GRID-CONNECTED PV

OPERATIONS AND MAINTENANCE GUIDELINE

SEIAPI Sustainable Energy

SIDSDOCK SMALL ISLAND DEVELOPING STATES ISLAND ENERGY FOR ISLAND LIFE

WORLD BANK GROUP

PPA PACIFIC POWER ASSOCIATION

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These guidelines have been developed for The Pacific Power Association (PPA) and the Sustainable Energy Industry Association of the Pacific Islands (SEIAPI).

They represent the latest industry BEST PRACTICE for the Operation and Maintenance of PV Systems. While all care has been taken to ensure this guideline is free from omission and error, no responsibility can be taken for the use of this information in the operation and maintenance of PV Systems.

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List of Abbreviations

A summary of the main acronyms and terms used in this document is listed below:

AC	Alternating Current
AS	Australian Standards
CT	Current Transformer
DAS	Data Acquisition System
DC	Direct Current
EN	European Standards (European Norms)
HMI	Human Machine Interface
HV	High Voltage
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IR	Infrared
IRT	Insulation Resistance Tester
I-V	Current-Voltage
kVA	Kilovolt Amp
KWh	Kilowatt Hour
LOTO	Lock Out-Tag Out
LV	Low Voltage
LVRT	Low Voltage Ride-through
MPP	Maximum Power Point
MV	Medium Voltage
NZS	New Zealand Standards
NEC	National Electricity Code
O&M	Operation and Maintenance
PF	Power Factor
PM	Preventative Maintenance
PPE	Personal Protection Equipment
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
SPD	Surge Protection Device
UL	Underwriters Laboratories

1. Introduction

Solar Photovoltaic (PV) technology makes possible electricity generation from sunlight that is fed into the grid to become an integral part of a utility's generation system. PV systems on the grid can be either centralised grid-connected solar farms or decentralised grid-connected systems such as usually are installed on residential, commercial or industrial buildings. Although off-grid installations are not specifically discussed in this guideline, most of the techniques for the troubleshooting and maintenance of PV arrays, DC wiring, earthing and AC inverters shown here are directly applicable to off-grid installations.

Centralised grid-connected systems are large-scale PV systems, also known as solar farms. These systems are typically ground mounted and are built to supply bulk power to the electricity grid like any other centralised power station. Declining costs of PV technology, coupled with government policies promoting large scale renewable energy use, has allowed utility-scale solar to become more and more competitive with other forms of electricity generation, driving its rapid deployment in many countries across the globe. With the help of policy support in the form of national renewable energy targets, deployment of solar farms worldwide is increasing at a faster rate than information and training specific to these larger-scale systems is being made available.

PV systems which include inverters and other Balance of System (BOS) components that enable safe interconnection with the grid are usually perceived to be 'low maintenance' systems but they are not completely maintenance free. The oversimplification of the working of a PV system leads to an underestimation of their operation and maintenance requirements thereby resulting in incorrect financial estimations for investment. A PV system installed at utility-scale requires constant monitoring and operation as well as proper maintenance so that they can offer electricity at lower costs and enable reduced use of fossil-fuel based generators.

Notes:

1. IEC standards use a.c. and d.c. for alternating and direct current respectively while the NEC uses ac and dc. This guideline uses ac and dc.

2. This guideline has generally been written in the perspective of large PV solar systems often called Utility Scale PV systems or Solar Farms that are ground mounted. However, with the exception of equipment such as ac transformers and associated switchgear, most of the principles are relevant to small solar systems that can be located on a roof.

2. Understanding a Grid-Connected Solar System

2.1 The solar resource

The electrical output of a PV module is proportional to the amount of solar irradiation incident on its surface. (note: Solar power is Irradiance and Solar energy is irradiation). Hence it is important to determine the amount of solar irradiation that is incident on the PV module throughout the day. Solar irradiation varies for different sites depending on their location (especially latitude), time and day of the year, weather and also on the orientation of the PV module.

The data for solar irradiation for different locations are often available from the meteorological departments though not always in a form easily used for solar design. In 2017, the solar irradiation data for Pacific Islands was made available through a new tool launched by the World Bank as part of their Global Solar Atlas (http://globalsolaratlas.info/). NASA's Surface Meteorology and Solar Energy is another resource available through their website https://power.larc.nasa.gov/. Please note that NASA data has, in some instances, had higher radiation figures than recorded by ground collection data source in a few countries. But if no other resource is available for a site, this data can be used.

Solar irradiation is typically provided as kWh/m^2, however, it can also be stated as daily peak Sun hours (PSH). This is the equivalent number of daily hours of solar irradiance of $1kW/m^2$.

Appendix 1 provides PSH data on the following sites:

- Alofi, Niue (Latitude 19°04'S, Longitude 169°55'W)
- Apia, Samoa (Latitude 13°50'S, Longitude 171°46'W)
- Hagåtña, Guam (Latitude 13°28'N, Longitude 144°45'E)
- Honiara, Solomon Islands (Latitude 09°27'S, Longitude 159°57'E)
- Koror, Palau (Latitude 7°20'N, Longitude 134°28'E)
- Lae, Papua New Guinea (Latitude 6°44'S, Longitude 147°00'E)
- Majuro, Marshall Islands (Latitude 7°12'N, Longitude 171°06'E)
- Nauru (Latitude 0°32'S, Longitude 166°56'E)
- Nouméa, New Caledonia (Latitude 22°16'S, Longitude 166°27'E)
- Nuku'alofa, Tonga (Latitude 21°08'S, Longitude 175°12'W)
- Pago Pago, American Samoa (Latitude 14°16'S, Longitude: 170°42'W)
- Palikir, Pohnpei FSM (Latitude 6°54'N, Longitude 158°13'E)
- Port Moresby, Papua New Guinea (Latitude 9°29'S, Longitude 147°9'E)
- Port Vila, Vanuatu (Latitude 17°44'S, Longitude 168°19'E)
- Rarotonga, Cook Islands (Latitude 21°12'S, Longitude 159°47'W)
- Suva, Fiji (Latitude 18°08'S, Longitude 178°25'E)
- Tarawa, Kiribati (Latitude 1°28'N, Longitude 173°2'E)
- Vaiaku, Tuvalu (Latitude 8°31'S, Longitude 179°13'E)

Solar irradiation data is one important parameter that is collected during PV system operation in order to evaluate and predict the system's performance.

2.1.1 Position of Sun

The amount of solar irradiance a surface receives (and thus the amount of electricity a solar module can produce) depends on the tilt and orientation of the surface relative to the Sun's position in the sky. Maximum irradiance is received when a surface is facing directly at the Sun. The position of the Sun varies throughout the day and over the year, and though PV systems can be designed to 'track' the path of the Sun in the sky for maximum production at all times, this is not typical of solar systems in the Pacific, which are usually installed at a fixed tilt and orientation due to the lack of affordable tracker installations suitable for the high wind loading conditions (e.g cyclones and typhoons) in the Pacific islands.

In general, the maximum amount of irradiation is received annually by a fixed module when it is pointed towards the equator at an angle equal to the latitude of the site. For sites located close to the equator, the solar modules would receive the maximum solar radiation when positioned horizontally, however it is recommended that they are installed with a minimum tilt angle of 10° so that debris like dirt or leaves on the modules can be washed off by the rain.

2.2 Solar modules

Photovoltaic (PV) modules, also called solar panels, convert sunlight into electricity and form the basis of any solar electric system. Solar modules shall meet the following IEC standards:

- IEC 61215 Terrestrial photovoltaic (PV) modules - Design qualification and type approval
    - IEC 61215-1 Part 1: Test Requirements
    - One of IEC 61215 Part 1.1, Part 1.2 Part 1.3, part 1.4 which all relate to specific types of modules e.g. crystalline, thin film amorphous etc (See Section 2)
    - IEC 61215-2 Part 2: Test Procedures
- IEC 61730 Photovoltaic (PV) module safety qualification
    - IEC 61730-1 Part 1: Requirements for construction
    - IEC 61730-2 Part 2: Requirements for testing

Or the UL standard

- UL Standard 1703: Flat Plate Photovoltaic Modules and Panels

For modules with IEC certification they must be certified as Application Class A per IEC 61730.

Note: IEC61215 are also available as European Standards (EN) and Underwriters Limited Standards (UL)

2.2.1 Array configuration

Connecting PV cells in series make up a PV module and PV modules connected in series form a PV string. Large Scale PV systems have large number of PV strings that are typically connected in parallel to form a PV array (Figure 1).

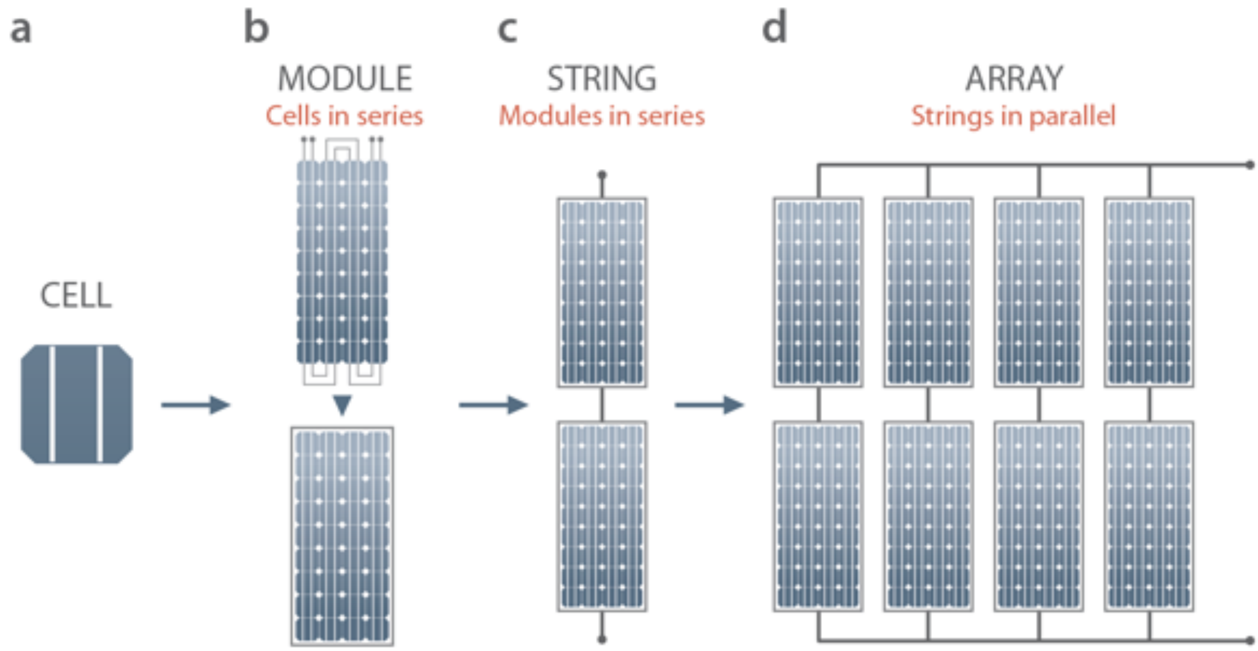

Figure 1: Arrangement of a PV Array

The voltage output of a PV string is defined by the sum of the voltage output of all the modules connected in series. But the current output of a PV string is set by the lowest current generated by a single module in the string.

String (modules in series):

- Voltage = sum of module voltage outputs
- Current = smallest module current output

Similarly, the voltage output of a PV array consisting of multiple PV strings in parallel will be equal to the lowest string voltage in the array and the array output current is given by the sum of output currents of all the individual PV strings.

Array (strings in parallel):

- Voltage = lowest string maximum power point voltage output (Note: it does depend on what voltage the Maximum Power Point tracker in the inverter selects for maximum power output)
- Current = sum of current outputs of all the strings that are connected in parallel.

The number of PV modules connected in series and the number of PV strings connected in parallel are determined based on the current and voltage requirements for the inverter system.

2.2.2 Operational Characteristics of A Solar Module

2.2.2.1 The I-V curve

The electrical characteristic of a PV module is determined by the relation between current and voltage of the electricity generated by each solar cell. This relationship is shown by a current-voltage (I-V) curve as shown in Figure 2 below. The I-V curve gives important data about the module at the conditions present at the time of measurement. Note that published data for solar modules are based on standard test conditions. Those conditions include a direct solar input of 1000 W/m^2 and a cell temperature of 25°C.

These data may include:

- Short Circuit Current (I_{sc}) – the current during a short circuit i.e. when resistance is zero. This is the maximum current output
- Open Circuit Voltage (V_{oc}) – the voltage during an open circuit i.e. when the resistance is maximum. This is the maximum voltage output
- Maximum Power Point (MPP) – the point on the I-V curve at which the module generates maximum power
- Maximum power (P_{MP}) – maximum power output
- Voltage at P_{MP} (V_{MP}) – voltage at the MPP of the I-V curve
- Current at P_{MP} (I_{MP}) – current at the MPP of the I-V curve
- Shunt Resistance and Series Resistance which can help determine performance degradation due to defects in manufacture
- Fill Factor which indicates the module performance.

PV modules in a large scale PV system will produce a different I-V curve than the published curve as the current and voltage of a PV cell depends on operating conditions including, among other things, irradiation levels, temperature, soiling, and shading. For example, a PV module under shade or that has dirt settled on it will have reduced solar energy reaching the cell which in turn reduces the maximum current that the PV string can produce. it may also have reduced voltage because of the operation of the bypass diodes (refer section 2.2.2.2). Measurement of the I-V curve is one of the quality assurance measures of system performance and the measured data provide means of checking the power produced by a PV module. A large sample of PV modules installed in the field can be easily tested and this helps identify faulty modules, connections, Potential Induced Degradation (PID), and other problems causing reduced output from the solar installation.

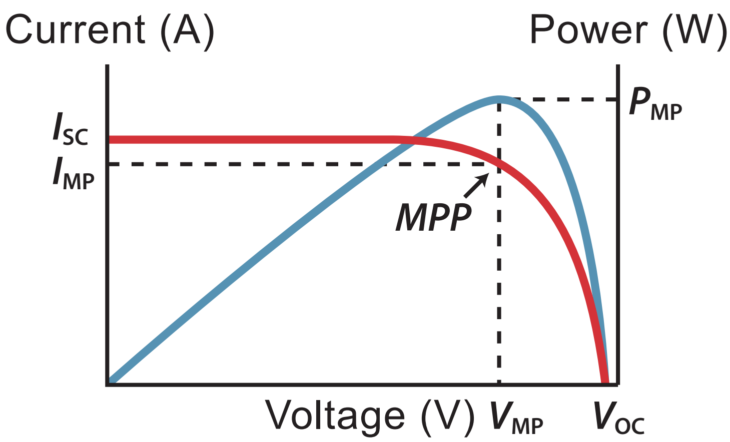

Figure 2: I-V curve of a solar cell

It is important that the system operator understands the effect of external factors acting upon the PV system and the measurement technique for performing an I-V curve test. Unfortunately, a troubleshooting manual cannot always provide detailed corrective actions based on the measurement results alone. This test is usually undertaken at the combiner boxes in a large scale PV system. If an underperformance of a section of the PV array is identified from the data collected, then the operator might need to schedule an inspection of the modules, wiring and connections in that particular section of the system to identify and rectify the specific problem causing the underperformance of that section.

It is also imperative that the operator understands the changes in the shape of the I-V curve as it varies due to various factors. A solar cell has internal resistances – series resistance and shunt resistance – that define the shape of the I-V curve. As the shunt resistance reduces, the Maximum Power Point of the module reduces as shown in figure 3(a). This is usually caused by manufacturing defects. The Series resistance, which is the 'parasitic resistance' of the module, is caused by the resistance due to metallic contacts. The effect of high series resistance is shown in figure 3(b) below.

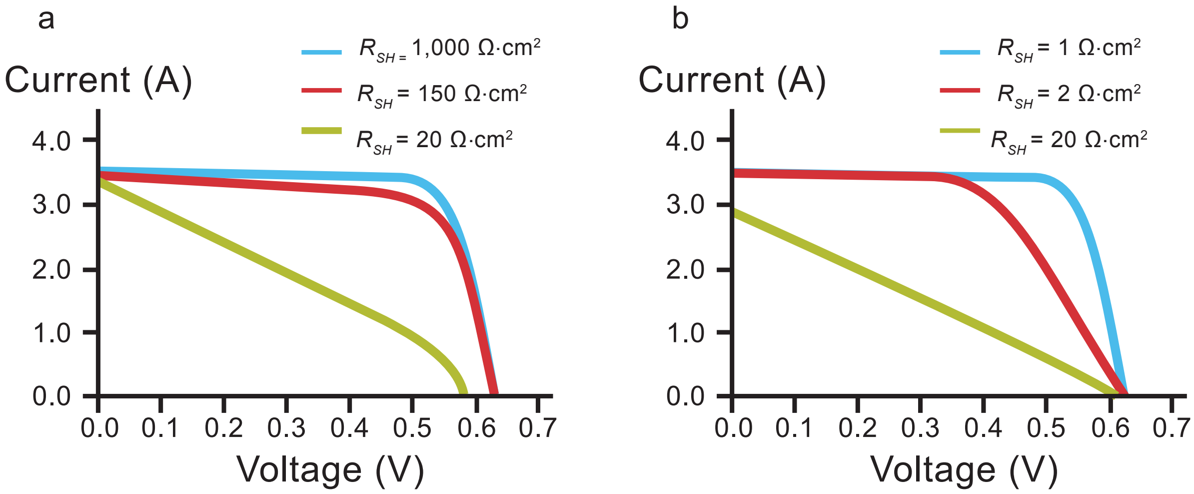

Figure 3: Effect of (a) shunt resistance and (b) series resistance on the I-V curve

2.2.2.2 Bypass Diodes

A string of cells is connected in series to form a solar module. The module will produce less power if:

- One or more of the cells is defective.
- One or more of the cells is shaded.

In both cases, the polarity of the defective or shaded cell that is in series with the rest of the cells will be reversed and the output of the module will be reduced even if the rest of the cells are in perfect working order and are in bright sunshine. The reverse polarity can also cause heat build-up in the cell, creating a hot spot in the module and causing the module to be damaged. These principles are the same for modules connected in series to form a string.

A bypass (or shunt) diode can be used (Figure 4) to provide an alternative path for current when a reverse voltage is present. The effect of bypass diodes is shown in Figure 5. The greater the number of bypass diodes, the greater the output if one of the modules is shaded or defective.

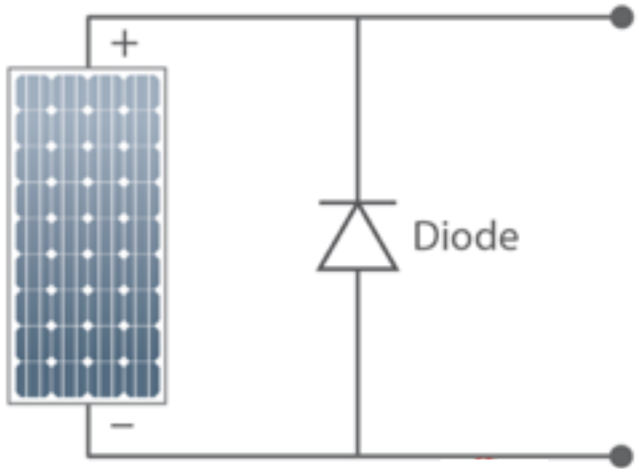

Figure 4: Use of a bypass diode across a module

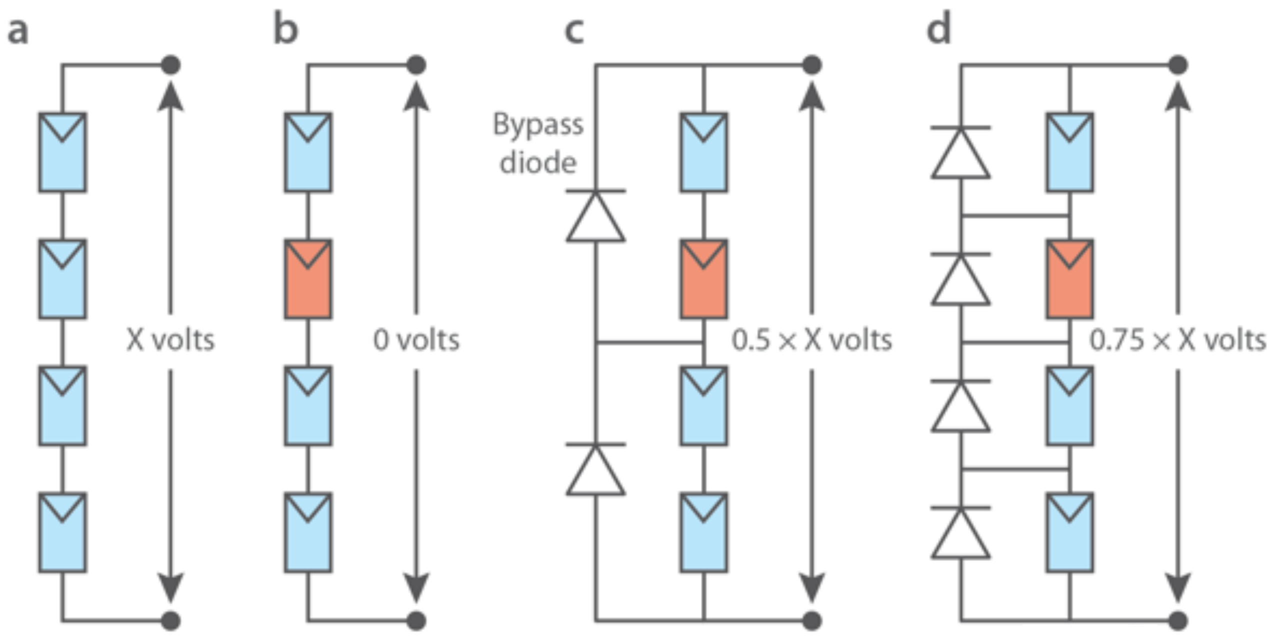

Figure 5: The effect of installing bypass diodes

a) No bypass diode and no defective or shaded module. The output is X volts.
b) No bypass diode and a defective or shaded module (red). The output of the string of modules will be zero.
c) Two bypass diodes and a defective or shaded module. The output of the array is 0.5 × X volts as the upper bypass diode provides an alternative path for current across the defective module and the top module.
d) Four bypass diodes and a defective or shaded module. The output of the array is 0.75 × X volts as the bypass diode around the defective module provides an alternative path for the current.

In most commercial crystalline modules, bypass diodes are not fitted to every cell. Most manufacturers provide 1 bypass diode across each string of 24 cells (requiring 3 diodes in a 72 cell module) or across each string of 20 cells in a 60-cell module. The module manufacturer's specifications should indicate the number of bypass diodes fitted in each module. The effect of shading on a cell with 3 bypass diodes in a 72 cell module is shown in Figure 6. In this situation, the MPP has decreased by approximately a third. For many thin-film modules, the cell bypass diodes are integrated into the surface of the module.

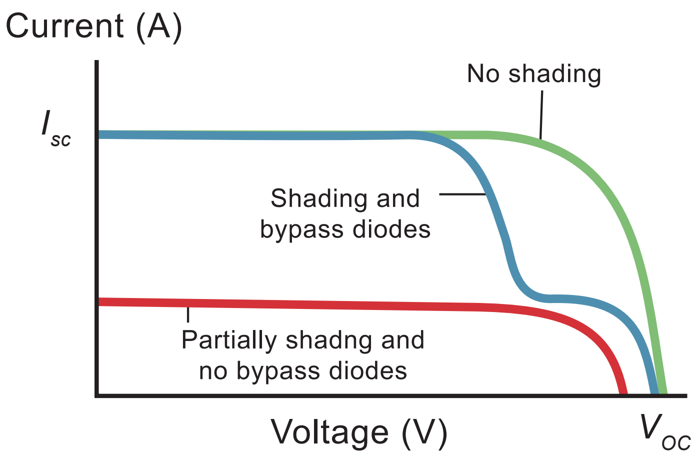

Figure 6: Example of typical array output with and without bypass diodes

2.3 Grid-connected inverters

Inverters or Power Conditioning Equipment (PCE) convert DC electricity generated by the PV modules into ac electricity with a voltage and frequency compatible for connection with the ac grid. A solar farm may use separate inverters for every few strings of modules (string inverters), a small number of large inverters for the entire system (central inverters), or more rarely, separate inverters for every one or two modules (micro inverters).

A grid-connected PV inverter can either be a transformer or transformerless type. A standard unipolar inverter with a low-voltage inverter incorporated in its design can output the ac voltage as per the grid requirement and also provide galvanic isolation between the ac output and dc input side of the inverter. However, an additional external transformer shall be required if the voltage has to be stepped up to Medium Voltage (MV) or (High Voltage) HV scale depending on the level of transmission to the substation. A transformerless inverter doesn't have an inbuilt transformer and couples the ac output of the inverter directly to the external transformer. Transformerless inverters have comparatively higher efficiency due to less conversion stages and they allow for design flexibility by allowing the paralleling of a number of inverters before connecting to a MV transformer. However, additional protection is required to provide galvanic isolation between the ac and dc side of the inverter. Transformerless inverters may also allow leakage currents that may cause electromagnetic interference (EMI).

Inverters shall meet either

- IEC62109 Safety of power converters for use in photovoltaic power systems
  - IEC62109-1 Part 1: General requirements
  - IEC62109-2 Part 2: Particular requirements for inverters

  or
- UL Standard 1741 Standard for Inverter, converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources.

2.3.1 Grid Connect Inverter Protection Systems

The grid-connect inverter acts as the interface to connect the PV generation to the local distribution network. However, a grid-connected PV system can create complications when the grid experiences abnormal conditions. For this reason, the grid requires protection so that the inverter is disconnected from the grid when:

1. The grid is interrupted (a blackout)
2. The grid operates over or under the permitted voltage and frequency thresholds.

Having the inverter disconnect under these conditions protects the grid and prevents islanding (Section 2.3.1.1). Grid-connect inverters incorporate two types of grid protection:

1. **Passive protection:** the inverter disconnects if it detects grid conditions that are over or under the voltage and/or over or under the frequency settings of the inverter.
2. **Active protection:** the inverter will cause its passive protection to operate if there is not a stable grid reference.

2.3.1.1 Anti-Islanding

Islanding is a condition in which a distributed generator (e.g. a grid-connected PV system) continues to supply power to part of the grid after the utility power generator is no longer supplying power, thereby creating an 'island' with live power. That power could pose a safety issue to utility workers who may be working on the supply lines at that time and could also cause further problems for the grid supply system.

To avoid islanding, grid-connected inverters must contain circuitry so that they do not export power when abnormal grid conditions are registered. This effectively shuts the ac delivery of the PV system down, although the dc side remains live. This shut-down feature is known as 'anti-islanding' and means the PV generation cannot worsen the grid conditions or cause injury to technicians working on the lines.

When the grid is normalised, the inverter will reconnect to the grid after the inverter has detected normal grid conditions and has cycled through its timed delay start-up, which is usually at least one minute.

2.3.1.2 Passive Protection

Passive protection disconnects the inverter from the grid if there is a grid failure or the grid operates outside the permitted voltage and frequency ranges. These preset voltage and frequency limits are programmed into the inverter and are determined by the relevant standards and/or the authorising network. Under certain circumstances, variations to these parameters may be negotiated with the electricity network in the area. Passive protection is also known as passive anti-islanding protection.

There are four forms of passive anti-islanding protection:

- Under-voltage protection (if under V_{MIN})
- Over-voltage protection (if over V_{MAX})
- Under-frequency protection (if under f_{MIN})
- Over-frequency protection (if over f_{MAX})

If the grid voltage moves outside the range V_{MIN} to V_{MAX} or its frequency moves outside the range f_{MIN} to f_{MAX}, the inverter's disconnection device is operated within a set time period (typically 2 seconds).

2.3.1.3 Active-Protection

If a sufficient number of inverters were connected to the grid within a limited area and the grid supply to that area failed, there is a concern that the inverters would reference each other and supply a grid reference so that each inverter continues to operate. That is, the voltage and frequency will become a reference to each other and remain within their limits, so that the passive protection would not operate properly. Therefore, the PV system would keep supplying power to a part of the grid during an interruption, when the lines should be 'dead', again creating an unsafe island effect.

Active protection (also known as active anti-islanding protection) forces the passive protection of the inverter to operate under certain situations. The inverter will allow the detected abnormality to 'drift' so that the inverter shuts down under its prescribed passive protection parameters.

There are several different methods of active protection, including:

- **Frequency instability:** The frequency of the inverter is inherently unstable in the absence of a reference frequency. This instability will lead to either the 'over frequency' or 'under frequency protection operating.
- **Frequency drift:** When there is no reference frequency, the inverter will shift its frequency away from its nominal condition and the frequency protection will operate.
- **Power variation:** If there is no stable voltage from the grid, periodic variations in the output power of the inverter will lead to a drift in voltage, thereby activating the under voltage or over voltage protection.

2.3.2 Faults in Inverters

The inverters for PV systems usually have integrated monitoring and communications interfaces to measure and record important inverter operating parameters such as:

- Inverter dc input operating parameters – PV array power, voltage and current
- Inverter ac output parameters – Grid voltage, frequency, current, power (active and reactive)
- Energy generated
- Fault conditions
- Irradiation, ambient temperature and module temperature when additional sensors and data loggers are installed

These data measured are essential for effective monitoring and operation of the PV system connected to the grid. Depending on the scale of installation and financial allocation for operation and maintenance, the data measured can either be retrieved at the inverter panel on site or remotely. An estimated 60%[1] of faults in a large scale PV power plant have been recorded as caused by the inverters. A loss of PV system operation for a day can result in huge economic loss and potential financial risk. Each inverter is a critical component of a grid-connect PV system and should not be susceptible to failure at any point during system operation.

Some of the common faults that can occur in an inverter are a blown fuse, unexpected tripping, issues with software or the control board, ground faults and operation of an alarm. Proper inverter monitoring and scheduled maintenance of inverters should be treated as the most significant component of the solar power plant's Operation and Maintenance strategy.

[1] *http://ise.innoenergy.com/documents/196863/282833/07_PV-PLANT-OPERATION_EN.pdf/adad76ef-17cb-4efa-8667-a607ffaf998c;jsessionid=054F03BC8B06E8220A12060B15B6DAB4?version=1.0*

2.4 Balance of system

2.4.1 Transformers

There will typically be two different types of transformers (other than transformers built into inverters) used in a utility-scale PV plant: the distribution transformer installed after each inverter, and a substation transformer used to step up the voltage for transmission. The primary role of these transformers is to step up the inverter output voltage to AC grid voltage levels. This could range between 12-132kV depending on the grid connection point and its requirements. Transformers also provide galvanic isolation between large-scale solar power systems and the utility grid, thereby improving safety and equipment protection by preventing ground fault loops. The use of any transformer will depend on the system's variables being known and therefore the transformer will typically have to be customised to ensure it will function properly with a specific system.

2.4.1.1 Distribution transformers

A distribution transformer is typically located after the inverter (if one central inverter) of inverters (if multiple string inverters) to step the voltage up from LV to MV or HV levels for transmission to a substation and is characterised by the following:

- Pad-mounted transformers are more common than conventional pole-mounted transformers in utility-scale PV plants; this is because cabling typically runs underground rather than overhead.
- Capacity typically ranges from 50 to 2,500 kVA.
- Maximum voltage for pad-mounted transformers is typically 35 kV or 36 kV, however some manufacturers offer higher voltage ratings on request.
- Liquid-type transformers are almost always used instead of dry-type transformers because they dissipate heat more efficiently, require less conductor insulation and are cheaper.

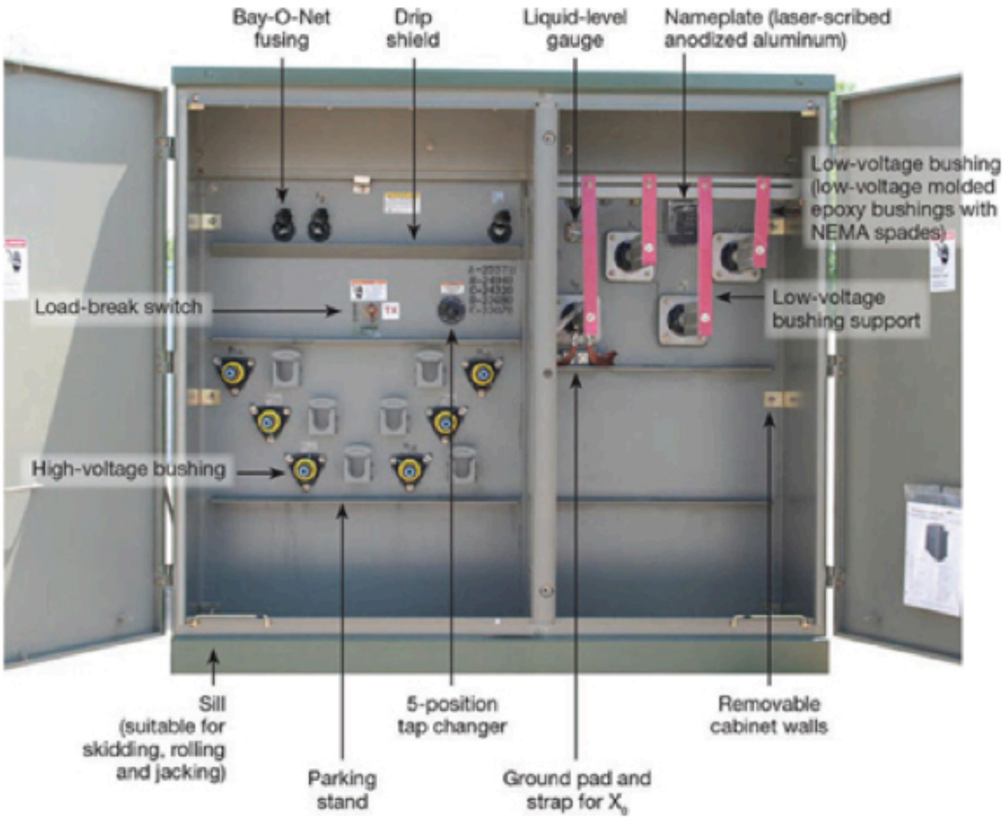

Figure 7: Basic anatomy of a typical 3-phase, pad-mounted distribution transformer. The compartment on the right is the low voltage side; the left is the high voltage compartment. Source: Image courtesy of Eaton

2.4.1.2 Substation transformer

A substation transformer is located at a substation and steps voltage up from MV to HV levels for transmission across long distances to where the electricity is distributed. This transformer is characterised by the following:

- Required when a transmission voltage is required greater than 36 kV.
- Capacity can vary from 2,500 kVA to more than 100 MVA.
- These are larger and more complex than distribution transformers and require more insulation to accommodate higher voltages.
- Liquid-cooling is used, similar to distribution transformers.

2.4.2 Cabling

A PV power plant has both dc and ac cabling. The dc cables are used to connect each PV module to the point of interconnection at the DC side of the inverter. To connect the inverter to the substation or the LV distribution board, ac cables are used.

Cables for dc need to be suitable for PV applications, double insulated, moisture resistant and UV-resistant or installed within trunking or conduit (see IEC 61386 Conduit systems for cable management). For safety and a clean installation, accessories like cable ties, cable clips/clamps, ducting, cable trays or ladder arrangements shall be used as required.

The dc cabling will include:

- **PV module cables:** These are typically pre-connected to the module and connect a set of PV modules in series, forming a string.
- **PV string cables:** These connect a string of modules to the PV string combiner box.
- **PV sub-array cables:** These connect the PV string combiner box to the PV array combiner box.
- **PV array cables:** These connect the PV array combiner box to the PV array DC switch-disconnectors.
- **Inverter dc cables:** These connect the PV array dc switch-disconnectors to the DC side of the inverter. This cabling may also be referred to as PV array cabling.

The ac cabling will include:

- **Inverter ac cables:** These connect the ac side of the inverter to the LV/MV transformer.
- **LV/MV transformer cables:** These connect the LV/MV transformers to the MV collection switchgear, or substation.
- **MV switchgear cables:** These connect the MV switchgear to the MV/HV transformers, which connect the system to the grid.

The cables may either be copper or aluminium conductors. The length of the cables will depend on the system design and layout of the plant. The cable sizes should be chosen such that power loss in the cables due to resistance is minimal. If cables are too small, excessive power will be lost, and there will be a substantial drop in voltage which may cause issues at the inverter or the grid interconnection point.

2.4.3 Electrical protection

Electrical protection devices are essential to ensure that a solar system operates safely and is safe to access by all related personnel. Electrical protection may include overcurrent protection devices, disconnection devices, earthing/grounding and lightning/surge protection.

Overcurrent protection devices automatically disconnect during a fault and are designed to prevent damage to components and cables due to overload currents or short circuits. These include fuses which are sized so that they carry the required load current but will create an open circuit under a fault condition – the conductor material in the fuse melts under excessive current, breaking the circuit; and circuit breakers which are mechanical devices installed to protect a circuit by opening that circuit under fault conditions. They can be reset when the fault is removed, so can be used repeatedly, unlike fuses.

Disconnection devices are manual switches used to break a circuit to allow parts of the system to be electrically isolated. For a utility-scale system, there should be a means of disconnection for both the dc and the ac circuits. The dc disconnection devices must be non-polarised, meaning that they operate effectively when installed in either direction. The disconnection devices installed in a utility-scale PV system are:

- String disconnectors (dc) – non-load-breaking disconnection switches
- Sub-array disconnectors (dc) – load-breaking disconnection switches (may be non-load-breaking)
- PV array DC switch-disconnectors (dc) - load-breaking disconnection switches
- Inverter disconnectors (ac) –load-breaking disconnection switches (may be non-load-breaking)
- Main switchboard disconnectors (ac) – load-breaking disconnection switches
- Transformer disconnectors (ac) – load-breaking disconnection switches

Earthing, or grounding, protects both the system equipment and people from dangerous fault conditions by directing fault current to earth via an earth stake. Earthing can also be used to improve the performance in some systems. Equipotential bonding (also known as protective earthing or equipment grounding) is used between exposed conductive parts of the PV array to ensure that there is no voltage (potential) difference between any two components in order to protect people from electric shock. Functional earthing (also known as system grounding) is only necessary for certain types or brands of modules to ensure optimal performance of the array.

Lightning and surge protection involves a combination of earthing/grounding and surge protection devices (SPDs) to protect the installation in the event of nearby or direct lighting strikes. Lightning/surge protection systems are designed to protect equipment from being directly struck by lightning, or being in the path of discharge from a strike, by directing the energy of the strike through large current-carrying conductors to earth. SPDs differ in that they provide overvoltage protection for direct and indirect lightning strikes that cause magnetic fields that induce transient currents in the wiring of the PV system. The associated transient voltages appear at equipment terminals and may cause insulation and dielectric failures to important system components.

2.4.4 Combiner boxes

For a utility-scale solar plant, a string junction/combiner box will be used to interconnect the string cables of each sub-array connected to the inverter input. In some cases, an array combiner box may be used to house the connection of these sub-arrays before entering the inverter. However, most utility scale central inverters have multiple DC inputs, so the sub-arrays are paralleled inside the inverter, leaving no need for a sub-array combiner box. Junction boxes may also be required at points where ac cables from inverters are connected together and then connected to a transformer via one ac cable. Where necessary, junction boxes will also house the overcurrent protection, the disconnection devices, the SPDs and monitoring equipment.

2.5 Metering

Large scale grid connected PV systems export the vast majority of their generation to the electricity grid since they consume only a small percentage of their generated power on site (the auxiliary load). It is essential for a system to measure the electricity generated and exported to the grid so that revenue from the installation can be calculated based on the reading. A revenue type interval meter should be installed on the grid side of the transformer to measure the amount of electricity exported to the grid in order to calculate revenue from feed-in-tariffs, power purchase agreements (PPAs) or the spot market, as well as providing a means of monitoring the performance of utility owned PV systems. An import-export revenue type interval meter should also be installed at the low voltage switchboard on the auxiliary circuit to measure the electricity consumed by the auxiliary loads (largely monitoring/control equipment and associated cooling and air-conditioning units) at the solar farm.

2.6 Monitoring

Large-scale solar systems require a high level of monitoring and control to ensure that the system runs optimally, to provide information needed for troubleshooting when there are problems and operates in accordance with the local grid requirements. Supervisory control and data acquisition (SCADA) systems are used to monitor and control various components of the PV system. There are different methods and equipment used to achieve SCADA, but the goal is generally the same (see Figure 8 .).

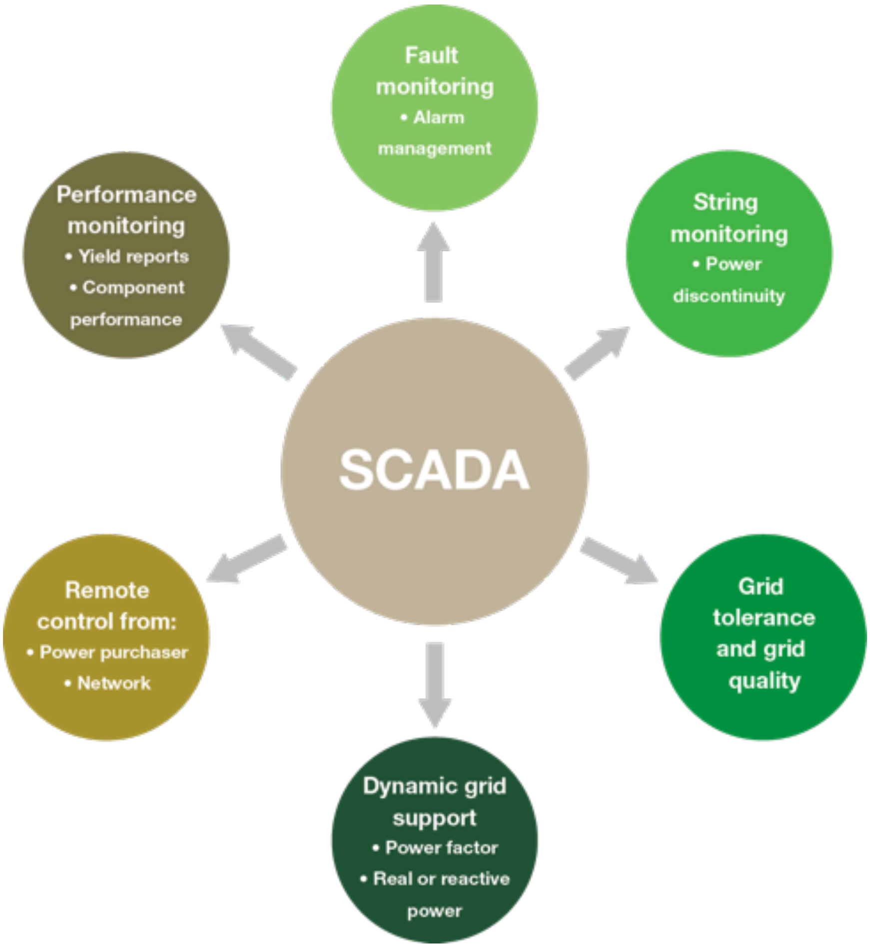

Figure 8: Goal of SCADA systems in a solar plant.

The following equipment can be used in the provision of SCADA services for large-scale PV systems:

- Programmable logic controllers (PLCs)
- Ripple control receivers
- Demand response-enabled devices (DREDs)
- Multi-function protection relays
- Object linking and embedding (OLE) for process control (OPC server)
- Power line communication
- Serial/Ethernet/Wi-Fi monitoring
- Weather sensors and weather prediction algorithms
- Building management systems (BMS) and energy management systems (EMS).

3. Integration of Variable Renewables into the Grid

Although solar irradiance can be predicted to follow seasonal and daily patterns, local weather can present unpredictable weather variations including cloud cover. The variability that unexpected PV generation intermittency produces can result in the local electricity network being negatively impacted: the impact can be local, e.g. a feeder or substation, or broader in effect, meaning it affects the entire network.

Where the network is unable to support the intermittency of the PV power through base load generation or battery storage, there can be problems with the network's power quality and potentially cause network failures. The installed capacity of the proposed large scale PV solar system may be limited because of these possible network problems. The variability of PV generation can produce problems over different timescales:

- Changes in power quality: fast changes in PV generation may cause power quality problems, e.g. flickering, harmonic distortion, frequency variations and voltage variations. The network should be able to respond to this in seconds.
- Network's total capacity: the network's power generation must be able to meet the capacity and ramping requirements if there are short-term variations in demand and PV generation. This can result in issues of power quality and cause system outages. The network can respond to this within minutes of the problem occurring.
- The network's ability to establish generating unit's commitments and scheduling: the network's generation planning requires that there is enough generation at any point in time to meet the demand and the operating reserve. The network will respond to this problem within hours to days.

The network demand must be well understood before determining the level of PV able to be successfully interconnected. Figure 9 provides an example of clear sky irradiance and the changes to that irradiance caused by intermittent cloud cover at that site. The system reliability calculations may indicate that it is preferable to install the required PV capacity over a larger area and a larger number of sites, assuming the network interconnections are viable, as this can greatly reduce the performance variability of the total solar PV power input.

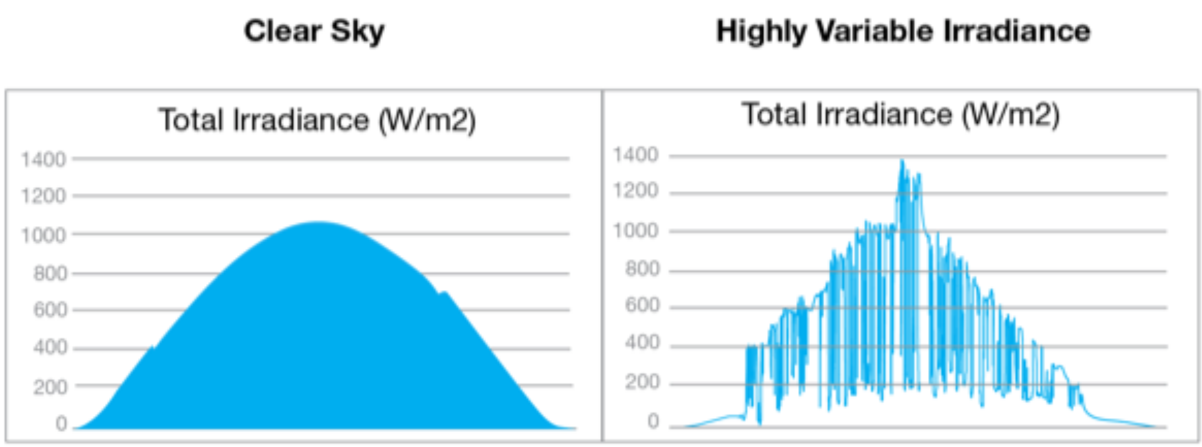

Figure 9: Comparison between irradiance on a day with clear sky, and irradiance on a day with intermittent cloud cover indicating the lack of reliability that intermittent PV generation introduces to any network. Source: CAT Projects & ARENA

Since the majority of electricity networks in the Pacific islands have been designed for electricity flowing from large centralised generators such as diesel power plants, they have not been designed to handle the intermittency of large-scale PV power plants. This can lead to the significant grid integration challenges described above. In order to ensure that the large scale PV system will not have adverse impacts on the network stability or system security, thorough grid-connection studies must be carried out in accordance with the local grid-connection rules and requirements.

International guidelines include:

- IEEE 1547 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
- IEC/TS 61727 Photovoltaic (PV) systems – Characteristics of the utility interface

The intermittency of solar generation can lead to changes in the local network's frequency and voltage, which can cause serious challenges for network stability, power quality and security of supply. Different networks have different voltage and frequency requirements that vary between countries, states and regions. In all cases it is very important to remain within the local standards for the grid voltage and frequency tolerances.

A suitable power factor, reactive power and voltage control strategy should be developed to ensure that the power quality of the grid connected large scale PV system remains within utility requirements. One solution is to install an active control system that reads the output of the inverters and compares it to the power factor required by the local grid. If the power factor is too low, the control system calculates a control signal to adjust the output of the inverter. A power factor range of 0.95 lagging or leading is typical for most networks.

In general, a large scale grid connected PV control system should include the following in order to effectively manage grid reliability and stability:

- reactive power capability to regulate the power factor and plant voltage/VAR controls;
- active power regulation to curtail active power when necessary;
- ramp rate control to limit the ramp rate from rapid variations in irradiance due to cloud passages;
- ride-through capability to prevent faults and other disturbances from causing system outages; and
- frequency droop control to monitor, track and react to changes in grid frequency.

Overall, the development of an adequate grid-connection strategy should be done early, and in close partnership with local network service providers to avoid costly time delays, and to ensure smooth integration of the system to the local grid.

3.1 Benefits of integration

Distributed solar generators play an important role in decarbonising the electricity sector, reducing transmission losses and the need for transmission and distribution infrastructure being located close to the demand. They also play a part in overcoming the effects of cloud cover by having the solar power systems dispersed. However, they are limited by scale and to suitable sites. Utility-scale PV systems take advantage of economies of scale, by deploying multi megawatts of solar modules and inverters in large open spaces but with the cost of absorbing more severe variations in power generation than would be the case with distributed solar installations.

Compared to other types of centralised power stations, large-scale PV systems can have little disturbance on the land:

- They can be fully decommissioned at the end of their lifetime, allowing the land to be restored to its original use.
- Once the PV system has been constructed, there is little ongoing disturbance from humans or

machinery on the site leaving opportunity to use the land beneath the installed solar system for grazing animals but it has not been undertaken on any system in the Pacific Islands.
- They can be built on land of limited financial or community value such as land having been previously developed, contaminated or industrial land.

Large scale PV systems can also have a range of social and economic benefits, including:
- Reduction of energy import dependency.
- Help meet national and international commitments for lower carbon energy generation.
- Diversification of the electricity generation mix – improving energy security if battery storage is included.
- Stimulation of the local economy by providing jobs and training in the local area, and supporting local suppliers and dealers.

3.2 Risks of integration

3.2.1 Variability in PV output

The output of a PV plant is subject to significant unpredictable variability, generally due to the passage of clouds. While clouds rapidly reduce generation by shading PV arrays, there also will be a sudden boost in PV array delivered energy when the sun is emerging from behind the cloud. This increased power effect, also known as 'edge of cloud effect' is caused by concentration of sunlight due to refraction while the edge of shadow passes by. Additionally, fluctuations in wind may change the cell temperature in PV arrays and result in a slow, relatively small effect on the array's generation.

The short-term variations can degrade power quality (voltage and power factor) and can result in frequent, rapid changes in the loading of diesel generators which can result in increased maintenance requirements as well as possibly causing frequent operation of transformer tap changers and capacitor bank switches, which increases wear and tear of these devices and shortens their lifetime. The longer term fluctuations may require substantial spinning reserves to maintain a sufficient supply for the load.

There are several approaches to minimizing the impact of such fluctuations and the coordinated use of all these approaches can reduce the impacts of variable generation from PV plants. Some of the approaches are:

Reactive power injection: Voltage control can be achieved through reactive power injection from PV inverters.

Geographical dispersion: With the installation of many geographically dispersed PV plants, short term intermittency of PV generation can be reduced since the shading effect of cloud passages is not synchronized as is the case when a large percentage of the solar generation is in a small geographical area.

Solar forecasting: Reliable solar forecasting and management tools can be used to provide forewarning that output is likely to vary. Such warnings can be responded to by preparing alternative sources of power like increasing spinning reserves and/or curtailing a portion of PV output beforehand so that the ramp rate of existing on-line generation can be reduced.

Storage: Various types of energy storage technologies including batteries, compressed air, super capacitors, flywheels and pumped hydro can be used to regulate power output. In addition, storage can also be used to provide several other services like peak shaving, load shifting, demand side management, and backup power during outages.

3.2.2 Diesel-PV hybrid grids

The most common technology used for electricity generation in the Pacific islands is diesel generators. The availability of relatively low-cost generators with flexible sizes to meet the local demand requirements has made it the only economic choice in the islands if hydro energy is not available. The increasing integration of the highly variable outputs of PV plants with existing diesel power plants has given rise to new grid integration challenges. These include maintaining reliable grid services, properly controlling grid voltage and frequency, the additional monitoring and control requirements required with many generating sites, changing the existing grid to provide for the new solar generation and training of personnel to operate and maintain the solar installations.

The major advantage of using PV power sourced plants is to reduce diesel fuel consumption due to reduced power output from the diesel generators. But with increasing PV integration into the grid, there is increased power output variability resulting in the need for diesel generators to stay online and act as a spinning reserve, often running at low load conditions. Generators when operated at frequent low load conditions with numerous start-stops can reduce the operating efficiency and also have safety and reliability implications in the long run. This increases the generator operation and maintenance costs and if not properly handled can result in plant failure.

Most diesel generators run efficiently when operated at more than 30%-40% of their rated capacity. One method of increasing efficient and safe operation of diesel generators is to limit the power capacity of the installed solar PV. With Diesel-PV Hybrid systems allowing low or medium PV penetration, control strategies can be adapted to limit PV power produced when higher levels of PV variability is forecast in such way that the risk of operating diesel generators at low load conditions is reduced. However, when this sort of power curtailment strategy is implemented for Diesel-PV Hybrid systems with high PV penetration, there can be a huge loss of PV generated power if grid stability is to be maintained through PV generation curtailment. In such cases, it is recommended that grid energy storage is included to ‘fill in the gaps’ when the PV output varies beyond acceptable values. High quality PV resource data is required for these control equipment to be automated with high accuracy as part of the power plant’s Operation and Maintenance strategy.

The existing diesel generators in the Pacific Islands are mostly traditional types that are not be equipped with the complex control equipment needed to directly integrate with PV inverters and manage PV variability when PV inputs exceed 20% or more of the peak power going into the grid. Hence replacement or upgrading of existing diesel generators to better integrate with PV systems should be considered during the initial design and investment stage of the project. Many modern inverters now employ complex communication and control architectures to increase savings on fuel usage in hybrid power plants. These systems allow communication interfacing between the PV plant and the diesel generator control systems to maximize fuel savings without greatly reducing the overall output of the solar PV installation.

3.2.3 Grid-derived voltage fluctuation

PV inverters are usually required to operate in grid ‘voltage-following’ mode and to disconnect from grid when the grid voltage or frequency swings outside the limits set as per the utility requirements. The inverters must comply with this requirement to ensure suitable power quality as well as protect against any unintentional islanding. Often, these same inverters are also used, in large numbers, for larger scale PV systems. However, the disconnection of a large PV plant in response to a voltage or frequency disturbance can depress the voltage on transmission and distribution networks over large geographical areas and engender near simultaneous tripping of a large number of other power sources that are designed to be disturbance sensitive. This sort of disturbance sensitivity of inverters can pose a high threat to bulk power system security, especially in high PV penetration scenarios.

To avoid this from happening, voltage tolerance limits can be further widened, and Low Voltage Ride-through Techniques (LVRT) may be incorporated into inverter design. Inverters with LVRT can tolerate moderately low voltage for a defined period but still disconnect rapidly if the grid voltage drops below a set level. In European countries, where there is high penetration of PV, there is a growing recognition that PV inverters may contribute to the bulk grid during disturbances, even when they are connected to distribution networks. For example, in Germany, inverters connected to distribution networks are also required to have LVRT capabilities.

Inverters can also be configured to operate in voltage-regulating mode, wherein inverters make use of reactive power to influence network voltage. However, allowing this should not interfere with any islanding detection system. In voltage-regulation mode, inverters inject reactive power to boost network voltage during voltage sags and absorb reactive power to reduce network voltage during voltage rise.

3.3 Reactive power control

Reactive power management is critical for maintaining proper voltage levels in the electricity network. When voltage levels are too low, reactive power can be generated to raise the voltage, or reactive power can be absorbed to lower the voltage level when it is too high. Depending on the local standards and grid requirements, large-scale PV systems must generally include reactive power control capabilities of 0.95 or 0.90 lag-to-lead power factor at the point of interconnection.

Most utility-scale inverters are capable of monitoring and interacting with the grid to provide reactive power support. Depending on the direction of the reactive power flow from the grid, the inverter can increase its apparent current output to either increase or decrease the grid voltage. While this additional current doesn’t affect the amount of electricity generated from the PV array, when the inverter is not operating at unity power factor, there is a slight loss in operating efficiency (approximately 0.1%). While the benefits of reactive power control outweigh this small loss in efficiency, it means that manufacturers must consider this in their designs. Manufactures may choose to make the maximum current capacity available for real power, or have a higher current rating to leave some reserve reactive capability when operating at its rated real power. For example, the SMA inverter given in Table 1, has the same real (kW) and apparent (kVA) power ratings, which means that when operating at peak output it is actually only capable of producing 720 kW at a power factor of 0.9 (800 kVA x 0.9 PF). On the other hand, the AESE inverter has a higher apparent than real power rating. This means that when it is operating at full capacity, it is capable of delivering close to its real power output at a power factor of 0.9: 1100 kVA x 0.9 = 990 kW. It is important for the system designers to understand these different ratings so that the loss of real power can be accounted for when modelling system yield and performance.

Table 1: Comparison of the reactive power control specification for different inverter models

Manufacturer	Model	kW rating	kVA rating	PF range at kW rating	Full PF range	Reactive capability at night	Realpower dependant PF	Inverter-level voltage control	Var ramp rate control
AESE	AE 1000NX	1,000	1,100	0.91 lag to 0.91 lead	0.80 lag to 0.80 lead	N	Y	N	Y
Bonfiglioli	RPS TL-UL 1000	1,200	1,333	0.90 lag to 0.90 lead	0.85 lag to 0.85 lead	N	Y	Y	Y
Eaton	Power Xpert Solar 1670kW	1,670	1,830	0.91 lag to 0.91 lead	0.00 lag to 0.00 lead	N	N	N	Y
Schneider	XC 680-NA	680	680	NA	0.80 lag to 0.80 lead	Y	Y	N	N
SMA	SMA SC 800CP-US	800	800	NA	0.80 lag to 0.80 lead	Y	Y	Y	Y
Solectria	SGI 750XTM	750	750	NA	0.80 lag to 0.80 lead	N	Y	Y	Y

3.4 Independent power producers

Independent grid-connected residential, government and commercial building PV systems are not uncommon in the islands and the impact of these independent power producers on the utility grid should be considered when implementing control strategies for the large scale PV system connected to the power grid. The power from these independent producers may decrease intermittency in the grid if they are geographically dispersed. However, when there is excess PV power from a grid-connected residential PV system, there can be a voltage rise at this section of the grid due to the power exported to the grid. The utility control model should be designed to be able to analyse and foresee these voltage changes along the grid circuit to avoid any disturbance. Further grid abnormalities such as power quality, voltage and frequency stability, harmonics, protection and security issues can be caused at the grid interconnection points.

If a grid-connected system services multiple buildings, e.g. in a large school or medical centre, it may constitute a 'micro-grid' where its control system needs to interface with the utility's monitoring and control systems, including the utility's SCADA system, to ensure that efficient interoperability of the micro-grid and the utility is established. Hence the micro-grid should use the same protection, automation and communication protocols as the utility's standards as there is not yet any single standard for communication interfacing in the PV industry.

4. Operation and Troubleshooting of Solar Systems - Solar Farms in Particular

Note: This section has been written with a focus on the large ground mounted systems that have been installed in the Pacific Islands. It has been aimed at adopting a practice of undertaking systems inspections quarterly. The information provided is relevant for all systems, however for smaller roof type systems that might be owned and maintained by the electricity utility some of the inspections might not necessarily be undertaken quarterly.

4.1 Monitoring performance

4.1.1 Weather monitoring

Weather monitoring is essential in order to evaluate and predict the PV plant's performance throughout its lifetime. The output data from the plant should be measured continually and adjusted using the actual weather parameters before comparing with the design values. This is because the output of PV systems constantly changes depending on the meteorological conditions of solar radiation and temperature. Weather data is also essential for analysing the weather pattern at the site in order to provide the data needed to forecast power generation from the solar installations based on weather forecasts (see Figure 10). Such analyses are also valuable for scheduling of O&M activities, setting control parameters for grid support and evaluating performance.

Figure 10: Energy production forecasts based measured weather data. This PVGuard HMI shows a) clear display of weather data and b) output forecast to hourly resolution compared to actual production. Source: Skytron

The solar irradiance and other relevant environmental conditions like temperature, wind speed and direction, precipitation etc. can be obtained using three methods:

- On-site weather stations – These are the most accurate and common methods employed to monitor and record data like tilted array and horizontal irradiance, module temperature, humidity, wind speed. These include a range of meteorological instruments installed on site (Figure 11) and these may include but not limited to those given in table 2. Remote data collection allows comparison of yield on daily basis and for immediate fault detection.

Note: The weather stations shown in Figure 11 do reflect some that are used in the industry, however in the Pacific because the sun can be in both the northern and southern hemisphere at various times in the year shading will occur on the pyranometer. It is best to locate a pyranometer on the array at the same tilt angle.

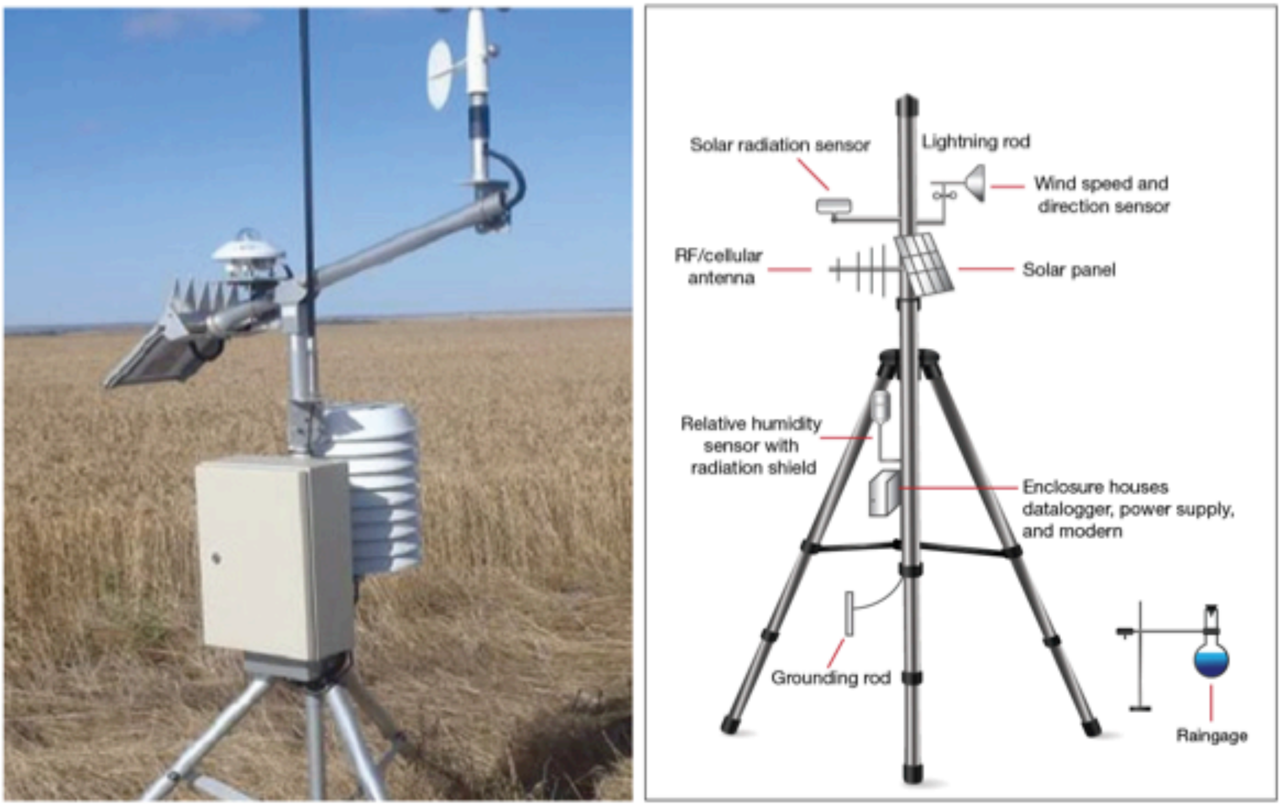

Figure 11: Automated weather monitoring station used for solar farm performance monitoring.
Source: First Solar

Table 2: Typical solar farm weather monitoring components

System Components	Function	Specifications
Pyranometer	Measures global horizontal irradiation (GHI, W/m^2) from a field of view of 180 degrees. Ventilation is essential.	- Spectral range: typically 300-2,800 nm - Sensitivity (Referring to accuracy with very low error margins) - Operating temperature range and temperature dependence - Maximum solar irradiance - Response time
Pyrheliometer	Measures direct normal irradiance (DNI)	- Spectral range - Sensitivity (Referring to accuracy with very low error margins) - Operating temperature range and temperature dependence - Maximum solar irradiance - Response time
Anemometer and wind vane	Measures wind speed (m/s) and direction	- Wind speed range (m/s) - Starting threshold (m/s) - Wind direction range and delay distance - Operating temperature range - Accuracy (both speed and direction)
Relative humidity sensor	Measure relative humidity	- Sensing element material - Humidity range - Temperature operation range - Response time - Accuracy of measurements
Temperature probe	Measure ambient air temperature	- Temperature range - Accuracy of measurements
Surface temperature thermistor	Measure solar module temperature	- Temperature range (needs high temperature tolerance - Linearity - Accuracy of measurements

System Components	Function	Specifications
Ambient dust monitor	Monitor ambient dust (in g or mg) per m^3 of air	- Measurement principle - Concentration range (mg/m^3 or g/m^3) - Concentration sensitivity - Particle size range and particle size sensitivity - Humidity, temperature and pressure range - Accuracy of measurements - Flow rate (m/s)
Barometer	Measure pressure	- Sensor material - Digital or analog output - Operating temperature - Measurement range - Accuracy of measurements
Rain gauge	Measures precipitation	- Sensor material - Sensitivity - Accuracy of measurements

- Meteorological data gathered from weather satellites – Weather data is collected from satellites removing the need for some on-site meteorological instruments. Simulations and complex algorithms measure and calculate the estimated PV plant output and are compared with daily plant output. These are available as packaged solutions and depend hugely on data from satellites and their capability of quick analyses.
- Local weather stations – Few Pacific Island weather stations track accurate conditions at the site of solar installations and have the necessary data available for power plant operations, hence this is the least desirable option for obtaining solar and weather data for a large-scale PV power system.

4.1.2 Cloud Monitoring

In recent years many research institutes and solar companies have been researching cloud monitoring. These systems comprise a number of cameras "observing" what is happening with clouds. Software algorithms are being developed to:

- Provide advanced forecasts of clouds affecting solar systems;
- Detect cloud formation in clear sky areas for advanced warning of shade events
- Have a number of cameras located around a network to facilitate more accurate wider area forecasts.
- Predict PV power based on direct and global irradiance values based on past measurements and cloud forecasts.

4.1.3 Monitoring System Performance

Knowing what is the expected power output of the system based on the monitored irradiance or the total expected daily energy output based on the monitored irradiation will allow the operational personnel to determine if the system is underperforming. Section 4.2.2 covers the diagnosis of low power production in more detail.

4.1.4 Monitoring for Faults and Failures

Faults and failures in the system can range from being very minor, such as a temporary ground fault due to rain, to serious issues such as output from the plant failing to synchronise with the grid in terms of voltage, PF or frequency. Either way, it is important that operations personnel are notified in some way of the fault or failure so that appropriate action can be taken based on the severity of issue. For example, if a blown string fuse is detected, it may be more economic to have it replaced during scheduled maintenance rather than sending maintenance personnel out to the site to fix it immediately. However, if a tripped breaker is detected in the ac switchgear, it is likely that an immediate response is necessary, as this would affect a large portion of the PV plant, and may reduce its yield significantly.

String monitoring remains the convention, but as systems become increasingly larger, the level and type of monitoring may change over time. String faults will be detected by string monitoring which are basically current transformers, and are typically built into string combiner boxes. dc isolation is also built into string combiner boxes, and often has the ability to remote trip when signalled by the SCADA system.

Monitoring provided at the inverter level will provide the majority of fault detection capability. These days most utility-scale inverters are embedded with monitoring capabilities which typically include:

- Monitoring voltage, current, power and energy (daily, monthly, lifetime) for the sub-array that they are connected to
- Keeping a fault log, including residual current levels and ground fault detection
- Providing active inverter comparison (where inverter output is compared in real time against predefined tolerances)
- Showing communication (comms) status (i.e. any comms dropouts, length of time without comms, etc.)
- Showing inverter attenuation level based on SCADA or network control. Inverter monitoring also generally records a myriad of grid-side status and fault information including line voltage, frequency, power factor and insulation resistance. It may also record more detailed grid parameters such as vector shift, rate of change of frequency, and total harmonic distortion.

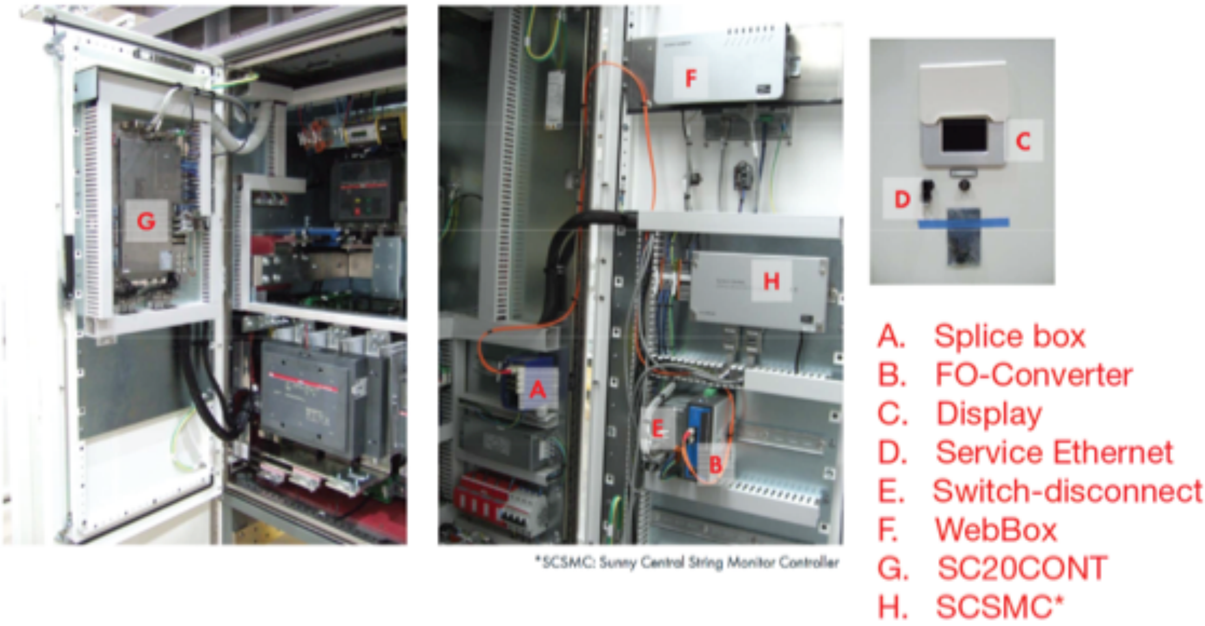

Figure 12: Inside an SMA Sunny Central CP inverter with string monitoring equipment.
Source: SMA Solar Technology

The operational personnel may be notified of a fault or failure in the system via either of the following ways:

- An alarm or error report sent from the monitoring system
- Routine inspection conducted by maintenance personnel
- Performance analysis of the power plant
- An alarm or error report sent from a third party such as a customer or a network services provider.

4.1.5 Supervisory Control and Data Acquisition (SCADA) Systems

Large scale PV power plants require a range of data acquisition and control equipment. The system, which combines this equipment and the communication network that connects them all, is called the SCADA system. The SCADA system brings in field information from the weather station, string monitoring, inverters, step-up transformers, switch gear, site security system etc. The SCADA system will parse the information in real-time to ensure the system is operating as expected and will trigger alarms if it is not. The SCADA system may be able to respond to information with automatic controls or may need operator input using a human machine interface (HMI).

The basic frameworks comprising the SCADA system are:

- **Field devices** that include transducers (i.e. CT's, VT's, weather station equipment, etc.) and operational control gear (i.e. contactors, motorised circuit protection, relay state indicators, etc.).
- **Remote Telemetry Units (RTUs) and Programmable Logic Controllers (PLCs)** that connect the field devices to the communication system for data collection, aggregation, analysis and response.
- **The communication architecture** that consists of the infrastructure and protocol for data packaging and transmission. The actual communication infrastructure may use power-line communications, analogue or digital control cables, ethernet or fibre optic communication cable or use any number of wireless protocols.
- **SCADA host platform** that takes the data from RTUs and PLCs, stores and processes it to show graphical displays, trends, trigger alarms and generate reports.

- **The human machine interface (HMI)** that most often uses a graphical user interface (GUI) setup to connect human operators with process monitoring and control.

The SCADA system becomes more complex if fixed grid restrictions (i.e. connection to a local diesel grid) or grid support functionality is included in the system. This requires more field devices and more complex monitoring hardware and software.

The SCADA host platform should back-up all the information retrieved from the system including information on performance, production and maintenance, status reports, etc. in an archiving server which ensures that the data is available in case the system crashes or becomes corrupted. The historic archive is usually backed up on both local and remote workstations for additional redundancy.

Given plant information and weather monitoring, it may be possible to compare the plant's output in real-time to a predictive model of energy performance, for rapid identification of faults.

4.2 Inspecting in accordance with standards and guidelines

The inspection and hands-on maintenance of site and equipment shall be carried out at regular scheduled periods to identify existing problems if any and prevent any future issues that can compromise uptime of the PV power plant. A checklist shall be used for the specific PV plant's thorough inspection and manufacturer's recommendations shall be followed where required.

At the time of installation, the PV system should have been tested and commissioned in accordance to the following standards:

IEC 62446-1 Photovoltaic (PV) systems - Requirements for testing, documentation and maintenance - Part 1: Grid connected systems - Documentation, commissioning tests and inspection

IEC 62446-3 Photovoltaic (PV) systems - Requirements for testing, documentation and maintenance - Part 3: Photovoltaic modules and plants - Outdoor infrared thermography

The systems can also be inspected in accordance to the following standards if the country is following the Australian and New Zealand Standards:

- AS/NZ 3000 Wiring Rules.
- AS/NZS 3008 Electrical Installations-Selection of Cables.
- AS 4777.1 Grid connection of energy systems via inverters: Installation requirements.
- AS 4777.2 Grid connection of energy systems via inverter: Inverter requirements.
- AS/NZS 5033 Installation and Safety Requirements of PV Arrays.

If the country is following the NEC standards then the system can also be inspected in accordance to the following standards:

- Electrical Codes-National Electrical Code and NFPA 70:
    - Article 690: Solar Photovoltaic Systems.
    - Article 705: Interconnected Electric Power Production.
- Building Codes- ICC, ASCE 7
- UL Standard 1703 Flat Plate Photovoltaic Modules and Panels.
- IEEE 1547 Standards for Interconnecting Distributed Resources with Electric Power Systems.

Note: Sample inspection sheets based on the Australian and New Zealand Standards and the NEC have been developed as separate documents that can then be altered to apply to the particular system being inspected. These have been developed to be followed when system is initially installed. The tables in next section refer to the regular inspections relevant to operation and maintenance of a system.

4.2.1 Inspection checklist

The following tables discuss general inspection activities to be carried out on major power equipment and accessories in PV plants. As a general rule, it is crucial to follow the following points while carrying out a general inspection on any equipment in PV plants.

- Comply with all warning placards including arc flash or Personal Protection Equipment (PPE) requirement for accessing equipment. If some placards or labels are absent or missing, it should be noted and missing placards or labels should be immediately installed during the next maintenance visit.
- All activities, except those that explicitly need power on the equipment, must be carried out after proper shut down and de-energising of the equipment.
- Instructions for cleaning inside the cabinet are usually manufacturer specific. As a rule, a vacuum type cleaner is used to do cleaning whereas pressurized air is not preferred in order to avoid a dust cloud or imbedding of dust particles.
- Depending on the size, location and accessibility of the system to unqualified personnel, all equipment should require tools or have locks to prevent any unauthorized access. Replace any missing locks, and after completing the inspection activities, ensure the equipment locks are locked again.
- The recommendations made in this section for maintenance inspection activities and their frequencies are generic. For safety reasons, several of these activities require isolating and de-energising equipment prior to conducting the activities. Refer to the maintenance manual from the manufacturer for detailed and specific instructions. Beware not to void any warranty requirement. Contact the installer and/or manufacturer about any issues found.
- Document findings for all works performed during each visit to the PV plant.

4.2.1.1 Site Inspection

Note: All the inspection checklists have been written generally and not all systems will have to undertake the checks as listed. Each checklist should be customised to suit each system.

Table 3: Site Inspection Checklist

Frequency	General inspection Activities	Remedial actions
Quarterly	Check for shading on solar modules or other items such as weather monitoring sensors due to vegetation growth	Remove such vegetation and, if the shading is detrimental and likely to reoccur, relocate the shaded device
Quarterly	Check if proper signage and warnings are in place	Replace any missing signage and warnings
Quarterly and after any heavy rain	Check for ground erosion near the base of ground mounting structure	Investigate the cause of erosion. If the mounting structure is inclined at unacceptable angle, readjust it. Refill the area with soil and tamp.
Quarterly	Confirm the conduits are connected using appropriate expansion joints	Replace as required

Quarterly	Confirm the conduits are connected using appropriate expansion joints	Replace as required
Quarterly	Confirm electrical enclosures are accessible to authorized personnel only. Check for appropriate signage and security padlocks	Replace locks as required
Quarterly	Check for corrosion outside of enclosures and the framing (racking) system	Repair or replace as required
Quarterly	Confirm the cleanliness throughout the site	If dirty, clean the site
Quarterly	Check for loose hanging wires in the array	Rearrange and tighten the wire appropriately
Quarterly	Check for signs of animal infestation under the array	Get rid of such animals from the site. Employ appropriate measures to prevent any infestation in future
Quarterly	Check for any signs of theft or vandalism	Replace the missing or damaged equipment. Employ appropriate security measures to prevent such activities in future
During each visit	During each visit Document findings for all works performed	

4.2.1.2 PV Array, Mounting System and Wiring

Large-scale PV systems are usually ground mounted systems and have extensive framing (racking) systems that might be prone to corrosion. Some foundations for array structure supports use galvanised steel poles set in concrete or screwed or driven into the ground. The systems are sometimes installed specific to the site with modifications that might not be recommended by the manufacturer and these should be identified during the inspection. Regular visual inspection for defects like corrosion, degraded concrete bases, missing or broken cable clips or missing bolts shall be carried out. The PV array mounting structure, cables, conduits and other support structures shall be inspected periodically for mechanical integrity and for signs of corrosion. This inspection can also help identify signs of top soil layer erosion which can destabilise the PV array structure.

PV modules shall be inspected for dirt, debris or bird droppings and the proper cleaning of module surfaces shall be scheduled accordingly. PV modules may also be discoloured due to contamination, thermal damage or more serious issues such as breaking and cracking, resulting in a noticeable performance loss. Relevant inspection tasks include:

- Inspect PV modules for damage such as hot-spots (using infrared camera), corrosion or delamination
- Check connection and string wiring condition (e.g. loose plugs, insulation conditions)
- Identify and replace broken and damaged PV modules
- Check serial numbers as documented and correct documentation to reflect changes
- Measure string I-V curves

Table 4: PV Array, Mounting System and Wiring Inspection Checklist

Frequency	General inspection Activities	Remedial actions
Quarterly	Inspect PV modules for defects such as burn marks, discolouration, delamination, or broken glass	Replace any defected PV module
Dependent on site-as required	Check modules for excessive soiling from dirt build-up, debris or bird droppings.	Clean small traces of soiling by spraying demineralized water. Follow array washing procedure if array cleaning is decided by the O&M management
Quarterly	Confirm that the module wiring is not hanging loose, resting on the surface, bent to an unapproved radius, stretched across sharp or abrasive surface. Check for any visible damage to wire insulation	Rearrange the wires to proper wiring condition. Repair or replace any damaged wires

Quarterly	Inspect framing (racking) system for defects including rust, corrosion, sagging, and missing or broken clips or bolts	Repair any such defects
Quarterly	Check conduits for proper support, bushings, and expansion joints, where needed	Replace or add as required
Quarterly	Check for the signs of corrosion near the supports in ground mounted systems	Repair or replace as required
Quarterly	Check the continuity of equipment earthing (grounding) randomly throughout the array, mounting frames and lightning protection termination	Locate the discontinuity in earthing (grounding) system and repair as required

The inspection of cables ensures system integrity. Any loose cable connections should be identified and immediately tightened. Large scale PV systems can be located on agricultural land with cables buried in conduit in the ground. After the commissioning period, when a solar plant goes into full operation, the ground on the construction site may gradually stabilize. Ground movements due to stabilization or erosion due to flood or water run-off can break the conduit and system cables buried underneath thus increasing safety risks by creating danger of shock, or even fire due to damaged cable insulation. To identify possible conduit breaks resulting in cable damage, the insulation on cables should be monitored regularly.

Table 5: Combiner Boxes Inspection Checklist

Frequency	General inspection Activities	Remedial actions
Quarterly	Large PV arrays might have combiner boxes (dc and/or ac) mounted in a switchboard type enclosure and mounted on a concrete pad. If so, inspect the pad to ensure it does not show excessive signs of cracking or wear. Confirm that the equipment is properly bolted to the pad as per the manufacturer installation requirements	Repair any such damage or compromise in mounting
Quarterly	Check the status of indicator LEDs, where applicable, on boards, communication equipment, enclosure within the combiner box	Follow the instructions per error message
Quarterly	Open combiner boxes and check the connections	Tighten all loose connectors after de-energizing all connections
Quarterly	Look for the signs of dust, water or any foreign body intrusion into the combiner box	Clean inside the combiner box after de-energizing all connection
Quarterly	Check for any vegetation growth or debris or equipment around the pad	Remove any such thing around the pad
Quarterly	Look for discolouration or corrosion or damage on boards, terminals, disconnector and fuse holders	Repair or replace as required after de-energizing the connections in that part of the system
Quarterly	Look for the end of life indicators in surge arresters	Replace the damaged ones
Quarterly	Check fuses	Investigate the cause of blown fuse. Replace any blown fuse as per the instruction manual (do not take the rating of the blown fuse as the reference for replacement)

Quarterly	Check the continuity of equipment earthing (grounding) in each combiner box	Locate and repair any discontinuity in earthing (grounding) circuit
Quarterly	Measure open circuit voltage (V_{OC}) of all strings after following the inverter isolation procedure	Note: This is not required if the monitoring system indicates the operating voltage of each string

4.2.1.3 Inverters

An inverter can be damaged in several ways. Failed inverters may cause performance failure of the large scale PV system because they are the core components for grid-connected solar systems which transform the dc electricity from solar modules into ac electricity compatible with the grid. Basic maintenance of inverters can use simple methods such as general cleaning to remove any dust ingress. Regarding detailed inverter inspections, for large inverters (e.g 1 MW) that require very specialised knowledge, there are many manufactures offering professional inspection services for their own products. Inverter inspection involves measuring conversion rates (maximum, minimum and average), comparing inverter performance with solar irradiance, removing insects, inspecting and cleaning the ventilation system, and checking cables to ensure that the inverter is correctly connected.

Table 6: Inverters Inspection Checklist

Frequency	General inspection Activities	Remedial actions
Quarterly	Large inverters might be mounted on a concrete pad. If so, inspect the exterior of inverter pad for any signs of excessive cracking, wear, or corrosion. Confirm that the equipment is properly bolted to the pad	Repair any such damage
Quarterly	Check for any vegetation growth or debris or equipment around the pad	Remove any such foreign materials from around the pad
Quarterly	For smaller string inverters that are mounted on the array frame structure, check the mechanical integrity of the inverter mounting system	Rectify as required
Quarterly	Check for any vegetation growth or debris or equipment around the pad	Remove any such foreign materials from around the pad
Quarterly	Look for the signs of dust, water or any foreign body in the inverter. Check for dust accumulation in filters and ventilation area	Clean inside of the cabinet, filters and ventilation area. After isolating the inverter from both dc and ac systems

Quarterly	Check for any abnormal operating noise	Discuss with the service providers
Quarterly	Record and validate all voltages and production values from the human- machine interface (HMI) display. Check all status indicators and record last logged system error	Follow instructions per error message
Quarterly	Ensure fans are properly operating	Repair or replace as required
Quarterly	Check tightness of all terminations	Tighten the loose connectors after isolating the inverter from both dc and ac systems
Quarterly	Check gasket seal (if appropriate)	Replace as required
Quarterly	Check tightness of all terminations	Tighten the loose connectors after isolating the inverter from both dc and ac systems
Quarterly	Look for discolouration or damage due to excessive heat build-up inside the cabinet	Confirm if fans, ventilations, and filters are in proper condition and call for service
Quarterly	Look for the end of life indicators in surge arresters	Replace the dead ones
Quarterly	Check fuses	Investigate the cause for blown fuse. Replace fuse as per the instruction manual
Quarterly	Confirm the continuity of equipment earthing (grounding) and system earthing grounding	Locate and repair any discontinuity in grounding
Quarterly	Check for operation of the earth (ground) fault monitoring unit	Troubleshoot the earth (ground) fault and replace any failed component in the earth (ground) fault monitoring unit as per manufacturer's instructions
Annually	Confirm that current software in installed	If not installed, call for service

Quarterly	Check the operation of ac and dc disconnect/circuit breaker on inverter or located beside the inverter	Replace as required or call for service
As per manufacturer's instruction	Maintenance of internal dc disconnect and ac circuit breaker	Replace or repair as required or call for service

4.2.1.4 Data Acquisition System

Table 7: Data Acquisition System Inspection Checklist

Frequency	General inspection Activities	Remedial actions
Quarterly	Record the status of all indicators and/or error messages in the data acquisition system	Follow the instructions per error message
Quarterly	Check for dust, water or any foreign body intrusion inside the electronics	Clean the equipment
Quarterly	Measure voltages of power supplies	Replace power supply if abnormal voltage on power supply is measured
Quarterly	Validate all readings, if applicable, including temperature, irradiance and voltage measurements by comparing to calibrated equipment	Recalibrate or replace sensors as required. Call for service is if the problem persists
Quarterly	Ensure that the sensors of the weather station are in the correct location and at the correct tilt and direction	A global irradiance sensor must be mounted horizontally, and an array plane irradiance sensor must be tilted in the plane of the array. A module surface temperature sensor should be mounted on the back surface of the module, away from the frame
Dependent on site - as required	Check if irradiation and temperature sensors are dirty	Clean the sensors

4.2.1.5 Substation System

Transformer leakage should be dealt with great concern since oil spills not only cause land contamination, but also brings safety risks to site workers. To prevent accidents, several parameters are to be set at standard values and automatic alarms should be included as part of the pre-warning system.

Table 8: Auxiliary Transformer Inspection Checklist

Frequency	General inspection Activities	Remedial actions
Quarterly	Check the unprotected surfaces and base for corrosion and other signs of wear and tear	Repair as required

Table 9: Step up Transformers Inspection Checklist

Frequency	General inspection Activities	Remedial actions
Quarterly	Inspect the exterior of the transformer pad for any signs of excessive cracking, wear, or corrosion. Confirm that the equipment is properly bolted to the pad	Repair any such damage
Quarterly	Check for any vegetation growth or debris or equipment around the pad	Remove any such foreign materials from around the pad
Quarterly	Check for any abnormal operating noise	Discuss with the service providers
Quarterly	Check the tank exterior for signs of leaks	Repair any such leaks
Quarterly	Check for the proper operation of gauges and controls	Repair or replace defective equipment
Quarterly	Look for the signs of dust, water or rodent intrusion into the transformer. Check for dust accumulation in filters and ventilation area	Clean inside of cabinet, filters and ventilation area

Quarterly	Inspect fuse mountings and switches. Look for signs of any liquid seepage around gaskets, seals, etc.	Repair or replace as required
Quarterly	Check oil level gauge	Check for the signs of leaks if oil level is below the nominal level. If none, refill oil to normal level
Quarterly	Ensure the tank pressure and fluid temperature are within the normal operating range	If tank pressure has been below the nominal level for a long time, check for signs of leaks and make repairs as needed. If the fluid temperature is elevated, call for transformer service immediately
Quarterly or after each trip	Check for damaged lightening arresters	Replace damaged arresters
Quarterly	Look for any signs of dirt or damage in LV and HV bushings	Clean out any dirt in the bushings. Call for service from a qualified technician to repair any damage
Quarterly	Check the torque marks on all connectors	Tighten any loose connector
Quarterly	Confirm the continuity of equipment grounding and system grounding	Locate and repair any discontinuity in grounding
As per manufacturer's instructions	Perform maintenance of ac circuit breaker	

The above table shows checklist for general inspection for maintenance for outdoor oil immersed self-cooled pad mounted transformers. These are the most common types installed for large PV power plants.

Table 10: HV Switchgear Inspection Checklist

Frequency	General inspection Activities	Remedial actions
Quarterly	Inspect the exterior of transformer pad for any signs of excessive cracking, wear, or corrosion	Repair any such damage
Quarterly	Check for any vegetation growth or debris or equipment around the pad	Remove any such thing around the pad
Quarterly	Check for any abnormal noise	Talk to the service providers
As per manufacturer's instruction	Perform maintenance of switchgear	Remove any such thing around the pad

Prior to commencing any activity on HV Switchgear or the transformer that involves the risk of electrical hazard, the transformers need to be electrically isolated and de-energised by the electricians licensed to work on HV systems. After that, the O&M personnel can carry out the maintenance inspection safely.

4.2.2 Diagnosing and testing for low power production

Low power production from PV plants can result from various causes like soiling and shading of arrays, equipment failure, defects in meters, etc. The losses from such events may be substantial, and O&M personnel need effective strategies for identifying and solving problems quickly. Sound knowledge in handling and interpreting the results from several diagnostic tools including an IR camera, IV tracer, etc. is an essential component of such strategies. Plant operators can be aware of underperformance of the system through any of the following means:

1. An alert from DAS (Data Acquisition System)
2. Manual review of DAS data can also reveal performance related problems.
3. Comparing present performance with past data trends and identifying any drastic or gradual trend in reduction in output.

4.2.2.1 General diagnosis

After confirming the underperformance, a diagnosis procedure appropriate to the installation should be employed to find the actual cause of the problem. Depending on the size of plant and availability of diagnostic tools, the diagnosis can have different approaches. In general, the diagnosis approach includes the following steps:

1. Estimate the losses due to low performance of plants by comparing the weather corrected performance data with actual data. Perform a cost benefit analysis of carrying out maintenance by weighing the cost of maintenance and potential revenue recovery and dispatch a crew to the site for maintenance accordingly. In the meantime, any anomaly resulting in underperformance, that can incur high cost in the backend, such as a ground fault, should be considered for maintenance even though the resulting loss at the time of fault detection is not substantial.
2. Check and compare the readings on meters at different stages. For example, the readings from utility metering can be compared with those from inverters in total. The difference, if present, might be a result of several events, including an instrumentation problem. One phase can have a different output from the others (can be checked in DAS) due to a bad current transformer (CT) or a blown fuse in the CT circuit. If the CT circuit is working fine, call an HV technician to find any fault on the HV side.
3. If no difference is observed in recorded values, use the HMI of the inverters, if applicable, to identify any inverter error. Follow the instruction manual from the manufacturer to interpret and resolve the problem.
4. If individual strings are being monitored, this helps narrow down where the poor performance is occurring. Some large systems use many individual string inverters, so monitoring of those can also help locate where the system might be underperforming. Sometimes it is only sections of the array that are suffering a higher soiling issue from dirt, dust or salt mist build up causing reduced output.
5. Using an I-V curve tracer, verify the performance of each group of strings and narrow down the zone of error to a few strings. Also, check if the array MPP voltage is in the MPP tracking window of the inverter.
6. Look for any external causes of low output, such as shading of arrays due to vegetation or other structures. Take photographs of the site during commissioning to enable finding any new source of shading that was not present when the system was built and keep a record of any noticeable differences.
7. Perform the following general tests as required to identify problems:
    a. Check all the fuses at the inverter and work from there out to the combiner boxes
    b. Perform V_{OC} string testing.
    c. Perform I_{MP} string testing.
    d. Validate weather sensors.

e. Look for soiling. If soiling might be a problem, test an individual string (V_{OC}, I_{MP}, IV curve), clean the string following array washing procedure, and then retest.
f. Perform I-V curve tracing.
g. Take infrared (IR) images of the PV cells and module connectors if accessible.

4.2.2.2 Diagnostic testing

The procedures for diagnostic tools explained in this section are only generic. Depending on the specifics of the PV system, target equipment under measurement, measuring equipment or the test goals, the procedures and other requirements may vary.

4.2.2.2.1 IR imaging

Thermal imaging using IR cameras offers an economical and quick way to localize faults. In addition, it is one of the safest inspection methods in solar power plants, as it does not involve any contact with target equipment. A thermal imager assigns a visible graduated colour or grey scale to the image of the scene. As a rule, hotspots are displayed as white with diminishing temperatures through red-orange-yellow-green-blue –indigo-violet to black being cold. This data on the heat profile can be analysed both qualitatively and quantitatively to identify a wide range of problems, including interconnection faults, defective bypass diodes and cells, mismatch and shading in modules, and so on.

Note: On large systems, drones fitted with thermal image cameras have been successfully used to inspect for any hot spots on the arrays.

Safety requirements

- Wear appropriate PPE and adopt safety precautions while working near active high voltage systems or near hot surfaces.
- Meet all safety requirements, especially while working on heights. Sometimes, the task may even involve the use of helicopters, and the corresponding safety measures should be taken.

Testing tools required

- IR camera

For the inspection of PV modules on site, an IR camera with thermal sensitivity ≤0.08K is advisable. For long distance observations, an image resolution of at least 320×240 pixels, preferably 640×480 pixels, is recommended. Also, it is preferable to have a manual adjustment of the level and span to clearly visualize small temperature differences. During inspection of large-scale PV plants, another useful feature for an IR imaging camera would be tagging the image with GPS data to localize a faulty module in large areas.

- Clamp-on ammeter

Favourable test conditions

- To achieve sufficient thermal contrast, irradiance greater than 500W/m^2 or higher is needed. For maximum results irradiance greater than 700 W/m^2 is recommended making it necessary to do IR photographs of arrays around mid-day.
- The sky should be clear since clouds produce interference through reflections and also reduce solar irradiance.
- Wind can cause convective cooling of modules and thus reduce the thermal gradient; hence calm conditions are desirable for IR photography.
- Thermal contrast is higher when air temperature is cooler; therefore, performing thermographic inspections in the early morning is may be useful
- During rainy or wet conditions, it is not advised to work in outdoor electrical boxes.

Imaging Procedure

- Before starting an IR scan, check the inverter display for power output to verify that the PV array is operating, because when the system is not operational, the temperature difference in modules is not present.
- Setting the camera
    - Set the emissivity value to 0.95, which is enough for capturing most active components in PV plants such as modules, combiner boxes, and cables. However, thermal cameras do not properly capture some low emissivity objects, such as polished metal surfaces. If emissivity adjustment is needed, a black tape electrical tape can be fastened to the surface and emissivity can be adjusted until the taped and untaped surface show same temperature.
    - Set the camera to auto scaling rather than manual scaling to allow for automatic temperature scale adjustments. For detailed visualization of small temperature differences, level and span settings can be adjusted. Level and gain represent expected target temperature and the range above and below the target temperature respectively. For example, a setting with 200°C level and 50°C gain would have a measuring temperature range of 150 – 250°C.
- Positioning the camera
    - In order to avoid reflections of the operator and the camera itself on the target surface, especially on PV modules, the camera should not be positioned perpendicular to the module or target object. However, the thermal contrast, which depends on emissivity, is the maximum at perpendicular position. Hence, a viewing angle of 5-60° (Figure 13) is a good compromise (Source: FLIR).
    - Position the camera as close to the module as possible to get the best results. The maximum distance camera and target surface, usually in the range of 3 meters for ground observation cameras, depends on the minimum focal distance of the camera.
    - Avoid shading any part of the module while scanning for thermal images.
- In ground-mounted systems, unlike roof-mounted installations, an IR camera can also be used to inspect installed PV modules from the rear side. In this method, the measured temperature might be higher as the cells are being directly measured and not through the glass. This method benefits from having minimal interfering reflections from the sun and clouds. In addition, cabling and connectors usually will be included in the picture.
- Ground based thermal inspection of multi-megawatt scale PV plants would be highly labour intensive and time consuming, thus rendering high O&M costs. In some countries, long distance observations, for example from a helicopter, are initially performed to get valuable data for quickly localizing the zones with faults. After that, a detailed inspection can be worked out in the faulty zone. Unfortunately, this would not be practical in many Pacific Island countries. Alternatively, a new and innovative way to inspect PV modules in large-scale solar plants also includes the use of Unmanned Aerial Vehicles – UAVs (drones) for aerial thermography.
- Measure the current flowing through the circuit where hotspot is observed and make a note of it. If the current is above the rated operating range, look for signs of short circuits or insulation damage in the circuit.
- Record the module serial number, time, date, image number and module or equipment location. Also, capture a visible image of the target if any issue is detected and link it to the corresponding thermal image in the record (some IR cameras superimpose the visual image on the IR image to help locate the problem area). The combined use of thermal and visible image allows recognising, for example, the effect of shadows.

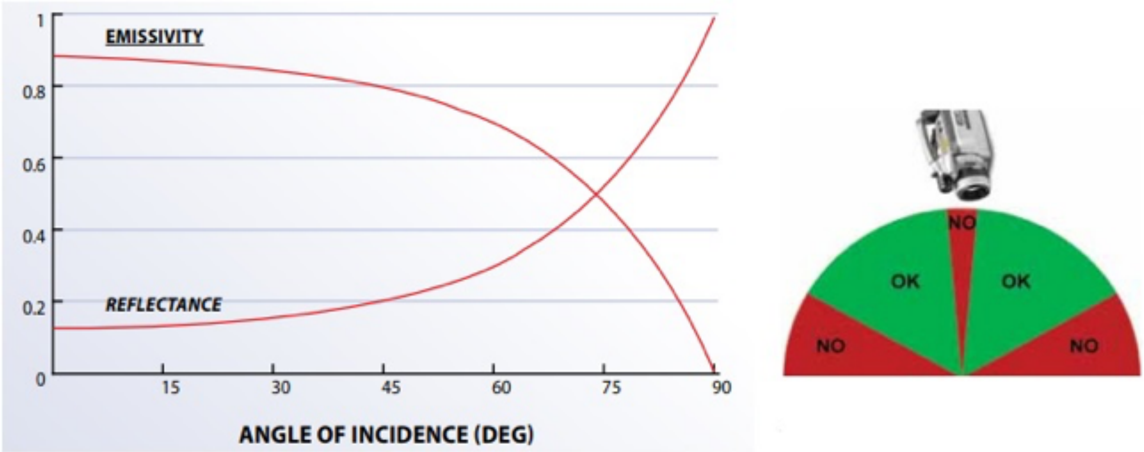

Figure 13: (left) Angle dependence of the emissivity of glass; (right) Viewing angle recommended (green) and to be avoided (red) during thermographic inspections. (Source: FLIR)

Interpreting thermal images

Shadowing and reflection from surrounding objects, for example, clouds as shown in Figure 14 (top left); and improper viewing angle can deliver inaccurate thermal images and lead to false conclusions. The technician should be skilled enough to recognize such false results and adjust the position and settings of the IR camera to get accurate data.

Any fault in the system is indicated as a relatively hot area in the thermographic image and depending on the shape and location, these hotspots can reveal a variety of faults. If an entire module is warmer than the usual ones, there might be some interconnection problems (Figure 14 - Top right). Any hotspot in a cell or part of a cell can be the result of shadowing or cracks in the cell (Figure 14 – Bottom left). Likewise, faulty diodes, internal short-circuits, and cell mismatches are revealed as hotspots or warmer patches (Figure 14 – Bottom right).

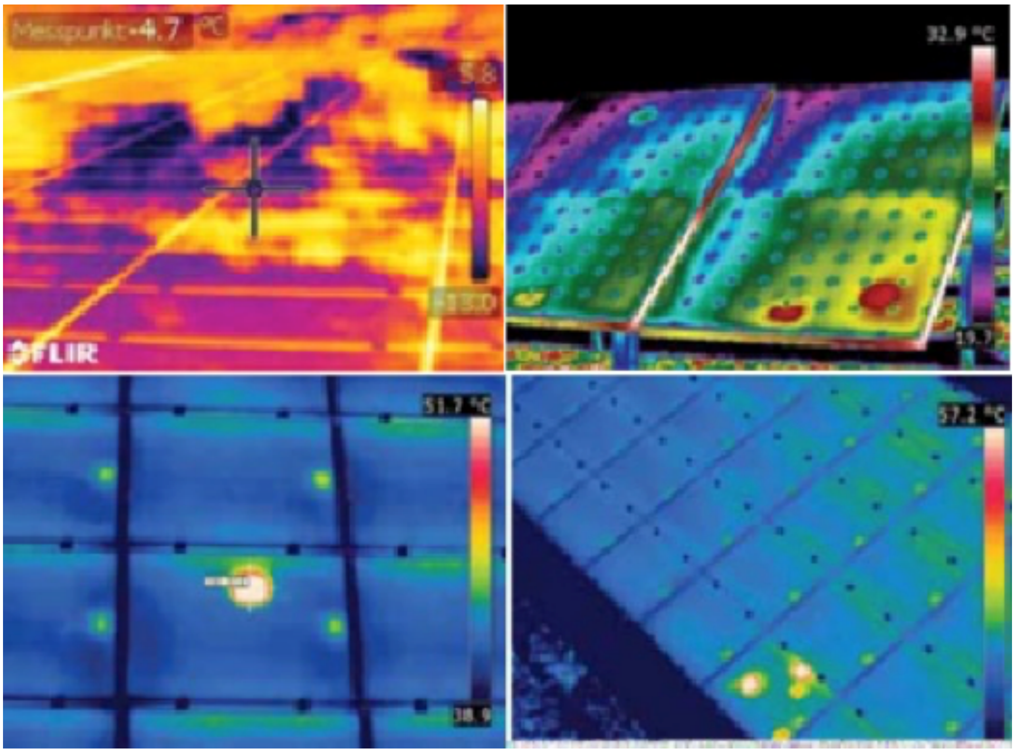

Figure 14: Thermal image of PV arrays: (Top left) distorted due to thermal image of reflection of clouds; (right top) The entire module with red spots is consistently hotter than the others indicating faulty connections; (bottom left) A hotspot in the module may be the result of physical damage or shading in the cell; (bottom right) The warmer patches indicates the module has defective bypass diodes; (source: FLIR)

Similarly, any significant difference in temperature between electrical connections along conductor lengths can be qualitatively identified as poor electrical connections or faults. Without thermography it is a very painful and tedious job to exactly locate any faulty connection through electrical measurements. To this end, thermography can be used to confirm electrical integrity in conducting cables, electrical equipment like fuses, switches, disconnects, busbars and so on (Figure 15 and Figure 16). Further, any fault in temperature alarm or DAS equipment can be revealed, if the operating temperature of inverters and transformers is above the rated limits.

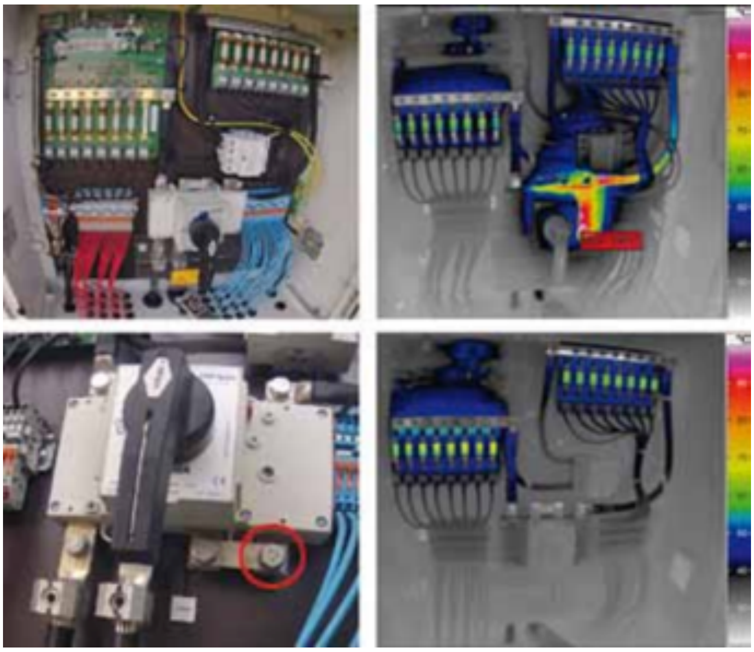

Figure 15: A string combiner box with a loose screw connection, with and without IR imaging. The fault cannot be detected visually, even if its position is worked out in the combiner box. The IR image on top left shows that a loose screw is causing temperature rise. The image on bottom right shows temperature distribution in a fault free string combiner box. (Source: FLIR)

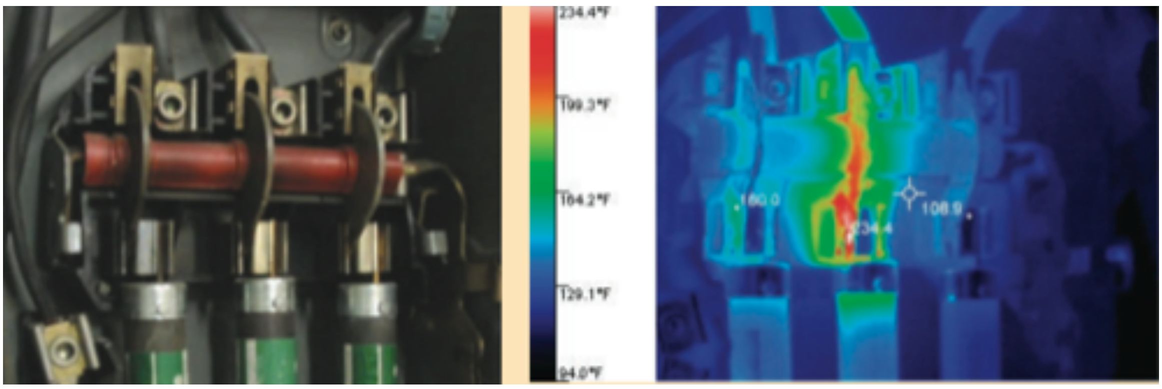

Figure 16: Interconnection problem in fused power disconnect revealed by thermal image. Source: Fluke

4.2.2.2.2 I-V curve tracing

I-V curve tracing is generally used to measure I-V curve traces in combiner boxes that are isolated from the rest of the PV system. As PV circuits do not need to be under inverter load during tracing, this approach reduces the arc flash hazard, and therefore offers a relatively safer inspection process relative to other electrical testing methods. I-V curve tracers are excellent devices for identifying underperforming source circuits when visual inspections and conventional electrical tests cannot point out the exact cause.

Safety requirements

- Use appropriate PPE to avoid any hazards, such as electrical, falls from heights and so on.
- Meet all safety requirements, especially while working on heights.
- Verify that the measuring equipment is properly rated for the voltages and currents it will be exposed to.

Testing tools required

- I-V curve tracer unit with sufficient voltage and current range for the PV system under measurement. Wireless sensor kits for measuring irradiance and temperature are desirable. In addition, if PV sensors are used, it is also important to have the spectral response of the irradiance sensor matched with the type of PV modules under test. A sweep time of less than 1 second for the I-V curve is recommended to mitigate the errors resulting from rapid fluctuations in irradiance due to moving clouds.
- A laptop, if required to run the application software of the I-V curve tracer.
- dc voltmeter.
- dc clamp-on meter.

Favourable test conditions

- For accurate results, a clear sky with minimum irradiance level of 700W/m^2 is preferred. Varying irradiance due to clouds causes corresponding fluctuation in the height of I-V curve while translation to STC is much less accurate with low light conditions.
- The most optimum time for I-V measurements would be within the 4-hour window centred on solar noon in order to avoid low light, spectral, and angle of incidence induced errors.
- Low wind or calm conditions are desirable for a more consistent module temperature.
- During rainy or wet conditions, it is not advised to work on outdoor electrical boxes.

Testing Procedure

- Isolate the combiner box or the PV circuit to be tested from the inverter and follow LOTO (Lock Out-Tag Out) procedures to ensure it remains in the disconnected state.
- Use a dc current meter to ensure there is no current present in the combiner box.
- Look for any visible defects such as heat discolouration, corrosion, water intrusion, etc. in the system.
- Specify the number of modules connected in series and parallel in the PV circuit under test. Also, specify the PV module manufacturer and model number, if applicable, or manually enter the performance model parameters from the manufacturer's specifications, as well as the wire gauge and wire length.
- For calibrated performance measurements, install an irradiance sensor in the plane of the array and attach a temperature sensor, preferably using polyimide tape for best mechanical properties at high temperatures, to the backside of a thermally representative module.
- Once the PV system is isolated from the load, open each fuse-holder in the combiner box.
- Connect one test lead of the tracer to the positive busbar and the other to the negative busbar.
- Close the appropriate fuse holder to initiate the I-V curve tracing of the desired circuit. Once the curve is traced, lift the fuse and interpret the curve.
- Repeat the same process for other PV circuits as well. Move the sensors if necessary to get them into wireless range.

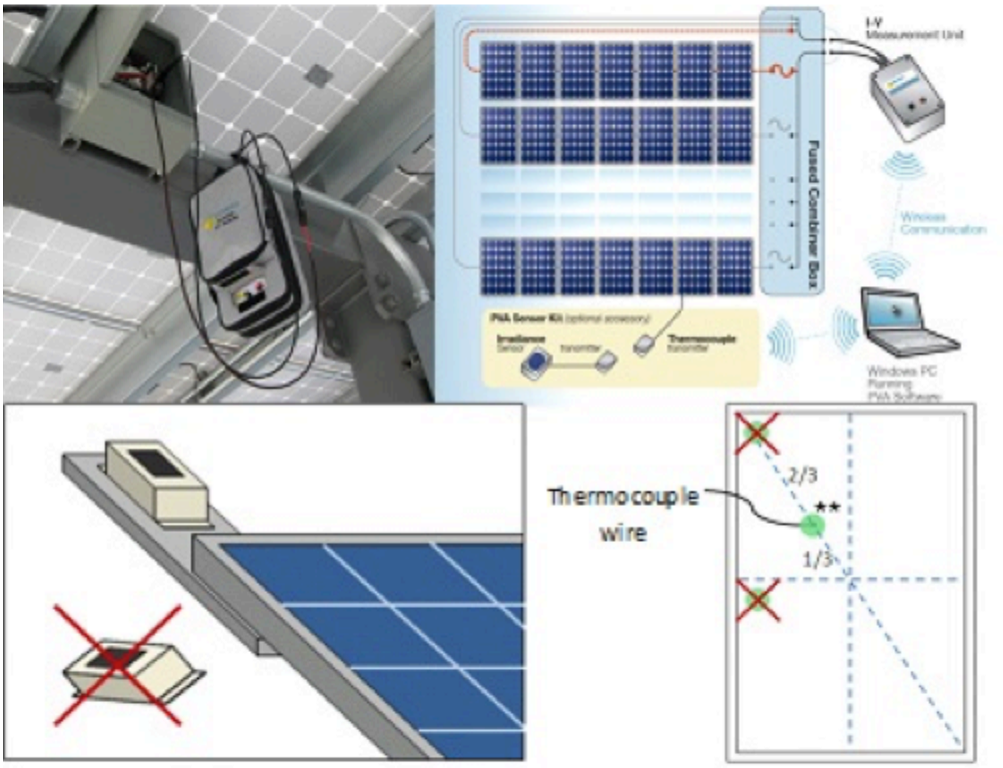

Figure 17: Images showing real setup (top left) and schematic (top right) of I-V curve tracer. The correct way for mounting an irradiance sensor (bottom left) is in the array plane and a temperature sensor (bottom right) on the back of the representative module. Source: Solmetric

Interpretation of results

- If the test does not return a useful I-V curve, check if the test leads are intact. If they are, look for any discontinuity in the source circuit, for example, blown fuses, or any discontinuity in wiring, or open module interconnections as indicated by burn marks in modules.
- If the I-V curve is useful and normal with above a 90% performance factor (as shown by the black curve in Figure 18) the PV circuit is normal and continue to testing another circuit. (Here, the performance factor refers to the ratio of measured maximum power to predicted maximum power in the ambient conditions during the measurement)
- A stepped I-V curve, as shown by curve 1 in Figure 18, is associated with a current mismatch in the tested array. Often, such mismatch results from partial shading due to bird droppings on a module, the shadow of nearby objects, soiling, etc. Prior to conducting further performance tests, it is important to clear such shading as it makes it difficult to identify any other performance issues. Similarly, if the test circuit has two or more parallel strings, then the stepped curve might also result from an unequal number of modules in the paralleled strings, shorted bypass diodes or damaged cells. Likewise, another common cause for current mismatch among PV modules is cracked cells.
- If a low short circuit current, as shown by curve 2 in Figure 18. is traced, verify if the model number or parameters of PV module entered in the tracer are correct. If they are correct, check if the irradiance sensor is mounted properly in the array plane. Also confirm that the spectral and angular response of the irradiance sensor matches that of the PV modules. If there is no operator or irradiance sensor related issues, the possible causes can be uniform soiling, shading, strip shading, or edge soiling.

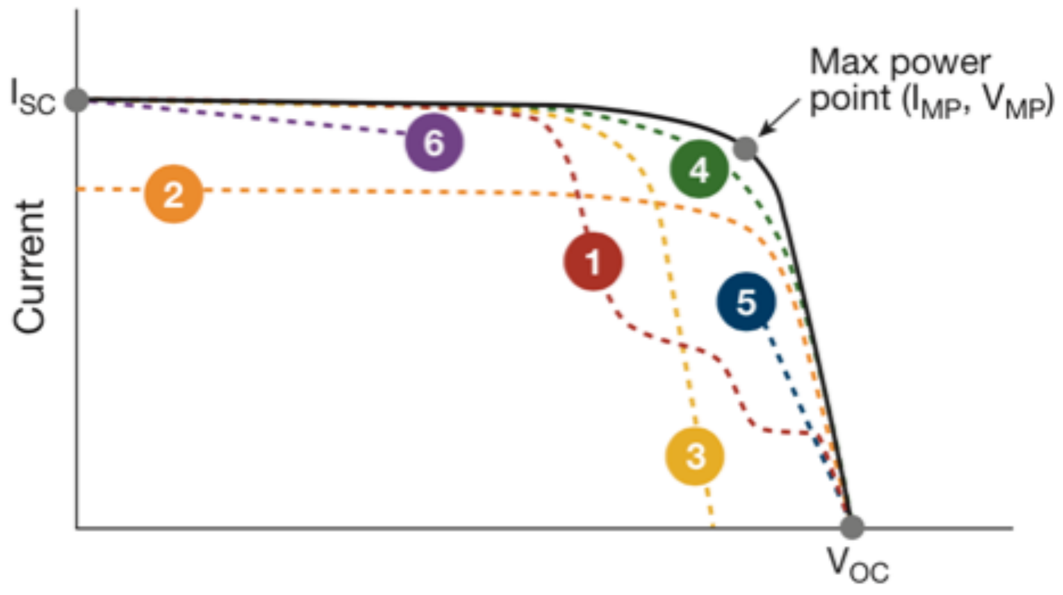

Figure 18: Different types of I-V curve obtained from I-V curve tracing in PV plants. Source: SolarPro

- Another kind of deviation is low open circuit voltage, as shown by curve 3 in Figure 18. In such case, check the quality of the thermal connection between the temperature sensor and the back of the PV module as V_{OC} is inversely related to the cell temperature. Also, verify the input parameters of the modules in the tracer. If everything is found to be in order, the potential causes could be shorted bypass diodes, shorted modules or cells, missing modules, a hard ground fault or potential induced degradation (PID).
- A rounder knee, as shown by curve 4 in Figure 18, is often a result of ageing processes.
- Similarly, a lower than expected slope in the vertical leg of the I-V curve, as shown by curve 5 in Figure 18, is associated with an increase in series resistance and can be quantified by the voltage ratio metric as:

$$\text{Voltage ratio} = V_{MP} / V_{OC}$$

As the homerun (end connectors of PV strings) conductors add external series resistance to PV modules, an inaccurate estimate while specifying wire length and cross sectional area (wire gauge) might lead to such errors. If not, the most common cause for increased series resistance is bad module solder joints. These joint faults might lead to a series arc fault that could potentially start a fire and have catastrophic results. Other likely causes are undersized conductors, resistive interconnections due to corrosion in terminal blocks and inter-module connectors, or in a module junction box as well as module degradation due to aging.

- Likewise, a higher than expected slope of the horizontal leg of the I-V curve, as shown by curve 6 in Figure 18, results from leakage within the PV circuit due to reduced shunt resistance and can be quantified by the current ratio metric as:

$$\text{Current ratio} = I_{IM} / I_{SC}$$

The horizontal leg of the curve can also be affected if irradiance changes rapidly during measurement, and I-V tracers with longer measurement times just make it worse. It is recommended to use I-V tracers with measurement time less than 1 second to minimise this error. Also avoid testing when there are clouds that may change the solar irradiation during the test. Separately, a thin wedge-shaped soiling or shading along the bottom edge of the PV module can also cause the I-V curve to have a low current ratio. It is important to clear any shading or

soiling, if identified, before performing any further tests for performance issues.
Another major cause for reduction in shunt resistance of modules is aging, which is normal. However, sometimes, some localized shunt may develop, usually detectable by an IR camera, and that can damage cells or even modules by concentrating a large amount of current.

Once the faulty string is confirmed, use visual inspection, IR imaging, V_{OC} tests, I_{SC} tests and ground-fault measurements to precisely locate the faulty modules, or wiring, or equipment. Repair or replace as required.

The below standards outline the procedures to undertaking I-V curve tracing in the field.

- IEC 60904-1:2006 Photovoltaic devices - Part 1: Measurement of photovoltaic current-voltage characteristics
- IEC 60891 Photovoltaic devices - Procedures for temperature and irradiance corrections to measured I-V characteristics

4.2.2.2.3 Megohmmeter testing

Megohmmeter testing is used to identify any damaged or failed electrical insulation or loose wiring connection. It is generally used during commissioning of the system or when troubleshooting a fault condition, but not often as a general maintenance activity. The testing device, commonly known as an Insulation Resistance Tester (IRT) or "megger", applies a set value of test voltage to the circuit for measuring insulation resistance. The commonly available IRTs can have various test voltage settings, such as 50V, 100V, 250V, 500V, and 1000V.

Safety requirements

- As Megohmmeter testing involves using potentially fatal levels of voltages for testing, the risk of shock hazard is very high; the appropriate PPE for electrical voltage testing should be used. Similarly, appropriate PPE must be used to avoid other potential hazards such as falling.
- Warning signs, including the one saying: "High voltage – Testing in progress – Stay clear of photovoltaic array!" must be installed in the required quantity and locations to prevent other personnel in the solar system field from the electrical hazard.

Testing tools required

- Megohmmeter

High voltage settings, such as 1000V, are better for detecting high impedance shorts in wirings. Although, most modules and wiring are rated to withstand such testing voltages for the short term, it is better to confirm the warranty requirements against Megohmmeter testing at high voltages. Moreover, a lower voltage setting is also desirable when testing on systems with surge protection. Some IRT devices, due to their improved filter capacity for compensating array capacitance, allow insulation resistance measuring even at voltages as low as 50 Vdc. In addition to providing safer measurements, these devices also facilitate fault detection in surge protection; leaking surge protectors contribute to a major share of faults in older PV plants. Megohmmeter testing is done only in circuits isolated from grounds and any other equipment. Many newer meggers have the additional useful feature of detecting any voltage between the conductors being tested and automatically disable showing an alert.

- dc clamp-on meter
- dc voltmeter

Favourable test conditions

- During rainy or wet conditions, it is not advised to work in outdoor electrical boxes.

Testing procedure

- Follow LOTO procedures to isolate the inverter from the test PV circuit. If applicable, open the disconnect switch on combiner box. It is crucial to isolate the test circuit from inverters because the high voltage from IRT can damage inverter circuits.
- Install “High voltage - Testing in progress – Stay clear of photovoltaic array!” warning sign around all entry points to the array.
- Look for any visible defects such as heat discolouration, corrosion, water intrusion, etc. in the system.
- In case of grounded PV systems, isolate the grounded conductor from earth by removing the cable from its termination. If testing voltage is more than 50 Vdc, remove any surge protection devices from circuits being tested.
- Open all fuse holders and ensure there is no current in the combiner box by using the dc current meter.
- Verify the continuity of the box enclosure to the ground using an ohmmeter. If the box is non-metal, confirm the continuity of the grounding wire to the ground. Test for current in the equipment grounding conductor using a clamp-on meter. If present, proceed to ground fault troubleshooting procedure, repair any ground fault and then continue this Megohmmeter procedure.

Figure 19: Megohmmeter testing in combiner box wearing appropriate PPE

- Connect the positive lead of the Megohmmeter to the conductor being tested (positive or negative) and negative to ground and set the meter to the appropriate voltage setting as directed. Press and hold the test button for a specific but consistent period of time – at least 15 seconds – and record the result after the 15 seconds interval.
- In larger systems, the time consumed in testings can be saved by performing insulation resistance tests on the whole sub-array first, at the busbar level. If the measured impedance is lower than the prescribed minimum value, test each individual string, else move to another sub-array. Test insulation resistance on both the conductors with respect to ground, separately (positive and negative) at each step.
- IEC62446 recommends the minimum values of insulation resistance that must be present while testing individual string conductors separately at various voltage levels as listed in the table below:

Table 11: Minimum values of insulation resistance

Test voltage (V)	Minimum insulation resistance (MΩ)
250	0.5
500	1
1000	1

It should be noted that the above mentioned values are for string level measurements, however, at the busbar level, measurements can be as low as 500 kΩ even at 1000 V test voltage.

- If a string fails the test, isolate the conductors from the array and test again. Replace or repair wiring in any failed strings and record all results.

4.2.2.2.4 Short Circuit Current Measurement

Some projects require short-circuit currents to be recorded to characterize array behaviour. These tests are performed sometimes in association with I-V curve tests. Low I_{sc} measurements can signify presence of circulating ground-fault currents in the array which may be due to multiple ground faults or shading.

Testing tools required

- Clamp meter

Testing procedure

- Ensure each string fuse (where required) is not connected or that the LV array is disconnected somewhere in each string as shown in Figure 21 below.
- Leave the solar array cable connected to the PV array switch disconnector.
- Remove the cable from the PV array switch disconnector to the inverter.
- With the PV array switch disconnector off - put a link or small cable between the positive and negative outputs of the PV array switch disconnector (Figure 20).
- Install the string fuse for string 1 or connect the string disconnect (Figure 21) to complete the wiring of the string. Turn on PV array switch disconnector then using a dc clamp meter, measure the dc short circuit current for String 1. Turn off PV array switch disconnector.
- Repeat for each string

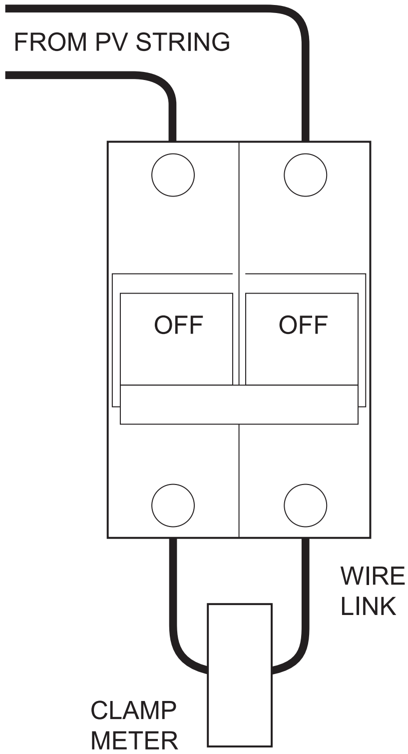

Figure 20: Measuring short circuit current

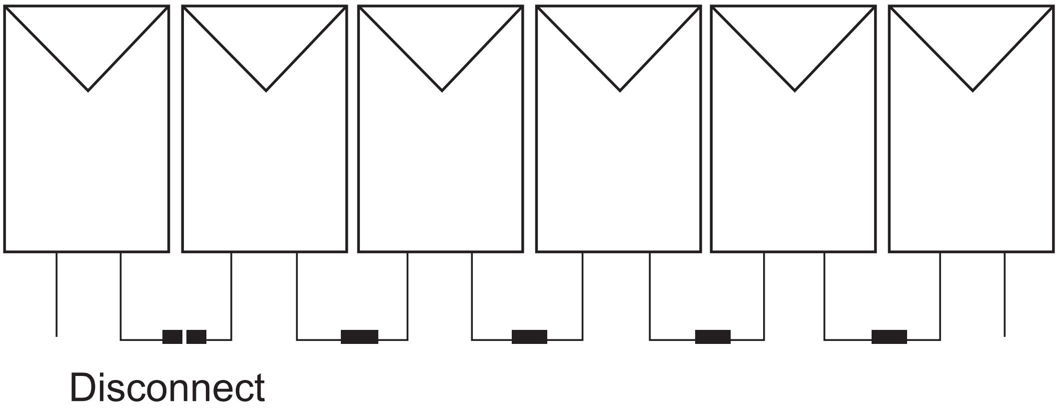

Figure 21: Disconnected interconnect cable

4.2.2.2.5 Fuse Checks

When a blown fuse is identified, investigate the cause and repair any problem found before replacing the fuse.

Safety requirements

- Perform fuse checks and replacements only after ensuring that the system is de-energised
- Always wear proper PPE for at least electrical voltage testing, operating on fuse holders, and fall hazards when working on elevated combiner boxes.

Testing tools required

- Digital multimeter

Favourable test conditions

- Any condition is suitable for fuse check except for rainy or wet conditions where it is not advisable to work on outdoor electrical boxes.

Testing procedure

- Follow LOTO procedures and ensure the test system is de-energised using a voltmeter. Fuses must not be removed or replaced in an energised system.
- Perform a continuity test on the fuse without taking it out from the fuse holder if it is clear that there is no alternative conductive path that can lead to a false continuity test. If not, remove the fuse from fuse holder and test it for continuity. Many meters make a beep sound when there is continuity in a circuit. A continuous beep sound means the fuse is intact.
- In the case of intermittent beep sounds, measure the resistance of the fuse which should be very low, usually some fraction of an ohm, otherwise replace the fuse. If the fuse passes the resistance test, confirm that the multimeter battery has enough charge by shorting the meter leads together to see if a beeping noise results when the meter is set for continuity testing. If not, replace the meter battery.
- Refer to the product manual for the physical and electrical specifications of the fuse. It should be noted that the ratings of the blown fuse might not necessarily be the correct one; an incorrect fuse rating can also be one of the causes of the fuse blowing.
- Test the new fuse for continuity and correct specifications before it is used to replace any incorrectly rated or damaged fuse.

4.2.2.2.6 V_{oc} and I_{mp} checks in dc system

V_{OC} and I_{MP} checks in the dc system are the most basic but, at the same time, the most reliable and decisive diagnostic tests for underperformance. These tests are done when any problem is identified in the dc system or any adjustment, like replacing modules, wires or connectors, is done in the PV circuit.

Safety requirements

- Always wear proper PPE for electrical voltage testing and fall hazard in elevated combiner boxes.

Testing tools

- dc voltmeter
- dc clamp meter
- Irradiance meter
- Temperature sensor

Favourable test conditions

- Best results can be obtained in clear sky conditions with a minimum irradiance of 700 W/m^2. However, comparison among strings is still possible in stable conditions with more than 200 W/m^2 for V_{OC} tests and 500 W/m^2 for I_{MP} tests.
- During rainy or wet conditions, it is not advised to work on outdoor electrical boxes.

Testing procedure

- Follow LOTO procedures to isolate the inverter from the PV system being tested.
- Record test conditions including ambient temperature, representative module temperature at its back surface and irradiance at the module orientation. Calculate the expected temperature compensated V_{OC} and irradiance compensated I_{MP} as reference values for comparing the results.
- Open the disconnect switch on the combiner box, if applicable.
- Look for any visible defects such as heat discolouration, corrosion, water intrusion, etc. in the system.
- Remove the fuses from all fuse holders inside the combiner box.
- Verify the continuity of the box enclosure to the ground using an ohmmeter. If the box is non metal, confirm the continuity of its grounding wire to the ground. Test for current in the equipment grounding conductor using a clamp-on meter. If present, proceed to the ground fault troubleshooting procedure, repair any ground fault and then continue this procedure.
- Measure V_{OC} of each individual string using a dc voltmeter and record the values. If the polarity is incorrect, investigate the problem before switching the conductors and re-labelling the conductors. The measured values for identical strings should be within 5% of each other as long as there is no change In the level of sunlight falling on the array during the test. Lower than expected values can be due to a disconnected cable or module connector failure, loose connections, a failed bypass diode or failed modules. Use an IR camera to precisely locate the fault. Incorrect string connections, where one or more modules from a string are wrongly wired to another string, can be easily identified by deviations from expected results by the multiple/s of V_{OC} of a module. (Note if system is large, then one string known to be installed correctly will have to be used as the test comparison string. All other strings are compared with this string. Tests should be carried out close to the same time because Voc will change as cell temperatures change)
- Replace fuses, close the combiner box disconnect, and torque all terminals properly. Measure the V_{OC} of the sub-array at busbars. If a low voltage is measured, check fuses and connections.
- For measuring I_{MP}, close the dc disconnector and bring the system back into operation. While the system is operating, measure the current by placing a dc clamp-on meter around each individual string. Compare the measured IMP with the expected value and that of the strings that have an identical tilt and orientation to identify low-performing strings. Low performing strings should be further investigated for any soiling or shading. Additional tests involving IR imaging and I-V curve tracing may be required to further identify and locate the fault.

The above section focuses on voltage and current tests at the combiner box level. An error report from the inverter saying “Low dc input current” or “Low dc input voltage” should be addressed by performing V_{OC} and I_{MP} checks in the PV system feeding that inverter. In this case, the voltage and current tests should be conducted starting from the DC input of the inverter and working back to individual strings and modules. The possible causes for underperformance in the downstream circuit of the dc system are defects in array cables, problems with connections and with the disconnector switches.

4.2.2.2.7 Earthing (Grounding) system integrity checks

All exposed non-current carrying metal parts in the PV plants must be connected to the equipment earthing (grounding) all the time and all grounding points of both the dc and ac side of the system must be interconnected. This equipotential bonding provides a path to any unwanted surges or fault current to ground and mitigates the risk of potential damage to equipment, electric shocks or fire. For that reason, the equipment earthing (grounding) should not be compromised even during removal of any component, such as during module replacement. If it does, a jumper of suitable capacity must be used as a temporary ground connection.

Testing for earth (ground) system integrity is simply a continuity test using an ohmmeter between two nearby metal surfaces or earth (ground) wire. This process is repeated randomly throughout the array and at every electrical enclosure.

4.2.2.2.8 Earth (Ground) fault troubleshooting

Troubleshooting earth (ground) faults is fairly straightforward, but potentially dangerous; in large PV systems, it requires close attention to detail, good record keeping and proper safety practices. Before starting any maintenance task that involves contact with metal parts of the system, it is recommended to check for a ground fault. Whenever a earth (ground) fault is detected, any further work on the system must be immediately stopped and the earth (ground) fault issue must be resolved before resuming the task.

Safety requirements

- Always wear proper PPE, especially to prevent any electric shock hazard. If working on equipment located at unsafe heights, such as combiner boxes and weather stations, use appropriate fall protection.
- Keep on mind that normally un-energised components may become energised under fault conditions.

Testing Tools required

- dc voltmeter/multimeter
- Megohmmeter

Favourable test conditions

- Testing can be done under any conditions, except at night when there is no voltage generated by the PV array.

Testing procedure

- Follow LOTO procedure to isolate the inverter from PV system.
- Visually inspect the system starting at the inverter and moving along the wiring to the array. Look for any signs of fire or electric arc, or melted or scorched components.
- In functionally earthed (grounded) PV systems, check continuity of any Earth (Ground) Fault Detect Interruption (EFDI or GFDI) fuse at the inverter. Also check the fuse for correct rating type and size. If the fuse is blown, it is an indication of a ground fault.
- Remove the EFDI (GFDI) fuse. Under non-fault conditions, this would convert the grounded PV system into an ungrounded PV system.
- Measure the voltage between the positive conductor and ground, and the negative conductor and ground at the line side of the dc disconnect. Under non-fault conditions, the voltage measured between line conductors and ground should not be well-defined. The measured voltage is often around half of V_{OC} due to capacitive coupling between the conductors and ground and slowly decays to zero. However, a consistent measured voltage is an indication of a ground fault. It should be noted that, in the case of single ground fault, the sum of voltages – positive line conductor to ground and negative line conductor to ground – is equal to the voltage between both line conductors, i.e. V_{OC}.
- If a fault is detected, isolate all combiner boxes by taking out the homerun wires from the inverter or switching off the disconnect at the combiner box, if applicable. Check voltages at both the busbars with respect to ground in each combiner box and narrow down the fault to a sub-array. Also, using a Megohmmeter, test the insulation resistance in homerun wires from the combiner box towards the inverter to check if there is any fault is in that section.
- Open all fuse holders in the combiner box. In ungrounded systems, test voltages to find any fault at the line side of the fuses. In grounded systems, remove grounded conductors one at a time, test the voltage to ground, and if it is normal, then put a wire nut or electrical tape around the exposed end of the conductor before testing another conductor.
- Once the faulty string is identified, the voltages measured at both ends of the string to ground can be used to locate the fault in string. For example, consider a string of five modules with V_{OC} of 50V each. If the fault is between second and third modules, as shown in Figure 22, the voltages measured at negative terminal to ground and positive terminal to ground should be 100V and 150V respectively. Likewise, if the fault is at either end of the string full V_{OC} and 0V are measured accordingly. This method is extremely useful in quickly locating a fault in long strings.

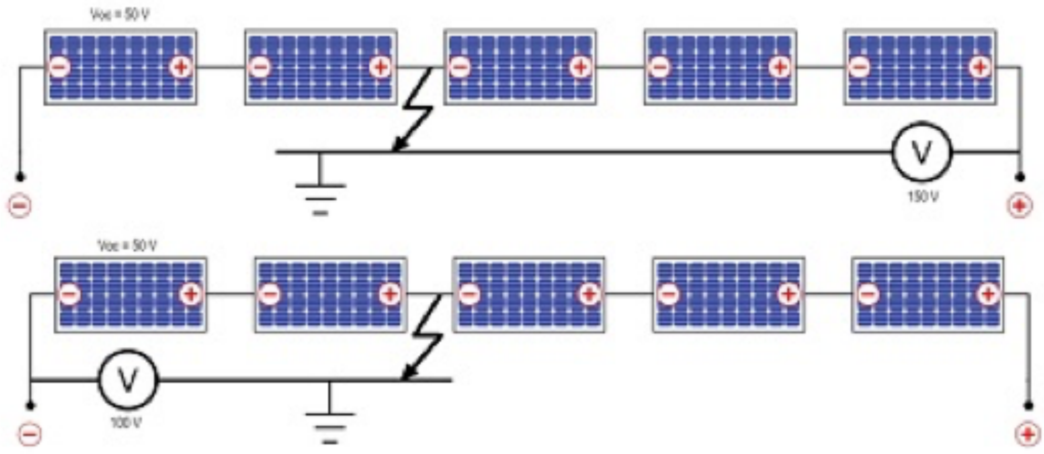

Figure 22: Ground fault troubleshooting in strings using voltage tests

- Where string or multi string inverters are installed, troubleshooting ground faults becomes easier. Such inverters usually have four or fewer inputs. Once the fault is identified at the inverter stage using the above described procedure, the strings should be isolated and subjected to voltage tests to find the ground fault.

On the event of a ground fault, the ground fault monitoring unit sets off an alarm sound or sends a message to alert the concerned personnel. However, a ground fault in grounded conductors cannot be reliably detected by most of the inverters in today's market. To address this issue, it is recommended to check for a ground fault at each inverter stage at least once a year during a routine inspection. In this case, the, maintenance of string and multi string inverters is highly labour intensive compared to central inverters.

4.2.3 Inverter troubleshooting and service

Among all components of PV system, inverters tend to have the most frequent failure rate and are the major contributors to expensive system downtime. It is therefore crucial to immediately bring an inverter that goes offline back to service in order to maintain the plant's generation. Most inverters now used in large-scale PV systems, are intelligent enough to report the type of error that has occurred, and established procedures are generally available to troubleshoot such errors. The following table lists the commonly reported inverter errors pertaining to large-scale PV systems, and the corresponding remedial actions.

Table 12: Minimum values of insulation resistance

Inverter error	Remedial action
Low dc voltage	Follow steps to diagnose underperformance
High dc voltage	Immediately disconnect array from the inverter. Perform V_{OC} tests in strings
High input current	Immediately disconnect array from the inverter. Check string wiring
Low input power	Normal if sunshine is low. If it is sunny, follow steps to diagnose underperformance
dc earth (ground) fault	Follow steps to troubleshoot earth (ground fault
Defective surge arrester	Replace damaged surge arresters
Low ac voltage	Confirm all breakers are on and test ac voltage with voltmeter. If within range, perform a manual restart, otherwise, contact the network provider
High ac voltage	Test ac voltage with a voltmeter. If within the proper range, perform a manual restart, otherwise, contact the network provider
Out of range power frequency	Check power frequency. Check the grid monitoring relay display. Make sure the fuses in the load circuit function properly. If the problem persists, contact the network provider
High line impedance	Check that none of the connections on the ac side are loose, contact the network provider if a fault persists
High temperature – Fan not operating	Check the fan power supply. If good, replace fan; if bad, replace power supply.
High temperature – Fan operating	Check to confirm temperature sensor readings. If not correct, replace sensor, if good, investigate further
High temperature – Fan operating, sensors accurate	Check intake and filters for excessive build-up. Check for external materials blocking intake or exit areas of the cooling system

Communication failure	Check indicators and error messages in the communication equipment and follow instructions. If good, check the power supply. Contact the manufacturer if the problem persists
Software error	Contact manufacturer

The most common hardware fault in inverters occurs in the switching transistors in the bridge circuit and filter capacitors in both ac and dc sections. Check for the signs of any discolouration or heating or leakage, especially around these components. Apart from this, it is also recommended to follow the general inspection procedure to locate and repair any general maintenance issue. Finally, complete the written inspection report and call the manufacturer if the problem persists. If repairs cannot be made within a reasonable time, to avoid further financial losses due to system downtime, replace the problem inverter if a working spare is available.

5. Storm Damage

The islands in the Pacific are prone to severe weather events like storms and cyclones (typhoons) which can in some instances be of Category 5 with maximum wind speeds up to 345 km per hour. These events can have a disastrous impact on the installed PV systems and also operation and maintenance personnel in the field. Hence it is important that a Disaster Management Plan and an Emergency Management Plan is included as part of any large-scale PV system's Operation and Maintenance strategy. The weather extremities of the site including the site's prior maximum wind speed and the level of past flooding at the site shall be considered at the design stage to design the PV array structure and to map out the potential flooding areas and their maximum flood levels. The inverters and data acquisition platforms to be installed on the field should be elevated above the ground level based on historic flood level data.

Severe wind conditions during storms can become dangerous due to flying debris. The modules not bolted properly to the mounting system could easily be displaced off their structures and damage other modules and also create dangerous situations to field personnel. It is important that the installation has been properly designed and constructed to withstand storm winds.

Other effects of storms include flooding caused by a storm surge and/or excessive rain. Storms can cause excessive water run-off or flooding in the PV field when an adequate storm water drainage system is not installed. The rainfall levels at the site should be a major parameter to be considered when designing large scale PV systems in the Pacific islands. The storm water run-off could also cause erosion that disturbs the stability of ground-mount array structure foundations and also may expose buried cables. These could pose a potential electrical or fire hazard when someone comes in contact with the system or the stormwater itself. Hence, the PV system design should include the construction of drainage features to collect and direct water run-off away from the PV array structure foundations, and upgrade any existing stormwater collection system to include rock-lined or concrete run-off pathways, check dams, storm water piping, drainage matting or other bedding requirements.

5.1 Emergency shut down

Severe weather events can result in emergency situations, where the plant has to be shut down for the safety of the transmission/distribution system and to avoid further infrastructure and financial losses.
In case of emergency, for example electrical hazard or fire hazard:

1. Push the emergency stop button in each inverter, if applicable. If the inverter has an on/off switch, turn it to off position.
2. If the inverter does not have an on/off switch or emergency stop button, turn off the disconnect switches located near the inverter. It is safer to operate the first available ac load break switch or circuit breaker before the dc switch. Do not open any no-load break switch until the current flow through it has been stopped.
3. Lock and tag the opened switches until the fault condition is repaired or it is safe to turn them back on.

In some instances, such as failure of plant-grid synchronizing equipment or grid failure, a complete plant shutdown may be required. To completely shut off the plant:

1. Follow the procedure for isolating all inverters, transformers and combiner boxes as mentioned above.
2. Follow instructions from the manufacturer to turn off the switchgear.
3. Lock and tag the switches in open state.

5.2 Assessing storm damage

Though PV systems today can be constructed to withstand the strongest wind that the site could experience, there could still be damage to the system due to falling and flying debris, unforeseen storm surges etc. When the storm is forecast to be so severe that it could cause damage to the PV system, it should be taken offline following the isolation procedures as per section 6.3.2. This is to avoid possible damage to the transmission and distribution lines. It is also good practice to disconnect the inverters from their dc input to both reduce the safety hazard and to avoid damage to the inverter due to storm created problems in the dc circuitry. The emergency shutdown procedure as per section 5.1 should be followed when an emergency situation like an electric or fire hazard is foreseen in the plant.

The down-time of the PV plant after the storm passes can result in a huge financial loss; hence the damage assessment and restoration of the PV plant should be carried out as quickly as possible. Visual inspection of the PV plant should first be carried out to assess the damage to the PV modules after the storm has passed. Depending on the size and location of the power plant, flooding of the the PV array field can be inspected from nearby higher land or using drones or a helicopter to assess the extent of damage. Care should be taken when assessing the DC side of the system, as the modules are uncontrolled generating sources which produce power anytime there is sunlight. Damaged modules, cables, conduits, array structures and other components at the site shall be assessed for physical damage and recorded for repair or replacement depending on the degree of their damage. The foundations of the array mounting structures should be checked for stability as issues arise due to storm water run-off eroding the soil around the mounts. The combiner boxes and protection devices shall be assessed for water intrusion or damage due to debris. Any central inverters are mostly not affected by storms as they are usually designed to be mounted on higher land in enclosures that are rated for the extreme weather conditions. String inverter and micro-inverters on the other hand are installed on the PV field and any physical damage detected on the inverter enclosure or inverter cabling should be recorded. The inverters should be checked for error messages and their operating conditions need to be tested.

5.3 Repairing storm damage

If possible, large-scale PV systems should be covered by Property Risk insurance as generally storm damage to the PV modules or other equipment are not covered under the manufacturer's warranty. However, it is appreciated that this type of insurance may not be available (or affordable) in countries subject to cyclones/(typhoons).

Any restoration work on the PV plant should be carried out after the conditions in the field are found to be safe. The system should be isolated for the safety of the undamaged equipment and personnel. Complete re-structuring of the PV array mounting systems and re-wiring of the system may be required depending on the extent of the damage to the system.

Storm debris in the field shall first be cleared followed by temporary repairs to the array and other equipment support structures to avoid any further damage. The specific problems that were caused by the storm should be carefully recorded and as permanent repairs are carried out, modifications that will reduce the chance of future storm damage should be made.

6. Maintenance

6.1 Maintenance procedures

There are many different maintenance procedures that must be performed over the lifetime of a large solar system. Examples of some of these activities are given below in Figure 23. These procedures will include preventive maintenance, corrective maintenance and maybe even condition-based maintenance activities. When determining the extent of these maintenance procedures, it is very important to find the optimum balance between the scheduled maintenance cost and the cost of lowered plant reliability and performance when that maintenance is not carried out on that schedule.

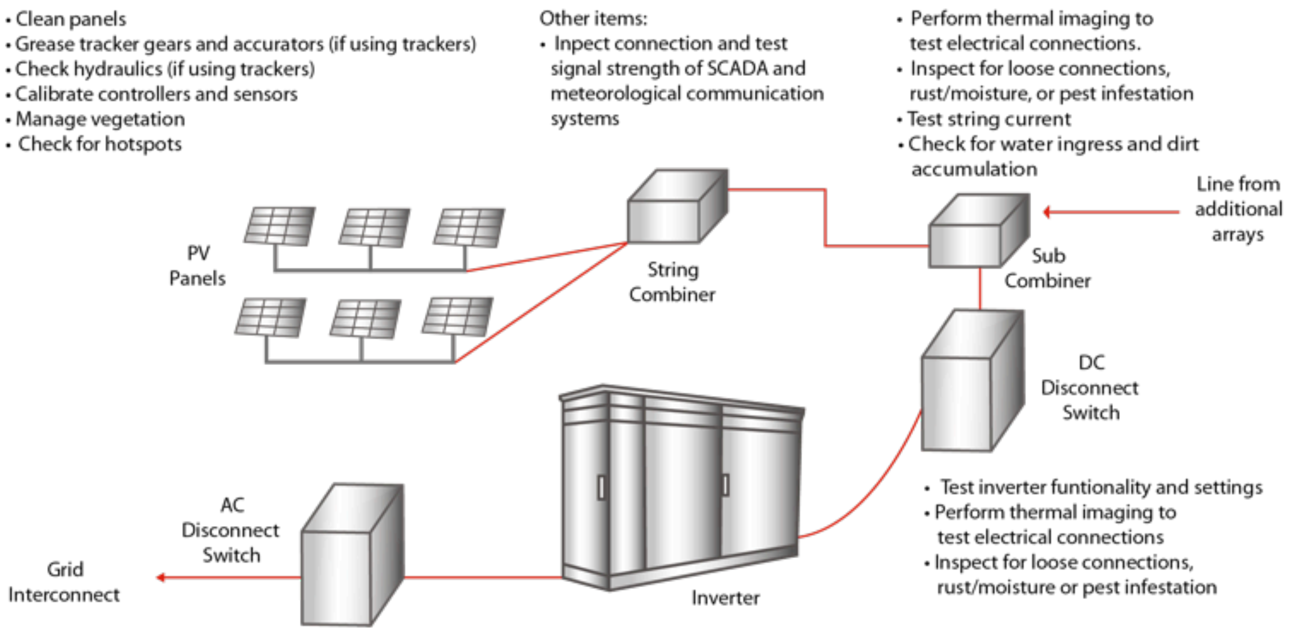

Figure 23: Some of the maintenance procedures required in order to operate a utility-scale PV system. It is important that all maintenance procedures and scheduling are factored into the O&M budget.

6.1.1 Preventive maintenance

Preventive maintenance (PM) includes scheduled activities carried out to prevent issues occurring with the system equipment that may lead to a reduction in performance and loss of revenue. The extent and period of PM activities will depend largely on the manufacturers' recommendations and the equipment warranty requirements. It will also depend on the specific environmental conditions at the site, such as the type of vegetation, the level of rainfall, the dustiness or saltiness of the area etc. The climatic conditions and seasonable climatic variability are also factors to consider.

PM activities improve system availability and performance, and hence maximise production and also prolong the life of the system. However, these activities also increase the operating costs by incurring extra expenses and also by the loss of revenue during periods when the maintenance activities require the plant to be shut down. When designing the PM schedule, it is important to find the optimum balance between the cost of these activities and the increased revenue that it provides through the resulting increased yield over the system lifetime.

PM activities may include:

- Module cleaning
- Vegetation management
- Prevention of damage by wildlife and insects
- Water drainage / erosion control
- Upkeep of weather monitoring system
- Upkeep of data acquisition and monitoring systems
    - Servicing electronics, wiring and sensors
- Upkeep of major components
    - Inverter inspection and servicing
    - Transformer inspection and servicing
    - Checking module connection integrity
    - Checking for hotspots
    - Checking junction/combiner boxes for water ingress, dirt or dust accumulation and integrity of the connections within the boxes
- Upkeep of balance of system components
    - Framing (racking) system maintenance
    - Check all wiring
    - Checking and servicing security systems
    - Checking the signal strength and connection of communication systems.

6.1.2 Corrective maintenance

Corrective maintenance is performed in the event of failures within the system. When designing the corrective maintenance plan it is important to consider how the problem will be diagnosed, how fast the response will be and how long the repair is expected to take. If the operation and maintenance is to be performed by others and not the utility personnel, these parameters should be specified in the O&M contract and will depend on the site-specific conditions, as well as any availability and performance guarantees.

Again, while minimising the response and repair time will increase the yield of the system, it may also increase the cost of the repair. Therefore, it important to balance the increased contractual costs (if being performed by others) of achieving shorter response times with the increase in revenue from increased yield.
Corrective maintenance is made up of:

- On-site monitoring/mitigation
- Critical reactive repair

• Address production losses
- Non-critical reactive repair
    • Address production degradation
- Warranty enforcement (as needed).

While most corrective maintenance activities are typically related to inverter faults, they may also relate to a number of other components and include:

- Repairing cable connections that have loosened or corroded
- Replacing blown fuses
- Repairing lightning damage
- Repairing equipment damaged by intruders or during module cleaning
- Rectifying SCADA faults
- Repairing mounting structure faults

6.1.3 Condition-based maintenance

Condition-based maintenance employs real-time data to prioritise and optimise maintenance and resources. The plant operator will schedule O&M activities when deemed necessary based on the monitored data. While this approach may offer higher O&M efficiency, the cost of communication and monitoring systems required incur high upfront costs. In addition, any errors in communication or failures in the monitoring system may lead to poor maintenance scheduling, resulting in severe losses. While condition-based maintenance activities may be used instead of certain scheduled maintenance activities when more economic to do so, some manufactures will require that their products are maintained according to a recommended schedule in order for warranty claims to remain valid. Therefore, it is important to find the right balance between condition-based maintenance and preventive/scheduled maintenance activities (see Figure 24).

Condition-based maintenance may require the need to enforce the warranty on components that have failed despite following the recommended maintenance schedule.

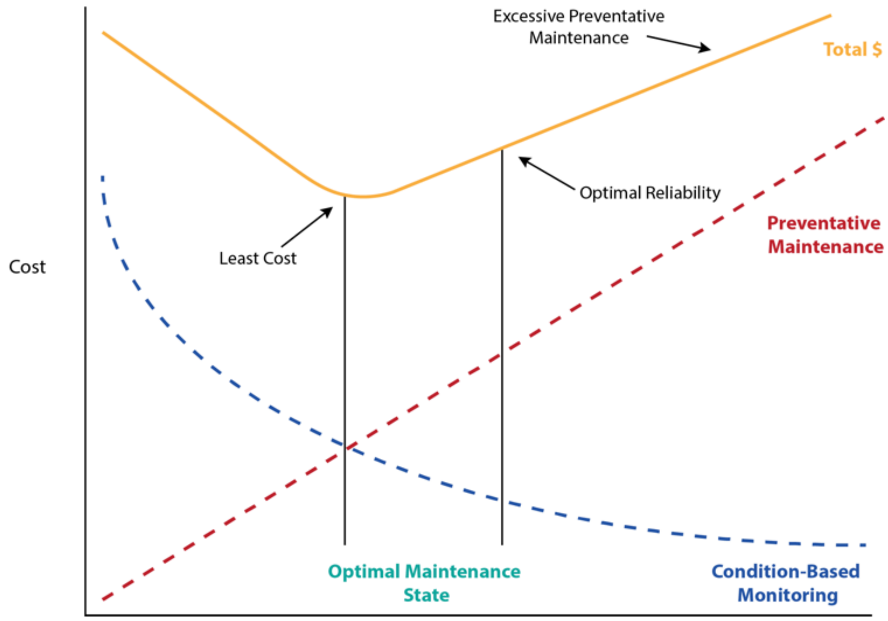

Figure 24: Cost vs maintenance curve. This figure illustrates that at excessively high levels of either preventive or condition-based maintenance, the O&M costs are very high. It is important to find the optimum balance between the two to find a solution that minimises O&M costs, but ensures adequate plant reliability. Note that this is just an example of what an optimal maintenance state may look like, in reality it will be more complex and will vary from project to project.

6.2 Maintaining equipment

6.2.1 Cleaning modules

Over the course of time, depositions on PV modules like dirt, dust, debris, salt, pollen and bird droppings can significantly reduce system efficiency. In order to maintain the system efficiency, modules may require periodic cleaning. However, the need for cleaning is highly context specific, and tends to be governed predominantly by site conditions, operating priorities and budget constraints. Modules do not typically need cleaning during periods of frequent rainfall. Depending on site and climatic conditions, module cleaning may be advisable during a dry season. Unlike tilted PV arrays, flat PV arrays are highly prone to soiling and may not be cleaned effectively by rainfall. A minimum 10° tilt angle is recommended to facilitate cleaning by rain; PV modules at a lower angle than this (e.g. for optimal annual radiation in locations close to the equator) may require regular manual cleaning which may incur a higher cost than the loss of few percent of generation caused by modules being tilted more than the latitude angle. Frameless modules are less likely to require cleaning than standard framed modules that tend to have a build-up of soil/debris in the frame edges.

The main decision criteria for array cleaning are cost versus performance trade-offs. The decision calculation involves adjusting actual energy production measured at the meter using the ratio of actual solar irradiation received at the solar cell surface to expected solar irradiation for a PV plant, and comparing the result to the projected production adjusted for degradation over time. If the loss of production exceeds the cost of array cleaning, a cleaning crew can be dispatched. However, the actual decision to dispatch also depends on O&M budget constraints and other cost-benefit variables.

Safety requirements

- Cleaning must be done only by someone with proper training, particularly if the array is on a roof and requires the maintenance person to work at heights.
- To prevent slips and falls, wear appropriate proper PPE; especially wear rubber sole shoes with good traction.
- Walking on modules must be avoided. Instead, non-conductive handles should be used with cleaning equipment to reach modules.

Favourable conditions

- Depending on the local climate, it is better to wash modules during early mornings when the modules are cool, it is cooler for the person doing the cleaning and the solar arrays output performance for that day will improve.

General array washing procedure

- Confirm that there are no broken modules and replace those modules immediately following the isolation procedure for modules. Never spray water on broken modules, as they are electrical safety hazards.
- The runoff water should be disposed of according to local rules and regulations if any harmful chemical is used. Likewise, plan for collection and disposal of runoff if the site has any storm water prevention plan. Otherwise, simply drain the water.
- Identify the water source to be used, preferably near the array. In some cases, it may be required to bring water from outside in a tank or water truck. For cleaning large arrays, a narrow trailer with a large water tank that is drawn by a small tractor through the space between arrays may be practical.
- Set up hoses and tools. Block or install drain guards for filtration or water capture, if required.
- Both right before cleaning, record the kilowatt-hour (kWh) output of each of the inverters and the weather conditions, especially ambient temperature, module temperature and irradiance, to record a baseline production level of the system before and after cleaning.
- Preferably, use deionized water for washing to avoid any spotting and calcium build-up.

- The water pressure should be within the limits specified by the manufacturer of PV modules. As a rule, normal water pressure of 50 to 70 per square inch is recommended.
- Remove stubborn dirt using a soft-bristled brush. Use insulated extensions with the cleaning tools to reach extended distances. Normally plain water is adequate. If soap is required, use regular laundry soap (not an industrial cleansing soap) and squeegee modules dry.
- After washing the array, wait until there is no impact from the cooling effect of washing and the system returns to steady-state temperature. This can be confirmed by monitoring the back surface temperature of a representative module. Take another production reading of the system, noting both kWh output of each inverters and weather conditions including ambient temperature, module temperature and irradiance. It is important to take this reading after cleaning as this can provide a baseline for determining the need for cleaning in the future.
- Clean up tools and remove any drain guards and blocks.
- Record the washing in the maintenance log.

6.2.2 Weed and vegetation control

Vegetation growth, particularly in ground-mounted systems, can cause shading, problems with array wiring, access problems, etc. In addition, vegetation around pad mounted structures such as inverters and transformers can obstruct ventilation in the equipment cabinets and cause thermal damage to the equipment. The situation can become even worse when plants find a substrate to grow on debris that has accumulated on PV modules that have not been properly cleaned. Regular inspection and management of vegetation is therefore an important aspect of maintenance in PV power plants.

Spraying chemicals to prevent vegetation growth is a potentially inexpensive solution, but can lead to environmental and health related issues and may create the need to clean the array due to a deposit of the chemicals on the modules. Moreover, chemicals may render the whole area barren, allowing wind to carry dust to modules and cause soiling problems.

Mowing or trimming plants seems to offer proper vegetation management at moderate upfront costs, however the ongoing labour costs for this option can be very expensive. Separately, there is always the risk of projectiles thrown from the equipment damaging a module. Further, debris like grass, pollen and dust ejected by the mower may accumulate on modules and cause shading problems. In many cases, where arrays are close to the ground, it may not be practical to trim vegetation growing underneath the array. Another potential and very effective solution may be planting low growing grass. Solar arrays with a ground clearance of about 18 inches or above can have no mowing requirement with low growing grass planted on the site. In the meantime, having grass under the system helps to retain moisture and prevents heat radiation from the ground upwards to the modules, thus producing a cooling effect and enhancing the PV system's performance. The cost of seeding the ground are one-off and relatively low compared to other options such as mowing, spraying chemicals and using vegetation barriers.

Use of animals for grazing is becoming an increasingly popular and ecofriendly vegetation management approach in solar farms in Europe, Japan, United States etc however it has not been used on any system in the Pacific Islands. In addition to offering a low cost solution to vegetation growth, this method also provides an opportunity to incorporate agri-business with energy production. The only design concern for adopting this method is that the clearance underneath the array should be about 200-300 mm higher than the animal. It should be noted that some animals such as goats, horses and cattle are not recommended. Goats are more likely to damage the system as they jump, climb, break and eat everything, including wires. Horses and cattle are too strong and can damage the system while scratching against the posts. In some countries sheep, geese and even the Australian Emu have been used with varying success.

6.2.3 Erosion control

Excavation for the installation of footings for ground-mounted systems exposes soil underneath the array that can be vulnerable to erosion. Some of the Pacific islands are prone to extreme weather events including cyclones/ typhoons that include heavy rainfall, storm surges and high winds. The resultant storm water can cause erosion of the top soil layer and endanger the stability of the PV array foundations, as well as expose buried conductors possibly creating a serious danger to personnel. Hence it is recommended that specific water pathways such as rock or concrete lined check dams for directing storm water run-off are built that discharge into the site's storm-water management system such as a retaining basin, storm sewer or natural stream. Based on historic data such as rainfall intensity at the site, the run-off pathways shall be paved wide to avoid over-flowing. Soil erosion around the array structure foundations is then controlled.
The soil surface can be further stabilised for erosion prevention by using soil conditioners like polymers that can be sprayed on a dry soil surface before the cyclone / typhoon season. The type of soil and other conditions at site affect the choice of soil conditioner and the amount to be applied but it is vital that during the application of such conditioners, they must not be allowed to settle on module surfaces.

6.2.4 Other equipment

The inverter and protection devices installed in the system have specific testing, inspection and maintenance procedures that are usually dictated by the manufacturers. The manufacturer recommended procedures shall be complied with to ensure safety and to meet the product warranty obligations.
The maintenance of the inverter should not be limited to the generic inverter inspection checklist in section 4.2.5. Actions such as re-tightening inverter conductor connectors (sometimes screw lugs on terminal blocks), and thermal imaging of sand-clearing air filters shall also be carried out during the scheduled maintenance. Depending on the location of of the inverter mounts, the frequency of cleaning and removing dust from the inverter enclosures shall be determined and scheduled. The maintenance of a central inverter can be scheduled at more regular intervals than the string inverters or micro-inverters in the field as the effect of the latter is marginal when compared to the cost of having a central inverter failure. Central inverters usually have sub-system repair support from the manufacturer and spare parts such as control cards, driver cards, IGBT matrix and capacitors are usually stocked at the time of installation. Micro-inverters and string inverters may require replacement rather than a repair when a fault is recorded and the photos of the fault and faulty inverters on site should be recorded.

6.3 Safely shutting down the system for maintenance

6.3.1 Testing on energised components

Some maintenance activities and tests require O&M personnel to work on or near the equipment while the system is energised. For example, while performing megohmmeter testing, unsafe voltage is induced in the wiring or other components by the megohmmeter to test for any insulation damage or leakage. Another example is string current and voltage testing where testing is done on a live string circuit. Similarly, IR imaging where thermal images are taken in close proximity to energised components requires attention to safety measures. Considering the potential hazards in such testings, it is critical that only qualified personnel (at least two people) work on energised electric circuits and equipment.

6.3.2 General isolation procedures

Several regular maintenance activities, like cleaning the inverter cabinet or replacing surge arresters, require isolating and de-energising the equipment for safety reasons. Only qualified personnel must be allowed to carry out the isolation of equipment. Any operations on energised high voltage sections such as step-up transformers and switchgear must be done only by specially trained technicians with a certification to work on high voltage equipment. It is recommended that personnel follow the instructions from the manufacturer when isolating any equipment.

The general isolation procedures for some major equipment are:

Inverter pad equipment

1. Follow LOTO procedures during the entire process.
2. Follow the inverter manufacturer's guideline for a controlled shutdown using the HMI keypad, if applicable.
3. Turn off the ac disconnect switch on the inverter.
4. Turn off the dc disconnect switch on the inverter. It is important to turn off the ac side before the dc side to prevent arcing and save wear and tear on the dc disconnect.
5. Turn off any remaining external disconnect switches connected to the inverter.
6. If applicable, check readings and indicators on inverters to confirm that both ac and dc sides are disconnected.
7. Turn off the switches corresponding to the inverter in the control and supply panel, if applicable.
8. Install lockout devices on all disconnects.
9. Always wear appropriate PPE and ensure that the system is completely isolated by testing for voltage with a proper meter.
10. Repeat the same for all inverters and switches, as required, to completely isolate the entire inverter layer from both the PV system and the grid.

Transformer isolation

1. Follow LOTO procedures during the entire process.
2. Follow the general isolation procedure for inverters to disconnect inverters from the system.
3. Turn off the switches corresponding to the transformer on the control and supply panel, if applicable.
4. Turn off the transformer switch on the secondary side, which is either a stand-alone switch or is located in the switchgear.
5. Install a lockout device on the transformer switch.
6. Always wear appropriate PPE and ensure that the system is completely isolated by testing for voltage with a proper meter.
7. Repeat the same for all transformers, as required, to completely isolate them from switchgear.

Field combiner box

1. Turn off the inverters as described above.
2. Turn off the switch of the combiner box, if applicable.
3. Ensure that there is no current through the conductors in the combiner box by using a dc clamp meter, and then open (remove) all fuses.
4. If further isolation is needed, use the string wiring diagram to locate the homeruns (end connectors of PV strings). Confirm that the homeruns are not carrying any current using a DC clamp meter. Disconnect the homerun positive and negative connectors and put caps on the source circuit connectors.
5. Measure the voltage on terminals of the string combiner box using a voltmeter to confirm that each string has been successfully disconnected.
6. Repeat the same process on each combiner box to be isolated.

Modules and string wiring

1. Turn off the inverter, switches and isolate the combiner boxes from the array as described above.
2. Ensure no current is passing through the string.
3. Disconnect the module connector using the appropriate unlocking tool.
4. It should be confirmed that the equipment grounding remains intact, even if the module is being removed temporarily. If removing the module compromises the grounding, a bypass should be used before removing the module.
5. Repeat the same for each module to be isolated.

Appendix 1: Solar Irradiation Data

Table showing Peak Sun hours for various sites and tilt angles.

Alofi, Niue
Latitude: 19°04' South | Longitude: 169°55' West

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	6.47	6.2	5.67	4.81	4.26	3.86	4.01	4.61	5.35	6.02	6.53	6.46	5.34
19° Tilt[2]	6.43	5.88	5.7	5.2	4.96	4.46	4.75	5.14	5.53	5.81	5.98	6.47	5.53
34° Tilt[2]	6.06	5.39	5.47	5.24	5.24	4.78	5.08	5.29	5.41	5.41	5.35	6.15	5.41

Apia, Samoa
Latitude: 13°50' South | Longitude: 171°46' West

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.39	5.47	5.16	5.09	4.63	4.46	4.71	5.25	5.77	5.91	5.76	5.51	5.25
13° Tilt[2]	5.32	5.24	5.12	5.31	5.06	4.99	5.23	5.60	5.85	5.72	5.67	5.46	5.38
28° Tilt[2]	5.14	4.86	4.93	5.37	5.34	5.40	5.62	5.79	5.74	5.35	5.45	5.3	5.36

Hagåtña, Guam
Latitude: 13°28' North | Longitude: 144°45' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.33	5.87	6.73	7.12	7.04	6.44	6	5.3	5.42	5.46	5.16	5.05	5.9
13° Tilt[2]	5.94	6.27	6.85	6.88	6.97	6.43	5.95	5.17	5.38	5.7	5.66	5.69	6.07
28° Tilt[2]	6.40	6.48	6.75	6.39	6.71	6.27	5.77	4.90	5.18	5.77	6.00	6.19	6.06

Honiara, Solomon Islands

Latitude: 09°27' South | Longitude: 159°57' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.99	5.55	5.61	5.41	4.76	4.59	4.45	5.19	5.81	6.26	6.4	6.22	5.52
9° Tilt[2]	5.98	5.47	5.54	5.52	5.00	4.90	4.69	5.36	5.81	6.15	6.38	6.24	5.59
24° Tilt[2]	5.92	5.29	5.34	5.58	5.26	5.28	4.98	5.52	5.71	5.88	6.29	6.22	5.61

Koror, Palau

Latitude: 07°20' North | Longitude: 134°28' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.19	5.59	6.18	6.3	5.71	5.01	5.12	5.2	5.56	5.39	5.26	4.93	5.45
7° Tilt[2]	5.4	5.7	6.16	6.22	5.7	5.01	5.11	5.15	5.49	5.45	5.44	5.16	5.5
22° Tilt[2]	5.74	5.85	6.06	6.01	5.67	5.03	5.11	5.03	5.3	5.3	5.73	5.53	5.55

Lae, Papau New Guinea

Latitude: 06°44' South | Longitude: 147°00' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.13	4.85	5.03	4.85	4.58	4.29	4.17	4.51	4.97	5.27	5.35	5.13	4.84
6° Tilt[2]	5.2	4.88	5.03	4.93	4.73	4.47	4.32	4.61	5	5.28	5.41	5.21	4.92
21° Tilt[2]	5.2	4.77	4.86	4.97	4.96	4.77	4.55	4.72	4.91	5.12	5.39	5.25	4.96

Majuro, Marshall Islands
Latitude: 7°12' North | Longitude: 171°06' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.26	5.86	6.11	5.89	5.66	5.31	5.35	5.63	5.42	5.15	4.88	4.84	5.44
7° Tilt[2]	5.47	5.98	6.09	5.81	5.65	5.32	5.35	5.58	5.35	5.2	5.03	5.05	5.49
22° Tilt[2]	5.83	6.16	5.99	5.62	5.62	5.35	5.35	5.46	5.16	5.24	5.27	5.4	5.53

Nauru
Latitude: 0°32' South | Longitude: 166°56' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.77	6.24	6.27	6.04	5.99	5.75	5.85	6.25	6.7	6.5	6.12	5.5	6.07
15° Tilt[2]	5.94	6.26	6.08	6.05	6.28	6.15	6.20	6.39	6.51	6.46	6.28	5.69	6.19

Noumea, New Caledonia
Latitude: 22°16' South | Longitude: 166°27' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	7.31	6.7	5.73	4.97	3.94	3.47	3.91	4.73	6.05	7.09	7.41	7.6	5.73
22° Tilt[2]	6.61	6.34	5.83	5.55	4.75	4.19	4.69	5.50	6.44	6.88	6.77	7.54	5.92
37° Tilt[2]	5.74	5.8	5.59	5.62	5.02	4.48	4.99	5.69	6.32	6.37	5.94	7.03	5.72

Nuku'alofa, Tongatapu, Tonga
Latitude: 21°08' South | Longitude: 175°12' West

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	6.69	6.3	5.62	4.65	4.04	3.58	3.78	4.43	5.23	6.28	6.69	6.7	5.32
21° Tilt[2]	6.1	5.96	5.69	5.1	4.81	4.25	4.41	5.03	5.46	6.07	6.16	6.65	5.47
36° Tilt[2]	5.35	5.47	5.45	5.14	5.08	4.55	4.67	5.18	5.34	5.64	5.45	6.25	5.3

Pago Pago, American Samoa

Latitude: 14°16' South | Longitude: 170°42' West

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.87	5.93	5.54	5.18	4.63	4.4	4.59	5.2	5.78	6.05	6.11	5.93	5.43
14° Tilt[2]	5.79	5.66	5.51	5.43	5.11	4.98	5.14	5.59	5.87	5.84	6.01	5.87	5.57
29° Tilt[2]	5.57	5.22	5.29	5.48	5.4	5.39	5.51	5.77	5.76	5.45	5.75	5.69	5.53

Palikir, Pohnpei FSM

Latitude: 6°54' North | Longitude: 158°13' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	4.97	5.57	5.91	5.79	5.44	5.33	5.51	5.54	5.66	5.29	5.03	4.83	5.4
6° Tilt[2]	5.11	5.65	5.88	5.72	5.42	5.34	5.51	5.49	5.59	5.32	5.15	4.99	5.43
21° Tilt[2]	5.42	5.81	5.79	5.55	5.41	5.39	5.54	5.40	5.40	5.38	5.42	5.34	5.49

Port Moresby, Papua New Guinea

Latitude: 9°29' South | Longitude: 147°9' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.71	5.14	5.32	5.33	4.98	4.67	4.75	5.29	5.95	6.42	6.51	6.04	5.51
9° Tilt[2]	5.81	5.15	5.33	5.5	5.29	5.03	5.09	5.53	6.03	6.4	6.61	6.17	5.66
24° Tilt[2]	5.72	4.96	5.12	5.55	5.58	5.43	5.43	5.69	5.91	6.1	6.5	6.13	5.68

Port Vila, Vanuatu

Latitude: 17°44' South | Longitude: 168°19' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	6.68	6.2	5.76	4.98	4.2	3.79	4.04	4.75	5.65	6.47	6.67	6.93	5.5
17° Tilt[2]	6.69	5.89	5.77	5.32	4.75	4.41	4.65	5.21	5.82	6.25	6.47	7.01	5.69
32° Tilt[2]	6.38	5.42	5.55	5.38	5.01	4.74	4.97	5.37	5.7	5.82	6.08	6.74	5.6

Rarotonga, Cook Island

Latitude: 21°12' South | Longitude: 159°47' West

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	6.45	6.14	5.78	4.59	3.86	3.54	3.73	4.46	5.16	5.94	6.63	6.56	5.23
21° Tilt[2]	5.9	5.82	5.86	5.04	4.56	4.2	4.34	5.07	5.38	5.74	6.11	6.51	5.38
36° Tilt[2]	5.19	5.34	5.62	5.08	4.8	4.48	4.6	5.22	5.26	5.34	5.41	6.11	5.2

Suva, Fiji

Latitude: 18°08' South | Longitude: 178°25' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	6.2	6.2	5.54	4.67	4.05	3.72	3.89	4.44	5.08	6.04	6.32	6.38	5.21
18° Tilt[2]	6.27	5.88	5.55	4.99	4.61	4.38	4.51	4.88	5.21	5.83	6.1	6.41	5.38
33° Tilt[2]	5.95	5.4	5.33	5.03	4.84	4.7	4.8	5	5.1	5.43	5.71	6.13	5.28

Tarawa, Kiribati

Latitude: 01°28' North | Longitude: 173°02' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.58	5.98	5.99	5.87	5.82	5.7	5.87	6.15	6.52	6.4	6.1	5.5	5.95
16° Tilt[2]	5.9	6.1	5.83	5.79	5.95	5.93	6.06	6.17	6.28	6.45	6.43	5.88	6.06

Vaiaku, Tuvalu

Latitude: 8°31' South | Longitude: 179°13' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	5.16	5.27	5.33	5.29	4.93	4.66	4.76	5.3	5.72	5.8	5.57	5.23	5.25
8° Tilt[2]	5.14	5.2	5.26	5.37	5.14	4.92	4.99	5.45	5.71	5.71	5.55	5.23	5.31
23° Tilt[2]	5.09	5.05	5.08	5.43	5.41	5.29	5.32	5.61	5.61	5.49	5.48	5.21	5.34

[1] *Monthly Averaged Insolation Incident On A Horizontal Surface (kWh/m²/day)*
[2] *Monthly Averaged Radiation Irradiance for Equator Facing Tilted surface tilted at an angle equal to the latitude of the location and at an angle equal to the latitude of the location plus 15 degrees (kWh/m²/day)*
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