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Photovoltaic Power Systems Programme

Task 13 Reliability and Performance of Photovolatic Systems

PVPS

Optimisation of Photovoltaic Systems for Different Climates

2025

Report IEA-PVPS T13-32:2025

What is IEA PVPS TCP?

The International Energy Agency (IEA), founded in 1974, is an autonomous body within the framework of the Organisation for Economic Cooperation and Development (OECD). The Technology Collaboration Programmes (TCP) were created with a belief that the future of energy security and sustainability starts with global collaboration. The programmes are 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." To achieve this, the programme's participants have undertaken a variety of joint research projects in PV power systems applications. The overall programme is headed by an Executive Committee, comprised of one delegate from each country or organisation member, which designates distinct 'Tasks,' that may be research projects or activity areas.

Australia, Austria, Belgium, Canada, China, Denmark, European Union, Finland, France, Germany, India, Israel, Italy, Japan, Korea, Malaysia, Morocco, the Netherlands, Norway, Portugal, Solar Energy Research Institute of Singapore (SERIS), SolarPower Europe, South Africa, Spain, Sweden, Switzerland, Thailand, Türkiye, United Kingdom and United States of America.

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What is IEA PVPS Task 13?

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

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

IEA PVPS Task 13 has so far managed to create a framework for the calculations of various parameters that can indicate the quality of PV components, systems and applications. The framework is available and can be used by the PV industry which has expressed appreciation towards the results included in the high-quality reports.

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

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COVER PICTURE

PV system located in Albuquerque US, source: Sandia/Laurie Burnham; PV system in northern Chile, source: PVRadar/Thore Müller; PV system located at Pitea Sweden, source: OFI/Gabriele Eder; AES Lawai Solar Project- Kauai in Hawaii, US (Photo by Dennis Schroeder, NREL 58001), source: NREL Image Gallery,

INTERNATIONAL ENERGY AGENCY

PHOTOVOLTAIC POWER SYSTEMS PROGRAMME

IEA PVPS Task 13

Reliability and Performance of Photovoltaic Systems

Optimisation of Photovoltaic Systems for Different Climates

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List of abbreviations

Al-BSF	Aluminium Back Surface Field
AOI	Angle Of Incidence
BOM	Bill of Material
CAPEX	Capital Expenditure
C-AST	Combined-Accelerated Stress Testing
CdTe	Cadmium Telluride
CINEA	Climate, Infrastructure and Environment Executive Agency
CIS	Copper Indium Selenide
CONUS	Contiguous United States
CSER	Climate-specific energy rating
DNI	Direct Normal Irradiance
ECA	Electrically Conductive Adhesive
EEI_M	Energy Efficiency Index
EPREL	European Product Registry for Energy Labelling
EQE	External Quantum Efficiency
ER	Energy Rating
EVA	Ethylene Vinyl Acetate
EY	Energy Yield
FEA	Finite Element Analysis
FF	Fill Factor
GCR	Ground Cover Ratio
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IP	Ingress Protection
Isc	Short-circuit current
KGPV	Koppen-Geiger-Photovoltaic
KPI	Key Performance Indicator
LeTID	Light and elevated Temperature Induced Degradation
LID	Light Induced Degradation
MD	Machine Direction
ML	Machine Learning
mono-Si	Mono-crystalline Silicon
multi-Si	Multi-crystalline Silicon
NUS	National University of Singapore
OPEX	Operational Expenditure
PE	Polyethylene

PERC	Passivated Emitter and Rear Contact
PET	Polyethylene terephthalate
PID	Potential Induced Degradation
PLR	Performance Loss Rate
PO	Polyolefin
PP	Polypropylene
PV	Photovoltaics
PV CAMPER	PV Collaborative to Advance Multi-climate Performance and Energy Research
PVCZ	Photovoltaic-Climate-Zones
RTC	Regional Test Center
SABs	Sub-Aerial Biofilms
SERIS	Solar Energy Research Institute of Singapore
SLIPS	Slippery Liquid-Infused Porous Surface
SoG	Slope of Ground
SSER	Site-Specific Energy Rating
STC	Standard Test Conditions
STDev	Standard Deviation
T98	98th percentile of the module temperature distribution
TCEP	Tracking Clean Energy Progress
TD	Transversal Direction
TOPCon	Tunnel Oxide Passivated Contact
UV	Ultraviolet
Voc	Open circuit voltage

EXECUTIVE SUMMARY

The impressive worldwide growth in installed photovoltaic (PV) capacity is mainly driven by cost reductions and progress in cell and module technology. This growth is also advanced by increasing global energy demand and the urgent need to combat climate change and reduce dependence on fossil fuels. This has led to PV systems recently being built in harsh climates and becoming economically attractive where they were not previously a viable option. Deserts and tropical zones, as well as cold and snowy regions - once considered either challenging or not affordable for energy production - are today recognised for their significant PV potential. These areas offer high or at least seasonally favourable solar irradiance levels, which can lead to consistent or enhanced energy production.

Large-scale PV deployment in desert climates like the Middle East, North Africa, Northern India, and the Atacama Desert, where high irradiance levels and vast land spaces are available, started already in the early 2000s. In recent years, driven in part by the introduction of bifacial modules, the PV market has also expanded rapidly to latitudes above 40°N, such as the North of America, Europe, and Asia. More recently, PV at high altitudes, such as in the European alpine countries as Switzerland and Austria, where space for ground-based systems is limited and an increase in winter production from renewables is envisaged, has gained interest. The tropical PV market has also grown, driven by rising energy demand and an increasing commitment to renewable energy, combined with consistent daily sunlight near the equator. However, the scarcity of land has favoured the installation of PV on buildings or floating PV over utility-scale ground-mounted systems.

The increasing deployment of PV installations in these very different geographical regions presents numerous challenges in design, commissioning, and operation. Therefore, climate-specific strategies are crucial to address environmental stressors affecting energy yields, module lifetime, and system efficiency. While the design and operation of climate-specific PV systems have progressed, research and innovation must continue to enhance the efficiency, durability, and cost-effectiveness in a wider range of environments. The goal is to ensure that PV can be a reliable energy source regardless of local weather patterns or environmental challenges.

This report specifically explores strategies for enhancing the performance and reliability of PV systems in harsher climates: 'Cold & Snowy', 'Hot & Dry', and 'Hot & Humid'. Guidance is provided to PV system developers on the selection of the most suitable PV module technology by assessing theoretical and real-world energy yield data, performance losses and degradation rates across different climates. The key climate-specific environmental stressors and existing mitigation strategies are reported. Details are given for optimising module and system design for each environment, starting from the site assessment, followed by the component selection, and finally the system design. Case studies showing practical approaches and experience to mitigate risks and optimise performance for each climate are presented.

One of the aspects to be considered at the beginning of a PV project design is the selection of the best PV module technology for a specific climate. The implementation of the IEC 61853 PV module energy rating (ER) standard series IEC61853 provides the end-users with an easy and repeatable method for comparing different products for their energy yield. In addition, it delivers all relevant PV module parameters to increase the accuracy of energy predictions and foster innovation. It can be used by module manufacturers to maximise the energy yield, and not just the efficiency, of the various PV cell and module technologies for different climatic conditions. The increasing number of ER-related publications and the ongoing efforts to introduce a European Energy label for PV modules, described within this report, demonstrates the growing interest and need for standardised and climate-specific energy yield assessment tools.

However, the ER as present today does not give any indication about the long-term reliability of a PV module, which depends on many other aspects such as the bill of material (BOM) and manufacturing process. The degradation rate expressed in percentual power loss per year is needed to determine the payback time and lifetime energy production of a PV project. The inclusion of the degradation rate of PV modules into the ER concept however still represents a bottleneck. In the absence of a standardised approach to assessing the PV module degradation rate, the de-rating information (rate and years) stated in the power warranties are currently used. These are however mainly representative for moderate climates and do not reflect real degradation rates. For example, tropical regions typically show higher degradation rates, whereas colder climates show lower values. How to assess climate-specific degradation rates and include them in the current energy rating approach is still under discussion within the research community.

Understanding PV losses and planning adequate mitigation strategies require a good knowledge of the climate- or site-specific stressors. These start with site assessments, which can be carried out either through specific field campaigns, such as deploying sensors in the field, by collecting data from nearby PV installations, or by analysing satellite/re-analysis data. The early identification of stressors is crucial for all subsequent phases, from the selection of the components through the system design up to the definition of the most cost-efficient O&M strategy. Based on this information, a conscious selection of PV system components and of PV module types is possible.

In cases where knowledge about site-specific requirements and/or the availability of climate-specific PV modules is lacking, standard products are often deployed with a high risk of under-performance or high susceptibility to failures. For instance, the failures occurring in the first desert installations highlighted the need to develop PV encapsulants which can withstand the high irradiation at increased temperatures of that environment. Furthermore, the push for cheaper modules has driven the trend toward larger PV modules with thinner glass, cheaper encapsulants and backsheets, and reduced frame thickness, which are nowadays increasing the degradation and failure rates in harsh environments.

While existing climate-specific testing procedures are described and discussed in more detail in a dedicated IEA PVPS TASK 13 Report ‘Accelerated testing - combined vs. sequential testing and inclusion of specific load situations’, this document gives recommendations on the need to select PV modules with known BOM and tested for the specific climate in which they will be installed. Solutions like thicker front glass in glass/glass modules, innovations in module design like new frame geometries, micro-crack-resistant cell interconnection technologies, or encapsulants with lower glass transition temperatures - such as POE or silicone - improve resistance to mechanical stress in harsher environments. Special coatings, such as anti-soiling or heat-dissipating coatings for deserts, snow-repellent coatings for cold climates, or corrosion-resistant coatings for humid environments, are used or under investigation. Although promising, further studies are needed to prove their durability and cost-effectiveness.

Often, mitigation measures aimed at addressing one issue can inadvertently exacerbate another, making it essential to conduct thorough testing or gain a deeper understanding of actual load conditions to identify the most effective solution. For instance, frameless modules are designed to shed snow more efficiently but have a lower mechanical stability and vice versa. The choices in the system design influence the type of modules and components which can be used. Climate-specific system design is often the key to further reducing the risks of underperforming PV systems. The orientation of PV modules and mounting structures play not only a crucial role in performance but can also impact the reliability and lifetime of a system. Mounting structures in cold and snowy regions are typically the most complex and costly, due to high structural demands and the need to manage large snow loads and ice formation.

Soiling is one of the main factors affecting performance, degradation, and system design, although of very different origin for the three climates. While dust dominates soiling in hot & arid locations, snow is predominant in cold & snowy and biological contamination is a main concern in hot & humid locations. Soiling loss modelling is increasingly employed to predict and mitigate soiling-induced energy losses, though accurately isolating soiling effects remains a challenge. In hot and arid climates, systems must be designed to facilitate cleaning, with requirements varying based on the selected business model. In equatorial locations, soiling losses can be so severe that steeper-than-optimal tilts may be preferable to reduce accumulation, despite the lower irradiation. In cold climates, high tilt angles and sufficient ground clearance help minimise snow accumulation and shading, while snow fences and snow transport simulations further prevent unwanted build-up. The table below provides an overview of stressors, their effects in different climates, and mitigation strategies, described in more detail within the report.

Table 1: Climate specific stressors, failures and mitigation measures.

Stressors	Failures	Cold & Snow	Hot & Arid	Hot & Humid	Mitigation Measures
Low temperatures	Embrittlement of materials, cracking of encapsulant and solder joints	high	-	-	Use of flexible encapsulants and back sheets
Extreme temperature fluctuations	Thermal cycling cracks (solder joints, inter-connections)	low-medium	low-medium	low-medium	Use thermally stable materials, reinforced inter-connections
Mechanical Stress (Snow, Ice, Wind, Sandstorms)	Glass breakage, frame deformation, cell cracks, (severe) power loss	high (snow load)	high (sandstorms)	-	Strengthened module frames, thicker glass, special coatings, smart tracking (for wind or snow)
UV Exposure	Backsheet cracking, encapsulant yellowing, loss of adhesion	low-medium (high altitude)	high	low-medium	UV-resistant cells, backsheet and encapsulant materials
Moisture Ingress & Humidity	Corrosion (junction box, interconnections), delamination	low-medium (frost)	-	high	Edge sealants, high barrier backsheet, improved lamination techniques, moisture resistant cells
High Operating Temperatures	Hot spots, microcracks, encapsulant degradation	-	high	medium	Optimised ventilation, high-temperature-resistant encapsulants
Soiling	Power loss, surface degradation, hot spot	high (snow load)	high (dust, sand)	high (biofilm)	Frameless modules, self-cleaning coatings, scheduled cleaning, tilted installation to minimise accumulation of snow or dust
Salt Mist	Corrosion, electrical insulation failure, PID	-	High (coastal)	High (coastal)	Anti-corrosion coatings, PID-resistant materials, sealed junction boxes

This report aims to raise awareness about the risks associated with specific stressors and highlights how developing climate-specific strategies is essential to enhance the reliability and cost-effectiveness of PV systems worldwide. It shows how innovation in module design, adaptation of bill of materials, and system configurations can support the further deployment of PV systems in harsher climates. Experience with climate-optimised PV modules is still limited, requiring more field data and lessons learned to be exchanged within the PV community.

1 INTRODUCTION

In 2022, solar PV passed the threshold of 1 TWp of installed capacity worldwide and achieved the largest absolute generation growth of all renewable technologies. Toward the end of 2024, the global PV capacity reached 2 TWp [1]. These major milestones have resulted in solar PV becoming "on track" in 2023, according to the IEA's Tracking Clean Energy Progress (TCEP) [2].

As the global deployment continues, PV installations can be seen today practically in any geographical region, bringing new challenges in terms of design, operation and commissioning. The synergy between climate and PV systems is critical, as environmental stressors, such as temperature, irradiance, wind, and humidity, can significantly influence energy yields, module lifetime, and overall system efficiency. Developing climate-specific strategies to address these challenges is essential to enhance the reliability and cost-effectiveness of PV systems worldwide. The need for such strategies becomes even more pressing when PV systems start showing high performance loss as well as degradation rates [3], [4].

This report aims to offer comprehensive guidance and an overview of current strategies for optimising the performance of photovoltaic (PV) systems across various climatic conditions.

Chapter 2 provides a brief introduction to common climate classification methods and outlines the three broad categories used for the purpose of this report: *'Cold & Snowy', 'Hot & Dry'* and *'Hot & Humid'*. **Chapter 3** of the report focuses on the methodologies for selecting the best PV module technology for a specific climate. The concept of climate-specific module energy rating (CSER) and the importance of considering climate-specific performance loss rates (PLR) are introduced, together with some practical examples of where these are applied for the purpose of technology benchmarking.

The core **Chapters 4 to 6** detail strategies for optimising module and system design for each of the three climate zones: '*Cold & Snowy', 'Hot & Dry'* and *'Hot & Humid'*. First, the typical conditions of each climate zone are described, followed by the typical stressors affecting photovoltaic power plants in such climates and their potential consequences. The chapters present available mitigation and optimisation strategies through the different project phases: site assessment, component selection and system design.

Site assessments are critical to minimising the impact of stressors on PV systems. The magnitude and the impact of the various environmental factors need to be assessed at this stage to ensure a comprehensive understanding of site-specific conditions. In general, assessments can be carried out either through specific field campaigns, such as deploying sensors in the field, by collecting data from nearby PV installations, or by analysing data available from satellite-derived or reanalysis datasets, each with its own advantages and disadvantages.

By precisely identifying the magnitude of the stressors, stakeholders can develop and implement effective, reliable, and cost-efficient mitigation strategies. These strategies encompass a range of actions tailored to the specific environmental challenges, starting from the **component selection**, with a particular focus on the possible module designs, and extending than to the optimisation of the overall **system design**. This approach ensures enhanced system performance and longevity while minimising operational risks and costs. As a rule, it is recommended to consider risk mitigation, O&M costs and performance optimisation as early as possible and to tailor the plant design and financial planning to the specific conditions of the local site.

In the conclusion of each chapter, two climate-specific **case studies** are presented, highlighting different aspects such as plant configurations, site conditions, and key performance indicators.

2 CLIMATE CLASSIFICATION

The challenge when thinking about tailored climate-specific approaches is to define climate zones. Recognising the weather dependencies, international standards, testing protocols, and research methodologies have increasingly emphasised the need for robust climate classifications to support the deployment and optimisation of PV technologies.

This can be tackled in a structured way that can help to classify climatic conditions. The most popular way to classify climate areas is the Koppen-Geiger climate classification [5], [6], expanded for PV technologies with the Koppen-Geiger-Photovoltaic climate classification (KGPV) [7]. The KGPV divides the globe into six main climate categories (tropical, desert, arid, temperate, cold, and snow), followed by an irradiation layer that differentiates Low, Medium, High and Very High irradiation locations. Another data-driven approach developed is called Photovoltaic-Climate-Zones (PVCZ) [8], which focuses on climate variables most relevant to PV technologies, such as irradiance, temperature, and seasonal variability. Additionally, emerging machine learning (ML) techniques offer innovative approaches by uncovering complex synergies between meteorological variables, such as temperature, solar irradiance, humidity, and wind speed [9]. Unlike traditional threshold-based systems, ML-based methodologies can identify non-linear relationships and hidden patterns.

Nevertheless, those are not the only systems that have been used in the industry and academia; the International Electrotechnical Commission (IEC) has published standards describing certain conditions to emulate climate regions in indoor testing facilities, including hot and dry, hot and humid, cold and snowy, temperate, and other specialised climates such as high-altitude or maritime regions [10], [11], [12]. Depending on the purpose of testing, these classifications account for factors like temperature, humidity, precipitation, and irradiance, helping standardise testing, performance evaluation, and system monitoring across diverse geographic locations. The example of classification for the purpose of climate-specific module energy rating (CSER) determination according to IEC 61853 is described in chapter 3.

To describe strategies for optimising the performance of PV systems in non-moderate climates, the report is organised into three main sections, each representing a specific climate zone: *“Cold & Snowy”, “Hot & Dry” and “Hot & Humid”.* For better understanding and application of the classification, in the introduction of each chapter the relation with the different threshold-based climate classifications is given.

3 CLIMATE SPECIFIC MODULE ENERGY YIELD

One of the steps in the design of a photovoltaic system is the choice of the PV module technology with respect to its energy yield. Guidance is here provided on how to identify the module type/technology with the theoretical highest annual and lifetime energy yield for a specific climate representing the site where the photovoltaic system is to be built, and examples are given of how the theoretical numbers compare to real module or system data.

The energy production of a PV module over its lifespan is influenced by its initial energy yield, as well as its performance and degradation over time. There are several approaches to assess the expected energy yield of a PV module. Table 2 summarises these approaches, highlighting their respective advantages and disadvantages.

Table 2: Inter-comparison of different module energy yield assessment approaches.

PV Module Performance in kWh			
Scope	**Energy rating**	**Energy yield simulation**	**Energy yield measurements**
	Product selection/benchmarking	Energy prediction for specific location and installation	Benchmarking under real conditions
	Used for relative comparison between different modules to identify the best one for a specific climate	*Used for absolute comparison between modules and selection, as well as input for the economics of the PV project*	*Used for relative comparison between different modules under real operating conditions and for validation of energy yield simulations*
Module data	IEC 61853-1 & 2	Specific to simulation tool (e.g. datasheets, STC values, temperature coefficients, IEC 61853-1 etc.)	Real field data (P_{mpp}, IV-curves)
Model	IEC 61853-3	Specific to simulation tool (e.g. PV_{SYST} model, SAM model)	NA
Meteorological data	IEC 61853-4 (6 reference climates)	Meteorological data base (e.g. Meteonorm, Solargis)	Measured meteorological data
Pros	Fast, repeatable, uncertainties coming from the model and the meteorological data are avoided, measurement uncertainties are well known	Fast prediction of the energy output for a specific location and any system configuration, degradation rates can be simulated	Allows for technology benchmarking under real conditions, degradation rates are also detected
Cons	The CSER values do not give any information about the real performance, modules are compared for 20°tilt (AZ 0°) open rack only, degradation rates are not considered, extension to bifacial modules under development	High uncertainty, strongly dependent on the used simulation tool and meteorological data, real degradation rates are not known, and theoretical values must be assumed.	Requires long-term measurement campaigns, higher uncertainty, not repeatable, the result is site dependent

Energy Rating (ER) is a standardized method to assess PV module energy output under representative climate conditions. It is not meant for site-specific predictions but serves to benchmark different PV technologies under comparable conditions. Because the ER is derived using controlled lab data, a standardized calculation method and climate profiles, its uncertainty is lower compared to field measurements (which are subject to varying and often uncontrolled real-world factors), or energy yield simulations (which depend heavily on site-specific inputs and assumptions). As the name says it is used to rate a PV module with respect to another one based on an annual energy yield calculated according to the IEC 61853 Energy Rating standard series [13]. The KPI obtained by this approach is the dimensionless climatic specific energy rating (CSER) which will be described in more detail in 3.1. The purpose of ER is to help the end-user choose the module with the potentially highest energy output for a specific climatic zone. The method has the main advantage of being easy and reproducible, but it gives no information about the real energy output of a PV module in a specific location or installation, as it is based on a fixed meteorological data set and fixed module mounting conditions (stand-alone ground mounted open rack facing the equator and 20º tilt). In this regard, the standard defines six reference climatic profiles. System losses due to the inverters or string inter-connection and external losses due to soiling or shading are not considered. The current version of the standard applies only to monofacial PV modules and does not consider the degradation rate of a PV module under different climatic or working conditions. Ongoing efforts to include these aspects, as well as studies on the uncertainty and validation of ER, including the representativeness of the proposed reference climates, are discussed in 3.1.

Energy yield simulation tools have the advantage of allowing the user to input site-specific weather data, actual orientation, expected soiling, shading scenarios and albedo, etc. Compared to ER user-defined annual degradation rates can be applied. Potential disadvantages are that each tool is based on its own ‘PV module’ model and meteorological database, increasing the risk of unrealistic inter-comparisons. The absolute and relative accuracy of the simulations are strongly dependent on the source and accuracy of the module input data, the model itself and the meteorological data. Validations of the models and the use of comparable module input data are here the key. The use of module input data from test laboratories measured according to IEC 61853-1 and IEC 61853-2 and tools accepting these inputs and capable of simulating various effects like the spectral effects or the angle of incidence effect increases the accuracy of the estimated power output data.

Energy yield measurements are instead used to compare different modules under real operating conditions. The measurements allow to detect also degradation rates and under-performing modules, but long measurement campaigns of good quality data are needed. Module energy yield benchmarking is site and season dependent and consequently not reproducible or easily comparable between test sites. Besides, a PV module outperforming another one in one location would not necessarily perform better under other circumstances regarding both the climatic conditions and the mounting configuration. Examples of field data are given in chapter 3.2.

3.1 Climatic specific module energy rating (CSER)

3.1.1 IEC 61853 energy rating standard

The climatic specific energy rating (CSER), defined by the IEC 61853 energy rating standard series, is a theoretical KPI, corresponding to the module performance ratio, which helps in comparing the annual energy yield of different modules.

$$CSER = \frac{EY_{M(DC)Y1} \cdot G_{ref}}{P_{max,STC} \cdot H_p}$$

Where $EY_{M(DC)Y1}$ is the estimated energy yield for one module over the first year of operation (kWh), G_{ref} is the irradiance under Standard Test Conditions (STC) of 1000 W/m^2, $P_{max,STC}$ is the module's power output under STC in W and H_p is the total yearly in-plane irradiation provided in Part 4 of the standard series, in kWh/m^2. For c-Si technologies, typical *CSER* values lie in the range between 0.8 to 0.95.

The IEC standard series Part 1 and Part 2 describe how to measure the module parameters required as input for the determination of the energy rating. Part 3 describes how to calculate the *CSER* values for different reference climatic profiles listed in Part 4 and shown in Figure 1.

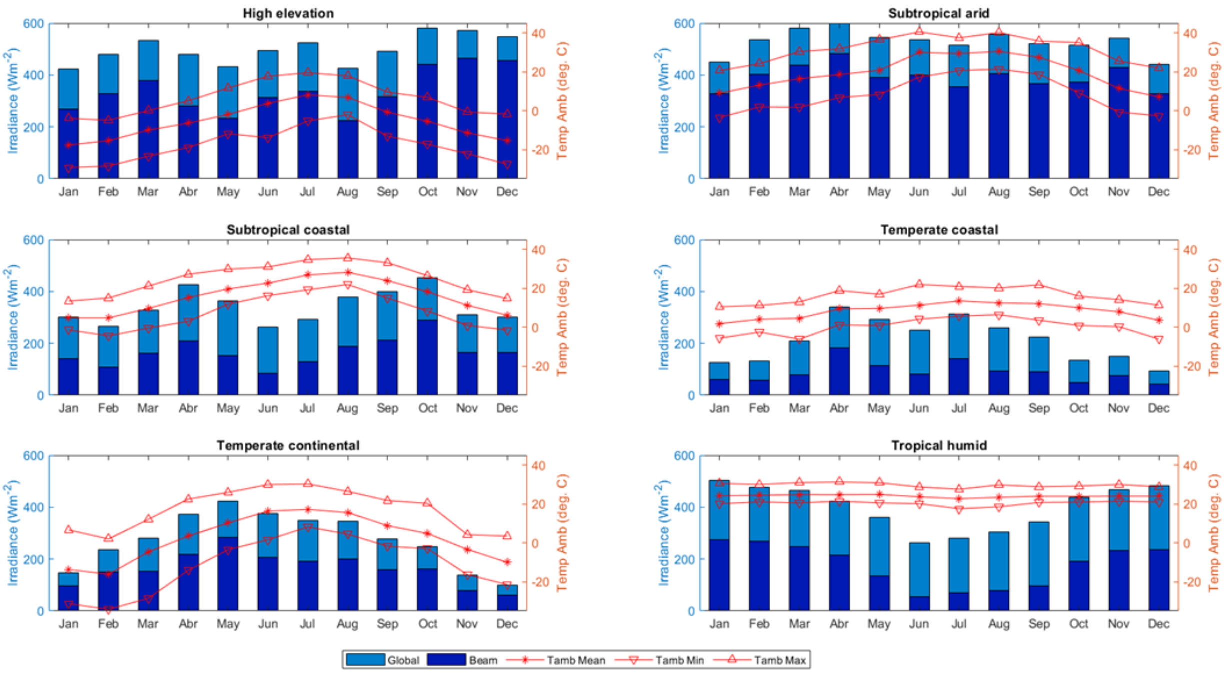


Figure 1: IEC 61853 reference climates. Monthly average global and beam (direct) horizontal irradiance (W/m^2) and monthly mean, maximum and minimum ambient temperature (ºC) (source: ©European Union, 2024-2025).

Detailed information about the ER approach can be found in an earlier IEA PVPS TASK 13 report [14]. The IEC TC82 WG2 is currently working on an amendment to the whole standard series including the extension of the scope to bifacial modules. Based on the approach elaborated within the European PV ENERATE project, Vogt et al. (2023) [15] proposed a new methodology for bifacial modules. A new project was launched in 2023 by the Climate, Infrastructure and Environment Executive Agency (CINEA) to further develop and validate different methodologies for bifacial devices and to develop a methodology or testing sequence to determine the degradation rate of PV modules [16].

The current IEC 61853-4 standard [17] defines six climatic profiles (tropical humid, subtropical arid, subtropical coastal, temperate coastal, temperate continental and high elevation), by a dataset of hourly values over one year containing data of the horizontal and in-plane (20°tilt) global and direct irradiances, spectrally resolved global in-plane irradiance, ambient temperature and wind speed. The average monthly values of global horizontal and direct irradiances and ambient temperature ranges are shown in Figure 1.

The choice of these six reference climates was based on the requirement that the differences between the estimated *CSER* values in the different climates should be higher than the uncertainty in the estimation of the *CSER*, as explained by Huld et al. analysing considered KPIs at various studies at continental scale [18], [19], [20]. The uncertainty of *CSER* depends mainly on the uncertainty of the module parameters described in Part 1 and 2, which are defined through the measurement uncertainties of the test laboratory at which the module is tested. The model and the climatic datasets defined in Part 3 and 4, respectively, are not contributing to this if the standard approach is followed correctly. A best practice guideline and data-set for the validation of the *CSER* calculation were developed within the European Project METRO-PV [21]. Within the same project, Herrmann et al. calculated a typical combined *CSER* uncertainty of ±2.3% for c-Si modules [22]. The uncertainty is dominated by the contribution of the (G-T) power matrix (75%), followed by the contribution of the thermal module parameters u0 and u1 (20%), the angular response (5%) and spectral responsivity (1%). Similarly, Blakesley et al. [23], obtained an average *CSER* uncertainty ranging from ±1.9% to ±2.18% depending on the testing scenario.

The *CSER* estimated for a c-Si module using input data of irradiance, ambient temperature and wind speed with global coverage is shown in Figure 2 [24]. However, due to the lack of spectrally resolved irradiance at global scale, the spectral effects could not be considered in the estimation of the *CSER*. Notwithstanding, as shown by Huld [19], this effect could have a significant impact in certain regions, like high elevation areas. Therefore, for the delimitation of the geographical distribution of the six reference climates, all effects should be considered, including the analysis of other PV technologies as well. A recent study by Anderson [25] added spectral irradiance data to analyse how different PV module technologies perform across climates in the contiguous United States (CONUS).

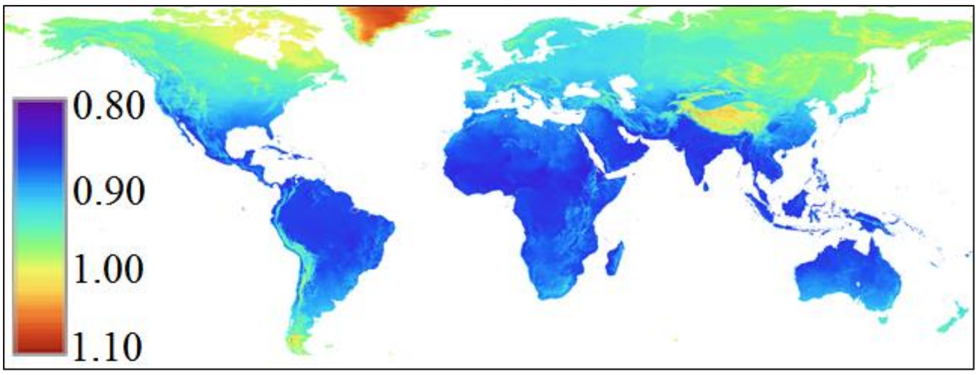


Figure 2: CSER of a c-Si module, estimated without considering spectral effects [24].

3.1.2 Implementation of CSER into European Energy Label

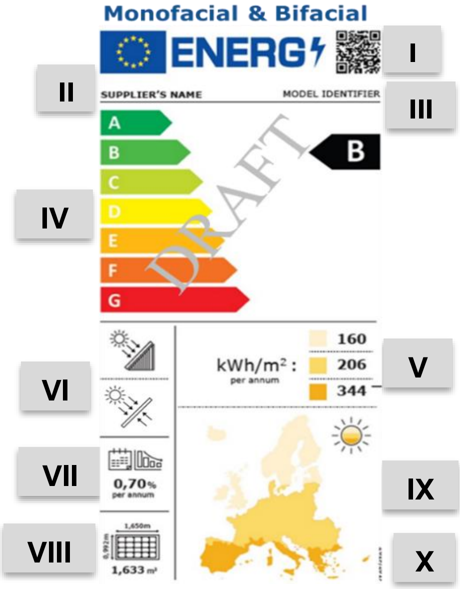
The IEC 61853 Energy Rating standard series is the base of a proposal for a European Energy Label for PV modules. The proposal is part of the Ecodesign Directive (2009/125/EC) [26] and Energy Labelling Regulation (EU 2017/1369) [27]. The Ecodesign establishes a framework under which manufacturers of energy-using products are obliged to reach a minimum level of quality and performance considering the energy consumption and other negative environmental impacts occurring throughout the product life cycle. It establishes performance criteria, which manufacturers must meet to legally bring their product to the market, whether produced inside or outside the EU. It is complemented by the Energy Labelling scheme through which the consumer can recognise the best-performing products. In follow-up of a feasibility analysis, carried out by the Joint Research Centre of the European Commission [28], [29], the proposed legislation is in the process of being approved [30].

Instead of *CSER*, the Label proposes to rate a module according to its energy efficiency index (EEI_M in kWh/m^2), i.e. the ratio between the estimated annual energy yield (*EY*) per unit area (A_M, module area in m^2), which uses *CSER* as an input (see Table 3). As the IEC 61853 standard still takes into consideration only monofacial PV modules, a transitional method is applied for bifacial modules until harmonised standard or technical specification becomes available for bifacial modules [31]. Instead of using the nameplate STC power ($P_{max,STC}$), the use of the Power at Bifacial nameplate irradiance (P_{BNPI}) is proposed, which corresponds to the power output of the module obtained under irradiance corresponding to 1000 W/m^2 on the module front and 135 W/m^2 on the module rear as defined in IEC 61215-1 [32], and taking into account the power bifaciality coefficient (φ_{Pmax}) according to IEC TS 60904-1-2 [33]. Ground albedo is not considered here.

Table 3: Methodology for the estimation of EEI_M for mono and bifacial PV modules [32]**.**

Energy efficiency index (kWh/m^2)	PV monofacial	PV bifacial
$EEI_{M\_c} = EY_{M(DC)Y1\,c} / A_M$	$EY_{M(DC)\_Y1} = \frac{CSER \cdot P_{max,STC} \cdot H_p}{G_{ref}}$	$EY_{MB(DC)\_Y1} = \frac{CSER \cdot P_{BNPI} \cdot H_p}{G_{ref}}$ $P_{BNPI} = P_{max,STC} + (P_{max,STC} \cdot \varphi_{Pmax} \cdot 0.135)$

An example of the latest version of the proposed label for PV modules is shown in Figure 3. The label aims to give information on the area specific energy yield of a module, i.e. the energy that the PV device would generate for one year if it was installed in the representative location of each of the three European reference climatic regions, namely, ‘temperate coastal’, ‘temperate continental’ and ‘subtropical arid’, represented in the label. The geographical distribution of the three most relevant reference climates for Europe are based on the average yearly global horizontal irradiation described in the transitional method [34]. The label allows consumers and professionals to have immediate and comparable information on the product performance for reliable purchasing decision. The example label exhibits both pictograms, for monofacial and bifacial modules, while a unique icon would appear on the label corresponding to a specific PV module type. For clarity in the example, a unique energy class for all three climatic areas in Europe is proposed. The exact values of EEI_M for the three climatic zones will be also displayed.



	Module Energy Efficiency Index, EEI_M ($kWhm^{-2}$)		
Energy Class	Subtropical arid	Temperate coastal	Temperate continental
A	> 679	> 308	> 396
B	[678 – 598]	[307 – 271]	[395 – 349]
C	[597 – 511]	[270 – 235]	[348 – 305]
D	[510 – 427]	[234 – 197]	[304 – 256]
E	[426 – 372]	[196 – 168]	[255 – 218]
F	[371 – 318]	[167 – 140]	[217 – 181]
G	≤ 317	≤ 139	≤ 180

Legend: I: QR code; II: Supplier's name or trade mark; III: Supplier's model identifier; IV: Scale of energy efficiency classes (from A to G); V: Module energy efficiency index value EEI_M under 'temperate coastal' (Northern Europe, light yellow) 'temperate continental' (Central Europe, dark yellow) and 'subtropical arid' (Southern Europe, orange) climate conditions, expressed in kWh/m^2; VI: Typology of PV module: monofacial or bifacial; VII: Annual performance degradation rate, expressed in %; VIII: Photovoltaic module area, expressed in m^2; IX: Climatic condition's map of Europe; X: Regulation number; Table: Energy efficiency index (EEI_M) granularity.

Figure 3: Example of a possible energy label for PV modules (monofacial or bifacial) (source: ©European Union, 2024-2025).

The scale of energy efficiency classes ranging from A to G corresponds to "the best" (class A) and "the worst" (class G) (see table in Figure 3). Additional information regarding module lifetime degradation rate (VII) and dimensions (VIII) are also suggested. The module lifetime degradation rate is not considered for the calculation of the EEI_M, but it would be contemplated for a specific requirement included in the Ecodesign Directive. The energy efficiency classes have been determined to stand for homogeneous distribution along the different geographic areas. The proposed label granularity is shown in the Table in Figure 3 and expressed by EEI_M threshold values. To stimulate further technological progress, the energy classes "A" and "B" would initially remain unpopulated. Hence, the high-quality PV modules currently available on the market would fall into class "C" or "D". Before energy-related products covered by energy labelling are placed on the EU market, the products must be registered by their supplier in the European Product Registry for Energy Labelling database (EPREL) for public access and consultation [35]. A link to the EPREL database is provided via the QR code depicted on the label (see Figure 3).

Validation of the applicability of the European Energy Label standard across different geographic regions is currently underway. The following section presents some of the initial results.

3.1.3 CSER validations

As a validation of the ER methodology, Rivera et al. [36] conducted outdoor performance measurements in Freiburg, Germany. They calculated the DC Performance Ratio (the site-specific energy rating, as $SSER_{REAL}$) for two types of SHJ PV modules over a year and compared it with the site-specific energy rating ($SSER_{MODEL}$) for the same location and time period using specific climate profiles, generated following the IEC 61853 methodology. The modules were tilted at 20° and facing the equator as foreseen by the standard. The results revealed a strong correlation between $SSER_{REAL}$ and $SSER_{MODEL}$ for Freiburg. The weekly comparison (Figure 4) shows the *SSER* values for Freiburg (green line) modelled by the methodology for the year 2022 and also from two PV modules exposed outdoors (dashed lines) from October 2022 to October 2023, with the standard *CSER* for the temperate continental climate as a reference (red line). The average deviations of real (dashed lines) and modelled (green line) daily *SSER* values were around 1.8%

to 2%, highlighting how the ER methodology aligns well with the expected uncertainties. The deviation with respect to the *CSER* highlights the climatic difference between Freiburg and the reference climate.

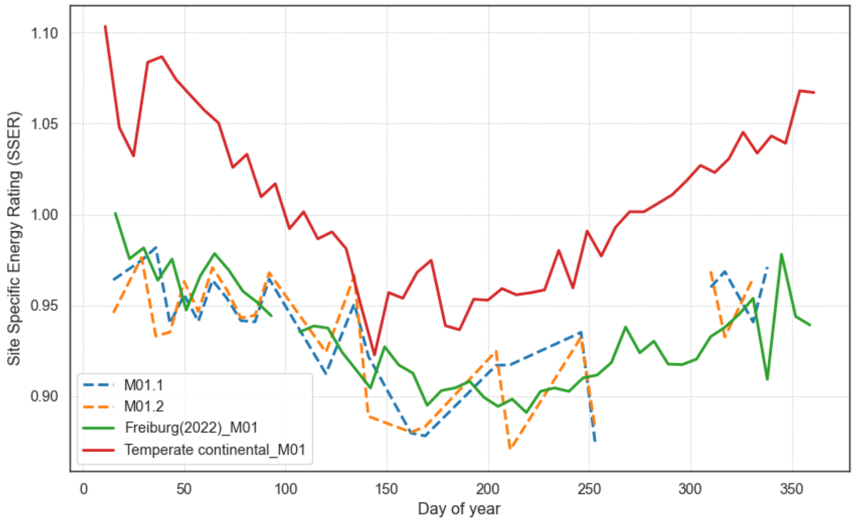


Figure 4: Weekly *CSER* in Temperate continental (red), SSER$_{MODEL}$ in Freiburg (green) and SSER$_{REAL}$ (dashed lines) for a year of outdoor exposure between 2022-2023 with module manufacturer M01 (Modules M01.1 and M01.2) [36].

A further validation of the ER methodology for benchmarking of different PV technologies is described in Rivera et al. [37], where the *CSER* and *SSER$_{MODEL}$* values were compared for 3 different locations representing temperate continental, subtropical arid and subtropical coastal conditions. The site-specific climatic profiles were generated with data from weather monitoring stations at Fraunhofer ISE, in Freiburg (Germany), in the Negev Desert (Israel) and in Gran Canaria (Spain). The benchmarking study analysed 11 different monocrystalline silicon PV modules from technologies like SHJ, IBC and PERC (Figure 5). PV modules showed standard deviations (STDev) of *CSER* ranging from 0.5% to 0.7% across southern climates, and with higher deviations ranging from 1% to 1.4% for profiles in northern regions (temperate coastal, high elevation, and temperate continental) where high diffuse ratios and high angles of incidence (*AOI*) can be found. Nevertheless, these deviations remain within the expected uncertainty range of approximately 2% for the methodology across all climates.

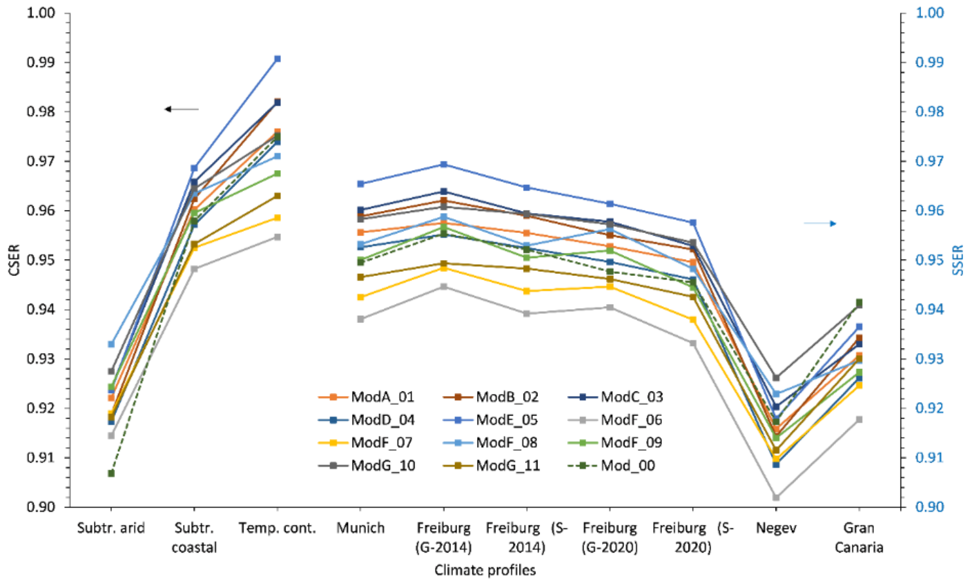


Figure 5: CSER (left) and SSER (right) for 11 monocrystalline silicon PV modules from different manufacturers and a reference PV module (Mod_00). Comparing Temperate continental-Munich/Freiburg, Subtropical arid-Negev, and Subtropical coastal-Gran Canaria. "G": ground, "S": satellite measurements [37].

The study demonstrated that the ER methodology effectively describes the ranking of PV modules in different climate conditions, whereas the absolute values differ significantly depending on the location. As an example, the PERC modules (Figure 5: ModE_05, ModC_03, ModB_02) present the highest *CSER* but lower performance in high-temperature, high-irradiance conditions, which is well correlated with their high temperature coefficients and low open-circuit voltage. Conversely, HJT modules (Figure 5: ModF) with an overall lower performance, outstand in high temperature high-irradiance climates due to their favourable temperature coefficients.

The study by Anderson [25], which validated the ER approach came to the conclusion that the IEC 61853-4 reference datasets do not represent the full range of climates where PV systems are currently deployed in United States and an alternative approach is proposed.

Monokroussos et al. [38] demonstrated the comparability of the IEC 61853 energy rating to a commonly used simulation tool like PVSYST, by performing climate specific simulations with the same input parameters. Despite differences in the modelling, minor differences in mean annual specific energy yields (<0.9%) were observed for c-Si modules. The good agreement is given using all input parameters of the IEC 61853 Standard Part 1 and Part 2. There are some differences of how these are implemented in the calculations, which leads to differences particularly at low irradiances. Also, spectrally sensitive devices could lead to different results, as PVSYST is primarily validated for c-Si modules.

3.2 Climate specific performance loss rates (PLR)

The Performance Loss Rate (*PLR*) quantifies the power loss over time in units of percent per year (%/year) and it is one of the most important KPIs needed to determine the payback time and lifetime energy production of a PV project [39]. The PLR is also a valuable diagnostic indicator for plants that are underperforming. In absence of real data, the derating and years stated in the power warranties are used. Numerous studies, listed at the end of this chapter, have shown that the warranty data mainly represent moderate climates and do not accurately reflect the degradation rates observed in harsh climates (e.g., desert or alpine) or in specific environments (e.g., building integration, floating PV). Climate specific *PLRs* that account for such variability range from 0.3%/year to around 2.5%/year, leading to significant yield and revenue differences for the owners of PV systems. Uncertainties and approaches for the determination of *PLRs* are discussed in a former IEA report [40]. One of the main contributors to the PLR is certainly the PV module degradation rate - which as indicated by the following simulations and supported by subsequent field studies - is influenced by the climate in which the modules are deployed.

J. Ascencio-Vásquez, in his work [41] modelled climate-specific degradation rates worldwide. The simulations do not include temporal or external degradation factors or failure modes such as light-induced degradation (LID), light and elevated temperature degradation (LeTID), potential-induced-degradation (PID) or mechanical damage due to wind or snow loads which must be determined separately through laboratory tests performed according to the relevant IEC standards (e.g. IEC 61215). One of the outcomes is shown in Figure 6 below, where the globe is divided into the KGPV climate zones [7], clustering the modelled degradation rates. Hereby, the tropical climate with high irradiation zones exhibits the highest degradation rates with an average of 1.03%/year, while the colder areas, such as snowy and cold climates, can get below 0.25%/year on average.

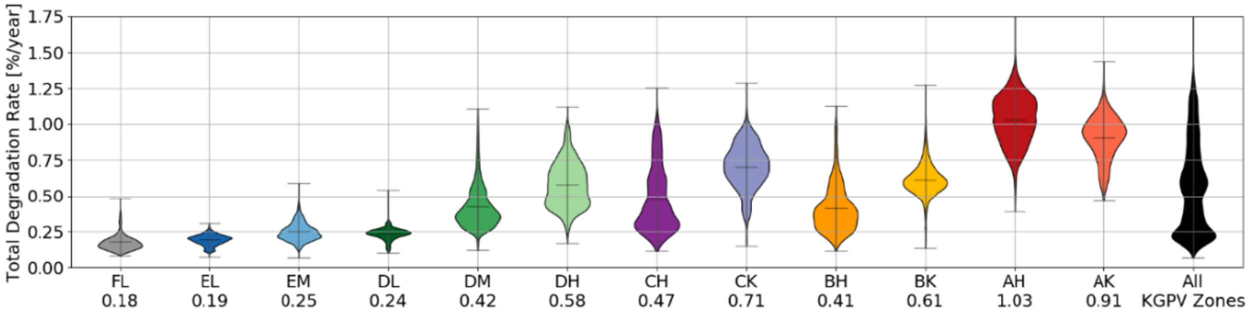


Figure 6: Distribution of degradation rates in different KGPV climate zones (the average total degradation is indicated below in %/year). The width of each shape represents the density of degradation rates within each zone; wider sections indicate more frequent values. KGPV climate legend: A(tropical), B(desert), C(steppe), E(temperate), D(cold), F(polar), K(very high irradiance), H(high irradiance), M(medium irradiance), L(low irradiance) [41]**.**

Even though the theoretical results are coherent with what is observed in the field, some climate and degradation modelling topics need further investigation: (1) lack of UV irradiance measurements spread around the world does not allow a representative validation of models, (2) moisture ingress and related triggering of degradation processes, such as corrosion or delamination, need to be understood for different interaction of materials, and (3) the understanding of degradation mechanisms under high UV irradiation and shallow humidity exposure.

Because of this, and to validate the existing degradation models, further field data are crucial. Field data are collected worldwide to validate the performance of mainstream and emerging PV module technologies across different climates. A former IEA PVPS TASK 13 report [42] presented some of the major test laboratories performing technology benchmarking in the field. Some of the new initiatives are here presented with a focus on climate specific testing.

Fraunhofer ISE operates solar test sites that enable precise monitoring data collection, customised performance and reliability evaluations of components and systems, and benchmarking of different module types. The available sites include the "Outdoor Performance Lab" located in Merdingen, Germany, as one of the largest test fields for solar energy systems in Europe, as well as additional sites in Gran Canaria, Spain, and the Negev Desert, Israel. Studies have focused on estimating degradation rates in these diverse climates [43], [44], where monitored data has also served as validation for degradation models. For example, Kaaya et al. [45] reported a degradation rate of 0.74%/year in the arid climate of Negev, dominated by thermomechanical-induced degradation modes. In comparison, degradation rates of 0.5%/year and 0.3%/year were observed in maritime and alpine environments, respectively, with photothermal degradation being more prominent in Gran Canaria due to high UV exposure and relatively high average temperatures.

The US Department of Energy's Sandia National Laboratories oversees a network of multi-climate field sites - so-called Regional Test Centers (RTCs) for Emerging Solar Technologies - that have comparable instrumentation and adhere to the same technical standards for data collection. The RTCs are of high value for both validation of new technologies and for R&D studies that illuminate the climatic influences and design factors that contribute to PV performance and reliability [46]. The RTC program expanded five years ago when the PV Collaborative to Advance Multi-climate Performance and Energy Research (PV CAMPER) was formed [47], [48]. Like the RTCs, PV CAMPER is a network of global outdoor sites spread across six continents and all major climate zones, with members committed to common standards for data quality and availability. To date, members of PV CAMPER have tackled R&D challenges of global interest, including soiling, measurement uncertainty and albedo modelling (see Figure 7).

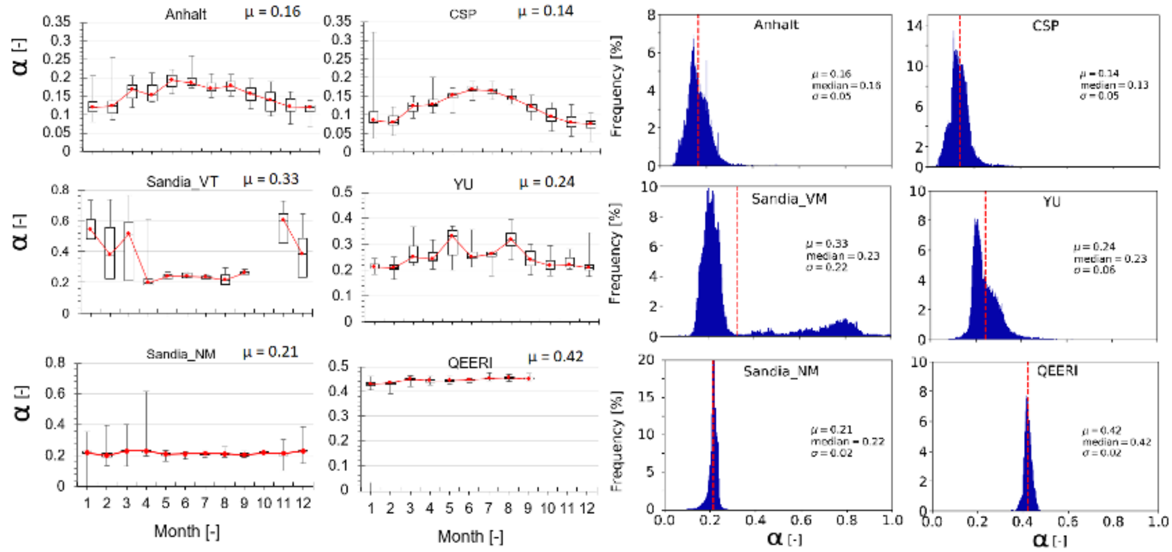


Figure 7: PV CAMPER cross-climate albedo study. Results of one-year albedo data: (left) - Histogram of α for each test site together with mean (μ), median and the standard deviation (σ), (right) - Seasonal variation, monthly average of rear/front side ratio.

Sandia has also published an early-life solar module degradation study, that examined 834 fielded PV modules taken from different PV systems, representing 13 types from seven manufacturers in three climates [49]. Six of the studied modules were determined to have power degradation rates that will exceed panel warranty limits in the future, while 13 systems demonstrated the ability to extend their lifetime beyond 30 years. The mean degradation rate values of 0.62%/year are consistent with rates measured for older modules. As shown in some studies of SUPSI [50], [89], the degradation rates are not only driven by the cell technology, but also by the BOM which can lead to different degradation rates.

A study conducted by the TruePower^{TM} Alliance under the leadership of the Solar Energy Research Institute of Singapore (SERIS) at the National University of Singapore (NUS), investigates the PV module performance and prediction uncertainty across varying climate zones. Identical

PV systems with mono-c-Si modules situated in four locations - Australia (hot and dry), Germany (temperate), Singapore (hot and humid), and China (cold) - are analysed for the impact of climate factors such as temperature, humidity, irradiance, and spectral variations on performance compared to the operation under standard test conditions. As shown in Figure 8, the PV systems in the hot climates (Singapore and Australia) experience much larger performance losses because of temperature, named here as temperature losses, compared with Germany and China. The temperature losses in Singapore are higher than those in Australia because of the lack of winter in Singapore, the lower wind speed (characteristic of equatorial regions). Furthermore, the PV modules in Singapore are installed almost horizontal (which will further reduce the wind influence on temperature reduction). Meanwhile, the PV systems in Germany and China experience much lower temperature losses (average of 2.2% and 4.0% respectively) and sometimes even a temperature gain during winter months as the module temperature goes below that of STC (25°C). The lower temperature loss is the main factor of higher PR in Germany and China compared with Singapore and Australia.

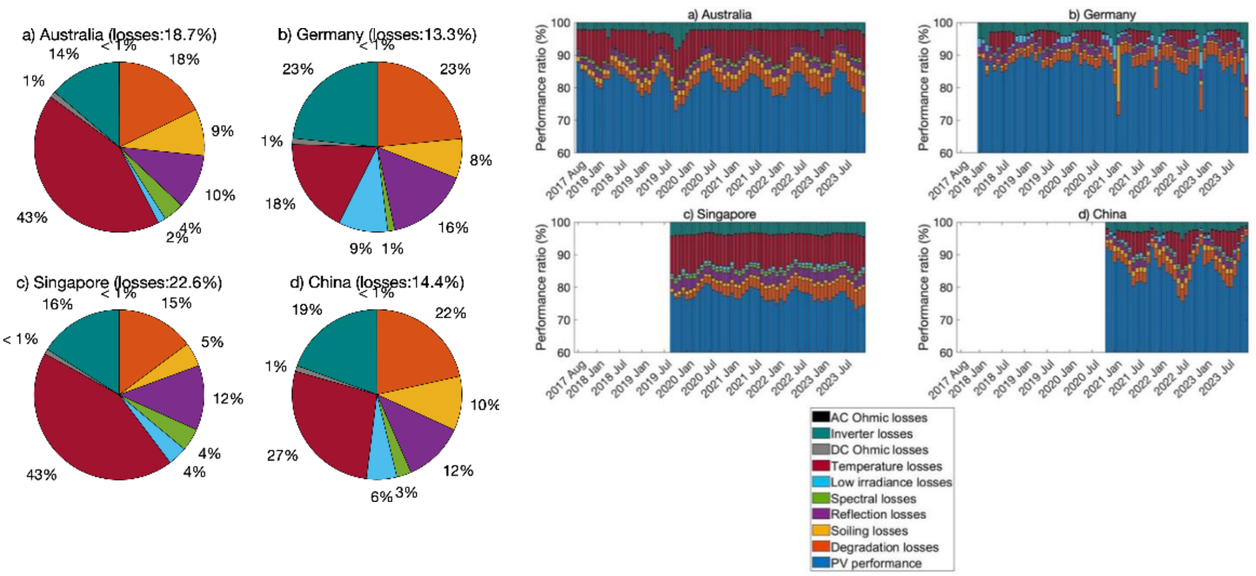


Figure 8: Monthly and Total average values of different sources of PR reduction in a) Australia, b) Germany, c) Singapore, and d) China sites. Source (TruePower™ Alliance, SERIS).

The magnitude of spectral losses in the Singapore location is also the largest among the four locations, although the magnitude is much lower (average of 1.92%) than temperature losses. Furthermore, the PV system in Singapore experienced the highest degradation rate, followed by the systems in Australia, China, and Germany. The higher degradation rate experienced by systems in Singapore and Australia might be due to higher temperature and UV radiation (as well as humidity for the case of Singapore).

3.3 Case studies: Climate specific technology benchmarking

The main advantages of climate-specific energy ratings and performance loss rates are: (1) to provide end-users an easy method for selecting a product based on its energy yield, which is essential for estimating economic revenue, (2) to increase the accuracy of energy predictions by providing access to module parameters measured in accordance with Part 1 and Part 2 of the Energy Rating standard and (3) to foster innovation and stimulate PV module manufacturers for optimising PV cell and module technology with respect to energy yield and lifetime and not just efficiency and STC power. Practical examples of implementation are given here including other energy prediction tools.

Protti at el. [51] used climate specific energy rating to study and quantify the effect of module design parameters using Cell-to-Module simulations and by performing a sensitivity analysis with 11 different module design parameters (e.g. number of strings and cells in series, thickness and width of interconnectors, thickness of encapsulant, cell distances etc.) to optimise the energy yield of a half-cut cell module. The paper demonstrates how ER can assist module manufacturers in their decision making and speed up the development of photovoltaic modules with improved performance by reducing the need for prototyping and testing especially in the early stages of product development. S. Ramesh et al. performed a similar study [52] but based on a one-diode model and 13 different climates to study how modules with the same nominal efficiency and bifaciality, but with varying combinations of V_{OC}, I_{SC} and *FF*, have different yields at the same operating conditions. With this study they could quantify the energy gain obtained for the oceanic-temperate climate by optimising $I_{SC}×V_{OC}$, in tropical-humid zones V_{OC} and in hot arid/desert areas with high albedo $V_{OC}×FF$. This translates into a cell technology choice which favours PERC technology for oceanic-temperate climates and HJT or TOPCon cells for hot climatic zones that require a high V_{OC} and respectively lower temperature coefficients. The authors highlight also how degradation of e.g. *FF* will have a different effect on the yield at different locations although the underlying degradation mechanisms and *FF* loss may be similar.

M. Kumari at el. [53] adds the electricity price to their analysis to estimate the regional revenue gain by choosing modules with different temperature coefficients or anti reflective coatings. They highlighted also how higher temperature coefficients lead to higher yields in regions where the modules operate at temperatures below 25°C for longer periods of time over the year. The lowest energy and revenue gains come from the antireflecting coating analysis, which was however limited to fixed latitude tilted modules. The study of Rivera et al. [37] showed how at lower tilt angles and moderate climates, where the temperature coefficients have a lower impact, the angular losses can dominate privileging technologies with low angular losses compared to a HJT modules with worse angular response. In building integrated modules reaching module temperatures comparable to hot climate simulations, it is recommended to quantify the thermal losses.

However, it has to be highlighted here that the differences in annual kWh/kW$_p$ in today's mainstream silicon-based PV modules are in the range of ±2.5% or lower [54], [55] and that technological differences in climate specific degradation rates can compensate after a few years the initial advantage given by a better temperature coefficient. To assess the economic impact of performance losses over the PV system lifetime, one also has to consider the price of electricity. Micheli et al. [56] investigate the distribution and the variability of the PV revenues for different countries and its evolution over time, as well as when mitigation measures and lower degradation rates have the highest impact.

4 OPTIMISATION OF MODULE/SYSTEM DESIGN FOR COLD & SNOWY CLIMATES

Nearly 50% of the total land area in the northern hemisphere, equivalent to 67 million km^2, is covered with snow in a typical winter. Moreover, depending on the latitude and altitude, snow may persist for as long as nine months a year and account for more than a third of the total annual precipitation. Today, the economics of solar have shifted dramatically and, as a result, some of the fastest growing regions in the world for solar are above 40ºN [57], where snow is a repetitive occurrence and a significant challenge for PV systems across North America, Europe and Asia. Also, high-altitude PV installations are becoming increasingly important, particularly in alpine countries such as Switzerland and Austria [58], where the availability of open space for ground-based PV systems is limited or in conflict with other interests such as agriculture, landscape or biodiversity. Due to the high irradiance combined with low temperatures and high albedo when snow is present, alpine PV systems are particularly suitable for increasing the contribution of renewable energy during the winter months and, thus, reducing the dependence on electricity imports. High altitude PV also has strong synergies with hydropower due to the pre-existing infrastructure and grid connection and the greater flexibility in the management of water reservoirs and ski resorts, which require a lot of energy.

4.1 Cold & snowy climates

Cold and snowy climates are characterised by consistently low ambient temperatures and, in certain areas, substantial snowfall. In these climates, temperatures are often well below freezing for long periods of time. This reduces heat losses from PV systems, which, although favourable for performance, can pose a risk to long-term stability. Additionally, such climates can have increased snow shading and/or long winters with reduced sun-light hours, decreasing the annual energy yield and potential PV system profitability caused by snow covers on the modules. Increased mechanical stress at low temperatures can lead to an increased frequency of failures in laminates and connectors. Chemical material (polymer) degradation, however, is drastically slowed down at low temperatures resulting in lower overall degradation rates. Heavy snowfall and ice accumulation add significant weight, potentially damaging modules, structures or equipment. In such climates, precipitation in the form of snow can be abundant, and persistent snow cover can limit access and increase maintenance challenges.

Cold and snowy climates primarily fall into two groups of the Köppen-Geiger Classification: Continental (Group D) and Polar and Alpine (Group E). Within Group D, the main cold and snowy climate categories are:

- Dfa and Dfb (humid continental climates), characterised by cold snowy winters, with the coldest month mean temperature below -3°C. In Dfa, the warmest month average is above 22°C, while in Dfb between 10°C and 22°C. These climates are primarily found in the northern United States, southern Canada, Eastern Europe, and parts of northern Japan. Precipitation is distributed relatively evenly throughout the year.
- Dfc and Dfd (subarctic climates), characterised by long, cold winters and short summers. They can be found in northern Canada, Alaska, Siberia, and parts of Scandinavia above the 60° north latitude. The warmest month has an average temperature between 10°C and 18°C. Precipitations are consistently distributed throughout the year. Dfc climate is characterised by average temperature below -3°C in the coldest month, which can go below -38°C in Dfd.

- Dwc and Dwd (Monsoon-influenced humid subarctic climates), characterised by long, cold winters and short humid summers. Precipitation is seasonal, with a distinct dry winter and wet summer due to monsoonal influence. They can be found in northeastern Siberia, northern China, and parts of Mongolia. The warmest month has an average temperature between 10°C and 18°C, while the coldest month has an average temperature below -3°C in Dwc and -38°C in Dwd.
- Dsc and Dsd (dry-summer subarctic climates), characterised by long, cold winters and short and dry summers. They can be found in high-altitude regions of mountainous areas, such as in Alaska and Northeast Canada. The warmest month has an average temperature between 10°C and 18°C, while the coldest month has an average temperature below -3°C in Dsc and -38°C in Dsd.

In group E, the most common climate for PV installations so far has been the Tundra climate (Et), characterised by cold temperatures year-round (maximum average monthly temperature between 0°C and 10°C). This climate is typically found in high-altitude regions, such as the Swiss Alps, the Rocky Mountains, and the Andes. Precipitation mainly occurs as snow, resulting in extended snow cover.

Following the KGPV climate classification, and as shown in Figure 9 and Figure 10, the cold and snowy climates exhibit the lowest average temperatures worldwide, most of them located in the Arctic (this study excludes the Antarctic) and a couple of other locations in the southern hemisphere – notably in the Andes. Interestingly, high annual solar irradiation can be achieved in these regions – especially in the mountains. Regardless of the solar potential, the low temperatures also generate ice and snow, which leads to risks for performance and reliability, as mentioned below.

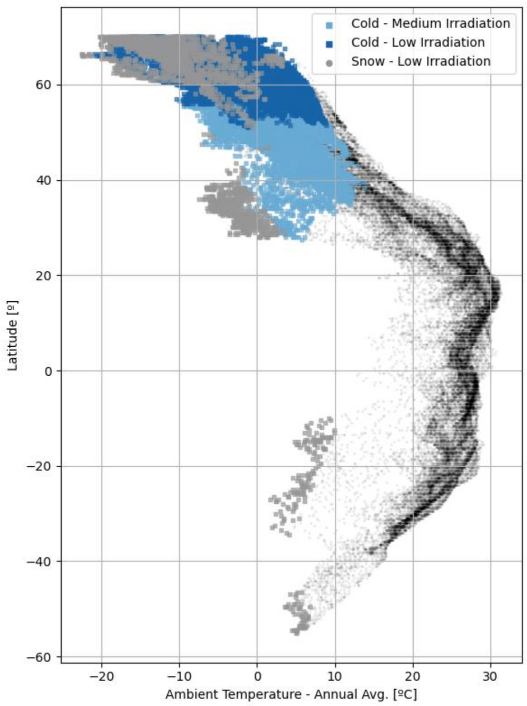


Figure 9: Correlation of latitude with annual ambient temperature highlighting the cold and snowy/polar KGPV climate zones.

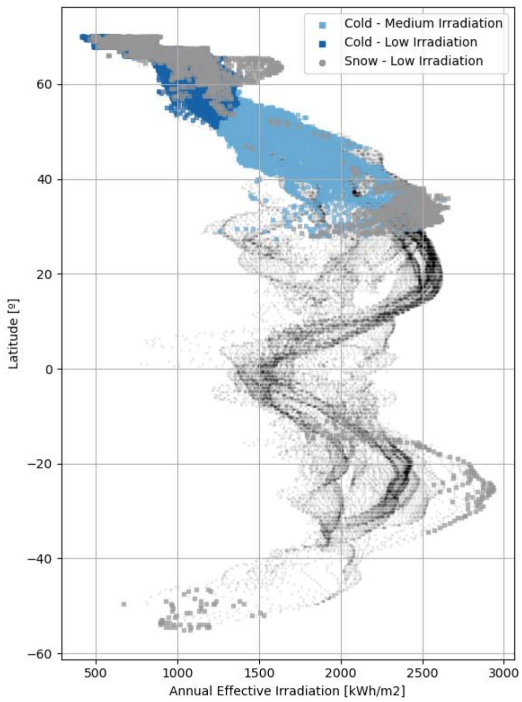


Figure 10: Correlation of latitude with annual effective irradiation highlighting the cold and snowy/polar KGPV climate zones.

Figure 11 presents a map of snow loads across Europe, highlighting the regions that are the most impacted by snow, like the Scandinavian countries at high latitudes and the alpine regions with high altitudes.

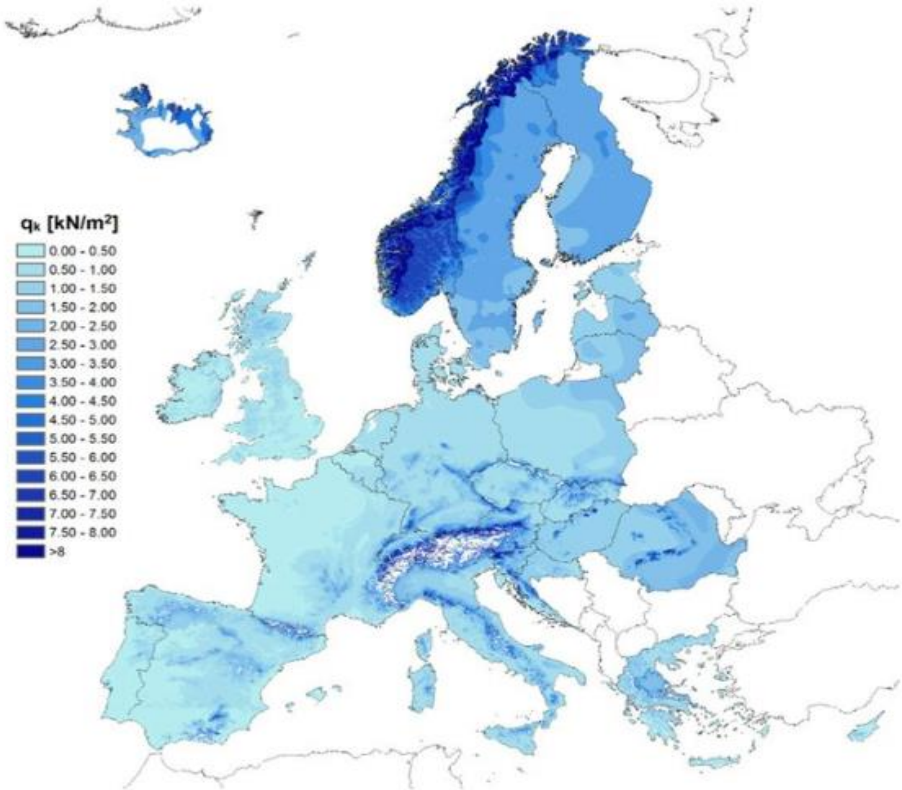


Figure 11: European ground snow load map, resulting from the current set of available National Annexes to EN1991-1-3 "Actions on structures: Snow loads" [59].

4.2 Stressors and typical problems (cold & snowy)

The stressors encountered in cold and snowy regions can be divided into three categories: (i) main stressors that are present in all regions and occur with some regularity, (ii) site-specific stressors, and (iii) stressors with low probability but significant impact on failure load. See stressors and failures compilation for the cold and snowy climate in Figure 12.

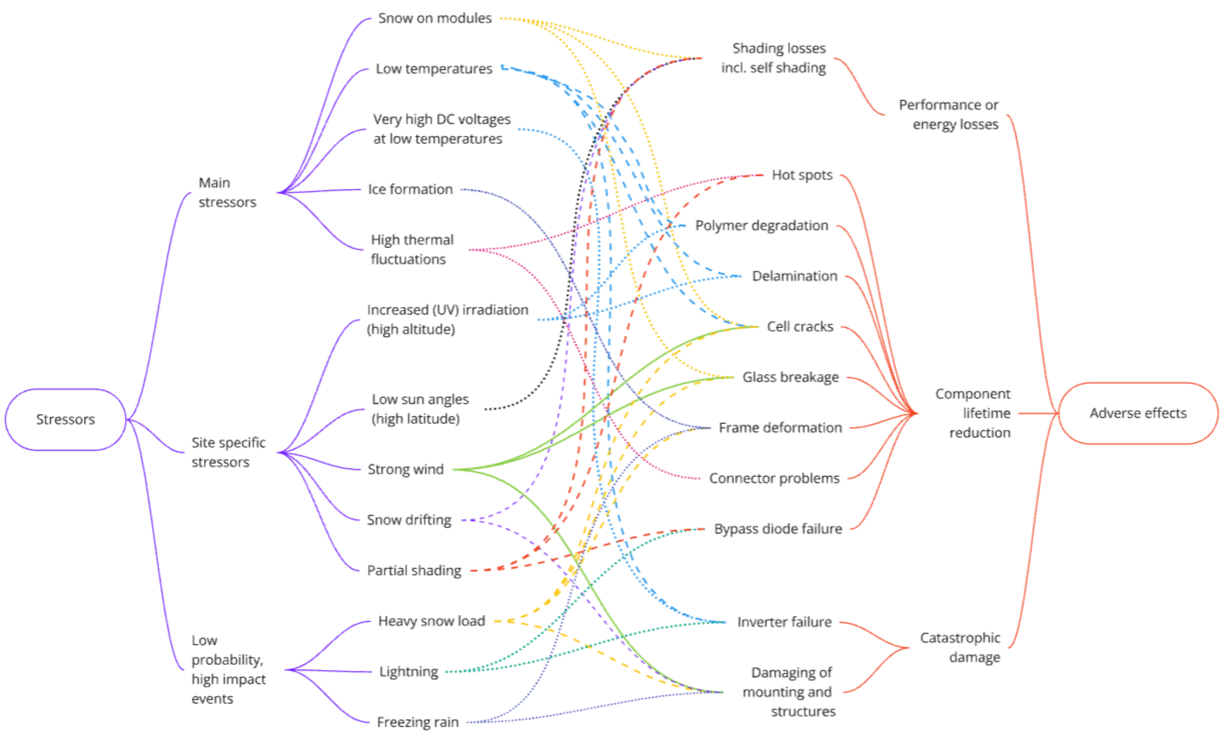


Figure 12: Mind map of stressors and corresponding adverse effects for PV powerplants in cold & snowy climates.

The most important stressors encountered in cold and snowy regions are snow and ice formation accompanied by low temperatures as well as higher module temperature fluctuations compared to lowland which can occur under certain circumstances. Some stressors are site-specific such as increased (UV) radiation (at high altitudes or in presence of snow, which increases albedo), strong wind conditions leading to snow drifts or low sun angles (at high latitudes). Further singular high impact events in cold and snowy climates are extreme snowfalls or snowstorms, lightning and freezing rain.

Concerning the long-term reliability of modules exposed to repetitive winter stress, including cold, snow and wind loading, only a few studies exist [60], [61], [62]. Despite there are good examples of systems in cold and snowy climates that have been functioning without issue for long periods, as for example the system installed in the Swiss alps [63], the trend towards larger, thinner and less robust modules driven by cost considerations is increasing the risk of higher degradation and failure rates in harsh conditions. Therefore, the consideration of climate specific stressors and mitigation measures is crucial.

The impact of the most important stressors is discussed in more detail in the following sub-chapters.

4.2.1 Snow and ice formation

Snow is ubiquitous for PV in cold climates. Snow and its characteristics can however vary greatly. As represented in Figure 13, individual snow crystals' formation in the atmosphere changes with both temperature and water saturation [64], [65]. Individual snow crystals will then adhere together and form a porous sintered material that is undergoing constant transformation throughout the winter, changing its properties further [66]. Snow adhesion is not the sole mechanism that interacts with PV modules. Ice adhesion from meltwater, freezing rain or sleet, as well as ice accretion such as frost can all affect modules on their own, or enable snow to adhere to a surface where it otherwise might not [67].

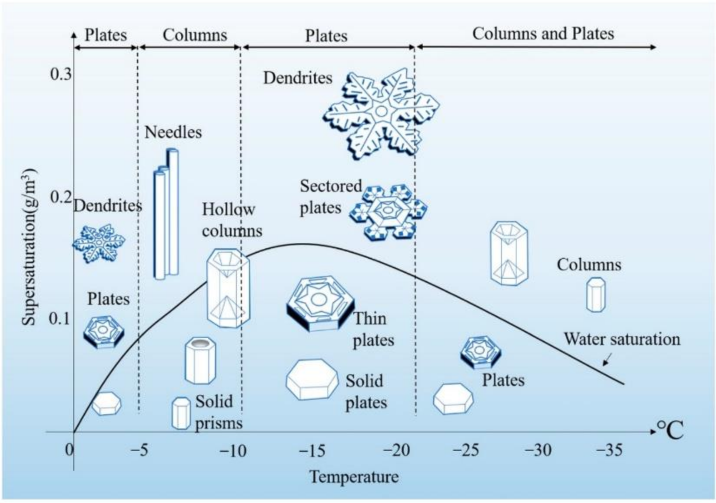


Figure 13: Nakaya diagram showing the change in snow crystal structure with temperature and supersaturation [64], [68]**.**

The weight of the **snow load** primarily acts as a mechanical stressor on the modules, BOS components, and racking system. Snow loads typically accumulate in a non-uniform manner, with greater weight concentrated on the lower portions of the modules, including the frames, if present [69]. Microcracks in the cells can form and progressively propagate over time. The ingress of meltwater into module frames or other electrical components can cause the connection to the frame (components) to burst/dissolve due to the increase in volume during freezing after several thaw-freeze cycles [70].

Furthermore, snow coverage of a PV module will lead to periods with little or no electricity production. Snow both absorbs and reflects solar radiation, but in general transmitted light levels are low, with maximum values measured between 450 nm and 550 nm. Research has shown, for example, that as little as 10 cm of snow can reduce visible transmission at 500 nm to about 5% of the incident irradiance and infrared transmission at 800 nm to less than 1%, with further decreases depending on increasing grain size and snow density [71]. Detailed information on soiling from snow can be found in a previously published IEA PVPS TASK 13 report [72].

4.2.2 Low temperatures and thermal cycling

Low temperatures and fast temperature changes/fluctuations can lead to failures such as delamination or mechanical damage of the laminate stack with strong focus on the interlayers with polymer films, encapsulant and backsheet [73]. But the electrical connection systems (e.g., cell interconnections, polymer cable sheaths and module connectors) and the inverters are also severely affected by low operating temperatures, which can destroy or drastically reduce the service life of the components. Despite the strong impact of low temperatures on physical and thermo-mechanical degradation modes it must be noted that, in principle, lower ambient temperatures slow down most (chemical) material degradation reactions [41].

The **low-temperature behaviour of polymers** is characterised by several key phenomena that affect their mechanical, thermal, and physical properties [74]. The modulus-temperature curve of polymers illustrates how a polymer's stiffness, typically measured by its elastic modulus, varies with temperature. Generally, the curve can be divided into several distinct regions, each corresponding to different physical states of the polymer [74]:

- At low temperatures, **polymers** are in a **glassy state** where the modulus is high, indicating that the material is **rigid and brittle**. In this region, molecular chain movements are practically frozen, and the polymer exhibits minimal deformation under stress.
- As the temperature approaches the **glass transition temperature**, the modulus drops significantly. The polymer becomes softer and more pliable because molecular motion increases, allowing for more segmental mobility.
- Above the glass transition the polymer reaches the **rubbery plateau region**, the modulus stabilises at a lower level compared to the glassy state. The polymer is now flexible and elastic, capable of significant deformation. Molecular chains have increased mobility but are still entangled, providing elasticity.
- With increasing temperature, the modulus decreases further as the polymer transitions into a **viscous or flow state**. The material behaves like a viscous liquid, with chains moving freely past one another, resulting in significant deformation under stress.

At high temperatures, materials become more ductile, increasing their impact toughness. In contrast, at low temperatures, certain plastics that are typically ductile at room temperature become brittle due to reduced molecular mobility. This transition is especially pronounced in amorphous polymers near their glass transition temperature (*Tg*) – see Figure 14.

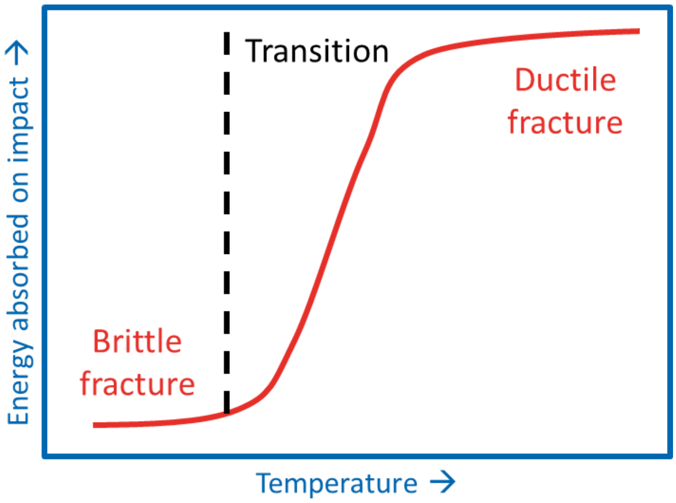


Figure 14: Ductile-brittle transition temperature curve of polymers.

Polymers with higher degrees of crystallinity are generally more brittle because the ordered crystalline regions restrict molecular mobility. Amorphous polymers, with less ordered structures, are typically more ductile as their molecular chains can move more freely. Also, the incorporation of additives and plasticizers can enhance the ductility of polymers by increasing the free volume and reducing intermolecular forces, allowing chains to slide past each other more easily [74].

At low temperatures, encapsulants based on polyethylene (PE) copolymers (e.g., EVA, POE, TPO and EPE) become much stiffer. While the storage modulus value of these encapsulants ranges between 1 to 50 MPa at room temperature, this value increases to about 1000 MPa at temperatures below 0°C indicating a significant increase in stiffness [75], [76]. This can affect the mechanical performance of PV modules as a stiff encapsulant cannot deform as easily to absorb and distribute mechanical loads, resulting in higher stress concentrations in the solar cells and interconnections. The increased stress can lead to micro-cracks or even fractures in the brittle silicon cells, which can have adverse effects on the electrical performance of the PV module. The metallic interconnections, which are usually made of soldered ribbons or wires as well as conductive adhesive materials, can also experience higher stress, potentially leading to fatigue and failure over time [77], [78], [79], [80].

These effects are strongly enhanced when PV modules are subjected to temperature variations caused by passing clouds, day night variations or seasonal temperature variations, leading to repeated expansion and contraction of the materials (thermal cycling, TC). Over time, the repeated thermal cycling can accumulate fatigue damage in the cells and interconnections and the stiffer encapsulant amplifies these stresses, accelerating the fatigue process [81], [82].

The differential thermal expansion between the encapsulant and other materials in the PV module can also lead to delamination, where layers of the module separate, further compromising the structural integrity and performance [81], [82].

One example of polymers exhibiting a brittle-ductile transition is polypropylene (PP). This effect has already been observed and reported for PP based backsheets [83]. At room temperature, the PP backsheet exhibits high plastic deformation ability. At -40°C however, strain at break values drop dramatically (see Figure 15) and differentially in the two directions. It was concluded that PP backsheets might have a higher likelihood of crack formation if subjected to prolonged operation at temperatures well below 0°C (-10°C to 0°C = glass transition PP), when the backsheet shows significant damage due to material degradation combined with high thermo-mechanical stresses.

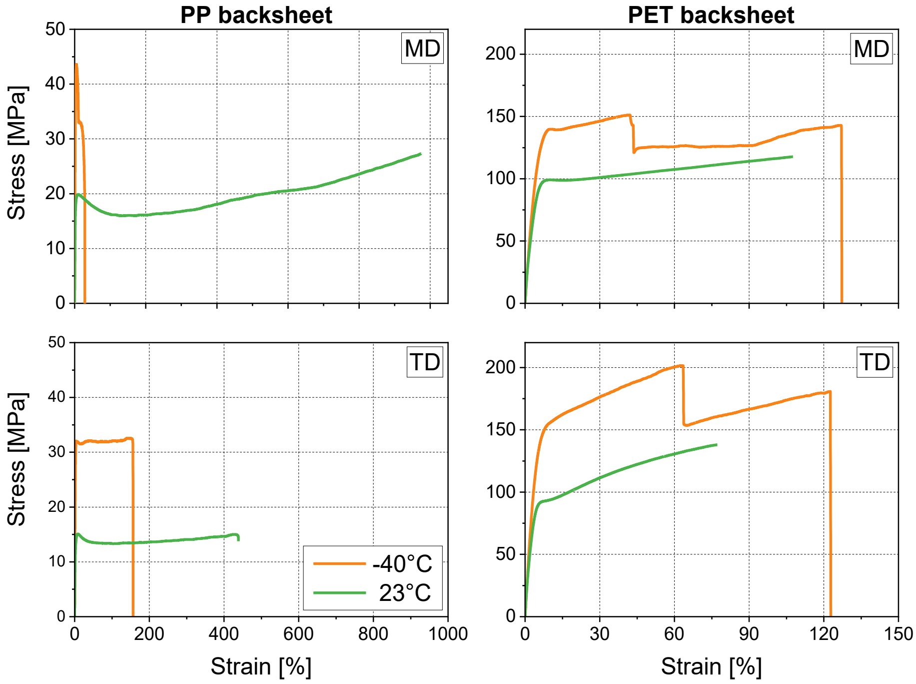


Figure 15: Tensile test curves of PP and PET backsheets measured at -40°C and 23°C, both in machine direction (MD) and transversal direction (TD) [83]**.**

4.2.3 High irradiance and UV exposure

For PV systems in mountainous regions, i.e., at high altitudes, higher irradiance and UV inputs are added to the above-mentioned loads. A higher total irradiance of up to max. 1700 W/m^2 was measured at Jungfraujoch [63], which is due to the combination of the altitude effect and the high albedo of snow-covered ground. Snow reflects up to 80-90% of the radiation in the UV range [84]. Therefore, high albedo leads to higher UV doses on the back sheets or rear side of bifacial modules which accelerates the degradation of materials or cells [84], [85], [86]. Due to the high altitude, many days with snow-covered ground and less fog [87], the total insolation can also reach about 1600 kWh/m^2/year (measured on the Zugspitze, Germany at 2656 m above sea level). In addition, the percentage of UV insolation was higher there than in other climate zones in the world (4.7%) [88].

4.2.4 Wind and snow drifts

The snowpack formed on the ground can be susceptible to erosion and transportation by strong wind. Strong wind can transport snow from open and wind-exposed areas to areas with lower wind speeds, typically the aerodynamic wake of an obstacle such as a building, roof ridge, or PV-array [89]. This phenomenon can concentrate seemingly low levels of snowfall into a large snow drift that can cause uneven shading, or heavy snow loads on PV modules [89]. High snow pressure from the rear can also occur. These stressors can cause mechanical failures, such as glass or cell breakage, or damage to the mounting structure [90]. The special mounting construction (see Figure 16) allowing for change between a steeper winter and lower summer seasonal angle can further increase the accumulation of snow.

Figure 16: PV-system at Wildkogel/Austria; wrong site-selection: every winter, a snow roll always covers the PV fields and causes severe damage; the PV plant must be relocated.

4.3 Best practice and mitigation strategies (cold & snowy)

4.3.1 Site assessment

When the question comes to the assessment of the optimal installation site, the following parameters must be taken into consideration, particularly for high altitudes:

- Environmental conditions: UV irradiance, snow depth, wind loads/direction, fog frequency
- Specific local conditions: snow deposits and wind drifts, albedo, terrain morphology/horizon, thawing and freezing ground, geology/soil conditions, hydrology
- Local restrictions: environmental constrains, grid connection, remoteness, seasonal accessibility, glare
- Probability of catastrophic events: avalanches, rockfall, earth slides, hail, lightning

The safe installation of PV modules in mountainous terrain or remote areas often requires exceptionally strong foundations, mounting structures and fastenings to withstand the high mechanical loads of the harsh environment. The transport of this heavy and bulky infrastructure to the high-altitude locations is often associated with great challenges and costs.

Depending on the specific location chosen for the PV system, stressors such as high wind loads, and snow drifts may occur. A thorough knowledge of the site-specific wind and snow depth conditions is therefore essential. If there is no existing measuring station in the project area, wind data must be extrapolated based on neighbouring stations at the expense of precision. To select the right components and better dimension the PV mounting structure, it can be useful to install a measuring station in advance. The maximum wind gusts and the frequency with which they can occur must be considered. Another important aspect that must be determined for the site is the expected snow depth, which must then be included in the design phase of the system together with the topography and wind data.

4.3.2 Optimisation of module design and BOM

After having assessed the local conditions for the installation site, the next step involves the selection of the best module-type for the cold and snowy environment. In general, the cell and connection technology, the materials and thickness of the polymer embedding films and the glass as well as the module structure/design (including the frame) can be selected for a PV module.

An open question remains, for example, on how the different thermal expansion coefficients of a module's laminates may impact module integrity over multiple winters. Similarly, not much is known about the long-term durability of solar cells and modules with large surface to volume ratios, although cold is known to increase the risk of cell cracks [91]. In addition, the trend toward thinner front glass for glass/glass large format modules does not favour reliability under heavy snow loads. Studies on this topic are underway at Sandia National Laboratories. More data exists on the impact of module selection and system design on the performance of PV systems in winter, with multiple studies demonstrating [92], [93], [94] the efficacy of design choices that minimise snow adhesion and accelerate snow shedding.

The **mechanical stability** of the module is the primary requirement in cold and snowy regions, on which the module size, glass thickness, frame selection and mounting structures have a strong influence. One effective design choice is the use of frameless modules, which lack the physical impediment created by the module frame and have been demonstrated to shed snow 50% faster than their framed counterpart [94], [95]. In frameless modules, the snow slides off more easily avoiding high snow loads and shading [92], [95]. On the other hand, framed modules are mechanically more stable and easier to attach to the substructure. Higher glass thickness, glass/glass configuration, modules with back rails and a reduction of the module size are some of the available options to increase the mechanical stability of modules. Such modules are, for example, modules with a front glass thickness of 4 mm, an area of 2 m² and a design load of 5.3 kPa, which corresponds to a typical test load of 8 kPa. Thicker, reinforced or special shaped module frames (e.g., larger glass surface contact area) or steel frames can further increase the stability of modules [96]. Special geometries of the frame which avoids snow accumulation or facilitates melt water drainage mitigates frame deformation caused by snow loads or ice formation. For example, snow clings more to a sharp edge than a smooth one. Frames with silicone-based adhesives can resist higher loads without any frame bending or permanent damage while the tape-based adhesives are less resistant [97]. Finally, the mechanical load resistance of a module depends strongly on the mounting configuration, in particular on the type, number and position of module clamps. Module data sheets specify which mechanical loads are compatible for which type of mounting.

Also, selection and design of the **cell interconnection** can increase the robustness of a PV module in cold climates. Invisible cracks can occur more easily under high snow load conditions or transport to remote areas. Compared to former ribbon-based modules with 2 to 4 cell interconnect ribbons, more recent multi wire/busbar solar modules demonstrate much lower power losses due to cell cracks. Another example, using finite element analysis (FEA), Lang et al. [77] showed that for solar cells that are shingled using an electrically conductive adhesive (ECA), joint thickness, joint width, and cell overlap each significantly reduce stress in both the joint and adjacent silicon cells at low temperatures. Specifically, increasing the joint thickness from 20 μm to 40 μm reduces stress in the x-direction by about 40% at -40°C. Increasing the cell overlap reduces stress by approximately 23% and 25%, while joint width increases contribute to 18% and 19% reductions at these respective temperatures. This suggests joint thickness has the most impact on stress reduction, while cell overlap, and joint width are comparatively less effective.

In addition, the choice of **encapsulation and backside material** has a strong influence on reliability, including UV stability, when used at high altitudes. Encapsulation materials with a lower glass transition such as POE or silicone polymers retain their elasticity even at low temperatures [98], [99] which ensures that the cells are best protected against high mechanical loads such as snow and wind in cold weather. The same is valid for backsheets, where each single backsheet layer material must be checked for a ductile-brittle transition [83]. Also, backsheets with fewer layers are favoured, as they provide less potential for delamination, especially as the adhesive layers within laminated backsheets are susceptible to degradation.

Some last generation **cell technologies** like TOPCon and SHJ seem to be affected by UV induced degradation [100]. It is however not clear how these test results translate from lab into the field. Selecting modules manufactured with UV-blocking encapsulants can help mitigate UVID by preventing UV radiation from reaching the UV-sensitive c-Si/passivation interface. A technical specification for UV-induced degradation is under development [101].

Mitigating problems caused by snow accumulation on PV modules is one of the main concerns in cold climates. New module types with 6 or more **bypass diodes** minimise the effects of snow shadow losses. Compared to monofacial modules, **bifacial modules** have the inherent advantage that the additional energy captured from the backside can promote faster snowmelt at the module surface, even under diffuse or low-light conditions [102].

More specific **snow clearing measures** are described in the following, going from passive to active snow removal technologies. **Snow repellent coatings** are a topic of great interest in cold climates not just for PV, but also for wind turbines, aviation, power distribution, heat pumps, and ventilation. As previously mentioned, snow characteristics can vary greatly; a well performing coating needs to efficiently prevent snow and ice adhesion, as well as ice accretion [67]. Coating should also be durable enough to remain effective throughout the module's technological lifespan. For most PV applications it should also not negatively affect the PV module's performance in antireflectivity, light transmittance, heat retention, and non-snow soiling, as to not lower energy output during periods without snow. A study from Sandia National Laboratories in the US showed initial promise for a thin polymeric coating with high transmissivity, low interfacial toughness and strength but its reliability needs to be evaluated over multiple winters and in different climatic zones [103]. Hydrophobic coatings are commercially available but tend to offer little to no performance gain, limited to certain snow conditions and can struggle with durability and degradation [104], [105], [106], [107]. Super-hydrophobic coatings typically rely on a nanostructure that minimises contact area with water droplets. They can see an increased performance [108], [109], but suffer from poor durability and can struggle with ice accretion [110], [111], as frost can form within the nanostructure and then increase ice adhesion. SLIPS (slippery liquid-infused porous surface) coatings also consist of a porous nanostructure but are also infused with a lubricant that enhances certain properties, for instance a lipid for hydrophobicity. They have shown promising performance for both ice and snow [112], [113], but there is concern of the lubricants retaining soiling particles such as dirt or depleting over an extended period. Elastomer coatings have shown promising results when applied to PV [103] but require further validation across multiple locations and winters. There are no commercially available coatings that, at the time of writing, have been proven in literature to be truly crynerophobic for a wide range of real-world conditions and subsequently increase net energy output across an extended period of time [67].

Actively removing snow can in some instances be warranted to avoid catastrophic failure, e.g. from a rooftop-mounted installation near its snow load limit. Active snow shedding and removal can be done either mechanically or thermically. **Mechanical snow removal** typically utilises tools to physically remove snow. As snow's characteristics can vary widely, so does the suitability of different types of tools [105]. Using tools also introduces a risk of mechanically damaging the modules. It is therefore in many cases only relevant to use tools as a last resort to avoid snow loads that would otherwise risk catastrophic failure to the PV system or underlying construction. **Snow melting solutions**, thermically removing snow, are another possibility. This can be done by either forward biasing a direct current through the modules or by installing a heating wire or mesh on its rear side. This heats up the module and either facilitates snow shedding or complete melting of the snow [105], [114], [115]. A PV module is not typically designed to also function as a heater, since in regular operation a cool temperature and efficient heat transfer from the module is desired to operate optimally. This means that the entire surface, front and back, should transfer heat away as much as possible. There are commercially available forward bias snow melting solutions primarily meant for snow load reduction of commercial and industrial rooftop mounted PV. This has however mostly been tested in southern Norway but not in regions with longer winters yet [116]. Specifically for rooftop-mounted PV, snow melting systems could prove problematic. If they become inoperable during heavy snow loads, the snow must still be removed. Densely packed PV modules on a snow-covered roof can make it difficult to maneuver around and remove snow from in a safe manner. In contrast to forward bias heating, external heating has been demonstrated in a few cases applied to either the front or back surface of the module. In a study by Tanahashi et al. [117], a copper mesh was applied to the PET backsheet of test modules under heavy snow at 10°, 20°, and 30° tilts. Furthermore, a study by Khodakarmi et al. combined both active and passive snow shedding methods. Resistive heating of a front side transparent conducting oxide was used to cause melting at the snow-module interface combined with hydrophobic aluminum nanostructures to enhance snow sliding [118]. Completely melting the snow requires a lot of energy and is likely only justifiable as a means to avoid heavy snow loads and failure, whereas melting to facilitate snow shedding would require less energy and ideally give a net gain in energy due to the negated shading losses [115]. Electrical heating through forward biasing requires a DC power source and would affect the bill of materials and cost. The long-term impact of sending a current through the module in a way that it is not designed for are yet unknown.

4.3.3 System design

Snow, ice, and frost can stick to PV modules at any inclination. However, the steeper the **inclination**, the less soiling is to be expected [119]. Snow that accumulates on tilted modules will come off and form a pile at the bottom of the installation [120]. Depending on the **ground clearance**, these piles can become large enough to cover the bottom module rows, thus shading them and possibly damaging them. **Module orientation** also impacts the performance and reliability of a system. With a transversely aligned (landscape) module, the frame is more perpendicular to the falling snow, which hinders snow shedding. Module orientation influences the behaviour of a module's bypass diodes in inhomogeneous snow cover. Partial snow coverage typically occurs at the bottom edge of the PV modules and therefore it is advantageous to shade as few strings of cells as possible. For the most common bypass diode configurations, a transversely (landscape) aligned orientation is therefore advantageous [72]. The newer module types with 6 or more bypass diodes, minimise the impact of the orientation choice on performance. System design should consider the local conditions to identify the most appropriate module orientation.

The **mounting structure** of a PV system typically consists of the module support structure and the poles with their anchors. The entire system must be designed to withstand the specific site conditions. Where necessary, the structures must be adjustable and modular to accommodate steep and uneven terrain. Ground clearance is generally increased to account for local snowfall or to allow for animal grazing or access for agricultural vehicles. The steeper the terrain, the more difficult it is to install the system. Structures adaptable to different module sizes, modular mounting, ease of transport and easy replacement of individual modules in the event of damage must be considered. Additionally, anchorage points and typology should be determined based on ground conditions. Different module mounting structures are used in cold and snowy climates (see Figure 17):

- Rack-mounted PV modules (mainly high tilt to facilitate snow shedding)
- Vertically mounted bifacial modules (east/west or cross structure)
- Rope mounted PV modules (1-axis tracking possible)
- Bifacial tracking systems

Figure 17: Examples of mounting structures in cold & snowy climates. Legend: Sedrun Solar (top-left), Pitztaler Gletscher (centre-left), Bartholet [121] (bottom-left), HELIO-PLANT® (top-right), Next2Sun (centre-right), All Earth Renewables (bottom-right).

PV racking in cold climates can be subject to **frost heave**, a phenomenon where the ground moves upward as the soil freezes. The extent of the ground's movement depends on factors such as soil type, moisture content, and frost depth. Well drained soil such as gravel and sand suffer less from frost heave than clay and silt that can retain plenty of moisture [122]. The frost depth might also change with the installation of a PV systems as the modules shields the ground directly beneath them from snow accumulation, which in turn reduces insulation against cold air and could enable the frost to penetrate deeper down into the ground. Frost heave can grip the shafts of poles and unevenly lift the racking of a PV system and cause stress in its structure and potentially bend racking, loosen clamps, or damage modules. Some potential ways of mitigating the impact of frost heave are: deeper poles, if they reach beneath the frost depth they will have more traction to stationary soil and are then more likely to remain in place; reduce traction, opt for a smooth pile without perforations or other points of contact within the frost depth that could enable lifting; gravel sleeve, encasing piles with well drained particles; ground screws, unlike a pile, a ground screw has a wider tip than shaft which if located below the frost depth can act as an anchor and resist lifting forces on the shaft [122].

The chosen mounting structure influences strongly the snow accumulation. Snow transport simulations that consider the system and local wind conditions are therefore recommended.

Preventive measures can be taken to avoid undesired **snow drifts**. If a site has a prevailing wind direction, snow fences can be installed in front of the PV arrays. These are designed to ensure that a significant portion of the snow transported by the wind is deposited far away from the modules [123]. Changing some parameters in the system design of the PV array itself can also minimise snow drifts but can have a negative impact on the power output of the system. Increasing the distance between the modules and the ground should reduce snow drifts without affecting performance, although probably at a higher cost for installation [123]. Reducing the slope and/or module tilt or changing azimuth to align the modules parallel to the wind direction should reduce snow drifts but also decrease the overall power output [123].

To predict how **snow losses** will affect the performance of a proposed PV project, or to forecast energy production, snow loss algorithms are required. For example, meteorological parameters that influence the removal (or shedding) of snow from PV module surfaces may be used to estimate array energy losses based on curve-fitting formulae from empirical correlations between measured array outputs and meteorological sensors [124]. Alternatively, threshold models employ simple limits based on the ambient temperature/ irradiance to predict snow sliding. Models are generally based on a foundation of free-body physics for snow sliding down an inclined plane but may also involve more complexity incorporating first principal energy balance equations to model melting and sliding. In a recent study by Pawluk et al. [125], 11 models were identified to quantify energy losses due to snow. Some were validated at multiple sites, while others remain relatively untested. Of these, the Marion et al. [126], [127], [128], Townsend and Powers [124], SunPower [129], and Andrews et al. [69] models seem to be the most documented in the literature. Comparison of different snow loss models using data from utility-scale arrays in partnership with O&M companies would be helpful to gain further experience on how snow loss modelling can be integrated into best-practice procedures. PV software can simulate array performance to a high degree of accuracy when irradiance, wind speed, ambient temperature and other data are provided. In this case, the primary challenge is not simulating the array output under snow-free conditions but rather finding a way to identify exactly when the array is covered. This may be accomplished by examining camera images, the performance ratio, or monitoring the output from inverters. However, snow effects must be clearly isolated from other confounding factors.

Compared to systems in moderate climates, at high altitudes or latitudes factors such as increased or low solar irradiance, high albedo, low ambient temperatures, and the potential use of bifacial modules require inverters to be sized differently. High latitude systems often experience a higher energy share at irradiances greater than 1000 W/m² than low altitude systems, while cell temperatures can be below STC (25°C). Depending on their specific situation, high-latitude systems might see either higher or lower relevant irradiance peaks. The higher the share of energy at irradiances above 1000 W/m², the smaller the DC/AC ratio (sizing ratio) should be chosen. For low latitude PV systems, the sizing ratio is often around 1.1 to 1.2. Especially for high latitude systems, the sizing ratio is normally chosen at 1.0 or even below. Besides the energy yield, the maximum short-circuit current capacity of the inverters should be taken into account when selecting the inverter for high altitude or latitude systems. As the maximum input short circuit current of an inverter must not be exceeded at any time, extra high irradiances must be considered when planning these systems. Measurements have shown peak irradiances exceeding 1600 W/m² for high-altitude systems.

4.4 Case studies: Bifacial system at high altitude and high latitude

4.4.1 Case study 1: Optimisation of winter yield in the Alps

This chapter provides an overview of various simulation results for bifacial PV systems conducted for an alpine location in Switzerland [130]. Key parameters such as Ground Cover Ratio (GCR), azimuth, module tilt, and Slope of Ground (SoG) were systematically varied and analysed (Figure 18 and Table *4*). The simulations were performed using the PVsyst software tool version 7.4.6.

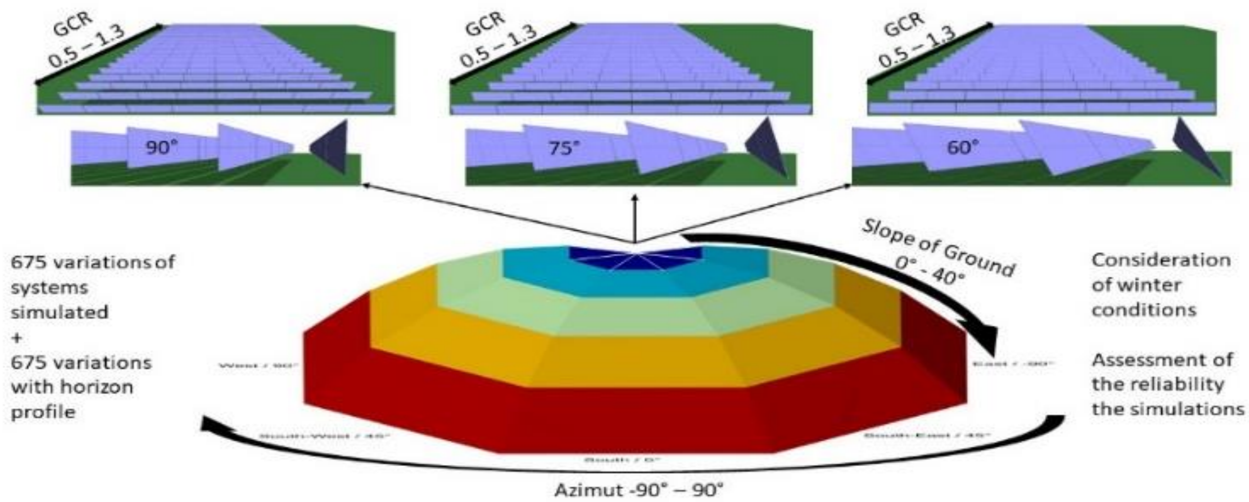


Figure 18: Systematic analysis of the System design.

A uniform PV system with adjustable azimuth, GCR, and SoG parameters was utilised for the simulations. The design consists of 10-module tables arranged in eight-table rows across 40 rows. The Swiss alpine location “Davos Totalp” at 2470 m.a.sl. was chosen as site for the simulation, using weather data of Meteonorm 7.3 and horizon profiles relevant to the simulations, but without considering the specific topography.

Table 4: Analysed parameters and parameter settings.

Simulation Batch	Horizon Considered?	GCR	Azimuth [°]	Module Tilt [°]	Slope of Ground [°]	Number of Simulations
1	Yes	0.5 – 1.3 (0.1; step size)	-90 – 90 (45; step size)	60, 75, 90	0 – 40 (10; step size)	675
2	No					675

The parametric study varies parameters from Table 4, with each combination simulated for one year at hourly resolution (675 simulations per batch). Each batch is also recalculated without a horizon profile for broader applicability.

Simulations using Meteonorm data show that the global irradiation in Davos Totalp is ~50% higher compared to typical Swiss location in the lowlands. Bifacial modules were utilised in the simulation, with albedo values set to 0.8 from November to May and 0.2 from June to October.

Simulation Results

To evaluate the performance of the configuration, the "specific energy yield" (kWh/kWp) and the "energy yield per area" (kWh/m²) were employed. Exemplary results for specific yield at an azimuth of 0° are presented in Figure 19. Similar analyses were performed for an azimuth of -45°/45° and -90°/90°. In all cases, the energy yield per area was included (not shown here).

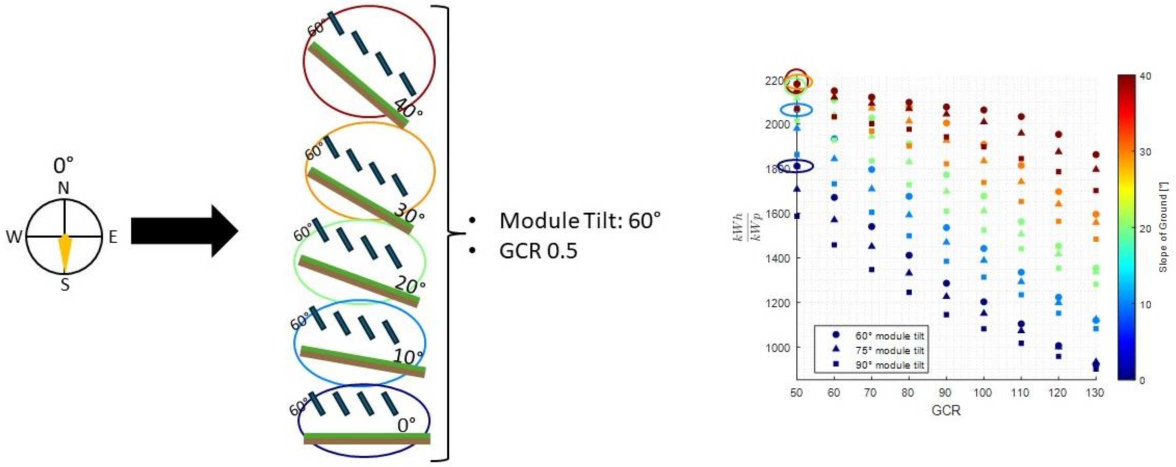


Figure 19: Simulation results for annual specific yield at an azimuth of 0°.

Higher SoG enables the use of an increased GCR without reducing specific yield due to the reduction of self-shading of neighboured module rows with increasing SoG. The highest annual yields were achieved with module tilt angles of 60°.

Figure 20 provides an overview of the systems with the highest and lowest shares of specific yield during the winter months (October – March).

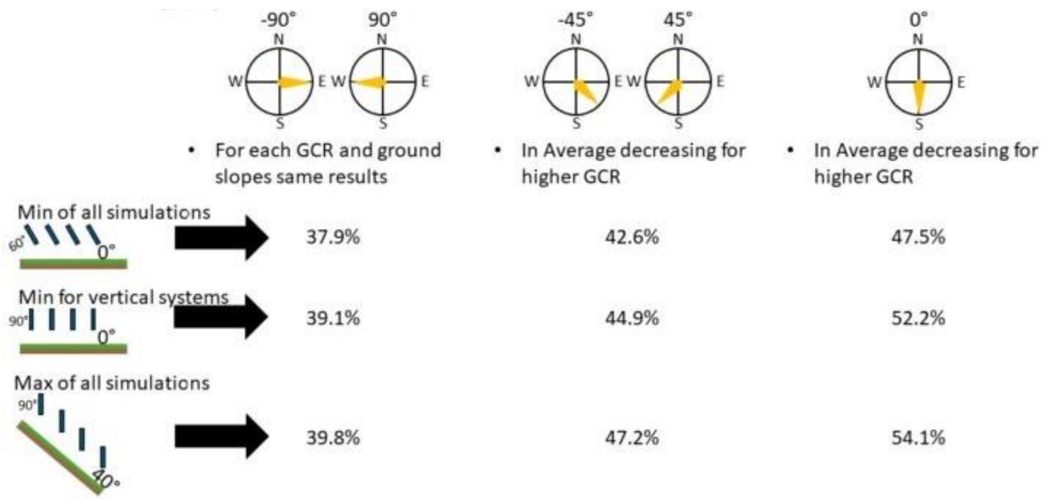


Figure 20: Winter energy yield percentages of the simulated systems.

The simulation results confirm the expected trend that systems oriented closer to the south orientation exhibit a higher winter share of specific yield. The highest winter share was achieved by a vertically installed system facing south with a ground slope of 40°. The annual yield maximum is achieved for a module tilt angle of 60° for south-facing systems.

4.4.2 Case study 2: Lessons learned from East-West facing bifacial PV systems at high latitudes

This chapter provides an overview of field experience with vertical bifacial systems at high latitudes, where the extreme sun angles and long winter months are to be taken into account.
The vertical East-West configuration has the advantages of potentially catching the light under low sun elevations and a wide range of solar azimuth angles in the summer as well as the reflected light from snow covered ground and minor snow coverage of modules in the cold seasons.
Studies show that PV systems with vertical East-West mounted bifacial modules has virtually the same annual production as south-facing latitude tilted bifacial modules, but with an energy production profile which matches better the typical grid load profiles [131]. The paper of E. Tonita [132] describes how row spacing affects system performance comparing southfacing fixed-tilt, horizontal single-axis tracked, and East–West vertical configurations for North American locations at latitudes of 17˚N up to 75˚N.

Figure 21 shows an example of a vertical east/west bifacial pilot system built in Northern Sweden where snow depth typically does not exceed 1.5 meters, but is present for a long period of the year [https://sunnagroup.com/en/project/lilla-norrskenet/].

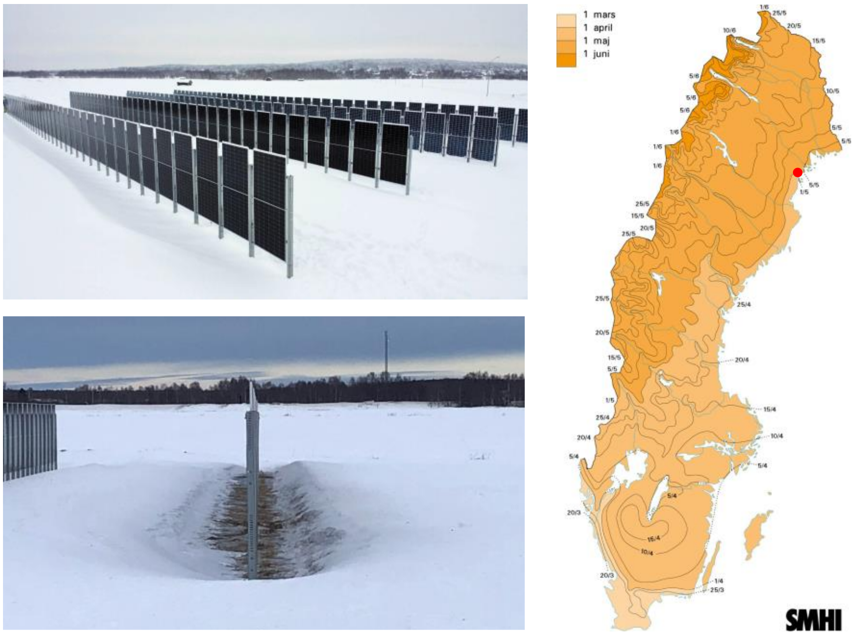


Figure 21: ***Vertical bifacial 90 kWp PV system (Lilla Norrskenet) in Northern Sweden with pictures showing natural snow accumulation around the vertically mounted PV modules and the map of the last day of snow cover in Sweden from the SMHI (Swedish Meteorological and Hydrological Institute).***

The system aims to study the potential for electricity production and profitability of large vertical solar parks in Norrland (Northern Sweden region) in conjunction with hydropower stations of the region and to test the mounting configuration and related snow losses and gains under real operating conditions.

The vertical configuration offers clear advantages due to its resilience (natural shedding) against snow-related losses. However, it introduces new challenges in mounting structures, particularly regarding wind loads and snow drifts. Vertical panels can create wind barriers, causing snow to accumulate on the ground near the base of the system. Over time, the drifted snow can become substantial and may block sunlight from reaching the lower sections of the panels or nearby rows in a solar farm. Local snow depths and wind conditions must therefore be well known. Figure 21 shows an example of how, under optimal conditions, the vertical configuration favours the snow accumulation away from the modules due to wind scouring caused by aerodynamic snow drift effects. The pilot system combines strings with East-West and West-East orientated bifacial modules of high bifaciality (>80%). Figure 22 shows the energy production during two different days of the year. The production curve follows the consumption demand with peak in morning and afternoon and with highest production at times with generally higher electricity prices. Shading losses are observed. This leads to a slightly lower power production compared to a closeby south facing tilted power plant, but with production starting earlier in spring.

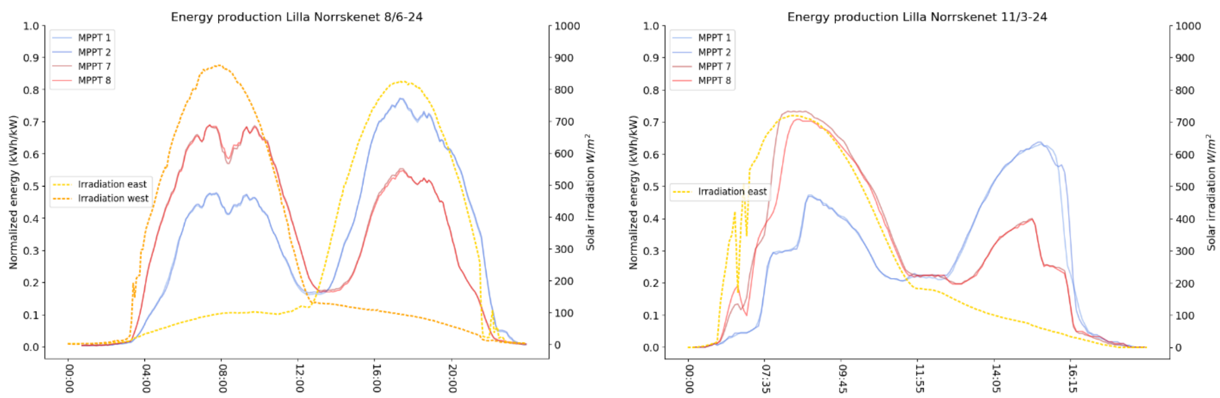


Figure 22: Daily production profile of 4 strings within summer (left) and winter (right) of solar parks in Norrland, Sweden.

Figure 23 on the left shows a detail of the mounting frame of the pilot system. The vertical configuration of half-cut cell modules, with junction boxes and cables in the centre, encourages snow accumulation. In addition, snow tends to accumulate along the lower edges of the frames. Both issues contribute to electrical loss and potential structural damage if the frames and cable routing are not properly designed. The landscape configuration together with the use of unframed modules would mitigate electrical losses caused by snow, but little experience is available in such environments.

Figure 23: Portrait (vertical) mounting configuration in pilot system compared to landscape (horizontal) configuration.

In general vertical racking systems are more expensive and less readily available but are gaining traction with new products emerging on the market and the more recent adoption of vertical configurations in agrivoltaics. On the right, Figure 23 provides an example of a horizontal mounting configuration for frameless modules from Next2Sun.

5 OPTIMISATION OF MODULE/SYSTEM DESIGN FOR HOT & DRY CLIMATES

Hot & dry climates offer large areas with high solar irradiation levels. These have led to the increasing development of large-scale projects in regions such as the Middle East, North Africa, North India, and the Atacama Desert, which currently stand out as new industry hotspots. Despite the many advantages, the installation of PV power plants in hot and dry regions also presents drawbacks. For example, the high temperatures and dusty conditions typical of these environments can dramatically decrease the performance of solar systems.

5.1 Hot & Dry climates

Hot and dry climates such as deserts are characterised by high temperatures and scarce rainfall. In this environment, modules can heat up to challenging temperatures well above standard testing conditions. With hot days and (relatively) cold nights, modules can also undergo severe thermal cycles. In addition, these regions receive exceptionally low precipitation, typically less than 250 millimetres per year. This low precipitation, coupled with high temperatures, leads to high evaporation rates which further amplify aridity.

According to the Koppen-Geiger Classification, arid and semi-arid conditions are subdivided in four categories depending on the typical temperatures, namely BWh, BWk, BSh, BSk.

- BWh (Hot Desert Climate) represents the hottest and driest of the four climate categories. Examples of BWh environments are the Sahara Desert in North Africa or the Simpson Desert in Australia. BWh climates experience scorching year-round temperatures, with average monthly temperatures exceeding 18°C. Rainfall is extremely scarce and highly erratic. While these regions are characterised by high solar insolation throughout the year, the lack of reliable rainfall and the presence of dust storms can pose challenges for solar panel maintenance and efficiency.
- BWk (Cold Desert Climate) experiences relatively colder winters compared to BWh. This climate is typically found at higher latitudes or in continental interiors, further from moderating influences of sea and oceans. The Gobi Desert in Mongolia is an example of this category undergoing a high variation of thermal cycles. Precipitation remains scarce throughout the year, though snowfall may occur during the colder months. Here, solar energy production can be significant during the long hot summers. However, winter performance will be lower due to shorter daylight hours.
- BSh (Hot Semi-Arid Climate) showcases hot summers and mild to warm winters. Regions with such climate, like the Great Plains of North America or the grasslands of central Asia, experience more precipitations than deserts, but it is still insufficient to support extensive tree growth. Grasses and shrubs dominate the landscape, providing sustenance for grasing animals. BSh climates offer excellent potential for solar energy generation, thanks to the high solar insolation during the extended summers and the minimal dust concerns. However, careful consideration of seasonal precipitation patterns may be needed to optimise system design and ensure proper drainage around panels.
- BSk (Cold Semi-Arid Climate) experiences hot summers, but considerably colder winters. Examples are the Patagonian steppes in South America or the Eurasian steppe region. Precipitation remains low throughout the year, limiting tree cover and favouring grasslands. Compared to BWk climates, winters are less severe, allowing for a wider range of plant and animal life to thrive. While solar energy production will be lower during colder months in BSk regions, it can still be a viable option.

Figure 24 and Figure 25 show a correlation between the Köppen-Geiger-Photovoltaic classification introduced by Ascencio-Vásquez et al. [7] with the latitude, ambient temperature and irradiation. It is observed that, as expected, the steppe and desert areas, where ambient temperature and irradiations are considerably high, are mainly located between latitudes of -40 and +40 degrees.

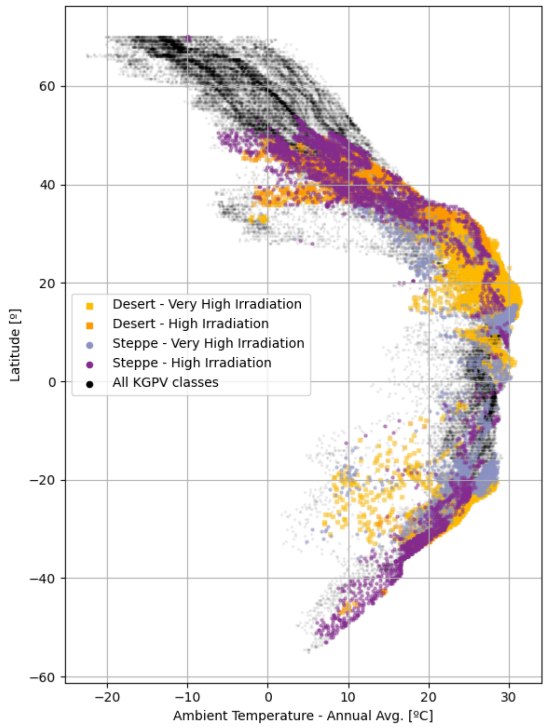


Figure 24: Correlation of KGPV climate zones with annual average temperature highlighting the Desert and Steppe climate zones.

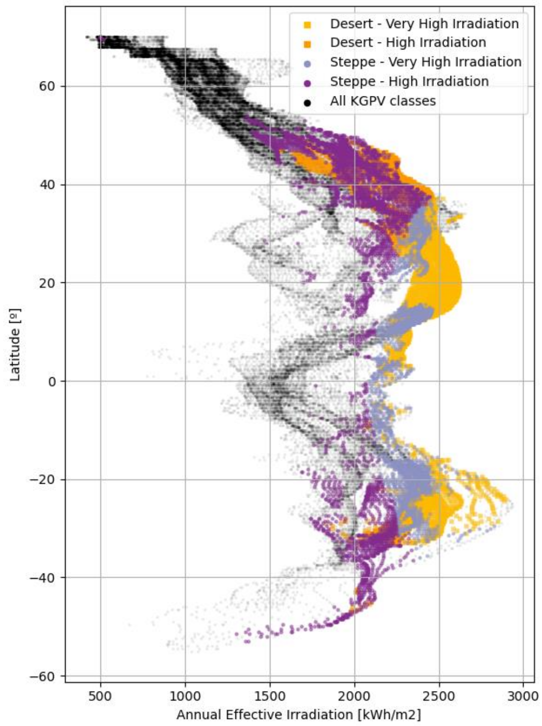


Figure 25: Correlation of KGPV climate zones with annual effective irradiation highlighting the Desert and Steppe climate zones.

5.2 Stressors and typical problems (hot & dry)

Physical, chemical, mechanical, or biological phenomena can produce adverse effects on one or multiple Key Performance Indicators (KPIs) of PV power plants. Stressors specific to the Hot and Dry climates are shown in Figure 26 and are categorised into three distinct groups: main stressors, site-specific stressors, and low probability high impact events. Main stressors, such as soiling, high temperatures, and thermal cycling, persistently manifest in hot and arid climates. Site-specific stressors, such as intense UV irradiation, strong winds, and windborne sand, appear in some locations but are absent in others. For example, in coastal desert regions (e.g., parts of the Arabian Peninsula or Northern Chile), salty mist may be present and contribute to corrosion and soiling. The last category groups events like strong winds and dust storms that may have severe or even catastrophic effects.

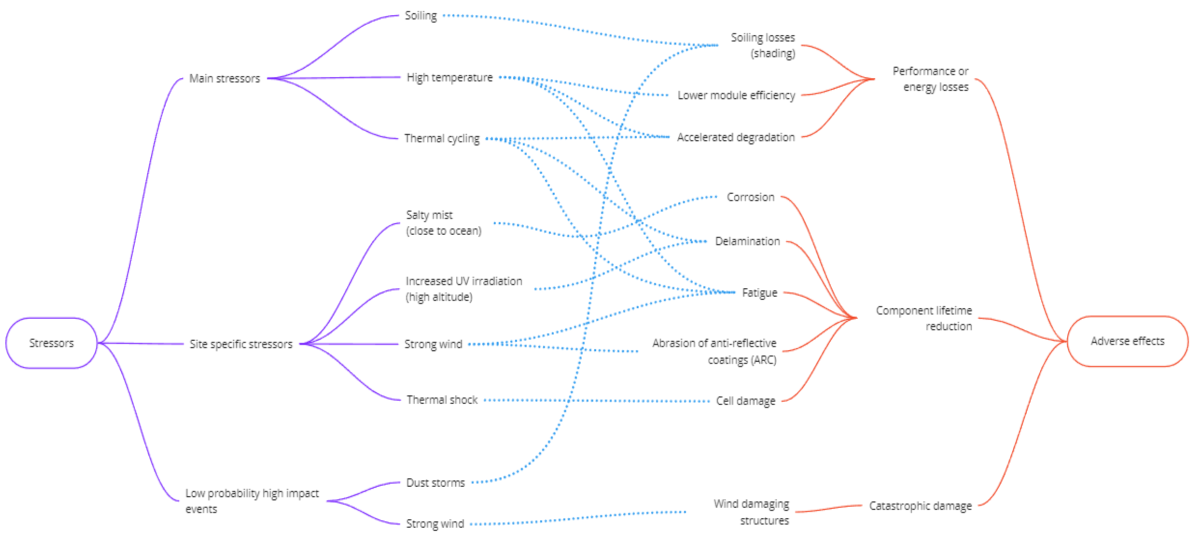


Figure 26: Stressors and corresponding adverse effects for PV power plants in hot & arid climates.

5.2.1 Soiling

Soiling refers to the accumulation of dust, dirt, and other particles on the surface of PV modules. This contamination reduces the energy conversion and can also cause partial shading, leading to permanent damages in case of hot spots. A previous IEA PVPS TASK 13 report provides detailed information on both soiling losses and mitigation strategies [133].

The losses due to soiling can be particularly significant in the Hot & Dry climates, because of the increased resuspension of dust and sand from arid soils and the lack of regular rainfall events. For example, Li et al. [134] reported annual soiling losses as high as 20% in Egypt and 15% in Saudia Arabia, while most global locations experience losses closer to 5% or less. According to a different estimate, losses can be as high as 35% in Hot & Arid locations of North Africa and Middle East [135]. These can have substantial economic repercussions in heavily soiled locations, since one must consider both the missed revenues due to the energy loss as well as the increased costs for operation and maintenance. A report by IRENA indeed showed that preventive maintenance and module cleaning can make up to 75%-90% of the total operation costs [136].

As discussed in chapter 5.3.3, given the substantial impact of soiling, planning cost-effective mitigation strategies at the early stages of power plant design is crucial.

5.2.2 High Temperatures

High ambient temperatures, coupled with high irradiance levels cause the operating temperature of PV modules to rise. Depending on the temperature coefficient of the solar cell technology, this results in higher or lower efficiency and performance losses. Very high temperatures can also lead to accelerated ageing and increase material fatigue.

On top of the short- and long-term impacts on PV modules, high temperatures will also affect inverters. Above certain temperatures (i.e., 45°C to 60ºC), indeed, depending on the manufacturer and inverter design, the inverters will start limiting the power conversion to prevent further damage to the power electronic devices. Figure 27 shows a real example of central inverters running in Texas, USA, where ambient temperatures can reach 50º Celsius, forcing the inverters to downtime for safety reasons.

Experience also shows that high temperatures, and extreme temperature cycles (discussed in the following section) can induce failures into batteries, which can cause may cause tracker malfunctions or blockages, introducing additional performance losses.

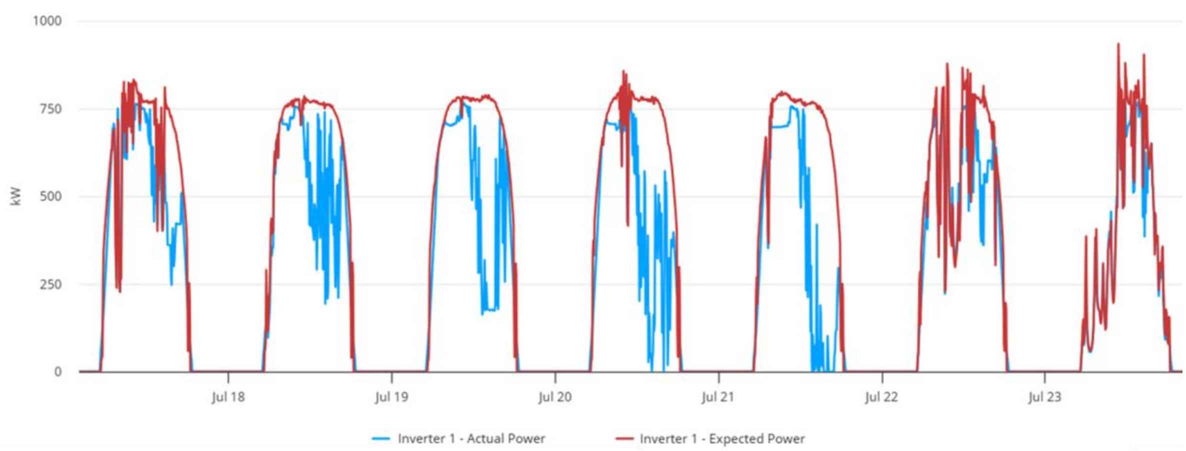


Figure 27: Visualisation of measured and modelled active power of an inverter suffering from strong thermal derating (Source: Univers).

5.2.3 Thermal Cycling

Thermal cycling refers to high temperature variation, which induces thermo-mechanical stresses in the structure of PV panels. Due to very hot operating temperatures during the daytime and quite low temperatures at night, PV modules and structures in Hot & Dry climates experience mechanical stresses that can lead to delamination and material fatigue. Adothu et al. [137] listed several failures that thermal cycling can induce in desert climates due to the different thermal expansion coefficients of PV components. These include, for example, finger and interconnect breakage, ribbon interface and cell cracks, and delamination [138].

5.2.4 Salty Mist

In addition to these chronic stressors, PV power plants in hot and dry climates occasionally face site-specific stressors. Many of these climates are found in coastal areas, where the atmosphere is rich with various salt components. Near the sea, salty mist induces high humidity every night. For example, the relative humidity can be higher than 90% in the Arabian desert, while the Atacama Desert experiences nearly 100% relative humidity due to the Camanchaca, a daily west-east wind from the sea. This moisture, combined with fine dust containing a high salt concentration leads to detrimental corrosive reactions [139].

High humidity can favor the ingress of water vapor in the modules, and this can deteriorate the electrical insulation and degrade other components [137]. Additionally, salt-mist can corrode PV systems components, e.g., frames, mounting system and silicon adhesives that seal the edges of the PV modules [140]. Furthermore, research suggests salt mist can accelerate degradation processes such as potential-induced degradation (PID) due to erosion and penetration of salts (e.g., sodium ions) into the encapsulant, so far just tested at small scale under experimental conditions [140], [141].

Salty mist can also worsen the soiling loss. Kazem and Chaichan [142] conducted a study of six sites in a coastal area of Oman, where the composition of dust particles showed high concentrations of sodium salts, calcium, and magnesium oxides. They found that, due to the high relative humidity at night, a layer of dew formed, reacting with dust components on the surface of PV modules and dissolving the salts. This enabled the salts to enter cracks, and, after the water evaporated after sunrise, the remaining salt and sulphates formed a solid layer adhering to the surface. This layer prevented sunlight from reaching the cell and increased its temperature.

5.2.5 UV Irradiance

UV radiation significantly impacts the degradation of polymer materials in PV modules. The ultraviolet (UV) region, spanning from 280 to 400 nm, accounts for approximately 4.6% of the total solar power under reference conditions. Despite this small fraction, UV photons possess high energy capable of causing significant damage to polymeric materials used in PV modules. High-energy UV photons, particularly in the UVB range (280–315 nm) cause bond scission, breaking down carbon-carbon and carbon-oxygen bonds within the polymer chain [82], [143], [144]. This leads to the formation of free radicals and subsequent auto-accelerated photo-oxidation. As a result, embrittlement and discolouration of the affected polymers can be observed. Although UVB constitutes only about 1.5% of the UV region's power, its impact on polymer degradation is more pronounced compared to UVA (315–400 nm), which makes up about 98.5% of the UV power [82]. Additionally, UV-induced degradation can cause surface cracking and delamination, further compromising the module's performance and durability and leading to issues such as moisture ingress, reduced electrical insulation, and potential structural failures [145], [146]. To mitigate these effects, manufacturers incorporate UV stabilisers and absorbers into polymer formulations, develop advanced materials with better UV resistance, and apply protective coatings [147], [148], [149].

PV degradation may be accelerated by the detrimental mix of high-ultraviolet solar radiation dosage in combination with damp heat, or with salt mist or aggressive thermal cycling, which can cause degradation of materials of such PV panels not adapted to harsh conditions [150].

In addition to polymer degradation, UV radiation can also affect the solar cells. Recent evidence suggests that newer generations of solar cells are increasingly susceptible to UV-induced degradation, because of higher vulnerability to UV deterioration of the passivation layer, compared to conventional aluminum back surface field cells [137], [151].

5.2.6 Strong Wind

Strong wind load can occur in locations such as the Atacama Desert, where surface winds can reach speeds above 8 m/s in summer and autumn, and between 11 m/s and 13 m/s in winter and spring [139]. This wind load has two paramount impacts. First, it favours the transportation and the deposition of soiling (and potentially of chemical components from nearby mining infrastructures for example). Second, it causes strong mechanical-load-stress and vibration, especially on the tracking systems, which can lead to damages and failures. Depending on the design, however, trackers can be used to move PV modules into a stow positions to reduce such loads [152].

5.2.7 Dust and Sandstorms

Hot & arid locations can also be subject to frequent dust and sandstorms, whose effects on PV power plants are thoroughly discussed in this report. In these events, a large amount of sand and dust is suspended, and can have a double effect on PV modules. First, the suspended particles lower the visibility, therefore reducing the intensity of the surface irradiance. The drop in irradiance is particularly intense for the direct component, with attenuations in direct normal irradiance (DNI) that can be as high as 80-90% [153]. The repercussions on the global horizontal irradiance are lower but can still result in substantial performance losses at both local and national scales [154]. Second, if the particles deposit on the PV modules, exceptionally intense soiling losses can be experienced, which could require extraordinary cleaning efforts. Furthermore, one should consider that dust and sandstorms can contribute to if not even accelerate the abrasion of coatings deposited on the PV module surface [155].

5.3 Best practice and mitigation strategies (hot & dry)

5.3.1 Site Assessment

In the following section the assessment of soiling, one of the main stressors in hot & arid locations, is presented.

If soiling losses are known beforehand, their energy and economic impacts can be included in the preliminary analysis of a site for a new PV installation, along with the expected mitigation expenses. Also, as later discussed in 5.3.3, the system can be designed to reduce the soiling accumulation rates, and to facilitate cleaning operations. An early assessment of the soiling loss and mitigation profits is especially important as experience shows that if cleaning budgets are defined based on standard values, O&M operators might have a hard time ensuring top performance of the asset while staying within their (usually very small) budgets. Due to the nature of contracts signed it is usually very difficult to increase the budget locking the plant in a suboptimal solution.

In this phase, soiling can be assessed in different ways. First, experimental campaigns can be put in place by deploying specific soiling sensors to the location of interest. Several sensors, based on different technologies are commercially available, and have been discussed in a previous IEA PVPS TASK13 report [72]. However, at least 6 months (ideally 12) of data are necessary for a preliminary assessment, which might delay the site selection and assessment process. Another option consists of estimating soiling at a location using the losses measured at nearby sites. Several spatial interpolation techniques can be used for this purpose, depending on the number, the distance and the geographical distribution of the available sites [156]. However, this approach can lead to significant errors if only few data are available, and if the climate, the geography, or the configuration of the sites differ substantially. Research also indicates that this approach is unreliable if only a single site is available more than 40-60 km from the location of interest [157].

Alternatively, soiling losses can be estimated through the analysis of historical environmental data. The literature offers several soiling estimation models, which have also been described in a previous IEA PVPS TASK 13 report [72]. These include the HSU model [158], which is readily available in the pvlib python library [159]. Models can be fed with local ground monitoring data or with satellite or reanalysis derived data, depending on the availability [160]. Additionally, commercial providers can offer tailored soiled estimations based on such data. This approach allows reducing the time needed for the site assessment but the uncertainty associate with this estimation is higher compared to that offered by a well-maintained soiling sensor. However, this approach also offers a longer-term perspective on the soiling losses, as the estimation is typically based on multi-year datasets, rather than on a shorter experimental campaign, allowing a better understanding of soiling seasonality and inter-annual variability.

Once soiling is estimated, a preliminary cleaning schedule, and, therefore, the associated costs, revenues and technical requirements (e.g. minimum row spacing), can be defined. Nowadays, mechanical cleanings are still the most common strategy to tackle soiling [161]. Since they have a cost, a cleaning optimisation process must be conducted to find the most cost-effective cleaning schedule. This involves determining the ideal frequency and methods for cleaning to maximise the difference between the additional revenues due to the increase in energy output after cleaning and the cost of cleaning. An adequately planned cleaning schedule is typically profitable, meaning that soiling mitigation represents an investment rather than a solely maintained task. A cleaning optimisation process typically follows the steps depicted in Figure 28.

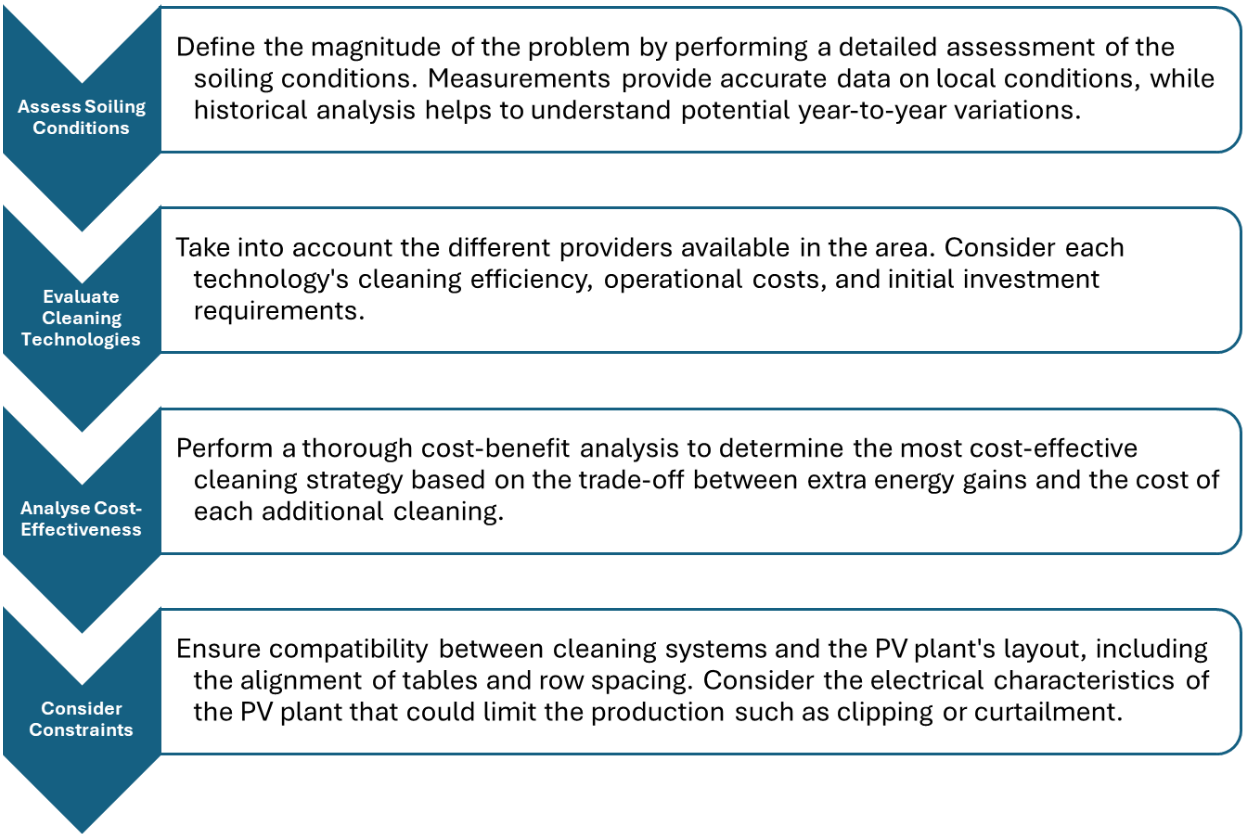


Figure 28: Recommended Cleaning Optimisation Process (Source: PVRADAR).

Soiling is typically quantified through the soiling level, defined as the percentage of potential energy production lost due to light blockage by dust [162]. Typically, the monthly average soiling levels, also referred to as soiling loss factors, are required inputs for every energy yield simulation. The general accepted soiling model suggests that the loss level gradually increases over time and abruptly drops when artificial or natural cleanings occur. The daily variation in soiling levels is represented by the soiling rate. While this rate can often be approximated to a linear trend, it can also change seasonally driven by the interplay of dry and wet weather patterns. For example, a soiling rate of 3% per month - or 0.1% per day - implies that an initially cleaned module will reach a 3% soiling level at the end of the month if no rain or mechanical cleaning occurs. Conversely, as shown in Figure 29, if cleaning does take place, the soiling level rapidly decreases and then starts raising again. The area in between the red and the blue line, multiplied by the energy yield, expresses the energy gain achievable through cleaning. If multiplied by the electricity price, this returns the economic value of cleaning.

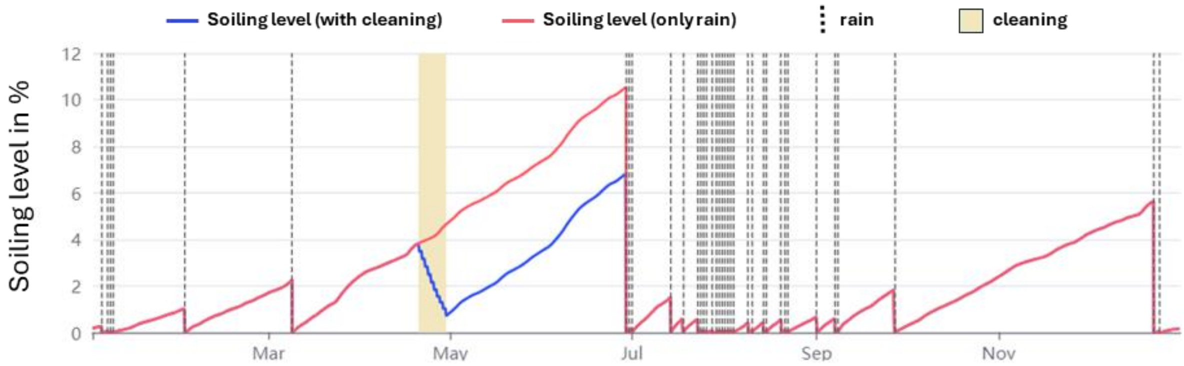


Figure 29: Example of soiling levels with and without artificial cleaning, simulated with PVRADAR software. A longer dry period stretching from March to July is followed by two months of frequent rain. The blue line shows the soiling level if the systems is cleaned in April by the O&M team. The red line shows the soiling level if no artificial cleaning is performed (Source: PVRADAR).

In addition to evaluating the energy and economic losses due to soiling, cleaning optimisation requires the understanding of the cleaning costs. These depend on the size of the PV power plant and on the cleaning technology. The latter is mainly influenced by the technical specifications of the machines, such as cleaning speed, water, fuel consumption, and cleaning efficiency. However, the choice of the cleaning technology might not be solely based on its economics, as it must consider its compatibility with the installation environment, the operational needs and the available resources, such as manpower and water. The market offers a diverse range of cleaning technologies, from tractors equipped with rotating brushes suitable for both dry and wet cleaning, to semi and fully autonomous cleaning robots.

5.3.2 Optimisation of module design and BOM

The high temperatures experienced in Hot & Arid locations worsen the performance of PV modules, whose thermal degradation is expressed through the temperature coefficients (performance drop per increase in operating temperature). Different module types have different temperature coefficients, meaning that some technologies could therefore be more suitable for application in hot & dry environments (see chapter 3.3). In addition, several solutions have been proposed, such as heat spreading plates, air cooled fins, phase change materials [163], to actively or passively cool down PV modules, but are not yet used in large commercial applications.

In addition to initial failure modes that lead to a rapid drop in performance at the beginning of the service life of PV modules, performance losses due to progressive aging and degradation of materials/components ("midlife failures") determine the long-term stability and profitability of PV systems in specific climate regions [164], [165]. Therefore, artificial accelerated aging tests that simulate this aging-related degradation of PV modules under specific (e.g. hot and dry; arid) stress conditions are needed to enable climate-specific development of new PV module designs, components and innovative material [166], [167]. Accelerated ageing test for hot and dry conditions ($T_{chamber}$ = 95°C, RH = 50%, 1200 W/m^2 Xenon irradiation = simulated sunlight) result in severe electrical degradation. Significant correlations were found between the material changes - as indicated by the spectral measurements - and the electrical power loss of the test modules during climate-specific ageing. Another test approach is the combined-accelerated stress testing (C-AST), proposed by Hacke et al. [11], that also includes a test sequence for desert environment and was successfully validated by reproducing failure modes from the field like backsheet cracking [168].

As the main stressors – apart from soiling - in arid regions are high temperatures, high temperature differences, and increased irradiation levels at low humidity levels, accelerated ageing tests combining these stressors are used. Climate specific failures and degradation effects observed in PV-plants in hot and dry areas are mainly related to the cells and busbars (29%), followed by glass (22%), junction box (15%), encapsulant (11%) and backsheet (8%) [164], [165]. By comparing these findings with the results of specific accelerated ageing tests [169], [170], it can be demonstrated that additional irradiation had a strong influence on the degradation of power and materials. High irradiance doses (simulated sunlight 1200 W/m^2) caused high module temperatures and resulted in enhanced stress for the polymeric materials: the backsheet material (PET) showed high colour change, embrittlement and cracking, the encapsulant (EVA) exhibited high UV-Fluorescence paired with chemical degradation as detected in the pronounced formation of (corrosive) acetic acid. The IEC TS 63126:2020 standard describes methods to calculate an estimated annual module temperature distribution, depending on location and mounting conditions [171], [172]. If the 98th percentile of the distribution (T98) is between 70° and 80°C (Level 1) or between 80° and 90°C (Level 2), different test modifications in [32] and [173] test protocols are recommended. For T98 exceeding 90°C, no material combinations are known to mitigate failures in modules induced by such high temperatures. The encapsulation degradation results in subsequent corrosion effects and cell problems and electrical degradation. Direct evidence for the formation of acetic acid and lead-acetate in the encapsulant EVA was found by TD-GC/MS and FTIR-measurements of the encapsulant of the test modules after storage in the arid accelerated ageing test [170], [174]. Formation of increased amounts of acetic acid in the encapsulant was always paralleled by strong UV-F and mainly triggered by high irradiation doses which caused increased module temperatures. For TPO and POE no such corrosion effects were observed up to now [175]. Polyolefin encapsulation materials TPO and POE show great potential to be a valid replacement for EVA for hot and dry climates.

As PV modules without permeable backsheets (glass/glass-types) lead to an accumulation of acetic acid within the EVA encapsulant, the corrosion effects are even stronger with this module type. However, when polyolefin encapsulants are used, also glass/glass modules are applicable.

PV panels are typically designed for standard test conditions, and these might not adequately account for harsh desertic conditions. This is the case, for example, of the intense UV radiation present in desert environments. In the Atacama Desert, the total UV annual dosage reaches approximately 175 kWh/m²/year [139], while in the Negev Desert it is around 120 kWh/m²/year [176], values substantially higher than those considered in current testing standards. For example, IEC 61730 includes a UV dose of 60 kWh/m²/year, and IEC 61215 applies a dose of 15 kWh/m²/year [139][176]. Similar considerations have been reported for the temperature fluctuations, whose typical values in the desert climates are not adequately reproduced in the IEC 61215 [176].

After assessing the main degradation mechanisms, Adothu et al. [137] recommended, for desert applications, the development of modules with low-temperature coefficients, high efficiency, and stability under both high UV light and elevated temperatures. Additionally, they highlighted the need for thermally and UV stable back sheets and encapsulants, free of acetic acid groups and with low water vapor transfer rates. However, it should be noted that the module selection is typically taken on the procurement level, depending on price, availability, quality, compliance and contracts. This means that, even if optimal modules for a given site were available, it might be difficult to install them there, for example because of pre-existing long-term contracts with other suppliers.

5.3.3 System Design

The design of PV systems in hot & arid locations must consider the effects of the various previously mentioned harsh stressors.

As described in 4.3.1, a first cleaning optimisation analysis should be performed during the site assessment phase. This must be reviewed during the design phase and then later during operation. The key task during the system design phase is to (i) identify how the system configuration (i.e., tilt angles, tracking, etc.) affects the soiling accumulation, and (ii) facilitates the cleaning operation. Indeed, the selected cleaning technology might require specific changes in the layout of the power plants. In addition, one should always try to minimise the time needed by the O&M team to operate, for example considering the distance between the combiner boxes and the roads.

Fully autonomous cleaning robots, for instance, require precision in solar tracker alignment to meet strict tolerance levels, as well as adequate space for docking stations and rails. Similarly, considerations for cleaning tractors include ensuring adequate row-to-row distance, sufficiently levelled terrain, and sufficient space for turning around. It is very important for project developers to discuss these requirements as early as possible with the EPC contractor and structure OEM to avoid any mismatch. Sometimes increasing the row-to-row distance a little bit might result in much lower cleaning cost even if it requires a slight increase in CAPEX.

When cleaning modules, it is vital to handle them with care, especially when using water. Spraying cold water on hot modules can cause thermal shock, potentially damaging the modules and voiding the module guarantee. To mitigate this risk, some cleaning providers might heat the water, operate during cooler nighttime hours or employ dry cleaning methods that prevent damage and preserve module warranties.

In some areas, water may be scarce or its usage restricted due to competing demands, particularly from local agricultural communities. Transporting water over long distances can be both costly and environmentally unsustainable. Additionally, if the available water has high hardness, it may require treatment before use to avoid leaving residues on the modules. In such cases, evaluating the feasibility of dry-cleaning methods may be advisable, even if they offer slightly lower cleaning efficiency.

Beyond technical considerations, the crucial strategic question is the business model: the power plant could either purchase and operate the cleaning system or contract a cleaning service provider. The "buy and operate" model typically involves a substantial initial capital expenditure (CAPEX) but can lead to reduced operational expenses (OPEX), thereby allowing more frequent cleaning which might optimise performance. Conversely, the "service" model offers greater flexibility in resource usage.

In some cases, the DC side of the power plant can be oversized compared to the size of the inverter (*inverter undersizing*) to mask DC losses as those due to temperature, degradation, and soiling. When the energy produced by the DC side of the power plant is greater than the inverter size, “clipping” takes place [177]. During clipping, the excess DC energy is not converted into AC. Therefore, DC losses are not visible on the AC side during clipping if they do not exceed the difference between the energy rating of the modules and the inverter's capacity (Figure 30) [178]. However, inverter undersizing might not always completely mask the losses, leaving the need for additional mitigation actions, as shown for soiling losses occurring in the U.S. [179]. In addition, as the system ages, clipping becomes less frequent and, thus, a less effective loss mitigation strategy. Furthermore, it is always important to regularly monitor the performance of the inverter to detect any sign of temperature-induced inverter derating. Additionally, it should be considered that clipping can induce higher operating temperatures [180], which may lead to higher degradation rates.

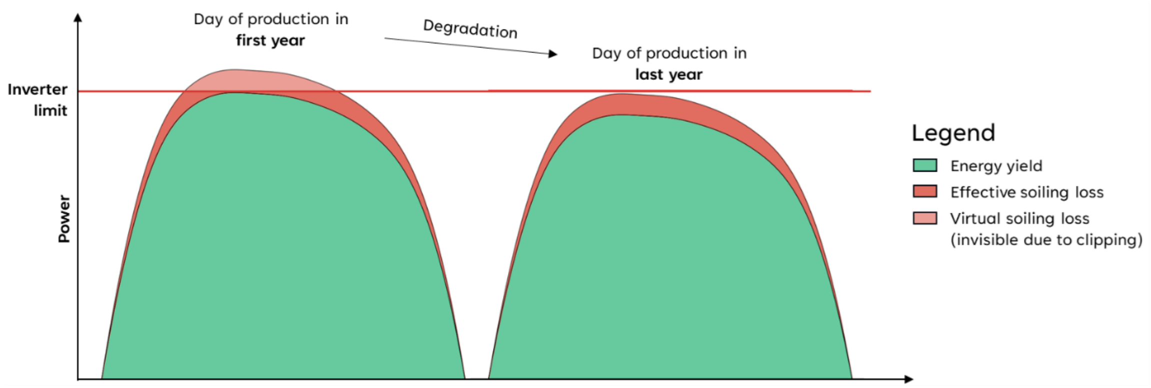


Figure 30: The effect of inverter clipping on soiling losses. (Source: PVRADAR)

The PV system design and installation methodology is a challenge in desert areas also due to hard soil corrosion. Corrosion generated by electrochemical interaction between soil and steel has become one of the biggest challenges for many PV plants during construction. This problem raises serious concerns both in the acquisition of existing assets and in the development and maintenance of new facilities. The foundation of the panels using steel profiles is the most common approach worldwide due to its low cost and quick installation, and it works well if the slow thickness loss of metallic coatings and steel under the surface is considered. Therefore, an appropriate soil study must be conducted during or even before the design phase to plan an adequate mitigation strategy. In general, the industry should review at which rate corrosion is occurring and how it will affect the metal infrastructure and, in the long-term, their asset.

In addition to corrosion, the soil hardness also makes the installation of structures on the ground very difficult, increasing CAPEX during the PV project construction phase as pre-drilling can induce many design challenges during the installation of the foundations. Not considering or investigating this ahead of time can lead to significant cost increases, time delays, and, subsequently, liquidated damages.

The strong winds occurring in some hot & arid locations can pose significant loads on the systems. Therefore, when designing PV systems for desert conditions, it is essential to engineer structural solutions that can withstand the mechanical stresses imposed by strong wind loads, particularly on tracking systems. In the current hyper-competitive solar market, tracker manufacturers are forced to take risks to be competitive and this can lead to reckless designs [181]. Wherever possible, smart tracking solutions can be put in place to reduce the wind load by stowing the PV panels when wind speeds exceed predetermined thresholds. wind sensors and automated stow strategies to reduce the risk of wind-related damage. However, these measures, along with the installation of anemometers, are not necessarily sufficient as wind-induced failures have often been reported due to poor implementation, misconfigured thresholds, or communication issues [152].

One should consider that any mitigation efforts will require proper monitoring as a first step. This can be realised through specific measurements done by the O&M team, which might be effective, even if slower, less systematic and potentially more expensive, than automatic sensors. In addition, operators may be prone to occasional human errors, particularly when involved in routine or monotonous tasks. On the other hand, sensors may sometimes provide inaccurate reading, such as when dust accumulates on pyranometers, and therefore require careful and regular maintenance.

5.4 Case studies: Cleaning strategies for Southern Spain and Negev Desert.

This section presents two examples of cleaning optimisations: one in Southern Spain and one in the Negev desert (see Figure 31). The process is performed using PVRADAR and starts with the definition of the most likely soiling conditions for each PV plant. This estimation is made through the analysis of the historic environmental conditions for the period 2002-2022 and of the geometrical characteristics of each facility. Subsequently, the impact on energy and revenue of multiple cleaning scenarios are assessed.

Figure 31: Location of the example projects for the two case studies.

In these scenarios, different cleaning technologies are considered, from wet and dry-cleaning tractors to full or semi-autonomous robots. For each technology, technical characteristics and representative costs have been defined based on the products currently available on the market. For each site, the result is a cleaning strategy that yields the maximum economic benefit at minimal cost.

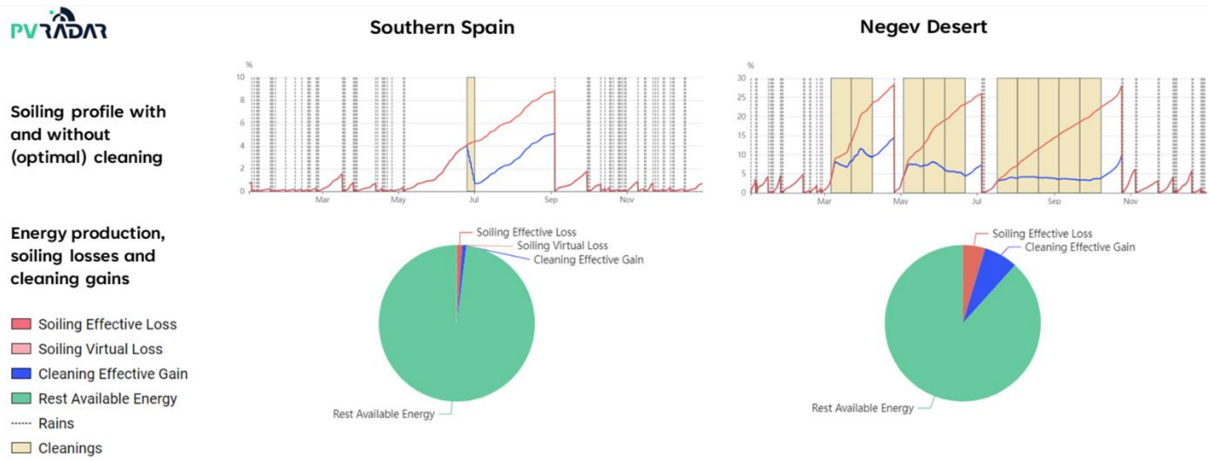


Figure 32: Direct comparison of optimal cleaning strategies for both sites, for one particular year. The exact cleaning dates (and number) changes depending on the expected rain patterns. "Virtual" gains and losses refer to energy that is lost due to inverter clipping. (Source: PVRADAR)

The cleaning optimisation, whose results are summarised in Figure 32, returns that a single wet tractor cleaning during the summer, performed by an external cleaning service provider, is the most cost-effective approach in Southern Spain. In this region, the low cleaning frequency yields modest economic benefits. In contrast, the Negev Desert demands a more intensive cleaning strategy due to its harsh environment. In this example, the plant invests in three cleaning tractors, enabling it to lower the cost per cleaning compared to relying on external services and to utilise the equipment year-round for a significant increase of revenue after cleaning cost.

5.4.1 Case Study 1: Southern Spain

The 30 MWp project is located in the Southern region of the country, exposed to long hot and dry summers, followed by a higher frequency of rainfall in winter. The area enjoys abundant irradiance, exceeding 1,800 kWh/m^2 per year.

Soiling has a seasonal behaviour, influenced by dust storms and olive harvesting. Historical analysis shows low to medium soiling, with an average annual loss factor of 1.3%. During winter, soiling remains below 1%, increasing from May onwards and reaching a maximum in August of up to 10% recorded in some years of high soiling. From September onwards, rainfall reduces soiling to around 0.5% by the end of the year.

The most cost-effective cleaning strategy proved to be the 1-wet tractor cleaning service. The frequency of cleaning varied depending on the cost of cleaning, however the best time to perform the cleaning remains fixed between July/August. The results of a cleaning optimization process obtained using PVRADAR are reported in Table 5. This web-application optimises cleaning strategies by modelling energy and economic losses and using historic dust concentration and environmental data and considering a set of technical parameters (e.g., cleaning efficiency, cleaning speed) and costs (e.g., labour, water, fuel). It iterates through numerous scenarios, varying the type of cleaning system (e.g., tractor, robot, manual), the number of systems, and cleaning schedules to identify the most cost-effective strategy. Specifically, Table 5 shows the optimal cleaning frequency for three different cleaning costs ranging from 250 to 750 EUR per MWp cleaned. For the highest assumed cost, the optimal strategy would be to only clean in years with especially dry summers, roughly every 5 years. For the lower end of the range, the optimum means cleaning every year at least once and sometimes even twice.

Dry tractors and semi-autonomous robots were viable options but proved to be less economical. Wet cleaning recovered more energy compared to dry cleaning, which justified the higher expenses for water and equipment. Conversely, semi-autonomous robots require higher labour costs, rendering them uncompetitive. Fully autonomous robots were also not cost-effective due to their significant initial investment.

Table 5: Optimal cleaning strategy for Southern Spain depending on cleaning cost (assuming an energy sales price of 60 EUR/MWh), simulated with PVRADAR.

Assumed cleaning cost [EUR/MWp/cleaning]	Cleaning frequency [number of cleanings/year]	Economic benefit [kEUR/MWp]
750	0 – 1 (0.2 avg.)	0.2
500	0 – 1 (0.5 avg.)	1.2
250	1 – 2 (1.3 avg.)	4.3

5.4.2 Case study 2: Negev Desert

The Negev Desert has extremely scarce rainfall and high solar isolation. A soiling assessment based on historical conditions indicates an average loss factor of 16.2%, which is more than 11 times higher than the average loss found in the Spanish project. The dry season lasts from April to early November and allows soiling to accumulate to values above 20%. Considering an energy selling price of 35 EUR/MWh, the project is expected to experience revenue losses of about 200 kEUR/MWp during the 30-year lifetime.

The most cost-effective cleaning strategy for this 150 MW power plant is investing in three dry-cleaning tractors and use them to clean the plant 10 times per year in average, depending on precipitation. This approach provides the best balance between cost and recovered energy, delivering the highest economic benefit while keeping soiling losses low.

Fully autonomous robots, operated every two days, also present a profitable alternative, though they produce about 10% less benefit compared to the dry tractor method. This frequency has been identified as optimal after evaluating various options, considering the additional energy revenues and costs associated with consumables and the lifespan of each component. The profitability of this approach largely depends on the configuration of module tables that can be connected and cleaned by each robot. For this analysis, a four-table setup was assumed, and the economic evaluation should be reassessed for different scenarios. Implementation feasibility, including table alignment and compatibility with robotic systems, should also be carefully considered.

Table 6: Optimal use and resulting economic benefit of dry-cleaning tractors and fully autonomous cleaning robots for site in Negev Desert, simulated with PVRADAR.

Cleaning technology	Nb of cleaning devices	Cleaning frequency	Economic benefit [kEUR/MWp]
Dry-cleaning tractor	3	10 cleanings per year (avg.)	128.2
Fully autonomous Robot	1031 (1 every 4 tables)	Every 2 days	114.7

6 OPTIMISATION OF MODULE/SYSTEM DESIGN FOR HOT & HUMID CLIMATES

While Chapter 5 addressed the challenges faced by PV systems in hot and dry climates, this chapter focuses on the unique issues arising from hot and humid environments. Humidity introduces a new set of complications that can significantly impact the performance, reliability, and longevity of PV systems. High moisture content in the air, coupled with elevated temperatures, creates a particularly challenging environment for solar energy installations. This chapter explores the various ways in which hot and humid conditions affect PV systems and their components and discusses strategies for optimising their performance in these demanding conditions.

6.1 Hot & Humid Climates

Hot and humid climate zones, typically found in tropical and subtropical regions, are characterised by high temperatures and elevated moisture levels throughout the year. Those conditions often come with heavy rainfall, with annual precipitation typically exceeding 1000 mm, and humidity levels frequently above 70%. These regions typically experience minimal temperature variation, with averages remaining above 18°C throughout the year. In such locations, the combination of heat and moisture accelerates the risk of certain failure modes for PV modules and system components. Corrosion, mold, and material degradation are some of the challenges to overcome to improve PV durability in highly humid conditions. In addition, high temperatures can decrease yield performance, reducing module and inverter efficiencies, while frequent rain and high humidity increase the potential for water ingress and electrical failures [182]. Hot and humid regions can exhibit very high irradiation profiles and be subject to occasional extreme weather events, such as tropical storms, further amplifying the performance and reliability risk.

In the Köppen-Geiger climate classification system [6], hot and humid areas are classified as "Af" (tropical rainforest) or "Am" (tropical monsoon). The Af climate is characterised by consistently high temperatures around 30°C, abundant annual rainfall ranging from 150 to 1000 cm and heavy cloud cover. The Am climate is also characterised by high temperatures, with small annual variations, and abundant precipitation, which however often exceeds that of Af zones. Both zones can be found in the sub-tropical belt, particularly in southern and southeastern Asia.

Figure 33 and Figure 34 exhibit two illustrations that correlate weather variables (annual temperature and annual irradiation) with latitude for all the globe excluding Antarctica. As shown, tropical climates are primarily located between -20° and 20° latitude and achieve the highest annual average temperatures (higher than 20°C) but not the highest annual irradiation due to high cloud coverage, frequent rainfall and other atmospheric phenomena.

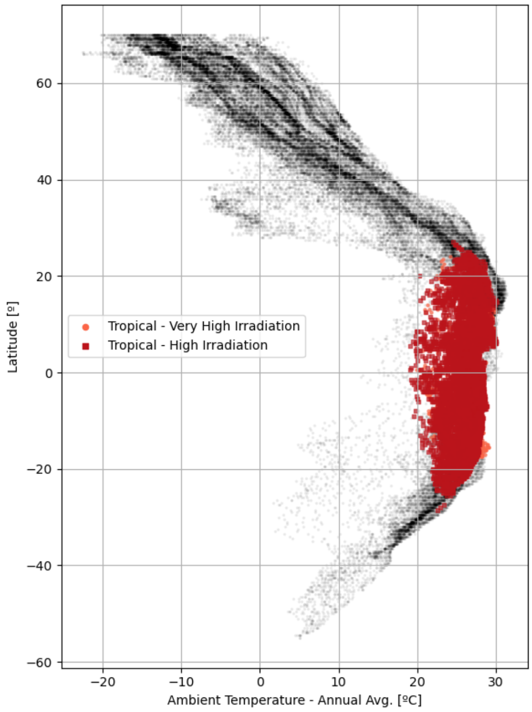


Figure 33: Correlation of KGPV climate zones with annual ambient temperature highlighting the Tropical climates.

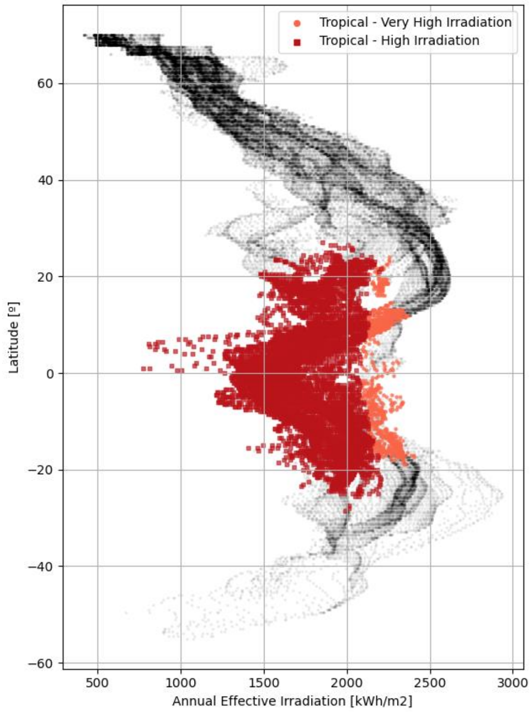


Figure 34: Correlation of KGPV climate zones with annual effective irradiation highlighting the Tropical climates.

6.2 Stressors and typical problems (hot & humid)

This section explores the key environmental factors that stress PV systems in hot and humid climates and the typical problems they cause. These environmental stressors and their adverse effects are also visually represented in the mind map in Figure 35. They include high temperatures, elevated humidity levels, intense UV radiation, frequent precipitation, and in coastal areas, exposure to salt mist. Also, these climates often favor biological growth and are prone to extreme weather events like tropical storms. Most of the adverse effects are associated with stressors like heat, humidity, UV radiation, and salt spray. In contrast, low-impact stressors such as wind, precipitation, and biological growth contribute to fewer effects.

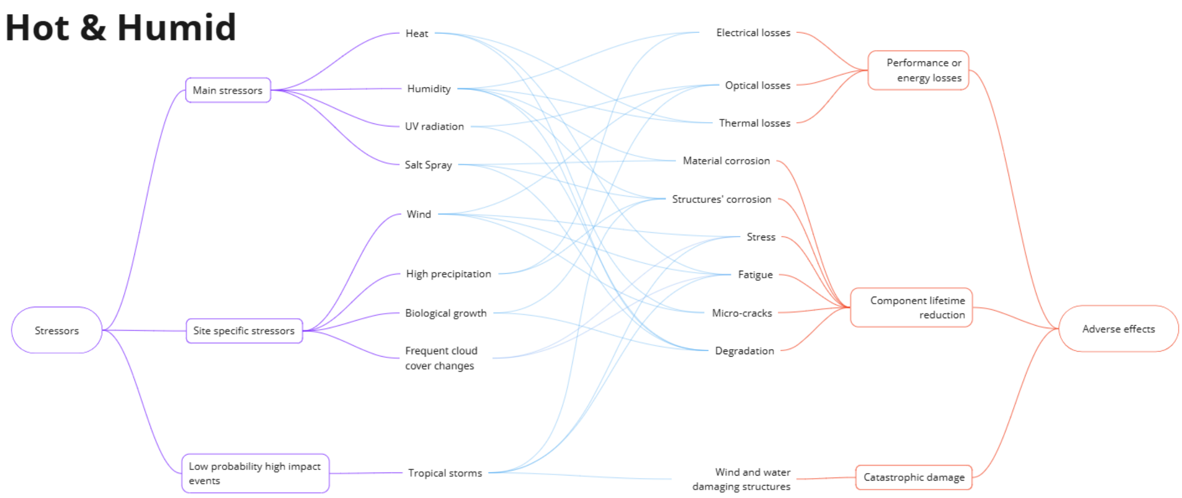


Figure 35: Mind map of stressors and their adverse effects in hot and humid climates.

6.2.1 High humidity in combination with high temperature

High temperatures significantly impact the performance of solar cells, by reducing their voltage output and consequently lowering power production. While the exact impact varies depending on the specific cell technology and module design, the temperature effect remains a critical factor in hot climates. High humidity worsens this issue by hindering effective heat dissipation from the modules, leading to even higher cell temperatures and further efficiency reductions. Additionally, the accumulation of water droplets on solar panels can diminish the level of direct solar irradiation they receive since the light is backscattered by the droplets, leading to an additional drop in power output [183].

The combination of heat and humidity also accelerates the various degradation mechanisms in a PV system. Hacke et al. [184] found that high humidity can contribute to PID, especially when combined with high system voltages and elevated temperatures. The study also revealed that conditions exceeding 70°C and 70% relative humidity triggered water-induced chemical reactions leading to degradation effects, such as silicon nitride deterioration and increased cell series resistance. Modules in tropical Singapore were found to be more susceptible to PID than those in subtropical and continental climates [185]. This highlights the critical influence of humidity on PID progression. PID reduces shunt resistance and fill factor (FF), and therefore the module power output.

Prolonged exposure to a humid environment can cause the PV module components (solder joints, busbars and fingers) to corrode because moisture seeps into the solar cells. This trapped moisture also raises the electrical conductivity of the materials, leading to leakage currents. Cracks in the cells of modules in hot & humid locations have been found in the same place as the crack in the backsheet [186], suggesting that moisture enters through the crack in the backsheet, deforms the EVA and cracks the solar cells. Additionally, when water condenses between the encapsulant and the solar cell materials, it speeds up corrosion, which can result in the encapsulant peeling away [187].

In high-humidity environments, especially near water bodies, photovoltaic systems can experience significant drops in insulation resistance [188], [189]. Inverters typically monitor insulation resistance during startup and may not activate if minimum thresholds are not met. A study of a Singapore floating PV testbed revealed frequent delayed morning startups for some systems, resulting in notable energy production losses. This effect is illustrated by the red dots in Figure

36, whereby despite the increasing irradiance from 7 to 8 AM, the current, and therefore power, output of the inverter remained zero [190].

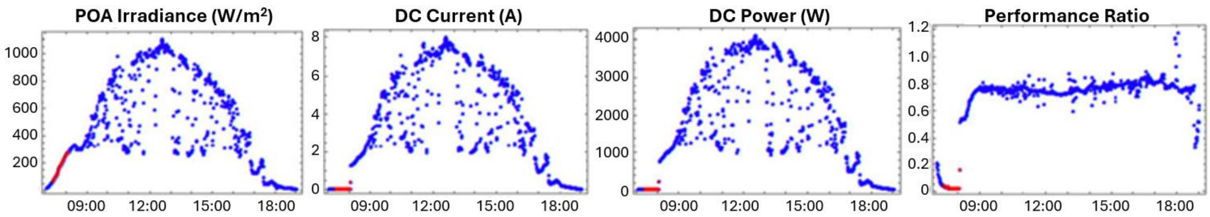


Figure 36:. Startup delay measured at floating PV in the Tengeh reservoir (Singapore) because of reduced insulation resistance. Source: SERIS

6.2.2 Enhanced dust adhesion

Humidity plays a significant role in the accumulation of dust on PV module surfaces. In regions with high humidity, dust particles adhere more easily and strongly to module glass cover which then requires thorough cleaning to restore the PV modules to their initial power output levels [191] [192]. The increased adhesion of dust to the PV surface is due to the stronger capillary forces, which prevent wind from resuspending particles [193].

In addition, high relative humidity values can favour gravitational settling, further worsening the soiling deposition [193]. Indeed, high humidity can also contribute to the formation of stubborn dust layers on PV module surfaces, further complicating maintenance efforts and potentially reducing system efficiency [191]. Therefore, the cumulative effect of dust accumulation in humid conditions over time can result in substantial energy losses which happens due to reduced light transmittance.

Dew can also have a significant impact on soiling accumulation, as it can cause cementation of dust particles making them hard to remove by natural cleaning [194]. Condensation should be measured, rather than estimated from dew point and surface temperature, and can be monitored using industrial moisture sensors. These are available at lower costs than scientific-grade tools and were found to provide reliable results when employed to characterise condensation on PV modules [195].

6.2.3 Biological growth

PV systems installed in hot and humid climates face unique challenges, particularly in the form of organic growth on PV modules and other system components. These biological agents can not only negatively impact the performance and longevity of PV installations but also increase maintenance costs for PV system operators.

A study conducted in São Paulo [196] revealed insights into the formation and impact of biological growths on solar panels. The research found that biofilms begin to develop on photovoltaic surfaces within a half-year period, progressively maturing over time. These formations result from a complex interaction between airborne particles and microbial communities known as sub-aerial biofilms (SABs). This biological fouling has substantial consequences for solar energy production, with the study reporting a notable 11% decrease in photovoltaic cell efficiency over an 18-month timeframe.

Another study [197] investigated the composition of soiling on photovoltaic glass in two distinct soiling-prone locations: Dubai (hot and dry) and Mumbai (hot and humid). The two sites showed markedly different soiling patterns. Mumbai's samples exhibited substantial growth of filamentous fungi, while Dubai's were primarily affected by inorganic contaminants. This highlights how local environmental factors like humidity can significantly influence the type of soiling that occurs.

Typically, this biological contamination is harder to clean than inorganic soiling and is not removed by natural cleaning [198]. Rinse or low-pressure washing might not be an effective solution to remove fungi from PV modules. Wiping techniques and more frequent cleaning should be adopted in such cases.

Biological growth on PV system components beyond the modules themselves is an often overlooked but significant issue in solar energy installations, particularly in hot and humid climates. Components such as mounting structures, cables, and junction boxes are susceptible to biofouling. These growths can lead to accelerated corrosion of metal parts, degradation of cable insulation materials, and potential short circuits in electrical connections.

6.2.4 High irradiation and frequent cloud cover changes

Tropical and subtropical locations can be characterised by rapid and frequent variations in irradiance, due to frequent cloud cover changes, which cause rapid, low-amplitude temperature changes in PV modules. A study by Bosco et al. showed that this variation in temperature, together with the mean daily maximum temperature and the daily maximum temperature variation, is one of the three key factors in determining thermo-mechanical fatigue stress on cell interconnects [138]. The IEC 62892:2019 (Annex B) provides a metric, r(55), which quantifies how often within a year the module temperature fluctuates across the 55°C threshold.

6.3 Best practice and mitigation strategies (hot & humid)

While the previous section explored the challenges faced by PV systems in hot and humid climates, this section focuses on strategies to optimise their performance and longevity in these demanding environments. Three key areas of optimisation are examined: site assessment, component selection, and system design. Each of these aspects plays a crucial role in ensuring that PV installations can withstand the stressors of high temperatures and elevated humidity while maintaining optimal efficiency. The following subsections will discuss some of the best approaches for each of these optimisation strategies.

6.3.1 Site assessment

Site assessment and selection are critical steps in optimising photovoltaic (PV) systems for hot and humid climates. This process involves evaluating several key factors specific to these challenging environments: solar resource and atmospheric conditions, temperature and humidity patterns and environmental factors affecting system performance.

Solar resource and atmospheric conditions

In hot and humid climates, the assessment of solar resources must account for unique atmospheric conditions that can affect PV performance. A previous study [199] showed that cloud cover can significantly impact PV output. When planning large photovoltaic systems, the effects of cloud cover and the resultant output loss can be mitigated by distributing the PV capacity across multiple, spatially separated sites, so that localized cloud events are less likely to impact the entire system simultaneously.

The following atmospheric conditions could be considered in the site assessment:

- ***Assess seasonal variations in atmospheric conditions:*** historical weather data should be analysed to identify recurring patterns of dense cloud cover and heavy precipitation.

These. Understand how these seasonal variations in atmospheric conditions can affect solar irradiance levels and cause fluctuations in PV system output over the course of a year. Evaluate whether the site experiences prolonged periods of reduced solar resource during certain seasons and assess the impact on overall energy yield.

- ***Air quality assessment:*** Assess the local and regional air quality data. Analyse how air pollution levels can vary seasonally and the potential impact on solar irradiance reaching the PV system. Prioritise sites with relatively cleaner air, or identify potential mitigation strategies, such as enhanced cleaning schedules, to address the effects of air pollution on system performance
- ***Atmospheric aerosol monitoring:*** Assess long-term trends and seasonal patterns in atmospheric aerosol levels, as these can significantly affect solar radiation reaching PV panels. This is particularly important in regions prone to biomass burning, dust storms, or industrial emissions that can cause sudden or periodic increases in aerosol concentrations. Monitoring long-term aerosol trends and seasonal variability can improve the accuracy of solar resource assessment and highlight periods of increased atmospheric attenuation

Temperature and humidity patterns

As discussed in Section 6.2.1, the combination of high temperature and high humidity presents significant challenges for PV systems in tropical climates. High temperatures reduce voltage output and overall power production, particularly in crystalline silicon modules, while high humidity exacerbates these effects by hindering heat dissipation. The synergistic impact of heat and humidity accelerates various degradation mechanisms, including potential-induced degradation (PID), corrosion, and encapsulant delamination. Additionally, high humidity environments can lead to reduced insulation resistance, potentially causing safety issues and system startup delays, especially in floating PV installations. Given these effects, the following recommendations could be considered in the site assessment for high temperature and humidity environments.

- ***Microclimate analysis:*** Conduct detailed assessments of local microclimates, including temperature and humidity patterns, seasonal variations, and any unique geographical features that might influence these factors.
- ***Elevation and air circulation:*** Evaluate site elevation and natural air circulation patterns, as higher elevations or areas with better air movement may offer slightly cooler temperatures and reduced humidity.
- ***Extreme events:*** Pay attention to extreme weather events, monsoon patterns, and periods of exceptionally high temperature or humidity that could impact system performance and durability, to guide decisions on structural robustness, component selection, and O&M planning.
- ***Urban heat island effects:*** For building-mounted systems in urban or industrial areas, consider the potential impact of heat island effects on local temperatures, which may influence operating conditions and performance.
- ***Available space for optimal layout:*** Evaluate whether the site offers sufficient space for an optimal system layout that maximises natural cooling and minimises the operating temperature of the modules.
- ***Long-term climate projections:*** Consider long-term climate change projections to anticipate potential increases in temperature, frequency of extreme weather events, or changes in precipitation patterns. Such changes can provide important information to guide site selection and system design.

Environmental Factors Affecting System Performance

As discussed in Sections 6.2.2 and 6.2.3, high humidity levels can contribute to enhanced dust adhesion on PV module surfaces, leading to stubborn soiling that is harder to remove. The presence of dew can further exacerbate this issue by causing cementation of the dust particles. Additionally, the combination of hot and humid conditions can promote the development of biofilms and other biological growths on PV modules, as well as on other system components, which can significantly impact system performance. As such, the following considerations could be included in the site assessment process.

- ***Consider the effects of vegetation growth:*** Analyse the potential for vegetation, such as trees or shrubs, to encroach on the PV system over time, leading to increased shading or other issues. Incorporate vegetation management plans into the site assessment and long-term maintenance strategy to ensure that the system's performance is not compromised by environmental changes.
- ***Evaluate the risk of biological growth and biofouling:*** Assess the potential for the development of biofilms, algae, or other biological contaminants on the PV modules and other system components, and implement appropriate mitigation strategies, such as an effective cleaning strategy.

6.3.2 Optimisation of module design and BOM

Like for hot & dry climates, the choice of solar cell technology significantly impacts the module's performance under high temperatures typical of tropical climates. Cell technologies with lower temperature coefficients minimise efficiency losses as temperatures rise [201]. But differently from hot & dry climates, the solar cells have also to be resilient towards high humidity levels. Conventional wafer-based mono-crystalline silicon solar cells, such as Aluminum Back Surface Field (Al-BSF) and later Passivated Emitter and Rear Contact (PERC) cells, are generally not highly susceptible to degradation caused by moisture exposure. However, the global solar market is currently undergoing a rapid shift toward high-efficiency solar cells based on n-type silicon wafers. Two primary solar cell architectures are driving this transition: (a) silicon heterojunction (SHJ) and (b) tunnel oxide passivated contact (TOPCon). Among these, TOPCon appears poised to become the dominant platform in the near future [202]. However, both technologies share a significant vulnerability to moisture and water exposure, requiring careful module packaging considerations to ensure durability and long-term performance [203], [204], [205], [206].

In SHJ modules, moisture-related issues can be mitigated or eliminated at the module level by employing high-resistivity encapsulants with low water vapor transmission rates, such as polyolefins (POs). Alternatively, encapsulating SHJ solar cells in a water-impermeable double glass configuration using an edge sealant combined can effectively address the problem [205], [206]. Also, for TOPCon cells, the use of PO encapsulants is often recommended as the preferred choice. However, as highlighted by [207], the compatibility of TOPCon cells with PO encapsulants from various suppliers - and with differing formulations - requires careful evaluation. Issues can arise from the improper selection of additives, emphasising the need for thorough testing to ensure optimal performance and long-term reliability.

In general, all polymers used in PV modules for tropical regions should be moisture resistant and show high UV stability. Similarly, the frame should be corrosion-resistant, using anodised aluminum or stainless steel to endure humid and salty air, especially in coastal regions. The junction box, an integral part of the system, must have a high ingress protection (IP) rating, such as IP67 or IP68, to remain waterproof and dustproof [208], [209]. Also, the other electrical components must be adapted to the harsh conditions of tropical climates. Cables and connectors should be moisture-proof to prevent insulation damage and corrosion.

The module components as well as cable and connectors should be made of UV-resistant materials. Measurement of UV radiation conducted in Singapore indicated that the annual UV radiation is around 100 kWh/m^2 [210], greater than the 15 kWh/m^2 UV dosage typically tested following IEC 61215 standard [32].
Self-cleaning glass surfaces can reduce the need for frequent manual cleaning, particularly in areas with heavy rainfall and dust [211], [212]. To ensure consistent energy output, protective features such as hydrophobic and oleophobic coatings can minimise the accumulation of dust, pollen, and organic debris. These must guarantee adequate durability to the harsh outdoor conditions.

The module must possess mechanical strength to withstand strong winds and potential hurricanes. A robust frame and impact-resistant glass can ensure durability.

There have been efforts to produce modules optimised for hot and humid climate [213]. The frameless "Singapore module" is equipped with Albarino G textured glass to allow more diffuse irradiance to reach the solar cells and humidity-resistant encapsulant and backsheet. Manufacturers – such as Hyundai [214], QW Solar [215] – have also introduced humidity-resistant modules for floating PV applications. Nevertheless, PV module production is very competitive. As such, customisation for specific climates may increase production cost more than it increases yield over the lifetime of the system such that LCOE of the PV system may be higher.

6.3.3 System design

The design of PV systems in hot & humid locations must consider the characteristics of the stressors typical of these climates.

For instance, the system must be designed to minimise the effect of soiling and to limit any biological growth. Soiling must be regularly monitored, as it may vary with the season and from year to year. Rainfall is the dominant natural cleaning agent for soiling, but at the same time it might interact with dust particles resulting in non-uniform, caked soiling buildup. Also, the presence of frame can provide elevated boundaries above the glass where particles can collect. So, even if particles are washed off by rain, they can still accumulate along the bottom frame. For this reason, maximum power-based measurements should be preferred as non-uniform soiling might not be measured by short-circuit current based methods.Figure 37 gives an example of how soil accumulates over time at low tilt angles if no cleaning is performed.

Figure 37: Evolution of soiling on an unmaintained flat PV system in Singapore [216]**.**

A regular cleaning schedule is recommended, especially during the dry periods, but care should also be taken during rainy seasons, to remove any accumulation of soiling along the frame. Because of the enhanced adhesion, contact-based cleaning procedures (such as dry brush or wet sponge and rubber squeegee) should be preferred, even if they increase the risk of abrasion [197]. If biological contamination is present, this often cannot be removed by natural agents alone, and may require more frequent cleaning and, possibly, the employment of mild cleaning solutions [198]. The use of anti-soiling coatings could be considered to improve the cleaning effect of rainfall and dew, even their durability can be affected by factors such as the pH of rainwater or acidic substances secreted by fungi.

Even if low tilts ensure a higher irradiation on the modules at low latitudes, designers should take into account that lower tilts will favor soiling accumulation [217]. For example, PV systems in Singapore (located at 1°N latitude) are typically installed with tilt angle of 10° to facilitate the cleaning effect of rain [216]. Additionally, the optimal tilt direction (azimuth) is not necessarily towards the equator. Tropical places are characterised by unique cloud behaviors and as a result, the rule of thumb of facing the equator may not be accurate. For the case of Singapore where the mornings tend to be sunnier than the afternoons, PV modules facing East received more irradiance and generated 1–2% more energy than those facing North or South [218].

Additionally, the use of high IP rating equipment, including electrical boxes, is recommended as it can help to avoid moisture ingress and reduce risks related to circuit breakers in conditions of constant high humidity. Similarly, corrosion-resistant materials for all the PV system components should be preferred.

6.4 Case Studies: Module Technology Selection

6.4.1 Case study 1: PV module degradation in tropical Singapore

The tropical rainforest climate (Af) of Singapore, a city-state in southeastern Asia, is characterised by consistently high temperatures (monthly average of 26-28°C) and relative humidity levels (average 83.9%). In addition, it is subject to frequent rainfall, occurring averagely on 169 days a year, and intense UV radiation year-round. These conditions, coupled with urban pollution, exacerbate the degradation mechanisms of PV modules.

This case study summarises the findings of an analysis conducted on PV modules after more than 10 years of field operation [219]. The modules were randomly selected from a 10°-tilted roof-mounted PV system, which was made of three different module technologies: multi-crystalline (multi-Si), mono-crystalline silicon (mono-Si), and Copper indium selenide (CIS). Two modules per technology were analysed.

Figure 38 summarises the Standard Test Condition (STC) performance degradation of the analysed PV modules compared to their initial ratings [219]. Among the multi-Si modules, causes of the power loss were primarily due to reductions in fill factor (FF), while the short-circuit current (Isc) and the open circuit voltage (Voc) were essentially unaffected. The power loss in the mono-Si modules was driven by severe reductions in FF and Isc (~12-15%). The latter can be attributed to encapsulant discolouration.

Encapsulant degradation, corrosion, and potential-induced degradation (PID) emerged as the most critical issues. Multi-crystalline silicon (multi-Si) modules exhibited encapsulant discolouration (more pronounced near cell centres), corrosion near cell edges, and some power loss (~9%). Mono-Si modules suffered catastrophic power losses (>40%), mainly due to severe encapsulant discolouration, PID, and metallisation corrosion. The two silicon technologies were sourced from the same manufacturer and showed different patterns in their degradation mechanisms. Multi-Si modules exhibited discolouration concentrated in the centre of the cells, whereas mono-Si modules showed more intense browning uniformly across the entire cell surface. The more severe loss in encapsulant transmission was also confirmed by the external quantum efficiency (EQE) analysis, which showed, for the mono-Si modules, substantial EQE loss for the waveband from 400 to 1000 nm. Air bubbles were also found in the cell gaps of the mono-Si modules, which was possibly attributed to a low-quality lamination process.

CIS modules showed two different degrees of degradation. In one case, encapsulant discolouration and corrosion caused a power loss of 15.7%, whereas in the second case, power losses reached 45.3%, primarily attributed to PID. The latter was predominantly attributed to significant reductions in Voc (~16%) and FF (~24%), consistent with the effects of PID.

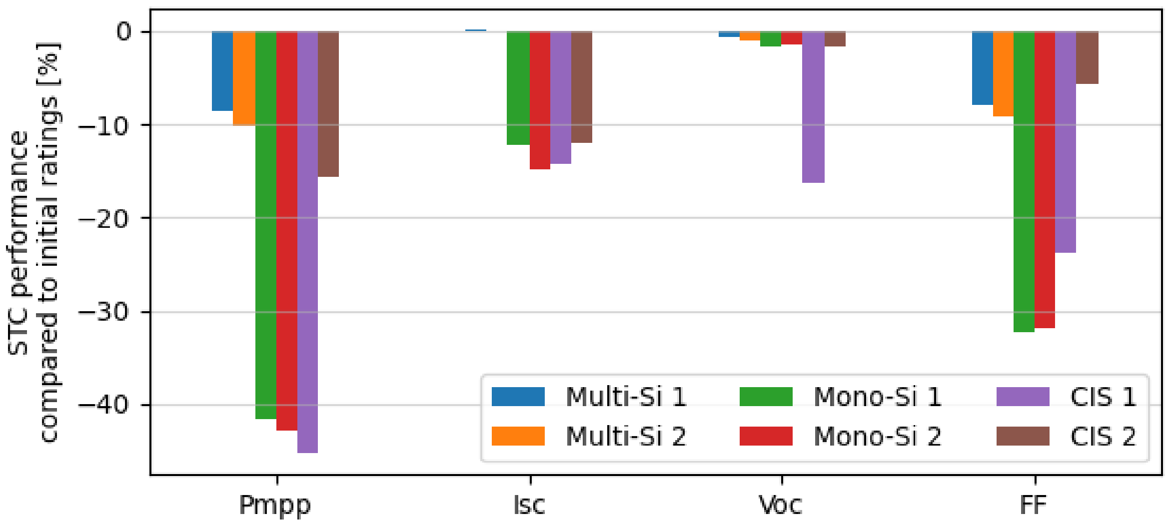


Figure 38: Comparison of STC performance of the six modules investigated in [219]**, compared to their initial ratings.**

Some important lessons can be drawn from this analysis. Constant exposure to high humidity and UV radiation likely accelerated encapsulant degradation and corrosion processes. Additionally, the maritime environment introduced salt mist and haze, further exacerbating soiling and corrosion.

However, it should also be noted that the module technologies analysed in the aforementioned study [219], and in similar long-term efforts [186], [220], such as the multi-crystalline Al-BSF and PERC, are no longer dominant today. The industry has shifted towards n-type monocrystalline TOPCon, heterojunction, and IBC technologies [221]. As module technologies change, the dominant forms of degradation may also change. For example, recent modules (e.g., [222]) have an “Anti-PID Guarantee” through optimisation of cell production technology and material control.

6.4.2 Case study 2: Soiling in Southern Brazil and the role of the PV module technology

Brazil is a country with generally favourable conditions for PV, although climates vary significantly across its territory. The southern region is characterised by tropical and subtropical conditions, with high humidity and precipitation levels.

Costa et al. [223] monitored soiling losses for over a year in the cities of Porto Alegre (Southern region, humid subtropical climate) and Belo Horizonte (Southeastern region, tropical wet and dry climate). The authors deployed at each location a soiling monitoring system, composed of thin-film CdTe and mc-Si soiling stations. Each system measured the I-V curves of two PV devices; one kept regularly clean and the other left to naturally soil.

Over the investigated period, the authors found that both the CdTe and Si modules remained consistently clean in Porto Alegre, thanks to the frequent year-round precipitation, even if losses as high as 5-7% were observed after the longest 12-day dry period. Conversely, moderate soiling was found in Belo Horizonte, with more severe accumulation during the dry summer months (April-October). Over the longest 85-day dry period, losses as high as 27% were registered. The authors also noted nonuniform soiling accumulating on the bottom frame of the Si modules, as this provided an elevated boundary above the glass where the particulates collected during rainfalls (Figure 39).

Precipitation was found to be the dominant natural cleaning factor in both locations. Therefore, regular cleaning was recommended in Belo Horizonte during the longer dry season, along with additional extraordinary cleanings during the rainier seasons to remove soiling accumulated on the frames. On the other hand, the year-round rainfall pattern in Porto Alegre was sufficient to naturally keep the modules clean in that region.

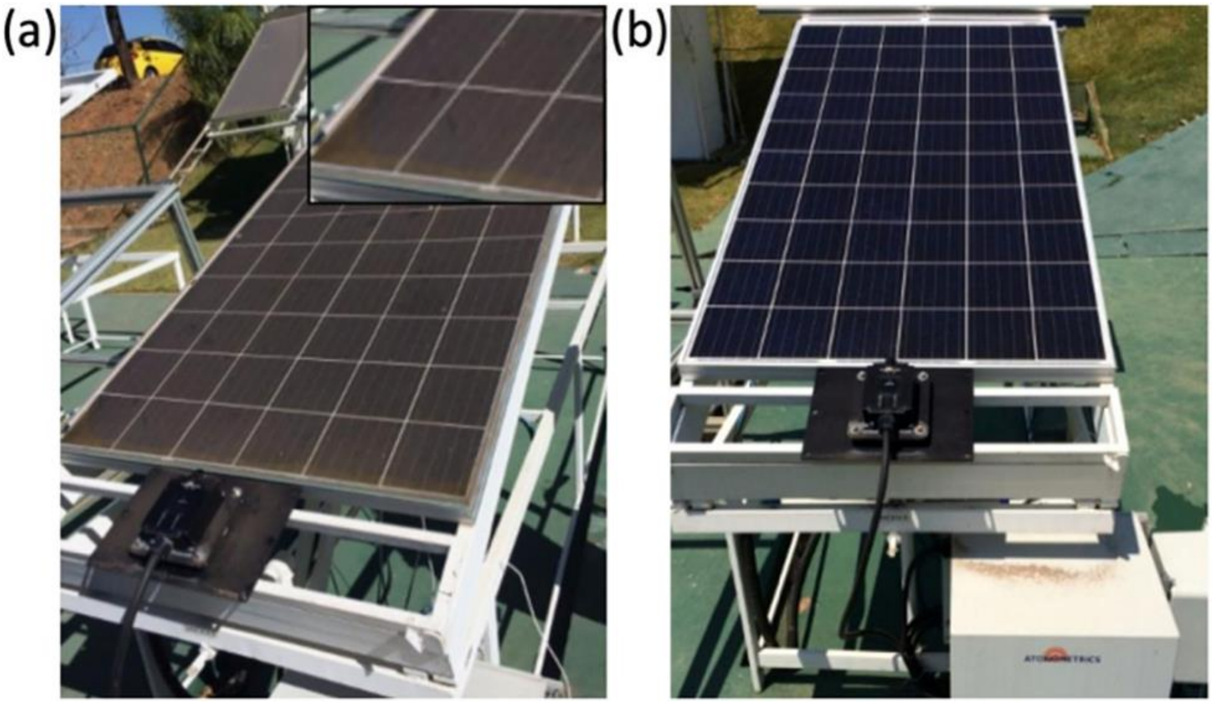


Figure 39: The monocrystalline soiling station installed in Belo Horizonte. In (a), the nonuniform soiling accumulated on the bottom frame at the end of the 85-day dry period. In (b), the clean module after a 20 mm rainfall [223]**.**

In a subsequent work, Diniz et al. [224] evaluated the performance of the two PV technologies in Belo Horizonte, taking into account the spectral effects of soiling as well as the spectral response and the temperature coefficient of each material. Using approximately 4 years of experimental data, the authors confirmed that the frameless CdTe modules were less prone to non-uniform soiling distribution across their surface.

Soiling is known to have nonuniform spectral transmittance, with greater losses occurring in the blue portion of the spectrum, due to Mie scattering, and higher transmittance in the infrared [225]. As a result, thin-film technologies with higher band gaps (i.e., lower-wavelength spectral regions) are more impacted by soiling than, for instance, crystalline silicon technologies [226]. This could suggest that silicon materials are always superior to wider band gap thin films in dust-prone regions. However, this assumption is based on normalised conditions and do not account for the impact of additional variables, such as temperature. This is particularly important in hot climates, where thermal losses can be significant, as CdTe is less sensitive to temperature than crystalline silicon (i.e., it has temperature coefficients of lower absolute values).

For this reason, the authors of [227] specifically investigated the magnitudes of the soiling spectral transmittance and temperature effects on the modules' performance. They identified the conditions that, under Belo Horizonte's climate, would lead to either temperature losses or soiling losses being dominant. As shown in Figure 40, they provided guidelines to determine, based on these conditions, whether silicon modules could outperform CdTe modules, or vice versa, concluding that temperature is the dominant parameter at temperatures beyond the 40º–50ºC range.

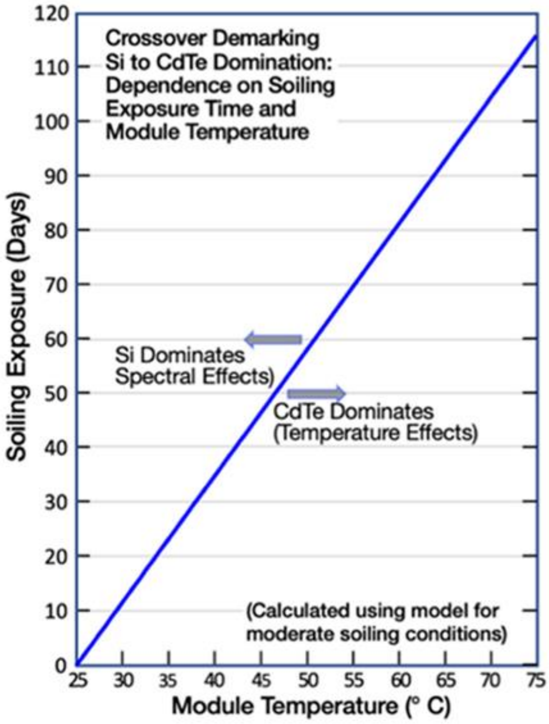


Figure 40: Dominating factor and best performing modules, depending on soiling exposure time and typical module temperature [227]**.**

7 CONCLUSIONS

As global capacity grows, PV systems are being deployed across diverse geographical regions, each characterised by specific stressors, that in the case of harsher environments require tailored solutions to optimise their long-term operation. The main challenges and mitigation solutions for three common PV climates characterised by harsher environmental conditions are discussed in this report. The level of field experience and readily available solutions differs significantly between the three. Challenges, available mitigation measures and needs for further development in each of the three climates are here summarised.

- **Cold & Snowy**: These typically high-latitude or high-elevation sites are characterised by consistently low, if not even freezing, temperatures and snowfalls. Low temperatures improve the module's efficiency and slow down chemical material degradation reactions, but, at the same time, expose PV modules and system components to additional physical and thermomechanical degradation modes which can lead to catastrophic failures. Similarly, snow ensures a high albedo but poses also potentially threatening load on the modules, BOS components, and racking system, and shades the sunlight, reducing the intensity of the irradiance reaching the PV cells. High-tilt systems with sufficient ground clearance as well as fences for the avoidance of snow drifts help in minimising snow losses. Mounting structures are reinforced and adapted to the diverse terrain's morphologies and soil characteristics. The mostly custom-designed solutions are often complex and cost intensive. PV modules can be optimised through thicker glass, use of micro-crack tolerant cells, special encapsulants and frames. Research on encapsulant properties, UV resistance, and innovative snow-clearing methods shows promising results, but field experience with climate-optimised PV modules and mounting structures is still very limited. Snow loss modelling is increasingly used to predict and minimise energy losses, but the challenges remain in accurately isolating snow effects.
- **Hot & Dry**: These high-solar irradiance locations are characterised by high temperatures, arid climate and scarce rainfall. The main stressors are soiling, high temperatures, and thermal cycling, while salty mist, intense UV irradiation, and strong winds affect only some locations. These stressors can cause performance losses and accelerate degradation. Low-temperature coefficient modules with alternative encapsulants, and UV- and heat-resistant materials, are recommended to enhance durability. Systems in these climates must be designed to facilitate cleaning operations, whose requirements change depending on the selected business model. Further strategies include conducting soil studies to mitigate corrosion, engineering systems to withstand wind loads, implementing smart tracking solutions. Proposed cooling solutions, like heat spreading plates, air-cooled fins, and phase change materials, remain largely uncommercialised. Continuous performance and environmental monitoring through a combination of manual and automated methods is crucial to address aging-related inefficiencies.
- **Hot & Humid**: These climates are characterised by consistently high temperatures and elevated levels of moisture in the air, whose combination poses substantial risks, such as corrosion, and material degradation, to PV modules and components. High humidity can also lead to increased dust adhesion and biological growth, with substantial impacts on the energy yields. In equatorial locations, the losses induced by these phenomena can be so significant that higher-than-optimal tilts and frameless configuration might be preferable to limit the accumulation of soiling, even if they cause higher reflection and angular losses. Designing PV modules for tropical regions includes moisture-resistant encapsulants, corrosion-proof frames, and UV-stable components. Implementing regular cleaning

schedules, particularly during dry periods and for areas with frequent rainfall-induced caked soiling or biological contamination, reduces soiling losses and prolongs lifetime.

Regardless of the location, the mitigation of climate-specific stressors starts with site selection and continues throughout the lifetime of the systems. The identification of the stressors and their impact must be conducted as early as possible to provide sufficient information for the subsequent phases, i.e. module and component selection, and system design. Preventive and corrective mitigation strategies indeed influence both these phases and must be planned according to the expected stressors' impact. Different approaches, each with its own advantages and limitations, are available to choose the best PV modules for each climate. For example, the IEC 61853 Energy Rating offers fast, repeatable results based on standard conditions and climate specific testing procedures, described within a previously published IEA PVPS TASK 13 report [14], and the collection of field data. Similarly, techno-economic models can be used to assess the viability of different cleaning schedules and solutions, which differs in dependence of the climate zone and type of soiling.

Overall, the design and operation of PV systems, as well as the selection of sites, modules, and components, can be optimised to improve lifetime performance depending on the specific climate. However, despite technological advancements, other constraints often prevent the adoption of climate-specific PV modules. These include, for example, additional factors such as price, availability, and existing contracts that could also influence the choice of modules and components and the design of the system and which are discussed in more detail in a dedicated IEA PVPS TASK 13 report [228].

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