CS-CSI-P3/G2

Inspection and Testing Guidelines for Solar PV Systems connected to the LV and MV Distribution Network

Table of Contents

Contents **Page**

1 Purpose

These guidelines set out the criteria that need to be considered when performing the inspection of a solar PV System to be connected to the distribution network. In order to assess a PV System, a set of checks and verifications shall be passed before connecting it to the distribution network. These checks and verifications are performed through on-site Inspection and Testing of the REG at different stages of construction and vary according to the size of the PV System being installed.

2 Scope

This document contains specific guidelines to help the Consumer and his selected Contractor prepare the technical documents required for installing a PV System. This guideline assists the Constructor During the Connection Process to deliver Kahramaa the set of documents, reports and information required during the final steps of the Connection Process.

The document highlights the checks and the overall procedure envisaged to perform on-site Inspections and Tests and helps the Consumer and his Consultant/Contractor be aware of the information that Kahramaa expects to find in the various documents required, such as Drawings and Test Reports.

During the Inspection, Testing and Energization stage, after the PV System construction is over, the following activities shall take place:

Activities to be performed by the Contractor of the Consumer	REG off-line commissioning of the DC part → Off-line Commissioning Report
	Off-line Test → Issue of REG off-line Commissioning Report[1]
	Commissioning Test → Issue of Commissioning Test Report

Activities made by Kahramaa	Site Inspection
	Voluntary Witnessing the Commissioning Test (if PV capacity ≤ 50 kW)
	Mandatory Witnessing the Commissioning Test (if PV capacity > 50 kW)

DISCLAIMER

The guidelines of this document are valid for all PV Systems and thus represent a minimum set of requirements for testing. The Consultant/Contractor should consider the following guidelines and checklists as a starting point. The Consultant/Contractor may require more detailed tests and can be performed accordingly.

[1] The Contractor shall prepare and submit to Kahramaa other relevant documents before applying for the Inspection, as described in the Solar PV Connection Guidelines

2.1 Notice to Users of these Guidelines

This document is for use by employees of Kahramaa, Consultants, Contractors and Manufacturers. The checklists included in this document are for common use of Kahramaa and the approved Consultants/Contractors.

Users of this document should consult all applicable laws, regulations and standards. Users are responsible for observing or referring to the applicable regulatory requirements. Kahramaa does not, by the publication of its standards, intend to urge action that is not in compliance with applicable laws, and these documents may not be construed as doing so.

Users should be aware that this document may be superseded at any time by the issuance of new editions or may be amended from time to time through the issuance of amendments, corrigenda, or errata. All users should ensure that they have this document's latest edition uploaded on the Kahramaa website.

Finally, unless otherwise specified, the User shall refer to all applicable Kahramaa Standards, Qatar Standards, or International Standards mentioned in this document.

3 Abbreviations, Definitions of Terms & Key References

Abbreviations

AC	:	Alternating Current	AFCI	:	Arc Fault Circuit Interrupter
ASTM	:	American Society for Testing and Materials	BAPV	:	Building-Attached Photovoltaic Modules
BIPV	:	Building-Integrated Photovoltaic modules	$cos\ \varphi$	:	Power factor
DC	:	Direct Current	GHI	:	Global horizontal irradiance
IEC	:	International Electrotechnical Commission	IP	:	Interface Protection
IR	:	Infrared	ISO	:	International Organization for Standardisation
ITP	:	Inspection and Test Plan	LOM	:	Loss of Mains
LV	:	Low Voltage (namely 220/127 V or 380/220 V or 400/230 V)	LVRT	:	Low Voltage Ride Through
MV	:	Medium Voltage (namely 13.8kV or 33 kV)	MS	:	Method Statement
NEC	:	National Electrical Code	NFPA	:	National Fire Protection Association
P	:	Active power	P_{ELV}	:	Protected Extra Low Voltage
P_{nom}	:	Nominal active power of the equipment	POA	:	Plane of Array
PPE	:	Personal protective equipment	PR	:	Performance Ratio
PV	:	(Solar) Photovoltaic	Q	:	Reactive Power
RCD	:	Residual Current Device	ROCOF	:	Rate of Change of Frequency expressed in Hz/s.
S/S_n	:	Apparent Power	SELV	:	Safety extra-low voltage

SPD	:	Surge Protection Device	SR	:	Soiling Ratio
STC	:	Standard Test Condition	UL	:	Underwriters Laboratories
UV	:	Ultraviolet	V_{nom}	:	Nominal Voltage
WMO	:	World Meteorological Organization	CS	:	Customer Services Dept

Term	Description
AC Module	PV module with an integrated inverter in which the electrical terminals are AC only
Active Power	Active Power is the real component of the apparent power, expressed in watts or multiples thereof, e.g., kilowatts (kW) or megawatts (MW). In the text, this will be generically referred as P or P_{nom} in case of the nominal active power of equipment
Apparent Power	The product of voltage and current at the fundamental frequency, and the square root of three in the case of three-phase systems, usually expressed in kilovolt-amperes (kVA) or megavolt-amperes (MVA). It consists of a real component (Active Power) and the reactive component (Reactive Power). This will be generically referred to S or S_n in case of the rated apparent power of equipment
Apparent power of an Inverter	The rated apparent power of an Inverter is the product of the rms voltage and current and is expressed in kVA or MVA.
Auxiliary Supply Power	Electricity supply for supporting auxiliary systems and services such as Interface Protection or circuit breaker and contactor opening coils.
Building-Attached Photovoltaic Modules (BAPV modules)	Photovoltaic modules are considered to be building-attached if the PV modules are mounted on a building envelope. The integrity of the building functionality is independent of the existence of a building-attached photovoltaic module.
Building Attached Photovoltaic system (BAPV system)	Photovoltaic systems are considered to be building attached if the PV modules they utilise do not fulfil the criteria for BIPV modules.
Building-Integrated Photovoltaic modules (BIPV modules)	Photovoltaic modules are considered to be building-integrated if the PV modules form a construction product providing a function. Thus, the BIPV module is a prerequisite for the integrity of the building's functionality. If the integrated PV module is dismounted (in the case of structurally bonded modules, dismounting includes the adjacent construction product), the PV module would have to be replaced by an appropriate construction product. The building's functions in the context of BIPV are one or more of the following: • mechanical rigidity or structural integrity • primary weather impact protection: rain, snow, wind, hail • energy economy, such as shading, daylighting, thermal insulation • fire protection • noise protection • separation between indoor and outdoor environments • security, shelter or safety Inherent electro-technical properties of PV, such as antenna function, power generation and electromagnetic shielding etc., alone do not qualify PV modules to be building-integrated.

Term	Description
Building-Integrated Photovoltaic system (BIPV system)	Photovoltaic systems are considered to be building-integrated if the used PV modules fulfil the criteria for BIPV modules.
Circuit Breaker (CB)	As per the Kahramaa Electricity and Wiring Code definition
Connection Point	Also referred to as *Point of Connection*, is the interface point at which a PV System of the Consumer is connected.
Consultant	A qualified consultant for the design of grid-connected solar PV Systems.
Consumer	Any Person supplied with electricity services for his own consumption. In this context, this term will also be used to refer to a User owning a solar PV System.
Contractor	A certified contractor for the installation of grid-connected solar PV Systems.
Delay time (of a protection relay)	Indicates the minimum duration of a fault detected by the protection relay before the output of the protection relay is triggered.
Delivery Point	The interface point at which electrical energy is delivered by Kahramaa to a Demand Facility or Generating Unit or by a Demand Facility or Generating Unit to Kahramaa.
Distribution System / Distribution Network	Qatar electrical infrastructure (lines, cables, substations, etc.) at 33 kV and below, operated by Kahramaa. The Distribution network can be either a Medium or Low Voltage system for the scope of the present document and in accordance with international standards: • A Low Voltage (LV) Distribution System is a network with a nominal voltage lower than 1 kV AC or 1.5 kV DC. The LV network in the State of Qatar is 240/415 V ± 6%, 3 Phase, 4 Wire. • A Medium Voltage (MV) Distribution System is a network with nominal voltage included in the range from 1 kV AC up to 33 kV. The MV Distribution System nominal voltages in Qatar are 11, 22 and 33 kV. • Electrical network voltages equal to or higher than 33 kV are not considered in this document. According to the Transmission Grid Code, the 33 kV is considered a sub-transmission network. To avoid doubt, the term Distribution Network will be preferred in this document in place of Distribution System.
Electricity Transmission Network (ETN)	Qatar electrical infrastructure (lines, cables, substations, etc.) from above 33 kV up to 400 kV operated by Kahramaa.
Global horizontal irradiance (GHI)	Direct and diffuse irradiance incident on a horizontal surface expressed in W/m^2.
In-plane irradiance (Gi or POA)	The sum of direct, diffuse, and ground-reflected irradiance incidents 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
$I_{MOD\_MAX\_OCPR}$	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 in order to ascertain correct selection, design and proper erection of electrical equipment.
Interface protection (IP)	Electrical protection part of the solar PV System that ensures the PV System is disconnected from the network in case of an event that compromises the integrity of Kahramaa's distribution network.

Term	Description
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 given time interval and measured in energy units (e.g., $kWh/m^2/day$).
Islanding	Situation where a portion of the distribution network containing generating plants becomes physically disconnected from the rest of the distribution network. One or more generating plants maintain electricity supply to such isolated parts of the distribution network.
Load Flow	It is a numerical analysis of the electric power flow in a transmission and/or distribution systems. A power-flow study usually uses simplified notations such as a one-line diagram and per-unit system, and focuses on various parameters, such as voltages, voltage angles, real power and reactive power. It analyses the power systems in normal steady-state operation.
Loss Of Mains (LOM)	Represents an operating condition in which a distribution network, or part of it, is separated from the main power system (on purpose or in case of a fault) with the final aim of de-energisation. The protection that detects this condition is known as anti-islanding protection.
Main Meter	It is the bidirectional smart meter installed at the Connection Point which measures the amount of electric energy actually exchanged (import or export) by the Consumer with the distribution network.
Maximum Available Active Power Output	This is the Active Power Output based on the primary resource (for example, sun irradiance) and the maximum steady-state efficiency of the Solar PV System for this operating point.
Maximum Capacity (P_{max})	It is the maximum continuous active power which a Generating Unit can produce, less any auxiliary consumption associated used to facilitate the operation of that Generating Unit. The Maximum Capacity shall not be fed into the distribution network as specified in the *Connection Agreement*. In this document, this term is also referred to as Maximum Connected Capacity.
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 the module).
Module Integrated Electronics	Any electronic device fitted to a PV module that provides control, monitoring or power conversion functions (Note: Module integrated electronics may be factory fitted or assembled on-site).
National Control Centre (NCC)	Main Kahramaa's facility used to operate and control/maintain the Electric Power System.
Peak Power (Wp)	The output power achieved by a Photovoltaic Module under Standard Test Conditions (STC). It is measured in W_p (W peak). The sum of the peak power of the photovoltaic modules of either a string or an array determines the peak power of the string and the array, respectively (usually measured in kW_p). The peak power of a photovoltaic array at STC is conventionally assumed as the rated power of the array.
Photovoltaic (PV) cell	The most elementary device that exhibits the photovoltaic effect, i.e., the direct non-thermal conversion of radiant energy into electrical energy.
Power Factor	It is the ratio of Active Power to Apparent Power.

Term	Description
Power Park Module (PPM)	A unit or ensemble of units generating electricity, which is either non-synchronously connected to the network or connected through power electronics, and that also has a single Connection Point to the ETN.
PV Array	Assembly of electrically interconnected PV modules, PV strings or PV sub-arrays. For the purposes of this document, a PV Array comprises all components up to the DC input terminals of the Inverter.
PV Module	PV modules are electrically connected PV cells packaged to protect them from the environment and protect the users from electrical shock.
PV String	A set of series-connected PV modules.
PV String Combiner Box	A box where PV strings are connected, which may also include circuit breaker, monitoring equipment, and electrical protection devices.
Rated Active Power	Represents the sum of the nominal active power of all the Solar PV Units which compose the Solar PV System; it is generally referred to as *Pnom* of the Solar PV System.
Reactive Power	Represents a component of the apparent power at the fundamental frequency, usually expressed in kilovar (kVAr) or Megavar (MVAr).
Reactive Power Capability	Defines the reserves of inductive/capacitive reactive power which can be provided by a generating system/unit. The reactive power capability usually varies with the active power and the voltage of the generating system/unit.
Residual Current Device (RCD)	A sensitive switch that disconnects a circuit when the residual current exceeds the operating value of the circuit, referred as RCD in this document.
Soiling ratio (SR)	A 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.
Solar PV System	This term also has the same meaning as Power Plant or User's System or Grid User, defined in the Transmission Grid Code. It is a solar PV installation of not more than 25 MW and not less than 1 kW capacity installed in one Premise and connected in parallel to Kahramaa's Distribution Network. This document aims to be considered a power plant with one or more Solar PV Units. Besides, circuits and auxiliary services are also part of a solar PV System. To avoid doubt, in this document, the generic term Solar PV System is considered equivalent to solar PV System. This PV System includes the PV array, controllers, inverters, batteries (if used), wiring, junction boxes, circuit breakers, and electrical safety equipment.
Solar PV System Meter	It is the smart metering installed at the output point of the solar PV System and measures the total energy produced from the Solar PV Units.
Solar PV Unit	A group of devices that collects the sun's irradiance in a Solar PV System, together with all plant and apparatus and any step-up transformer which relates exclusively to the operation of that part of the same Solar PV System. Only units that are Inverter based (i.e., Asynchronously connected to the Distribution Network through power electronics devices) are considered in this document. This definition will be equivalent to that of the Power Park Module as given in the Transmission Code. For the avoidance of doubt, in this document, the generic term Solar PV Unit will be considered equivalent to a solar PV Unit.
Standard test conditions (STC)	Reference values of in-plane irradiance (1 000 W/m2), PV cell junction temperature (25 °C), and the reference spectral irradiance defined in IEC 60904-3.
Switch	As per the Kahramaa Electricity and Wiring Code definition.

Term	Description
Testing	Implementing measures in an electrical installation to prove its effectiveness (Note: It includes ascertaining values using appropriate measuring instruments, said values not being detectable by inspection).
Time Current Curve (TCC)	The time current curve plots the interrupting time of an overcurrent device based on a given current level. These curves are used for the protection coordination and are provided by the manufacturers of electrical overcurrent interrupting devices such as fuses and circuit breakers.
THD (Total Harmonic Distortion)	Concerning an alternating quantity, it represents the ratio of the r.m.s. value of the harmonic content to the r.m.s. value of the fundamental component or the reference fundamental component.

Key References

[1] The Qatar Transmission Grid Code – Issue ES-M4 – Revision 0.0 – March 2020 and amendments in force until 02/2022 (in this document referred to as “Transmission Code”)
[2] CS-CSI-P1/C1 Kahramaa’s Low Voltage Electricity Wiring Code 2016
[3] Safety Rules for the Control, Operation and Maintenance of Electricity Transmission & Distribution System of Qatar General Electricity & Water Corporation.
[4] System Operation Memorandum (SOM).
[5] Kahramaa interlocking document, (Qatar Power Transmission System Expansion – Latest phase – Substations).
[6] Qatar Construction Specifications, Latest edition
[7] ET-P26-G1 Guidelines for Protection Requirements.
[8] ES–EST-P1-G1 Guidelines for System Control Requirements for Power Supply to Bulk Consumers.
[9] ET-P20-S1 Transmission Protection Standards for TA and ET Projects.
[10] ES-M2 Qatar Power System Restoration Plan; and
[11] ES-M3 System Emergency, Categorization, Communication & Restoration Responsibility.
[12] QCDD (Qatar Civil Defence Department) regulations
[13] CS-CSI-P2 E_W – Infrastructure Preparation for Service Connection Purpose
[14] CS-CSI-P3 E_W – Services Inspection
[15] CS-CSI-P4 – Low Voltage Electrical Contractor Licensing
[16] CS-CSI-P5 – Handling of Contractors Violations Procedure
[17] CS-CSI-P6 – Illegal Connections Reconnections
[18] CS-CSM-P2 E_W – Supply Connection and Disconnection
[19] CS-MAS-P1 – Operation and Maintenance of AMI
[20] CS-MAS-P2 E_W – Meter Installation
[21] CS-MAS-P3 – Maintenance of Electricity and Water Meter
[22] CS-MAS-P5 – Materials Submittal Review _ Approval Procedure
[23] Energy and Water Conservation Code 2016
[24] EPD-P1 – Electricity Supply Approval
[25] EPD-P4 – Processing Service Notes
[26] EPD-P6 11kV – Load Flow Study
[27] EPP-C1 – Electricity Planning Regulations for Supply
[28] EPP-P3 – Early Arrangement for Supply Connection
[29] EPP-P5 – Electricity Supply Application
[30] EPT-P2 – Basic Concept Report-Direct Connection Notification
[31] EPT-P3 – Peak Demand Forecast

[32] EPT-P4 – Power System Studies and Five Years Development Plan
[33] ES-ESN-P3 – Dispatching Procedure
[34] ES-ESN-P4 – Bulk Industrial Consumers Energy Meter Readings Collection
[35] ES-ESP-P1 – Creating Operational Load Forecast
[36] ES-ESP-P2 – Long Term Operation Planning
[37] ES-ESP-P3 – Develop Monitor Energy Purchase Schedules and Allocation Plans
[38] ES-ESP-P4 – Operation Studies
[39] ES-ESP-P7 – Develop Surplus Available Capacity Plan for Marketing
[40] ES-M4 – Qatar Transmission Grid Code 2020
[41] ET-P26 ETD – Responsibilities for Bulk Consumer's Request for Supply of Electricity
[42] PW-PWK-P1 – Bulk Supply of Electricity and Water
[43] PW-PWP-P1 E_W – Demand Forecasting
[44] PW-PWP-P2 – Additional Capacity Planning
[45] PW-PWP-PL1 – Planning _ Procurement Policy
[46] PW-PWR-P2 – Renewable Energy Standards Development
[47] IEC 60364-6 – Low voltage electrical installations. Part 6: Verifications
[48] IEC 61010 – Safety requirements for electrical equipment for measurement, control and laboratory use
[49] IEC 61557 – Electrical safety in low voltage distribution systems up to 1000 V AC and 1500 V DC
[50] IEC 61724-1 – Photovoltaic system performance. Part 1: Monitoring
[51] IEC 61724-2 – Photovoltaic system performance. Part 2: Capacity evaluation method
[52] IEC 61724-3 – Photovoltaic system performance. Part 3: Energy evaluation method
[53] IEC 61730-2 – Photovoltaic (PV module safety qualification. Part 2: Requirements for testing
[54] IEC 62446-1 – Photovoltaic (PV) systems. Requirements for testing, documentation and maintenance. Part 1: Grid connection systems. Documentation, commissioning, tests and inspection
[55] IEC TS 62446-3:2017- Photovoltaic (PV) systems - Requirements for testing, documentation and maintenance - Part 3: Photovoltaic modules and plants - Outdoor infrared thermography
[56] IEC 61829:2015 Photovoltaic (PV) array - On-site measurement of current-voltage characteristics
[57] IEC 62548 – Photovoltaic (PV) arrays. Design requirements
[58] NEC / NFPA 70 – Section 690.11 Arc-Fault Circuit Protection (Direct Current)
[59] UL 1699B – Photovoltaic (PV) DC Arc-Fault Circuit Protection

EARTHING

[60] IEC 60364-5-54 for all LV installations.
[61] IEC 60364-7-712 and IEC 62548 specifically for PV Systems.
[62] IEEE 80 Guide for Safety in AC Substation Grounding

LIGHTNING

[63] IEC 62305 - Lightning Protection standard.

Companion Documents

The documents listed hereinafter have to be considered a compendium of the current document. Therefore, they should be carefully read in addition to this.

a) EP-EPP-P7-S1Technical Specifications for the Connection of PV Systems to the Network
b) EP-EPP-P7-G2 Guidelines for Information in Basic and Final Design, last revision
c) EP-EPM-G2 Guidelines for the Eligibility of Manufacturers' Equipment, last revision
d) PW-PWR/G2 - Safety related to the installation of Solar PV Systems, last revision

4 Types of Tests and Responsibilities

4.1 Off-line Tests and Commissioning Test

The Off-line Tests and the Commissioning Test described in these Guidelines are specific of small-scale PV Systems. The Off-line Test and the Commissioning Tests are arranged by the Contractor and undertaken by a qualified Test Engineer under his responsibility.

4.2 Responsibilities in Inspection and Testing

Figure 1 summarizes the timeline of the verification process, the inspection and other related activities according to the different roles:

- The Contractor is in charge of carrying out the tests.
- Kahramaa is in charge of carrying out Inspections, the meter installation and the connection to the Distribution Network.

The diagram in Figure 1 does not consider the information flow, the documents produced in the process and the checks between actions.

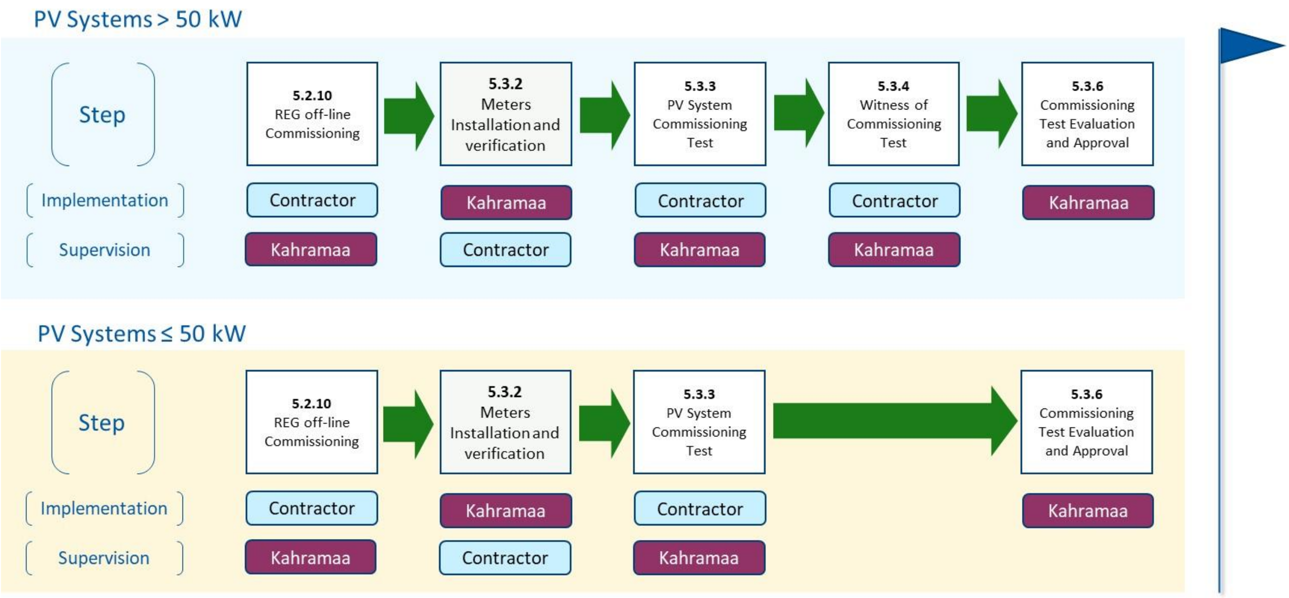

Figure 1 – Inspections to verify and test a PV System

As can be seen in Figure 1, the assessment of a PV System for its connection to the distribution network requires witnesses of the Commissioning Test (and inspection) that depend on the maximum capacity of the PV System:

- PV Systems below or equal to 50 kWp.
- PV Systems above 50 kWp.

After the Tests and Inspection has been carried out, everything is assembled correctly, and the PV System works properly, the authorization to start the production is given by Kahramaa.

The goal of the overall assessment is to verify the PV System and its compliance with the document “*EP-EPP-P7-S1 Technical Specifications for the Connection of PV Systems to the Network*".

The Contractor of the Consumer shall carry out the following actions:

- Off-line Tests
- Commissioning Tests
- Any additional tests required by Kahramaa

After the Inspections and tests were successfully conducted with satisfactory results, Kahramaa issues the *REG Commissioning Test Report* and the Connection Agreement, which certifies that the installation is compliant with Kahramaa rules and regulations, and that the electricity production can start.

The requirements of the above-described Inspection follow the requirements of the standard IEC 62446 "Grid-connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection".

4.2.1 Inspection and Witnessing the Test arranged by the Contractor

The aim of Kahramaa Witnessing the Commissioning Test arranged by the Contractor is to verify the PV System, at least in those parts that are relevant to Kahramaa Distribution Network.

Before witnessing tests, the Kahramaa inspector shall initially inspect the site and after witnessing the tests.

The witnessing of Kahramaa is mandatory for PV Systems that exceed 50 kW. It could be the case that either some or all the tests are undertaken by the Contractor have to be repeated in Kahramaa inspector's presence.

5 Tests Methodology and Documentation

5.1 Test Methodology

The methodology of the Test is outlined below:

1. The installation to be evaluated follows the tests and checklists of this document.
2. The Contractor will be responsible for calibrate the equipment required for all checks and verifications. They have to be available for the tests.
3. All checks and technical verifications must be performed by the Test Engineer delegated by the Contractor for this activity. The Test Engineer is to ensure the availability of the necessary test equipment at site.
4. A check or test yielding a negative result can be repeated in case an adequate correction measure can be applied (e.g., retest a PV string that was found not properly connected) and the result of the test repetition acknowledged; in case a negative result cannot be corrected, the check or test shall be considered failed.
5. In case of a negative result, the Contractor shall apply corrective measures before the checks and verifications that end with a negative result are repeated in the frame of the next site inspection. A revision of the inspection report shall be issued.
6. In case of positive results, the installation will be approved, and the PV System will be allowed to start the production.
7. MS and ITP approved by Kahramaa prior to start of any work.

5.2 PV System Documents Required during the Inspection

In case Kahramaa witnesses the Commissioning Test, the design documents relevant to the inspection and Inspection Test Plan (ITP) with acceptance criteria shall be made available by the Contractor on-site for consultation by Kahramaa inspectors visiting the site where the PV system is installed. Also, the contractor shall provide the undertaking letter for the safety and stability of civil structures.

Details of the minimum information required are contained in section 8.2.

6 Safety issues

This chapter does not substitute the safety laws and rules in force in Qatar regarding the works on electric, mechanical and civil installations[2].

The purpose is to integrate the existing rules with some indications which focus on particular safety aspects related to PV systems.

6.1 Hazards and Safety Measures

The on-site test, particularly on electrical installations, is the Test Engineer's task and responsibility. 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 Qatar, his experience and the description of his activities are provided below.

All that is located upstream of a circuit-breaker on the DC section of a PV system (PV modules and their connections) remains under voltage (during the day) even after opening this device.

All combiner boxes of the PV system on the DC side shall expose a warning sign, which indicates the presence of live parts even after the opening of DC circuit-breaker devices.

Figure 2 shows a warning sign to indicate the presence of a PV system with possible danger.

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

[2] It is not the responsibility of Kahramaa to check the compliance of the design of the Small-scale Solar PV systems with the Building Code

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 PV System 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 a 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).

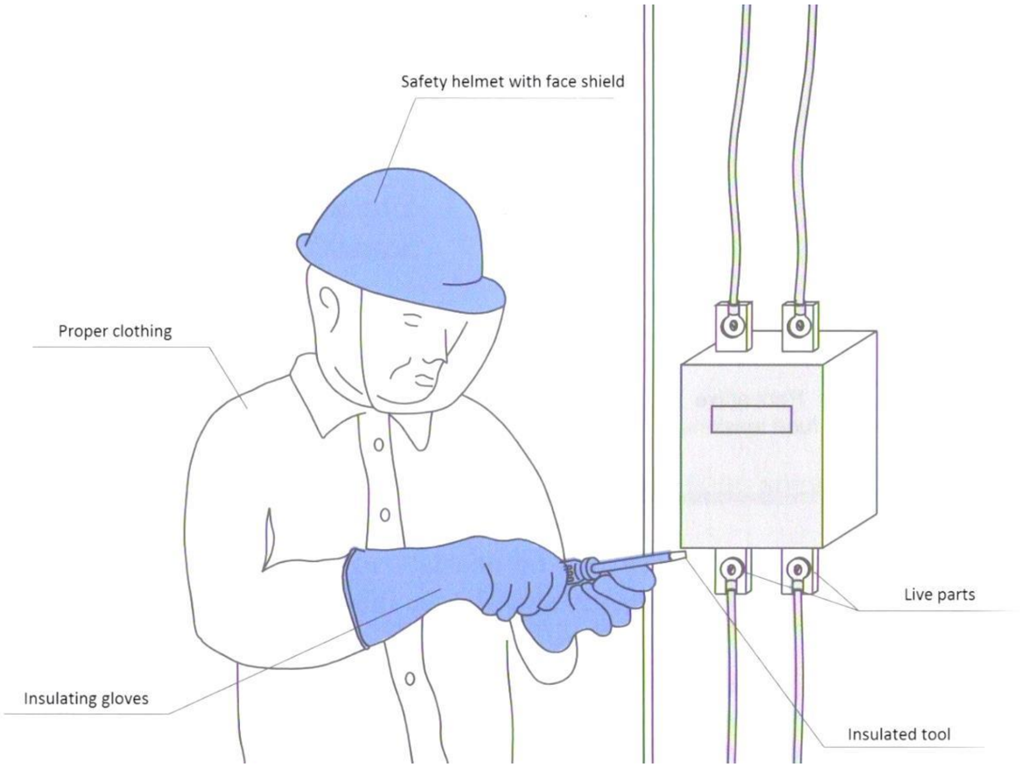

Figure 3 – Main safety measures for works under voltage

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 and damage to the eyes and skin, and this energy increases with the arcing current and the duration of the intervention.

In the 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 storms, 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 overvoltage on circuits.

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 installing a PV System 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 4 and consists of keeping the connectors of a module and the string circuit-breaker open during installation.

In Figure 4, 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 during construction and inspection and maintenance of a PV array shall be considered works/ interventions under voltage.

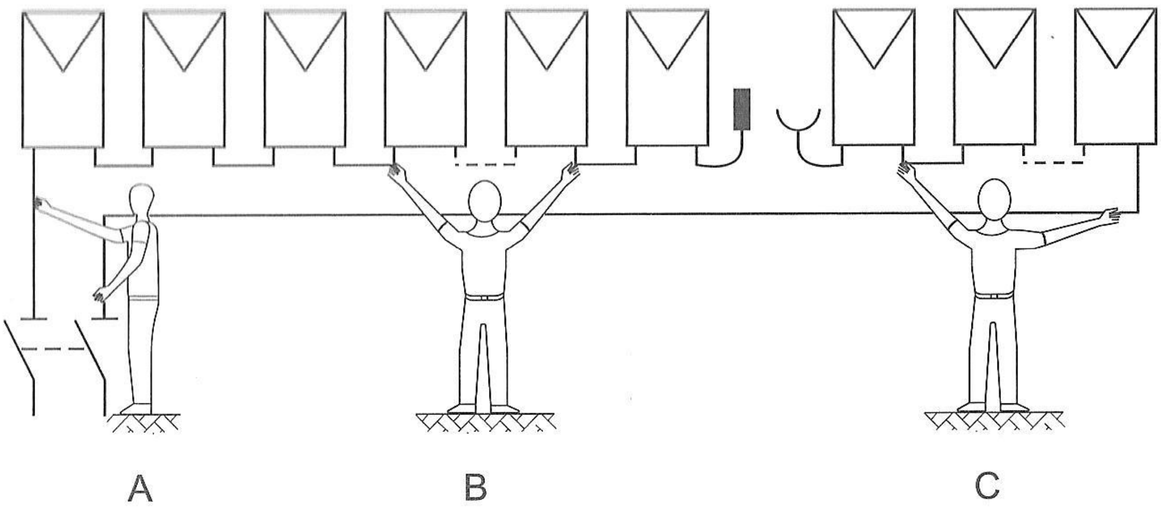

Figure 4 – The interruption of a string makes the worker A safe but keeps the workers B and C unsafe

Interventions on PV 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 must 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.

6.2 Information from Contractor about Specific Risks on-site and Safety Measures

The form CS- CSI-P3-G2/F4 shall be filled and delivered by the Contractor of the Consumer to Kahramaa identifying specific risks and on-site safety measures before the Inspectors perform an on-site visit to the PV system.

7 Off-line Tests

7.1 Overview

This test is part of Stage 2 of the connection Process of Kahramaa, and it is connected with the activities named 5.2.12 of the General Connection Process.

5.2.12 REG off-line Commissioning

Figure 5 – Connection Process steps related to Off-line Test

The “REG Off-line Commissioning” (5.2.12) is the Contractor’s responsibility and shall be performed on all PV systems, regardless of their power capacity. The Off-line Test applies to all PV systems regardless of their nominal power and voltage connection.

The Off-line Test is composed of an inspection and a set of tests made by a Test Engineer appointed by the Contractor.

As a rule, this test begins after completing the PV system, particularly the DC circuits (i.e., PV strings and arrays). However, for large PV systems, for safety reasons, the Test Engineer may initiate the tests on strings during installation to prevent parallel strings with a 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.

7.1.1 Basic Tests and Additional tests

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

These guidelines define a Basic Test procedure and some additional tests that 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 Small-scale PV systems.
- Additional tests – Further tests assuming that all Basic tests have already been undertaken. They also contain tests that may be performed in some circumstances. Unless differently agreed, these tests are optional.

7.1.2 Special considerations for PV systems with module-level electronics

Table 1 shall be used to determine a suitable test procedure for systems constructed using AC modules, power optimisers, or any other form of module-level electronics.

Table 1 – Modifications to the test procedure for Small-scale PV systems with module-level electronics

Type of equipment	Modifications to test procedure
PV 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 V_{oc})

Due to the diverse nature of the different module-level electronics equipment available, it is impossible to specify what tests can be performed or to detail the expected results. In all cases of PV Systems with any form of module-level electronics (such as power optimizers), the manufacturer should be consulted prior to commissioning.

7.2 Common Requirements

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

Measuring instruments and monitoring equipment and methods shall be chosen following the applicable relevant parts of IEC 61557 and IEC 61010. If other measuring equipment is used, they shall provide an equivalent level 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 if the fault influenced the result of these tests.

7.3 Solar PV Systems Inspection

The inspection shall precede testing and normally be done before energizing the installation.

If the wiring of the DC section will not be readily accessible after the installation, wiring may need to be inspected before or during installation works.

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

7.4 DC System

7.4.1 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 IEC 62548.
b) The maximum PV array voltage is suitable for the chosen array location, , except residential (1000 Vdc on buildings, 1500 Vdc otherwise).
c) The maximum PV array voltage suitable for residential location should not exceed 600V.
d) Where necessary, roof fixings and cable entries are weatherproof.

7.4.2 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 using class II or equivalent insulation adopted on the DC side.

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

7.4.3 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 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 IEC 62548 (this is typically provided within the inverter).

7.4.4 DC system –Verification of the Protection against Overcurrent

The 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 a string overcurrent protective device, verify that:
   - $I_{MOD\_MAX\_OCPR}$ (the module maximum series fuse rating) is not greater than the maximum reverse current; and
   - string cables are sized to accommodate the maximum combined fault current from parallel strings according to 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 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 IEC 62548.

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

7.4.5 DC system – Verification of Earthing and Bonding Arrangements

The inspection shall include the followings points:

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

7.4.6 DC System – Verification of the Protection against the effects of Lightning and Overvoltage

The inspection shall include the followings points:

a) Verify the area of all wiring loops has been kept as small as possible to minimize voltages induced by lightning.
b) Verify if measures are in place to protect long cables (e.g., cables with screening or the use of surge protective devices, SPDs).
c) In case SPDs are fitted, verify if the installation has been made according to the requirements of IEC 62548.

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

The inspection shall include the followings points:

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

7.4.8 Checklist for DC System Verification

A checklist for the verification of the DC part is in the Table 1 of the Form CS- CSI-P3-G2/F1.

7.5 Labelling and Fire Protection

7.5.1 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 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 the interconnection point;
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); and
j) all signs and labels are suitably affixed and durable.

A checklist for labelling verification is in the Table 2 of the Form CS- CSI-P3-G2/F1.

7.5.2 Fire Protection Verification – (in coordination with Civil Defence as necessary)

7.5.2.1 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 PV System 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 trunking with fire-rated protection of at least one-and half-hour
c) Except for One-and-Two-Family Dwelling, electrical disconnection is operated using 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.
   - It is located close to external access to be easily operated by personnel or firefighters.

- Follows the NFPA 72 and a proper label indicating it actuates the disconnection of the PV planting.

d) PV array is equipped with an earth fault detector that preferably shuts 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, is marked by proper signs. They are also placed in correspondence with each PV System access door. The same signs 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)

A checklist for the verification the fire protection in all the PV Systems is in the Table 3 of the Form CS- CSI-P3-G2/F1.

7.5.2.2 Verifications for BAPV

Inspection of the BAPV system shall include the following verifications:

a) Adoption of one of the following measures when the PV system is installed on a rooftop:
   - PV modules and their interconnections are placed on a roof made of non-combustible material according to ASTM E 136 or EN 13501-3 (class A1)
   - Interposition of a non-combustible layer between PV modules with their interconnections and the roof. The non-combustible layer is at least one-half-hour fire-rated.
   - A new risk assessment to be prepared which takes into account the presence of the PV system to be approved by a competent body in Qatar.

b) PV modules, wirings, switchboard assemblies and other equipment do not cover any possible ventilation systems on the roof, e.g., skylights, smoke extraction systems or chimneys.

c) PV components and wirings are placed at a minimum distance of 1 m (top view) from the perimeter of the ventilation systems. In any case, their position and installation are following the manufacturer’s prescriptions.

d) PV components and wirings are placed at a minimum distance of 0.5 m (top view) from the perimeter of skylights, chimneys or other openings.

e) Components and equipment installed internally or externally do not obstruct in any way the existing means of egress.

f) Minimum elevation of the PV modules above the roof is 50 mm.

A checklist for the verification the fire protection in the BAPV Systems is in the Table 4 of the Form CS- CSI-P3-G2/F1.

7.5.2.3 Verifications for BIPV

Inspection of the BIPV system shall include the following verifications:

a) In case of BIPV is not installed in compartmented fire areas, at least one of the following further measures is adopted:

  - The manual call point also disconnects or short-circuits separately each PV module or groups of PV modules, each of them having an open-circuit voltage at STC not greater than 120 VDC.
  - An Arc Fault Circuit Interrupter (AFCI) to protect the DC side from series arcs following NEC Section 690.11 and UL 1699B is installed. When AFCI detects a failure, it disconnects the DC side of the PV System and generates an audible signal.

b) Where applicable, PV modules, wirings, switchboard assemblies and other equipment do not cover any possible ventilation systems on the roof, e.g., skylights, smoke extraction systems or chimneys.
c) Where applicable, PV components and wirings are placed at a minimum distance of 1 m (top view) from the perimeter of the ventilation systems. In any case, their position and installation are following the manufacturer's prescriptions.
d) Where applicable, PV components and wirings are placed at a minimum distance of 0.5 m (top view) from the perimeter of skylights, chimneys or other openings.
e) Where applicable, components and equipment installed internally or externally do not obstruct the existing means of egress.

A checklist for the verification the fire protection in the BIPV Systems is in the Table 5 of the Form CS- CSI-P3-G2/F1.

7.5.3 Verification of the Special Requirements for Households

Inspection of the PV systems in households shall include the following verifications:

a) The back sheet, the junction box and the wiring of each PV module are compliant with at least one of the following conditions:
  - Not reachable without a proper provisional tool (stair, scaffold, etc.).
  - Protected with at least IP67A degree, that means against access with the back of the hand according to IEC 60529.
  - Outside arm's reach is a vertical distance of up to 2.5 m from the floor.

b) The supporting structures placed in rows on the floor are compliant with all the following prescriptions:
  - When the spacing between rows exceeds 0.5 m, the connections are placed on the floor, not higher than 50 mm, without sharp edges and clearly visible. They withstand the weight of a person (100 kg).
  - Module mounting structure (MMS)/ Ballasts and their arrangements are clearly visible and without sharp edges.
  - Electrical connections between the PV array and combiner boxes or inverters preferably do not interfere with existing passages for people. In the case of passage crossing, the connections are placed on the floor, not higher than 50 mm, without sharp edges and clearly visible. Furthermore, the top of the trunking and the floor surface is matched with sloped surfaces to avoid the step. This trunking withstands the weight of a person (100 kg).

A checklist for the verification the fire protection in in households is in the Table 6 of the Form CS-G2/F1.

7.6 Basic Tests

The procedures established in the IEC 62446-1 standard shall be followed for the basic tests presented in the following sections.

The Basic Tests represent the expected minimum test sequence and shall be applied to all small-scale PV Systems.

In some circumstances, the 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 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 IEC 60364-6 requirements.

DC Side

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

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 safety reasons and the prevention of damage to the 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 (to minimize voltages induced by lightning) and short circuit current (I_{sc}). Where an *I-V* test is performed, separate V_{oc} and I_{sc} tests are not required.

7.6.1 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.

7.6.2 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 to system devices such as switching devices or inverters.

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

7.6.3 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 combiner box test aims to ensure all strings interconnected at the combiner box are connected correctly. This shall be physically verified against the approved DC SLD also. SPD connection, fuse rating, and earthing can also be checked.

7.6.4 Open Circuit Voltage Measurement of PV Strings

The purpose of the open-circuit voltage (V_{oc}) measurement within the Basic Test procedure is to check that module strings are correctly wired. Specifically, 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. Before closing any switches or installing string overcurrent protective devices (where fitted), this should be done.

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 considers the type and number of modules and the module cell temperature.
b) For systems with multiple identical strings and where there are stable irradiance conditions, voltages between strings can be compared and shall be within 5% variation.

7.6.5 Current measurement of PV strings

7.6.5.1 General

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

Two test methods are possible (short circuit test or operational test), and both will provide information on the correct functioning of the PV string. 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.

7.6.5.2 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 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 to 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 IEC 62446-1.

7.6.5.3 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.

7.6.6 Functional Tests

The following functional tests shall be performed:

a) Switchgear and other control apparatus shall be tested to ensure correct operation and 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).

7.6.7 PV Array Insulation Resistance Test

7.6.7.1 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 understand the procedure before starting any work. The following basic safety measures should be followed:

- Limit access to the working area.
- Do not touch and take measures to prevent any other persons from touching any metallic surface when performing the insulation test.
- Do not touch and take measures to prevent 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 a voltage in the testing area. The equipment is to have the automatic-discharge capability.
- Appropriate personal protective clothing/equipment should be worn for the test duration.

A wet array insulation test may be appropriate if the test results are questionable or if insulation faults are suspected due to installation or manufacturing defects. It may help locate the location of a fault – see Paragraph 7.7.5 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.

7.6.7.2 PV Array Insulation Resistance Test – Test method

The test should be repeated, as a 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 good contact, and have 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 with 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 positive and negative cables of the array should be short-circuited safely. 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 to the device.

The test procedure should ensure that the peak voltage does not exceed module, switch, surge arrestor or other system component ratings.

7.6.7.3 PV Array Insulation Resistance – Test procedure

7.6.7.3.1 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 (IEC 62446-1) – PV arrays up to 10 kWp

System voltage (V_{oc} (STC) ´ 1.25) [V]	Test voltage [V]	Minimum insulation resistance (IEC 62446-1) [MW]
< 120	250	0.5
120 to 500	500	1
500 to 1000	1 000	1
> 1000	1500	1

7.6.7.3.2 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.

7.6.8 Checklist for the PV Array Tests

This section aims to report the tests made on all the strings of the PV array.

Each copy of the document may contain tests on up to five strings. In case of more than five stings in parallel on the same PV array, a progressive Sheet number and the same PV array number for each PV array shall be indicated in the heading.

In case of more than one independent PV array being present, several documents equal to the number of independent PV arrays, or to a multiple of them if more than five strings per each independent PV array are present, will be used. A different progressive PV Array number shall be indicated for each PV array.

A checklist for the verification the results of the PV Array Tests is in the Table 7 of the Form CS- CSI-P3-G2/F1.

7.6.9 Earth Resistance of the PV System

The test should be performed following the Kahramaa Electricity and Wiring Code.

7.6.10 Infrared Camera Inspection for Inverters and Circuit Breakers

The purpose of an infrared (IR) camera inspection is to detect unusual temperatures in the inverter and circuit breaker. Such temperature may indicate problems within the equipment.

This test is primarily looking for anomalous temperature; overheating equipment and possible overloaded equipment; overheating connections of the equipment that means loose or weak connections; defective electrical component and load imbalances.

For an IR camera inspection, scan the equipment in question and their electrical connections, or any specifically identified problem that exhibits a discernible temperature difference from its immediate surroundings.

When scanning from the front of equipment, the camera and operator shall not cast shadows on the area under investigation.

IEC TS 62446-3:2017 standard may also be referred for the requirement of the inspection equipment, inspection procedure, evaluation, minimum environmental conditions and reporting required for performing the outdoor thermography.

7.6.11 Final Result page of the Off-line Test

The final result of the verification of the off-lines tests is in the Table 8 of the Form CS-G2/F1.

7.7 Additional Tests

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, verifying 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 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 I_{sc} and V_{oc}.

In some circumstances, just one element or part of the Additional test regime may be chosen to be implemented. An example of this is when 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, the additional tests may only be implemented on a sample portion of the system. An example is when 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 system sample (a fixed percentage of the strings / modules). The client shall agree upon such a selective approach and the percentage of the system to be tested before commissioning.

7.7.1 String I-V curve Measurement

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

- Measurements of string open-circuit voltage (V_{oc}) and short circuit current (I_{sc}).
- Measurements of max power voltage (V_{mpp}), current (I_{mpp}), and max power (P_{max}).
- 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 (V_{oc}) and short circuit current (I_{sc}). Where an *I-V* curve test is performed, separate V_{oc} and I_{sc} 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 V_{oc} and I_{sc}, 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 nameplate 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 depending 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).

7.7.2 PV Array Infrared Camera Inspection Procedure

7.7.2.1 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.

7.7.2.2 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.

7.7.2.3 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 to avoid recording these normal temperature variations.

Daily, 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 normal 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 the array / string layout drawings. Investigate each thermal anomaly to determine the cause(s). 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.

7.7.3 Voltage to Ground – Resistive Ground Systems

This test evaluates systems that use a high impedance (resistive) connection to the 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 the ground or within acceptable ranges of leakage current.

7.7.4 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.

7.7.5 PV Array – Wet Insulation Resistance Test

7.7.5.1 General

The wet insulation resistance test is primarily used 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. It 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 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 (nominally) dry test results 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). If just parts of the array are being tested, these should be selected based on a known or suspected problem identified during previous tests.

In some circumstances, the wet insulation test may be requested on a sample proportion of the array.

7.7.5.2 Wet insulation Test Procedure

The procedure to be followed is the same as described in the standard insulation test but with an additional initial step of wetting the array.

Prior to the test, the section of the array under test should be thoroughly wetted with a mixture of water and surfactant, and the mixture should be sprayed onto all parts of the array under test. Before 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 in which the test will be performed.

A minimum of two people is recommended to perform this test (as wetness dries up quickly in the field resulting in a large variety of results) – one person will conduct the measurement immediately after the second person has completed wetting the area of concern has given the approval to test.

7.7.6 Shade Evaluation

The purpose of performing a shade evaluation is to record the shade and horizon conditions present at the site.

For small systems, the shade record should be taken as close as 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 sun-path diagram, as shown in Figure 6, using horizon measuring equipment.

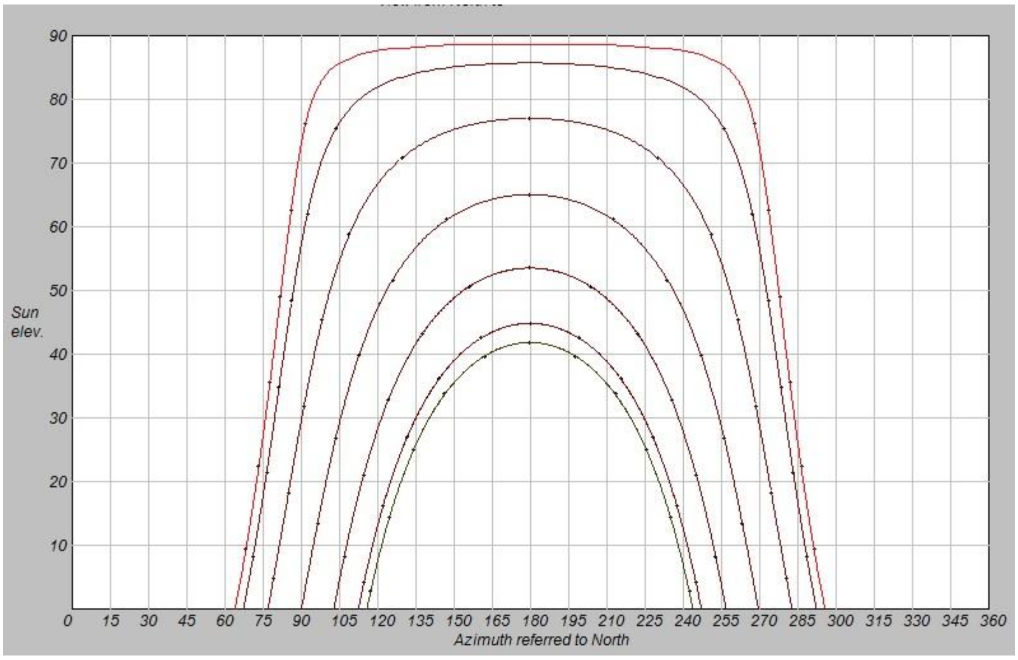

Figure 6 – Example of sun-path diagram

In all cases, the shade record shall:

- Record the location where the shade record was taken.
- Show South or North (as appropriate).
- Be scaled 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.

8 PV System Commissioning Test (After Grid Connection)

8.1 Scope

The PV Commissioning Test will be performed after the PV System is connected to Kahramaa network.

This test is part of Stage 3 of the connection Process of Kahramaa, and it is connected with the activity named 5.3.5 of the General Connection Process.

5.3.5
REG Commissioning Test by Contractor with Witnessing of KM Depts (CS and PW)
Form F8

Figure 7 – Connection Process steps related to Commissioning Test

The “REG Commissioning Test” (5.3.5) is the full responsibility of the Contractor and shall be performed on all PV systems, regardless of their power capacity. However, different requirements apply to the PV Systems depending on their power capacity.

The Commissioning Test includes the verifications listed below.

- Documentation available;
- Interface Protection;
- Performance monitoring functions; and
- Evaluation of the "Performance Ratio".

The Witness of Kahramaa during the Commissioning Test is not mandatory for PV Systems < 50 kW, and Kahramaa may witness the REG Commissioning Test if deemed necessary. The Depts that participate in the commissioning test are the Customer Service Dept (for the installations of the Consumer) and Production, Water Resource Planning & Business Dev Dept (PWR) (for the Inverter and network Interface protection settings, relevant protection scheme and belonging to Kahramaa) as detailed in the inspection checklists and forms.

8.2 Documentation for Commissioning Test

The documentation required for verifying the Commissioning Test. The (minimum) information that shall be delivered is specified below:

8.2.1 Basic System Information

Basic information shall be provided on the cover page of the system documentation pack.

a) Project identification reference (Application Number).
b) Rated system power (kW DC or kVA AC).
c) PV modules and inverters (manufacturer, model and quantity). For generators with different types of modules and inverters, detailed data shall be provided inside the document pack.
d) Installation date (start date; expected end date).
e) Commissioning date (expected).
f) Consultant's/Contractor's names.
g) Owner's name.
h) Site address (including any additional information such as a site map showing the exact location of the PV System and the access route).

8.2.2 Documentation of the PV System

For the testing, the following documents and As-Built drawings are to be made available (according to the "PV System Connection Guidelines).

- Building Permit approved plan/other utilities Affection plan;
- Building Completion Certificate from MME;
- Owner's Passport copy/Trade License copy;
- Authorization letter from the owner to his Contractor;
- A copy of Kahramaa approved Final Design Approval and Shop Drawings;
- A copy of Kahramaa approved Connected Load/Max;
- Demand Details;
- Building Permit (6-month validity from the date of issue) with submission of:
    - Approved Substation location and size; and
    - Setting out Key Plan showing the Electricity Metering Location.

For MV connections with private substations, the following additional information is required:

- Revised/updated copy of a single line diagram with details on metering and protection system;
- Step by step relay setting calculations;
- Owner's undertaking stating, "Our equipment is suitable to energize in line with Kahramaa network system" and a confirmation that the protection relays are set as per Kahramaa approved setting;
- HV cable Jointer's list in detail;
- Names and telephone numbers of contact person for the project who should be available to contact on a 24-hour basis;
- Name of technical staff, competent in switchgear operation, and their statement that the cable is safe for work, with insurance that no one will operate the system during test & repair time.
- Factory & Site Test Report for the transformer/breaker, MV cable, etc., and test result for the transformer inrush unbalance current to be forwarded for verification;
- Operation philosophy (interlocking details) - to be incorporated in the single line diagram; and
- All catalogues for CT, VT, relay & motor.

8.2.3 Information from Contractor about Specific Risks on-site and Safety Measures

On-site testing activities are to be carried out by a licensed engineer, designated for this purpose as the Test Engineer by the Contractor. However, all operators on-site, including Kahramaa inspectors, shall be aware of the specific risks and the safety measures to be adopted before on-site verification and tests. For this purpose, the Contractor shall deliver to Kahramaa a form with information regarding the risks and the recommended Personal Protective Equipment (PPE).

8.2.4 Checklists for Verifying the Available Documentation and General Data

A checklist for verifying the available documentation of the PV System is in Table 1 of the Form CS- CSI-P3-G2/F2.

The checklist for verifying the general data of the PV System is in Table 2 of the Form CS-CSI-P3-G2/F2.

8.3 Verification of the AC System

The inspection of the PV System, as for the compliance with certain equipment requirements and standards, 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; and
c) if an RCD is installed in the AC circuit feeding an inverter, the RCD type has been selected according to IEC 62548 requirements.

The checklist for the verification of the AC System of the PV System is in Table 3 of the Form CS-CSI-P3-G2/F2.

8.4 Interface Protection

8.4.1 Interface Protection Verifications

After the 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 Kahramaa following the parameters defined in the "- *EP-EPP-P7-S1 Technical Specifications for the Connection of PV Systems to the Network*"
- The Interface device disconnects the PV system in case of power failure on command of the Interface Protection
- After a power recovery, the Interface Protection recloses the Interface device.

The checklist for the verification of the Interface Protection of the PV System is in Table 4 of the Form CS-CSI-P3-G2/F2.

8.5 Performance Monitoring Functions (optional)

All 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 used. However, the same considerations may also be applied to temporary solutions that use 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 diverse 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. In contrast, for analysing performance trends and localizing faults, there may be a need for greater resolution at sub-levels of the system and emphasising measurement repeatability and correlation metrics rather than absolute accuracy.

The required accuracy and complexity of the monitoring system depend 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		

The classes specified in Table 3 apply to the test as follows, depending on the power capacity of the PV system (Pn):

- Pn ≤ 250 kW: Class C or better (A, B)
- Pn > 250 kW: Class B or better (A)

The checklist used for the Performance Monitoring test of the PV System is in Table 5 of the Form CS-CSI-P3-G2/F2.

8.6 Data Acquisition, Timing and Reporting (optional)

8.6.1 Calibration and Inspection

Sensors and signal-conditioning electronics used in the monitoring system shall be calibrated before starting monitoring.

Recalibration of sensors and signal-conditioning electronics is 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.

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.

A user guide shall be provided for the monitoring system software.

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

8.6.2 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, and samples do not need to be permanently stored.

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

Each record and each report shall include a timestamp.

Table 4 lists the maximum values for sampling intervals and recording intervals.

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 – For soiling, rain and humidity	3 s 1 min	1 min* 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			

The checklist for verifying the sensors used in the Commissioning Tests is in Table 6 of the Form CS-G2/F2.

8.7 Measured Parameters

8.7.1 General Requirements

In Table 5, there are listed measured parameters and a summary of measurement requirements. More details and additional requirements are provided in the next paragraphs and Annex A – Measurement of Environmental Parameters.

A checkmark (✓) 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 1 for PV systems up to 5 MW (although redundant sensors are typically advisable) and 2 for larger systems.

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/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	T_{mod} [°C]	Determining temperature-related losses	✓	✓ or E	
Ambient air temperature	T_{amb} [°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)	V_a [V]	Energy output, diagnostic and fault localization	✓		
Array current (DC)	I_a [A]		✓		
Array power (DC)	P_a [W]		✓		
Electrical parameters					
Output voltage (AC)	V_{out} [V]	Energy output	✓	✓	
Output current (AC)	I_{out} [a]		✓	✓	
Output power (AC)	P_{out} [W]		✓	✓	✓
Output energy	E_{out} [kWh]		✓	✓	✓
Output power factor	λ	Utility request compliance	✓	✓	
Reduced load demand		Determine utility or load request compliance and impact on PV system performance	If applicable	If applicable	
System output power factor request	λ_{req}		If applicable	If applicable	

8.7.2 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 in 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 before power conversion and AC measurements following power conversion. Optionally the DC measurements may be performed at each combiner box or string, in addition to or instead of measurements 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

8.7.3 Step and Touch Potential

Step and touch potential measurement should be made, with suitable instruments, to verify as far as practicable that the requirements of the Section 3 of the Kahramaa Electricity and Wiring Code have been met, that the installations of all conductors and PV System are satisfactory and that the earthing arrangements are such that, in the event of an earth fault the faulty circuit or sub circuit or the PV System is automatically disconnected from supply so as to prevent danger.

8.7.4 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.

8.8 Data processing and Quality Check

The performance monitoring system collects the measures relevant to the environment and the electrical parameters. The reliability of these measures shall be checked for these measures to be effectively used for the monitoring of the PV System or to compile the periodical reports that document the performance of the renewable generator.

8.8.1 Daylight hours

Processed data for irradiance and PV-generated power should be restricted to the day's daylight hours (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.

8.8.2 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 from the subsequent analysis. The monitoring system shall document such missing or invalid data.

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;

8.8.3 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 analysed interval;
- the data may be treated in a manner specified in a valid contract, performance guarantee document, or other specification covering the installation;
- the analysed interval may be treated as missing or invalid.

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

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

8.9 Calculated Parameters

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

Table 7 – Calculated parameters

Parameter	Symbol	Unit
In-plane irradiation	H_i	kWh/m^2
PV array output energy (DC)	E_a	kWh
Energy output from PV system (AC)	E_{out}	kWh
Array power rating (DC)	P_o	kW
Array power rating (AC)	$P_{o,ac}$	kW
Final system yield	Y_f	kWh/kW
Reference yield	Y_r	kWh/kW

8.9.1 Description of Calculated Parameters

8.9.1.1 Notes on Summations

In the formulas given below involves summation, τk denotes the duration of the kth recording interval within a reporting period, and the symbol:

$$\sum_k \square$$

denotes summation of overall 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 to obtain energy in kWh units.

8.9.1.2 In-plane Irradiation

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

In-plane irradiation quantity H_i corresponding to an irradiance quantity G_i is calculated by summing the irradiance as follows:

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

8.9.1.3 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:

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

8.9.1.4 Final System Yield

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

$$Yf = Eout/Po$$

8.9.1.5 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 $G_{i,ref}$ (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 Y_r would be, in effect, the equivalent number of sun hours at the reference irradiance per day.

8.10 Performance Ratio

8.10.1 Overview

Several 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 Contractor of the Consumer shall agree on 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 system performance model.

The rating-based performance ratio metrics are adopted in this document.

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

- Performance ratio (*PR*)
- Annual performance ratio (PR_{annual})
- Annual temperature-equivalent performance ratio ($PR'_{annual\text{-}eq}$)
- STC-temperature performance ratio PR'_{stc}

8.10.2 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*. It indicates the overall effect of losses on system output due to array temperature and system component inefficiencies or failures, including the 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, the 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, PR_{annual}, 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 increases 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.

8.10.3 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'*.

8.10.4 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 metric's value 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:

$$Ck = 1 + \gamma \times (Tmod,k - 25\ ^\circ\mathrm{C})$$

Here γ is the relative maximum-power temperature coefficient (in units of 1/°C), and $T_{mod,k}$ is the module temperature (in °C) in time interval *k*.

γ is typically negative, e.g., for crystalline silicon.

The formula may use the measured PV module temperature for $T_{mod,k}$. However, if the monitoring objective is to compare PR'_{stc} to a target value associated with a performance guarantee, $T_{mod,k}$ 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 the expected cell operating temperature is shown.

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

8.10.5 Annual-temperature-equivalent performance ratio

The annual-temperature-equivalent performance ratio $PR'_{annual\text{-}eq}$ is constructed to approximate the annual performance ratio PR_{annual} 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. It leaves the value of the metric comparable to the value of PR_{annual}.

$PR'_{annual\text{-}eq}$ is calculated by introducing a power rating temperature adjustment factor *Ck* into the formula, as follows:

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

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 $T_{mod,k}$ is the module temperature (in °C) in time interval *k* and $T_{mod,avg}$ is an annual-average module temperature.

The temperature coefficient γ is typically negative, especially for crystalline silicon.

$T_{mod,avg}$ 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 $PR'_{annual\text{-}eq}$ for the historical data is the same as the annual performance ratio PR_{annual} for the historical data.

The measured module temperature may be used for $T_{mod,k}$. However, if the monitoring objective is to compare $PR'_{annual\text{-}eq}$ to a target value associated with a performance guarantee, $T_{mod,k}$ 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 the expected cell operating temperature is shown.

8.10.6 Test duration

The duration of the Commissioning Test will depend on the size of the PV system 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)

8.11 PV System Commissioning Test Report

This part reports the final outcome of the Commissioning Test performed by the Contractor and witnessed by Kahramaa.

8.11.1 Final Results of the Commissioning Test

The table that summarises the Final Results of the Commissioning Test of the PV System is in Table 7 of the Form CS-CSI-P3-G2/F2.

8.11.2 Commissioning Test Report

The Commissioning Test Report is in step 5.3.6 of the General Connection Process, which summarises and documents all the tests performed by the Contractor for implementing the PV System.

The Commissioning Test Report must also have an explicit declaration of responsibility by the Contractor and his signature as responsible for the commissioned REG.

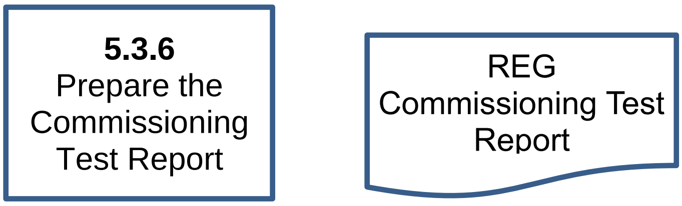

Figure 8 – Connection Process step related to Commissioning Test Report

The Commissioning Test Report must be well documented and 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

Facultative sections are recommended for large PV systems > 250 kW

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 was collected during the test, including a 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 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.

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.

9 Kahramaa Inspections

9.1 Overview

As previously mentioned, Kahramaa can verify the PV System, at least in those parts that may affect the Distribution Network operation. Kahramaa may also witness the Commissioning Test if the capacity of the PV System does not exceed 50 kWp but should be present in case of the PV System has a capacity greater than 50 kWp. In the former case, some or all the tests undertaken by the Contractor have to be repeated in the presence of Kahramaa Inspector. Then Kahramaa witnesses the Commissioning Test, in particular as regards the inspection and test of the Interface Protection (IP).

9.2 Site Inspection (PV ≤ 50 kWp)

If Kahramaa decides to attend to Commissioning Test for PV System ≤ 50 kWp, the starting point is a quick inspection. For performing this inspection, some documentation has to be available.

The checklist to verify the available documentation for the inspection is in Table 1 of the Form CS-CSI-P3-G2/F3.

9.3 Kahramaa Inspection and Witnessing the Site Test (PV > 50 kW)

When the PV System size exceeds 50kW, Kahramaa Inspectors witness either some or all the Commissioning Test already undertaken by the Contractor, which has then to be repeated by the Contractor in the presence of the Kahramaa Inspector.

9.4 Quality Assurance Documents

The review of the Contractor's presented Method Statement (MS) and the Inspection and Test Plan (ITP) already approved by Kahramaa in the Final Design of the PV System should be performed. The generic templates used by the Contractor should follow the Form EP-EPP-P7-G2-F3.

Annex A – Measurement of Environmental Parameters

A1. Irradiance

A1.1 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.

A1.2 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 using a decomposition and transposition model from POA irradiance.

A1.3 Irradiance sensors

Suitable irradiance sensors include the following equipment:

– thermopile pyranometers ();
– PV reference devices, including reference cells (Figure 10) and reference modules; and
– Photo-diode sensors.

Figure 9 – Example of an in-plane pyranometer

Figure 10 – 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 following procedures therein. The devices shall meet the short circuit current versus irradiance linearity requirements of IEC 60904-10, and PV reference device calibration is performed concerning the reference spectrum provided in IEC 60904-3.

Each irradiance sensor type has its benefits:

- Thermopile pyranometers are insensitive to typical spectral variations and 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 the instrumentation used.
- Photodiode sensors have a 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.

A1.4 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 half an hour of sunrise or sunset, this shall be documented.

The irradiance measurement sensors shall be placed 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 represent the albedo experienced by the system without the effects of adjacent module shading. If the ground covering is not 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.

Kindly refer to IEC 61724-1 – Photovoltaic system performance for the irradiance sensor alignment and maintenance. Part 1: Monitoring.

A2. PV MODULE TEMPERATURE

The PV module temperature, T_{mod}, 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 two years for Class A and per the 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 under site conditions. It should be checked to be compatible with the surface material on the module's rear 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^{2}K or greater 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 cell temperature 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 cell's temperature 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 the array, and substantial temperature differences 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 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 to obtain the desired information. For performance monitoring, some temperature sensors should be distributed throughout the system as per 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 V_{oc}-based on the method described in IEC 60904-5 as an alternative to using a temperature sensor in contact with the module back surface. This may require using an additional reference module not connected to the PV array for temperature measurement purposes.

A3. AMBIENT AIR TEMPERATURE

As required by Table 5, the ambient air temperature, Tamb, shall be measured at locations that represent the array conditions by means of temperature sensors located in solar radiation shields that are ventilated to permit the 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 the manufacturer’s recommendations for Class B.

As suggested in Table 5, ambient air temperature at the site may be estimated based on local or regional meteorological data for Class B and Class C.

A4. 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 that represents 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 averaged and maximum values.

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

The uncertainty of the wind speed sensor measurement 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 the direction from which the wind blows and is measured clockwise from the geographical north. It shall be measured with an accuracy of 5°.

Wind sensors shall be recalibrated as per the manufacturer's recommendations.