

INTERNATIONAL STANDARD



Photovoltaic system performance – Part 1: Monitoring



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INTERNATIONAL ELECTROTECHNICAL COMMISSION

PHOTOVOLTAIC SYSTEM PERFORMANCE –

Part 1: Monitoring

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International Standard IEC 61724-1 has been prepared by IEC technical committee 82: Solar photovoltaic energy systems.

This second edition cancels and replaces the first edition, published in 2017. This edition constitutes a technical revision.

This edition includes the following significant technical changes with respect to the previous edition:

- Monitoring of bifacial systems is introduced.
- Irradiance sensor requirements are updated.
- Soiling measurement is updated based on new technology.
- Class C monitoring systems are eliminated.
- Various requirements, recommendations and explanatory notes are updated.

The text of this standard is based on the following documents:

FDIS	Report on voting
82/1904/FDIS	82/1925/RVD

Full information on the voting for its approval can be found in the report on voting indicated in the above table.

The language used for the development of this International Standard is English.

This document was drafted in accordance with ISO/IEC Directives, Part 2, and developed in accordance with ISO/IEC Directives, Part 1 and ISO/IEC Directives, IEC Supplement, available at www.iec.ch/members_experts/refdocs. The main document types developed by IEC are described in greater detail at www.iec.ch/standardsdev/publications.

A list of all parts in the IEC 61724 series, published under the general title *Photovoltaic system performance*, can be found on the IEC website.

The committee has decided that the contents of this document will remain unchanged until the stability date indicated on the IEC website under webstore.iec.ch in the data related to the specific document. At this date, the document will be

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- withdrawn,
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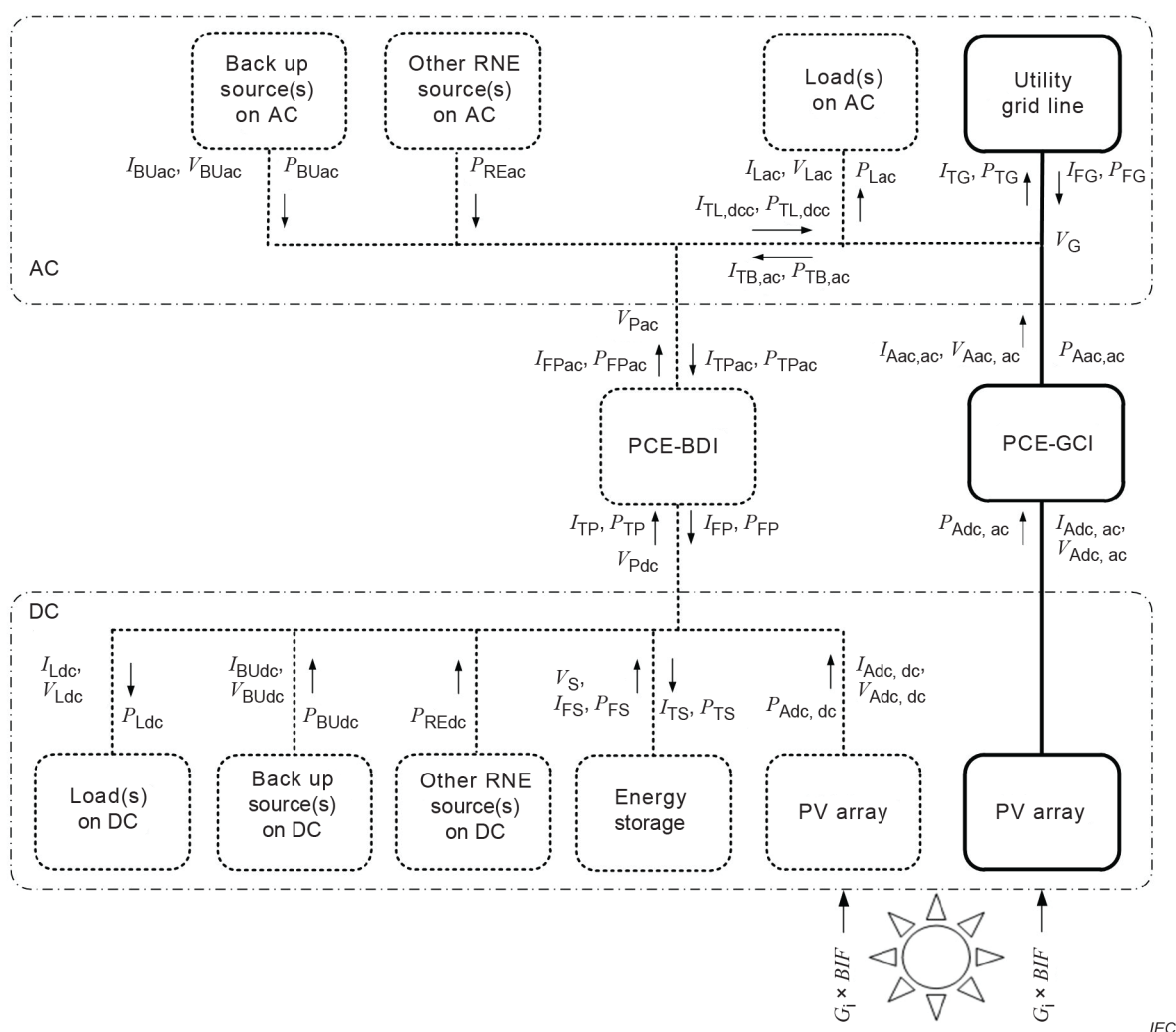
INTRODUCTION

This document defines classes of photovoltaic (PV) performance monitoring systems and serves as guidance for ~~various~~ monitoring system choices.

Figure 1 illustrates ~~possible~~ major elements comprising different PV system types.

The main clauses of this document are written for grid-connected systems without local loads, energy storage, or auxiliary sources, as shown by the bold lines in Figure 1. Annex E includes some details for systems with additional components.

The PV array may include both fixed-axis and ~~tracking~~ ~~tracker~~ systems and both flat-plate and concentrator systems. ~~Module-level electronics, if present, may be a component of the monitoring system.~~



Key

RNE: renewable energy

PCE: power conditioning equipment

BDI: bi-directional inverter

GCI: grid-connected inverter

Bold lines denote simple grid-connected system without local loads, energy storage, or auxiliary sources.

Figure 1 – Possible elements of PV systems

The purposes of a performance monitoring system are diverse and ~~can~~ could include ~~the following:~~

- ~~identification of performance trends in an individual PV system;~~
- ~~localization of potential faults in a PV system;~~
- ~~comparison of PV system performance to design expectations and guarantees;~~
- ~~comparison of PV systems of different configurations; and~~
- ~~comparison of PV systems at different locations.~~

comparing performance to design expectations and guarantees as well as detecting and localizing faults.

~~These diverse purposes give rise to a diverse set of requirements, and different sensors and/or analysis methods may be more or less suited depending on the specific objective. For example, For comparing performance to design expectations and guarantees, the focus should be on system-level data and consistency between prediction and test methods, while for analysing performance trends.~~

For detecting and localizing faults there ~~may~~ should be ~~a need for~~ greater resolution at sub-levels of the system and an emphasis on measurement repeatability and correlation metrics ~~rather than absolute accuracy.~~

The monitoring system should be adapted to the PV system's size and user requirements. In general, larger ~~and more expensive~~ PV systems should have more monitoring points and higher accuracy sensors than smaller and lower-cost PV systems. ~~This document defines three classifications of monitoring system with differentiated requirements which are appropriate to a range of purposes.~~

PHOTOVOLTAIC SYSTEM PERFORMANCE –

Part 1: Monitoring

1 Scope

This part of IEC 61724 outlines terminology, equipment, and methods for performance monitoring and analysis of photovoltaic (PV) systems. ~~It addresses sensors, installation, and accuracy for monitoring equipment in addition to measured parameter data acquisition and quality checks, calculated parameters, and performance metrics.~~ It also serves as a basis for other standards which rely upon the data collected.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

IEC 60050-131, *International Electrotechnical Vocabulary (IEV) – Part 131: Circuit theory*

IEC 60904-2, *Photovoltaic devices – Part 2: Requirements for photovoltaic reference devices*

~~IEC 60904-3, *Photovoltaic devices – Part 3: Measurement principles for terrestrial photovoltaic (PV) solar devices with reference spectral irradiance data*~~

IEC 60904-5, *Photovoltaic devices – Part 5: Determination of the equivalent cell temperature (ECT) of photovoltaic (PV) devices by the open-circuit voltage method*

IEC 60904-7, *Photovoltaic devices – Part 7: Computation of the spectral mismatch correction for measurements of photovoltaic devices*

~~IEC 60904-10, *Photovoltaic devices – Part 10: Methods of linearity measurement*~~

IEC 61215 (all parts), *Terrestrial photovoltaic (PV) modules – Design qualification and type approval*

IEC 61557-12, *Electrical safety in low voltage distribution systems up to 1 000 V AC and 1 500 V DC – Equipment for testing, measuring or monitoring of protective measures – Part 12: Power metering and monitoring devices (PMD)*

IEC TS 61724-2, *Photovoltaic system performance – Part 2: Capacity evaluation method*

IEC TS 61724-3, *Photovoltaic system performance – Part 3: Energy evaluation method*

IEC TS 61836, *Solar photovoltaic energy systems – Terms, definitions and symbols*

~~IEC 62053-21, *Electricity metering equipment (a.c.) – Particular requirements – Part 21: Static meters for active energy (classes 1 and 2)*~~

IEC 62053-22, *Electricity metering equipment – Particular requirements – Part 22: Static meters for AC active energy (classes 0,1S, 0,2S and 0,5S)*

IEC 62670-3, *Photovoltaic concentrators (CPV) – Performance testing – Part 3: Performance measurements and power rating*

IEC 62817:2014, *Photovoltaic systems – Design qualification of solar trackers*

ISO/IEC Guide 98-1, *Uncertainty of measurement – Part 1: Introduction to the expression of uncertainty in measurement*

ISO/IEC Guide 98-3, *Uncertainty of measurement – Part 3: Guide to the expression of uncertainty in measurement (GUM:1995)*

ISO 9060:2018, *Solar energy – Specification and classification of instruments for measuring hemispherical solar and direct solar radiation*

ISO 9488, *Solar energy – Vocabulary*

~~ISO 9846, *Solar energy – Calibration of a pyranometer using a pyrheliometer*~~

~~ISO 9847, *Solar energy – Calibration of field pyranometers by comparison to a reference pyranometer*~~

~~WMO No. 8, *Guide to meteorological instruments and methods of observation*~~

~~ASTM G183, *Standard Practice for Field Use of Pyranometers, Pyrheliometers and UV Radiometers*~~

3 Terms and definitions

For the purposes of this document, the terms and definitions given in IEC 60050-131, IEC TS 61836, ISO 9488, and the following apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at <http://www.electropedia.org/>
- ISO Online browsing platform: available at <http://www.iso.org/obp>

3.1

sample

data acquired from a sensor or measuring device

3.2

sampling interval

time between samples

3.3

record

data recorded and stored ~~in data log, based on acquired samples~~

3.4

recording interval

τ

time between records

3.5**report**

aggregate value based on series of records

3.6**reporting period**

time between reports

3.7**front side**

side of a surface which normally faces the sky

3.8**rear side**

side of a surface which normally faces the ground

3.9**monofacial PV device**

PV device in which only the front side is used for power generation

3.10**bifacial PV device**

PV device in which both front side and rear side are used for power generation

3.11**bifaciality coefficient** **φ**

ratio between an I-V characteristic of the rear side and the front side of a bifacial device, typically at Standard Test Conditions (STC), unless otherwise specified

Note 1 to entry: Bifaciality coefficients include the short-circuit current bifaciality coefficient φ_{ISC} , the open-circuit voltage bifaciality coefficient φ_{VOC} and the maximum power bifaciality coefficient φ_{Pmax} .

Note 2 to entry: Bifaciality coefficients are defined in IEC TS 60904-1-2.

3.12**irradiance****G**

incident flux of radiant power per unit area

Note 1 to entry: Expressed in units of $\text{W}\cdot\text{m}^{-2}$.

3.13**in-plane irradiance**

G_{i} or POA

sum of direct, diffuse, and ground-reflected irradiance incident upon the front side of an inclined surface parallel to the plane of the modules in the PV array, also known as plane-of-array (POA) irradiance

Note 1 to entry: Expressed in units of $\text{W}\cdot\text{m}^{-2}$.

3.14**horizontal albedo**

ρ_{H}

proportion of incident light reflected by a ground surface as measured in a horizontal plane

Note 1 to entry: It is a property of a ground surface and is a dimensionless quantity on a scale from 0 to 1.

3.15**in-plane rear-side irradiance ratio** ρ_i

ratio of the irradiance incident on the rear side of the modules in the PV array to the irradiance incident on the front side

Note 1 to entry: It is a dimensionless quantity but can exceed a value of 1 since, in addition to reflected light, diffuse and direct components of the solar resource may also be measured on the rear-side of the plane of array.

3.16**spectrally matched in-plane rear-side irradiance ratio** ρ_i^{SP}

in-plane rear-side irradiance ratio per 3.15 when both irradiance quantities are measured with a spectrally matched reference device or with the application of spectral correction factors per IEC 60904-7

3.17**spectrally matched reference device**

reference device such as a PV cell or module with spectral response characteristics sufficiently close to those of the PV modules in the PV array such that spectral mismatch errors are small under the typical range of incident spectra

3.18**in-plane rear-side irradiance** G_i^{rear} or POA^{rear}

sum of direct, diffuse, and ground-reflected irradiance incident on the rear side of the modules in the PV array, also known as rear-side plane-of-array irradiance

Note 1 to entry: Expressed in units of $\text{W}\cdot\text{m}^{-2}$.

Note 2 to entry: (If measured via in-plane rear-side irradiance ratio): $G_i^{\text{rear}} = \rho_i \times G_i$ or $G_{i,SP}^{\text{rear}} = \rho_i^{SP} \times G_i$.

3.19**bifacial reference device**

bifacial PV device, such as a cell or module, having substantially the same properties, with respect to response to front-side and rear-side irradiance, as bifacial modules to be monitored

3.20**bifacial irradiance factor** BIF

dimensionless factor that can be directly multiplied by the front-side in-plane irradiance (G_i) to calculate the “effective” irradiance reaching a bifacial device from both the front and rear side collectively

Note 1 to entry: $BIF = (1 + \phi_{Pmax} \times \rho_i)$ or $BIF^{SP} = (1 + \phi_{Pmax} \times \rho_i^{SP})$. See 3.11, 3.15, 3.16.

Note 2 to entry: Rear-side POA irradiance can be measured simultaneously with front-side POA irradiance using a bifacial reference device. In that case, $BIF = G_i^{BIF \text{ Ref Device}} \div G_i$. For consistency, the front-side POA irradiance should be measured with the same or similar type of device as the bifacial reference device.

Note 3 to entry: “Effective” irradiance may include the effect of inhomogeneities in rear-side irradiance.

3.21**global horizontal irradiance** GHI

direct plus diffuse irradiance incident on the front side of a horizontal surface

Note 1 to entry: Expressed in units of $\text{W}\cdot\text{m}^{-2}$.

Note 2 to entry: $GHI = DNI \cdot \cos Z + DHI$ where Z is the solar zenith angle.

3.22**circumsolar**

immediately surrounding the solar disk

3.23**direct normal irradiance**

DNI

irradiance emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5° falling on a plane surface normal to the sun's rays

~~Note 1 to entry: Some *DNI* measurement instruments have a field of view with a subtended full angle of up to 6°.~~

Note ~~2~~ 1 to entry: Expressed in units of $\text{W}\cdot\text{m}^{-2}$.

Note 3 to entry: $GHI = DNI \cdot \cos Z + DHI$ where Z is the solar zenith angle.

3.24**circumsolar contribution**

contribution of a specific portion of the circumsolar normal irradiance to the direct normal irradiance. The circumsolar contribution refers to a specific ring-shaped angular region described by an inner and the outer angular distance from the centre of the sun (see ISO 9488)

Note 1 to entry: If the inner angle describing this angular region is the half-angle of the sun disk the circumsolar contribution is also called circumsolar ratio.

Note 2 to entry: Depending on the circumsolar irradiance measurement instrument or the solar technology involved, different wavelength ranges are included. In order to describe circumsolar irradiance correctly, the wavelength range or the spectral response of the instrument or the involved technology has to be specified.

3.25**circumsolar ratio**

~~CSR~~

fraction of measured direct normal irradiance (*DNI*) emanating from the circumsolar region of the sky, i.e. within the angular acceptance of the *DNI* sensor but outside the solar disk

3.26**sunshape**

azimuthal average radiance profile as a function of the angular distance from the centre of the sun, normalized to 1 at the centre of the sun and considering the wavelength range of shortwave radiation (see ISO 9488)

3.27**diffuse horizontal irradiance**

G_d or *DHI*

global ~~horizontal~~ irradiance on the front side of a horizontal surface excluding the portion emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5°

~~Note 1 to entry: Some diffuse irradiance measurement instruments exclude a circumsolar region within a subtended full angle of up to 6°.~~

Note ~~2~~ 1 to entry: Expressed in units of $\text{W}\cdot\text{m}^{-2}$.

Note 3 to entry: $GHI = DNI \cdot \cos Z + DHI$ where Z is the solar zenith angle.

3.28**in-plane direct beam irradiance**

$G_{i,b}$

in-plane irradiance incident upon the front side of an inclined surface parallel to the plane of the modules in the PV array emanating from the solar disk and from the circumsolar region of the sky within a subtended full angle of 5°, ~~excluding scattering and reflections~~

Note 1 to entry: The in-plane direct beam irradiance $G_{i,b} = \cos(\theta) \times DNI$, where θ is the angle between the sun and the normal to the plane. When the plane of array is normal to the sun, $G_{i,b} = DNI$.

Note 2 to entry: Expressed in units of $\text{W}\cdot\text{m}^{-2}$.

~~3.15~~

~~in-plane diffuse irradiance~~

~~$G_{i,d}$~~

~~in-plane irradiance excluding the direct beam irradiance~~

~~Note 1 to entry: $G_{i,d} = G_i - G_{i,b}$.~~

~~Note 2 to entry: Expressed in units of $\text{W}\cdot\text{m}^{-2}$.~~

3.29

irradiation

H

irradiance integrated over a specified time interval

Note 1 to entry: Expressed in units of $\text{kW}\cdot\text{h}\cdot\text{m}^{-2}$.

3.30

standard test conditions

STC

~~reference values of~~ in-plane irradiance $1000 \text{ W}\cdot\text{m}^{-2}$, normal incidence, PV cell junction temperature 25°C , and the reference spectral irradiance defined in IEC 60904-3

3.31

soiling ratio

SR

ratio of the actual power output of the PV array under given soiling conditions to the power that would be expected if the PV array were clean and free of soiling

3.32

soiling level

SL

fractional power loss due to soiling, given by $1 - SR$

3.33

soiling rate

rate of change of soiling ratio, typically expressed in percent per day

3.34

active power

P

under periodic conditions, mean value, taken over one period, of the instantaneous product of current and voltage

Note 1 to entry: Under sinusoidal conditions, the active power is the real part of the complex power.

Note 2 to entry: Expressed in units of W.

3.35

apparent power

S

product of the rms voltage between the terminals of a two-terminal element or two-terminal circuit and the rms electric current in the element or circuit

Note 1 to entry: Under sinusoidal conditions, the apparent power is the modulus of the complex power.

Note 2 to entry: Expressed in units of VA.

3.36 power factor

λ

under periodic conditions, ratio of the absolute value of the active power P to the apparent power S :

$$\lambda = \frac{|P|}{S}$$

4 Monitoring system classification

~~The required accuracy and complexity of the monitoring system depends on the PV system size and user objectives. This document defines three classifications of monitoring systems providing varying levels of accuracy, as listed in Table 1.~~

~~The monitoring system classification shall be stated in any conformity declarations to this standard. The monitoring system classification may be referenced either by its letter code (A, B, C) or its name (high accuracy, medium accuracy, basic accuracy) as indicated in Table 1. In this document, the letter codes are used for convenience.~~

~~Class A or Class B would be most appropriate for large PV systems, such as utility-scale and large commercial installations, while Class B or Class C would be most appropriate for small systems, such as smaller commercial and residential installations. However, users of the standard may specify any classification appropriate to their application, regardless of PV system size.~~

This document defines two classifications of monitoring system, Class A and Class B.

Class A is intended for large PV systems such as utility-scale or large commercial installations.

Class B is intended for smaller systems such as rooftop or small to medium-size commercial installations.

Users of the document may specify whichever classification is most appropriate to their application, regardless of PV system size.

The monitoring system classification shall be stated in any conformity declarations to this document.

Throughout this document, some requirements are designated as applying to a particular classification. Where no designation is given, the requirements apply to ~~all~~ both classifications.

Table 1 – Monitoring system classifications and suggested applications

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

5 General

5.1 Measurement precision and uncertainty

~~Where requirements on measurement uncertainties are stated in the document, they refer to the combined uncertainties of the measurement sensors and any signal-conditioning electronics.~~

~~Measurement uncertainties shall apply over the typical range of values of each measured quantity indicated in the document, as well as over the typical temperature range at which the system will operate. The effect of non-linearity of the measurement within the typical range shall be included within the stated uncertainty.~~

Measurement precision refers to repeatability and resolution, which have the meanings defined in the IEC Electropedia.

Measurement uncertainty refers to accuracy and otherwise has the meaning defined in the IEC Electropedia.

Measurement uncertainties can be calculated as outlined in ISO/IEC Guide 98-1 and ISO/IEC Guide 98-3.

5.2 Calibration

~~Sensors and signal-conditioning electronics used in the monitoring system shall be calibrated prior to the start of monitoring.~~

Recalibration of sensors and signal-conditioning electronics is to be performed as ~~required~~ recommended by the manufacturer or at more frequent intervals where specified in the standard.

It is recommended to perform periodic cross-checks of each sensor against sister sensors or reference devices in order to identify out-of-calibration sensors.

5.3 Repeated elements

Depending on system size and user requirements, the monitoring system may include redundancy in sensors and/or repetition of sensor elements for different components or subsections of the full PV system. Accordingly, the measured and calculated parameters defined in this document may have multiple instances, each corresponding to a subsection or subcomponent of the PV system.

5.4 Power consumption

The parasitic power drawn by ~~tracking, monitoring, and other ancillary~~ any systems required for operation of the PV plant shall not be considered ~~a power loss of the plant, not~~ as a load supplied by the plant.

5.5 Documentation

~~Specifications of all components of the monitoring system, including sensors and signal-conditioning electronics, shall be documented.~~

~~User guides shall be provided for the monitoring system software.~~

~~All system maintenance, including cleaning of sensors, PV modules, or other soiled surfaces, shall be documented.~~

~~A log should be kept to record unusual events, component changes, sensor recalibration, changes to the data acquisition system, changes to the overall system operation, failures, faults, or accidents.~~

~~When a conformity declaration is made, documentation shall demonstrate consistency with the indicated class A, B, or C.~~

Details of all components of the monitoring system shall be documented. All system inspection and maintenance, including cleaning, shall be documented.

5.6 Inspection

~~For Class A and Class B the monitoring system should be inspected at least annually and preferably at more frequent intervals, while for Class C inspection should be per site specific requirements. Inspection should look for damage to or displacement of exterior sensors, evidence of moisture or vermin in enclosures, loose wiring connections at sensors or within enclosures, detachment of temperature sensors, embrittlement of attachments, and other potential problems.~~

The monitoring system shall be inspected at least annually and preferably at more frequent intervals. Inspection should look for damage, deterioration, or disconnection of sensors and electrical enclosures, soiling or displacement of optical sensors, loose wiring connections, detachment of temperature sensors, embrittlement of attachments, and other potential problems.

6 Data acquisition timing and reporting

6.1 Samples, records, and reports

Figure 2 illustrates the relations between samples, records, and reports.

A sample is data acquired from a sensor or measuring device. The sampling interval is the time between samples. Samples do not need to be permanently stored.

A record is data entered into ~~a data log for~~ data storage, based on acquired samples. The recording interval, denoted by τ in this document, is the time between records. The recording interval should be an integer multiple of the sampling interval, and an integer number of recording intervals should fit within 1 h.

The recorded parameter value for each record is the average, maximum, minimum, sum, or other function of the samples acquired during the recording interval, as appropriate for the measured quantity. The record can also include supplementary data such as additional statistics of the samples, number of missing data points, error codes, transients, and/or other data of special interest. (For wind data records, see statement in 9.3.)

A report is an aggregate value covering multiple recording intervals. The reporting period is the time between reports. Typically the reporting period would be chosen to be days, weeks, months, or years.

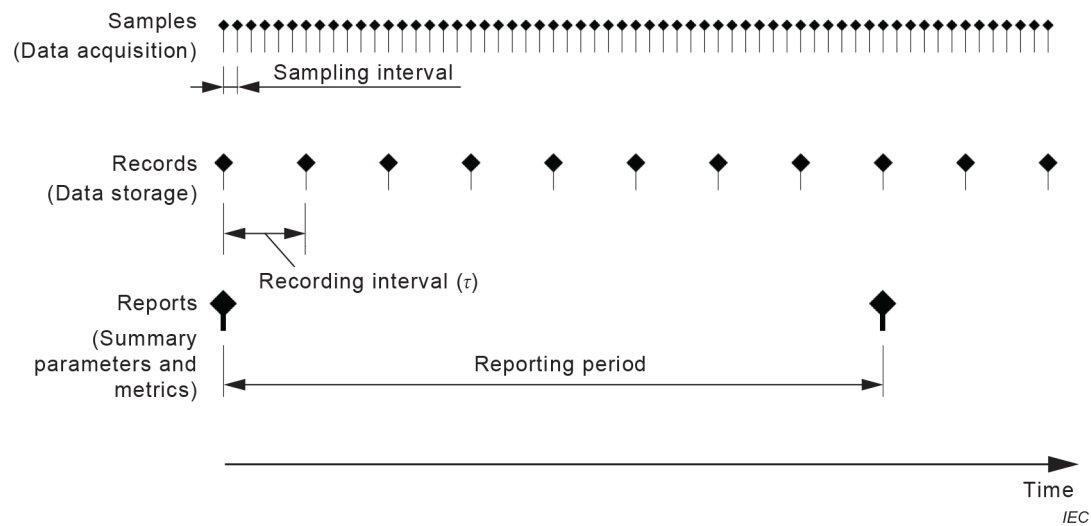


Figure 2 – Samples, records and reports

Table 1 lists maximum values for sampling intervals and recording intervals.

Further considerations relating to the sampling interval are addressed in Annex A. The maximum sampling interval for Class A is longer than the typical signal and instrument time constants for irradiance, wind and electrical output, however, the value is chosen for practicality considering common data acquisition systems.

The indicated sampling and recording interval recommendations apply to on-site ground-based measurements. For satellite-based measurement of irradiance, longer intervals of up to 1 h may be used. A ground-based instrument will require frequent samples to construct a valid time average over a recording interval, e.g. in the case of partly cloudy conditions, while satellite-based estimation uses the spatial average of many pixels in a single image as a substitute for time averaging.)

Table 1 – Sampling and recording interval requirements

	Class A High accuracy	Class B Medium accuracy	Class C Basic accuracy
Maximum sampling interval			
For irradiance, temperature, wind [±] , and electrical output	3 s	1 min ^{**}	1 min ^{**}
For soiling, rain, snow, and humidity	1 min	1 min ^{**}	1 min ^{**}
Maximum recording interval	1 min	15 min	60 min
[±] —See statement in 7.3.3 regarding including maximum and minimum readings in wind data records. ^{**} —The indicated sampling interval requirements for class B and class C apply to ground-based measurements, but do not apply when using satellite-based estimation of irradiance or meteorological parameters. (A ground-based instrument will require frequent samples to construct the proper average over a recording interval, e.g. in the case of partly cloudy conditions, while satellite-based estimation may derive the same average from a single image during the reporting period.)			

	Class A High accuracy	Class B Medium accuracy
Maximum sampling interval		
For irradiance, temperature, wind and electrical output	5 s	1 min
Maximum recording interval	5 min (1 min – recommended)	15 min

6.2 Timestamps

Each record and each report shall include a timestamp.

Timestamp data shall include the date and time corresponding to the beginning or end of the recording interval or reporting period and the choice shall be specified.

The time should refer either to local standard time (not daylight savings time) or universal time, to avoid winter/summer time changes, and the choice of time shall be specified.

Midnight shall be treated as the start of a new day and expressed as 00:00:00.

When multiple data acquisition units are involved that each independently apply timestamps, the clocks of the units ~~shall~~ **should** be synchronized, preferably by an automated mechanism such as global positioning system (GPS) or network time protocol (NTP).

~~It is recommended that documentation of timestamps follow ISO 8601, Data elements and interchange formats – Information interchange – Representation of dates and times.~~

6.3 Parameter names

For consistency in data extraction across multiple platforms, it is recommended to use standardized parameter names. Standardized names for parameters in this document are listed in *Orange Button Taxonomy Data Definitions*.

7 ~~Measured parameters~~ Required measurements

7.1 ~~General requirements~~

Table 2 lists measured parameters defined by this document and a summary of measurement requirements.

The purpose of each monitoring parameter is listed in Table 2 in order to guide the user. More details and additional requirements are provided in the subsequent referenced subclauses.

A check mark (✓) in Table 2 indicates a required parameter to be measured on site, qualified by specific notes where included.

The symbol ~~“E”~~ “R” in Table 2 indicates a parameter that may be ~~estimated~~ determined based on ~~local or regional~~ remote meteorological data or satellite data, rather than by on-site measurement.

Table 2 lists the minimum number of on-site sensors ~~where required~~. In many cases ~~by reference to~~ this is shown as a factor times a multiplier from Table 3. Where no number is given, only one sensor is required, although redundant sensors are typically advisable.

When multiple sensors are required, they shall be distributed throughout the PV plant at ~~representative locations~~ or placed at monitoring points indicated in the table ~~where specified~~. If the plant includes multiple sections that have different ~~PV~~ technology types or substantially different local geography or other operation characteristics, then at least one sensor shall be placed in each ~~such section and additional sensors shall be added, if necessary, to meet this requirement~~.

Empty cells in Table 2 indicate optional parameters that may be chosen for specific system requirements or to meet project specifications.

~~NOTE The most significant and direct impacts on PV performance are in-plane irradiance received by the PV array, the PV cell temperature, and shading losses due to soiling or snow. Monitoring of meteorological parameters listed in Table 3 aids in estimating some of these factors independently, provides the ability to compare to historical meteorological data for the site, and can aid in identifying system design or maintenance problems. Additional parameters listed in Table 3 aid in fault localization and assessing utility grid interactions.~~

Table 2 – Measured parameters and requirements for each monitoring system class

Parameter	Symbol	Units	Monitoring purpose	Required?			Number of sensors
				Class-A High accuracy	Class-B Medium accuracy	Class-C Basic accuracy	
Irradiance (see 7.3)							
In-plane irradiance (POA)	G_t	$W \cdot m^{-2}$	Solar resource	✓	✓ or E	✓ or E	Table 4 column 1
Global horizontal irradiance	G_{HH}	$W \cdot m^{-2}$	Solar resource, connection to historical and satellite data	✓	✓ or E		Table 4 column 1
Direct normal irradiance	DNI	$W \cdot m^{-2}$	Solar resource, concentrator	✓ for CPV	✓ or E for CPV		Table 4 column 1
Diffuse irradiance	G_D	$W \cdot m^{-2}$		✓ for CPV with $\leq 20\times$ concentration	✓ or E for CPV with $\leq 20\times$ concentration		Table 4 column 1
Circumsolar ratio	CSR						
Environmental factors (see 7.3)							
PV module temperature	T_{mod}	$^{\circ}C$	Determining temperature-related losses	✓	✓ or E		Table 4 column 2
Ambient air temperature	T_{amb}	$^{\circ}C$	Connection to historical data, plus estimation of PV temperatures	✓	✓ or E	✓ or E	Table 4 column 1
Wind speed		$m \cdot s^{-1}$	Estimation of PV temperatures	✓	✓ or E		Table 4 column 1
Wind direction		degrees		✓			Table 4 column 1
Soiling ratio	SR		Determining soiling-related losses	✓ if soiling losses expected to be $>2\%$			Table 4 column 1
Rainfall		mm	Estimation of soiling losses	✓	✓ or E		Table 4 column 1
Snow			Estimation of snow-related losses				

Parameter	Symbol	Units	Monitoring purpose	Required?			Number of sensors
				Class-A High accuracy	Class-B Medium accuracy	Class-C Basic accuracy	
Humidity			Estimation of spectral variations				
Tracker system (see 7.4)							
Error in dual-axis tracker primary angle	$\Delta\phi_1$	degrees	Tracker system fault detection, dual-axis	∇ for CPV with $>20\times$ concentration			Table 4 column 1
Error in dual-axis tracker secondary angle	$\Delta\phi_2$	degrees		∇ for CPV with $>20\times$ concentration			Table 4 column 1
Single-axis tracker tilt angle	ϕ_1	degrees	Tracker system fault detection, single-axis	∇ for single-axis tracker			Table 4 column 1
Electrical output (see 7.6 and 7.6)							
Array voltage (DC)	V_A	V	Energy output, diagnostics and fault localization	∇			At each inverter (optionally at each combiner box or each string)
Array current (DC)	I_A	A		∇			
Array power (DC)	P_A	kW		∇			
Output voltage (AC)	V_{out}	V	Energy output	∇	∇		At each inverter and at system level
Output current (AC)	I_{out}	A		∇	∇		
Output power (AC)	P_{out}	kW		∇	∇	∇	
Output energy	E_{out}	kWh		∇	∇	∇	
Output power factor	γ		Utility request compliance	∇	∇		At each inverter and at system level
Reduced load demand			Determine utility or load request compliance and impact on PV system performance	If applicable	If applicable		At system level
System output power factor request	γ_{req}			If applicable	If applicable		At system level

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system		
				Required?	Minimum number of sensors	Required?	Minimum number of sensors	
Irradiance (see Clause 8)								
In-plane irradiance (POA)	G_i	$\text{W}\cdot\text{m}^{-2}$	Solar resource	✓	1 × Table 3	✓		
Global horizontal irradiance	GHI	$\text{W}\cdot\text{m}^{-2}$	Solar resource, connection to historical and satellite data	✓	1 × Table 3	✓ or R		
Horizontal albedo	ρ_H	Unitless	Solar resource, rear side	✓	1 × Table 3			
In-plane rear-side irradiance (POA) or spectrally matched in-plane rear-side irradiance	G_i^{rear}	$\text{W}\cdot\text{m}^{-2}$		✓	3 × Table 3			
	$G_{i,\text{sp}}^{\text{rear}}$	$\text{W}\cdot\text{m}^{-2}$		for bifacial, Option 2 per 8.3.3				
Diffuse irradiance	G_d	$\text{W}\cdot\text{m}^{-2}$	Solar resource	✓	1 × Table 3			
				for bifacial, Option 1, per 8.3.3 (optional)				
Direct normal irradiance	DNI	$\text{W}\cdot\text{m}^{-2}$		for CPV with < 20× concentration	✓	1 × Table 3		
				for CPV				
Circumsolar contribution, circumsolar ratio, sunshape								

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system	
				Required?	Minimum number of sensors	Required?	Minimum number of sensors
Environmental factors (see Clause 9)							
PV module temperature	T_{mod}	°C	Determining temperature-related losses	✓	3 × Table 3	✓	
Ambient air temperature	T_{amb}	°C	Estimation of PV temperatures, connection to prediction models	✓	1 × Table 3	✓ or R	
Wind speed		m·s ⁻¹		✓	1 × Table 3	✓ or R	
Wind direction		degrees		✓	1 × Table 3		
Soiling ratio	SR		Determining soiling-related losses	✓ if typical annual soiling losses without cleaning expected to be > 2 %	1 × Table 3		
Rainfall		cm	Estimation of soiling losses	✓	1 × Table 3	✓ or R	
Snow		cm	Estimation of snow-related losses	✓ if typical annual snow losses without cleaning expected to be > 2 % and soiling measurement does not measure snow loss	1 × Table 3		
Humidity		%	Estimation of spectral variations				
Tracker system (see Clause 10)							
Single-axis tracker tilt angle	ϕ_{T}	degrees	Tracker system fault detection, single-axis	✓ for single-axis tracker	1 × Table 3		
Dual-axis tracker error in primary angle	$\Delta\phi_1$	degrees	Tracker system fault detection, dual-axis	✓ for dual-axis tracker	1 × Table 3		
Dual-axis tracker error in secondary angle	$\Delta\phi_2$	degrees					

Parameter	Symbol	Units	Monitoring purpose	Class A system		Class B system	
				Required?	Minimum number of sensors	Required?	Minimum number of sensors
Electrical output (see Clause 11)							
Array voltage (DC)	V_A	V	Energy output, diagnostics and fault localization	✓	At each inverter – if applicable (see 11.1)		
Array current (DC)	I_A	A		✓			
Array power (DC)	P_A	kW		✓			
Output voltage (AC)	V_{out}	V		✓	At each inverter and at system level	✓	At each inverter and at system level
Output current (AC)	I_{out}	A		✓		✓	
Output power (AC)	P_{out}	kW		✓		✓	
Output energy	E_{out}	kWh		✓		✓	
Output power factor	λ			✓		✓	
Reduced load demand				✓	At system level		
System output power factor request	λ_{req}			✓	At system level		

Table 3 – ~~Relation between system size (AC) and number of sensors for specific sensors~~ Multiplier referenced in Table 2

System size (AC)	Number of sensors	
	Column 1	Column 2
< 5 MW	1	6
≥ 5 MW to < 40 MW	2	12
≥ 40 MW to < 100 MW	3	18
≥ 100 MW to < 200 MW	4	24
≥ 200 MW to < 300 MW	5	30
≥ 300 MW to < 500 MW	6	36
≥ 500 MW to < 750 MW	7	42
≥ 750 MW	8	48

System size (AC) MW	Multiplier
< 40	2
≥ 40 to < 100	3
≥ 100 to < 300	4
≥ 300 to < 500	5
≥ 500 to < 700	6
≥ 700	7, plus 1 for each additional 200 MW.

8 Irradiance

7.2.1 — On-site irradiance measurement

7.2.1.1 — General

~~Irradiance quantities are to be directly measured on-site when required by Table 3.~~

7.2.1.2 — In-plane irradiance

~~For flat plate systems, in-plane irradiance is measured with an irradiance sensor with aperture oriented parallel to the plane of array (POA), having a field of view of at least 160° (in any plane perpendicular to the sensor aperture), mounted either on the module support structure or on another structure that is aligned parallel to the modules.~~

~~See 7.2.1.4, 7.2.1.5, and 7.2.1.7 for sensor choices and requirements.~~

~~In the case of tracked systems, the irradiance sensor shall be continuously aligned with the actual plane of array of the modules, including backtracking, if used.~~

~~For concentrator systems, see 7.2.1.8.3.~~

~~NOTE 1 — The measurement of irradiance on a tracked surface can become erroneous if the tracker supporting the sensor does not track correctly. An approach to verification is to use the measured direct normal irradiance and horizontal diffuse irradiance, DNI and G_d , respectively, and a transposition model to calculate the expected in-plane irradiance and then compare this with the measured value.~~

~~NOTE 2 — POA irradiance can also be estimated from GHI using a decomposition and transposition model.~~

7.2.1.3 — Global horizontal irradiance

Global horizontal irradiance (*GHI*) is measured with a horizontally oriented irradiance sensor.

See 7.2.1.4, 7.2.1.5, and 7.2.1.7 for sensor choices and requirements.

NOTE 1 — Measurements of horizontal irradiance are useful for comparison to historical meteorological data and can be relevant to documentation of a performance guarantee.

NOTE 2 — GHI can also be estimated from POA irradiance using a decomposition and transposition model.

7.2.1.4 — Irradiance sensors

Suitable irradiance sensors include the following:

- thermopile pyranometers;
- PV reference devices, including reference cells and reference modules; and
- photodiode sensors.

Thermopile pyranometers shall be classified according to ISO 9060 or WMO No. 8. Pyranometers shall be calibrated as stipulated by ISO 9846 or ISO 9847.

For class A systems, angle of incidence and temperature corrections to pyranometer measurements should be considered; see ASTM G183.

PV reference devices shall conform to IEC 60904-2 and be calibrated and maintained in accordance with procedures therein. The devices shall meet the short circuit current versus irradiance linearity requirements of IEC 60904-10. PV reference device calibration is to be performed with respect to the reference spectrum provided in IEC 60904-3.

Table 5 lists sensor choices and accuracy requirements for in-plane and global irradiance measurement, and Table 7 lists maintenance requirements for these sensors.

The sensor, signal-conditioning electronics, and data storage shall provide a range including at least $0 \text{ W}\cdot\text{m}^{-2}$ to $1\,500 \text{ W}\cdot\text{m}^{-2}$ and a resolution of $\leq 1 \text{ W}\cdot\text{m}^{-2}$.

NOTE — Over irradiance in the range $1\,000 \text{ W}\cdot\text{m}^{-2}$ to $1\,500 \text{ W}\cdot\text{m}^{-2}$ or higher can occur due to reflections from clouds under partly cloudy conditions.

Table 5 — Sensor choices and requirements for in-plane and global irradiance

Sensor Type	Class A High-accuracy	Class B Medium-accuracy	Class C Basic-accuracy
Thermopile pyranometer	Secondary standard per ISO 9060 or High-quality per WMO Guide No. 8 (Uncertainty $\leq 3\%$ for hourly totals)	First class per ISO 9060 or Good quality per WMO Guide No. 8 (Uncertainty $\leq 8\%$ for hourly totals)	Any
PV reference device	Uncertainty $\leq 3\%$ from $100 \text{ W}\cdot\text{m}^{-2}$ to $1\,500 \text{ W}\cdot\text{m}^{-2}$	Uncertainty $\leq 8\%$ from $100 \text{ W}\cdot\text{m}^{-2}$ to $1\,500 \text{ W}\cdot\text{m}^{-2}$	Any
Photodiode sensors	Not applicable	Not applicable	Any

Each irradiance sensor type has its benefits:

- ~~Thermopile pyranometers are insensitive to typical spectral variations and therefore measure total solar irradiance. However, this can vary from the PV usable irradiance by 1 % to 3 % (monthly average) under typical conditions. In addition, thermopile pyranometers have long response times compared to PV devices and photodiodes.~~
- ~~Matched PV reference devices measure the PV usable portion of the solar irradiance which correlates with the monitored PV system output. However, this may deviate from historical or meteorological measurements of irradiance, depending on instrumentation used.~~
- ~~Photodiode sensors have significantly lower cost than the other two types and are appropriate for smaller or lower cost systems, but are typically less accurate.~~

~~The angular sensitivity of the various sensors may differ from each other and from that of the PV system, becoming especially a factor when measuring global horizontal irradiance (*GHI*) in the winter or at times when the angle of incidence may be far from normal.~~

~~Thermopile pyranometers may be best for *GHI* measurement, while matched PV reference devices may be best for in-plane (*POA*) measurement.~~

7.2.1.5 Sensor locations

~~The location of the primary irradiance measurement sensors shall be chosen to avoid shading conditions from sunrise to sunset, if possible. If shading occurs within a half an hour of sunrise or sunset, this shall be documented.~~

~~Secondary irradiance sensors may be placed in locations that are temporarily shaded by adjacent module rows, e.g. during backtracking of a tracking system, in order to monitor this shading effect, but the performance metrics always use unshaded sensors unless explicitly noted.~~

~~The irradiance measurement sensors shall be placed so as to capture the irradiance without impact from local surroundings (shading or reflections), including nearby portions of the PV array, at all times of the year, from sunrise to sunset. When mounted near or on a building, care should be used to identify nearby vents that could discharge vapors that could condense on the sensors.~~

~~For plane-of-array measurement, for either fixed-tilt or tracking systems, irradiance sensors shall be placed at the same tilt angle as the modules, either directly on the module racking or on an extension arm maintained at the same tilt angle as the modules, avoiding shadings and reflections completely.~~

~~NOTE The measured irradiance may differ depending on the position of the sensor. For example, if the sensor is placed below a row of modules, it may show a different reading than when placed above the row of modules, since a contribution to the irradiance in a tilted plane originates from the ground or nearby features.~~

~~The local albedo should be representative of the albedo experienced by the system without the effects of adjacent module shading. If the ground covering is not a constant throughout the field, the ground covering next to the irradiance sensors shall be documented relative to what is present in the rest of the field.~~

7.2.1.6 Sensor alignment

~~Irradiance sensor angular alignment accuracy requirements are listed in Table 6.~~

Table 6 — Irradiance sensor alignment accuracy

	Class-A High-accuracy	Class-B Medium-accuracy	Class-C Basic-accuracy
Tilt angle	1°	1,5°	2°
Azimuthal angle	2°	3°	4°

The following are suggested methods of aligning the irradiance sensor to the desired angles.

- a) Tilt: Adjust the sensor mounting plate to a horizontal position, verify with a digital inclinometer, level the sensor to the plate, and secure the sensor to the plate; then adjust the mounting plate to the desired tilt angle as verified with the digital inclinometer, and tighten the plate's tilt adjustment when done.
- b) Azimuth: Using a GPS receiver, start at the sensor's location and then walk out approximately 100 m in the direction of the desired azimuth, then mark this point with an indicator such as a flag; returning to the sensor, sight along a square edge of the sensor mounting plate while adjusting the mounting plate azimuthal angle until the sight line intersects the marker previously placed with the aid of the GPS receiver; tighten the mounting plate's azimuth adjustment when done.

7.2.1.7 — Sensor maintenance

Irradiance sensor maintenance requirements are listed in Table 7.

Table 7 — Irradiance sensor maintenance requirements

Item	Class-A High-accuracy	Class-B Medium-accuracy	Class-C Basic-accuracy
Recalibration	Once per year	Once every 2 years	As per manufacturer's requirements
Cleaning	At least once per week	Optional	
Heating to prevent accumulation of condensation and/or frozen precipitation	Required in locations where condensation and/or frozen precipitation would affect measurements on more than 7 days per year	Required in locations where condensation and/or frozen precipitation would affect measurements on more than 14 days per year	
Ventilation (for thermopile pyranometers)	Required	Optional	
Desiccant inspection and replacement (for thermopile pyranometers)	As per manufacturer's requirements	As per manufacturer's requirements	As per manufacturer's requirements

Recalibration of sensors and signal conditioning electronics should be performed on-site when possible to minimize the time that sensors are offline. If sensors are to be sent off-site for laboratory recalibration, the site should be designed with redundant sensors or else backup sensors should be used to replace those taken offline, in order to prevent interruption of monitoring.

Cleaning of irradiance sensors without cleaning the modules can result in a lowering of the measured PV system performance ratio (defined in 10.3.1). In some cases contract requirements may specify that irradiance sensors are to be maintained in the same state of cleanliness as the modules.

Night-time data should be checked to ensure accurate zero-point calibration.

~~NOTE It is common for pyranometers to show a small negative signal, $-1 \text{ W}\cdot\text{m}^{-2}$ to $-3 \text{ W}\cdot\text{m}^{-2}$, at night time.~~

~~7.2.1.8 Additional measurements~~

~~7.2.1.8.1 Direct normal irradiance~~

~~Direct normal irradiance (DNI) is measured with a pyrheliometer on a two-axis tracking stage which automatically tracks the sun.~~

~~7.2.1.8.2 Diffuse horizontal irradiance~~

~~Diffuse horizontal irradiance G_d (or DHI) is measured with a horizontally mounted irradiance sensor with a rotating shadow band or tracked ball that blocks rays emanating directly from the solar disc.~~

8.1 Sensor types

Approaches to ground-based on-site irradiance measurement include:

- Measure total broadband hemispherical solar irradiance, independent of spectral or angular distribution. Instruments with this objective are classified as pyranometers, regardless of technology type.
- Measure matched irradiance corresponding to the PV-usable portion of the incident spectral and angular distribution. PV reference devices (reference cells and modules) are used for this objective.
- Measure spectral irradiance, from which spectrally matched irradiance can be determined. Spectroradiometers or multi-spectral instruments can be used for this objective.

Measurements can be transposed between approaches using appropriate models, with some uncertainty. If used, model-based transpositions and corrections shall be documented.

Irradiance may also be determined from remote measurements using satellite instrumentation as a supplement, or replacement (when permitted by Table 2), for ground-based on-site measurements. See 8.3.12.

The selected sensor and sensor type shall be documented.

8.2 General requirements

8.2.1 Overview

This subclause 8.2 provides general requirements applicable to most on-site irradiance measurements. Subsequent subclauses on specific irradiance measurement types may include different and/or additional requirements.

8.2.2 Sensor requirements

Sensors shall meet the requirements of Table 4 according to sensor type.

Table 4 – Irradiance sensor requirements

Sensor type	Class A system	Class B system
Pyranometer	<u>Front side (POA and GHI):</u> Class A per ISO 9060:2018, Spectrally flat Calibration uncertainty $\leq 2\%$ at $1\,000\text{ W}\cdot\text{m}^{-2}$ Range up to $1\,500\text{ W}\cdot\text{m}^{-2}$ Resolution $\leq 1\text{ W}\cdot\text{m}^{-2}$ <u>Rear side:</u> Class C or better per ISO 9060:2018 Calibration uncertainty $\leq 3\%$ at $1\,000\text{ W}\cdot\text{m}^{-2}$ Range up to $1\,500\text{ W}\cdot\text{m}^{-2}$ Resolution $\leq 1\text{ W}\cdot\text{m}^{-2}$	Class C or better per ISO 9060:2018 Calibration uncertainty $\leq 3\%$ at $1\,000\text{ W}\cdot\text{m}^{-2}$ Range up to $1\,500\text{ W}\cdot\text{m}^{-2}$ Resolution $\leq 1\text{ W}\cdot\text{m}^{-2}$
PV reference device	Working reference device per IEC 60904-2 Calibration uncertainty $\leq 2\%$ at $1\,000\text{ W}\cdot\text{m}^{-2}$ Range up to $1\,500\text{ W}\cdot\text{m}^{-2}$ Resolution $\leq 1\text{ W}\cdot\text{m}^{-2}$	Working reference device per IEC 60904-2 Calibration uncertainty $\leq 3\%$ at $1\,000\text{ W}\cdot\text{m}^{-2}$ Range up to $1\,500\text{ W}\cdot\text{m}^{-2}$ Resolution $\leq 1\text{ W}\cdot\text{m}^{-2}$

Pyranometers include a wide range of instrument technologies, including but not limited to thermopile pyranometers and single- or multi-photodiode-based instruments. For front-side solar irradiance measurement in Table 4, spectrally flat means that the pyranometer's broadband irradiance measurement is negligibly affected by the spectral distribution of the incident sunlight.

8.2.3 Sensor locations

8.2.3.1 Front side

The location of front-side irradiance measurement sensors, including GHI and plane-of-array sensors, shall be chosen to be representative and to avoid shading conditions from sunrise to sunset, if possible. Shading should only occur within a half hour of sunrise or sunset and any shading shall be documented.

For front-side plane-of-array irradiance measurements, for either fixed-tilt or tracking systems, sensors shall be maintained at the same tilt and azimuth angles as the modules. This may be achieved by placing the sensors either directly on the module racking or on separate poles or extension arms with tracking, if applicable.

NOTE Optionally, additional front-side irradiance sensors may be placed in locations that are temporarily shaded by adjacent module rows, e.g. during backtracking of a tracking system, in order to monitor this shading effect, but these sensors do not satisfy the requirements of Table 2 and Table 3 and the performance metrics always use unshaded sensors, unless explicitly noted.

8.2.3.2 Rear side

The location of rear-side irradiance and/or in-plane rear-side irradiance ratio sensors shall be chosen such that they have a field of view representative of the conditions present on the rear side in the majority of the array, while minimizing shading on the modules. If the expected ground surface varies throughout the site, use an appropriate quantity of sensors and sampling methodology to capture the variations. The sensors should also be placed to capture the rear-side irradiance without impact from local surroundings other than representative shading by nearby portions of the PV array.

The sensors should be placed at the same tilt angle as the modules, directly on the module racking, by using beam or rail support structures, and positioned away from row ends, mounting piers, and other sources of localized shading or enhanced illumination phenomena such as reflections from the module racking.

A concern regarding in-plane rear-side irradiance sensors and in-plane rear-side irradiance ratio sensors is the non-uniformity of the irradiance reaching the back side of the module surface from edge to edge. It is recommended to place multiple sensors along the rear side of the racking structure to follow and measure the non-uniform illumination profile throughout the day. This allows both quantifying the non-uniformity of the rear-side irradiance and calculating an effective average of the rear-side irradiance for introduction into selected performance formulas.

NOTE The measured irradiance may differ depending on the position of the sensor, especially in the case of rear-side POA sensor measurements. For example, if the sensor is placed below a row of modules, it may show a different reading than when placed above the row of modules, since a contribution to the irradiance in a tilted plane originates from the ground or nearby features.

8.2.3.3 Horizontal albedo

The location of horizontal albedo sensors shall be chosen to be representative of the albedo at the site. The sensors should be mounted at a minimum height of 1,0 m in order to allow for a sufficient field of view of irradiance reflecting from the ground and should not be shaded by vegetation or any nearby structures, including modules and the module support structure, within a ± 80 degree viewing angle. Shading by the albedo measurement device and its support structure should be minimized. If the expected ground surface varies throughout the site, use an appropriate quantity of sensors and sampling methodology to capture the variations.

8.2.4 Recalibration

Recalibration of sensors shall be conducted in a manner that minimizes downtime and sensor outages in order to prevent interruption of monitoring. Effective methods may include:

- Exchanging installed sensors with new or recalibrated units
- Performing on-site recalibration of sensors where possible
- Providing redundant sensors and alternating laboratory recalibration schedules.

For Class A systems, sensors shall be recalibrated once every 2 years, or more frequently per manufacturer recommendations.

For Class B systems, recalibrate sensors according to manufacturer recommendations.

8.2.5 Soiling mitigation

For Class A systems the effects of soiling accumulation on irradiance sensors shall be mitigated. For typical sensors and installations, weekly cleaning is required. Cleaning may be employed less frequently when local conditions allow or when technology is employed which mitigates or corrects for sensor soiling equivalently to weekly cleaning or detects soiling so that cleaning can be scheduled when needed.

8.2.6 Dew and frost mitigation

For Class A systems, the effects of dew and frost accumulation on irradiance sensors shall be mitigated for locations where dew or frost is expected during more than 2 % of annual GHI-hours.

Determination of whether an installation site requires mitigation may be performed by examining typical meteorological year data for the site, paying attention to ambient temperature and dew point. For the purposes of this assessment, dew or frost is considered expected when ambient temperature is within 1,5 °C of dew point.

Various means of mitigation, including heating and external ventilation, can be effective. Irradiance sensors shall maintain their accuracy and classification while dew and frost mitigation is applied. Heating shall not disturb the sensor's accuracy and classification. For pyranometers, effective means of ensuring accurate performance while the sensor is heated may include, but are not limited to, internal and external ventilation.

8.2.7 Inspection and maintenance

Routine inspection of sensors shall be performed to check for soiling, misalignment, and other fault conditions. For Class A systems, front-side sensors shall be inspected weekly.

Sensors shall be maintained according to manufacturer requirements. Maintenance requirements may include, for example, desiccant inspection and/or replacement, where applicable.

8.2.8 Sensor alignment

Irradiance sensors for global horizontal irradiance (*GHI*) shall be levelled to within 0,5°.

Irradiance sensors for plane-of-array (*POA*) irradiance shall be aligned with their intended plane within 0,5° of tilt and 1° of azimuth (Class A) or 1° of tilt and 2° of azimuth (Class B), with the following provisions:

- When the sensors are placed directly on the module racking, the alignment requirement is met if it can be shown that the sensors are aligned to the racking to within the stated tolerances.
- When the sensors are placed on another mounting structure independent of the modules, care shall be taken to achieve and verify alignment to within stated tolerances. If alignment cannot be achieved, the alignment error shall be measured and documented.

NOTE Sensor tilt can be measured with an inclinometer. Azimuthal alignment of plane-of-array sensors can be verified by reviewing and modelling a time series of irradiance data in clear-sky conditions.

8.3 Measurements

8.3.1 Global horizontal irradiance

Global horizontal irradiance (*GHI*) is measured with a horizontally oriented upwards-facing irradiance sensor or is determined from the combination of direct normal irradiance and diffuse horizontal irradiance per formula in 3.21.

8.3.2 In-plane irradiance

For flat-plate systems, in-plane irradiance is measured with an irradiance sensor with aperture oriented parallel to the plane of array (*POA*) mounted either on the module support structure or on another structure that is aligned parallel to the modules.

In the case of tracked systems, the irradiance sensor shall be continuously aligned with the actual plane of array of the modules, including backtracking if used.

For concentrator systems, see 8.3.9.

If any trackers are programmed to operate in a non-standard way relative to the rest of the array, these trackers should be excluded as sensor locations for the purposes of Table 2 and Table 3, but may optionally receive additional complementary sensors.

NOTE 1 The measurement of irradiance on a tracked surface can become erroneous if the tracker supporting the sensor does not track correctly. An approach to verification is to use the measured direct normal irradiance and horizontal diffuse irradiance, *DNI* and G_d respectively, and a transposition model to calculate the expected in-plane irradiance and then compare this with the measured value.

NOTE 2 POA irradiance can also be estimated from GHI using a decomposition and transposition model.

8.3.3 In-plane rear-side irradiance

Accurately determining the rear-side solar resource of bifacial systems is difficult. The rear-side irradiance on a PV array, as well as the spectral content of the irradiance, varies strongly spatially and temporally depending on shading patterns, details of the mounting structure, ground surface properties, and seasonal variations.

Table 2 provides two options for determining rear-side irradiance in bifacial systems:

- Option 1: Measure horizontal albedo and optionally diffuse irradiance, and use an optical model, such as a view-factor or ray-tracing model, to estimate rear-side irradiance.
- Option 2: Directly measure rear-side in-plane irradiance or, optionally, spectrally matched in-plane rear-side irradiance.

Direct measurement of rear-side in-plane irradiance is performed with an irradiance sensor with aperture oriented parallel to the plane of array (*POA*) mounted on the rear side of the module support structure. This may also be performed with a bifacial reference device (see 3.19).

8.3.4 In-plane rear-side irradiance ratio

For bifacial systems, in-plane rear-side irradiance ratio is measured by taking the ratio of the in-plane rear-side irradiance (see 8.3.3) to the in-plane irradiance (see 8.3.2).

8.3.5 Horizontal albedo

Horizontal albedo is determined by measuring the downwelling irradiance from the sky in a horizontal plane (*GHI*) and the upwelling ground-reflected irradiance in a horizontal plane and calculating the ratio of upwelling to downwelling irradiance.

See Option 1 and Option 2 in 8.3.3.

8.3.6 Direct normal irradiance

Direct normal irradiance (*DNI*) is measured with an instrument that blocks or corrects for diffuse irradiance contributions. Examples include pyrheliometers, rotating shadow band radiometers, tracked disk or ball radiometers, and others. *DNI* may be calculated from *GHI* and *DHI* per the formula in 3.23.

8.3.7 Diffuse horizontal irradiance

Diffuse horizontal irradiance G_d (or *DHI*) is measured with an instrument that blocks or corrects for direct irradiance contributions. Examples include rotating shadow band radiometers, tracked disk or ball radiometers, and others. *DHI* may be calculated from *GHI* and *DNI* per the formula in 3.27.

8.3.8 Spectrally matched irradiance

For determination of the usable solar resource, optional spectral matching of irradiance measurements for the user's specific PV modules should be considered.

Spectrally matched rear-side irradiance is particularly relevant because the spectrum of ground-reflected radiation can differ significantly from the incident solar radiation.

Methods for determining spectrally matched irradiance include:

- Measuring spectrally-matched irradiance using a spectrally matched reference device per 3.17. The residual spectral mismatch can be determined by IEC 60904-7 considering typical spectra for the application. Users should select a degree of residual spectral mismatch appropriate to their application. Identical PV technology is not necessarily required; for example, commercial monocrystalline silicon reference cells will provide beneficial spectral matching (compared to broadband measurement) for most commercial crystalline silicon PV technologies.
- Measuring broadband or non-spectrally-matched irradiance, e.g. using a pyranometer, plus performing a model-based spectral mismatch correction using environmental data such as temperature, humidity, etc.
- Measuring spectral irradiance, e.g. using a spectroradiometer or other multi-spectral instrument, from which spectral correction factors may be derived and applied to broadband irradiance data to obtain spectrally matched irradiance.

8.3.9 In-plane irradiance for concentrator systems

For concentrator systems, the total in-plane irradiance is replaced by the irradiance captured by the concentrator.

- For concentrator systems that capture only the direct beam:

The in-plane irradiance G_i is replaced by the in-plane direct beam irradiance $G_{i,b}$:

$$G_i = G_{i,b} \quad (1)$$

- For concentrator systems that capture some diffuse light in addition to the direct beam:

The in-plane irradiance is replaced by the effective irradiance (G_{eff}) owing to partial diffuse capture, where the fraction of diffuse light is quantified by the parameter f_d :

$$G_i \rightarrow G_{\text{eff}} = (G_{i,b} + f_d \cdot (G_i - G_{i,b})) \quad (2)$$

Determination of f_d begins by obtaining full current and voltage characteristics of a CPV module over many days with varying fractions of diffuse energy; a clear day will have little diffuse energy while a cloudy day will provide mainly diffuse energy. Analysis of a diffuse fraction for a given low and medium concentration CPV module should be based upon a large number of I - V curves where global in-plane irradiance (G_i) is above $21 \text{ W} \cdot \text{m}^{-2}$.

A fundamental premise of this method is that the short-circuit current (I_{sc}) can be consistently and reliably estimated by acquiring a full trace of the current-voltage (I - V) curve for the device under test (DUT) and that the temperature coefficient for the I_{sc} parameter of the DUT has been well characterized in advance. When this premise is valid, the diffuse light capture characterization of a CPV module or receiver becomes simply a matter of determining the short-circuit current, $I_{\text{sc},0}$ normalized to standard test conditions (STC) and then relating the as-measured $I_{\text{sc},0}$ to this reference using an "effective irradiance" G_{eff} , such as that shown in Formula (2). One significant advantage of this approach is that compensating for the effects of solar spectrum can be accomplished by adjusting only the I_{sc} parameter.

By plotting the terms on the left-hand side of Formula (3) on the y -axis of a 2D graph and by plotting $G_{i,b}/G_i$ on the x -axis, the slope and intercept can be easily determined from the form $y = mx + b$ after performing a linear regression analysis of the I_{sc} vs. $G_{i,b}/G_i$ data.

$$\frac{1000 \text{ W} \cdot \text{m}^{-2}}{G_i} \times \frac{I_{sc}}{[1 + \alpha_{I_{sc}} \times (T_c - 25^\circ \text{C})]} = (I_{sc,0} \times f_d) + \left(\frac{G_{i,b}}{G_i}\right) \times (I_{sc,0} - f_d \times I_{sc,0}) \quad (3)$$

where

$\alpha_{I_{sc}}$ is the temperature coefficient for I_{sc} ,

T_c is the cell temperature in $^\circ\text{C}$,

$I_{sc,0}$ is the short circuit current at STC ~~(see Clause 3)~~ and 0° angle of incidence.

The term f_d then becomes:

$$f_d = \frac{b}{m + b} \quad (4)$$

One limitation to this approach that should be noted is the inherent assumption that the amount of diffuse light captured will be constant throughout the entire range of climatic conditions that are being observed. This will certainly introduce noise into the measurements, but if sampling is high enough, the linear regression analysis discussed above can provide a reasonable estimate for an average amount of diffuse capture that can be used to better define the solar resource for such concentrator PV modules.

If the results observed present a clear inflection or break in the diffuse capture response behaviour of the CPV module, the regression analysis can be split into multiple parts in a piecewise manner. This could be a likely outcome given that the nature of diffuse light is quite variable in the relative amounts of circumsolar vs. isotropic diffuse light. By treating the linear regression analysis in this fashion, one can determine the amount of diffuse capture (f_d) as a function of a specific range of the $G_{i,b}/G_i$ ratio.

8.3.10 Spectral irradiance for concentrator systems

For concentrator systems when a power rating according to IEC 62670-3 is to be performed, the system should include a device for determining the direct normal spectral irradiance. Refer to IEC 62670-3 for additional details.

8.3.11 Circumsolar ~~ratio~~ measurements for concentrator systems

For concentrator systems, it may be useful to measure circumsolar irradiance. Circumsolar irradiance is irradiance emanating from a region of the sky immediately surrounding the solar disk. Useful parameters to measure may include circumsolar contribution, circumsolar ratio, and sunshape. See ISO 9488.

The measured direct normal irradiance (DNI) may include circumsolar contributions due to the angular acceptance of the DNI sensor. The fraction of measured DNI which is circumsolar is defined as the circumsolar ratio.

Concentrator systems may or may not be able to capture a portion of the circumsolar irradiance, depending on their design. However, measuring circumsolar ~~ratio~~ quantities may be useful for performance characterization purposes; ~~however, CSR measurement devices have not yet been standardized.~~

8.3.12 Satellite remote sensing of irradiance

~~When permitted by Table 3, irradiance quantities may be estimated from satellite remote sensing. Such satellite-derived irradiances are extensively used for monitoring the performance of distributed generation systems including non-instrumented class B and class C systems, in order to avoid the cost and maintenance requirements of on-site measurements.~~

~~Satellite remote sensing is an indirect approach to reliably estimate site- and time-specific surface downwelling irradiance. The approach is indirect because on-board satellite instruments measure the radiance emitted/reflected by the earth's surface through the filter of the atmosphere in a selected number of visible and infrared spectral bands; surface downwelling irradiance is inferred from these on-board satellite measurements via radiative transfer models. In-plane and other irradiance components are further modeled from the radiative transfer model output.~~

~~Satellite-derived irradiances, including global horizontal, direct normal, diffuse, and in-plane irradiances are typically available in real time from commercial services.~~

~~Important considerations when selecting satellite models are as follows:~~

- ~~• satellite-derived data should be carefully selected after a review of their accuracy, e.g., by reviewing application-pertinent (localized) validations associated with the data source;~~
- ~~• good satellite models can be trained locally using short-term, regionally/environmentally representative ground measurements.~~

~~NOTE 1 Satellite-derived irradiances have both advantages and disadvantages compared to on-site measured irradiances. Their main advantage is their reliability and consistency in terms of calibration and maintenance. With a single set of carefully monitored on-board sensors covering entire continents at once, satellites remove the uncertainty and cost associated with on-site maintenance, instrumentation soiling, calibration drifts and location to location mismatches. The main limitation of satellite irradiances versus on-site measured irradiances is their intrinsic accuracy. Unlike ground-based instruments, the accuracy of satellite models is not constant in relative terms over the entire range of irradiances, but tends to be constant in absolute terms. For the primary product of the radiative transfer models — global horizontal irradiance (GHI) — well trained satellite models typically have an accuracy of better than 2 % at $1\,000\text{ W}\cdot\text{m}^{-2}$, but 20 % at $100\text{ W}\cdot\text{m}^{-2}$ — i.e., a constant $\sim 20\text{ W}\cdot\text{m}^{-2}$ throughout the $100\text{ W}\cdot\text{m}^{-2}$ to $1\,000\text{ W}\cdot\text{m}^{-2}$ range. Note that this uncertainty is not defined in absolute terms, but in relation to — hence above and beyond — the ground-based instruments against which satellite models are evaluated.~~

~~NOTE 2 The best trained satellite models can deliver an accuracy of 1 % at $1\,000\text{ W}\cdot\text{m}^{-2}$, and 10 % at $100\text{ W}\cdot\text{m}^{-2}$ — i.e., a constant $\sim 10\text{ W}\cdot\text{m}^{-2}$ throughout the $100\text{ W}\cdot\text{m}^{-2}$ to $1\,000\text{ W}\cdot\text{m}^{-2}$ range — relative to the instrumentation used to train them. Quantities derived from the primary radiative transfer model output GHI, including tilted in-plane irradiance, direct normal irradiance, and diffuse irradiance, have a higher uncertainty due to application of secondary models. Uncertainty for tilted, south-facing (northern hemisphere) or north-facing (southern hemisphere) in-plane irradiances is typically 1,25-times larger than for GHIs, i.e. 2,5 % at $1\,000\text{ W}\cdot\text{m}^{-2}$ for an untrained model, and 1,25 % for a trained model, relative to the training instrumentation. Direct normal irradiance uncertainty is of the order of 4 % at full range ($1\,000\text{ W}\cdot\text{m}^{-2}$) for an untrained model and 2 % for a trained model, relative to the training instrumentation.~~

~~NOTE 3 If satellite-derived data have not been trained for a local area, variations in the local terrain can introduce substantial error on the order of 10 %. This is especially true in a desert with white sand, which may be difficult to distinguish from white clouds in some situations.~~

~~NOTE 4 Satellite-derived data may be less accurate for short periods but more accurate when averaged over long periods. Therefore satellite-derived data may be more appropriate, for example, for evaluating system energy production over an extended period as compared to instantaneous power production.~~

Satellite remote sensing techniques use a dual approach to measuring the total surface downwelling irradiance at the global horizontal plane. The on-board satellite instruments measure the radiance emitted or reflected by the earth's surface through the column of the atmosphere at specific visible and infrared spectral bands. The emitted radiance represents conditions where cloud cover is present, so measurements by this technique need to be framed in reference of the clear sky irradiance models. Thus, the base of satellite remote sensing uses radiative transfer models to predict the clear sky condition, then satellite measurements are applied to the clear sky as reduction in irradiance due to cloud opacity.

Operating plants considering satellite remote sensed irradiance should consider the following when comparing to on-site measured irradiances. Validated sources of satellite irradiance will have documented reliability and consistency in terms of data availability and calibration, respectively. Because satellite remote sensed irradiance sources use a single set of carefully monitored on-board sensors covering entire continents at once, data can be delivered with reduced uncertainty and cost associated with on-site maintenance, instrumentation soiling, calibration drifts and location-to-location mismatches. The accuracy benefits of satellite remote sensed data come at different temporal and spatial averaging versus on-site measurements. Satellite measurement of cloud opacity occurs at the spatial scale determined by the resolution of the measurement hardware on the satellite. For most modern satellite networks, this is approximately $0,01^\circ$ by $0,01^\circ$ latitude or longitude (roughly 1 km by 1 km). Thus, the representation of the irradiance condition from satellite sources reflects the average irradiance over a $0,01^\circ$ by $0,01^\circ$ square area. In contrast, on-site measurements reflect irradiance conditions at the surface area of the sensor, effectively a single point. This difference in measurement area leads to differences in irradiance over various time averaging periods. Additionally, the satellite image capture frequency is typically less than ground hardware data logging. As a result of both effects, satellite and ground may show greater differences in irradiance measurements on the order of 10 % to 20 % for sub-hourly to hourly periods where plant operators may be seeking analysis to diagnose plant underperformance. However, at monthly up to yearly averaging periods, satellite and ground will align on the order of < 1 % to 5 %, where plant operators may be seeking analysis to demonstrate overall plant performance.

Satellite remote sensed irradiances, including global horizontal, direct normal, diffuse, and in-plane irradiances are typically available in real time from commercial services. Long-histories of satellite measurements can be beneficial to plant operators as a reference for plant performance against long-term average/financial forecast conditions.

Important considerations when selecting satellite data are as follows:

- Satellite remote sensed irradiance data should be carefully selected after a review of accuracy and uncertainty.
- Satellite accuracy and uncertainty should be assessed against quality ground data from well-maintained sensors.
- Satellite sources should have a long history of measurement to verify accuracy across changes in satellite hardware.
- Satellite sources should provide data up to current time, also for the purpose of evaluating accuracy.
- Satellite data should be versioned; e.g. the metadata about the satellite measurements should be traceable to a repeatable model basis.
- Satellite data should provide measurements at the native satellite hardware device precision.
- The satellite remote sensed method should be specifically designed for measuring solar irradiance.

9 Environmental factors

9.1 PV module temperature

PV module temperature, T_{mod} , is measured with temperature sensors affixed to the back of ~~one~~ ~~or more~~ PV modules.

~~The measurement uncertainty of the temperature sensors, including signal conditioning, shall be $\leq 2^\circ\text{C}$.~~

~~Temperature sensors shall be replaced or recalibrated as per Table 8.~~

Table 8 – PV module temperature sensor maintenance requirements

Item	Class A High accuracy	Class B Medium accuracy	Class C Basic accuracy
Recalibration	Once every 2 years	Per manufacturer's recommendations	Not applicable

For bifacial modules, rear-side temperature sensors and wiring shall obscure < 10 % of the area of any cell, and wiring should be routed in between cells when possible.

Temperature sensors shall have a measurement resolution $\leq 0,1$ °C and uncertainty ± 1 °C or better.

If adhesive is used to affix the temperature sensor to the back surface of the module, the adhesive should be appropriate for prolonged outdoor use at the site conditions and should be checked to be compatible with the surface material on the rear of the module to prevent degradation by the adhesive.

Adhesive or interface material between the temperature sensor and the rear surface of the module shall be thermally conductive. The total thermal conductance of the adhesive or interface layer shall be $500 \text{ W}\cdot\text{m}^{-2}\cdot\text{K}^{-1}$ or greater, in order to keep the maximum temperature difference between the module's rear surface and the temperature sensor on the order of approximately 1 K. For example, this may be achieved using a thermally conductive adhesive with thermal conductivity greater than $0,5 \text{ W}\cdot\text{m}^{-1}\cdot\text{K}^{-1}$ in a layer not more than 1 mm thick.

See Annex B for additional recommendations on temperature sensor attachment.

Care ~~shall~~ should be taken to ensure that the temperature of the cell in front of the sensor is not substantially altered due to the presence of the sensor or other factors.

NOTE 1 Cell junction temperatures are typically 1 °C to 3 °C higher than the temperature measured on the module's rear surface, depending on the module construction. The temperature difference may be estimated, as a function of irradiance, using the thermal conductivity of the module materials.

NOTE 2 An infrared image of the front of the module may help confirm that the temperature of the cell in front of the sensor is not substantially altered by the presence of the sensor or other factors.

Module temperature varies across each module and across the array ~~and substantial differences in temperature may be observed. For example, strong winds blowing parallel to the module surfaces may introduce a temperature difference > 5 °C. Similarly, a module may be cooler near a frame that is clamped to the rack, since the rack may act as a heat sink. Concentrator modules may show even larger variations between the outer edges of the heat sink and the heat sink that is closest to the concentrated light.~~ Temperature sensors shall be placed in representative locations to capture the range of variation and allow determination of an effective average.

~~Therefore, care shall be taken to place temperature sensors in representative locations such that the desired information is obtained. For performance monitoring, a number of temperature sensors should be distributed throughout the system so that the average temperature can be determined.~~

~~In addition, when the array consists of more than one module type or includes sections with different orientations or other attributes that can affect temperature, at least one temperature sensor is required for each module type or section type, and additional sensors, if required according to array size, are to be distributed in a representative manner amongst the different module types and section types.~~

~~Module temperature measurement may also be performed with the V_{oc} -based method described in IEC 60904-5 as an alternative to using a temperature sensor in contact with the module back surface. This may require use of an additional reference module, not connected to the PV array, for temperature measurement purposes.~~

Temperature sensors shall be replaced or recalibrated as per manufacturer's requirements.

Module temperature measurement may alternatively be performed with the V_{oc} -based method described in IEC 60904-5. This may require use of an additional reference module, not connected to the PV array, for temperature measurement. The module should be independently calibrated for this purpose. The module should be held at maximum power point in between brief V_{oc} measurements to ensure temperature is representative of the PV array. Considering the degradation of V_{oc} over time, the relation between module temperature and V_{oc} should be recalibrated at periodic intervals. If the module is not held at maximum power point, a calibrated temperature offset between maximum power point and the actual operating condition should be determined.

9.2 Ambient air temperature

~~When required by Table 3, the ambient air temperature, T_{amb} , shall be measured at locations which are representative of the array conditions by means of temperature sensors located in solar radiation shields which are ventilated to permit free passage of ambient air.~~

~~Temperature sensors and signal conditioning electronics shall together have a measurement resolution $\leq 0,1^{\circ}\text{C}$ and maximum uncertainty $\pm 1^{\circ}\text{C}$.~~

~~Temperature sensors should be placed at least 1 m away from the nearest PV module and in locations where they will not be affected by thermal sources or sinks, such as exhausts from inverters or equipment shelters, asphalt or roofing materials, etc.~~

~~Temperature sensors shall be replaced or recalibrated as per Table 9.~~

Table 9 — Ambient air temperature sensor maintenance requirements

Item	Class A High accuracy	Class B Medium accuracy	Class C Basic accuracy
Recalibration	Once every 2 years	Per manufacturer's recommendations	Not applicable

~~When permitted by Table 3, ambient air temperature at the site may be estimated based on local or regional meteorological data.~~

Ambient air temperature, T_{amb} , is measured by means of temperature sensors located in solar radiation shields which are ventilated to permit free passage of ambient air.

The sensors shall have a measurement resolution $\leq 0,1^{\circ}\text{C}$ and uncertainty $\pm 1^{\circ}\text{C}$ or better.

The sensors should be placed at least 1 m away from the nearest PV module and in locations where they will not be affected by thermal sources or sinks, such as exhausts from inverters or equipment shelters, asphalt or roofing materials, etc.

The sensors shall be replaced or recalibrated as per manufacturer's requirements.

9.3 Wind speed and direction

Wind speed and wind direction are used for estimating module temperatures. They may also be used for documenting warranty claims related to wind-driven damage.

Wind speed and direction are to be measured at a height and location which are representative of the array conditions and/or the conditions assumed by any applicable performance model used for a performance guarantee of the PV installation.

In addition, wind speed and direction may also be measured at heights and locations suitable for comparison with historical or contemporaneous meteorological data.

In some cases data on wind gusts (typically gusts up to 3 s in length) may be required to compare with project design requirements. When necessary the monitoring system sampling period should be sufficiently small (e.g. ≤ 3 s) and the data record should contain not only averaged but also maximum values. (See 6.1.)

Wind measurement equipment ~~shall~~ **should** not shade the PV system at any time of day or year and should be located at a point that is sufficiently far from obstructions.

Wind speed sensor measurement uncertainty shall be $\leq 0,5 \text{ m}\cdot\text{s}^{-1}$ for wind speeds $\leq 5 \text{ m}\cdot\text{s}^{-1}$, and $\leq 10 \%$ of the reading for wind speeds greater than $5 \text{ m}\cdot\text{s}^{-1}$.

Wind direction is defined as the direction from which the wind blows, and is measured clockwise from geographical north. It shall be measured with an accuracy of 5° .

Wind sensors shall be recalibrated as per ~~Table 10~~ manufacturer's recommendations.

Table 10 — Wind sensor maintenance requirements

Item	Class-A High-accuracy	Class-B Medium-accuracy	Class-C Basic-accuracy
Recalibration	Per manufacturer's recommendations	Per manufacturer's recommendations	Per manufacturer's recommendations

9.4 Soiling ratio

~~7.3.4.1~~ Definition

~~The soiling ratio is the ratio of the actual power output of the PV array under given soiling conditions to the power that would be expected if the PV array were clean and free of soiling.~~

~~7.3.4.2~~ Equipment

~~Measurement of the soiling ratio requires the following:~~

- ~~A reference PV device, designated the "soiled" device, which is allowed to accumulate soiling at the same rate as the PV array. The soiled device may be either a PV reference cell or PV module, but should preferably be a PV module that is identical to or representative of those used in the PV array to be monitored so that it will soil at the same rate. It shall be mounted in the same plane as and at the average height of the PV array, preferably with identical mounting mechanisms.~~
- ~~A reference PV device, designated the "clean" device, which is regularly cleaned so that it is kept free of soiling. The clean device may be either a PV reference cell or PV module, but shall have similar spectral and angular response to the soiled device. The effect of any differences in response should be included in the measurement uncertainty. The clean device shall be mounted close to the soiled device and co-planar to it within $0,5^\circ$ of each other.~~

~~may be performed either manually or by an automated system and shall be done daily or at least twice per week, for Class A, or at lesser intervals if desired for Class B and Class C. The clean device should be heated to remain free of frozen precipitation if installed in areas that typically receive more than 7 days of frozen precipitation per year.~~

- ~~c) A measurement system for measuring the maximum power (method 1 in 7.3.4.4) and/or short-circuit current (method 2 in 7.3.4.5) of the soiled device. Maximum power may be measured using I-V curve tracing or max-power-point tracking electronics.~~
- ~~d) A measurement system for measuring the short-circuit current of the clean device.~~
- ~~e) A measurement system for measuring the temperatures of both the soiled and clean devices using temperature sensors affixed to their rear surfaces.~~

~~For items c) and d), in between measurements, the measurement system shall not hold the module in an electrical state which may cause degradation or metastable drift of the device. Therefore, typical crystalline silicon modules should be held at open-circuit (or max power) in between measurements, to avoid hot spot generation, while typical thin film modules should be held at short-circuit (or max power) in between measurements. Observe the module manufacturer's directions as needed to choose the appropriate hold state.~~

~~For tracking systems, the soiled and clean devices shall be mounted in the module plane of the tracker.~~

7.3.4.3 — Calibration

- ~~a) Choose a reference condition of irradiance and PV device temperature, e.g. STC.~~
- ~~b) Determine a calibration value for the short-circuit current of the clean device at the designated reference condition. It is sufficient to use the manufacturer's datasheet values.~~
- ~~c) Using the clean device to measure irradiance, determine calibration values for the max power (method 1 in 7.3.4.4) and/or short-circuit current (method 2 in 7.3.4.5) of the soiled device at the reference condition as follows:

 - ~~1) Completely clean the soiled device.~~
 - ~~2) Simultaneously measure the soiled device maximum power and/or short-circuit current and temperature as well as the clean device short-circuit current and temperature.~~
 - ~~3) Using the clean device measured short-circuit current and temperature, with the calibration data determined in step b), calculate the effective irradiance.~~
 - ~~4) Using this calculated irradiance and the measurements for the soiled device, calculate the maximum power and/or short-circuit current of the soiled device corrected to the reference condition of irradiance and temperature.~~~~

7.3.4.4 — Measurement method 1 — max power reduction due to soiling

~~Perform the measurement as follows:~~

- ~~a) Measure the short-circuit current and temperature of the clean device.~~
- ~~b) Measure the max power and temperature of the soiled device.~~
- ~~c) Calculate the effective irradiance from the values measured in a), using the calibration values determined in 7.3.4.3 b).~~
- ~~d) Calculate the expected max power of the soiled device at the irradiance determined in c) and the temperature measured in b), using the calibration values determined in 7.3.4.3 c).~~
- ~~e) Calculate the soiling ratio SR by dividing the soiled device max power measured in b) by its expected max power calculated in d).~~

7.3.4.5 — Measurement method 2 — short-circuit current reduction due to soiling

~~Perform the measurement as follows:~~

- ~~a) Measure the short-circuit current and temperature of the clean device.~~

- ~~b) Measure the short-circuit current and temperature of the soiled device.~~
- ~~c) Calculate the effective irradiance from the values measured in a), using the calibration values determined in 7.3.4.3 b).~~
- ~~d) Calculate the expected short-circuit current of the soiled device at the irradiance determined in c) and the temperature measured in b), using the calibration values determined in 7.3.4.3 c).~~
- ~~e) Calculate the soiling ratio SR by dividing the soiled device short-circuit current measured in b) by its expected short-circuit current calculated in d).~~

7.3.4.6 — Preferred method

~~Method 1 (7.3.4.4) is generally preferred because it best represents the actual power loss due to soiling, and in particular it produces more accurate results when soiling may be non-uniform across the modules, especially for typical crystalline silicon modules. Method 2 (7.3.4.5) may be used when soiling is known to be uniform across the modules or when the effects of soiling non-uniformity on the ratio of maximum power to short-circuit current are known to be small due to the construction or device physics of the module, e.g. for typical thin film modules. Both methods may be employed simultaneously and the most appropriate value or a weighted average may be used.~~

7.3.4.7 — Daily average value

~~The soiling ratio measured by the method above is an instantaneous value. Since the instantaneously measured soiling ratio tends to show a time-of-day dependence due to residual angular misalignment of the two reference devices as well as angle-dependent light scattering from soiling particles, for proper interpretation the measured soiling ratio values should be integrated to compute a daily average value.~~

~~Perform the integration by calculating the irradiance-weighted average of the measured soiling ratio values for a given day. The data may be filtered to exclude outliers and/or to limit the measured values to a specific time window that minimizes the effects of angular misalignment.~~

~~NOTE For example, when the clean and soiled devices are fixed in position (not tracking), the integration could include only times within ± 2 h of solar noon. When the clean and soiled devices are installed on a tracking system, analysis could include only times when solar angle of incidence is $\leq 35^\circ$.~~

7.3.4.8 — Recalibration

~~The calibration step in 7.3.4.3 shall be repeated at least annually.~~

~~Immediately following the calibration or following any significant rainfall, the measured soiling ratio should be close to unity. Significant deviation from unity indicates a problem with the setup. This can be used as a check of the calibration, so that the calibration may be repeated if necessary.~~

Per 3.31, the soiling ratio is a property of the PV array cleanliness condition. Soiling measurement instruments approximate the true soiling ratio of the PV array by measuring the impact of soiling on a sensor surface of the instrument and assuming that the soiling condition of the PV array is the same as that of the sensor surface.

Soiling measurement instruments use various physical principles:

- One measurement approach, which has many variations, compares a pair of PV reference devices, one of which is routinely cleaned and the other of which soils naturally at the same rate as the PV array. Methods for implementing this approach are described in detail in Annex C.
- Other approaches are based on optical principles, detecting soiling particles on a collection surface according to their effect on either reflection or transmission of light.

Some of the instrument types can measure the effect of non-uniform soiling on the power loss of PV modules. Non-uniform soiling occurs when deposited soiling particles move under the influence of dew, rain, wind, and gravity, often collecting along PV module edges, especially bottom edges. This can have a disproportionate effect on power, depending on module type. See Annex C.

9.5 Rainfall

Rainfall measurements may be used to estimate the cleanliness of modules. If soiling ratio is also measured, ~~the module cleanliness is directly known~~ these data are complementary.

9.6 Snow

Snowfall measurements ~~may~~ can be used to estimate losses due to shading from snow. However, these losses ~~will~~ may also be included in measurements of soiling ratio, depending on the soiling measurement device. ~~Therefore, if soiling ratio is measured, snow measurements may be unnecessary, unless the devices used for soiling measurement are not characteristic of the array or are mounted differently or at different height.~~

9.7 Humidity

Relative humidity measurements may be used to estimate changes in incident spectrum which may affect PV module power output as well as irradiance sensor readings. Humidity data with temperature data can also be used to calculate the times of wetness due to condensation. (Alternatively, surface condensation sensors can be used to directly gather these data.)

10 Tracker system

10.1 Single-axis trackers

Measurement of the real-time tracker tilt angle ϕ_T shall be ~~measured on representative trackers~~ performed with accuracy $\pm 1^\circ$ for Class A systems. Measurement may be performed with motor or position counters or other sensors integrated into the tracker mechanism, ~~if desired, and does not require separate instrumentation~~ such as an inclinometer.

10.2 Dual-axis trackers ~~for >20x systems~~

10.2.1 Monitoring

~~For high-concentration (> 20x) systems,~~ The real-time tracker pointing errors ($\Delta\phi_1$ and $\Delta\phi_2$) ~~shall be~~ are measured on representative trackers using sensors defined and calibrated as per 7.3 of IEC 62817:2014. Selected trackers should coincide with a measurement location for DC output power (see Clause 11). Reporting of tracker pointing error data shall be per 7.4.6 of IEC 62817:2014.

10.2.2 Pointing error sensor alignment

The tracker pointing error sensor is typically mounted on the tracker such that the pointing vector of the sensor is normal to the plane of the PV system.

Initial alignment of a pointing error sensor shall be confirmed by intentionally scanning across the optimal alignment while measuring the pointing error. This may be done either by driving the tracker through the desired angle in each relevant axis or by moving the tracker ahead of the sun, stopping the tracker, and waiting for the sun to move into and out of the optimal position. The measured pointing error is plotted against the normalized system maximum power divided by direct normal irradiance (DNI). The data shall be measured under clear sky conditions with wind speeds in a range from $0,5 \text{ m}\cdot\text{s}^{-1}$ to $3,5 \text{ m}\cdot\text{s}^{-1}$, and shall be recorded within a 1 h time period. These requirements are to minimize noise associated with variation in power output from factors other than alignment.

Ideal alignment is achieved if the pointing error is zero when the irradiance-normalized power curve is at the maximum value. No tolerance is stated here for the deviation from ideal alignment as acceptable tolerance is dependent on the given system. The width of the scan will depend upon the response of the system, but should be at most $\pm 0,75^\circ$ so that the scan is compatible with the *DNI* sensor.

The test is usually applied to an individual tracker with measurement of power generation associated only with that individual tracker, but it may be possible to plot the power generation of multiple trackers as long as all of them move together.

The plots shall be included in a test report and shall serve as indication that alignment tolerance is sufficient.

11 Electrical measurements

11.1 Inverter-level measurements

~~All electrical measurements shall have a range extending up to at least 120 % of the expected electrical output when the PV array is operating at STC or up to the maximum rating of the inverter, whichever is lower.~~

~~NOTE Electrical output can significantly exceed the expected STC value due to over irradiance (above $1\,000\text{ W}\cdot\text{m}^{-2}$) and low module temperature (below 25°C).~~

~~Electrical measurements shall have uncertainty meeting the requirements listed in Table 11 and Table 12 for measurements corresponding to $\geq 20\%$ of the expected electrical output when the array is operating at STC.~~

~~Table 11 lists the requirements for inverter-level electrical measurements, including DC measurements on the PV array prior to power conversion and AC measurements following power conversion. Optionally the DC measurements may be performed at each combiner box or each string in addition to or instead of at the inverters.~~

Inverter-level electrical measurements shall meet the requirements in Table 5 if applicable for the system configuration. DC measurements may be omitted when the modules include microinverters. In Table 5 precision refers to measurement repeatability and resolution, not absolute accuracy.

Optionally, for greater fault detection capability DC measurements may be performed at sublevels of the system (e.g. strings, combiners, feeders, etc.) in addition to or instead of at the inverters.

Table 5 – Inverter-level electrical measurement requirements

Parameter	Measurement Uncertainty		
	Class A High-accuracy	Class B Medium-accuracy	Class C Basic-accuracy
Input voltage (DC)	$\pm 2,0 \%$	n/a	n/a
Input current (DC)	$\pm 2,0 \%$	n/a	n/a
Input power (DC)	$\pm 2,0 \%$	n/a	n/a
Output voltage (AC)	$\pm 2,0 \%$	$\pm 3,0 \%$	n/a
Output current (AC)	$\pm 2,0 \%$	$\pm 3,0 \%$	n/a
Output power (AC)	$\pm 2,0 \%$	$\pm 3,0 \%$	n/a

Parameter	Measurement precision % of max inverter rating	
	Class A systems %	Class B systems %
Input voltage (DC)	$\pm 2,0$	n/a
Input current (DC)	$\pm 2,0$	n/a
Input power (DC)	$\pm 3,0$	n/a
Output voltage (AC)	$\pm 2,0$	$\pm 3,0$
Output current (AC)	$\pm 2,0$	$\pm 3,0$
Output power (AC)	$\pm 3,0$	$\pm 4,5$

11.2 Plant-level measurements

~~Table 12 lists the requirements for electrical measurements at the output of the power plant, i.e. the aggregate output produced by all inverters in the system.~~

Electrical measurements at the output of the power plant shall meet the requirements of Table 6. The output of the power plant is the aggregate net output produced by the entire system.

For multi-phase systems, each phase shall be measured, or 2 of 3 phases shall be measured (two wattmeter method).

Table 6 – Plant-level AC electrical output measurement requirements

Parameter	Class A High-accuracy	Class B Medium-accuracy	Class C Basic-accuracy
Active power and energy	Class 0,2 S as per IEC 62053-22	Class 0,5 S as per IEC 62053-22	Class 2 per IEC 62053-24
Power factor	Class 4 as per IEC 61557-12	Class 1 as per IEC 61557-12	n/a

Parameter	Class A system	Class B system
Active power and energy	Class 0,2 S as per IEC 62053-22	Class 0,5 S as per IEC 62053-22
Power factor	Class 1 as per IEC 61557-12	Class 1 as per IEC 61557-12
Recalibration	Per manufacturer's requirements and/or local codes and contracts	Per manufacturer's requirements and/or local codes and contracts

~~7.6 External system requirements~~

For Class A, the monitoring system ~~should~~ shall document periods during which the PV system does not deliver its maximum output power to the utility grid and/or local loads as a result of external system requests or requirements, which may include, for example, system output power factor demand and system power curtailment.

12 Data processing and quality check

~~12.1 Daylight hours~~ Night

~~Processed data for irradiance and PV-generated power should be restricted to the daylight hours of each day (sunrise to sunset, irradiance $\geq 20 \text{ W/m}^2$) to avoid extraneous night-time data values that introduce errors in analyses, unless such errors have been demonstrated to be negligible.~~

Night-time data may contain valuable information for quality checking, such as pyranometer and other instrumentation offsets. However, processed data for irradiance, PV-generated power, and other quantities expected to be zero at night should be set to zero during night-time after quality checks are performed, to avoid extraneous values.

12.2 Quality check

12.2.1 Removing invalid readings

The measured data ~~shall~~ should be checked and filtered, either automatically or manually, to identify missing or invalid data points and filter them out of subsequent analysis. Such missing or invalid data ~~shall~~ should be documented by the monitoring system.

Recommended methods of identifying missing or invalid data points include:

- applying physically reasonable minimum and maximum limits
- applying physically reasonable limits on maximum rates of change
- applying statistical tests to identify outlying values, including comparing measurements from multiple sensors
- applying contract data to identify viable parameter boundaries for certain performance data
- noting error codes returned by sensors
- identifying and deleting redundant data entries
- identifying missing data
- identifying readings stuck at a single value for an extended time
- checking timestamps to identify gaps or duplicates in data
- checking system availability reports.