SEIAPI
Sustainable Energy

PPA
PACIFIC POWER ASSOCIATION

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.

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 design of any grid connected PV System.

Cover Photos: Clay Energy

Table of Contents

1 Introduction 1
2 Standards for Design 5
3 Steps when Designing a Grid Connected PV System 6
4 Site Visit 6
5 Selecting a PV Module 7
6 Choosing an Array Structure 7
  6.1 Modules Mounted on Roofs (AS/NZS standards) 8
  6.2 Ground Mounted Array (AS/NZS standards) 8
  6.3 Array Frame Manufacturers (AS/NZS standards) 9
7 Energy Output of a Solar Array 9
  7.1 Solar Irradiation 9
  7.2 Effect of Orientation and Tilt 11
  7.3 Shading of Array 12
  7.4 Glare 13
  7.5 Factors Affecting the Solar Module's Power Output 14
  7.6 Derating Solar Modules Power Output 17
8 Inverter Selection 18
  8.1 PV Array to Inverter Interface 18
    8.1.1 Micro-inverters (or module inverters) 19
    8.1.2 Single-tracking Inverters (string inverters) 19
    8.1.3 Multi-tracking Inverters 19
    8.1.4 Central Inverters 19
    8.1.5 Inverters with Solar or Power Optimisers: MPPTs at Module Level 19
  8.2 Number of Inverters Required? 20
  8.3 Selecting the Size of the Inverter 21
  8.4 Matching Array Power to the Inverter 21
  8.5 Matching Array Voltage to the Inverter 22
    8.5.1 Minimum Number of Modules in the String 23
    8.5.2 Maximum Number of Modules in the String 26
  8.6 Matching Array Current to the Inverter 28
9 Electrical Losses in the Grid Connected PV System 29
10 Energy Yield 30
  10.1 Effect of Shading 31
  10.2 Sizing the PV system 31
11 Specific Yield 32
12 Performance Ratio 32
13 Designing the Cabling, Protection and Isolation Requirements of a System 33
14 Fuel Generator 33
  14.1 Selecting the Fuel Generator 34
  14.2 Determining the capacity of the fuelled generator 35
  14.3 Derating factors 35
15 Providing a Quotation 36
  15.1 Providing quotation to the customer 36
  15.2 System design and drawings to the installer 37
16 Grid Connection Application Process 38
  16.1 Application 38
17 Appendix 1: Temperature Conversion Tables 39
18 Appendix 2: Solar Irradiation Data 40
19 Appendix 3: Effect on Irradiation Due to Orientation and Tilt Angle 44

List of Figures

Figure 1: Components of a Grid Connected PV System-String Inverter 1
Figure 2: Components of a Grid Connected PV System – Module Inverter.. 2
Figure 3: Ground Mounted Solar Array 2
Figure 4: Showing Inverter and Frame... 3
Figure 5: Isolators and Surge Protection Devices 3
Figure 6: Array on House Roof... 4
Figure 7: Household Installation 4
Figure 8: Roof Zones for Panel Array 8
Figure 9: Wind Pressures on Ground Mounted Solar Panel Arrays as Shown in AS1170.2................... 9
Figure 10: Fiji Global Horizontal Irradiation.. 10
Figure 11 An example of a micro-inverter 19
Figure 12 An example of a solar optimiser 20
Figure 13 Interconnection of Fuel Generator and Grid Connected System in Switchboard 34
Figure 14 Sample Site Plan.. 37
Figure 15 Example of electrical schematic of a grid connected PV system layout as per AS/NZS standards. 37
Figure 16 Wiring schematic (NEC).. 38

List of Tables

Table 1: Sites for Orientation and Tilt Tables in Appendix 3.. 12
Table 2: Cell Temperature Rise for Various Installations.. 14
Table 3: Generator derating factors 35

Abbreviations

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

a.c.	Alternating current
AS	Australian standards
BESS	Battery Energy Storage Systems
d.c.	Direct current
DCU	d.c. conditioning units
EN	European Standards (European Norms)
ESMAP	Energy Sector Management Assistance Program
IEC	International Electrotechnical Commission
LED	Light-emitting Diode
kW_p	Kilowatt Peak
kWh	Kilowatt hour
MP	Maximum Power
MPP	Maximum Power Point
MPPT	Maximum Power Point Tracker
NASA	National Aeronautics and Space Administration
NZS	New Zealand Standards
PSH	Peak sun hours
P_{mod}	Rated maximum power rating
POWER	Prediction of Worldwide Energy Resources
PCE	Power conversion equipment
PNG	Papua New Guinea
PV	Photovoltaic
STC	Standard Test Conditions

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 kWp) for an array;
- Available budget; and
- 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 modules in the array.
- Matching the array/panel configuration to the selected inverters:
    - Maximum voltage and voltage operating window;
    - Maximum allowable d.c. input power rating; and
    - Maximum d.c. 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.

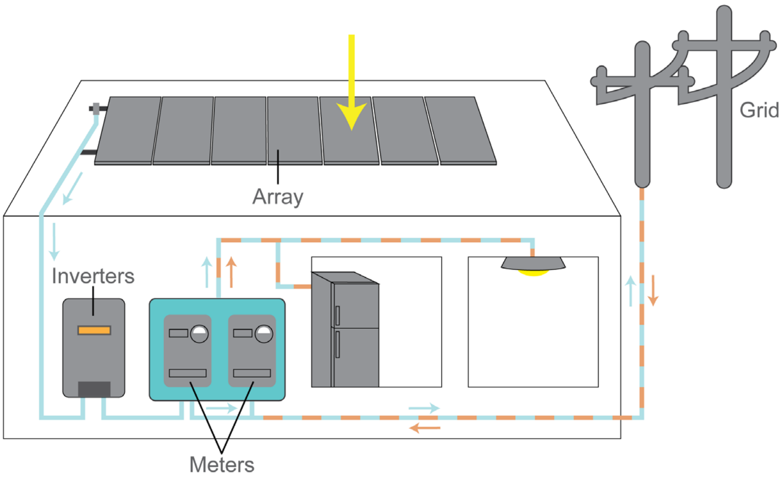

Figure 1: Components of a Grid Connected PV System-String Inverter

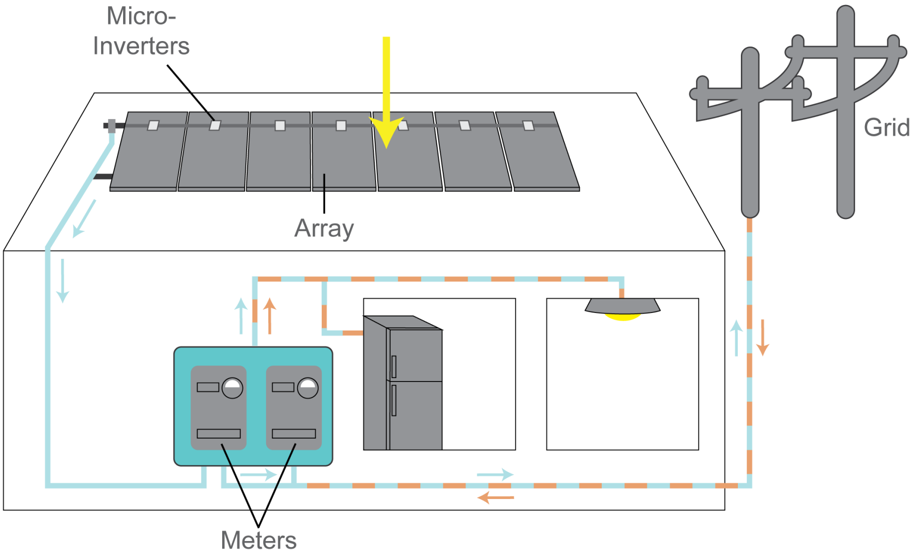

Figure 2: Components of a Grid Connected PV System – Module Inverter

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 for Design

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 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/NZS 3000 Wiring Rules.
- AS/NZS 3008 Electrical Installations-Selection of Cables.
- AS/NZS 4777 Grid connection of energy systems by inverters (series)
- AS/NZS 5033 Installation and safety requirements of PV arrays.
- AS/NZS 1170 Structural design actions
- AS/NZS 1170.2 Structural design actions – Wind actions
- AS 1768 Lightning protection.
- IEC 61215 Crystalline silicon 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 61701 Photovoltaic (PV) modules - Salt mist corrosion testing
- IEC 62804 Photovoltaic (PV) modules - Test methods for the detection of potential-induced degradation (PID) - Part 1-1: Crystalline silicon – Delamination
- 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.
- IEC 62930 Electric cables for photovoltaic systems with a voltage rating of 1.5 kV d.c. Solar Plugs and Connectors
- AS/NZS 62852 Connectors for d.c. application in photovoltaic systems - Safety requirements and tests.
- AS/NZS 60947.3 Low-voltage switchgear and control gear switches, disconnectors, switch-disconnectors and fuse-combination units. The switch disconnectors shall conform with utilization category d.c. PV2.

In USA the relevant codes and standards include:

- Electrical Codes National Electrical Code (NEC), also known as 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.
- 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 7, 9 and 10)
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 15)

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 than installing a separate solar hot water unit.
    iii. Replacing incandescent light bulbs and fluorescent lights 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 – if roof mounted.
9. Determine how the modules will be mounted on the roof – if roof mounted.
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 the PV system main switch and necessary remote monitoring equipment (when required) can be installed within the existing switchboard.
13. Determine whether monitoring equipment 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 PV Module

When selecting a solar PV module to be used in a Grid Connected PV system the solar modules shall comply with 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 II per IEC 61730.

It is recommended that the modules have the following enhancements:
- IEC 61701 Photovoltaic (PV) modules - Salt mist corrosion testing
- IEC 62804 – (2020) Photovoltaic (PV) modules - Test methods for the detection of potential-induced degradation (PID) - Part 1-1: Crystalline silicon – Delamination

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

For those countries complying with AS/NZS standards, the modules may be selected from those on the Australian Clean Energy Council's approved product list:
https://www.cleanenergycouncil.org.au/industry/products/modules/approved-modules

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.

The mounting of the system including brackets and clamps must be robust to be able to withstand movement either from wind or seismic activity.

For those countries following AS/NZS standards, the mounting system structure shall comply with the requirements set in AS1170.2 Structural design actions – Part 2: Wind actions.

Appendix B.6 in AS1170.2 relates to the design of solar modules with net pressure coefficients provided for varying wind directions, array dimensions, spacings and panel pitches.

6.1 Modules Mounted on Roofs (AS/NZS standards)

Section B.6.1 in AS1170.2 provides design guidelines for wind pressures for structures that meet the following conditions:

a) Modules attached to enclosed buildings with aspect ratios h/b ≤ 0.5 and h/d ≤ 0.5.
b) Modules be attached parallel to the roof plane.
c) Modules with a gap of between 50 mm and 300 mm between the underside of the panel, and
d) Modules with a minimum distance between panel and roof edge of 2s where s is the gap between the underside of the panel and the roof surface, as shown in Figure 8.9 (in AS1170.2) (roof edge includes ridges with pitch ≥ 10°).

Figure 8 below shows an excerpt from Section B.6.1 in AS1170.2 with wind pressure zones shown upwind end, central, downwind end, upwind central and downwind central. Table B.12 in AS1170.2 provides the wind pressure coefficients to each zone that relate to the array arrangement.

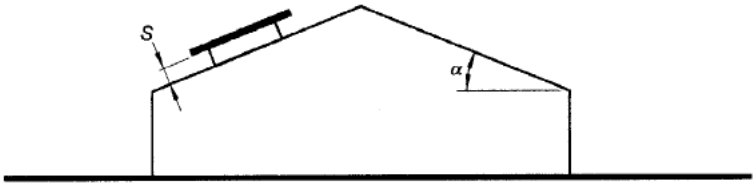

Figure B.9 — Panel mounted parallel to roof plane

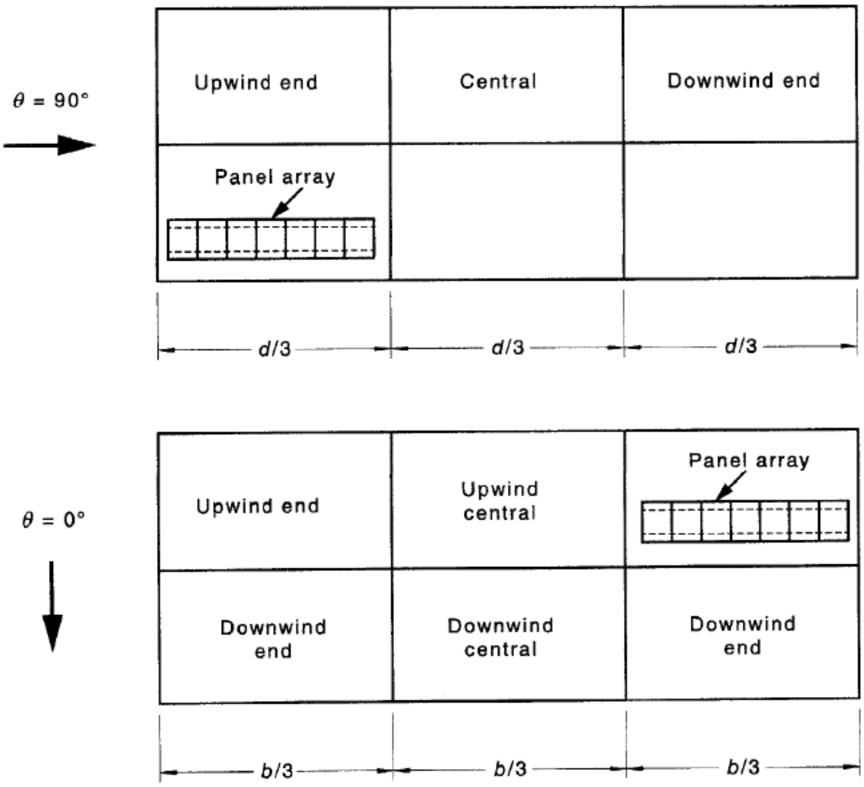

Figure 8: Roof Zones for Panel Array

6.2 Ground Mounted Array (AS/NZS standards)

Section B.6.2 in AS1170.2 provides design guidelines for wind pressures for structures that meet the following conditions:

a) Modules attached to a ground mounted frame with aspect ratios 2 ≤ d/h ≤ 5 and b/d ≥ 2.

b) Modules attached to the frame at an inclination to ground, α ≤ 30°.
c) Panel arrays with a spacing of 3.5 ≤ s/h ≤ 10.
d) Modules with a minimum gap between the underside of the panel and the ground surface c/h ≥ 0.2.

Figure 9 below shows an excerpt from Section B.6.2 in AS1170.2 with wind pressure zones shown by A1 to A3, B1 to B3, C1 to C3 and D1 to D3. Tables B.13 and B.14 in AS1170.2 provide the wind pressure coefficients to each zone that relate to the array arrangement.

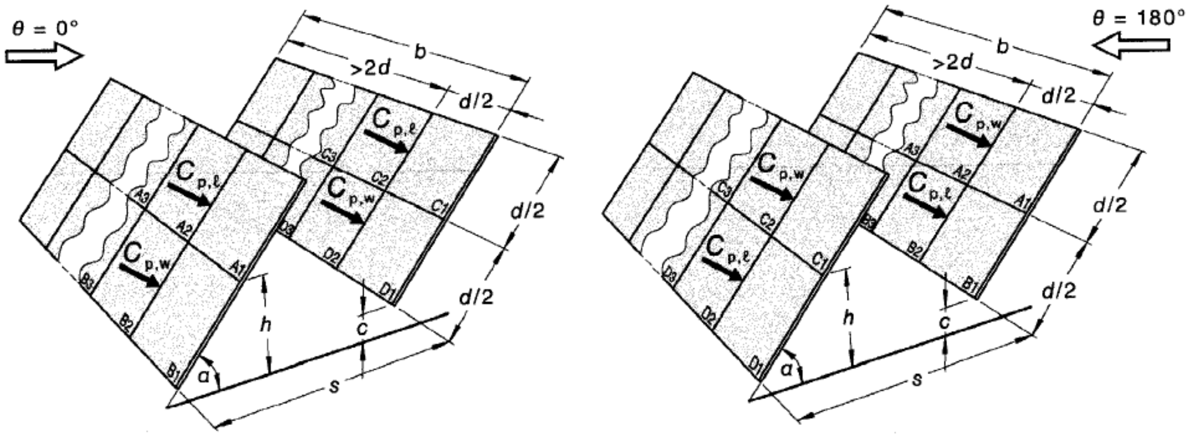

Figure 9: Wind Pressures on Ground Mounted Solar Panel Arrays as Shown in AS1170.2

For smaller ground mount systems (generally **<100kW**), the modules could be attached to a pre-engineered frame, often designed to house up to 10 kW of PV modules per frame. Several of these fixed frames could be used for large capacity arrays. Either the modules could be clamped or bolted to the frame or the framing structure may use a U-shaped channel into which the modules slide; in both cases, the framing structure is fixed to concrete foundations. In areas where the soil is suitable and wind conditions sufficiently mild, earth screws may be suitable replacements for a concrete foundation.

For large ground-mounted installations, a pile-driven installation may be suitable. A geotechnical survey should be conducted to survey the ground and check for soil compactness, site classification, shrink swell index (in accordance with AS2870 - Residential slabs and footings), soil type, soil moisture content, aggressivity assessment (in accordance with AS2159 - Piling - Design and installation), rock or rubble size and depth and thermal and electrical resistivity (for the design of the cabling). Note, looser soils will require posts to be driven deeper. Site pull out and lateral load testing of the piles can be performed to predict the load carrying capacity of the soil used in the design.

6.3 Array Frame Manufacturers (AS/NZS standards)

The design of the array mounting system shall incorporate the recommendations of the array frame manufacturer. Generally, the mounting system manufacturers of pre-fabricated mounting systems provide installation guides that incorporate the requirements set in AS1170.2 and these installation guides are easier to interpret and comply with in comparison to the standards. For the mounting system concerned, it is recommended that installation guides are utilised for the design phase.

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.

As an example, the maps and data for Papua New Guinea have been released in parallel with Global Solar Atlas, which is published by the World Bank Group, funded by ESMAP, and prepared by Solargis. This is available from: https://solargis.com/resources/free-maps-and-gis-data?

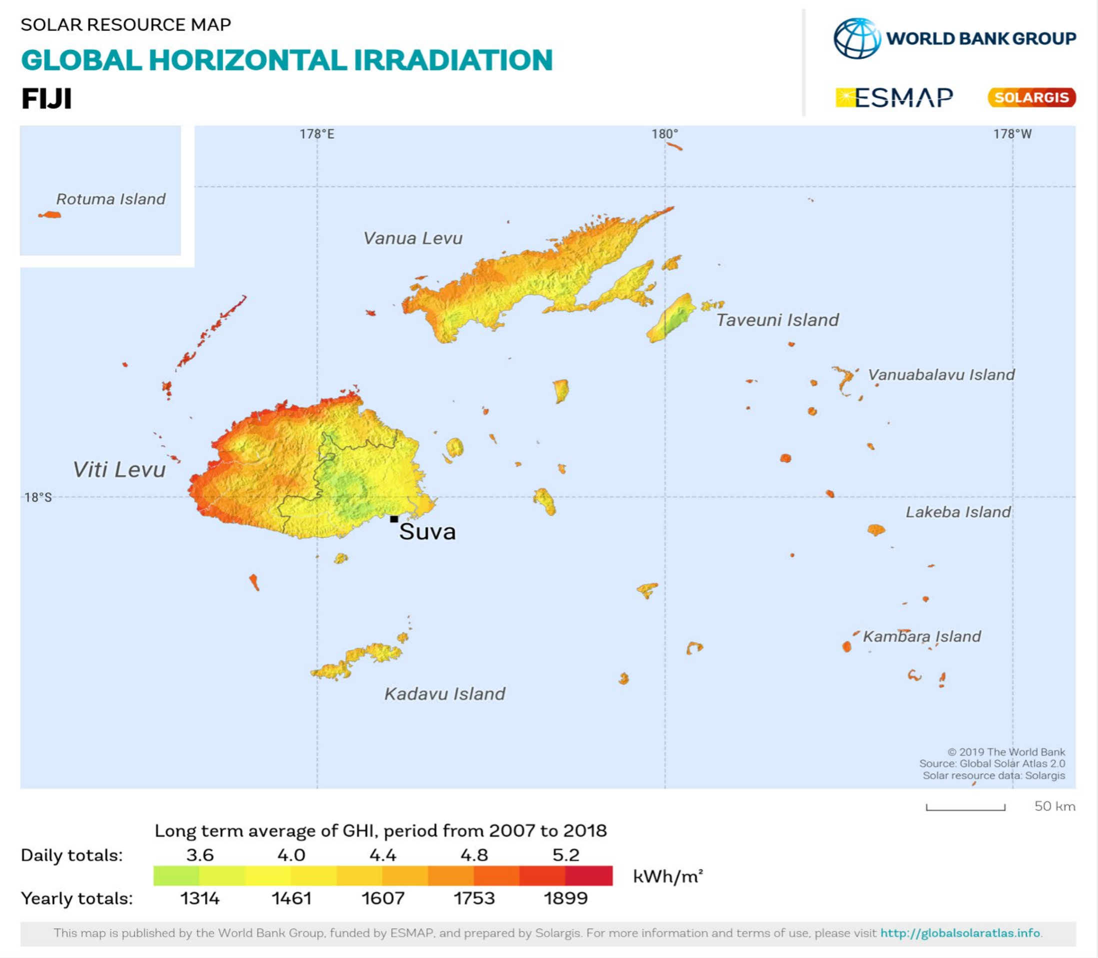

Figure 10: Fiji Global Horizontal Irradiation

© 2020 The World Bank, Source: Global Solar Atlas 2.0, Solar resource data: Solargis.

Also 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 reliable source for solar irradiation data is the NASA's Prediction of Worldwide Energy Resources (POWER) 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 ideal 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/m^2. (Refer Appendix 2)

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

This would then be 365 x 5.38kWh/m^2 = 1963.7kWh/m^2

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 in Appendix 2 show the average daily total irradiation represented as a percentage of the maximum value i.e. PV orientation at True North in the Southern Hemisphere (azimuth = 0°) 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

N°	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

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 PSH data for the site to determine the expected PSH 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 92% or 0.92.

Therefore, the available irradiation for the site is 0.92 × 5.38kWh/m^2 = 4.95kWh/m^2

Annual yearly irradiation will be 4.95 kWh/m^2 x 365 days = 1806.75 kWh/m^2 (H_{tilt})

7.3 Shading of Array

In towns and cities where Grid Connected PV 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 hence array will have some shading. This will affect the output of the array.

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

If it affects 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.
The solar resource and weather conditions of the site should be measured, especially any shading of the potential installation area. A solar siting tool (e.g. Solar Pathfinder or SunEye) could be used for these measurements.

a. **The Solar Pathfinder**: This kit uses Sun path diagrams to determine the shading experienced for a proposed site. A Sun path diagram for a specified latitude band shows the position of the Sun throughout the day for each month of the year. A plastic dome is placed above the Sun path diagram to reflect a panoramic view of the site, showing sources of shading. The intersections between the reflected sources of shading and the Sun path diagram identify the site shading throughout the year, allowing the system's site-specific performance to be calculated.

b. **Solmetric SunEye**: This measuring device (or similar) acts as a digital version of the Solar Pathfinder. It takes a digital picture of the horizon and analyses the effect of the surrounding objects for the specified latitude. Accessories, such as GPS units, can be purchased to further improve the accuracy of the analysis. The digital camera uses a fish-eye lens and can provide digital images of the horizon and the amount of shading throughout the year. The SunEye also has an inclinometer and compass function to measure roof pitch and orientation, respectively.

Other software design tools for analyzing shading include:

- **Pylon Observer** (Pylon's solar design and quoting tool) – Using this tool, users can get a year-round estimate of shading on their proposed solar panel installations, with visualizations of how shadows move around during the day and providing installers projected annual energy yield for their design without an on-site visit.
- **HelioScope –** HelioScope is an increasingly popular PV system simulation software for the early stages of project development. HelioScope allows for remote aerial site assessments and shade analyses; preliminary system designs and equipment layouts; rough-order-of-magnitude energy and financial models; and automated proposals. One of the unique benefits of HelioScope is its ability to model energy losses due to shading for a solar array.
- **OpenSolar –** The OpenSolar's software provides free end-to-end tools for solar designers including solar design accuracy, proposals, shading reports, etc. You can access the OpenSolar tool from: https://www.opensolar.com/features. You will have to create an account here first. A video explaining on creating proposals, etc is available at: https://youtu.be/-CRh7Aux4nw
- **PVsyst –** software package for the study, sizing and data analysis of complete PV systems. It deals with grid-connected, stand-alone, pumping and DC-grid (public transportation) PV systems, and includes extensive meteo and PV systems components databases, as well as general solar energy tools.

7.4 Glare

The glass front of the solar modules does reflect the sun and could be a glare issue in some sites. For most systems this will not be an issue because modules are on the roof and the glare would be reflected upward and therefore typically not affecting anyone unless there is a taller building nearby. However, the glare would normally only occur for a short period of time in the day and these building can normally have glare from just the windows of other buildings.

Where it is mainly an issue is when the PV array is located near an airport and hence in the flight path of the planes. If installing in the flight path then glare calculations might need to be undertaken and the in-country aviation authority might need to be consulted.

Notably, there are tools available for evaluating photovoltaic glare such as GlareGauge (ForgeSolar), Solar Glare Hazard Analysis Tool (Sandia National Laboratories), etc. Generally, this tool determines when and where solar glare can occur throughout the year from a user-specified PV array as viewed from user-prescribed observation points. The potential ocular impact from the observed glare could also be determined, along with a prediction of the annual energy production. Configurations could be quickly modified (e.g., tilt, orientation, shape, location) to identify a design that mitigates glare while maximizing energy production.

7.5 Factors Affecting the Solar Module's Power Output

The output of the solar module is affected by temperature, dirt, module age and possibly manufacturer's 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

Solar modules are tested and rated at 25°C (77°F). 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) .(Note: For those following Australia and New Zealand standards refer to Clause 2.2.2 of AS/NZS 5033 on considerations due to operating temperature for more information.) 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:

$$T_{Cell-Eff} = T_{a.day} + T_r$$

Where:

$T_{Cell-Eff}$ = 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.

Table 2: Cell Temperature Rise for Various Installations

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

Note: Taken from previous versions of Clean Energy Council (Australia) Design Guidelines

The 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 – 0.35%/°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.

D. Passivated Emitter and Rear Cell (PERC)
PERC solar modules are an improvement of the traditional monocrystalline cell. PERC Modules typically have a temperature coefficient between – 0.34%/°C and – 0.36%/°C.

E. TOPCon (Tunnel Oxide Passivated Contact)
TopCon cells typically offer higher efficiency rates exceeding 25%, significantly higher than conventional solar cell technologies. In comparison with PERC cells, they are more expensive due to their complex n-type silicon substrate and additional manufacturing steps.Typical temperature coefficients for TOPCon cells are between -0.29%/ °C and -0.32%/°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 standards 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 = $\gamma \times (T_{Cell-Eff} - T_{STC})$

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.

Note: Some books and training manuals will have the above formula with a + replacing the –, this is because it allows for the negative value of the temperature coefficient to be inserted into the formula.

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 -0.35%/°C. The average day-time ambient temperature is 26°C (78.8°F).

What is the percentage (%) power loss due to temperature for this solar? What is the temperature derating factor?

From table 31 the rise in temperature (T_r) is 35°C. The effective cell temperature is therefore:
$T_{Cell-Eff} = T_{a.day} + T_r$
$= 26℃ + 35℃$
$= 61℃$

The percentage power change due to effective cell temperature = $\gamma \times (T_{Cell-Eff} - T_{STC})$
$= -0.35\ \%/℃ \times (61℃ - 25℃)$
$= -0.35\ \%/℃ \times 36℃$
$= -12.6\ \%$

As a fraction -12.6% converts to 12.6/100= -0.126 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 – 0.126
= 0.874

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

Manufacturer’s 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/m^2 and with a manufacturing tolerance based on a cell temperature of 25°C (77°F). Historically this was ±5% and in recent years’ typical figures have been 0% to +3% or 0~+5W (positive tolerance) 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

7.6 Derating Solar Modules Power Output

Solar modules have a rated output measured at Standard Test conditions (STC). (STC are irradiation of 1000W/m^2, Temperature 25°C and Air Mass of 1.5). 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:

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

Worked Example 6

A module has a rated power output of $440\ W_p$. Based on previous examples the module has the following derating factors:

$f_{temp} = 0.874$
$f_{dirt} = 0.9$
$f_{man} = 0.97$

What is the derated output power of the module?

$P_{derated} = P_{mod} \times f_{temp} \times f_{dirt} \times f_{man}$
$= 440\ W_p \times 0.874 \times 0.9 \times 0.97$
$= 335.7\ W$

Note:

Solar Modules reduce efficiency over time. This can result in a loss of rated power of 0.5% to 1.0% per year. For Grid Connected PV systems this is often accounted for when undertaking life cycle analysis, such that the amount of energy generated each year will decrease.

8 Inverter Selection

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

Australia requires inverters that connect to the grid to comply with: AS/NZS 4777.2 Grid connection of energy systems via inverter: Inverter requirements. This standard has requirements that are required by the numerous power utilities and the Australian Energy Market Operator for the operation of the Australian grid.

If you source the inverter from Australia then:,

1. the inverters should also comply with AS/NZS4777.2 Grid Connection of energy systems by Inverters- Part 2: Inverter requirements; and
2. the inverters are recommended to be selected from those on the Australian Clean Energy Council's approved product list:

https://www.cleanenergycouncil.org.au/industry/products/inverters/approved-inverters

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.
- Single phase or three phase.

For those following Australia and New Zealand standards and hence, AS/NZS 4777, the following will be useful: AS/NZS 4777.2 has three settings for Australia and the settings are dependent on your location. The three settings are:

- Australia A – applies to the configuration of inverter settings in Victoria, South Australia, New South Wales, ACT and Queensland.
- Australia B – applies to the configuration of inverter settings in Western Australia (Western Power).
- Australia C – applies to the configuration of inverter settings in North-western Australia (Horizon Power) and Tasmania.

Inverters in the relevant country should be set to the applicable settings.

8.1 PV Array to Inverter Interface

There are many types and sizes of inverters on the market suitable for use with PV arrays: from single-module inverters to multi-string array inverters, from inverters for small arrays generating less than 1 kW to inverters for large arrays generating hundreds of kW. Generally, the following types of grid-connect inverters exist:

- Micro-inverters
- Single-tracking inverters
- Multi-tracking inverters
- Central inverters
- Inverters with solar optimisers (module-level MPPTs or DCUs).

8.1.1 Micro-inverters (or module inverters)

Micro-inverters are small transformerless inverters (some will have an isolating transformer to minimise DC injection currents). They are designed to be mounted either on the back of or adjacent to every solar module, or every second solar module, in an array.

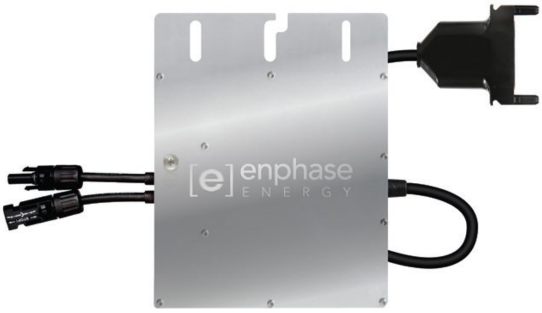


Figure 11 An example of a micro-inverter

Source: Enphase Energy

These are also included under the term PCE (as referenced in AS/NZS 5033) and they need to conform to AS/NZS 4777 and IEC 62109-2 for grid connected PV systems.

8.1.2 Single-tracking Inverters (string inverters)

Single-tracking inverters (also known as string inverters) have one MPPT for the entire array and are used in small grid-connected PV systems. The MPPT establishes the array's MPP and then maintains this throughout the day in relation to different operating conditions. A single tracking inverter is connected to a single string of modules or to multiple strings of modules.

8.1.3 Multi-tracking Inverters

A multi-tracking inverter (also known as a multi-string inverter) has multiple MPPTs. Each string, or a set of strings, can be connected to an individual MPPT, enabling the MPP of each string, or set of strings, to be achieved. For arrays that have strings, or sets of strings, oriented in different directions, multitracking inverters are able to produce a higher energy yield than single-tracking inverters. For example, an array with module strings on the eastern roof and module strings on the western roof of a building would preference the use of a multi-tracking inverter rather than a single-tracking inverter.

8.1.4 Central Inverters

Central inverters are used for large grid-connected PV systems and constitute the equivalent to multiple large string inverters. Central inverters are used in a similar manner to single-tracking inverters with multiple strings, except that central inverters could have the PV array divided into several sub-arrays, each comprising several strings.

8.1.5 Inverters with Solar or Power Optimisers: MPPTs at Module Level

Solar optimisers, also known as power optimisers or DCUs (d.c conditioning units), are d.c – d.c converters connected to or embedded in each module and used to operate the module at its maximum power. For installations where the modules have solar optimisers fitted, the inverter functions to control the optimisers and convert the DC power to AC power.

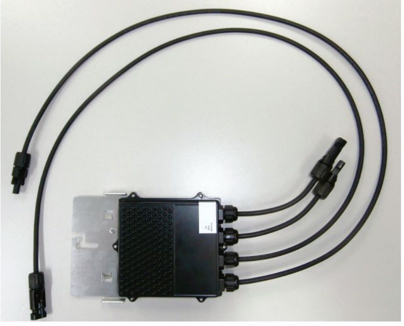


Figure 12 An example of a solar optimiser

For those countries following Australia and New Zealand standards, AS/NZS 5033 refers to solar optimisers as d.c. conditioning units. Refer to Clause 2.1.5 of AS/NZS 5033 for information on strings constructed using d.c. conditioning units. It states that module(s) on the input side of the DCUs are not considered to be an individual PV array. They are deemed to be a part of the PV array.

8.2 Number of Inverters Required?

A system might comprise 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. Strings in parallel connected to the same MPPT must have the same number of modules in each string.
   A separate MPPT will be required for each section of the array that has a different number of modules in each string. This could be achieved by using an inverter with multiple maximum power point trackers (MPPT's). Each MPPT in the inverter can be connected to a portion of the array that has a different number of modules in a string as a result of there being 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. (Refer to section 8.1)

   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.

8.3 Selecting the Size of the Inverter

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

- Maximum d.c. input power;
- Maximum specified output power;
- Maximum d.c. input voltage;
- Minimum d.c. MPPT input operating voltage; and
- Maximum d.c. input current.
- Single phase or three phase.

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 d.c. input voltage; and
- Minimum d.c. MPPT input operating voltage.

Note: Some inverters will state a minimum input voltage which is less than the minimum MPPT voltage, it is the minimum MPPT voltage which is used when determining the minimum number of modules in a string.

To reach the maximum level of d.c. 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 d.c. currents must not exceed the maximum input current allowed for the MPPT that is connected to those strings.

8.4 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 Fourteen (14) modules with a peak rating of $440\ W_p$.

$$Array\ Peak\ Power = 14 \times 440\ W\ = 6160\ W_p$$

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 d.c. 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, module 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 d.c. input power unless the designer has obtained written permission from the manufacturer.

Worked Example 8

The inverter data sheet provides the following information:

Max a.c. Output Power	5000 W
Max Generator Power (PV Array)	7500 Wp
Max d.c Input Voltage	600 V
Min d.c Input Voltage/ initial input voltage	100V / 125V

The array in the example is 6160W, this is less than the 7500W max generator power allowed.
It is also above the a.c. rating of the inverter so allowing for losses it could operate at its full 5000W rating at times.

8.5 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 d.c. input voltage; and
- Minimum d.c. MPPT input operating voltage. (Not minimum d.c. input 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 MPPT operating voltage;
- Maximum 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 and on at the beginning 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 array's MPP voltage is always greater than the inverter minimum MPPT operating voltage.
- At the coldest temperature of the day (this will be typically 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 (V_{mp}) 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 (V_{oc}) at the coldest temperature must not be above the maximum input voltage. If this requirement is met and the arrays MPP voltage (V_{mp}) 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 (V_{mp}) 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 d.c. 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.

8.5.1 Minimum Number of Modules in the String

When the temperature is at a maximum then the (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 Vmp of the array, the voltage drop in the d.c. 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 PNG can reach, or exceed, 35°C (95°F) 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 cables. 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 – 0.02) = 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:

- $P_{mp} = 440\ W_p$
- $V_{oc} = 41.02\ V$
- $V_{mp} = 33.72\ V$
- $I_{sc} = 13.73\ A$
- $I_{mp} = 13.05\ A$
- Power temperature coefficient = -0.35%/°C
- V_{oc} temperature coefficient = -0.28%/°C
- No V_{mp} temperature coefficient.
- Manufacturers Tolerance 0 to +3%
- Measurement Tolerance ±3%

Therefore, in V/°C the Voc temperature coefficient = -0.28/100 per °C x 41.02V = -0.1149V/ °C

Applying the power temperature coefficient then the Vmp temperature coefficient = -0.35/100 x 33.72 = -0.1180V/ °C. This will be used in the rest of the example.

Based on the maximum temperature of 75°C then the:
reduction in Vmp due to temperature = 75°C - 25°C = 50°C times the voltage temperature coefficient (V/°C).
= 50° C x -0.1180V/°C
= -5.90V (this means a reduction in voltage)

So the effective Vmp of the module due to temperature = 33.72V-5.90V = 27.82V

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) x 27.82 = 0.99 x 27.82 = 27.54 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 temperature does approach 75°C (167°F).

Worked Example 10

The inverter data sheet provides the following information and the inverter has two MPPTs (A and B) with different input current ratings:

Max a.c. Output Power	5000 W
Max Generator Power (PV Array)	7500 Wp
Max d.c Input Voltage	600 V
Min d.c Input Voltage/ initial input voltage	100V / 125V
MPPT Voltage Range	175 V to 500 V
Number of independent MPP inputs / strings per MPP input	2 / A:2; B:2
Max. input current input A / input B	15 A / 15 A
d.c short-circuit current input A / input B	20 A / 20 A

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

The minimum operating voltage of the MPPT is 175V.

Allowing for the safety margin of 10% the effective minimum operating voltage of the MPPT:

$$(1 + 10\%) \times 175\ V = 1.1 \times 175\ V = 192.5\ V$$

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 = 192.5V

The effective minimum MPP voltage input at the inverter for each module = 27.54V

Therefore, the minimum number of modules in a string = 192.5V/27.54V = 6.99

This would have to be rounded up to 7 since rounding down to 6 would sometimes cause the input voltages to be too low for the inverter to function.

8.5.2 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, 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:
$V_{oc} = 41.02\ V$
V_{oc} temperature coefficient = -0.28%/°C

Therefore, in V/°C the Voc temperature coefficient =
− 0.28/100 per °C $\times\ 41.02\ V = -0.1149\ V/℃$

Based on the minimum temperature of 15°C then the:
Increase in Voc due to temperature = (15°C – 25°C) = -10 °C times the voltage temperature coefficient (V/°C).
$= -10℃ \times -0.1149\ V/℃ = 1.15\ V$

So the effective Voc of the module due to temperature = 41.02V+ 1.15 = 42.17V 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 inverter data sheet provides the following information:

Max Input Voltage	600 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 = 600V

The effective maximum V_{oc} input at the inverter for each module = 42.17 V

Therefore, the maximum number of modules in a string = (600V x 0.95)/42.17V = 13.51
(Considering 5% safety factor to the max input voltage)
This would be rounded down to 13 modules in a string.
You could also connect 14 modules if the safety factor is not considered. (not recommended)

So in the worked example we can have between 7 (the minimum number) and 13 (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. It is a best practice to use 1.25 safety factor to calculate the maximum string current (mono-facial modules) i.e., $I_{STRING\ MAX}$= 1.25 x $I_{sc\ MOD}$(mono-facial)

Worked Example 15

When determining the array power and matching it to the inverter, an array of 14 modules was selected. So these, from a voltage perspective, could either be installed as one string of 14 modules (without considering the safety factor) or two strings of 7 modules.
The inverter has two MPPT's so each string of 7 modules 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.

8.6 Matching Array Current to the Inverter

Inverters have a maximum input current. However, since many inverters now have multiple MPPT's and can have multiple connections, often plugs, for the PV array d.c. 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	15A / 15 A
Max d.c short-circuit current – input A / input B	20 A / 20 A
Number of independent MPPT inputs/ strings per MPPT input	2 / A:2; B:2

This is saying that maximum input current (generally the operating current or maximum power point current) is 15A for input A and 15A for input B. It allows a maximum array short circuit current of 20A for A and 20A for B.

The module data sheet provides the following information:

– $I_{mp} = 13.05\ A$

– $I_{sc} = 13.73\ A$

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.

Max number of strings = $I_{dc\ max}$ / (1.25 x I_{sc}) = 20 / (1.25 x 13.73) = 1.17 rounded down to 1 string per MPPT.

Best practice is to calculate maximum string current using 1.25 safety factor for mono-facial modules i.e. $I_{STRING\ MAX}$= 1.25 x $I_{sc\ MOD}$)

So, there are still two solutions that will work: one long string of 14 modules or two short strings of 7 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 14-module string will have double the voltage of a 7-panel string and lower voltage arrays tend to be safer for maintenance personnel and less likely to have a problem with arcing in wiring, modules 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

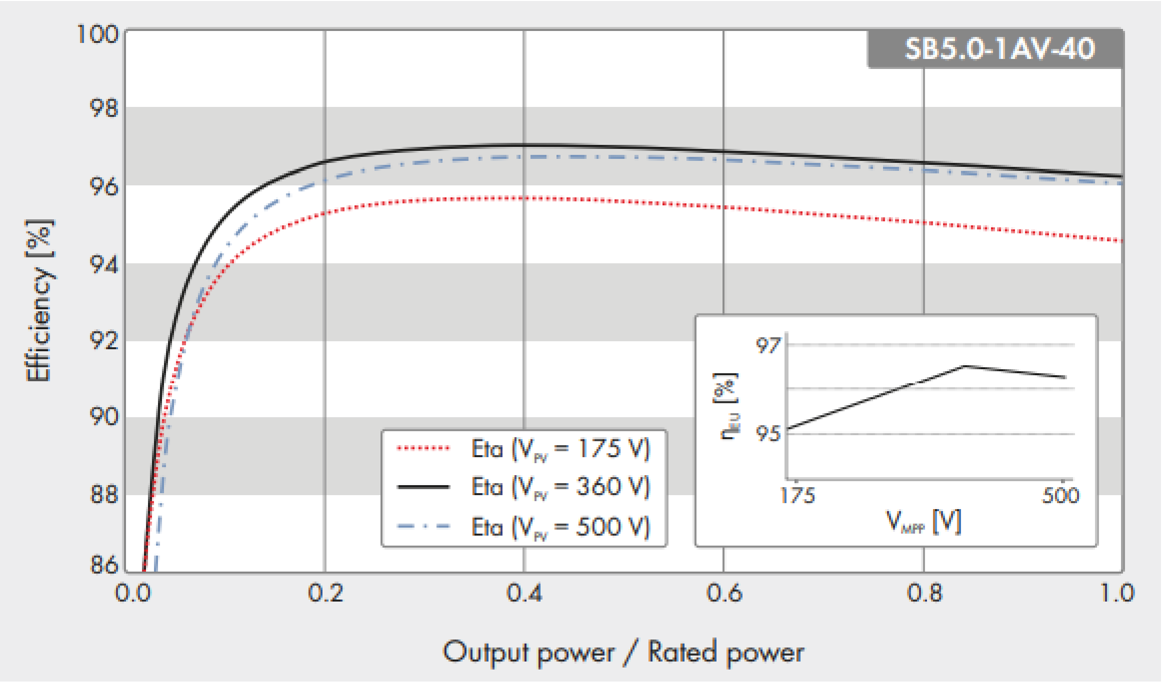
The electrical losses in the Grid Connected PV system include all the losses between the PV array and the point of connection to the grid. This connection point is typically at a switchboard or distribution board but when the solar power is being metered as it is supplied onto the grid then it will be 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 5% for PV arrays operating above 120V. (Note; For those countries following Australia and New Zealand standards refer to Clause 4.4.2.4 of AS/NZS 5033 for voltage drop considerations.
- 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 97% 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 d.c. cables and 1% loss for the a.c. 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 system's "Energy Yield".

The average yearly energy yield can be determined as follows:

$$E_{Sys} = P_{Array\_STC} \times f_{temp} \times f_{man} \times f_{dirt} \times H_{tilt} \times \eta_{pv\_inv} \times \eta_{inv} \times \eta_{inv-sb}$$

Where:

E_{Sys} = average yearly energy output of the PV array, in watthours
P_{Array_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
$\eta_{\,inv-sb}$ = 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 module's 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_STC} = $6160\ W_p$
f_{temp} = 0.874
f_{man} = 0.97
f_{dirt} = 0.9
H_{tilt} = $1806.75\ kWh/m^2$
η_{inv} = $0.96\ (96\%)$
η_{pv_inv} = $0.97\ (97\%)$
$\eta_{\,inv-sb}$ = $0.99\ (99\%)$

$$E_{Sys} = P_{Array\_STC} \times f_{temp} \times f_{man} \times f_{dirt} \times H_{tilt} \times \eta_{pv\_inv} \times \eta_{inv} \times \eta_{\,inv-sb}$$

$$E_{Sys} = 6160 \times 0.874 \times 0.97 \times 0.9 \times 1806.75 \times 0.97 \times 0.96 \times 0.99$$

$$E_{Sys} = 7{,}828{,}573\ Wh\ or\ \ 7{,}828.6\ kWh$$

10.2 Sizing the PV system

The system yield formula assumes all potential solar power becomes a.c. power via the inverter. However, if zero export requirements are stipulated by the Utility, the inverter is to be programmed for zero export, that is no power will be supplied to the grid. This means that when power produced by the inverter is greater than the power demand of the site connected to the PV system, then the inverter will curtail the solar power. This then makes it difficult to determine exactly the energy yield of the system.

Therefore, unless there is a battery system installed, the peak kW rating of the array and peak kVA of the inverter should be sized to meet the typical average daily power demand. If not, the customer must be informed that not all the solar energy created from the system will be consumed.

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 a.c. 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 7828.6 $kWh/year$ and the array was rated at 6160 W_p which is 6.16 kW_p.

Therefore, the specific energy yield is $7828.6/6.16 = 1270.94$ kWh 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 be determined as follows:

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

Where:

$H_{tilt} =$ yearly average daily irradiation, in kWh/m^2 for the specified tilt angle
$E_{ideal} =$ 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 $1806.75\ kWh/m^2$

The array is rated at $6.16\ kW_p$ $(@\ 1\ kWh/m^2)$

Therefore, the ideal energy from the array per year would be:

$6.16\ kW_p\ (@\ 1\ kWh/m^2) \times 1806.75\ kWh/m^2 = 11{,}129.6\ kWh$

The AC energy from the solar array was $7828.6\ kWh$ per year. Therefore, the performance ratio is:

$7828.6/11{,}129.6 = 0.70$

13 Designing the Cabling, Protection and Isolation Requirements of a System

A designer shall be able to design the complete wiring system of a Grid Connected PV system. This includes:

- Selecting the correct cable size based on current carrying capacity.
- Selecting the correct cable size to meet voltage drop requirements.
- Identifying when and where cable electrical protection is required and selecting the correct size
- Identifying where switch disconnection (isolation) is required and selecting the correct size.

This is all detailed in the Grid Connected PV- Install Guidelines and therefore is not repeated in this guideline. A designer shall be fully aware of all the requirements of the install guideline when designing a system.

However, for those countries following Australia and New Zealand standards the voltage drop (that is voltage rise) between the point of attachment with the grid and inverter shall be less than 2%.

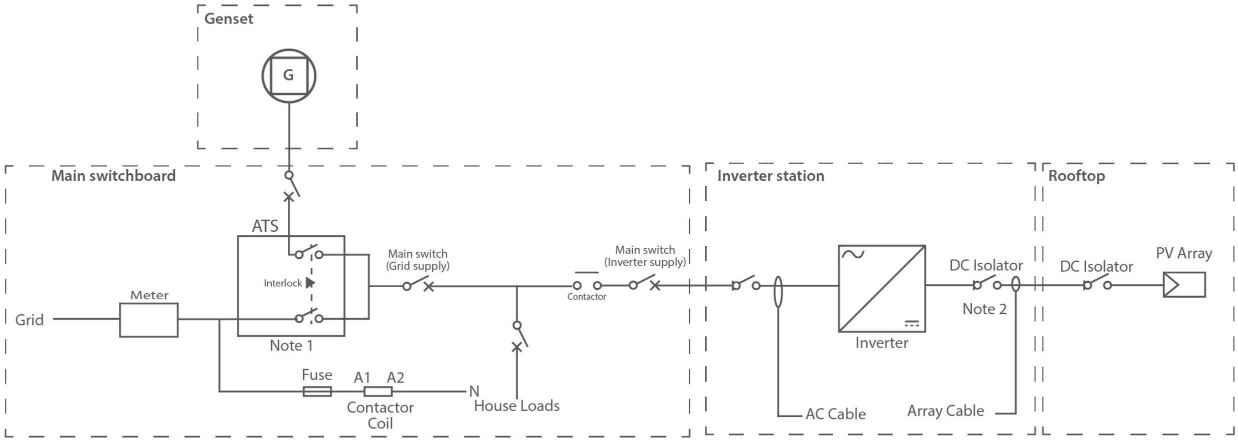
14 Fuel Generator

Some customers might already have a fuel generator being used for back-up or want to install a backup fuel generator at the same time as installing the grid connected PV system. For those countries following Australia and New Zealand standards, in accordance with AS/NZS 3000, these are known as alternative and supplementary supplies and these systems must be designed and installed in accordance with section 7.3 of AS/NZS 3000.

The fuel generator shall be interconnected at the switchboard on the load side of the meter via an automatic changeover switch. The fuel generator shall have an auto start function so that it senses the grid and starts when there is no grid power available. When this happens the load circuits in the house are supplied by the generator. (Note for those countries following Australia and New Zealand standards please refer to figure 7.3 of AS/NZS 3000 for example of the connection.)

Though there have been some PV inverters specifically designed as “fuel saving” inverters to work in parallel with the fuel generators output, the typical and most common grid connect PV inverter does not. So, when a fuel generator is installed with a PV system a relay/contactor (refer figure 13) must be installed so when the grid fails and generator starts then the output of the inverter, (unless there is a specific generator/PV controller- see note below) is disconnected from the switchboard. This is to ensure that, if the load power is less than PV inverter output, no solar power back feeds into the fuel generator.

Note: If a separate synchronising controller is installed which will monitor the loads and solar generation and ensure that there is no back-feed from the solar into the generator then the contactor as shown in figure 13 might not be required.



Note 1: The diagram above does not show the control wiring of the back-up generator and grid change-over, this control wiring needs to be installed as required.
Note 2: The load breaking d.c. disconnection device near inverter could be integrated within the inverter. If the integrated disconnector complies with relevant standard requirements, an external d.c disconnection device may not be required.

Figure 13 Interconnection of Fuel Generator and Grid Connected System in Switchboard

If the fuel generator is being installed with a Battery Energy Storage System (BESS), then the relay and contactor to disconnect the PV inverter and/or battery inverter might not be required. The generator will typically interconnect with the system by connecting directly to the battery inverter within the BESS.

14.1 Selecting the Fuel Generator

When selecting a fuelled generator, the following critical factors should be considered:

- Can the generator meet the maximum and surge demand of all the appliances that may operate when the generator is running? In general, this will be the same calculation as that undertaken in determining the rating of the battery inverter, but the battery charger must be included as an additional component of the load for the fuelled generator.
- How consistent is the load power profile? Will the profile result in the generator being under-loaded for a long period of time? Under-loaded generators may have increased maintenance costs and typically also consume more fuel per kWh delivered.
- Will the generator be used only when the battery/PV cannot supply the load, or will it be used daily for a specified number of hours?
- What should be the engine speed: 1500 rpm (revolutions per minute) or 3000 rpm. Higher speed engines will require more maintenance but typically have a lower initial cost; so higher speed engines usually are selected for installations that have generators that are only started when the solar cannot provide sufficient energy to meet the load while higher efficiency, lower speed engines are generally installed where the engine is regularly used every day.
- What is the preferred fuel type: diesel, petrol (gasoline), LPG or biofuels? This will be determined by a combination of fuel availability, fuel cost, noise, access to maintenance and its cost, generator lifetime, load type and environmental considerations.
- Physical specifications, including weight, dimensions, transportability, temperature ratings, ingress protection (IP) ratings (against the entry of moisture, dust, etc.), noise ratings and fuel efficiency.

- Electrical specifications, including apparent power, voltage and frequency regulation, rated voltage, rated amperage, harmonic distortion, number of phases, monitoring and control system typology.

For systems that include a BESS and the battery inverter can operate in parallel with the generator then the generator must be capable of operating in parallel with the inverter(s), a generator must be selected that is designed to properly work in parallel with other sources of power generation. Since the inverter and generator must synchronise, the output of the generator should have minimum harmonic distortion, or the inverter may have difficulty synchronising with the generator.

High speed (3000 rpm) petrol generators should only be used with systems where the generator does not operate in parallel with the inverter(s) and is only required as a back-up that operates to carry all the load when the battery charge is too low to handle the load.

14.2 Determining the capacity of the fuelled generator

The generator shall be sized to meet the maximum and surge demands of all the loads when it is operating, that is the maximum demand of the site. A safety margin should be included e.g. oversize by at least 10%.

14.3 Derating factors

Generators need to be derated for the site-specific temperature, humidity and altitude. The derating factors should be supplied by the generator manufacturer, however typical values are shown in Table 3. The deratings are *added* together *not multiplied* as often is the case with losses in a system.

Table 3: Generator derating factors

Site factor		**Derating**
Air Temperature		Derate 2.5% for every 5°C above 25°C
Altitude		Derate 3% for every additional 300 m above 300 m altitude
Humidity	Air Temperature between 30°C and 40°C	Derate 0.5% for every 10% above 60% humidity
	Air Temperature between 40°C and 50°C	Derate 1.0% for every 10% above 60% humidity
	Air Temperature between 50°C and 60°C	Derate 1.5% for every 10% above 60% humidity

Source: ***AS/NZS 4509.2:2010*** Clause 3.4.11.5.

Worked Example 21: Calculating derated output of the generator

The 30 kVA generator is located at a height of 900 m. Air temperature is 32°C and humidity is 90%. What is the total general derating factor? What is the derated output of the generator at this site?

Temperature is 32°C which is 7°C (32-25) above the rated test temperature of the generator (25°C). Therefore, the derating factor due to temperature = 7 x 0.5% = 3.5%

Altitude is 900 m, which is 600 m (900-300) above the maximum altitude (300 m) the generator can operate before being derated.

Therefore, the derating factor due to altitude = 600/300 x 3% = 6%

Temperature is 32ºC so the derating factor from table is 0.5% for every 10% humidity above 60% humidity.

Humidity is 90% which is 30% (90-60) above the maximum humidity (60%) the generator can operate before being derated.
Therefore, the derating factor due to humidity = 30/10 x 0.5% = 1.5%

Total derating factor = 3.5%+ 6% + 1.5% = 11% which can be expressed as 0.11

So, the derated output of the generator is (1-0.11) x 30 kVA = 0.89 x 30 kVA = 26.7 kVA

15 Providing a Quotation

15.1 Providing quotation to the customer

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) based on existing electrical energy pricing.
- A firm quotation which shows the installed cost of the complete system.
- Estimated payback period.
- Warranty information relating to each of the items of equipment (refer to PPL Equipment guidelines and Grid Connected PV System Installation guidelines for minimum requirements).
- Warranty information relating to the installation of the system (minimum of 1 year)

Note, there are computer programs and sizing tools available that can provide more detailed quotes. One such free software is OpenSolar. The OpenSolar's software provides free end-to-end tools for your solar business including solar design accuracy, proposals, etc. You can access the OpenSolar tool from: https://www.opensolar.com/features. You will have to create an account here first. A video explaining on creating proposals, etc is available at: https://youtu.be/-CRh7AUx4nw.

15.2 System design and drawings to the installer

The designer should provide a copy of the system design and drawings to the installer for the installation works.

The system design should specify each component, including the make and model. The drawings should identify the location for each piece of equipment, as determined in the design process in consultation with the system owner.

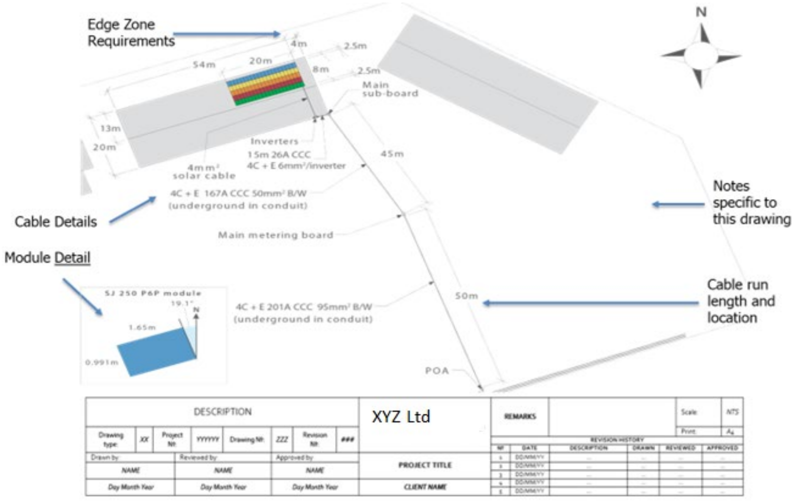
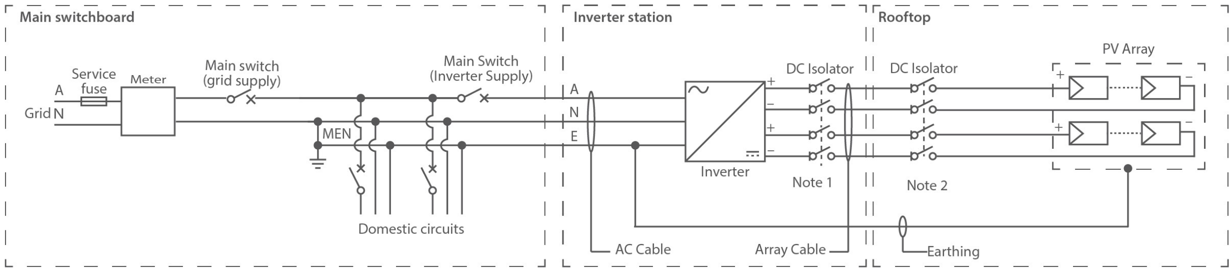


Figure 14 Sample Site Plan.



Note 1: The load breaking d.c. disconnection device near inverter could be integrated within the inverter. If the integrated disconnector complies with relevant standards requirements, an external d.c disconnection device will not be required. (For countries following AS/NZS standards)
Note 2: This could either be a ‘’disconnection point’’ (non-load breaking) or a switch disconnector (for arrays greater than 120V). (For countries following AS/NZS standards)

Figure 15 Example of electrical schematic of a grid connected PV system layout as per AS/NZS standards.

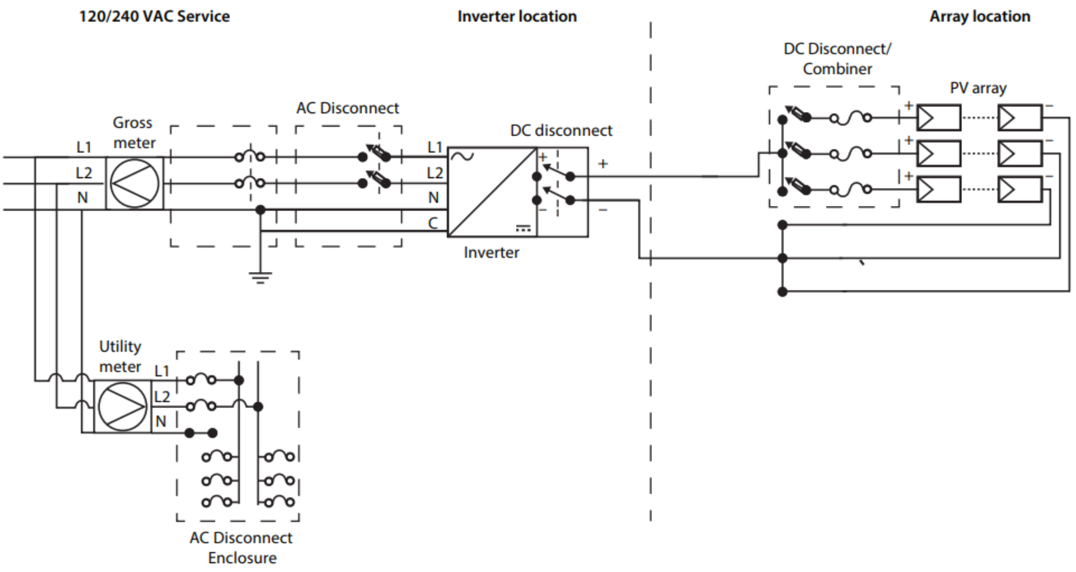


Figure 16 Wiring schematic (NEC)

16 Grid Connection Application Process

The designer is required to explain the application process to the customer.

16.1 Application

The customer shall submit an application to the Utility using the relevant application form and through relevant application procedures

As a minimum, the following information should be submitted with the application:

- Single-line diagram of the proposed installation showing cable sizing, all switch disconnectors and protection devices.
- Layout of proposed Solar PV System.
- List of protective devices between the inverter output and the point of interconnection to the grid, and their protection settings.
- Voltage rise calculation.
- A tentative bill of material of proposed solar PV system (includes name of component, component description, make/model, and quantity).

17 Appendix 1: Temperature Conversion Tables

Celsius °C	Fahrenheit °F
0 °C	32.0 °F
1 °C	33.8 °F
2 °C	35.6 °F
3 °C	37.4 °F
4 °C	39.2 °F
5 °C	41.0 °F
6 °C	42.8 °F
7 °C	44.6 °F
8 °C	46.4 °F
9 °C	48.2 °F
10 °C	50.0 °F
11 °C	51.8 °F
12 °C	53.6 °F
13 °C	55.4 °F
14 °C	57.2 °F
15 °C	59.0 °F
16 °C	60.8 °F
17 °C	62.6 °F
18 °C	64.4 °F
19 °C	66.2 °F
20 °C	68.0 °F
21 °C	69.8 °F
22 °C	71.6 °F
23 °C	73.4 °F
24 °C	75.2 °F
25 °C	77.0 °F
26 °C	78.8 °F
27 °C	80.6 °F
28 °C	82.4 °F
29 °C	84.2 °F
30 °C	86.0 °F
40 °C	104 °F
50 °C	122 °F
60 °C	140 °F

18 Appendix 2: Solar Irradiation Data

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

Location **Peak Sunlight Hours (kWh/m^2/day)**

Suva, Fiji		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *18°08′ South*	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
Longitude*: 178°25′ East*	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

Apia, Samoa		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *13°50′ South*	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
Longitude*: 171°46′ West*	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

Port Vila, Vanuatu		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *17°44′ South*	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
Longitude*: 168°19′ East*	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

Tarawa, Kiribati		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *01°28′ North*	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

***Longitude**: 173°02′ East*	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

Rarotonga, Cook Islands		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
***Latitude:** 21°12′ South*	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
***Longitude**: 159°47′ West*	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

Nuku'alofa, Tongatapu, Tonga		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
***Latitude:** 21°08′ South*	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
***Longitude**: 175°12′ West*	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

Honiara, Solomon Islands		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
***Latitude:** 09°27′ South*	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
***Longitude**: 159°57′ East*	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		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
***Latitude:** 07°20′ North*	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
***Longitude**: 134°28′ East*	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	5.51	5.73	5.53	5.55

Palikir, Pohnpei FSM		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *6°54′ North*	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
Longitude*: 158°13′ East*	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

Majuro, Marshall Islands		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *7°12′ North*	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
Longitude*: 171°06′ East*	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

Alofi, Niue		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *19°04′ South*	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
Longitude*: 169°55′ West*	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

Nauru		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *0°32′ South*	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
Longitude*: 166°56′ East*	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

Vaiaku, Tuvalu		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: *8°31′ South*	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
Longitude*: 179°13′ East*	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

Hagåtña, Guam

Latitude: *13°28′ North*

Longitude*: 144°45′ East*

	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

Noumea, New Caledonia

Latitude: *22°16′ South*

Longitude*: 166°27′ East*

	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

Pago Pago, American Samoa

Latitude: *14°16′ South*

Longitude*: 170°42′ West*

	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

[1] *Monthly Averaged Insolation Incident On A Horizontal Surface (kWh/m^2/day)*

[2] *Monthly Averaged Radiation Incident On An Equator-Pointed Tilted Surface (kWh/m^2/day)*

Source: NASA Surface meteorology and Solar Energy (http://eosweb.larc.nasa.gov)

19 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 degrees 08 minutes South
Longitude: 178 degrees 25 minutes 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 degrees 32 minutes South
Longitude: 166 degrees 56 minutes 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 degrees 31 minutes South
Longitude: 179 degrees 13 minutes 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 degrees 50 minutes South
Longitude: 171 degrees 46 minutes 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 degrees 08 minutes South
Longitude: 175 degrees 12 minutes West

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	96%	99%	100%	99%	96%	92%	85%	78%	69%	57%
10	96%	99%	100%	99%	96%	91%	85%	77%	69%	57%
20	96%	99%	100%	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%	97%	95%	91%	85%	78%	69%	60%	49%
60	96%	97%	96%	93%	89%	82%	74%	66%	56%	45%
70	96%	96%	95%	91%	86%	79%	71%	62%	52%	41%
80	96%	96%	93%	89%	83%	76%	67%	58%	48%	37%
90	96%	95%	92%	87%	81%	73%	64%	54%	43%	33%
100	96%	94%	91%	85%	78%	70%	60%	49%	38%	29%
110	96%	94%	89%	83%	76%	66%	56%	45%	34%	25%
120	96%	93%	88%	81%	73%	63%	53%	41%	30%	22%
130	96%	93%	87%	80%	71%	61%	50%	38%	27%	21%
140	96%	92%	86%	78%	69%	58%	47%	36%	26%	21%
150	96%	92%	85%	77%	67%	57%	45%	34%	25%	20%
160	96%	91%	85%	76%	66%	55%	44%	34%	24%	20%
170	96%	91%	84%	76%	66%	54%	43%	33%	24%	20%
180	96%	91%	84%	76%	65%	54%	43%	33%	24%	20%
190	96%	91%	84%	76%	66%	54%	43%	33%	24%	20%
200	96%	91%	85%	76%	66%	55%	44%	34%	24%	20%
210	96%	92%	85%	77%	67%	57%	45%	34%	25%	20%
220	96%	92%	86%	78%	69%	58%	47%	36%	26%	21%
230	96%	93%	87%	80%	71%	61%	50%	38%	27%	21%
240	96%	93%	88%	81%	73%	63%	53%	41%	30%	22%
250	96%	94%	89%	83%	76%	66%	56%	45%	34%	25%
260	96%	94%	91%	85%	78%	70%	60%	49%	38%	29%
270	96%	95%	92%	87%	81%	73%	64%	54%	43%	33%
280	96%	96%	93%	89%	83%	76%	67%	58%	48%	37%
290	96%	96%	95%	91%	86%	79%	71%	62%	52%	41%
300	96%	97%	96%	93%	89%	82%	74%	66%	56%	45%
310	96%	98%	97%	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%	100%	98%	95%	90%	84%	76%	67%	56%
350	96%	99%	100%	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 degrees 54 minutes North
Longitude: 158 degrees 13 minutes 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 degrees 28 minutes North
Longitude: 144 degrees 45 minutes 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%