SEIAPI
Sustainable Energy



OFF GRID PV POWER SYSTEMS SYSTEM DESIGN GUIDELINES

Includes Solar only PV Systems and Hybrid Systems Comprising PV and Engine Driven Generator Sets.





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These guidelines have been developed for Pacific Off-grid power sector
These guidelines represent latest industry BEST PRACTICE for the design of Off grid PV Power Systems.
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Cover Photos: Its Time Foundation

Contents Page

1. Overview 1
PART 1 - COMMON FOR dc AND ac COUPLED SYSTEM CONFIGURATIONS 3
2. Introduction 4
3. Standards Relevant to the Design of Off-Grid PV Power Systems 5
4. Typical Off-Grid PV Power System Configuration (Solar Only). 7
5. Steps When Designing an Off-Grid PV Power System 9
6. Site Visit 10
7. Energy Source Matching 12
8. Energy Efficiency 12
9. Power and Energy Assessment 12
10. Selecting Battery System Voltage 16
11. Selecting Lead Acid and Lithium-Ion Battey Systems 17
11.1. Lead Acid Battery System 17
11.2. Lithium-Ion Battery System 18
12. Determining the Required Capacity of the Battery system 18
13. Selecting a Battery Inverter 26
13.1. Battery Inverter Sizing 27
14. Solar Irradiation 27
14.1. Irradiation for Design Month 29
14.2. Effect of Orientation and Tilt 31
14.3. Shading of the Array 33
15. Factors That Affect a Solar Module's Output Power 34
15.1. Derating Due to Temperature 34
15.2. Derating Due to Dirt and Other Foreign Materials on the Module Surface 36
15.3. Manufacturers Output Tolerance 37
15.4. Solar Module Ageing Factor 37
15.5. Derating Solar Modules 38
16. Selecting a Solar Module 38
17. Selecting an Array Structure 39
17.1. Modules Mounted on Roofs 39
17.2. Ground Mounted Array 40
17.3. Array Frame Manufacturers 41
17.4. Structural Approvals 41
17.5. Glare 41
18. Relationship between Solar Controller and Solar Modules 42
PART 2- DETERMINING THE SOLAR SYSTEM FOR dc COUPLED CONFIGURATIONS 43
19. Sizing a Solar Array - General 44
19.1. Sub-System Losses in an Off-Grid PV Power System. 44
19.2. Determining the Energy Requirement of the PV Array 45
19.3. What About the Loads that Operate During the Day? 45
19.4. Oversize Factors 46
20. Sizing a PV Array— non-MPPT Solar Controller 46
21. Sizing a PV Array - MPPT Solar Controller 50
22. Selecting a Solar controller: non-MPPT Controller 53
23. Selecting a Solar Controller - MPPT Type Controller 54
23.1. Matching the PV array to the Voltage Specifications of the MPPT 55
PART 3- DETERMINING THE SOLAR SYSTEM FOR ac COUPLED SYSTEM CONFIGURATIONS 57
24. Sizing a Solar Array-General 58
24.1. Sub-System Losses in an Off-Grid PV System. 58

24.2. Determining the Energy Required from the PV Array 58
24.3. What about the loads that operate during the day? 58
24.4. Oversize Factors 60
25. Sizing a PV Array - ac Coupled System 60
26. Selecting a PV Inverter – ac Coupled System 62
26.1. How Many PV Inverters? 63
26.2. Selecting the Size of PV Inverter 63
26.3. Matching Array Power to the PV Inverter 64
26.4. Matching Array Voltage to Inverter 65
26.4.1. Minimum Number of Modules in a String 66
26.4.2. Maximum Number of Modules in a String 69
26.5. Matching Array Current to the Inverter 71
PART 4 - HYBRID POWER SYSTEMS 73
27. Hybrid System Configurations 74
28. Types of Inverters 76
29. Site Visit - Hybrid Systems 80
30. Energy Source Matching 81
31. Energy Efficiency 81
32. Power and Energy Assessment 82
33. Determining the Capacity and Selecting the Battery system Inverters 84
33.1. Inverter 85
33.2. Inverter Charger 85
33.3. dc coupled interactive inverter 85
33.4. ac coupled interactive inverter 85
34. Determining the Capacity and Selecting a Battery system Chargers 86
35. Selecting the Generator and Determining its Capacity 86
35.1. Selecting the Generator 86
35.2. Determining the Capacity of the Generator 87
35.2.1. Generator as a Back Up 87
35.2.2. Generator Used Daily 88
35.3. Derating of Generators 90
36. Generator as Back-up Only 91
36.1. Determining the Battery system Capacity and Selecting the Battery system 91
36.2. Sizing the Solar Array and associated Solar Controllers and PV Inverters 92
36.2.1. dc Coupled System: Non-MPPT Solar Controller 92
36.2.2. d.c Bus: MPPT Controller 93
36.2.3. AC coupled system 94
36.3. Calculating the Generator's Operating Hours 94
36.3.1. Generator required due to excess loads or extended cloudy weather 94
36.3.2. Generator required due to PV array sized for yearly average irradiation 96
37. Generator Used Daily 97
37.1. Determining the Proportion of Daily Energy being Provided by the Different Sources 97
37.2. Determining the Energy to be Supplied by the Battery system 98
37.3. Determining the Battery system Capacity and Selecting the Battery system 100
37.4. Determining the Energy Supplied by Generator Charging Battery system 101
37.5. Determining the Daily Load Energy to Be Provided by the PV Array 102
38. Summary of Hybrid System Losses 103
38.1. System Efficiencies in a DC Coupled Systems Supplying AC Loads 103
38.2. System Efficiencies in an AC Coupled systems Supplying AC Loads 105
Note: If battery system charging current from ac coupled interactive battery system inverter is specified then losses similar to that of Case 3 in Table 10 would be applied. 106

38.3. Combined AC and DC Coupled System Configurations 106
PART 5 - Designing the System Wiring, Isolation and Protection Requirements 108
PART 6- Preparing Diagrams, Bill of Materials and Quotation 109
39. Draw-Schematic/Single Line diagram 110
40. Prepare Bill of Materials 113
41. Providing a Quotation 113
42. Appendix 1: Summary of systems failures vs days of autonomy and array oversizing 114
43. Appendix 2: Solar Irradiation Data 120
44. Appendix 3: Effect on Irradiation Due to Orientation and Tilt Angle 124

List of Figures

Figure 1: System Powering dc loads only (this is also a simple dc coupled system) 8
Figure 2: dc coupled system 8
Figure 3: ac coupled system 9
Figure 4: Guideline to Selecting Battery System Voltage 17
Figure 5 Example 1 – lithium-ion battery datasheet with max discharge and surge (peak) currents 23
Figure 6 Example 2 - Lithium-ion battery datasheet with max discharge and surge (peak) currents 24
Figure 7: Temperature Correction Factor 25
Figure 8: Example of Inverters 27
Figure 9: Global Horizontal Irradiation 28
Figure 10: Roof Zones for Panel Array 40
Figure 11: Wind Pressures on Ground Mounted Solar Panel Arrays as Shown in AS1170.2 41
Figure 12: Example of MPPT Solar controller 55
Figure 13 Energy pathway in AC coupled system with PV array supplying the loads directly 59
Figure 14 Energy pathway in ac coupled with PV array supplying the loads by charging the battery bank 59
Figure 15: Generator connected to both the battery system (via a battery charger) and the AC load (via a changeover switch) 74
Figure 16: Generator connected to an inverter/charger or an interactive DC inverter connecting to a DC coupled system. 74
Figure 17: Generator connected to an ac coupled inverter connecting to an ac coupled system 75
Figure 18: ac coupled system with multiple inverters connected to a cluster controller with the generator connected to it. 75
Figure 19: Basic battery system inverter application 76
Figure 20: Inverter/Charger application 77
Figure 21: PV Inverter application 77
Figure 22: dc coupled inverter application 78
Figure 23: ac coupled inverter application 78
Figure 24: Simple Change over contactor 79
Figure 25: Instantaneous Power for a Data Logged Site 83
Figure 26: Cumulative Energy for the Data Logged Site 84
Figure 27: System Losses in a DC coupled configured hybrid system-excluding cable losses 104
Figure 28: System Losses in an ac coupled configured hybrid system-excluding cable losses 105
Figure 29: System Losses in a combined ac and dc coupled configured hybrid system 107
Figure 30 Sample Site Plan 110
Figure 31 Example of electrical schematic of an off-grid PV system as per AS/NZS standards 112

List of Tables

Table 1: Relevant Standards 6
Table 2: dc Power and Energy Assessment 15
Table 3: ac Power and Energy Assessment 15
Table 4: Examples of typical number of days of autonomy for various applications 20
Table 5: Example of varying battery system capacities based on discharge rates to specified cut-off voltages 22
Table 6: Ratio of PV energy output (proportional to available irradiation) to daily energy consumption requirement 31
Table 7: Sites for Orientation and Tilt Tables in Appendix 3 32
Table 8: Values of T_r 34
Table 9: Minimum Maximum Point Voltage (V_{mp}) of Array 55
Table 10: Generator derating factors 90
Table 11: System efficiency losses for DC coupled system supplying AC loads 104
Table 12: System efficiency losses for ac coupled system supplying ac loads 106
Table 13: Electrical Schematic Symbols 110
Table 14: Bill of materials and costings for a typical Solar Home System 113
Table 15: Average number of days system failures with 1 day of autonomy vs array oversizing 115
Table 16: Average number of system failures with 2 days of autonomy vs array oversizing 116
Table 17: Average number of days system failures with 3 days of autonomy vs array oversizing 117
Table 18: Average number of days system failures with 4 days of autonomy vs array oversizing 118
Table 19: Average number of days system failures with 5 days of autonomy vs array oversizing 119

List of Abbreviations

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

A	Amps (or Amperes)
AC	Alternating Current
Ah	Amp hour
AS	Australian Standards
C_x	Capacity of battery system at specified charging rate x in hours
CCC	Current-Carrying Capacity
DC	Direct Current
DOD	Depth of Discharge
ESMAP	Energy Sector Management Assistance Program
IEC	International Electrotechnical Commission
IP	International Protection sometimes known as Ingress protection
ISO	International Organization for Standardization
K	Degrees Kelvin
kW	Kilowatts
LED	Light-emitting Diode
LV	Low Voltage
MPP	Maximum Power Point
MPPT	Maximum Power Point Tracker
NZS	New Zealand Standards
NOCT	Normal Operating Conditions of Temperature
OC	Open Circuit
PSH	Peak Sun Hours
PV	Photovoltaic
SC	Short Circuit
STC	Standard Test Conditions

UV	Ultraviolet
V	Volt
VA	Voltage amperes
VRLA	Valve-regulated lead-acid battery system
W	Watts
Wh	Watt-Hours
W_p	Watts Peak (also known as Peak-Watt)

1. Overview

This Guideline provides a minimum set of design requirements for engineers and electricians/technicians who are designing off-grid solar PV Power system for the Pacific region. There is an accompanying guideline titled Off Grid PV Power Systems System Installation Guidelines. The installation guideline is meant for the installers of the off-grid PV system; however the designer also needs to include in their design the relevant technical requirements listed in the installation guideline.

This Guideline includes systems where all the energy is supplied either from solar photovoltaic (PV) modules only or when an engine driven generator set (as per description in AS/NZS3000 but in this document just called generator) is used either as a back-up or used daily. Part 1 is common for all off-grid systems, parts 2 and 3 mainly refers to solar only PV systems while part 4 refers to hybrid systems with generators.

An off-grid solar PV system includes following system configurations:

- dc coupled systems that consist of solar array(s) connected to the batteries by solar controller(s) and loads are dc only
- dc coupled systems that consist of solar array(s) connected to the batteries by solar controller(s) and battery system inverter(s);
- ac coupled systems comprising solar array(s) connected to the ac side of grid forming battery system inverter(s) (ac coupled inverter) by PV inverter(s) (grid interactive inverter);
- PV systems comprising both ac and dc coupled configuration and
- PV systems with a generator (hybrid system)

These systems can be connected to a single structure or multiple structures via a mini-grid. This guideline does not include design or installation guidelines of the poles, wires and protection requirements of a mini grid.

The guideline can be used to design systems that deliver only dc to the load; systems that deliver ac to the load and configured as a dc coupled system(charge controller, battery system and battery system inverter); systems that deliver ac to the load and configured as a ac coupled system (PV inverter connected directly to solar modules, a battery system and an inverter that operates off the battery system while providing battery system charging from the PV inverter) and PV systems that include a generator (Hybrid systems)

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

Part 1 has information common to both dc and ac coupled installations for systems. This includes:

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

Part 2 is dedicated to the specific requirements of dc coupled configurations (with no generator). It focuses on the design parameters of an off-grid PV system delivering ac to a load while using a dc coupled configuration. This part includes consideration of sub-system losses including:

a) battery system inverter efficiency

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

Part 3 is dedicated to the specific requirements of ac coupled configurations (with no generator). It focuses on the design parameters of an off-grid PV system delivering ac to a load while using an ac coupled configuration. This part includes consideration of sub-system losses including:

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

Part 4 is dedicated to the specific requirements of hybrid systems using generators. A generator in a hybrid system may be used as a:

a) Back-up for periods of bad weather or when there are low levels of irradiation for a few days; or
b) Key component of the system that is operated daily to meet some of the daily energy requirements.

Part 4 has one section for sizing the components of a hybrid system where the generator is being used as a backup to provide power when there is insufficient energy available from the PV installation and battery system and another section for sizing the components where the generator is being used on a daily basis to always provide power for some of the daily energy consumption.

The layout is to allow the designer to follow the parts relevant for the system they are designing. That is:

- dc Coupled Solar Systems: follow parts 1 and 2
- ac Coupled Solar Systems: follow parts 1 and 3
- dc Coupled Hybrid Systems: follow parts 1, 2 and 4
- ac Coupled Hybrid Systems: follow parts 1, 3 and 4

PART 1 - COMMON FOR dc AND ac COUPLED SYSTEM CONFIGURATIONS

2. Introduction

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

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

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

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

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

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

[2] The solar controller could be a Maximum Power Point Tracking (MPPT) controller or a fixed input voltage controller such as a Non-MPPT controller.

        - maximum input voltage;
        - voltage operating window;
        - maximum allowable dc input power rating; and
        - maximum dc input current rating.
    - Matching the ac coupled interactive inverter to the PV inverter; and
    - Matching the ac coupled interactive inverter to the battery system charging requirements
- For hybrid power systems:
    - Determine the capacity rating in kilovolt-amp (kVA) for the generator.
    - Determine the battery system capacity, in amp hour (Ah) or kilowatt-hour (kWh) based on the energy that must be supplied by the battery system along with maximum depth of discharge, days of autonomy, demand and surge currents and charging current required.
    - Determine the minimum required true power, or volt-amp (VA) rating, of the battery system inverter using a load assessment form (similar to that in the Off-grid PV Power System Design Guideline) or the hourly load profile.
    - Determine whether the rating of the battery system inverter changes when it is an inverter/charger or interactive inverter charger using the generator and/or PV array powering a PV inverter.
    - Determine the rating of the battery system charger if supplied as a separate component and not included in the battery system inverter.
    - Determine the size of the array based on the load energy that the array needs to provide using the selected irradiation value.
    - Determine the hours of operation for the generator if the PV array does not provide all the daily load energy during the months having the lowest irradiation values.

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

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

This guideline refers to relevant Australia and New Zealand Standards (AS/NZS) and International Electrochemical Commission (IEC) standards (https://www.iec.ch/).

The component standards specify the testing and performance requirements of components used in PV systems. In the main, readers will not need to read any of these component standards that apply to testing, however, where applicable, relevant Australia and New Zealand related to the installation PV systems and the various components are referenced in this guideline.

System designs should comply with Australian/New Zealand Standards (AS/NZS) and International Electrotechnical Commission (IEC) standards mentioned below.

The standards are often updated and amended so the latest version should always be applied.
The relevant standards are listed in Table 1.

Table 1: Relevant Standards

Equipment Standards			
Modules			
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.	
Recommended additional standards for Solar Modules installed in PNG			
IEC 61701	Photovoltaic (PV) modules - Salt mist corrosion testing		
IEC 62804	(Photovoltaic (PV) modules - Test methods for the detection of potential-induced degradation (PID) - Part 1-1: Crystalline silicon – Delamination		
Inverters			
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.	
Solar Controllers			
IEC 62109	Safety of power converter for use in photovoltaic power systems.		
	IEC 62109-1	Part 1: General requirements	
IEC 62509	Battery charge controllers for photovoltaic systems - Performance and functioning		
Battery Systems			
AS/NZS 4029	Stationary batteries.		
	AS/NZS 4029.1	Part 1: Vented type	
	AS/NZS 4029.2	Part 2: Valve regulated type.	
AS 60896.11	Stationary lead-acid batteries, Part 11: Vented types - General requirements and methods of tests		
AS 60896.21	Stationary lead-acid batteries, Part 21: Valve regulated types - Methods of test		
AS 60896.22	22 Stationary lead-acid batteries, Part 22: Valve regulated types - Requirements		
Note: the above 3 are direct adoptions from the IEC 60896 Stationary lead-acid batteries (series)			
AS/NZS IEC 60622	Secondary cells and batteries containing alkaline and other non-acid electrolytes - Sealed nickel-cadmium prismatic rechargeable single cells		
IEC 62619	Safety requirements for secondary lithium cells and batteries, for use in industrial applications.		
IEC 62932	Flow battery energy storage systems for stationary applications		
	IEC 62932-1	Part 1 Terminology and general aspects.	
	IEC 62932-2	Part 2 Performance general requirements and test methods	
	IEC 62932-3	Part 3 Safety requirements	
PV Cables			
IEC 62930	Electric cables for photovoltaic systems with a voltage rating of 1.5 kV dc.		
Switch disconnectors			

AS 60947.3	Low-voltage switchgear and controlgear switches, disconnectors, switch disconnectors and fuse combination units	
Plugs and Sockets		
AS/NZS 62852	Connectors for d.c. application in photovoltaic systems - Safety requirements and tests.	
Plug and play solar home systems		
IEC TS 62257-9	Recommendations for renewable energy and hybrid systems for rural electrification -	
	IEC TS 62257-9-5	Part 9-5: Integrated systems - Laboratory evaluation of stand-alone renewable energy products for rural electrification
	IEC TS 62257-9-8	Part 9-8: Integrated systems - Requirements for stand-alone renewable energy products with power ratings less than or equal to 350 W
Installation Standards		
AS/NZS 3000	Wiring Rules.	
AS/NZS 3008	Electrical Installations - Selection of Cables.	
AS/NZS 5033	Installation and safety requirements for PV Arrays.	
AS/NZS 4509	Stand-alone power systems	
AS/NZS 5139	Electrical installations - Safety of battery systems for use with power conversion equipment.	
AS 1768	Lightning Protection.	
AS/NZS 1170	Structural Design Actions	
	AS/NZS 1170 .1	Structural design actions; Part 1: Permanent, imposed and other
	AS/NZS 1170 .2	Structural design actions; Part 2: Wind actions
	AS/NZS 1170 .4	Structural design actions; Part 4: Earthquake actions in Australia

Note: For the plug & play solar home systems, products that meet this standard are tested and approved by Verasol (https://verasol.org) (formerly known as Lighting Global Quality Standards. They shall have a Verasol Standardized Specifications Sheet and Verification letter.

Relevant Australian Guideline:

- Best Practice Guideline: Battery Storage equipment - Electrical safety requirements

4. Typical Off-Grid PV Power System Configuration (Solar Only).

Off-grid PV power systems can range from a single module, single battery system providing energy to dc loads in a small residence to a large system comprising an array with hundreds of kW of PV modules with a large battery system and an inverter (or inverters) providing ac power to the load. Note that those larger systems may integrate a generator using fossil fuel or biofuel generator.

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

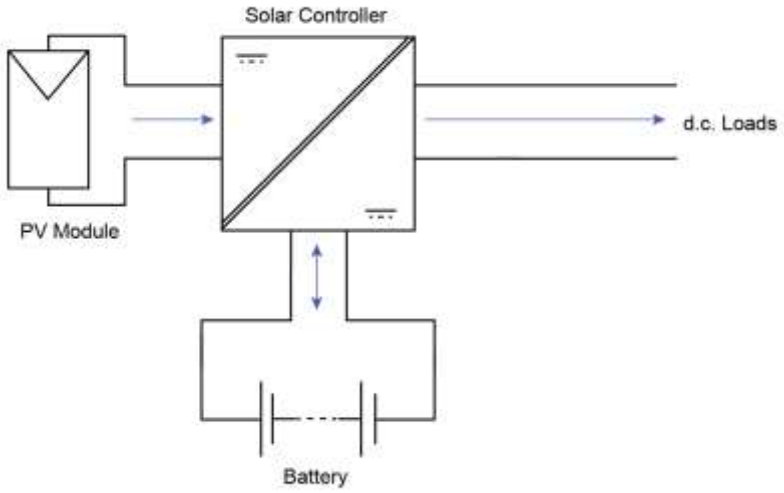


Figure 1: System Powering dc loads only (this is also a simple dc coupled system)

Notes: 1. Arrows in the drawings show power/energy flow. Wherever applicable, dc power flow is shown in blue and while in figures 2 and 3 ac power flow is shown in red.
2. The drawings use the term battery but in accordance with AS/NZS5139 they are now referred to as battery system to allow for the different types of battery chemistries.
3. The drawings and this document use the term battery inverters and ac coupled inverters for those inverters connected to the battery system and supply the ac power. AS/NZS 3000 call these inverters, Stand-alone inverters however in this guideline the terms battery inverter and at times AC coupled inverter to distinguish these from the PV inverter connected to the PV array in an ac coupled system.

Systems that include one or more inverters providing ac power to ac loads (along with possibly dc loads) can be provided as either:

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

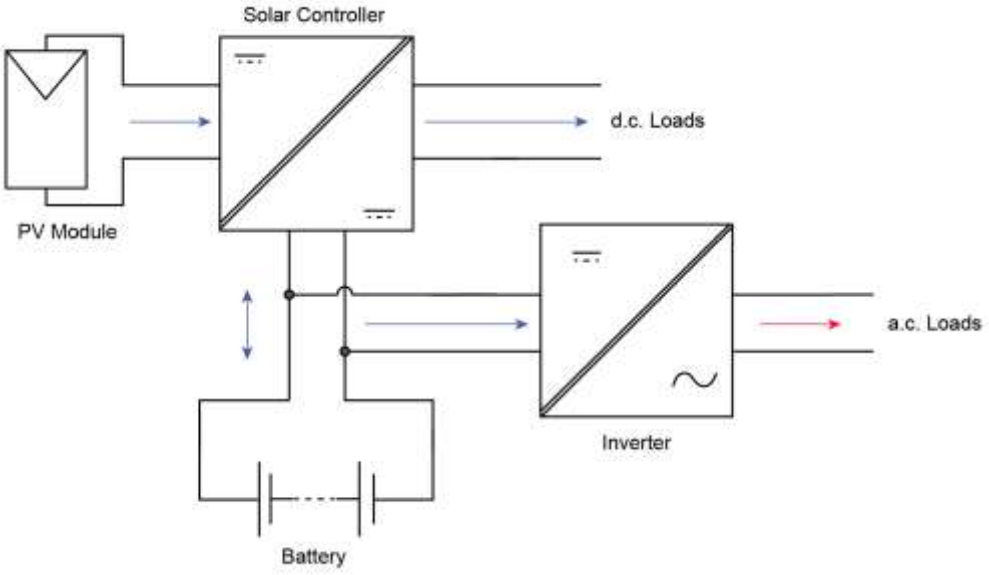


Figure 2: dc coupled system

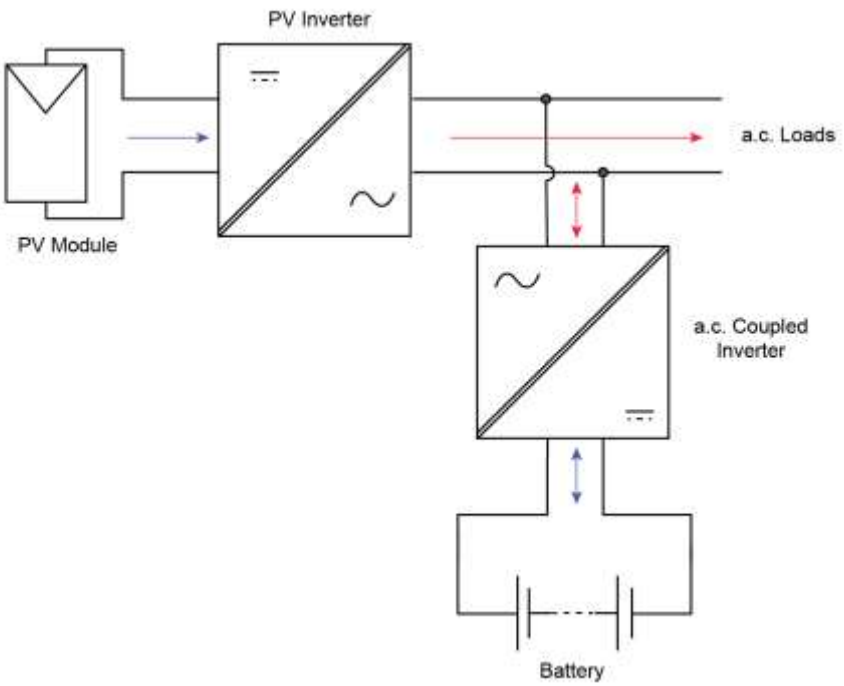


Figure 3: ac coupled system

Many ac coupled inverters are capable of being paralleled with similar inverters up to a specified number. Some manufacturers allow 3 inverters to be connected in parallel to create three phase and are sometimes collectively called a cluster. These clusters are then allowed to be in parallel up to a specified maximum number. (Refer Figure 18 in Part 4). Each cluster is connected to their own battery system. Hence when this configuration is allowed, extra clusters and hence inverters and batteries can be added in the future, thereby allowing an increase in the inverter and battery system capacity. This can be undertaken because the systems are paralleled on the ac side not the dc side of the system.

Note: Though they are paralleled systems, this can only be undertaken if the manufacturer has allowed this facility. It is only inverters from the same manufacturer where this can be facilitated. The inverter must communicate with each other because one of the inverters (and hence clusters) must take control of forming the ac grid and ensuring the inverters are in the appropriate phase and synchronised with each other.

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

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

Configurations of systems with generators are shown in Part 4.

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

Issues to be addressed when designing an off-grid PV power system include:

1. The power and hence energy required to be supplied by the system is not constant over the period of one day.

2. The daily energy consumption varies greatly over a week (office buildings typically have much lower loads on holidays and weekends than during the work week).
3. The daily energy consumption for tourism facilities may have very different loads at different times of the year, office building climate control energy requirements may vary substantially according to the time of year.
4. The power available from the PV array will vary greatly during the day according to the time of day and cloudy periods.
5. The total daily energy available from the PV array will vary during the year as weather conditions vary over the year and as the sun changes its position in the sky over the year.

The designer should compare the available daily energy from the sun with the actual daily energy consumption over a typical year. The worst month, often then the design month, will be when the ratio between solar energy available (irradiation) and average daily energy consumption is smallest. Often the average daily solar energy (irradiation) available during that worst month is chosen as the design basis for the PV system. However, since the cost of solar modules has reduced significantly some designers will oversize the array, possibly using the lowest daily irradiation figure in the worst month, to reduce the capacity of the battery system. (Refer to section 12 and 14.1)

The steps in designing a system include:

1. Carrying out a site visit and determining the limitations for installing a system and examining the location where the equipment will be installed (see section 6)
2. Determining the energy needs of the end-user (see section 9)
3. Determining the voltage and capacity of the battery system and selecting the appropriate battery system (see sections 10, 11 and 12)
4. Determining the size of battery inverter (Note AS/NZS 3000 call these inverters, Stand-alone Inverters) connected to systems supplying AC power (Section 13). (Note: Systems with parallel inverters shall follow manufacturer's instructions and preferably been trained by the manufacturer)
5. Determining the size of the array (sections 14, 15, 16, 17, 18, 19, 20, 21).
6. Determining the size of the solar controller (Section 22 for Non-MPPT solar controllers and section 23 for MPPT based controllers).
7. Determine cable size and calculate voltage drop (Refer Installation Guideline section 11 and section 19).
8. Determine system protection and disconnection requirements (Refer Installation Guideline Sections 20 to 21).
9. Draw a schematic / single line diagram (Section 39).
10. Prepare bill of quantity (Section 40).
11. Providing a quotation to the end-user. (Section 41).

6. Site Visit

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

1. Discuss the energy needs of the end-user. (Section 7 for more detail).
2. Complete a power and energy assessment form (See Section 9 for more detail).
3. Assess the occupational safety and health risks when working on that particular site.
4. Determine the solar access for the site or determine a position where the solar has the most available sunlight.
5. Determine whether any shading will occur and estimate its effect on the system.
6. Determine the orientation and tilt angle of the roof if the solar array is to be roof mounted. (Refer to Off-Grid PV Power Systems Installation Guideline 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 battery system(s) will be located.
11. Determine where the solar controller(s) and/or PV Inverter (s)will be located.
12. Determine where the battery inverter (s) will be located (if applicable).
13. Determine the cabling route and therefore estimate the lengths of the cable runs and cable sizes.
14. Determine whether monitoring panels or screens are required and determine a suitable location with the end-user.

If a site visit is unable to be undertaken, then the information will need to be obtained via an off-site conversation with the end-user. This could occur either via the end-user visiting the designer or a phone call and will also require the end-user to provide photos/videos of the site. This process could require numerous phone calls with the overall objective that the designer obtains all the information as listed above.

In the first communication with the end-user the designer should:

1. Provide the end-user with an energy assessment form for them to complete or go through the form in person or on the phone the same as you would undertake in a site visit.
2. Discuss with the end-user what the system comprises and that locations will need to be found for installing the equipment. As a minimum, the discussion shall include:
    a. Where the solar PV array would be located and if on the roof what is the roof constructed of. What is the size /orientation of the roof? Ask the end user to take photos/video of the roof and if possible, under the roof to see the positioning of battens and other roof support material.
    b. What is the solar access like? Are there trees, hills etc that would be causing shading of the array? Ask the client to do a 360-degree video from the site of the view. The designer might also be able to use internet tools for doing this evaluation
    c. Where the battery systems, inverters, controllers etc will be located and whether the end-user has suggestions for the locations. Ask the end user to take photos/video of the site and do they have possible locations

After the photos/videos have been provided then follow up comminutions will be required to finalise obtaining the information required for designing a system. The installer will need to be flexible and might need to do variations when on site. This should be explained to the end-user and state that it might cause a variation in the installation cost.

Following the site visit the designer shall estimate the available solar irradiation for the array based on the available solar irradiation for the site and the tilt, orientation and effect of any shading. (See section 14.1, 14.2 and 14.3).

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

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

7. Energy Source Matching

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

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

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

8. Energy Efficiency

The size of the PV systems is based on the power and energy demand of the lights and appliances, that is the loads. Reducing the amount of power required and hence the amount of energy required will reduce the size of PV system required. Therefore, it is important to review all the appliances and determine whether any of them can be cost effectively replaced with more efficient models.

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

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

9. Power and Energy Assessment

Electrical power is supplied from the batteries (dc) or via an inverter to produce either 230/240 volts ac (South Pacific) or 110/120 volts ac (North Pacific). ac electrical energy consumption is normally expressed in watt hours (Wh) or kilowatt hours (kWh).

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

Appliances can either be dc or ac. An energy assessment should be undertaken for each type. Examples of these are shown in tables 2 and 3.

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

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

A system designer can only design a system to meet the power and energy needs as stated by the end-user. The system designer must therefore use this process to clearly understand the needs of the end-

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

Tables 2 and 3 are used throughout the guideline as a worked example for dc coupled systems. Larger ac energy demand will be used as the worked example for ac coupled systems. For the dc coupled system design, if the loads are dc, then table 2 will be used. If the loads are ac, then table 2 will be used.

Table 2 shows dc lighting loads and table 3 shows ac appliance loads. In reality there could be other dc loads and lighting that could be ac.

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

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

In the worked example of a power and energy assessment (Tables 2 and 3), the TV, fan and refrigerator are using ac electricity, so have to take into account the efficiency of the inverters used when calculating energy usage. 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 consumption used by the load plus the losses in the inverter to obtain the total energy required to be supplied to the inverter from the battery bank.

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

Tables 2 and 3 show the daily energy usage for each appliance. The daily energy usage of each appliance is added together to provide the daily energy consumption for the dc loads and daily energy consumption for the ac loads.

For the ac table a term called power factor is introduced. This is from the formula:

True power (W) = Apparent power (VA) x Power factor (sometime expressed as Cos φ where φ is the angle between true power and apparent power or between voltage and current))

The power factor is used in table 3 to determine the apparent power. Battery inverters sold on the market have a power factor rating of 2. That is the true power in W is the same as the apparent power in VA. The maximum demand, that is maximum apparent power is calculated in the table to help select the inverter. The inverter must have a continuous power rating in VA equal to but probably greater that the maximum demand determined in table 3.

The maximum demand column contains all the appliances that will operate at the exact same time. In table 3 all appliances are shown to operate however that is expected when there are only 3 appliances. If a house contains many appliances, the designer in consultation with the end-user must determine what are the loads that might all operate at same time and hence determine the maximum demand.

Some appliances, such as motors, require a higher current to start and hence have a surge power rating as well as a continuous power rating. The inverter must be able to provide sufficient surge power (typically for 1 to 3 seconds) to start a motors or other appliances that might have higher currents at the start.

For every appliance that operates at the same time, the surge power should be added into column titled “potential surge”. This are added together to determine the maximum surge demand which must be supplied by the inverter. However, when there are many appliances, they will not all be on at the same time and they definitely will not start at the same time. The designer must determine the actual surge demand that will be used when selecting an inverter—that is the design surge.

When there are many appliances, the designer must try many combinations when determining the maximum and surge demands.

Worked Example 1: Completing Power and Energy Assessment Form

Table 2: dc Power and Energy Assessment

Appliance	**Qty**	**Power**	**Dry season**		**Wet season**		**Contribution to maximum demand**	
			Usage Time	**Energy**	**Usage Time**	**Energy**		
		W	H	Wh	h	Wh	W	
Light	4	7	4	112	5	140	28	
Daily dc Loads energy consumption (Wh)				112		140		
Peak dc demand (W)							28	

Table 3: ac Power and Energy Assessment

Appliance	**Qty**	**Power**	**Dry season**		**Wet season**		**Power Factor**	**Contribution to max demand**	**Surge Factor**	**Contribution to surge demand**		
			Usage Time	**Energy**	**Usage Time**	**Energy**				**Potential**	Design	
		W	**H**	**Wh**	**h**	**Wh**		**VA**		**VA**	VA	
TV	1	25	4	100	4	100	0.8	31	1	31	31	
Fan	1	60	0	0	6	360	0.9	67	1	67	67	
Refrigerator	1	100	14	1400	14	1400	0.8	125	4	500	500	Duty cycle of 0.58 included (24*0.58 = 14 hr)
Daily ac Loads Energy consumption (Wh)				1500		1860						
Peak ac demand (VA)								223		598		
Surge ac demand (VA)											598	

In worked example 1 for the power and assessment the TV, fan and refrigerator are using ac electricity, so we have to take into account the efficiency of the inverters used. Typically, the peak efficiency of an inverter may be over 95% but in many systems the inverter will sometimes be running even when there is very little load on the inverter and some energy will be used by the inverter even though it is not operating a load, so the average efficiency is typically about 90% to 96%. Then we must divide the total ac energy used by the load plus the losses in the inverter to obtain the total energy required to be supplied to the battery inverter from the battery system.

Worked Example 2: Calculating Daily Energy as seen (provided) by the Battery system
(Based on the power and energy tables 2 and 3)
This example shows how to determine the energy at the battery system for both the humid season and the rest of the year.
Assume the overall efficiency of the chosen inverter is 90%.

Wet Season
Daily battery system load (energy) from DC loads = 140 Wh
Daily battery system load (energy) from AC loads = 1860 Wh ÷ 0.9 = 2067 Wh

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

2067 + 140= 2207 Wh

Dry Season
Daily battery system load (energy use) from DC loads = 112 Wh
Daily battery system load (energy use) from AC loads = 1500 Wh ÷ 0.90 = 1667 Wh

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

1667 + 112= 1779 Wh

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

10. Selecting Battery System Voltage

System battery system voltages are generally 12 V, 24 V or 48 V. The actual voltage is determined by the requirements of the system. For example, if the battery system and the inverter are a long way from the PV array and system comprises of a non-MPPT type solar controller, then a higher voltage may be required to offset the power lost in the cables. In larger systems, 120 V or 240 V dc could be used, but these are not typical household systems and due to the potentially fatal voltages used, the standards for construction at those high voltages are much more complex and the resulting system more expensive than would be the case for systems using voltages below 60 V dc that are not so dangerous. To avoid the problems of using dc battery system voltages greater than 60 V, even large systems with more than 200 kW_p of array often have a multiple cluster design with each cluster using a 48 V battery system. There are also some lithium battery systems on the market with nominal voltages in excess of 500V.

In ac coupled systems the PV array will often be in the 200V to 1000V dc range. In off grid systems the term system dc voltage typically refers the battery system voltage not necessarily that of the PV array.

As a general rule, the recommended battery system voltage increases as the total daily energy consumption increases. For small daily energy consumption, a 12 V battery system voltage can be used. For intermediate daily energy consumptions, 24 V is used and for larger loads 48 V, 120V or higher voltages may be is used.

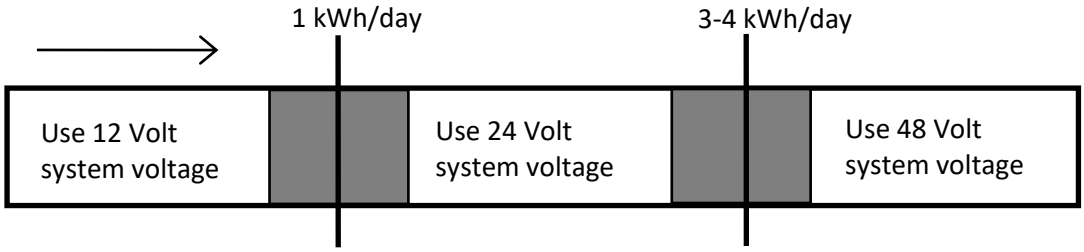


Figure 4: Guideline to Selecting Battery System Voltage

Figure 4 is just to be used as a guide only. It shows the changeover points being roughly at total energy consumption 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 100 W continuous power demand. A 12 V system could still be used even though the total energy usage is 2400 Wh/day. The current being drawn from the battery system is only 8.33 A (100 W/12 V). On the other hand, a pump drawing 800 W that only operates 3 hours a day will also use 2400 Wh but will draw almost 67 A when it runs, requiring very large cables and high Ah capacity batteries at 12 V. If operated at 48V, the current draw will be about 17 A and much smaller cables can be used without excessive losses plus the battery system Ah requirement will be ¼ that of using a 12 V battery system.

One of the general rules of thumbs is, if possible, aim to keep the maximum continuous current being drawn from the battery system less than 150 A. This is to reduce the size of the required cable and minimise any problems with voltage drop. However again this might not always be possible and higher DC battery voltages might be required.

Note: The term battery system is being used in the guideline but in some small systems it may be a single 12V monobloc battery, but AS/NZS5139 still refers to this as a battery system.

11. Selecting Lead Acid and Lithium-Ion Battey Systems

11.1. Lead Acid Battery System

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 are 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 and AS/NZS 5139 are followed.

Lead acid batteries shall comply with one of the following standards:

- AS 60896.11 Stationary lead-acid batteries, Part 11: Vented types - General requirements and methods of tests
- AS 60896.21 Stationary lead-acid batteries, Part 21: Valve regulated types - Methods of test
- AS 60896.22 Stationary lead-acid batteries, Part 22: Valve regulated types - Requirements.
- IEC 60896 Stationary lead-acid batteries (series).

11.2. Lithium-Ion Battery System

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.

The individual cells and the assembled battery system pack for lithium-ion batteries included in a system battery system designed for a stationary application 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

- A Pre-Assembled Battery System comprising lithium-ion batteries can comply with the Australian Best Practice Guide- Battery Storage equipment- Elec

If the solar home system battery system has been tested and approved in accordance with IEC62619 and the battery system's transportable mass is less than 18kg, then the individual cells and the assembled battery system pack shall also meet:

- IEC 62281 Safety of Primary and Secondary Lithium Cells and Batteries during Transport

or

- UN 38.3 United Nations Manual of Tests and Criteria: Lithium Battery system Testing Requirements.

Lithium-ion batteries shall be supplied with a manufacturer's approved Battery Management System (BMS).

The individual cells and the assembled battery system pack for lithium-ion batteries included in a system battery system for systems designed to be portable (i.e. easily hand carried) shall meet either the requirements above or:

- IEC 62133-2 Secondary cells and batteries containing alkaline or other non-acid electrolytes - Safety requirements for portable sealed secondary lithium cells, and for batteries made from them, for use in portable applications - Part 2: Lithium systems.

12. Determining the Required Capacity of the Battery system

If the energy assessment is undertaken based on two different weather seasons (or even monthly), the highest daily energy consumption is used to determine the required battery system capacity.

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

Lithium-ion batteries are typically supplied based on their Wh capacity and manufacturers provide a term known as useable energy to specify the maximum amount of energy that can be discharged from the battery system.

Lead acid batteries are typically supplied based on their ampere-hour (Ah) capacity and the maximum energy that can be discharged from the battery systems is specified by the manufacturer as maximum depth of discharge.

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

Worked Example 3: Calculating the Battery system Energy Usage in Ah (lead acid batteries)

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

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

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

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

However, for long-life, lead-acid batteries should not regularly be discharged more than 50% or 60% (depth of discharge) with 20% to 30% daily depth of discharge being a common average discharge level for rural off-grid solar installations. So, the actual Ah of the battery system installed will be at least double and possibly three to five times the calculated one-day Ah requirement.

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

1. The ability of the battery system to provide the daily energy consumption without any charging, typically for one to five days, sometimes specified as “days of autonomy” of the battery system;

or

2. The ability of the battery system to supply peak power demand in delivered Volt amperes (VA) (Amperes delivered times Volts at the battery system terminals).

(Refer to peak demand values in Tables 2 and 3)

How to determine the daily energy usage of the system was shown in example 3.

Worked Example 4: Calculating maximum current that will be discharged from battery system
The peak dc demand in table 2 is 28 W.

The peak ac demand in table 3 is 223 VA. This is the demand out of the inverter so at the battery system terminals the maximum demand would be 223/0.9 = 247.8 VA.

The maximum current that will be discharged from the batteries= (247.8 + 28)/24 = 11.5 A

The critical design parameters include:

Parameters relating to the energy requirements of the battery system:

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

Parameters relating to the discharge power (current) of the battery system:
a) Peak power demand.
b) Surge power demand.

Parameters relating to the charging of the battery system:
a) Maximum charging current

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

1. Days of Autonomy

Extra capacity is necessary where the loads require power during periods of reduced solar irradiation input. The battery system is often sized to provide for a number of days of autonomy (days of operation without solar charging). In earlier guidelines and within the 2010 version of AS/NZS4509.2 a common period selected was between two to five days, but it depends on how critical the loads are. For example, a site could provide critical services and therefore more than 5 days of autonomy might be required to ensure continuous operation. For example, an important telecommunications station may require a solar installation with sufficient battery system capacity for 14 days of autonomy.

Table 4 show the examples of typical number of days of autonomy for various applications as specified in AS/NZS 4509.2 (2010).

Table 4: Examples of typical number of days of autonomy for various applications

System	Days of autonomy (d)	Considerations
System with automatic generating set control	2	Reliability of auto start
System with manual generating set control	2 to 3	User
PV system with no generator	4 to 5	Probability of number of consecutive days of low solar irradiation

Long battery system life is important for remote sites because battery system exchanges are easily the most expensive on-going cost in operating a remote off-grid electricity system. Often transport and labour for the new battery system and the transport and cost of recycling the old battery system will together be more than the cost of purchasing the new battery system itself. There is also the inconvenience of not having power or reduced availability of power.

The previous version of this guideline specified 3 days of autonomy, however with the price of photovoltaic solar modules dropping greatly in recent years, it is now far more economical to purchase additional PV generation capacity than battery storage capacity. Based on recent studies and data on oversizing PV arrays, reducing the designed days of autonomy from 3 days to 2 days (reducing by a day from previous guidelines and AS/NZS4509.2 (2010)), could easily be compensated by oversizing the PV array by at least 30% to maintain system performance reliability for the system equivalent to or better than 3 days of autonomy. Hence, using 2 days of autonomy with at least 30% oversized PV arrays could be adopted. For the exercises in this guideline, 2 days has been used.

When oversizing the array, it is important that the available charging current from the array is not greater than the maximum charging current of the selected battery.

The days of autonomy could also be selected based on thorough analysis of solar irradiation levels at a site and the expected no-sun days along with correlation with load usage pattern (involving interval load data analysis) analysis to establish the suitable days of autonomy and relevant array oversizing that does not adversely affect the battery life and ensures reliability and longevity of the system but also makes it cost-effective.

Appendix 1 provides the results of a study undertaken on oversizing an array from 10% to 100% (in 10% intervals oversizing) compared to 1, 2, 3, 4 and 5 days of autonomy. The study was undertaken for different cities in Australia using over 20 years of daily irradiation data. The data shown in Appendix 1 is based on Cairns, the Australian city included in the study that would have the closest weather pattern similar to parts of the Pacific region.

In conclusion the number of days selected should be undertaken in consultation with the end-user and based on the overall reliability of the system.

For the exercises in this guideline, 2 days has been used as a compromise.

Worked Example 5: Calculating battery system capacity based on days of autonomy.

Assume a daily load of 92 Ah (24 V battery system voltage) with 2 days autonomy.

Adjusted battery system capacity = 92 Ah x 2 = 184 Ah for lead acid batteries.

and

Adjusted Battery system Capacity = 2 x 2207 Wh= 4414 Wh for lithium-ion batteries

2**. Maximum Depth of Discharge (Useable Energy)**

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

Some new battery chemistries such as lithium ion rate their batteries in terms of “usable energy”, in which case it is important to understand what depth of discharge the manufacturer is using to calculate the value for usable energy. This is generally between 80-95% of the rated capacity.

Notes: **1**. If the usable energy of a lithium-ion battery is specified at say 95%, it is recommended that the battery does not go more than 90% as a safety margin. This is because some Lithium-ion batteries if they reach their lowest value might “lock-up” and then become unusable. Always follow battery manufacturer’s recommended values on depth of discharge.

2. Battery manufacturers will typically state the minimum voltage that a battery system can operate. If the battery system voltage is lower than the specified minimum voltage value, the battery might be damaged.

Worked Example 6: Calculating battery system capacity based on maximum depth of discharge.

Assume a maximum DOD of 70% for a lead acid battery and the usable capacity with a lithium-ion battery is applied.

Adjusted Battery system capacity = 184 ÷ 0.7 = 263 Ah for the lead acid battery system
and
Adjusted Battery system capacity = 4414 ÷ 0.7 = 6306 Wh for the lithium-ion battery system
Note: Lithium-ion battery manufacturers will typically state the actual usable energy value.

3. 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. For lead acid type batteries, this is indicated by the capital letter C (for capacity) and small numbers that follow representing the hours of charge available at that discharge rate. The Ah capacity of solar batteries, particularly small 12 V solar batteries, are typically given for a discharge rate of C_{100} – that means the time it takes to fully discharge the rated Ah capacity of the battery system at the given Amperes of delivery is 100 hours.

For deep-cycle mono-block batteries, often used in small Solar Home Systems, the Ah capacity is often provided at the C_{20} discharge rating.

Many appliances operate for short periods only, drawing power for minutes rather than hours. This affects the battery system selected, as battery system capacity varies with discharge rate. Information such as a power usage profile over the course of an average day is required for an estimate of the appropriate discharge rate to use in the design. For many systems, and particularly small systems, this is often impractical to obtain.

Table 5: Example of varying battery system capacities based on discharge rates to specified cut-off voltages

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

Source: GNB Sonnenschein Batteries

Where the average rates of power usage are low, such as for most residential loads, the battery system capacity for 5 days of autonomy is often selected at the 100 hr (C_{100}) rate of discharge for the battery system while for 1 ½ or 2 days of autonomy is often selected at the 10 hr (C_{10}) or 20 hr (C_{20}) rate of discharge for the battery system.

Where average power usage rates are high, as is often the case for commercial/industrial applications, it may be necessary to select the battery system capacity for 2 to 5 days autonomy at a higher discharge rate than C_{100} e.g. a 10 hr (C_{10}) rate.

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

The capacity of lithium-ion batteries does not vary greatly with discharge rate, so it is less critical to ensure the selected C-rating is realistic, compared with lead acid technologies. Lithium-ion batteries specify charge/discharge currents using #C ratings. The '#' in this notation indicates the fraction of an hour during which the battery is discharged. The hours for this notation are determined as 1/X.

Examples include:
1C is the 1-hour rating (1/1)
2C is the ½ hour rating (1/2)
0.5C is the 2-hour rating (1/0.5)
0.05C is the 20-hour rating (1/20)
0.01C is the 100-hour rating (1/0.01)

Lithium-ion batteries experience a lower rate of capacity loss under high discharge currents than lead acid batteries; therefore, lithium-ion technologies usually provide less data regarding the capacity discharge characteristics for these batteries. Most lithium-ion battery manufacturers specify max output power/current and peak output power/current.

Number of Modules	2	3	4	5
Usable Energy [1]	5.12 kWh	7.68 kWh	10.24 kWh	12.8 kWh
Max Output Current [2]	25 A	25 A	25 A	25 A
Peak Output Current [2]	50 A, 5 s	50 A, 5 s	50 A, 5 s	50 A, 5 s
Nominal Voltage	204 V	307 V	409 V	512 V
Operating Voltage	160~240 V	240~360 V	320~480 V	400~600 V
Dimensions (H/W/D)	712x585x298 mm	945x585x298 mm	1178x585x298 mm	1411x585x298 mm
Weight	91 kg	129 kg	167 kg	205 kg

Figure 5 – lithium-ion battery datasheet with max discharge and surge (peak) currents example 1

Basic Parameters		
Nominal Voltage (Vdc)		48
Nominal Capacity(Wh)		4800
Depth of discharge (%)		95
Usable Capacity(Wh)		4560
Dimension(mm)		442*420*161
Weight (Kg)		38
Discharge Voltage (V)		44.5 ~ 53.5
Charge Voltage (V)		52.5 ~ 53.5
Charge/Discharge Current (A)	Recommend	50
Charge/Discharge Current(A)	Max.	100
Charge/Discharge Current (A) 1	Peak 1	101~120@15min
Charge/Discharge Current (A) 2	Peak 2	121~200@15sec
Communication		RS485, CAN

Figure 6 - Lithium-ion battery datasheet with max discharge and surge (peak) currents example 2

Worked Example 7: Checking battery system capacity against maximum load current.
In a 24 V system the discharge current for the battery system with all the loads on is only approximately 11.5 A. C_{20} capacity to provide this current is 230 Ah.

Battery system Capacity of 263 Ah (@ C_{20}) for the lead acid battery system would have a discharge current of 13.15A which is suitable. Using Table 5, the selected battery would be SB6 330.

Lithium battery system is still 6306 Wh useable energy.

Worked Example 8
The following specifications are given for a lithium-ion battery:

- Nominal Capacity: 2400Wh at 1C
- Nominal Voltage
- Maximum discharge/charge current rate 1C
- Recommended discharge/ charge current 0.5C

To calculate the recommended / discharge current, first we need to calculate the amount of time the battery is being discharged over:
1/0.5 = 2 hours
From this we can calculate the nominal current:
(2400Wh/24V)/2h = 100Ah/2h = 50 A
The 0.5C rate is therefore 50 A,
The maximum charge current (1C) = 100Ah/1 = 100 A

4. Battery system temperature derating

The capacity of lead-acid batteries is affected by temperature. As the temperature goes down, the battery system capacity also goes down. Figure 7 shows a typical battery system correction factor for low temperature operation. Note that the temperature correction factor is 1 at 25°C as this is the reference temperature at which battery system capacity is specified, while the European standards now use 20°C as the test temperature. So, if using this graph for those batteries tested at 20°C and no other graph is available, change the bottom scale to reflect 20°C as the temperature with a factor of 1 and adjust other temperatures accordingly.

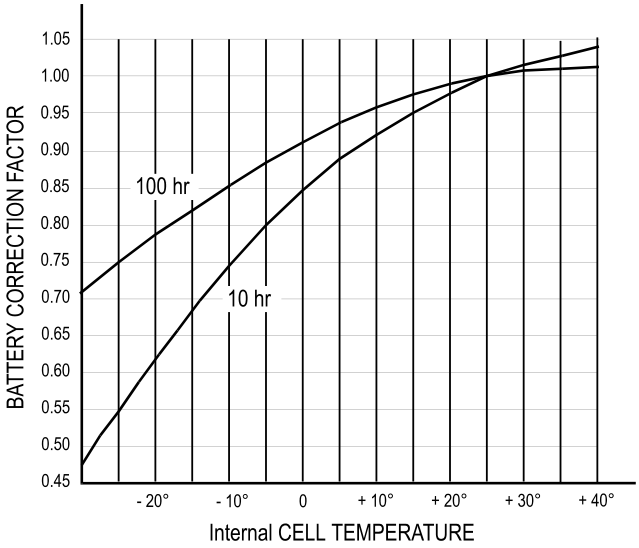


Figure 7: Temperature Correction Factor

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

For lithium-ion batteries please check with the manufacturer.

Worked Example 9: Adjusting battery system capacity due to temperature affect.

Allow 5% to the capacity to allow for effect of temperature.

Adjusted battery system capacity = 263 x 1.05 = 276 Ah for the lead-acid battery system
and
Adjusted battery system capacity = 6306 x 1.05 = 6621 Wh for the lithium-ion battery system

Worked Example 10: Selecting the battery system using manufacturers data.
For lead acid batteries, a battery system of at least 276 Ah (@ C_{20}) should be used.

Using Table 5 the SB6/330 A battery system has a C_{20} rating of 280 Ah and hence this would be the selected battery system. It is 6 V so 4 of these in series will be required for a 24 V battery system.

Lithium ion
Using the lithium-ion datasheet below, 3 parallel strings i.e 3 x 3.10kWh = 9.3kWh would be required, which is greater than 6621Wh or 6.62kWh. Else, a single battery with minimum rating of 6.62kWh could be used (24V battery).

DC Voltages - Nominal	25.6 VDC
Amp-Hours	151 Ah
Maximum Rated kWh Capacity	3.87 kWh DC @ 100% DOD 3.10 kWh DC @ 80% DOD
MAX Discharge Rate (10 minutes)	80 Amps DC (2.05 kW DC)
MAX Continuous Discharge Rate	75 Amps DC **(1.9 kW DC)**
MAX Continuous Charge Rate	75 Amps DC (1.9 kW DC)
DC Voltage Range[1]	24 VDC to 28 VDC

13. Selecting a Battery Inverter

When selecting a battery system inverter to power an ac appliance that is to be connected to an off-grid PV system that is also delivering dc power to the user, the inverter must have an input dc voltage rating that is the same as the voltage of the dc power provided by the system and shall comply with 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.

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

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

Sine wave inverters are increasingly affordable and often provide even better-quality power than some urban grid supply. Most inverters available are sine wave inverters.

13.1. Battery Inverter Sizing

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

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

Worked example 11: Specifying minimum inverter rating

From the power and energy assessment in table 3, the selected inverter must be capable of supplying 223 VA continuously with a surge capability of 598 VA for a short period of time, typically only a few seconds.

A suitable minimum model meeting the system battery voltage, continuous power (the peak demand in the power and energy assessment) and peak power (surge power in the power and energy assessment could be selected from an inverter range. Sample system specifications are provided in Figure 8. The 24/375 inverter highlighted would meet these requirements.

Inverter **12 Volt** **24 Volt** **48 Volt**	**12/250** **24/250** **48/250**	**12/375** **24/375** **48/375**	**12/500** **24/500** **48/500**	**12/800** **24/800** **48/800**	**12/1200** **24/1200** **48/1200**
Cont. power at 25 C°	250VA	375VA	500VA	800VA	1200VA
Cont. power at 25 C / 40˚C	200/175W	300/260W	400/350W	650/560W	1000/850W
Peak power	400W	700W	900W	1500W	2200W
Output AC voltage/frequency (adjustable)	230VAC or 120VAC +/-3% 50Hz or 60Hz +/-0,1%				

Figure 8: Example of Inverters

14. Solar Irradiation

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

The maps and data for most countries including the Pacific island countries have been released in parallel with Global Solar Atlas, which is published by the World Bank Group, funded by ESMAP, and prepared by Solargis. This is available from: https://solargis.com/resources/free-maps-and-gis-data? An example of Papua New Guinea is shown below.

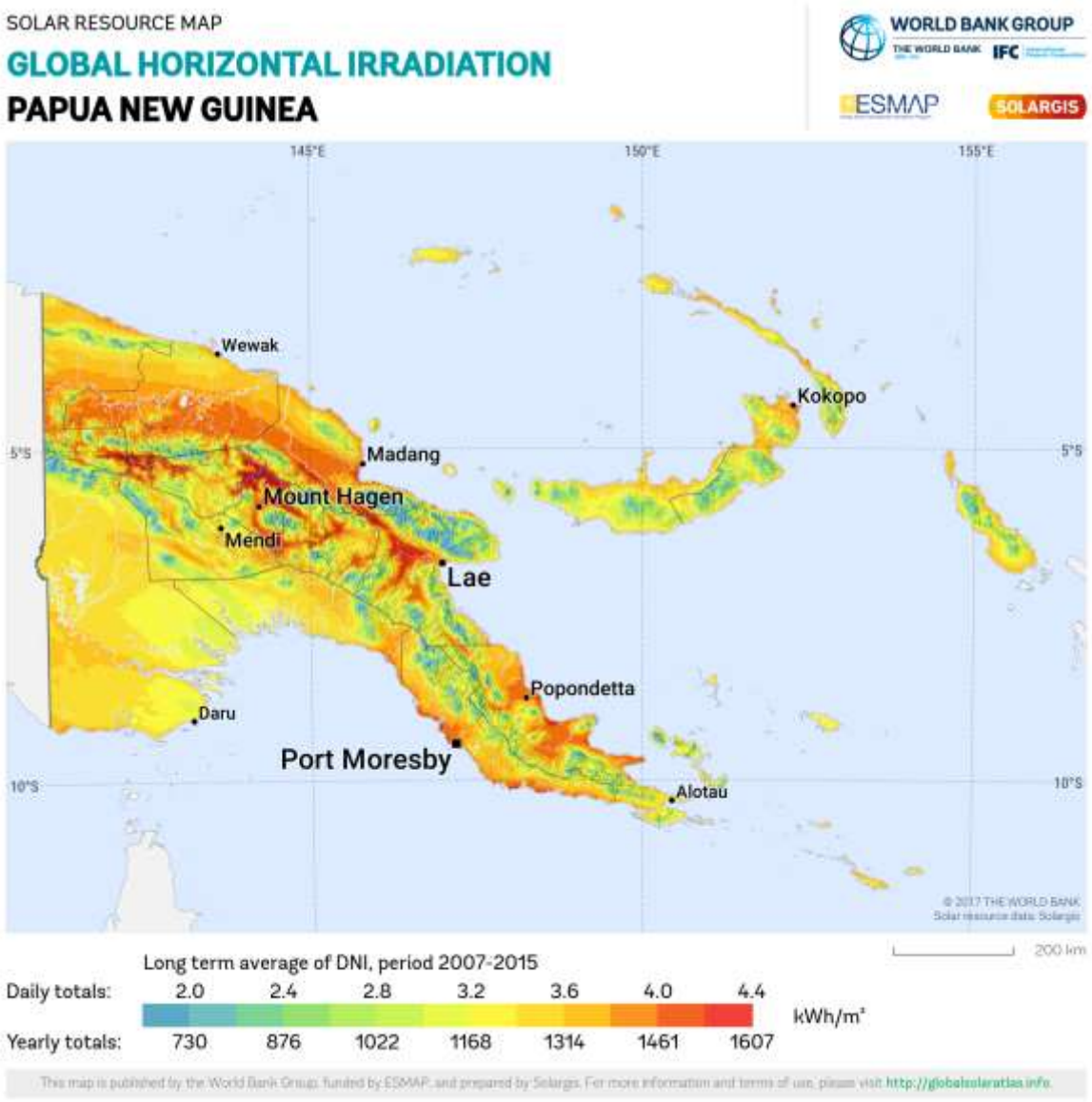


Figure 9: Global Horizontal Irradiation

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

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

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

Another source for solar irradiation data that is available at no cost is the following site established through funding from the European Commission:
http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php?lang=en&map=africa

With this site, latitude and longitudes can be entered, and irradiation data can be obtained for horizontal, optimum tilt, and also for a specified array tilt angle.

Solar irradiation is typically provided as kWh/m^2; however, it can also be stated as daily Peak Sun Hours (PSH). PSH is the equivalent number of hours to equal the kWh/m^2 listed if the solar irradiance always equals 1 kW/m^2. E.g. 4.5 kWh/m^2 is 4.5 PSH

Appendix 2 provides PSH data on the following sites:

- Alofi, Niue (Latitude 19°04'S, Longitude 169°55'W)
- Apia, Samoa (Latitude 13°50'S, Longitude 171°46'W)
- Hagåtña, Guam (Latitude 13°28'N, Longitude 144°45'E)
- Honiara, Solomon Islands (Latitude 09°27'S, Longitude 159°57'E)
- Koror, Palau (Latitude 7°20'N, Longitude 134°28'E)
- Lae, Papua New Guinea (Latitude 6°44'S, Longitude 147°00'E)
- Majuro, Marshall Islands (Latitude 7°12'N, Longitude 171°06'E)
- Nauru (Latitude 0°32'S, Longitude 166°56'E)
- Nouméa, New Caledonia (Latitude 22°16'S, Longitude 166°27'E)
- Nuku'alofa, Tonga (Latitude 21°08'S, Longitude 175°12'W)
- Pago Pago, American Samoa (Latitude 14°16'S, Longitude: 170°42'W)
- Palikir, Pohnpei FSM (Latitude 6°54'N, Longitude 158°13'E)
- Port Moresby, Papua New Guinea (Latitude 9°29'S, Longitude 147°9'E)
- Port Vila, Vanuatu (Latitude 17°44'S, Longitude 168°19'E)
- Rarotonga, Cook Islands (Latitude 21°12'S, Longitude 159°47'W)
- Suva, Fiji (Latitude 18°08'S, Longitude 178°25'E)
- Tarawa, Kiribati (Latitude 1°28'N, Longitude 173°2'E)
- Vaiaku, Tuvalu (Latitude 8°31'S, Longitude 179°13'E)

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

If 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 14.2) for determining peak sun hours for sites not facing the ideal direction.

14.1. Irradiation for Design Month

Two PV array output energy considerations arise when designing an off-grid PV power system are:

1. the energy available from the PV array will vary greatly during the day according to the time of day and cloud passages;
2. the energy available from the PV array will vary during the year as weather conditions vary over the year and as the sun changes its position in the sky over the year.

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

If the daily energy usage varies throughout the year, then a comparison should be undertaken between the average daily irradiation and the average daily energy consumption for each month of the year or at least two seasons.

The design month is the month where the ratio of available irradiation (PSH) to daily energy consumption for that month is the smallest. The irradiation of the design month is then used when determining the size of the required PV array for solar only systems. (Note: As mentioned in section 12, a designer might decide to use the expected lowest irradiation in the design month with the aim of oversizing the PV array and reducing the size of the battery system)

If the energy usage stays relatively constant throughout the year, then the design month will the month with the lowest irradiation.

Worked Example 12: Determining the design month and selecting average daily irradiation for that month
From the power and energy assessment in tables 1 and 2:

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

The humid season energy consumption (at the battery bank) = 2207Wh= 2.21 kWh

Assume:

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

Using the irradiation data in Appendix 2, the ratio of PV energy output (which is proportional to available irradiation) to load energy is shown in Table 6:

Table 6: Ratio of PV energy output (proportional to available irradiation) to daily energy consumption requirement

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Irradiation (kWh/m^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
Daily Energy used (kWh)	2.21	2.21	2.21	1.78	1.78	1.78	1.78	1.78	1.78	2.21	2.21	2.21
Irradiation/ Daily energy	2.85	2.66	2.51	2.80	2.59	2.46	2.53	2.74	2.93	2.64	2.76	2.90

The lowest ratio is 2.46, so June will be the design month and the available irradiation in June is $4.38kWh/m^2$ or 4.38 Peak Sun hours.

14.2. Effect of Orientation and Tilt

If the array is to be mounted on a roof and the roof is not oriented true north (Southern Hemisphere) or south (Northern Hemisphere) and/or not at the optimum inclination, the daily output from the array will generally be less than the maximum possible.

Appendix 3 provides tables that reflect the variation in irradiation due to different tilts and azimuths from those measured and recorded from the optimums as shown for the locations shown in Table 7. 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 7: Sites for Orientation and Tilt Tables in Appendix 3

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

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

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

Worked Example 13
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.

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR SUVA - FIJI
Latitude: 18 degrees 08 minutes South
Longitude: 178 degrees 25 minutes East

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	97%	100%	100%	98%	95%	90%	83%	76%	67%	54%
10	97%	100%	100%	98%	95%	90%	83%	75%	67%	54%
20	97%	99%	100%	98%	94%	89%	82%	74%	66%	53%
30	97%	99%	99%	97%	93%	88%	81%	73%	64%	51%
40	97%	99%	98%	96%	92%	86%	79%	71%	62%	49%
50	97%	98%	98%	95%	91%	84%	77%	68%	59%	47%
60	97%	98%	97%	94%	89%	82%	74%	65%	56%	44%
70	97%	97%	96%	92%	87%	80%	71%	62%	52%	41%
80	97%	97%	95%	90%	84%	77%	68%	59%	48%	38%
90	97%	96%	93%	89%	82%	74%	65%	55%	44%	35%
100	97%	96%	92%	87%	80%	72%	62%	51%	41%	32%
110	97%	95%	91%	85%	78%	69%	59%	48%	37%	28%
120	97%	95%	90%	84%	76%	66%	56%	45%	33%	26%

Therefore, the available irradiation for the site is 0.93 x 4.38kWh/m^2 = 4.07kWh/m^2 or 4.07 PSH

14.3. Shading of the Array

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

However, if it is only shading part of the array the exact effect is hard to predict because it is not necessarily the equivalent of a decrease in available irradiation because it is only affecting the output power of those few modules not the whole string.

For larger off grid PV systems, the solar resource and weather conditions of the site should be measured, especially any shading of the potential installation area. A solar siting tool (e.g. Solar Pathfinder or SunEye) could be used for these measurements.

a. **The Solar Pathfinder**: This kit uses Sun path diagrams to determine the shading experienced for a proposed site. A Sun path diagram for a specified latitude band shows the position of the Sun throughout the day for each month of the year. A plastic dome is placed above the Sun path diagram to reflect a panoramic view of the site, showing sources of shading. The intersections between the reflected sources of shading and the Sun path diagram identify the site shading throughout the year, allowing the system's site-specific performance to be calculated.
b. **Solmetric SunEye**: This measuring device (or similar) acts as a digital version of the Solar Pathfinder. It takes a digital picture of the horizon and analyses the effect of the surrounding objects for the specified latitude. Accessories, such as GPS units, can be purchased to further improve the accuracy of the analysis. The digital camera uses a fish-eye lens and can provide digital images of the horizon and the amount of shading

throughout the year. The SunEye also has an inclinometer and compass function to measure roof pitch and orientation, respectively.

Other software design tools for analyzing shading include:

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

15. 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 with an irradiance of 1000 W/m^2 and in Uganda in particular, cell temperatures when exposed to the sun are a lot always greater than the standard 25°C. Also, average irradiance is generally much less than 1000 W/m^2. So actual solar array outputs are always less than the standard rated values so modules must be "derated" when estimating their actual outputs.

15.1. Derating Due to Temperature

A solar module's output power decreases with a solar cell temperature above 25°C and increases with temperatures below 25°C. Refer to Clause 2.2.2 of AS/NZS 5033 on considerations due to operating temperature for more information 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 8.

Table 8: 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 different from 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

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

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

A) Monocrystalline Modules

Monocrystalline Modules typically have a temperature coefficient between -0.3%/°C and -0.45%/°C. Assuming it is -0.45%/°C, for every degree above 25°C, the rated output power must be derated by 0.45%.

B) Polycrystalline Modules

Polycrystalline Modules typically have a temperature coefficient of -0.35%/°C to -0.5%/°C

C) Thin Film Modules

Thin film modules have a quite different temperature characteristic, resulting in a lower coefficient, typically around 0%/°C to -0.3%/°C.

D) Passivated Emitter and Rear Cell (PERC)

PERC solar modules are an improvement of the traditional monocrystalline cell. PERC Modules typically have a temperature coefficient between – 0.34%/°C and – 0.36%/°C.

Note: The above values have been reducing over the years so always check with the module manufacturer for the exact value for the module being used in the system design. The data is available on the product brochure and must be available if the product has been tested and approved in accordance with the IEC standards

Note: On a solar module data sheet three temperature coefficients will be provided. The different temperature coefficients provided are for maximum (or peak) power (W_p), open circuit voltage (V_{oc}) and short circuit current (I_{sc}). Some brochures might also include a temperature coefficient for maximum power voltage.

The symbol used for temperature co-efficient is γ and it is expressed on data sheets as a negative number (e.g. γ = -0.35%/°C).

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

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

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

Written as a formula it is:

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

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

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

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

Worked Example 14: Calculating the temperature derating factor of a solar module
The solar array is mounted parallel to a 20-degree pitched roof with an air gap of 100mm.

The solar module has a power temperature coefficient of -0.35%/°C.
The average daytime ambient temperature in the design month of June is 30°C.
What is the percentage (%) power loss due to temperature for this solar?
What is the temperature derating factor?
From table 8, the rise in temperature (T_r) is 35°C.

The effective cell temperature is therefore:
$T_{cell\text{-}eff} = T_{a.day} + T_r$
$= 30°C + 35°C$
$= 65°C$

As a fraction -0.35%/°C. is represented as -0.0035/°C.

The temperature derating factor (f_{temp}) is calculated as follows:
$f_{temp} = 1- (\gamma \times (T_{STC} - T_{cell\text{-}eff}))$
$= 1- (-0.35\%/°C \times (25°C - 65°C))$
$= 1- (-0.0035 \times -40)$
$= 1 - (0.140)$
$= 0.86$
This means that the array actually provides only 86% of its rated output power due to its operation at 60°C instead of STC (25°C).

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

The output of a PV module can be reduced as a result of a build-up of dirt on the surface of the module. The actual value of this loss will be dependent on the conditions at the actual location of the modules, but in some city locations this could be high due to the amount of car pollution and dust in the air. It can also be high in coastal regions during long periods of no rain when salt may build up on the module surface.

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

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

This loss is generally expressed as a dirt derating factor (f_{dirt}).

f_{dirt} = 1- the loss due to dirt

Worked Example 15: Calculating the dirt derating factor
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

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

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

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

Worked Example 16: Calculating the manufactures' derating factor
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

15.4. Solar Module Ageing Factor

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

Worked Example 17: Calculating the module ageing derating factor.
If the loss due to *Ageing is* 10% what is the derating factor for ageing?

As a fraction 10% converts to 10/100 = 0.1
f_{ageing} = 1 - the ageing loss
= 1 - 0.1 = 0.90

Note: In sections 19.4 and 24.4 an oversizing factor of 30% is recommended for off-grid PV systems using lead acid battery systems. This 30% would cater for the ageing of the module. In addition, many system designers are oversizing the PV array to help reduce the capacity of the battery system. For these reasons in later examples the ageing is not taken into account. It has been left here for information purposes.

15.5. Derating Solar Modules

Solar modules have a rated output measured at Standard Test conditions (STC). (STC are irradiation of 1000W/m^2, Temperature 25°C and Air Mass of 1.5). Based on the factors affecting the power output of the module (P_{mod}), the derated power output ($P_{derated}$) of the module is determined as follows:

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

Worked Example 18: Calculating derated module output power (ageing not included

If the temperature derating factor is 0.86, the dirt derating factor is 0.95 and derating factor for manufacturers tolerance is 0.97, what is the overall derating factor for the modules?

0.86 x 0.95 x 0.97 = 0.79 which means that the actual output from the module is expected to be 0.79 times the rated output. Thus a 400 W_p module can be expected to provide at least:

400 W_p x 0.79= 316 W_p.

Note that the output will also be reduced by some percentage if the module is not properly oriented as to azimuth and tilt.

16. Selecting a Solar Module

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

- One of the following design qualification and type approval standards:
    - IEC 61215 Terrestrial photovoltaic (PV) modules - Design qualification and type approval
        - IEC 61215-1 Part 1: Test Requirements
        - One of IEC 61215 Part 1.1, Part 1.2 Part 1.3, part 1.4 which all relate to specific types of modules e.g. crystalline, thin film amorphous etc (See Section 2)
        - 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

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

It is recommended that the modules have the following enhancements:

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

The modules could be selected from those on the Australian Clean Energy Council's approved product list which only lists modules that comply with IEC6215 and IEC61730. The list does state which modules comply with IEC61701 and IEC62804. The list is available from: :
https://www.cleanenergycouncil.org.au/industry/products/modules/approved-modules

The solar module should have the following warranties:

- 10-year limited product warranty
- Limited Power Warranty with 25 years at 80% of the minimal output power

17. 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.

The mounting of the system including brackets and clamps must be robust to be able to withstand movement either from wind. The mounting system structure shall comply with the requirements set in AS1170.2 Structural design actions – Part 2: Wind actions.

For those countries where seismic activity needs to be considered, the array design shall incorporate guidance and recommendations with any in country relevant earthquake loading guidelines.

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

17.1. Modules Mounted on Roofs

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

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

Figure 9 below shows an excerpt from Section B.6.1 in AS1170.2 with wind pressure zones shown upwind end, central, downwind end, upwind central and downwind central. Table B.12 in AS1170.2 provides the wind pressure coefficients to each zone that relate to the array arrangement.

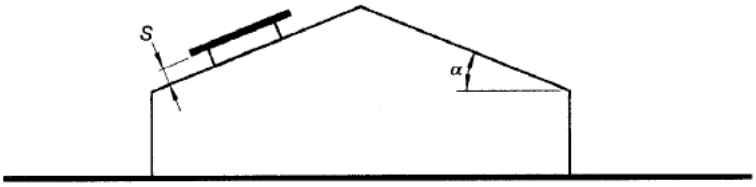


Figure B.9 — Panel mounted parallel to roof plane

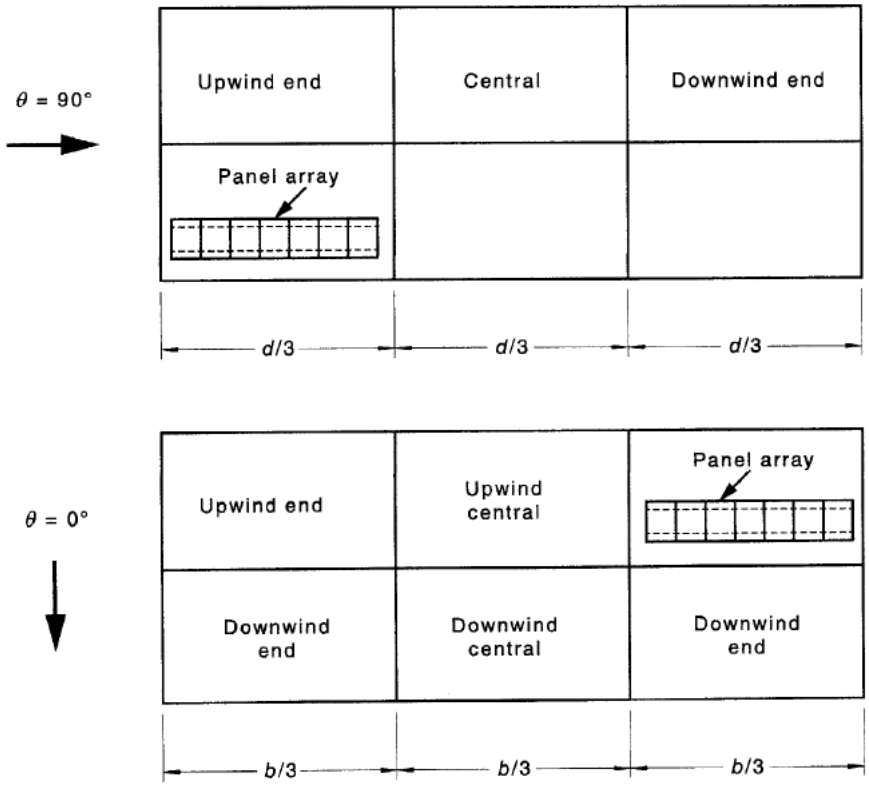


Figure 10: Roof Zones for Panel Array

17.2. Ground Mounted Array

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

a) Modules attached to a ground mounted frame with aspect ratios $2 \leq d/h \leq 5$ and $b/d \geq 2$.
b) Modules attached to the frame at an inclination to ground, $\alpha \leq 30°$.
c) Panel arrays with a spacing of $3.5 \leq s/h \leq 10$.
d) Modules with a minimum gap between the underside of the panel and the ground surface $c/h \geq 0.2$.

Figure 10 below shows an excerpt from Section B.6.2 in AS1170.2 with wind pressure zones shown by A1 to A3, B1 to B3, C1 to C3 and D1 to D3. Tables B.13 and B.14 in AS1170.2 provide the wind pressure coefficients to each zone that relate to the array arrangement.

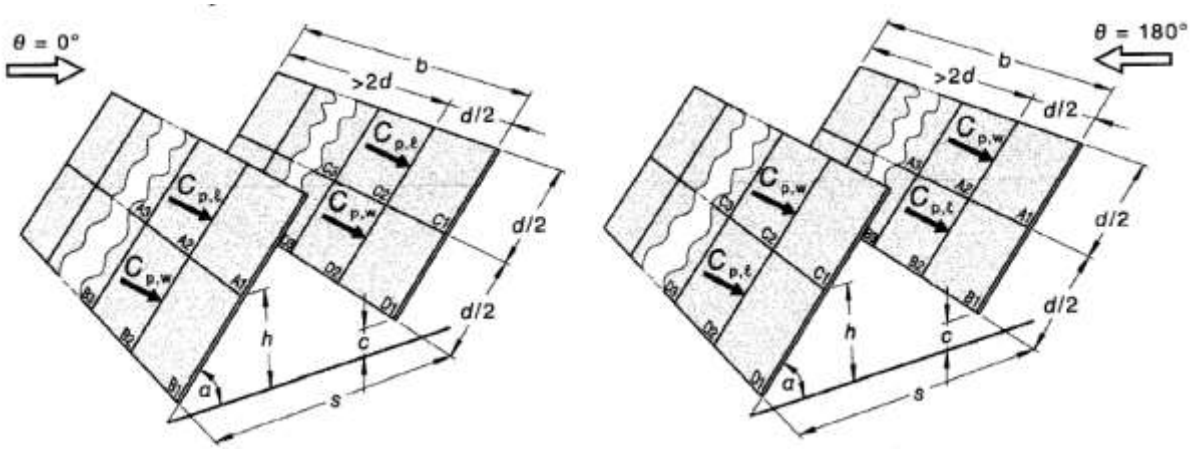


Figure 11: Wind Pressures on Ground Mounted Solar Panel Arrays as Shown in AS1170.2

- The array structures shall be designed to withstand the aggressively salty atmosphere that would occur in the coastal regions of the Pacific region
- Installation of footings, posts, screws and/or in-ground fasteners shall follow manufacturer's instructions and installation manuals. If using posts or screws then a geotechnical study shall be undertaken to determine the suitability of the ground.

17.3. Array Frame Manufacturers

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

17.4. Structural Approvals

Where required, the designer shall support the customer in obtaining any structural approvals that are required to allow the array structure to be installed on the building.

17.5. Glare

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

Where it is mainly an issue is when the PV array is located near an airport/airstrip and hence in the flight path of the planes. If installing in the flight path then glare calculations might need to be undertaken and the relevant Civil Aviation Safety Authority or similar authority might need to be consulted.

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

18. Relationship between Solar Controller and Solar Modules

Historically, switched solar controllers were the most common solar controllers.

The initial version applied “on-off” type switching between the solar array and the battery system using relays. These operated such that the solar array was either directly connected to the battery system and charging the battery system with the relay in the “on” (or closed) state or the solar array was disconnected from the battery system with the relay in the “off” (or open) state.

The modern switched type controllers employ Pulse Width Modulation (PWM) technology however similar technology is applied to MPPT controllers and hence for this reason this guideline defines what used to be called PWM controllers as non-MPPT solar controllers. Non-MPPT controllers use electronic switches to rapidly turn on and off the direct connection between the solar array and battery system to provide an average charging current necessary to maintain the required battery system voltage.

Traditionally solar modules were designed to charge a 12 V battery system. To effectively charge the 12 V battery system the solar module comprised 36 solar cells and manufacturers data sheets specified the module as a nominal 12 V module.

To have an efficient system the non-MPPT type controller should be connected to a PV array which has a “nominal” voltage equivalent to the nominal battery system voltage. That is, a solar system using a non-MPPT type solar controller with a 12 V battery system should be connected to a 36cell module with a “nominal” voltage of 12 V. A 24 V battery system should be connected to 72 cells while a 48 V battery system should be connected to 144 cells.

In the current market the great majority of solar modules are used for grid-connected systems and the number of cells depends more on the power desired than the voltage required of the module. The solar modules designed for the grid connect market typically contain either 60 or 72 solar cells. Half-cut cell modules, which are now widely used, often have 120 or 144 cells. Therefore, many solar modules that are readily available should not be used with non-MPPT type solar controllers because they have more than the 36 cells and the module voltage does not match the voltage of the battery system. If a 60-cell module is connected to a non-MPPT controller and a 12 V battery system, the solar module will charge the battery system however 40% (24 of the solar cells) of the module capacity would never be used resulting in an inefficient system.

The result is solar controllers known as maximum power point trackers (MPPT) have become more common. These can have an input voltage range much greater than the charging voltages of the battery system. These are dc to dc power converters where the controller is designed to track the maximum power point of the solar array. This maximum power point voltage will (and should) be greater than the voltage of the battery system connected to the output of the MPPT controller. Since the battery system must be charged at a voltage applicable to its voltage rating, the extra power available, due to the input voltage being higher than the battery system voltage, is converted into a battery system charging current greater than that which would be available if the solar array was directly connected to the battery system.

PART 2- DETERMINING THE SOLAR SYSTEM FOR dc COUPLED CONFIGURATIONS

19. Sizing a Solar Array - General

The calculations for determining the size of the PV array are dependent on the type of controller used. Historically, switched solar controllers were the most common controllers used with "on-off" type switching using relays the oldest type and semiconductor-based Pulse Width Modulation (PWM) types the modern version These are called non-MPPT solar controllers in this guideline. Semiconductor based maximum power point trackers (MPPT) are now commonly available.

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

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

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

The points a through to (f) have been covered in sections 14 and 15. This section looks at points (g) through to (k). Points (g), (h), (i) and (j), when grouped together, are commonly known as the sub-system efficiency, the sub-system being defined as the solar array and the associated loads.

19.1. Sub-System Losses in an Off-Grid PV Power System.

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

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

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

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

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

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

The average coulombic efficiency of a new lead-acid battery system (in terms of the ratio of Ah of discharging to Ah of charging) is typically 90% (variations in battery system voltage are not considered, only Ah in and out)

while the average watt-hour (Wh) efficiency (in terms of the Ah times the voltage of the battery system during discharging and charging over a specific time) of a new battery system is typically 80%. As the battery system ages, the columbic and watt-hour efficiency both decline slowly.

The average watt-hour efficiency for Lithium-ion battery systems is in the order of 95% or higher.

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

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

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

Worked Example 19: Converting % to a number used on calculations
If battery system has an efficiency of 90%, then the fraction used in determining the required PV array power output would be 0.9.

19.2. Determining the Energy Requirement of the PV Array

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

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

19.3. What About the Loads that Operate During the Day?

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

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

With the introduction of ac coupled system configurations where the PV array interconnects with a PV powered (grid connected) inverter directly onto the ac grid, the ac coupled proponents emphasised how efficient these systems were in supplying the load directly, which is true for loads during the day. Meanwhile, these systems had a greater loss when supplying the loads via the battery system due to losses in the battery system itself plus losses in the ac inverter and plus losses in the ac to dc battery system charging feature in the battery system inverter. When designing systems using an ac coupled configuration designers started to estimate how much of the daily energy was supplied directly by the PV array during the day.

To not do this for dc coupled systems could lead to an apparent cost disadvantage when designing a system and make the dc coupled system appear more expensive in a competitive quote situation. This guideline describes how to determine the array size if the daily energy consumption is divided between daytime energy

consumption being supplied directly by PV array and the nighttime energy consumption being supplied by the battery system.

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

The total number of modules required in the array equals the number of modules to supply the daytime energy consumption directly plus the number of modules needed to charge the battery system for delivery of energy to the night time energy consumption and when the daytime power exceeds the generation power from the solar modules.

For small home systems with only a few modules configured in dc coupled arrangement, and considering the fact there are days when it is cloudy it is recommended that the PV array is designed based on the assumption that all the daily energy consumption is supplied by the battery system being charge by the PV array. This is a conservative approach however it is only the columbic efficiency of typically 90% which is the difference in dc coupled systems. Therefore, the number of modules based on this conservative approach would only be a maximum of 10% higher than the number required if all the loads were supplied by the PV during the day.

19.4. Oversize Factors

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

Therefore, when designing a solar system comprising lead acid batteries the array should be oversized by at least 30% to allow for faster full charging of the battery system and to provide equalizing charging when needed. An oversize factor of 30% should also effectively cover the ageing of the solar module in the first 10 years.

An oversize factor of 10%, to effectively cover the aging of the solar module should be included with systems that include lithium-ion batteries.

20. Sizing a PV Array— non-MPPT Solar Controller

When using a non-MPPT solar controller, the calculations are all based on determining the required Ah from the array. The losses in the cable and the solar controller are only reflected as voltage drops which therefore dictates the operation point on the current-voltage characteristic curve (IV curve) of the PV array. That is, if the battery system is at 12 V, then the PV array will be operating at 12 V plus the voltage drop in the connecting cable plus any voltage drop across the controller. Since the maximum power point of a nominal 12 V module will be at 17-18 V and the maximum charge voltage of a lead acid battery system is between 14.4 V and 15 V, then the typical voltage drop of around 1 V 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 only losses that need to be taken into account are any battery inverter losses (when ac appliances are powered by an inverter connected to the system) so the battery system losses are assumed to be its 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 20: Calculating the required output current of an array based on daily energy consumption using a non-MPPT controller

Figures used in this example are from the tables 2 and 3

Assume the total daily energy consumption is supplied by the PV array charging the battery system.

Based on the design month the solar array is to be sized based on the humid season average energy usage.

The efficiency of the chosen inverter is 90%.

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

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

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

1667 + 112= 1779 Wh

The system voltage is 24 V.

The daily energy requirement expressed in Ah from the battery system is 74.13 Ah (1779 Wh/24 V).

Allowing for the battery system efficiency, the solar array then needs to produce:

74.13 Ah ÷ 0.9 = 82.4 Ah

The PSH in the design month is 4.38.

Therefore, the required PV array derated output current is:

82.4 Ah ÷ 4.38 PSH = 18.81 A

The oversize factor then needs to be applied. A minimum of 30% is recommended for the Pacific Island Countries when using lead acid batteries and 10% when using lithium-ion batteries.

Worked Example 21: Adjusting the required array output current based on oversize factor

The adjusted required PV array derated output current (when using Lead Acid battery systems) is:

18.81 A x 1.3 = 24.45 A

The PV array will be derated due to:

- Manufacturer's Tolerance
- Dirt
- Module Temperature greater than 25°C
- and potentially for ageing of the module that results in decrease in efficiency and hence power output., however the 30% oversizing takes this into account.

Traditionally solar modules have had nominal voltages of 12 V by using 36 cells per module. These were designed to charge a 12 V battery system. In the current market the great majority of solar modules are used for grid-connected systems and the number of cells depends more on the power desired than the voltage required of the module. Therefore, many PV modules that are readily available are not suitable to be used with simple non-

MPPT type solar controllers because they have many more than 36 cells and the module voltage does not match the input voltage needed by the switching controller. The designer, when using a **non-MPPT type solar 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 cell modules for 12 V batteries or 72 cell modules suitable for 24 V 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 panels matched with a simple switching controller still provides the simplest and most cost-effective solution for lighting and basic entertainment but locating a source of cost effective 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 12 V battery system charging or series connected as a 72-cell module for 24 V battery system charging.

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

- 12 V battery system- charge range 12 V to 15 V (wet cells/flooded) or 12 V to 14.4 V (Valve regulated battery system)
- 24 V battery system- charge range 24 V to 30 V (wet cells/flooded) or 24 V to 28.8 V (Valve regulated battery system)
- 48 V battery system- charge range 48 V to 60 V (wet cells/flooded) or 48 V to 57.6 V (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 12 V module: current at 14 V and at the effective cell temperature
- For 24 V module: current at 28 V and at the effective cell temperature.
- For 48 V module: current at 56 V and at the effective cell temperature

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

If the IV curves at different temperatures are not available, it is recommended that the current halfway 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 12 V, a 60-cell module has a nominal voltage of 20 V and a 72-cell module has a nominal voltage of 24 V.

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 22: Calculating the number of modules required using non-MPPT controller. (Assuming no daytime loads)
A 72-cell module with the following characteristics is selected:

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

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

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

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

Calculated module current = (9.27 + 8.73)/2 = 9 A

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 = 9 x 0.97 x 0.95 = 8.3 A per module string

From worked example 21, adjusted required array current = 24.45 A

Number of module strings in parallel = 24.45 A/8.3 A = 2.95

Theoretically, the designer should round up to 3 strings..

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

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

Worked Example 23: Calculating the number of modules required using non-MPPT controller (total daily energy consumption being supplied by PV array during day

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

From worked example 20, the daily energy requirement expressed in Ah from the battery system is 74.13 Ah (1779 Wh/24 V). (Battery Inverter losses already taken into account)

The PSH in the design month is 4.38

Therefore, the required PV array output current is:

74.13 Ah ÷ 4.38 PSH = 16.92 A

Allowing for 30% oversizing, the adjusted PV array output current required
= 1.3 x 16.92 A = 22 A

The derated array current for each module = 8.3 A

Number of module strings in parallel = 22 A ÷ 8.3 A = 2.65

Realistically, depending on how much power is supplied directly to loads by the PV array, the number of module strings required in parallel for this example varies between 2.65 and 2.95 with both cases potentially ending up with three strings in parallel when the selected modules are used.

21. 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 to and from the battery system to account for all the sub-system losses.

Worked Example 24: Calculating the size of array to provide all the daily energy consumption when using MPPT controller. (Assuming no daytime loads)

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

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

dc Subsystem efficiency = 0.97 x 0.95 x 0.8 = 0.737

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

The design month PSH is 4.38.

Therefore, the required PV array derated output power is:

2414 Wh ÷ 4.38 PSH = 551.1 W

Assuming the battery systems is lead acid and allowing for an oversize factor of 30%, the adjusted required derated array output is:
551.1 W x 1.3 = 716.4 W

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

Solar modules have a rated output measured at Standard Test conditions (STC). Based on the factors affecting the power output of the module (P_{mod}) as detailed in section 15.5, the derated power output ($P_{derated}$) of the module is determined as follows:

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

Worked Example 25: Calculating number of modules required based on load energy when using MPPT controller. (Assuming no daytime loads)

In the worked example

- Derating due to temperature f_{temp}= 0.86
- Derating due to dirt f_{dirt} = 0.95
- Derating due manufacturers tolerance f_{man} = 0.97
- Note for this example ageing factor has not been taken into account since it is effectively covered by the 30% oversizing factor that allows for battery system equalization and fast recharging in order to extend battery system life

Module rating is 440W_p

The PV module data sheet provides the following information:

- $P_{mp} = 440\ W_p$
- $V_{oc} = 41.02\ V$
- $V_{mp} = 33.72\ V$
- $I_{sc} = 13.73\ A$
- $I_{mp} = 13.05\ A$

- Power temperature coefficient = -0.35%/°C
- V_{oc} temperature coefficient = -0.28%/°C
- No V_{mp} temperature coefficient.
- Manufacturers Tolerance 0 to +3%
- Measurement Tolerance ±3%

Derated module output = 440 W x 0.86 x 0.95 x 0.97 = 348.7 W

The adjusted required derated array output from worked example 24 = 716.4 W

The required number of modules = 716.4 W ÷ 348.7 W = 2.05 which would be rounded up to 3.

In reality a smaller module could be selected so that exactly 3 modules are required based on this example and using a 440 W_p module the actual required array W_p is 2.05 times 440 W_p = 902 W_p not the 1320 W_p that 3 solar modules would provide. Three 305 W_p modules would provide 915 W_p which slightly exceeds the requirement of a 902 W_p array. (Note two 460W would achieve the same total array power)

If there are daytime loads:

For systems with MPPT controllers there will be no battery system losses for the loads being supplied directly.

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

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

Worked Example 26: Calculating number of modules required based on daily energy consumption when using MPPT controller. (Total daily energy consumption supplied by PV array during the day)

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

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

dc Subsystem efficiency factor which excludes battery system efficiency = 0.97 x 0.95 = 0.922.

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

The design month PSH is 4.38.

Therefore, the required derated PV array output power is:

1930 Wh ÷ 4.38 PSH = 441 W

Assuming the battery systems is lead acid and allowing for oversize factor of 30% therefore the adjusted required derated PV array output power is:
441 W x 1.3 = 573.3 W

Derated module output = 348.7 W. (refer worked example 25)

The required number of modules = 573.3 W÷348.7 W= 1.64 so probably round up to 2.

What is required is an array comprising 2 of 440 W_p modules, that is 880 W_p

However, an array of 1.64 x 440W_p = 722 W_p.

Based on worked examples 25 and 26 and depending on how much load energy is assumed to be supplied directly by the array and how much via the battery system, the required array is rated between 722 W_p (total daily energy consumption supplied power directly by solar array) and 902 W_p (total daily energy consumption supplied power from the battery system).

22. Selecting a Solar controller: non-MPPT Controller

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

- IEC 62509 Battery charge controllers for photovoltaic systems - Performance and functioning
- IEC 62109 Safety of power converters for use in photovoltaic power systems
    - IEC 62109-1 Part 1: General requirements

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

- Non-MPPT and equalisation charge modes
- dc Load control
- Voltage and current metering

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

In accordance with AS/NZS4509.2 unless the non-MPPT solar controller is a model that is internally current limited, these should be sized so that they are capable of carrying at least 125% of the array short circuit current and withstanding the open circuit voltage of the array. If there is likelihood that the array may need to be increased in the future, then the controller should be oversized to cater for future growth.

(Note: sometimes the controller is called a regulator)

Worked Example 27: Calculating required current rating of non-MPPT controller
If three modules in parallel are selected (Worked example 22) with I_{sc} of 9.27 A, the controller chosen must have a current rating > 1.25 x 3 x 9.27 A = 34.7 A at a system voltage of 24 V.

23. Selecting a Solar Controller - MPPT Type Controller

When selecting a solar controller to be used in an off-grid PV system the controller shall either meet one of the standards listed below or one of the markings listed below.

Standards include:
- IEC 62109 Safety of power converters for use in photovoltaic power systems.
    - IEC 62109-1 Part 1: General requirements
- IEC 62509 Battery system charge controllers for photovoltaic systems - Performance and functioning

The MPPT controller must be matched with the array in relation to:
- Maximum solar power rating in Watts;
- Input voltage; and
- Input current if nominated by the manufacturer.

Worked Example 28: Calculating required power rating of MPPT controller
The number of modules required was 2.05 so unless a different size module was chosen select a MPPT which will be suitable for 3 modules.

The module rating is 440W_p.
3 x 440W_p = 1320W, the power rating of MPPT should be equal or higher than 1320W.
Voltage compatibility should also be checked.
An example datasheet is shown in figure 12.

Nominal battery voltage	12 / 24 / 36 / 48V Auto Select	
Rated charge current	70A @ 40°C (104°F)	85A @ 40°C (104°F)
Maximum solar array input power 1)	12V: 1000W / 24V: 2000W / 36V: 3000W / 48V: 4000W	12V: 1200W / 24V: 2400W / 36V: 3600W / 48V: 4850W
Maximum PV open circuit voltage	150V absolute maximum coldest conditions 145V start-up and operating maximum	
Minimum PV voltage	Battery voltage plus 7 Volt to start	Battery voltage plus 2 Volt operating
Standby power consumption	12V: 0,55W / 24V: 0,75W / 36V: 0,90W / 48V: 1,00W	
Efficiency at full load	12V: 95% / 24V: 96,5% / 36V: 97% / 48V: 97,5%	
Absorption charge	14.4 / 28.8 / 43.2 / 57.6V	
Float charge	13.7 / 27.4 / 41.1 / 54.8V	
Equalization charge	15.0 / 30.0 / 45 / 60V	

Figure 12: Example of MPPT Solar controller

23.1. Matching the PV array to the Voltage Specifications of the MPPT

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

The maximum power point voltage of a PV module decreases as the cell temperature rises. A 36-cell module is required for effective charging of a 12 V battery system connected to the module via a switched 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 12 V battery system.

Some MPPT controllers may allow the minimum array nominal voltage to be equal to that of the battery system. However, the MPPT will work better when the minimum nominal array voltage is higher than the nominal voltage of the battery system. Some manufacturers state 5 V to 6 V higher than the battery system voltage.

Table 9 shows the suggested minimum number of cells in a string for the different nominal battery system voltages when using a MPPT controller, however, always follow manufacturers recommendations.

Table 9: Minimum Maximum Point Voltage (V_{mp}) of Array

Nominal Battery system voltage (V)	Minimum V_{mp} of Array
12	24V
24	36V
48	60V

Worked Example 29: Determining number of modules required based on number of cells in module

Battery voltage is 24V so the array voltage should be at least 36 V. The module selected for the worked example has V_{mp} of 33.72V 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 temperature for that specific site is required. For PNG, that will be the temperature at dawn on the day of the year that is historically the coldest.

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

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 30: Calculating the smallest maximum voltage required for the MPPT

The selected module has the following characteristics:
V_{oc} = 41.02V
V_{oc} temperature coefficient = -0.28%/°C

The temperature co-efficient in V/^{o}C = -0.28 ÷ 100/°C x 41.02V= - 0.115V/°C

If the minimum temperature is 20°C (68°F) this is 5°C below the STC temperature of 25°C(77°F). Therefore, the effective variation in voltage is:
5 x 0.115 = 0.58V

So, the maximum open circuit voltage of the module = 41.02V + 0.58V = 41.6V

As stated, the MPPT should be selected to be suitable for three modules. To achieve the required power, these could either be installed three in series or three in parallel. However, if there are three in parallel then this does not meet the minimum voltage requirement of at least 36V.

Therefore, with three in series the MPPT must have a maximum voltage rating equal to or greater than 3 x 41.6V = 124.8V.

Suppose the MPPT has maximum PV open circuit voltage of 150V, then 150V/41.6V = 3.6 ROUNDED DOWN to 3 modules in a string. Hence, using 3 modules in series will suffice.

PART 3- DETERMINING THE SOLAR SYSTEM FOR ac COUPLED SYSTEM CONFIGURATIONS

24. Sizing a Solar Array-General

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

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

The points a through to f have been covered in sections 14 and 15. This section looks at points g through to j. Points g, h, i and j are commonly known as the sub-system efficiency, the sub-system being defined as the components between the solar array and the loads.

24.1. Sub-System Losses in an Off-Grid PV System.

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

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

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

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

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

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

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

24.2. Determining the Energy Required from the PV Array

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

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

24.3. What about the loads that operate during the day?

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

However, realistically some of the load energy will be supplied directly to the load from the PV inverter during the day. To determine exactly how much, a detailed interval analysis would be required where the load power

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

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

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

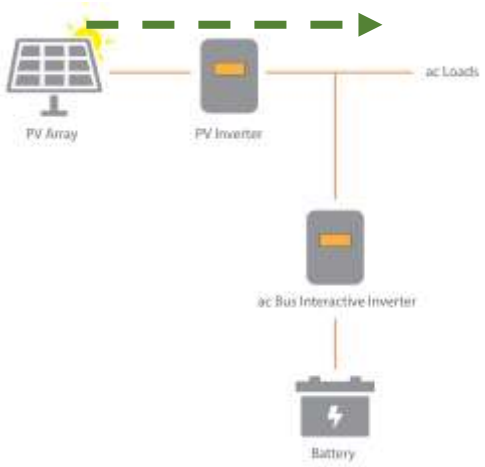


Figure 13 Energy pathway in AC coupled system with PV array supplying the loads directly

The losses when providing ac loads from the battery system include:

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

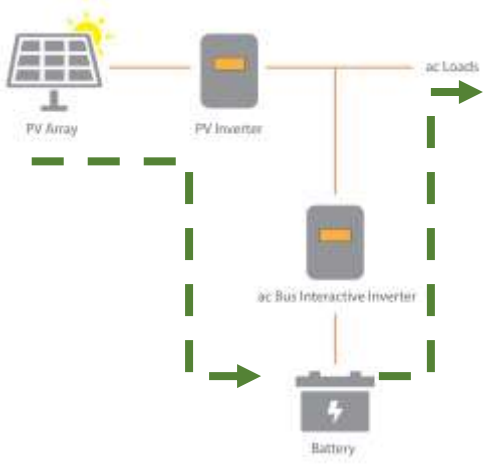


Figure 14 Energy pathway in ac coupled with PV array supplying the loads by charging the battery bank

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

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

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

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

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

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

24.4. Oversize Factors

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

Therefore, when designing a solar system comprising lead acid batteries the array should be oversized by at least 30% to allow for faster full charging of the battery system and to provide equalizing charging when needed. An oversize factor of 30% should also effectively cover the ageing of the solar module in the first 10 years.

An oversize factor of 10%, to effectively cover the aging of the solar module should be included with systems that include lithium-ion batteries.

25. Sizing a PV Array - ac Coupled System

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

- PV array powers ac loads directly via the PV inverter,
- PV array powers ac loads from the battery system through the PV inverter with the battery system inverter acting as a battery system charger and batteries and battery system inverter acting as the ac source.

Worked Example 31: Calculating size of array and number of modules based on total daily energy consumption supplied by PV array charging batteries

Assume the loads are only ac and that the dc loads as specified in table 1 are ac and are supplied by the PV array charging the battery system.

Assume the following system losses (efficiencies)

- cable loss from PV array to ac loads via batteries is 4% (efficiency of 96%) i.e 0.97 (dc cable losses) x 0.99 (ac cable losses) = 0.96);
- PV inverter efficiency is 97%;
- battery system inverter charging efficiency is 96%;
- battery system Wh efficiency is 80%; and
- battery system inverter efficiency 96%

Note: Since the smallest PV inverters are in the range of 3 to 4 kW it is best that the daily energy consumption for the ac couped system is larger than that used for the dc coupled systems designed previously.

For design month assume the Daily ac energy consumption = 8000 Wh and there is no dc loads

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

The required energy output of PV array to provide the AC loads = 8000 Wh/0.687 = 11645 Wh

The design month PSH is 4.38.

Therefore, the required derated PV array output power needed is:

11645 Wh ÷ 4.38 PSH = 2659 W

Assuming the battery systems is lead acid and allowing for an oversize factor of 30%, the adjusted required derated array output is:
2659W x 1.3 = 3457 W

Derated module output = 348.7 W. (refer worked example 25)

Note: for this example, ageing factor has not been taken into account since it is effectively covered by the 30% oversizing factor that allows for battery system equalization and fast recharging in order to extend battery system life.

The required number of modules = 3457 W/348.7 W= 9.91

This should be rounded up to 10 modules. The actual required array is 9.91 x 440W_p = 4360.4W_p and 10 modules of 440W_p each will provide a total of 4400 W_p capacity.

Worked Example 32: Calculating size of array and number of modules based on total daily energy consumption supplied by PV array directly

Assume the following system losses (efficiencies)

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

Daily ac energy consumption = 8000 Wh

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

The required energy output of PV array to provide ac loads = 8000 / 0.96 = 8334Wh

The design month PSH is 4.38.

Therefore, the required derated PV array output power is:

8334Wh ÷ 4.38 PSH = 1903 W

Assuming the battery systems is lead acid and allowing for an oversize factor of 30%, the adjusted required derated array output is:
1903W x 1.3 = 2474 W

Derated module output = 348.7 W. (refer worked example 25)

The required number of modules = 2474 W ÷ 348.7 W= 7.09

This would be rounded up to 8 modules, but it would be an array of 7.09 x 440 W_p = 3120W_p that is required if all loads could be supplied power directly by the PV array

Based on worked examples 31 and 32 and depending on how much load energy is assumed to be supplied directly by the array and how much via the battery system, the required array is rated between 3120 W_p (total daily energy consumption supplied power directly by solar array) and 4400 W_p (total daily energy consumption supplied power from the battery system).

26. Selecting a PV Inverter – ac Coupled System

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

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

- The power output of the array;
- Whether the system will have one inverter or multiple (smaller) inverters; and

- The matching of the allowable inverter string configurations (based on voltage and current) with the size of the array in kW and the specifications of the individual modules within that array.

Note: It is very important the PV inverter and the ac coupled inverter are matched. Correct matching requires the PV inverter and the ac coupled inverter to be able to communicate with each other to ensure that the PV array output power is controlled, to avoid overcharging the battery system.

26.1. How Many PV Inverters?

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

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

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

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

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

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

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

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

26.2. Selecting the Size of PV Inverter.

Inverters currently available are typically rated for:

- maximum dc input power;

- maximum specified output power;
- maximum dc input voltage;
- minimum dc MPPT input operating voltage; and
- maximum dc input current.
- single phase or three phase.

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

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

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

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

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

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

26.3. Matching Array Power to the PV Inverter

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

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

Note:

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

Worked Example 33: Selecting PV inverter to suit array power

The example being used so far only requires an array consisting of between 8 and 10 modules each with a peak rating of 440 W_p. Assume that 10 modules have been chosen.

The Array Peak Power = 10 x 440 W_p = 4400 W_p

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

If the inverter data sheet only specifies the maximum dc power input to the inverter the designer should attempt to contact the manufacturer and determine if there is a maximum allowed PV array power rating.

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

Worked Example 34: Matching array power to inverter power specifications
The inverter data sheet provides the following information:

Max dc Power	4500 W
Max. input voltage	1000 V
MPP voltage range	160 V to 800V
Number of MPPT trackers:	2
Max. input current	24A /24 A

The array in the example is 4400W so it meets the requirements for power

26.4. Matching Array Voltage to Inverter

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

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

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

This variation in power due to temperature is also reflected as a variation in the open circuit voltage and maximum power point voltage. Array I_{sc} is little affected by array temperature.

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

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

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

The MPPT units in the inverter will only track the maximum power point voltage of the array when the arrays MPP voltage is between the inverter's specified MPP minimum operating voltage and maximum MPP operating voltage, that is, the voltage input is within the operating window of the MPPT. If the solar array voltage is outside this window the MPPT does not track the MPP voltage of the array and the output power of the system may be greatly reduced.

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

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

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

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

In practice the array should be designed such that:

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

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

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

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

26.4.1. Minimum Number of Modules in a String

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

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

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

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

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

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

Since the maximum temperature to use has been specified as 75°C then the difference between the maximum cell temperature and the STC temperature will be 75°C - 25°C = 50°C. So, a reduction in V_{mp} is 50°C times the voltage temperature coefficient (V/°C). (Note: It is a reduction because the temperature co-efficient has a negative value)

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

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

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

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

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

or

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

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

Worked Example 35: Calculating V_{mp} of module at the inverter for specified highest expected cell temperature

A module data sheet provides the following information:

- $P_{mp} = 440\ W_p$
- $V_{oc} = 41.02\ V$
- $V_{mp} = 33.72\ V$
- $I_{sc} = 13.73\ A$
- $I_{mp} = 13.05\ A$

- Power temperature coefficient = -0.35%/°C
- V_{oc} temperature coefficient = -0.28%/°C
- No V_{mp} temperature coefficient.
- Manufacturers Tolerance 0 to +3%
- Measurement Tolerance ±3%

Therefore, in V/°C the V_{oc} temperature coefficient = -0.28/100 per degree C x 41.02V = -0.115V/ °C

Applying the power temperature coefficient then the V_{mp} temperature coefficient = -0.35/100 x 33.72 = -0.118V/ °C. This will be used in the rest of the example.

Based on the maximum temperature of 75°C (167°F) then the reduction in V_{mp} due to temperature (takes the negative value into account)
= 50°C times the voltage temperature coefficient (V/°C).
= 50°C x 0.118V/°C
= 5.9V

So, the effective V_{mp} of the module due to temperature = 33.72V – 5.9V = 27.82V

If we assume a maximum voltage drop in the cables of 1% then the voltage at the inverter for each module would be:
0.99 x 27.82 = 27.54 V

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

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

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

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

Worked Example 36: Calculating minimum input voltage of inverter's MPPT
The inverter data sheet provides the following information:

Max DC Power 4500 W

Max. input voltage 100 V

MPP voltage range 160 V to 800 V

Number of MPPT trackers: 2

Max. array short circuit current = 24A / 24A

The minimum operating voltage of the MPPT is 160 V.

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

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

Since it is the minimum number, it should always be rounded up.

Worked Example 37: Calculating minimum number of modules in a string

The effective minimum operating voltage of the MPPT = 176 V

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

Therefore, the minimum number of modules in a string = 176V/27.54 V = 6.4

This would be rounded up to 7.

26.4.2. Maximum Number of Modules in a String

At the coldest daytime temperature, the open circuit voltage of the array shall never be greater than the maximum allowed input voltage for the inverter. The open circuit voltage (V_{oc}) is used because this is greater than the MPP voltage and it is the voltage applied at sunrise when the system detects the sun and begins its start-up sequence – that will be prior to the inverter starting to operate and connecting to the grid.

In early morning, at first light, the cell temperature will be very close to the ambient temperature because the sun has not had time to heat up the module.
Therefore, the lowest dawn temperature for the area where the system is installed shall be used to determine the maximum V_{oc}.

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

Determine Maximum Open Circuit Voltage (V_{oc}) of a Module at the Inverter
The maximum V_{oc} of a module is determined by calculating the increase in V_{oc} due to the minimum daytime cell temperature.

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

Using 15°C as the minimum temperature, then the increase in V_{mp} is (15°C - 25°C) = -10 times the voltage temperature coefficient (V/°C). *(Note it is an increase because the co-efficient is a negative number and the difference in temperatures is also a negative number, so the two multiplied becomes a positive number. Keep in mind that lower temperatures result in higher voltages)*

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

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

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

Worked Example 38: Calculating Maximum V_{oc} of module based on minimum effective cell temperature
Assume the minimum effective cell temperature is 15°C(59°F),
The module data sheet provides the following information:

- V_{oc}= 41.02V
- V_{oc} temperature coefficient = 0.28%/°C

Therefore, in V/°C the V_{oc} temperature coefficient = 0.28/100 per °C x 41.02V = 0.115V/°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 0.115V/°C
= 1.15V

So, the effective V_{oc} of the module due to temperature = 41.02 + 1.15 = 42.17V

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

Determine Maximum Operating Voltage of the Inverter
The inverter data sheet specifies the actual Maximum operating voltage.

Worked Example 39: Determining maximum operating voltage of inverter
The inverter data sheet provides the following information:

Max. input voltage	1000 V

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

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

Worked Example 40: Calculating maximum number of modules in the string

The maximum voltage of the Inverter = 1000V

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

Therefore, the maximum number of modules in a string = (1000 x 0.95) V/42.17V = 22.53
(Applying a 5% safety margin on the maximum input voltage)
This would be rounded down to 22.

So, in the worked example we can have between 7 and 22 modules in a string and still stay within the maximum and minimum voltage ratings of the inverter.

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

Worked Example 41: Calculating how many strings connected to the inverter
When determining the array power and matching it to the inverter an array of 10 modules has been selected and hence only one string of 10 modules would be required.

26.5. Matching Array Current to the Inverter
Inverters have a maximum input current. However, since many inverters now have multiple MPPTs and can have multiple connections (often module connector sockets) for the PV array dc wiring to the inverter, these also have a maximum current specified.

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

Worked Example 42: Matching maximum array current to the maximum input current of inverter
The inverter data sheet provides the following information:

Number of MPPTs = 2

Max. array short circuit current = 24A / 24A

The module data sheet provides the following information:

- $I_{sc} = 13.73\ A$
- $I_{mp} = 13.05\ A$

So, one string is suitable

PART 4 - HYBRID POWER SYSTEMS

27. Hybrid System Configurations

How the generator interconnects within the hybrid system depends on the type of inverter, the load characteristics and the size of the system. Figures 15 to Figure 18. show some configurations for PV/generator hybrid systems.

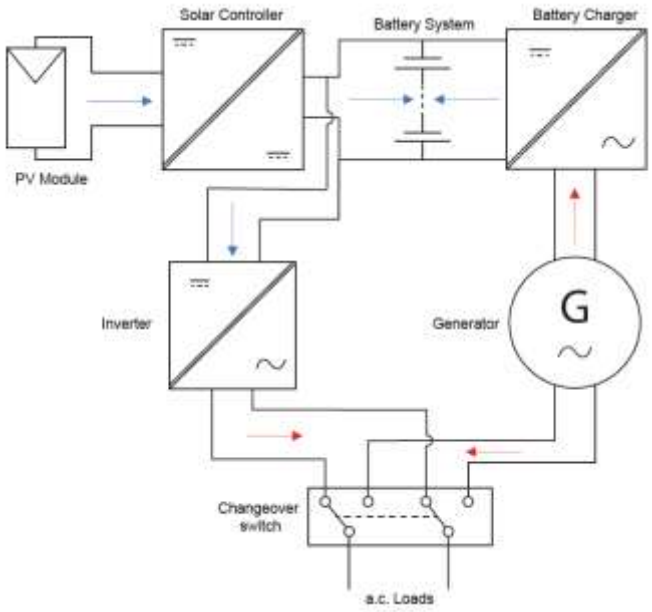


Figure 15: Generator connected to both the battery system (via a battery charger) and the AC load (via a changeover switch)

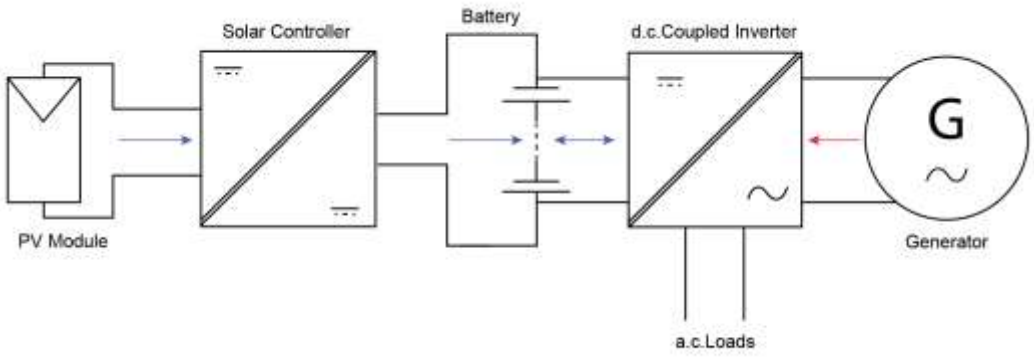


Figure 16: Generator connected to an inverter/charger or an interactive DC inverter connecting to a DC coupled system.

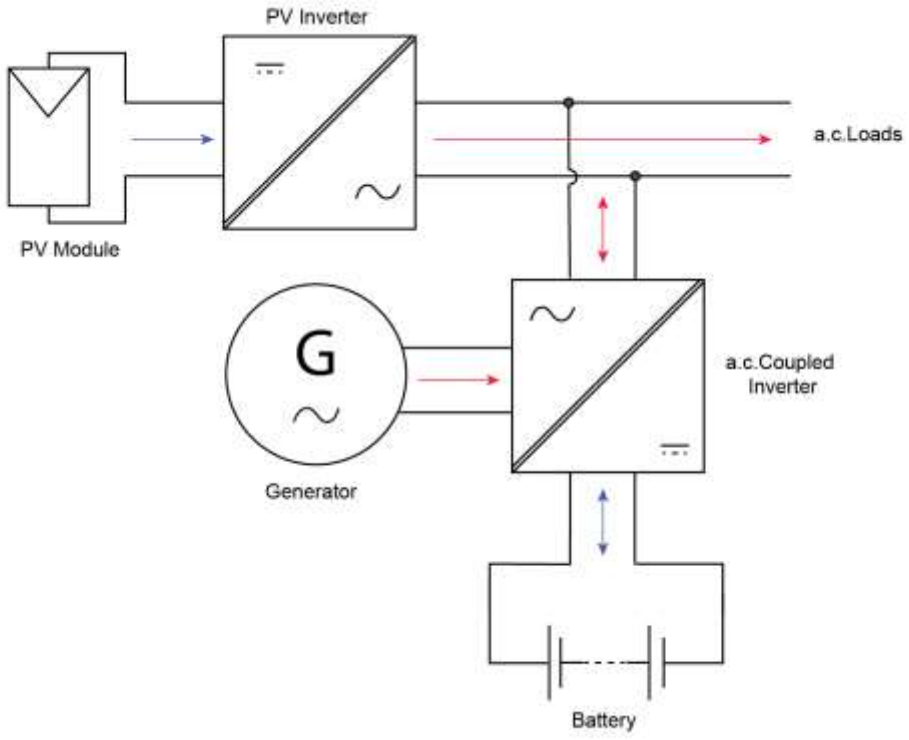


Figure 17: Generator connected to an ac coupled inverter connecting to an ac coupled system

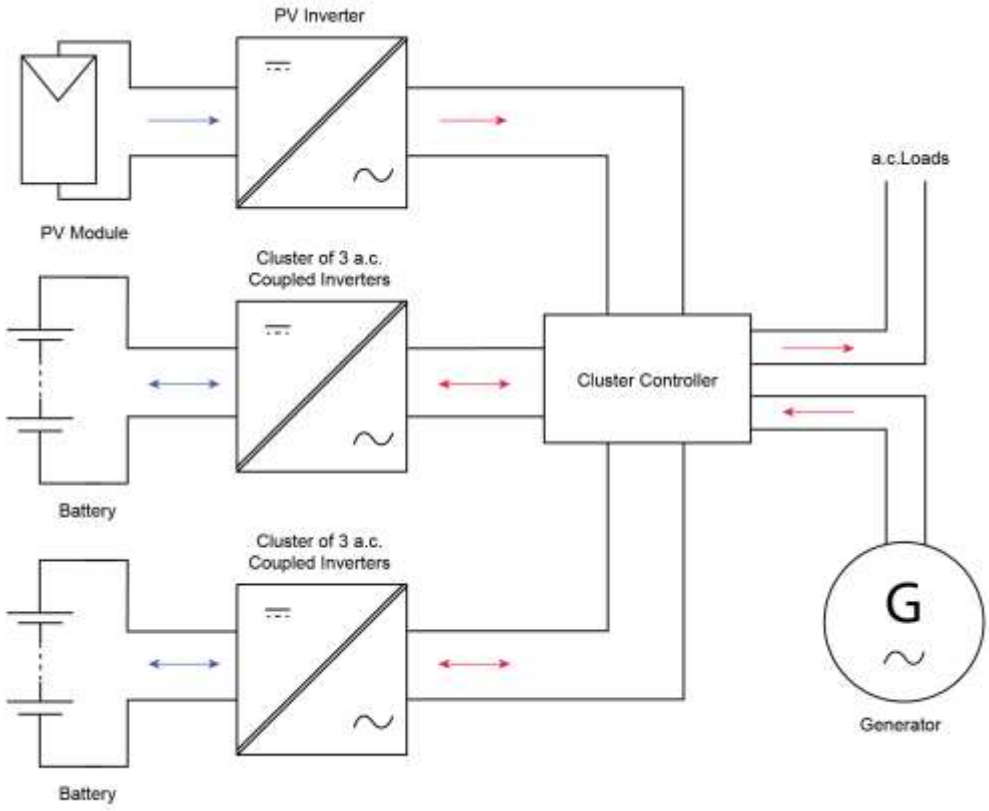


Figure 18: ac coupled system with multiple inverters connected to a cluster controller with the generator connected to it.

Certain models of ac coupled interactive inverters require a cluster controller or cluster box for interconnecting the multiple ac generating devices. These are generally required when there are numerous clusters of ac coupled inverters in parallel. Each cluster comprise 3 single phase inverters providing 3 phases.

The cluster controller (or box) is provided by the manufacturer of the ac coupled inverter and the installer shall follow the installation requirements of the manufacturer. Note that Figure 18 shows the PV inverter connected to the cluster controller. The PV inverter can also be connected directly onto the ac load line and the PV systems does not need to be located in the same location as the rest of the system (battery system, ac coupled inverters, cluster control and generator)

All the configurations shown above can potentially be used for hybrid systems where the generator is either used as a back-up or is being used daily. However, where the generator is being used daily, it is very unlikely to use the hybrid system shown in Figure 15 that has a separate battery charger.

28. Types of Inverters

Within a hybrid system there are 5 different types of inverters that could be used. These include:

1. **Basic Battery Inverter**

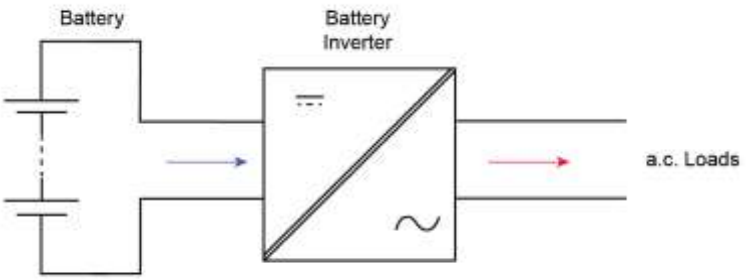


Figure 19: Basic battery inverter application

The battery inverter as shown in Figure 19 converts the DC power from the battery system to provide ac power to the loads. Some manufacturers allow these inverters to parallel with a similar model inverter but one will have to be the master to ensure they are synchronised. Theses inverters cannot parallel to any other ac source like a generator. If used in a hybrid system, they would require a separate battery charger as shown in figure 15. The PV array that is part of the hybrid system will be connected to the battery system via a solar controller.

2. Inverter/Charger

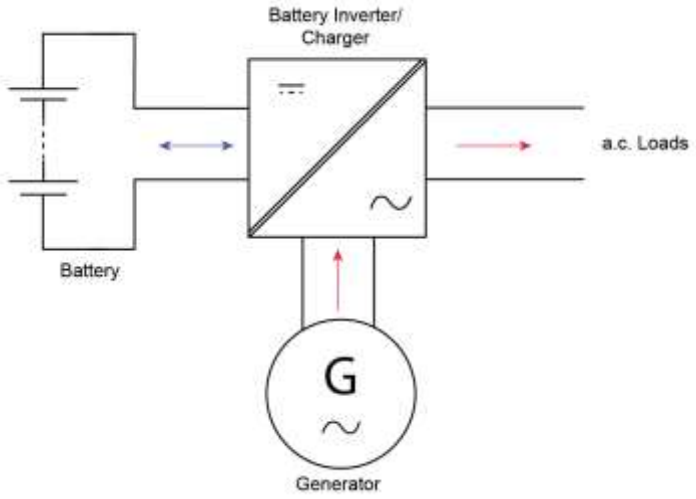


Figure 20: Inverter/Charger application

The Inverter/Chargers as shown in Figure 20 do not parallel with the generator. They are either in inverter mode or charger mode. When the generator is not operating, the inverter will convert the dc power from the battery system to provide ac power to the loads. When the generator starts, the inverter will switch the generator ac power to the loads, and the inverter will operate in charging mode converting the generator's ac power to dc power and charge the battery system. The PV array that is part of the hybrid system will be connected to the battery system via a solar controller.

3. PV inverter

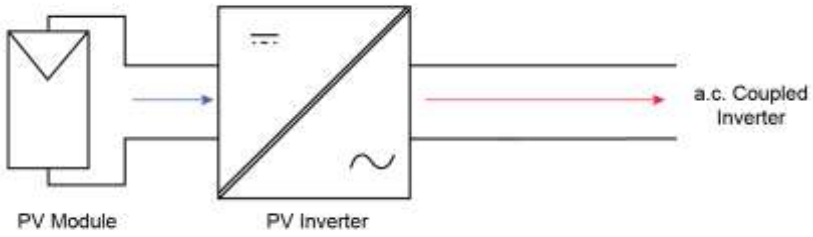


Figure 21: PV Inverter application

The PV inverter shown in Figure 21 converts the dc power from the PV array to provide ac power to the ac bus. However, there must already be ac power on the ac bus from another source (generator or ac coupled inverter) for the PV inverter to operate.

4. dc coupled inverter

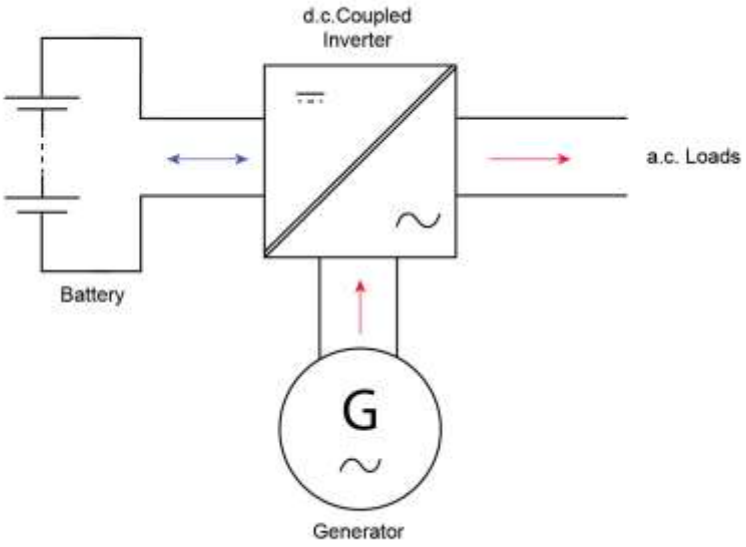


Figure 22: dc coupled inverter application

When the generator is not operating, the dc coupled inverter as shown in Figure 22 will convert the dc power from the battery system to provide ac power to the loads. When the generator starts, the inverter will synchronise with the generator so that the ac loads can be supplied by the generator and inverter in parallel. If there is excess generator power compared to the load, the dc coupled inverter will convert to a battery system charger and charge the battery system from the generator while the generator continues to provide ac power to the loads. The dc coupled inverter will only parallel with the generator connecting to the inverter. There can be no other sources of ac power on the ac load line from the inverter. The PV array that is part of the hybrid system will be connected to the battery system via a solar controller.

5. ac coupled inverter

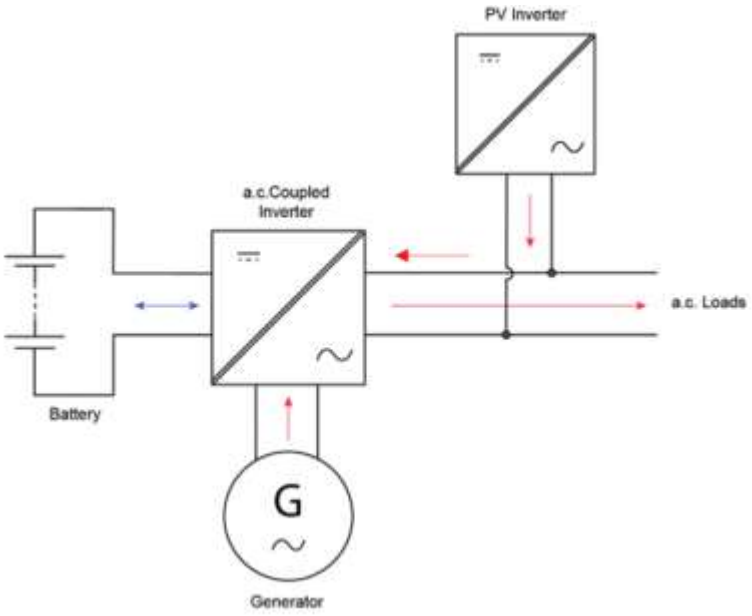


Figure 23: ac coupled inverter application

When the generator is not operating, the ac coupled inverter as shown in Figure 23 will convert the dc power from the battery system to provide ac power to the loads. When the generator starts the inverter will

synchronise with the generator so that the ac loads can be supplied by the generator and inverter in parallel. If there is excess generator power compared to the load, the ac coupled inverter will convert to a battery system charger and charge the battery system from the generator while the generator continues to provide ac power to the loads. The ac coupled inverter will allow PV inverters to be connected to the ac bus. The ac coupled inverter and PV inverters must be compatible and be able to communicate with each other. If there is excess ac power from the PV array (and PV inverter) compared to the load, the ac coupled inverter will convert to a battery system charger and charge the battery system from the PV array via the PV inverter

In a hybrid system the ac power is supplied and controlled by the battery inverter. Sometimes it can be called a "grid forming" inverter. That is the inverter takes the dc power from the battery system and creates the ac power at the required single or three phase voltage and frequency.

This is 230 V or 240 V single phase at 50 Hz and 400 V or 415 V three phase at 50 Hz.

Not all battery inverters are designed to connect in parallel with other generating sources. The typical inverter (refer Figure 19) and inverter/charger (refer Figure 20) fall into this category in that they cannot parallel with the generator and for this reason the load shall be connected by a changeover contactor as shown in Figure 24. For the inverter/charger shown in Figure 20, the changeover switch is internal to the inverter/charger. However, some of this type of inverter and inverter/charger are able to parallel with each other up to a specified number, typically 3 or 4. In these systems one inverter will take the lead, often called master, while the others will follow, often called slaves. That is, the master creates the 50 Hz waveform and then the others will then synchronise with the master.

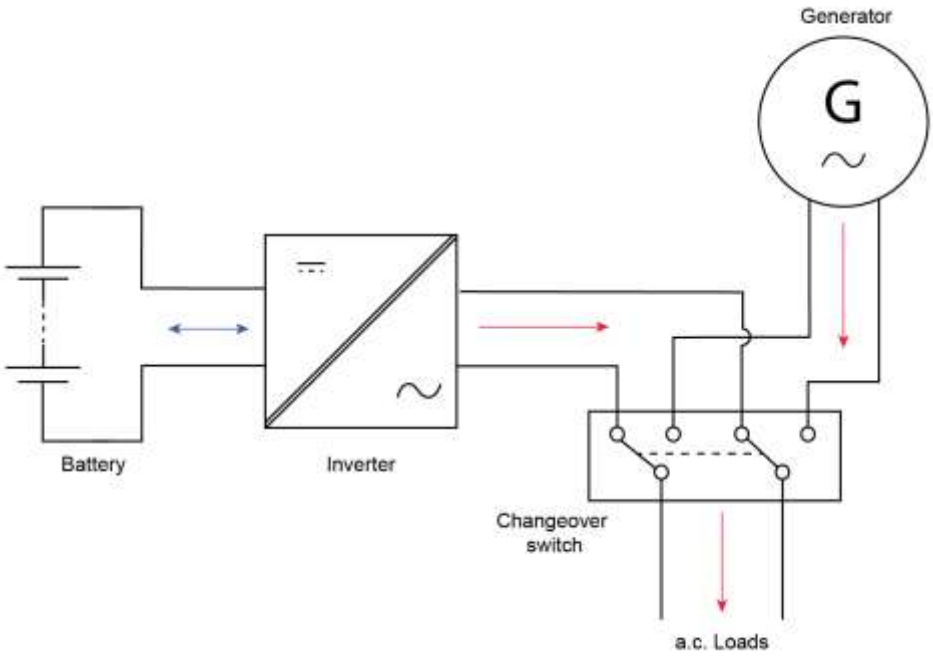


Figure 24: Simple Change over contactor

The inverter/charger in Figure 20 will have an ac input terminal for a generator (or possibly the grid) to connect. When there is ac power at these terminals the inverter will revert to acting as a battery system charger and an internal changeover switch will connect the loads to the generator.

Different brands of inverters and inverter/chargers will not parallel with each other and even with the same brand, some models will not operate properly in parallel and must be connected through a separate device that properly combines their individual outputs.

The dc coupled (refer **Error! Reference source not found.**) and ac coupled (refer Figure 23) inverters are able to parallel with other generating sources, but again typically only one or two sources, except possibly in large systems in the hundreds of kWs. When operating alone, the inverter does take the lead, forming the grid at the appropriate voltage and frequency, however when the generator starts, the inverter will then synchronise with the generator and the generator becomes the lead with respect to the voltage and the input to the grid. According to its design, the interactive inverter may then continue supplying the loads in parallel with the generator or it may revert to acting only as a battery system charger.

For the dc coupled and ac coupled inverters, different brands will not work in parallel because each one wants to be the lead and there will be communication issues. There is also a maximum number that can be connected in parallel. The manufacturer will specify that. When they are in parallel, one inverter will be the "master" and the others ("slaves") will synchronise with the master inverter.

The PV inverter, often called the grid connect inverter, will only generate ac power when there is already ac power on their output terminal supplied by another source. In grid connect systems this is the grid power. In hybrid systems it is an ac coupled inverter. Having the PV inverter require an ac source is due to a safety issue: when the grid is not available the PV inverter must turn off to avoid powering the grid when it has been shut down for maintenance or due to a fault.

The ac coupled inverter is different from the dc coupled inverter because it will provide a source of ac power, even when it is operating in battery system charging mode, when there is no grid power present from another source.

The PV inverter (current source inverter) converts the dc power from the PV array to ac power but it does this by synchronizing with an external ac source. It is not able to form the ac power (voltage and frequency) like the inverters (voltage source inverters) that are connected to batteries.

The grid PV inverters are able to parallel with other PV inverters because they are following an ac grid. Technically this is the same for hybrid systems. However, because the ac inverter and PV inverter need to communicate with each other when charging the battery system, the designer shall ensure that the two items are matched and compatible when designing a system

The hybrid systems designer must:

- Ensure they select the correct type of inverter(s) for the application;
- Not parallel more inverters than approved by the manufacturer;
- Not connect different brands of inverter in parallel in the same installation; and
- Ensure that the PV inverter and the ac coupled inverter are compatible.

29. Site Visit - Hybrid Systems

Prior to designing any hybrid system, the designer should visit the site and undertake/determine/obtain the following:

1. The energy needs of the end-user through discussions with the developer or the end user. (Section 32 for more detail).
2. Prepare an hour-by-hour load analysis or if that is not practical, complete a load assessment form (See Section 32 for more detail).
3. Assess the occupational safety and health risks that will be present when working on that particular site.
4. Determine the solar access for the site or determine a position where the solar has the most available sunlight (refer to section 14).

5. Determine whether any shading will occur over a full year's time and if so, estimate its effect on the output of the system (refer to section 14).
6. Determine the orientation (azimuth and tilt angle) of the roof if the solar array is to be roof mounted (refer to section 14).
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) or arranged on the ground. Note that if roof mounted, if different sections of the roof that has a different orientation and/or tilt need to be used, a separate MPPT controller must be connected to the solar modules of each different orientation. When Inverters having only one MPPT controller input are used, there will need to be separate inverters for each section of modules that has a different orientation.
10. Determine where the batteries will be located.
11. Determine where the solar controller(s) or PV inverter(s)will be located.
12. Determine where the battery system inverter(s) will be located.
13. Determine where any battery system chargers will be located
14. Determine where the generator will be located (if not already installed).
15. Determine the cabling routes and estimate the lengths of all the cable runs including all the control cables between generators and the battery system inverters or other control equipment.
16. Determine whether monitoring panels or data screens are required and through consultations with the end users, determine a suitable location.

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 of the modules and the effect of any shading on the output of the PV array. This was covered in detail in Part 1 (section 14.1, 14.2 and 14.3) and is not repeated for this part of the guideline.

If the site is remote and the system size is relatively small, then all the above information may be obtained through discussions with the end-user, however the final location of all equipment must be determined by the time of installation. If the system is for a resort or for a village, then a site visit should be undertaken unless all the information can be supplied in detail by the client funding the project.

30. Energy Source Matching

If the system is not for a village (e.g. a mini grid with multiple users) then using other energy sources than solar generated electricity may be possible for the site. Though the price of solar modules has reduced dramatically in recent years it is still usually best to match some of the energy needs of the client with other sources (e.g. LPG) if possible. For example, though microwave ovens are suitable for cooking using electric power from hybrid systems, it may be more appropriate to use biomass, kerosene or LPG if available for cooking instead of an electric appliance.

If hot water for showers and washing is required, then a separate solar hot water system could be used.

31. Energy Efficiency

When the system is for a village (e.g. a mini grid) then energy efficiency should be promoted so that the villagers will use the most efficient appliances within their houses.

When the system is being designed for a homeowner or small business then the designer should discuss energy efficiency initiatives with the owner for implementation. These could include:

- Replacing inefficient electrical appliances with new energy efficient electrical appliances;

- Replacing incandescent or fluorescent light bulbs with more efficient LED (light-emitting diode) type lights;
- Using laptop computers instead of desktop units;
- Using energy efficient flat-screen TVs instead of bulky older units with cathode ray tubes.
- Replacing cooking appliances that have a high electricity demand with LPG, biomass or kerosene appliances.

For hotels and resorts it might include:

- Providing ceiling fans instead of, or as well as, energy efficient inverter type air-conditioners;
- Installing in-room card systems so room power is only available when the guest is in the room.
- Using LED exterior lighting that is on a timer so that the level of area lighting is greatly reduced after a pre-set time or motion sensors that illuminate for a pre-set time after detecting motion.
- Using office machines (e.g. copiers and printers) that have a standby power mode that greatly reduces their load when not in use after a specified period of time.
- Using laptop computers instead of desktop computers

32. Power and Energy Assessment

In a hybrid system electrical power is either supplied from a dc source such as batteries or PV modules via an inverter, or the generator is used to produce 230/240 volts 50 Hz ac. During the day the electrical power may be entirely from the PV modules through a PV inverter (grid connect type inverter), however the "grid waveform" required for the PV inverter to operate will be formed by the ac coupled inverter (battery system inverter) connected to the batteries. The battery inverter will deliver energy to the load using the battery system as a source when there is insufficient solar output to meet the load requirements. When there is insufficient sun and insufficient battery system charge to meet the load requirements, the generator will provide sufficient power to meet the full load requirement. Electrical energy usage is normally expressed in watt hours (Wh) or kilowatt hours (kWh).

Part 1, section 9 details how to complete a power and energy assessment form through discussions with the client. This method is still appropriate for smaller systems where the generator is being used as a back-up or when power comes primarily from the generator during the months with the lowest solar irradiation.

Where the daily energy usage is in the 10s or 100s of kWh range, e.g. village mini-grid, hotel/resort, or commercial business, developing a power and energy assessment form to detail all the loads may be impractical. As a minimum, the designer does need to obtain the average daily energy usage for work days and for weekends and for all months of the year. For some cases, the client might already have detailed information on the energy usage but in any case, when designing a system for sites with large daily energy usage it is recommended that the designer obtain the typical hourly energy usage as well as the variations in average daily energy usage for the various months of the year.

For facilities already electrified by a generator or the utility grid, the daily energy profile can be obtained by using a data logger that logs kWh, energy used each hour, or kW power demand observed at hourly intervals. This should be installed for as long as possible but should be a minimum of 1 week. Ideally it should be installed for different times of the year if it is known that the energy usage varies seasonally. If this is not possible then the designer will need to discuss with the client how the energy profile differs during other times of the year relative to the information obtained from the data logger.

The data logger should be installed at the main switchboard of the existing generator/grid connection to record the following information:

- Voltage per phase (V)
- Load current per phase (A)

- Power factor per phase
- Real power (kW)
- Apparent power (kVA)
- Energy over a stated period of time (kWh)
- Maximum demand (kVA)
- Time
- Date

A load profile generated from monitored data for a real site is shown in Figure 25. This diagram shows the average instantaneous power being consumed by the loads for a typical week. The figure shows that for this site there is no fixed daily pattern. The only regular feature is that the peak demand is about 6pm each day, although other peaks do show up on most days. This profile helps to select the size of the inverter and the hours when the generator should operate.

To design the capacity of the battery system, the daily total load in kWh is required. This may be monitored directly or calculated from the instantaneous power.

Figure 26 shows the cumulative energy in kWh for each day for the site. The data is reset to zero every night at midnight. This is the same week as shown in Figure 25 and it can be seen that the average daily energy usage is between 200 kWh and approximately 240 kWh.

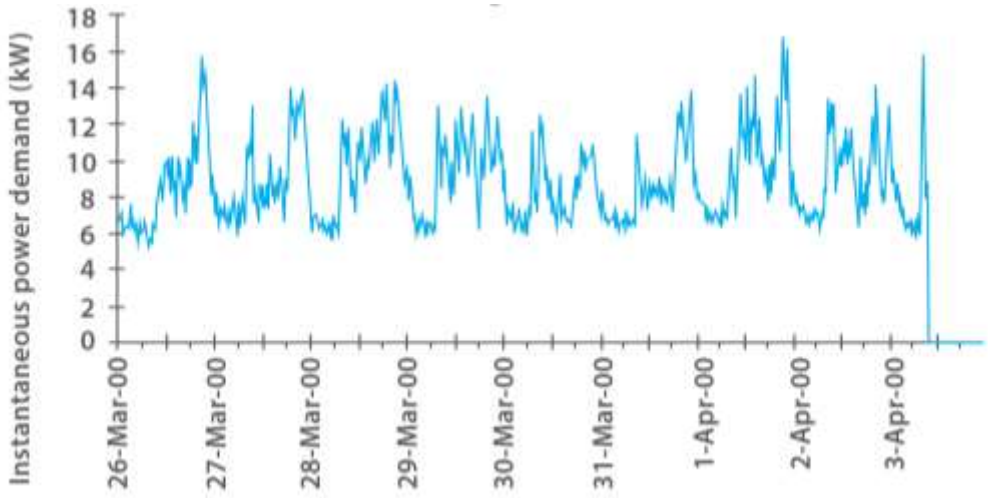


Figure 25: Instantaneous Power for a Data Logged Site

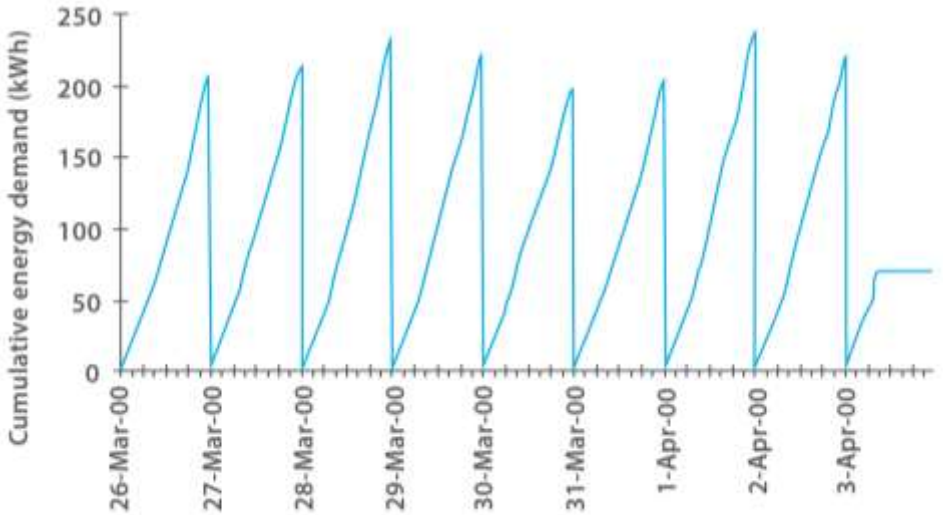


Figure 26: Cumulative Energy for the Data Logged Site

33. Determining the Capacity and Selecting the Battery system Inverters

The type of battery system inverter selected will be dependent on the system configuration. The different configurations were detailed in section 27 while the types of inverters were detailed in section 28.

The battery system inverter must be sized to meet the peak power demand and also the surge demand. In section 13, it was shown that the power rating of the inverter is determined from the power and energy assessment form.

For systems where there are only a few ac appliances, the battery system inverter should be capable of supplying continuous power to all loads that are connected to it and must have sufficient surge capacity to start all loads that may surge when turned on, should they all be switched on at the same time. Loads with electric motors are particularly likely to have a large surge capacity requirement.

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

If a power and energy assessment form has been completed, then the inverter shall be sized based on the peak demand shown by the data in the form. To do that, the power rating of the appliances needs to be converted to VA based on the power factor of the appliance. This is because inverters are rated at unity power factor, i.e. a 5-kW inverter is also a 5 kVA inverter, but if a load is 5 kW and 6 kVA then the 5 kW/5 kVA inverter will not be sufficient to provide power to the load. An inverter with a minimum rating of 6 kVA (6 kW) will be required. In general, for new installations, it is always good practice to oversize because load growth is likely. So, the inverter selected will typically be larger than needed for the existing demand.

As a minimum, the battery system inverter must be rated to suit the maximum and surge power demands. Inverter chargers and interactive inverters can have higher ratings based on their capacity needed when acting as battery system chargers. The following sections summarise how to determine the ratings for the four battery system inverters described in section 28: inverter, inverter charger, dc coupled interactive inverter and ac

coupled interactive inverter. The fifth inverter described in section 28 was the PV inverter that has its size based on the size of the array, a process that is detailed in section 25/26 and is not repeated here.

With hybrid systems the inverters can be supplied as single phase or three phase, though sometimes three phase inverters are not available at the power rating desired and three single phase inverters are used with one inverter acting as the "master" and the others the slaves. The "master" ensures that the three inverters are each 120 degrees out of phase with the others.

If the required capacity of the required inverter is greater than 20 kVA then these may be supplied as either one inverter or as a "cluster" of inverters. Some brands will provide their inverters with a maximum of 5 kVA per inverter; hence a 3 phase 15 kVA inverter will consist of three of these inverters. The inverter manufacturers may then allow these three inverter clusters to be connected in parallel up to a specified number, each cluster will then have their own battery system and in effect will be independent of the others. One cluster will be assigned the role of "master" and the others will be set to be "slaves".

As an example, if one 90 kVA 3-phase inverter is required then it could either be supplied as one single large 3 phase inverter or as six clusters of 3 x 5 kVA inverters. The cluster approach allows inverter (and battery system) capacity to be added to a system up to the limit of parallel clusters allowed by that manufacturer. This approach has the added advantages of being able to operate with somewhat reduced power if one cluster malfunctions, while greatly simplifying maintenance personnel training requirements and significantly reducing the cost of the spare parts stock needed.

33.1. Inverter

In systems that use standard battery system inverters, the inverter must be sized to meet the maximum and surge demands as described above.

33.2. Inverter Charger

Battery system inverter-chargers will be sized to meet the maximum and surge demands as described above. However, in some systems, the battery system inverter-charger required may have a higher rating than the size determined via maximum and surge demand calculations if the system design calls for the charging current required to exceed the charging capacity of the inverter that is sized to meet the maximum load and surge demand calculations. In particular, when the battery system is low and a generator is operating, the system design may be such that a very high charge current is required for the inverter to charge the batteries in a shorter time period than is normally the case when charging from the solar modules

33.3. dc coupled interactive inverter

Theoretically the DC coupled interactive inverter can operate in parallel with the generator and hence the sizing of the generator and DC coupled interactive inverter combined can be sized to meet the maximum and surge demands, hence resulting in the selection of an inverter rated smaller than that required to meet the maximum and surge demands by itself. In practice, though, the dc coupled inverter should be sized the same as the inverter charger described in section 33.2. That is, it is sized to meet the maximum and surge demand and, if needed, should be oversized if that is needed to meet its charging requirement. This allows the system to meet the maximum and surge demands without always needing to operate the generator.

33.4. ac coupled interactive inverter

The ac coupled interactive battery system inverter is initially sized the same as the dc coupled interactive battery system inverter. It is sized to meet the maximum and surge demand and may be oversized to provide for additional charging capability if required by the overall system. However, since the charging source is the PV array and the generator, the ac coupled inverter generally must be sized to at least match the size of the PV array and its corresponding PV inverter(s).

Because of the low cost of PV modules and the ease that ac coupled systems allow for larger PV arrays, it is not uncommon to have a PV array and PV inverter much larger than the ac coupled interactive inverter. For example, a PV array of 30 kW may be connected to a 25 kW (25 kVA) or 30 kW (kVA) PV inverter while the ac coupled interactive inverter only needs to be 10 kVA to meet the maximum and surge demands.

It is recommended that the battery system inverter rating is between 50% and 100% of the PV inverter. If there are many daytime loads such that a high proportion of the PV array will be supplying loads directly during the day, then the ac coupled interactive inverter rating could be as low as 50% of the PV inverter rating. However, if there are not many day time loads then the ac coupled interactive inverter rating should be closer to the full PV inverter rating in order to allow all the available PV power to be used in charging the battery system via the ac coupled interactive inverter and to assure sufficient generation for powering the loads when the PV is not generating sufficiently due to a rainy day or clouds. In general, for hybrid installations in remote areas, it is important to design the system to minimize the requirement to operate the generator since fuel costs and therefore electricity costs are very high. Carefully monitored generators supplying remote island telecom installations show a per kWh cost of well over $1.00 and in some cases over $2.50 per kWh. For standalone solar at sites where the fuel cost is not much more than the solar generation cost, keeping the operation of the generator to a minimum is not so important.

34. Determining the Capacity and Selecting a Battery system Chargers

A separate battery system charger may be required for systems that are not using battery system inverters that include an internal battery system charger for charging from the generator.

Critical factors when selecting a battery system charger that charges from the generator include:

- Appropriateness for the type of battery system selected
- System voltage
- Voltage regulation
- Output current limiting
- Battery system manufacturer's recommended charge voltage
- Availability of controls and metering as needed for proper operation of the system.

The maximum rate of charge of the batteries must be specified by the battery system manufacturer and the battery system charger must not provide a charge current greater than that specified by the battery system manufacturer. The battery system charger must have a dc voltage rating sufficient to provide the charging voltage required by the battery system.

For systems with lead-acid batteries, the battery system charger ideally should be capable of providing all available charging current during the initial charging stage and then gradually reduce the current so as to maintain a manufacturer's specified voltage after being fully charged. This allows the charger to carry out float charging and as required, extra current for equalisation charging.

If the batteries use lithium-Ion technology, then the selected battery system charger must be able to communicate with the Battery system Management System (BMS) provided with Lithium-Ion battery system.

35. Selecting the Generator and Determining its Capacity

35.1. Selecting the Generator

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

- Can the generator meet the maximum and surge demand of all the appliances that may operate when the generator is running? In general, this will be the same calculation as that undertaken in determining the rating of the battery system inverter, but the battery system charger must be included as an additional component of the load for the generator.

- How consistent is the load power profile? Will the profile result in the generator being under-loaded for a long period of time? Under-loaded generators may have increased maintenance costs and typically also consume more fuel per kWh delivered.
- Will the generator be used only when the battery system/PV cannot supply the load, or will it be used daily for a specified number of hours?
- What should be the engine speed: 1500 rpm (revolutions per minute) or 3000 rpm. Higher speed engines will require more maintenance but typically have a lower initial cost; so higher speed engines usually are selected for installations that have generators that are only started when the solar cannot provide sufficient energy to meet the load while higher efficiency, lower speed engines are generally installed where the engine is regularly used every day.
- What is the preferred fuel type: diesel, petrol (gasoline), LPG or biofuels? This will be determined by a combination of fuel availability, fuel cost, noise, access to maintenance and its cost, generator lifetime, load type and environmental considerations.
- Physical specifications, including weight, dimensions, transportability, temperature ratings, ingress protection (IP) ratings (against the entry of moisture, dust, etc.), noise ratings and fuel efficiency.
- Electrical specifications, including apparent power, voltage and frequency regulation, rated voltage, rated amperage, harmonic distortion, number of phases, monitoring and control system typology.

If the generator is operating on a daily program, then a medium speed (1500 rpm) diesel generator is recommended.

For systems using a dc coupled or have ac coupled interactive inverters where the generator must be capable of operating in parallel with the inverter(s), a generator must be selected that is designed to properly work in parallel with other sources of power generation. Since the inverter and generator must synchronise, the output of the generator should have minimum harmonic distortion, or the inverter may have difficulty synchronising with the generator.

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

35.2. Determining the Capacity of the Generator

Theoretically, if the generator can operate in parallel with interactive inverters (ac and dc coupled systems) and the sizing of the generator and the interactive inverter combined can meet the maximum and surge demands, it may seem that a smaller generator can be installed than that required to meet the maximum and surge demands. In practice, though, the generator must be sized to meet the maximum and surge demands of all the loads when it is operating. This allows the generator to meet the maximum and surge demands should the solar installation fail to deliver power to the load.

35.2.1. Generator as a Back Up

The battery system charger, whether a part of the interactive inverter(s) or as a standalone device, should always be included as a load on the generator. This could be the kVA rating of a separate battery system charger though for most designs, it will be the rating of the inverter-charger in the dc or ac coupled interactive battery system inverter. Though the battery system charger rating of the inverter may be less than that of the full rating of the inverter that is used, for the purpose of sizing the generator, it is assumed that the battery system charger rating is the same as the continuous rating of the inverter.

The generator should therefore be sized to meet the larger of the results of the S_{GEN} calculated using each of the following formula:

$$S_{GEN} = (S_{BC} + S_{MAX_CHG}) \times F_{GO}$$

And

$$S_{GEN} = \frac{(S_{BC} + S_{SUR_CHG}) * F_{GO}}{ALT\ SURGE\ RATIO}$$

Where,

S_{GEN} = Minimum apparent power rating of the generator (kVA)

S_{BC} = Maximum apparent power consumed by the battery system charger under conditions of maximum output current and typically maximum charge voltage (kVA)

S_{MAX_CHG} = Maximum ac demand from the loads when generator is operating (kVA)

F_{GO} = Generator oversize factor (dimensionless)

S_{SUR_CHG} = Maximum ac surge demand during battery system charging (kVA)

ALT SURGE RATIO = Ratio or instantaneous current to continuous current output of the alternator

The oversize factor is a safety margin and often an oversize of 10% is allowed. That represents an oversize factor of 1.1.

Worked Example 43: Calculating minimum kVA rating of generator required

S_{BC} = 5 kVA

S_{MAX_CHG} = 10 kVA

F_{GO} = 1.1

S_{SUR_CHG} = 15 kVA

ALT SURGE RATIO = 2

What is the minimum sized generator you should select?

The generator must be sized to meet the following formula:

$$S_{GEN} = (S_{BC} + S_{MAX_CHG}) * F_{GO}$$

= (5 +10) x 1.1

= 16.5 kVA

And

$$S_{GEN} = \frac{(S_{BC} + S_{SUR_CHG}) * F_{GO}}{ALT\ SURGE\ RATIO}$$

= ((5 + 15) x 1.1)/2

= 22/2 = 11 kVA

Therefore, the generator capacity shall be at least 16.5 kVA

35.2.2. Generator Used Daily

In some sites a generator may already be installed and therefore may not have any excess capacity available for properly charging the battery system at the same time as it serves the load. In that case the generator will need to be operated such that it only charges the battery system when the load is low, and the generator has excess capacity relative to the load. Every site will be different.

If the system to be installed is a new system, then the designer has the choice:

- select a generator just to meet the load maximum demand requirements when the generator is operating and arrange the generator operation so that the battery system charging will only occur during low load periods;

or

- include the battery system charger as one of the loads that operates at full capacity when the generator is operating in which case the generator can charge the battery system at any time.

Currently, the cost of PV when meeting loads directly is cheaper than operating a diesel generator, however when combined with the cost of batteries it is not. To determine which option is the best – whether to install a larger generator to allow for effective battery system charging by the generator when operating or to add more modules to the PV array to do most of the charging through increased solar capacity – then the extra fuel cost of operating the larger generator plus the added cost of installing and using a larger generator needs to be compared with the costs of adding more solar modules and their cost of operation. This analysis needs to be undertaken for each site and it will depend on the size of the various equipment required and the load characteristics.

If the generator is sized to include the capacity of the battery system charger, then the generator size is determined using the formula specified in 35.2.1.

If the generator is sized to only meet the power of the loads operating while the generator is operating, this is the same as sizing the battery system inverter except the ability of the generator to supply surge current should be investigated with the generator manufacturer.

The generator should therefore be sized to meet the following two formula:

$$S_{GEN} = \left(S_{MAX_DEM}\right) * F_{GO}$$

and

$$S_{GEN} = \frac{\left(S_{SUR_DEM}\right) * F_{GO}}{ALT\ SURGE\ RATIO}$$

Where,

S_{GEN} = Minimum apparent power rating of the generator (kVA)

S_{MAX_DEM} = Maximum AC demand during when generator operating (kVA)

F_{GO} = Generator oversize factor (dimensionless)

S_{SUR_DEM} = Maximum AC surge demand when generator operating (kVA)

ALT SURGE RATIO = Ratio or instantaneous current to continuous current output of the alternator

The oversize factor is a safety margin and typically an oversize of 10% is allowed which is an oversize factor of 1.1.

Worked Example 44: Calculating minimum kVA rating of the generator

S_{MAX_CHG} = 10 kVA
F_{GO} = 1.1
S_{SUR_CHG} = 15 kVA
ALT SURGE RATIO = 2
What is the minimum sized generator you should select?

The generator must be sized to meet the following two formulae:

$$S_{GEN} = (S_{MAX_CHG}) * F_{GO}$$

= (10) x 1.1
= 11 kVA

and

$$S_{GEN} = \frac{(S_{SUR_CHG}) * F_{GO}}{ALT\ SURGE\ RATIO}$$

= ((15) x 1.1)/2
= 16.5/2 = 8.25 kVA

The generator shall be at least 11 kVA

35.3. Derating of Generators

Generators need to be derated for the site-specific temperature, humidity and altitude. The derating factors should be supplied by the generator manufacturer, however typical values are shown in Table 10. The deratings are *added* together *not multiplied* as often is the case with losses in a system.

Table 10: Generator derating factors

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

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

Worked Example 45: Calculating derated output of the generator

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

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

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

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

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

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

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

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

36. Generator as Back-up Only

Systems using generators as back-up only typically use the generator when either:

- The daily energy usage has increased due to a specific event, e.g. a family function;
- There is a failure in the solar installation that reduces or shuts down its generation

or

- During periods of extended cloudy weather.

It was recommended in the Part 1 that the PV array be sized based on the average irradiation given in Peak Sun Hours (PSH) figure for the design month. The design month is the month where the ratio of available irradiation (PSH) to daily load energy for that month is the smallest. The irradiation of the design month is then used when determining the size of the required PV array. Determining the design month and hence the relevant irradiation value used for designing the PV array is detailed in section 14.1.

When a generator is available as a back-up, then the PV array may be sized based on the yearly average irradiation figure instead of the irradiation of the design month. The generator will then need to operate to make up for inadequate energy generation by the PV array in the months when the irradiation figure is less than the yearly average. However, with today's relatively low cost of PV modules and the high cost of fuel, it is recommended that even with a back-up generator, that the PV array be designed for the design month as detailed in section 14.1.

36.1. Determining the Battery system Capacity and Selecting the Battery system

For hybrid systems where the generator is only being used as a back-up, determining the required battery system capacity and selecting the battery system is undertaken in exactly the same way as is detailed in Part 1 sections 11 and 12 and hence is not repeated in this guideline.

Part 1 section 10 details how to select the dc system battery system voltage however with many of the larger hybrid systems the battery system voltage is determined by the interactive battery system inverter model selected.

36.2. Sizing the Solar Array and associated Solar Controllers and PV Inverters

For hybrid systems where the generator is only being used as a back-up, determining the required PV array size is undertaken exactly the same way as detailed in the Part 2 for dc coupled systems and Part 3 for ac coupled systems and is not repeated in this guideline. As stated above, it is recommended that the PV array be sized based on the irradiation for the design month.

The oversizing factor of 30% specified in the Parts 2 and 3 can be ignored because the back-up generator will be able to provide the extra charging required when equalising the lead acid batteries. However, it is recommended that this oversize factor of 30% be included to overcome the issue of the efficiency of the solar modules decreasing with time as well as minimising the volume of high-cost fuel needed for the generator.

As can be seen in the Part 1 the PV system can either be a dc coupled or ac coupled system configuration. With the dc coupled configuration, the solar controller can either be a switching controller, a pulse width modulated (PWM) controller or an MPPT controller. This results in numerous formulae for determining the available energy that can come from a PV array. In Part 1, 2 and 3, words were sometimes used in the formulas instead of symbols. However, due to the many configurations possible with a hybrid system, it is easier to introduce symbols for developing the different formulae. The formulae do have similarities and it is mainly the different sub-system losses that vary depending on the configuration.

The various formulae also vary slightly depending on whether the load energy is being supplied directly by the PV array or by the battery system being charged by the PV array. The difference in the two formulae is determined by whether or not the battery system charge/discharge efficiency needs to be included in the formula.

Based on the various formulae in Parts 2 and 3, the following three sections summarise the energy output formulas for the different system configurations. Note: When calculating the size of the array in the Parts 2 and 3, an oversize factor is applied. This is not included in the formula when just determining the energy delivered by the PV array.

36.2.1. dc Coupled System: Non-MPPT Solar Controller

Load Energy (dc) directly supplied by PV array

$$E_{DC1} = I_{MOD} \times N_p \times H_{TILT} \times V_{DC}$$

Load Energy (ac) directly supplied by PV array

$$E_{ac1} = I_{MOD} \times N_p \times H_{TILT} \times V_{DC} \times \eta_{INV}$$

Load Energy (dc) directly supplied by battery system charged by PV array

$$E_{DC2} = I_{MOD} \times N_p \times H_{TILT} \times V_{DC} \times \eta_{COUL}$$

Load Energy (ac) directly supplied by PV array

$$E_{ac2} = I_{MOD} \times N_p \times H_{TILT} \times V_{DC} \times \eta_{COUL} \times \eta_{INV}$$

Where,

E_{DC1} = dc energy directly supplied by PV Array (Wh)
E_{DC2} = dc energy directly supplied by battery system charged by PV Array (Wh)
E_{ac1} = ac energy directly supplied by PV Array (Wh)

E_{ac2} = ac energy directly supplied by battery system charged by PV Array (Wh)
I_{MOD} = Derated current from a module (A)
N_p = Number of parallel strings of modules (Dimensionless)
H_{TILT} = Daily irradiation (in PSH) for the specified tilt angle and orientation (H)
V_{DC} = Battery system (system) voltage (in V)
η_{COUL} = Coulombic efficiency of the battery system (dimensionless)
η_{INV} = Inverter efficiency (dimensionless)

Now

$$I_{MOD} = I_{T,V} \times F_{MAN} \times F_{DIRT}$$

Where,

$I_{T,V}$ = The output current (in A) of the module at the average effective cell temperature and system operating voltage
F_{MAN} = De-rating factor for manufacturer's tolerance (dimensionless)
F_{DIRT} = De-rating factor for dirt (dimensionless)

Note: The battery system and inverter efficiency can be combined together and called sub-system efficiency

36.2.2. d.c Bus: MPPT Controller

Load Energy (dc) directly supplied by PV array

$$E_{DC3} = P_{MOD} \times N \times H_{TILT} \times \eta_{MPPT} \times \eta_{PV\text{-}Load}$$

Load Energy (ac) directly supplied by PV array

$$E_{ac3} = P_{MOD} \times N \times H_{TILT} \times \eta_{MPPT} \times \eta_{INV} \times \eta_{PV\text{-}Load}$$

Load Energy (dc) directly supplied by battery system charged by PV array

$$E_{DC4} = P_{MOD} \times N \times H_{TILT} \times \eta_{MPPT} \times \eta_{WH} \times \eta_{PV\text{-}Load}$$

Load Energy (ac) directly supplied by PV array

$$E_{ac4} = P_{MOD} \times N \times H_{TILT} \times \eta_{MPPT} \times \eta_{WH} \times \eta_{INV} \times \eta_{PV\text{-}Load}$$

Where,

E_{DC3} = dc energy directly supplied by PV Array (Wh)
E_{DC4} = dc energy directly supplied by battery system charged by PV Array (Wh)
E_{ac3} = ac energy directly supplied by PV Array (Wh)
E_{ac4} = ac energy directly supplied by battery system charged by PV Array (Wh)
P_{MOD} = Derated power from a module (W)
N = Number of modules in the array (Dimensionless)
H_{ILT} = Daily irradiation (in *PSH*) for the specified tilt angle and orientation (H)
η_{WH} = Watt-Hour efficiency of the battery system (dimensionless)
η_{MPPT} = MPPT efficiency (dimensionless)
η_{INV} = Inverter efficiency (dimensionless)
$\eta_{PV\text{-}Load}$ = Cable (transmission) efficiency (dimensionless)

Now

$$P_{MOD} = P_{STC} \times F_{TEMP} \times F_{MAN} \times F_{DIRT}$$

Where,

P_{STC} = The rated output power(P) of the module at Standard test conditions
F_{TEM} = Derating factor for module temperature (dimensionless)

F_{MAN} = Derating factor for manufacturer's tolerance (dimensionless)
F_{DIRT} = Derating factor for dirt (dimensionless)

Notes:
1. The actual value of $\eta_{PV\text{-}Load}$ will vary for each formula depending on the number of cables and length of cables between the PV array and the load
2. The battery system, inverter, MPPT and cable efficiency can be combined together and called sub-system efficiency

36.2.3. AC coupled system

There is typically no dc load in ac coupled systems so no formulas have been provided for dc loads.

Load Energy (ac) directly supplied by PV array

$$E_{ac5} = P_{MOD} \times N \times H_{TILT} \times \eta_{PV} \times \eta_{PV\text{-}Load}$$

Load Energy (ac) directly supplied by the inverter via the battery system charged by the PV array

$$E_{ac6} = P_{MOD} \times N \times H_{TILT} \times \eta_{PVINV} \times \eta_{INV\text{-}CHG} \times \eta_{Wh} \times \eta_{INV} \times \eta_{PV\text{-}Load}$$

Where:
E_{ac5} = ac energy directly supplied by PV Array (Wh)
E_{ac6} = ac energy directly supplied by battery system charged by PV Array (Wh)
P_{MOD} = Derated power from a module (W)
N = Number of modules in the array (Dimensionless)
H_{TILT} = Daily irradiation (in *PSH*) for the specified tilt angle and orientation (H)
η_{Wh} = Watt-Hour efficiency of the battery system (dimensionless
η_{PV} = PV Inverter efficiency (dimensionless)
η_{INV_CHG} = Inverter efficiency acting as battery system charger (dimensionless)
η_{INV} = Inverter efficiency (dimensionless)
$\eta_{PV\text{-}Load}$ = Cable (transmission) efficiency (dimensionless)

Now

$$P_{MOD} = P_{STC} \times F_{TEMP} \times F_{MAN} \times F_{DIRT}$$

Where
P_{STC} = The rated output power(P) of the module at Standard test conditions
F_{TEM} = De-rating factor for the module temperature (dimensionless)
F_{MAN} = De-rating factor for manufacturer's tolerance (dimensionless)
F_{DIRT} = De-rating factor for dirt (dimensionless)

Note:

1. The actual value of $\eta_{PV\text{-}Load}$ will vary for each formula depending on the number of cables and length of cables between the PV array and the load
2. The battery system, PV inverter, Inverter (as charger), Inverter, and cable efficiency can be combined together and called sub-system efficiency

36.3. Calculating the Generator's Operating Hours

36.3.1. Generator required due to excess loads or extended cloudy weather

If the energy requirements are higher than what the system was designed for, e.g. a social function being held, then either the generator may operate during the time the function is being held or the generator will be

required to start when the battery system reaches a specified discharge level, typically 70-80% depth of discharge for a lead acid battery system or the minimum usable energy level in a Lithium-Ion battery system.

The time taken to recharge the battery system by a generator is dependent on:

- The amount of energy (in Wh or ampere hours) that is reflected in the 70-80% depth of discharge or effective battery system capacity that is required to be replaced by the generator providing charging.
- The efficiency of the battery system: either Ah (coulombic) efficiency or energy (Wh) efficiency.
- The charging current (or power) from the battery system charger (either stand-alone battery system charger or inverter operating as a charger).

The generator run-time to recharge the battery system is calculated by either of the following two formulas:

$$T_{GEN} = Batt_{Ah} / (I_{bc} \times \eta_{coul})$$

Where,
T_{GEN} = Required generator run time (hours)
$Batt_{Ah}$ = Battery system ampere hours that needs to be replaced by the generator charging (Ah)
I_{bc} = Charging current from battery system charger (A)
η_{coul} = Battery system coulombic efficiency

or

$$T_{GEN} = Batt_{Wh} / (P_{bc} \times \eta_{Wh})$$

Where,
T_{GEN} = Required generator run time (hours)
$Batt_{Wh}$ = Battery system energy that needs to be replaced by the generator charging (Wh)
P_{bc} = Charging power from battery system charger (power)
η_{Wh} = Battery system energy (Wh) efficiency

Worked Example 46: Calculating generator run time for charging batteries (System with Lead acid batteries)
Lead Acid Battery system has a capacity of 1200 Ampere-hours
It has been discharged by 80%.
Battery system Charger has a charging current of 80 A.
Coulombic efficient is 90% (0.9).
How long will the generator need to operate to fully recharge the battery system? .

Battery system Ah that needs to be replaced = 0.8 (80%) × 1200 Ah = 960 Ah.

The generator run time is:
$T_{GEN} = Batt_{Ah} / (I_{bc} \times \eta_{coul}) = 960 / (80 \times 0.9) = 13.33$ hours

Worked Example 47: Calculating generator run time for charging batteries (System with Li Ion batteries)
A Lithium-Ion Battery system has a capacity of 60 kWh but a useable capacity of 54 kWh Ampere-hours which has been depleted.
Battery system Charger has a charging power of 5 kW
The energy efficiency of the Lithium-Ion battery system is 95% (0.95).
How long will the generator need to operate to fully recharge the battery system?

The generator run time is:
T_{GEN}= $Batt_{Wh}$/ (P_{bc} × η_{Wh}) = 54000/ (5000 × 0.95) = 11.37 hours

36.3.2. Generator required due to PV array sized for yearly average irradiation

When the PV Array is sized for the yearly average irradiation figure instead of that for the design month, then there will be months when the irradiation will be less than the yearly average and the generator will be required to operate to overcome the energy deficit in the system on those days. While the generator is operating it will meet some loads directly, however, to keep the explanation simple it is assumed that when the generator is operating it will meet the energy deficit by charging the batteries. This conservative approach does result in the generator not actually operating for as long as predicted.

To determine the generator run time then the solar fraction needs to be determined. The solar fraction (F_{pv}) is defined as: The total load energy that is supplied by the PV array (E_{PV}) divided by the total daily load energy required by the site (E_{load})

The formula is $F_{pv} = E_{PV} / E_{load}$

Where,
F_{pv} = Solar fraction
E_{PV} = Load energy supplied by PV
E_{load} = Daily load energy required

The exact formula will depend on:

- Whether the loads are all dc, all ac or a combination of both.
- The configuration of the PV system, that is: is it a dc coupled system using a non-MPPT controller, a dc coupled system using a MPPT controller, or an ac coupled system.

The formula can be very complicated if consideration is given to whether all the load energy is being supplied directly from the batteries (being charged by the PV array) or some of the load energy is being supplied directly by the PV array and the rest is then being supplied by the batteries (that are charged by the PV array). As can be seen in section 36.2 there are many formulae used for determining the load energy being supplied by the PV array, but they are similar and the variation is just in the sub-systems losses that are taken into account in the formulae.

The solar fraction for a site will vary for each month that the monthly average irradiation is less than the yearly irradiation figure used in determining the capacity of the PV Array.

Once the solar fraction is calculated then the balance of daily energy that must be supplied by the generator charging the battery system can be calculated by the following formula:

$$E_{Load\text{-}BC} = (1- F_{pv}) \times E_{load}$$

The generator run time can then be determined as follows:

$$T_{GEN}= E_{Load\text{-}BC} / (P_{bc} \times \eta_{Wh} \times \eta_{inv})$$

Where,
T_{GEN} = Required generator run time (hours)
$E_{Load\text{-}BC}$ = Load energy that needs to be replaced by the generator charging (Wh)
F_{pv} = Solar fraction
E_{load} = Daily load energy required
P_{bc} = Charging power from battery system charger (power)
η_{Wh} = Battery system energy (Wh) efficiency
η_{inv} = Inverter energy (Wh) efficiency

Worked Example 48: Calculating generator run time based on solar fraction
A hybrid system has been designed where the PV array has been sized based on the average yearly irradiation. The daily load energy (E_{load}) = 20 kWh
In the month with lowest irradiation the PV array will meet a load of 16 kWh
The inverter/Charger has a charging power of 5 kW
The inverter has an efficiency of 93%
The battery system has a Wh efficiency of 80%

What is the solar fraction?
How long will the generator be required to operate to overcome the energy deficit?

The solar fraction is $F_{pv} = E_{PV}/E_{load} = 16/20 = 0.8$

The load energy that must be supplied by generator charging the batteries is
$E_{Load\text{-}BC} = (1- F_{pv}) \times E_{load} = (1-0.8) \times 20 = 4$ kWh

The generator run time is
$T_{GEN} = E_{Load\text{-}BC} / (P_{bc} \times \eta_{Wh} \times \eta_{inv}) = 4/ (5 \times 0.80 \times 0.93) = 1.08$ hrs

37. Generator Used Daily

37.1. Determining the Proportion of Daily Energy being Provided by the Different Sources

For large villages and resorts where the daily energy usage is in the many hundreds of kWh, a generator may need to operate daily. In particular it may be needed during the evening peak (for example 6 p.m. to 10 p.m.) and possibly the morning peak around breakfast time. The generator is used because the power requirements at that time can be very large and trying to meet the power demand (and energy usage) by battery system power may be more expensive than that from the generator since the available solar will either be small (morning) or non-existent (evening). However, if prices of lithium batteries decrease as predicted this cost could come down rapidly in the next few years.

For this section it is assumed that all the loads are ac only.

For a hybrid system where the generator is operating daily, the total daily energy requirement is determined as follows:

$$E_{Load} = E_{gen} + E_{gen\text{-}batt} + E_{PV} + E_{PV\text{-}batt}$$

Where,
E_{Load} = Total Daily Energy Requirement
E_{gen} = Energy supplied by generator directly

$E_{gen\text{-}batt}$ = Energy supplied by generator charging battery system
E_{PV} = Energy supplied directly by PV array
$E_{PV\text{-}batt}$ = Energy supplied directly by PV array charging battery system

How much power is available from the generator for charging the batteries will be dependent on the capacity rating of the generator and the loads that are being powered directly by the generator at that point of time. Any excess generator capacity can be used to charge the battery system.

In some sites the generator might already be installed and there may not be any excess capacity available for properly charging the battery system at the same time. Every site will be different.

If the system to be installed is a new system, then the designer has the choice:

- select a generator just to meet the load maximum demand requirements when the generator is operating;

or

- include the battery system charger as one of the loads that operates at full capacity when the generator is operating

Currently the cost of PV when meeting loads directly is cheaper than operating a diesel generator, however when combined with the cost of batteries it is often not. To determine which option is the best, a larger generator to allow for effective battery system charging by the generator when operating or adding more modules to the PV array, the extra fuel costs in operating the larger generator plus the cost of a larger generator needs to be compared with the costs of adding more solar modules. This analysis needs to be undertaken for each site and it will depend on the size of the various equipment required.

37.2. Determining the Energy to be Supplied by the Battery system

When preparing the load profile, the system designer must determine what loads (and therefore energy) will be met directly by the generator.

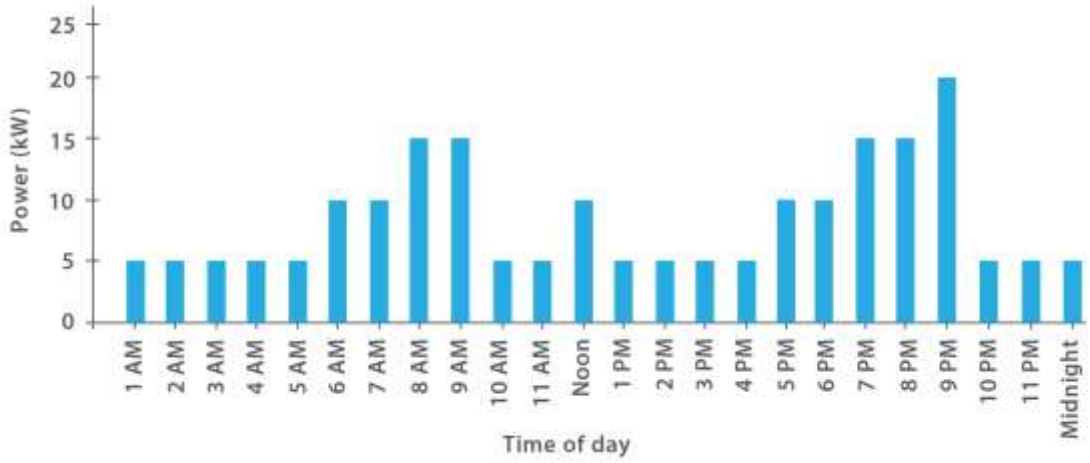
If the load profile has the form of a "double hump" (higher than average morning and evening loads) then ideally the generator should operate mainly during the largest of, or both of these two humps. If the system is being designed with the generator operating once per day only, then it should operate during the hump (the period of high-power usage) when the greatest *energy* use occurs. This is generally in the evening.

Once the system designer has determined how much energy is supplied directly from the generator, the designer must then determine the energy that is required to be met directly by the batteries. The simplest and most conservative approach is to assume that no solar power/energy is supplied directly to the loads, thus the daily load energy not supplied from the generator is supplied from the batteries.

It is recommended that, even with two generator starts every day that the designer use the conservative approach that assumes that the batteries must meet the total daily energy demand outside of the generator run times. While in theory the battery system only needs to store the largest amount of energy between the two peaks and hence the two generator operating times, it becomes very complicated to determine this value with a reasonable level of confidence. Such a small battery system would also leave little time for responding to generator failures.

Worked Example 49: Calculating average daily energy supplied by batteries

The site has a daily load of 200 kWh and has the following load profile with two humps.



The generator operates only between 6 p.m. and 9 p.m. each night. (Note: the energy shown for each time is for the proceeding hour e.g. 1 a.m. is for midnight to 1 a.m.)

What daily energy must be supplied directly by the batteries?

From the above load profile, 50 kWh (15 + 15 + 20) of load operates between 6 p.m. and 9 p.m. This is therefore supplied directly from the generator.

Therefore, the energy that must be supplied directly by the battery system is the total daily load minus 50 kWh:

$E_{batt,day}$ = 200 kWh - 50 kWh = 150 kWh

Note that in practice the actual energy provided by the battery system will depend on the amount of solar energy input when the generator is not running.

In worked example 49, the solution assumes that there is no input from solar, which is a “worst case” situation of a very overcast day. If this is the basis for sizing of the battery system, the generator will never need to start more than once per day. However, the daily depth of discharge should be less than estimated because the solar will provide loads directly and possibly charge the battery system during the day. This may result in longer battery system life, but it may also mean that the investment in batteries is not being utilised as much as it could. The alternative is to size the battery system assuming that there is a certain amount of solar input.

If the renewable energy input is taken into account in sizing the battery system, the size specified will of course be smaller (and lower cost). The maximum demand will then be at higher discharge rate for that smaller battery system, than for a larger battery system. The ability of the battery system to meet the maximum and surge demands is therefore more critical.

Whatever assumptions are used in the design process, the system must be able to cope with variations in both load and also solar input. These variations in both load and solar input make it very difficult to accurately determine how much load each day is expected to be supplied from the batteries.

In addition, the effect of these variations on the actual operation of the generator will depend on how the generator is controlled.

i) If the generator starts at a pre-determined time each day, then the battery system depth of discharge will vary, and the generator run-time will vary;
ii) If the generator is started on 'low battery system' state of charge signal, then the generator start time will vary each day, and the frequency of starts may vary;
iii) If the generator is started on both time of day or state of charge, the result will be a mixture of the above, depending on which condition is reached first.

Note: in the previous discussion, generator starting due to excessive inverter load has been omitted for clarity and it is assumed that the inverter will have sufficient capacity to meet the required load.

The variations in operating conditions mentioned above may have serious consequences. Firstly, the client may only want the generator to start during certain times of the day. Secondly, and more importantly in a PV-generator-hybrid system, if the generator fully charges the battery system in the morning just before the PV array starts to generate, valuable PV power may be wasted, and fuel consumption and generator operating time may increase. Also, the generator should not start in the middle of sunny days and therefore potentially wasting solar power. Avoiding these potential problems requires careful thinking-through of the implications of battery system sizing and generator control strategies in relation to the points mentioned above.

37.3. Determining the Battery system Capacity and Selecting the Battery system

When the generator is operating every day, the battery system capacity depends on the energy that the battery system will supply each day and the design depth of discharge. The concept of "days of autonomy" does not apply in this case, because the generator would recharge the battery system if there has been no input from the solar.

In terms of energy, the battery system capacity is

$$E_{batt} = (E_{batt,day})/ (DOD_{day} \times \eta_{inv})$$

Where,

E_{batt} = The battery system energy storage capacity (to 100% DOD), (Wh)
DOD_{day} = Daily depth of discharge of the battery system, expressed as a percentage
$E_{batt,day}$ = The load energy drawn from the batteries each day, (Wh)
η_{inv} = inverter energy (Wh) efficiency

This requires the daily depth of discharge to be specified. The above formula can be applied to lead acid batteries which though they often have a maximum depth of discharge of 70-80% they should not have a daily depth of discharge greater than 50% while only 30% is preferred

For Lithium-Ion battery system, the battery system is defined as having a specified capacity and then a maximum usable energy value—often 80-100% of the actual capacity. The formula for determining the usable battery system capacity is:

$$E_{batt\text{-}usable} = E_{batt,day}/ \eta_{inv}$$

Where,

$E_{batt\text{-}usable}$ = The usable battery system energy storage capacity (between 80%- 100% of rated capacity), (Wh)
$E_{batt,day}$ = The load energy drawn from the batteries each day, (Wh)
η_{inv} = Inverter energy (Wh) efficiency

For lead acid batteries the batteries are specified in Ampere Hours (Ah). The capacity in Ah is then given by

$$C_x = \frac{E_{batt}}{V_{dc}}$$

Where,

E_{batt} = The battery system energy storage capacity (to 100% DOD), (Wh)
V_{DC} = Nominal voltage of the battery system voltage, (V)
C_x = Battery system capacity, specified for an appropriate discharge rate x, (Ah)

For hybrid systems the battery system voltage is determined by the battery system inverter dc input voltage and these typically are 12 V, 24 V or 48 V dc However, some brands of inverters may have battery system voltages of 120 V dc or higher. Most medium sized hybrid systems tend to have inverters with a 48 V dc rating. For rural area electricity supply a battery system voltage higher than 48 V is not recommended due to higher voltages have safety issues requiring much more highly trained maintenance personnel.

It is recommended that the C_{10} rating of lead acid type battery system is applied and 1C for Li-Ion

Worked Example 50: Calculating Battery system Capacity

From worked example 49, the battery system must provide 150 kWh per day and the design daily depth of discharge is specified as 70%.
The inverter has an efficiency of 93%

What is the required battery system capacity in kWh? If the nominal system voltage is 48 V, what is the capacity in Ah?

Given DOD_{day} = 0.7 and $E_{batt,day}$ = 150 kWh.
The required battery system capacity is

E_{batt} = (150/ 0.7 × 0.93)
= 230.4 kWh
rounded to = 230 kWh

Assume the battery system is 48V DC

The capacity in Ah is then $C_x = \frac{E_{batt}}{V_{dc}}$

C_x = 230,000 Wh/48 V
= 4800 Ah

37.4. Determining the Energy Supplied by Generator Charging Battery system

If the generator is sized to allow the inverter charger (or battery system charger) to operate at full capacity, then the amount of daily load energy that will be supplied via the generator charging the battery system will depend on the effective charging capability of the inverter charger. Some inverter/chargers charging capacity will be specified in kW (or Watts) while others may be specified in Amperes. The charging current (or power) allowed by the inverter/charger shall not be greater than the maximum charge current (or power) of the selected battery system unless the inverter charge software can be set to limit the charge current to the maximum acceptable current for the installed battery system.

If the maximum charging capacity of an inverter/charger is specified as a current, then the daily load that will be met by the generator charging the battery system is:

$$E_{gen} = T_{GEN} \times I_{bc} \times V_{DC} \times \eta_{inv\text{-}chg} \times \eta_{coul}$$

Where,
T_{GEN} = Generator run time (hours)
I_{bc} = Charging current from battery system charger (A)
V_{DC} = Nominal voltage of the battery system voltage, (V)
η_{coul} = Battery system coulombic efficiency
$\eta_{inv\text{-}chg}$ = Inverter's charging energy (Wh) efficiency

If the maximum charging capacity of an inverter/charger is specified in power then the daily load that will be met by the generator charging the battery system is:

$$E_{gen} = T_{GEN} \times P_{bc} \times \eta_{inv\text{-}chg} \times \eta_{Wh}$$

Where,
T_{GEN} = Generator run time (hours)
η_{Wh} = Battery system energy (Wh) efficiency
$\eta_{inv\text{-}chg}$ = Inverter's charging energy (Wh) efficiency
P_{bc} = Charging power from battery system charger (W)

Worked Example 51: Calculating load energy supplied by generator charging batteries

Assume the inverter for the system in the worked example is 25 kW and it can provide the full 25 kW when charging the battery system and the generator has the capacity to provide the 25-kW allowing for charger efficiency.
The inverter's charger has an efficiency of 93%.
The battery system has an energy efficiency of 80%.

What load energy can be supplied by the generator charging the battery system?

From worked example 49 the generator operates for 3 hours.

From $E_{gen} = T_{GEN} \times P_{bc} \times \eta_{inv\text{-}chg} \times \eta_{Wh}$ = 3 hrs × 25 kW × 0.93 × 0.8 = 55.8 kWh

37.5. Determining the Daily Load Energy to Be Provided by the PV Array

If the generator has the capacity to meet the loads and provide charging of the battery system, the amount of daily load energy to be supplied by the PV array is:

$$E_{pv} = E_{PV\text{-}dir} + E_{PV\text{-}batt} = E_{Load} - E_{gen} - E_{gen\text{-}batt}$$

Where,
E_{Load} = Total Daily Energy Requirement
E_{gen} = Energy supplied by generator directly
$E_{gen\text{-}batt}$ = Energy supplied by generator charging battery system
$E_{PV\text{-}dir}$ = Energy supplied directly by PV array
$E_{PV\text{-}batt}$ = Energy supplied directly by PV array charging battery system

However, if the generator does not have the capacity to provide charging of the battery system a different equation must be used. If the generator only has the capacity to meet the loads, the amount of daily load energy to be supplied by the PV array is:

$$E_{pv} = E_{PV\text{-}dir} + E_{PV\text{-}batt} = E_{Load} - E_{gen}$$

In practice since the loads will vary over time the generator may still be able to charge the battery system at sometimes but trying to estimate exactly how much is difficult and usually not very accurate. Assuming that no charging occurs from the generator is the conservative approach.

Once the amount of daily load energy to be supplied by the PV array is determined then the designer will need to determine the size of the array. How this is undertaken will depend on the configuration of the system. The different formulas are contained in Part 2 and Part 3 and the designer should refer to relevant sections guideline when determining the size of the array. The respective formulae have also been summarised in section 36.2 of this guideline and a summary of the different system losses is provided in section 36 of this guideline.

Worked Example 52: Calculating load energy to be provided by PV array

Based on worked example 49, 50 and 51, what is the load energy that shall be provided by the PV array assuming that the generator has the capacity to meet the loads and provide charging of the battery system?

$E_{pv} = E_{Load} - E_{gen} - E_{gen\text{-}batt}$

From example 49: E_{Load} = 200 kWh and E_{gen} = 50 kWh

From worked example 51: $E_{gen\text{-}batt}$=55.8 kWh

Therefore E_{pv} = 200 kWh - 50 kWh - 55.8 kWh = 94.2 kWh.

38. Summary of Hybrid System Losses

Hybrid systems can consist of AC coupled systems, DC coupled systems or a combination of both. Trying to remember and apply all the formulas related to losses between the energy sources and the loads for the various configurations can be very difficult. It is best that the designer always first draws the configuration of the system that is proposed for the design and then determines the sub-system losses for that configuration among the various energy sources, (e.g. PV array, battery system, generator) and the loads. These will be required when trying to determine the size of the PV array required. This section summarises the various losses in the different configurations

38.1. System Efficiencies in a DC Coupled Systems Supplying AC Loads

Figure 27 shows the various system losses in a dc coupled system providing ac energy to loads. Table 11 summarises the typical losses for the many pathways between the energy sources and the loads.

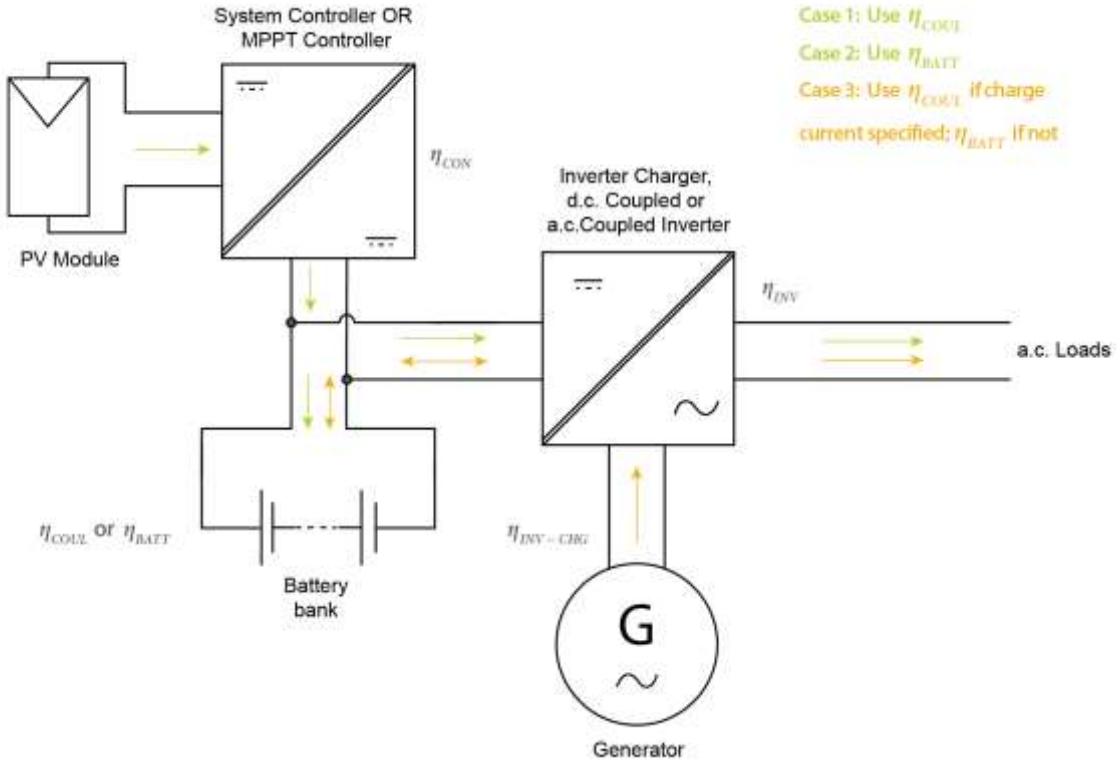


Figure 27: System Losses in a DC coupled configured hybrid system-excluding cable losses

Note: The arrows in Figures 27 and 28 show how power/energy flows from one component to another. They are not colour coded as dc and ac as shown in earlier figures

Table 11: System efficiency losses for DC coupled system supplying AC loads

Case 1: Switched/non-MPPT Solar controller. The PV Array charges battery system via a switching or PWM controller & the battery system inverter supplies ac loads. **The system is based upon Ah.**	**Case 2: MPPT Solar controller.** The PV array charges battery system via a MPPT controller & the battery system inverter supplies ac loads. **The system is based upon Wh.** Note: Individual cable losses can be combined and stated as cable losses (transmission losses) between PV array and inverter or loads.	**Case 3: Generator and inverter-charger.** When the generator is running, it can charge the battery system via the inverter-charger and the maximum charge current is based upon the battery system requirement and the maximum current rating for the charging circuit in the inverter. When the generator is off the battery system inverter-charger supplies all the ac loads. **The system is based upon Ah.** Note: The inverter-charger could be bidirectional or dc coupled interactive.
1) Battery system coulombic efficiency losses when charging *(typ ~10%)*	**1)** Cable losses between the PV array to MPPT *(typ <1%)*	**1)** Battery system coulombic efficiency losses when charging *(typ ~10%)*

2) Battery system inverter efficiency losses *(typ ~4-12%)*	**2)** MPPT efficiency losses may also apply *(typ ~4-5%)*	**2)** Battery system inverter efficiency losses *(typ ~4-12%)*
	3) Cable losses between MPPT and battery system *(typ <1%)*	
	4) Battery system watt-hour efficiency losses when charging *(typ ~10-30% depending on technology)*	
	5) Cable losses between battery system and battery system inverter *(typ <1%)*	
	6) Battery system inverter efficiency losses *(typ ~4-12%)*	

38.2. System Efficiencies in an AC Coupled systems Supplying AC Loads

Figure 28 shows the various system losses in an ac coupled system providing ac energy to the loads. Table 12 summarises the typical losses for the many pathways between the loads and the energy sources.

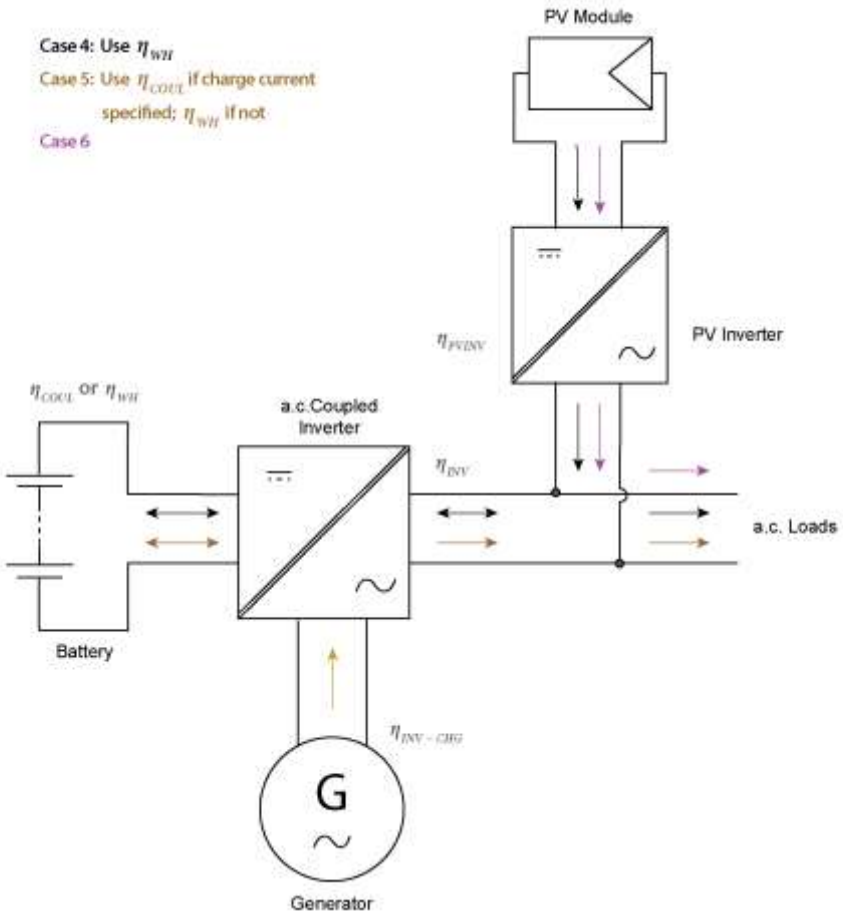


Figure 28: System Losses in an ac coupled configured hybrid system-excluding cable losses

Table 12: System efficiency losses for ac coupled system supplying ac loads

Case 4: PV array is connected to PV inverter, charges batteries via battery system inverter and batteries supply load. **The battery system inverter would be ac coupled interactive.**	**Case 5: generator powers the ac load and charges battery system via the battery system inverter. At times the battery system supplies none, some or all of the ac load.** **The battery system inverter would be ac coupled interactive.**	**Case 6: PV array is connected to PV inverter and supplies ac loads directly.**
1) Cables losses between the PV array to PV inverter *(typ <1%)*	**1)** Cable losses between the generator and battery system inverter *(typ <1%)*	**1)** Cables losses between the PV array to PV inverter *(typ <1%)*
2) PV inverter efficiency losses *(typ ~3-6%)*	**2)** Battery system inverter efficiency losses *(typ ~4-12%) acting as charger*	**2)** PV inverter efficiency losses *(typ ~3-6%)*
3) Cable losses between PV inverter and battery system inverter *(typ <1%)*	**3)** Cable losses between battery system inverter and battery system *(typ <1%)*	
4) Battery system inverter efficiency losses *(typ ~4-12%) acting as charger*	**4)** Battery system watt-hour efficiency losses *(typ ~20%)*	
5) Cable losses between AC battery system inverter and battery system *(typ <1%)*	**5)** Cable losses between battery system and battery system inverter *(typ <1%)*	
6) Battery system watt-hour efficiency losses *(typ ~20%)*	**6)** Battery system inverter efficiency losses *(typ ~4-12%)*	
7) Cable losses between battery system and battery system inverter when inverting *(typ <1%)*	Note: If battery system charging current from ac coupled interactive battery system inverter is specified then losses similar to that of Case 3 in Table 10 would be applied.	
8) Battery system inverter efficiency losses *(typ ~4-12%)*		

38.3. Combined AC and DC Coupled System Configurations

Figure 29 shows the various system losses in a combined ac and dc coupled system providing ac energy to loads. Table 11 and Table 12 provide the typical figures.

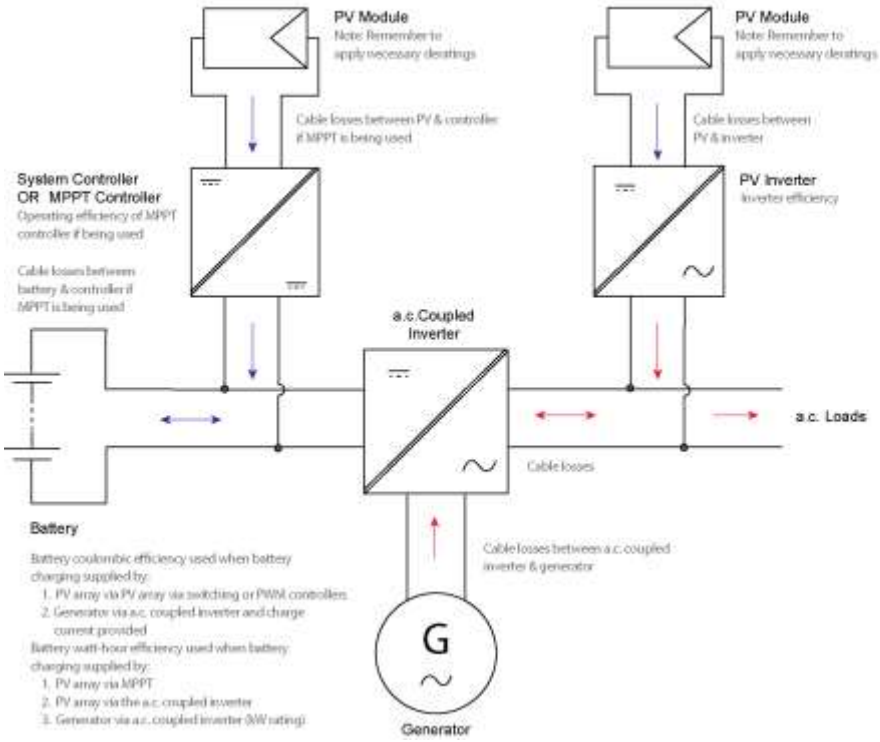


Figure 29: System Losses in a combined ac and dc coupled configured hybrid system

PART 5 - Designing the System Wiring, Isolation and Protection Requirements

A systems designer shall also be fully aware of the installation requirements of the various components, including battery system ventilation requirements and also able to determine the system wiring, Isolation and protection requirements.

These are covered in the separate document *Off-Grid PV Power Systems – System Installation Guidelines*. To reduce the size none of that information is repeated in this guideline.

PART 6- Preparing Diagrams, Bill of Materials and Quotation

39. Draw-Schematic/Single Line diagram

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

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

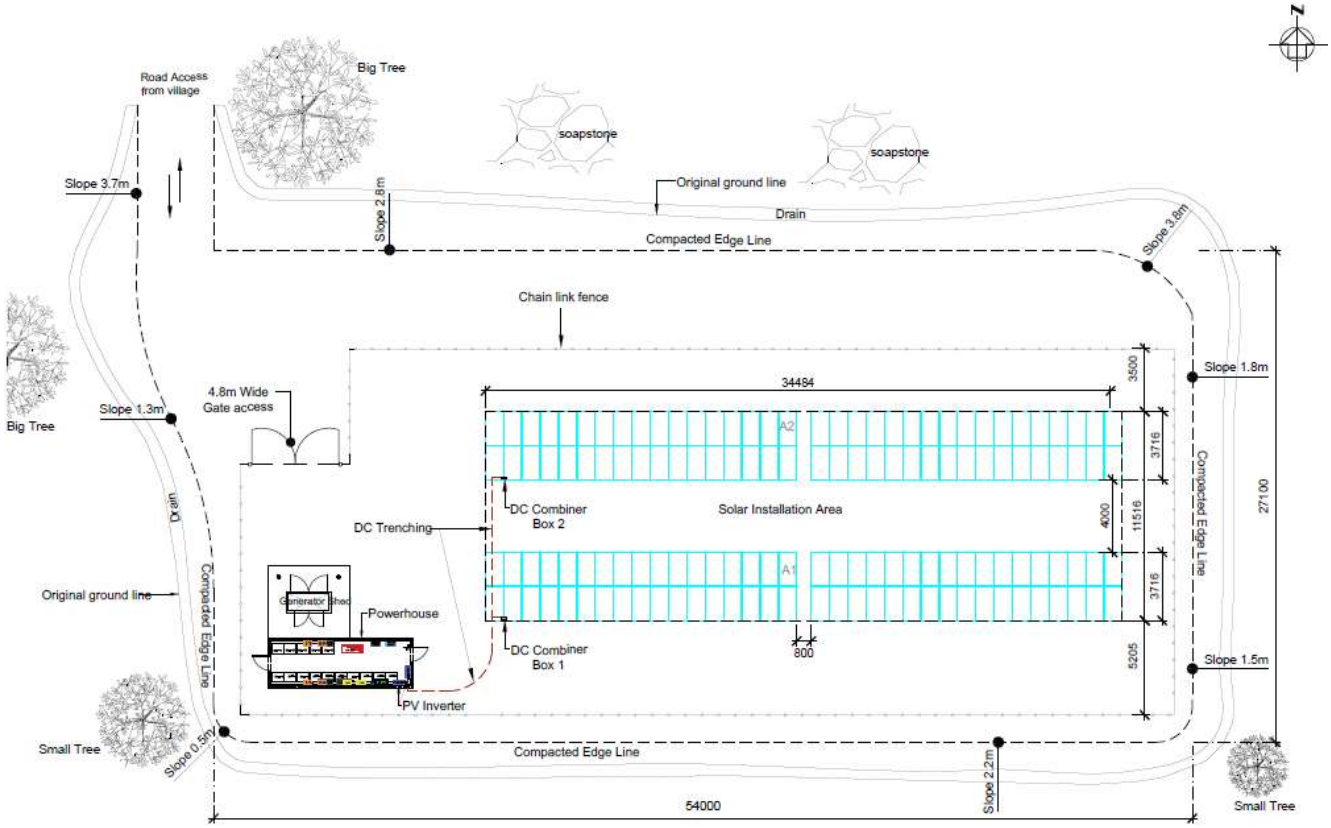
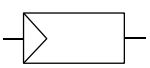
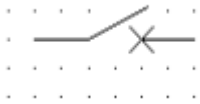
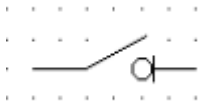
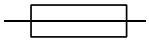
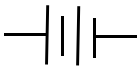
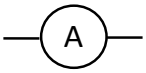
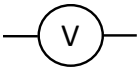
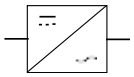


Figure 30 Sample Site Plan

A schematic circuit diagram is the representation of a power system using the simple symbol for each component. This diagram should show the main connections and arrangement of the system components along with their data such as current rating, voltage, power rating, cable size, etc. Table 13 shows universally accepted electrical symbols to represent the different electrical components are generally applicable for Solar Home System circuit diagram. A designer must prepare this diagram and include it as part of design document. This will help in procuring and installing the right components and wiring the system correctly.

Table 13: Electrical Schematic Symbols

Symbol	Identification	Explanation
	PV Module	Represents solar PV modules
	Circuit breaker	Represents a fixed mounted low voltage circuit breaker

		
	Disconnect switch	Represents a switch (open position shown)
	Fuse	Represents fuses in DC circuit
	Ground (earth)	Represents a grounding (earthing) point
	Battery system	Represents a battery system in an equipment package
	Ammeter	Represents ammeter
	Voltmeter	Represent voltmeter
	Inverter	Represents inverter

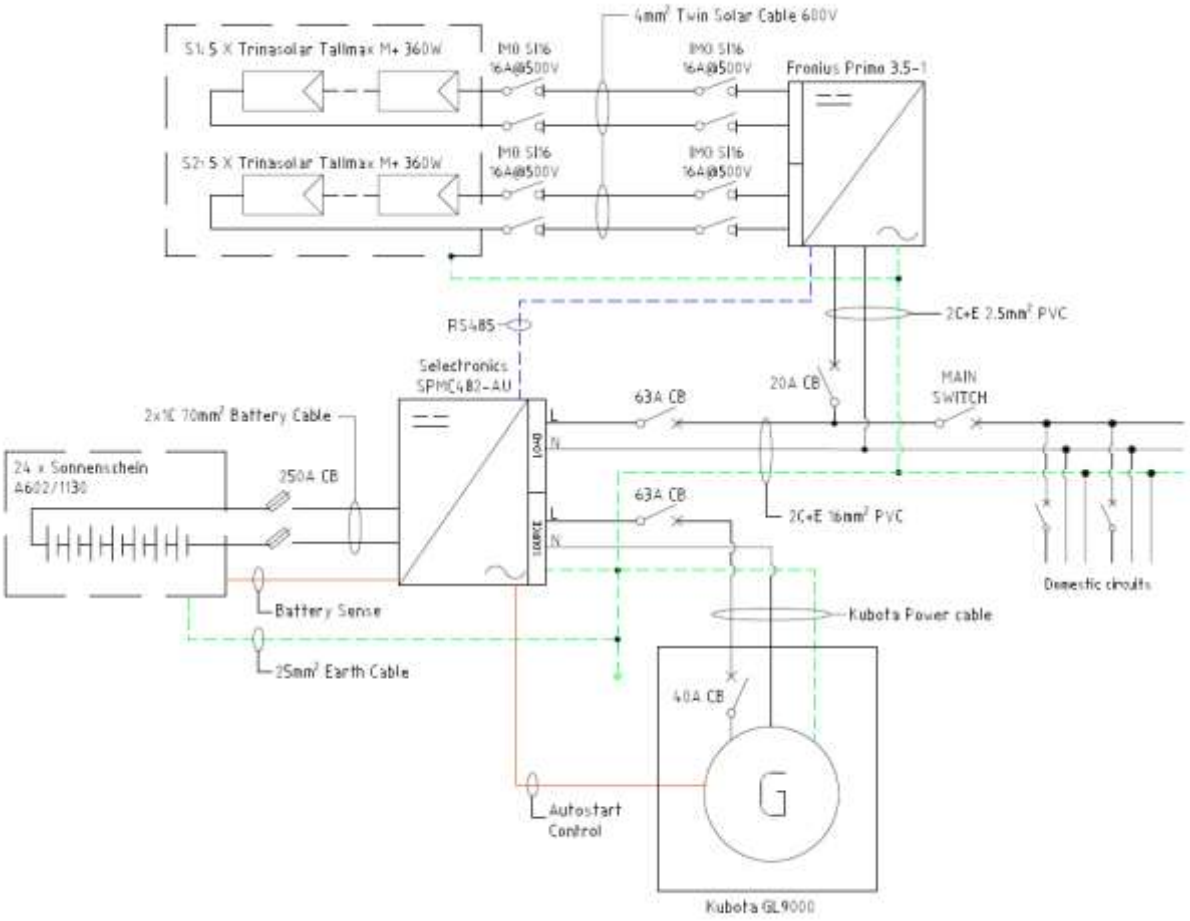


Figure 31 Example of electrical schematic of an off-grid PV system as per AS/NZS standards

40. Prepare Bill of Materials

After design is complete, a bill of materials or bill of quantity should be prepared to estimate the system cost. An example of a bill of materials for a typical small Solar Home System is presented in table 14.

Table 14: Bill of materials and costings for a typical Solar Home System

Sl. No.	Description	Specification	Qty.
1.	Poly-crystalline solar PV module		
2.	Storage battery system		
3.	Battery system inverter		
4.	MPPT		
5.	Mounting structure for roof		
6.	Battery system rack		
7.	Single core dc cable		
8.	Two or three core ac cable		
9.	Battery system fuses		
10.	dc switch to disconnect PV modules		
11.	dc switch to disconnect battery system		
12.	ac switch to disconnect ac loads		
13.	dc combiner box		

A hybrid system would also include generators and more isolation/protection equipment and cables

41. Providing a Quotation

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

- Full specifications of the system including quantity, make (manufacturer) and model number of the relevant components, whichever applicable, including solar modules, inverter(s), solar charge controller, battery system and array frame.
- A copy of the load assessment sheet showing the details of how the load that the system is designed for was calculated.
- The expected performance of the system and how it will meet the power and energy requirements specified in the load assessment sheet.
- Expected levelized cost of energy (LCOE) i.e $/kWh and life cycle cost of the system.
- A firm quotation which shows the installed cost of the complete system.
- Warranty information relating to each of the items of equipment
- Warranty information relating to the installation of the system (minimum of 1 year)

Note, there are computer programs and sizing tools available that can provide more detailed quotes.

42. Appendix 1: Summary of systems failures vs days of autonomy and array oversizing

Introduction

Battery system energy storage is essential to off-grid PV power systems relying on intermittent renewable energy as the primary generation source, and the sizing of this battery systems storage has long been a critical and sometimes contentious issue in the industry. Due to the nature of stand-alone power systems, it is always necessary to size the battery according to the site-specific loads, customer requirements and customer expectations.

The industry has adopted the term "days of autonomy" as one way of specifying the size of battery system storage with reference to the site's particular needs; this is defined as the number of days that the battery can supply the site's loads without any support from generation sources. For example, it is the number of days a stand-alone power system with solar PV and battery systems experiencing several days of low solar irradiance can rely solely on the battery before having to operating a fuel generator. Autonomy is defined in AS/NZS4509.2:2010 as "*The number of days of operation of the power system without energy input from generators before exceeding the design maximum depth of discharge of the battery".* The minimum number of days of autonomy for sustainable system function is generally recommended anywhere from 2 to 5 days, depending on a number of variables.

However, the price of photovoltaic solar modules has dropped greatly in recent years, and it is now far more economical to purchase additional PV generation capacity than battery storage capacity. It is known that even on cloudy days, some solar irradiation is still available. A PV array that has a rated capacity significantly larger than that required by the site loads may be able to generate enough energy even on overcast days to support the battery storage. In this scenario, fewer days of autonomy should theoretically be required, as the batteries are no longer operating for long periods without any substantial energy input. Therefore, a common question now arising in the industry is: **Is it reasonable to install an oversized solar PV array and reduce the battery bank's days of autonomy, while maintaining quality outcomes for a stand-alone power system?**

Solar Resource Analysis

In the early days of system designs, monthly irradiation data, commonly stated as average daily peak sun hours (PSH) was typically used. Now more and more data is available. Within Australia, daily irradiation figures can be obtained for each day over the previous 20 to 30 years for most weather stations from the Bureau of Meteorology (http://www.bom.gov.au/climate/data/).

The granular data from weather stations made it possible to undertake analysis to determine when a stand-alone PV power system could not provide the required daily energy for various days of autonomy given the PV array and battery capacity. In this analysis, the event where the PV and battery could no-longer provide the required energy, and a back-up generator would be required, is described as a blackout.

The analysis was then combined with increasing the size of the PV array to estimate the PV array oversize required for different days of autonomy. GSES has used the data to undertake analysis for a number of sites around Australia. The following tables show the tables relevant to Cairns, Queensland.

28 years of data was analysed.

Table 15: Average number of days system failures with 1 day of autonomy vs array oversizing

Average Number of days with system failures each month and year												
		Oversizing of array										
Month	Avg PSH	No Oversize	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	5.47	4.79	3.48	2.69	2.17	1.62	1.38	1.07	0.90	0.72	0.55	0.55
February	5.39	5.93	4.21	3.41	2.55	2.00	1.72	1.38	1.07	0.79	0.69	0.62
March	5.58	5.55	3.72	3.10	2.41	1.86	1.69	1.45	1.21	1.10	0.90	0.83
April	5.66	3.55	1.93	1.28	1.00	0.86	0.72	0.55	0.38	0.34	0.21	0.17
May	5.50	3.79	1.72	1.00	0.66	0.48	0.31	0.28	0.17	0.10	0.10	0.07
June	5.28	5.86	2.41	1.07	0.62	0.45	0.28	0.17	0.14	0.10	0.07	0.00
July	5.54	4.17	2.21	1.38	0.66	0.41	0.17	0.14	0.07	0.07	0.03	0.03
August	6.15	1.38	0.59	0.24	0.14	0.14	0.14	0.07	0.07	0.03	0.03	0.03
September	6.67	0.76	0.31	0.14	0.14	0.07	0.03	0.00	0.00	0.00	0.00	0.00
October	6.48	0.76	0.31	0.31	0.24	0.21	0.10	0.10	0.10	0.10	0.10	0.10
November	6.07	1.97	1.00	0.72	0.45	0.28	0.21	0.10	0.07	0.07	0.03	0.03
December	5.80	3.10	2.45	1.59	1.28	1.00	0.79	0.59	0.41	0.34	0.28	0.21
Average for year	**5.80**	41.62	24.34	16.93	12.31	9.38	7.55	5.90	4.59	3.79	3.00	2.66
Summary of System Failures												
Number of years out of 28 with system failures		28	28	28	27	27	26	26	26	23	23	22
Maximum Number of system failures in a year		97	60	39	30	27	23	19	14	12	9	8
Minimum Number of system failures in a year		5	4	2	0	0	0	0	0	0	0	0

Table 16: Average number of system failures with 2 days of autonomy vs array oversizing

Average Number of days with system failures each month and year												
		Oversizing of array										
Month	Avg PSH	No Oversize	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	5.47	3.24	1.97	1.38	1.00	0.79	0.55	0.38	0.31	0.24	0.17	0.10
February	5.39	3.93	2.48	1.76	1.45	1.00	0.59	0.24	0.14	0.07	0.07	0.07
March	5.58	4.00	2.28	1.28	0.93	0.72	0.66	0.52	0.41	0.34	0.24	0.21
April	5.66	1.69	0.72	0.48	0.28	0.24	0.17	0.14	0.00	0.00	0.00	0.00
May	5.50	1.79	0.69	0.28	0.07	0.03	0.03	0.00	0.00	0.00	0.00	0.00
June	5.28	4.14	0.97	0.52	0.14	0.10	0.07	0.00	0.00	0.00	0.00	0.00
July	5.54	2.69	0.79	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
August	6.15	0.38	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
September	6.67	0.17	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
October	6.48	0.24	0.17	0.14	0.10	0.10	0.07	0.03	0.03	0.00	0.00	0.00
November	6.07	0.86	0.41	0.28	0.07	0.03	0.00	0.00	0.00	0.00	0.00	0.00
December	5.80	1.97	1.24	0.83	0.62	0.38	0.24	0.07	0.00	0.00	0.00	0.00
Average for year	**5.80**	25.10	11.83	7.14	4.66	3.41	2.38	1.38	0.90	0.66	0.48	0.38
Summary of System failures												
Number of years out of 28 with system failures		28	27	24	23	22	20	15	10	7	6	5
Maximum Number of system failures in a year		61	36	24	17	14	13	10	6	6	5	4
Minimum Number of system failures in a year		1	0	0	0	0	0	0	0	0	0	0

Table 17: Average number of days system failures with 3 days of autonomy vs array oversizing

Average Number of days with system failures each month and year												
		Oversizing of array										
Month	Avg PSH	No Oversize	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	5.47	2.21	1.03	0.76	0.52	0.34	0.24	0.14	0.14	0.07	0.03	0.00
February	5.39	3.03	1.55	0.69	0.31	0.14	0.00	0.00	0.00	0.00	0.00	0.00
March	5.58	3.10	1.38	0.62	0.52	0.31	0.21	0.17	0.10	0.10	0.10	0.07
April	5.66	0.97	0.24	0.21	0.17	0.14	0.00	0.00	0.00	0.00	0.00	0.00
May	5.50	1.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
June	5.28	2.90	0.45	0.17	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
July	5.54	1.72	0.28	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
August	6.15	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
September	6.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
October	6.48	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
November	6.07	0.52	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
December	5.80	1.10	0.83	0.45	0.17	0.10	0.00	0.00	0.00	0.00	0.00	0.00
Average for year	**5.80**	16.72	6.03	2.97	1.72	1.03	0.45	0.31	0.24	0.17	0.14	0.07
Summary of System Failures												
Number of years out of 28 with system failures		27	23	19	15	11	5	3	2	2	2	1
Maximum Number of system failures in a year		50	23	16	13	11	6	4	4	3	3	2
Minimum Number of system failures in a year		0	0	0	0	0	0	0	0	0	0	0

Table 18: Average number of days system failures with 4 days of autonomy vs array oversizing

Average Number of days with system failures each month and year												
		Oversizing of array										
Month	Avg PSH	No Oversize	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	5.47	1.34	0.59	0.41	0.24	0.17	0.10	0.07	0.03	0.00	0.00	0.00
February	5.39	2.59	1.03	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
March	5.58	2.41	0.90	0.21	0.17	0.10	0.10	0.07	0.07	0.07	0.03	0.00
April	5.66	0.76	0.17	0.14	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
May	5.50	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
June	5.28	1.93	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
July	5.54	1.21	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
August	6.15	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
September	6.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
October	6.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
November	6.07	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
December	5.80	0.90	0.38	0.14	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Average for year	**5.80**	12.00	3.34	1.17	0.52	0.28	0.21	0.14	0.10	0.07	0.03	0.00
Summary of System Failures												
Number of years out of 28 with system failures		23	17	9	5	2	2	2	2	1	1	0
Maximum Number of system failures in a year		42	15	10	8	5	3	2	2	2	1	0
Minimum Number of system failures in a year		0	0	0	0	0	0	0	0	0	0	0

Table 19: Average number of days system failures with 5 days of autonomy vs array oversizing

Average Number of days with system failures each month and year												
		Oversizing of array										
Month	Avg PSH	No Oversize	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	5.47	0.86	0.34	0.17	0.10	0.07	0.03	0.00	0.00	0.00	0.00	0.00
February	5.39	2.00	0.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
March	5.58	1.93	0.52	0.10	0.10	0.07	0.03	0.03	0.00	0.00	0.00	0.00
April	5.66	0.62	0.10	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
May	5.50	0.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
June	5.28	1.24	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
July	5.54	0.90	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
August	6.15	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
September	6.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
October	6.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
November	6.07	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
December	5.80	0.59	0.07	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Average for year	**5.80**	8.76	1.79	0.34	0.21	0.14	0.07	0.03	0.00	0.00	0.00	0.00
Summary of System Failures												
Number of years out of 28 with system failures		21	10	4	2	2	2	1	0	0	0	0
Maximum Number of system failures in a year		41	10	5	3	2	1	1	0	0	0	0
Minimum Number of system failures in a year		0	0	0	0	0	0	0	0	0	0	0

43. Appendix 2: Solar Irradiation Data

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

Location		**Peak Sunlight Hours (kWh/m²/day)**												
Alofi, Niue		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 19°04′ South	0° Tilt[1]	6.47	6.2	5.67	4.81	4.26	3.86	4.01	4.61	5.35	6.02	6.53	6.46	5.34
Longitude: 169°55′ West	19° Tilt[2]	6.43	5.88	5.7	5.2	4.96	4.46	4.75	5.14	5.53	5.81	5.98	6.47	5.53
	34° Tilt[2]	6.06	5.39	5.47	5.24	5.24	4.78	5.08	5.29	5.41	5.41	5.35	6.15	5.41
Apia, Samoa		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual average
Latitude: 13°50′ South	0° Tilt[1]	5.39	5.47	5.16	5.09	4.63	4.46	4.71	5.25	5.77	5.91	5.76	5.51	5.25
Longitude: 171°46′ West	13° Tilt[2]	5.32	5.24	5.12	5.31	5.06	4.99	5.23	5.6	5.85	5.72	5.67	5.46	5.38
	28° Tilt[2]	5.14	4.86	4.93	5.37	5.34	5.4	5.62	5.79	5.74	5.35	5.45	5.3	5.36
Hagåtña, Guam		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 13°28′ North	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
Longitude: 144°45′ East	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]	6.4	6.48	6.75	6.39	6.71	6.27	5.77	4.9	5.18	5.77	6	6.19	6.06
Honiara, Solomon Islands		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 09°27′ South	0° Tilt[1]	5.99	5.55	5.61	5.41	4.76	4.59	4.45	5.19	5.81	6.26	6.4	6.22	5.52
Longitude: 159°57′ East	9° Tilt[2]	5.98	5.47	5.54	5.52	5	4.9	4.69	5.36	5.81	6.15	6.38	6.24	5.59
	24° Tilt[2]	5.92	5.29	5.34	5.58	5.26	5.28	4.98	5.52	5.71	5.88	6.29	6.22	5.61

Koror, Palau		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 07°20′ North	0° Tilt[1]	5.19	5.59	6.18	6.3	5.71	5.01	5.12	5.2	5.56	5.39	5.26	4.93	5.45
Longitude: 134°28′ East	7° Tilt[2]	5.4	5.7	6.16	6.22	5.7	5.01	5.11	5.15	5.49	5.45	5.44	5.16	5.5
	22° Tilt[2]	5.74	5.85	6.06	6.01	5.67	5.03	5.11	5.03	5.3	5.51	5.73	5.53	5.55

Lae, Papua New Guinea Latitude 6°44′S, Longitude 147°00′E		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		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 7°12′ North	0° Tilt[1]	5.26	5.86	6.11	5.89	5.66	5.31	5.35	5.63	5.42	5.15	4.88	4.84	5.44
Longitude: 171°06′ East	7° Tilt[2]	5.47	5.98	6.09	5.81	5.65	5.32	5.35	5.58	5.35	5.2	5.03	5.05	5.49
	22° Tilt[2]	5.83	6.16	5.99	5.62	5.62	5.35	5.35	5.46	5.16	5.24	5.27	5.4	5.53

Nauru		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 0°32′ South	0°Tilt[1]	5.77	6.24	6.27	6.04	5.99	5.75	5.85	6.25	6.7	6.5	6.12	5.5	6.07
Longitude: 166°56′ East	15° Tilt[2]	5.94	6.26	6.08	6.05	6.28	6.15	6.2	6.39	6.51	6.46	6.28	5.69	6.19

Noumea, New Caledonia		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 22°16′ South	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
Longitude: 166°27′ East	22° Tilt[2]	6.61	6.34	5.83	5.55	4.75	4.19	4.69	5.5	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		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 21°08′ South	0° Tilt[1]	6.69	6.3	5.62	4.65	4.04	3.58	3.78	4.43	5.23	6.28	6.69	6.7	5.32
Longitude: 175°12′ West	21° Tilt[2]	6.1	5.96	5.69	5.1	4.81	4.25	4.41	5.03	5.46	6.07	6.16	6.65	5.47

	36° Tilt[2]	5.35	5.47	5.45	5.14	5.08	4.55	4.67	5.18	5.34	5.64	5.45	6.25	5.3
Pago Pago, American Samoa		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 14°16′ South	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
Longitude: 170°42′ West	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		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 6°54′ North	0° Tilt[1]	4.97	5.57	5.91	5.79	5.44	5.33	5.51	5.54	5.66	5.29	5.03	4.83	5.4
Longitude: 158°13′ East	6° Tilt[2]	5.11	5.65	5.88	5.72	5.42	5.34	5.51	5.49	5.59	5.32	5.15	4.99	5.43
	21° Tilt[2]	5.42	5.81	5.79	5.55	5.41	5.39	5.54	5.4	5.4	5.38	5.42	5.34	5.49
Port Moresby, Papua New Guinea		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual average
Latitude: 9°29′ South	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
Longitude: 147°9′ East	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	5.42	5.43	5.69	5.91	6.1	6.5	6.13	5.68
Port Vila, Vanuatu		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual average
Latitude: 17°44′ South	0° Tilt[1]	6.68	6.2	5.76	4.98	4.2	3.79	4.04	4.75	5.65	6.47	6.67	6.93	5.5
Longitude: 168°19′ East	17° Tilt[2]	6.69	5.89	5.77	5.32	4.75	4.41	4.65	5.21	5.82	6.25	6.47	7.01	5.69
	32° Tilt[2]	6.38	5.42	5.55	5.38	5.01	4.74	4.97	5.37	5.7	5.82	6.08	6.74	5.6
Rarotonga, Cook Islands		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 21°12′ South	0° Tilt[1]	6.45	6.14	5.78	4.59	3.86	3.54	3.73	4.46	5.16	5.94	6.63	6.56	5.23
Longitude: 159°47′ West	21° Tilt[2]	5.9	5.82	5.86	5.04	4.56	4.2	4.34	5.07	5.38	5.74	6.11	6.51	5.38
	36° Tilt[2]	5.19	5.34	5.62	5.08	4.8	4.48	4.6	5.22	5.26	5.34	5.41	6.11	5.2

Suva, Fiji		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual average
Latitude: 18°08′ South	0° Tilt[1]	6.29	6.2	5.54	4.67	4.05	3.72	3.89	4.44	5.08	6.04	6.32	6.38	5.21
Longitude: 178°25′ East	18° Tilt[2]	6.27	5.88	5.55	4.99	4.61	4.38	4.51	4.88	5.21	5.83	6.1	6.41	5.38
	33° Tilt[2]	5.95	5.4	5.33	5.03	4.84	4.7	4.8	5	5.1	5.43	5.71	6.13	5.28

Tarawa, Kiribati		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual average
Latitude: 01°28′ North	0° Tilt[1]	5.58	5.98	5.99	5.87	5.82	5.7	5.87	6.15	6.52	6.4	6.1	5.5	5.95
Longitude: 173°02′ East	16° Tilt[2]	5.9	6.1	5.83	5.79	5.95	5.93	6.06	6.17	6.28	6.45	6.43	5.88	6.06

Vaiaku, Tuvalu		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
Latitude: 8°31′ South	0° Tilt[1]	5.16	5.27	5.33	5.29	4.93	4.66	4.76	5.3	5.72	5.8	5.57	5.23	5.25
Longitude: 179°13′ East	8° Tilt[2]	5.14	5.2	5.26	5.37	5.14	4.92	4.99	5.45	5.71	5.71	5.55	5.23	5.31
	23° Tilt[2]	5.09	5.05	5.08	5.43	5.41	5.29	5.32	5.61	5.61	5.49	5.48	5.21	5.34

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

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

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR SUVA - FIJI Latitude: 18 degrees 08 minutes South Longitude: 178 degrees 25 minutes East										
Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	97%	100%	100%	98%	95%	90%	83%	76%	67%	54%
10	97%	100%	100%	98%	95%	90%	83%	75%	67%	54%
20	97%	99%	100%	98%	94%	89%	82%	74%	66%	53%
30	97%	99%	99%	97%	93%	88%	81%	73%	64%	51%
40	97%	99%	98%	96%	92%	86%	79%	71%	62%	49%
50	97%	98%	98%	95%	91%	84%	77%	68%	59%	47%
60	97%	98%	97%	94%	89%	82%	74%	65%	56%	44%
70	97%	97%	96%	92%	87%	80%	71%	62%	52%	41%
80	97%	97%	95%	90%	84%	77%	68%	59%	48%	38%
90	97%	96%	93%	89%	82%	74%	65%	55%	44%	35%
100	97%	96%	92%	87%	80%	72%	62%	51%	41%	32%
110	97%	95%	91%	85%	78%	69%	59%	48%	37%	28%
120	97%	95%	90%	84%	76%	66%	56%	45%	33%	26%
130	97%	94%	89%	82%	74%	64%	53%	42%	30%	25%
140	97%	94%	88%	81%	72%	62%	51%	39%	29%	24%
150	97%	94%	88%	80%	71%	61%	49%	38%	28%	24%
160	97%	93%	87%	79%	70%	59%	48%	37%	27%	24%
170	97%	93%	87%	79%	69%	59%	47%	36%	27%	24%
180	97%	93%	87%	79%	69%	58%	47%	36%	27%	24%
190	97%	93%	87%	79%	69%	59%	47%	36%	27%	24%
200	97%	93%	87%	79%	70%	59%	48%	37%	27%	24%
210	97%	94%	88%	80%	71%	61%	49%	38%	28%	24%
220	97%	94%	88%	81%	72%	62%	51%	39%	29%	24%
230	97%	94%	89%	82%	74%	64%	53%	42%	30%	25%
240	97%	95%	90%	84%	76%	66%	56%	45%	33%	26%

250	97%	95%	91%	85%	78%	69%	59%	48%	37%	28%
260	97%	96%	92%	87%	80%	72%	62%	51%	41%	32%
270	97%	96%	93%	89%	82%	74%	65%	55%	44%	35%
280	97%	97%	95%	90%	84%	77%	68%	59%	48%	38%
290	97%	97%	96%	92%	87%	80%	71%	62%	52%	41%
300	97%	98%	97%	94%	89%	82%	74%	65%	56%	44%
310	97%	98%	98%	95%	91%	84%	77%	68%	59%	47%
320	97%	99%	98%	96%	92%	86%	79%	71%	62%	49%
330	97%	99%	99%	97%	93%	88%	81%	73%	64%	51%
340	97%	99%	100%	98%	94%	89%	82%	74%	66%	53%
350	97%	100%	100%	98%	95%	90%	83%	75%	67%	54%

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR NAURU

Latitude: 0 degrees 32 minutes South

Longitude: 166 degrees 56 minutes East

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

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

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR VAIAKU - TUVALU
Latitude: 8 degrees 31 minutes South
Longitude: 179 degrees 13 minutes East

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	99%	100%	99%	97%	92%	87%	79%	71%	60%	49%
10	99%	100%	99%	97%	92%	86%	79%	71%	60%	49%
20	99%	100%	99%	96%	92%	86%	79%	70%	60%	48%
30	99%	100%	99%	96%	91%	85%	78%	69%	58%	47%
40	99%	100%	98%	95%	90%	84%	76%	68%	57%	46%
50	99%	99%	98%	94%	89%	83%	75%	66%	55%	44%
60	99%	99%	97%	93%	88%	81%	73%	64%	53%	43%
70	99%	99%	96%	92%	87%	79%	71%	61%	51%	41%
80	99%	98%	96%	91%	85%	78%	69%	59%	49%	38%
90	99%	98%	95%	90%	84%	76%	66%	56%	46%	36%
100	99%	97%	94%	89%	82%	74%	64%	53%	44%	34%

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

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR APIA - SAMOA
Latitude: 13 degrees 50 minutes South
Longitude: 171 degrees 46 minutes West

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	99%	100%	99%	97%	92%	86%	79%	71%	60%	48%
10	99%	100%	99%	97%	92%	86%	79%	70%	60%	48%
20	99%	100%	99%	96%	92%	86%	78%	70%	59%	47%

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

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR TONGATAPU - TONGA
Latitude: 21 degrees 08 minutes South
Longitude: 175 degrees 12 minutes West

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	96%	99%	100%	99%	96%	92%	85%	78%	69%	57%
10	96%	99%	100%	99%	96%	91%	85%	77%	69%	57%
20	96%	99%	100%	98%	95%	90%	84%	76%	67%	56%
30	96%	98%	99%	97%	94%	89%	82%	74%	66%	54%
40	96%	98%	98%	96%	93%	87%	80%	72%	63%	51%
50	96%	98%	97%	95%	91%	85%	78%	69%	60%	49%
60	96%	97%	96%	93%	89%	82%	74%	66%	56%	45%
70	96%	96%	95%	91%	86%	79%	71%	62%	52%	41%
80	96%	96%	93%	89%	83%	76%	67%	58%	48%	37%
90	96%	95%	92%	87%	81%	73%	64%	54%	43%	33%
100	96%	94%	91%	85%	78%	70%	60%	49%	38%	29%
110	96%	94%	89%	83%	76%	66%	56%	45%	34%	25%
120	96%	93%	88%	81%	73%	63%	53%	41%	30%	22%
130	96%	93%	87%	80%	71%	61%	50%	38%	27%	21%
140	96%	92%	86%	78%	69%	58%	47%	36%	26%	21%
150	96%	92%	85%	77%	67%	57%	45%	34%	25%	20%
160	96%	91%	85%	76%	66%	55%	44%	34%	24%	20%
170	96%	91%	84%	76%	66%	54%	43%	33%	24%	20%
180	96%	91%	84%	76%	65%	54%	43%	33%	24%	20%
190	96%	91%	84%	76%	66%	54%	43%	33%	24%	20%
200	96%	91%	85%	76%	66%	55%	44%	34%	24%	20%
210	96%	92%	85%	77%	67%	57%	45%	34%	25%	20%
220	96%	92%	86%	78%	69%	58%	47%	36%	26%	21%
230	96%	93%	87%	80%	71%	61%	50%	38%	27%	21%
240	96%	93%	88%	81%	73%	63%	53%	41%	30%	22%
250	96%	94%	89%	83%	76%	66%	56%	45%	34%	25%
260	96%	94%	91%	85%	78%	70%	60%	49%	38%	29%
270	96%	95%	92%	87%	81%	73%	64%	54%	43%	33%

280	96%	96%	93%	89%	83%	76%	67%	58%	48%	37%
290	96%	96%	95%	91%	86%	79%	71%	62%	52%	41%
300	96%	97%	96%	93%	89%	82%	74%	66%	56%	45%
310	96%	98%	97%	95%	91%	85%	78%	69%	60%	49%
320	96%	98%	98%	96%	93%	87%	80%	72%	63%	51%
330	96%	98%	99%	97%	94%	89%	82%	74%	66%	54%
340	96%	99%	100%	98%	95%	90%	84%	76%	67%	56%
350	96%	99%	100%	99%	96%	91%	85%	77%	69%	57%

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR PALIKIR - POHNPEI FSM
Latitude: 6 degrees 54 minutes North
Longitude: 158 degrees 13 minutes East

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

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

ANNUAL DAILY IRRADIATION ON AN INCLINED PLANE EXPRESSED AS % OF MAXIMUM VALUE FOR HAGATNA - GUAM
Latitude: 13 degrees 28 minutes North
Longitude: 144 degrees 45 minutes East

Plane Azimuth (degrees)	Plane Inclination (degrees)									
	0	10	20	30	40	50	60	70	80	90
0	98%	94%	89%	82%	73%	64%	52%	41%	33%	24%
10	98%	95%	89%	82%	73%	64%	52%	41%	33%	24%
20	98%	95%	89%	82%	74%	65%	52%	41%	32%	24%
30	98%	95%	90%	83%	74%	65%	53%	42%	32%	24%
40	98%	95%	90%	83%	75%	66%	54%	43%	32%	24%
50	98%	95%	91%	84%	76%	67%	56%	45%	33%	24%
60	98%	96%	91%	85%	77%	67%	58%	47%	35%	24%
70	98%	96%	92%	86%	78%	68%	59%	49%	37%	26%
80	98%	97%	93%	87%	80%	70%	61%	52%	40%	29%
90	98%	97%	94%	89%	81%	71%	64%	54%	43%	32%
100	98%	98%	95%	90%	82%	72%	66%	57%	46%	35%

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