

INTERNATIONAL STANDARD

NORME INTERNATIONALE

**Photovoltaic system performance –
Part 1: Monitoring**

**Performances des systèmes photovoltaïques –
Partie 1: Surveillance**



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Part 1: Monitoring**

**Performances des systèmes photovoltaïques –
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INTERNATIONAL
ELECTROTECHNICAL
COMMISSION

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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

- reconfirmed,
- withdrawn,
- replaced by a revised edition, or
- amended.

INTRODUCTION

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

Figure 1 illustrates 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 tracker systems and both flat-plate and concentrator systems.

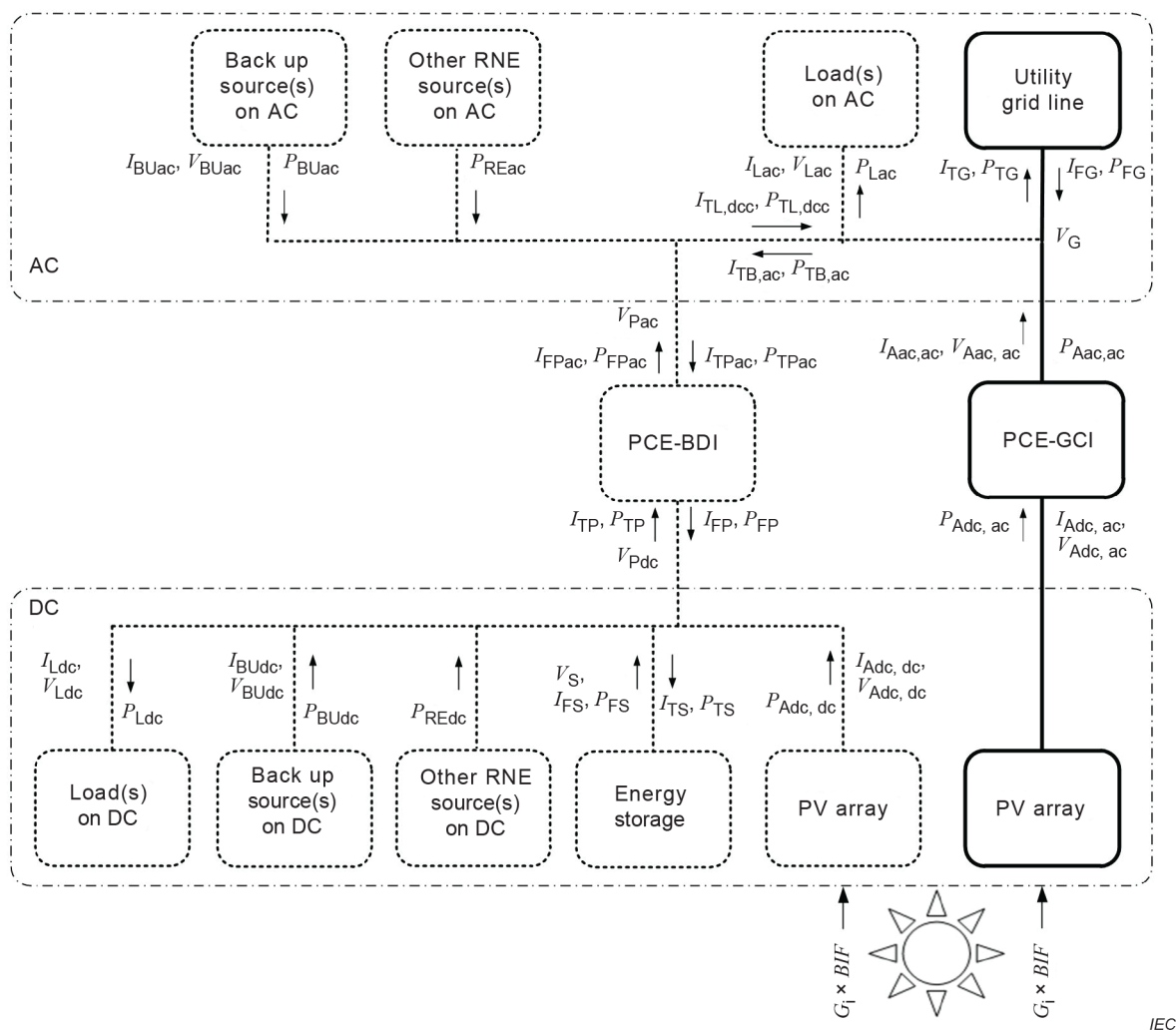


Figure 1 – Possible elements of PV systems

The purposes of a performance monitoring system are diverse and could include comparing performance to design expectations and guarantees as well as detecting and localizing faults.

For comparing performance to design expectations and guarantees, the focus should be on system-level data and consistency between prediction and test methods.

For detecting and localizing faults there should be greater resolution at sub-levels of the system and an emphasis on measurement repeatability and correlation metrics.

The monitoring system should be adapted to the PV system's size and user requirements. In general, larger PV systems should have more monitoring points and higher accuracy sensors than smaller and lower-cost PV systems.

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 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 60904-5, *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 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 62053-22, *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*

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

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 $\varphi_{I_{sc}}$, the open-circuit voltage bifaciality coefficient $\varphi_{V_{oc}}$ and the maximum power bifaciality coefficient $\varphi_{P_{max}}$.

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 $W \cdot m^{-2}$.

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 $W \cdot m^{-2}$.

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 $G_{i,SP}^{\text{rear}} = \rho_i^{\text{SP}} \times G_i$.

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: $BIF = (1 + \varphi_{pmax} \times \rho_i)$ or $BIF^{SP} = (1 + \varphi_{pmax} \times \rho_i^{SP})$. 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: 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.

3.24**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**

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 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: 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.

3.28**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°

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 $\text{W}\cdot\text{m}^{-2}$.

3.29**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

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

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 both classifications.

5 General

5.1 Measurement precision and 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

Recalibration of sensors and signal-conditioning electronics is to be performed as 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 any systems required for operation of the PV plant shall not be considered as a load supplied by the plant.

5.5 Documentation

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

5.6 Inspection

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 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.

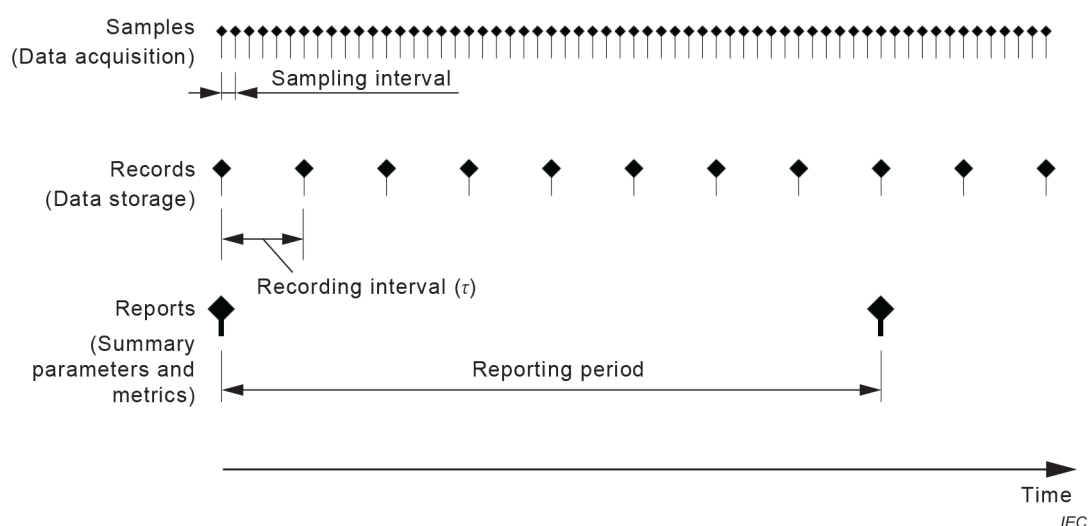


Figure 2 – Samples, records and reports

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
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 should be synchronized, preferably by an automated mechanism such as global positioning system (GPS) or network time protocol (NTP).

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 Required measurements

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 “R” in Table 2 indicates a parameter that may be determined based on 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 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 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.

Table 2 – Measured parameters and requirements

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	$W \cdot m^{-2}$	Solar resource	✓	1 × Table 3	✓	
Global horizontal irradiance	GHI	$W \cdot m^{-2}$	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		
	G_i^{rear}	$W \cdot m^{-2}$		✓			
In-plane rear-side irradiance (POA) or spectrally matched in-plane rear-side irradiance	$G_{i,sp}^{rear}$	$W \cdot m^{-2}$		for bifacial, Option 2 per 8.3.3	3 × Table 3		
				✓			
Diffuse irradiance	G_d	$W \cdot m^{-2}$	Solar resource	✓	1 × Table 3		
				for bifacial, Option 1, per 8.3.3 (optional)			
				for CPV with < 20× concentration			
Direct normal irradiance	DNI	$W \cdot m^{-2}$		✓ for CPV	1 × Table 3		
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		Utility request compliance	✓			
Reduced load demand			Determine utility or load request compliance and impact on PV system performance	✓	At system level		
System output power factor request	λ_{req}			✓	At system level		

Table 3 – Multiplier referenced in Table 2

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

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 pyheliometers, 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.

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

where

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

T_c is the cell temperature in °C,

$I_{sc,0}$ is the short circuit current at STC 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 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 quantities may be useful for performance characterization purposes.

8.3.12 Satellite remote sensing of irradiance

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 PV modules.

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 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. Temperature sensors shall be placed in representative locations to capture the range of variation and allow determination of an effective average.

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

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 $\leq 0,1$ °C and uncertainty ± 1 °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. ≤ 5 s) and the data record should contain not only averaged but also maximum values. (See 6.1.)

Wind measurement equipment 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 ≤ 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 manufacturer's recommendations.

9.4 Soiling ratio

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, these data are complementary.

9.6 Snow

Snowfall measurements can be used to estimate losses due to shading from snow. However, these losses may also be included in measurements of soiling ratio, depending on the soiling measurement device.

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 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, such as an inclinometer.

10.2 Dual-axis trackers

10.2.1 Monitoring

The real-time tracker pointing errors ($\Delta\phi_1$ and $\Delta\phi_2$) 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

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

11.2 Plant-level measurements

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 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

For Class A, the monitoring system 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 Night

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 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 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.

12.2.2 Treatment of missing data

Missing or invalid data may be treated in one of the following ways:

- the invalid or missing data may be replaced by values estimated from the valid data recorded before and/or after the invalid or missing data;
- the invalid or missing data may be replaced with an average value for the analyzed interval;
- the data may be treated in a manner specified in a valid contract, performance guarantee document, or other specification covering the installation;
- the analysed interval may be treated as missing or invalid.

The treatment of missing or invalid data may depend on the goal of the measurement. For example, missing or invalid data associated with inverter issues should be discarded if the goal is strictly to quantify module performance, but should be retained if the goal is to capture all aspects of plant performance and availability.

Additional recommendations and requirements for treatment of missing or invalid data are included in IEC TS 61724-2 and IEC TS 61724-3.

The specific treatment of missing or invalid data should be documented in any reports.

13 Calculated parameters

13.1 Overview

Table 7 summarizes calculated parameters which are further defined below. All quantities in the table shall be reported with respect to the reporting period (typically a day, month, or year).

Table 7 – Calculated parameters

Parameter	Symbol	Unit
Irradiation (see 13.3)		
In-plane irradiation	H_i	kWh·m ⁻²
In-plane rear-side irradiation (for bifacial)	H_i^{rear}	kWh·m ⁻²
Electrical energy (see 13.4)		
PV array output energy (DC)	E_A	kWh
Energy output from PV system (AC)	E_{out}	kWh
Array power rating (see 13.5)		
Array power rating (DC)	P_0	kW
Array power rating (AC)	$P_{0,\text{AC}}$	kW
Yields and yield losses (see 13.6 and 13.7)		
PV array energy yield	Y_A	kWh·kW ⁻¹
Final system yield	Y_f	kWh·kW ⁻¹
Reference yield	Y_r	kWh·kW ⁻¹
Array capture loss	L_C	kWh·kW ⁻¹
Balance of system (BOS) loss	L_{BOS}	kWh·kW ⁻¹
Efficiencies (Subclause 13.8)		
Array efficiency	η_A	None
System efficiency	η_f	None
BOS efficiency	η_{BOS}	None

13.2 Summations

In the formulas given below involving summation, τ_k denotes the duration of the k^{th} recording interval within a reporting period (see Clause 6), and the symbol

$$\sum_k$$

denotes summation over all recording intervals in the reporting period.

Note that in formulas involving the product of power quantities with the recording interval τ_k the power should be expressed in kW and the recording interval in hours to obtain energy in units of kWh.

13.3 Irradiation

Irradiation, also known as insolation, is the time integral of irradiance.

Each irradiation quantity H corresponding to an irradiance quantity G defined in Clause 3 is calculated by summing the irradiance as follows:

$$H = \sum_k G_k \times \tau_k \quad (5)$$

For example, the front-side in-plane or front-side plane-of-array (POA) irradiation, H_i , is given by:

$$H_i = \sum_k G_{i,k} \times \tau_k \quad (6)$$

and rear-side in-plane or rear-side plane-of-array (POA) irradiation, H_i , is given by:

$$H_i^{rear} = \sum_k G_{i,k}^{rear} \times \tau_k \quad (7)$$

13.4 Electrical energy

13.4.1 General

Energy quantities may be calculated from the integral of their corresponding measured power parameters over the reporting period.

Alternatively, if power measurements are performed using sensors with built-in totalizers, the energy quantities may be taken directly as measurement readings from the sensors.

13.4.2 DC output energy

The PV array DC output energy is given by:

$$E_A = \sum_k P_{A,k} \times \tau_k \quad (8)$$

13.4.3 AC output energy

The AC energy output is given by:

$$E_{out} = \sum_k P_{out,k} \times \tau_k \quad (9)$$

13.5 Array power rating

13.5.1 DC power rating

The array DC power rating, P_0 , is the sum of the DC power output of all installed PV modules at the power rating reference condition, which is either:

- standard test conditions (STC), for monofacial and bifacial modules; or
- concentrator standard test conditions (CSTC), for concentrator systems. P_0 is given in units of kW.

P_0 should be calculated by using data from manufacturer datasheets or module labels, or, provided that the choice is specified, using alternative data such as laboratory or on-site test data.

The definition of P_0 that is used should be specified explicitly whenever quantities that depend on P_0 are reported.

Note that the definition of P_0 ignores any rear-side contribution for bifacial modules. IEC 61215 includes provisions for measuring bifacial modules using rear-side irradiance; however, these are provided for the purpose of indoor accelerated stress testing, not performance rating.

13.5.2 AC power rating

The array AC power rating, $P_{0,AC}$, is the lesser of:

- the array DC power rating P_0 , and
- the sum of the inverter ratings in the system at specified operating temperature.

13.6 Yields

13.6.1 General

Yields are ratios of an energy quantity to the array power rating P_0 . They indicate actual array operation relative to its rated capacity.

Yields have units of $\text{kWh} \cdot \text{kW}^{-1}$, where units of kWh in the numerator describe the energy production and units of kW in the denominator describe the system power rating. The ratio of units is equivalent to hours, and the yield ratio indicates the equivalent amount of time during which the array would be required to operate at P_0 to provide the particular energy quantity measured during the reporting period.

13.6.2 PV array energy yield

The PV array energy yield Y_A is the array energy output (DC) per rated kW (DC) of installed PV array:

$$Y_A = E_A / P_0 \quad (10)$$

13.6.3 Final system yield

The final PV system yield Y_f is the net energy output of the entire PV system (AC) per rated kW (DC) of installed PV array:

$$Y_f = E_{\text{out}} / P_0 \quad (11)$$

13.6.4 Reference yield

The reference yield Y_r for a monofacial PV system can be calculated by dividing the total front-side in-plane irradiation by the module's reference plane-of-array irradiance:

$$Y_r = H_i / G_{i,\text{ref}} \quad (12)$$

where the reference plane-of-array irradiance $G_{i,\text{ref}}$ ($\text{kW}\cdot\text{m}^{-2}$) is the irradiance at which P_0 is determined, usually defined under STC.

The reference yield represents the number of hours during which the solar radiation would need to be at reference irradiance levels in order to contribute the same incident solar energy as was monitored during the reporting period while the utility grid and/or local load were available.

If the reporting period is equal to one day, then Y_r would be, in effect, the equivalent number of sun hours at the reference irradiance per day.

13.6.5 Bifacial reference yield

The reference yield Y_r^{bi} for a bifacial PV system can be calculated by taking the product of the front-side in-plane irradiation and the bifacial irradiance factor and dividing by the module's reference plane-of-array irradiance:

$$Y_r^{\text{bi}} = \sum_k (G_{i,k} \times \tau_k \times \text{BIF}_k) / G_{i,\text{ref}} \quad (13)$$

The reference yield represents the number of hours during which the solar radiation would need to be at reference irradiance levels in order to contribute the same incident solar energy as was monitored during the reporting period while the utility grid and/or local load were available.

If the reporting period is equal to one day, then Y_r would be, in effect, the equivalent number of sun hours at the reference irradiance per day.

13.7 Yield losses

13.7.1 General

Yield losses are calculated by subtracting yields. The yield losses also have units of $\text{kWh}\cdot\text{kW}^{-1}$ (or h). They represent the amount of time the array would be required to operate at its rated power P_0 to provide for the respective losses during the reporting period.

13.7.2 Array capture loss

The array capture loss L_C represents the losses due to array operation, including losses in wiring and junction boxes prior to DC measurement, array temperature effects, soiling, etc., and is defined as:

$$L_C = Y_r - Y_A \quad (14)$$

13.7.3 Balance of systems (BOS) loss

The balance of systems (BOS) loss L_{BOS} represents the losses in the BOS components, including the inverter and all wiring and junction boxes not included in array capture loss, and is defined as:

$$L_{\text{BOS}} = Y_{\text{A}} - Y_{\text{f}} \quad (15)$$

13.8 Efficiencies

13.8.1 Array (DC) efficiency

The rated array efficiency is given by:

$$\eta_{\text{A},0} = P_0 / (G_{\text{i,ref}} \times A_{\text{a}}) \quad (16)$$

where the overall array area A_{a} is the total module area, corresponding to the sum of the areas of the front surfaces of the PV modules as defined by their outer edges.

For a concentrator module, if the front surface is not coplanar, the front surface shall be projected onto an appropriate two-dimensional surface to define the area.

The mean actual array efficiency over the reporting period is defined by:

$$\eta_{\text{A}} = E_{\text{A}} / (H_{\text{i}} \times A_{\text{a}}) \quad (17)$$

13.8.2 System (AC) efficiency

The mean system efficiency over the reporting period is defined by:

$$\eta_{\text{f}} = E_{\text{out}} / (H_{\text{i}} \times A_{\text{a}}) \quad (18)$$

Formula (18) can also be rewritten as:

$$\eta_{\text{f}} = \eta_{\text{A},0} \times PR \quad (19)$$

where

$\eta_{\text{A},0}$ is the rated array efficiency defined in 13.8.1, and

PR is the performance ratio defined in 14.3.1.

13.8.3 BOS efficiency

The mean BOS efficiency over the reporting period is defined by: