# Technical Expert to develop grid connection guidelines and standards for the Kingdom of Bahrain

*Inspection and Testing Guidelines*
*for Distributed Solar PV Plants*

Draft 2.2

October 2017

*Table of contents*

# 1 SCOPE

These Guidelines provide information on the Inspection and Testing procedures to be adopted after the erection of a solar PV plant in order to connect it to the public Electric Network in Bahrain.
The Figure 1 shows the general sequence of the testing activities from the end of construction to its final connection to the electric network. The number and type of tests depends on the size of the solar PV plant and we may see that for plants whose nominal power Pn is up to 100 kW only two test sets are necessary, while for larger plants four test sets are required.

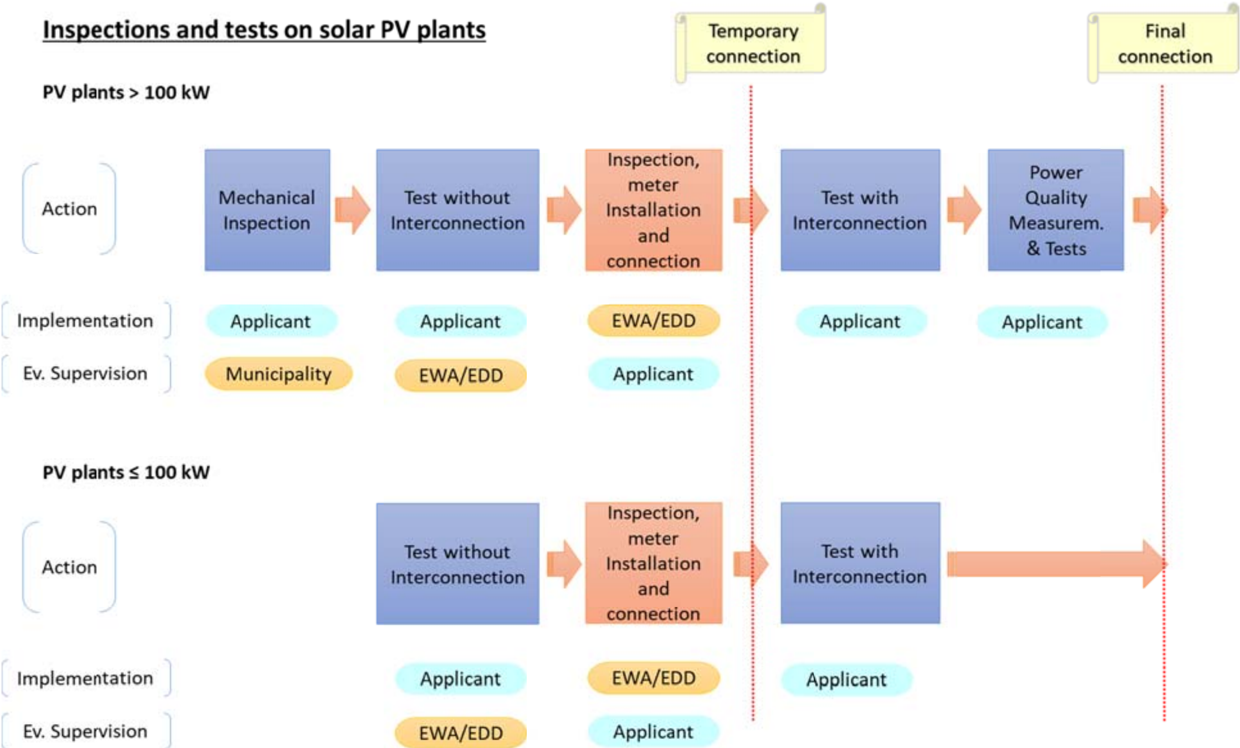


**Figure 1 – Sequence of the testing activities for solar PV plants**

The Figure 1 shows also that the Applicant - under the eventual supervision of EWA Electricity Distribution Directorate (EDD) or the Municipality for the Mechanical Inspection - shall make all tests. However, EWA/EDD shall:

- Inspect test and approve the installation as per the Regulations for Electrical Installations [2], and
- install the meters,

before the solar PV plant can be energized.

Depending on the capacity Pn of the Solar PV plant the Applicant shall carry out the inspections and tests as shown in the following Table 1.

**Table 1 – Main steps of the Inspection and Testing of the Solar PV plants**

| Description | Section or Paragraph | Capacity of the Solar PV plant (Pn) | | |
|---|---|---|---|---|
| | | Pn ≤ 11 kW | 11 kW < Pn ≤ 100kW | Pn >100kW |
| Safety information from Applicant | 3.3 | X | X | X |
| System documentation | | | | |
| Layout, SLD, datasheets, drawings, etc. | 4.2, 4.3 | X | X | X |
| Technical report and additional diagrams, drawings, etc. | 4.2, 4.4 | - | X | X |
| Mechanical Inspection (§) | | | | |
| Mechanical inspection (separate inspection) | 5 | - | - | X |
| Test without interconnection (§) | | | | |
| Inspection – general inspection before all tests are carried out | 6.3 | X | X | X |
| Category 1 test regime | 6.4 | X | X | X |
| Category 2 test regime | 6.5 | - | - | Recommended (*) |
| Additional tests | 6.6 | - | Facultative (*) | Facultative (*) |
| Test with interconnection (§) | | | | |
| Interface protection | 7.2 | X | X | X |
| Performance monitoring functions | 7.3 | X | X | X |
| Performance ratio | 7.8 | X | X | X |
| Power Quality measurements and tests (§) | | | | |
| Assessment of the harmonic content | 8.2 | - | - | X |
| Additional measurements | 8.3 | - | - | X (^) |

(§) report to be delivered with the results of the inspections and tests
(*) type of tests or percentage of plant tested: to be agreed between Customer and Contractor
(^) if required after assessment of harmonic content in 8.2

# 2 FOREWORD

## 2.1 Reference documents

[1] EWA – Standards for Solar PV Systems to be connected in parallel with the distribution networks of the Kingdom of Bahrain
[2] Ministry of Electricity and Water, Electricity Distribution Directorate – Regulations for electrical installations (Second edition, 2004)
[3] EWA – Guidelines for Solar PV systems to be connected in parallel with the distribution networks of the Kingdom of Bahrain
[4] IEC 60364-6 – Low voltage electrical installations. Part 6: Verifications
[5] IEC 61010 – Safety requirements for electrical equipment for measurement, control and laboratory use
[6] IEC 61557 – Electrical safety in low voltage distribution systems up to 1000 V a.c. and 1500 V d.c.
[7] IEC 61724-1 – Photovoltaic system performance. Part 1: Monitoring
[8] IEC 61724-2 – Photovoltaic system performance. Part 2: Capacity evaluation method
[9] IEC 61724-3 – Photovoltaic system performance. Part 3: Energy evaluation method
[10] IEC 61730-2 – Photovoltaic (PV module safety qualification. Part 2: Requirements for testing
[11] IEC 62446-1 – Photovoltaic (PV) systems. Requirements for testing, documentation and maintenance. Part 1: Grid connection systems. Documentation, commissioning, tests and inspection
[12] IEC 62548 – Photovoltaic (PV) arrays. Design requirements

## 2.2 Terms and definitions

**AC module** – PV module with an integrated inverter in which the electrical terminals are AC only
**Active power (P)** – under periodic conditions, mean value, taken over one period, of the instantaneous product of current and voltage expressed in W. Under sinusoidal conditions, the active power is the real part of the complex power.
**Apparent power (S)** – product of the r.m.s. voltage between the terminals of a two-terminal element or two-terminal circuit and the r.m.s. electric current in the element or circuit expressed in VA. Under sinusoidal conditions, the apparent power is the modulus of the complex power.
**Cable type** – description of a cable to enable its rating and suitability for a particular use or environment to be determined (Note: In many countries this is done via a code number e.g. “H07RNF”)
**Data sheet** – basic product description and specification (Note: Typically one or two pages, not a full product manual)
**Global horizontal irradiance (GHI)** – direct plus diffuse irradiance incident on a horizontal surface expressed in W/m$^2$
**$I_{MOD\_MAX\_OCPR}$** – PV module maximum overcurrent protection rating determined by IEC 61730-2 (Note: This is often specified by module manufacturers as the maximum series fuse rating)
**Inspection** – examination of an electrical installation using all the senses in order to ascertain correct selection and proper erection of electrical equipment
**In-plane irradiance (Gi or POA)** – the sum of direct, diffuse, and ground-reflected irradiance incident upon an inclined surface parallel to the plane of the modules in the PV array, also known as plane-of-array (POA) irradiance. It is expressed in W/m$^2$

**Interface Protection (IP) -** The electrical protection required to ensure that either the generating plant and/or any generating unit is disconnected for any event that could impair the integrity or degrade the safety and reliability of the distribution network.
**Inverter** – electric energy converter that changes direct electric current to single-phase or polyphase alternating current
**Irradiance (G)** – incident flux of radiant power per unit area expressed in $W/m^2$
**Irradiation (H)** – irradiance integrated over a specified time interval expressed in $kWh/m^2$
**Micro-inverter** – small inverter designed to be connected directly to one or two PV modules (Note: A micro inverter will normally connect directly to the factory fitted module leads and be fixed to the module frame or mounted immediately adjacent to the module)
**Module integrated electronics** – any electronic device fitted to a PV module intended to provide control, monitoring or power conversion functions (Note: Module integrated electronics may be factory fitted or assembled on site)
**Point of Connection or POC** - Is the location at which a solar PV generating plant is connected to the distribution network and where the main electricity meter is installed.
**Power factor (λ)** – under periodic conditions, ratio of the absolute value of the active power P to the apparent power S
**PV array** – assembly of electrically interconnected PV modules, PV strings or PV sub-arrays.
**PV cell** – most elementary device that exhibits the photovoltaic effect, i.e the direct non-thermal conversion of radiant energy into electrical energy
**PV module** – smallest complete environmentally protected assembly of interconnected PV cells
**PV string** – circuit of one or more series-connected PV modules
**PV string combiner box** – junction box where PV strings are connected which may also contain overcurrent protection devices, electronics and/or switch-disconnectors
**Record** – data recorded and stored in data log, based on acquired samples
**Recording interval (τ)** – time between records
**Report** – aggregate value based on series of records
**Reporting period** – time between reports
**Reporting** – recording of the results of inspection and testing
**Residual current device (RCD)** – is a sensitive safety device that switches off when the residual current exceeds the operating value of the device
**Sample** – data acquired from a sensor or measuring device
**Sampling interval** – time between samples
**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
**Switch** – Mechanical device capable of making, carrying and breaking currents in normal circuit conditions and, when specified, in given operating overload conditions. In addition, it is able to carry, for a specified time, currents under specified abnormal circuit conditions, such as short-circuit conditions.
**Standard test conditions (STC)** – reference values of in-plane irradiance (1 000 $W/m^2$), PV cell junction temperature (25 °C), and the reference spectral irradiance defined in IEC 60904-3
**Testing** – implementation of measures in an electrical installation by means of which its effectiveness is proved (Note: It includes ascertaining values by means of appropriate measuring instruments, said values not being detectable by inspection)

**Verification** – all measures by means of which compliance of the electrical installation to the relevant
standards is checked

**Voltage** - Unless stated otherwise, voltage refers to the root-mean-square value of phase-to-phase voltages.

# 3 SAFETY ISSUES

## 3.1 Foreword

This chapter does not substitute the safety laws and rules in force in Bahrain as regards the works on electric, mechanical and civil installations.
The purpose is to integrate the existing rules with some hint focused on particular safety aspects of solar PV plants.

## 3.2 Hazards and safety measures

The on-site tests, particularly of electrical tests, is the task and the responsibility of the Test Engineer. This must be aware of the main details of such electrical tests and the associated hazards, according to the laws and rules in force in Bahrain, its experience and the description provided below.
All what is located upstream of a circuit-breaker device on the DC section of a PV plant (PV modules and their connections) remains under voltage (during the day) even after the opening of this device.
All combiner boxes of the solar PV plant on DC side shall expose a warning, which indicates the presence of live parts even after the opening of the inverter circuit-breaker devices.
Figure 2 shows an example of warning sign to indicate the presence of a solar PV plant with a possible danger.


**Figure 2 – Example of a warning, which indicates the presence of solar PV plant with possible hazardous voltage**

All interventions on the live parts of PV strings are therefore to be considered works under voltage. This difference is unusual for an installer who is accustomed to thinking that the plant is off-voltage when the general circuit breaker is switched off.
Only a qualified person, i.e. a professional with sufficient knowledge and experience can work safely on live parts and successfully carry out electric interventions under voltage.
The protection provisions and the proper PPE are specified in relevant international and local standards. However, it is worth mentioning that when working under voltage, the operator must wear the following (see Figure 3):

- A safety helmet made of insulating material with face shield (mainly to protect him against electric arcing);

- Flame-retardant clothing that does not leave uncovered parts of the trunk or limbs;
- Insulating gloves (of appropriate voltage class).

Insulated tools for electrical work are also to be used. An alternative to insulated tools is an insulating mat for electrical purposes, placed beneath the operator.
After the electric shock, arcing represents the main danger in electric interventions under voltage. The energy released by electric arcs may cause burns, damage to eyes and skin and this energy increases with the arcing current and the duration of the intervention.
In case of short-circuit, the arcing current in PV plants is lower than that in other electric plants supplied by the grid, but the duration is greater because it is more difficult to extinguish a DC arc.
Works under voltage carried out in open air spaces shall be avoided in case of:

- Fog, rain, snow or dust storm, mainly because of the scarce visibility.
- Very low temperatures or strong wind, because of the difficulty to grip and hold tools.
- Thunderstorms, because of the possible over voltages on circuits.

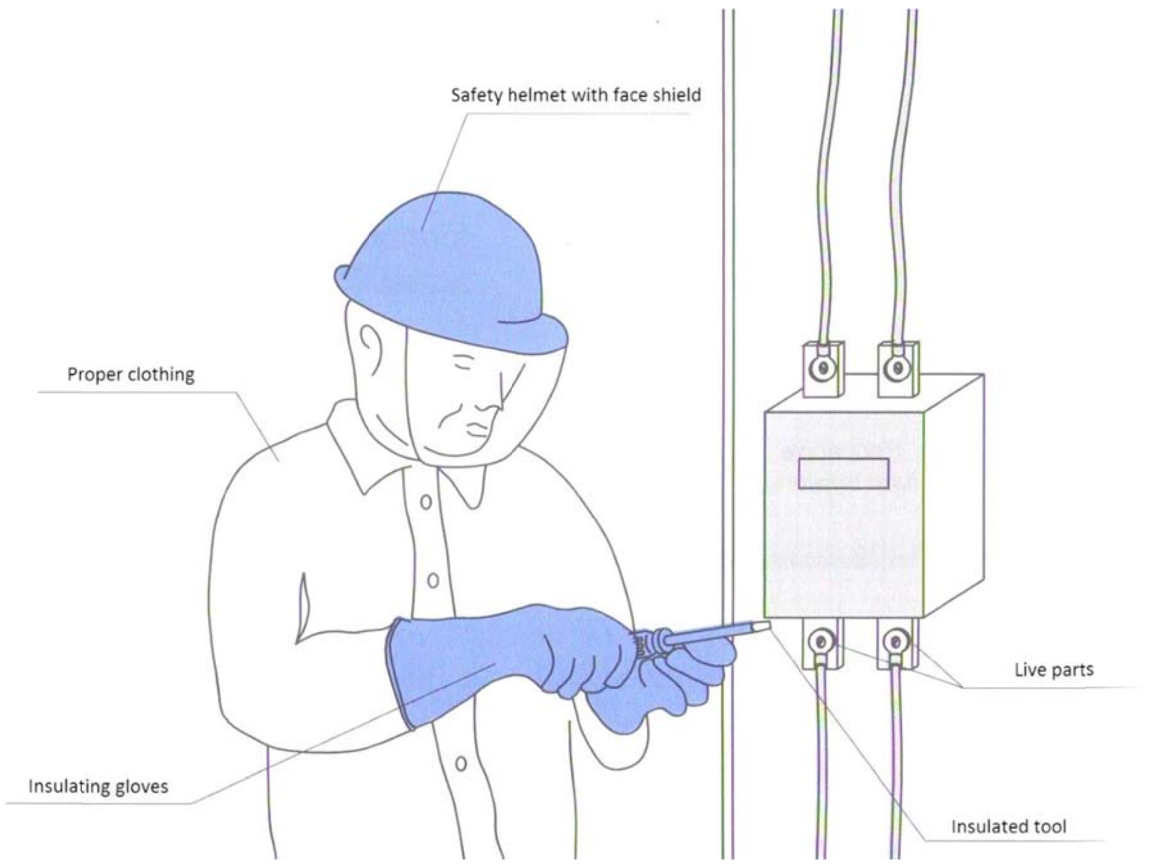


**Figure 3 – Main safety measures for works under voltage**

Construction works of an ordinary electric plant do not present any risk of electrical nature, until the plant has been completed and connected to the grid.
However, this is not valid for the installation of a photovoltaic plant, because the exposure of a PV module to sunlight produces a voltage between the poles of the module itself. To avoid this, one

may short-circuit both connectors of a PV module or of a series of modules (the short circuit current does not damage the PV modules because it is only slightly greater than the rated current).
Another possible expedient is shown in Figure 4, and consists of keeping the connectors of a module and the string circuit-breaker open during installation.
Figure 4 illustrates that a person with access to the positive (+) and negative (-) poles upstream or downstream of the circuit-breaker **is safe** (case A). Alternatively, a person who touches two poles on the same branch **is not safe** (cases B and C).
In all cases, the work and interventions in construction and during inspection and maintenance of a PV array shall be considered works/ interventions under voltage.

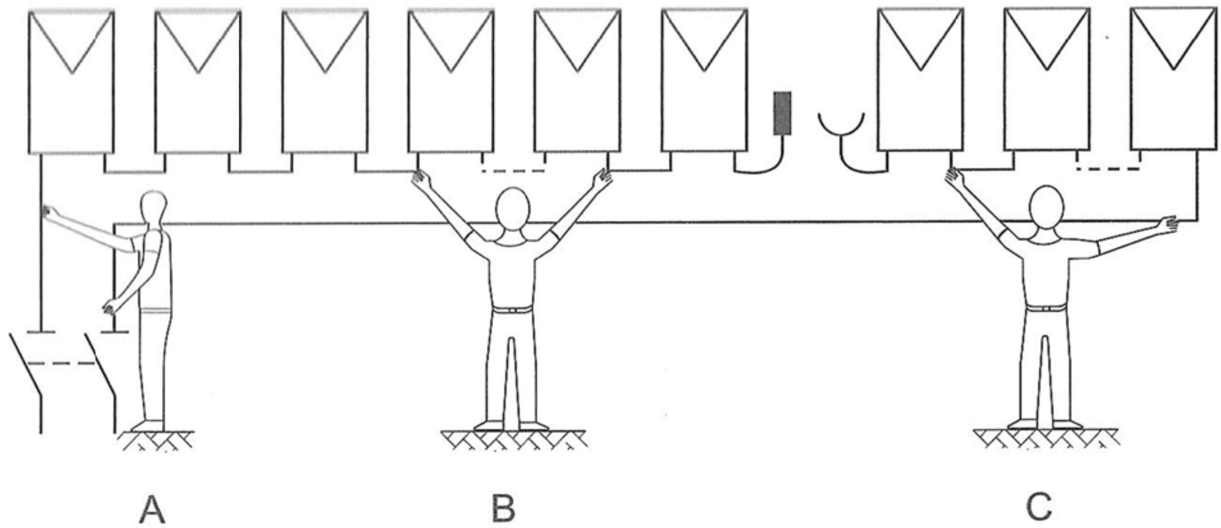


**Figure 4 – The interruption of a string makes the worker A safe but keeps the workers B and C unsafe**

Interventions on PV plants also involve non-electric risks, as follows:

- **Burning when touching PV modules.** If modules are exposed to sunrays, they may reach temperatures of almost 100 °C at the front and 80 °C at the rear. Operators are to wear work gloves resistant to up to 100 °C and proper clothing.
- **Risk of falling.** When the PV plant is installed on a roof, operators shall adopt the safety measures prescribed for the given circumstance, for instance a safety harness anchored with a carabineer to a stable element of the roof (hooks, safety ropes, pillars, etc.).
- **Insect stings.** Bees, hornets and other insects can nest behind a PV module or in another sheltered place.

## 3.3 Information from Applicant about Specific Risks on-site and Safety Measures

A form indicating specific risks and on-site safety measures (see Annex A - Safety Information Form) shall be filled and delivered by the Applicant / Contractor to EWA/EDD or to the concerned Authority, before the respective Inspectors visit the site of the PV plant.

# 4 SYSTEM DOCUMENTATION REQUIREMENTS

## 4.1 Preface

In this section the minimum documentation that should be provided following the installation of a grid connected PV system is listed. This information will ensure key system data is readily available to a customer, inspector or maintenance engineer. The documentation includes basic system data and the information expected to be provided in the operation and maintenance manual.
The list reported hereafter is based on the IEC 62446-1, but depending on the size of the PV plant, that is up to 11 kW or above, the design documentation required and its organization is different.
The documentation on Operation and Maintenance is listed separately.

## 4.2 All Solar PV plants

### *4.2.1 Basic system information*

As a minimum, the following basic system information shall be provided. This "nameplate" information should be preferably presented on the cover page of the system documentation pack:

a) Project identification reference (where applicable)
b) Rated (nameplate) system power (kW DC and kVA AC)
c) PV modules and inverters – manufacturer, model and quantity
d) Installation date
e) Commissioning date
f) Customer name
g) Site address

### *4.2.2 System designer information*

As a minimum, the following information shall be provided for all bodies responsible for the design of the system. Where more than one company has responsibility for the design of the system, the following information should be provided for all companies together with a description of their role in the project.

a) System designer, company.
b) System designer, contact person.
c) System designer, postal address, telephone number and e-mail address.

### *4.2.3 System installer information*

As a minimum, the following information shall be provided for all bodies responsible for the installation of the system. Where more than one company has responsibility for the installation of the system, the following information should be provided for all companies together with a description of their role in the project.

a) System installer, company.
b) System installer, contact person.
c) System installer, postal address, telephone number and e-mail address.

## 4.3 Solar PV plants up to 11 kW

### *4.3.1 Wiring diagram*

As a minimum, a single line wiring diagram in a suitable and readable format shall be provided.
In general, it is expected that this information will be presented as annotations to the single line wiring diagram. In some circumstances, typically for larger systems where space on the diagram may be limited, this information may be presented in table form.

#### *4.3.1.1 Array – General specifications*

The wiring diagram or system specification shall include the following array design information.

a) PV module type(s).
b) Total number of PV modules.
c) Number of strings.
d) Number of PV modules per string.
e) Identify which strings connect to which inverter.

Where an array is split into sub-arrays, the wiring diagram shall show the array – sub-array design and include all of the above information for each sub-array.

#### *4.3.1.2 PV string information*

The wiring diagram or system specification shall include the following PV string information.

a) String cable specifications – size and type.
b) String overcurrent protective device specifications (where fitted) – type and voltage/current ratings.
c) Blocking diode type (if relevant).

#### *4.3.1.3 PV array electrical details*

The wiring diagram or system specification shall include the following array electrical information (where fitted).

a) Array main cable specifications: Size, type manufacturer and model.
b) Array junction boxes / combiner boxes: Locations, manufacturer, model and internal electric diagram.
c) DC switch disconnector: Location and rating (voltage / current), manufacturer and model.
d) Array overcurrent protective devices: Type, location, rating (voltage / current), manufacturer and model.
e) Other array electronic protective circuitry (such as arc fault detection), if applicable: Type, location, rating, manufacturers and models.

#### *4.3.1.4 AC system*

The wiring diagram or system specification shall include the following AC system information.

a) AC isolator location: Type, rating, manufacturer and model.
b) AC overcurrent protective device: Location, type, rating, manufacturer and model.
c) Residual current (where fitted): Device location, type and rating.
d) Interface protection: Type, manufacturing and model
e) Interface switch (and backup switch if applicable): Location, type, rating, manufacturer and model.

#### *4.3.1.5 Earthing and overvoltage protection*

The wiring diagram or system specification shall include the following earthing and overvoltage protection information.

a) Details of all earth / bonding conductors – size and type. Including details of array frame equipotential bonding cable where fitted.
b) Details of any connections to an existing Lightning Protection System (LPS).
c) Details of any surge protection device installed (both on AC and DC lines) to include location, type and rating.

### *4.3.2 Planimetry and String layout*

Planimetry of the PV array with the indication of tilt and orientation. Possible sources of shading shall be clearly indicated.

For systems with three or more strings, a layout drawing of the PV system showing how the array is split and connected into strings shall be provided.

This is particularly useful for finding faults in larger systems and on building mounted arrays where access to the rear of the modules is difficult.

### *4.3.3 Datasheets*

As a minimum, datasheets shall be provided for the following system components:

a) PV module datasheet for all types of modules used in system
b) Inverter datasheet for all types of inverters used in system.
c) Interface protection datasheet

The provision of datasheets for other significant system components should also be considered.

### *4.3.4 Mechanical design information*

A data sheet for the array mounting system shall be provided. If the mounting structure was custom engineered, include the relevant documentation.

### *4.3.5 Emergency systems*

Documentation of any emergency systems associated with the PV system (fire alarms, smoke alarms, etc.). This information shall include both operation and design details.

### *4.3.6 Shading diagram*

The shading diagram consists in a drawing with the indication of the monthly solar paths and the reported shading to the direct solar irradiation on the solar paths.

### *4.3.7 Esteem of the yearly energy production*

An esteem of the yearly energy production, based on data from literature, shall be calculated.

## 4.4 Solar PV plants above 11 kW

### *4.4.1 Technical report*

Here below the structure of the Technical report is described along with a list of the minimum information to be included. Further information might be required, depending on the type and size of the PV system, and the document might be organized differently. For example, in case of MV connection, a further section dedicated to MV shall be included.

Although the organization of the Technical report as described below is recommended, one may adopt a different structure, provided the general criteria be fulfilled (e.g. separation of the input data from the information elaborated during the design) and no information are missing.

#### *4.4.1.1 Preliminary information*

As a minimum, the following basic system information shall be provided. This "nameplate" information preferably shall be presented on the cover page of the system documentation pack:

a) Project identification reference or name
b) Rated (nameplate) system power (kW DC and kVA AC)
c) PV modules and inverters – manufacturer, model and quantity
d) Installation date
e) Commissioning date
f) Customer name
g) Site address

#### *4.4.1.2 Chapter 1 – Foreword (or Introductory section, or Preface, …)*

As a minimum, the following information shall be provided:

- Type of solar system (rooftop, ground mounted, façade, …), integration if relevant (BAPV, BIPV, …), fixed mounting or tracking, technology (monocrystalline, polycrystalline, thin-film, …)
- A short description of the purpose of the project, also referring to the benefits for the client, for the environment, for the electric system, for the Nation, etc…
- System designer information for all bodies responsible for the design of the system. Where more than one company has responsibility for the design of the system, the following information should be provided for all companies together with a description of their role in the project.
  a. System designer, company.
  b. System designer, contact person.
  c. System designer, postal address, telephone number and e-mail address.
- System installer information for all bodies responsible for the installation of the system. Where more than one company has responsibility for the installation of the system, the following information should be provided for all companies together with a description of their role in the project.
  a. System installer, company.
  b. System installer, contact person.
  c. System installer, postal address, telephone number and e-mail address.

#### *4.4.1.3 Chapter 2 – Input data*

It is important to separate the input data for the design (environment, local laws and rules, constraints, relevant grid characteristics, etc.) listed here below from the information elaborated at design stage that will be detailed in further chapters.

As a minimum, the following information shall be provided:

- Definitions (recommended)
- Laws and standards applicable (the most relevant ones)

- Solar and environmental data on the site (monthly averages of direct and diffuse solar radiation, wind speed, average and maximum temperatures, …)
- Geological and environmental constraints (if any) as type of soil, inclination, need of stabilization or other treatment, shading, presence of vegetation, animals, etc…
- Characteristics of the grid at POC: voltage, frequency, No. of phases, type of earthing system (TT, TN, IT, etc…), short circuit current, any further available information on power supply.

#### *4.4.1.4 Chapter 3 – Characteristics of the main devices and equipment*

As a minimum, the following information shall be provided:

- PV modules (Manufacturer, model, technology, type of PV cells, Pn, Vm, Im, Voc, Isc, Temperature coefficients $\alpha$ $\beta$ $\gamma$, NOCT, dimensions and weight, certifications, etc…)
- Inverters (manufacturer, model, Pn, Max input current, Max input voltage, MPPT range, output voltage and frequency range, Max temperature, IP enclosure, dimensions, weight, certifications, etc…)
- DC combiner boxes – if present – (Manufacturer, model, No. of inputs, protection on inputs, switch/disconnector, PV string monitoring if any, IP enclosure, dimensions, weight, certifications, etc…)
- Interface protection – if external to the inverters – (Manufacturer, model, functions, standards compliance, certifications, etc…)
- Monitoring system – if present – (manufacturer, model, solar and meteo inputs, DC inputs, AC inputs, data line exchange, storage, data display, certifications if any, etc…)

#### *4.4.1.5 Chapter 4 – System architecture and dimensioning*

As a minimum, the following information shall be provided:

- DC and AC capacity and how is obtained from PV modules and inverters
- General architecture of the system from PV modules to the POC (this should include a very simple block diagram with PV modules, inverters, main switches and protections, meters, POC, energy flows, etc…)
- Characteristics of the PV strings and PV array(s) (Vm, Im, Voc, Isc, inclination(s), orientation(s))
- Verification of compliance for PV strings/array(s) and inverters (MPPT range, max volt ages, max currents, etc…)
- Description of the grid connection and power delivery (protection, grid services, capability, etc…)

#### *4.4.1.6 Chapter 5 – DC section*

As a minimum, the following information shall be provided:

- Verification of compliance for DC cables (current, voltage drops)
- Measures to prevent overcurrent in parallel PV strings

#### *4.4.1.7 Chapter 6 – AC section*

As a minimum, the following information shall be provided:

- Measures to prevent electric shocks from direct contacts (class II insulations, tubes and channels, etc…)
- Measures to prevent electric shocks from indirect contacts (earthing, RCDs, etc…)
- Characteristics of the main AC devices (Manufacturer, model, type of device, No. of poles, aux contacts, nominal current, short-circuit current, characteristics of the protection, etc…)
- AC calculations (verification of compliance for AC devices and cables)

##### *4.4.1.8 Chapter 7 – Civil and mechanical installation*

As a minimum, the following information shall be provided:

- Description of the mounting structures
- Structural calculations (if necessary)

##### *4.4.1.9 Chapter 8 – Performance calculation*

As a minimum, the following information shall be provided:

- Calculation of the solar radiation on the PV system
- Energy Yield (monthly and yearly)
- $CO_2$ saved

Furthermore, a shading diagram shall be included. It consists in a drawing with the indication of the monthly solar paths and the reported shading to the direct solar irradiation on the solar paths.

#### *4.4.2 Wiring diagram*

As a minimum, a multiple line wiring diagram in a suitable and readable format shall be provided. If necessary, the diagram may be distributed in more than one sheet.
In addition, a single line diagram, which contains the most relevant information and gives an overview of the PV plant is recommended, especially in case of large plants.
The information listed below are also required. In general, it is expected that this information will be presented as annotations to the single line wiring diagram. In some circumstances, typically for larger systems where space on the diagram may be limited, this information may be presented in table form.

##### *4.4.2.1 Array – General specifications*

The wiring diagram or system specification shall include the following array design information.

a) PV module type(s).
b) Total number of PV modules.
c) Number of strings.
d) Number of PV modules per string.
e) Identify which strings connect to which inverter.

Where an array is split into sub-arrays, the wiring diagram shall show the array – sub-array design and include all of the above information for each sub-array.

##### *4.4.2.2 PV string information*

The wiring diagram or system specification shall include the following PV string information.

a) String cable specifications – size and type.

b) String overcurrent protective device specifications (where fitted) – type and voltage/current ratings.
c) Blocking diode type (if relevant).

#### *4.4.2.3 PV array electrical details*

The wiring diagram or system specification shall include the following array electrical information (where fitted).

a) Array main cable specifications: Size, type manufacturer and model.
b) Array junction boxes / combiner boxes: Locations, manufacturer, model and internal electric diagram.
c) DC switch disconnector: Location and rating (voltage / current), manufacturer and model.
d) Array overcurrent protective devices: Type, location, rating (voltage / current), manufacturer and model.
e) Other array electronic protective circuitry (such as arc fault detection), if applicable: Type, location, rating, manufacturers and models.

#### *4.4.2.4 AC system*

The wiring diagram or system specification shall include the following AC system information.

a) AC isolator location: Type, rating, manufacturer and model.
b) AC overcurrent protective device: Location, type, rating, manufacturer and model.
c) Residual current (where fitted): Device location, type and rating.
d) Interface protection: Type, manufacturing and model
e) Interface switch (and backup switch if applicable): Location, type, rating, manufacturer and model.

#### *4.4.2.5 Earthing and overvoltage protection*

The wiring diagram or system specification shall include the following earthing and overvoltage protection information.

a) Details of all earth / bonding conductors – size and type. Including details of array frame equipotential bonding cable where fitted.
b) Details of any connections to an existing Lightning Protection System (LPS).
c) Details of any surge protection device installed (both on AC and DC lines) to include location, type and rating.

### *4.4.3 Planimetry and String layout*

Planimetry of the PV array with the indication of tilt and orientation. Possible sources of shading shall be clearly indicated.
For systems with three or more strings, a layout drawing of the PV system showing how the array is split and connected into strings shall be provided.
This is particularly useful for finding faults in larger systems and on building mounted arrays where access to the rear of the modules is difficult.

### *4.4.4 Datasheets*

As a minimum, datasheets shall be provided for the following system components:

a) PV module datasheet for all types of modules used in system

b) Inverter datasheet for all types of inverters used in system.
c) Interface protection datasheet

The provision of datasheets for other significant system components should also be considered.

#### *4.4.5 Mechanical design information*

A data sheet for the array mounting system shall be provided. If the mounting structure was custom engineered, include the relevant documentation.

#### *4.4.6 Emergency systems*

Documentation of any emergency systems associated with the PV system (fire alarms, smoke alarms, etc.). This information shall include both operation and design details.

### 4.5 Operation and maintenance information

Operation and maintenance information shall be provided and shall include, as a minimum, the following items:

a) Procedures for verifying correct system operation.
b) A checklist of what to do in case of a system failure.
c) Emergency shutdown / isolation procedures.
d) Maintenance and cleaning recommendations (mechanical, civil & electrical) – if any.
e) Considerations for any future building works related to the PV array (e.g. roof works).
f) Warranty documentation for PV modules and inverters – to include starting date of warranty and period of warranty.
g) Recommendations of manufacturers on operation and maintenance of main components and equipment
h) Documentation on any applicable workmanship or weather-tightness warranties.

# 5 MECHANICAL INSPECTION – SOLAR PV PLANTS > 100 KW

## 5.1 Overview

The Mechanical Inspection applies to all solar PV plants whose Pn is above 100 kW, regardless their voltage connection.

A Test Engineer appointed by the Applicant makes this inspection.

As a rule, this test begins after the completion of the solar PV plant, although the Test Engineer may initiate the inspection on those sections that have been erected and fully completed. In this case, the results of these tests shall be duly reported and completed with date and time.

Important note: Although the separate Mechanical Inspection applies to all solar PV plants whose Pn is above 100 kW, a verification of the mechanical installation is required regardless the capacity of the PV plants. As a result, for the PV plants whose Pn is up to 100 kW, this verification has to be done during "Testing Without Interconnection".

## 5.2 General Assessment of the solar PV plant

With reference to 100% of the installation, to verify the compliance with the drawings and design documents regarding the quantity, type, sizing, installation and integrity of components and materials, the following verifications shall be performed:

a) Layout and total number of PV modules and related supporting structures.
   1) Layout details:
      i. Configuration of the system and the division into sub-arrays
      ii. Layout of the strings with reference to supporting structures / frames
   2) Number of PV modules
      i. Confirm total DC peak power
   3) Positioning of supporting and fixing structures
   4) Status of the surface of the PV modules

b) Substations and main cable ways and connections (if already finished); Safe access to the rooftop and Exit plan; Internal roads (for ground plants); Fences or any other barriers required for segregation of hazardous areas; Rainwater drainage; and Warning signs.

c) Availability of documents and drawings inside substations: single line diagrams, PV modules/strings layout, detailed diagrams, etc.

## 5.3 Civil Works

With reference to 100% of the installation, to verify the compliance with the drawings and design documents regarding the quantity, type, sizing, installation and integrity of components and materials, the following verifications shall be performed:

a) Foundations (state, breakage, deterioration of the surface)
b) Structural alignments: within the tolerances set by design
c) Placement of inserts and holes in foundations and precast
d) General conditions of the cabins and related foundations
e) Waterproofing of the cabins
f) Roof integrity and ingress protection (water proof) of mounting system to the roof
g) Access doors of the cabins
h) Ventilation grills / fans / air conditioning of the cabins

i) Integrity and layout of cableways / conduits

## 5.4 Support Structures

With reference to 100% of the installation, to verify the compliance with the drawings and design documents regarding the quantity, type, sizing, installation and integrity of components and materials, the following verifications shall be performed:

a) Mounting of supporting structures and of fixation elements
b) Condition of the components (damages, defects, weld quality, loss of galvanic protection, corrosion)
c) Planarity of the PV modules supporting structures (sags)
d) Inclination of PV modules: within the tolerances set in the design
e) Bolts and tightening torque corresponding to design (sample check)

## 5.5 Photovoltaic Modules

With reference to the percentage of the installed plant, ranging between the 15% and the 20%, to verify the compliance with the drawings and design documents regarding the quantity, type, sizing, installation and integrity of components and materials, the following subsets of tests can be considered:

a) Visual inspection of PV modules.
   1) Mechanical integrity of the modules (faults, breakdowns or incomplete assembly)
   2) Integrity functional parts of the modules (delamination, discoloration, dirt, etc.)
   3) Labeling of modules
   4) Fixation system
   5) Bolts and tightening torques corresponding to design (on a sample basis)
b) Quality of cabling
   1) Tightening of cable glands
   2) Correct installation of DC cables (clamps, sharp edges, folds too narrow, etc.).
   3) Assembly and crimping of plug-in connectors

# 6 TEST WITHOUT INTERCONNECTION

## 6.1 Overview

### *6.1.1 General*

The Test without Interconnection applies to all solar PV plants regardless their nominal power and voltage connection.

This test is composed by an inspection and a set of tests made by a Test Engineer appointed by the Applicant.

As a rule, this test begins after the completion of the solar PV plant, although for large PV plants with Pn above 100 kW for safety reason the Test Engineer may initiate the tests on strings during installation in order to prevent parallel of strings with different length or reversed polarity. In this case, the results of these tests shall be duly reported and completed with date and time.

In all the cases where tests are initiated and completed in a single day it is sufficient to add the date of the day and the times of initiation and completion.

### *6.1.2 Compliance to the Regulations for Electrical Installations in Bahrain*

The Regulations for Electrical Installations [2] issued by the Kingdom of Bahrain in 2004 includes a section dedicated to the Inspection and Testing for the electrical installation.

The Test without Interconnection here described encompasses the activities described in [2] because it is focused on PV systems, where the DC and AC sections are both important and must be verified by means of suitable procedures that refers to the most recent experiences and international standards on electric safety.

However, it is always possible to perform, on a voluntary basis, a number of additional verifications and tests based on [2].

### *6.1.3 Test regimes and additional tests*

The test regime that is applied to a solar PV system needs to be appropriate to the scale, type, location and complexity of the system in question.

This standard defines two test regimes together with a number of additional tests which can also be performed once the standard sequence is completed.

- <u>Category 1 tests</u> – The minimum requirement – A standard set of tests that shall be applied to all solar PV plants.
- <u>Category 2 tests</u> – An expanded sequence of tests that assumes all Category 1 tests have already been undertaken. It shall be applied to PV plants whose nominal power Pn is above 100 kW.
- <u>Additional tests</u> – Other tests that may be performed in some circumstances. Unless differently agreed, these tests are facultative.

#### *6.1.4 Test regimes for systems with module level electronics*

For systems constructed using AC modules, power optimizers or with any other form of module level electronics, Table 1 shall be used to determine the correct test regime.

**Table 2 – Modifications to the test regime for solar PV plants with module level electronics**

| System | Modification to standard test regime |
|---|---|
| AC Module | – No DC test or inspection works required |
| Micro inverter<br>No site constructed wiring is used (all connections using module and inverter leads) | – Testing of DC circuits is not required<br>– Inspection of DC works is required |
| Micro inverter<br>Site constructed wiring is used | – Testing of DC circuits is required<br>– Inspection of DC works is required |
| Module integrated electronics | – Where possible, a standard test regime to be followed<br>– Manufacturer to be consulted to determine any restrictions to tests (e.g. insulation resistance test)<br>– Manufacturer to be consulted on pass / fail criteria for tests (e.g. expected Voc) |

Due to the diverse nature of the different module level electronics equipment available, it is not possible to specify what tests can be performed or to detail the expected results that may be expected from those tests. In all cases of solar PV systems with any form of module level electronics (such as power optimizers), the manufacturer should be consulted prior to commissioning.

## 6.2 Common requirements

Testing of the electrical installation shall be done according to the requirements of IEC 60364-6 and IEC 62446-1.

Measuring instruments and monitoring equipment and methods shall be chosen in accordance with the relevant parts of IEC 61557 and IEC 61010. If other measuring equipment is used, it shall provide an equivalent degree of performance and safety.

All tests shall be carried out where relevant and should be made in the sequence listed.

In the event of a test indicating a fault, once that fault has been rectified all previous tests shall be repeated in case the fault influenced the result of these tests.

## 6.3 Inspection – All Solar PV plants

### *6.3.1 General*

Inspection shall precede testing and shall normally be done prior to energizing the installation.

The inspection shall be done to the requirements of IEC 60364-6.

If wiring will not be readily accessible after the installation, wiring may need to be inspected prior to or during installation works.

The following items, specific to grid connected PV systems, shall be included in the inspection.

### *6.3.2 DC system – General*

Inspection of the DC installation shall include at least verification that:

a) the DC system has been designed, specified and installed to the requirements of IEC 60364 and IEC 62548;
b) the maximum PV array voltage is suitable for the array location (IEC 62548 and local codes may dictate that installations above a certain voltage may only be placed in certain locations);
c) all system components and mounting structures have been selected and erected to withstand the expected external influences such as wind, sand storms, temperature and corrosion;
d) roof fixings and cable entries are weatherproof (where applicable).

If further checks concerning the points c) and d) are deemed necessary, the chapter 5 - Mechanical Inspection – Solar PV plants > 100 kW shall be taken as a reference.

### *6.3.3 DC system – Protection against electric shock*

Inspection of the DC installation shall include at least verification of the measures in place for protection against electric shock:

a) Protective measure provided by extra low voltage (SELV / PELV) – yes / no.
b) Protection by use of class II or equivalent insulation adopted on the DC side – yes / no.
c) PV string and array cables have been selected and erected so as to minimize the risk of earth faults and short-circuits. Typically achieved by the use of cables with protective and reinforced insulation (often termed “double insulated”) – yes / no.

### *6.3.4 DC system – Protection against the effects of insulation faults*

Inspection of the DC installation shall include at least verification of the measures in place for protection against the effects of insulation faults, including the following:

a) Galvanic separation in place inside the inverter or on the AC side – yes / no.
b) Functional earthing of any DC conductor – yes / no (the Knowledge of the galvanic separation and functional earthing arrangements is necessary in order to determine if the measures in place to protect against the effects of insulation faults have been correctly specified).
c) That a PV Array Earth Insulation Resistance detection and alarm system is installed – to the requirements of IEC 62548 (this is typically provided within the inverter).
d) That a PV Array Earth Residual Current Monitoring detection and alarm system is installed – to the requirements of IEC 62548 (this is typically provided within the inverter).

### *6.3.5 DC system – Protection against overcurrent*

Inspection of the DC installation shall include at least verification of the measures in place for protection against overcurrent in the DC circuits:

a) For systems without string overcurrent protective device, verify that:
   - $I_{MOD\_MAX\_OCPR}$ (the module maximum series fuse rating) is greater than the possible reverse current;
   - string cables are sized to accommodate the maximum combined fault current from parallel strings (see IEC 62548 for calculation of array reverse currents).
b) For systems with string overcurrent protective device, verify that:
   - the string overcurrent protective devices are fitted and correctly specified to the requirements of IEC 62548.

c) For systems with array / sub-array overcurrent protective devices, verify that:
   - the overcurrent protective devices are fitted and correctly specified to the requirements of IEC 62548.

The potential for the system inverter(s) to produce a DC back-feed into the PV array circuits shall also be verified. It shall be verified that any back-feed current is lower than both the module maximum fuse rating and the string cable ampere rating.

### *6.3.6 DC system – Earthing and bonding arrangements*

Inspection of the DC installation shall include at least verification that:

a) where the PV system includes functional earthing of one of the DC conductors, the functional earth connection has been specified and installed to the requirements of IEC 62548;
b) where a PV system has a direct connection to earth on the DC side, a functional earth fault interrupter is provided to the requirements of IEC 62548;
c) array frame bonding arrangements have been specified and installed to the requirements of IEC 62548 (local codes may require different bonding arrangements).
d) where protective earthing and/or equipotential bonding conductors are installed, they are parallel to, and bundled with, the DC cables.

### *6.3.7 DC system – Protection against the effects of lightning and overvoltage*

Inspection of the DC installation shall include at least verification that:

a) to minimize voltages induced by lightning, the area of all wiring loops has been kept as small as possible;
b) measures are in place to protect long cables (e.g. screening or the use of surge protective devices, SPDs);
c) where SPDs are fitted, they have been installed to the requirements of IEC 62548.

### *6.3.8 DC system – Selection and erection of electrical equipment*

Inspection of the DC installation shall include at least verification that:

a) the PV modules are rated for the maximum possible DC system voltage;
b) all DC components are rated for continuous operation at DC and at the maximum possible DC system voltage and current as defined in IEC 62548 (Inspection of the DC system requires knowledge of the maximum system voltage and current. The maximum system voltage is a function of the string / array design, the open circuit voltage (Voc) of the modules and a multiplier to account for temperature and irradiance variations. The maximum possible fault current is a function of the string / array design, the short circuit current (Isc) of the modules and a multiplier to account for temperature and irradiance variations);
c) wiring systems have been selected and erected to withstand the expected external influences such as wind, ice formation, temperature, UV and solar radiation;
d) means of isolation and disconnection have been provided for the PV array strings and PV sub-arrays – to the requirements of IEC 62548;
e) a DC switch disconnector is fitted to the DC side of the inverter to the requirements of IEC 62548 (IEC 60364-9-1 provides four different methods for providing this switch disconnector. It is expected that the type and location of the switch disconnector be shown on the verification report);

f) if blocking diodes are fitted, their reverse voltage rating is at least 2 × Voc (STC) of the PV string in which they are fitted (see IEC 62548);
g) plug and socket connectors mated together are of the same type and from the same manufacturer and comply with the requirements of IEC 62548.

#### *6.3.9 AC system*

Inspection of the PV system shall include at least verification that:

a) a means of isolating the inverter has been provided on the AC side;
b) all isolation and switching devices have been connected such that PV installation is wired to the “load” side and the public supply to the “source” side;
c) the inverter operational parameters have been programmed to local regulations;
d) where an RCD is installed to the AC circuit feeding an inverter, the RCD type has been selected according to the requirements of IEC 62548 (some inverters require a type B RCD).

#### *6.3.10 Labelling and identification*

Inspection of the PV system shall include at least a verification that:

a) all circuits, protective devices, switches and terminals are suitably labelled to the requirements of IEC 60364 and IEC 62548;
b) all DC junction boxes (PV generator and PV array boxes) carry a warning label indicating that active parts inside the boxes are fed from a PV array and may still be live after isolation from the PV inverter and public supply;
c) means of isolation on the AC side is clearly labelled;
d) dual supply warning labels are fitted at point of interconnection;
e) a single line wiring diagram is displayed on site;
f) installer details are displayed on site;
g) shutdown procedures are displayed on site;
h) emergency procedures are displayed on site (where relevant);
i) all signs and labels are suitably affixed and durable (the requirements for signs and labelling of the PV system are detailed in IEC 62548).

## 6.4 Category 1 test regime – All solar PV plants

#### *6.4.1 Foreword*

A Category 1 test regime is the minimum test sequence that is expected and shall be applied to all systems irrespective of the system scale, type, location or complexity.
System testing needs to address both the AC and DC sides of the PV system. In general, AC testing should be completed prior to proceeding to DC testing.
In some circumstances, AC side testing may only be practical at a later stage in a project and may need to be scheduled after the DC testing phase. Where this is necessary, some of the DC functional tests (e.g. ensuring correct inverter operation) will need to be postponed until after the AC testing is complete.
The following test regime shall be performed on all systems:

**AC side**

Tests to all AC circuit(s) to the requirements of IEC 60364-6.

**DC side**

The following tests shall be carried out on the DC circuit(s) forming the PV array.

a) Continuity of earthing and/or equipotential bonding conductors, where fitted.
b) Polarity test.
c) Combiner box test.
d) String open circuit voltage test.
e) String circuit current test (short circuit or operational).
f) Functional tests.
g) Insulation resistance of the DC circuits.

For reasons of safety and for the prevention of damage to connected equipment, the polarity test and combiner box test must be performed before any strings are interconnected.

An I-V curve test is an acceptable alternative method to derive the string open circuit voltage (Voc) and short circuit current (Isc). Where an I-V test is performed, separate Voc and Isc tests are not required – provided the I-V curve test is performed at the appropriate stage in the Category 1 test sequence.

**Note**: Some systems are constructed using factory assembled string wiring harnesses, which are cable assemblies that aggregate the output of multiple PV string conductors into a single main conductor. Alternative string test requirements for systems using harnesses are under consideration.

### *6.4.2 Continuity of protective earthing and equipotential bonding conductors*

Where protective earthing and/or equipotential bonding conductors are fitted on the DC side, such as bonding of the array frame, an electrical continuity test shall be made on all such conductors. The connection to the main earthing terminal should also be verified.

### *6.4.3 Polarity test*

The polarity of all DC cables shall be verified using suitable test apparatus. Once polarity is confirmed, cables shall be checked to ensure they are correctly identified and correctly connected into system devices such as switching devices or inverters.

**Note**: For reasons of safety and for the prevention of damage to connected equipment, it is extremely important to perform the polarity check before other tests and before switches are closed or string overcurrent protective devices inserted. If a check is made on a previously connected system and reverse polarity of one string is found, it is then important to check modules and bypass diodes for any damage caused by this error.

### *6.4.4 PV string combiner box test*

A single string connected in reverse polarity within a PV string combiner box can sometimes be easy to miss. The consequence of a reversed string, particularly on larger systems with multiple often interconnected combiner boxes, can be significant. The purpose of the combiner box test is to ensure all strings interconnected at the combiner box are connected correctly.

While it is possible to do a polarity test with a digital multimeter, when checking a large number of circuits, the appearance of the "-" symbol can be relatively easy to overlook. As an alternative, the following test sequence indicates a reverse connection through a substantially different voltage reading.

The test procedure is as follows and shall be performed before any string fuses / connectors are inserted for the first time:

– Select a volt meter with voltage range at least twice the maximum system voltage.

- Insert all negative fuses / connectors so strings share a common negative bus.
- Do not insert any positive fuses / connectors.
- Measure the open circuit voltage of the first string, positive to negative, and ensure it is an expected value.
- Leave one lead on the positive pole of the first string tested, and put the other lead on the positive pole of the next string. Because the two strings share a common negative reference, the voltage measured should be near-zero, with an acceptable tolerance range of ±15 V.
- Continue measurements on subsequent strings, using the first positive circuit as the meter common connection.
- A reverse polarity condition will be very evident if it exists – the measured voltage will be twice the system voltage.

#### *6.4.5 PV string – Open circuit voltage measurement*

The purpose of the open circuit voltage (Voc) measurement within the Category 1 test sequence is to check that modules strings are correctly wired, and specifically that the expected number of modules are connected in series within the string. Missing an interconnection or mistakenly interconnecting the wrong number of modules within a string is a relatively common error, particularly on larger systems, and the open circuit voltage test will rapidly identify such faults.

**Note**: Voltages significantly less than the expected value may indicate one or more modules connected with the wrong polarity, one or more shorted bypass diodes or faults due to poor insulation, subsequent damage and/or water accumulation in conduits or junction boxes. High voltage readings are usually the result of wiring errors.

The open circuit voltage of each PV string should be measured using suitable measuring apparatus. This should be done before closing any switches or installing string overcurrent protective devices (where fitted).

The resulting string open circuit voltage reading shall then be assessed to ensure it matches the expected value (typically within 5 %) in one of the following ways:

a) Compare with the expected value derived from the module datasheet or from a detailed PV model that takes into account the type and number of modules and the module cell temperature.
b) Measure Voc on a single module, then use this value to calculate the expected value for the string (most suitable where there is stable irradiance conditions).
c) For systems with multiple identical strings and where there is stable irradiance conditions, voltages between strings can be compared.
d) For systems with multiple identical strings and where there is non-stable irradiance conditions, voltages between strings can be compared using multiple meters, with one meter on a reference string.

#### *6.4.6 PV string – Current measurement*

##### *6.4.6.1 General*

The purpose of a PV string current measurement test is to ensure the correct operational characteristics of the system and to verify that there are no major faults within the PV array wiring. These tests are not to be taken as a measure of module / array performance.

Two tests methods are possible (short circuit test or operational test) and both will provide information on the correct functioning of the PV string. Where possible, the short circuit test is preferred as it will exclude any influence from the inverters.

**Note**: An I-V curve test is also independent of the inverter and provides a good alternative means to perform this test.

### *6.4.6.2 PV string – Short circuit test*

#### 6.4.6.2.1 General

The short circuit current of each PV string should be measured using suitable test apparatus.

The making / interruption of string short circuit currents is potentially hazardous and a suitable test procedure, such as that described below, should be followed.

Measured values should be compared with the expected value. For systems with multiple identical strings and where there are stable irradiance conditions, measurements of currents in individual strings shall be compared. These values should be the same (typically within 5 % of the average string current, for stable irradiance conditions).

For non-stable irradiance conditions, the following methods may be adopted:

- Testing may be delayed.
- Tests may be done using multiple meters, with one meter on a reference string.
- An irradiance meter reading or visual appraisal of the sunlight conditions may be used to consider the validity of the current readings.

**Note**: The use of an irradiance meter or visual appraisal of the sunlight conditions is included here solely as a means of determining if the measured current is within the band expected. As noted in the introduction to this section, the short circuit current test is intended to detect faults rather than give any indication of system performance. System performance measurements are deemed to be part of a Category 2 test regime and are best achieved by performing an I-V curve test.

#### 6.4.6.2.2 Short circuit test procedure

Ensure that all switching devices and disconnecting means are open and that all PV strings are isolated from each other.

A temporary short circuit shall be introduced into the string under test. This can be achieved by one of the following techniques:

a) use of a test instrument with a short circuit current measurement function (e.g. a specialized PV tester);
b) a short circuit cable temporarily connected into a load break switching device already present in the string circuit;
c) use of a "short circuit switch test box" – a load break rated device that can be temporarily introduced into the circuit to create a switched short circuit.

The test instrument shall have a rating greater than the potential short circuit current and open circuit voltage. Where a switching device and/or short circuit conductor is used to form the short circuit, these shall be rated greater than the potential short circuit current and open circuit voltage.

The short circuit current can then be measured using a suitably rated clip-on ammeter, in-line ammeter or test instrument with a short circuit current measurement function.

The short circuit current shall then be interrupted using the load break switching device and the current checked to have gone to zero before any other connections are changed.

**Note**: A "short circuit switch box" is an item of test apparatus that can be used for both short circuit tests and also array insulation tests.

#### *6.4.6.3 PV string – Operational test*

With the system switched on and in normal operation mode (inverters maximum power point tracking), the current from each PV string should be measured using a suitable clip-on ammeter placed around the string cable.

Measured values should be compared with the expected value. For systems with multiple identical strings and where there are stable irradiance conditions, measurements of currents in individual strings shall be compared. These values should be the same (typically within 5 % of the average string current for stable irradiance conditions).

For non-stable irradiance conditions, the following methods may be adopted:

- Testing may be delayed.
- Tests may be done using multiple meters, with one meter on a reference string.
- An irradiance meter reading may be used to adjust the current readings.
- A specialized PV test meter (with irradiance measurement) may be used.
- An I-V curve test may be performed.

### *6.4.7 Functional tests*

The following functional tests shall be performed:

a) Switchgear and other control apparatus shall be tested to ensure correct operation and that they are properly mounted and connected.
b) All inverters forming part of the PV system shall be tested to ensure correct operation. The test procedure should be as defined by the inverter manufacturer.

Functional tests that require the AC supply to be present (e.g. inverter tests) shall only be performed once the AC side of the system has been tested.

### *6.4.8 PV array insulation resistance test*

#### *6.4.8.1 General*

PV array DC circuits are live during daylight and, unlike a conventional AC circuit, cannot be isolated before performing this test.

Performing this test presents a potential electric shock hazard; therefore, it is important to fully understand the procedure before starting any work. The following basic safety measures should be followed:

- Limit the access to the working area.
- Do not touch and take measures to prevent any other persons touching any metallic surface when performing the insulation test.
- Do not touch and take measures to prevent any other persons from touching the back of the module/laminate or the module/laminate terminals when performing the insulation test.
- Whenever the insulation test device is energized, there is voltage on the testing area. The equipment shall have automatic auto-discharge capability.

- Appropriate personal protective clothing / equipment should be worn for the duration of the test.

Where the results of the test are questionable, or where insulation faults due to installation or manufacturing defects are suspected, a wet array insulation test may be appropriate and may help locate the location of a fault – see Paragraph 6.6.4 for a suitable test procedure.
Where SPDs or other equipment are likely to influence the verification test, or be damaged, such equipment shall be temporarily disconnected before carrying out the insulation resistance test.

### *6.4.8.2 PV array insulation resistance test – Test method*

The test should be repeated, as minimum, for each PV array or sub-array (as applicable). It is also possible to test individual strings if required.

- TEST METHOD 1 – Test between array negative and earth followed by a test between array positive and earth.
- TEST METHOD 2 – Test between earth and short circuited array positive and negative.

Where the structure/frame is bonded to earth, the earth connection may be to any suitable earth connection or to the array frame (where the array frame is used, ensure a good contact and that there is continuity over the whole metallic frame).
For systems where the array frame is not bonded to earth (e.g. where there is a class II installation) a commissioning engineer may choose to do two tests: i) between array cables and earth and an additional test ii) between array cables and frame.
For arrays that have no accessible conductive parts (e.g. PV roof tiles) the test shall be between array cables and the building earth.
Where test method 2 is adopted, to minimize the risk from electrical arcs, the array positive and negative cables should be short-circuited in a safe manner. Typically this would be achieved by an appropriate short-circuit switch box. Such a device incorporates a load break rated DC switch that can safely make and break the short circuit connection – after array cables have been safely connected into the device.
The test procedure should be designed to ensure the peak voltage does not exceed module, switch, surge arrestor or other system component ratings.

### *6.4.8.3 PV array insulation resistance – Test procedure*

#### 6.4.8.3.1 General

Before commencing the test:

- limit access by non-authorized personnel;
- isolate the PV array from the inverter (typically at the array switch disconnector); and
- disconnect any piece of equipment that could have impact on the insulation measurement (i.e. overvoltage protection) in the junction or combiner boxes.

Where a short circuit switch box is being used to test to method 2, the array cables should be securely connected into the short circuit device before the short circuit switch is activated.
The insulation resistance test device shall be connected between earth and the array cable(s) or combiner bus bar – as appropriate to the test method adopted. Test leads should be made secure before carrying out the test.

Follow the insulation resistance test device instructions to ensure the test voltage is according to Table 2 and readings in megaohms.
Ensure the system is de-energized before removing test cables or touching any conductive parts.

6.4.8.3.2 Insulation resistance – PV arrays up to 10 kWp

For PV arrays of up to 10 kWp, the insulation resistance shall be measured with the test voltage indicated in Table 2. The result is satisfactory if each circuit has an insulation resistance not less than the appropriate value given in Table 3.

**Table 3 – Minimum values of insulation resistance – PV arrays up to 10 kWp**

| System voltage (Voc (stc) × 1.25) [V] | Test voltage [V] | Minimum insulation resistance [MΩ] |
|---|---|---|
| < 120 | 250 | 0.5 |
| 120 to 500 | 500 | 1 |
| > 500 | 1 000 | 1 |

6.4.8.3.3 Insulation resistance – PV arrays above 10 kWp

For PV arrays of over 10 kWp, one of the following two test methods shall be followed.

Method A
Perform the insulation resistance test on:
• individual strings; or
• combined strings, where the total combined capacity is no more than 10 kWp.
The insulation resistance shall be measured with the test voltage indicated in Table 3. The result is satisfactory where the insulation resistance is not less than the appropriate value given in Table 3.

Method B
Method B is an alternative that allows for testing of an entire array (or sub-array) even if it is larger than 10 kWp. Arrays larger than 10 kWp may pass the requirements of Table 3; hence Method B provides a shortcut (testing the entire array at the outset) – only if it fails this test should the test be performed on sub-sections as per Method A.
The insulation resistance shall be measured with the test voltage indicated in Table 3. The result is satisfactory where the insulation resistance is not less than the appropriate value given in Table 3.
If the measurement falls below the appropriate value given in Table 3, the system should be re-tested using fewer strings in the test circuit.

## 6.5 Category 2 test regime – Recommended for Solar PV plants > 100 kW

### *6.5.1 Foreword*

A Category 2 test regime includes additional tests and is intended for larger or more complex systems. Therefore they are recommended for PV plants with Pn > 100 kW. All Category 1 tests shall have been undertaken and passed before commencing on the additional Category 2 tests.
In addition to the Category 1 tests, the following tests may be applied:

a) String I-V curve test.

b) IR inspection.

As noted in the Category 1 test description, where an I-V curve test is being performed, it provides an acceptable means to derive Isc and Voc.
**Note** 1: In some circumstances just one element or part of the Category 2 test regime may be chosen to be implemented. An example of this is where a client wants the performance evaluation provided by the I-V curve test to be added to the standard Category 1 test sequence.
**Note** 2: In some circumstances Category 2 tests may only be implemented on a sample portion of the system. An example of this is where a client wants I-V curve tests and/or IR inspection on a fixed proportion of the strings.
Category 2 tests can be implemented on all parts of a system or only upon sample portions.
**Note**: It is relatively common, particularly for large systems, that some of the Category 2 tests are performed on a selected sample of the system (a fixed percentage of the strings / modules). Such a selective approach and the percentage of the system to be tested will be agreed with the client prior to commissioning.

### *6.5.2 String I-V curve measurement*

#### *6.5.2.1 General*

A string I-V curve test can provide the following information:

- Measurements of string open circuit voltage (Voc) and short circuit current (Isc).
- Measurements of max power voltage (Vmpp), current (Impp), and max power (Pmax).
- Measurement of array performance.
- Measurement of module / string fill factor.
- Identification of module / array defects or shading issues.

Before undertaking an I-V curve test, the I-V curve test device shall be checked to ensure it is suitably rated for the voltage and current of the circuit under test.

#### *6.5.2.2 I-V curve measurement of Voc and Isc*

An I-V curve test is an acceptable alternative method to derive the string open circuit voltage (Voc) and short circuit current (Isc). Where an I-V curve test is performed, separate Voc and Isc tests are not required – provided the I-V curve test is performed at the appropriate stage in the Category 1 test sequence.
The string under test should be isolated and connected to the I-V curve test device. If the purpose of the I-V curve test is solely to derive values for Voc and Isc, then there is no requirement to measure irradiance (or cell temperature).

#### *6.5.2.3 I-V curve measurement – Array performance*

Given suitable irradiance conditions, an I-V curve test provides a means to measure that the performance of a PV array is meeting the rated (nameplate) performance.
PV string and array performance measurements shall be performed at stable irradiance conditions of at least 400 W/m$^2$ as measured in the plane of the array.

**Note 1**: Poor results may be expected where measurements are taken in low irradiance or where the angle of incidence is too oblique.

**Note 2**: The maximum power current and voltage of a PV string are directly affected by irradiance and temperature, and are indirectly affected by any changes in the shape of the I-V curve. In general, I-V curve shape varies slightly with irradiance, and below a critical level of irradiance the curve shape changes dramatically. The details of the variation depend on the PV technology and the extent to which module performance has been degraded over time. Changes in the shape of the curve can cause errors in evaluating array performance, regardless of the method used to characterize string performance (I-V curve tracing or separate current and voltage measurements).

The procedure for undertaking the I-V curve test is as follows:

- Ensure system is shutdown and that no current is flowing.
- The string under test should be isolated and connected to the I-V curve test device.
- The test instrument should be programmed with the characteristics, type and quantity of modules under test.
- The irradiance meter associated with the I-V curve tester should be mounted such that it matches the plane of the array and checked to ensure it is not subject to any localized shade or reflected light (albedo). Where a reference cell device is used, this shall be checked to ensure it is of the same cell technology as the array under test, or suitably corrected for the difference in technologies.
- Where the I-V curve tester uses a cell temperature probe, this shall be in firm contact with the rear of the module and in the centre of a cell towards the centre of a module. Where temperature corrections are calculated by the I-V curve test device, a check shall be undertaken to ensure that the correct module characteristics are inputted onto the device and that the string Voc value is within the range expected (a check of Voc is performed to ensure that the string is not missing a module and, to the extent possible, that it has no shorted bypass diodes. Either condition would cause an error in the calculation of temperature from the measured Voc).
- Prior to commencing the test, the irradiance levels shall be checked to ensure they are greater than 400 $W/m^2$ in the plane of the array.

On completion of the test, the measured maximum power value should be compared to the rated (nameplate) value of the array under test. The measured value should lie within the stated power tolerance for the modules under test (together with an allowance for the accuracy of the I-V curve test equipment).

#### *6.5.2.4 I-V curve measurement – Identification of module / array defects or shading issues*

The shape of an I-V curve can provide valuable information on the array under test. Defects including the following may be identified:

- Damaged cells / modules.
- Short circuited bypass diodes.
- Local shading.
- Module mismatch.
- The presence of shunt resistance in cells / modules / arrays.
- Excessive series resistance.

If the goal of the I-V curve measurement is to verify that there are no steps or notches of the type caused by mismatch effects, the measurement may be conducted at lower irradiance and greater incident angles than required for performance testing.
For most shape tests, irradiance values should be greater than 100 W/m$^2$. However, useful data may also be obtained at lower irradiance levels. Where shape defects are spotted at irradiance levels of less than 100 W/m$^2$, while it may merit investigation of the potential fault, the test should also be repeated at a time when values over 100 W/m$^2$ are present.
On recording an I-V curve, the shape shall be studied for any deviation from the predicted curve. Deviations to I-V curves demand particular attention as they can signal otherwise undetected and significant faults within the PV array. Information on interpreting deviations to an I-V curve is contained in IEC 62446-1 – Annex D.
For systems with multiple identical strings and where there are stable irradiance conditions, curves from individual strings shall be compared (overlaid). Curves should be the same (typically within 5 % for stable irradiance conditions).
If the irradiance conditions are not stable, visual comparison may be aided by translating the curves to a common irradiance and temperature (e.g. to Standard Test Conditions, STC) before overlaying.

### *6.5.3 PV array infrared camera inspection procedure*

#### *6.5.3.1 General*

The purpose of an infrared (IR) camera inspection is to detect unusual temperature variations in operating PV modules in the field. Such temperature variations may indicate problems within the modules and/or array, such as reverse-bias cells, bypass diode failure, solder bond failure, poor connections and other conditions that lead to localized high temperature operation.

**Note**: As well as forming part of an initial or periodic verification process, an IR test may also be used to
troubleshoot suspected problems in a module, string or array.

#### *6.5.3.2 IR test procedure*

For an IR camera inspection, the array should be in the normal operating mode (inverters maximum power point tracking). Irradiance in the plane of the array should be greater than 400 W/m$^2$ and sky conditions should be stable. Ideally, irradiance should be relatively constant and more than 600 W/m$^2$ in the plane of the array to ensure that there will be sufficient current to cause discernible temperature differences.
Depending on the module construction and mounting configuration, determine which side of the module produces the most discernible thermal image (the procedure may need to be repeated for each side).
Scan each module in the array or sub-array in question, paying particular attention to the blocking diodes, junction boxes, electrical connections, or any specifically identified array problem that exhibits a discernible temperature difference from its immediate surroundings.
When scanning from the front of an array, the camera and operator shall not cast shadows on the area under investigation.

**Note**: Viewing the array from the rear will minimize interference from light reflected from the module glass, but viewing from the front usually provides easily discernible images due to the thermal conductivity of glass.

### *6.5.3.3 Interpreting IR test results*

#### 6.5.3.3.1 IR test results – General

This test is primarily looking for anomalous temperature variations in the array. Normal temperature variations due to mounting points, adhesive stickers, and other items should be identified only in order to avoid recording these normal temperature variations.
On a daily basis, the average temperature of a PV array will vary quite dramatically, so an absolute temperature standard for identifying anomalies is not particularly useful. The temperature difference between the hot spot and the normally operating array is most important. It should be noted that array temperature is a function of irradiance, wind speed, and ambient temperature, which vary significantly throughout the daylight hours.
Document areas of temperature extremes by clearly marking their location on the suspect components themselves, or on the array / string layout drawings. Investigate each thermal anomaly to determine what the cause(s) might be. Use visual inspection and electrical (string and module level) tests to investigate. In some cases an I-V curve of one or more modules with a thermal anomaly compared to the I-V curve of a module without any thermal anomalies may prove a useful tool.
With a wide-angle IR camera, it may be possible to detect modules and strings that are not generating or not connected, as their overall temperature will be noticeably different to that of the neighbouring modules.
In some circumstances repeating a scan with the array segment open circuited may be informative. Allow at least 15 minutes after open circuiting the array for thermal equilibration. Module strings whose IR image does not change may not be producing current under load conditions.

#### 6.5.3.3.2 IR test results – Module hotspots

Module temperature should be relatively uniform, with no areas of significant temperature difference. However, it is to be expected that the module will be hotter around the junction box compared to the rest as the heat is not conducted as well to the surrounding environment. It is also normal for the PV modules to see a temperature gradient at the edges, labels, periphery and supports.
A hot spot elsewhere in a module usually indicates an electrical problem, possibly series resistance, shunt resistance or cell mismatch. In any case, investigate the performance of all modules that show significant hot spot(s). Visual inspection may show signs of overheating, for example a brown or discoloured area.

#### 6.5.3.3.3 IR test results – Bypass diodes

If any bypass diodes are hot (on), check the array to look for obvious reasons like shadowing or debris on the module protected by the diode. If there is no obvious cause, suspect a bad module.

6.5.3.3.4 IR test results – Cable connections

The connections in the wires between modules should not be significantly hotter than the wire itself. If the connections are hotter, check to see if the connection has come loose or is corroded.

## 6.6 Additional tests – Facultative for all Solar PV plants

### *6.6.1 Foreword*

In addition to the standard suite of tests described in the Category 1 and 2 test sequences, there are also other tests that may be performed in some circumstances. These tests are likely to be implemented either due to a specific request from a client or as a mean of detecting faults when other tests or operational abnormalities have suggested a problem that has not been identified by the standard tests.

a) <u>Voltage to ground</u> – resistive ground systems – This test is used to evaluate systems that use a high impedance (resistive) connection to ground.
b) <u>Blocking diode test</u> – Blocking diodes can fail in both open and short circuit states. This test is important for installations where blocking diodes are fitted.
c) <u>Wet insulation test</u> – A wet insulation test is primarily used as part of a fault finding exercise: where the results of a standard (nominally dry) insulation test are questionable or where insulation faults due to installation or manufacturing defects are suspected.
d) <u>Shade evaluation</u> – When inspecting a new PV system, a verification of the as-built shade conditions can be a useful record. Like the electrical measurements described in this standard, the shading evaluation provides a baseline for future comparisons as the shading environment changes. A shade record can also be useful to verify that the shading assumptions used for system design are reflected in the as-built system. Shade records are of particular use where a project is subject to a performance guarantee or other similar performance contract.

### *6.6.2 Voltage to ground – Resistive ground systems*

This test is used to evaluate systems that use a high impedance (resistive) connection to ground. Specific test procedures are provided by the module manufacturers who require resistive ground systems for their modules.
The test shall be performed to the specific requirements of the module manufacturer, to verify that the resistance in place is the correct value and is maintaining the DC system at acceptable voltages relative to ground, or within acceptable ranges of leakage current.

### *6.6.3 Blocking diode test*

Blocking diodes can fail in both open and short circuit states. This test is important for installations where blocking diodes are fitted.
All diodes shall be inspected to ensure that they are correctly connected (polarity correct) and that there is no evidence of overheating or carbonization.
In normal operating mode, the voltage across the blocking diode ($V_{BD}$) shall be measured.

- Pass criterion: $V_{BD}$ between 0.5 V and 1.65 V.

Where the voltage is outside this range, the system shall be further investigated to determine if the diode failure is an isolated incident or the result of another system fault.

### *6.6.4 PV array – Wet insulation resistance test*

#### *6.6.4.1 General*

The wet insulation resistance test is primarily of use as part of a fault finding exercise.
The wet insulation resistance test evaluates the PV array's electrical insulation under wet operating conditions. This test simulates rain or dew on the array and its wiring and verifies that moisture will not enter active portions of the array's electrical circuitry where it may enhance corrosion, cause ground faults, or pose an electrical safety hazard to personnel or equipment.
This test is especially effective for finding above ground defects such as wiring damage, inadequately secured junction box covers, and other similar installation issues. It also may be used to detect manufacturing and design flaws including polymer substrate punctures, cracked junction boxes, inadequately sealed diode cases, and improper (indoor rated) connectors.
A wet insulation test would typically be implemented when the results of a (nominally) dry test are questionable, or where insulation faults due to installation or manufacturing defects are suspected.
The test can be applied to a whole array or on larger systems to selected parts (to specific components or sub-sections of the array). Where only parts of the array are being tested, these are typically selected due to a known or suspected problem identified during other tests.
In some circumstances, the wet insulation test may be requested on a sample proportion of the array.

#### *6.6.4.2 Wet insulation test procedure*

The procedure to be followed is to be the same as that described in the standard insulation test but with an additional initial step of wetting the array.
Prior to test, the section of the array under test should be thoroughly wetted with a mixture of water and surfactant. The mixture should be sprayed onto all parts of the array under test. Prior to testing, the area of the array under test should be checked to ensure that all parts are wetted, including the front, rear and edges of modules, together with all junction boxes and cables.
Performing this test presents a potential electric shock hazard and the safety preparations described for a standard insulation test should be followed. The selection of personal protective equipment to be worn during the test should consider the wet environment that the test will be performed under.
A minimum of two people are recommended to perform this test (as wetness dries up quickly in the field resulting in large variation of results) – one person to conduct the measurement immediately after the second person has completed wetting the area of concern and has given the approval to test.

### *6.6.5 Shade evaluation*

The purpose of performing a shade evaluation is to record the shade and horizon conditions present at the time – to provide a baseline for future comparisons.
For small systems, the shade record should be taken as close a practical to the centre of the array. For larger systems, for systems with multiple sub-arrays or complex shading, a series of shade measurements may be required.
A number of means exist to measure and record shade. One suitable method is to record the shade scene on a sunpath diagram as shown in Figure 5.

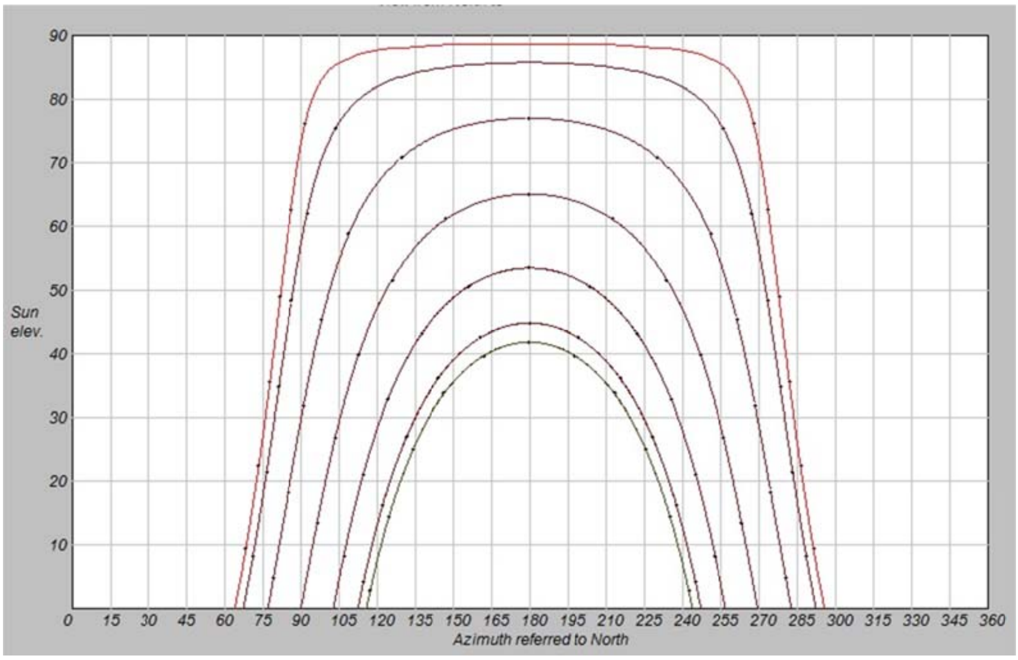


**Figure 5 – Example of sun-path diagram**

In all cases the shade record shall:

- Record the location that the shade record was taken from.
- Show South or North (as appropriate).
- Be scaled so as to show the elevation (height) of any shade object.

**Note**: A description of any shading features that are likely to be an issue in the future can also be a useful record. These include construction projects underway or planned, and any vegetation likely to grow to the point of obstructing part of the array.

# 7 TEST WITH INTERCONNECTION

## 7.1 Overview

The Test with Interconnection shall be performed on all PV plants, regardless their power capacity. However different requirements apply to the PV plants with reference to their power capacity.
The Test with Interconnection includes the verifications listed below.

All Solar PV plants:

- Interface Protection;
- Performance monitoring functions;

Solar PV plants > 100 kW:

- Evaluation of the "Performance Ratio";
- Power Quality measurements and test

## 7.2 Interface Protection

After the Solar PV plant has been connected to the grid and powered, the following verifications shall be performed:

- The Interface Protection settings (functions, thresholds and times) are those required by EWA in accordance with the parameters defined in the Standards [1].
- The Interface device disconnects the solar PV plant in case of power failure on command of the Interface Protection
- After a power recovery the Interface Protection recloses the Interface device.

## 7.3 Performance monitoring functions

All Solar PV plants are fitted with performance monitoring functions.
These functions are integrated in the inverters or are available through the dedicated monitoring and control system usually installed in the larger plants.
For this test it is possible to use:

- The monitoring system of the PV plant, or
- External instruments that measure and log the relevant electric and environmental parameters

Hereafter it will be assumed that a proper monitoring system be used. However, the same considerations may be applied also to temporary solutions that make use of external instruments.
The adopted criteria are taken from the international standard IEC 61724-1 and the technical specifications IEC 61724-2 and IEC 61724-3.

The purposes of a performance monitoring system are diverse and can 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.

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 analyzing performance trends and localizing faults, there may 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 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 4.
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 4.
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.

**Table 4 – Monitoring system classifications and suggested applications**

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

The classes specified in Table 4 apply to the Testing without Interconnection as follows, depending on the power capacity of the solar PV plant (Pn):

- Pn ≤ 11 kW: Class C
- 11 kW > Pn ≤ 100 kW: Class B (Class C acceptable)
- Pn > 100 kW: Class A (Class B acceptable)

## 7.4 General on data acquisition, timing and reporting

### *7.4.1 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 by the manufacturer or at more frequent intervals where specified.
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.

### *7.4.2 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.

### *7.4.3 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.

### *7.4.4 Sampling, recording, and reporting*

A sample is defined as data acquired from a sensor or measuring device, and the sampling interval is the time between samples. Samples do not need to be permanently stored.
A record is defined as data entered into a data log for data storage, based on acquired samples, and the recording interval, denoted by $\tau$ 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.
A report is defined as an aggregate value covering multiple recording intervals, and the reporting period is the time between reports. Typically the reporting period would be chosen to be days, weeks, months, or years.

Table 5 lists the maximum values for sampling intervals and recording intervals.

**Table 5 – Sampling and recording interval requirements**

| Maximum interval | Class A<br>High accuracy | Class B<br>Medium accuracy | Class C<br>Basic accuracy |
|---|---|---|---|
| Maximum sampling interval<br>– For irradiance, temperature, wind and electrical output<br>– For soiling, rain and humidity | <br>3 s<br><br>1 min | <br>1 min*<br><br>1 min | <br>1 min*<br><br>1 min |
| Maximum recording interval | 1 min | 15 min | 60 min |
| * 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 | | | |

### *7.4.5 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.
When multiple data acquisition units are involved that each independently apply timestamps, the clocks of the units shall 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*.

## 7.5 Measured parameters

### *7.5.1 General requirements*

The Table 6 lists measured parameters and a summary of measurement requirements. The purpose of each monitoring parameter is listed in order to guide the user. More details and additional requirements are provided in the next paragraphs and in Annex B – Measurement of environmental parameters.

A check mark (√) in Table 6 indicates a required parameter to be measured on site, qualified by specific notes where included.

The minimum number of on-site sensors is 1 for PV plants up to 5 MW and 2 for larger ones.
If the PV plant includes multiple sections that have different PV technology types or substantially different local geography, then at least one sensor shall be placed in each section.
The symbol "E" in Table 6 indicates a parameter that may be estimated based on local or regional meteorological data or satellite data, rather than measured on site.

**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. Monitoring of meteorological parameters listed in Table 4 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 6 aid in fault localization and assessing utility grid interactions.

**Table 6 – Measured parameters and requirements for each monitoring system class**

| Parameter | Symbol / Units | Monitoring purpose | Measurement required | | |
|---|---|---|---|---|---|
| | | | Class A | Class B | Class C |
| Environmental parameters | | | | | |
| In-plane irradiance (POA) | Gi [W/m$^2$] | Solar resource | √ | √ or E | √ or E |
| Global Horizontal Irradiance | GHI [W/m$^2$] | Solar resource, connection to historical and satellite data | √ | √ or E | |
| PV module temperature | Tmod [°C] | Determining temperature-related losses | √ | √ or E | |
| Ambient air temperature | Tamb [°C] | Connection to historical data and estimation of PV temperature | √ | √ or E | √ or E |
| Wind speed | WS [m/s] | Estimation of PV temperature | √ | √ or E | |
| Wind direction | WD [°] | | √ | | |

| Parameter | Symbol / Units | Monitoring purpose | Measurement required | | |
|---|---|---|---|---|---|
| | | | Class A | Class B | Class C |
| Soiling ratio | SR | Determining soiling-related losses | √ (if SR > 2%) | | |
| Array voltage (DC) | Va [V] | Energy output, diagnostic and fault localization | √ | | |
| Array current (DC) | Ia [A] | | √ | | |
| Array power (DC) | Pa [W] | | √ | | |
| Electrical parameters | | | | | |
| Output voltage (AC) | Vout [V] | Energy output | √ | √ | |
| Output current (AC) | Iout [a] | | √ | √ | |
| Output power (AC) | Pout [W] | | √ | √ | √ |
| Output energy | Eout [kWh] | | √ | √ | √ |
| Output power factor | λ | Utility request compliance | √ | √ | |
| Reduced load demand | | Determine utility or load request compliance and impact on PV system performance | If applicable | If applicable | |
| System output power factor request | λreq | | If applicable | If applicable | |

### *7.5.2 Environmental parameters*

The environmental parameters are listed in the Section A of the Table 6.

The instructions regarding the verification of the correct installation of the environmental sensors and the requirements for the measurements of the environmental parameters are available in the Annex B – Measurement of environmental parameters.

### *7.5.3 Electrical 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 1000 W/m$^2$) and low module temperature (below 25 °C).

Electrical measurements shall have uncertainty meeting the requirements listed in Table 7 and Table 8 for measurements corresponding to ≥ 20 % of the expected electrical output when the array is operating at STC.

Table 7 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.

Table 7 – Inverter-level electrical measurement requirements

| Parameter | Measurement uncertainty | | |
|---|---|---|---|
| | **Class A**<br>**High accuracy** | **Class B**<br>**Medium accuracy** | **Class C**<br>**Basic accuracy** |
| Input voltage (DC) | ±2.0 % | n/a | n/a |
| Input current (DC) | ±2.0 % | n/a | n/a |
| Input power (DC) | ±2.0 % | n/a | n/a |
| Output voltage (AC) | ±2.0 % | ±3.0 % | n/a |
| Output current (AC) | ±2.0 % | ±3.0 % | n/a |
| Output power (AC) | ±2.0 % | ±3.0 % | n/a |

Table 8 – Plant-level AC electrical output measurement requirements

| Parameter | Class A<br>High accuracy | Class B<br>Medium accuracy | Class C<br>Basic accuracy |
|---|---|---|---|
| Active power and energy | Class 0,2 S<br>as per IEC 62053-22 | Class 0,5 S<br>as per IEC 62053-22 | Class 2<br>per IEC 62053-21 |
| Power factor | Class 1<br>as per IEC 61557-12 | Class 1<br>as per IEC 61557-12 | Class 2<br>per IEC 62053-21 |

#### *7.5.4 External system requirements*

The monitoring system should 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.

## 7.6 Data processing and quality check

The performance monitoring system collects the measures relevant to the environmental and to the electrical parameters. The reliability of these measures shall be checked in order these measures can be effectively used for the monitoring of the Solar PV plant or to compile the periodical reports that document the performance of the renewable generator.

### *7.6.1 Daylight hours*

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

### *7.6.2 Removing invalid readings*

The measured data shall 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 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.

A recommendation for application of this procedure for this application is given in more detail in Table 9 with values suggested when the collected data have been averaged 15 minute time periods. Depending on the local conditions, the details of the plant design, the addition of other data streams and the frequency of data collection, the filtering criteria may be modified, but all four types of filters (range, dead value, abrupt change/stability and inverter status) shall be applied and documented as part of the final report.

**Table 9 – Data validation and filtering criteria**

| Flag type | Description | Suggested Criteria for Flagging Rejected Data (15 min data) | | | |
|---|---|---|---|---|---|
| | | Irradiance [W/m$^2$] | Ambient temperature [°C] | Wind speed [m/s] | Power (AC power rating) |
| Range | Value outside of acceptable bounds | Irradiance < 0 W/m$^2$ or > 1200 W/m$^2$ | > 55 or < -10* | >15 or < 0,5 | > 1,02 × rating or < 0 |
| Dead value | Values stuck at a single value over time. Detected using derivative | Derivative < 0,0001 while value is > 5 | < 0,0001 and > -0,0001 | < sensitivity of sensor | < 0.1% change in 3 readings |
| Abrupt change and stability | Values change unacceptably between data points. Detected using derivative for temperature and wind speed | Assuming 15 min data derived from at least 1 min data, standard deviation > 5% of average | > 4 | > 10 | Assuming 15 min data derived from at least 1 min data, standard deviation > 5% of average |

* May be adjusted depending on the season of data acquisition.
** The maximum irradiance included in the analysis may be adjusted to account for the possibility of cloud edge effects, whereby light is reflected by a nearby cloud and can cause irradiance readings up to approximately 1500 W/m$^2$. For most systems, these conditions will cause saturation of the inverter, and will typically be excluded from the evaluated data by the stability filter.

**Note**: Potential-induced degradation (PID) effects may start to reduce the power output at low irradiance conditions remarkably, without a measurable effect at high irradiance.

The stability filter recommended here calculates the average of at least 15 data points (measured at least every minute during 15 minutes) and confirms that the standard deviation for those data points is less than 5% of the average of the same data points. It is recommended to apply the stability filter to both the irradiance and power data.

The number of data points identified as meeting the criteria in Table 9 will affect the uncertainty of the test. As a guide to determining an adequate, yet reasonable, number of data points, Table 10 may be taken as a guide. The larger number of data points during the summer reflects the ease of collecting more data on longer days and is expected to result in a higher accuracy measurement, depending on the local weather.

Table 10 – Example guide for seasonal minimum stable irradiance requirements for flat-plate applications

| Season | Dates | Minimum POA irradiance | Required Number of 15-Minute Average Data Points |
|---|---|---|---|
| Winter | November 22 – January 21 | 450 | 20 |
| Spring | January 22 – March 23 | 550 | 30 |
| Summer | March 24 – September 21 | 650 | 60 |
| Autumn | September 22 – November 21 | 550 | 40 |

### *7.6.3 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 analyzed 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.

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

## 7.7 Calculated parameters

Table 11 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 11 – Calculated parameters

| Parameter | Symbol | Unit |
|---|---|---|
| In-plane irradiation | *Hi* | $kWh/m^2$ |
| PV array output energy (DC) | *Ea* | kWh |
| Energy output from PV system (AC) | *Eout* | kWh |
| Array power rating (DC) | *Po* | kW |
| Array power rating (AC) | *Po,ac* | kW |
| Final system yield | *Yf* | kWh/kW |
| Reference yield | *Yr* | kWh/kW |

### *7.7.1 Description of calculated parameters*

#### *7.7.1.1 Notes on summations*

In the formulas given below involving summation, *tk* denotes the duration of the $k^{th}$ recording interval within a reporting period, and the symbol: Σ denotes summation over all recording intervals in the reporting period.

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

### *7.7.1.2 In-plane irradiation*

Irradiation, also known as insolation, is the time integral of irradiance.
In-plane irradiation quantity *Hi* corresponding to an irradiance quantity *Gi* is calculated by summing the irradiance as follows:

$$Hi = \sum_k Gi,k \times \tau k$$

### *7.7.1.3 Electrical energy*

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.
The PV array DC output energy is given by:

$$Ea = \sum_k Pa,k \times \tau k$$

The AC energy output is given by:

$$Eout = \sum_k Pout,k \times \tau k$$

### *7.7.1.4 Final system yield*

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

$$Yf = Eout/Po$$

### *7.7.1.5 Reference yield*

The reference yield Yr can be calculated by dividing the total in-plane irradiation by the module's reference plane of array irradiance:

$$Yr = Hi/Gi,ref$$

where the reference plane of array irradiance *Gi,ref* ($kW/m^2$) is the irradiance at which Po is determined.
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 *Yr* would be, in effect, the equivalent number

of sun hours at the reference irradiance per day.

## 7.8 Performance ratio

### *7.8.1 Overview*

A number of metrics are defined here for quantifying system performance. The most appropriate metric for a given system depends on the system design and user requirements. Therefore the Customer and the Contractor shall agree the kind of performance test to be carried out.
Performance ratios are based on the system name-plate rating, while a performance index is based on a more detailed model of system performance.
The rating-based performance ratio metrics are adopted in this document.

**Note**: Performance ratios are relatively simple to calculate but may omit known factors that cause system power output to deviate from expectations based on the name-plate rating alone. For example, systems with high DC-to-AC ratio operate at less than the DC nameplate rating during times of high irradiance, but this is an expected attribute of the system design. Such effects are better treated by a performance index based on a detailed system model.
For the above reasons, in particular cases performance indices may be used along with or alternatively to performance ratios.

The performance ratios described in the IEC 61724-1 are the following:

- Performance ratio (*PR*)
- Annual performance ratio (*PRannual*)
- Annual temperature-equivalent performance ratio (*PR'annual-eq*)
- STC-temperature performance ratio *PR'stc*

### *7.8.2 Performance ratio and Annual performance ratio*

The performance ratio *PR* is the quotient of the system's final yield *Yf* to its reference yield *Yr*, and indicates the overall effect of losses on the system output due to both array temperature and system component inefficiencies or failures, including balance of system components. It is defined as:

$$PR = Yf/Yr = (Eout/Po)/(Hi/Gi,ref)$$

Expanding the formula and moving *Po* to the denominator, sum expresses both numerator and denominator in units of energy, giving PR as the ratio of measured energy to expected energy (based only on measured irradiance and neglecting other factors) over the given reporting period:

$$PR = \left(\sum_k Pout,k \times \tau k\right) \Big/ \left(\sum_k \frac{Po \times Gi,k \times \tau k}{Gi,ref}\right)$$

The Annual performance ratio, *PRannual*, is the performance ratio of the above formula evaluated for a reporting period of one year.

**Note**: The energy expectation expressed by the denominator of the above formula neglects the effect of array temperature, using the fixed value of array power rating, *Po*. Therefore, the performance ratio usually decreases with increasing irradiation during a reporting period, even though energy production is increased, due to increasing PV module temperature which usually accompanies higher irradiation and results in lower efficiency. This gives a seasonal variation, with higher PR values in winter and lower values in summer. It may also give geographic variations between systems installed in different climates.

### *7.8.3 Temperature-corrected performance ratios*

The seasonal variation of the performance ratio *PR* can be significantly reduced by calculating a temperature-corrected performance ratio *PR'* (STC performance ratio or Annual temperature-equivalent performance ratio).

It should be noted that while variations in average ambient temperature are the most significant factor causing seasonal variations in measured performance ratio, other factors, such as seasonally dependent shading, spectral effects, and others can also contribute to the seasonal variation of *PR'*.

### *7.8.4 STC performance ratio*

The STC performance ratio, *PR'stc* is calculated by adjusting the power rating at each recording interval to compensate for differences between the actual PV module temperature and the STC reference temperature of 25 °C.

The value of the metric will be closer to unity than for the performance ratio calculated without the temperature correction.

*PR'stc* is calculated by introducing a power rating temperature adjustment factor *Ck* into the formula, as follows:

$$PR'stc = \left(\sum_k Pout,k \times \tau k\right) \Big/ \left(\sum_k \frac{(Ck \times Po) \times Gi,k \times \tau k}{Gi,ref}\right)$$

Where *Ck* is given by:

$$Ck = 1 + \gamma \times (Tmod,k - 25)$$

Here $\gamma$ is the relative maximum-power temperature coefficient (in units of 1/°C), and *Tmod,k* is the module temperature (in °C) in time interval *k*.

$\gamma$ is typically negative, e.g. for crystalline silicon.

The measured PV module temperature may be used for *Tmod,k* in the formula. However, if the monitoring objective is to compare *PR'stc* to a target value associated with a performance guarantee, *Tmod,k* should instead be estimated from the measured meteorological data with the same heat transfer model used by the simulation that set the performance guarantee value to avoid a bias error. In IEC TS 61724-2 Annex A, a heat transfer model to calculate expected cell operating temperature is shown.

Note that the formula that calculates *Ck* can be used to calculate performance ratio adjusted to a different reference temperature by substitution of the desired reference temperature in place of 25 °C.

### *7.8.5 Annual-temperature-equivalent performance ratio*

The annual-temperature-equivalent performance ratio *PR'annual-eq* is constructed to approximate the annual performance ratio *PRannual* regardless of the duration of the reporting period. It

calculates the performance ratio during the reporting period with the power rating at each recording interval adjusted to compensate for differences between the actual PV module temperature and an expected annual-average PV module temperature. While this reduces seasonal variation in the metric, it does not remove the effect of annual-average temperature losses and leaves the value of the metric comparable to the value of *PRannual*.
*PR'annual-eq* is calculated by introducing a power rating temperature adjustment factor *Ck* into the formula, as follows:

$$PR'annual\_eq = \left(\sum_k Pout,k \times \tau k\right) \Big/ \left(\sum_k \frac{(Ck \times Po) \times Gi,k \times \tau k}{Gi,ref}\right)$$

Where *Ck* is given by:

$$Ck = 1 + \gamma \times (Tmod,k - Tmod,avg)$$

Here $\gamma$ is the relative maximum-power temperature coefficient (in units of 1/°C), and *Tmod,k* is the module temperature (in °C) in time interval *k* and *Tmod,avg* is an annual-average module temperature.
$\gamma$ is typically negative, e.g. for crystalline silicon.
*Tmod,avg* is chosen based on historical weather data for the site and an empirical relation for the predicted module temperature as a function of ambient conditions and module construction. It should be calculated by computing an irradiance-weighted average of the predicted module temperature and then verified using the historical data for the site by confirming that the annual-equivalent performance ratio *PR'annual-eq* for the historical data is the same as the annual performance ratio *PRannual* for the
historical data.
The measured module temperature may be used for *Tmod,k*. However, if the monitoring objective is to compare *PR'annual-eq* to a target value associated with a performance guarantee, *Tmod,k* should instead be estimated from the measured meteorological data with the same heat transfer model used by the simulation that set the performance guarantee value, to avoid a bias error. In IEC TS 61724-2, Annex A, a heat transfer model to calculate expected cell operating temperature is shown.

#### *7.8.6 Test duration*

The duration of the Test with Interconnection will depend on the size of the Solar PV plant as follows:

- Up to 11 kW – At least one valid measurement
- Above 11 kW and up to 100 kW – 1 day (99% valid data recorded)
- Above 100 kW – At least 10 days (95% valid data recorded)

## 7.9 Test report (Pn > 100 kW)

The Test report apples only to solar PV plants above 100 kW.
The final test report shall include both the Test Procedure (either explicitly or by reference) as well as the following items:

1) Relevant data on the Test Engineer
2) Description of the site being tested, including latitude, longitude, and altitude

3) Description of the system being tested. Specific note should be made of whether there are parasitic loads and how these are documented by the test
4) Description of the verification of the Interface Protection
5) Description of the verification of the performance monitoring system

Additional sections for Solar PV plants > 100 kW

6) A summary of the definition of the meteorological data taken during the test, including calibration data for all sensors (sensor identification, test laboratory, date of test) and sensor location, including photographs for documenting the sensor location and ground conditions like rough or smooth vegetation or snow and records of sensor cleaning.
7) A summary of the definition of the system output data collected during the test, including records of completed calibrations
8) The description of raw data that were collected during the test, including note of which data met the stability and other criteria
9) A list of any deviations from the test procedure and why these were taken
10) Summary of the correction factors that were calculated for the filtered data
11) Description of uncertainty analysis and statement of uncertainty associated with the correction factors, based on the uncertainty of the weather measurements and uncertainty of the model assumptions such as the temperature model and the assumption of linear response to irradiance.
12) A summary version of the test results may be provided containing the *PR* and the *PR'* (temperature corrected) in the test interval.

No pass/fail criteria based on *PR* and *PR'* are considered in the Test with Interconnection.

# 8 POWER QUALITY MEASUREMENTS AND TESTS – SOLAR PV PLANTS > 100 KW

## 8.1 Overview

The Power Quality measurements and tests applies to all solar PV plants whose Pn is above 100 kW, regardless their voltage connection.

A Test Engineer appointed by the Applicant makes this inspection.

The harmonic emissions generating from the solar PV plant shall be measured to allow EWA/EDD to verify that network power quality is actually in line with the requirements reported in the *Standards for Solar PV Systems to be connected in parallel with the distribution networks of the Kingdom of Bahrain* and in EN 60160. The solar PV plant shall not generate disturbances to other customers.

In principle, the tests are made for the whole power plant at POC. If the solar PV plant has different POCs, the tests must be performed at each POC.

## 8.2 Assessment of the harmonic content

The methodology of the tests is here summarised:

- Observation period of at least one week with fixed steps of 10 minutes.
- N = number of 10-minute intervals in which the supply voltage is within normal operating range.
- N1 = number of 10-minute intervals in which voltage harmonics level exceeds individual harmonic limit and the supply voltage is within normal operating range. Levels for individual harmonics limits are defined in [1].
- N2 = number of 10-minute intervals in which the THD value for one or more of the phase voltages exceeds the harmonic voltage limits defined in [1] and the supply voltage is within normal operating range.

The harmonic content on the voltage is acceptable whenever N1/N <= 5% for each individual harmonics and N2/N <= 5% for THD during the observation period.

The Harmonic Emissions Performance Tests may be performed indifferently using one of the following measurements methods:

- Taking advantage of the functionalities of the Smart Meter (if it is compliant with the above measurements requirements), by retrieving the measurements on a suitable time period.
- Installing and making use of specific instrumentation, compliant with the above requirements, to perform a dedicated test campaign.

The tests are deemed valid if they have been carried out considering operating conditions of the PV plant as specified in Chapter 7. In other words, it is advisable to measure the harmonic content in the voltages during the Test With Interconnection. The tests results and the measured values shall be clearly presented in tables for their analysis by EWA/EDD engineers and their confrontation with EWA/EDD planning levels or limits. In case some limits are exceeded, EWA/EDD is entitled to ask the customer for additional measurements on current harmonics emissions in order to check the actual current emission spectrum and investigate whether the causes of such limits violations are to be attributed to the solar PV plant or to the interaction with other equipment.

## 8.3 Additional measurements

If some voltage harmonics limits were found over the limits as specified in 8.2, the following additional measurements are needed:

- Background harmonic voltage of the existing grid at the Point of Connection, with the solar PV plant disconnected from the grid. The measurements with the methodology as described in the previous paragraph have to be carried out, after disconnection of the plant
- Emission of current harmonics during continuous operation.

The current harmonic measurements shall be made with an observation period of at least one week with fixed steps of 10 minutes. The values of the individual current components and the total harmonic current distortion shall be given in tables in percentage of In and for operation of the solar PV plant within the active power ranges 0-25, 25-50, 50-75 and 75-100% of Pn.

The individual harmonic current components shall be specified as sub grouped values for frequencies up to 50 times the fundamental grid frequency, and the total harmonic current distortion shall be calculated as derived from these.

The current harmonics shall be measured for the solar PV plant operating with reactive power as close as possible to zero, i.e. if applicable the reactive set-point control shall be set to Q=0. If other operational mode is used, this shall be clearly stated.

# ANNEXES

## Annex A - Safety Information Form

The following form indicating specific risks and on-site safety measures shall be filled and delivered by the Applicant / Contractor to EWA/EDD or to any other concerned Authority or Inspectors (e.g. Test Engineer) visiting the site of the PV plant.

| ***Safety Information Form*** | |
|---|---|
| ***Solar PV plant*** | |
| Type of Applicant | ☐ Individual ☐ Organization |
| Organization (if applicable) | |
| First name | |
| Last name | |
| P.O. Box | |
| Street number | |
| Street name | |
| Location / Area | |
| City | |
| Voltage delivery | ☐ 230V (1 phase) ☐ 400 V (3 phases) ☐ 11 kV |
| PV capacity [kW] | |
| Voltage delivery | ☐ 230V (1 phase) ☐ 400 V (3 phases) ☐ 11 kV |
| PV module installation | ☐ On building ☐ Other structure (e.g. canopy) ☐ Ground |
| Building installation (if applicable) | ☐ Flat rooftop ☐ Roof flap ☐ Façade ☐ Other |
| Building type (if applicable) | ☐ Villa or small household ☐ Apartment block ☐ Offices<br>☐ School/University ☐ Healthcare/Hospital ☐ Industrial<br>☐ Hotel/Restaurant ☐ Entertainment ☐ Agricultural/Stable<br>☐ Detention/Correctional ☐ Other . . . . . . . . . . . . . . . . . . . . . . |
| Tracking system if any | ☐ No tracking ☐ Single-axis tracking ☐ Two-axes tracking |
| Notes on safety measures to access the PV array | |
| ***Location of equipment*** | |
| Combiner boxes | |
| Inverters | |
| Switchgears | |
| Other | |
| Indications to put the PV plant off-line | |
| Notes on safety measures to access the equipment | |
| ***Interferences with other works*** | |
| ***Location of fire hydrants and fire extinguishers*** | |

| ***Safety Information Form*** | | |
| --- | --- | --- |
| ***risks in the workplace and related prevention and protection measures*** | | |
| **Specific risk** | **Collective Protection** | **PPE** |
| Electric shock | | |
| Falls | | |
| Slipping | | |
| Dust | | |
| Harmful substances | | |
| | | |
| | | |
| | | |

# Annex B – Measurement of environmental parameters

## 1 IRRADIANCE

### 1.1 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.

**Note**: POA irradiance can also be estimated from GHI using a decomposition and transposition model.

### 1.2 Global horizontal irradiance

Global horizontal irradiance (GHI) is measured with a horizontally oriented irradiance sensor.
Measurements of horizontal irradiance are useful for comparison to historical meteorological data and can be relevant to documentation of a performance guarantee.

**Note**: GHI can also be estimated from POA irradiance using a decomposition and transposition model.

### 1.3 Irradiance sensors

Suitable irradiance sensors include the following:

- thermopile pyranometers (Figure 6);
- PV reference devices, including reference cells (Figure 7) and reference modules; and
- photodiode sensors.

**Figure 6 – Example of an in-plane pyranometer**

Figure 7 – Example of an in-plane PV sensor

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.
The Table 12 lists sensor choices and accuracy requirements for in-plane and global irradiance measurement, and Table 13 lists maintenance requirements for these sensors.
The sensor, signal-conditioning electronics, and data storage shall provide a range including at least 0 W/m$^2$ to 1 500 W/m$^2$ and a resolution of ≤ 1 W/m$^2$.

**Note**: Over-irradiance in the range 1 000 W/m$^2$ to 1 500 W/m$^2$ or higher can occur due to reflections from clouds under partly cloudy conditions.

Table 12 – Sensor choices and requirements for in-plane and global irradiance

| Sensor type | Class A<br>High accuracy | Class B<br>Medium accuracy | Class C<br>Basic accuracy |
|---|---|---|---|
| Thermopile pyranometer | Secondary standard per ISO 9060<br>or<br>High quality per WMO Guide No. 8<br>(Uncertainty ≤ 3 % for hourly totals) | First class per ISO 9060<br>or<br>Good quality per WMO Guide No. 8<br>(Uncertainty ≤ 8 % for hourly totals) | Any |
| PV reference device | Uncertainty ≤ 3 %<br>from 100 W/m$^2$ to 1 500 W/m$^2$ | Uncertainty ≤ 8 %<br>from 100 W/m$^2$ to 1 500 W/m$^2$ | Any |
| Photodiode sensor | 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.

## 1.4 Sensor locations

The location of the 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.
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, 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.

## 1.5 Sensor maintenance

Irradiance sensor maintenance requirements are listed in Table 13.

**Table 13 – Irradiance sensor choices maintenance requirements**

| Item | Class A<br>High accuracy | Class B<br>Medium accuracy | Class C<br>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. 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, $-1\ W/m^2$ to $-3\ W/m^2$, at night time.

## 1.6 Satellite remote sensing of irradiance

When permitted by Table 6, 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 W/m$^2$, but 20 % at 100 W/m$^2$ – i.e, a constant ≅20 W/m$^2$ throughout the 100 W/m$^2$ to 1 000 W/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 W/m$^2$, and 10 % at 100 W/m$^2$ – i.e., a constant ≅10 W/m$^2$ throughout the 100 W/m$^2$ to 1 000 W/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 W/m$^2$ for an untrained model, and 1,25 % 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.

## 2 PV MODULE TEMPERATURE

The PV module temperature, Tmod, is measured with a temperature sensor affixed to the back of one or more modules.

The measurement uncertainty of the temperature sensors, including signal conditioning, shall be ≤ 2 °C.

Depending on the monitoring systems, temperature sensors shall be replaced or recalibrated at least every 2 years for Class A and per manufacturer’s recommendations for Class B.

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 so that the material is not attacked or degraded 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 $W/m^2K$ 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 W/mK in a layer not more than 1 mm thick.

Additional recommendations on temperature sensor attachment may be found in IEC 61724-1, Annex B.

Care shall 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 hotter 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 owing to 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.

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 Voc-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.

## 3 AMBIENT AIR TEMPERATURE

When required by Table 6, the ambient air temperature, Tamb, 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 ≤ 0,1 °C and maximum uncertainty ±1 °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.

Depending on the monitoring systems, temperature sensors shall be replaced or recalibrated at least every 2 years for Class A and per manufacturer's recommendations for Class B.
When permitted by Table 6, ambient air temperature at the site may be estimated based on local or regional meteorological data.

# 4 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 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.
Wind measurement equipment shall 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 ≤ 0,5 m/s for wind speeds ≤ 5 m/s, and ≤ 10 % of the reading for wind speeds greater than 5 m/s.
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.

# 5 SOILING RATIO

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.

## 5.1 Equipment

Measurement of the soiling ratio requires the following:

a) 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.
b) 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°. Cleaning 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 (Measurement method 1) and/or short-circuit current (Measurement method 2) 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.

## 5.2 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 (Measurement method 1) and/or short-circuit current (Measurement method 2) 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.

The calibration 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.

## 5.3 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 for the short-circuit current.
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 for the maximum power.
e) Calculate the soiling ratio SR by dividing the soiled device max power measured in b) by its expected max power calculated in d).

## 5.4 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 for the short-circuit current.
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 for the maximum power.
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).

## 5.5 Preferred method

Measurement method 1 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 nonuniform across the modules, especially for typical crystalline silicon modules. Measurement method 2 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.

## 5.6 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.