Inspection and Testing Guidelines for Large-Scale Solar

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1 SCOPE

These Guidelines provide information on the Inspection and Testing procedures to be carried out by the eligible consumer at the end of the construction of a Large-Scale Solar PV System, in order to connect it to the Distribution Network in KSA. These Guidelines are providing the technical know-how and knowledge to the test engineers and contractors to help them conducting the commissioning successfully.

DISCLAIMER

The contractor, consultant and eligible consumer are the ultimate responsible for everything in the REG system and for the commissioning. SEC will inspect and commission these systems according to its internal checklist, focusing only on the components and equipment impacting the distribution network and the connection point.

Referring to the approved WERA regulations and SEC connection process, the inspection and testing are executed in Step 3 named as “REG Connection” phase. SEC’s responsibilities at this stage will be limited to the following:

- Inspect the REG system to verify the correspondence between the REG system and the documentation provided and approved during the Design Document evaluation stage:
  - Agree with the Eligible Consumer on the inspection date
  - Completeness of the documentation and its correspondence with the REG system on-site, as per SEC’s inspection checklist.
  - Inspect the presence of Interface Protection and required switches.
  - Witness Compliance test to be performed if necessary, during cold commissioning.
  - Temporary connection granted (known as “Limited Operational Notification”).
- Generation Meter installation if all tests have a positive outcome.

During REG Energization & Operation phase, SEC will have the right to witness the commissioning tests only if deemed necessary. SEC eventually will be responsible for issuing the “Final Operation Notification” and If deemed necessary, SEC is entitled to ask the Eligible Consumer to sign a REG System Operational Agreement. SEC will also check the commissioning report following SEC’s commissioning checklist.

2 COMPANION DOCUMENTS

[1] CESI_SEC-DREG Health and Safety Requirements for Large-Scale PV_Final.docx
[2] CESI_SEC-DREG Large-scale PV - Best Practice Design v1.0_Final.docx
[3] CESI_SEC-DREG Manual for the maintenance of Large-Scale PV Systems_Final.docx
[4] CESI_SEC-DREG PV components and recommendations for PV larger than 2 MW_Final.docx
[5] CESI_SEC-DREG PV Large Scale Technical Connection Standards_Final.docx
[6] CESI_SEC-DREG Inspection and Testing Checklists for Large Scale Solar_Final.docx
[7] CESI_SEC-DREG Connection Guidelines for Large-Scale PV_Final.pdf

DISCLAIMER
For understanding the connection process for connection large-scale PV systems, users must refer to the common connection process document for REG systems. The connection process for all DREG systems is the same, and hence, all users are shall be updated with the REG connection process which is applicable for Large Scale PV systems too.

3 HAZARDS AND SAFETY MEASURES

3.1 Foreword

This chapter does not substitute the safety laws and rules in force in KSA as regards the works on electric, mechanical and civil installations[1]. The purpose is to integrate the existing rules with some indications which focus on particular safety aspects related to solar PV systems.

3.2 Hazards and safety measures

The onsite tests, particularly on electrical installations, is the task and the responsibility of the Test Engineer. As he must be aware of the main details of such electrical tests and the associated hazards, according to the laws and rules in force in KSA, his experience and the description of his activities are provided below.

All what is located upstream of a circuit-breaker device on the DC section of a PV system (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 system on DC side shall have a warning sign, which indicates the presence of live parts even after the opening of DC circuit-breaker devices.

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 1):
- A safety helmet made of insulating material with face shield (mainly to protect him against electric arcing).
- Arc related PPE and 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

[1] It is not the responsibility of SEC to check the compliance of the design of the Large-scale Solar PV systems with the Saudi Building Code

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 systems is lower than that in other electric plants supplied by the grid, but the duration is greater because it is more difficult to quench 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.

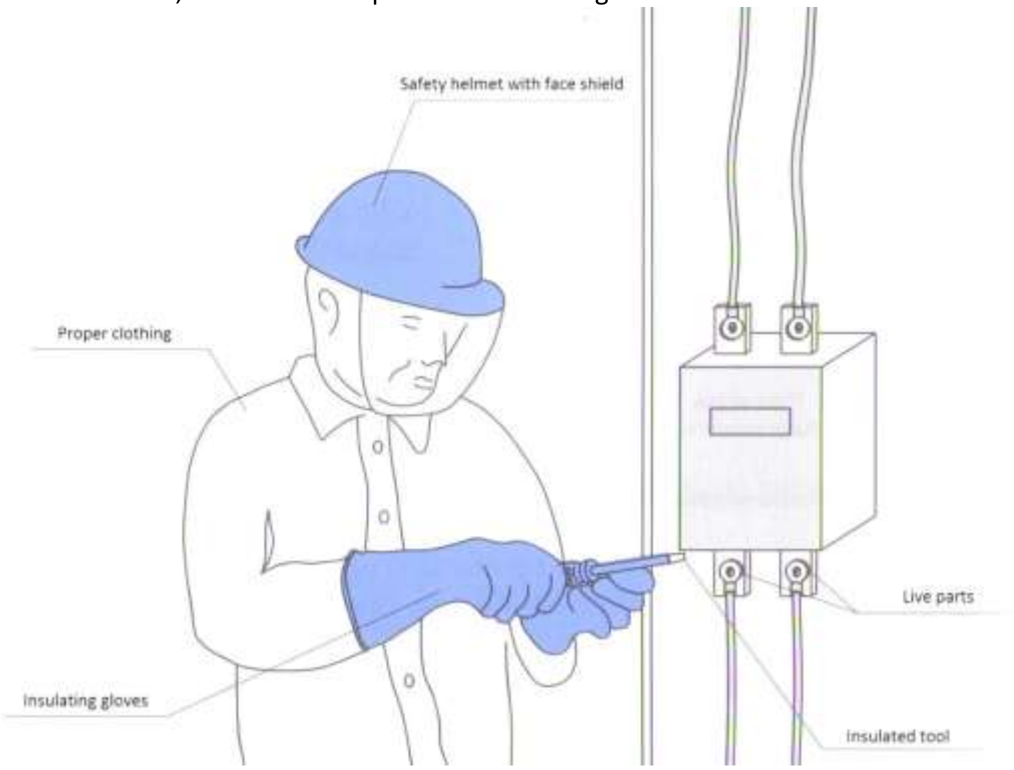

Figure 1 – Main safety measures for works under voltage

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, it is possible to 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 2 and consists of keeping the connectors of a module and the string circuit-breaker open during installation. In Figure 2 it is illustrated 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.

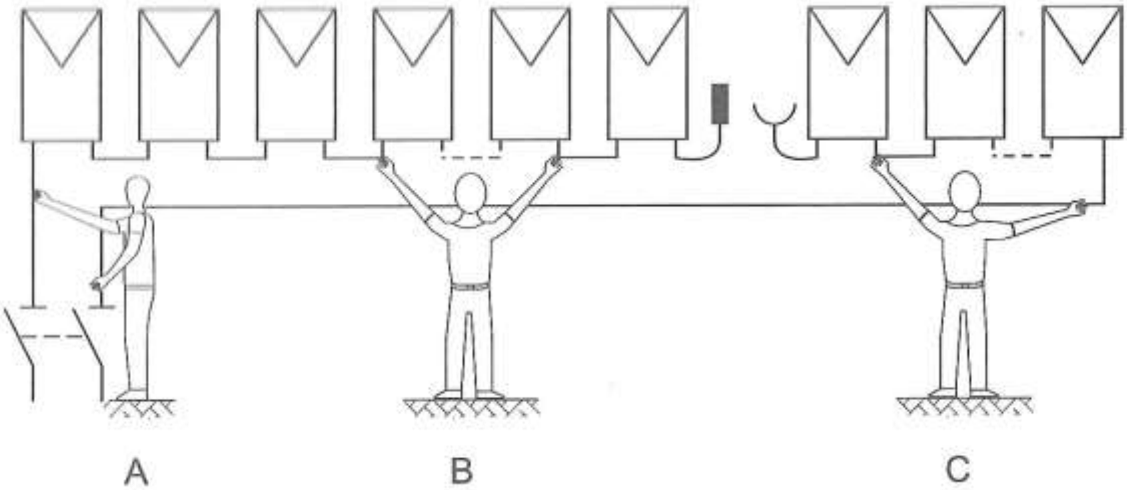

Figure 2 – The interruption of a string makes the worker A safe but keeps the workers B and C unsafe

Interventions on PV systems 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 system 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 Eligible Consumers about Specific Risks on-site and Safety Measures

A form indicating specific risks and onsite safety measures (see Annex A – Safety information Form) shall be filled and delivered by the Eligible Consumer/Contractor to SEC or to the concerned Authority, before the respective Inspectors visit the site of the PV system.

3.4 System documentation requirements

The minimum design documentation that needs to be provided with reference to a Large-Scale Solar PV system is specified in the Annex B. The design documentation shall be available onsite for consultation by the inspectors visiting the site where the Solar PV system is installed.

4 SITE TEST

4.1 Overview

4.1.1 General

The Site Test applies to all solar PV systems 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 Eligible Consumer. As a rule, this test begins after the completion of the solar PV system, although for large PV systems for safety reasons the Test Engineer may initiate the tests on strings during installation, in order to prevent parallel of strings with different number of PV modules 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 time of test initiation and completion.

4.1.2 Basic Tests and Additional tests

The test procedure that is applied to a Large-Scale Solar PV System needs to be appropriate to the scale, type, location and complexity of the system in question.

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

- Basic tests – The minimum requirement – A standard set of tests that shall be applied to all Large-Scale Solar PV systems.
- Additional tests – Further tests assuming that all Basic tests have already been undertaken. They contain tests that may be performed in some circumstances. Unless differently agreed, these tests are optional.

4.1.3 Special considerations for Solar PV 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 a suitable test procedure.

Table 1 – Modifications to the test procedure for Solar PV systems with module level electronics

Type of equipment	Modifications to test procedure
AC Module	– No DC test or inspection works required
Micro inverter where no site constructed wiring is used (all connections using module and inverter leads)	– Testing of DC circuits is not required – Inspection of DC works is required
Micro inverter where site constructed wiring is used	– Testing of DC circuits is required – Inspection of DC works is required
Module integrated electronics	– Where possible, the Basic tests are to be followed – Manufacturer to be consulted to determine any restrictions to tests (e.g. insulation resistance test) – 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 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.

4.2 Common requirements

Testing of the electrical installation shall be done according to the requirements of IEC 60364-6 and SASO IEC 62446-1. Measuring instruments and monitoring equipment and methods shall be chosen in accordance with the applicable relevant parts of IEC 61557 and IEC 61010. If other measuring equipment is used, they 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 cleared all previous tests shall be repeated in case the fault influenced the result of these tests.

4.3 Large-Scale Solar PV systems Inspection

4.3.1 General

Inspection shall precede testing and shall normally be done prior to energizing the installation. If wiring of the DC section 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. SEC main focus will be on the AC side and the connection point; however, the below section purpose is to provide technical indication for the contractors and consultant.

4.3.2 DC system – General verifications

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

a) the DC system has been designed and installed according to the requirements of IEC 60364 and SASO IEC 62548.
b) the maximum PV array voltage is suitable for the chosen array location.
c) all system components and mounting structures have been selected, designed and erected to withstand the expected external influences such as wind, sandstorms, temperature and corrosion.
d) Where necessary, roof fixings and cable entries are weatherproof.

4.3.3 DC system – Verification of the protection against electric shock

In the DC installation at least one of the following measures in place for protection against electric shock shall be adopted:

a) Protective measure provided by extra low voltage (SELV / PELV)
b) Protection by use of class II or equivalent insulation adopted on the DC side

Furthermore, PV string and array cables have been selected and erected so as to minimize the risk of earth faults and short-circuits. This is typically achieved by the use of cables with protective and reinforced insulation (often termed “double insulated”).

4.3.4 DC system – Verification of the 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) That a PV Array Earth Insulation Resistance detection and alarm system is installed – to the requirements of SASO IEC 62548 (this is typically provided within the inverter).
b) That a PV Array Earth Residual Current Monitoring detection and alarm system is installed – to the requirements of SASO IEC 62548 (this is typically provided within the inverter).

4.3.5 DC system –Verification of the 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 not greater than the maximum reverse current.
   - string cables are sized to accommodate the maximum combined fault current from parallel strings according to SASO IEC 62548.
b) For systems with string overcurrent protective device, verify that:
   - the string overcurrent protective devices are fitted and correctly specified according to the requirements of SASO IEC 62548.
c) For systems with array / sub-array overcurrent protective devices, verify that:
   - the overcurrent protective devices are fitted and correctly specified according to the requirements of SASO IEC 62548.

The potential for the system inverter(s) to produce a DC back-feed into the PV array circuits shall also be verified.

4.3.6 DC system – Verification of earthing and bonding arrangements

Inspection shall include the followings points:

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 SASO IEC 62548.
b) where a PV system has a direct connection to earth on the DC side, a functional earth fault interrupter is provided according to the requirements of SASO IEC 62548.
c) array frame bonding arrangements have been specified and installed according to the requirements of SASO IEC 62548 (functional earthing is normally required by the PV Array Earth Insulation Resistance detection and alarm system).
d) where protective earthing and/or equipotential bonding conductors are installed, they are parallel to, and bundled with, the DC cables.

4.3.7 DC system – Verification of the protection against the effects of lightning and overvoltage

Inspection shall include the followings points:

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. cables with screening or the use of surge protective devices, SPDs).
c) where SPDs are fitted, the installation has been made according to the requirements of SASO IEC 62548.

4.3.8 DC system – Verification of the selection and erection of electrical equipment

Inspection shall include the followings points:

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 SASO IEC 62548.
c) cables are certified according to EN 50618 or another equivalent standard
d) wiring systems have been selected and erected to withstand the expected external influences such as wind, ice formation, temperature, UV and solar radiation.
e) suitable means of isolation and disconnection have been provided for the PV array strings and PV sub-arrays – to the requirements of SASO IEC 62548.
f) a DC switch disconnector is fitted to the DC side of the inverter according to the requirements of SASO IEC 62548.
g) if blocking diodes are fitted, their reverse voltage rating is at least 2 × Voc (STC) of the PV string in which they are installed.
h) plug and socket connectors, including multiple connectors (if any) mated together are of the same type, same specifications and comply with the requirements of SASO IEC 62548.
i) IP rating of the junction boxes
j) DC Disconnector rating, wiring drawing, fuse rating, SPD rating, voltage rating and IP rating of combiner boxes.

4.3.9 Verification of the AC system

Inspection of the PV system shall at least verify that:

a) a means of isolating the inverter has been provided on the AC side.
b) the inverter operational parameters have been programmed to operate at local grid regulations.
c) where an RCD is installed to the AC circuit feeding an inverter, the RCD type has been selected according to the requirements of SASO IEC 62548.

4.3.10 Labelling and identification

Inspection of the PV system shall at least verify that:

a) all circuits, protective devices, switches and terminals are suitably labelled to the requirements of IEC 60364 and SASO IEC 62548.
b) all PV string combiner boxes carry a warning label indicating that active parts inside the boxes are fed from a PV array and may still be energized 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) Inverter protection settings are displayed at the site [IEC 62446]
g) installer details are displayed on site.
h) shutdown procedures are displayed on site.
i) emergency procedures are displayed on site (where relevant).
j) all signs and labels are suitably affixed and durable.

4.3.11 Fire protection verification

4.3.11.1 Verifications common to all PV systems

Inspection of the PV system as regards the fire protection shall include the following verifications applicable to all PV systems (BAPV, BIPV, ground mounted, etc.):

a) A manual emergency system for the disconnection of the PV modules from the internal electric plant of the building is present and operates in one of the following ways:
    - Outside the building on the DC side

- When the inverter is placed outside the building, on the AC and DC side outside the building.
- In a proper fire-compartmented area.

b) When there is a passage of cables from PV modules inside the building before the disconnector, cables inside the building are placed in a trouncing with a fire-rated protection of at least one-and half-hour

c) Electrical disconnection is operated by means of a manual call point with all the following characteristics:
- installed at the height of 1.1 – 1.4 m above floor level and in a plain, accessible, well-lit and free-hindrance place
- close to an external access in order to be easily operated by personnel or firefighters
- in accordance with NFPA 72 and a proper label indicate that it actuates the disconnection of the PV plant

d) PV array is equipped with an earth fault detector that preferably shut down the array in case of failure

e) A simplified site plan with the position of PV modules, cables and disconnectors is exposed close to the main energy meter. If a manual call point is present in the building a further copy of the simplified site plan is exposed on the side.

f) The area where PV modules, cables and other equipment are located, if accessible, are marked by proper signs. They are also placed in correspondence of each access door to the PV plant. The same signs are used to indicate cables before disconnectors and are placed every 5 meters along the cable. These signs are UV resistant, and indicate the DC voltage as the Open Circuit Voltage at STC of the PV array. Their minimum size is 200 × 200 mm (w × h)

4.4 Basic Tests

For the basic tests other than the section provided below, SASO IEC 62446-1 shall be followed for the procedures of the tests.

4.4.1 Foreword

Basic Tests represent the minimum test sequence that is expected and shall be applied to all Large-Scale PV Systems. 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

Insulation resistance test of the AC circuit to be performed according 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) PV string 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.

4.4.2 Continuity test 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.

4.4.3 PV string polarity test

The polarity of all PV string 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.

4.4.4 PV string Combiner box test

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. This shall be physically verified against the approved DC SLD also. Additionally, SPD connection, fuse rating, earthing can also be checked.

4.4.5 Open circuit voltage measurement of PV strings

The purpose of the open circuit voltage (Voc) measurement within the Basic Test procedure is to check that modules strings are correctly wired, and specifically that the expected number of modules are connected in series within the string.

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. Conversely, 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 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) For systems with multiple identical strings and where there is a stable irradiance conditions, voltages between strings can be compared and shall be within 5% variation.

4.4.6 Current measurement of PV strings

4.4.6.1 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.
An I-V curve test is also independent of the inverter and provides a good alternative means to perform this test.

4.4.6.2 PV string – Short circuit test

The short circuit current of each PV string should be measured using suitable test apparatus. The making / interruption of string short circuit current 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, an irradiance meter reading or visual appraisal of the sunlight conditions may be used to consider the validity of the current readings. Further possibilities are listed in SASO IEC 62446-1.

To safely perform the test, it is necessary to introduce a temporary short-circuit by using one of the following methods:

a) 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) 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 breaking device used (test instrument or circuit breaker) shall have a rating greater than the potential short circuit current and open circuit voltage. Further possibilities are listed in SASO IEC 62446-1.

4.4.6.3 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, an irradiance meter reading may be used to adjust the current readings.

4.4.7 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 (Commissioning test).

4.4.8 PV array insulation resistance test

4.4.8.1 General

PV array DC circuits are live during daylight and, unlike a conventional AC circuit, cannot be isolated from the voltage source 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 with any part of your body when performing the insulation test.
- Whenever the insulation test device is energized there is voltage on the testing area. The equipment is to have automatic-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 4.5.6 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.

4.4.8.2 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 without a functional earthing) a commissioning engineer may choose to do two tests:

a) between array cables and earth, and
b) an additional test 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.

4.4.8.3 PV array insulation resistance – Test procedure

4.4.8.3.1 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 2.

Table 2 – 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

4.4.8.3.2 Insulation resistance – PV arrays above 10 kWp

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 2. The result is satisfactory when the insulation resistance is not less than the appropriate value given in Table 2.

4.5 Additional tests

4.5.1 Foreword

Additional tests are normally intended for larger or more complex systems. All Basic tests shall have been undertaken and passed before commencing on the Additional tests. In addition to the Basic tests, the following Additional tests as per IEC 62446-1 may be applied:

a) String I-V curve test
b) Infra-Red (IR) inspection
c) Voltage to ground – resistive ground systems – This test is used to evaluate systems that use a high impedance (resistive) connection to ground
d) 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
e) Wet insulation test – 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
f) Shade evaluation – 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.

As noted in the Basic test description, where an I-V curve test is being performed, it provides an acceptable means to derive Isc and Voc. In some circumstances just one element or part of the Additional test regime may be chosen to be implemented. An example of this is where a client requires the performance evaluation provided by the I-V curve test to be added to the standard Basic test sequence.

In some circumstances Additional tests may only be implemented on a sample portion of the system. An example of this is where a client requires I-V curve tests and/or IR inspection on a fixed proportion of the strings. It is relatively common, particularly for large systems, that some of the Additional 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.

4.5.2 String I-V curve measurement

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 string performance.
- Measurement of module / string fill factor.
- Identification of module / string 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. 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.

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).

Given suitable irradiance conditions, an I-V curve test provides a means to assess that the performance of a PV string / module 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. If the measurements are intended for reference to STC (the purpose is to calculate the name plate rated power of the modules/array) the irradiance shall be at least 800 W/m^2 as per IEC 60904-1

IEC 61829 standard shall be followed (in addition to the points noted above) for the requirement of the inspection equipment, inspection procedure, evaluation, minimum environmental conditions and reporting required for performing the outdoor IV curve testing.

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 the method used to characterize string performance (I-V curve tracing or separate current and voltage measurements).

4.5.3 PV array infrared camera inspection procedure

4.5.3.1 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, open strings, PID issues 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.

4.5.3.2 IR test procedure

For an IR camera inspection, the array should be in the normal operating mode (inverters maximum power point tracking. 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.

4.5.3.3 Interpreting IR test results

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 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.

Identify 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 adjacent 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.

IEC TS 62446-3:2017 standard may also be referred (in addition to the points noted above) for the requirement of the inspection equipment, inspection procedure, evaluation, minimum environmental conditions and reporting required for performing the outdoor thermography.

4.5.4 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.

4.5.5 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.

4.5.6 PV array – Wet insulation resistance test

4.5.6.1 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 develop 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.

4.5.6.2 Wet insulation test procedure

The procedure to be followed is 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.

4.5.7 Shade evaluation

The purpose of performing a shade evaluation is to record the shade and horizon conditions present at the site at the time. This can provide a baseline for future comparisons.

For small systems, the shade record should be taken as close as practical to the center 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 sun-path diagram as shown in Figure 3, using horizon measuring equipment.

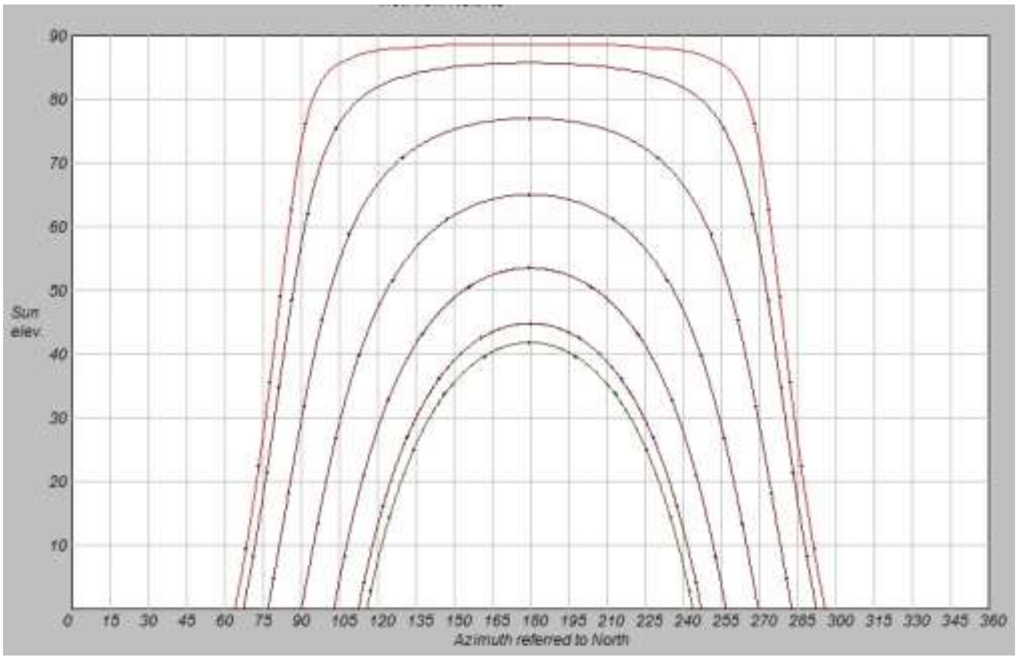

Figure 3 – Example of sun-path diagram

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.

5 COMMISSIONING TEST

5.1 Overview

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

- Interface Protection.
- Performance monitoring functions.
- Evaluation of the "Performance Ratio".

DISCLAIMER
SEC has the right to attend the commissioning test, but SEC will follow the commissioning test following SEC internal checklist. SEC will also review the commissioning report following its internal checklist focusing only on the components that are impacting the distribution network and the point of connection.

5.2 Interface Protection

After the Solar PV system 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 SEC in accordance with the parameters defined in the Technical Standards
- The Interface device disconnects the solar PV system in case of power failure on command of the Interface Protection
- After a power recovery the Interface Protection recloses the Interface device.

5.3 Performance monitoring functions

All Solar PV systems 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 systems.

For this test it is possible to use:

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

Hereafter it will be assumed that a proper monitoring system is to 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 SASO IEC 61724-1 and the technical specifications SASO IEC 61724-2 and SASO 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 3.

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 3.

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 3 – Monitoring system classifications and suggested applications

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

Large-Scale projects need to fulfill all suggested applications as per Table 3 above. Large-Scale PV systems in KSA shall use only Class A monitoring system as per IEC 61724[2].

5.4 Data acquisition, timing and reporting

5.4.1 Calibration and inspection

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. Periodic cross-checks of each sensor against sister sensors or reference devices are recommended.

[2] As per IEC 61724-1: 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.

For Class A the monitoring system should be inspected at least annually and preferably at more frequent intervals. A 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.

5.4.2 Sampling, recording, and reporting

A sample is defined as data acquired from a sensor or measuring device. The sampling interval is the time between samples. Samples do not need to be permanently stored. A record is defined as data entered into a data log for data storage, based on acquired samples, and the recording interval, denoted by τ in this document, is the time between records. The recording interval should be an integer multiple of the sampling interval, and an integer number of recording intervals should fit within 1 h.

Each record and each report shall include a timestamp. Table 4 lists the maximum values for sampling intervals and recording intervals as per IEC 61724-1.

Table 4 – Sampling and recording interval requirements

Maximum interval	Class A High accuracy	Class B Medium accuracy	Class C Basic accuracy
Maximum sampling interval			
– **For irradiance, temperature, wind and electrical output**	3 s	1 min*	1 min*
– **For soiling, rain and humidity**	1 min	1 min	1 min
Maximum recording interval	1 min	15 min	60 min
*** The indicated sampling intervals apply to ground-based measurements, but do not apply when using satellite-based estimation of irradiance or meteorological parameters**			

5.5 Measured parameters

5.5.1 General requirements

In Table 5 there are listed measured parameters and a summary of measurement requirements. The purpose of each monitoring parameter is reported 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 5 indicates a required parameter to be measured on site, qualified by specific notes where included.

The minimum number of on-site sensors is as specified IEC 61724-1. When multiple sensors are required, they shall be distributed throughout the PV plant. If the PV system consists of multiple sections that have different PV technology, different orientations or substantially different geographic location, at least one sensor shall be placed in each section. The symbol “E” in Table 5 indicates a parameter that may be estimated based on local or regional meteorological data or satellite data, rather than measured on site.

Table 5 – 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/m²]	Solar resource	√	√ or E	√ or E
Global Horizontal Irradiance	GHI [W/m²]	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 [°]		√		
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	

5.5.2 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. Electrical measurements shall have uncertainty meeting the requirements listed in Table 6 for measurements corresponding to ≥ 20 % of the expected electrical output when the array is operating at STC. Table 6 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 6 – Inverter-level electrical measurement requirements

Parameter	Measurement uncertainty		
	Class A High accuracy	Class B Medium accuracy	Class C 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

5.5.3 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.

5.6 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 system or to compile the periodical reports that document the performance of the renewable generator.

5.6.1 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.

5.6.2 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 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.

5.6.3 Missing data treatment and documentation

In principle, 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 reports.

5.7 Calculated parameters

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

Table 7 – Calculated parameters

Parameter	Symbol	Unit
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

5.7.1 Description of calculated parameters

5.7.1.1 Notes on summations

In the formulas given below involving summation, τk denotes the duration of the k^{th} recording interval within a reporting period, and the symbol:

$$\sum_k \tau k$$

denotes summation over all recording intervals in the reporting period.

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

5.7.1.2 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:

$$Hi = \sum_{k} Gi, k \times \tau k$$

5.7.1.3 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:

$$Eout = \sum_{k} Pout, k \times \tau k$$

5.7.1.4 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:

$$Yf = Eout/Po$$

5.7.1.5 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.

5.8 Performance ratio

5.8.1 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. The performance ratios described in the SASO 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*

5.8.2 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:

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

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

It is important to note that 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.

5.8.3 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'*.

5.8.4 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:

$$Ck = 1 + \gamma \times (Tmod,k - 25\text{ °C})$$

Here γ 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*. *Factor* γ 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 SASO 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.

5.8.5 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 γ 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. The temperature coefficient γ is typically negative, especially 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 SASO IEC TS 61724-2, Annex A, a heat transfer model to calculate expected cell operating temperature is shown.

5.8.6 Test duration

The duration of the Commissioning Test will depend is as follows:

- Above 2MWp: 2 to 15 days (Valid data recorded as per agreement between Customer and Contractor)

Duration depends if sufficient stable data are acquired. The test may be extended to more days if desired to assess repeatability or if weather is volatile.

5.9 Test report

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 verification of the Interface Protection
4) Description of the verification of the performance monitoring system
5) 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.
6) A summary of the definition of the system output data collected during the test, including records of completed calibrations
7) The description of raw data that were collected during the test, including note of which data met the stability and other criteria
8) A list of any deviations from the test procedure and why these were taken
9) Summary of the correction factors that were calculated for the filtered data
10) Description of uncertainty analysis and statement of uncertainty associated to 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.
11) 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 Commissioning Test.

ANNEXES

ANNEX A – SAFETY INFORMATION FORM

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

Safety Information Form	
Solar PV system	
Type of Applicant	☐ Individual ☐ Organization
Organization (if applicable)	
First name	
Last name	
P.O. Box	
Street number	
Street name	
Location / Area	
City	
Voltage delivery	☐ 220 V (3 phases) ☐ 230V (1 phase) ☐ 400 V (3 phases) ☐ 13.8 kV ☐ 33 kV
PV capacity [kW]	
PV module installation	☐ On building ☐ open field ☐ Ground
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 system 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		
Collision with the module mounting structures or other erected structures on the roof		

ANNEX B – MEASUREMENT OF ENVIRONMENTAL PARAMETERS

6 IRRADIANCE

6.1 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.

6.2 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.

6.3 Irradiance sensors

Suitable irradiance sensors include the following equipment:

- thermopile pyranometers (Figure 4).
- PV reference devices, including reference cells (Figure 5) and reference modules; and
- Photo-diode sensors.

Figure 4 – Example of an in-plane pyranometer

Figure 5 – 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 SASO 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 SASO IEC 60904-10. PV reference device calibration is to be performed with respect to the reference spectrum provided in SASO IEC 60904-3.

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.

6.4 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, special attention is required to identify nearby vents that could discharge vapours 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. For the irradiance sensor alignment and maintenance kindly refer SASO IEC 61724-1 – Photovoltaic system performance. Part 1: Monitoring.

7 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.

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 damaged 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 SASO 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 as per requirements of Clause 8.5.1 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 on the method described in SASO IEC 60904-5 as an alternative to using a temperature sensor in contact with the module back surface. This may require the use of an additional reference module, not connected to the PV array, for temperature measurement purposes.

8 AMBIENT AIR TEMPERATURE

As required by Table 5, 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.

9 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 is 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 be compared with the 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 shall be ≤ 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°.