GRID CONNECTED PV SYSTEMS WITH BATTERY ENERGY STORAGE SYSTEMS DESIGN GUIDELINES

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

They represent latest industry BEST PRACTICE for Design of Grid Connected PV Systems with Battery Energy Storage Systems

While all care has been taken to ensure this guideline is free from omission and error, no responsibility can be taken for the use of this information in the Design of Grid Connected PV Systems with Battery Energy Storage Systems.

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1. Introduction

This guideline provides an overview of the formulas and processes undertaken when designing (or sizing) a Battery Energy Storage System (BESS) connected to a grid-connected PV system. It provides information on the sizing of a BESS and PV array for the following system functions:

- BESS as backup
- Offsetting peak loads
- Zero export

The battery in the BESS is charged either from the PV system or the grid and discharged to the household loads differently depending on the system function. The BESS can either be fitted to a household with an existing PV array or a PV array can be designed in conjunction with the BESS.

This document provides the minimum knowledge required to design a BESS. The design of a BESS should meet the required energy requirements 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, but are not limited to:

- 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;
- Determine the size of the PV array (in kW_p) required to charge the battery system and/or meet the daytime loads as required by the end user;
- Determine the size of the PV grid connect inverter (in VA or kVA) appropriate for the PV array;
- Selecting the most appropriate PV array mounting system;
- Determining the appropriate dc voltage of the battery system;
- Determining the capacity (in Ah and V or Wh) and output power/current (in W or A) of the battery system to meet the energy and maximum demand requirements of the end user;
- Determining the size of the battery inverter in VA (or kVA) to meet the end-user's requirements;
- Ensuring the solar array size, battery system capacity and any inverters connected to the battery system are well matched;
- The system functions are met.

A system designer will also determine the required cable sizes, isolation (switching) and protection requirements.

Notes:

1. The new standard AS/NZS5139 introduces the terms "battery system" and "Battery Energy Storage System (BESS)". Traditionally the term "batteries" describe energy storage devices that produce dc power/energy. However, in recent years some of the energy storage devices available on the market include other integral components which are required for the energy storage device to operate.
   The term battery system replaces the term battery to allow for the fact that the battery system could include the energy storage plus other associated components. For example, some lithium ion batteries are provided with integral battery management systems while flow type batteries are provided with pumping systems.
   The term battery energy storage system (BESS) comprises both the battery system, the inverter and the associated equipment such as protection devices and switchgear. However, the main two types of battery systems discussed in this guideline are lead-acid batteries and lithium-ion batteries and hence these are described in those terms.
   Since the two main battery systems used in this guideline are lead acid-batteries and li-Ion batteries the inverter connected to the battery systems within this guideline is simply described as the battery inverter.

2. 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.
3. 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 °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.

2. System Functions

The designer of a grid connected PV system with a BESS is responsible for understanding why a system is being installed so the system can be designed to meet the needs of the end-user. The three functions that are covered in this document are:

- BESS as backup
- Offsetting peak load
- Zero export

A system may be required to meet multiple functions. The designer should identify all the functions of the system by consulting the end-user and design a system to meet all their expectations. If the system cannot meet their requirements, they should be informed of the limitations of the system.

2.1. BESS as Backup

A BESS may be installed as backup when the end-user requires improved electricity reliability. This could be due to an unreliable grid where the end-user is often left without power, or if the end-user has critical loads that must be powered during grid outages such as hospital equipment. In this case, the system will be required to power specified loads for the expected duration of the grid outages. In some cases, multiple days of backup could be required.

The end user may want their whole house/commercial building to be supplied for days from the BESS because they have experienced grid outages that have lasted many days. If this is the requirement, then consideration should be given to designing a stand-alone power system (Off-grid PV power system) where the system can supply all the loads (appliances) for continuous operation. The grid can then be used similar to a back-up generator to provide power on the days when there is cloud and the available solar irradiation is not sufficient to fully charge the BESS. The grid would also be used to recharge the BESS quickly when it is deeply discharged.

Figure 1 shows how a system would operate when the PV and BESS are being used to supply all the daily energy.

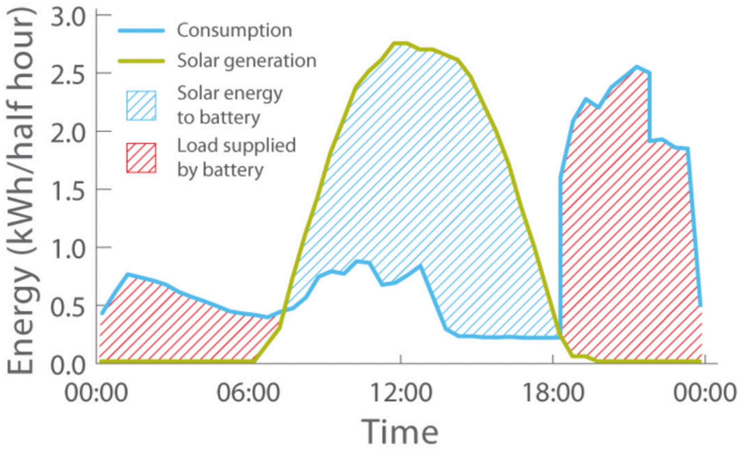

Figure 1: PV system meeting energy demand during day and charging batteries for energy to be used in the night

2.2. Offsetting Peak Loads

When a BESS is intended to offset peak loads, the aim is to reduce the peak demand by using energy from the BESS which has been charged by excess solar.

In some countries this will because the end-user is on a time-of-use tariff. When this is the situation, the main purpose of the system is to reduce either overall energy consumption during the peak pricing period. The system will therefore be sized to meet some, or all of the loads during the peak pricing period. The BESS will be charged with excess PV generation, and possibly grid electricity during off-peak pricing periods. The main goal of this system is to reduce the end-use electricity costs.

Figure 2 shows the power/energy profile of a building connected to time-of-use tariff.

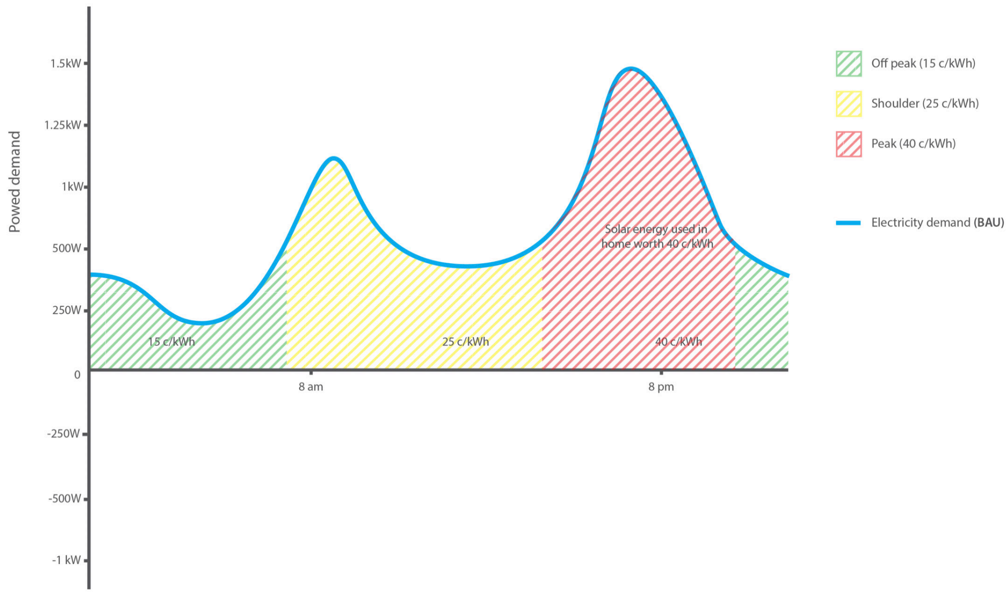

Figure 2: Daily power profile for a building with time-of-use tariff

In some countries the feed in tariff (FIT) being paid by the electricity utility for the excess solar energy from the solar system is less than the tariff being paid by the customer for the electricity they use from the grid. In this situation they will want to store the solar energy in the BESS and use it later in the day and at night when the solar is reduced or unavailable. If they are also on a time-of-use tariff then the system will be designed to use the excess solar via the BESS to offset the energy usage when the electrify tariff is at its highest.

Figure 3 provides an example of how the excess solar is stored to avoid the low FIT and then used later in the day for the power profile shown in figure 5. Since the graph is showing different electricity rates during the 24-hour period it also shows how the solar with the BESS will then reduce the different tariff rates and hence how the excess solar is being used to reduce the grid energy being used during the expensive tariff periods.

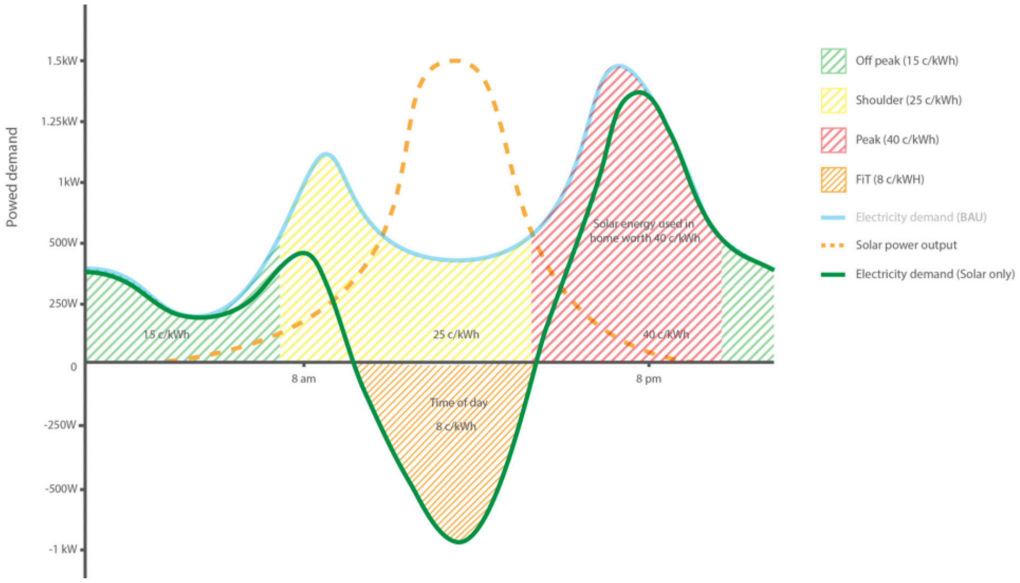

Figure 3: Daily power profile for a building with time-of-use tariff and BESS

2.3. Zero Export

As a result of the increasing number of PV installations, some electricity networks are not allowing excess PV generation to be exported to the grid. In this scenario, the end-user has two options, they can allow their system to be curtailed when the loads are less than the PV generation, or store the excess generation in a BESS. The BESS will therefore be sized to store some, or all of the excess PV generation, and will discharge to loads during the night time. As excess generation and the loads both vary according to season, the system should be designed to store the maximum expected excess generation. If this results in a BESS that is over budget, the end-user should be consulted to see if it is acceptable to curtail the system output.

Theoretically the PV system with BESS operates the same way when in zero export mode as when offsetting peak loads. That is all the excess solar is being stored in the BESS and used at a later time. The reason why an end-user is doing it is just different. However, the one difference is that in a zero export scenario the excess solar must be curtailed if it is not being stored, while in the off-setting peak loads (or low feed in tariff) systems then excess solar can still be supplied to the grid.

2.4. Summary of the Operation of PV Systems with BESS

Figure 4 shows how energy is typically supplied over a 24-hour period with a PV systems with a BESS.

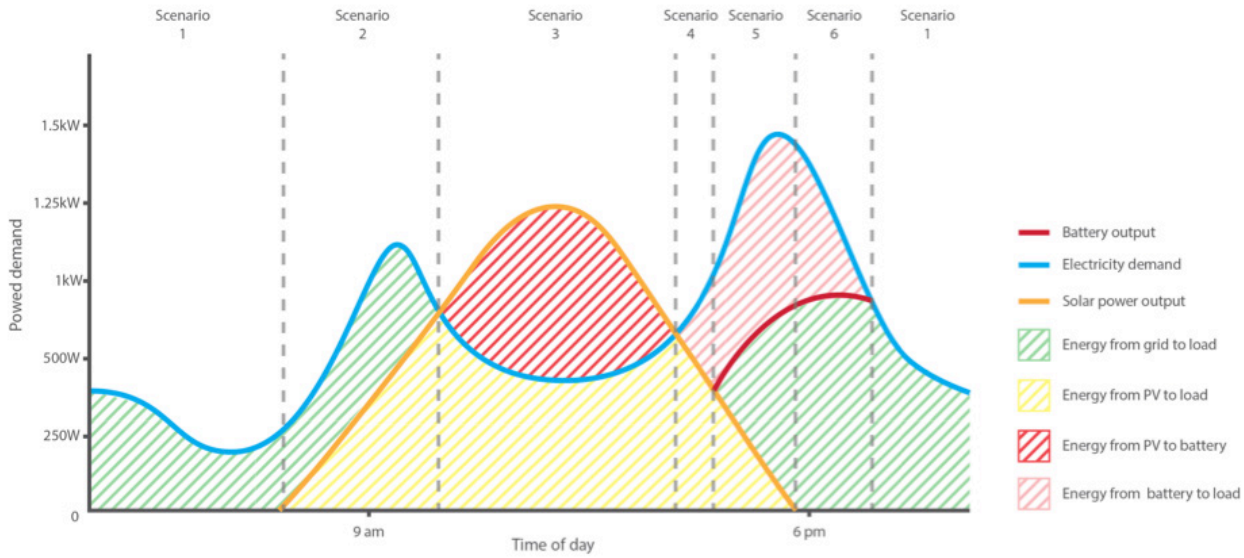

Figure 4: Daily power profile for a building with a PV System and BESS

The six scenarios are:

- Scenario 1 &7: Only grid used to meet the load
- Scenario 2: Grid and direct PV used to meet the load
- Scenario 3: Direct PV used to meet the load, excess PV used to charge the battery system
- Scenario 4: Direct PV and BESS used to meet the load
- Scenario 5: Direct PV, grid and BESS used to meet the load
- Scenario 6: Grid and BESS to meet the load

If the available excess solar energy and BESS capacity are sized accordingly then all the energy during the night could be supplied by the BESS as shown in Figure 1.

3. Typical Battery Energy Storage Systems Connected to Grid-Connected PV Systems

At a minimum, a BESS and the associated PV system will consist of a battery system, a multiple mode inverter (for more information on inverters see Section 5) and a PV array. Some systems have additional power conditioning equipment (PCE) to add functionality to the system. Below are examples of typical system configurations, note that this is not an exhaustive list.

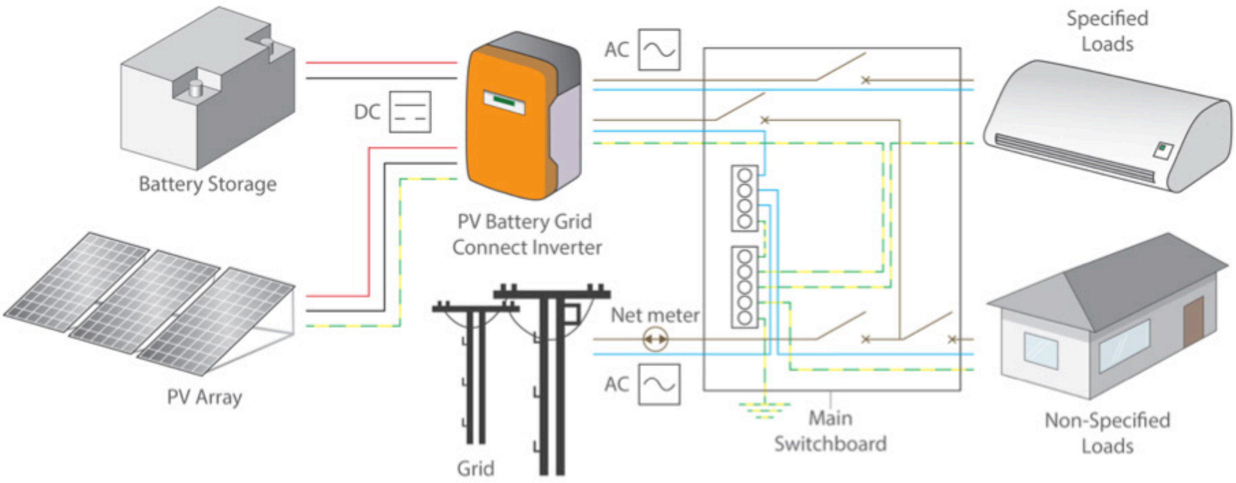

Figure 5: Single PV Battery Grid Connect inverter layout (hybrid)

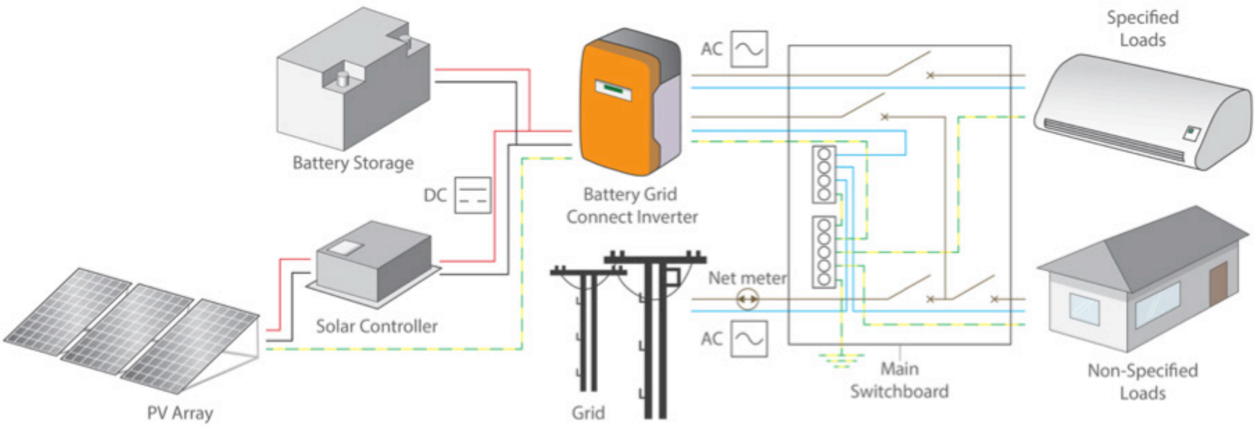

Figure 6: Single battery grid connect inverter with separate solar controller (dc coupled)

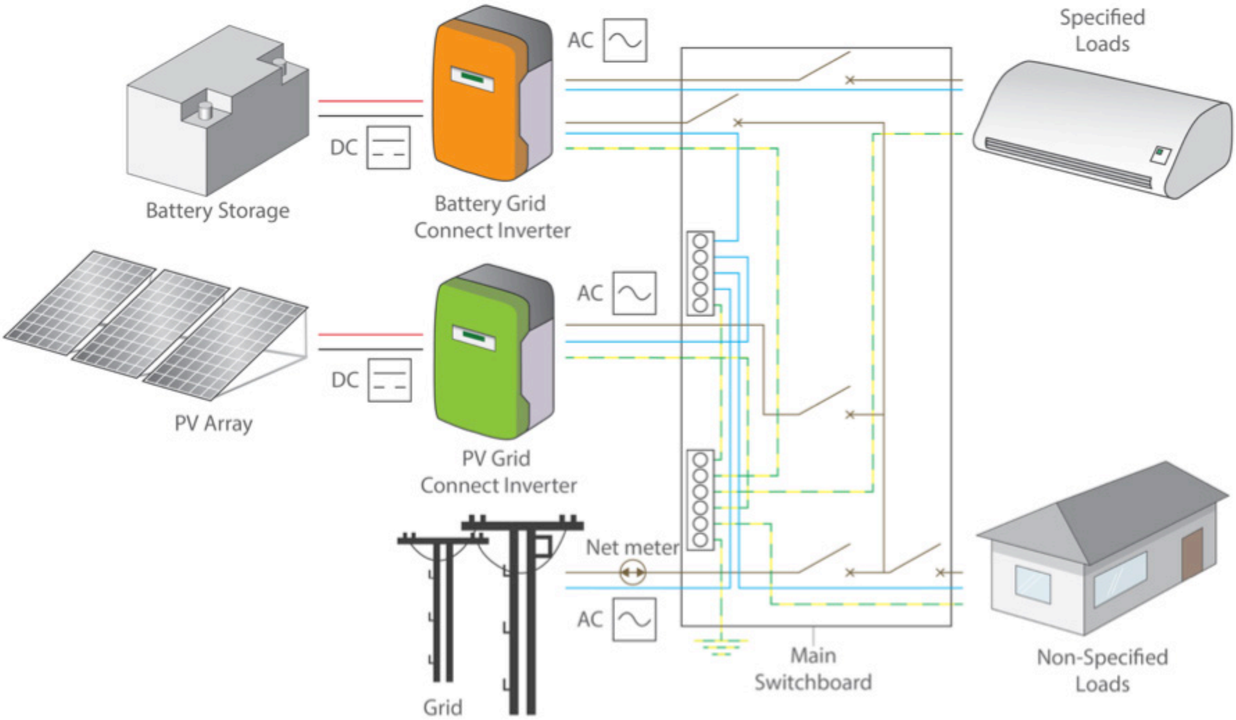

Figure 7: Two inverters, including PV inverter connected directly to specified loads (ac coupled)

Some inverters can have both battery system and PV inputs which results in a system with a single PV battery grid connect inverter (as shown in Figure 5). These systems will be referred to as “hybrid” throughout the guideline. It would require changing the existing PV inverter to a multimode inverter if retrofitted to an existing grid-connected PV system.

Figure 6 shows a system with a single battery grid connect inverter and a solar controller. These systems will be referred to as “dc coupled” throughout the guideline. The solar controller can be either a PWM type or MPPT type. It would require changing the existing PV inverter to a battery grid connect inverter if retrofitted to an existing grid-connected PV system.

Figure 7 shows a system with two inverters, one battery grid connect inverter and one PV grid-connect inverter. These systems will be referred to as “ac coupled” throughout the guideline. The two inverters can be connected in a number of different ways to provide different functionality to the system. This system can be easily retrofitted to an existing PV system.

4. Standards Relevant to the Design of Grid Connect PV System with BESS

System designs should follow all standards that are normally 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 follow many of 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 /NZS4777 Grid Connection of energy systems by Inverters.
- AS 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
- Building Codes- I CC, 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.

5. Types of Inverters

Within AS/NZS4777 there are two definitions:

Inverter: A device that uses semiconductor devices to transfer power between a dc source(s) or load and an ac source(s) or load.

Multiple mode inverter (MMI): An inverter that operates in more than one mode. For example, having grid-interactive functionality when grid voltage is present, and stand-alone functionality when the grid is de-energized or disconnected.

The problem is that though there are two definitions there are still many types of inverter based on the differences in the operating functions of the inverter. For that purpose, in this guideline is made more definitive through naming the inverter by its function.

There are four main types of inverters on the market that could be used be used in a grid connected PV system with associated battery systems. These are: PV grid connect, stand alone, battery grid connect and PV Battery multimode. A minimum of 1 inverter is required for a BESS system to operate as battery systems typically produce dc electricity, and typical household appliances use ac electricity.

Note: The term battery inverter is used here when the inverter input is connected to the battery system.

5.1. PV Grid Connect Inverter

A PV grid connect inverter is capable of producing an ac output that can interact with the grid. It cannot independently produce ac output as it requires a reference to ac power (typically the grid or another ac source). Therefore, a PV array cannot power loads via a PV grid connect inverter without additional equipment. They typically contain an MPPT for controlling the PV array output. (Note: Considering the two definitions above, the PV Grid Connect Inverter would be defined as an “Inverter”).

5.2. PV Battery Grid Inverter

A PV Battery grid connect inverter (hybrid) has both a PV inlet port and a battery system inlet port. It will also have a port for interconnecting with the grid and an outlet port for dedicated (specified) loads. Hence it is capable of operating with or without the grid. The multimode ability is required for the system to operate during certain conditions such as blackouts, or to offset peak loads. When it operates in this mode, the inverter isolates from the grid, and is often configured so it can still supply specified loads. (Note: Considering the two definitions above the PV Battery Grid Connect Inverter would be defined as a “Multimode Inverter”).

5.3. Battery Grid Connect Inverter

A battery grid connect inverter is capable of producing an ac signal compatible with the grid. It is able to synchronise with the grid and it can independently produce ac output if there is no grid. (Note: Considering the two definitions above the Battery Grid Connect Inverter would be defined as a “Multimode Inverter”).

5.4. Stand Alone Inverter

Stand alone inverters are designed to provide ac power from batteries which are typically charged by renewable energy sources. These inverters are not designed to connect to or to inject power into the electricity grid so they can only be used in a grid connected PV system with BESS when the inverter is connected to dedicated loads either permanently or via a change-over switch when the grid is not available. (Note: Considering the two definitions above the Stand Alone Inverter would be defined as an “Inverter”).

6. Site Visit

Prior to designing any grid connected PV with BESS 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 7 for more detail).
3. Assess the occupational safety and health risks when working at that particular site.
4. Determine the solar access for the site or determine the 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 Grid Connected PV Systems with BESS 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 system's inverters will be located.
12. Determine the cabling route and therefore estimate the lengths of the cable runs.
13. Determine whether monitoring panels or screens are required and if so 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.

7. Energy Assessment

Electrical power is supplied 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).

The specified loads (listed appliances) are the loads that will be supplied by the BESS. The loads to be included are determined in the site visit (see Section 6) and will be dependent on the actual application of the systems.

When the system is being used as a back-up system the loads could either be all the loads in the house/building or they could just be a limited number of loads that the client wants to operate when there is a grid failure.

When the system is being used for offsetting peak loads it would be some of those loads that have been identified that operate when the load is at peak and these will be selected to have their energy supplied at that time by the batteries via the inverter.

After the specified loads have been determined, an energy assessment form such as Table 1 is completed.

Table 1: Example energy assessment form

[1] Load (Appliance)	[2] No.	[3] Power (W)	[4] Usage Time (Hours)	[5] Energy (Wh)	[6] Power Factor	[7] Maximum Demand (VA)	[8] Surge Factor (VA)	[9] Potential Surge Demand (VA)	[10] Design Surge Demand (VA
Total energy (Wh) [11]									
Maximum Demand (VA) [12]									
Potential Surge Demand (VA) [13]									
Design Surge Demand (VA) [14]									

This power and energy assessment is completed as follows:

i. List all or the specified loads/appliances identified in the site visit [1]
ii. List the number of each loads/appliances [2]
iii. Determine the power rating of the load/appliance. Some appliances have a maximum power rating while others have an average power rating. [3]
iv. Estimate the number of hours that the load/appliance will be operating when the BESS is discharging. [4] In some cases, this may only be a few hours such as for offsetting peak loads. In other cases, it may be the average number of hours over an entire day when the system is being used as for backup. (Refer to the PPA/SEIAPI Guideline: Off Grid PV Power Systems Design Guideline if the system is being designed for back-up for many days)
v. Multiply the power rating [3] by the number of hours [4] to determine the energy usage in Wh. [5] Some appliances will give an energy usage rather than power rating. This can be recorded instead.
vi. List the power factor of each load/appliance. [6]
vii. Determine which of the loads/appliances will be on at any one time. [7]
When there is a small number of appliances then all might be on at the one time, however when there are many appliances not all may be operating at the same time. For instance, if there is a microwave, washing machine and iron then all these would not operate at same time. If all were assumed to be operating, then the calculated inverter rating could be larger than required. For those loads/appliances that will operate at the same time divide the power rating [3] by the power factor [6] to determine the demand of the load/appliance in VA.
viii. List the surge factor of each load/appliance. [8]
ix. To determine the potential surge demand of each load/appliance, [9]Multiply the demand [7] by the surge factor [8].
x. Sum the energy usages [5] for each load/appliance to determine the total energy usage of the loads in Wh. [11] This will determine the size of battery system that is required.
xi. Sum the demands [7] for each load/appliance to determine the total maximum demand of the loads in VA. [12] This would determine the size of the battery inverter that will be required.
xii. Sum the surge demands [9] of the largest loads/appliances that could be starting at the same time to determine the potential surge demand of the loads in VA. [13]
xiii. Many inverters will surge to 2 x their rating. If the potential surge demand is more than 2 x (or cannot be met by the inverter that might be selected) then either a larger inverter is required, or the surge demand needs more investigation. A motor only surges for 1 or 2 seconds, so the chances of all appliances which have a surge starting at the same time is very small. It is wise to allow for 2 appliances starting the exact same time but unless there are many motors then that would be sufficient. Therefore, the design surge demands [10) are either those few appliances that will surge or the maximum demand value because they are operating.
xiv. Sum the design surge demands [10] of each load/appliance to determine the design surge demand of the specified loads in VA. [14]

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 2) 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 what loads are to be powered by the BESS and you can educate the end-user about energy efficiency.

Table 2 is used throughout the guideline as a worked example. The energy assessment has been developed based on the need for a system which could provide the loads/appliances during a 6-hour power failure.

All the loads/appliances in this example are powered by 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 system.

Table 2: Example of completed load assessment for a 6-hour peak evening period

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Appliance	**No.**	**Power (W)**	**Usage time (hour)**	**Energy (Wh)**	**Power factor**	**max demand (VA)**	**Surge factor**	**Potential surge demand (VA)**	**Design surge demand (VA)**
Lounge room lights	2	15	5	2 x 75W x 5h = 150Wh	0.9	(2 x 15)÷0.9 = 33.3VA	1	33.3VA x 1 = 33.3VA	33.3VA x 1 = 33.3VA
Bedroom 1 lights	1	15	1	15	0.9	16.7	1	16.7	16.7
Bedroom 2 lights	1	15	1	15	0.9	16.7	1	16.7	16.7
Bathroom lights	1	15	1	15	0.9	16.7	1	16.7	16.7
Fridge	1	150	3	450	0.9	166.7	2	333.3	333.3
Phone Charger	1	10	3	30	0.9	11.1	1	11.1	11.1
Television	1	180	3	540	0.9	200.0	1.1	220.0	220.0
Laptop computer	2	60	2	240	0.9	133.3	1	133.3	133.3
Pedestal fan	1	150	6	900	0.9	166.7	1	166.7	166.7
Microwave	1	1200	0.5	600	0.9	1333.3	1.1	1466.7	1466.7
Total energy load (11)				2955Wh					
Maximum demand (12)						2094.5VA			
Potential surge demand (VA) (13)								2414 VA	
Design surge demand (VA) (14)									2414 VA

In table 2 the design surge demand and potential surge demand are the same because the surge of 2414VA would easily me provided an inverter selected to meet the maximum demand of 2094.5VA. As stated above, if the potential surge demand is too great because of too many loads that surge, analyse more closely and predict the loads that would start at the same time and include all others in the maximum demand as operating.

8. Selecting Battery System Voltage

Battery system 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 PWM solar controller, then a higher system 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 and maintenance at those higher voltages are much more complex and the resulting system more expensive than would be the case for systems using voltages below 60Vdc 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 can have a multiple cluster design with each cluster using a 48V battery system.

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.

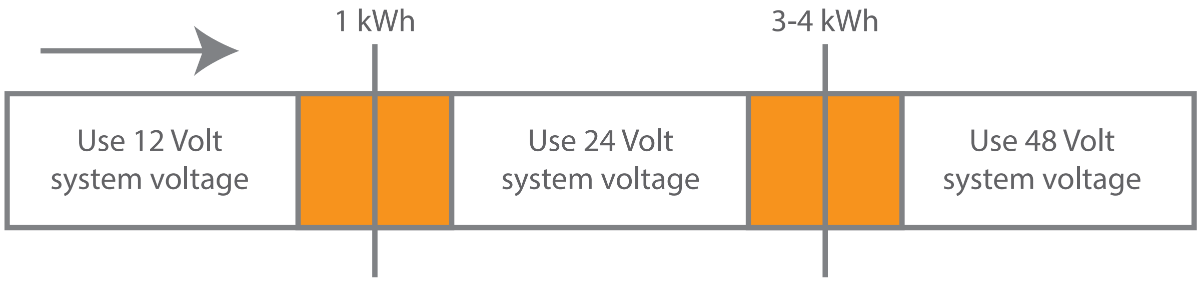

Figure 8: Guideline to Selecting Battery System Voltage

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 12V system could still be used even though the total energy usage is 2400Wh/day. The current being drawn from the battery system is only 8.77A (100W/12V/0.95 inverter efficiency). On the other hand, a pump drawing 800W that only operates 3 hours a day will also use 2400 Wh but will draw almost 70.2 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 17.9A and much smaller wiring can be used without excessive losses plus the battery system Ah requirement will be ¼ that of using a 12V system battery, but with four times the system voltage.

One of the general limitations is that the maximum continuous current being drawn from the battery system should not be greater than 150A. This is to reduce the size of the required cable and minimise any problems with voltage drop.

Note: PV battery grid connect inverters and battery grid connect inverters are generally not provided to suit 12V battery systems. 48V is probably the most common but some manufacturers do provide inverters suitable for 24V battery systems.

Worked Example 1

Using the load assessment in Table 2 the system energy usage is 2955Wh.

Therefore, a 24V system voltage is suitable.

9. Selecting a Lead-Acid or Li-Ion Battery

For lead-acid batteries, a battery with deep discharge type batteries/cells are selected and they 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 cells for the battery system, it is preferable that solar type batteries are selected. In any case, lead-acid batteries must be designed for deep discharge applications. Engine starting batteries have a short life when used in solar installations as they designed for short duration high starting currents, not deep cycling applications.

Parallel strings of lead acid 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 more chance there is of uneven charging/discharging which can lead to shorter battery system 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 for lead-acid batteries and some manufacturers void their battery system warranty if more than 2 battery systems are placed in parallel. Never have more than 4 battery systems in parallel and ensure all the requirements for wiring parallel battery system strings as specified in the installation guideline are followed.

For lithium-ion batteries, the battery system should be rated for the required system voltage and capacity. Connecting lithium-ion batteries is less flexible than connecting lead-acid batteries. The manufacturer's recommendations should always be followed for how many, if at all, batteries can be connected in series or parallel.

Lead-acid batteries shall meet one of the following standards:

- IEC 61427-1 Secondary Cells and Batteries for Renewable Energy Storage – General Requirements and Methods of Test – Part 1: Photovoltaic Off-grid Application
- IEC 60896 Stationary lead-acid batteries (series)
- UL 1973 Standard for Batteries for Use in Light Electric Rail (LER) Applications and Stationary Applications
- UL 1989 Standby Batteries

Batteries that meet one of the above UL standards shall also meet:

- UL-2054 Safety Standard for household and commercial batteries

- The individual cells and the assembled battery pack for lithium-ion batteries shall meet either:
- 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.

or

- UL 1642 Standard for Lithium Batteries; and
- UL 2054 Safety standard for household and commercial batteries.

When the function of the battery system is to meet specified loads, the energy and power as seen by the battery system shall be used to calculate the size of the battery system. That is calculated by dividing the energy usage or power demand by the system efficiency. The system efficiency is found by multiplying the inverter efficiency and the cable efficiency.(Note cable efficiency relates to the voltage drop and hence is the transmission efficiency of the cable)

Worked Example 2

(Based on Table 2)

Assume the overall system efficiency is 90%.

Daily load (energy) as seen by the battery system = 2955Wh ÷ 0.90 = 3283Wh

Maximum demand (power) as seen by the battery system = 2095VA ÷ 0.90 = 2328VA

Maximum surge demand (power as seen by the battery system = 2414 ÷ 0.90 = 2682VA

10. Selecting the Inverter that Connects to the Battery System

When selecting the inverter that connects to the battery system, the dc input voltage range of the inverter must match the battery system dc output voltage range. The inverter shall meet the following standards:

- IEC 62109 Safety of power converters for use in photovoltaic power systems
  - IEC 62109-1 Part 1: General requirements
  - IEC 62109-2 Part 2: Particular requirements for inverters.
- UL Standard 1741: Standard for Inverter, converters, Controllers and Interconnection System Equipment for use with Distributed Energy Resources

Note: For convenience this inverter will be referred to as the “battery inverter” however it must be appreciated that in some systems the battery inverter will be a PV battery grid connect inverter and hence that inverter must be sized as the battery inverter and also sized to suit the PV array.

11. BESS Sizing - BESS as Backup

During the site visit, the installer should determine if the end-user requires whole of house backup or just partial backup. Sizing a BESS for whole of house backup for a regular household is very costly and should be avoided if possible. Instead, essential loads should be selected to reduce the energy requirements. When calculating the maximum demand, using the total power ratings of all loads will require a large inverter. Instead, loads should be included based on what would realistically be operating at the same time.

11.1. Battery Inverter Sizing

For a system that is being used for backup, the selected battery inverter should be capable of supplying continuous power to the specified loads connected to the BESS and must have sufficient surge capacity to start all loads that may surge when turned on. Electric motors are particularly likely to have a large surge capacity requirement.

If the system configuration is either hybrid or ac coupled, the battery inverter should also be sized to the maximum power output of the PV system. The battery inverter size will be determined by the larger of the maximum demand or the rated output of the PV array.

It is recommended that a 10% safety margin be applied to the maximum demand when sizing the battery inverter.

Worked Example 3

Using Table 2, the maximum demand of the system is 2095VA and the maximum surge demand is 2414VA.

Assume a 10% safety margin is used.

The selected inverter must have a continuous rating of 2095VA x 1.1 = 2305VA,

and a surge rating of 2414VA x 1.1 = 2655VA

11.2. Battery System Sizing

When sizing a battery system for backup functionality, the battery system must meet the energy and power (both continuous and surge) requirements during disconnection from the grid, as determined in the load assessment.

Capacity

The minimum capacity of the selected battery system will be the energy usage as seen by the battery system (see Section 9) divided by the maximum depth of discharge (DoD_{MAX}).

Lithium-ion batteries are typically specified based on their watt-hour (Wh) capacity and the capacity of interest is usable capacity, not total capacity.

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

To convert Wh to Ah you need to divide Wh by the battery system voltage.

Battery System 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 current available at that discharge rate. The Ah capacity of solar lead-acid batteries are typically given for a discharge rates ranging between C_1 and C_{100} – for a C_{100} rate, that means the time it takes to fully discharge the rated Ah capacity of the lead acid 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 lead-acid battery selected, as lead-acid 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.

Table 3: Example of varying lead acid 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 Sonnenschien Batteries

The lead-acid battery system capacity should be matched to the expected length of disconnection from the grid. If the grid outages are usually only a few hours, then the C_5 or C_{10} rating could be used. If the grid outages last for a day or more, then the C_{20} or higher may be used however it is important to analyse the expected discharge currents. If full analysis is difficult then it is recommended that the C_{10} capacity is used when designing the system for long grid outages.

The battery system must meet the maximum and surge demands. The actual discharge current will depend on the loads that are operating at any one time. Though some will typically be on for long periods some will turn on for only short times. Therefore, the battery system should be capable of providing a current required that meets the battery inverter's continuous rating. However, if the battery inverter's rating has been increased to be greater than the maximum demand because of the rating of the PV array then the maximum demand (with a safety margin of 10%) as determined in Table 2 should be applied. It is preferred that the C_5 discharge current of a lead-acid battery system is equal to or greater than the maximum current required by the inverter based on continuous rating (or maximum demand loads) however the C_3 discharge current could be used as long as the reduced capacity of the lead-acid battery system does not affect the ability of the lead-acid battery system to meet the system requirement of providing power for a specified period of time. It is recommended that the C_1 discharge current of the lead-acid battery system is equal to or greater than the surge current required by the inverter (or calculated surge demand if the inverter is sized for PV array)

The C_5 discharge current is calculated by dividing the C_5 capacity in Ah by 5 hours while the C_1 discharge current is calculated by dividing the C_1 capacity in Ah by 1 hour.

For lithium-ion batteries the battery system capacity is only slightly reduced at higher discharge currents. So, the lithium-ion battery system can be selected based on the energy and power ratings provided by the manufacturer without consideration of the discharge rate.

Worked Example 4

The selected battery system must meet both the energy and power requirements of the end user. For a lithium-ion battery, assume a usable capacity of 90% of the rated capacity.

The daily load as seen by the battery system during grid disconnection is 3283Wh, therefore, based on the energy requirements, the minimum battery capacity is:

3283Wh ÷ 0.90 = 3648Wh

The maximum demand and surge demand of the specified loads as seen by the battery system was calculated as 2328VA and 2682VA respectively. The selected lithium-ion battery should have a rated output greater than 2328VA, and a short peak (surge) output greater than 2682VA.

Worked Example 5

For a lead-acid battery, assume a DoD_{MAX} of 50%. Based on the daily load of 2955Wh, a battery system voltage of 24V is acceptable.

Therefore, the minimum battery system capacity is:

3283Wh ÷ (0.50 x 24) = 274 Ah

The maximum demand and surge demand of the specified loads as seen by the battery was calculated as 2328VA and 2682VA respectively. The maximum current and surge current will be:

Maximum current = 2328VA ÷24V = 97A

Maximum surge current = 2682VA ÷ 24V = 111.8A.

If the C_5 capacity is used to estimate maximum demand, the selected lead-acid battery must have a C_5 rating greater than 97A x 5 hours = 485Ah

If the C_3 capacity is used to estimate maximum demand, the selected lead-acid battery must have a C_3 rating greater than 97A x 3 hours = 291Ah

If the C_1 capacity is used to estimate the surge demand, the selected lead-acid battery must have a C_1 rating greater than 111.8A x 1 hour = 111.8Ah

12. BESS Sizing - Off-Set Peak Load

A BESS which has a main function to off-set peak loads will usually be installed on a property having either a time-of-use tariff or a maximum demand charge. The load assessment should be undertaken for the peak usage period – usually in the evenings for residential systems. The loads selected can either be the entire site's loads or a selection of loads. When calculating the maximum demand, using the total power ratings of all loads will require a large inverter. Instead, loads should be included based on what would realistically be operating at the same time during the peak load period.

The sizing principles are the same for off-setting peak loads and BESS as backup, only the loads will be different. See Section 11.1 for inverter sizing and Section 11.2 for battery system sizing.

13. BESS Sizing - Zero Export

A BESS may be designed for zero export if the electricity distributor does not allow PV electricity export, or if the end user would like to self-consume all of the PV generation. Rather than being sized to loads, a BESS designed for zero export will instead be sized to the excess PV generation. The excess PV generation data can be determined a number of ways including monitoring, possibly using data from the property's meter if it has interval monitoring/logging capability, with modelling or by contacting the electricity distributor, but the amount of excess generation will fluctuate based on the available solar irradiation.

If the system is sized for the maximum expected PV generation, then it may result in a large BESS which is underutilised for a significant portion of the year, and the cost of the system will be high. If the system is sized to the average excess PV generation, then the PV system may be curtailed throughout some of the year. This should be discussed with the end-user during the site assessment to determine what will be used to size the BESS.

If the excess PV generation data cannot be obtained, or the PV array is being installed alongside the BESS, then the excess generation can be estimated. Firstly, the irradiation data for the shall be obtained. The PV system output can be estimated as:

Daily irradiation (PSH) x Array rated power (kW_p) x system efficiency = Daily output of PV system (Wh or kWh)

The amount of excess generation will be the total daily output of the PV system minus the daytime loads. Note, if the excess generation exceeds the charging capabilities of the battery system, then the PV system should be curtailed. Note that in many cases, weekend usage is much lower than during the work week and BESS capacity will need to be sufficient to accept the surplus energy from the solar installation if there is to be no curtailment.

Worked Example 6

Assume a $2kW_p$ PV array receives a maximum daily irradiation of 5.83 PSH. PV system efficiency is 80% and the daytime loads are 4.5kWh.

The PV system output calculated as:

$2kW_p \times 5.83 \times 0.8 = 9.3kWh$

The excess PV generation is therefore:

9.3kWh – 4.5kWh = 4.8kWh

Note: The actual amount of excess energy will depend on the relationship between the available solar power and the load power. If the load power is less than the solar power at that time then not all the load will be provided by the solar power. This might result in more excess solar energy being stored than that determined by this simplified method.

The daily loads of the system should also be considered, especially if the system has a low energy usage. The loads must sufficiently discharge the battery system each night so that there is enough available capacity to store the excess PV generation the next day.

A BESS designed for zero export can also have backup functionality, if the end user would like this functionality then the BESS should also meet the sizing requirements from Section 11.

13.1. Battery Inverter Sizing

The battery inverter shall be sized to the maximum PV power output of the solar controller or PV inverter. If the system also requires backup then the inverter shall also be sized to meet the maximum demand and surge demand of the loads. The inverter will be selected based on whichever is larger, the PV array output or the loads.

13.2. Battery System Sizing

The battery system shall be sized to have adequate capacity to store excess generation and have a maximum charging current greater than the output of the PV inverter. If the battery system is being used for backup and the backup requirements are greater, then the battery system shall be sized following calculations in Section 11 based on the energy usage and the maximum demand of the loads.

Capacity

The battery system capacity is calculated as:

Minimum battery system capacity (Wh) = Excess PV generation (Wh) ÷ DoD_{MAX}

OR

Minimum battery system capacity (Ah) = Excess PV generation (Wh) ÷ (VDC x DoD_{MAX})
For a lead acid-battery system, the C_{10} capacity can be used when selecting a battery system based on minimum capacity.

Charge Rate

The maximum charging rate of the battery system must be greater than the output of the PV system. The maximum charging rate of a lead-acid battery system is typically defined by:

Maximum charge current (A) = 0.1 x C_{10} rating (Ah)

However, some manufacturers are allowing higher charging rate if the charge current is only being provided by PV as the high current is not continuous.

The maximum charge rate for lithium-ion batteries is typically provided by the manufacturer.

Worked Example 7

The excess PV generation from Worked Example 6 was determined to be 4.8kWh. Assume a DoD_{MAX} of 70% if using a lead acid battery and that the PV inverter maximum ac output is 2kVA/2kW.

Minimum battery system capacity = 4800Wh ÷ 0.70 = 6857Wh

If a lithium-ion battery is used then the minimum usable battery capacity is 6857Wh and the maximum charging rate must be greater than 2kW.

If a lead-acid battery is used, assume a system voltage of 48V. Therefore, the minimum battery capacity is 6857Wh ÷ 48V = 143Ah

To meet the charging requirements, the lead-acid battery must have a C_{10} rating greater than:

Minimum C_{10} rating = 2000W ÷ (48V x 0.1) = 417Ah

14. PV Array

A BESS can either be installed into a site with an existing PV system or a PV system can be designed in conjunction with the BESS. For a grid connected PV system without BESS, the design criteria for the PV system includes:

- Specifying a specific size (in kW_p) for an array;
- Available budget;
- Available mounting space;
- An annual kWh delivery goal;
- Goal for reducing reliance on fossil fuel generated electricity.

Many of these criteria can apply to a PV system installed in conjunction with a BESS, but there may be a few additional criteria including:

- Sized to charge the battery system within a specified time
- Sized as to not produce excess generation (zero export)

Hence the sizing of the array in a GC PV systems with BESS can be based on a number of different scenarios depending on the reason for the BESS and how it is being applied. In summary, the PV array could:

- Provide all of the array output directly to the grid/loads; or
- Provide all the array output to the grid/loads via charging the battery system; or
- Combination of both, that is, a portion of the array's output directly to the loads/grid and a portion of array output to the grid/loads via charging the battery system.

In section 3, Figures 5 to 7 showed three system configurations: hybrid, dc coupled, and ac coupled. There are different system losses between the PV array and the grid/loads in each of the three scenarios.

Section 16 details the factors that affect the output of a PV array independent of the system configuration. Sections 19, 20 and 21 describe the system losses between the array and the grid/loads for each of the three system configurations.

These sections can then be used to determine the output of the array, or the size of the array for the many different reasons a Grid Connect PV System with BESS could be installed.

15. 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 and 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 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). Additionally, at latitudes greater than about 10° there may be seasonal variations that will change the optimum tilt angle for the PV modules so it is preferable to obtain solar data on a monthly rather than a yearly basis. 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 (towards the equator) have a relatively small impact on daily irradiation totals when the latitude of sites are less than 10°.
I

f the PV array is mounted on the roof of a building, the roof may not be facing the optimum direction of true north (Southern Hemisphere) or true south (Northern Hemisphere) or may not be at the optimum tilt angle. The irradiation data for the actual roof orientation (true installed azimuth) and pitch (true tilt angle) shall be used when preparing the design. Please see the discussion on tilt and orientation (Section 16.1) for determining peak sun hours for sites not facing the ideal direction.

15.1. Effect of Tilt and Orientattion

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 4. 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 4: 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 rain to run off fast enough to help keep the module surface clean. Modules tilted less than 10° may require frequent manual cleaning.

Worked Example 8

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

15.2 Shading of the Array

The PV array may be shaded part of the day by local vegetation, landforms, buildings or other infrastructure. 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.

16. 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/m2 and in the Islands, cell temperatures when exposed to the sun are always substantially greater than the standard 25°C (77°F).

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 5.

Table 5: Values of T_r

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

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%.

A. Polycrystalline Modules

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

B. 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 Υ and it is expressed on data sheets as a negative number (e.g.Υ = -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 (TSTC) of 25°C (77°F).

Written as a formula it is:

Percentage power loss due to effective cell temperature = $\Upsilon \times (T_{cell\text{-}eff} - T_{STC})$

Note: Since the temperature coefficient: Υ 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 loss due to cell temperature above 25°C

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 9

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 5 the rise in temperature (T_r) is 25°C.

The effective cell temperature is therefore:

$T_{cell-eff} = T_{a.day} + T_r$
$= 30°C + 25°C$
$= 55°C$

The percentage power loss due to effective cell temperature $= \Upsilon \times (T_{cell-eff} - TSTC)$
$= -0.39\%/°C \times (55°C - 25°C)$
$= -0.39\% \times 30$
$= -11.7\%$

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

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

f_{temp} = 1- loss due to temperature
= 1- 0.117
= 0.883

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 tand 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. 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 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 10

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 up to 6%).

When designing a system, it is important to incorporate the actual figure for the selected module, taking into account any measuring tolerances, then 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 11**
>
> 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 grid connected PV systems the effect of this is taken into account through reducing the expected yearly energy output per year when undertaking life cycle analysis.

Solar Module De-Rated Power

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 12**
>
> If the temperature derating factor is 0.883, the dirt derating factor is 0.95 and derating factor for manufacturer's tolerance is 0.97, what is the overall derating factor for the modules?
>
> 0.883 x 0.95 x 0.97 = 0.81 which means that the actual output from the module is expected to be 0.755 times the rated output. Thus, a 270W_p module can be expected to provide at least:
>
> 270W_p x 0.81 = 218.7W_p

17. Selecting a Solar Module

When selecting a solar module to be used in a 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

  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 must be certified as Class II per IEC 61730 (or Application Class A per IEC 61730:2004).

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

18. 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.

19. Sizing a dc Coupled PV Array

The formulas and calculations shown here are for the PV array output to be charging the battery system and then providing power from the battery system through the inverter to the ac loads. However, there will be times during the day that the PV array dc output will go via the dc bus to the inverter straight to the a.c. loads

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 PWM 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 system requirements. A MPPT controller can deliver more charge to the battery system per day than a switching controller. The MPPT controller is required when the solar module being used does not have the suitable voltage (number of cells) for proper battery charging with a PWM controller.

19.1 Sizing a PV array – PWM Controller

When using a PWM 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 system is at 12V then the PV array will be operating at the battery system voltage 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 (36 cells) will be at 17-18V and the maximum charge voltage of a lead acid battery system is between 14.4V and 15V, then the typical voltage drop of around 1V that occurs between the array and the battery system is not an issue for most of the time the battery system is being charged.

The losses that need to be taken into account between the PV array and the ac loads are:

- battery inverter losses when the PV is providing power to the grid/loads during the day; and
- battery inverter losses and battery losses when providing the grid/loads via the battery system.

The battery system losses are assumed to be the average columbic efficiency (in terms of Ah in and Ah out) of a new battery system. That is typically 90% (variations in battery system voltage are not considered)

Worked Example 13

From table 2 the daily ac power required is 2955Wh.
Assume inverter efficiency (and cables on ac side) is 90%
Columbic efficiency is 90%.

Ah that must be provided by the array if it supplies the grid/loads directly during the day is:
ac load energy/(inverter efficiency x battery system voltage) = 2955Wh/(0.9 x24V) = 137Ah

The Ah that must be provided by the array if it supplies the grid/loads via the batteries is:
ac load energy/ inverter efficiency x battery coulombic efficiency x battery system voltage)

= 2955Wh/(0.9 x0.9 x24V) = 152Ah

As shown in section 16, The PV array will be de-rated due to:

- Manufacturer's Tolerance
- Dirt
- Module Temperature greater than 25°C

The designer, when using a **PWM controller, must use solar modules that have a nominal voltage rating that is appropriate for the battery system voltage**. In the market today these are either 36 solar cell modules for 12V battery system or 72 solar cell modules suitable for 24V battery systems. 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 modules 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 system charging or series connected as a 72 cell module for 24V battery system charging.

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

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

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 (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 current (I_{mp}); the operating current will 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 manufacturer's tolerance derating factor x dirt derating factor

Or

Derated Module current = Calculated module current x manufacturer's tolerance derating factor x dirt derating factor

The number of modules in a string is determined by dividing the battery system 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 14

A module with the following characteristics is selected:
STC Electrical Data
P_{mp} = 220W
V_{oc} = 46.2V
V_{mp} = 37.8V
I_{sc} = 6.18A
I_{mp} = 5.82A
Power Temperature coefficient= - 0.39%/oC
V_{oc} temperature coefficient = -0.29%/oC
Manufacturer's Tolerance = 0 to +5%
Test Tolerance ±3%

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 = (5.82 + 6.18) / 2 = 6A

Manufacturer's 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 = 6 x 0.97 x 0.95 = 5.53A per module string

From Worked Example 8 assume the irradiation is 5 PSH

Ah from each module string = 5.53A x 5 h= 27.65Ah

From worked example 13 the Ah to be provided by the array is 152Ah for the grid/loads when supplied via the batteries and 137Ah when provided by the PV array during the day.

Therefore, the array required when providing the load/grid via batteries = 152Ah/27.65 = 5.5 strings
Round up to 6

The PWM controller (if current limited) will require a minimum current rating of 6 x 6.18A = 37.1A
Or
1.25 x 6 x 6.18A = 46.4A   if not current limited.

Therefore, the array required when providing the load/grid direct during the = 137Ah/27.65 = 5 strings

The PWM controller (if current limited) will require a minimum current rating of at
5 x 6.18A = 30.9A
Or
1.25 x 5 x 6.18A = 38.6A   if not current limited.

19.2 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 system 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 system to account for all the sub-system losses.

Worked Example 15

From table 2 the daily ac power required is 2955Wh.
Assume

- ac cables losses and inverter losses assumed to be 90%
- dc cable losses are assumed to be 3% (transmission efficiency of 97%),
- MPPT efficiency of 95% and
- battery WH efficiency of 80%

Energy (Wh) that must be provided by the array if it supplies the grid/loads directly during the day is:
ac load energy / (inverter efficiency x MPPT efficiency x dc cable efficiency)
= 2955Wh / (0.9 x 0.95 x 0.97) = 3563Wh

Energy that must be provided by the array if it supplies the grid/loads via the batteries is:
ac load energy/ inverter efficiency x battery energy efficiency x MPPT efficiency x dc cable efficiency battery voltage)
= 2955Wh / (0.9 x 0.95 x 0.97 x 0.80) = 4454Wh

Assume: same module as specified in worked example 14
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).
From worked example 9 the temperature derating factor is 0.883.

The derated power from the module = Module rating at STC x temp derating factor x manufacturers derating x dirt derating
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.

So, Module derated power =220W x 0.883 x 0.95 x 0.97 = 179W
From Worked Example 8 assume the irradiation is 5 PSH

Wh from each module = 197W x 5h = 895Wh

Therefore, the array required when providing the load/grid via batteries = 4454Wh/895 = 5 modules

That is an array rated at 5 x 220W_p = 1100W_p

Therefore, the array required when providing the load/grid direct during the = 3563Wh/895 = 4 modules
That is an array rated at 4 x 220W_p = 880W_p

The array configuration shall be such that the maximum and minimum array voltages after accounting for temperature are within the voltage range of the MPPT controller.

The MPPT typically will have a recommended minimum 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.

The maximum power point voltage of a solar module decreases as the cell temperature rises. A 36-cell module is required for effective charging of a 12V battery system connected to the module via a PWM controller. For the MPPT to work effectively the maximum power point voltage of the array must always be greater than the maximum charge voltage of the battery system. So though a 36 cell module could be connected to a battery system via an MPPT, the MPPT will work more efficiently if the number of solar cells in the array is greater than 36 for a 12V battery system.

Some manufacturers state that their MPPTs will operate if the temperature compensated V_{mp} of the module is at least 1V greater than the battery system charge voltage, while others say it should be greater than 5 to 6V higher (or more) than the battery system voltage. Always follow what the manufacturer states.

Since interpreting the manufacturers requirements can be difficult Table 6 shows the suggested minimum number of cells or modules in a string for the different nominal battery system voltages when using a MPPT controller.

Table 6: Minimum Number of Cells or Modules in a String

Nominal Battery System Voltage (V)	Suggested Minimum Number of Cells per string of modules	Suggested Minimum Number of 60 cell modules	Suggested Minimum Number of 72 cell modules
12	54	1	1
24	90	2	2
48	162	3	3

Worked Example 16

Battery system voltage is 24 V so the array should have at least 90 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 module 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 module will also be very low, 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 17

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

19.3 Selecting a Solar Controller: PWM Controller

When selecting a solar controller to be used in a 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

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.

Worked Example 18

From Worked example 14 the PWM must be able to withstand a V_{oc} of 46.2V @ STC. As shown in the worked example this could rise to 46.9V at 20°C

The array required when providing the load/grid via batteries was 6 strings ion parallel

The PWM controller (if current limited) will require a minimum current rating of 6 x 6.18A = 37.1A
or
1.25 x 6 x 6.18A = 46.4A if not current limited.

The array required when providing the load/grid directly is 5 strings

The PWM controller (if current limited) will require a minimum current rating of a 5 x 6.18A = 30.9A
or
1.25 x 5 x 6.18A = 38.6A if not current limited.

19.4 Selecting a Solar Controller: MPPT Type Controller

When selecting an MPPT controller to be used in a 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 19

From worked Example 15 the number of modules required is:
5 when the array is providing the load/grid via batteries modules
and
4 when the array is providing the load/grid direct.

Worked example 16 determined minimum number of modules in series was 2.

So, for the 5 modules the MPPT would need to have an upper voltage of 5 x 46.9V = 234.5V.
If MPPT maximum voltage allowed is less than this then 6 modules might be required to have either 2 modules in series string and 3 strings in parallel or 3 modules in series and 2 strings in parallel.

The MPPT would need to have a power rating of 1320W and have a maximum input current of (when 3 strings in parallel):
3 x 6.18A = 18.5A
or
1.25 x 3 x 6.18A = 23.2 A if not current limited.

If 2 strings or 1 string then the currents can be calculated the same way.

The 4 modules provide more options. If 4 in series the upper voltage would be 4 x 46.9V = 187.6V. If MPPT maximum voltage allowed is less than this then the other option is 2 modules in series string and 2 strings in parallel.

The MPPT would need to have a power rating of 880W and have a maximum input current of (when 2 strings in parallel):
2 x 6.18A = 12.4A
or
1.25 x 2 x 6.18A = 15.5A   if not current limited.

20. Sizing an ac Coupled PV Array

The loads may be supplied by the PV array as follows:

- PV array powers ac loads directly via the PV inverter:
- PV array providing ac loads from the battery system via the PV inverter, the battery inverter acting as a battery system charger via the battery system and then via the battery inverter to the loads;

The losses relevant losses should be considered based on the system layout to determine the energy requirement, and in turn the size of the PV array.

Worked Example 20

From table 2 the daily ac power required is 2955Wh.
Assume

- PV Inverter efficiency is 96%
- Battery Inverter acting as charger has efficiency of 96%
- Battery inverter efficiency and ac cable efficiency to loads/grid is 95% (total)
- cable loss is 1% between PV array and loads via PV Inverter (transmission efficiency of 99%),
- cable loss is 3% between PV array and loads via battery (transmission efficiency of 97%),
- battery Wh efficiency of 80%

Energy (Wh) that must be provided by the array if it supplies the grid/loads directly during the day is:
ac load energy / (PV inverter efficiency x transmission efficiency)
= 2955Wh / (0.96 x 0.99) = 3109Wh

Energy that must be provided by the array if it supplies the grid/loads via the batteries is:
ac load energy/ (PV inverter efficiency x battery inverter as charger efficiency x battery inverter efficiency x battery efficiency x transmission efficiency)
= 2955Wh / (0.96 x 0.96 x 0.95 x 0.80 x 0.97) = 4349Wh

Assume: same module as specified in worked example 14 and same installation conditions as worked example 15 then from worked example 15 the Module derated power = 179W
From Worked Example 8 assume the irradiation is 5 PSH

Wh from each module = 179W x 5 h= 895Wh

Therefore, the array required when providing the load/grid direct during the = 3109Wh/895 = 3.5 modules rounded up to 4

That is an array rated at 4 x 220W_p = 880W_p

Therefore, the array required when providing the load/grid via batteries = 4349Wh/895 = 4.86 rounded up to 5 modules

That is an array rated at 5 x 220W_p = 1100W_p

20.1 Sizing a PV Array – 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 maximum PV array power if stated by the manufacturer.

Worked Example 21

Based on worked example 20 and assuming the array is Qty 5 220W modules with a total array rating of 1100W.

There are few inverters on the market this small however we should be able to achieve this using solar module based inverters for two or three modules.

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 PV Inverter's MPPT input operating voltage.

The maximum array is the V_{oc} of the array at the coldest temperature possible for the location. Assume 15°C for the Pacific unless the site is known to have a lower temperature.

The minimum V_{mp} of the array is the V_{mp} voltage at the hottest possible cell temperature and for the Pacific this is assumed to 75°C.

Worked Example 22

The inverter data sheet provides the following information:

Max. dc Power	1200W
Max. input voltage	600 V
MPP voltage range	140 V to 500 V
Max. input current	15 A

The module data is the same as that in Worked Example 15

P_{mp} = 220W
V_{oc} = 46.2V
V_{mp} = 37.8V
I_{sc} = 6.18A
I_{mp} = 5.82A
Power Temperature coefficient= -0.39%/°C
V_{oc} temperature coefficient = -0.29%/°C
Manufacturer's Tolerance = 0 to +5%
Test Tolerance ±3%

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 examples.

Based on the maximum temperature of 75°C then the reduction in Vmp 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 Vmp 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.
Therefore, in V/°C the V_{oc} temperature coefficient = -0.29/100 per degree
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.

Worked Example 22 Continued

The minimum operating voltage of the MPPT of the Inverter is 130V

Allowing for the safety margin of 10% to the effective minimum operating voltage of the MPPT = 1.1 x 130V = 143V

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

Therefore, the minimum number of modules in a string = 143V / 30.14V = 4.7

This would be rounded up to 5

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 5 and 12 modules in a string and still stay within the maximum and minimum voltage ratings of the inverter.

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.

Worked Example 23

Based on worked example 20 the number of modules required was 5. These therefore will be one string of 5 modules.

The short circuit current is 6.18A and this is then the maximum allowed for the inverter of 15A.

20.2 Selecting a PV Inverter

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

21. Sizing a Hybrid System PV Array

The loads may be supplied by the PV array as follows:

- PV array provides ac loads directly via the PV Battery GC inverter
- PV array providing ac loads from the battery system through the MPPT in the PV inverter to the battery system and then back via the battery inverter to the loads;

The relevant losses should be considered based on the system layout to determine the energy requirement, and in turn the size of the PV array.

The Energy (Wh) that must be provided by the array if it supplies the grid/loads directly during the day is identical to that calculated in example 20 for the ac coupled system using a PV inverter.

The Energy (Wh) that must be provided by the array if it supplies the grid/loads via the is identical to that calculated in example 20 for the dc coupled system using a MPPT controller.

Determining the PV energy to loads directly via the PV Battery GC Inverter is identical using a PV inverter as shown in worked example 15.

The PV Battery GC inverter must be matched to the array the same as that for the PV inverter in the ac coupled system as shown in worked examples 22 and 23.

21.1 Selecting a PV Battery GC Inverter (multimode)

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

22. 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 battery systems, 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

Annex 1: Temperature Conversion Tables

°F	°C	°F	°C	°F	°C
32	0	64	18	96	36
33	1	65	18	97	36
34	1	66	19	98	37
35	2	67	19	99	37
36	2	68	20	100	38
37	3	69	21	101	38
38	3	70	21	102	39
39	4	71	22	103	39
40	4	72	22	104	40
41	5	73	23	105	41
42	5	74	23	106	41
43	6	75	24	107	42
44	6	76	24	108	42
45	7	77	25	109	43
46	8	78	26	110	43
47	8	79	26	111	44
48	9	80	27	112	44
49	9	81	27	113	45
50	10	82	28	114	46
51	11	83	28	115	46
52	11	84	29	116	47
53	12	85	29	117	47
54	12	86	30	118	48
55	13	87	31	119	48
56	13	88	31	120	49
57	14	89	32	121	49
58	14	90	32	122	50
59	15	91	33	123	51
60	16	92	33	124	51
61	16	93	34	125	52
62	17	94	34	126	52
63	17	95	35	127	53

Annex 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° Tilt[1]	5.77	6.24	6.27	6.04	5.99	5.75	5.85	6.25	6.7	6.5	6.12	5.5	6.07
15° Tilt[2]	5.94	6.26	6.08	6.05	6.28	6.15	6.20	6.39	6.51	6.46	6.28	5.69	6.19

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

Peak Sunlight Hours (kWh/m²/day)

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

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

Peak Sunlight Hours (kWh/m²/day)

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

Pago Pago, American Samoa
Latitude: 14°16' South | Longitude: 170°42' West

Peak Sunlight Hours (kWh/m²/day)

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

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

Peak Sunlight Hours (kWh/m²/day)

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

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

Peak Sunlight Hours (kWh/m²/day)

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

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

Peak Sunlight Hours (kWh/m²/day)

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

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

Peak Sunlight Hours (kWh/m²/day)

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

Suva, Fiji

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

Peak Sunlight Hours (kWh/m²/day)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
0° Tilt[1]	6.29	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 Radiation Incident On An Equator-Pointed Tilted Surface (kWh/m²/day)*

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

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