GRID-CONNECTED PV SYSTEMS

SYSTEM DESIGN GUIDELINES

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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 latest industry BEST PRACTICE for the design of Grid Connected 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
DC	Direct Current
EN	European Standards (European Norms)
IEC	International Electrotechnical Commission.
KW_p	Kilowatt Peak
KWh	Kilowatt Hour
LED	Light-emitting Diode
MP	Maximum Power
MPP	Maximum Power Point
MPPT	Maximum Power Point Tracker
NEC	National Electrical Code
NZS	New Zealand Standards
PNG	Papua New Guinea
PSH	Peak Sun Hours
PV	Photovoltaic
STC	Standard Test Conditions
UL	Underwriters Laboratories

1. Introduction

This document provides an overview of the formulas and processes undertaken when designing (or sizing) a grid connected PV system.

This document provides the minimum knowledge required when designing a grid connected PV system. Design criteria may include:

- Specifying a specific size (in kW_p) for an array;
- Available budget;
- Available module mounting space;
- An annual kWh delivery goal such as wanting to zero the owner's annual electrical usage from the grid;
- Wanting to reduce the use of fossil fuel in the country or meet other specific customer related criteria.

Whatever the final design criteria, a designer shall be capable of:

- Determining the energy yield, specific yield and performance ratio of the grid connected PV system.
- Determining the inverter size and quantity based on the size and number of the panels in the array.
- Matching the array/panel configuration to the selected inverters:
    - Maximum voltage and voltage operating window;
    - Maximum allowable d. input power rating; and
    - Maximum dc input current rating.

A system designer will also determine the required cable sizes, isolation (switching) and protection requirements. This information is included in the companion guide titles: Installation of grid connected PV systems.

Figures 1 & 2 show 2 types of typical interconnection of a grid connected PV system.
Examples of the individual components are shown in Figures 3 to 7.

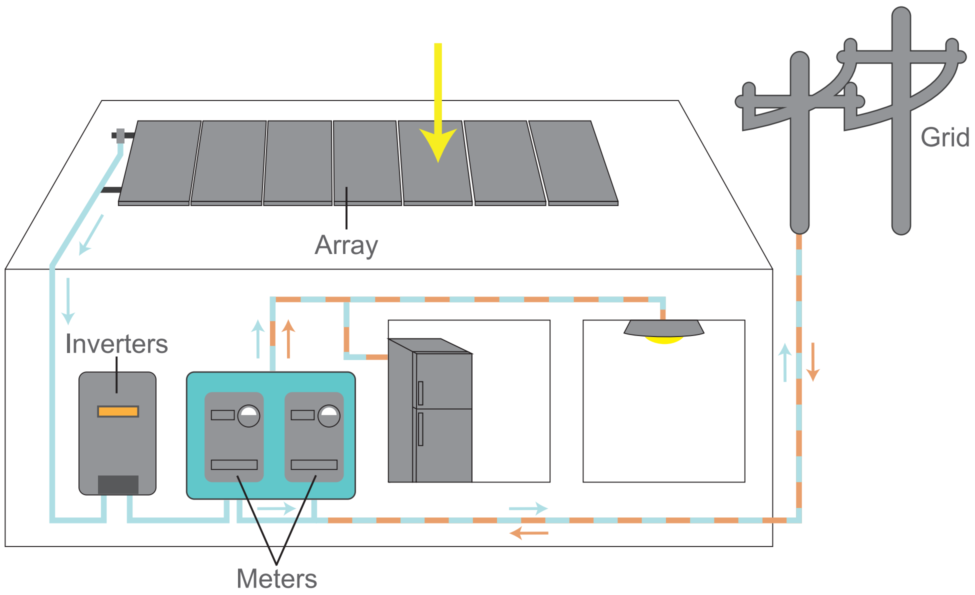


Figure 1: Components of a Grid Connected PV System-String Inverter

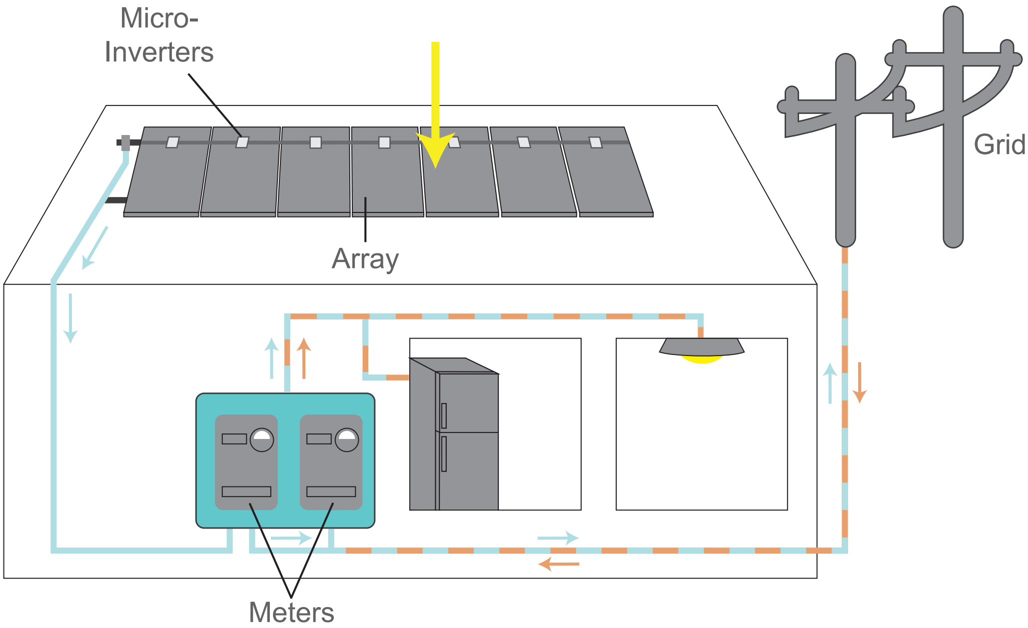


Figure 2 : Components of a Grid Connected PV System- Module Inverter

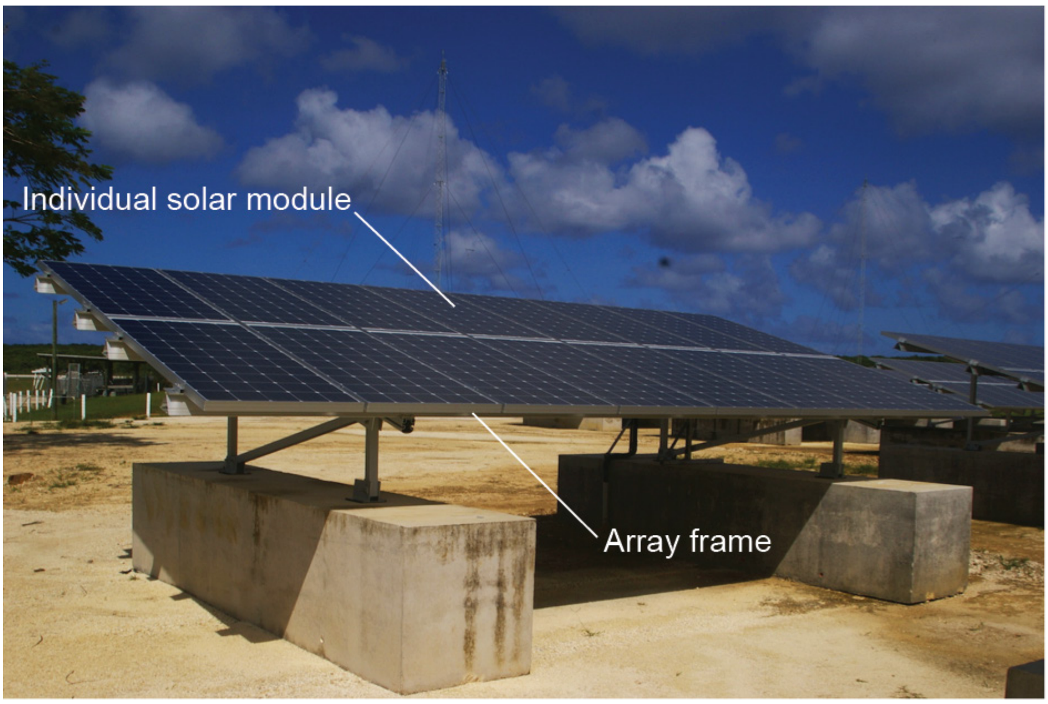


Figure 3: Ground Mounted Solar array

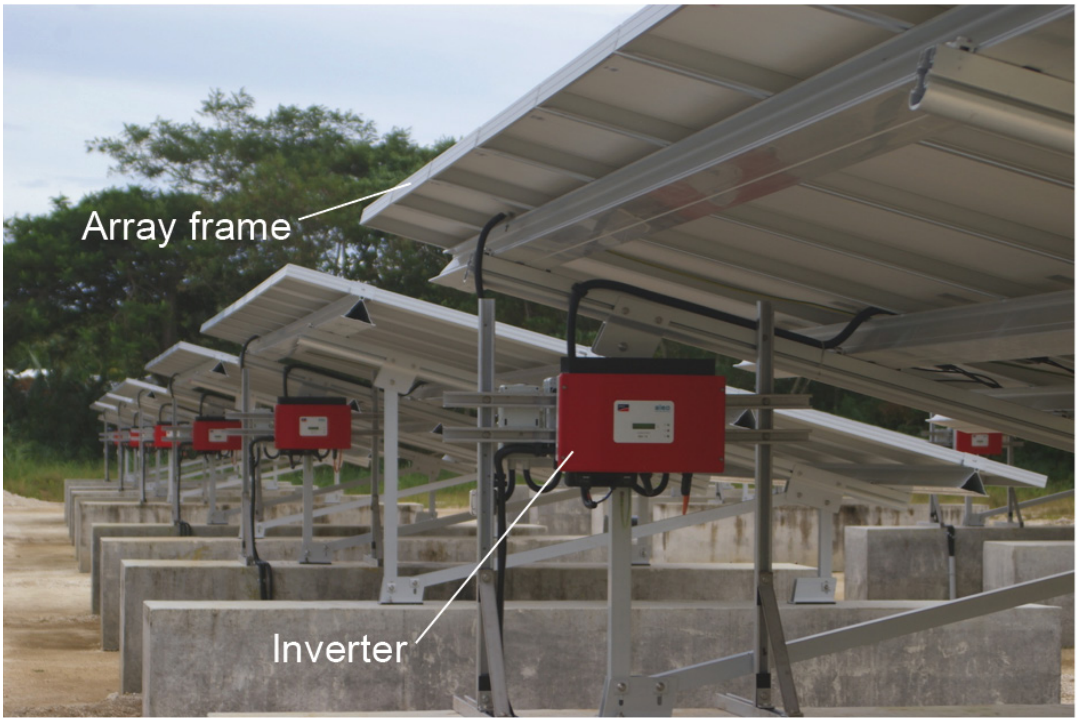


Figure 4: Showing Inverter and Frame

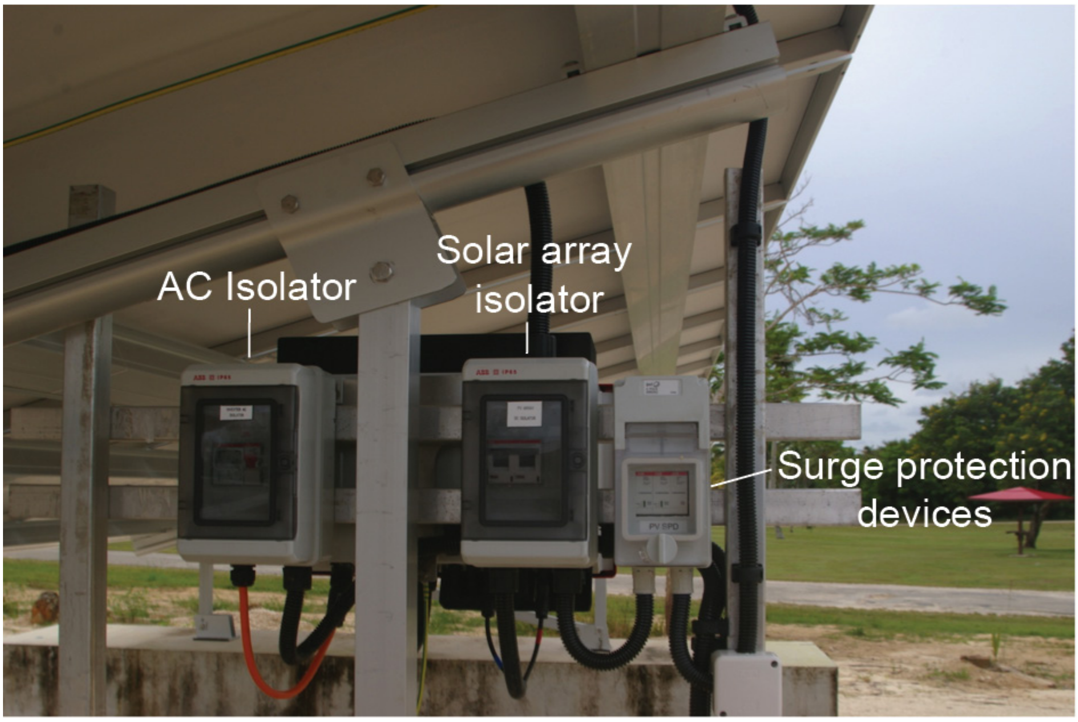


Figure 5: Isolators and Surge Protection Devices

Figure 6: Array on House Roof

Figure 7: Household Installation

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. In this document there are calculations based on temperatures in degrees centigrade (°C). The formulas used are based on figures provided from solar module manufactures where the temperature coefficients are generally expressed in °C in degrees while there are some from the USA that have used degrees kelvin (K). A one-degree change in C is equal to a one-degree change in K. So if the module manufacturer provides the temperature coefficient in K, just change the K to a °C.

If your local temperatures are given in Fahrenheit degrees, to use the formulas shown in this guideline, you must convert °F to °C. For your convenience in making that conversion, Appendix 1 is a table to convert from °F to °C from 32°F to 127°F (0°C to 53°C). Use the appropriate Fahrenheit number in a °F column and use the number in the adjacent °C column in the formulas given in this guideline.

2. Standards Relevant to Design of Grid Connected PV Systems

System designs should follow any standards that are typically applied in the country or region where the solar installation will occur as well as any additional standards specific to the island country where the installation is located. The following are the relevant standards in Australia, New Zealand and USA. They are listed because some Pacific island countries and territories do follow those standards. These standards are often updated and amended so the latest version should always be applied.

In Australia and New Zealand, the relevant standards include:

- AS/NZ 3000	Wiring Rules.
- AS/NZS 3008	Electrical Installations-Selection of Cables.
- AS /NZS 4777	Grid Connection of energy systems by Inverters.
- AS/NZS 5033	Installation and Safety Requirements of PV Arrays.
- AS/NZS 4509	Stand-alone power systems (note: some aspects of these standards are relevant to grid connect systems).
- AS 3595	Energy management programs.
- AS 1768	Lightning Protection.
- IEC 61215	Terrestrial photovoltaic (PV) modules - Design qualification and type approval
• IEC 61215-1	Part 1: Test requirements
• IEC 61215-1-1	Part 1-1: Special requirements for testing of crystalline silicon photovoltaic (PV) modules
• IEC 61215-1-2	Part 1-2: Special requirements for testing of thin-film Cadmium Telluride (CdTe) based photovoltaic (PV) modules
• IEC 61215-1-3	Part 1-3: Special requirements for testing of thin-film amorphous silicon based photovoltaic (PV) modules
• IEC 61215-1-4	Part 1-4: Special requirements for testing of thin-film Cu(In,GA) $(S,Se)_2$ based photovoltaic (PV) modules
• 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.
- IEC 62109	Safety of power converter for use in photovoltaic power systems.
• IEC 62109-1	Part 1: General requirements.
• IEC 62109-2	Part 2: Particular requirements for inverters.

In USA the relevant codes and standards include:

- 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 1703 Flat Plate Photovoltaic Modules and Panels.
- IEEE 1547 Standards for Interconnecting Distributed Resources with Electric Power Systems.
- UL Standard 1741 Standard for Inverter, converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources.
- UL 62109: Standard for Safety of Power Converters for Use in Photovoltaic Power Systems.
- UL 2703 Standard for Mounting Systems, Mounting Devices, Clamping/ Retention Devices, and Ground Lugs for Use with Flat-Plate Photovoltaic Modules and Panels.
- UL(IEC) 61215 Crystalline silicon terrestrial photovoltaic (PV) modules— Design qualification and type approval.
- UL(IEC)61646 Thin-film terrestrial photovoltaic (PV) modules— Design qualification and type approval

3. Steps when Designing a Grid Connected PV System

The steps in undertaking a system design include:

1. Determining why the potential client/owner wants a grid connected PV system.
2. Undertaking a site visit and determining the limitations for installing a system and where all the equipment will be installed (Section 4)
3. Determining the size of the array (Section 5,6 and 7)
4. Selecting an inverter(s) and matching the inverter(s) to the array. (Section 8)
5. Estimating the annual solar input at the site (Section 7)
6. Estimating the system yield. (Section 10)
7. Providing a quotation to the client/customer. (Section 13)

4. Site Visit

Prior to designing any Grid Connected PV system a designer shall visit the site and undertake/determine/obtain the following:

1. The reason why the client wants a grid connected PV system.
2. Discuss energy efficiency initiatives that could be implemented by the site owner. These could include:
   - i. Replacing inefficient electrical appliances with new energy efficient electrical appliances
   - ii. Possibly replacing tank type electric hot water heaters with a solar water heater either gas or electric boosted. (If applicable)

     Note:

     Price of PV modules has reduced so much that for some locations, using PV modules on an electric hot water unit may be cheaper then installing a separate solar hot water unit.
   - iii. Replacing incandescent light bulbs with efficient LED lights.
3. Assess the occupational safety and health risks when working on that particular site.
4. Determine the solar access for the site.
5. Determine whether any shading will occur and estimate its effect on the system.
6. Determine the orientation and tilt angle of the roof if the solar array is to be roof mounted.
7. Determine the area available for mounting the solar array.
8. Determine whether the roof is suitable as-is for mounting the array or if roof renovation could make it suitable.
9. Determine how the modules will be mounted on the roof.
10. Determine where the inverter(s) will be located.
11. Determine the cabling route and estimate the lengths of the cable runs.
12. Determine whether monitoring panels or screens are required and determine a suitable location for them with the owner

Following the site visit the designer shall estimate the available solar irradiation at the array based on the available solar irradiation for the site as affected by the tilt, orientation and effect of any shadows. (See section 7.1 and 7.2)

5. Selecting a Solar Module

When selecting a solar module to be used in a grid connected PV system the 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
• IEC 61215-2	Part 2: Test Procedures
• 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 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 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)

6. Choosing an Array Structure

The array structure and module attachment system selected for the PV modules shall be designed to resist the ultimate wind actions for the site where the array will be located and be constructed of material suitable for the location. For those countries which have experienced Category 3 to 5 cyclones/typhoons then the frames shall be designed to meet the wind speeds expected in a Category 5 cyclone/typhoon.

Array frames that are designed for winds experienced in Category 5 cyclones typically have mid-clamps longer than 50 mm (2 inches) in length and there can be as many as 3 railings per module. In a large system, consideration shall be given to using an end clamp for every fourth module so if one does become loose then only a few other modules would be affected, not necessarily the whole array.

7. Energy Output of a Solar Array

7.1 Solar Irradiation

Solar data obtained from ground mounted instruments should be the first choice for estimating the solar energy input at the site. Such data may be available from various local sources, typically the national meteorological or agricultural departments. In the case of some islands, (e.g. Nauru and Papua New Guinea) international agencies have collected high quality multi-year, ground level solar data that can be obtained from the home office of the agency collecting the data.

In 2017 the World Bank launched a new tool, for the Pacific Islands as part of their solar atlas. Data can be downloaded from Global Solar Atlas - http://globalsolaratlas.info/.

One other source for solar irradiation data is the NASA website: https://power.larc.nasa.gov/data-access-viewer/ RETSCREEN: (https://www.nrcan.gc.ca/energy/software-tools/7465), a program available from Canada that incorporates the NASA data, is easier to use. Please note that the NASA data has, in some instances, had higher irradiation figures than that recorded by ground collection data in some countries. But if there is no other data available it is data that can be used. One advantage of this data is that it is shown as monthly averages and the timing of high and low solar inputs can be easily seen.

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 hours with a solar irradiance of $1kW/m^2$.

Appendix 2 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)

Note: PV arrays in grid-connected systems are often mounted on the roof of a building. The roof might not be facing true north (Southern Hemisphere) or south (Northern Hemisphere) or at the optimum tilt angle for the site. The irradiation data as corrected for the roof orientation (azimuth)and pitch (tilt angle) shall be used when undertaking the design. Please see the following discussion on tilt and orientation for determining peak sun hours for sites not facing the deal direction.

Worked Example 1

For our worked example we will use the irradiation for Suva at Tilt angle equal to the latitude which is 18°S - that is daily average 5.38kWh/m². (Refer Appendix 2)

Often grid connected system yields are expressed as yearly figures and therefore require a yearly irradiation figure.

This would be 365 x 5.38kWh/m² = 1963.7kWh/m²

7.2 Effect of Orientation and Tilt

When the roof is not oriented true north (southern hemisphere) or true south (northern hemisphere) and/or not at the optimum inclination, the output from the array will be less than the maximum possible.

Appendix 3 provides tables that reflect the variation in irradiation due to different tilts and azimuths from those measured and recorded from the optimums as shown for the locations shown in Table 1. The tables show the average daily total irradiation represented as a percentage of the maximum value i.e. PV orientation is true North (azimuth = 0°) in the Southern Hemisphere or true South in the Northern Hemisphere (azimuth = 180°) with an array tilt angle equal to the latitude angle or 10° whichever is greater[1]. If the location for the system you are designing is not shown it is recommended that you use the site with the nearest latitude.

Table 1: Sites for Orientation and Tilt Tables in Appendix 3

Nº	Site	Latitude	Longitude
1	Nauru	0°32' South	166°56' East
2	Vaiaku, Tuvalu	8°31' South	179°13' East
3	Apia, Samoa	13°50' South	171°46' West
4	Suva, Fiji	18°08' South	178°25' East
5	Tongatapu, Tonga	21°08' South	175°12' West
6	Palikir, Pohnpei FSM	6°54' North	158°13' East
7	Hagåtña, Guam	13°28' North	144°45' East

[1] *It is not advisable to mount panels at a tilt angle less than 10° since panels need to be self-cleaned by the rapid run-off of rain.*

Using these tables will provide the system designer/installer with information on the expected output of a system (with respect to the maximum possible output) when it is located on a surface that is not facing true north (or south) or at an inclination equal to the latitude angle. The designer can then use the peak sun hour data for the site to determine the expected peak sun hours of sun falling on the array at the orientation and tilt angle for the system to be installed. Note that in the case of arrays that are mounted on several roofs at different orientations and tilts, each roof must have the solar input calculated separately as kWh per individual roof then all the kWh that result can be added together to get the total from all the modules in the installation.

Worked Example 2

The array is tilted at 20 degrees and its orientation is east, that is azimuth of 90 degrees. There is no shading.

From the Suva table in Appendix 2 the irradiation derating factor will be 93% or 0.93.

Therefore the available irradiation for the site is 0.93 x 5.38kWh/m² = 5.0kWh/m²

7.3 Shading of Array

In towns and cities where grid connect systems will be most likely, the roof of the house or building will not always be free of shadows during parts of the day and the array will have some shading. This will affect the output of the array.

If it effects the whole array, then it can be considered as a reduction in irradiation.
However, if it is only shading part of the array the exact effect is hard to predict because it is not necessarily the equivalent of a decrease in available irradiation because it is only affecting the output power of those few modules not the whole string. This is discussed again under system yield.

7.4 Factors Affecting the Solar Module's Power Output

The output of the solar module is affected by temperature, dirt, panel age and possibly manufacturers tolerances and/or module mismatch. This means that the power output of the solar module should be adjusted for those factors when determining the energy output of the solar array.

Adjustment Due to Temperature

A solar module's output power typically decreases with cell temperatures above 25°C (77°F) and increases with temperatures below 25°C (77°F). During the day, the average cell temperature will be higher than the ambient temperature because of the glass shielding the solar cells in the module and the fact that the module absorbs some heat from the sun. The output power and/or current of the module must be based on the temperature of the cell, not that of the ambient air. This is estimated by the following formula:

$$T_{cell\text{-}eff} = T_{a.day} + T_r$$

Where

$T_{cell\text{-}eff}$ = the average daytime effective cell temperature in degrees Celsius (°C)

$T_{a.day}$ = the daytime average ambient temperature for the month that the sizing is being undertaken.

T_r = rise in temperature of the array when exposed to the sun.

The value of T_r to be used for calculations when actual measurements of cell temperatures are not available is selected from Table 2.

Table 2: Values of T_r

Installation of Array Frame	T_r
Ground Mounted Array	25°C
Array on roof where the array tilt angle is at least 20 degrees greater than the actual roof	25°C
Array structure parallel to roof with air gap greater than 150 mm	30°C
Array structure parallel to roof with air gap less than 150 mm	35°C

The three different types of solar modules available on the market each have different temperature coefficients. These are:

A) Monocrystalline Modules
Monocrystalline Modules typically have a temperature coefficient between – 0.4%/°C and – 0.45%/°C .
Assuming it is – 0.45%/°C, that means that for every degree above 25°C the output power is decreased by 0.45%.

B) Polycrystalline Modules
Polycrystalline Modules typically have a temperature coefficient of – 0.4%/°C and –0.5%/°C

C) Thin Film Modules
Thin film Modules have a different temperature characteristic resulting in a lower co-efficient typically around 0%/°C to – 0.3%/°C.

Always check with the product manufacturer for the exact value for the module being used in the system design. The data is available on the product brochure and must be available if the product has been tested and approved in accordance with the IEC and UL standards.

The symbol used for temperature co-efficient is γ and it is expressed on data sheets as a negative number.

The derating of the array due to temperature will be dependent on the type of module installed and the average maximum ambient temperature for the location.

The typical ambient daytime temperature in many parts of the Pacific is between 30°C (86°F) and 35°C (95°F) during some times of the year. So it would not be uncommon to have module cell temperatures of 55°C (131°F) and higher.

The percentage power loss due to effective cell temperature is the Cell Temperature Coefficient multiplied by the difference between the cell's effective temperature when exposed to full sunlight and the Standard Test Condition (STC) temperature (T_{STC}) of 25°C.

Written as a formula it is:
Percentage power loss due to effective cell temperature = γ x ($T_{cell\text{-}eff}$ - T_{STC})

Note: Since the temperature coefficient, γ, is expressed as negative, using the above formula will provide a negative answer. This is why it is then defined as a loss.

This loss is generally expressed as a temperature derating factor (f_{temp}) which is calculated as follows:
f_{temp} = 1- the percentage of power lost due to heating of the cells above the STC

The result, f_{temp}, is the percentage of power left after correction for cell temperature, called the temperature derating factor.

Worked Example 3

A solar array is mounted on a roof. It is parallel to the roof and the air gap is less than 150mm.

The solar module has a temperature coefficient of -0.43%/°C.

The average day-time ambient temperature is 30°C (86°F).
What is the percentage (%) power loss due to temperature for this solar?
What is the temperature derating factor?

From table 1 the rise in temperature (T_r) is 35°C.

The effective cell temperature is therefore:

$T_{cell-eff} = T_{a.day} + T_r$
$= 30°C + 35°C$
$= 65°C$

The percentage power change due to effective cell temperature = γ x ($T_{cell-eff}$ - T_{STC})
= -0.43%/°C x (65°C- 25°C)
= -0.43% x 40
= -17.2%

As a fraction -17.2% converts to 17.2/100= -0.172 with the minus sign showing it as a loss

temperature derating factor (f_{temp}) is calculated as follows:

f_{temp} = 1- loss due to temperature
= 1- 0.172
= 0.828

Derating Due to Dirt

The output of a PV module can be reduced as a result of a build-up of dirt on the surface of the module. The actual value of this loss will be dependent on the actual location but in some city locations this could be high due to the amount of pollution in the air and in coastal regions during long periods of no rain, salt may build up on the module surface. These reduce the transparency of the glass cover and therefore reduce the solar energy getting through to the cells.

In dusty or salty environments this loss could be as high as 20%.

If in doubt, an acceptable value for this loss would be 5% and can be used when there is no specific evidence of significant dirt or salt accumulation.

This loss is generally expressed as a dirt derating factor (f_{dirt}).
f_{dirt} = 1- the energy loss

> **Worked Example 4**
>
> If the loss due to dirt is 10% what is the dirt derating factor?
>
> As a fraction 10% converts to 10/100= 0.1
> f_{dirt} = 1- the energy loss
> = 1-0.1 = 0.9

Manufacturers Output Tolerance

The output of a PV module is specified in Peak Watts which is the module's output with a solar input of 1000 W/m² and with a manufacturing tolerance based on a cell temperature of 25° C. Historically this has been ±5% and in recent years' typical figures have been 0% to +3% however, in small print on the data sheet there is often stated: Measuring tolerance: ±3%. This effectively means the module could have a manufacturing tolerance which leads to a loss of up to 3%.

When designing a system, it is important to incorporate the actual figure for the selected module and take into account the measuring tolerances.

This loss is generally expressed as a manufacturer's derating factor (f_{man}) .
f_{man} = 1- manufacturer's tolerance (or measuring tolerance loss)

> **Worked Example 5**
>
> If the loss due to Measuring tolerance is 3% what is the derating factor?
>
> As a fraction 3% converts to 3/100= 0.03
> f_{man} = 1- the measuring tolerance loss
> = 1-0.03 = 0.97

7.5 Derating Solar Modules Power Output

Solar modules have a rated output measured at Standard Test conditions (STC). Based on the factors affecting the power output of the module (P_{mod}) as detailed in section 7.3 the derated power output ($P_{derated}$) of the module is determined as follows:

$$P_{derated} = P_{mod} \text{ x } f_{temp} \text{ x } f_{dirt} \text{ x } f_{man}$$

Worked Example 6

A module has a rated power output of 275W. Based on the previous examples the module has the following derating factors:

$f_{temp} = 0.828$

$f_{dirt} = 0.9$

$f_{man} = 0.97$

What is the derated output power of the module?

$P_{derated} = P_{mod} \text{ x } f_{temp} \text{ x } f_{dirt} \text{ x } f_{man}$.

$= 275\text{W x } 0.828 \text{ x } 0.9 \text{ x } 0.97$

$= 198.8\text{W}$

Note: Solar Modules reduce efficiency over time. This can result in a loss of rated power of 0.5% to 1.0% per year.

8. Inverter Selection

When selecting an inverter to be used in a grid connected PV system the inverter(s) 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

The final selection of the inverter for the installation will depend on:

- The power output of the array;
- Whether the system will have one inverter or multiple (smaller) inverters; and
- The matching of the allowable inverter string configurations (based on voltage and current) with the size of the array in kW and the voltage and current specifications of the individual modules within that array.

8.1 How Many Inverters?

A system might comprise of only one inverter or it might comprise multiple inverters. The reasons why multiple inverters could be used include:

1. The array is spread over a number of roofs that have different orientations and tilt angles. Modules in the same string must have the exact same orientation and have the same tilt angle. If there are parallel strings connecting to the same maximum power point tracker (MPPT) in an inverter, then these two strings must also have the same orientation and tilt angle for the MPPT to work properly.

   A separate MPPT will be required for each section of the array which has a different orientation or tilt angle. This could be achieved by using an inverter with multiple maximum power point trackers (MPPTs). Each MPPT in the inverter can be connected to a portion of the array that has a different orientation if there are multiple roofs.

   Using separate inverters is also possible since in that case each inverter has its own separate MPPT.

   Note: There are also inverters, each having its own MPPT, available on the market that mount on individual modules which can also overcome the issue of modules in an array having to be mounted with different orientations and tilt angles.

   There are also products available on the market where there is one inverter but individual MPPTs. Each MPPT is mounted on individual modules and then all the MPPTs interconnect to the inverter. These also overcome the issue of modules in an array having to be mounted with different orientations and tilt angles

2. Multiple inverters allow a portion of the system to continue to operate if one inverter fails.

3. Allows the system to be constructed in independent, standardized sections, so that increasing the system capacity involves adding a predetermined number of standard sections with each having its own inverter and array of modules. Also locating problems tends to be easier when a large array is divided into multiple standard sections instead of installing it as one giant array.

The potential disadvantage of multiple inverters is that in general the cost of a number of inverters with lower power ratings is generally more expensive than one single inverter with a higher power rating.

8.2 Selecting the Size of Inverter

The array and the inverter must be matched to function properly. Inverters currently available are typically rated for:

- Maximum dc input power;
- Maximum specified output power;
- Maximum dc input voltage;
- Minimum dc MPPT input operating voltage; and
- Maximum dc input current.

Note: Some inverter data sheets also specify maximum PV array power. In this case, the array's total rated power must not be greater than the inverter's stated maximum PV array power

To reach the operating voltage of the inverter MPPT, usually a number of modules must be connected in series. The number of modules in a string, and hence maximum and minimum voltages of the string, must be matched to the:

- Maximum dc input voltage; and
- Minimum dc MPPT input operating voltage.

To reach the highest level of dc current that the MPPT can accept from the array it may be necessary to connect strings of modules in parallel. The number of parallel strings, and hence maximum dc currents must not exceed the maximum input current allowed for the MPPT that is connected to those strings.

8.3 Matching Array Power to the Inverter

The maximum power of the array is calculated by the following formula:

Array Peak Power =

Number of modules in the array x the rated maximum power (P_{mod}) of each module at STC.

Worked Example 7

An array consists of twenty two (22) modules with a peak rating of 275 W_p.

The Array Peak Power = 22 x 275W = 6050W_p.

If the inverter data sheet does specify the maximum array power, then the designer shall not design an array with rated peak power greater than the specified maximum array power.
If the inverter data sheet only specifies the maximum dc power input to the inverter the designer should contact the inverter manufacturer and determine if there is a maximum allowed PV array power rating.

The array's output power at the inverter will be less than the rated maximum rated power of the array due to the effects of temperature, dirt, manufacturers tolerances, panel age and the voltage drop in the wiring between the array and inverter. However, if there is no specified maximum array power for the inverter, the designer shall not design an array with a rated output greater than the inverters rated dc input power unless the designer has obtained written permission from the manufacturer.

Worked Example 8

The inverter data sheet provides the following information:

Max AC Output Power	5000W
Max Generator Power (PV Array)	$9000W_p$
Max. input voltage	1000 V
MPPT voltage range	245 V to 800 V
Min. input voltage	150 V
Max. input current input A / input B	11 A / 10 A
Max. short-circuit current input A / input B	17 A / 15 A
Number of independent MPPT inputs/ strings per MPPT input 2/	A:2; B:2

The array in the example is 6050W, this is less than the 9000W max generator power allowed.
It is also above the AC rating of the inverter so allowing for losses it could operate at its full 5000W rating at times.

8.4 Matching Array Voltage to the Inverter

The number of modules in a string, and hence the maximum and minimum voltages of the string, must be matched to the:

- Maximum dc input voltage; and
- Minimum dc MPPT input operating voltage.

The output power of a solar module is affected by the temperature of the solar cells. As shown in previous sections for polycrystalline PV modules this effect can be as much as 0.5% for every 1-degree Celsius variation in temperature.

This variation in power due to temperature is also reflected in a variation in the open circuit voltage and maximum power point voltage.

Most modern grid interactive inverters include one or more Maximum Power Point Trackers (MPPT) at their inputs.

The inverter manufacturer on the data sheet should specify the following voltages:

- Minimum voltage for inverter operation;
- Minimum Maximum Power Point Tracker (MPPT) operating voltage;
- Maximum Maximum Power Point Tracker (MPPT) operating voltage; and
- Maximum voltage allowable to the inverter input.

The inverter's MPPT will only track the maximum power point voltage of the array when the array's Maximum Power Point (MPP) voltage is between the inverter's specified MPP minimum operating voltage and maximum MPP operating voltage making it within the operating voltage window. If the solar array voltage is outside this window the MPPT does not track the MPP voltage of the array and the output power of the system could be greatly reduced.

The minimum input voltage is the voltage where the inverter will turn off at the end of the day. Between the minimum operating voltage of the MPPT and this voltage, the MPPT does not necessarily track the maximum power point voltage. So it is important that the MPP voltage of the array is always greater than the minimum operating voltage of the MPPT of the inverter.

The maximum voltage of the inverter is the point where any voltage above that value may damage the inverter and/or cause a shut-down of the system.

For the best performance of the system the output voltage of the solar array should be matched to the operating voltages of the MPPT it is connected to in the inverter. To minimise the risk of damage to the inverter the maximum voltage of the inverter should never be reached.

As stated earlier the output voltage of a module is affected by cell temperature changes in a similar way as the output power. The PV module manufacturer will provide a voltage temperature coefficient. It can be specified in V/°C (or mV/°C) but it is now generally specified in %/°C.

In practice the array should be designed such that:

- At the maximum temperature expected during the day the arrays MPP voltage is always greater than the inverter minimum operating voltage.
- At the coldest temperature of the day (in the Pacific this will be early in the morning) the open circuit voltage of the array is less than the maximum input voltage allowed for the inverter.

The design should ensure that the array's MPP voltage at the coldest temperature is below the inverters MPPT maximum operating voltage, but this is not too critical since it will only result in the maximum power point not being properly tracked, it will not result in damage. The critical issue is that open circuit voltage at the coldest temperature must not be above the maximum input voltage. If this requirement is met and the arrays MPP voltage at the coldest temperature is above the inverters MPPT maximum operating voltage, then the MPPT will connect to the array at the inverters MPPT maximum operating voltage but will not track the maximum power point until the voltage falls to the MPPT maximum voltage. This would only happen first thing in the morning when the power output is small. As the temperature increases the array's MPP voltage will decrease soon to the point where the MPPT voltage will enter the operating voltage window and the MPPT unit will become operational until late in the day when the voltage falls below the minimum MPPT voltage.

To design systems where the output voltages of the array do not fall outside the range of the inverter's dc operating voltages and maximum input voltage, the historical minimum and maximum day time temperatures for that specific site are required.

The following sections details how to determine the minimum and maximum number of solar modules allowed to be connected in series to match the operating voltage window of an inverter. Many of the inverter manufacturers do have software programs for doing this matching.

8.4.1 Minimum Number of modules in the string

When the temperature is at a maximum then the Maximum Power Point (MPP) voltage (V_{mp}) of the array should never fall below the minimum operating voltage of the MPPT of the inverter. The actual voltage at the input of the inverter is not just the V_{mp} of the array, the voltage drop in the dc cabling between the array and the inverter must also be included when determining the actual inverter input voltage.

Since the daytime ambient temperature in some areas of the Pacific Islands can reach, or exceed, 35°C (95ºF) it is recommended that a maximum effective cell temperature of 75°C (167°F) is used.

Note: While the maximum temperature used may seem high, Germany specifies 70°C (158°F) even though on average their summer temperatures are generally less than 35°C (95°F).

Determine Minimum MPP Voltage (V_{mp}) of a Module at the Inverter

The minimum MPP voltage (V_{mp}) of a module is determined by calculating the reduction in V_{mp} due to the effective cell temperature.

The reduction in V_{mp} is calculated by multiplying the voltage temperature coefficient (V/°C) by the difference between the effective cell temperature and the STC temperature (25°C).

Since the maximum temperature has been specified as 75°C then the reduction in V_{mp} is 50 (75°C - 25°C) times the voltage temperature coefficient (V/°C).

Note: It is a reduction because the temperature co-efficient has a negative value

The effective V_{mp} out of the module due to the maximum temperature
= V_{mp} less the reduction in V_{mp} due to a module temperature above STC.

This value is then reduced by the voltage drop in the connecting wires. Since voltage drop is typically expressed as a percentage (%) value then the reduction factor due to voltage drop is (1 – %voltage drop). So if the % voltage drop in the wires is 2%, voltage after wiring loses are included would be (1.00 - .02) = 0.98 x the operating voltage. That would be the voltage actually reaching the MPPT.

Therefore,
the effective minimum MPP voltage input at the inverter for each module in the array
= the effective V_{mp} out of the module at the maximum module temperature x (1 – % voltage drop in the wires)

Many module manufacturers do not supply the voltage coefficient for V_{mp}. It is supplied only for V_{oc} (the open circuit voltage). If the V_{mp} temperature coefficient is not available then either

- The V_{oc} temperature co-efficient can be used;
  or
- P_{mp} temperature coefficient can be used in place of the V_{oc} temperature coefficient for determining the V_{mp} temperature coefficient because the current temperature coefficient is negligible so the V_{mp} temperature coefficient is very close to the P_{mp} temperature coefficient.

Worked Example 9

A module data sheet provides the following information:

- P_{mp} = 275W_p
- V_{oc} = 37.7V
- V_{mp} = 31.3V
- I_{sc} = 9.34A
- I_{mp} = 8.78A
- Power temperature coefficient = -0.41%/°C
- V_{oc} temperature coefficient = 0.32%/°C
- No V_{mp} temperature coefficient.
- Manufacturers Tolerance 0 to +3%
- Measurement Tolerance +- 3%

Therefore, in V/°C the V_{oc} temperature coefficient = 0.32/100 per degree C x 37.7V = 0.121V/°C

Applying the power temperature coefficient then the V_{mp} temperature coefficient = 0.41/100 x 31.3 = 0.128V/ °C . This will be used in the rest of the example.

Based on the maximum temperature of 75°C then the:
Reduction in V_{mp} due to temperature = 75° C - 25° C = 50° C times the voltage temperature coefficient (V/°C).
= 50° C x 0.128V/°C
= 6.4V

So the effective V_{mp} of the module due to temperature = 31.3V-6.4V = 24.9V

If we assume a maximum voltage drop in the cables of 1% then the voltage at the inverter for each module would be

$$(1 - 0.01) \times 24.9 = 0.99 \times 24.9 = 24.65 \text{ V}$$

This is the effective minimum MPP voltage input at the inverter for each module in the array.

Determine Effective Minimum MPPT Operating Voltage of the Inverter

The inverter data sheet specifies actual minimum MPPT operating voltage.

However, The MPP voltage of a solar module rises with increases in irradiance. Since the array is typically operating with irradiance levels less than 1kW/m² (the STC value) when the effective cell temperature is still high then the actual MPP voltage will be reduced. The exact variation is dependent on the quality of the solar cell so it is recommended that a safety margin of 10% is added to the minimum MPPT operating voltage.

Note: This is just a recommendation and there will be times when it might not be practical, however be aware that if it is not applied then the system might underperform if the effective cell temperatures does approach 75°C.

Worked Example 10

The inverter data sheet provides the following information:

Max AC Output Power	5000 W
Max Generator Power (PV Array)	9000 W_p
Max. input voltage	1000 V
MPP voltage range	245 V to 800 V
Min. input voltage	150 V
Max. input current input A / input B	11 A / 10 A
Max. short-circuit current input A / input B	17 A / 15 A
Number of independent MPP inputs / strings per MPP input	2 / A:2; B:2

Though there is a minimum input voltage it is the Minimum Voltage range that is selected for determining minimum number of modules.

The minimum operating voltage of the MPPT is 245V

Allowing for the safety margin of 10% the effective minimum operating voltage of the MPPT
(1 + 10%) x 245V = 1.1 x 245V = 269.6V

Determine Minimum Number of Modules in the String

The minimum number of modules in a string is determined by dividing the effective minimum operating voltage of the MPPT by the effective minimum MPP voltage input at the inverter for each module.

Since it is the minimum number it should always be rounded up when a fraction of a module is indicated by the calculations.

> **Worked Example 11**
>
> The effective minimum operating voltage of the MPPT = 269.6V
>
> The effective minimum MPP voltage input at the inverter for each module =24.65V
>
> Therefore, the minimum number of modules in a string = 269.6V/24.65V = 10.94
>
> This would have to be rounded up to 11 since rounding down to 10 would sometimes cause the input voltages to be too low for the inverter to function.

8.4.2 Maximum Number of modules in the string

At the coldest daytime temperature, the open circuit voltage of the array shall never be greater than the maximum allowed input voltage for the inverter. The Open Circuit voltage (V_{oc}) is used because this is greater than the MPP voltage and it will be the voltage applied to the inverter when the system is first operating in the early morning – the time prior to the inverter starting to operate on its MPPT and connecting to the grid.

In early morning, at first light, the cell temperature will be very close to the ambient temperature because the sun has not had time to heat up the module.

Therefore the lowest daytime temperature for the area where the system is installed shall be used to determine the maximum V_{oc}.

In some areas of the Pacific the minimum daytime ambient temperature can reach 15°C (59°F). In some areas of the Pacific it might fall below this. It is recommended that 15°C (59°F) is used unless you know that your area has a lower historical minimum temperature for your location, if so use that.

Determine Maximum Open Circuit Voltage (V_{oc}) of a Module at the Inverter

The maximum V_{oc} of a module is determined by calculating the increase in V_{oc} due to the effective cell temperature.

The increase in V_{oc} is calculated by multiplying the voltage temperature coefficient (V/°C) by the difference between the effective cell temperature and the STC temperature (25°C).

If we use 15°C (59°F), then the increase in V_{mp} is (15°C – 25°C) = –10 times the voltage temperature coefficient (V/°C).

Note: it is an increase because the co-efficient is a negative number and the difference in temperatures is also a negative number, so the two multiplied becomes a positive number)

The effective V_{oc} of the module due to the minimum temperature = V_{oc} plus the increase in V_{oc}.

There is no voltage drop included because the V_{oc} is being applied at first light before the inverter has turned on and hence no significant current is flowing.

This is the effective maximum open circuit voltage input at the inverter for each module.

Worked Example 12

Assume the minimum effective cell temperature is 15°C (59°F),
The module data sheet provides the following information:

- V_{oc} = 37.7V
- V_{oc} temperature coefficient = 0.32%/°C

Therefore, in V/°C the V_{oc} temperature coefficient =
– 0.32/100 per degree C x 37.7V = – 0.121V/°C

Based on the minimum temperature of 15°C then the:
Increase in V_{oc} due to temperature = –10°C times the voltage temperature coefficient (V/°C).
= –10°C x – 0.121V/°C
= 1.21V

So the effective Voc of the module due to temperature = 37.7V+ 1.21 = 38.91V for each module in the string.

This is the effective maximum open circuit voltage input at the inverter for each module in the array.

Determine Maximum Operating Voltage of the Inverter

The inverter data sheet specifies actual Maximum operating voltage.

Worked Example 13

The sample inverter data sheet provides the following information:

Max. input voltage	1000 V

Determine Maximum Number of Modules in the string

The maximum number of modules in a string is determined by dividing the maximum operating voltage of the inverter by the effective maximum open circuit voltage for each module.

Since it is the maximum number it should always be rounded down when an exact number of modules is not the result.

> **Worked Example 14**
>
> The maximum voltage of the inverter = 1000V
>
> The effective maximum V_{oc} input at the inverter for each module =38.91 V
>
> Therefore, the maximum number of modules in a string = 1000V/38.91V = 25.7
>
> This would be rounded down to 25 modules in a string.
>
> So in the worked example we can have between 11 (the minimum number) and 25 (the maximum number) of modules in a string and the inverter will function properly.

How Many Strings?

Depending on how many modules have been selected to meet the client's requirements and the characteristics of the inverter to be used, the array could include one string or could be divided into multiple strings. The final configuration can be determined by matching the output currents of the array to the maximum input current of the inverter

> **Worked Example 15**
>
> When determining the array power and matching it to the inverter, an array of 22 modules was selected. So these could either be installed as one string of 22 modules or two strings of 11 modules.
>
> The inverter has two MPPT's so each string of 11 could be connected to one MPPT input of the inverter.
>
> Matching the output currents of the array with the maximum input currents can help determine the final string arrangement.

8.5 Matching Array Current to the Inverter

Inverters have a maximum input current. However, since many inverter now have multiple MPPT's and can have multiple connections, often plugs, for the PV array dc wiring to the inverter, these also have a maximum current specified.

The final configuration of the array must ensure that no strings or array connection to the inverter has an output current greater than that specified for that inverter input.

Worked Example 16

The inverter data sheet provides the following information:

Max. input current input A / input B	11 A / 10 A
Max. short-circuit current input A / input B	17 A / 15 A
Number of independent MPP inputs / strings per MPP input	2 / A:2; B:2

This is saying that maximum input current (generally the operating current or maximum power point current) is 11A for input A and 10A for input B. It allows a maximum short circuit current of 17A for A and 15A for B.

The module data sheet provides the following information:

- I_{sc} = 8.78A
- I_{mp} = 9.34A

If there are two parallel strings on either MPPT input, then the maximum currents would be greater than that allowed. So only one string per MPPT is allowed for this inverter.

So there are still two solutions that will work: one long string of 22 modules or two short strings of 11 modules with each string connected to a separate MPPT. Either approach will stay within the acceptable voltage and current range of the inverter inputs. Which is better? Generally using shorter strings is preferred because of the lower voltages that are present in the module circuits. A 22 module string will have double the voltage of an 11 panel string and lower voltage arrays tend to be safer for maintenance personnel and less likely to have a problem with arcing in wiring, panels or connectors. Also if there is partial shading of the array and the array is split over two MPPT units, the overall array output may be somewhat better than if a single MPPT connection is used since the shading will affect the whole array if there is only one string but may affect only half the array if there are two strings with one in the shade and one staying in the sun.

9. Electrical Losses in the Grid connected PV System

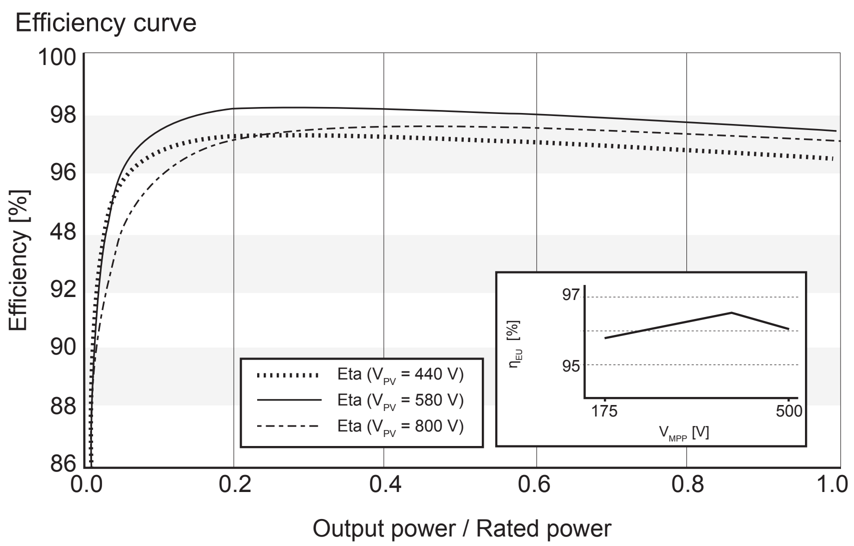
The electrical losses in the grid connected system include all the losses between the PV array and the point of connection to the grid. This connection point is typically at a switchboard or distribution board but when the solar power is being metered as it is supplied onto the grid then it will be at the location of the meter.

The losses typically include:

- Power loss due to voltage drop between the PV array and inverter. This should not exceed 3%
- Power loss resulting from inverter efficiency. This is typically supplied on the Inverters data sheet as a curve showing efficiency vs inverter output.
- Power loss due to voltage drop between the PV inverter and the interconnection to the grid. This should not exceed 1%.

Worked Example 17

The data sheet states that the maximum inverter efficiency is 98% and provides the following efficiency curve.



This curve indicates that the inverter is above 96% efficiency for most of its operating range so using 96% would be good conservative figure.

For the example we will use 3% loss for the dc cables and 1% loss for the ac cables. These are the worst case scenario.

10. Energy Yield

For a specified peak power rating (kW_p) for a solar array a designer can determine the systems energy output over the whole year. The system energy output over a whole year is known as the systems "Energy Yield".

The average yearly energy yield can be determined as follows:

$$E_{sys} = P_{array\_STC} \times f_{temp} \times f_{mm} \times f_{dirt} \times H_{tilt} \times \eta_{pv} \times \eta_{pv\_inv} \times \eta_{inv} \times \eta_{inv\text{-}sb}$$

Where:

E_{sys}	=	average yearly energy output of the PV array, in watthours
$P_{array\text{-}stc}$	=	rated output power of the array under standard test conditions, in watts
f_{temp}	=	temperature de-rating factor, dimensionless
f_{man}	=	de-rating factor for manufacturing tolerance, dimensionless
f_{dirt}	=	de-rating factor for dirt, dimensionless
H_{tilt}	=	yearly irradiation value (kWh/m^2) for the selected site (allowing for tilt, orientation and shading)
η_{inv}	=	efficiency of the inverter dimensionless
η_{pv_inv}	=	efficiency of the subsystem (cables) between the PV array and the inverter
$\eta_{inv\text{-}sb}$	=	efficiency of the subsystem (cables) between the inverter and the switchboard

Note: The efficiency of solar modules reduce efficiency over time. This can result in a loss of rated power of 0.5% to 1.0% per year. The above formula determines the expected energy yield in the first year of operation. The expected energy yield will reduce each year due to the effect of the reduction in the solar modules efficiency.

10.1 Effect of Shading

Care should be taken when selecting the number of modules in a string because the shading could result in the maximum power point voltage at high temperatures being below the minimum operating voltage of the inverter causing the inverter to shut down until the shading is reduced.
Determining the effect of shading on the energy yield can be difficult to predict exactly and the designers should use a suitable program or be conservative when providing the energy yield to the client.

Worked Example 18

Throughout this guide we have determined the following data for the sample system:

$P_{array\text{-}stc}$	=	6050 W_p
f_{temp}	=	0.828
f_{man}	=	0.97
f_{dirt}	=	0.9
H_{tilt}	=	1846.9kWh/m^2
η_{inv}	=	0.96 (96%)
η_{pv_inv}	=	0.97 (97%)
$\eta_{inv\text{-}sb}$	=	0.99(99%)

$$E_{sys} = P_{array\_STC} \times f_{temp} \times f_{mm} \times f_{dirt} \times H_{tilt} \times \eta_{pv} \times \eta_{pv\_inv} \times \eta_{inv} \times \eta_{inv\text{-}sb}$$

E_{sys} = 6050 x 0.828 x 0.97 x 0.9 x 1846.9x 0.96 x 0.97 x 0.99

E_{sys} = 7445974 Wh or 7445.97kWh

11. Specific Yield

The specific energy yield is expressed in kWh per kW_p and it is calculated as follows:

$$SY = \frac{E_{sys}}{P_{array\_STC}}$$

If the performance of systems in different regions is to be compared the shading loss must be estimated and eliminated from the calculation of energy yield. It is based on the yearly energy output of the system.

The AC energy of the solar array delivered to the grid is the E_{sys} in the above formula while the actual STC rating of the array is P_{array_STC} in the above formula.

Worked Example 19

The AC energy from the array was 7445.97kWh/year and the array was rated at 6050W_p which is 6.05kW_p.

Therefore the specific energy yield is 7445.97/6.05= 1230.7kWh per kW_p.

12. Performance Ratio

The performance ratio (PR) is used to access the installation quality. The PR provides a normalised basis so comparison of different types and sizes of PV systems can be undertaken. The performance ratio is a reflection of the system losses and is calculated as follows:

$$PR = \frac{E_{sys}}{E_{ideal}}$$

Where

E_{sys} = actual yearly energy yield from the system

E_{ideal} = the ideal energy output of the array.

The PV arrays ideal energy yield E_{ideal} can determined as follows:

$$E_{ideal} = P_{array\_STC} \times H_{tilt}$$

Where

H_{tilt} = yearly average daily irradiation, in kWh/m² for the specified tilt angle

$P_{array..STC}$ = rated output power of the array under standard test conditions, in watts

If the performance of systems in different regions is to be compared, then any shading loss must be estimated and eliminated from the calculation when determining the actual energy yield.

Worked Example 20

The yearly irradiation is 1846.9 kWh/m²
The array is rated at 6.05kW_p (@1kWh/m²)

Therefore the ideal energy from the array per year would be:
6.05kW_p (@kWh/m²) x 1846.9 kWh/m²= 11173.7kWh

The AC energy from the solar array was 7445.97KWh per year.
Therefore the performance ratio is 7445.97/11173.7 = 0.67

13. Providing a Quotation

When providing a quotation to a potential customer, the designer should provide (as a minimum) the following information

- Full Specifications of the system including quantity, make (manufacturer) and model number of the solar modules, inverter and array frame (if applicable).
- An estimate of the yearly energy output (yield) of the system. This should be based on the available solar irradiation for the tilt angle and orientation of the array. If the array will be shaded at any time the effect of the shadows must be taken into account when determining the yearly energy output.
- The money savings (in local currency) this represents based on existingelectrical energy pricing.
- A firm quotation which shows the installed cost of the complete system.
- Warranty information relating to each of the items of equipment.

Appendix 1: Temperature Conversion Tables

°F	°C
32	0
33	1
34	1
35	2
36	2
37	3
38	3
39	4
40	4
41	5
42	5
43	6
44	6
45	7
46	8
47	8
48	9
49	9
50	10
51	11
52	11
53	12
54	12
55	13
56	13
57	14
58	14
59	15
60	16
61	16
62	17
63	17

°F	°C
64	18
65	18
66	19
67	19
68	20
69	21
70	21
71	22
72	22
73	23
74	23
75	24
76	24
77	25
78	26
79	26
80	27
81	27
82	28
83	28
84	29
85	29
86	30
87	31
88	31
89	32
90	32
91	33
92	33
93	34
94	34
95	35

°F	°C
96	36
97	36
98	37
99	37
100	38
101	38
102	39
103	39
104	40
105	41
106	41
107	42
108	42
109	43
110	43
111	44
112	44
113	45
114	46
115	46
116	47
117	47
118	48
119	48
120	49
121	49
122	50
123	51
124	51
125	52
126	52
127	53

Appendix 2: 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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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° Tilt¹	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° Tilt²	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° Tilt²	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]	6.29	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)
These data were obtained from the NASA Langley Research Center (LaRC) POWER Project funded through the NASA Earth Science/Applied Science Program. (https://power.larc.nasa.gov/)

Appendix 3: Effect on Irradiation Due to Orientation and Tilt Angle

Annual daily irradiation on an inclined plane expressed as % of maximum value for Suva - Fiji

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

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	97%	100%	100%	98%	95%	90%	83%	76%	67%	54%
10	97%	100%	100%	98%	95%	90%	83%	75%	67%	54%
20	97%	99%	100%	98%	94%	89%	82%	74%	66%	53%
30	97%	99%	99%	97%	93%	88%	81%	73%	64%	51%
40	97%	99%	98%	96%	92%	86%	79%	71%	62%	49%
50	97%	98%	98%	95%	91%	84%	77%	68%	59%	47%
60	97%	98%	97%	94%	89%	82%	74%	65%	56%	44%
70	97%	97%	96%	92%	87%	80%	71%	62%	52%	41%
80	97%	97%	95%	90%	84%	77%	68%	59%	48%	38%
90	97%	96%	93%	89%	82%	74%	65%	55%	44%	35%
100	97%	96%	92%	87%	80%	72%	62%	51%	41%	32%
110	97%	95%	91%	85%	78%	69%	59%	48%	37%	28%
120	97%	95%	90%	84%	76%	66%	56%	45%	33%	26%
130	97%	94%	89%	82%	74%	64%	53%	42%	30%	25%
140	97%	94%	88%	81%	72%	62%	51%	39%	29%	24%
150	97%	94%	88%	80%	71%	61%	49%	38%	28%	24%
160	97%	93%	87%	79%	70%	59%	48%	37%	27%	24%
170	97%	93%	87%	79%	69%	59%	47%	36%	27%	24%
180	97%	93%	87%	79%	69%	58%	47%	36%	27%	24%
190	97%	93%	87%	79%	69%	59%	47%	36%	27%	24%
200	97%	93%	87%	79%	70%	59%	48%	37%	27%	24%
210	97%	94%	88%	80%	71%	61%	49%	38%	28%	24%
220	97%	94%	88%	81%	72%	62%	51%	39%	29%	24%
230	97%	94%	89%	82%	74%	64%	53%	42%	30%	25%
240	97%	95%	90%	84%	76%	66%	56%	45%	33%	26%
250	97%	95%	91%	85%	78%	69%	59%	48%	37%	28%
260	97%	96%	92%	87%	80%	72%	62%	51%	41%	32%
270	97%	96%	93%	89%	82%	74%	65%	55%	44%	35%
280	97%	97%	95%	90%	84%	77%	68%	59%	48%	38%
290	97%	97%	96%	92%	87%	80%	71%	62%	52%	41%
300	97%	98%	97%	94%	89%	82%	74%	65%	56%	44%
310	97%	98%	98%	95%	91%	84%	77%	68%	59%	47%
320	97%	99%	98%	96%	92%	86%	79%	71%	62%	49%
330	97%	99%	99%	97%	93%	88%	81%	73%	64%	51%
340	97%	99%	100%	98%	94%	89%	82%	74%	66%	53%
350	97%	100%	100%	98%	95%	90%	83%	75%	67%	54%

Annual daily irradiation on an inclined plane expressed as % of maximum value for Nauru

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

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	100%	99%	97%	93%	87%	79%	71%	59%	47%	36%
10	100%	99%	97%	93%	86%	79%	70%	59%	47%	36%
20	100%	99%	97%	92%	86%	79%	70%	59%	47%	35%
30	100%	99%	97%	92%	86%	78%	70%	59%	47%	35%
40	100%	99%	97%	92%	86%	78%	69%	58%	46%	34%
50	100%	99%	97%	92%	85%	77%	68%	57%	46%	34%
60	100%	99%	96%	92%	85%	77%	67%	57%	45%	34%
70	100%	99%	96%	91%	85%	76%	66%	56%	45%	33%
80	100%	99%	96%	91%	84%	75%	65%	55%	44%	33%
90	100%	99%	96%	91%	83%	75%	64%	54%	44%	33%
100	100%	99%	96%	90%	83%	74%	63%	53%	43%	32%
110	100%	99%	95%	90%	82%	73%	62%	52%	43%	32%
120	100%	99%	95%	90%	82%	72%	61%	51%	42%	31%
130	100%	99%	95%	89%	82%	72%	60%	50%	42%	31%
140	100%	99%	95%	89%	81%	71%	59%	50%	41%	32%
150	100%	98%	95%	89%	81%	71%	58%	49%	41%	32%
160	100%	98%	95%	89%	81%	70%	58%	49%	41%	33%
170	100%	98%	95%	89%	80%	70%	58%	49%	41%	33%
180	100%	98%	95%	89%	80%	70%	58%	49%	41%	33%
190	100%	98%	95%	89%	80%	70%	58%	49%	41%	33%
200	100%	98%	95%	89%	81%	70%	58%	49%	41%	33%
210	100%	98%	95%	89%	81%	71%	58%	49%	41%	32%
220	100%	99%	95%	89%	81%	71%	59%	50%	41%	32%
230	100%	99%	95%	89%	82%	72%	60%	50%	42%	31%
240	100%	99%	95%	90%	82%	72%	61%	51%	42%	31%
250	100%	99%	95%	90%	82%	73%	62%	52%	43%	32%
260	100%	99%	96%	90%	83%	74%	63%	53%	43%	32%
270	100%	99%	96%	91%	83%	75%	64%	54%	44%	33%
280	100%	99%	96%	91%	84%	75%	65%	55%	44%	33%
290	100%	99%	96%	91%	85%	76%	66%	56%	45%	33%
300	100%	99%	96%	92%	85%	77%	67%	57%	45%	34%
310	100%	99%	97%	92%	85%	77%	68%	57%	46%	34%
320	100%	99%	97%	92%	86%	78%	69%	58%	46%	34%
330	100%	99%	97%	92%	86%	78%	70%	59%	47%	35%
340	100%	99%	97%	92%	86%	79%	70%	59%	47%	35%
350	100%	99%	97%	93%	86%	79%	70%	59%	47%	36%

Annual daily irradiation on an inclined plane expressed as % of maximum value for Vaiaku - Tuvalu

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

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	99%	100%	99%	97%	92%	87%	79%	71%	60%	49%
10	99%	100%	99%	97%	92%	86%	79%	71%	60%	49%
20	99%	100%	99%	96%	92%	86%	79%	70%	60%	48%
30	99%	100%	99%	96%	91%	85%	78%	69%	58%	47%
40	99%	100%	98%	95%	90%	84%	76%	68%	57%	46%
50	99%	99%	98%	94%	89%	83%	75%	66%	55%	44%
60	99%	99%	97%	93%	88%	81%	73%	64%	53%	43%
70	99%	99%	96%	92%	87%	79%	71%	61%	51%	41%
80	99%	98%	96%	91%	85%	78%	69%	59%	49%	38%
90	99%	98%	95%	90%	84%	76%	66%	56%	46%	36%
100	99%	97%	94%	89%	82%	74%	64%	53%	44%	34%
110	99%	97%	93%	88%	81%	72%	62%	51%	41%	32%
120	99%	97%	93%	87%	79%	70%	60%	48%	39%	30%
130	99%	97%	92%	86%	78%	69%	58%	46%	37%	29%
140	99%	96%	92%	85%	77%	67%	57%	44%	35%	28%
150	99%	96%	91%	85%	76%	66%	55%	43%	34%	28%
160	99%	96%	91%	84%	76%	66%	54%	42%	34%	29%
170	99%	96%	91%	84%	75%	65%	54%	41%	34%	29%
180	99%	96%	91%	84%	75%	65%	54%	41%	33%	29%
190	99%	96%	91%	84%	75%	65%	54%	41%	34%	29%
200	99%	96%	91%	84%	76%	66%	54%	42%	34%	29%
210	99%	96%	91%	85%	76%	66%	55%	43%	34%	28%
220	99%	96%	92%	85%	77%	67%	57%	44%	35%	28%
230	99%	97%	92%	86%	78%	69%	58%	46%	37%	29%
240	99%	97%	93%	87%	79%	70%	60%	48%	39%	30%
250	99%	97%	93%	88%	81%	72%	62%	51%	41%	32%
260	99%	97%	94%	89%	82%	74%	64%	53%	44%	34%
270	99%	98%	95%	90%	84%	76%	66%	56%	46%	36%
280	99%	98%	96%	91%	85%	78%	69%	59%	49%	38%
290	99%	99%	96%	92%	87%	79%	71%	61%	51%	41%
300	99%	99%	97%	93%	88%	81%	73%	64%	53%	43%
310	99%	99%	98%	94%	89%	83%	75%	66%	55%	44%
320	99%	100%	98%	95%	90%	84%	76%	68%	57%	46%
330	99%	100%	99%	96%	91%	85%	78%	69%	58%	47%
340	99%	100%	99%	96%	92%	86%	79%	70%	60%	48%
350	99%	100%	99%	97%	92%	86%	79%	71%	60%	49%

Annual daily irradiation on an inclined plane expressed as % of maximum value for Apia - Samoa

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

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	99%	100%	99%	97%	92%	86%	79%	71%	60%	48%
10	99%	100%	99%	97%	92%	86%	79%	70%	60%	48%
20	99%	100%	99%	96%	92%	86%	78%	70%	59%	47%
30	99%	100%	99%	96%	91%	85%	77%	69%	58%	46%
40	99%	100%	98%	95%	90%	84%	76%	67%	56%	45%
50	99%	99%	98%	94%	89%	82%	74%	65%	55%	44%
60	99%	99%	97%	93%	88%	81%	73%	63%	53%	42%
70	99%	99%	96%	92%	87%	79%	70%	61%	50%	40%
80	99%	98%	96%	91%	85%	77%	68%	58%	48%	38%
90	99%	98%	95%	90%	84%	75%	66%	55%	46%	36%
100	99%	98%	94%	89%	82%	74%	64%	53%	43%	34%
110	99%	97%	93%	88%	81%	72%	62%	50%	41%	32%
120	99%	97%	93%	87%	79%	70%	60%	48%	38%	30%
130	99%	97%	92%	86%	78%	69%	58%	46%	36%	29%
140	99%	96%	92%	85%	77%	67%	56%	44%	35%	29%
150	99%	96%	91%	84%	76%	66%	55%	42%	34%	29%
160	99%	96%	91%	84%	75%	65%	54%	41%	34%	29%
170	99%	96%	91%	84%	75%	65%	53%	41%	34%	29%
180	99%	96%	91%	84%	75%	65%	53%	40%	34%	29%
190	99%	96%	91%	84%	75%	65%	53%	41%	34%	29%
200	99%	96%	91%	84%	75%	65%	54%	41%	34%	29%
210	99%	96%	91%	84%	76%	66%	55%	42%	34%	29%
220	99%	96%	92%	85%	77%	67%	56%	44%	35%	29%
230	99%	97%	92%	86%	78%	69%	58%	46%	36%	29%
240	99%	97%	93%	87%	79%	70%	60%	48%	38%	30%
250	99%	97%	93%	88%	81%	72%	62%	50%	41%	32%
260	99%	98%	94%	89%	82%	74%	64%	53%	43%	34%
270	99%	98%	95%	90%	84%	75%	66%	55%	46%	36%
280	99%	98%	96%	91%	85%	77%	68%	58%	48%	38%
290	99%	99%	96%	92%	87%	79%	70%	61%	50%	40%
300	99%	99%	97%	93%	88%	81%	73%	63%	53%	42%
310	99%	99%	98%	94%	89%	82%	74%	65%	55%	44%
320	99%	100%	98%	95%	90%	84%	76%	67%	56%	45%
330	99%	100%	99%	96%	91%	85%	77%	69%	58%	46%
340	99%	100%	99%	96%	92%	86%	78%	70%	59%	47%
350	99%	100%	99%	97%	92%	86%	79%	70%	60%	48%

Annual daily irradiation on an inclined plane expressed as % of maximum value for Tongatapu - Tonga
Latitude: 21° 08' South | Longitude: 175° 12' West

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	96%	99%	99%	99%	96%	92%	85%	78%	69%	57%
10	96%	99%	99%	99%	96%	91%	85%	77%	69%	57%
20	96%	99%	99%	98%	95%	90%	84%	76%	67%	56%
30	96%	98%	99%	97%	94%	89%	82%	74%	66%	54%
40	96%	98%	98%	96%	93%	87%	80%	72%	63%	51%
50	96%	98%	98%	95%	91%	85%	78%	69%	60%	49%
60	96%	97%	97%	93%	89%	82%	74%	66%	56%	45%
70	96%	96%	96%	91%	86%	79%	71%	62%	52%	41%
80	96%	96%	96%	89%	83%	76%	67%	58%	48%	37%
90	96%	95%	95%	87%	81%	73%	64%	54%	43%	33%
100	96%	94%	94%	85%	78%	70%	60%	49%	38%	29%
110	96%	94%	93%	83%	76%	66%	56%	45%	34%	25%
120	96%	93%	93%	81%	73%	63%	53%	41%	30%	22%
130	96%	93%	92%	80%	71%	61%	50%	38%	27%	21%
140	96%	92%	92%	78%	69%	58%	47%	36%	26%	21%
150	96%	92%	91%	77%	67%	57%	45%	34%	25%	20%
160	96%	91%	91%	76%	66%	55%	44%	34%	24%	20%
170	96%	91%	91%	76%	66%	54%	43%	33%	24%	20%
180	96%	91%	91%	76%	65%	54%	43%	33%	24%	20%
190	96%	91%	91%	76%	66%	54%	43%	33%	24%	20%
200	96%	91%	91%	76%	66%	55%	44%	34%	24%	20%
210	96%	92%	91%	77%	67%	57%	45%	34%	25%	20%
220	96%	92%	92%	78%	69%	58%	47%	36%	26%	21%
230	96%	93%	92%	80%	71%	61%	50%	38%	27%	21%
240	96%	93%	93%	81%	73%	63%	53%	41%	30%	22%
250	96%	94%	93%	83%	76%	66%	56%	45%	34%	25%
260	96%	94%	94%	85%	78%	70%	60%	49%	38%	29%
270	96%	95%	95%	87%	81%	73%	64%	54%	43%	33%
280	96%	96%	96%	89%	83%	76%	67%	58%	48%	37%
290	96%	96%	96%	91%	86%	79%	71%	62%	52%	41%
300	96%	97%	97%	93%	89%	82%	74%	66%	56%	45%
310	96%	98%	98%	95%	91%	85%	78%	69%	60%	49%
320	96%	98%	98%	96%	93%	87%	80%	72%	63%	51%
330	96%	98%	99%	97%	94%	89%	82%	74%	66%	54%
340	96%	99%	99%	98%	95%	90%	84%	76%	67%	56%
350	96%	99%	99%	99%	96%	91%	85%	77%	69%	57%

Annual daily irradiation on an inclined plane expressed as % of maximum value for Palikir - Pohnpei FSM

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

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	99.8%	98%	94%	88%	81%	73%	64%	51%	41%	31%
10	99.8%	98%	94%	88%	81%	73%	64%	51%	41%	31%
20	99.8%	98%	94%	88%	81%	73%	64%	52%	41%	31%
30	99.8%	98%	94%	88%	82%	73%	64%	52%	41%	31%
40	99.8%	98%	94%	89%	82%	74%	64%	53%	42%	31%
50	99.8%	98%	94%	89%	82%	74%	64%	54%	43%	31%
60	99.8%	98%	95%	89%	83%	74%	64%	54%	43%	32%
70	99.8%	98%	95%	90%	83%	74%	65%	55%	44%	34%
80	99.8%	99%	95%	90%	83%	75%	65%	56%	46%	35%
90	99.8%	99%	96%	91%	84%	75%	65%	57%	47%	36%
100	99.8%	99%	96%	91%	84%	75%	65%	59%	48%	37%
110	99.8%	99%	97%	92%	85%	76%	66%	60%	49%	39%
120	99.8%	99%	97%	92%	85%	76%	66%	61%	50%	40%
130	99.8%	99.6%	97%	93%	86%	76%	66%	61%	51%	41%
140	99.8%	99.7%	97%	93%	86%	77%	66%	62%	52%	42%
150	99.8%	99.8%	98%	93%	86%	77%	66%	63%	53%	42%
160	99.8%	99.9%	98%	93%	87%	77%	66%	63%	53%	43%
170	99.8%	100%	98%	93%	87%	77%	67%	63%	53%	43%
180	99.8%	100%	98%	94%	87%	77%	67%	64%	53%	43%
190	99.8%	100%	98%	93%	87%	77%	67%	63%	53%	43%
200	99.8%	99.9%	98%	93%	87%	77%	66%	63%	53%	43%
210	99.8%	99.8%	98%	93%	86%	77%	66%	63%	53%	42%
220	99.8%	99.7%	97%	93%	86%	77%	66%	62%	52%	42%
230	99.8%	99.6%	97%	93%	86%	76%	66%	61%	51%	41%
240	99.8%	99%	97%	92%	85%	76%	66%	61%	50%	40%
250	99.8%	99%	97%	92%	85%	76%	66%	60%	49%	39%
260	99.8%	99%	96%	91%	84%	75%	65%	59%	48%	37%
270	99.8%	99%	96%	91%	84%	75%	65%	57%	47%	36%
280	99.8%	99%	95%	90%	83%	75%	65%	56%	46%	35%
290	99.8%	98%	95%	90%	83%	74%	65%	55%	44%	34%
300	99.8%	98%	95%	89%	83%	74%	64%	54%	43%	32%
310	99.8%	98%	94%	89%	82%	74%	64%	54%	43%	31%
320	99.8%	98%	94%	89%	82%	74%	64%	53%	42%	31%
330	99.8%	98%	94%	88%	82%	73%	64%	52%	41%	31%
340	99.8%	98%	94%	88%	81%	73%	64%	52%	41%	31%
350	99.8%	98%	94%	88%	81%	73%	64%	51%	41%	31%

Annual daily irradiation on an inclined plane expressed as % of maximum value for Hagatna - Guam

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

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	98%	94%	89%	82%	73%	64%	52%	41%	33%	24%
10	98%	95%	89%	82%	73%	64%	52%	41%	33%	24%
20	98%	95%	89%	82%	74%	65%	52%	41%	32%	24%
30	98%	95%	90%	83%	74%	65%	53%	42%	32%	24%
40	98%	95%	90%	83%	75%	66%	54%	43%	32%	24%
50	98%	95%	91%	84%	76%	67%	56%	45%	33%	24%
60	98%	96%	91%	85%	77%	67%	58%	47%	35%	24%
70	98%	96%	92%	86%	78%	68%	59%	49%	37%	26%
80	98%	97%	93%	87%	80%	70%	61%	52%	40%	29%
90	98%	97%	94%	89%	81%	71%	64%	54%	43%	32%
100	98%	98%	95%	90%	82%	72%	66%	57%	46%	35%
110	98%	98%	96%	91%	84%	73%	68%	60%	48%	38%
120	98%	99%	97%	92%	85%	74%	70%	62%	51%	40%
130	98%	99%	97%	93%	86%	75%	71%	64%	53%	43%
140	98%	99%	98%	94%	87%	75%	73%	66%	55%	45%
150	98%	100%	98%	95%	88%	76%	74%	68%	56%	47%
160	98%	100%	99%	95%	88%	76%	75%	69%	58%	48%
170	98%	100%	99%	96%	89%	77%	75%	70%	58%	49%
180	98%	100%	99%	96%	89%	77%	76%	70%	59%	49%
190	98%	100%	99%	96%	89%	77%	75%	70%	58%	49%
200	98%	100%	99%	95%	88%	76%	75%	69%	58%	48%
210	98%	100%	98%	95%	88%	76%	74%	68%	56%	47%
220	98%	99%	98%	94%	87%	75%	73%	66%	55%	45%
230	98%	99%	97%	93%	86%	75%	71%	64%	53%	43%
240	98%	99%	97%	92%	85%	74%	70%	62%	51%	40%
250	98%	98%	96%	91%	84%	73%	68%	60%	48%	38%
260	98%	98%	95%	90%	82%	72%	66%	57%	46%	35%
270	98%	97%	94%	89%	81%	71%	64%	54%	43%	32%
280	98%	97%	93%	87%	80%	70%	61%	52%	40%	29%
290	98%	96%	92%	86%	78%	68%	59%	49%	37%	26%
300	98%	96%	91%	85%	77%	67%	58%	47%	35%	24%
310	98%	95%	91%	84%	76%	67%	56%	45%	33%	24%
320	98%	95%	90%	83%	75%	66%	54%	43%	32%	24%
330	98%	95%	90%	83%	74%	65%	53%	42%	32%	24%
340	98%	95%	89%	82%	74%	65%	52%	41%	32%	24%
350	98%	95%	89%	82%	73%	64%	52%	41%	33%	24%