GRID-CONNECTED PV SYSTEMS
(No Battery Storage)
SYSTEM DESIGN GUIDELINES

These guidelines have been developed by the Sustainable Energy Industry Association of the Pacific Islands in Collaboration with the Pacific Power Association
They represent latest industry BEST PRACTICE for the design and installation of PV Grid Connect Systems.

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INTRODUCTION

This document provides an overview of the formulas and processes undertaken when designing (or sizing) a grid connected PV system. It is based on the guidelines originally developed in Australia for the Solar Energy Industries Association (Now Clean Energy Council).

This document provides the minimum knowledge required when designing a PV Grid connect system. The actual design criteria could include: specifying a specific size (in kW_p) for an array; available budget; available roof space; wanting to zero their annual electrical usage; wanting to reduce the use of fossil fuel in the country or a number of 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 connect PV system.
- Determining the inverter size based on the size of the array.
- Matching the array configuration to the selected inverter maximum voltage and voltage operating windows.

Note: In this document there are calculations based on Temperatures in degrees C. The formulas used are based on figures provided from solar module manufactures where the coefficients are in degrees C. If your local temperatures are in Fahrenheit then you might need to convert them to degrees C to do the calculations.

SITE VISIT

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

1. Discuss energy efficient initiatives that could be implemented by the site owner. These could include:
    - replacing inefficient electrical appliances with new energy efficient electrical appliances
    - replacing tank type electric hot water heaters with a solar water heater either gas or electric boosted.(If applicable)
    - replacing incandescent light bulbs with compact fluorescents and/or efficient LED lights
2. Assess the occupational safety and health risks when working on that particular site.
3. Determine the solar access for the site.
4. Determine whether any shading will occur and estimate its effect on the system.
5. Determine the orientation and tilt angle of the roof if the solar array is to be roof mounted.
6. Determine the available area for the solar array.
7. Determine whether the roof is suitable for mounting the array.
8. Determine how the modules will be mounted on the roof.
9. Determine where the inverter will be located.
10. Determine the cabling route and therefore estimate the lengths of the cable runs.
11. Determine whether monitoring panels or screens are required and determine a suitable location with the owner

Following the site visit the designer shall estimate the available solar irradiation for the array based on the available solar irradiation for the site and the tilt, orientation and effect of any shadows.

QUOTATION DOCUMENTATION

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 and inverter.
- An estimate of the yearly energy output (yield) of the system. This should be based on the available solar irradiation for the tilt angle and orientation of the array. If the array will be shaded at any time the effect of the shadows must be taken into account when determining the yearly energy output.
- The money savings (in local currency) this represents based on existing electrical energy pricing
- A firm quotation which shows separately the equipment , installation material and installation labour costs and charges
- Warranty information relating to each of the items of equipment

If possible the savings in CO_2 (either tonnes or kg) could also be provided.

STANDARDS for DESIGN

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

In Australia and New Zealand the relevant standards include:

AS/NZ 3000	Wiring Rules
AS 3008	Selection of Cables
AS /NZS4777	Grid Connection of energy systems by inverters
AS/NZS 5033	Installation of PV Arrays
AS 4509	Stand-alone power systems (note some aspects of these standards are relevant to grid connect systems)
AS 3595	Energy management programs
AS 1768	Lightning Protection

In USA the relevant codes and standards include:

- Electrical Codes-National Electrical Code Article 690: Solar Photovoltaic Systems and NFPA 70 Uniform Solar Energy Code
- Building Codes- ICC, ASCE 7
- UL Standard 1701; Flat Plat 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

ENERGY YIELD

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

The average yearly energy yield can be determined as follows: $E_{sys} = P_{array\_STC} \times f_{temp} \times f_{mm} \times f_{dirt} \times H_{tilt} \times \eta_{pv\_inv} \times \eta_{inv} x \eta_{inv-sb}$

Where:

E_{sys} = average yearly energy output of the PV array, in watthours

$P_{array\text{-}stc}$ = rated output power of the array under standard test conditions, in watts

f_{temp}	=	temperature de-rating factor, dimensionless (refer next section)
f_{man}	=	de-rating factor for manufacturing tolerance, dimensionless (refer next section)
f_{dirt}	=	de-rating factor for dirt, dimensionless (refer next section)
H_{tilt}	=	yearly irradiation value (kWh/m^2) for the selected site (allowing for tilt, orientation and shading)
η_{inv}	=	efficiency of the inverter dimensionless
η_{pv_inv}	=	efficiency of the subsystem (cables) between the PV array and the inverter
$\eta_{inv\text{-}sb}$	=	efficiency of the subsystem (cables) between the inverter and the switchboard

It is recommended that:

- the maximum voltage drop between the PV array and the inverter is 3% ; and
- the voltage drop between the inverter and the switchboard is 1%.

How to understand and apply this formula is explained in the following section.

AC ENERGY OUTPUT OF A SOLAR ARRAY

The AC energy output of a solar array is the electrical AC energy delivered to the grid at the point of connection of the grid connect inverter to the grid.

The output of the solar array is affected by:

- Average solar radiation data for selected tilt angle and orientation;
- Manufacturing tolerance of modules;
- Temperature effects on the modules;
- Effects of dirt on the modules;
- System losses (eg power loss in cable); and
- Inverter efficiency

SOLAR IRRADIATION DATA

Solar irradiation data is available from various sources, some countries have data available from their respective meteorological department. One source for solar irradiation data is the NASA website: http:/eosweb.larc.nasa.gov/sse/. RETSCREEN, 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.

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

Attachment 1 provides PSH data on the following sites:

- Suva, Fiji (Latitude 18°08 'S Longitude 178°25 'E)
- Apia, Samoa (Latitude 13°50' S' Longitude 171°44' W)
- Port Vila, Vanuatu (Latitude 17° 44' S Longitude 168° 19' E)
- Tarawa, Kiribati (Latitude 1°28'N, Longitude 173°2 'E)
- Raratonga, Cook islands(Latitude 21°30'S, Longitude 160°0'W)
- Nuku'alofa, Tonga (Latitude 21º14'S Longitude 175º22'W)
- Honiara, Solomon Islands (Latitude 09°27'S, Longitude 159°57'E)
- Koror, Palau (Latitude 7°20'N Longitude 134°28'E)
- Palikir, Pohnpei FSM (Latitude: 6°54'N, Longitude: 158°13'E)
- Majuro, Marshall Islands (Latitude: 7º 12N, Longitude 171º 06E)
- Alofi, Niue (Latitude 19°04' S. Longitude 169° 55' W)
- Nauru (Latitude 0º55'S, Longitude 166º 91'E)
- Tuvalu (Latitude 8°31 'S, Longitude 179°13 'E)

- Hagåtña, Guam (Latitude 13°28′N Longitude: 144°45′E)
- Noumea, New Caledonia (Latitude 22°16′S Longitude: 166°27′E)
- Pago Pago, American Samoa (Latitude 14°16′ S Longitude: 170°42′W)

Note: PV grid-connect 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. The irradiation data 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.

EFFECT OF ORIENTATION AND TILT

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

Attachment 2 provides a table derived from the Australian Solar Radiation Data Handbook. This table is for Cairns, a coastal city located in the tropics. Hence the figures in the table would be similar to that for some cities/islands within the Pacific Island countries because it reflects the variation in irradiation due to different tilts and azimuths from that measured and recorded at horizontal. The table shows the average daily total irradiation represented as a percentage of the maximum value i.e. PV orientation is true North (azimuth = 0°) with an inclination equal to the latitude angl e.

The table provides values for a plane in 36 orientations (azimuths) and 10 inclination (tilt) angles. [increments of 10^{o}] .

Using the table from Australia 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 roof that is not facing true north (or south) or at an inclination equal to the latitude angle. The designer can then use the peak sun hour data for their particular country to determine the expected peak sun hours at the orientation and tilt angles for the system to be installed. Over the next few years SEIAPI hope that they can produce these tables for actual sites within the Pacific islands.

DERATING MODULE PERFORMANCE

1. Manufacturers Output Tolerance

The output of a PV module is specified in watts and with a manufacturing tolerance based on a cell temperature of 25 degrees C. Historically this has been ±5% but in recent years typical figures have been ±3% so when designing a system it is important to incorporate the actual figure for the selected module.

As a worked example, assuming the tolerance is ±5% the “worst case” adjusted output of a 160W PV module is therefore around 152W (0.95 x 160W), or 5% loss from the rated 160W.

Note: Manufacturers tolerance of -5% is a manufacturers tolerance de-rating factor (f_{man}) of 0.95 as applied in the energy yield formula (refer previous section)

2. 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 derating will be dependent on the actual location but in some city locations this could be high due to the amount of car pollution in the air or in coastal regions during long periods of no rain then salt could build up on the module.

If in doubt, an acceptable derating would be 5% from the already derated figure that includes manufacturers' tolerances.

Worked example continues: Assuming power loss due to dirt of 5% then the already derated 152 W module would now be derated further to 144.4W (0.95 x 152W).”

Note: Power loss due to dirt of -5% is a dirt de-rating factor(f_{dirt}) of 0.95 as applied in the energy yield formula (refer previous section)

3.Derating Due to Temperature

A solar modules output power decreases with temperature above 25℃ and increases with temperatures below 25℃. The average cell temperature will be higher than the ambient temperature because of the glass on the front of 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 effective temperature of the cell. This is determined by the following formula:

$T_{cell\text{-}eff} = T_{a.day} + 25℃$

Where

$T_{cell\text{-}eff}$ = the average daily effective cell temperature in degrees Celsius (℃)

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

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

A) Monocrystalline Modules

Monocrystalline Modules typically have a temperature coefficient of –0.45%/^{o}C. That is for every degree above 25^{o}C the output power is derated by 0.45%.

B) Polycrystalline Modules

Polycrystalline Modules typically have a temperature coefficient of –0.5%/^{o}C.

C) Thin Film Modules

Thin film Modules have a different temperature characteristic resulting in a lower co-efficient typically around 0%/℃ to -0.25%/℃, but remember to check with the manufacturer

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

The typical ambient daytime temperature in many parts of the Pacific is between 30 and 35^{o}C during some times of the year. So it would not be uncommon to have module cell temperatures of 55^{o}C or higher.

For the worked example, assume the ambient temperature is 30^{o}C.

Therefore the effective cell temperature is

30^{o}C +25^{o}C = 55^{o}C

Therefore this is 30^{o}C above the STC temperature of 25^{o}C

Assume the 160W_p module used in the example is a polycrystalline module with a derating of -0.5%/^{o}C

Therefore the output power losses due to temperature would be:

Temperature loss = 30^{o}C x 0.5%/^{o}C = 15% loss.

Assuming power loss due to temperature of 15% then the already derated 144.4 W module would now be derated further to 122.7W (0.85 x 144.4W)."

Note: Temperature loss of 15% is a temperature de-rating factor(f_{temp}) of 0.85 as applied in the energy yield formula (refer previous section)

Summary of Module Derating

A solar module has an derated output power = Module power @ STC x Derating due to manufacturers tolerances x derating due to dirt x derating due to temperature.

For the worked example:

Derated output power = 160 x 0.95 x 0.95 x 0.85 = 122.7W

DC ENERGY OUTPUT FROM ARRAY

The actual DC energy from the solar array = the derated output power of the module x number of modules x irradiation for the tilt and azimuth angle of the array.

If the irradiation figure is provided for the year then the above calculation will determine the annual DC energy output of the array. If it is a daily irradiation figure (daily PSH) then the calculation will determine the daily DC energy output of the array.

For the worked example assume that the average daily PSH is 5 and that there are 16 modules in the array. Therefore the DC energy output of the array = 122.7 x 16 x 5 = 9816Wh

DC SYSTEM LOSSES

The DC energy output of the solar array will be further reduced by the power loss in the DC cable connecting the solar array to the grid connect inverter. That is, a voltage drop in the cable is equivalent to a power loss (and therefore energy loss) in the output of the array that is delivered to the input of the inverter.

For the worked example assume that the cable losses for the DC cables is 3%. This is a DC subsystem efficiency of 97%. Therefore the DC energy from the array that will be delivered to the input of the inverter will be = 9816 x 0.97 = 9521 Wh

Note: Cable loss of 3% is efficiency of the subsystem (cables) between the PV array and the inverter (η_{pv_inv}) of 0.97 as applied in the energy yield formula (refer previous section)

INVERTER EFFICIENCY

The DC energy delivered to the input of the inverter will be further reduced by the power/energy loss in the inverter.

For the worked example assume that the inverter efficiency is 96%. Therefore the AC energy delivered from the output of the inverter will be = 9521 x 0.96 = 9140 Wh

Note: This efficiency of the inverter (η_{inv}) of 0.96 is that as applied in the energy yield formula (refer previous section)

AC SYSTEM LOSSES

The AC energy output of the inverter will be further reduced by the power loss in the AC cable connecting the inverter to the grid, say switchboard where it is connected. That is, a voltage drop in the cable is equivalent to a power loss (and therefore energy loss) in the output of the array that is delivered to the grid connection point.

For the worked example assume that the cable losses for the AC cables are 1%. This is an AC subsystem efficiency of 99%. Therefore the AC energy from the inverter (and originally from the array) that will be delivered to the grid will be = 9140 x 0.99 = 9048 Wh

Note: Cable loss of 1% is efficiency of the subsystem (cables) between the Inverter and the grid/switchboard ($\eta_{inv\text{-}sb}$) of 0.99 as applied in the energy yield formula (refer previous section)

SUMMARY

This section provided a step by step method for determining the AC energy delivered by a solar array to the grid. The worked example showed how to apply the different sections of the energy yield formula that was shown in the previous section titled Energy Yield.

The worked example included an array of 16 modules each with a STC rating of 160Wp. Therefore the array is rated 2560W_p.

The average daily AC energy that was delivered by the array to the grid was 9048Wh or 9.05kWh.

Therefore over a typical year of 365 days then Energy Yield of the solar array is = 365 days x 9.05kWh/day = 3303kWh/year

SPECIFIC ENERGY YIELD

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

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

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

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

For the worked example: The AC energy from the array was 3303kWh/year and the array was rated at 2560W_p

Therefore the specific energy yield is 3303/2560= 1290kWh per kW_p

PERFORMANCE RATIO

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

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

Where
E_{sys} = actual yearly energy yield from the system
E_{ideal} = the ideal energy output of the array.

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

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

Where
H_{tilt} = yearly average daily irradiation, in kWh/m^2 for the specified tilt angle
$P_{array..STC}$ = rated output power of the array under standard test conditions, in watts

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

For the worked example:

- The average daily PSH was 5. Therefore the yearly irradiation (or PSH) would be 5 x 365= 1825 kWh/m^2 (that is 1825 PSH).
- The rated power of the array at STC is 2560W_p (@kWh/m^2)

Therefore the ideal energy from the array per year would be: 2.56kW x 1825h = 4672kWh

The AC energy from the solar array was 3303 Kwh per year.

Therefore the performance ratio is 3303/4672 = 0.71

This is the opposite of system losses of 29% (that is 1-0.71=0.29)

INVERTER SELECTION

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

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

WHY MULTIPLE INVERTERS?

1. If the array is spread over a number of roofs that have different orientations and tilt angles then the maximum power points and output currents will vary from roof to roof. If economic, installing a separate inverter for each section of the array which has the same orientation and angle will maximise the output the total array. This could also be achieved by using an inverter with multiple maximum power point trackers (MPPT's). That is, the section of the array connected to one MPPT could be on a separate roof (and orientation) to another section of the array mounted on another roof orientation and connected to another MPPT within the same inverter.
2. Multiple inverters allow a portion of the system to continue to operate if one inverter fails.
3. Allows the system to be modular, so that increasing the system involves adding a predetermined number of modules with one inverter.

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.

INVERTER SIZING

Inverters currently available are typically rated for:

- Maximum DC input power. i.e. the size of the array in peak watts;
- Maximum DC input current; and
- Maximum specified output power. i.e. the AC power they can provide to the grid;

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_{mp}) of the selected module at STC.

The designer shall follow the manufacturer's recommendation when matching the peak power rating of the array to that of the inverter. If the manufacturer does not have specific recommendations then the designer should follow the following guidelines for specifying the rating of the inverter.

For the worked example

The array comprises 16 of the 160W_p crystalline modules.

Therefore the array peak power = 16 x 160
= 2.56kW

Should the inverter be rated 2.56kW?

Many manufacturers provide the maximum rating of a solar array in peak power for a specific size inverter. Accredited designers shall follow the recommendations of the manufacturer.

If the manufacturer does not provide any recommendations then the designer shall match the array to the inverter allowing for the derating of the /array.

In the section on Derating Module performance, the typical PV array output in watts is derated due to:

- Manufacturers tolerance of the modules
- Dirt
- Temperature

Inverter with Crystalline Module

Based on figures of :

- 0.95 for manufacturer,
- 0.95 for dirt and
- 0.85 for temperature (Based on ambient temperature of 30^o C)

The derating of the array is: 0.95 x 0.95 x 0.85 = 0.77

As a result of this type of derating being experienced in the field, the inverter can easily be rated at 77% of the peak power of the array and possibly even less.

Inverter with Thin Film Module

The temperature effect on thin modules is less than that on crystalline modules. Assuming the temperature coefficient is only 0.1% then the temperature derating at ambient temperature of 30^o C is 0.97
Based on figures of :

- 0.95 for manufacturer,
- 0.95 for dirt and
- 0.965 for temperature (Based on ambient temperature of 30^o C)

The derating is: 0.95 x 0.95 x 0.97 = 0.875

As a result of this type of derating being experienced in the field, the inverter can easily be rated at 88% of the peak power of the array and possibly even less.

For the worked example …

The array peak power is 2.56kW.

This array can be connected to an inverter with an output rating of:

0.77x 2.56kW = 1.97kW (for crystalline modules)

If thin film modules then the inverter could have an output rating of:

0.875x 2.56kW = 2.24kW (for crystalline modules)

MATCHING ARRAY VOLTAGE TO THE MAXIMUM AND MINIMUM INVERTER OPERATING VOLTAGES

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

With the odd exception grid interactive inverters include Maximum Power Point (MPP) trackers.

Many of the inverters available will have a voltage operating window. If the solar array voltage is outside this window then either the inverter will not operate or the output power of the system will be greatly reduced.

Minimum and maximum input voltages will be specified by the manufacturer. The maximum voltage is the voltage where above this the inverter could be damaged. Some inverters will nominate a voltage window where they will operate and then a maximum voltage, higher than the maximum operating voltage of the window, which is the voltage where the inverter could be damaged.

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

As stated earlier the output voltage of a module is effected by cell temperature changes in a similar way as the output power . The PV module manufacturers will provide a voltage temperature co-efficient. It is generally specified in V/℃ (or mV/℃) but it can be expresse d as a %/℃ .

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 voltage (if different), the 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.

MINIMUM VOLTAGE WINDOW

When the temperature is at a maximum then the Maximum Power Point (MPP) voltage (V_{mp}) of the array should never fall below the minimum operating voltage of the inverter. The actual voltage at the input of the inverter is not just the V_{mp} of the array, the voltage drop in the d.c. cabling must also be included when determining the actual inverter input voltage.
.
Since the daytime ambient temperature in some areas of the Pacific Islands can reach, or exceed, 35℃ it is recommended that maximum effective cell temperature of 70℃ is used.

For the worked example assume that the minimum voltage window for an inverter is 140V.
The module selected has a rated MPP voltage of 35.4V and a voltage (V_{mp})co-efficient of-0.177V /℃.

An effective cell temperature of 70℃ is 45° above the STC temperature of 25℃.

Therefore the V_{mp} voltage would be reduced by 45 x 0.177= 7.97V

The V_{mp} @ 70℃ would be 35.4-7.97 = 27.4V

If we assume a maximum voltage drop in the cables of 3% then the voltage at the inverter for each module would be

0.97 x 27.4 = 26.6 V

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

The minimum voltage allowed at the inverter, in this example, is 140V. The MPP voltage rises with increases in irradiance. Since the array is typically operating with irradiance levels less than 1kW/m² then the actual MPP voltage would 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 used.

For the worked example a minimum inverter voltage of 1.1 x 140V = 154V should be used

The minimum number of modules in a string is
= 154 / 26.6 = 5.79 rounded up to 6 modules

MAXIMUM VOLTAGE WINDOW

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 is the applied voltage when the system is first connected – prior to the inverter starting to operate and connecting to the grid.

Note: Some inverters provide a maximum voltage for operation and a higher voltage as the maximum allowed voltage. In this situation the MPP Voltage is used for the operation window and the open circuit voltage for the maximum allowed voltage.

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℃ I(59 °F). In some areas of the Pacific it might fall below this.

For the worked example, assume the minimum effective cell temperature is 15℃, with the open circuit voltage (V_{oc}) of 43.2 V and a voltage (V_{oc})co-efficient of-0.14V /℃. (Note the temperature coefficients for maximum powerpoint and open circuit will be different).

An effective cell temperature of 15℃ is 10° below the STC temperature of 25℃.

Therefore the V_{oc} voltage would be increased by 10 x 0.14= 1.4V

The V_{oc} @ 15℃ would be 43.2+1.4 = 44.6V

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

For the worked example, assume the maximum voltage allowed by the inverter is 400V.

The maximum number of modules in the string, is
= 400 / 44.6 = 8.96
rounded down to 8 modules

In the example presented the PV string must consist of between 6 -8 modules only.

For the worked example we required 16 modules. Therefore we could have two parallel strings of 8 modules.

It is important that the number of modules in a string is selected to ensure that the output voltage of the array is always within the voltage operating window of the inverter.

EFFECT OF SHADOWS

In towns and cities where grid connect systems will be predominant the roof of the house or building will not always be free of shadows during parts of the day. Care should therefore be taken when selecting the number of modules in a string because the shadow could result in the maximum power point voltage at high temperatures being below the minimum operating voltage of the inverter.

ATTACHMENT 1: : Table showing Peak Sun hours for various sites and tilt angles.

<u>Location</u>

Peak Sunlight Hours (kWh/m²/day)

Suva, Fiji

	Tilt	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	5.22	5.83	6.1	6.41	5.38
	33° Tilt [2]	5.95	5.4	5.33	5.03	4.85	4.7	4.8	5	5.1	5.43	5.71	6.12	5.29

Apia, Samoa

	Tilt	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]	5.31	5.24	5.12	5.32	5.07	5	5.24	5.61	5.85	5.72	5.67	5.45	5.38
	28° Tilt [2]	5.13	4.86	4.93	5.38	5.36	5.42	5.64	5.81	5.75	5.36	5.45	5.3	5.37

Port Vila, Vanuatu

	Tilt	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	5.9	5.78	5.33	4.76	4.42	4.66	5.22	5.82	6.26	6.46	7.01	5.69
	32° Tilt [2]	6.38	5.43	5.56	5.39	5.02	4.75	4.98	5.39	5.72	5.83	6.07	6.73	5.61

Tarawa, Kiribati

	Tilt	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	6.11	5.83	5.79	5.94	5.92	6.06	6.17	6.28	6.45	6.43	5.88	6.06

Rarotonga, Cook Islands

Latitude: *21°12 ' South*

Longitude: *159°47 ' West*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt [1]	6.45	6.14	5.78	4.59	3.86	3.54	3.73	4.46	5.16	5.94	6.63	6.56	5.23
21° Tilt [2]	5.9	5.82	5.86	5.04	4.56	4.2	4.35	5.07	5.39	5.74	6.11	6.51	5.38
36° Tilt [2]	5.19	5.34	5.62	5.08	4.8	4.49	4.6	5.22	5.27	5.35	5.41	6.11	5.21

Nuku'alofa, Tongatapu, Tonga

Latitude: *21°08 ' South*

Longitude: *175°12 ' West*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt [1]	6.69	6.3	5.62	4.65	4.04	3.58	3.78	4.43	5.23	6.28	6.69	6.7	5.32
21° Tilt [2]	6.1	5.97	5.69	5.1	4.81	4.25	4.41	5.03	5.46	6.08	6.16	6.65	5.48
36° Tilt [2]	5.35	5.47	5.46	5.14	5.08	4.55	4.68	5.18	5.34	5.65	5.45	6.25	5.3

Honiara, Solomon Islands

Latitude: *09°27 ' South*

Longitude: *159°57 ' East*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt [1]	5.99	5.55	5.61	5.41	4.76	4.59	4.45	5.19	5.81	6.26	6.4	6.22	5.52
9° Tilt [2]	5.98	5.47	5.54	5.52	5.01	4.91	4.7	5.36	5.82	6.15	6.38	6.24	5.59
24° Tilt [2]	5.91	5.29	5.35	5.59	5.27	5.28	4.99	5.53	5.72	5.88	6.28	6.22	5.61

Koror, Palau

Latitude: *07°20 ' North*

Longitude: *134°28 ' East*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt [1]	5.19	5.59	6.18	6.3	5.71	5.01	5.12	5.2	5.56	5.39	5.26	4.94	5.45
7° Tilt [2]	5.4	5.7	6.16	6.22	5.7	5.01	5.11	5.15	5.49	5.45	5.44	5.16	5.5
22° Tilt [2]	5.75	5.86	6.06	6.01	5.66	5.03	5.1	5.03	5.3	5.51	5.74	5.54	5.55

Palikir, Pohnpei FSM

Latitude: *6°54 ' North*

Longitude: *158°13 ' East*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt [1]	4.97	5.57	5.91	5.79	5.44	5.33	5.51	5.54	5.66	5.29	5.03	4.83	5.4
6° Tilt [2]	5.12	5.65	5.88	5.72	5.42	5.33	5.51	5.49	5.59	5.33	5.16	5	5.43
21° Tilt [2]	5.43	5.82	5.8	5.55	5.4	5.39	5.53	5.39	5.41	5.39	5.43	5.36	5.49

Majuro, Marshall Islands

Latitude: *7°12 ' North*

Longitude*: 171°06 ' East*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt [1]	5.26	5.86	6.11	5.89	5.66	5.31	5.35	5.63	5.42	5.15	4.88	4.84	5.44
7° Tilt [2]	5.47	5.99	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	5.61	5.35	5.35	5.46	5.16	5.25	5.27	5.4	5.53

Alofi, Niue

Latitude: *19°04 ' South*

Longitude*: 169°55 ' West*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt [1]	6.47	6.2	5.67	4.8	4.26	3.86	4.01	4.61	5.35	6.02	6.53	6.46	5.34
19° Tilt [2]	6.43	5.88	5.7	5.2	4.96	4.47	4.75	5.14	5.53	5.81	5.98	6.47	5.53
34° Tilt [2]	6.06	5.4	5.47	5.24	5.24	4.78	5.08	5.29	5.42	5.41	5.35	6.15	5.41

Nauru

Latitude: *0°32 ' South*

Longitude*: 166°56 ' East*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0°Tilt [1]	5.77	6.24	6.27	6.04	5.99	5.75	5.85	6.25	6.7	6.5	6.12	5.5	6.07
15° Tilt [2]	5.94	6.26	6.07	6.06	6.28	6.16	6.21	6.4	6.52	6.45	6.27	5.69	6.19

Vaiaku, Tuvalu

Latitude: *8°31 ' South*

Longitude*: 179°13 ' East*

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt [1]	5.16	5.27	5.33	5.29	4.93	4.66	4.76	5.3	5.72	5.8	5.57	5.23	5.25
8° Tilt [2]	5.14	5.2	5.26	5.37	5.14	4.92	5	5.45	5.71	5.71	5.54	5.22	5.31
23° Tilt [2]	5.09	5.05	5.08	5.43	5.42	5.3	5.33	5.62	5.61	5.49	5.47	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]	5.95	6.27	6.86	6.88	6.97	6.43	5.95	5.06	5.38	5.7	5.66	5.7	6.07
28° Tilt [2]	6.41	6.49	6.75	6.4	6.7	6.27	5.76	4.68	5.19	5.78	6.01	6.2	6.05

Noumea, New Caledonia

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average

Latitude: *22°16 ' South*

Longitude*: 166°27 ' East*

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	5.56	4.76	4.19	4.69	5.51	6.44	6.88	6.77	7.53	5.93
37° Tilt [2]	5.75	5.8	5.6	5.63	5.03	4.48	5	5.7	6.33	6.38	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	4.99	5.15	5.59	5.88	5.84	6.01	5.87	5.57
29° Tilt [2]	5.57	5.22	5.3	5.49	5.4	5.39	5.52	5.77	5.77	5.46	5.75	5.68	5.53

[1] *Monthly Averaged Insolation Incident On A Horizontal Surface (kWh/m²/day)*

[2] *Monthly Averaged Radiation Incident On An Equator-Pointed Tilted Surface (kWh/m²/day)*

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

ATTACHMENT 2: TABLE FROM AUSTRALIA

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR CAIRNS Latitude: 16 degrees 52 minutes South Longitude: 145 degrees 44 minutes East										
	Plane Inclination (degrees)									
Plane Azimuth (degrees)	0	10	20	30	40	50	60	70	80	90
0	95%	99%	100%	99%	96%	90%	82%	73%	62%	52%
10	95%	99%	100%	99%	95%	90%	82%	73%	62%	52%
20	95%	98%	100%	98%	95%	90%	82%	73%	63%	53%
30	95%	98%	99%	98%	94%	89%	82%	73%	64%	54%
40	95%	98%	99%	97%	94%	88%	81%	73%	64%	55%
50	95%	97%	98%	96%	93%	87%	80%	73%	64%	56%
60	95%	97%	97%	95%	91%	86%	79%	72%	64%	56%
70	95%	96%	96%	94%	90%	84%	78%	71%	63%	55%
80	95%	96%	95%	92%	88%	82%	76%	69%	62%	54%
90	95%	95%	94%	90%	85%	80%	74%	67%	60%	53%
100	95%	95%	92%	89%	83%	78%	71%	64%	58%	51%
110	95%	94%	91%	87%	81%	75%	68%	61%	54%	48%
120	95%	94%	90%	85%	79%	72%	65%	58%	51%	45%
130	95%	93%	89%	83%	76%	69%	62%	54%	48%	41%
140	95%	93%	88%	82%	74%	66%	58%	50%	44%	38%
150	95%	92%	87%	80%	72%	63%	55%	47%	40%	35%
160	95%	92%	87%	79%	71%	61%	52%	45%	38%	33%
170	95%	92%	87%	79%	70%	60%	51%	44%	37%	31%
180	95%	92%	86%	79%	69%	60%	51%	43%	36%	31%
190	95%	92%	87%	79%	70%	60%	51%	44%	37%	31%
200	95%	92%	87%	80%	71%	62%	53%	45%	38%	33%
210	95%	92%	88%	81%	73%	64%	55%	48%	41%	36%
220	95%	93%	88%	82%	75%	67%	59%	51%	45%	39%
230	95%	93%	89%	83%	77%	69%	62%	55%	48%	42%
240	95%	94%	90%	85%	79%	73%	65%	59%	52%	46%
250	95%	94%	91%	87%	81%	75%	69%	62%	55%	49%
260	95%	95%	93%	89%	84%	78%	72%	65%	58%	51%
270	95%	95%	94%	91%	86%	80%	74%	67%	61%	53%
280	95%	96%	95%	92%	88%	83%	76%	69%	62%	55%
290	95%	97%	96%	94%	90%	84%	78%	71%	63%	55%
300	95%	97%	97%	95%	91%	86%	79%	72%	64%	56%
310	95%	98%	98%	96%	93%	87%	80%	73%	64%	55%
320	95%	98%	99%	97%	94%	88%	81%	73%	64%	55%
330	95%	98%	99%	98%	94%	89%	81%	73%	63%	54%
340	95%	98%	100%	98%	95%	90%	82%	73%	63%	53%
350	95%	99%	100%	99%	95%	90%	82%	73%	62%	52%

Appendix 1 – Table of Abbreviations and Acronyms

d.c.	Direct current
a.c.	Alternating current
LED	Light Emitting Diode
CO_2	Carbon dioxide (greenhouse gas)
AS/NZS	Australia Standard/New Zealand Standard
UL	Underwriters Laboratory
ICC	International Code Council
NFPA	National fire Protection Association
ASCE	American Society of Civil Engineers
IEEE	Institute of Electrical and Electronics Engineers
Wh	Watt hours
kWh	Kilowatt hours
W	Watts
kW_P	Kilowatts peak
W_p	Watts peak
H	hours
V	Volts
A	Amps
PV	Photovoltaic
PSH	Peak sun hours (kWh/m^2)
H_{tilt}	Yearly irradiation value (kWh/m^2)
kWh/m^2	Kilowatt hours/metres squared
°C	Degrees Celsius
$T_{cell\text{-}eff}$	the average daily effective cell temperature (degrees Celsius)
$T_{a.day}$	the daytime average ambient temperature for the month that the sizing is being undertaken (degrees Celsius)
f_{man}	Derating due to manufacturers tolerance (Dimensionless)
f_{dirt}	Derating due to dirt (Dimensionless)
E_{sys}	average yearly energy output of the PV array (watthours)
$P_{array\text{-}stc}$	rated output power of the array under standard test conditions (watts)
f_{temp}	Derating due to temperature (Dimensionless)
η_{inv}	Inverter efficiency (Dimensionless)
η_{pv_inv}	DC Subsystem (cables between PV array and inverter) efficiency (Dimensionless)
$\eta_{inv\text{-}sb}$	AC Subsystem (cables between inverter and switchboard) efficiency (Dimensionless)
E_{ideal}	Ideal energy output from the array (watt hours)
V_{oc}	Open circuit voltage (volts)
V_{mp}	Maximum power point voltage (volts)
I_{sc}	Short circuit current (amps)
I_{mp}	Maximum power point current (amps)
STC	Standard test conditions
MPPT	Maximum power point tracker
P_{mp}	Rated maximum power (watts)