OFF GRID PV POWER SYSTEMS

SYSTEM DESIGN GUIDELINES

SEIAPI Sustainable Energy

SIDSDOCK SMALL ISLAND DEVELOPING STATES ISLAND ENERGY FOR ISLAND LIFE

WORLD BANK GROUP

PPA PACIFIC POWER ASSOCIATION

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These guidelines have been developed for The Pacific Power Association(PPA) and the
Sustainable Energy Industry Association of the Pacific Islands (SEIAPI).
They represent latest industry BEST PRACTICE for the Design of OFF-Grid PV Power Systems

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List of Abbreviations

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

AC	Alternating Current
Ah	Amp Hour
AS	Australian Standards
ASCE	American Society of Civil Engineers
DC	Direct Current
EMI	Electromagnetic Interference
EN	European Standards (European Norms)
ICC	International Code Council
IEC	International Electrotechnical Commission
ISO	International Organization for Standardization
IV	Current vs Voltage Curve
K	Degrees Kelvin

List of Abbreviations

LED	Light-emitting Diode
MPP	Maximum Power Point
MPPT	Maximum Power Point Tracker
NEC	National Electricity Code
NFPA	National Fire Protection Association
NOCT	Normal Operating Conditions of Temperature
NZS	New Zealand Standards
PSH	Peak Sun Hours
PV	Photovoltaic
PWM	Pulse Width Modulation
STC	Standard Test Conditions
UL	Underwriters Laboratories
VA	Voltage Amperes
W_p	Watts Peak (also known as Peak-Watt)

Overview

This Guideline supports solar installations that are off-grid with all energy supplied from solar photovoltaic modules. It covers the design of installations that deliver only dc to the load, installations that deliver ac to the load and use a dc bus (charge controller, battery and battery connected inverter) and installations that deliver ac to the load and use an ac bus (ac inverter connected directly to solar modules, a battery and an inverter that operates off the battery while providing battery charging from the ac inverter).

In general dc bus systems are used for loads that are primarily at night (e.g. residences, boarding schools and outdoor lighting systems) while ac bus systems provide the most value for sites that have their main loads during the day (e.g. government facilities and agricultural processing facilities).

Part 1 has information common to both dc and ac bus installations. This includes:

- Carrying out a site survey
- Estimating the energy and power requirements for the loads to be connected
- Estimating the available solar irradiance at the site
- Estimating the output from PV modules installed at the site
- Design parameters and basic specifications for modules, batteries, inverters, controllers and mounting systems.

Part 2 is dedicated to the specific requirements of dc bus configurations. It focuses on the design parameters of an off-grid PV system delivering ac to a load while using a dc bus internally. This part includes consideration of sub-system losses including:

a) battery inverter efficiency
b) battery efficiency
c) controller efficiency
d) oversizing factor and allowing for module efficiency decreasing over the lifespan of the installation.
e) Electrical losses in off-grid PV systems due to component efficiencies and cable voltage drop and the effect of those losses on the overall system design.

Part 3 is dedicated to the specific requirements of ac bus configurations. It focuses on the design parameters of an off-grid PV system delivering ac to a load while using an ac bus internally. This part includes consideration of sub-system losses including:

a) battery inverter efficiency
b) battery efficiency
c) PV inverter efficiency
d) oversizing factor and allowing for module efficiency decreasing over the lifespan of the installation.
e) Electrical losses in off-grid PV systems due to component efficiencies and cable voltage drop.

Notes:
1. IEC standards use a.c. and d.c. for abbreviating alternating and direct current 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 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 and use the formulas shown in this guideline.
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.

PART 1

Common for dc and ac bus system configurations

1. Introduction

This guideline provides an overview of the formulas and processes undertaken when designing (or sizing) an off-grid PV power system, sometimes called a stand-alone power system. It provides information for designing an off-grid dc bus (with battery charging directly from the panels) or an off-grid ac bus (battery charging from an ac source, usually an inverter connected directly to solar panels) system configuration.

The content includes the minimum information required when designing an off-grid connected PV system. The design of an off-grid PV power system should meet the required energy demand and maximum power demands of the end-user. However, there are times when other constraints need to be considered as they will affect the final system configuration and selected equipment. These include:

- available budget;
- access to the site;
- the need to easily expand the system in the future; and
- availability of technical support for maintenance, troubleshooting and repair.

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

- Determining the expected power demand (loads) in kW (and kVA) and the end-user's energy needs in kWh/day;
- Determining the size of the PV array (in kW_p) and the capacity of the battery bank (in Ah and V or Wh) needed to meet the end-users' requirements;
- Selecting the most appropriate PV array mounting system;
- Determining the appropriate dc voltage of the battery bank[1];
- Determining the rated capacity of the battery bank;
- Determining the size of the battery inverter in VA (or kVA) to meet the end-user's requirements;
- Ensuring the solar array size, battery and any inverters connected to the battery are well matched
- For dc bus systems
    - Determining the size of the solar controller (sometimes called regulator)[2] with respect/ to the PV array
    - For non-MPPT controllers matching the array to the controller so that its voltage and current outputs:
        – fit the battery voltage and is less than the maximum allowable input voltage of the controller:
        – does not to exceed the maximum controller input current.
    - For MPPT controllers, matching the array configuration to fit the controller's:
        – maximum allowable input voltage
        – input voltage operating window;
        – maximum allowable dc input power rating; and
        – maximum dc input current rating.

[1] For the battery to have a long useful life, the rated Ah capacity of the battery will generally need to be substantially larger than the Ah capacity actually needed to reliably operate the load because of losses in the system and to have the reserve needed to handle short term increases in the load. Also, as the battery ages, its effective capacity decreases.

[2] The solar controller could be a fixed input voltage controller—such as a Pulse Width Modulated (PWM) controller—or a Maximum Power Point Tracking (MPPT) controller

- For ac bus systems:
  - Determining the PV inverter capacity based on the size of the array;
  - Matching the array configuration to the selected inverter's:
    – maximum input voltage
    – voltage operating windows;
    – maximum allowable dc input power rating; and
    – maximum dc input current rating.
  - Matching the ac bus-interactive inverter to the maximum load
  - Matching the ac bus-interactive inverter to the battery charging requirements

A system designer will also determine the required cable sizes, isolation (switching) and protection requirements. This information is included in the companion guide title Installation of Off-Grid PV Power systems.

2. Typical Off-Grid PV Power System Configuration

Off-grid PV power systems can range from a single module, single battery system providing energy to dc loads in a small residence to a large system comprising an array totaling hundreds of kW of PV modules with a large battery bank and an inverter (or inverters) providing ac power to the load. Note that those larger systems may integrate a generator using fossil fuel or biofuel. The design of that type of system is covered in a separate guideline titled Design of PV-Fuel Generator Hybrid Power Systems.

Figure 1 shows the configuration of a system that provides dc power only. These systems are typically installed on rural housing and village meeting houses where the dc power directly feeds lights and small dc appliances or small ac appliances that are each powered by their own dedicated inverter operating off the dc power. These installations typically range between about 100W_p to 1000 W_p of solar though smaller or larger installations are possible. The dc voltage provided to loads is usually 12V, 24V or 48V. This type of installation is often called a Solar Home System (SHS) and is widely used for remote island village electrification.

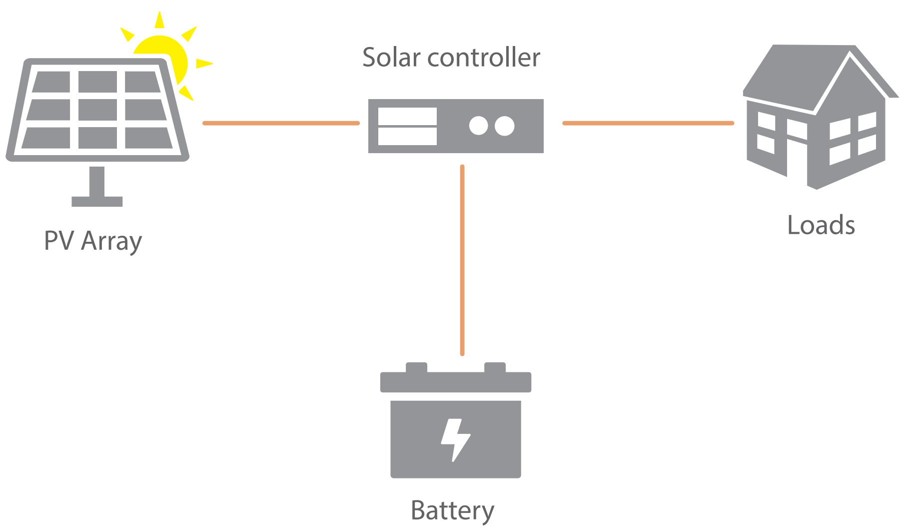

Figure 1: System Powering dc loads only (also known as a simple dc bus system)

Systems that include one or more inverters providing ac power to all loads can be provided as either:

- dc bus systems as in Figure 2 or
- ac bus systems as in Figure 3.

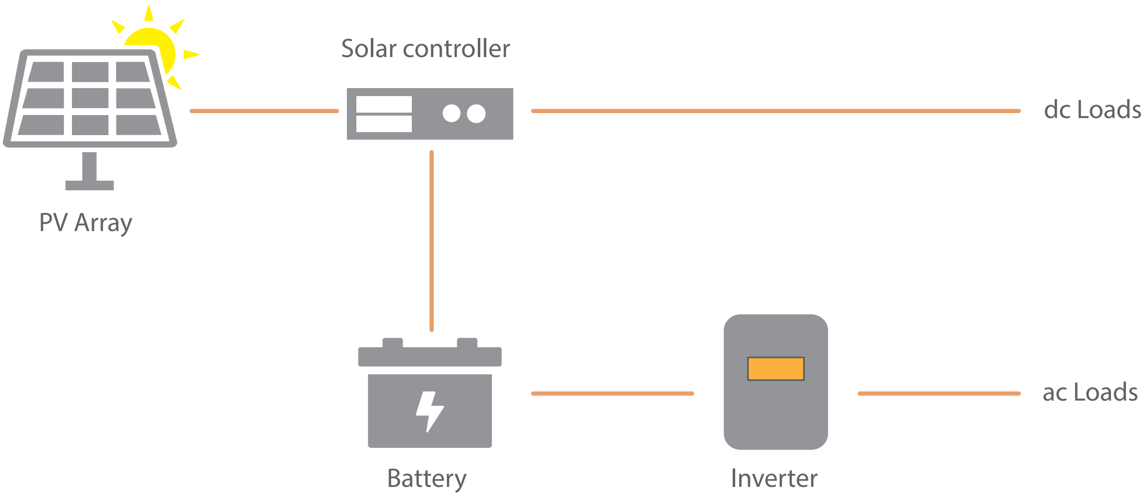

Figure 2: dc bus system

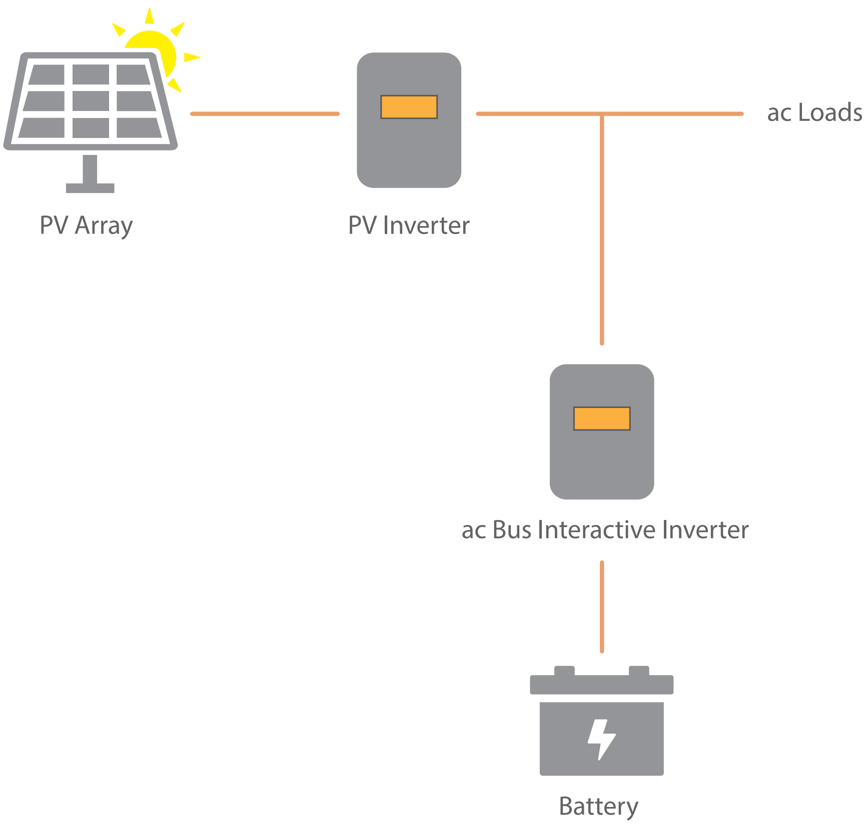

Figure 3: ac bus system

Some systems can be a combination of ac bus and dc bus systems where part of the array is connected through a solar controller to the battery and part of the array is connected to the ac side via a PV inverter. This configuration is typically used when the battery charger feature inside the ac bus interactive inverter is not able to provide an effective equalisation charge of the battery.

This guide contains the basic formulas for dc only, dc bus and ac bus systems. It does not include systems that combine the ac bus and dc bus systems.

3. Standards Relevant to the Design of Off-Grid PV Power Systems

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 most Pacific island countries and territories do follow some these standards though often with modifications as needed to fit local conditions. The 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 4086 — Secondary Batteries for use with stand-alone power systems (Note this will soon be superseded by AS/NZS 5139 Electrical installations — Safety of battery systems for use with power conversion equipment).
- AS 3011 — Electrical Installations- Secondary batteries installed in buildings.
- AS 2676 — Guide to the installation, maintenance, testing and replacement of secondary batteries in building.
- AS/NZS 5033 — Installation and safety requirements for PV Arrays.
- AS/NZS 4509 — Stand-alone power systems.
- AS 3598 — Energy audits.
- AS 1768 — Lightning Protection.
- AS/NZS 1170 — Structural Design Action Set.
- IEC 61215 — Terrestrial photovoltaic (PV) modules - Design qualification and type approval.
    - IEC 61215-1 — Part 1: Test requirements.
    - IEC 61215-1-1 — Part 1-1: Special requirements for testing of crystalline silicon photovoltaic (PV) modules.
    - IEC 61215-1-2 — Part 1-2: Special requirements for testing of thin-film Cadmium Telluride (CdTe) based photovoltaic (PV) modules.
    - IEC 61215-1-3 — Part 1-3: Special requirements for testing of thin-film amorphous silicon based photovoltaic (PV) modules.
    - IEC 61215-1-4 — Part 1-4: Special requirements for testing of thin-film Cu(In,GA (S,Se)2 based photovoltaic (PV) modules.
    - IEC 61215-2 — Part 2: Test Procedures.
- IEC 61730 — Photovoltaic (PV) module safety qualification.
    - IEC 61730-1 — Part 1: Requirements for construction.
    - IEC 61730-2 — Part 2: Requirements for testing.
- IEC 62109 — Safety of power converter for use in photovoltaic power systems.
    - IEC 62109-1 — Part 1: General requirements.
    - IEC 62109-2 — Part 2: Particular requirements for inverters.

In USA the relevant codes and standards include:

- Electrical Codes-National Electrical Code and NFPA 70:
    - Article 690 — Solar Photovoltaic Systems.
    - Article 706 — Energy storage Systems.
    - Article 710 — Stand-alone systems.
- Building Codes — ICC, ASCE 7.
- UL Standard 1703 — Flat-Plate Photovoltaic Modules and Panels.
- IEEE 1547 — Standard for Interconnecting Distributed Resources with Electric Power Systems.

- UL Standard 1741	Standard for Inverters, 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.

4. Steps When Designing an Off-Grid PV Power System

Four major issues arise when designing an off-grid PV power system:

1. the load (power and energy) required to be supplied by the system is not constant over the period of one day;
2. the daily usage varies greatly over a week (office buildings typically have much lower loads on holidays and weekends than during the work week)
3. the daily energy usage varies over the year (schools may have months of school holidays when loads are low. Tourism facilities may have very different loads at different times of the year, office building climate control energy requirements may vary substantially according to the time of year)
4. the energy available from the PV array will vary greatly during the day according to the time of day and cloud passages;
5. the energy available from the PV array will vary during the year as weather conditions vary over the year and as the sun changes its position in the sky over the year.

Since the system is based on photovoltaic modules, the designer should compare the available energy from the sun and the actual energy demands over a typical year. The worst month will be when the ratio between solar energy available and energy demand is smallest. The solar energy available during that worst month should be chosen as the design basis for the installation.

The steps in designing a system include:

1. Carrying out a site visit and determining the limitations for installing a system and examining the location where the equipment will be installed (see section 5)
2. Determining the energy needs of the end-user (see section 8)
3. Determining the voltage and capacity of the battery bank. (see sections 9 & 10)
4. Determining the size of any inverter connected to systems supplying dc power (Section 12).
5. Determining the size of the array (sections 13,14 and 15).
6. Determining the size of the solar controller (Section 18 for standard switched controllers and section 20 for MPPT based controllers).
7. Providing a quotation to the end-user. (Section 17).

5. Site Visit

Prior to designing any off-grid power system a designer should visit the site and undertake/determine/obtain the following:

1. Discuss the energy needs of the end-user. (Section 6 for more detail).
2. Complete a load assessment form (See Section 8 for more detail).
3. Assess the occupational safety and health risks when working on that particular site.
4. Determine the solar access for the site or determine a position where the solar has the most available sunlight.
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. (See the guide for Installation of Off-Grid PV power systems for further information)
7. Determine the available area for the solar array.
8. Determine whether the roof is suitable for mounting the array (if roof mounted).
9. Determine how the modules will be mounted on the roof (if roof mounted).
10. Determine where the batteries will be located.
11. Determine where the solar controller will be located.
12. Determine where the battery inverter will be located (if applicable).
13. Determine the cabling route and therefore estimate the lengths of the cable runs.
14. Determine whether monitoring panels or screens are required and determine a suitable location with the end-user.

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 shading. (See section 12.1, 12.2 and 12.3).

If the site is too remote, then all the above information might need to be obtained through discussions with the end-user and the final location of all equipment selected at the time of installation.

Some small systems might be provided as plug-and-play systems (sometimes called pico-solar systems). In this case the designer/supplier must provide the end-user with relevant manuals (refer to documentation in Off Grid Installation Guideline).

6. Energy Source Matching

Though the price of solar modules has reduced dramatically in recent years it is still best to match some of the energy needs of the end-user with other sources if possible.

For example, though microwave ovens are suitable for cooking using electric power from off-grid PV power systems, it is more appropriate to use biomass (or kerosene or LPG if available) for cooking.

If hot water for showers and washing is required, then a solar hot water system could be used.
(**Note:** Price of PV modules has reduced to a low price that at times using PV modules on an electric hot water unit is cheaper than installing a separate solar hot water unit, however it must be set up correctly to ensure that it never uses battery power but only power directly from PV modules).

7. Energy Efficiency

Discuss energy efficient initiatives that could be implemented by the site owner. These could include:

i. Replacing inefficient electrical appliances with new energy efficient electrical appliances;
ii. Replacing incandescent light bulbs with efficient LED lights;
iii. Using laptop computers instead of desktop units;
iv. Using energy efficient flat-screen TVs instead of older units with picture tubes.

8. Load (Energy Assessment)

Electrical power is supplied from the batteries (dc) or via an inverter to produce either 230 volts ac (South Pacific) or 110/120 volts ac (North Pacific). Electrical energy usage is normally expressed in watt hours (Wh) or kilowatt hours (kWh).

To determine the daily energy usage for an appliance, multiply the power required by the appliance in Watts times the number of hours per day it will operate. The result is the energy (Wh) consumed by that appliance per day.

Appliances can either be dc or ac. An energy assessment should be undertaken for each type. Examples of these are shown in tables 1 and 2.

You need to discuss the electrical energy usage in detail with the end-user. Many systems have failed over the years not because the equipment has failed or the system was installed incorrectly, **but because the end-user believed they could get more energy from their system than the system could deliver.** It failed because the end-user was unaware of the power/energy limitations of the system and attempted to use more energy than the system was designed to provide.

The problem is that the end-user may not want to spend the time determining their realistic power and energy needs which are required to successfully complete a load assessment form. They typically just want to know: “How much for a system to power my lights and radio or TV?”

A system designer can only design a system to meet the power and energy needs as stated by the end-user. The system designer must therefore use this process to clearly understand the needs of the end-user and at the same time educate the end-user regarding the capacity of the system to be installed. Completing a load assessment form correctly (refer to table 1 and 2 below) does take time; you may need to spend 1 to 2 hours or more with the potential end-user completing the tables. It is during this process that you will need to discuss all the potential sources of energy that can meet their energy needs and you can educate the end-user about energy efficiency.

Tables 1 and 2 are used throughout the guideline as a worked example. If the loads are dc then table 1 will be used. If the loads are ac then table 2 will be used.

The table shows dc lighting loads and ac appliance loads.

The table shows an energy assessment process that can include two types of seasons. Though some parts of the Pacific region do not have two significantly different seasons, others may have two seasons, where one season is more humid and possibly rainier than the rest of the year, thus dividing the year into dry (or clear) and wet (or cloudy) seasons. If this is the case, then in the more humid season some appliances (e.g. ceiling fans) are likely to operate for longer times in this season than in the drier season. The refrigerator is shown as an ac appliance but it is possible that this may be a dc appliance.

The season with the highest average daily energy usage is used to determine the size of the battery bank. A comparison is undertaken between available solar irradiation for each month and the pattern of seasonal energy use to determine the month that has the greatest disparity between energy needed by the end-user and the energy available from the sun. The kWh/day energy requirement of that month is then used to determine the size of the solar array needed to provide the required kWh of electrical energy during that month.

Though the total load energy might be high for some installations it can also be small for other installations, a careful survey for each installation has to be carried out. The table also shows both dc lighting loads and ac appliance loads. In real life this could be the case or all the loads might be dc or all ac. The principle of this guideline is to summarise how you use a load assessment form to design any off-grid system.

In the worked example of a load assessment (the following pages), the TV, fan and refrigerator are using ac electricity so we have to take into account the efficiency of the inverters used. Typically, the peak efficiency of an inverter may be over 95% but in many systems the inverter will sometimes be running even when there is very little load on the inverter and some energy will be used by the inverter even though it is not operating a load, so the average efficiency is typically about 90% to 96%. Then we must divide the total ac energy used by the load plus the losses in the inverter to obtain the total energy required to be supplied to the inverter from the battery bank.

The season with the highest energy usage is used to determine the size of the battery bank. A comparison is undertaken between available solar irradiation and the seasonal energy use to determine the worst month – the month where the ratio of solar irradiation and electrical load is the smallest – which is then used to determine the size of the solar array (refer to section 13.2).

Worked Example 1

(Based on the load tables shown on page 12)
This example shows how to determine the energy at the battery bank for both the humid season and the rest of the year.
Assume the overall efficiency of the chosen inverter is 90%.

Humid Season
Daily battery load (energy) from dc loads = 140Wh
Daily battery load (energy) from ac loads = 1860Wh ÷ 0.9 = 2067Wh

To get the total load (energy) as seen by the battery, you add the two figures together:

2067 + 140 = 2207Wh

Rest of Year
Daily battery load (energy use) from dc loads = 112Wh
Daily battery load (energy use) from ac loads = 1500Wh ÷ 0.90 = 1667Wh

To estimate the total load (energy) as seen by the battery, you add the two figures together:

1667 + 112 = 1779Wh

If there are no ac loads, then just work out the load from the dc appliances, and do not include any calculations for an inverter (or inverter efficiency).

Worked example 2

Table 1: dc Load (energy) Assessment

(1)	(2)	(3)	(4a)	(5a)	(4b)	(5b)	(6)	(Comments)
Appliance	Number	Power	Rest of the year		Humid Season		Contribution to maximum demand	
			Usage Time	Energy	Usage Time	Energy		
		W	H	Wh	H	Wh	W	
Light	4	7	4	112	5	140	28	
Daily Load energy-dc loads (Wh)			(DC 7a)	112	(DC 7b)	140		
Maximum dc demand (W)						(DC 8)	28	

Table 2: ac Load (energy) Assessment

(1)	(2)	(3)	(4a)	(5a)	(4b)	(5b)	(6)	(7)	(8)	(9a)	(9b)	(Comments)
Appliance	No.	Power	Rest of the year		Humid Season		Power Factor	Contribution to max demand	Surge Factor	Contribution to surge demand		
			Usage Time	Energy	Usage Time	Energy				Potential	Design	
		W	h	Wh	h	Wh		VA		VA	VA	
TV	1	25	4	100	4	100	0.8	31	1	31	31	
Fan	1	60	0	0	6	360	0.9	67	1	67	67	
Refrigerator	1	100	14	1400	14	1400	0.8	125	4	500	500	Duty cycle of 0.58 included
Daily Load Energy A.C Loads (Wh)			(AC10a)	1500	(AC10b)	1860						
maximum ac demand (VA)							(AC11)	223		598		
Surge demand (VA)									(AC12)		598	

9. Selecting Battery Voltage

System battery voltages are generally 12, 24 or 48 Volts. The actual voltage is determined by the requirements of the system. For example, if the batteries and the inverter are a long way from the PV array and it uses a standard switching type solar controller, then a higher voltage may be required to offset the power lost in the cables. In larger systems, 120V or 240V dc could be used, but these are not typical household systems and due to the potentially fatal voltages used, the standards for construction at those high voltages are much more complex and the resulting system more expensive than would be the case for systems using voltages below 60V dc that are not so dangerous. To avoid the problems of using dc voltages greater than 60V, even large systems with more than 200kW$_p$ of array often have a multiple cluster design with each cluster using a 48V battery bank.

As a general rule, the recommended system voltage increases as the total daily energy usage increases. For small daily loads, a 12V system voltage can be used. For intermediate daily loads, 24V is used and for larger loads 48V is used.

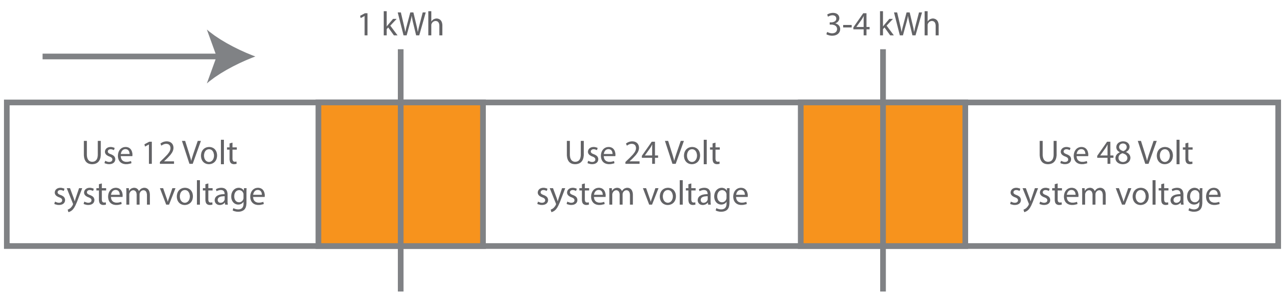

Figure 4: Guideline to Selecting Battery Voltage

The changeover points are roughly at total energy usage of 1 kWh/day and 3-4 kWh/day but this will also be dependent on the actual power profile. These are only a guide and there will be certain systems where this guide might not be applied. For example, assume a radio transmitter has a 100W continuous power demand. A 12 V system could still be used even though the total energy usage is 2400Wh/day. The current being drawn from the battery bank is only 8.33A (100W/12V). On the other hand, a pump drawing 800W that only operates 3 hours a day will also use 2400 Wh but will draw almost 67 Amperes when it runs, requiring very large wires and high Ah capacity batteries at 12V. If operated at 48V, the current draw will be about 17A and much smaller wiring can be used without excessive losses plus the battery Ah requirement will be ¼ that of using a 12V battery.

One of the general limitations is that the maximum continuous current being drawn from the battery bank should not be greater than 150A.

Note: The term battery bank is being used in the guideline but in some small systems it may be a single 12V monobloc battery.

10. Determining the Required Capacity of the Battery Bank

If the load energy assessment is undertaken based on two different weather seasons, the highest daily energy usage is used to determine the installed battery capacity.

Some people in the industry might argue that if some of the loads are working during the day the battery bank capacity does not need to be based on the total daily energy usage, it can be reduced due to the daytime loads being supplied directly by the PV array. However, the available solar irradiation can vary greatly from day to day so the best practice – and the recommendation of this guideline – is to determine the required battery capacity based on the total daily energy usage. This not only helps ensure that the system operates reliably; it also extends the battery life since it is less stressed during cloudy periods.

Lithium Ion batteries are typically supplied based on their Wh capacity.

Lead acid batteries are typically supplied based on their ampere-hour (Ah) capacity.

To convert Watt-hours (Wh) to Amp-hours (Ah) you need to divide by the battery system voltage.

Worked Example 3

The largest energy usage is 2207Wh/day, so select a battery system voltage of 24 Volts.

This means that the Ah/day usage on the battery bank will be:

Ah/day = Wh/day ÷ system voltage 2207 Wh/day ÷ 24 = 92 Ah/day

The minimum size battery to meet the daily energy requirements in the example is: 92Ah, for lead acid or 2207Wh for a lithium ion battery.

However, for long-life, lead-acid batteries should not regularly be discharged more than 60% with 20% a common average discharge level for rural off-grid solar installations. So the actual Ah of the battery installed will be at least double and often five times the calculated one-day Ah requirement.

Battery capacity is determined by whichever is the greater of the following two requirements:

1. The ability of the battery to meet the energy usage of the system, typically for three to five days, sometimes specified as “days of autonomy” of the system;
   OR
2. The ability of the battery to supply peak power demand in delivered watts (Amperes delivered times Volts at the battery terminals).

The critical design parameters include:

Parameters relating to the energy requirements of the battery:

a) Daily energy usage.
b) Daily average depth of discharge and maximum depth of discharge.
c) Number of days of autonomy.

Parameters relating to the discharge power (current) of the battery:

a) Maximum power demand.
b) Surge demand.

Parameters relating to the charging of the battery:

a) Maximum charging current

Based on these parameters there are a number of factors that will increase the required battery capacity in order to provide satisfactory performance. These factors must be considered when specifying the system battery.

Days of Autonomy

Extra capacity is necessary where the loads require power during periods of reduced solar input. The battery bank is often sized to provide for a number of days of autonomy (days of operation without solar charging). A common period selected is three to five days but it depends on how critical the loads are.
For example, a site could provide critical services and therefore more than 5 days of autonomy might be required to ensure continuous operation. For example, an important telecommunications station may require a solar installation with sufficient battery capacity for 14 days of autonomy.

The minimum that should be used is 3 days (with no generator as back-up) and 5 is preferred for remote sites because battery life may be significantly increased relative to a 3 day period of autonomy. Long battery life is important for remote sites because battery exchanges are easily the most expensive on-going cost in operating a remote off-grid electricity system. Often transport and labour for the new battery and the transport and cost of recycling the old battery will together be more than the cost of purchasing the new battery itself.

Worked Example 4

Assume 5 days autonomy

Adjusted battery capacity = 92Ah x 5 = 460 Ah for lead acid batteries.

and

Adjusted Battery Capacity = 5 x 2207Wh= 11035 Wh for lithium ion batteries

Maximum Depth of Discharge

Battery manufacturers recommend a maximum depth of discharge (DOD). If this is regularly exceeded the life of the battery is severely reduced. This could be 50% for some residential sized lead acid batteries or as high as 80% for some large industrial quality solar batteries.

In lithium ion batteries the term usable power is applied. This may be between 60% and 80% of the rated capacity.

Note: If the usable energy of a lithium ion battery is specified at say 80%, it is recommended that the battery does not go more than 70%. This is because some Lithium Ion batteries if they reach their lowest value might “lock-up” and then become unusable.

> **Worked Example 5**
>
> Assume a maximum DOD of 70% for a lead acid battery and the usable capacity with a lithium ion battery is 80% but 70% is applied.
>
> Adjusted Battery Capacity = 460 ÷ 0.7 = 657 Ah for the lead acid battery
> and
> Adjusted Battery Capacity = 11035 ÷ 0.7 = 15764 Wh for the lithium ion battery

Battery Discharge Rate

For lead acid batteries, the actual discharge rate selected for the capacity rating is highly dependent on the power usage rates of connected loads. This is indicated by the capital letter C (for capacity) and small numbers that follow representing the hours of charge available at that discharge rate. The Ah capacity of solar batteries, particularly small 12V solar batteries, are typically given for a discharge rate of C_{100} – that means the time it takes to fully discharge the rated Ah capacity of the battery at the given Amperes of delivery is 100 hours. Many appliances operate for short periods only, drawing power for minutes rather than hours. This affects the battery selected, as battery capacity varies with discharge rate. Information such as a power usage profile over the course of an average day is required for an estimate of the appropriate discharge rate to use in the design. For many systems, and particularly small systems, this is often impractical to obtain.

Table 3: Example of varying battery capacities based on discharge rates

Capacities C_1 - C_{100} (20°C)					
Type	C_1 1.70 V/C	C_5 1.70 V/C	C_{10} 1.70 V/C	C_{20} 1.75 V/C	C_{100} 1.80 V/C
SB12/60 A	34	45	52	56	60
SB12/75 A	48	60	66	70	75
SB12/100 A	57	84	89	90	100
SB12/130 A	78	101	105	116	130
SB12/185 A	103	150	155	165	185
SB6/200 A	104	153	162	180	200
SB6/330 A	150	235	260	280	330

Source: GNB Sonnenschein Batteries

Where the average rates of power usage are low, such as for most residential loads, the battery capacity for 5 days of autonomy is often selected at the 100hr (C_{100}) rate of discharge for the battery while for 3 days autonomy is often selected at the 20hr (C_{20}) rate of discharge for the battery

Where average power usage rates are high, as is often the case for industrial applications, it may be necessary to select the battery capacity for 3 to 5 days autonomy at a higher discharge rate than C_{100} e.g. a 10hr (C_{10}) or 20hr (C_{20}) rate.

For lithium ion batteries the battery capacity is only slightly reduced at higher discharge currents. So the battery can be selected based on the rating provided by the manufacturer without consideration of the discharge rate.

Worked Example 6

The discharge current for the battery with all the loads on is only approximately 10.5 A (Demand is 28W dc plus 223VA ac which is divided by 24V)

Adjusted Battery Capacity = 657 Ah (@ C_{100}) for the lead acid battery.

Lithium battery is still 11035Wh.

Battery Temperature Derating

The capacity of lead-acid batteries is affected by temperature. As the temperature goes down, the battery capacity also goes down. Figure 5 gives a battery correction factor for low temperature operation. Note that the temperature correction factor is 1 at 25°C as this is the temperature at which battery capacity is specified.

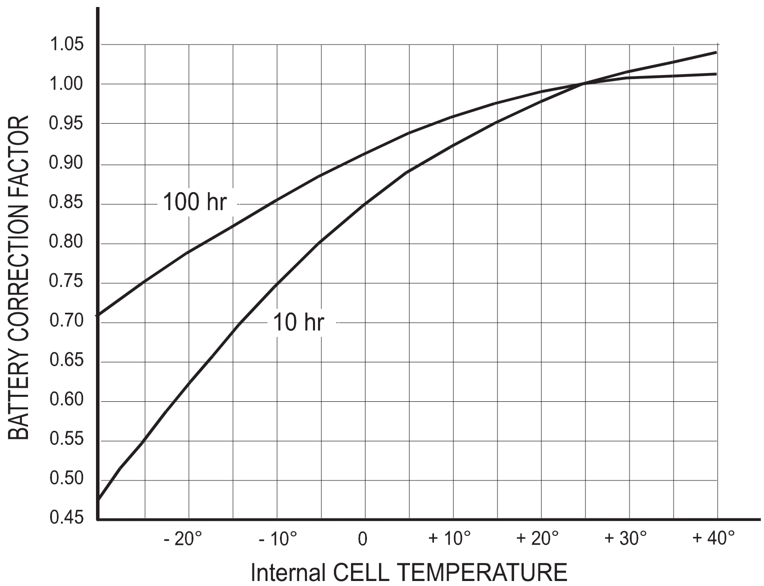

Figure 5: Temperature Correction Factor

In the tropics it is usually still over 20°C (68°F) in the evenings so unless the system is located in a mountainous region that does regularly get below 20°C (68°F) you can ignore the temperature derating. If you want to be conservative add 5% to the capacity to allow for this factor.

Battery Selection

For lead-acid batteries, a deep discharge type battery/cells must be selected and they must provide the required system voltage and capacity in a single series string of battery cells.

Parallel strings of batteries are not recommended.

Where paralleling strings cannot be avoided, each string must be separately fused.

For the worked example a battery of at least 657 Ah (@C_{100}) should be used.

11. Selecting a Battery

For lead acid batteries, the deep discharge type batteries/cells selected should be rated for the required system voltage and capacity and preferably uses a single series string of battery cells. Batteries designed for solar installations do exist even as single 2V cells and if purchasing 2V batteries for the battery bank, it is preferable that solar type batteries are selected. In any case, batteries must be designed for deep discharge applications, engine starting batteries have a short life when used in solar installations.

Parallel strings of batteries are not recommended. However, it is accepted that for some systems it is unavoidable, though as a rule, the more batteries there are connected in parallel, the shorter the battery life. If parallel batteries are unavoidable, then follow the manufacturer's recommendation for the maximum number of parallel strings. It is usually only 3 or 4 and some manufacturers void their battery warranty if more than 2 batteries are placed in parallel. Never have more than 4 batteries in parallel and ensure all the requirements for wiring parallel battery strings as specified in the installation guideline are followed.

When selecting the batteries, they should meet one of the following standards:

- IEC 61427 — Secondary Cells and Batteries for Solar Photovoltaic Energy Systems - General Requirements and Methods of Test
- IEC 62619 — Secondary cells and batteries containing alkaline or other non-acid electrolytes - Safety requirements for secondary lithium cells and batteries, for use in industrial applications
- IEC 60896 — Stationary lead-acid batteries (series)
- UL 1973 — Standard for Batteries for Use in Stationary, Vehicle Auxiliary Power and Light Electric Rail (LER) Applications
- UL 1642 — Standard for Lithium Batteries

12. Selecting a Battery Inverter

When selecting a battery inverter to power an ac appliance that is to be connected to an off-grid PV system that is delivering dc power to the user, the inverter must have an input dc voltage rating that is the same as the voltage of the dc power provided by the solar and should meet one of the following standards:

- IEC 62109	Safety of power converters for use in photovoltaic power systems
• IEC 62109-1	Part 1: General requirements
- UL Standard 1741:	Standard for Inverter, converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources

The type of inverter selected for the installation depends on factors such as availability, cost, surge requirements and power quality requirements. Inverters are available in three basic output types: square wave, modified square wave (sometimes called modified sine wave) and sine wave. There are few square wave inverters used today since most ac equipment works poorly on square wave ac power and modified square wave inverters are comparable in price.

Modified square wave inverters generally have good surge capacity, are available in a wide range of power capacities and are usually cheaper than sine wave types. However, many appliances, such as some audio equipment, some televisions and all appliances that have ac motors (e.g. fans) can be damaged or provide poor service because of the non-sine wave power input.

Sine wave inverters are increasingly affordable and often provide even better quality power than the urban grid supply.

Battery Inverter Sizing

For systems where there are only a few ac appliances (e.g. as shown in table 2) the selected battery inverter should be capable of supplying continuous power to all loads that are connected to it and must have sufficient surge capacity to start all loads that may surge when turned on, should they all be switched on at the same time. Electric motors are particularly likely to have a large surge capacity requirement.

For households with many ac loads where some loads, e.g. microwave and power tools, are only operating occasionally it is not practical to select an inverter based on the total power rating of all the loads. The inverter should be selected based on determining what loads would typically be operating at the same time. Attention might need to be given to load control and prioritisation strategies. For example, if the inverter has surge capacity sufficient for only one motor but there are several motors that it powers, the motor switching design should make it impossible for two or more of the connected motors to be switched on at the same time.

Worked Example 7

From the load (energy) assessment on page 13, the selected inverter must be capable of supplying 223VA continuously with a surge capability of 598VA for a short period of time.

13. Solar Irradiation

Solar irradiation data is available from various sources; some countries have data available from their respective energy office or from the national meteorological or agricultural department.

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 important source for solar irradiation data that is available at no cost is from the NASA website: https://power.larc.nasa.gov/data-access-viewer/. RETSCREEN (available from: https://www.nrcan.gc.ca/energy/software-tools/7465), a program available from Canada that incorporates the NASA data, is easy to use. Please note that in some island countries, the NASA satellite data has, in some instances, higher irradiation figures than those recorded by ground mounted instruments. This is particularly the case for sites on mountainous islands since there tend to be more clouds over the mountains than at sea or over low-lying areas. If there is no other data available this satellite data can be used though ground based data from a location near the site is always to be preferred.

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

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)

PV arrays in off-grid systems should always be installed facing the optimum orientation/azimuth. The optimum tilt direction is true (not magnetic) north in the southern hemisphere and true south in the northern hemisphere — the solar system should always face the equator. However, this can change due to local climatic conditions (clouds that consistently form at a particular time of the day) or topographical conditions (mountains or structures causing shading at consistent times in the mornings or afternoons). In latitudes between 10° south and 10° north the array can be oriented either north or south with little change in output. Also, orientations that are as much as 90° away from the optimum direction have a relatively small impact on daily irradiation totals when the latitude of sites are less than 10°.

Solar irradiation data is available from various sources; some countries have data available from their respective energy office or from the national meteorological or agricultural department.

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 important source for solar irradiation data that is available at no cost is from the NASA website: https://

13.1 Irradiation for Design Month

The design month is the month where the ratio of available irradiation (PSH) to daily load energy for that month is the smallest. The irradiation of the design month is then used when determining the size of the required PV array.

Worked Example 8

The rest of year energy usage (at the battery bank) = 1779Wh= 1.78kWh

The Humid Season energy usage (at the battery bank) = 2207Wh= 2.21 kWh

Assume:

- the site is near Suva and the array is tilted at 18 degrees,
- the rest of the year season is from April to September; and
- the humid season is from October to March

Using the irradiation data in Appendix 2, the ratio of PV energy output (which is proportional to available irradiation) to load energy is shown in Table 4:

Table 4: Ratio of PV energy output (proportional to available irradiation) to load energy requirement

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Irradiation (kWh/m²)	6.27	5.88	5.55	4.99	4.61	4.38	4.51	4.88	5.21	5.83	6.1	6.41
Daily Energy used (kWh)	2.21	2.21	2.21	1.78	1.78	1.78	1.78	1.78	1.78	2.21	2.21	2.21
Irradiation / daily energy	2.85	2.66	2.51	2.59	2.59	2.46	2.53	2.74	2.93	2.64	2.76	2.90

The lowest ratio is 2.46 so June will be the design month and the available irradiation in June is 4.38kWh/m² or 4.38 Peak Sun hours.

13.2 Effect of Orientation and Tilt

If the array is to be mounted on a roof and the roof is not oriented true north (Southern Hemisphere) or south (Northern Hemisphere) and/or not at the optimum inclination, the daily output from the array will generally 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 5.
The tables show the average daily total irradiation represented as a percentage of the maximum value i.e. PV orientation is true north (azimuth = 0°) for the southern latitudes or true south (azimuth = 180°) for northern latitudes with the array tilt angle equal to the latitude angle. If the location for the system being designed is not shown it is acceptable to use the site in the table that has the nearest latitude.

Table 5: List of sites with orientation and tilt tables in Appendix 3

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

The tables in Appendix 3 provide values for a plane in 36 orientations (azimuth angles) and 10 inclination (tilt) angles in increments of 10°.

Using these tables will allow the system designer/installer to estimate the expected output of a PV array when it is located on a roof that is not exactly facing the equator and/or is not at an inclination equal to the latitude. 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. This can then be used to determine the size of the PV array needed to generate the required daily energy for the site. Note that for latitudes less than 10° the tilt of the array should remain at 10° in order for rains to run off fast enough to keep the panel surface clean. Panels tilted less than 10may require frequent manual cleaning.

Worked Example 9

The array is tilted at 20° and its orientation is east (an azimuth of 90°). There is no shading.

From the Suva table in Appendix 3 the irradiation derating factor will be 93% or 0.93.

Therefore the available irradiation for the site is 0.93 x 5.38kWh/m^2 = 5.0kWh/m^2 or 5.0 PSH

13.3 Shading of the Array

In rural areas and villages where off-grid PV systems will be used for electrification, the PV array may be shaded part of the day by local vegetation, e.g. nearby trees, or land forms such as mountains. This may greatly affect the output of the array if it occurs between about 9 am and 3 pm.

There are many survey devices and computer programs to help determine the effect on irradiation due to shading. The result of shading will be a lower value of solar irradiation that reaches the array. That lower irradiation level must be used when determining the size of the solar array required to provide the calculated daily energy needs of the end-user.

14. Factors That Affect a Solar Module's Output Power

The output of the solar module is affected by temperature, foreign materials on its surface (dirt, leaves, pollution products, etc.) and possibly manufacturer's tolerances and/or module mismatches (connecting modules of different characteristics together). This means that the outputs of the solar modules will need to be adjusted relative to their standard rated values when estimating the actual energy output of the solar array. The rated output is determined with a solar cell temperature of 25°C (77°F) with an irradiance of 1000 W/m^2 and in the Islands, cell temperatures when exposed to the sun are a lot always greater than the standard 25°C (77°F). Also, average irradiance is generally much less than 1000 W/m^2. So actual solar array outputs are always less than the standard rated values so modules must be "derated" when estimating their actual outputs.

Derating Due to Temperature

A solar module's output power decreases with a solar cell temperature above 25°C (77°F) and increases with temperatures below 25°C (77°F). When exposed to the sun, the average cell temperature will be higher than the ambient temperature because of the glass on the front of the module insulates it from the cooler air around it 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 actual temperature of the cell. This is estimated by the following formula:

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

Where:

$T_{cell\text{-}eff}$ = the average daytime effective cell temperature in degrees Celsius (°C)
$T_{a.day}$ = the average daytime ambient temperature for the month that the sizing is being undertaken.
T_r = rise in temperature due to the type of installation used for the array

The value of T_r is selected from Table 6.

Table 6: Values of T_r

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

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

A) Monocrystalline Modules
Monocrystalline Modules typically have a temperature coefficient between -0.4%/°C and -0.45%/°C. Assuming it is -0.45%/°C, for every degree above 25°C (77°F) the rated output power must be derated by 0.45%.

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

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

Always check with the product manufacturer for the exact temperature coefficient for the module being used in the system design. That data should be available in the product brochure and must be available if the product has been tested and approved in accordance with the IEC and UL standards.

The symbol used for temperature co-efficient is γ and it is expressed on data sheets as a negative number (e.g. γ = -0.5%/°C).

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

The typical ambient daytime temperature in most parts of the Pacific is between 30°C (86°F) and 35°C (95°F). So it would not be uncommon to have module cell temperatures of over 55°C (131°F) with some installations possibly reaching 70°C (158°F) or even higher.

The percentage power loss due to the effective cell temperature is the Cell Temperature Coefficient multiplied by the difference between the cell effective temperature and the Standard Test Condition (STC) temperature (T_{STC}) of 25°C (77°F).

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

Note: Since the temperature coefficient: γ is expressed as a negative number, using the above formula will provide a negative answer when ambient temperatures are above 25°C.This is why it is then defined as a loss for arrays installed in the tropics.

This loss is generally expressed as a temperature derating factor (f_{temp}) which is calculated as follows:
f_{temp} = 1- the temperature loss

Note: In this formula the negative % value of percentage power loss is turned into a positive number that represents the percentage of the original output that is left for use.

Worked Example 10

The solar array is mounted on a flat roof but with a tilt angle of 20 degrees.
The solar module has a temperature coefficient of -0.39%/°C.
The average daytime ambient temperature is 30°C (86°F).
What is the percentage (%) power loss due to temperature for this solar?
What is the temperature derating factor?

From Table 6 the rise in temperature (T_r) is 25°C.

The effective cell temperature is therefore:

$$\begin{aligned} T_{cell\text{-}eff} &= T_{a.day} + T_r \\ &= 30°C + 25°C \\ &= 55°C \end{aligned}$$

The percentage power loss due to effective cell temperature

$$\begin{aligned} &= \gamma \times (T_{cell\text{-}eff} - T_{STC}) \\ &= -0.39\%/°C \times (55°C - 25°C) \\ &= -0.39\% \times 30 \\ &= -11.7\% \end{aligned}$$

As a decimal number, 11.7% converts to 11.7/100 = 0.117

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

$$\begin{aligned} f_{temp} &= 1\text{- loss due to temperature} \\ &= 1 - 0.117 \\ &= 0.883 \end{aligned}$$

Which means that the array actually provides only 88.3% of its rated output due to its operation at 30°C instead of STC (25°C).

Derating Due to Dirt and Other Foreign Materials on the Module Surface

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 conditions at the actual location of the modules, but in some city locations this could be high due to the amount of car pollution and dust in the air. It can also be high in coastal regions during long periods of no rain when salt may build up on the module surface. In dusty or salty environments this loss could be as high as 20%.

For most off grid rural areas, the typical loss will be no more than 5% though installations adjacent to factories, quarries or unpaved roads may be much higher if modules are not regularly cleaned by the end-user.

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

> **Worked Example 11**
>
> If the loss due to dirt is 5% what is the dirt derating factor?
>
> As a decimal fraction 5% converts to 5/100 = 0.05
>
> f_{dirt} = 1- the loss due to dirt
> = 1- 0.05 = 0.95

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°C(77°F). Historically this has been ±5% though in recent years typical figures have been 0% to +3% however, in small print on the data sheet there is often the statement: Measuring tolerance: ±3%. This effectively means the module could have a manufacturer's tolerance which leads to a loss of up to 3% (though there could also be a gain of 3%).

When designing a system, it is important to incorporate the actual figure for the selected module and take into account any measuring tolerances and to assume the worst-case conditions so the resulting design will not be underpowered.

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

> **Worked Example 12**
>
> If the loss due to Measuring tolerance is 3% what is the manufacturers derating factor?
>
> As a fraction 3% converts to 3/100 = 0.03
>
> f_{man} = 1 - the measuring tolerance loss
> = 1 - 0.03 = 0.97

Solar Module Ageing Factor

Another factor that will result in derating the solar array is ageing of the solar modules. When in service, solar modules gradually lose some capacity over time, though quite slowly. Manufacturers generally will provide a warranty that their solar module will not fall more than 15% below the rated value for 25 years. For the designer, it is reasonable to assume the useful life of the off-grid system is 20 years, so the array needs to continue to service the design load for those 20 years and may last longer. This means that the initial rating of the modules used will need to be about 10% higher than the value that will be sufficient to serve the load when new.

> **Worked Example 13**
>
> If the loss due to Ageing is 10% what is the derating factor for ageing?
>
> As a fraction 10% converts to 10/100 = 0.1
>
> $$f_{ageing} = 1 - \text{the ageing loss}$$
> $$= 1 - 0.1 = 0.90$$

Note: In sections 18.4 and 23.4 an oversizing factor of 20% is recommended. This 20% does cater for the ageing of the module and therefore in later examples the ageing is not taken into account. It has been left here for discussion purposes.

To determine the total derating factor for the solar modules, it is necessary to multiply all the derating factors together and then apply the result to the rated output of the modules.

> **Worked Example 14**
>
> If the temperature derating factor is 0.883, the dirt derating factor is 0.95 and derating factor for ageing is 0.90, what is the overall derating factor for the modules?
>
> 0.883 x 0.95 x 0.90 = 0.755 which means that the actual output from the module is expected to be 0.755 times the rated output. Thus a 100W_p panel can be expected to provide at least:
>
> 100W_p x 0.755 = 75.5W for the first 10 plus years of its service.
>
> The initial amount will be a bit more because ageing occurs over the long term, not initially. Note that the output will also be reduced by some percentage if the module is not properly oriented as to azimuth and tilt.

15. Selecting a Solar Module

When selecting a solar module to be used in an off grid PV power system the solar modules shall meet either:

One of the following design qualification and type approval 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
  - One of IEC 61215 Part 1.1, Part 1.2 Part 1.3, part 1.4 which all relate to specific types of modules e.g. crystalline, thin film amorphous etc (See Section 3)

and

- IEC 61730 Photovoltaic (PV) module safety qualification
  - IEC 61730-1 Part 1: Requirements for construction
  - IEC 61730-2 Part 2: Requirements for testing

or the UL standard:

UL Standard 1703 Flat Plate Photovoltaic Modules and Panels

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

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

16. Selecting 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.

17. Providing a Quotation

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

- Full Specifications of the system proposed including quantity, make (manufacturer) and model number of the solar modules, full specifications of any inverter(s) and drawings and specifications of the array mounting structure where applicable.
- A copy of the load assessment sheet showing the details of how the load was calculated.
- The expected performance of the system and how it will meet the power and energy requirements specified in the load assessment sheet.
- A firm quotation which shows the installed cost of the complete system.
- Warranty information relating to each of the items of equipment and the overall system performance.
- A complete listing of the regular maintenance requirements for the installation

PART 2

Determining solar system for dc bus configuration

18. Sizing a Solar Array - General

The calculations for determining the size of the PV array are dependent on the type of controller used. Historically, switched solar controllers were the most common controllers used with "on-off" type switching using relays the oldest type and semiconductor based Pulse Width Modulation (PWM) types the modern version. In recent years a number of maximum power point trackers (MPPT) have become available.

The switching solar controller has its output voltage tied to a fixed input voltage making it necessary to have that specific voltage available from the solar array— hopefully at a voltage near the maximum power point of the array— while a MPPT controller can manage a wide range of input voltages while seeking and tracking the voltage of the maximum power point of the solar array and simultaneously managing the output voltage to match the battery requirements. The MPPT controller can deliver more charge to the battery per day than a switching controller but for small installations the switching controller is still used because of its low cost and simplicity. The MPPT controller is required when the solar module being used does not have the suitable voltage (number of cells) for effective battery charging with a switching type controller.

The size of the PV array should be selected to take account of:

a) seasonal variation of solar irradiation
b) seasonal variation of the daily energy usage
c) manufacturing tolerance of modules
d) dirt accumulation
e) temperature of array (the effective cell temperature)
f) allowing for the module efficiency decreasing over time(ageing)
g) inverter efficiency
h) battery efficiency
i) controller efficiency
j) cable losses
k) oversize factor to allow for effective charging.

The points a through to f have been covered in sections 13 and 14. This section looks at points g through to j. Points g, h, i and j, when grouped together, are commonly known as the sub-system efficiency, the sub-system being defined as the solar array and the associated loads.

18.1 Sub-System Losses in an Off-Grid PV System

The sub-system losses are all those in the circuit from the output of the PV array to the load.

If the system is only providing dc loads, then the sub-system losses are:

- cable losses (due to voltage drop);
- solar controller losses; and
- battery losses.

If the system is only providing ac loads, then the sub-system losses are:

- cable losses (due to voltage drop);
- solar controller (dc bus system);
- battery losses; and
- battery inverter losses.

The battery losses can be based on either coulombic efficiency (in terms of Ah) or watt-hour efficiency.

The average coulombic efficiency of a new lead-acid battery (in terms of the ratio of Ah of discharging to Ah of charging) is typically 90% (variations in battery voltage are not considered, only Ah in and out) while the average watt-hour (Wh) efficiency (in terms of the Ah times the voltage of the battery during discharging and charging over a specific time) of a new battery is typically 80%. As the battery ages, the columbic and watt-hour efficiency both decline slowly.

When determining the PV array size for systems using switching solar controllers, the calculations are based in Ah and columbic efficiency is used.

When determining the PV array size for systems using a MPPT controller, Wh efficiency is used.

All these losses are expressed as percentages which are then converted into a fraction when applied in determining the PV array output.

Worked Example 15

Switching solar controller has an efficiency of 90%, then the fraction used in determining the required PV array power output would be 0.9.

18.2 Determining the Energy Requirement of the PV Array

The design month's daily load energy is used for determining the size of the PV array.

In order to determine the energy required from the PV array these sub-system losses need to be taken into account. That means that the output of the PV array must be greater than the daily load it is supplying. The total required output is calculated by dividing the required daily load energy by all the sub-system losses in the system expressed as decimal fractions.

18.3 What About the Loads That Operate During the Day?

When sizing the array, convention has been to be conservative and assume that all the loads are supplied by the battery bank so that the battery efficiency was taken into account for all loads when determining the size of the solar array required to meet the daily energy demand.

However, some of the load energy will be supplied directly during the day since typically the available output from the controller will be directly connected to both the battery and the input terminals of the battery inverter. To determine exactly how much, a detailed interval analysis would be required whereby the load power profile is compared to the available solar power profile. However, the available solar power and the loads will vary during the day and from day to day so the percentage of the load during the day that is directly powered by the array can only be estimated.

With the introduction of ac bus system configurations where the PV array interconnects with a PV powered (grid connected) inverter directly onto the ac bus, the ac bus advocates emphasised how efficient these systems were in supplying the load directly, which is true for loads during the day. Meanwhile, these systems had a greater loss when supplying the loads via the battery bank due to losses in the battery itself plus losses in the AC inverter and plus losses in the ac to dc battery charging feature in the battery inverter.

So people designing systems using an ac bus configuration started to estimate how much of the daily energy was supplied directly by the PV array during the day.

To not do this for dc bus systems could lead to an apparent cost disadvantage when designing a system and make the dc bus system appear costlier in a competitive quote situation. So this guideline describes how to determine the array size if the loads are divided between daytime loads being supplied directly by PV array and those loads being supplied by the battery bank either due to cloudy weather during the day or night time operation of the loads.

Therefore, the total energy that has to be supplied by the PV array is equal to the amount of energy being supplied to loads directly by the PV array plus the amount of energy being supplied to the loads from the battery that has been charged by the PV array adjusted to take the battery efficiency into consideration.

Therefore, the total number of modules required in the array equals the number of modules to supply the daytime load directly plus the number of modules needed to charge the battery for delivery of energy to the load during the night and when the daytime load exceeds the generation from the solar modules.

18.4 Oversize Factors

If the system does not include a fuel generator which can provide extra charging to the battery bank, then the solar array should be oversized to enable equalisation charging of the battery bank. Otherwise the battery life will be shortened due to it having to remain in a partially charged condition for many days during cloudy periods. That leads to sulfation of the battery and the loss of some battery Ah capacity unless an equalizing charge is carried out shortly after the sulfation occurs.

Therefore, when designing a solar system the array should be oversized by at least 20% to allow for rapid full charging of the battery and to provide equalizing charging when needed. An oversize factor of 20% should also effectively cover the ageing of the solar module in the first 10 years.

19. Sizing a PV Array - Switching Type Solar Controller

When using a switching type solar controller, the calculations are all based on determining the required Ah from the array. The losses in the cable and the solar controller are only reflected as voltage drops which therefore dictates the operation point on the current-voltage characteristic curve (IV curve) of the solar array. That is, if the battery is at 12V then the PV array will be operating at 12V plus the voltage drop in the connecting cable plus any voltage drop across the controller. Since the maximum power point of a nominal 12V module will be at 17-18V and the maximum charge voltage of a lead acid battery is between 14.4V and 15V, then the typical voltage drop of around 1V that occurs between the array and the battery is not an issue for most of the time the battery is being charged.

The only losses that need to be taken into account are any battery inverter losses (when AC appliances are powered by an inverter connected to the system) so the battery losses are assumed to be its average columbic efficiency (in terms of Ah in and Ah out) of a new battery. That is typically 90% (variations in battery voltage are not considered).

Worked Example 16

Figures used in this example are from the table on page 12.
Assume all the loads are supplied by the PV array charging the battery bank

Based on the design month the solar array is to be sized based on the rest of year average energy usage.

The efficiency of the chosen inverter is 90%.

Daily battery load (energy) due to ac loads = 1500Wh ÷ 0.9 = 1667Wh

Daily battery load (energy) due to dc loads = 112Wh

To get the total load (energy) as provided by the battery, you add the two figures together:

1667 + 112= 1779Wh

The system voltage is 24V.

The daily energy requirement expressed in Ah from the battery is 74.1 Ah (1779Wh/24V).

Allowing for the battery efficiency, the solar array then needs to produce:
74.1 Ah ÷ 0.9 = 82.33 Ah

The PSH in the design month is 4.38

Therefore the required PV array derated output current is:

82.33.9 Ah ÷ 4.38 PSH = 18.8 A

The oversize factor then needs to be applied. A minimum of 20% is recommended for the Pacific Island countries and territories.

Worked Example 17

The adjusted required PV array derated output current is:

18.8 A x 1.2 = 22.6 A

The PV array will be derated due to:

- Manufacturer's Tolerance
- Dirt
- Module Temperature greater than 25°C
- and potentially for ageing of the module that results in decrease in efficiency and hence power output., however the 20% oversizing takes this into account.

Traditionally solar modules have had nominal voltages of 12V by using 36 cells per module. These were designed to charge a 12V battery. In the current market the great majority of solar modules are used for grid-connected systems and the number of cells depends more on the power desired than the voltage required of the module. Therefore, many solar modules that are readily available are not suitable to be used with simple switching type solar controllers because they have many more than 36 cells and the module voltage does not match the input voltage needed by the switching controller. The designer, when using a **standard switching type solar controller, must use solar modules that have a nominal voltage rating that is appropriate for the battery voltage**. In the market today these are either 36 cell modules for 12V batteries or 72 cell modules suitable for 24V battery banks. Today 36 cell modules are typically costlier than 60 cell or 72 cell modules when compared on a per W_p basis because they have become a specialty item and are no longer mainstream. For rural residences, 36 cell panels matched with a simple switching controller still provides the simplest and most cost effective solution for lighting and basic entertainment but locating a source of low cost 36 cell modules is not always easy. A few manufacturers provide 72 cell modules that are internally split into two 36 cell units which can be electrically connected as paralleled 36 cell modules for 12V battery charging or series connected as a 72 cell module for 24V battery charging.

The typical charge voltage range for different lead acid battery banks is as follows:

- 12V battery bank- charge range 12V to 15V(wet cells/flooded) or 12V to 14.4V (Valve regulated battery)
- 24V battery bank- charge range 24V to 30V(wet cells/flooded) or 24V to 28.8V (Valve regulated battery)
- 48V battery bank- charge range 48V to 60V(wet cells/flooded) or 48V to 57.6V (Valve regulated battery)

To allow for temperature and the various charge voltages the module effective current used when determining the size of an array using crystalline type modules are as follows:

- For 12V module: current at 14V and at the effective cell temperature
- For 24V module: current at 28V and at the effective cell temperature.
- For 48V module: current at 56V and at the effective cell temperature

Unless the current vs voltage curves (IV curves) for different temperatures are available for the module selected, it is difficult to obtain this information. The module manufacturer's data sheets usually only provide short circuit current (I_{sc}) and maximum power point (I_{mp}) current; the operating current will be between these two values. The published values are usually only provided for Standard Test Conditions and for cells at the Nominal Operating Cell Temperature (NOCT).

If the IV curves at different temperatures are not available, it is recommended that the current half way between I_{sc} and I_{mp} be used as the module current.

That is: Calculated Module Current = $(I_{sc} + I_{mp})/2$

Also allowing for dirt and manufacturer's tolerance:

Derated Module current
= Module effective current x manufacturers tolerance derating factor x dirt derating factor
Or
Derated Module current
= Calculated module current x manufacturers tolerance derating factor x dirt derating factor

The number of modules in a string is determined by dividing the battery voltage by the nominal voltage of the module. It is reasonable to assume the nominal voltage of a module is number of cells per module divided by three. Thus a 36 cell module has a nominal voltage of 12V, a 60 cell module has a nominal voltage of 20V and a 72 cell module has a nominal voltage of 24V.

The number of module strings that need to be in parallel is determined by dividing the adjusted required array current by the derated module current.

Worked Example 18

A module with the following characteristics is selected:

STC Electrical Data
P_{mp} = 330W
V_{oc} = 46.2V
V_{mp} = 37.8V
I_{sc} = 9.27A
I_{mp} = 8.73A

Power Temperature co-efficient= -0.39%/°C
Voc temperature coefficient = -0.29%/°C
Manufactures Tolerance = 0 to +5%
Test Tolerance ±3%
Note for this example the oversize factor has taken into account the ageing factor.

Module has 72 cells and hence provides a nominal 24V.

The number of modules in a string
= the battery voltage / nominal voltage of the module.
=24V/24V =1

Module current = (9.27 +8.73)/2 = 9A

Manufacturers Tolerance = test tolerance = 3%
This is a derating factor of 0.97

Assume dirt derating is 5% and hence derating factor of 0.95.

Therefore the derated current = 9 x 0.97 x 0.95 = 8.3A per module string

Adjusted required array current = 22.6A

Number of module strings in parallel = 22.6A/8.3A = 2.72

Round up to 3.

If there are daytime loads:
For systems with standard switching type controllers there will be no battery losses for the loads being supplied directly.

So if the percentage of daily load energy being supplied directly is known then when determining the number of modules required to meet the load directly in the day, the only dc sub-system losses are the inverter loss, cable losses and any loss in the controller.

Worked Example 19

Assume all the power is being supplied directly to the loads by the PV array, therefore no battery losses.

From the example the daily energy requirement expressed in Ah from the battery is 74.1 Ah (1779Wh/24V). (Battery Inverter losses already taken into account)

The PSH in the design month is 4.38

Therefore the required PV array output current is:

$$74.1 \text{ Ah} \div 4.38 \text{ PSH} = 16.92\text{A}$$

Allowing for 20% oversizing, the adjusted PV array output current required
= 1.2 x 16.92 = 20.3A

The derated current for each module = 8.3A

Number of module strings in parallel = 20.3A ÷ 8.3A = 2.45 rounded up to 3.

Note: Instead of rounding up, a smaller module could also be selected so that the number of module strings in parallel is exactly 3.

Realistically, depending on how much power is supplied directly to loads by the PV array, the number of module strings required in parallel for this example varies between 2.45 and 2.72 with both cases ending up with the same three strings in parallel when the selected modules are used.

20. Sizing a PV Array - MPPT Solar Controller

When using a MPPT controller the calculations are in Wh and the dc sub-system losses in the system include:

- Battery losses (Watt-hour efficiency)
- Cable losses
- MPPT losses (controller efficiency); and
- Inverter losses (inverter efficiency)

In order to determine the energy required from the PV array, it is necessary to increase the energy from the battery bank to account for all the sub-system losses.

Worked Example 20

The energy supplied by the battery bank allowing for the inverter efficiency = 1779Wh
Assume

- Cable losses is assumed to be 3% (transmission efficiency of 97%),
- MPPT efficiency of 95% and
- Battery efficiency of 80%
- All the load energy is provided by the battery.

dc sub-system efficiency = 0.97 x 0.95 x 0.8 = 0.737

Energy required from the PV array = 1779Wh ÷ 0.737 = 2414Wh

The design month PSH is 4.38.

Therefore the required PV array derated output power is:

2414Wh ÷ 4.38 PSH = 551W

Allowing for an oversize factor of 20%, the adjusted required derated array output is:
551W x 1.2 = 661W

The output of the solar module is affected by temperature, dirt, possibly manufacturer's tolerances and/or module mismatches and module ageing. This means that the power output of the solar module should be derated when determining the energy output of the solar array.

Solar modules have a rated output measured at Standard Test conditions (STC). Based on the factors affecting the power output of the module (P_{mod}) as detailed in section 12.5, 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 21

In the worked example

- Derating due to temperature f_{temp}= 0.883
- Derating due to dirt f_{dirt} = 0.95
- Derating due manufacturers tolerance f_{man} = 0.97

Note for this example ageing factor has not been taken into account since it is effectively covered by the 20% oversizing factor that allows for battery equalization and fast recharging in order to extend battery life

Module rating is 330W_p

Derated module output = 330 x 0.883 x 0.95 x 0.97 = 268.5W

The adjusted required derated array output = 661W

The required number of modules = 661÷268.5 = 2.46 which must be rounded up to 3 modules.

In reality a smaller module could be selected so that exactly 3 modules are required based on this example and using a 330W_p array the actual required array W_p is 2.46 times 330W_p = 812W_p not the 990W_p that 3 solar modules would provide.
Three 280W_p modules would provide 840W_p

If there are daytime loads:
For systems with MPPT controllers there will be no battery losses for the loads being supplied directly.

So if the percentage of daily load energy being supplied directly is known, when determining the number of modules required to meet the load directly in the day the dc sub losses would only include:

- Cable losses;
- MPPT losses (controller efficiency); and
- Battery inverter losses (inverter efficiency)

Worked Example 22

The energy supplied by the battery bank allowing for the inverter efficiency = 1779Wh
Assume

- All the load energy is provided directly by the PV array during the day
- Cable losses are 3% (transmission efficiency of 97%), and
- MPPT efficiency of 95%.

dc sub-system efficiency factor from battery bank = 0.97 x 0.95 = 0.922

Energy required from the PV array = 1779Wh ÷ 0.922 = 1930Wh

The design month PSH is 4.38.

Therefore the required derated PV array output power is:

1930Wh ÷ 4.38 PSH = 441W

Allowing for oversize factor of 20% therefore the adjusted required derated PV array output power is:
441W x 1.2 = 592W

Derated module output = 268.5W

The required number of modules = 592 ÷ 268.5= 2.2

Question would be whether to round up or down.
What is required is an array comprising 2.2 of 330W_p modules, that is 726W_p.
So a smaller module (e.g. 245W_p) could be selected so only 3 would be required providing an array rated at 735W_p.

Based on worked examples 21 and 22 and depending on how much load energy is assumed to be supplied directly by the array and how much via the battery bank, the required array is rated between 726W_p (all loads supplied power directly by solar array) and 818W_p (all loads supplied power from the battery bank).

21. Selecting a Solar Controller - Standard Switched Controller

When selecting a solar controller to be used in an off-grid PV system the controller should meet one of the following standards

- IEC 62509 Battery charge controllers for photovoltaic systems - Performance and functioning
- IEC 62109 Safety of power converters for use in photovoltaic power systems
    - IEC 62109-1 Part 1: General requirements
- UL Standard 1741: Standard for Inverter, converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources

PV controllers on the market range from simple switched units that only prevent battery overcharge (and usually also excessive discharge) to microprocessor based units that incorporate many additional features such as:

- PWM and equalisation charge modes
- DC Load control
- Voltage and current metering
- Amp-hour logging
- Priority load connections (low priority connections shut down when the normal discharge limit for the battery is reached. Priority loads can continue running until the battery is more deeply discharged)
- Generator start/stop control (for a back-up generator to automatically start if the battery reaches its pre-set discharge limit)

Unless the controller is a model that is internally current limited, these should be sized so that they are capable of carrying at least 125% of the array short circuit current and withstanding the open circuit voltage of the array. If there is likelihood that the array may need to be increased in the future, then the controller should be oversized to cater for future growth.

(**Note:** sometimes the controller is called a regulator)

Worked Example 23

If three modules in parallel are selected, the controller chosen must have a current rating > 1.25 x 3 x 9.27 A = 35A at a system voltage of 24V.

22. Selecting a Solar Controller - MPPT Type Controller

When selecting an MPPT controller to be used in an off-grid PV system the controller should meet one of the following standards:

- IEC 62509 Battery charge controllers for photovoltaic systems - Performance and functioning
- IEC 62109 Safety of power converters for use in photovoltaic power systems
    - IEC 62109-1 Part 1: General requirements
- UL Standard 1741: Standard for Inverter, converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources

The MPPT controller must be matched with the array in relation to:

- Maximum Solar Rating in Watts;
- Input voltage; and
- Input current if nominated by the manufacturer.

Worked Example 24

The number of modules required was 2.67 so unless a different size module was chosen select a MPPT which will be suitable for 3 modules.

The module rating is $330W_p$.
Allowing for 125% oversizing, the required rating of the MPPT is:

$1.25 \times 3 \times 330W_p = 1240W$

22.1 Matching the PV Array to the Voltage Specifications of the MPPT

The MPPT typically will have a recommended minimum nominal array voltage and a maximum input voltage. In the case where a maximum input voltage is specified and the array open circuit voltage is above the maximum specified, the MPPT could be damaged.

Some MPPT controllers may allow the minimum array nominal voltage to be equal to that of the battery bank. However, the MPPT will work better when the minimum nominal array voltage is higher than the nominal voltage of the battery. As stated earlier, a 12V battery requires a module with 36 cells. So for the MPPT to work effectively the solar array should have a “nominal voltage” of at least the value seen with 36 cell modules (typical V_{oc} of 22V) which is greater than the battery voltage. Higher voltages (more cells in series) generally provide better charging, Table 7 shows the recommended minimum number of cells in a string for the different nominal battery voltages when using a MPPT controller.

Table 7: Minimum Number of Cells in a String

Nominal Battery voltage (V)	Recommended Minimum Number of Cells per string of modules
12	72
24	108
48	180

Worked Example 25

Battery voltage is 24V so the array should have at least 108 cells in series. The module selected for the worked example has 72 cells so a minimum of two of these in series will be required per string.

The output voltage of a module is affected by cell temperature changes in a similar way to the output power. The manufacturers will provide a *voltage temperature coefficient* on the panel specification sheet. It can be specified in V/°C (or mV/°C) but it generally expressed as a percentage %/°C.

To ensure that the V_{oc} of the array does not reach the maximum allowable voltage of the MPPT the minimum day time temperatures for that specific site are required, For the Pacific that will be the temperature at dawn on the day of the year that is historically the coldest.

In early morning at first light the cell temperature will be very similar to the ambient temperature because the sun has not had time to heat up the module. But though the energy from the sun at sunrise is very low and therefore the current (Amperes) that can come from the panel will be very low also, the solar module comes to almost full voltage as soon as the sun is on the horizon. In the Pacific Islands the average minimum temperature is 20°C (68°F) (this could be lower in some mountain areas and in islands with higher latitudes) and it is recommended that this temperature be used to determine the maximum V_{oc}. if there are no historical records of minimum temperatures for the site.

(**Note:** If installing in the mountains then use the appropriate minimum temperature for the elevation of the array. Many people also use 0°C, if appropriate for the area just to be on the safe side. The maximum open circuit voltage is determined similar to the temperature derating factor for module power.

When modules are connected in series then the maximum V_{oc} of the string shall always be less than the maximum allowable voltage of the MPPT.

So once the module V_{oc} at coldest temperature is calculated then the maximum number of modules allowed in series is determined by dividing the maximum MPPT allowable voltage divided by module V_{oc} at coldest temperature.

Worked Example 26

The selected module has the following characteristics:

V_{oc} = 46.2V

V_{oc} temperature coefficient = -0.29%/°C

The temperature co-efficient in V/°C = -0.29 ÷ 100/°C x 46.2V= - 0.134V/°C

If the minimum temperature is 20°C this is 5°C below the STC temperature of 25°C. Therefore the effective variation in voltage is:

5 x 0.134 = 0.67V

So the maximum open circuit voltage of the module = 46.2V + 0.67V = 46.9V

As stated the MPPT should be selected to be suitable for three modules. To achieve the required power, these could either be installed three in series or three in parallel. However, if there are three in parallel then this does not meet the minimum voltage requirement of at least 108 cells in series.

Therefore with three in series the MPPT must have a maximum voltage rating equal to or greater than 3 x 46.9V = 140.7V.

PART 3

Determining solar system for ac bus system configuration

23. Sizing a Solar Array - General

The size of the PV array should be selected to take account of:

a) seasonal variations of solar irradiation
b) seasonal variations of the daily energy usage
c) manufacturing tolerance of modules
d) dirt
e) temperature of array (the effective cell temperature)
f) allowing for the module efficiency decreasing over time (ageing)
g) battery inverter efficiency
h) battery efficiency
i) PV inverter efficiency
j) cable losses
k) oversize factor to allow for effective charging.

The points a through to f have been covered in sections 13 and 14. This section looks at points g through to j. Points g, h, i and j are commonly known as the sub-system efficiency, the sub-system being defined as the components between the solar array and the loads.

23.1 Sub-System Losses in an Off-Grid PV System

The sub system losses are all those from the output of the PV array to the load.

If the system is providing ac loads via the battery then the sub-system losses are:

- PV Inverter losses;
- cable loss (due to voltage drop);
- battery inverter/charging losses (ac bus system);
- battery losses; and
- battery inverter losses.

If the system is providing ac loads directly during the day then at that time, the sub-system losses are:

- PV Inverter losses; and
- cable loss (due to voltage drop);

The battery losses are based on the watt-hour efficiency of the battery and the average watt-hour (Wh) efficiency (in terms of Wh) of a new battery is typically 80%.

Note: Typically, ac bus systems do not have dc loads however if some do exist then all relevant losses between the solar array and the dc loads shall be taken into account.

23.2 Determining the Energy Required From the PV Array

The design month's daily load energy is used for determining the size of the PV array.

In order to determine the energy required from the PV array, it is necessary to divide the required daily load energy by all the sub-system losses in the system

23.3 What About the Loads That Operate During the Day?

In the past, when sizing the array, convention had been to be conservative and assume that all the loads were supplied by the battery bank so that the battery efficiency was taken into account when determining the size of the solar array required to meet the total daily energy demand.

However, realistically some of the load energy will be supplied directly to the load from the PV inverter during the day. To determine exactly how much, a detailed interval analysis would be required where the load power profile is compared to the available solar power over an extended period of time. The available solar power will vary during the day and the loads typically do also so the result of an interval analysis can only provide a rough estimate of future conditions. Since long cloudy periods of a week or more are possible in most island countries, for maximum battery life (and therefore minimum O&M cost), it is recommended that the design assume all energy must come from the battery even though on mostly clear days' substantial amounts may indeed be delivered directly from the panels and the batteries given a rest.

With the introduction of ac bus systems where the PV array connects directly to a PV (grid connected) inverter connected to the ac bus, then the losses to the ac loads that are directly powered by the PV inverter include:

- cable loss (due to voltage drop in the cables between the solar array and loads); and
- PV inverter losses.

The losses when providing ac loads from the battery include

- cable loss due to voltage drop (in the cables from the PV array to batteries and to the load);
- PV inverter losses (ac bus system);
- battery inverter/charging losses (ac bus system);
- battery losses; and
- battery inverter losses (when feeding ac into the grid via the battery inverter).

With the additional losses seen when powering ac loads from the battery, designers often either undertook detailed interval analyses or roughly estimated the percentage of the load energy supplied directly by the PV array to the ac loads.

Therefore, the total energy that has to be supplied by the PV array = total amount of energy being directly supplied to loads by the PV array + the total amount of energy being supplied to the loads from the battery bank that is being charged by the PV Array.

The total number of modules required = Number of modules needed to supply the load directly from the ac inverter + the Number of modules needed to supply the load from the battery.

For public facilities (e.g. schools, government facilities, health centres) it is recommended that the design assume that all energy provided to the load must come from the battery since then the design will not greatly stress the battery during cloudy periods and battery life will be maximized.

Since battery replacement costs are generally by far the largest component of O&M costs, extending the life of the battery will reduce those costs significantly.

For commercial applications (e.g. resorts, shops, factories) a design that includes allowing for direct solar power of loads during the day can be used in order to reduce the up-front installation cost if the customer is advised of the increase in O&M cost that my occur due to shortened battery life.

23.4 Oversize Factors

If the system does not include a fuelled generator that can provide extra charging to the battery bank when the battery reaches its lowest allowed level of charge, then the solar array should be oversized to provide the equalisation charging of the battery bank that is necessary for long battery life.

Therefore, when designing a solar system, the array should be oversized by 20% to allow for equalization charging of the battery. An oversize factor of 20% should also effectively cover the ageing of the solar module in the first 10 years.

24. Sizing a PV Array - ac Bus

As stated in the previous section the loads may be supplied by the PV array as follows:

- PV array services ac loads directly via the PV inverter:
- PV array providing ac loads from the battery bank through the PV inverter with the battery inverter acting as a battery charger and batteries and battery inverter acting as the ac source;

Worked Example 27

Assume the loads are only ac and are supplied by the PV array charging the battery bank.
Assume the following system losses (efficiencies)

- cable loss from PV array to ac loads via batteries is 4% (efficiency of 96%);
- PV inverter efficiency is 97%;
- battery inverter charging efficiency is 96%;
- battery efficiency is 80%; and
- battery inverter efficiency 96%

Daily ac load (energy) = 1500Wh

System efficiency factor when providing ac loads =
PV inverter efficiency x cables losses x battery inverter charging efficiency x battery efficiency x battery inverter efficiency
0.96 x 0.97 x 0.96 x 0.80 x 0.96 = 0.687

The required energy output of PV array to provide the ac loads = 1500/0.687 = 2183.4Wh

The design month PSH is 4.38.

Therefore the required derated PV array output power needed is:

2183.4Wh ÷ 4.38 PSH = 498W

Allowing for an oversizing factor of 20%, the adjusted required derated array output is:
498W x 1.2 = 598W

Derated module output = 268.5W (refer to Worked Example 21)

Note: for this example ageing factor has not been taken into account since it is effectively covered by the 20% oversizing factor that allows for battery equalization and fast recharging in order to extend battery life.

The required number of modules = 598/268.5= 2.2

This must be rounded up to three modules. However in reality you could select a smaller module (e.g. 245W_p) because the actual required array is 2.2 x 330W_p = 726W_p and three modules of 245W_p each will provide a total of 735 W_p capacity which is adequate.

Worked Example 28

All loads having their power supplied directly from the PV Array
Assume the loads are all ac

Assume the following system losses (efficiencies)

- cable loss from PV array to ac loads is 1% (efficiency of 99%); and
- PV inverter efficiency is 97%.

Daily ac load (energy) = 1500Wh

System efficiency factor when providing ac loads = 0.99 x 0.97 = 0.96

The required energy output of PV array to provide ac loads= 1500/0.96=1562.5Wh

The design month PSH is 4.38.

Therefore the required derated PV array output power is:

1562.5Wh ÷ 4.38 PSH = 357W

Allowing for an oversizing factor of 20%, the adjusted required derated array output is:
357W x 1.2 = 428W

Derated module output = 268.5W_p

The required number of modules = 428 ÷ 268.5= 1.6

This would be rounded up to 2 modules but it would be an array of 1.6 x 330Wp = 528W_p that is required if all loads could be supplied power directly by the PV array

Based on worked examples 27 and 28 and depending on how much load energy is assumed to be supplied directly by the array and how much via the battery bank, the required array is rated between 528W_p (all loads supplied power directly by solar array) and 726W_p (all loads supplied power from the battery bank).

25. Selecting a PV Inverter - ac bus

When selecting an inverter to be used, a PV inverter in the ac bus configuration the inverter shall meet either

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

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

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

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

25.1 How Many Inverters?

A small system will generally include only one inverter though a larger system may have multiple inverters. Reasons why multiple inverters may be used include:

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

   A separate MPPT will be required for each section of the array which has a different orientation and tilt angle. This may be achieved by using an inverter that has multiple maximum power point trackers (MPPTs) or by using multiple inverters. Therefore, the section of the array connected to one MPPT could be on a separate roof (and different orientation) than another section of the array mounted on another roof if connected to a separate MPPT within the same inverter or to an MPPT in another inverter.

   If there are so many different sections of the array that have different orientations that it is impossible to connect them all with one inverter that has multiple MPPTs then separate inverters must be available to provide more MPPT controllers so a different controller is available for each section of the array which has a unique orientation and tilt angle.

   There are module inverters and module MPPTs (independent inverters and MPPTs that are mounted on each individual solar module) available on the market which can also overcome the issue of arrays mounted with different orientations and tilt angles since every module has its own inverter and controller. So there are no strings, all modules have their own MPPT and inverter so each module can have a different orientation.

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

3. Allows the system to consist of identical clusters connected together; so that increasing the system involves adding a predetermined number of modules with each cluster having one or more inverters and its own battery bank. The main advantage of using multiple clusters is that spare parts needed are the same for all clusters and tend to be relatively inexpensive so a large array can consist of a number of identical, small and simple independent arrays. Also troubleshooting and training of operating and maintenance personnel are simplified because all clusters are identical and relatively simple. Finally, if one cluster has a failure, the rest can continue to operate though with the loss of the output from the failed cluster. Each cluster can also utilize a portion of the array that has its own unique orientation and can even be physically separate from other clusters.

The potential disadvantage of multiple inverters – either installed in a number of identical clusters or as a small one on each module – is that in general the initial cost of a number of inverters with lower power ratings is generally more expensive than one single inverter with a higher power rating. However, the advantages of higher system reliability, ease of operation and maintenance and less expensive spare parts requirements may be more valuable than a somewhat higher first cost.

25.2 Selecting the Size of PV Inverter

Inverters currently available are typically rated for:
- maximum dc input power;
- maximum specified output power;
- maximum dc input voltage;
- minimum dc MPPT input operating voltage; and
- maximum dc input current.

Note: some inverter data sheets also specify maximum PV array power.

The array and the inverter must be matched so that no ratings are exceeded at any point.

The array power must be matched to the inverters stated maximum PV array power if stated by the manufacturer

The number of modules in a string, and hence maximum and minimum voltages of the string, must be matched to the:
- maximum dc input voltage; and
- minimum dc MPPT input operating voltage.

The number of parallel strings, and hence maximum dc currents, must be matched to not exceed the maximum input current of the MPPT that the strings are connected to.

25.3 Matching Array Power to the Inverter

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

Array Peak Power = Number of modules in the array x the rated maximum power (P_{mod}) of the selected module at STC.

Note:
P_{mod} is also described as the peak power of the module. The unit is Watt-peak (W_p)

Worked Example 29

The example being used so far only requires an array consisting of three (3) modules each with a peak rating of $330W_p$.

The Array Peak Power = 3 x $330W_p$ = $990W_p$

It would be difficult getting an inverter this small that would have a voltage window suitable for only 3 modules in series. Unless individual module inverters are used, the module wattage would probably need to be reduced. That will require more modules in the string to meet both the load requirements and to meet the operating voltage requirement of the inverter.

So, if we match the PV array and inverter we will assume the array has to have six $330W_p$ modules in series in order to meet the input voltage window of the inverter. Six $330W_p$ panels in series will have a peak power rating of $1980W_p$, double the power required to meet the load. If 165W modules of the same voltage as the proposed $330W_p$ modules are available, six of those in series would provide the required input voltage and would also provide the required $990W_p$ to service the load at a lower cost.

If the inverter data sheet does specify the maximum array power, then the designer shall not design an array with its rated power greater than the specified maximum array power.

If the inverter data sheet only specifies the maximum dc power input to the inverter the designer should attempt to contact the 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 power of the array due to the effects of temperature, dirt, manufacturers tolerances and the voltage drop between the array and the inverter. However, if there is no specified maximum array power for the inverter input, the designer shall not design an array with a rated output greater than the inverters rated dc input power unless the designer has obtained permission from the manufacturer and is assured that all warranties will be honoured.

Worked Example 30

The inverter data sheet provides the following information:

Max dc Power	2000W
Max. input voltage	600 V
MPP voltage range	160 V to 500 V
Max. input current	10 A

The array in the example is $1980W_p$ so it meets the requirements for power.

25.4 Matching Array Voltage to the Inverter

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

- maximum dc input voltage; and
- minimum dc MPPT input operating voltage.

The output power of a solar module is affected by the temperature of the solar cells. As shown in previous sections for polycrystalline and monocrystalline 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 as a variation in the open circuit voltage and maximum power point voltage. Array I_{sc} is little affected by array temperature.

With few exceptions, high quality grid interactive inverters include Maximum Power Point Trackers (MPPT).

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

- Minimum input voltage for the inverter;
- Minimum MPPT input operating voltage;
- Maximum MPPT input operating voltage; and
- Maximum input voltage for the inverter.

The MPPT units in the inverter will only track the maximum power point voltage of the array when the arrays MPP voltage is between the inverter's specified MPP minimum operating voltage and maximum MPP operating voltage, that is, the voltage input is within the operating window of the MPPT. 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 may be greatly reduced.

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

The maximum voltage of the inverter is the point where any voltage above that specified may damage the inverter.

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 affected by cell temperature with changes in a similar manner as the output power. The PV module manufacturers will provide a voltage temperature co-efficient. It can be specified in V/°C (or mV/°C) but it is now generally specified in %/°C. It is often given as a negative but this is only above the STC temperature of 25°C. Below 25°C it is a positive value.

In practice the array should be designed such that:

- At the maximum temperature expected during the day the arrays MPP voltage is always greater than the inverter minimum operating voltage.
- At the coldest temperature of the day (in the Pacific Islands, this will be at sunrise) the open circuit voltage of the array must be less than the maximum input voltage specified for the inverter.

The design should also ensure that the array's MPP voltage at the coldest temperature is less than the inverters MPPT maximum operating voltage, but this is not critical since this means that the MPPT will not track properly above that voltage and no damage to the inverter should occur. The critical issue is that the open circuit voltage at the coldest temperature is never above the maximum input voltage. If this requirement is met and the arrays MPP voltage at the coldest temperature is above the inverters MPPT maximum operating voltage, then the MPPT will connect to the array at the inverters MPPT maximum operating voltage. This sequence will only happen first thing in the early morning when the power output is small. As the temperature increases due to increasing solar input, the array's MPP voltage will decrease and will reduce sufficiently to enter the MPPT voltage window and the maximum power point will be properly tracked for maximum output from the unit.

In order to design systems where the output voltages of the array do not fall outside the range of the inverter's dc operating voltages and its maximum input voltage, the minimum and maximum day time temperatures for that specific site are required. These should be the record high and record low temperatures for the site as recorded by the meteorology office to minimize the chance that the inverters will be damaged due to the input voltage exceeding the maximum voltage allowed for that inverter.

The following sections detail 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 have software programs that can be downloaded over the Internet for doing this matching.

25.4.1 Minimum Number of Modules in a String

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

Since the daytime ambient temperature in some areas of the Pacific Islands can reach or exceed 35°C (95°F), it is recommended that maximum effective cell temperature of 75°C (167°F) is used.
(**Note:** if this seems high, Germany specifies 70°C (158°F) to use for the cell temperature and on average their summer temperatures are less than 35°C).

Determine Minimum MPP Voltage (V_{mp}) of a Module at the Inverter
The minimum V_{mp} of a module is determined by calculating the reduction in V_{mp} due to the effective maximum 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 to use has been specified as 75°C then the difference between the maximum cell temperature and the STC temperature will be 75°C - 25°C = 50°C. So a reduction in V_{mp} is 50°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 calculated reduction in Vmp.

This value is then reduced by the voltage drop in the cabling. Since voltage drop is typically expressed as percentage (%) value then the reduction factor due to voltage drop is equal to (1- %voltage drop).

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 temperature x (1 - %voltage drop)

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

- V_{oc} temperature co-efficient can be used;

or

- P_{mp} temperature co-efficient applied to the V_{mp} voltage can be used for determining the V_{mp} temperature coefficient.

The P_{mp} temperature co-efficient can be used because the current (Amperes) temperature co-efficient is negligible so the V_{mp} temperature co-efficient is very similar to the P_{mp} temperature coefficient.

Worked Example 31

A module data sheet provides the following information:

P_{mp} = 330W
V_{oc} = 46.2V
V_{mp} = 37.8V
I_{sc}= 9.27A
I_{mp} = 8.73A

Power Temperature co-efficient= - 0.39%/°C
V_{oc} temperature coefficient = -0.29%/°C
Manufactures Tolerance =0 to +5%
Test Tolerance = ±3%

Therefore, in V/°C the V_{oc} temperature coefficient = -0.29/100 per degree C x 46.2V = -0.134V/°C

Applying the power temperature coefficient then the V_{mp} temperature coefficient = -0.39/100 x 37.8 =-0.147V/°C. This will be used in the rest of the example.

Based on the maximum temperature of 75°C then the reduction in V_{mp} due to temperature (takes the negative value into account)

= 50°C times the voltage temperature coefficient (V/°C).
= 50°C x 0.147V/°C
= 7.35V

So the effective V_{mp} of the module due to temperature = 37.8V-7.35V = 30.45V

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

0.99 x 30.45 = 30.14 V

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

Determine the Effective Minimum MPPT Operating Voltage of the Inverter
The inverter data sheet specifies the actual minimum MPPT operating voltage.

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

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

Worked Example 32

The inverter data sheet provides the following information:

Max DC Power	2000W
Max. input voltage	600 V
MPP voltage range	160 V to 500 V
Max. input current	10 A

The minimum operating voltage of the MPPT is 160V

Allowing for the safety margin of 10% to the effective minimum operating voltage of the MPPT = 1.1 x 160V = 176V

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.

Worked Example 33

The effective minimum operating voltage of the MPPT = 176V

The effective minimum MPP voltage input at the inverter for each module =30.14V

Therefore, the minimum number of modules in a string = 176V/30.14V = 5.8

This would be rounded up to 6.

25.4.2 Maximum number of modules in a 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 is the voltage applied at sunrise when the system detects the sun and begins its start-up sequence – that will be prior to the inverter starting to operate 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 dawn 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 dawn ambient temperature can reach 15°C (59°F). In a few areas of the Pacific it will fall below this. It is recommended that 15°C is used unless you know that the site for the array has a lower minimum temperature; if so use that lower temperature for your calculations.

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 minimum daytime 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).

Using 15°C as the minimum temperature, 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. Keep in mind that lower temperatures result in higher voltages)

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

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

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

Worked Example 34

Assume the minimum effective cell temperature is 15°C. The module data sheet provides the following information:

- V_{oc}= 46.2V
- V_{oc} temperature coefficient = 0.29%/°C

Therefore, in V/°C the V_{oc} temperature coefficient = 0.29/100 per °C x 46.2V = 0.134V/°C

Based on the minimum temperature of 15°C then the:
Increase in V_{oc} due to temperature = 10°C times the voltage temperature coefficient (V/°C).
= 10°C x 0.134V/°C
= 1.34V

So the effective V_{oc} of the module due to temperature = 46.2 + 1.34 = 47.54V
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 the actual Maximum operating voltage.

Worked Example 35

The inverter data sheet provides the following information:

Max. input voltage	600 V

Determine Maximum Number of Modules in the string

The minimum number of modules in a string is determined by dividing the maximum operating voltage of the Inverter by the effective maximum open circuit voltage input at the inverter for one module.

Since it is the maximum number it should always be rounded down.

Worked Example 36

The maximum voltage of the Inverter = 600V

The effective maximum V_{oc} input at the inverter for each module = 47.54V

Therefore, the maximum number of modules in a string = 600V/47.54V = 12.62

This would be rounded down to 12.

So in the worked example we can have between 6 and 12 modules in a string and still stay within the maximum and minimum voltage ratings of the inverter.

How Many Strings?
Depending on how many modules have been selected to meet the end-user's requirements, the array could include one string or could include multiple strings. The final configuration is determined by matching the output currents of the array to the maximum input current of the inverter

> **Worked Example 37**
>
> When determining the array power and matching it to the inverter an array of 6 modules has been selected. So these could either be installed as one string of 6 modules or two strings of 3 modules or 3 strings of 2 modules.
>
> The minimum number of modules is 6. So this determines the configuration

25.5 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 module connector sockets) for the PV array dc wiring to the inverter, these also have a maximum current specified.

The final configuration of the array shall ensure that no string or array connection has an output current greater than that specified for the Inverter.

> **Worked Example 38**
>
> The inverter data sheet provides the following information:
>
> Max. input current = 10 A
> The module data sheet provides the following information:
>
> I_{sc}= 9.27A
> I_{mp} = 8.73A
>
> So one string is suitable

Appendix 1: Temperature Conversion Tables

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

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

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

Appendix 2: Solar Irradiation Data

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

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

Peak Sunlight Hours (kWh/m²/day)

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

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

Peak Sunlight Hours (kWh/m²/day)

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

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

Peak Sunlight Hours (kWh/m²/day)

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

Honiara, Solomon Islands

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

Peak Sunlight Hours (kWh/m²/day)

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

Koror, Palau

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

Peak Sunlight Hours (kWh/m²/day)

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

Lae, Papau New Guinea

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

Peak Sunlight Hours (kWh/m²/day)

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

Majuro, Marshall Islands

Latitude: 7°12' North | Longitude: 171°06' East

Peak Sunlight Hours (kWh/m²/day)

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

Nauru

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

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt¹	5.77	6.24	6.27	6.04	5.99	5.75	5.85	6.25	6.7	6.5	6.12	5.5	6.07
15° Tilt²	5.94	6.26	6.08	6.05	6.28	6.15	6.20	6.39	6.51	6.46	6.28	5.69	6.19

Noumea, New Caledonia

Latitude: 22°16' South | Longitude: 166°27' East

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt¹	7.31	6.7	5.73	4.97	3.94	3.47	3.91	4.73	6.05	7.09	7.41	7.6	5.73
22° Tilt²	6.61	6.34	5.83	5.55	4.75	4.19	4.69	5.50	6.44	6.88	6.77	7.54	5.92
37° Tilt²	5.74	5.8	5.59	5.62	5.02	4.48	4.99	5.69	6.32	6.37	5.94	7.03	5.72

Nuku'alofa, Tongatapu, Tonga

Latitude: 21°08' South | Longitude: 175°12' West

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt¹	6.69	6.3	5.62	4.65	4.04	3.58	3.78	4.43	5.23	6.28	6.69	6.7	5.32
21° Tilt²	6.1	5.96	5.69	5.1	4.81	4.25	4.41	5.03	5.46	6.07	6.16	6.65	5.47
36° Tilt²	5.35	5.47	5.45	5.14	5.08	4.55	4.67	5.18	5.34	5.64	5.45	6.25	5.3

Pago Pago, American Samoa

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

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt¹	5.87	5.93	5.54	5.18	4.63	4.4	4.59	5.2	5.78	6.05	6.11	5.93	5.43
14° Tilt²	5.79	5.66	5.51	5.43	5.11	4.98	5.14	5.59	5.87	5.84	6.01	5.87	5.57
29° Tilt²	5.57	5.22	5.29	5.48	5.4	5.39	5.51	5.77	5.76	5.45	5.75	5.69	5.53

Palikir, Pohnpei FSM
Latitude: 6°54' North | Longitude: 158°13' East

Peak Sunlight Hours (kWh/m²/day)

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

Port Moresby, Papua New Guinea
Latitude: 9°29' South | Longitude: 147°9' East

Peak Sunlight Hours (kWh/m²/day)

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

Port Vila, Vanuatu
Latitude: 17°44' South | Longitude: 168°19' East

Peak Sunlight Hours (kWh/m²/day)

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

Rarotonga, Cook Island
Latitude: 21°12' South | Longitude: 159°47' West

Peak Sunlight Hours (kWh/m²/day)

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

Suva, Fiji

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

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	6.29	6.2	5.54	4.67	4.05	3.72	3.89	4.44	5.08	6.04	6.32	6.38	5.21
18° Tilt[2]	6.27	5.88	5.55	4.99	4.61	4.38	4.51	4.88	5.21	5.83	6.1	6.41	5.38
33° Tilt[2]	5.95	5.4	5.33	5.03	4.84	4.7	4.8	5	5.1	5.43	5.71	6.13	5.28

Tarawa, Kiribati

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

Peak Sunlight Hours (kWh/m²/day)

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

Vaiaku, Tuvalu

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

Peak Sunlight Hours (kWh/m²/day)

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

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

[2] *Monthly Averaged Radiation Irradiance for Equator Facing Tilted surface tilted at an angle equal to the latitude of the location and at an angle equal to the latitude of the location plus 15 degrees (kWh/m²/day)*
These data were obtained from the NASA Langley Research Center (LaRC) POWER Project funded through the NASA Earth Science/Applied Science Program. (https://power.larc.nasa.gov/)

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

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

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

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

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

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

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

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

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

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

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

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

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

Annual daily irradiation on an inclined plane expressed as % of maximum value for Tongatapu - Tonga

Latitude: 21° 08' South | Longitude: 175° 12' West

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

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

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

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

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

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

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