV/BOS technology terms, the site (location or land characteristics, climatic stress profiles, etc.), its contractual arrangements, as well as the adopted O&M plan (rigorousness, approach, stipulated labour, etc.) all contribute to a wide range of costs in relation to the aforementioned PM tasks.

In general, O&M service providers tend to overestimate PV O&M budgets to offset both their own margins and uncertainties or technical assumptions. On the other hand, PV plant developers typically follow a more moderate or underestimating budgeting approach for PV O&M, to allow higher PV plant valuations and more "motivating" revenue prospects. As aptly noted by Enbar et al. [82], such contrasting O&M budgeting viewpoints can ultimately undermine a PV plant's lifecycle performance economics. In the following Table 5, we provide a non-exhaustive list of representative costs and remarks associated with the main PM tasks, as publicly reported in the years 2021/2022, specific for utility-scale PV.

Table 5: Representative costs of main preventive maintenance tasks.

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, labor, and frequency of activity.
Cleaning/washing of PV modules [83]	0.5 - 2.5 €/ kWp/ year	Varying with the module technology, labor, 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	

4.2 Corrective Maintenance Actions

Corrective maintenance (CM) forms the second pillar of the PV plant maintenance during operational years. In contrast to preventive maintenance discussed previously, corrective maintenance actions are triggered only by the occurrence of events such as failures, breakdowns, malfunctions, anomalies, or damages. The trigger sources could be alarms in the monitoring system, or from findings during regular preventive maintenance inspections.

CM's primary goal is to restore the PV plant to its proper functioning state. Thus, the intervention time (i.e., from detection, to response, to rectifying the defect) from the moment the events occur is an important aspect in CM actions. The response time should be categorized for different types of fault events. In general, faults which will impact the safety operation of the PV plant, or 100% plant outage should be treated as critical and responded within four to eight hours. Faults resulting in major production loss should be treated as major and should be addressed within 24-48 hours. Ideally, the intervention time should be chosen to minimize the plant downtime. However, a more responsive CM programme could entail a more expensive O&M service price.

In this light, there has been an emerging maintenance to predict a fault event ahead of time. The progress in the field of data analytics and artificial intelligence/ machine learning has led to the development of predictive maintenance of PV plants. Predictive maintenance utilizes historical operational data of a PV plant obtained from the monitoring system and data on environmental parameters (weather conditions such as irradiance, temperature, rainfall, etc.), with the goal to learn the behaviour or performance pattern of the PV plant and using this to anticipate and plan for maintenance interventions before an event or fault occurs. An example is using predictive maintenance to anticipate and plan for the PV module cleaning cycle. Predictive maintenance is not a standard feature yet in the O&M scope of service but is gaining traction, especially with the advance of powerful and scalable tools for big data analytics.

4.2.1 Spare Parts

One important aspect of a good corrective maintenance plan for PV power plants is ensuring that spare parts are available and accessible when needed to avoid prolonged plant downtime/outage due to equipment malfunctioning or damage. An O&M programme of a PV plant thus should foresee a certain number of spare part stocks of the plant equipment, especially the key ones such as PV modules, inverters, tracker components (if applicable) and transformers. Best-practice recommendations regarding the operation of PV plants include well management of spare parts and consumables needed to maintain the proper functioning of the plants. This commences with the EPC contractor preparing a minimum spare parts list and procuring the initial stock of the spare parts. The spare parts (and the list) are then handed over to the plant owner or the O&M Operator during takeover.

During the operational years of PV plants, typically the management (managing stock levels, storage, and replenishment) of spare parts is typically included in the scope of O&M services. However, purchasing replacements of expensive key equipment leads to higher costs, and consequently, the O&M annual fee would be increased to cover the activities related to the management of spare parts stock. It is not uncommon that the owner of PV plant opts to exclude spare part management (sometimes only for certain types of key plant components) to be excluded from the O&M Operator’s responsibilities. Under this context, the plant owner could then address the foreseeable future maintenance of the excluded equipment either through an arrangement for extended service or warranty of the equipment from the equipment supplier, or through reserving the necessary budget. For the latter, a reserve account (MRA - maintenance reserve account) is thus recommended to be set aside by the plant owner to anticipate replacement costs of the excluded key equipment.

4.2.2 Future Inverter Replacements

The failure rate of inverters is driven by various factors; it is inverter specific (design, topology, supplier manufacturing quality) as well as affected by external factors from the quality of installation and maintenance of the PV plant the inverter is installed in, to the environmental conditions the inverter is operating in. A good source of inverter failure rate information will therefore include all these factors. Past studies of inverter failure rates in PV plants across the globe in different climates and over many years have indicated a mean time between failures of around 11-12 years for solar inverters.

At present, PV plants are expected to have a lifetime of more than 25 years. Considering the above average lifetime of solar inverters, inverter replacements should thus be anticipated roughly halfway through the PV plant life. The associated future inverter replacement costs thus need to be foreseen as operational costs of PV plants. The future replacement expenses are in fact commonly set aside as a maintenance reserve account. The amount of money to be set aside should be estimated based on the future costs of purchasing inverter replacements and calculated using reliable and relevant information regarding the failure rate of the inverters over the PV plant operational years.

5 O&M RECOMMENDATIONS IN DIFFERENT REGIONS

Our planet has many different climates, each one affecting PV systems in particular ways. In this chapter O&M recommendations are presented for different climate scenarios. The moderate climate O&M guideline will cover the basic or most common aspects and conditions that are relevant for all climates and regions. The recommendations will become more specific in the next subchapters where extreme climates present diverse particularities and may require greater attention of O&M operators.

Seven different types of climates are presented while addressing a wide spectrum of issues with the goal to raise the awareness of the O&M complexity to the PV community.

As a basis of any O&M activity in any region, we can find the following international standards in Table 6, which could offer support in topics such as test procedures, interpretations, and safety.

Table 6: O&M related international standards and technical specifications.

Standard / Technical Specification	Title	Highlights
IEC TS 63049	Terrestrial photovoltaic (PV) systems - Guidelines for effective quality assurance in PV systems installation, operation, and maintenance	Good practices for O&M management and development
IEC 62446-1:2016	Photovoltaic (PV) systems - Requirements for testing, documentation, and maintenance - Part 1: Grid connected systems - Documentation, commissioning tests and inspection	Verifications, test procedures (I-V curve, IR inspection, etc.), results interpretation
IEC 62446-2:2020	Requirements for testing, documentation, and maintenance - Part 2: Grid connected systems - Maintenance of PV systems	Maintenance protocols, verifications tasks, safety procedures
IEC TS 62446-3:2017	Photovoltaic (PV) systems - Requirements for testing, documentation, and maintenance - Part 3: Photovoltaic modules and plants - Outdoor infrared thermography	Equipment requirements, inspection procedure, evaluation

5.1 O&M Guidelines for Moderate Climates (Europe)

5.1.1 Description of Climatic Conditions

Moderate climates are very suitable for vegetation and wildlife development throughout the year, making the seasonal changes smooth enough for the survival of many species. Although this may seem contradictory in these times, the development of nature close to the PV modules is not always welcomed. Vegetation and wildlife, among others, may become persona non grata during certain periods of the year for the benefit of energy yields. There are many ways to avoid an undesirable situation and develop solutions where life can be respected. Soiling instead is potentially more harmful than vegetation and wildlife impacts, especially when it is composed of corrosive chemicals coming from an industrial environment.

5.1.2 Field Experiences

Vegetation around the PV modules may create undesired shadows or situations where branches wrap cables or cables trays. It may also occur that branches exert pressure on the backside of the modules as seen in Figure 11.


Figure 11: Growing bush in front of a tracker (left) and underneath an array (right) [Eurac Research].

Rodents pose a threat to electrical cabling integrity. The more accessible and thinner the cables are, the more damage can be done. Figure 12 shows the damage in string and sensor cabling in different PV installations.


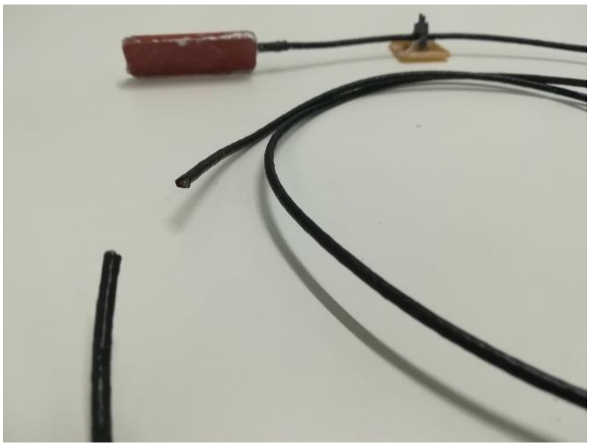

Figure 12: Cable bitten by a marten (left) (pveurope.eu © Leitl). Temperature sensor cable cut in half by a rodent (right) [Eurac Research].

The impact of **soiling** in a moderate climate will vary depending on environmental factors, dust type, location, and installation factors [84]. Cleaning thin-film modules in sunlight can lead to a permanent power loss, as the shaded cell parts switch to high resistance mode and therefore the remaining low resistance cell parts overheat due to the string current. Therefore, the recommendations of the module manufacturers must be strictly followed to avoid loss of warranty. A general introduction of this topic has been previously presented in another Task 13 report [1] and will be further analysed in later chapters of this report. The following examples in Figure 13, collected from a recent publication [83], present a general visualization of this problem.

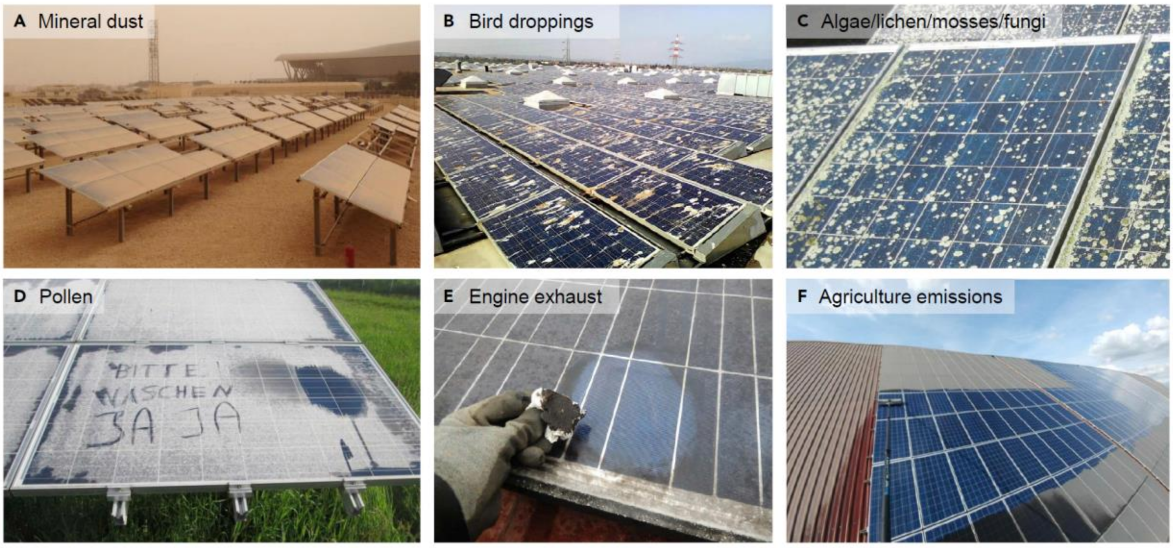

Figure 13: Examples of different types of soiling of PV arrays [83].

Concerning bird droppings, Figure 14's left image shows a thermal image from a bird dropping that may lead to hotspot conditions, possibly damaging the PV module.

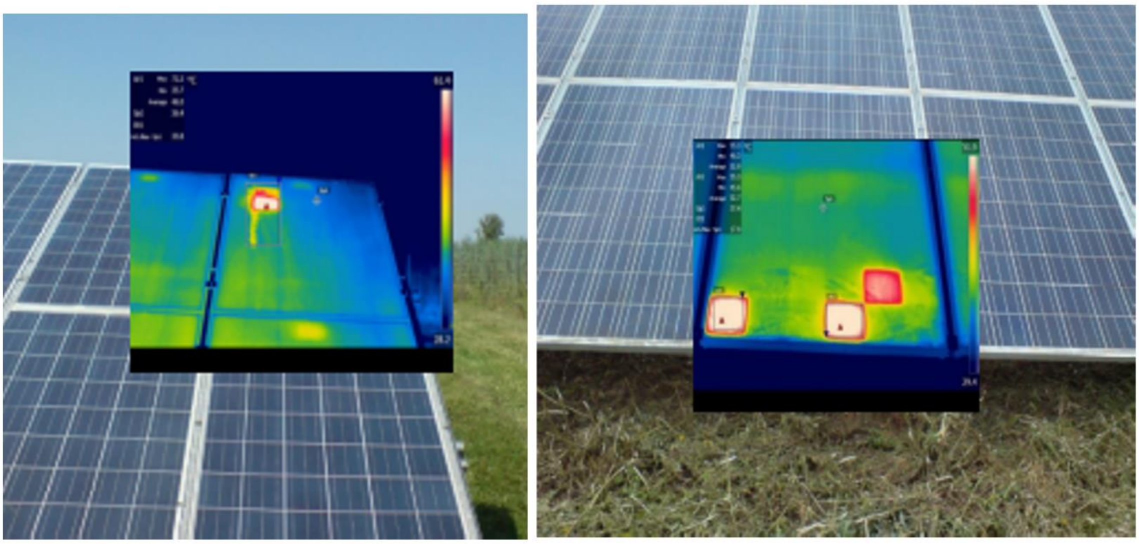

Figure 14: Impact of bird droppings and locally increased temperature (left), Impact of freshly cut green and unexpected hotspots (right) [Fraunhofer ISE].

What might be less known is the fact that O&M actions might also be a source of soiling if conducted in an erroneous way. Figure 14 right image shows a thermal image of a rack after fresh grass cuttings. It does make a difference if the lawnmower goes from left to right or vice versa if it throws out debris on one side only.

This heterogeneous soiling can also be seen in I-V curves from single modules. The difference to uniform soiling is the fact that heterogeneous soiling has a stronger influence on MPP rather than on I_{sc}, as can be seen in Figure 15.

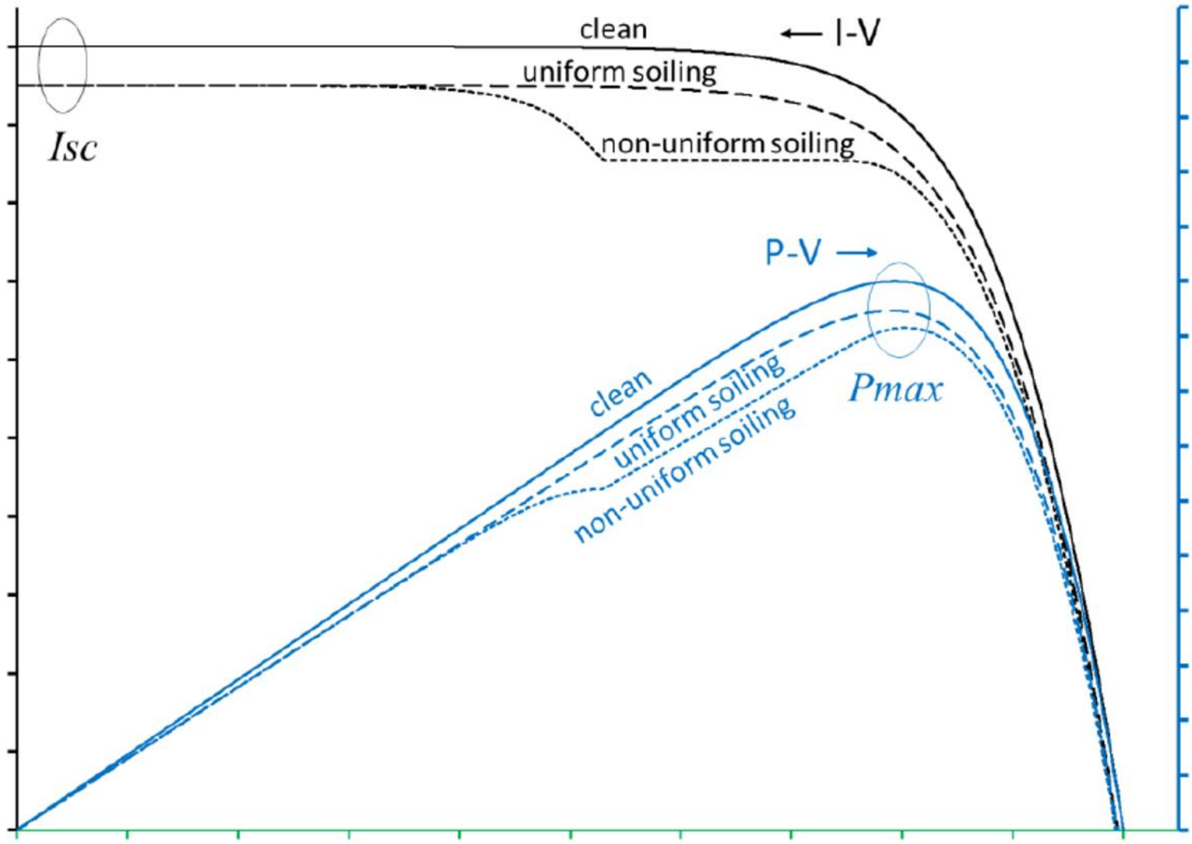

Figure 15: IV and P-V curves of clean, uniformly, and heterogeneously soiled PV modules [ATONOMETRICS soiling measurement system manual].

A special anecdote concerns the effect of the fungus Baudoinia compniacensis which prefers airborne alcohol that occurs close to whiskey distilleries and forms a black patina on PV modules, as can be seen in Figure 16 [85].

Figure 16: Effect of Baudoinia fungus in Scotland [85].

5.1.3 O&M Recommendations and Guidelines

In moderate climates, frequently, **soiled PV modules** bird droppings, agricultural emissions, pollen, lichen, and traffic emissions, such as engine exhausts, and this occurs with a strong seasonal variation. With frequent precipitation, most of the soiling will be washed away but there are conditions, especially during a dryer period or heavy agricultural activity, where the soiling rate - the comparison of “clean vs. dirty” - can vary by several percent.

Several methods to mitigate soiling - preventive and restorative - exist (see Report IEA-PVPS T13-21 on soiling [31] for a more in-depth discussion), such as manual, semi or fully automatic cleaning solutions. Fully automatic pre-installed solutions with very low water consumption or even dry brushing are attractive for utility-scale systems in regions with a very high risk of soiling, e.g., in the Middle East region. On the other hand, semi-automatic or manual cleaning systems using demineralized water or some biodegradable chemicals to wash off organic substances might be more cost-effective in moderate climates. There is no one-size-fits-all solution for the mitigation of soiling effects. It is a local economic decision to clean based on labour costs, water availability and costs, feed-in tariffs, and medium-term weather forecast. Further details are given in Report IEA-PVPS T13-21 on soiling for generic “Best-time-to-clean” models [31].

Bird dropping is the cause for soiling of PV modules in moderate climates. It is important to develop and execute a cleaning plan based on the frequency of droppings which will be very dependent on the kind of birds living in the area and those crossing it when migrating. This planning should avoid droppings sticking to the module glass for a long time for the following main reasons:

- Energy performance loss
- Hot spots, provoking material degradation and electrical risk increase
- Etching effect on the glass leaving a non-removable trace on the surface.

Many are the solutions to clean the PV panels [86], [87] and there are many solutions to deter birds in order to keep them away from PV systems [88]. The budget for this O&M measure will determine the type of solution. To conclude, it is important to be aware of the risk of different chemical products that can be harmful to the glass, glass coating and frames of the PV modules. They can put both the module and the product warranty in danger. In case of any doubt, it is recommended to be advised by professionals.

Proceeding with more issues, roof mounted systems and floating PV systems are preferred places for **animal nesting** such as birds or squirrels in rooftops. Both places offer shelter and minimal disturbance from humans for nesting and resting. In the case of squirrels or similar rodents, electrical wires are in danger of being chewed and damaged. Installing a mesh to close gaps can be a successful solution for rooftops, while for floating PV bird deterrent systems can be employed [89].

In large PV installations where the reflective surface may imitate sky or water, like the illusory effect in windows on a building, **birds and waterfowls** may impact or land on the panels resulting in broken wings or death due to high temperatures exposure [90].

From the O&M point of view, such situations are difficult to prevent. Good practices are to identify bird populations passing near the PV plant and to call the closest wildlife rehabilitation centre if an animal is injured. The areas where these incidents are most likely to occur seem to be deserts [91] and lakes for floating PV systems [92]. It goes without saying that after any such event, a visual inspection should be carried out in the impact area to detect any mechanical damage.

For rodents, a first recommendation is to fix cable loops and hanging cables as far as possible from the ground or from structures that are easy to climb. If more protection is needed, anti-rodent solutions are available on the market, such as cable shields.

Most animals living next to ground-mounted PV modules are farm animals such as sheep and small livestock (Figure 17). They can control vegetation in PV plants and usually do not climb on or damage the PV modules. The first row of modules might be exposed to them which could be pressed upon by their bodies when reaching for grass underneath the PV panels.

Figure 17: Farm animals in British solar farms [93].

Larger farm animals such as horses and cattle are considered unsuitable since they have the weight and strength to dislodge standard mounting systems, while pigs or goats may cause damage to cables [93].

It is worth mentioning that both PV modules and structures are an opportunity for animals to rub their bodies against. A follow-up of the mechanical status of the structure and first row of panels is recommended.

Before finishing with the wildlife chapter, we should not forget insect pests. The cool shade beneath a PV panel and the inner empty spaces of metal structures are ideal places for wasp or bee nests. In the case of the metal structures, blocking the holes may prevent any future nest to be built inside. In the case of the PV modules backside, nests may find structural support in frames and cables, making maintenance more difficult. In case of trouble, the safest thing is to hire professional service for pest control.

Cutting or herbicide spraying is the common way to control the vegetation. It should be applied in a proper way without spraying the PV modules. If it occurs, the modules can be washed off with water. After some days, once the vegetation is dead (Figure 18), it should be pulled up by the roots and the waste should be treated accordingly.

Figure 18: Vegetation before (left) and after spraying the herbicide (right) in a white stone ground [EURAC Research].

5.1.4 OHS Recommendations and Guidelines

Concerning occupational health and safety, section 5.1 does not address special issues related to extraordinary climate conditions. International standards as mentioned in a previous chapter and national codes are the references to follow. Public guidelines developed by the industry, research or national entities are as well a good source of summarized and detailed information as listed in Table 7.

Table 7: Available guidelines in different parts of the world.

Country / Continent	Title	Author/Editor
Europe	Operation & Maintenance Best Practice Guidelines / Version 4.0	SolarPower Europe [11]
India	Best Practices in Operation and Maintenance of Rooftop Solar PV Systems in India	Gujarat Energy Research & Management Institute
Japan	Report on Guidelines for Periodic Inspection and Failure Examination of PV Power Systems	Japan Electrical Safety & Environment Technology Laboratories
United States	Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems; 3rd Edition	National Renewable Energy Laboratory and others

5.2 O&M Guidelines for Hot and Dry Climates

5.2.1 Description of Climatic Conditions

Even though multiple PV-specific climate classification schemes have been proposed [94], [95], the best known is the Köppen-Geiger system [96]. In the context of this section, a hot and dry climate is the desert climate, classified as either BWh or BWk. These criteria are shown in Table 8. In a desert climate there is very little precipitation (by approximation: a total precipitation expressed in mm of less than 10 times the mean absolute annual temperature, e.g., less than 200 mm of precipitation per year for 20°C), hot summer daytime temperatures that can exceed 40°C (104°F), an excess of evaporation over precipitation, and low humidity throughout the year. The typical desert landscape in such locations has low vegetation and receives very little moisture most of the year, though heavy precipitation for short periods of time in the year can occur. This heavy precipitation may cause land erosion that can affect PV plant foundations.

Table 8: Köppen-Geiger requirements for hot and dry climates, from [96].

	Desert Arid climate: hot steppe/ desert	**Desert Arid climate: cold steppe/ desert**
Köppen-Geiger classification	BWh	BWk
Mean annual temperature T_{ann}	$T_{ann} \geq +18°C$	$T_{ann} < +18°C$
Average annual precipitation P_{ann}	$P_{ann} \leq 5 * Pth$ $P_{th} = \begin{cases} 2 * \lvert T_{ann} \rvert & \text{if at least } \frac{2}{3} \text{ of annual precipitation in winter} \\ 2 * \lvert T_{ann} \rvert + 28 & \text{if at least } \frac{2}{3} \text{ of annual precipitation in summer} \\ 2 * \lvert T_{ann} \rvert + 14 & \text{otherwise} \end{cases}$	

The challenging thermal range of hot and dry climates typically means that PV plants are located in areas with low population density and are at much more remote locations than similar systems in milder climates. The combination of physical remoteness and challenging climatic conditions results in a strong preference for remote monitoring of plants, with few plants having O&M personnel on-site or nearby. This is reflected in O&M KPIs, where availability values lower than 99% are occasionally seen.

5.2.2 Soiling Impact

There is a great amount of possible variation for the type of ecosystem defined by these two terms. A region defined as BWh can be comprised of loose sand dunes of coarse silicate sand with very little vegetation or a rocky terrain with scrub vegetation. The climatic variation may be the same, however the type of soiling experienced will be quite different.

Industrial development in these regions exists, though arguably less so than in the BWk regions. Industrial regions add further complexity to the soiling issue, due to the addition of soiling agents to the soil build-up on a solar module.

BWk regions may experience higher levels of moisture compared to BWh regions, particularly dew production at night, due to the temperature drop reducing the atmosphere's water retention ability. The level of moisture in the atmosphere will influence the choice of automatic module cleaning systems. Dry cleaning systems will work well where moisture in the atmosphere is very low, more typical for the BWh climate. Where dew can be expected, a dry-cleaning system will not be effective, exacerbating module soiling. An extreme example would be the choice of a dry-cleaning solution where moisture in the atmosphere is a possibility in the proximity of a cement factory.

It is not inconceivable for a small geographical area with varying altitudes to include areas requiring different automatic module cleaning characteristics. The O&M design should carefully examine the available meteorological data available to ascertain the level of moisture during defined cleaning times.

Figure 19 gives an example of automated cleaning of soiled PV modules.

Figure 19: Automated cleaning of soiled PV modules in the Negev Desert, Israel.

Experience in the Negev desert in Israel reflects manual washing of modules five times a year with additional washing sessions added as required during the transitional seasons when heat waves accompanied by dust clouds are broken by low volume rainfall. By contrast, PV systems in Central Australia which are close to population centres have typically low soiling rates and consequently have one to two manual cleaning sessions with water, with as-needed additional cleaning mandated by weather events, such as occasional dust storms.

5.2.3 Operational Health and Safety Issues

Aside from the usual OHS issues associated with a PV plant, roof top or ground mounted, there do exist several additional risks when operating in the desert. The typically highest risk in hot and dry climates as calculated through a risk matrix (likelihood or frequency multiplied by the consequence) are dehydration and sun stroke to O&M personnel performing the maintenance when onsite. An often overlooked yet important risk is travel to the site(s) in relation to the weather: to avoid the hottest hours of the day, early morning or night-time travel to remote sites may necessitate driving in the dark in areas where wildlife can be encountered. Ensuring that staff have the appropriate PPE as well as specialty communication tools (satellite phones or emergency locator beacons) is important.

As the cost of PV plants drop over time due to learning effects and commercial pressures, there is a tendency to maximize profits through economy of scale, including packing more installed DC capacity on a smaller footprint, thanks to increasing module efficiencies. In this context, plant designers and investors must be reminded that the final product must be maintainable, and O&M providers must evaluate the risk profile of plants ahead of taking on the O&M role. In a PV plant built in the desert or in remote locations, efficient operations by the maintenance personnel are of high importance. Foregoing access paths for ease of access to critical maintenance points in the field such as string boxes may cause maintenance staff to walk longer periods of time in the sun, reducing their efficiency and increasing their OHS risks. Similarly, removing control rooms or reducing the size of shaded LV stations to reduce CAPEX will increase OPEX costs due to lack of efficiency as the human element involved is weakened by the adverse desert climate.

OHS concerns in these areas include the danger to personnel of endemic reptiles and other threats. Electrical distribution panels are best opened with care in regions where such threats are realistic. Anecdotal evidence points to snakes, birds, or termites nesting in or near these distribution panels, with the risk of either short-circuits, arcing, or bites from snakes, scorpions or lizards occurring upon opening cabinets.

Vegetation control addresses several risk factors, by reducing usable habitat for reptiles, avoiding energy losses by keeping vegetation growth below the lowest module level, and reducing combustible material that may lead to fires. Examples of vegetation management and potential consequences are shown in Figure 20 and Figure 21.

Figure 20: Vegetation management of PV plant in Central Australia.

Figure 21: PV module damaged during vegetation management due to pebbles. Array in Central Australia.

Hot and dry climates present a challenge for PV equipment: The high temperature, solar irradiation (often with high UV content) and dry atmosphere accelerate decomposition of many PV elements, which include rubber seals, fiberglass cabinets, cable insulation, and cable ties. Significant cable insulation degradation has been recorded after only a few years for cables subjected to direct sunlight, despite the cables being certified as having been tested for such use.

It is recommended that all cables be shaded from direct sunlight, fiberglass and polymer cabinets installed in shaded areas and that rubber seals (e.g., around cabinet doors) be slated for replacement in realistic time spans. Similarly, cable ties should be shaded from direct sunlight, be made from metal instead of plastic polymers, and be installed to accommodate the thermal expansion seen over the day and the year.

An additional danger exists in the increased arc flash risk at low humidity due to static build-up. The use of protective equipment when approaching and operating electrical switch gears of any kind is of great importance.

The high temperature and high voltages introduced by the 1500 VDC standard equipment tends to increase the probability for module degradation due to PID or other degrading mechanisms. Though PID is typically considered a high risk in areas with both high heat and humidity together, many cases of PID have been registered in desert climates with little humidity.

When the sky is clear, radiation cools the modules, causing the module surface temperature to be several °C lower than the air temperature, which leads to wetting of the rear (and front) sheet surface, especially if the temperature falls below the dew point. At sunrise, low module temperatures lead to high open-circuit and string operating voltages and, together with the damp module surfaces, cause high leakage currents before the modules dry out in the sun. Whether modules are susceptible to PID caused by (high) leakage currents can be checked according to the parts of TS 62804 (-1 and -1-1 for crystalline silicon, -2 for thin-film modules), see also PID chapters 6.2.5, 7.5 in [31].

Table 9 compares two desert regions, both defined as BWh, yet with different operational parameters.

Table 9: O&M considerations in hot and dry climates.

	Hot and Dry: No Vegetation	**Hot and Dry: With Vegetation**
Example region/ country	Israel	Central Australia
Köppen-Geiger classification	BWh (Hot desert climates)	BWh (Hot desert climates)
Wildlife risks	Humans: Poisonous snakes Infrastructure: various species of wildlife attack cabling, nesting birds attempt to enter equipment,	Humans: Poisonous snakes, spiders, scorpions. Infrastructure: snakes, termites and birds may attempt to enter

	large birds drop objects on modules **Hot and Dry: No Vegetation**	electrical equipment, causing short-circuits. **Hot and Dry: With Vegetation**
External fire risks	Low – there is seldom little vegetation to feed a fire.	Seasonal; requires fire breaks to be maintained (dedicated space around PV farms to be kept devoid of vegetation), need to monitor & manage rapid vegetation growth in wetter months.
OHS requirements	Procedures to deal with extreme heat: avoiding full sun activities, appropriate PPE (protection against sunburn), increased hydration needs.	Procedures to deal with extreme heat: avoiding full sun activities, appropriate PPE (protection against sunburn), increased hydration needs. Extreme weather: Flash flooding, intense rain events require monitoring of weather. Similarly, bushfire risks need to be gauged before O&M activities are undertaken.
Module cleaning requirements	Transition seasons bring muddy rainfall. Occasionally occurring in summer as well.	Soiling typically of low impact on energy yield. Difficulty or cost of sourcing water for cleaning.
Electrical risks	High temperatures reduce current carrying capacity and switchboard design calling for forced ventilation requires extra care during summer months to avoid breakdown and dangerous overheating.	Static build-up due to low humidity can increase arc flash risks. Thermal expansion of components such as cables can cause the cables to loosen and arc at point of connection.
Special causes of module damage	Thermal cycling of modules (up to 40-50°C module temperature swings in one day), violent hailstorms, large bird droppings, rocks or animals on modules.	
Practical considerations	Careful planning of activities and properly maintained signage and maps to enable O&M staff to efficiently undertake the tasks quickly during summer months. High irradiance and temperature can stress components (fuses, cables, inverters) and shorten their lifetimes.	Relative remoteness of sites (distance to local and major population centres) needs to be considered for O&M activity planning & risk mitigation. High irradiance and temperature can stress components (fuses, cables, inverters) and shorten their lifetimes.

5.2.4 Recommended Practices

World-wide standard O&M best practices as discussed in section 5.1, apply to hot and dry climates, with a few aspects that need to be reiterated, such as evaluating wildlife risks, appropriate planning for visits to typically remote sites (hydration, anti-venom procedures, PPE, travel to and from sites).

Other aspects that can be re-evaluated include the installation of an automatic module cleaning system due to the remote nature of the typical large desert site, the objective difficulty of human activity in such climates and the unknown frequency of climatic events that require immediate module washing, such as when a transitional season heatwave is broken with a short period of low volume rain, creating a layer of dried soiling.

The weather extremes that can be encountered require equipment to be robust and resilient, which may counter-intuitively point to manual cleaning over automated solutions, or a hybrid combination. Given the remoteness and cost pressures encountered in both CAPEX and OPEX, some plant owners will accept higher O&M inventory costs to ensure higher uptime (e.g., storing high-cost items such as inverters or transformers at or near the PV farm), whereas other plants operate as lean as possible, and thus run the risk of prolonged periods of underperformance if critical parts cannot be sourced in time.

Depending on the local weather patterns, a contract for one to five washing sessions per year timed around the transition seasons, at the discretion of the owner's engineer can be assumed to be an average for plants in this type of climate. Aside from the real time monitoring and alarm protocol typical for daily operations, due to the remote nature typical to a desert plant, visual inspections of the plant are typically undertaken four times a year, although fewer inspections are accepted for (very) remote systems. During these inspections, all electrical panels are opened and visually examined. Land erosion is evaluated and compared to previous visits. Metal elements are examined for corrosion and the security system is examined.

During annual maintenance visits, special attention must be paid to the risk of termites, birds or snakes attempting to enter or nest in inverters and electrical switchboards, with cables or tubing being often inspected for entry points. Similarly, a verification that modules and cables remain fixed is required, as the thermal cycling throughout the year and the high irradiance and UV content can loosen modules, cables, or cable ties. Ideally, once a year, I-V curves are measured on a rotating sampling basis. All electrical panels and PV modules are photographed with an IR camera and analysed for defects.

5.3 O&M Guidelines for Desert Climates in High Altitudes

5.3.1 Description of Climatic Conditions

Desert regions have received much attention in recent years due to their solar potential for the implementation of photovoltaic power plants. They can take advantage of the outstanding conditions: clear skies, large number of sun hours per day throughout the year, higher (UV) radiation levels than most other places in the world, etc. Typically, deserts also face water scarcity and are barren, treeless, and sandy. This does not necessarily imply that they are regions that have high temperatures. Given the different characteristics that determine desert regions, they are classified according to the Köppen classification standard [2] in accordance with the local meteorological conditions and with the altitude compared to the sea level as: deserts with cloudy days, deserts, high altitude deserts, and high steppe deserts. This classification provides insights for the deployment of large-scale solar projects in each region.

Figure 22 presents a cross-section view of the Atacama Desert and its classification according to the Köppen classification standard. As it can be noticed, deserts offer a wide variety of possibilities for the implementation of photovoltaic power plants, and thus the effects of the weather conditions at these regions are being studied to generate operation and maintenance recommendations so that their solar potential can be effectively exploited. As a result of these studies, for instance, the Atacama Desert appears as one of the most interesting landscapes for installing PV worldwide.

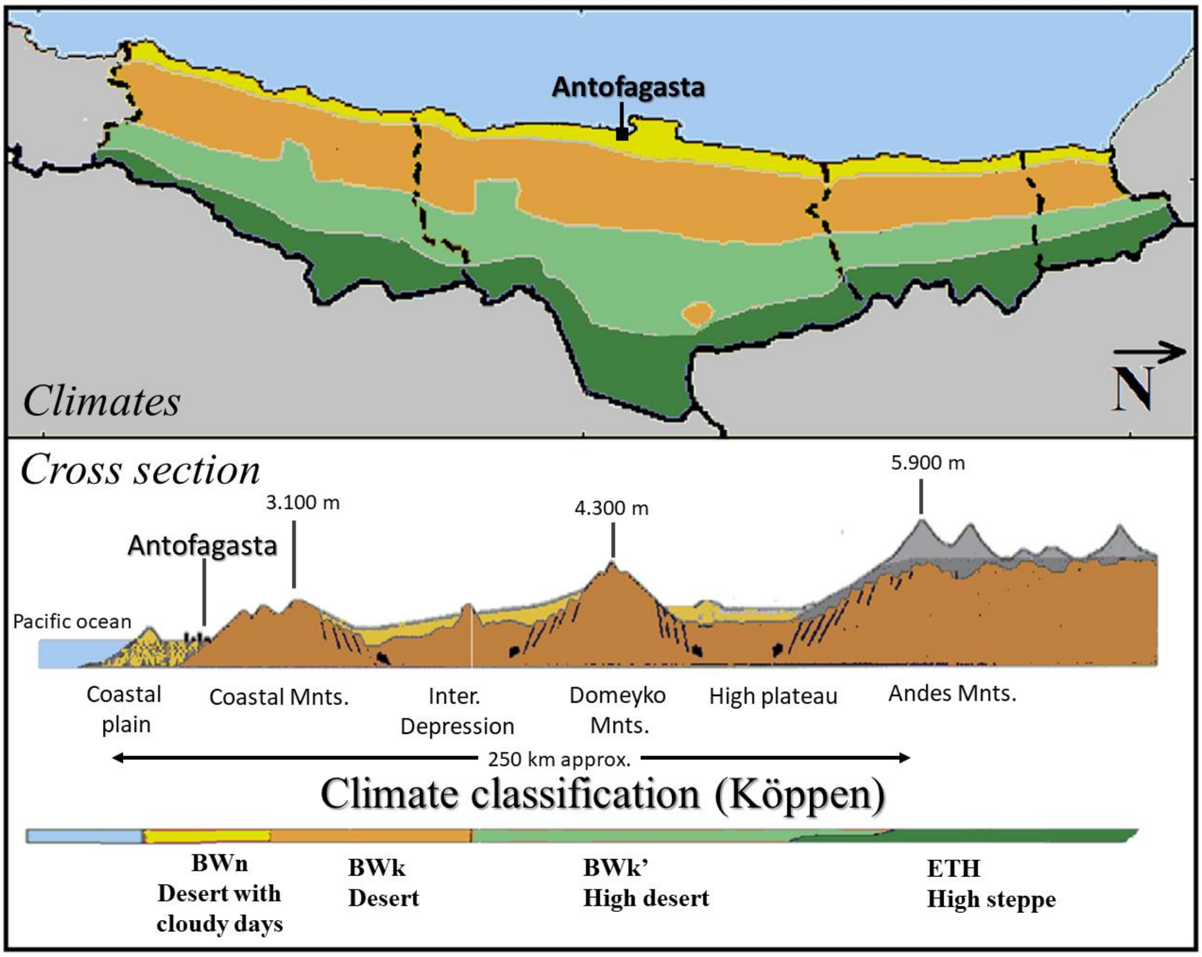

Figure 22: Cross-section view of the Atacama Desert according to the Köppen classification standard. BWn stands for deserts with cloudy days, BWk for deserts, BWk' for high altitude deserts, and ETh for high steppe deserts [97].

The Atacama Desert is exposed to a very high irradiation, many sun hours per year, one of the clearest skies in the world, the highest annual expected energy yield, and relatively low temperatures. The particular features that offer the Atacama Desert for the deployment of photovoltaic power plants are 1) irradiation levels of 2 500 kWh/m2 (GHI), 3 500 kWh/m2 (DNI), on average on a yearly basis; 2) 4 000 h/year, yearly total normal incidence irradiation on average;

3) 65% UV-B and about 25% UV-A irradiation (over the European average); 4) temperature levels below 30ºC, on average, in the summer season; and 5) 2 mm/year average rainfall in some areas of the desert. Additionally, there are systematic east-west winds that serve as a natural cooling system for photovoltaic modules, and a growing energy demand (due to the mining activity) that could take advantage of the potential of the desert to (partially) fulfil that growing demand with an environmentally friendly energy source.

In the following sections the main issues in the operation of PV power plants located at high radiation and high-altitude desert conditions will be addressed, and it will be shown from the experience gathered in the Atacama Desert how to deal with these conditions so that the performance and life span of the plant are not highly affected.

5.3.2 Field Experiences of Reliability in Desert Climate

The Atacama Desert offers unique conditions for high production of solar energy, but at the same time important challenges to guarantee the reliability and durability of PV systems. Owners of photovoltaic plants must carefully select the technology they are planning to install (e.g., modules, cables, mounting structures, and inverters), since international standards for accelerated ageing applied in the photovoltaic industry largely underestimate the ultraviolet (UV) conditions of the Atacama Desert. For instance, the standard IEC 61215 "Terrestrial photovoltaic (PV) modules - Design qualification and type approval - Part 1-1: Special requirements for testing of crystalline silicon photovoltaic (PV) modules" [98], used to pre-condition the modules for ageing tests, does not represent the UV conditions in the Atacama Desert.

Current technologies for the implementation of photovoltaic power plants are sensitive to extremely high irradiation levels and specific solar spectrum (in the UV-B range). Furthermore, some deserts have 1) corrosive environments due to the presence of salts and water condensation during night hours; and 2) sticking fine powder that adheres to the components of the power plant and causes operational problems. Therefore, the performance and life span of the plant may be severely affected by the desert conditions. One way to diminish the effect of the environmental conditions of desert regions on the performance of the plant is to make an overview of possible incidents in the plant and then to elaborate an operational and maintenance plan focused mainly on those incidents that have a high probability of occurrence and a high impact on the plant performance. For instance, in Chile, the Comite Solar developed a study focused on the failures in photovoltaic power plants [99]. From this study, 27% of the failures declared by the owners were in the PV modules and 49% of the failures were in the inverters. The remaining 24% of the failures were in the medium and low voltage installations, in the tracking system, in the communications and in the SCADA. Figure 23 presents the results reported by Comite Solar.

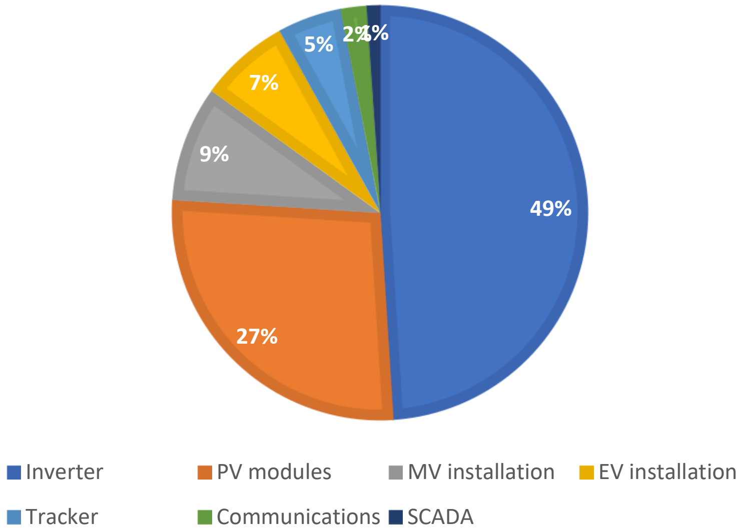

Figure 23: Typical failures in PV power plants in Chile reported by Comite Solar [99].

5.3.3 Performance and Safety Issues in Desert Climate

Although the typical failures have been identified for several desert regions around the world, there is not a compendium of recommendations focused on those desert regions with high radiation, low temperature, and high altitude, such as the Atacama Desert. The present section addresses the degradation of the main components of PV power plants located in high radiation and high-altitude desert regions. The components analysed are the following: modules, cables and cable ties, junction boxes, and mounting structures. To illustrate the degradation of these components, the experience gathered from the operation of power plants located in the Atacama Desert were considered, since the solar spectrum of the Atacama Desert does not completely correspond to the ASTM G173 spectrum [100], which is often used to assess the effect of the radiation on modules and other components of the power plants. Figure 24 compares both the ASTM G173 and the Atacama Desert spectrum [101].

The main differences between both spectrums lie in the range of the UVA and UVB, being more notorious in the UVA range. The key factors responsible for these spectral differences are 1) the high mean elevation above sea level; 2) the many days with clear skies due to the absence of cloud cover and, hence, a low diffuse radiation fraction; 3) small aerosol optical depth; 3) small total ozone column (TOC); and 4) small water vapour column. This finding indicates that the technologies to be installed in high radiation and high-altitude desert regions should be designed/selected to support considerable energy in the UVA range.

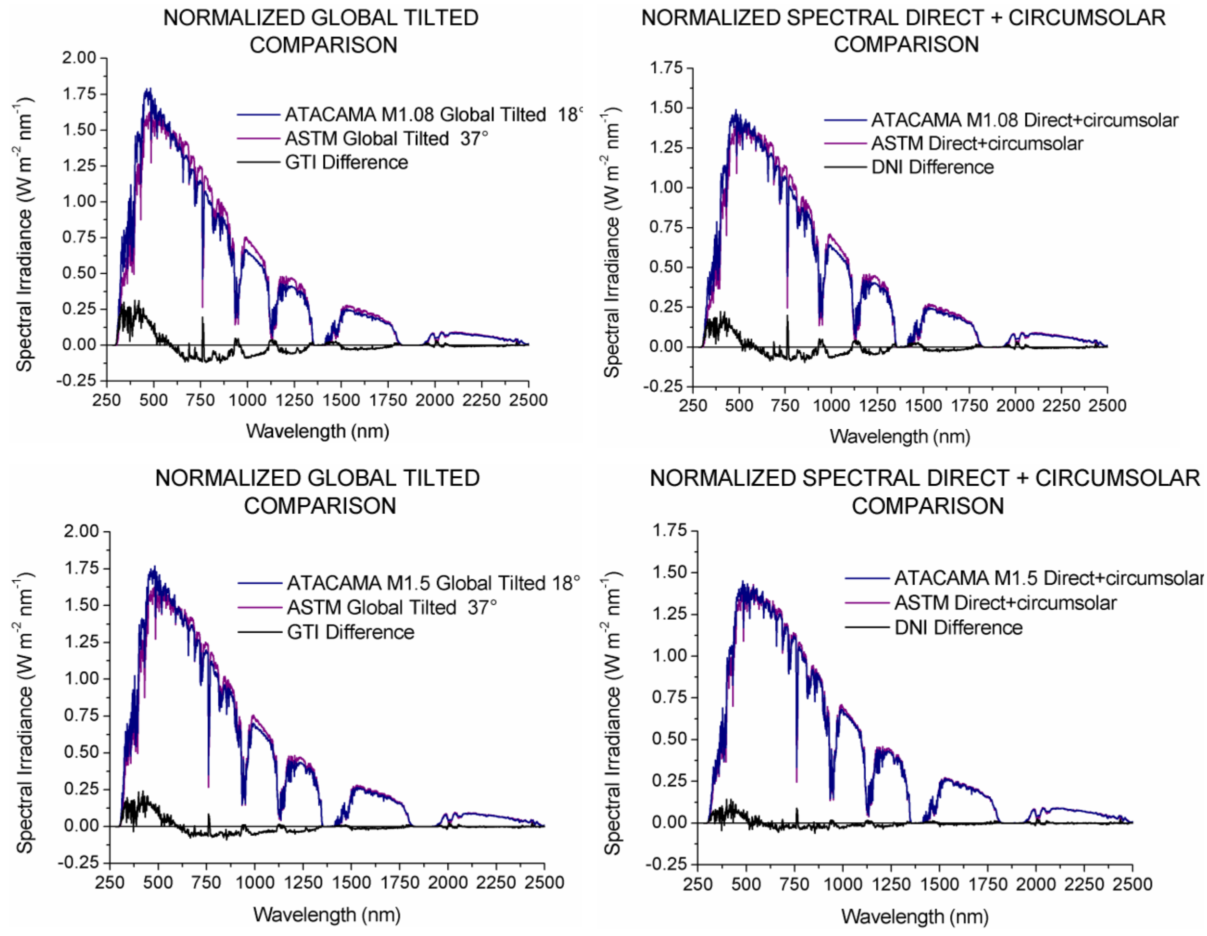

Figure 24: Comparison with the ASTM G173-03 reference spectra (purple) [100] and the Atacama Desert solar spectrum (blue) [101].

In literature, several factors have been reported that may be responsible for the degradation of PV modules [101]. In high irradiation and high-altitude desert regions, the main mechanisms are 1) the high UV radiation present in the solar spectrum, and 2) the temperature oscillations that could cover in a day from -10ºC to 30ºC. The former mechanism produces changes in the colour and/or brightness of the cells, indicating that the entire cell or the encapsulant, respectively, are being affected by the UV radiation, and consequently started an accelerated degradation process. The later mechanism could produce the condensation of the water present in bubbles inside the modules, which might drive towards 1) corrosion inside the cell; 2) corrosion in the frame of the module and in the supporting structures; and 3) the accelerated degradation of the encapsulant because of the interaction with the condensed water.

Both degradation mechanisms: UV radiation and temperature oscillation may lead to hotspots and isolation issues of the modules (often in the form of arc flashes). The severity of the hotspots and their number, and of the isolation issues as well, are directly correlated with the degree of degradation of the module (whatever the degradation mechanism) and are inversely correlated with the measures taken to prevent the progress of the degradation. Figure 25 presents some cases of degraded modules of PV power plants installed in the Atacama Desert. For explanations of which types of degradation can be seen in Figure 25, see technical reports [1], [28], and the PV module failure sheets in [102].

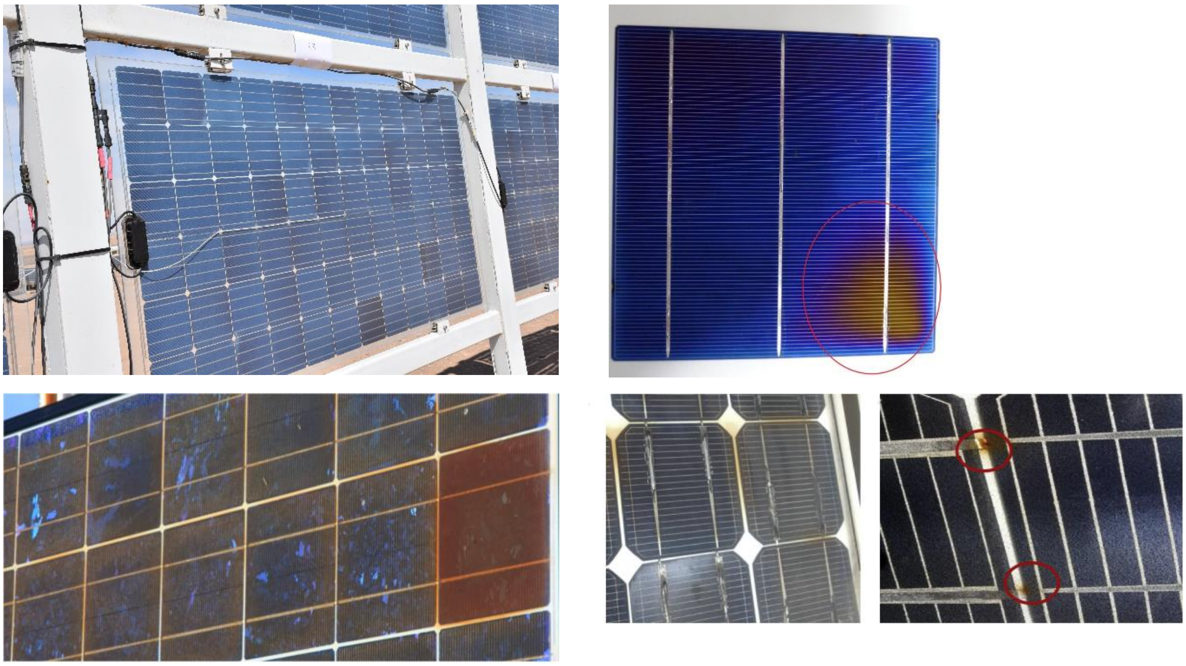

Figure 25: Degradation mechanisms evidenced in PV power plants installed in the Atacama Desert.

In addition to module degradation, the UV content of the solar spectrum and the temperature oscillations affect the cables and the cable ties. The UV content of the solar spectrum diminishes the flexibility of cables and cable ties increasing the possibility of cracking and cutting, whereas the temperature oscillations pose additional mechanical efforts to them. These factors, reduction in the flexibility and additional mechanical efforts, may lead to energy losses, short circuits, and arc flashes. Moreover, the presence of animals (mainly rodents) must be prevented. Wild animals could cause damages to cables and cable ties since they tend to bite these components, reducing their lifespan. Furthermore, wild animals can cause short circuits in cables by damaging the isolation.

Figure 26 shows examples of a cable affected by the UV radiation and bitten by a rodent. In the former (picture a), the isolation of the cable is completely cracked even though it was certified for operation under UV radiation. In the picture b, a rodent damaged the isolation of the cable. In both cases, a replacement is necessary to prevent any damage to the facilities.

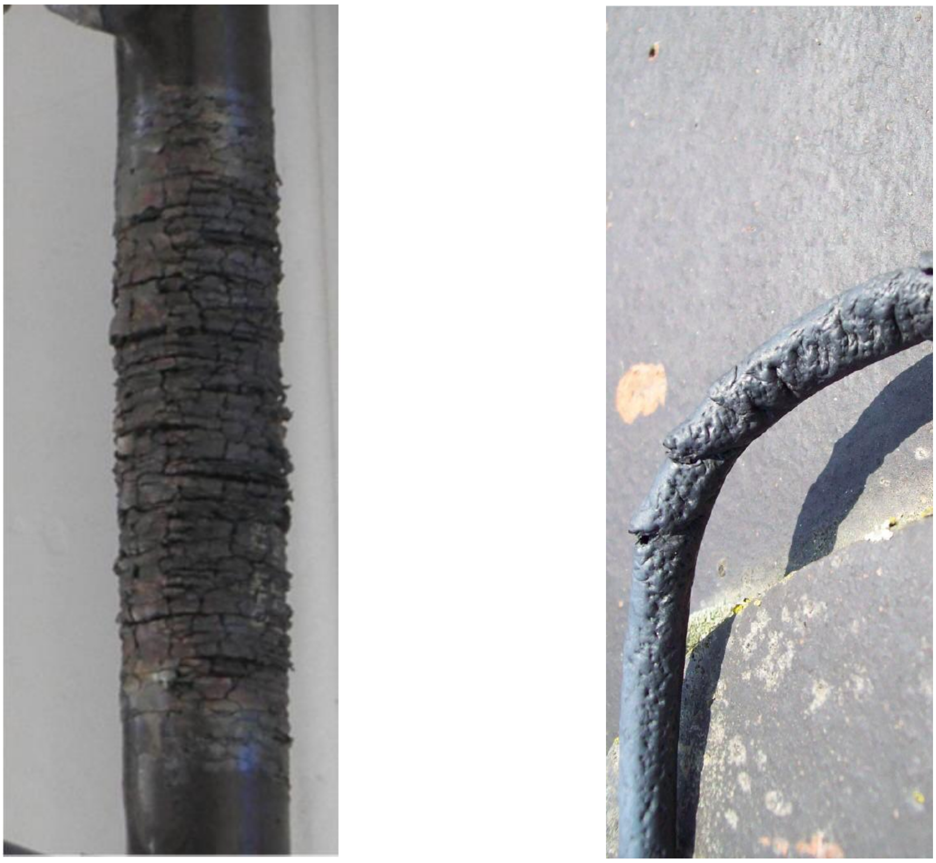

Figure 26: Examples of damages in cables in power plants located in the Atacama Desert.

Moreover, junction boxes are also highly sensitive to the environmental conditions of high radiation and high-altitude deserts. They are made and fixed to the modules with polymeric materials that are sensitive to heat and temperature oscillations (in general junction boxes are not exposed to the radiation, just the radiation reflected from the ground). Heat and temperature oscillations make the boxes themselves deteriorate and the polymer used for bonding them to the modules can become damaged, losing their fixing capacity.

The resultant failures are module detaching, case opening, and connection losses. Module detaching appears when the polymer used to fix the boxes to the modules expands and shrinks because of the heat and temperature oscillations. Increases in heat and temperature followed by a decrease at night can make the polymer become crystallized and lose its properties, resulting in the detachment of the box. The issue of case opening follows a similar mechanism, where the box is expanded and then shrunk from the heat and temperature oscillations. Then, the screws become loose, and the box gradually starts to open.

Connection losses arise due to the factors that affect the flexibility/mechanical properties of the cable, or because of an inappropriate installation. Degradation problems in junction boxes may lead towards energy losses, short circuits, and internal arc flashing that endanger the module and the operation of the facilities. Figure 27 presents these two cases: a detaching of the junction box and a junction box opening.

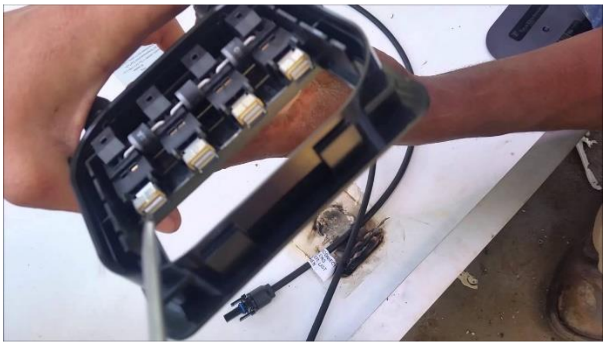

Figure 27: Failures in a junction box in operation during about a year due to degradation issues.

Other components that are highly degraded by the environmental conditions of high radiance and high-altitude desert regions are the mounting structures that support the modules. These structures degrade through temperature oscillations and the presence of salts. Temperature oscillations might cause water condensation, and the interaction between the condensed water and the structure's exposed parts could make them corrode. Indeed, a wrong selection of the materials for the structures and/or a lack of adequate surface finish may cause the structures to be damaged and/or corroded. This is because, for example, differences in the electrochemical potentials (corresponding to the electrochemical series) of the connected materials as well as moisture can cause electrolytic corrosion.

The presence of salts makes for a corrosive environment: the higher the concentration of salts, the higher the environmental corrosion level. Thus, the material selection for the structures as well as appropriate surface finish is mandatory. In the case of the Atacama Desert, for instance, both conditions are present: water condensation during night and dawn hours and salt presence in the environment since almost all the desert is a salt surface. Figure 28 shows typical corroded structures in photovoltaic power plants.

As can be noticed, the corrosion of the structure affects not only the surface of the structure but also its inner parts. This diminishes the mechanical properties of the structure as a whole and becomes a source of risks for the operators of the plant. Furthermore, a corroded structure could affect other nearby structures, hence reducing the life span of the plant itself.

Figure 28: Rusted mounting structure in a PV power plant located in the Atacama Desert. This mounting structure has been in operation for about one year.

5.3.4 Recommendations of O&M and OHS in Desert Climate

The present section puts forward several recommendations/guidelines for both:

- operation and maintenance of photovoltaic power plants in high radiation and high-altitude desert conditions
- and operation, health, and safety in these power plants

As in section 5.3.3, the operation and maintenance recommendations are focused on the following elements: modules, cables and cable ties, junction boxes, and mounting structures. Next, recommendations to prevent the risks associated with the exposure of the operators to high radiation and low oxygen environments are given.

A. Operation and maintenance recommendations/guidelines

Since the intensity of UV radiation and temperature oscillations are factors that cannot be controlled, it is recommended to perform periodic visual inspections of modules to detect if any of the phenomena illustrated in Figure 25 are taking place. These inspections should be accompanied with thermographic analyses and measurements of the quality of the modules' isolation to check for the formation of hotspots and the probability of losing electrical isolation. To determine when complementary analyses must be conducted, it is suggested to compare the energy production of the plant with the results of the visual inspections.

If a continuous decrease in the energy production is noticed, even after the plant has been cleaned, the maintenance plan must be executed to reduce the energy losses and avoid possible permanent damages to the facilities. It is important to remark that any change in the colour of the cells must be reported since such change indicates that something is happening with the encapsulant and/or the cells themselves. These changes must be carefully followed and the plant's zones with presence of these changes must be identified. This way, it is possible to focus the maintenance efforts on these zones that are most affected by problems in the modules, reducing the time taken to evaluate the plant, to determine the failures, and to isolate the failed zones.

To prevent that damage will happen from issues in the cables and cable ties, it is recommended to perform a visual inspection of the facilities with a certain regularity. These visual inspections can be done at the same time as the other inspections, in order to verify the degradation level of the modules. Visual inspections allow to verify that all the cable ties are working as expected. The focus is on the cable ties, as they could fail when exposed to UV radiation and wild animals. However, if the cable ties are intact, it is expected that the cables have not suffered any damage. Only if they were installed inappropriately, while being well tied, it may be expected that the cables have flexibility/mechanical problems. Furthermore, it is recommended that all cable ties are replaced periodically. Notably when they are made of a polymer that gradually, with the heat, temperature oscillations, and UV radiation, loses its properties. Indeed, the heat at midday combined with the weight of the cables make the ties become gradually warped. Thus, despite the efforts made to make them work properly, within a short period the cable ties may completely lose their capabilities to keep cables fixed and will fail, leaving the cables exposed to the hazards. Note that if there are cables exposed to radiation. They must be examined to determine if they must be replaced or tied adequately to avoid the exposure. If this is not carried out, any damage in the cable is expected to progress leading to undesired consequences for the operation and performance of the plant.

Like the recommendation for modules, cables, and cable ties, the main recommendation to avoid junction box failures due to degradation is to perform periodical visual inspections to assess the operating conditions of the junction boxes. All these inspections could be done simultaneously following a checklist that allows the operators to determine if the equipment is operating in adequate conditions or not. Furthermore, systematizing these checklists might help in determining the plant's zones with a larger number of degradation issues, and those zones with degradation problems (e.g., junction box failures mainly). In the specific case of detecting junction box problems, a report must be made so that corrective measurements can be immediately taken. Any junction box failure added with water condensation, for instance, could lead to short circuits causing fires impacting the facilities' operation. Hence, as in the case of the cable ties, it is highly important that the junction boxes prone to fail are detected in advance. Decisions on how to solve the issues detected and/or about their replacement should then be taken.

Finally, due to the potential risk associated with the loss of mechanical properties of the mounting structures, their "degree of health" must be evaluated constantly. The degree of health is assessed as the evolution of the corrosion process, starting from the day that it was first detected. This evolution not only comprises the corrosion process of the structure evaluated but also if this process is impacting other nearby structures or elements (e.g., cap screws and module frames). Moreover, the structure's mechanical properties must firstly be visually evaluated. This can be done by detecting if an abnormal buckling is taking place or not. The abnormal buckling of a structure indicates that it is becoming warped. If any of the aforementioned factors are present: evolution of the rusting process in the structure, evolution of the rusting towards closer structures, or abnormal structure warp, the recommendation is to schedule a replacement of the affected structure so that the associated risks are reduced.

B. Operation, health, and safety recommendations/guidelines

With respect to health issues in the operation of photovoltaic power plants located at high radiation and high-altitude desert regions, there are two main factors that must be considered: the first one is the exposure to high radiation of the operators, and the second one is the exposure of the operators to environments with low atmospheric pressure.

Both factors can significantly affect the capabilities (and even threaten the life) of the operators of the PV power plants. The former might produce burns to the skin from solar exposure and heatstroke, whereas the later would produce a decrease in the activities that the operators can safely do during a day and altitude sickness, which may lead to headaches, dizziness, and generate the feeling of sickness that may even require urgent medical care. Therefore, to prevent the effects of high radiation and high-altitude, the tasks must be carefully scheduled so that the risks for the operators are minimized. Furthermore, additional medical care equipment is recommended to locally address any medical emergency.

For example, to prevent sun burn, it is required that the operators, in addition to the personal protection equipment, wear long-sleeve shirts (desirable with some UV filter), trousers with UV protection, neck cover, glasses with UV filters, and "sunblock cream" to protect the parts exposed to the radiation (the face mainly). To prevent heatstroke, the activities of the operators must be done during the morning and the afternoon mainly. This allows avoiding the day hours with the highest radiation and therefore the hours with the highest risk for the personnel. Only critical activities must be done during these hours. This fact is crucial during the implementation phase and maintenance of photovoltaic power plants since activities with a high demand of physical work could be required. If these recommendations are not considered, several delays might be expected as well as health problems in the personnel. All the recommendations should be accompanied by a clearly understood health-care plan and self-care policy. It must be mandatory that every operator informs the health and security manager whether he/she is getting sick due to solar radiation exposure. In turn, the health and security manager must have internalized the procedure to be carried out. The World Health Organization (WHO) has published a practical guide to the "Global Solar UV Index", which should be taken into account and may be of practical benefit [103].

With regards to the exposure of operators to low oxygen environments, the measures to reduce the risk are more focused on health monitoring and on the scheduling of the activities than on the acquisition/wearing of additional equipment itself. In this context, the recommendations start with requiring a medical test that certifies that every operator can work at high altitude locations. Then, every operator must be trained in providing first aid and in the use of first aid equipment. The training must be accompanied by 1) a procedure for the attendance of medical emergencies that may occur when the team is travelling and when it performs activities at the photovoltaic power plant, and 2) the acquisition and placement in the plant of proper equipment to address medical emergencies. In addition, despite the first aid training of the operators, it is desirable that doctors/paramedics are present in the photovoltaic power plant in case of emergency situations and to periodically monitor the health of the operators.

Moreover, the displacements from/to the plant must be carefully scheduled. For this displacement it is recommended that 1) at least two people have a driving license with high-altitude driving certificate, 2) there exists programmed stops that allow the team to get accustomed to the changes in altitude (the number of stops and their duration will depend upon the altitude at which the activities will be done), and 3) the maximum driving hours per day are previously defined (it is recommended no more than eight hours per day per driver, is should be forbidden to drive at night hours). As a complement, oximetry measurements must be periodically taken (both during the travel and when performing activities at the plant) to anticipate the presence of undetected symptoms associated with altitude sickness.

In this regard, oximetry measures below 80% indicate that the operator must stop his/her activities and go for first aid (in this case, breathe oxygen from an oxygen bottle or similar). Finally, the activities to be done in the photovoltaic plant must be scheduled considering that, at least during the first days, the personnel must become accustomed to the new environmental conditions, and that it is therefore not safe to carry out activities that demand high physical effort.

5.3.5 Comparison with Issues and O&M in Moderate Climate

This section presents additional operation recommendations for photovoltaic power plants installed in high radiation and high-altitude desert regions. Besides the broadly used practices in this area, the recommendations presented here are focused on 1) the use of water and 2) soiling effects on the inverters. These specific topics were selected since water scarcity and therefore water costs increase the operation costs of photovoltaic power plants in these desert regions.

For instance, the water costs in high radiation and high-altitude desert regions could be ten times higher than in urban areas, and high radiation exposure could cause skin cancer to the operators. These issues make the operation of photovoltaic power plants located at high radiation and high-altitude desert regions a challenging task from a resource management point of view. Furthermore, in practice, it has been found that water scarcity, high temperatures in the inverter area, and the accumulation of dust particles in the refrigeration systems increase the operation costs and produce the largest number of failures.

Regarding the use of water, the main options explored/reported are the following: 1) the recycling of the water used for cleaning purposes, and 2) the use of dry systems for cleaning the modules. These options have been considered despite the cleaning task being accompanied either with diagnostics tools such as those based on drones and image processing or with other technological tools, such as cleaning robots. The idea behind this practice is to use of the water as intensely as possible and hence reduce the amount of water to be purchased for cleaning purposes (or reduce the frequency of water purchasing). To accomplish this objective, an alternative option is to install water capture systems at the bottom of the modules, so that the water is conducted towards a storage tank, instead of falling to the soil. After filtering the dirt from the water, it would be possible to use the water again.

It is important to note that, in the design of the water capture system, the evaporation rate must be considered to reduce the water losses. An alternative for reducing water losses is to schedule the cleaning task during the less warm hours of the day. The main advantage of this alternative is that the scale formation on the surface of the modules is prevented (and the exposure of the operators to high radiation). For photovoltaic power plants with tracking systems located in desert regions with water condensation (such as the Atacama Desert), an alternative is to leave the modules in an orientation that fosters self-cleaning during the night hours instead of the safer flat position. With this practice, the amount of water required for the cleaning task is highly reduced (or in some cases even avoided). Finally, the use of dry-cleaning systems is gaining attention, despite the need for a structure (fixed or with a solar tracking system). Depending on the type of dust particles (size, structure, chemical composition, and interaction with the glass surface of the modules), these systems can partially or totally clean the modules. Then, as in the case of the tracking systems, the use of water can be avoided. In the case that dry-cleaning systems are not totally able to remove the dust particles accumulated on the PV modules, the combination with a water capture system is the best option to reduce the water use in the plants.

With respect to high temperatures and the accumulation of dust particles in the refrigeration systems, the use of hermetic cases for the inverters and liquid cooling systems with heat exchangers have been proposed. However, the investment and maintenance costs associated with these alternatives make them unappealing. Thus, the use of air conditioners and air-based cooling systems for the inverters is likely to remain common practice. To prevent damage to this equipment, it is recommended that the air filters are cleaned and replaced periodically. Furthermore, the temperature inside the inverter areas must be continuously monitored to detect temperature increases that could cause either a loss of performance of the devices or even fires. In addition, it is recommended to periodically check that the heat dissipation systems installed in the inverters are clean. The accumulation of dust particles or any other foreign element may cause an increase in the internal temperature of the inverter, which makes it unable to work under its optimal range of operating conditions. This may lead to energy losses as well as the increased probability of major damage to the inverter’s electronics. Indeed, in the Atacama Desert, failures in the inverters’ electronics are the most common type of failure for these devices.

5.4 O&M Guidelines for Hot and Humid Climates (South-East Asia)

5.4.1 Description of Climatic Conditions

The increasing number of PV deployments in Asia, Africa and South America has led to significantly more PV modules being deployed in hot and humid climates. Moreover, many of the big cities in these regions are located in coastal areas, thus the PV deployments in and around these cities are exposed to heat and humidity. High temperature is generally known to accelerate several degradation modes in PV modules, however, when high temperature is combined with high humidity environments, different kinds of degradation modes can manifest themselves.

Southeast Asia lies in the tropical climatic zone and includes eleven countries. Thailand has three distinct seasons, namely hot, rainy, and dry or relatively cool season and an average temperature around 30°C Celsius throughout the year. The highest temperature typically occurs in April, regularly above 40°C. Most of the year, the region is covered by warm and moist air particularly in coastal areas. The relative humidity may be significantly reduced in the winter and summer months. Irradiation in Thailand is highest in April and lowest in December [104].

5.4.2 Field Experience of Reliability and O&M Issues Seen in Hot and Humid Climates

A. Potential Induced Degradation

The most common type of Potential Induced Degradation (PID) is caused by the shunting of P-N junctions in solar cells due to accumulation of Na+ ions in the stacking faults present in the wafers. PID can rapidly cause significant power loss in PV modules thus forcing large amounts of modules in a plant out of operation very early in their service life. It is known that for a given type of PV module, PID is accelerated by an increased negative voltage experienced by the cells with respect to ground, temperature, humidity, and the surface conductivity of the glass (all leading to higher leakage current).

As the maximum system voltage of PV systems has been increasing from 600 V a few years ago to 1500 V currently, newer PV modules must endure higher voltages during their service life. Due to power conditioners without transformers, it is often not possible to physically ground any end of the string of PV modules, and thus even for an electrically floating PV system, some modules in the string end up experiencing considerable amounts of negative voltage with respect to ground - thus attracting Na+ ions from glass, potentially leading to PID.

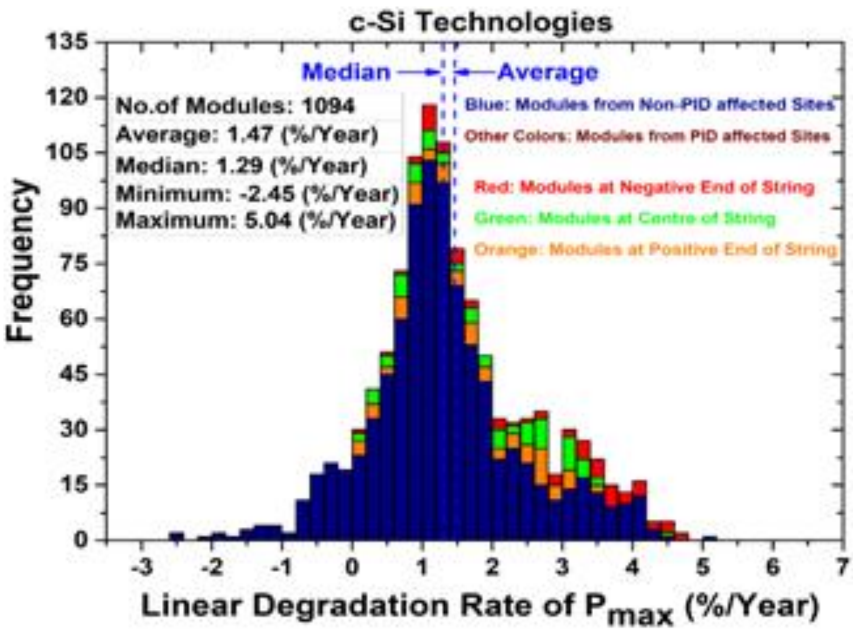

Figure 29 DEGRADATION RATE Histogram of linear degradation rates of P_{max}: All c-Si PV modules in which modules from PID affected sites differentiated along with their position in the string.

Figure 29 shows the histogram of module degradation rates for c-Si PV modules after discounting for 2% of initial power loss due to LID as observed in the All-India Survey of PV Module Reliability 2018 performed by the National Centre for Photovoltaic Research and Education (NCPRE), IIT Bombay. The modules coming from PID affected sites (highlighted in colours other than blue) tend to belong to the higher degradation rate side tail of the histogram. Moreover, the modules belonging to the negative end of the string tend to experience higher negative voltage with respect to ground. It is seen in Figure 29 that such modules (highlighted in red) tend to have higher degradation rates than the rest of the modules. Also, the severity of PID is shown by the fact that these PID affected modules tend to have significantly higher annual degradation rates than those warranted by the module manufacturers (~0.7%/year).

B. Wildlife

Most of the operation and maintenance risks for PV power plants, especially in ground-mounted systems in Thailand, originate from wildlife, especially rats, termites, and snakes. As most of PV power plants are installed in rural areas and surrounded by agricultural fields, wildlife management becomes an important issue to prevent failures in PV components and electrical breakdown of the PV system. The highest failure occurrence was recorded for effects due to termites, followed by rats and snakes, as shown in Figure 30. Solar cables and PV modules are the critical components that most frequently cause failures due to the impact by wildlife over a long period of time.

Figure 30: Impact by wildlife on PV components, such as a rat in the main distribution box (left) and termites around the DC cable under the PV module (right).

C. Soiling issues

Due to the dry climate and PV installations in agricultural areas, plants may be the main reason of the soiling impact on PV power plant, particularly for components such as PV modules and inverters. Different locations show specific types of dust which may be more or less difficult to remove. Dust accumulation must be removed from the top of the soiled inverters to avoid over-heating and them consequently switching off. A field study on the impact of dust on the performance of PV systems and suitable cleaning schemes for Thailand leads to the conclusion that appropriate cleaning can decrease the production loss due to soiling on the PV modules by 6-8% during the summer months [105].

D. Fire risks

Fire can easily occur in areas with a dry climate for various reasons. There are two kind of fire risks: internally and externally caused fires. Within the first group of risks, fire accidents may be caused by smoking or by fuel igniting inside a PV plant. External fire risks may typically be present at the end of the agricultural season, when agricultural waste is typically disposed of by burning it. If the wind blows the fire towards the PV installation, it can bring the flames to the PV power plant, which is the main cause of fire accidents in most PV power plants in Thailand.

E. Degradation rates

In hot and humid climates, weather conditions can very often result in partly cloudy skies causing rapid changes in module temperatures due to full solar irradiance (possibly enhanced by reflections from clouds up to 1200 W/m²) and a sudden change to diffuse irradiance conditions at much lower irradiance (e.g., below 300 W/m²) when the sun is hidden behind a cloud. The thermomechanical stress on the module components caused by such very frequent temperature changes was found to be more stressful (solder joint fatigue) than the thermal cycles in desert areas (change between cold night and hot daytime), although the amplitude is much lower. In IEC 62892 [106], Annex B provides a calculation based on temperature monitoring data to estimate this thermomechanical stress to decide whether to test modules with extended thermal cycling.

5.4.3 Operational Health and Safety Issues

The occupational health and safety (OHS) guidelines, described in section 5.2.3, are also valid for PV power plants in hot and humid climates such as that of Thailand. OHS guidelines should assist operating personnel and staff members to help with compliance and protect them from sudden situations, personal risks, and damage to their health.

In combination with the climatic conditions, e.g., hot temperatures and the agricultural season, certain risks of fire accidents may occur. The main reason for this is agricultural waste disposal at facilities to clear land and prepare for the next growing season. However, to prevent the risk of fire accidents, regular fire training (Figure 31) and the localisation of all potential fuel sources are the most important measures to prevent a fire accident. Finally, first aid training of PV power plant personnel is also essential. Receiving a basic background of first aid will encourage staff to prevent any calamity from worsening as well as enable them to properly take care of injured personnel (Figure 31).

Figure 31: Regular fire accident training (left) and first aid training (right) in Thailand.

Figure 32: Regular checking and performing preventive maintenance in PV power plants in Thailand.

5.4.4 Recommended Practices

Standard O&M best practices as described in section 5.1 also apply to PV power plants installed in hot and humid climates. Additional key recommendations for O&M to prevent typical risks in PV power plants operating in hot & humid climates are given in the

Table 10.

Table 10: Recommendations for O&M of power plants in hot and humid climates.

Risk Cause	Impact	Recommendation
Wildlife such as rats and snakes	Animal bites will threaten the health of operators working on site.	First aid training for PV power plant staff (Figure 31).
	Animals inside the PV system destroy components and cause failures.	Preventive maintenance actions and routines (Figure 32) and system monitoring to detect failures and to avoid performance losses.
Fire accidents	Health of operators and staff affected by fire risks.	Regular fire accident trainings and first aid trainings (Figure 31).
	Fire destroys PV components and the PV system.	Fire protection measures to be implemented. Increase communal responsibility to prevent agricultural waste disposal being burned.
Climate conditions (summer season)	When working under extreme weather conditions (hot temperature), the operating personnel may experience dehydration and heart stroke.	Install proper OHS guidelines for personnel and operators of PV power plants.
	High temperatures in the inverter cabinet (60°C in Thailand) may lead to power losses and switch off.	Adequate design of air ventilation is crucial for remaining good operation conditions for inverters as well as reducing temperature inside the inverter cabinet/ room.
	Imported inverters may have different initial settings given by the manufacturer. This may lead	Specific value settings for inverters considering the operating climate are highly important for the PV power plant commissioning process.

	to the mismatch due to hot temperatures.	
Climate conditions (rainy season)	Flooding of the PV system might impact operators during O&M service (electric shock). Furthermore, dangerous animals may come to the PV power plant and threaten the operators during their work.	Using Personal Protective Equipment (PPE) and performing the operation under the safety rules (Table 4) would help to prevent risks of electric shocks and dangerous animal attacks and bites.
	As most DC cables in Thailand are installed underground, floods may cause electrical leakage and system failures.	Leakage issues might be detected by using effective data monitoring system.
Soiling effects	Plant performance may be impacted by soiling on PV modules.	Regularly monitoring of PR output for cleaning decisions and frequency. Include PV module cleaning in O&M contact as basis practice for this climate.
	Inverter filter may be covered by dust, which might cause resistance of airflow, leading the performance loss.	Regularly cleaning inverter filter would help the resistance of airflow by dust accumulation.
Glass breakage	Stone impact on the module's surface can cause glass breakage and cause performance decline.	Regularly monitor the PR output of strings and array and check the PV modules by visual inspections.

5.5 O&M Guidelines in Flood-Prone Regions

5.5.1 Background and Motivation for Studying Reliability and Safety Issues in Flood Affected PV Plants

Ground mounted PV systems in flood-prone areas are susceptible to damages resulting in safety hazards and performance loss. Flooding can also increase the risk of erosion of the support structure and foundations, depending on geotechnical conditions. The findings and recommendations regarding flood-affected PV power plants in section 5.5 are largely based on the published paper by one of the contributing authors of this report in Shiradkar et al. [107].

Climate change has increased the frequency and severity of extreme weather events throughout the world [108]. Although PV plants are expected to have a service life of greater than 25 years under normal conditions, extreme weather events such as floods can cause significant and irreparable damage to them. Understanding the vulnerability of existing PV plants is an important step in the development of guidelines for flood resilient PV plants.

In recent years, flooding in the northern parts of India has caused significant damage to property and livelihood [109]. Flooding and waterlogging have also been observed in semi-arid areas that were considered less prone to it [110]. Moreover, floods in the southern state of Kerala were recorded to be the worst in a century [111]. PV plants in flooded areas experienced significant damage and/or disruption in the operations in many cases. The National Centre for Photovoltaic Research and Education (NCPRE) at the Indian Institute of Technology (IIT) Bombay had conducted a field study to identify reliability and safety issues seen in flood-affected plants to come up with guidelines for better operation and maintenance (O&M) and plant design in flood-prone areas. In this section, the technical, financial, and strategic motivation for studying flood-affected PV plants is presented.

While designing a PV plant, several decades of history of flooding are considered and typically channels are dug in the ground to direct the water during events of flash flooding. Since floods are considered as rare events, no other aspect of the PV plant is typically designed with flood endurance in mind. However, several studies have predicted that the frequency and severity of flooding are going to increase globally in the years to come and flooding would become common in areas where it is currently a rare event [112].

Therefore, the effects of climate change need to be considered while designing the PV plant that is built to last for 25 years. Merely looking at the history of flooding would result in a significant underestimation of the risk. For some PV plants, risk due to flooding is not a potential future problem caused by climate change but is a clear and present danger. For example, due to the scarcity of land in India and large land requirements of multi-MW PV plants, it is recommended that the land acquired for large PV parks should be unsuitable for agriculture, industry, forest, inhabitation, etc. This has forced the development of future large solar parks in some of the harshest environments observed in the country. For example, one location for a planned solar park is known to be affected by flooding and waterlogging two to three months in a year. Thus, a significant number of PV systems will be deployed in the harsh and flood-prone regions in the coming years. This requires innovative designs of modules and a suitable balance of system components (especially structures) that can survive in flood-prone locations.

It was also observed that insurance policies can vary significantly in terms of their coverage and conditions for extreme weather events. Some policies that are specially made for flooding events, require that the PV plant should be switched off in the anticipation of flooding and it should be only switched on, after technical experts have given permission. This is difficult to accomplish because most utility-scale PV power plants with central or string inverters do not have a ‘rapid shutdown’ feature. In other words, even when the inverters are turned off in anticipation of flooding, the strings of PV modules continue to generate high voltages and it is often impractical to disconnect all PV modules from each other during an emergency event.

Finally, even though the PV modules are not designed for continuous immersion in water, it is important to understand which types of modules and balance of system components show resilience to immersion and floods.

5.5.2 Field Experience of Investigations of Reliability and Safety Issues Observed in Flood Affected PV Plants

A. Demographics of Surveyed Sites and Classification of Damage

The demographic details of PV plants selected for the detailed study are given in Table 11 The damage caused by flooding can be classified into two types: 1) caused by fast-flowing water and/or impact with debris 2) caused by waterlogging and hence continuous submergence under water. The magnitude of type 1 damage depends on the resistance posed by the structures and modules to the fast-flowing water. It was found that no structure in a typical ground-mounted PV plant is strong enough to endure fast-flowing waters if it poses significant resistance to the water flow. On the other hand, the amount of type 2 damage depends on the duration and depth of submergence and the specific equipment such as modules, string combiner boxes (SCBs) or inverters that were submerged. Figure 33 shows an image of a partially submerged plant P1.

Figure 33: Partially submerged PV plant showing strings fully submerged in water (in blue circle) and those that are above water (in black circle).

Table 11: Details of the selected PV plants for investigation.

Plant Number	Plant Details	Flooding Status
P1	15 MW, Ground-Mounted, South facing, latitude tilt	Waterlogging, partially submerged
P2	6 MW, Canal Top, South Facing, 6° tilt	Submerged under fast-flowing water
P3	2 MW, Ground-Mounted, South Facing, latitude tilt	Submerged under fast-flowing water
P4	10 MW, Ground-Mounted, South Facing, latitude tilt	Waterlogging, partially submerged

B. Structural Issues

Significant structural issues were seen in PV plant P3. As seen in

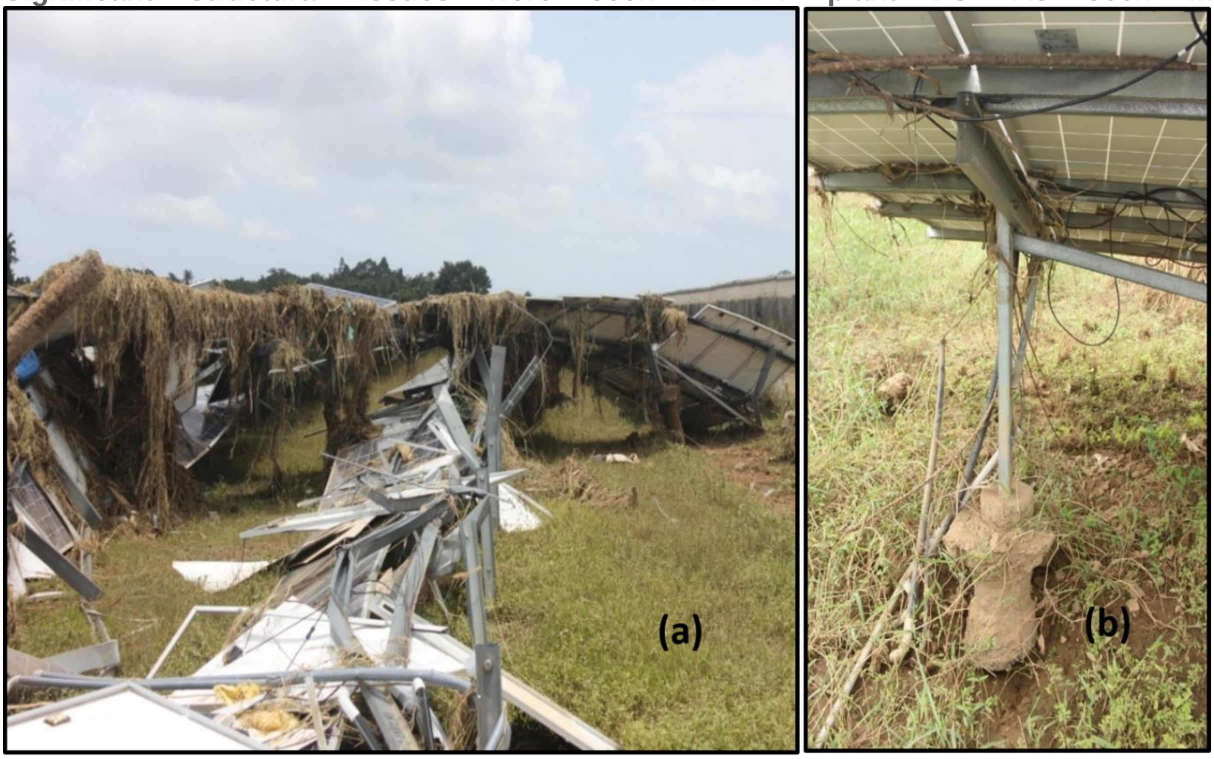

Figure 34 (a), the structures, module mounting clips, as well as modules were broken. In some cases, the laminates were seen to be separated from frames, wires detached from junction boxes, and broken glass was observed due to the impact of debris. In

some cases, (

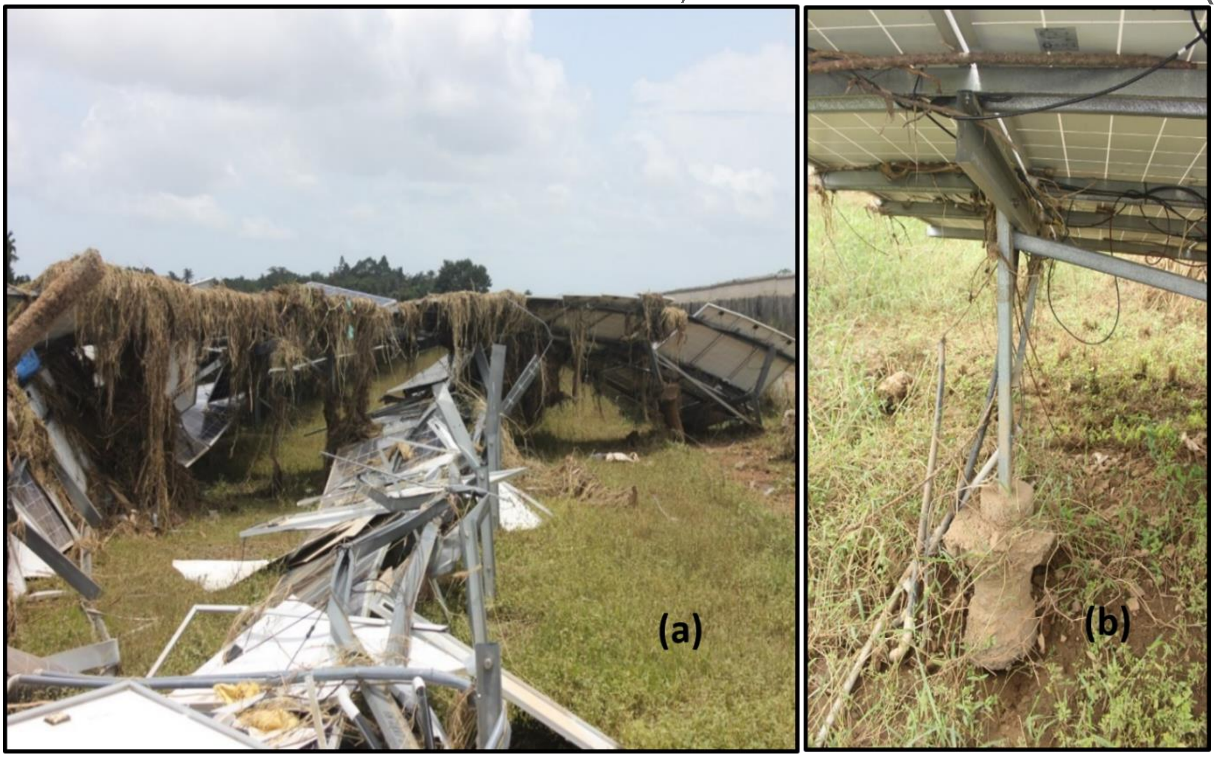

Figure 34 (b)) it was seen that the modules remained intact on the structures, but the pressure from water and debris stuck behind the module uprooted the concrete foundations of the structures. Further, erosion caused by soil around the foundations was also observed. It should be noted that even though this PV plant was south facing at latitude tilt, and the water flow direction was East/West, the perturbations in flowing water were sufficient for the modules and structures in the PV plant P3 to get severely damaged by the fast-flowing water as they offered too much resistance to the flow. Thus, typical steel structures with concrete foundations, modules and mounting fixtures used in PV plants are seen to be extremely vulnerable to damage when they pose resistance to fast-flowing flood water.

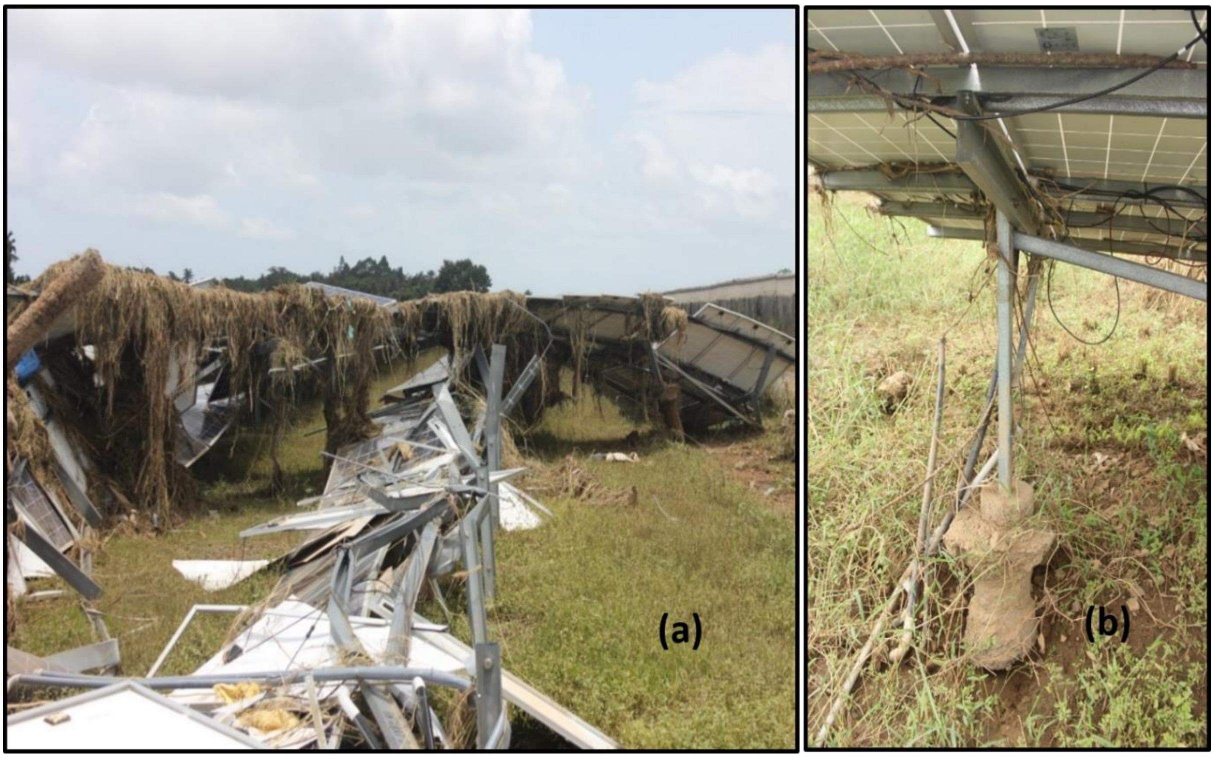

Figure 34: (a) Structural damage to PV plant P3 showing broken structures and modules. (b) An example where modules remained intact, but the foundations of structures were seen to be uprooted.

Figure 35 shows the top and bottom views of a PV plant (P2) that has been constructed above a water channel. This PV system has concrete structures with steel bars for module mounting which have been proved to be significantly resilient against floods. This PV plant has south-facing modules, mounted at an inclination of 6°, while the direction of the floodwaters was East/West. It is conjectured that due to the south-facing nature and low inclination angle, the modules posed minimal resistance to fast-flowing water. Moreover, the concrete beams proved to be considerably sturdy despite being in the way of flowing water. However, such concrete structures are rarely seen at ground-mounted utility-scale power plants.

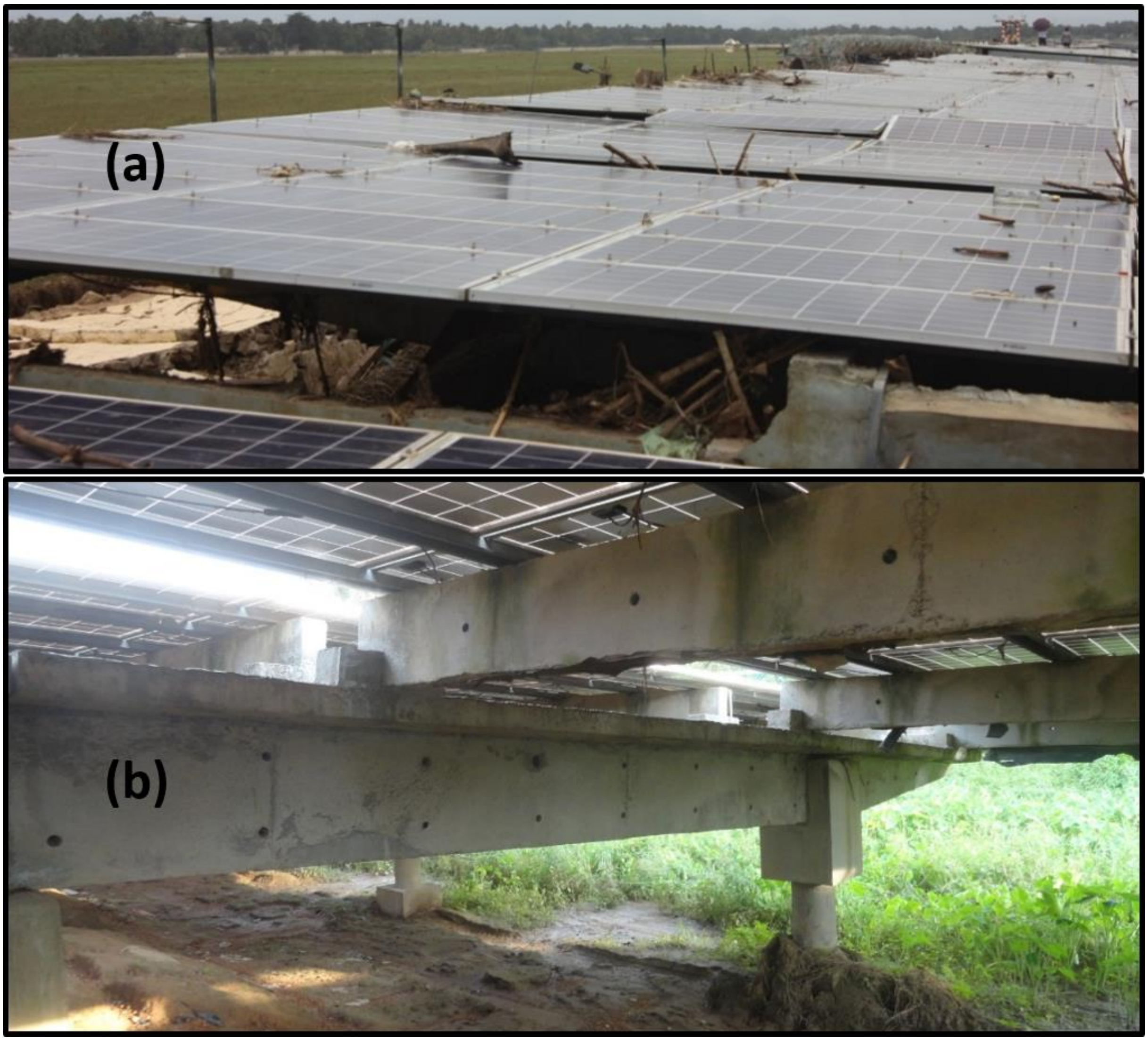

Figure 35: (a) Top view of Canal top plant P2 showing that hardly any damage to modules or structures was seen despite this plant being submerged under fast-flowing water. (b) Bottom view of the all-concrete structure of P2 showing concrete beams.

C. Soiling / Staining Issues

As shown in Figure 36 (a), silt was deposited on many modules of PV plant P2, that were mounted at a low inclination angle of 6°. After cleaning the silt by the O&M team of PV plant P2, uneven stains were observed on the glass of the modules as shown in Figure 36 (b).

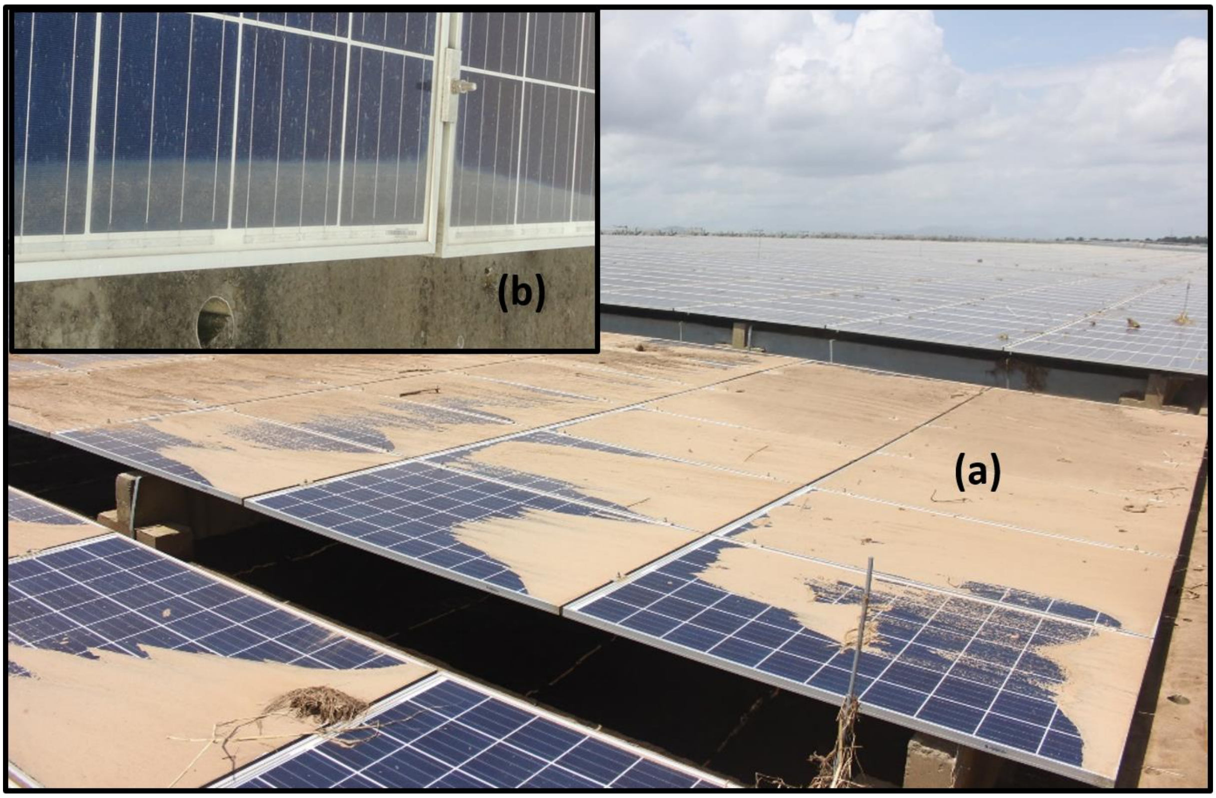

Figure 36: (a) Silt was seen to be deposited post-flooding on most of the low inclination angle mounted modules in P2. (b) Uneven stains were observed near the bottom edge of most of the modules which could not be removed even after cleaning with soap water and scrubbing.

Hotspots with a typical temperature difference of 10°C were observed in modules with stains on glass (Figure 37). These stains (and therefore hotspots) were permanent and could not be removed even after vigorous cleaning by soap water followed by scrubbing with a cloth. Since the stains were only observed near the bottom edge of the modules, it was conjectured that the dissolved minerals in the stagnant flood water that remained near the lower edge of the modules with low inclination angle could be the cause of staining (and not merely deposition of silt – which was distributed throughout the module). This shows that low inclination angle mounting may provide benefits of low resistance against floodwaters, but it can be vulnerable to soiling/staining issues if the water stays on PV modules for a long time.

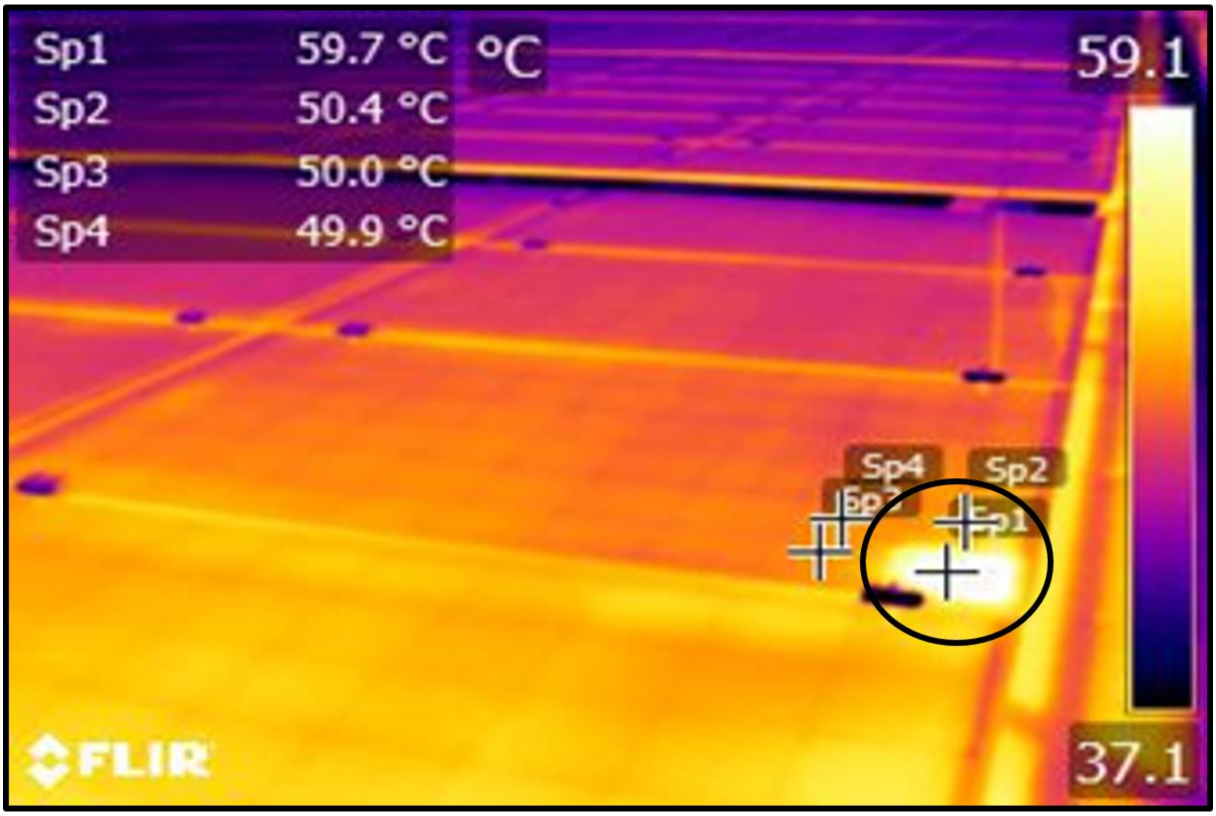

Figure 37: Modules with uneven stains on glass were seen to have developed hotspots with ΔT ~ 10°C.

5.5.3 Performance / Safety Issues in this Region

A. Effect of Continuous Submergence Underwater

In some parts of the PV plant P1, modules remained under about 0.3- to 1-metre-deep water for over two days. Since most commercial PV modules are not designed to withstand continuous underwater immersion, this could cause several kinds of reliability issues for the PV modules, depending on the design. For example – short-circuited/damaged bypass diodes, accelerated corrosion in the presence of water (in the junction box, connectors and even fingers on cells), accelerated potential induced degradation (PID), cell/backsheet cracking, etc. Note that these are problems merely due to submergence and not due to resistance to fast flowing water and debris hitting the modules.

Modules of PV plant P1 had IP67 rated junction boxes filled with pottant. Note that the test for IP67 rating involves immersion of junction boxes at 1 metre depth in water for 30 min. A significant number of bypass diode failures that have been found in PV plant P1 were limited to only one to two strings. Some of these were accompanied by visible burn marks on the junction boxes (Figure 38). Furthermore, diode failures were often accompanied by burn marks at the junction box. Any penetration of water inside the junction box would have caused an immediate short circuit and catastrophic failure. However, many submerged modules in PV plant P1 did not experience diode failures. This indicates that the IP67 rated junction box with pottant provided adequate protection for continuous submergence under 0.3- to 1-metre-deep water for two days.

Figure 38: Burn mark and deformation is seen at the centre of the junction box with diode failure. The manufacturer's name is masked in black.

To assess the effect of submergence on power degradation, seven modules each from two submerged strings and seven modules each from two non-submerged strings of PV plant P1 were selected for I-V analysis. The I-V curves of the modules were measured outdoors at irradiance > 700 W/m^2 and the power was translated to STC using modified IEC 60891 Procedure 1 [113]. From the results, it could be concluded that there were no statistically significant differences in power degradation between the submerged and non-submerged modules as shown in Figure 39. Furthermore, there were no signatures of accelerated PID or corrosion. Also, no significant cell cracking was observed in the submerged modules. However, on some modules backsheet scratches/cracks have been observed. It appears that the actual damage caused on the modules of P1 due to the submergence was much less than what could have been with a different (poorer) module design.

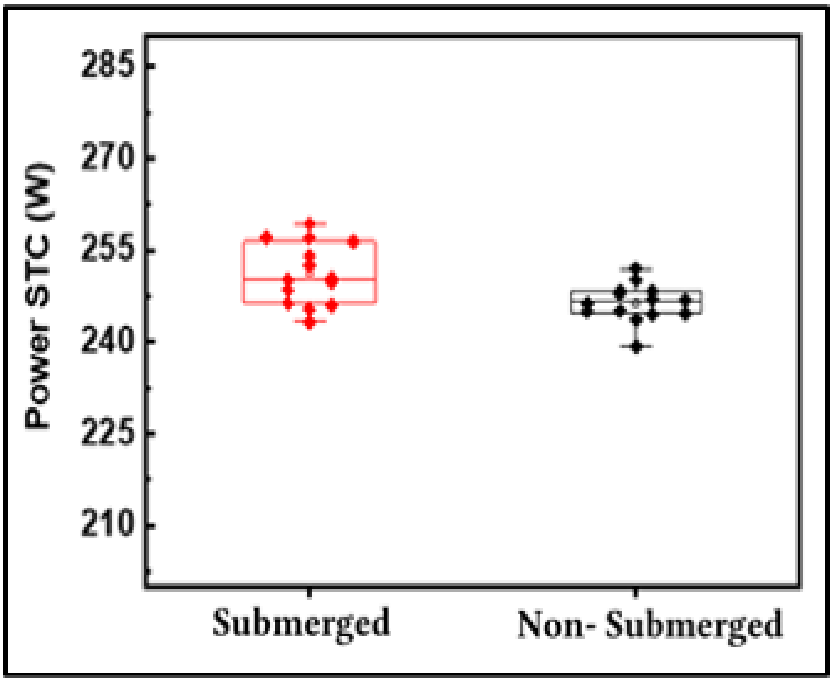

Figure 39: No statistically significant difference was seen in the power degradation of submerged and non-submerged modules.

B. Safety Issues

As the water level rose, the water entered the SCBs / Inverters of PV plant P1 and P2 first, as they were at a lower elevation than the modules. Since the modules were still producing voltage when this happened, every submerged SCB / inverter failed catastrophically. For example, Figure 40 (a) shows that fire was observed on an inverter, several hours after the floodwater had receded. Burn marks like those shown in Figure 40 (b) were observed in large numbers of submerged SCBs / inverters that had failed. Since flooded SCBs / inverters may be wet or internally damaged, they pose safety hazards even several hours after the floodwaters recede. It is difficult to further increase the height of SCBs / string inverters in PV plants (like P1) to avoid submergence as they can cause partial shading on the nearby modules.

Figure 40: (a) Fire was seen at an inverter several hours after the floodwaters had receded (b) A similar fire probably caused burn marks and failure of several submerged inverters. The manufacturer's name is masked in black.

In the case of PV plant P4, the SCBs were submerged and were damaged with burn marks as shown in Figure 41 (a). Even though the water level around this PV plant did not rise enough to submerge the modules, peculiar burn marks were observed near the frames of the modules as seen in Figure 41 (b). The burn marks were so severe that the module glass was melted. The SCBs in this plant did not have reverse current protection. The root cause of this phenomenon was not clear. Reverse currents flowing in the strings due to shorting as the SCB goes underwater could be one possible explanation. This case study shows that it may be dangerous to approach PV modules during flooding even though they are not submerged in water.

In addition to the electric safety issues discussed above, flood-affected PV plants also pose other kinds of safety risks such as displaced and distressed wildlife after flooding. For example, there were sightings of poisonous snakes and crocodiles in urban areas after the Kerala floods of 2018 [111]. Therefore, the personnel visiting the PV power plant immediately after floods should exercise precautions and expect to find wildlife at unusual places.

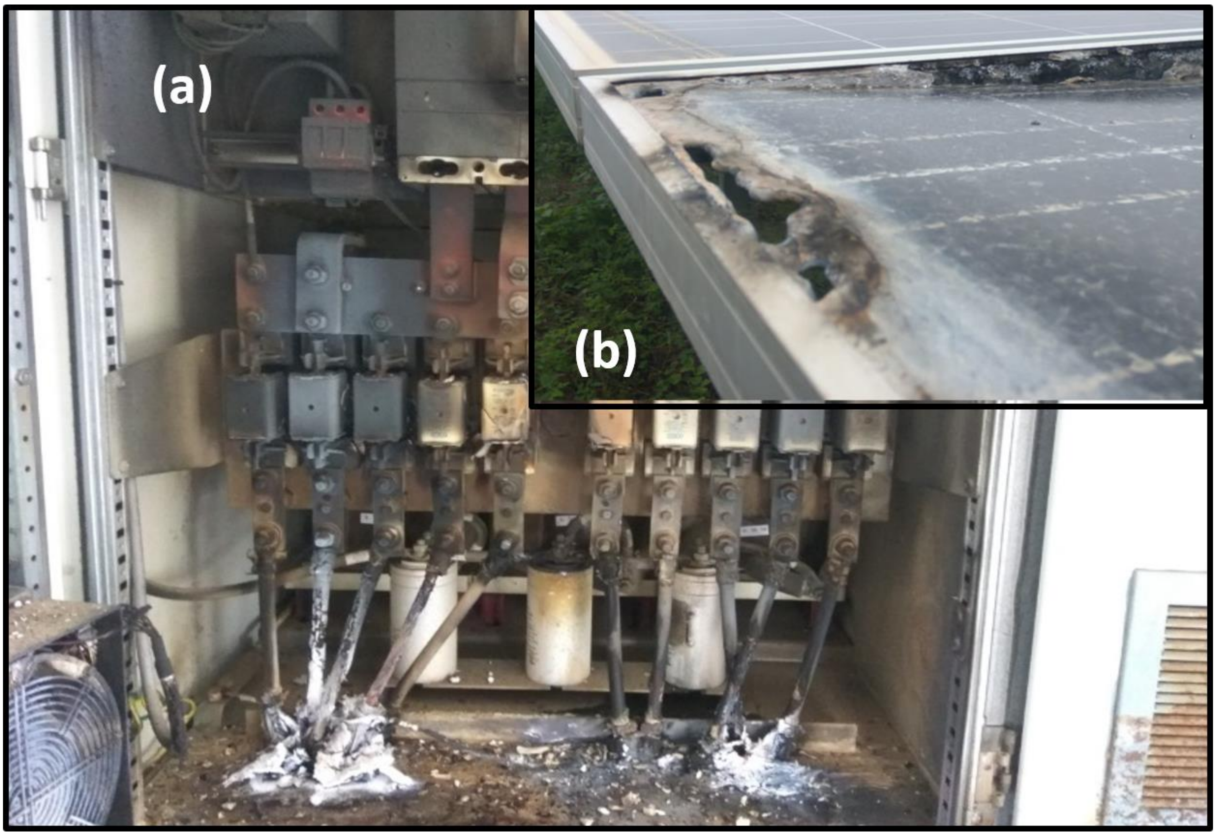

Figure 41: (a) Damaged SCB due to submergence. Prominent burn marks are seen. (b) Even though the modules were not submerged, severe burn marks that cause the melting of module glass were seen near module edges.

5.5.4 Recommendations

Since the frequency and severity of floods are expected to increase worldwide due to climate change, increasing numbers of PV plants would become vulnerable to flooding in the coming years. Various types of failure modes and mechanisms have been observed from flood-affected PV plants and have been discussed in this section. Floods expose the modules and balance of system (BoS) components to two types of stressors: 1) Fast flowing water and/or impact with debris 2) Continuous submergence.

Typical steel structures with concrete foundations used in ground-mounted PV plants have been seen to be extremely vulnerable for severe damage in the case of a type 1 stressor, wherever they pose resistance to fast-flowing water. Further, it was found that none of the structures of the typical ground-mounted PV plants were strong enough to endure fast-flowing waters if they pose significant resistance to the water flow. South facing and fixed tilt mounting at low inclination minimizes the resistance to water flow (East/West) and mitigates the damage due to the type 1 stressor. Also, an all-concrete structure with bars for module mounting in a canal-top plant was shown to be especially resilient against fast-flowing water. However, floodwater may contain minerals that could permanently stain the glass leading to hotspots. This happens when the floodwater stagnates on the low inclination mounted module surface and evaporates over time.

Despite being 0.3 to 1 metre under water for two days, the PV modules with IP67 rated junction boxes did not show any signs of accelerated degradation. Therefore, IP67 or better rated junction boxes with pottant are seen to provide enhanced protection even in the case of continuous submergence (for which the junction boxes are not certified). Therefore, such junction boxes are strongly recommended in flood-prone areas. Lack of significant degradation in submerged modules also shows that the IP67 rating could be used for all the PV modules and some modules (as in the ones encountered by NCPRE) may pass the test without needing any changes in the bills of materials (BoM). Module manufacturers could use this as a differentiating factor in favour of their products for example for the applications in flood-prone areas. This could be a significant added value for PV plant owners who have modules submerged in water but do not seem to have any apparent damage as seen in I-V / IR / EL measurements. Also, this would require the development of procedures to assess cases in which the manufacturer's warranty could be continued post submergence due to flooding.

IP67 or better rated boxes for inverters and SCBs could mitigate some of the problems due to submergence for a few days during flood events. However, it would significantly reduce their maintainability as the electrical access would not be possible in the case of pottant filled boxes. Increasing the height of SCBs / string inverters may not be an option as they may cause partial shading on the nearby modules. Using modules with micro inverters can be explored in such areas as the micro inverters are often potted and rated IP67 or better. They would not only provide advantages under continuous submergence scenarios, but they are also often equipped with a module-level rapid shutdown feature. This can be useful to quickly disconnect individual modules when floods are expected.

Before implementing PV plants in flood-prone areas, it is recommended to conduct studies regarding the floodplain area and the water surface elevation. The history and the future predictions of the water surface elevation for approximately 100 years for flood-prone areas considering the effects of climate change are recommended. If the maximum water level caused by the floods is known, weather bars or upstands can be used to prevent flooding of electrical equipment buildings. Further, elevated pads can be provided to prevent flooding of ground-mounted equipment. Existing and new drainage should also be considered to ensure that the run-off is controlled to minimise erosion [114].

Finally, extreme precautions should be taken by the O&M team when returning to the PV power plants after the floodwaters have receded. This because various electrical parts can still be wet, and live fires are often seen days after the floodwaters have receded. Moreover, danger due to the presence of wildlife at unusual places should also be considered while performing the O&M operations immediately after flooding. Overall, the PV system can behave unpredictably once its components have been submerged in water and all physical contact should be avoided until it is deemed safe to enter the PV plant. Post-flooding, drone-based inspections of PV plants can be performed to assess the status.

When developing procedures and standards to quantify the vulnerability of PV plants in case of flooding, the following should be considered: the module design, IP rating, structural design, SCB and inverter elevations, reverse current protection, etc. This may also be useful for the financial risk assessment of PV plants deployed in flood-prone areas.

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5.6 O&M Guidelines for Building Requirements for Cyclonic Regions

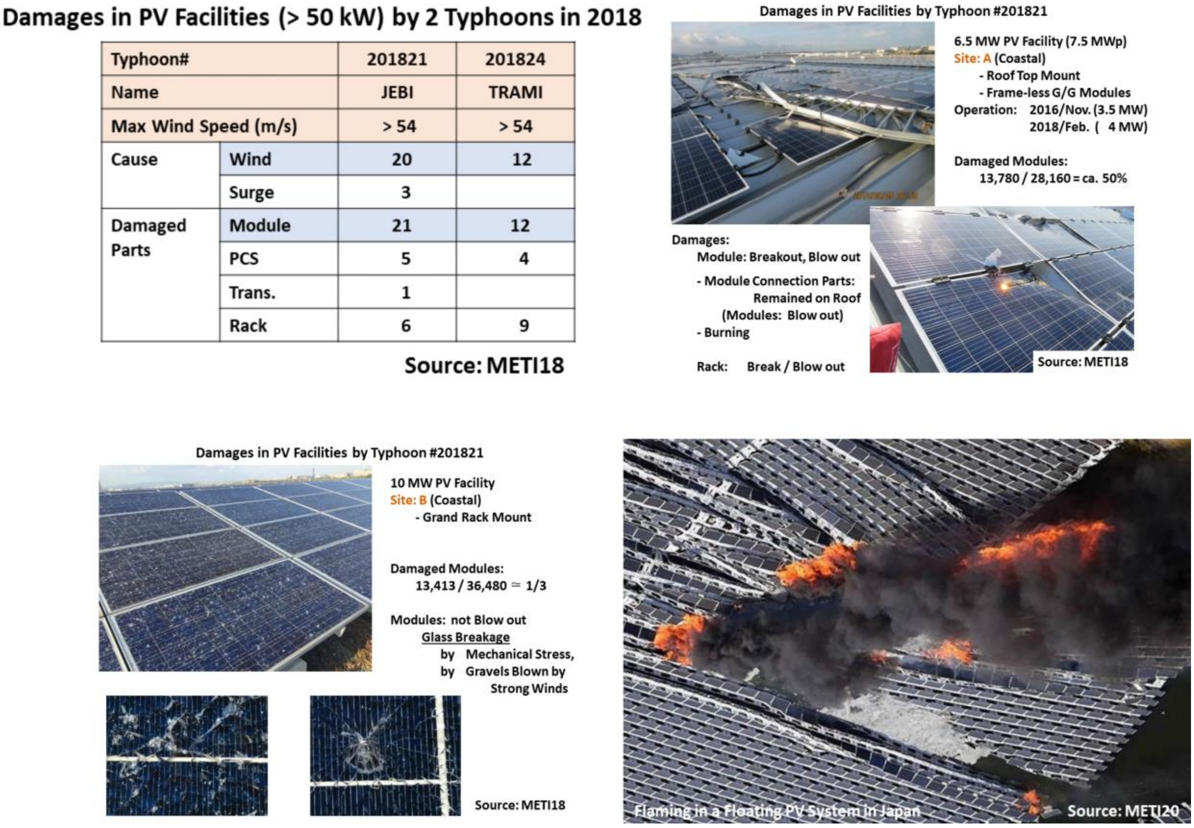
5.6.1 Description of Climatic Conditions

Strong winds attributed to a tropical cyclone (also known as hurricane, typhoon, or cyclone, depending on the region in which it developed) may cause severe damage to the PV systems located in its path. Damages that have occurred around the world are described in this section.

5.6.2 Field Experiences on Damages Caused by Strong Winds with Hurricane / Typhoon / Cyclone

In the last few years, several typhoons with strong winds (over 54 m/s) have hit the coasts of northeast Asian countries / regions. It has been recently revealed that the PV systems installed in these areas suffered from severe damage to PV modules, mounting structure, and their relevant equipment / architectures, which resulted in heavy financial losses (including the long-term reduction of revenue). As shown in Figure 42, two strong typhoons (JEBI and TRAMI) damaged respectively 20 and 12 PV facilities (in over 50 kWp facilities) in 2018, according to official reports published by the Japanese government [115], [116].

The damages in these PV facilities were primarily observed in PV modules and mounting racks. Nearly half of the installed PV modules were blown out or broken by ca. 60 m/s wind-gusts in a PV facility (6.5 MWp installed with ca. 28 000 modules) located at the coastal area in Japan, and the mounting rack on the rooftop was also broken. Even in a PV facility (10 MWp) installed in an inland area, the glass breakage was confirmed in about 13 400 out of 36 500 PV modules, although these PV modules were not blown out from the rack on the ground. Also he floating PV systems were impacted [115], as many PV modules were turned over (after the bolts connecting the anchors and floats fractured), and fire damage (maybe caused by electric arcing) was also observed [117], [118].



Damages in PV Facilities (> 50 kW) by 2 Typhoons in 2018

Typhoon#		201821	201824
Name		JEBI	TRAMI
Max Wind Speed (m/s)		> 54	> 54
Cause	Wind	20	12
	Surge	3	
Damaged Parts	Module	21	12
	PCS	5	4
	Trans.	1	
	Rack	6	9

Source: METI18

Figure 42: Damages of PV facilities by typhoons in Japan in 2018 and 2019.

Figure 43: Damages of PV facilities by hurricanes in U.S. Virgin Islands in 2017.

Also, in strong hurricane prone areas (especially in Caribbean islands), severe damages of PV systems have been reported [119], [120], [121], [122], as shown in Figure 43. Hurricanes Harvey, Irma, and Maria inflicted some hard blows on the PV systems installed in US Virgin Islands, in 2017. Two major damages were the blown-out of PV modules and the breakage of mounting racks. These damages occurred not only in the large PV plants but also in the rooftop

PV systems on individual residences. The breakage of fixing parts (bolts and clamping) was often observed in such damaged PV systems, which could be attributed to the uplift wind-pressure.

Europe is not exempt of harsh environments where wind is the main factor of natural catastrophes. The next case is an example of a windstorm destroying 30% of a roof mounted 115 kWp PV system in Northern Italy (Figure 44). The storm hit several Northern regions, where these unusual events have been increasing over the past few years and left 14 million trees razed at the end of October 2018 [123], [124].

Figure 44: PV System status after a windstorm in Baselga di Piné, Italy. Source: Dino Loriatti.

As shown in Figure 45, the maximum wind speed measured around Baselga di Piné that fatal day was 127 km/h (35.3 m/s). Although this wind speed was not evaluated as an extreme wind gust, the designs and constructions of the fixing system were arguably not solid enough, even for these quasi-extreme wind gusts and their consequences.

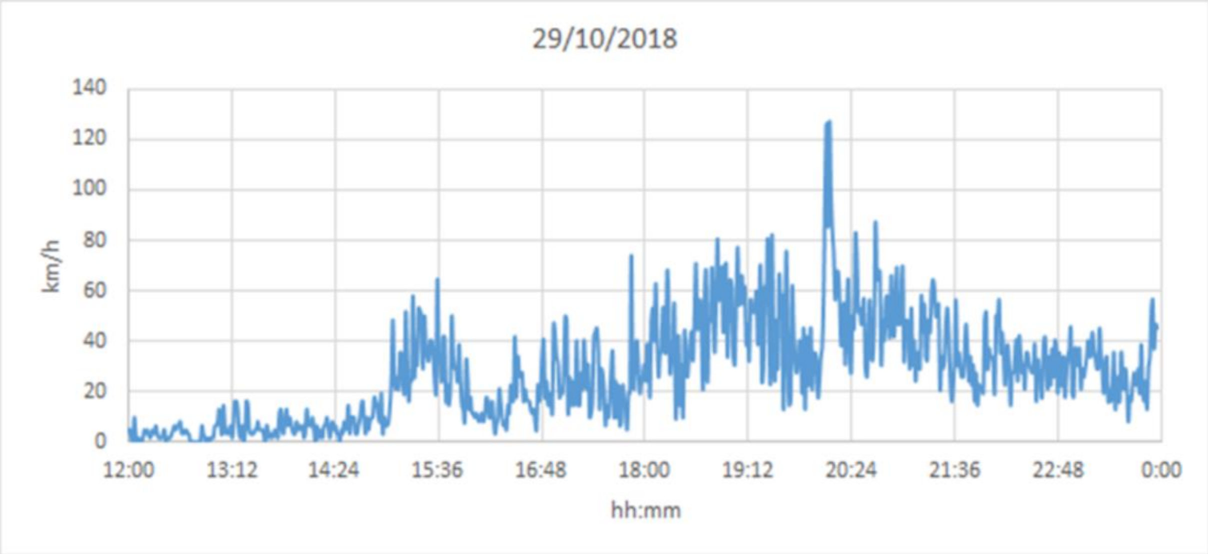


Figure 45: Gust speed during the windstorm day in Baselga di Piné, Italy. Source: Lorenzo Mercuri [125].

5.6.3 Performance and Safety Issues in this Climate

Cell cracks induced by deflection caused by strong wind loads is a major performance issue in this climate. As indicated in our previous Task 13 Report [28], the electrical isolation of a portion of PV cells is a crucial reason for power loss. Major electrical and structural safety issues are caused by the breakage of fixing parts / mounting structure, including PV modules being lifted of their structure or their roof and glass breakage of PV modules, as described in section 5.6.2.

5.6.4 Strong Wind Measures Described in Building Requirements and O&M Guidelines

Basically, the design of PV facilities is subjected to the building and electrical codes enacted in the individual countries or regions. In this subsection, the established guidelines and the proposal for the strong wind measures have been summarized.

In the USA, some codes and standards provided the design guidance for rooftop PV systems [122]. The wind load criteria for rooftop PV systems was added in the 2016 edition of ASCE 7 [American Society of Civil Engineers “Minimum Design Loads and Associated Criteria for Buildings and Other Structures'' (ASCE 7-16, 2017)] [126], as well as the updating of SEAOC PV2 [Structural Engineers Association of California “Wind Design for Solar Arrays” (SEAOC PV2-17)] [127]. ASCE 7-16 provides the criteria for determining wind loads on rooftop PV systems, although those on ground-mounted PV systems have not been included. If needed, the recommendations and guidelines on ground-mounted PV systems could be acquired from SEAOC PV2-17 and “FM global loss prevention data sheet 7-106” [128]. In the guidance for ground-mounted PV systems, the importance of wind tunnel testing on PV arrays and the dynamic effect of winds on ground-mounted PV arrays are emphasized to prevent the blow-off of PV modules, structural failures, and other types of damage.

In Japan, where some strong typhoons hit every year, "Load design guide on structures for photovoltaic array" has been established as a Japanese Industrial Standard (JIS C 8955: 2017) [129]. This standard provides a guidance for allowable stress in the design of structures that constitute a PV array to be installed on the ground or on building structures. However, the following are not covered by this standard:

- PV arrays exceeding nine m in maximum height.
- Building integrated arrays to be replaced with the building materials such as roofing, walling, or windows.
- PV arrays to be installed at a ground height exceeding 60 m.

In this standard, the design wind loads (unit: N) for PV array and structural components shall be calculated by the multiple of the wind factor, design wind pressure, and wind-receiving area. Depending on the mounting mode (on the ground, the sloped roof, or the flat roof), the tilt angle of PV array, the wind direction (same or opposite direction), and the position of interest in the PV array, the wind factor for the PV array is estimated through the defined formula in [129].

Although the wind factor for structural components should be determined by a wind tunnel test, it could also be estimated by the cross-sectional shape which is applied to the structure. The design wind loads are computed from the reference wind speed (which is assigned to the location), the environmental factor (which is specified by the ground surface roughness class, the gust factor, and the average height of PV array plane), and the quantified importance factor. The practical design principle and cases (including the case that the PV array would be installed in a sloped area) also have been published as an interpretive manual [130].

In Europe, the Eurocodes, a series of ten European Technical Standards that provide a common approach to the structural design of buildings and other civil engineering works applies [131] and [132]. Part 1-4 applies for wind actions on structures and the wind load design. Basic wind velocity values, as a 10-min-mean, at a height of 10 m above ground above an open terrain (category II) with a once in 50-year probability can be calculated based on country maps with wind zones. These values are then further modified by factors considering surface roughness, height, and shape of the structure, etc. [133].

Recently, in the IEC Photovoltaic Standardization Committee TC82, a new Working Group, WG9 was launched, because of a need to address standardization of the design and fabrication of structures used to support PV arrays and their associated system components [134]. First projects will focus on the update of tracker structures' design qualification (IEC 62817) [135] and safety requirements (IEC 63104) [136]. Recently, a new work item proposal was made to write a technical specification for the interface between modules, clamping and the mounting structure(s) [137].

During the last years, non-uniform dynamic mechanical load testing of PV modules and substructures was also investigated [138]. However, although a new work item within IEC TC82 was voted positively, it could not be launched because of a lack of experts/countries to form a project team.

5.6.5 Recommendations

In the "Operation & Maintenance Best Practice Guidelines" [11], the maintenance to prevent the damages with strong wind loads is positioned in the category of extraordinary maintenance, but not in the preventive-, corrective-, or predictive-maintenance, because the maintenance activities for strong wind loads are not generally covered by the O&M contract. That is, the damages with strong wind loads have been recognized as “Force Majeure” events. However, as described in section 5.6.1, the catastrophic failures of PV systems are easily induced tropical cyclones once they make landfall. Therefore, various recommendations for the specific damages with strong wind loads should be required, beyond ordinary maintenance activities (in the current O&M guidelines [11], [139], [140], [141], according to IEC 62446-1/-2 [142], [143], IEC TS 63049 [144], and other standards [145], [146], visual and physical inspections to detect the failures of PV modules/arrays and structural assemblies/components are specified as the regular maintenance procedures). In accordance with the valuable experiences, recommendations that will be useful for the prevention of damages due to strong wind loads are summarized in this subsection.

A. Planning and Design Stage

To estimate the effects of turbulent wind gust, wind tunnel tests (with high-speed wind) on the scale model of individual PV systems should be carried out in the first stage, in addition to the wind load calculations for that system. The obtained results should be carefully reviewed on wind load criteria of all assemblies and attachments.

A site-specific wind dynamic load should be considered for the reviewing of the design (including the combined effects of static and dynamic wind loads), not just the static wind load estimated by the calculation or wind tunnel test.

PV modules with sufficient uplift resistance should be specified, to meet the estimated wind loads.

In the structural design, sufficient size of structural members and connectors (including the fixing parts for PV modules) shall be specified, to meet the anticipated high wind magnitude and cyclic wind loads.

The closed ovular- or rectangular-section framing members should be specified in the mounting structure design, because the torsional resistance of these shapes is better than those in the open-section members (e.g., C-shape).

To avoid the loosening of bolted connections, stainless-steel locking (double) nuts with a nylon insert should be specified for the PV module clamping bolt-nut systems, and the appropriate torque levels of all bolted connections should be specified.

If possible, micro-inverters should be used for the PV systems, to allow the electrical-power production by the undamaged PV modules even when one PV module is blown out or damaged by wind-borne debris.

B. Construction Stage

To ensure the construction will be built according to the design, adequate quality-control/-assurance systems should be realized. All bolted connections should be made with a calibrated torque wrench, and the specified torque levels should be applied to respective connections.

C. Maintenance Stage

Periodical maintenance: To shorten the restoration time after the damages by strong wind loads, the appropriate types and number of repair parts should be stored, and the procedures for repairs should be made available.

Periodical maintenance: The torque levels of all bolted connections should be checked (preferably, an annual check is recommended).

Prior to the approach of a tropical cyclone: Tightness should be checked on all bolted connections with a torque wrench. At least, the connections at the clamps in PV modules should be checked.

Prior to the approach of a tropical cyclone: Additional anchors to reinforce the structural assembly should be applied, if needed.

Prior to the approach of a tropical cyclone: Debris and loose objects around PV systems should be removed, to avoid damage caused by windborne debris.

After a severe windstorm: loose PV modules should be removed, and the torque levels of all bolted connections in the remaining PV modules/arrays should be checked (if possible, within a few days/weeks after the storm).

D. Others

In accordance with the most recent codes and standards, the practical activities for design, maintenance, and others should be implemented. For example, because the cyclic (dynamic) mechanical load test on PV modules would be (has been) included in the new international qualification and type approval standards for PV modules with various technologies (IEC 61215 series) [98], [147], designers should specify an approved model(s) of PV modules in the planning of PV installations.

5.7 O&M Guidelines for Snowy Regions

5.7.1 Climates in Snowy Regions

As PV deployment grows, the need to quantify the effects of snow accumulation on array performance becomes increasingly important for accurate system sizing, yield forecasting, and service life prediction.

High plateau and mountain areas all over the world have snowy climate zones. 90% of the world population lives in the northern hemisphere (where most of the landmass is to be found), in regions where snow is common during the winter season.

Snow may have a positive effect on power generation from solar PV as it increases the albedo of the ground significantly. The positive effect increases when module tilt angle increases. In Figure 46 there is an example of calculated ground reflected irradiance G_g as a function of module tilt angle with albedo of 0.2 and 0.8 using Eq. (17), where β is the tilt angle, α is the albedo and G_h is the horizontal irradiance.

$$G_g = \alpha G_h [1 - \cos\beta]/2 \qquad (17)$$

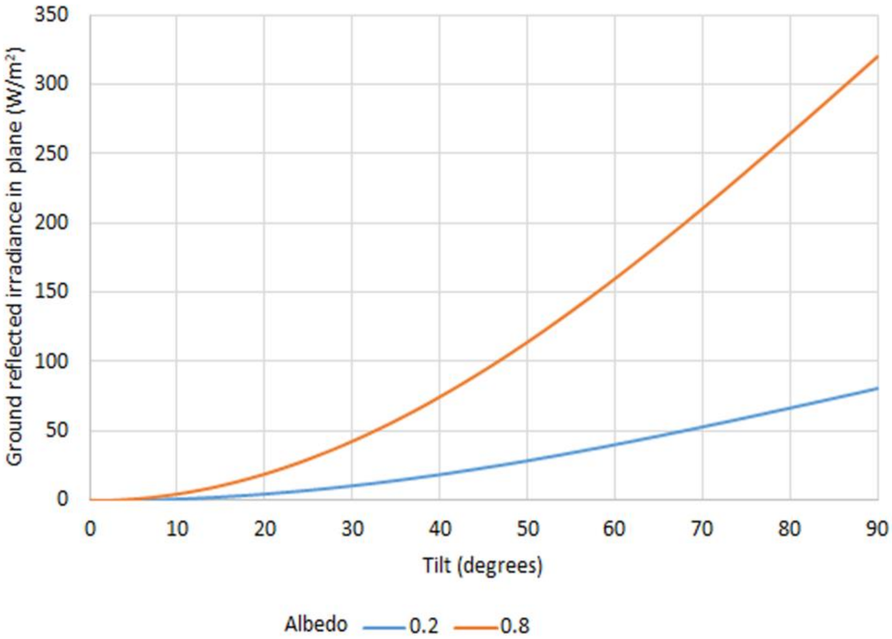


Figure 46: Ground reflected irradiance calculated as function of module tilt angle and different albedo at horizontal irradiance of 800 W/m^2, using Eq. (17).

A cold climate can be favourable for the efficiency of PV and frequent precipitation helps to avoid soiling of the modules. However, snow can also have adverse effects on photovoltaic electricity generation as heavy snow loads may cause loss of electricity generation due to hindered transmission of light to the cells or damage of the modules due to its heigh weight or because of icing [148].

Maps of mean seasonal snow cover extent for land in the northern hemisphere for the period 1981 to 2010 are shown in Figure 47. Snow cover extent reaches its maximum in January and minimum in August, ramping up quickly in the fall and melting at a slower pace in spring [149].

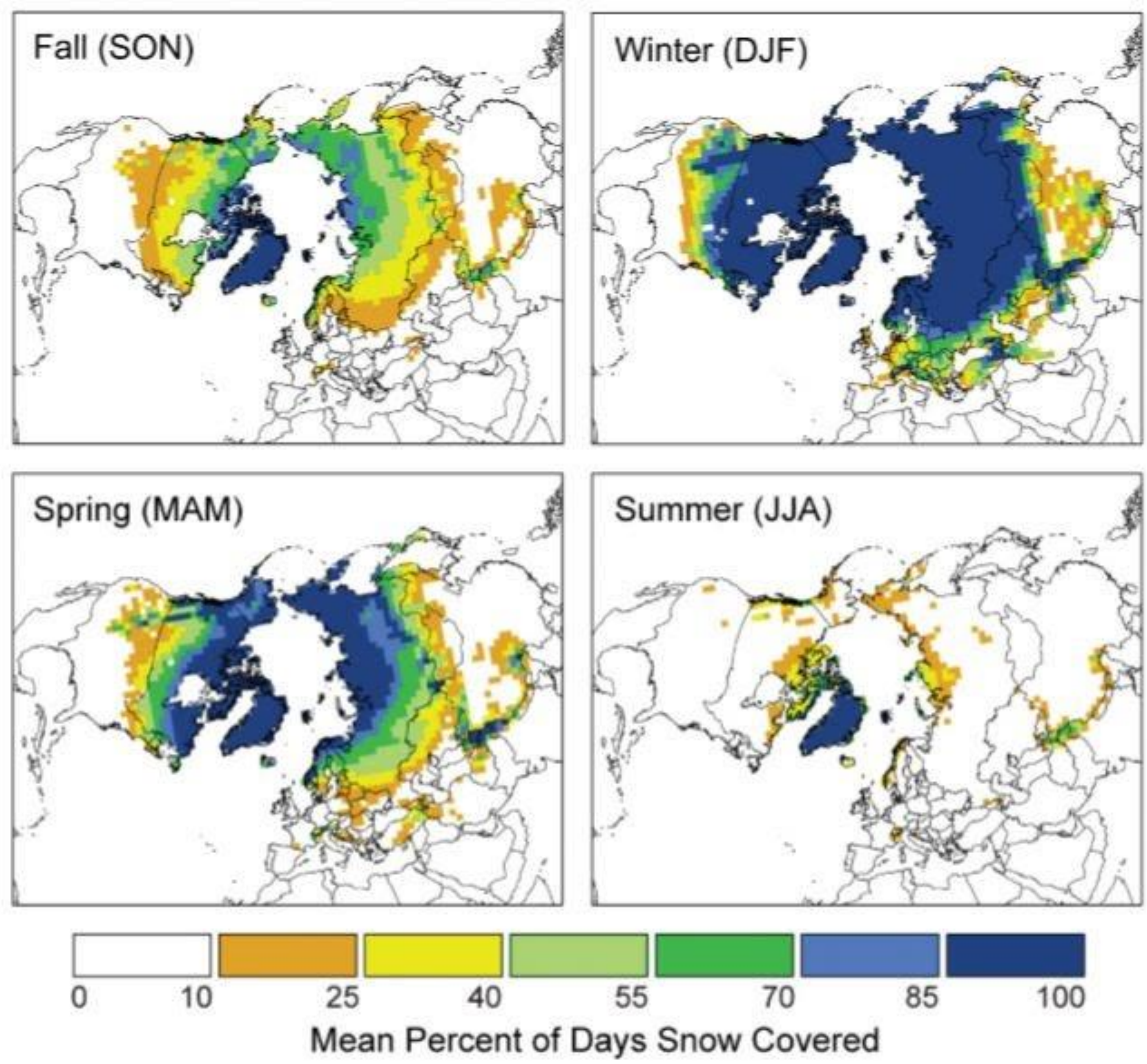


Figure 47: Mean spatial distribution of seasonal snow cover extent over northern hemisphere lands from January 1981 to December 2010 [149].

Scientists separate the Arctic into two major climate types. Near the ocean, a maritime climate prevails. In Alaska, Iceland, northern Russia and Scandinavia, the winters are stormy and wet, with snow. Summers in the coastal regions tend to be cool and cloudy; average temperatures hover around 10°C.

The interior regions of the Arctic have a continental climate. The weather is dryer, with less snow in the winter and sunny summer days. Winter weather can be severe, with frigid temperatures well below freezing. In some regions of Siberia and Alaska average January temperatures are lower than -40°C. In the summer, the long days of sunshine thaw the top layer on the permafrost and bring average temperatures above 10°C. At some weather stations in the interior, summer temperatures reach 30°C and higher.

Although native people traditionally have been living in the Arctic, most of the roughly four million living in the Arctic can be found living in modern towns and cities.

The rather mild climate in Western Europe south of the Arctic is mainly due to the warm Gulf Stream, which makes the climate warmer than their eastern counterparts. In Sweden, snow coverage effect is dominant for regions north of 60°N, i.e., north of the Swedish capital Stockholm. The mountains in Norway lead to more and stronger snow fall than in Sweden. Finland has a similar climate as Sweden north of 60°N. South Alaska is on the same latitude as Stockholm but has much colder winters with more snow. Canada and parts of the USA also have cold winters with snow issues. High mountain areas, more than 1 500 m over sea level, all over the world experience snow, while the properties of the snow differ from site to site. Solar irradiation is generally low in winter in areas where snow tends to cover the PV modules. Pawluk et.al. [148] state that annual losses due to snow coverage are less than 10% in most climates. This is also confirmed in studies made in Sweden by RISE Energy Technology Center [150].

How to calculate snow load on a building as in EN1991-1-3 Eurocode 1 [151] is based on historical weather data, and therefore might be subject to future changes due to climate change. Dimova et. al. [152] summarized results of a European workshop on climate change adaption of structural design, stating that - besides less frequent snow events - warmer and more stable weather conditions may also cause high snow density and extreme snowfalls in some regions.

5.7.2 Quality of Snow and Impact on Modules

A. Weight of snow and impact on modules

The impact of snow on modules is dependent on the character of snowfall, such as density of snow, snowdrift, and icing. The character of the snow is dependent on ambient temperature, wind and solar irradiance [148]. New snow generally has a lower density than wet or packed snow. Ambient temperature also influences the density and volume of snow. Wind packed snow or firn (dense granular snow) can have a density of more than ten times that of new snow, see [153]. The numerical values of densities in kg/m³ are equal to the pressure in N/m² for a 10.2 cm thick snow cover (last column). For a 1.4 m wind packed snow cover, the pressure would result in 4.8-5.5 kN/m². Therefore, it is of importance that snow is not accumulated on top of PV modules as these may be damaged by the snow mass.

Table 12: Density of snow/ice and corresponding pressure at 10.2 cm snow load [153].

Type of Snow or Ice	Density (kg/m^3)	Pressure (N/m^2)
New snow	50-70	50-70
Damp new snow	100-200	100-200
Settled snow	200-300	200-300
Depth hoar	100-300	100-300
Wind packed snow	350-400	350-400
Firn (granular)	400-830	400-830
Very wet snow	700-800	700-800
Glacier ice	830-902	830-902

The threshold above which snow must be removed from the PV modules cannot be answered unequivocally. Paterson [153] shows that about 1.4 m of heavy wind packed snow is needed to reach load values higher than 5.4 kN/m^2, the limiting value in mechanical load tests given in IEC 61215-2 [147]. But only half that height, 0.7 m of heavy wet snow gives the same load value. The study leads to a suggestion that 0.7 m of heavy snow can be a limit above which snow is recommended to be removed, especially if the snow sticks to the panel. A risk of damage due to repeated freezing-melting cycles is difficult to avoid in some climates.

Even though PV installations may be placed in windy areas so that snow coverage due to snowfall is not a problem, snowdrift often occurs. Snowdrift may accumulate large amounts of dense snow on PV panels.

B. Temperature of the snow

The temperature of snow cover may affect the shedding of snow from the PV panels. Research activities in Alaska indicate increased propensity for snow shedding when temperatures are around or slightly above freezing [154].

Existing mechanical durability test sequences typically perform mechanical loading prior to environmental exposures such as thermal cycling or humidity freeze. Recent work has shown that the fracture strength of silicon solar cells can be reduced after exposure to temperatures below -20°C [155]**.** To better evaluate modules with respect to cell crack durability, the use of a single thermal cycle prior to mechanical loading was explored. The results show a significant increase in the number of cell cracks that are generated at a given load after a single cold exposure. These results can be used to further optimize the qualification test sequence for mechanical durability [156].

Electroluminescence (EL) measurements of snow loaded PV modules with cracked cells have shown some open cracks which can close arbitrarily from one day to another. Researchers found that variations in current and temperature generated from resistive heating during EL measurements strongly influence crack closure. Because crack closure can lead to some gain in maximum power, there may be ramifications for IEC standards, namely that performing EL measurements before I-V measurements may lead to inflated results [157].

5.7.3 Racking and Spacer Elements

There are several issues to be aware of when it comes to racking in colder climates. Some installers who have installed solar PV in interior Alaska, where swings in temperatures between the winter lows and summer highs can reach 85°C, have reported that they prefer steel racking as opposed to the more common aluminum racking because of concerns with expansion and contraction. Aluminum expands and contracts up to 30% more than steel. However, steel becomes more brittle in the cold, therefore special considerations need to be made before choosing racking systems. In the Alaska Solar Manual [158], racking systems made of steel are advised.

Spacer elements have been explored as a novel solar panel mounting scheme. Such spacers can be applied to either the rear of the module or to the rails on the mounting structure and could be introduced for both new installations and as protective retrofits to existing systems. These spacers significantly reduce the panel deflection under load, and researchers have demonstrated a dramatic reduction in cell cracking at heavy load levels and in crack opening after cyclic loading [159].

5.7.4 Field Experiences of Reliability in Snowy Climate

Figure 48 and Figure 49 show examples of what can happen with heavy snow loads and freeze-thaw cycles in Northern Sweden, including roof collapse and destruction of PV modules. Especially if snow freezes and melts in cycles, as is common in spring, the snow load on modules can become heavy enough to burst and deform frames.

Figure 48: Picture taken on heavy snow and ice formation in spring in BJURÅS, Northern Sweden. Later, the frame showed a damage as in Figure 49 [Courtesy of Klaus Lorenz Högskolan Dalarna].

Figure 49: After winter, loose frames were observed on PV modules in Piteå in Northern Sweden [Picture from Mats Axelsson].

Performance examples are also provided from flat roofs and modules mounted at low tilt angles. A Swedish pre-study with results from north of 60° latitude on roof-mounted standard framed modules indicates an improvement of the Performance Ratio (PR) when modules were mounted with tilt angles greater than 30 degrees [160]. Most often the losses caused by snow for standard framed modules at latitudes greater than 60°N in Sweden are less than 10% on a yearly basis [160].

Powers et al. [161] assessed experimentally the power output of cleaned and snow-covered modules installed side-by-side in the Sierra Mountains in the United States and found annual production losses of 18%, 15%, and 12% for PV modules tilted at 0°, 24°, and 39° respectively. Townsend and Powers [162] showed that the effect of snowfall on PV energy production could be modelled as a function of tilt angle with acceptable result, using the same location as Powers in [161]. Estimated annual loss values were, using the model developed, determined as 26%, 17% and 13% for PV modules with 0°, 24° and 39° tilt angles, respectively.

Snow sliding has been reported several times as the most common cause of snow removal [150], [163]. Figure 50 shows an installation called “Snow-wave”, consisting of frameless bifacial modules in Piteå, northern Sweden, at 65°N. The picture shows that with a larger tilt the snow slides off the modules easier.

In some cases, snow naturally slides off tilted panels. First results from a study of unframed bifacial modules in northern Sweden (65°N), see Figure 50. Granlund et al. showed that if the panel tilt angle was greater than 15 degrees, snow slid off with small effects on the performance ratio (PR) [150].

Figure 50: Snow wave, frameless bifacial modules, Piteå, N65, Sweden early spring 2019.

A study from Bavaria, in southern Germany, of frameless PV modules at 28° tilt found that annual losses from snow cover for a grid connected system varied between 0.3% and 2.7% [164].

A study of production losses associated with snow coverage in Konya, Turkey, [165] in January 2017 showed that daily losses due to snow cover could be almost 100%, and the monthly loss was 23%. Konya is located 38°N and 32°E at an elevation 1030 meters above sea level. Cleaned modules were compared with snow covered modules of the same type and situated at the same place, as shown in Figure 51.

Figure 51: The system in Konya, Turkey, where one string was cleaned from snow every day at 09:00 AM [165].

5.7.5 Corrective Mitigation Strategies to Reduce the Impact of Snow Accumulations

This section considers corrective mitigation only, in terms of measures that are applied once the plant is built. Preventive mitigation measures (i.e., coatings, system design, elevation, etc.) have been presented in the Task 13 Report on soiling [31].

A. Cleaning or no cleaning?

In most places in Sweden the installer recommendation is to not actively remove snow from modules since often the guarantee is not valid after mechanical actions on the modules. In addition, most installations are residential and are to be found in the southern half of Sweden where production losses due to snow most often are small. Also risk for human injury must be accounted for, since private persons are not used to work on roofs. However, at locations in the northern half of Sweden there is in March strong sun and snow simultaneously that can lead to up to 10% annual losses due to snow.

Exceptions where cleaning is advised often is for flat roofs, see following sections. When planning for PV system on flat roofs it is recommended to leave room between rows for persons to be able to move. The roof shall be dimensioned to withstand the load of both snow and panels. The calculation for acceptable roof load shall be made by the supplier before installation.

B. Active cleaning methods such as brushing

Removing snow mechanically via brushing or other types of active cleaning can sometimes be necessary if the weight threatens to damage roof structures. However, there is also a risk of damaging the modules or scratching the glass while cleaning from snow, especially if there is ice build-up on the surface (Figure 52). There is also the potential issue of needing to find an appropriate place to dispose of the snow, especially in urban areas [166].

For roof mounts, care must also be taken to minimize risk of human injury. If really needed, snow can be removed with a soft brush as shown in Figure 53. Only loose snow should be brushed off. It is not advised to try scraping off frozen snow or ice, which can damage the surface of modules and reduce their efficiency.

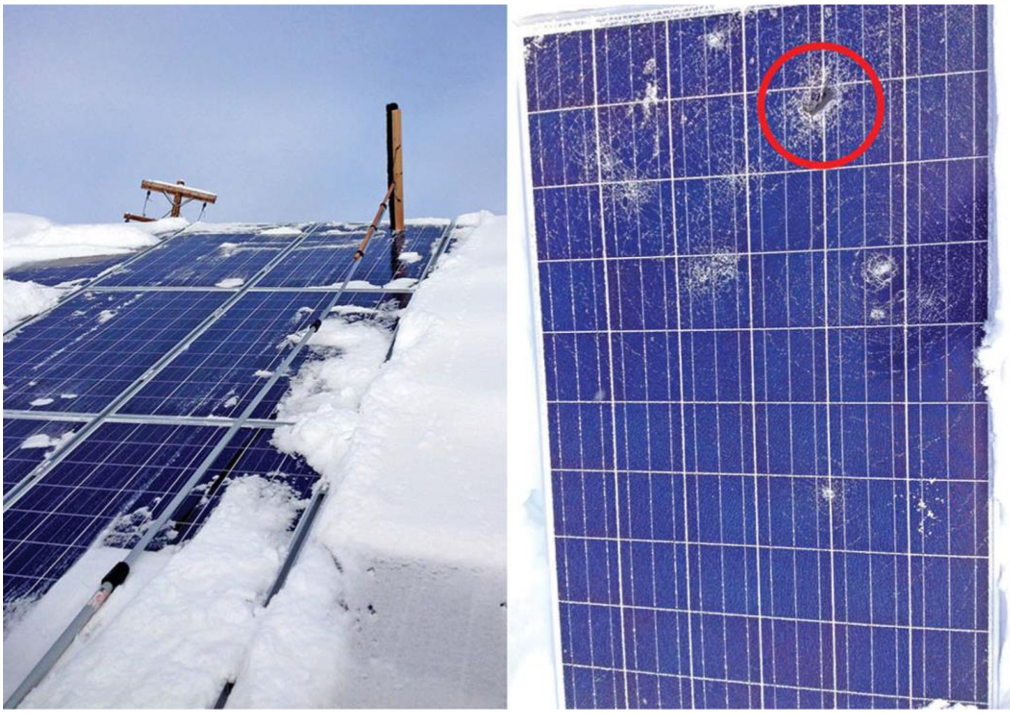


Figure 52: Careless removal of snow may destroy the surface of PV modules [166].

Figure 53: Brushing to remove snow from solar roofs [167].

C. Cleaning a buffer zone

Another option is to clean snow from the roof area immediately below the modules to enable snow sliding off the modules. This approach prevents snow accumulation below the panels and on the lower parts of the modules, which can lead to frame damage.

D. Reverse current melting

A Norwegian study [168] investigated the potential and technical limitations of applying a controlled forward bias (10-19 A) on PV modules to melt snow. In this study, the forward biased PV modules' abilities to melt snow was assessed both in a climate chamber as well as in an operating rooftop PV system covered with snow. The main purpose of the PV system investigated [168] is to mitigate snow from under-dimensioned roofs before, during, or after heavy snowfalls, and to keep the roof from collapsing from snow loads.

Calculations of the energy and economic payback times were made using assumptions of Norwegian power tariffs and taxes. The authors claim it is possible to recoup both energy and economic investment in snow mitigation measures, and that it was possible to earn money by removing snow to increase PV production. Actively melting snow does, however, require delicate peak load control and utilization of weather forecasts, to prevent that power used to mitigate snow does not increase the monthly peak load of the facility or would require more energy than the avoided energy losses.

E. Value of cleaning

Simple cost savings estimates for cleaning snow from a standard system, assuming a 10% annual loss from snow coverage in Sweden, are done as an example. Assuming an annual energy yield of 1000 kWh/kW, a 10% annual loss corresponds to a yearly reduction of 100 kWh/kW due to unremoved snow. Assuming an electricity value of 0.10-0.15 EUR/kWh, this lost production has a value of 10-15 EUR/kW. This figure can be compared with the cost of snow removal during the winter season to find out if there is any profitability for snow removal.

5.7.6 Standardisation and Test Methods

According to test standard IEC 61215 [147], modules are tested for mechanical loads ML up to 5.4 kPa (kPa = kN/m^2). The load is evenly distributed and must last for one hour. Snow loads, on the other hand, can last for weeks or months and can be unevenly distributed over the module [166].

Despite the stringent requirement of modules passing the above 5.4 kPa ML tests, frame breakages due to snow on pitched roofs happens in markets known for long winters, such as Europe, the USA and Japan. In order to better simulate the mechanical stress of snow settling on pitched residential installations, TÜV Rheinland has designed the inhomogeneous mechanical load (IML) test, which is also referred to as non-uniform snow load test [169]. The test begins with 240 hours of humidity freeze test [147] on the module, to simulate the freezing conditions. Then a carefully designed set of weights is placed on top of the test module installed at a 37° angle. Most of the weight is located near the bottom frame, with lesser weights toward the top of the module. The result is an uneven distribution of weight spread across the bottom two-thirds of the test module. This installation simulates the increased load exerted by settled snow around the eaves, as shown in Figure 54.

A standard module has successfully passed the 6.000 kPa IML test with less than 5% power degradation. A closer inspection of the force diagram shows the 6.000 kPa IML force is the vector sum of a 4.792 kPa perpendicular force and a 3.611 kPa horizontal force. The horizontal force directly pushes against the weakest points of the frame, as a pile of snow pulled down by gravitational force would. By adding a 1.5 safety factor, the module is then certified to withstand 4.000 kPa of non-uniform snow load, a pressure that simulates around 50 cm of settled snow on a pitched roof.

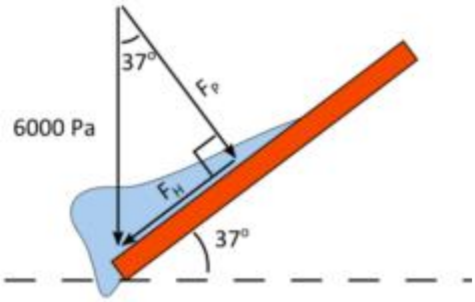


Figure 54: Left) IML test setup [169] using even weights on a pitched module installation. Right) A simplified force diagram that simulates the effects of settled snow.

In EN 1991-1-13 Eurocode 1 [151], the European Ground Snow Load Map is defined in EN 1991-1-3:2003, 2005 for mapping the European ground snow loads as shown in Figure 55.

Different distributions are adopted for the statistical analysis of extreme snow loads. The most widely used distribution, the Gumbel distribution, is implemented for the determination of basic ground snow loads in the development of EN 1991-1-3 (EN 1991-1-3:2003, 2005), Canadian Building Code (NBCC, 2010), Chinese Building Code (GB-50009, 2012), Architectural Institute of Japan (AIJ) and the recommendations (Architectural Institute of Japan, 2015), while the Log-Normal distribution was adopted in ASCE7–10 (American Society of Civil Engineers, 2013).

There are ground snow load maps, "how to" do in places with exceptional snow loads and conversion factors from ground to roof loads. The snow load on the roof is derived from the snow load on the ground, multiplying by conversion factors (shape, thermal and exposure coefficients). The shape of the snow has importance for the load on a roof, as the snow load is often caused by snow drift.

The characteristic ground snow loads (S_k) in Eurocode 1 [151] are given by the national Annex for each country in CEN, the European standardization body for the non-electrical issues. Regional maps for snow load are published in Annex C of EN 1991-1-3. In addition, snow loads for various altitudes are given.

For locations where exceptional loads may occur the ground snow load may be treated as accidental action with the value A_{Ad} according to Eq. (18), where C_{esl} = 2 is often recommended.

$$A_{Ad} = C_{esl} * S_k \tag{18}$$

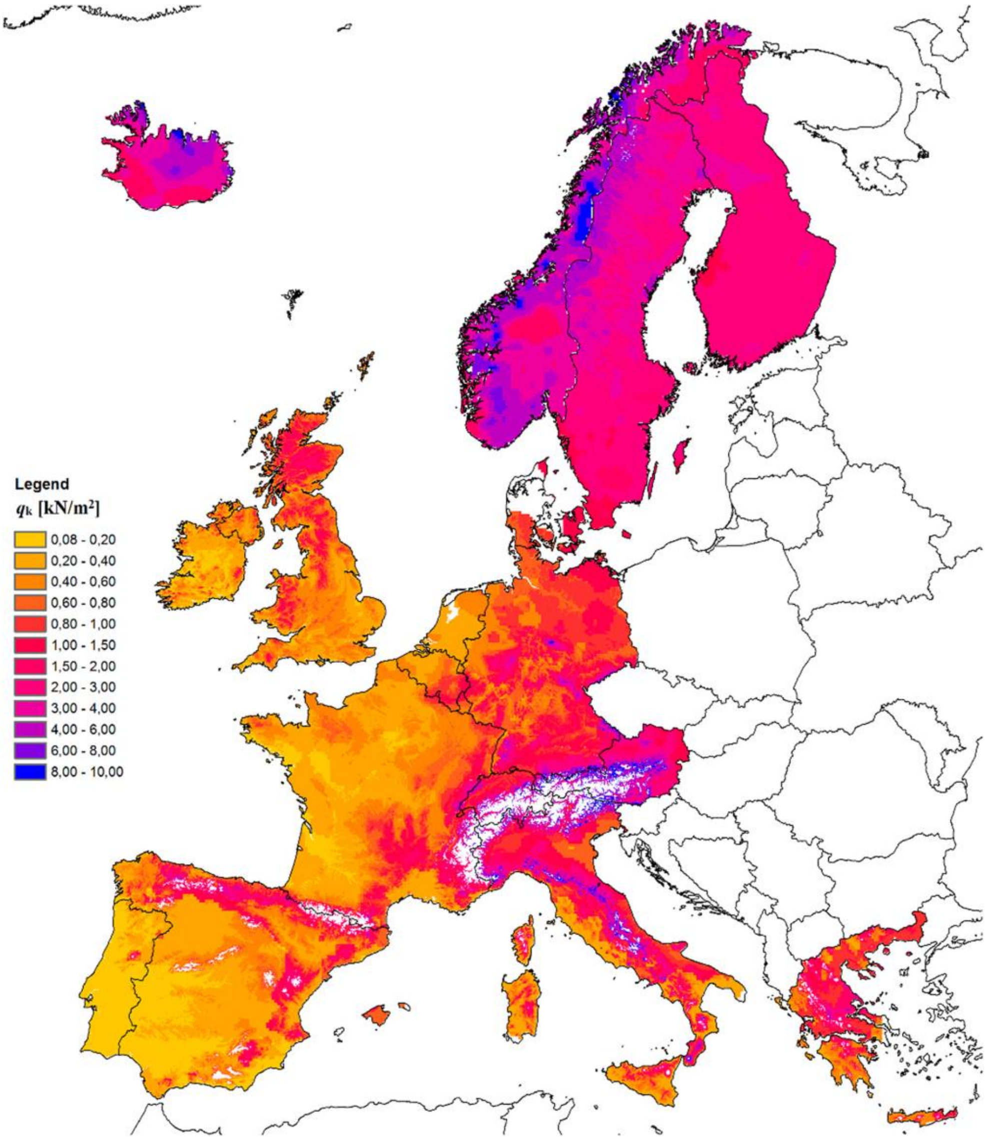


Figure 55: Eurocode 1, showing the European Ground Snow Load Map defined in EN 1991-1-3:2003, 2005 [151].

The Swedish National Board of Housing, Building and Planning (Boverket) construction rules uses a national recommendation for constructing buildings from the Swedish Eurocode 1: Part 1-3 [151]. In Figure 56, a map shows the snow loads on the ground in Sweden with a probability of 0.98, i.e., once in 50 years. The snow loads north of 60°N in Sweden reach 2.5-5.5 kN/m^2. The highest values are reached in the mountain boundaries to Norway in the west. The values in Eurocode 1 come from a very thorough investigation using 148 measurement stations in Europe and 40 measurement stations in Sweden [170].

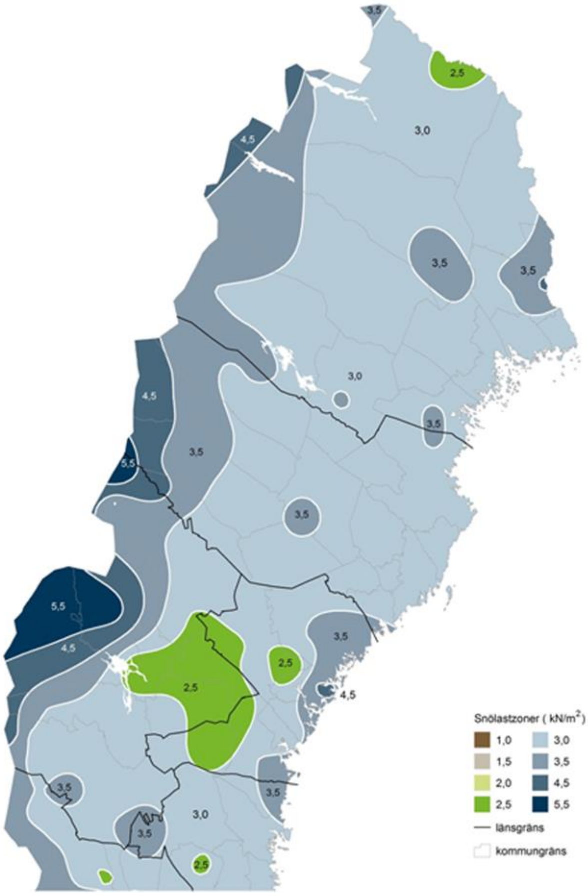


Figure 56: Snow load zones north of 60°N in Sweden, where it is most important to consider snow loads when constructing a building. The numbers given in this map range between 2.5 kN/m^2 and 5.5 kN/m^2. They can be used to dimension for extra roof loads due to snow when constructing a building in the regions described in the Swedish application of Eurocode 1 [171].

Monitoring the solar PV system can help operators to become more aware of the PV system's performance. This can offer information about energy generation and about possible damage to the PV solar system. Monitoring and follow-up also help to avoid downtime and may give an increase in production yield.

In IEC 61724-1 Photovoltaic system performance – Part 1: Monitoring [3], the soiling ratio SR is suggested to be estimated by comparing performance ratio PR with soil and PR without soil using Eq. (19) and definitions of PR as explained in section 2.1.2. In [3], it is suggested that snow is a type of soil that can be measured the same way as other types of soil. If one measures instantaneous values, it is suggested to integrate to get daily averages or monthly averages. After calibration and cleaning and after any significant rainfall SR is close to one and subsequently soiling loss SL=1-SR is close to zero.

$$\mathrm{SR} = \frac{\mathrm{PR(as\ it\ is)}}{\mathrm{PR(after\ cleaning)}} \tag{19}$$

6 CONCLUSIONS

Comprehensive and standardized guidelines for O&M programmes have been difficult to develop. Increasing adoption of PV systems in different climate zones and conditions worldwide has indicated that varied stress factors such as temperature, humidity, exposure to UV light, rain, and wind contribute to the occurrence of PV module and system failures. In view of this, O&M operators have been developing tailored O&M services to the climate zone in which the respective plants are located. With this gap in mind, this report aims to provide comprehensive guidance for customized O&M services in seven different climate zones.

The strategy for selecting a monitoring solution depends mainly on contractual agreements and it is directly related to the scale of the PV plant. Different international standards and publications provide guidelines on minimum requirements for different monitoring needs as summarized in this report. Smart PV performance monitoring solutions are indispensable, especially for large utility-scale PV plants today. A monitoring solution providing smart alarms with aggregation functionalities and possessing a strong simulation model or digital twin of the plant as a basis of comparison are key elements in providing business intelligence for performance optimization.

Large utility-scale PV plants require advanced functionalities in asset management and monitoring solutions allowing for fast reaction times and performance optimization. Fault detection and diagnosis capabilities, providing actionable recommendations and insights for the operators and asset managers are key to staying competitive.

The solar monitoring industry is moving towards “predictive” monitoring solutions. However, due to the high complexity of communication between devices and due to limited standardization, these capabilities are not yet fully deployed on an industrial scale and require further development, validation, and demonstration. A “predictive” smart solar monitoring system will provide insights on the optimal replacement cycle, including cost per time unit under the optimal age-based replacement policy information, which provides highly valuable information for an operator or asset manager.

While it can be assumed that grid compliance has defined the plants’ characteristics during the design, construction, and commissioning phase, it is very likely that grid compliance requirements will change over the lifetime of the installation, especially given the expected rapid expansion of renewable energy and foreseen changes to the grid. It is up to the O&M provider to plan and adapt accordingly.

The forecast of PV power is essential for trading PV electricity on the day-ahead or intraday electricity markets. It is particularly important for ensuring grid stability and for the bankability of PV plant projects without fixed feed-in tariffs. Furthermore, PV power forecasting enables the deployment and dispatching of conventional resources with their given ramp-up time. Therefore, PV power forecasting is particularly beneficial when combined with energy management/storage, and for microgrid applications in general.

The essential characteristics of PV power forecasts include the forecast horizon, the spatial and temporal resolution, and the update frequency, whereby the requirements vary depending on the intended application, data availability, etc. Basically, the forecast horizons are typically up to 48 hours, the temporal resolution is 15 minutes to one hour. Satellite-based cloud motion forecasts can improve PV power forecasts for several hours in advance, but so far there are only a comparatively small number of companies worldwide offering satellite-based short-term forecasts with good quality.

One of the factors behind the success of photovoltaics is its lower maintenance requirements compared to other types of electricity generation. However, low maintenance does not mean that no maintenance is required. While the PV industry has made great strides in detecting faults and even allows some faults to be fixed remotely, the safe and reliable operation of PV systems still requires scheduled and unscheduled maintenance for which personnel must be on site. Although most of the safety aspects are considered during the design and construction phases of PV plants, there are some elements that need to be considered during operations, most of which can be planned or mitigated:

- The safety systems and procedures in place.
- Well-trained personnel with the appropriate qualifications for the tasks to be performed.
- The availability of appropriate equipment to carry out maintenance tasks: PPE, consumables as well as durable maintenance tools.
- Site-specific risks to be considered, such as height (PV on buildings), presence of water (PV on water bodies) or increased fire risks; and,
- Weather and site conditions for site visits.

Both the human as well as the organisational aspects, such as the implementation of the control hierarchy and the development of PV systems in accordance with ISO 45001, IEC 63049, ISO 9001 or ANSI Z10, are central to ensuring that the PV power plant and the personnel who maintain it can operate safely.

Various field experiences have guided the formulation of recommendations and guidelines for O&M services. These have raised awareness of the fact that nature may have a significant impact on the performance and health of PV modules and systems. Recommendations for O&M work in all climates include:

- On-site assessment of vegetation, wildlife, and livestock.
- Mowing grass means checking the condition of the solar PV modules for the possible need for cleaning or possible damage.
- The industrial environment may lead to unexpected deterioration of the solar modules.
- Special attention must be paid when selecting cleaning products for PV modules. It is advisable to follow the recommendations of experts.

The global standard O&M procedures discussed in this report also apply to hot and dry climates, although some aspects such as wildlife risk assessment and appropriate planning for visits to typically remote sites (hydration, poisoning control procedures, PPE, travel to and from sites) deserve special attention. Wildlife risks include poisonous animals and insects that can directly harm humans, while nesting insects and animals can cause short circuits or arcing.

The typical remoteness of PV sites in hot and dry climates comes with significant travel and preparation requirements, as not all equipment and spare parts can be readily sourced, while personnel may be at risk of any injuries being exacerbated at non-remote sites due to distance and the longer time needed for getting medical attention.

To prevent various damages from occurring to PV modules/systems due to extreme weather events, including strong tropical cyclones, international, regional, and national standards/codes/recommendations have been discussed and endorsed. Therefore, stakeholders should comply with these guidelines for proper operation and maintenance of their PV plants, regardless of the size of the system.

In summary, a combination of well-designed O&M specifications, proactive monitoring systems and a flexible and tailored O&M regime that considers both possible weather impacts on systems as well as possible changes to grid requirements are good practices to ensure that PV systems perform according to or even beyond expected lifespans. Reducing risks by ensuring that personnel are trained and equipped for O&M operations, as well as employing PV forecasting to reduce possible downtimes, also contribute to maintaining PV plant performance according to specifications.

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