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Stand Alone Power Systems: Design & Installation Publication Updates

Revisions to the Stand Alone Power Systems Design and Installation Manual, Eight Edition (version 8.1)

GSES® global sustainable energy solutions

Figure 5.10: Pawicon 2.5kW Upwind Turbine.
(Source: Paul Gipe, WindEnergy)

Figure 5.11: Proven 6 kW Downwind Turbine
(Source: Tobi Kellner [CC BY-SA 3.0], via Wikimedia Commons).

Wind turbines can classified into two different types based on the orientation of their axis:

- Horizontal Axis Wind Turbine (HAWT)
- Vertical Axis Wind Turbine (VAWT)

5.2.1 Horizontal Axis Wind Turbine (HAWT)

Horizontal axis wind turbines (HAWTs) are the most common type of wind turbine. Their design is very similar to a windmill and the blades are of a propeller type that spins on a horizontal axis.

HAWTs have the main rotor shaft and electrical generator at the top of the tower. They may be divided into upwind and downwind turbines, depending on whether the tower is behind or in front of the blades, relative to the incoming wind.

Upwind turbines (Figure 5.10) must be pointed into the wind. Small wind turbines have a simple wind vane to point them into the wind (Figure 5.10), however bigger wind turbines use wind sensors coupled with a servo motor arrangement to turn them into the wind, rather than a vane. The tower is located behind the rotor blades and as a result doesn't produce much turbulence on the blades. The blades must be very stiff to prevent them being pushed or flexing into the tower.

Larger downwind turbines (Figure 5.11) have the advantage of requiring neither wind sensors nor servo motors to keep them in line with the wind direction. However, as the incoming wind impacts the turbine's tower before reaching the blades, significant amounts of turbulence is introduced. As this leads to fatigue failures and reliability issues, most HAWTs are upwind machines.

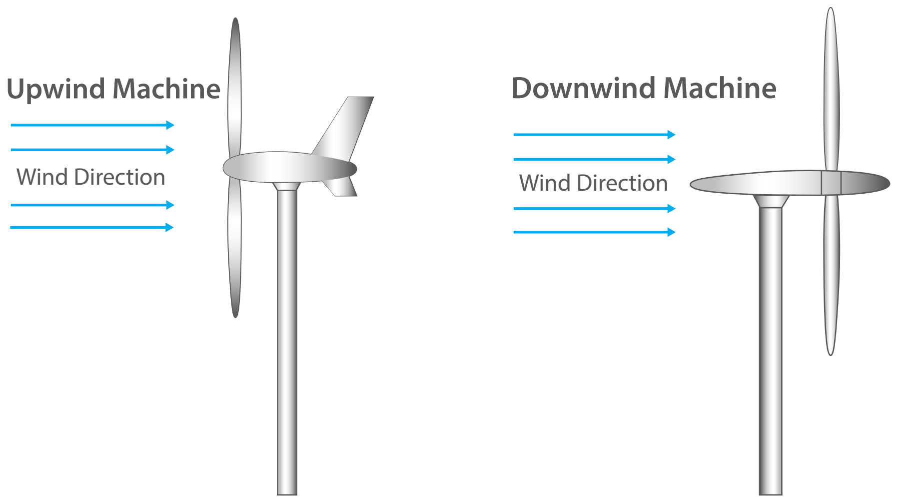


Figure 5.12: a) Upwind and b) downwind HAWTs.

5.2.2 Vertical Axis Wind Turbine (VAWT)

Vertical axis wind turbines or VAWTs have the main rotor shaft arranged perpendicular to the mounting surface. The main advantage of this is that they don't need to be pointed into the wind. This arrangement can be particularly beneficial at sites with highly variable direction and turbulent winds.

Unlike the HAWT the generator and other important components don't need to be lifted to the tower height but can stay near the ground.

9.3 Genset Efficiency and Yield

9.3.1 Machine Losses

Like all rotating electrical machinery, the alternator in each genset has certain fixed losses for a given operating point. These consist of the combination of friction in the bearings and any mechanical transmission, windage, winding resistances (copper losses) and magnetising losses (iron losses). These losses are combined to give the overall machine losses or machine efficiency.

9.3.2 Combustion Losses (Temperature, Humidity, Altitude)

The most efficient and complete combustion of fuel requires a very specific set of conditions with regard to the density of the air which is being mixed with the fuel. The optimum air to fuel ratio for burning all the fuel with no excess air or fuel left over is known as the stoichiometric mixture ratio (typically given as 14.7:1 for petrol, 14.5:1 for diesel and 17.19:1 for methane). Running higher quantities of fuel in the mixture (known as running rich) will result in incomplete combustion of the fuel but often results in more power and lower running temperatures, while reduced quantities of fuel in the mixture (running lean) means that excess air is being pulled through the engine unused and typically results in higher temperatures and reduced power. Variation in air density will also cause these problems, and air density is affected by temperature, humidity and altitude above sea level. Actual derating factors are given in manufacturer's specifications for the genset to be used. Turbocharging and/or intercooling of the inlet air can assist in improving performance under these conditions relative to a naturally aspirated genset.

AUSTRALIAN STANDARDS

If the manufacturer's derating specifications are not available, a generic set of derating factors is available in ***AS/NZS 4509.2:2010*** Table 4.

EXAMPLE

A manufacturer's specification sheet provides the following derating factors:
Altitude derating: 3.5% per 300 m above sea level.
Temperature derating: 2.8% per 5°C above 25°C.
Humidity derating: 1.5% per 10% humidity above 50% if ambient temperature is >40°C.
The genset is to be installed at a site 150 m above sea level, with ambient temperatures of up to 45°C and humidity of 65% during summer.
The site-specific derating factors are calculated as follows:

Altitude derating:

$$\left(\frac{3.5\ \%}{100\ \%} \times \frac{(150-0)m}{300m}\right) = 0.0175$$

Temperature derating:

$$\left(\frac{2.8\ \%}{100\ \%} \times \frac{(45-25)°C}{5°C}\right) = 0.1120$$

Humidity derating:

$$\left(\frac{1.5\ \%}{100\ \%} \times \frac{(65-50)\ \%}{10\ \%}\right) = 0.0225$$

The total genset efficiency is therefore:

$$(1 - 0.0175) \times (1 - 0.1120) \times (1 - 0.0225) = 0.8528$$
$$= 85.3\%$$

11.2.5 Stand-alone, Grid-connect and Multimode Inverters

There are three main categories of inverters available in the market: stand-alone inverters, multimode inverters and grid-connect inverters. It is important to understand the difference between these inverter types.

Stand-alone Inverters

Stand-alone inverters (Figure 11.19) are designed to provide AC power at Low Voltage from batteries which are typically powered by a renewable energy power source. These inverters are not designed to connect to or to inject power into the electricity grid.

The inverter's output provides mains equivalent power within the inverter's operating specifications. In this regard, a stand-alone inverter is a voltage source inverter and in fact is often responsible for "forming" and maintaining the stand-alone grid.

As stand-alone inverters connect to a battery bank, they are voltage-specific; that is, they are designed to operate from a nominal battery voltage, such as 12 V, 24 V, 48 V or 120 V DC (and indeed higher voltages are becoming more commonplace).

These inverters fall into the following categories: simple unidirectional inverters, bidirectional inverter-chargers, DC bus interactive inverters and AC bus interactive inverters. These are described as follows:

Unidirectional inverters only connect the battery bank to the AC loads. It is important to confirm the suitability of the stand-alone inverter's waveform for use with the intended loads. These inverters will fail if there is another AC source on the load side. However some inverter brands allow their inverters to parallel provided one inverter acts as the master to control synchronising the other inverters which act as the slaves. There is always a maximum number of inverters that can be paralleled in this way.

The traditional configuration of a stand-alone power system has the PV array connected to a solar charge controller, which feeds power to the battery storage system. The solar charge controller may have an MPPT but stand-alone inverters do not have the same MPPT function as grid-connect inverters. The stand-alone unidirectional inverter is connected to the battery bank and the loads (Figure 11.20).

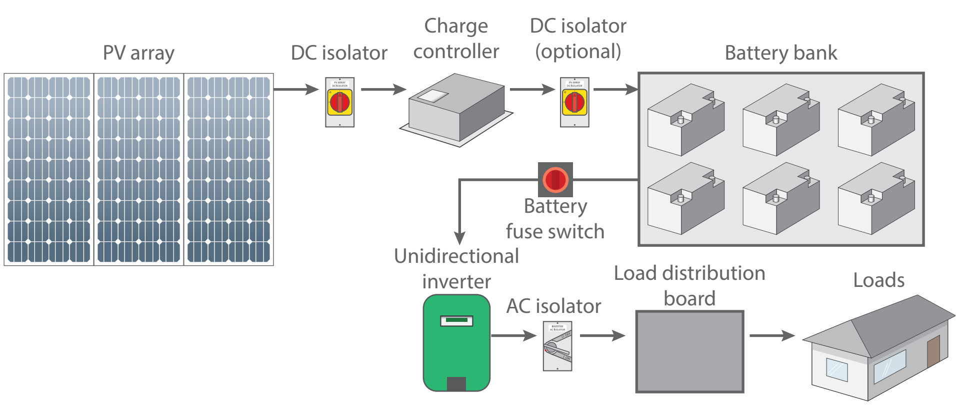


Figure 11.20: A typical SAPS configuration using a unidirectional inverter.

DID YOU KNOW?

Stand-alone, grid-connect and multimode inverters can also be referred to as grid-forming, grid-following and dual-mode respectively.

INTERNATIONAL STANDARDS

IEC 62109.2:2011 Clause 3.109 defines a stand-alone inverter as "an inverter or inverter function intended to supply AC power to a load that is not connected to the mains", regardless of whether it is designed to be paralleled with other non-mains sources (e.g other inverters, rotating generators).

Figure 11.19: An example of a stand-alone inverter – the Latronics LS Series.
(Source: Latronics)

REMEMBER

Battery voltage varies with SOC: the nominal voltage of a battery is a reference value that may be defined as the midpoint voltage of the battery cell between fully charged and fully discharged.

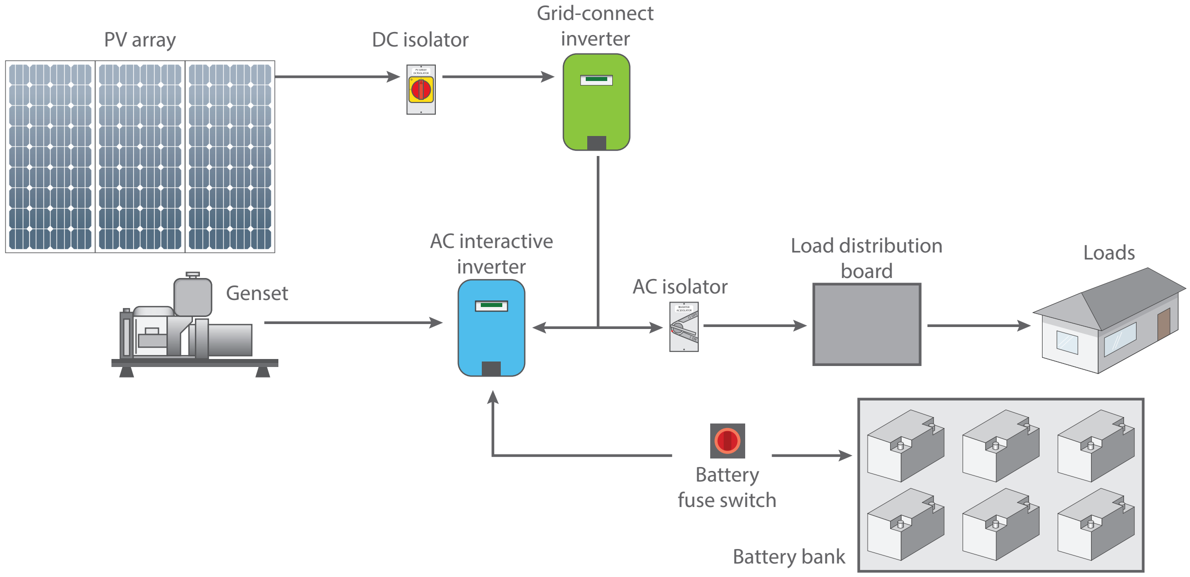


Figure 11.22: A typical SAPS configuration using an AC interactive inverter.

> ***INTERNATIONAL STANDARDS***
> ***IEC 62109.2:2011*** Clause 3.101 defines a grid-interactive inverter as "an inverter or inverter function intended to export power to the grid".

Grid-connect Inverters

A grid-connect inverter (Figures 11.23 and 11.24), also known as a grid-tied inverter, is capable of producing an AC signal compatible with the grid. This inverter must produce power within the acceptable voltage and frequency ranges specified by the relevant standards. Grid-connect inverters cannot independently produce an AC output: the inverter must be able to reference the grid or grid-substitute to be able to connect to it. Without the grid reference, the inverter will not operate.

Figure 11.23: An example of a grid-connect inverter – the Fronius IG TL.
(Source: Fronius International GmbH)

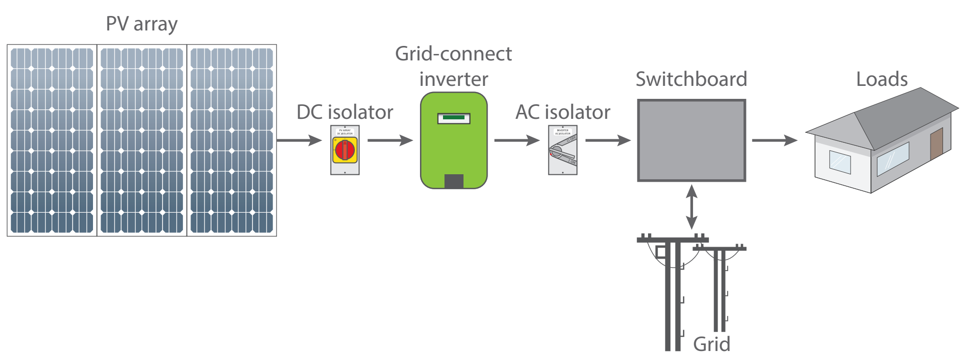


Figure 11.24: A typical grid-connected PV system configuration.

Grid-connect inverters generally contain an MPPT that keeps the PV array at its MPP. These inverters have a permissible DC voltage window within which the solar PV must be operating before the inverter is able to produce the necessary AC voltage output to match the grid (see Chapter 15 for more information on MPPT voltage windows).

Grid-connect inverters require grid protection to ensure that the inverter will not be exporting power to the grid when there are abnormal grid conditions. The operating requirements imposed on a grid-connect inverter mean that the inverter has active and passive protection and that the inverter must shut down in certain conditions.

Grid-connect inverters are installed in stand-alone systems with AC bus interactive inverters. The grid-connect inverters allow the renewable energy source, typically PV

14.1 Total Daily Energy Use

Once a load profile is recorded (as detailed in Chapter 13), the final design energy demand can be calculated. When selecting and sizing the battery bank for either a DC bus or AC bus system, the total energy demand at the battery bank is determined by all energy demand requirements and system losses up to the battery connection. This value is also used when determining the size of renewable energy generators in DC bus systems.

$$E_{TOT} = E_{DC} + \frac{E_{AC}}{\eta_{INV}}$$

Where:

- E_{TOT} = Total design daily energy demand from the DC bus, i.e. the battery (in Wh)
- E_{DC} = Daily design DC energy demand (in Wh)
- E_{AC} = Daily design AC energy demand (in Wh)
- η_{INV} = Average energy efficiency of the battery inverter when supplying the AC design energy demand (dimensionless)

The efficiency curves supplied by the battery inverter manufacturer must be used to determine the average conversion efficiency as it relates to the energy profile for the particular system being designed. Ideally, the conversion efficiency is calculated at some finite time interval to account for fluctuations in the load profile.

14.1.1 Determination of System Voltage

EXAMPLE

The total AC energy demand in a house for one day is 2 kWh (there are no DC loads). It was found that the load profile (Figure 14.1) only has two power steps, one where 200 Wh were consumed and another where 1,800 Wh were consumed. The 200 Wh energy demand (at 25 W) was supplied at an inverter efficiency of 60% and the 1,800 Wh energy demand (at 110 W) was supplied at an inverter efficiency of 90%. Cable losses are negligible.

$$E_{TOT} = \frac{200\ Wh}{0.6 \times 1} + \frac{1{,}800\ Wh}{0.9 \times 1} = 2{,}333\,Wh$$

Therefore the total energy required to supply the inverter in order to meet these loads was 2,333 Wh.

Traditional system voltages are 12, 24 and 48 volts DC, given the commonality of power conditioning equipment that operates at these voltages. However, as larger systems become more prevalent and system equipment reduces in cost, it is not uncommon to find systems that use 120, 240 or even 500 volts DC. System voltage may be determined by demand, conductor size, equipment cost/availability, or access and safety requirements.

As a general rule, for DC bus systems and AC bus systems less than 20 kWh, the recommended system voltage increases as the total load increases. For small daily energy demand, a 12 V system can be used; as the load increases (or as peak demand increases) the system voltage will increase possibly up to the limit of low voltage as defined in relevant standards. For some systems, multiple 48 V battery banks may be used in parallel to keep the sub-system at Extra Low Voltage (ELV) to provide the required capacity. Parallel battery banks can be used at any system

DID YOU KNOW?

There are software tools available, such as HOMER Energy, which can help to perform load profile analyses.

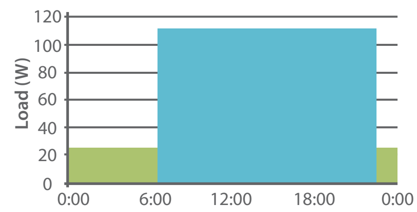


Figure 14.1: AC load profile. Inverter efficiency is 90% during the blue period (over which time 1800 Wh were consumed) and 60% during the green period (over which time 200 Wh were consumed).

REMEMBER

Australian Standards define the voltage classifications in Table 14.1.

***Table 14.1:** Voltage classifications as determined by Australian Standards.*

	DC (V_{DC}, ripple free)	AC (V_{RMS})
ELV	≤120	≤50
LV	120-1500	50-1000
HV	>1500	>1000

IMPORTANT

For safety purposes, including protection and signage requirements, battery systems and associated PCE may be classified using the Decisive Voltage Classification (DVC) system. This accounts for situations in which parts of the battery sub-system are at potentially harmful voltages. Parts of the battery sub-system may fall under different classifications. DVC classification of PCE ports is provided by manufacturers as part of ***IEC 62109-1***.

15.5 Genset Derating

Gensets need to be derated for the site-specific temperature, humidity and altitude. The derating factors should be supplied by the manufacturer; typical values are shown in Table 15.8.

AUSTRALIAN STANDARDS

Table 15.8 is taken from **AS/NZS 4509.2:2010** Clause 3.4.11.5.

Table 15.8: *Typical genset derating factors*

Air temperature		Derate 2.5% for every 5°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 above 50°C	Derate 1.5% for every 10% above 60% humidity

Each derating is subtracted from 100% and then the resulting efficiencies are multiplied together.

EXAMPLE

A genset is to be installed at an altitude of 1,500 metres above sea level, and may be operational during maximum ambient air temperatures of 35°C and 80% relative humidity.

$$\textit{Derating due to temperature} = \frac{35 - 25}{5} \times 2.5\% = 5\%$$

$$\textit{Derating due to humidity} = \frac{80 - 60}{10} \times 1.0\% = 2\%$$

$$\textit{Derating due to altitude} = \frac{1{,}500 - 300}{300} \times 3\% = 12\%$$

Total derating of the genset = 0.95 × 0.98 × 0.88 = 0.82, resulting in a derating factor of 82%.

If the minimum S_{GEN}, calculated in Section 15.4, was 8.9 VA, the smallest genset that could be used would have a rating of 8.9 VA ÷ 0.82 = 11 VA.

16.1 Cable Selection and Sizing

The cables in an installation must be selected with an insulation operating rating of at least the highest voltage expected to be to be encountered, indeed common practice is to test the insulation at twice the nominal operating voltage during system commissioning. It is important to note when working on ELV systems that the cable often sold in automotive and hardware stores for use on 12 V DC systems is often insulated to those levels and may not be suitable for use on 24 V DC or 48 V DC systems.

> ***AUSTRALIAN STANDARDS***
>
> For LV systems, as per ***AS/NZS 5033:2014*** Clause 4.3.6.2, tinned copper cabling is recommended for use in the array cable to reduce the cable's degradation over time.

The cables in an installation must be sized correctly so that:

1. There are not excessive line losses (called voltage drop) in the cable; and
2. There is not excessive current through the cables compared with the safe current handling capability of the cables.

Most cables available commercially can be used in SAPS wiring so long as the voltage drop and maximum current fall within the specified range as explained below. Some cables specifically designed for use in DC applications are also available.

> **NOTE**
>
> If the cables are selected to just carry the design maximum demand, then there is no scope for extending the system without re-wiring.

In some situations (e.g. leads from the battery) the current will be quite high and DC rated cables may be more appropriate. Always ensure that the maximum voltage rating of any cable is **never** exceeded.

The manufacturers of cables will have specified the current carrying capacity of their cables. Follow their guidelines at all times.

16.1.1 Excessive Current

Line losses in a wire are a function of three parameters:

1. Conductor cross sectional area;
2. Length of the conductor; and
3. Current flow through the conductor.

> **IMPORTANT**
>
> The greater the wire's length, the greater its resistance to current flow.

Line losses are measured in terms of voltage drop, which is the loss of voltage due to the wire's resistance. Excessively long wire runs will result in loss of power to the load and lower system efficiency. It will also reduce the life expectancy of most appliances and equipment. Inductive loads, such as motors, are particularly sensitive to voltage drop. Using a small wire size or increasing the current flow will result in a greater voltage drop in that wire. If the voltage drop is too large in the battery cable, there may at times be insufficient voltage to charge the batteries. Similarly if the voltage drop is large, there may be insufficient voltage under some circumstances to power an inverter.

The relationship between voltage drop, cable cross-sectional area (CSA), cable length and current flow is:

$$V_d = \frac{2 \times L \times \tilde{} \times I \times cos\ ^{\circ}}{A}$$

> **NOTE**
>
> The 2 in the formula assumes equal length positive and negative conductors, which is usually the case. If they are not equal then instead of using 2 x route length, use positive length plus negative length.

Where:

- V_d = Voltage drop (in V)
- L = Route length (in m)
- ρ = Resistivity of the cable (in Ω/m/mm^2)
- I = Current flow (in A)
- $cos\Phi$ = Power factor (include only for AC cables)
- A = Cross-sectional area (in mm^2)

However, resistivity depends on the material of the conductor (e.g. copper, tinned copper, aluminium) as well as temperature. For this reason, it is industry standard in Australia to state the equation in terms of V_C, voltage drop specified in millivolts per amp-metre (mV/Am), and refer to voltage drop tables specific to cable type, installation method, conductor CSA and temperature.

AUSTRALIAN STANDARDS

AS/NZS 3008.1.1:2017 Clause 4.2 specifies how to determine the voltage drop using V_C. Tables 40 to 51 in ***AS/NZS 3008.1.1:2017*** provide three-phase V_C values for different conductor types, sizes and temperatures.

$$V_d = \frac{L \times I \times V_C}{1{,}000}$$

Where:

- V_d = Actual voltage drop (in V)
- L = Route length (in m)
- I = Current flow (in A)
- V_c = Millivolt drop per amp-metre route length (in mV/Am)

Tables of V_C values may be provided by the cable manufacturer, or otherwise can be found in the relevant Australian standards. The voltage drop values are typically for three-phase AC circuits, which can then be converted to single phase AC or DC values by multiplying by 1.155.

EXAMPLE

The cable route between a battery inverter and main switchboard is 4 metres. The inverter has a maximum current output of 13 A, single phase AC. The cable manufacturer provides the following three-phase V_C values at 60°C for various conductor CSAs:

- 2.5 mm² copper multicore cable: 14.9 mV/Am
- 4 mm² copper multicore cable: 9.24 mV/Am
- 6 mm² copper multicore cable: 6.18 mV/Am

Since these values are for a three-phase circuit, they will need to be multiplied by 1.155 to find the single-phase voltage drop.

If using 2.5mm² cable, the actual voltage drop will be:

$$V_d = \frac{4\ m \times 13\ A \times (14.9\ mV/Am \times 1.155)}{1{,}000} = 0.89\ V$$

However, if a larger 6 mm² cable were to be used, the voltage drop would be:

$$V_d = \frac{4\ m \times 13\ A \times (6.18\ mV/Am \times 1.155)}{1{,}000} = 0.37\ V$$

As current is inversely proportional to voltage in a cable carrying a certain amount of power, a higher system voltage will reduce the voltage drop in the system's wiring.

EXAMPLE

If you are using a 100 W load, the current required from a 240 V supply is:

$$\frac{100\ W}{240\ V} = 0.42\ A$$

And the voltage drop over 10 m in a 2.5 mm^2 cable used in the previous example is:

$$\frac{10\ m \times 0.42\ A \times (14.9\ mV/Am \times 1.155)}{1{,}000} = 0.072\ V$$

If you have a 24 V system, the current required for the same 100 W load is:

$$\frac{100\ W}{24\ V} = 4.2\ A$$

And the voltage drop over 10 m in the same 2.5 mm^2 cable is:

$$\frac{10\ m \times 4.2\ A \times (14.9\ mV/Am \times 1.155)}{1{,}000} = 0.72\ V$$

So the voltage drop in a 24 V (ELV) circuit is ten times that in an equivalent 240 V (LV) circuit.

Permissible Voltage Drop in Conductors

Main battery cables are often supplied by the inverter manufacturer. Do not extend these cables. Their diameter has been carefully selected to minimise the voltage drop between the batteries and the inverter. If longer cables are necessary, fit new, correctly sized (larger cross-sectional area) cables.

Cables from the solar array to the batteries should be selected so that the voltage drop between the array and the batteries is less than 5% of the system voltage. It is also recommended that the voltage drop between the batteries and any load be limited to 5%, especially in 12 V systems.

To find the voltage drop as a loss percentage, simply divide the voltage drop in volts by the system voltage:

$$\text{Loss} = \frac{V_d}{V_{DC}}$$

Where:

- *Loss* = Maximum voltage drop in the cable (dimensionless, i.e. 5% = 0.05)
- V_d = Voltage drop (in V)
- V_{DC} = System voltage (in V)

AUSTRALIAN STANDARDS

AS/NZS 3000:2018 Clause 7.5.7 requires that voltage drop in an ELV installation does not exceed 10% of nominal voltage under normal operating conditions (excludes motor start etc.).

AS/NZS 4509.2:2010 Clause 3.4.12 and Table 5 override ***AS/NZS 3000:2018*** and call for less than 5% voltage drop in photovoltaic cables and battery bank to DC loads while wind and micro-hydro generators are allowed up to 10% voltage drop at rated output.

AS/NZS 5033:2014 Clause 2.1.10 (c) Voltage drop in cables does not apply to ELV installations.

Alternatively, the previous formulae can be rearranged to give the maximum permitted V_c for a given voltage drop:

$$V_C = \frac{1{,}000 \times Loss \times V_{DC}}{L \times I}$$

Where:

- V_c = Millivolt drop per amp-metre route length (in mV/Am)
- *Loss* = Maximum voltage drop in the cable (dimensionless, i.e. 5% = 0.05)
- V_{DC} = System voltage (in V)
- L = Route length (in m)
- I = Current flow through the cable (in A)

AUSTRALIAN STANDARDS

The values in Table 16.1 are taken from Table 47 in ***AS/NZS 3008.1.1:2017***, and will not be appropriate for all installations. Refer to Tables 40 to 51 in ***AS/NZS 3008.1.1:2017*** or manufacturer's datasheets for the table applicable to the install situation.

In conjunction with tabulated V_c values for a variety of cable sizes, the minimum required conductor CSA to meet the voltage drop requirements can then be determined.

Table 16.1 shows tabulated three-phase V_c values for a particular battery cable. Similar tables can be obtained from local standards or cable manufacturers.

Table 16.1: *Example three-phase V_c for single-core flexible battery cable in touching formation (mV/Am).*

Conductor CSA (mm²)	Conductor temperature (°C)				
	45	60	75	90	110
0.5	74.2	78.2	82.2	86.1	91.4
1.0	37.1	39.1	41.1	43.1	45.7
1.5	25.3	26.7	28.0	29.4	31.2
2.5	15.2	16.0	16.8	17.6	18.7
4	9.42	9.92	10.4	10.9	11.6
6	6.28	6.62	6.96	7.29	7.74
10	3.64	3.84	4.03	4.22	4.48
16	2.31	2.43	2.56	2.68	2.85
25	1.50	1.58	1.66	1.74	1.84
35	1.07	1.13	1.18	1.24	1.31
50	0.760	0.798	0.837	0.875	0.926
70	0.551	0.577	0.603	0.630	0.665

NOTE

In some cases, V_c tables are only available for three-phase values. Multiply the three-phase values by 1.155 to convert to single-phase values Similarly, divide the maximum V_c in single phase AC or DC values by 1.155 to convert to three-phase values.

EXAMPLE

Using Table 16.1, determine the minimum cable size required for an array where:

- Route length = 20 m,
- Maximum current = 15 A,
- System voltage = 24 V, and
- Maximum allowable voltage drop = 5%.

$$Maximum\ V_C = \frac{1{,}000 \times 0.05 \times 24\ V}{20\ m \times 15\ A} = 4\ \mathrm{mV/Am\ (DC)}$$

Converting to three-phase:

$$4\ mV/Am \div 1.155 = 3.46\ mV/Am\ (three\text{-}phase\ AC)$$

Assuming the selected cable may operate up to its rated insulation temperature of 90°C, the minimum conductor CSA that meets the calculated V_c requirement is a 16 mm² cable.

EXAMPLE:
An array consists of 3 parallel strings. These connect to a controller and then to a battery bank. For this exercise assume the main battery protection is not sized to protect the array cable. Each string has 2 modules in series, with the following characteristics:

- V_{MOD} 24 V
- I_{SC} 5.4 A
- $I_{MOD\ REVERSE}$ 15 A

What size array cable and array fuse are required?
What size string cable is required? Does it meet voltage drop requirements?
Is string protection required? If so, what size?
Table 16.6 has been provided by the cable manufacturer to assist in selection of cable sizes.

Table 16.6: *Examples of different conductor characteristics*

Conductor size (mm²)	Cable diameter (mm)	Current rating (A)	Voltage rating (VDC)
2.5	6.3	21	1,000
4	6.9	27	1,000
6	7.4	34	1,000
10	8.6	48	1,000
16	9.8	63	1,000

Array protection
Must be between 1.25 and 2.4 times the array short circuit current
Hence: Minimum fuse size = 1.25 × 3 × 5.4 = 20.25 A
Maximum fuse size = 2.4 × 3 × 5.4 = 38.9 A
The fuse chosen is 30 A.

Array cable
The nominal current of the fuse cannot exceed 90% of the current carrying capacity of the cable. 30 A divided by 90% is 33.3 A, so the CCC of the cable must be larger than this.
Thus the cable chosen (from Table 16.6) is 6 mm² with a CCC of 34 A.

String protection
Not required, as $I_{MOD\ MAX\ OCPR}$ = 15 A which is greater than $I_{SC\ MOD} \times (N_p - 1)$ = 5.4 A × 2 = 9.8 A.

String cable (without protection)
Must be between the rated trip current of the nearest downstream protection device (the array fuse) + 1.25 × the short circuit current from the other strings.
Hence string cable size = 30 A (array fuse) + 1.25 × 5.4 × 2
(fault current that can come from the other two strings) = 43.5 A
Based on Table 16.6, the cable chosen is 10 mm² with a CCC of 48 A.
Maximum permissible voltage drop (V_d)= 0.05 × 48 = 2.4 V

$$V_d = \frac{(2 \times L \times I \times R)}{A}$$

And

$$L = \frac{(V_d \times A)}{(2 \times I \times R)} = \frac{(2.4 \times 10)}{(2 \times 5.4 \times 0.0183)} = 121.4 \text{ m}$$

CONTINUED ON NEXT PAGE

EXAMPLE (CONTINUED)

Hence the maximum length for a voltage drop of 5% in this cable is 121 m. This is easily achieved for a string cable.
Hence voltage drop requirements are fulfilled.
String cable (where protection is used)
The string fuse, if present, must be between 1.25 and 2 times the module short circuit current.
Hence: Minimum fuse size = 1.25 × 5.4 = 6.75 A
Maximum fuse size = 2 × 5.4 = 10.8 A
The fuse chosen is 10 A, and the minimum CCC of the string cable is 10 A ÷ 0.9 =11.1 A.
Hence the cable chosen (from Table 16.6) is 2.5 mm2 with a CCC of 21 A.Evidently, with string protection, the cable required is much smaller (and hencecheaper), however the voltage drop requirements must still be met.

$$V_d = \frac{(2 \times L \times I \times R)}{A}$$

So

$$L = \frac{(V_d \times A)}{(2 \times I \times R)} = \frac{(2.4 \times 2.5)}{(2 \times 5.4 \times 0.0183)} = 30.4 \text{ m}$$

So the string cables must be less than 30 m to have a voltage drop of less than 5%. Otherwise, a larger cable must be selected.
Therefore, although string protection is not mandatory, it may be worth comparing the price of 3 string fuses and housing with the cost of 10 mm^2 string cabling instead of 2.5 mm^2 string cabling.

AUSTRALIAN STANDARDS

Appendix J of ***AS/NZS 5033:2014*** includes worked examples of many different types of installations.

16.2.4 Genset Overcurrent Protection

Genset connections must be protected from overcurrents. This is usually incorporated into commercially produced generating sets, but should otherwise be provided by an external circuit breaker or HRC fuse/s.

Other protective devices include reverse power and/or armature overspeed relays for protection against "motoring" the genset by back-feeding current into it. On three phase gensets, a phase failure relay is desirable to avoid overloading one or more phases and/or damaging external equipment should an internal open circuit develop in the genset windings.

16.2.5 DC Load Sub Circuit Protection

If the SAPS includes DC loads not supplied via the battery inverter, the system shall be protected against damage due to accidental short circuits by the use of fuses or circuit breakers. Individual circuits from the battery should have a maximum rated capacity of 20 amps where not otherwise specified (for example, a dedicated circuit for a DC water pump).

Every submain or final sub circuit shall be individually protected at its origin against overload and short circuit by a fuse or circuit breaker. This fuse or circuit breaker shall have a current rating:

a. not less than the maximum demand current of the protected circuit or circuits,
b. not less than the highest current rating of any overload protective device on the portion of the installation being protected, and
c. not exceeding the current carrying capacity of the protected conductors.

AUSTRALIAN STANDARDS

AS/NZS 4509.1:2009 Clause 4.5.2 states that the overcurrent protection at the output of a SAPS must be rated to protect the consumer mains. This applies specifically to AC load systems.

AUSTRALIAN STANDARDS

AS/NZS 4509.2:2010 Clause 3.7.2 requires each generating source in a SAPS to be able to be electrically isolated from the rest of the system, via fuses, circuit breakers or switches.

AUSTRALIAN STANDARDS

AS/NZS 5033:2014 Clause 1.4.13 defines the term disconnector, and Clause 4.3.5 covers the requirements for DC disconnection devices.

AS/NZS 3000:2018 states that load-breaking switches should be lockable in the off position.

IMPORTANT

Disconnection devices do not switch off during fault conditions.

Circuit breakers can be used to provide overcurrent protection and disconnection, so that they switch off during fault conditions.

If separate overcurrent protection is present, the disconnection device must have the same current rating: otherwise it may be damaged by overcurrent.

AUSTRALIAN STANDARDS

According to ***AS/NZS 5033:2014*** Clause 4.2, the PV array maximum voltage is calculated using:

$$V_{MAX\_OC\_ARRAY} = V_{OC\_ARRAY} + \gamma_{OC} \times (T_{MIN} - T_{STC}) \times N_S$$

Where:

- $V_{MAX\_OC\_ARRAY}$ = PV array maximum voltage (in V)
- V_{OC_ARRAY} = PV array open circuit voltage at standard test conditions (in V)
- γ_{OC} = Negative temperature coefficient of V_{OC} per degree Celsius (in V/°C)
- T_{MIN} = Minimum cell temperature (in °C)
- T_{STC} = Cell temperature at standard test conditions (constant of 25°C)
- N_S = Number of modules in series

Fault in the AC Distribution Board (or AC Bus)

A fault in the AC bus only permits fault current from the battery inverter, as shown by the green arrow in Figure 16.4. Possible causes might be:

- Short circuit.
- Overload.
- Earth leakage (insulation breakdown or person providing current path to earth through body).

Inverters are inherently a current limited source: i.e. internal protection will shut down the inverter if an external short circuit or overload condition is detected; however up until that point is reached an inverter will attempt to supply up to its rated surge current into the load. Accordingly, circuit breakers and/ or HRC fuses will be required to protect the cables.

Personnel protection will need to be provided in accordance with local codes and regulations – typically by means of an RCD, either a dedicated RCCD (residual current fault only) or combined with the overload protection in the form of an RCBO.

16.2.7 Disconnection Devices

Disconnection devices allow parts of the system to be electrically isolated. They can be split into two categories:

1. Load-breaking, where they can be disconnected when current is flowing through them; these devices are switch-disconnectors or circuit breakers, although the term 'isolators' is used for simplicity in labelling.
2. Non-load-breaking, where they can be disconnected only when there is no current flowing through them.

PV Array Isolation

Disconnection devices may be required at the string, sub-array and/or array level of a PV SAPS. For all levels of disconnection, the device used should have no live parts exposed at any time, regardless of whether the device is switched on or off. It also must comply with any other requirements set by the appropriate standards and guidelines.

The disconnection device may be combined with the overcurrent protection in the form of a DC circuit breaker. If this is done, a suitable circuit breaker must be selected. According to the latest standards, circuit breakers must be non-polarised. It can be advantageous to install disconnection devices on each string for easier maintenance and fault-finding.

Table 16.7 summarises the requirements for all DC protection devices for PV strings, sub-arrays and arrays, including overcurrent protection and disconnection. The relevant Australian Standards explain how the PV array maximum voltage is calculated.

Table 16.7: Overview of the DC protection requirements for PV systems.

Location	Protection/ Disconnection Description	Protection/ Disconnection Device	Protection Sizing and Guidelines	Australian Standards
String	String overcurrent protection device (Section 16.2.3)	Fuse or circuit breaker	**Required if:** $I_{SC} \times$ *(No. of strings - 1)* $\geq$ *Module reverse current rating* **Sizing:** $1.5 \times I_{SC\_MOD} < I_{TRIP} < 2.4 \times I_{SC\_MOD}$ AND $I_{TRIP} \leq I_{MOD\_REVERSE}$	***AS/NZS 5033:2014*** Clause 3.3.4 and 3.3.5.1
	String disconnection device	Switch-disconnector, circuit breaker, or plug and socket	• Can be non-load-breaking • Rated for PV array maximum voltage • Current rating ≥ string overcurrent protection or, if no string overcurrent protection present, current rating ≥ CCC of string cable • No live parts may be exposed at any time	***AS/NZS 5033:2014*** Clause 4.3.5.2 and 4.4.1.3
Sub-array	Sub-array overcurrent protection device (Section 16.2.3)	Fuse or circuit breaker	**Required if:** $1.25 \times I_{SC\ ARRAY} >$ *CCC of any sub-array cable, switching and connection device* OR More than two sub-arrays are present within the array **Sizing:** $1.25 \times I_{SC\ SUB\text{-}ARRAY} \leq I_{TRIP} \leq 2.4 \times I_{SC\ SUB\text{-}ARRAY}$	***AS/NZS 5033:2014*** Clause 3.3.5.2
	Sub-array disconnection device	Switch-disconnector, circuit breaker, or plug and socket (ELV)	• Can be non-load-breaking • Recommended to be load-breaking for LV systems • Rated for PV array maximum voltage • Current rating ≥ sub-array overcurrent protection or, if no sub-array overcurrent protection present, current rating ≥ CCC of sub-array cable • No live parts may be exposed at any time	***AS/NZS 5033:2014*** Clause 4.2, 4.3.5.2 and 4.4.1.3
Array	Array overcurrent protection device (Section 16.2.3)	Fuse or circuit breaker	**Required if:** Another source of current is available that may cause damage to the PV array when under fault conditions. **Sizing:** $1.25 \times I_{SC\ ARRAY} \leq I_{TRIP} \leq 2.4 \times I_{SC\ ARRAY}$	***AS/NZS 5033:2014*** Clause 3.3.5.3
	Array disconnection device	Switch-disconnector or circuit breaker	• Load-breaking and lockable in off position • Non-polarised • Voltage and current rating outlined below • No live parts may be exposed at any time	***AS/NZS 5033:2014*** Clause 4.2, 4.4.1.3, 4.4.1.4 and 4.4.1.5

Selection of the PV Array DC Isolator

The relevent Australian standards contain specific requirements for the array disconnection device, known as the PV Array DC Isolator. The requirements may differ for sizing and installing a PV array DC isolator that is integrated into the inverter. It is important to refer to the inverter manufacturer or installation manual to determine whether an in-built isolator is suitable for the system. An additional external isolator will be required if the in-built isolator does not meet all the requirements.

> ***AUSTRALIAN STANDARDS***
> ***AS/NZS 5033:2014*** Amendment 2 specifies the changes on sizing DC isolators, particularly Clause 4.3.3 and Clause 4.3.5. Appendix I contains calculated examples.

To check whether an isolator is suitable for a system, perform the three steps below while referring to the isolator's datasheet. For these calculations, the maximum current is defined as $1.25 \times I_{SC\ ARRAY}$.

Step 1: Thermal effects

The maximum current must be less than or equal to I_{the} for the installation conditions:

- Indoors at 40°C ambient for isolators installed indoors.
- Outdoors at 40°C ambient for isolators installed outdoors in a location fully shaded all day (e.g. carport, verandah).
- Outdoors at 60°C ambient with solar effects for rooftop isolators or isolators installed externally where the enclosure or shroud will receive direct sunlight.

Step 2: Operational conditions

Consider the isolator configuration when the positive and negative conductors are operating in series. Looking at the first row where U_e is higher than the PV array max voltage, check that I_e is higher than the maximum current.

Step 3: Fault conditions

This step is for non-separated (transformerless) inverters only. Considering the isolator configuration when the positive and negative conductors are not working in series (e.g. due to an earth fault on one of the conductors), check that I_{make} and $I_{c\ (break)}$ are higher than your maximum current for the maximum voltage U_e.

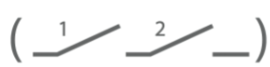
When in fault conditions, the isolator must be able to withstand the maximum current using half of the poles (either the negative or the positive side only). The I_{make} and $I_{c\ (break)}$ is the current that one pole can withstand for very short periods of time. The isolator should be replaced after breaking this current.

EXAMPLE

The switch-disconnector with specifications given in Figure 16.5 will be used as the rooftop PV array isolator for an array with a transformerless inverter. The system has a PV array maximum voltage of 840 V and an array short circuit current of 17 A. The following example checks whether the isolator selected is suitable for this purpose.

Identification	Rating Data
I_{th} rated thermal current, unenclosed, at 40°C shade ambient air temperature	32 A
I_{the} rated thermal current, indoors, at 40°C shade ambient air temperature, in a specific dedicated enclosure	32 A
I_{the} rated thermal current outdoors at 40°C shade ambient air temperature without solar effects in a specific dedicated enclosure rated IP 56NW	32 A
I_{the} *solar* current value, outdoors at 60°C shade ambient air temperature, with solar effects in a specific dedicated enclosure rated IP 56NW	28 A

	U_e rated operational voltage (V)	I_e DC-PV2 rated operational current (A)	$I_{(make)}$ and $I_{c(break)}$ DC-PV2 $4 \times I_e$ (A)
2 pole	≤500	32	128
	600	32	128
	800	27	108
	1000	13	52
4 pole	≤500	32	128
	600	32	128
	800	32	128
	1000	32	128



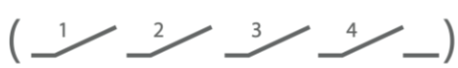


Figure 16.5: Example datasheet from an isolator manufacturer. Values will differ for different brands and models.

Step 1

$1.25 \times I_{SC\_ARRAY} = 1.25 \times 17\text{ A} = 21.25\text{ A}$. This isolator will be installed outdoors in direct sunlight. I_{the} under these conditions is 28 A according to Figure 16.5, which is higher than 21.25 A, so the rating is acceptable.

Step 2

The isolator has four poles and there is only one string to be switched, so the positive and negative conductors will each go through 2 poles (Figure 16.6). During normal operation, these operate in series, so there are 4 poles total operating in series. Looking at the 4 pole configuration in Figure 16.5, the next highest U_e above 840 V is 1000 V, and the corresponding I_e is 32 A. This is higher than 21.25 A, so the rating is acceptable.

EXAMPLE (CONTINUED)

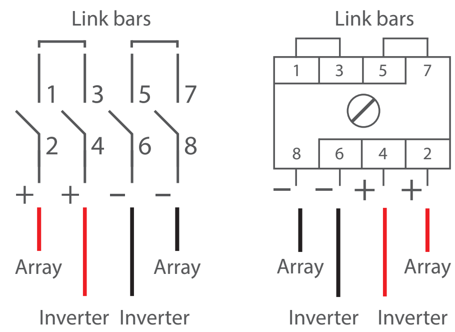


Figure 16.6: Connection diagram for the example four-pole switch-disconnector

Step 3

The positive and negative conductors each go through 2 poles. This is a transformerless inverter, so under earth fault conditions, either conductor may switch the full array current and voltage. Therefore, looking at the 2 poles in series configuration in Figure 16.5, at the 1000 V row, the $I_{(make)}$ and $I_{c\,(break)}$ for the chosen configuration is 52 A. This is higher than 21.25 A, so is acceptable.

The isolator meets all three sizing requirements. Therefore, this isolator and the PV array configuration are compatible.

AUSTRALIAN STANDARDS

AS/NZS 5033:2014 Clause 4.4 provides more information on the DC disconnection device requirements in Australia, including isolator installation and removal.

AUSTRALIAN STANDARDS

AS/NZS 5033:2014 Clause 4.4.1.2 outlines the requirements for when inverters with multiple inputs need to be removed for repairs or replacement.

The array DC switch-disconnectors can be integrated into the inverter as long as they are designed to remain operational when the rest of the inverter is removed (i.e. they stay behind). Otherwise, separate switch-disconnectors should be installed.

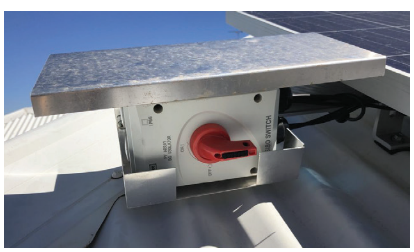


Figure 16.7: Isolator installed with shroud.

Installation of the PV Array DC Isolator

The location of the PV array DC isolators may vary depending on the applicable standards. The general rule is that there needs to be a switch-disconnector disconnection device adjacent to the array (micro-inverters may be the exception), and in many cases there also needs to be one adjacent to the inverter, unless the inverter is within 3 metres and in line of sight of the array.

PV inverters with multiple inputs connect the strings together within the PV inverter. This configuration determines the array disconnection device requirements, as there is no external array cable on which to install the array disconnection device. Therefore, a PV array DC switch-disconnector isolator must be installed on each string, regardless of whether the strings are connected to a single MPPT or individual MPPTs.

Some PV inverters with multiple inputs are supplied with a DC disconnection switch that isolates all of the strings at once. Care must be taken that this disconnection switch meets all relevant standards and guidelines.

Solar controllers with multiple inputs will probably require a PV array DC switch-disconnector isolator to be installed on each string.

PV array DC switch-disconnectors must:

- Comply with ***AS 60947.3***
- Be supplied with dedicated individual enclosures rated at least IP56NW if installed outdoors, to ensure that water jets and rain will not enter the enclosure.
- Have utilization category DC-PV2.
- Rooftop isolators must be installed with a shroud to protect against rain and direct sunlight (Figure 16.7).
- Must be installed vertically, unless otherwise allowed by the manufacturer, with cables entering the lower entry face of the enclosure. Cables and conduits may enter the isolator through the side faces if allowed by the manufacturer.

This is greater than 2, so is acceptable.

For the MPPT as a whole:

$$N_{MAX\ STRINGS} = \frac{I_{MAX\ REG}}{I_{SC}} = \frac{50\ \text{A}}{9.34\ \text{A}} = 5.35 \text{ rounded down to } 5$$

This is greater than 4, so the selected MPPT and array configuration is appropriately matched.

The maximum array current into the batteries is therefore:

$$I_{SC\ ARRAY} = I_{SC\ MOD} \times (N_{STRINGS\ MPPT1} + N_{STRINGS\ MPPT2}) = 9.34 \times (4 + 3) = 65.38\ A$$

21.1.10 Sizing the Genset

The genset is being used for back-up, and should be sized to meet both the following formulae:

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

and

$$S_{GEN} = \frac{(S_{BC} + S_{SUR\ CHG}) \times F_{GO}}{ALT\ SURGE\ RATIO}$$

Where:

- S_{BC} is the demand when the inverter is charging the battery at a maximum of 7.5 kVA.
- S_{MAX_CHG} is the maximum demand that is required to be met by the genset when it is operating and for this example it is assumed to be the maximum demand in Table 21.2 (i.e. 7.652 kVA).
- S_{SUR_CHG} is the surge demand that is required to be met by the genset when it is operating and for this example it is assumed to be the maximum demand in Table 21.2 (i.e. 11.143 kVA).

The genset brand has not been selected however any good 1500 RPM diesel genset will have an Alt (Alternator) Surge Ratio of at least 2 and in some gensets as high as 3. Petrol gensets will typically only be 1.

Using a diesel genset and an oversize factor (F_{GO}) of 10%:

$$S_{GEN} = (S_{BC} + S_{MAX\ CHG}) \times F_{GO} = (7.5 + 7.652) \times 1.1 = 16.7\ kVA$$

and

$$S_{GEN} = \frac{(S_{BC} + S_{MAX\_CHG}) \times F_{GO}}{ALT\ SURGE\ RATIO} = \frac{(7.5 + 11.143) \times 1.1}{2} = 10.3\ kVA$$

The minimum genset to meet the requirements is 16.7 kVA. However, the genset will also need to be de-rated due to temperature, humidity and altitude.

From Table 21.1, the maximum temperature is 38.1°C, maximum humidity is 82% and altitude is 930 metres. Applying the typical de-ratings from Table 15.8:

$$Derating\ due\ to\ temperature = \frac{38.1 - 25}{5} \times 2.5\% = 6.55\%$$

$$Derating\ due\ to\ humidity = \frac{82 - 60}{10} \times 1\% = 2.2\%$$

$$Derating\ due\ to\ altitude = \frac{930 - 300}{300} \times 3\% = 6.3\%$$

Total de-rating of the genset = (1 – 0.0655) × (1 – 0.022) × (1 – 0.063) = 0.9345 × 0.978 × 0.937 = 0.856. Therefore the required genset rating = 16.7 kVA ÷ 0.856 = 19.5 kVA.

NOTE

The maximum genset rating for the inverter is specified at 15 kW, which at 0.8 power factor (standard rating of inverters) would allow a 18.75 kVA genset. The possible need for a larger changeover switch to allow for the 19.5 kVA genset should be discussed with Selectronic.

AUSTRALIAN STANDARDS

Figure 21.9 makes up a part of ***AS/NZS 3008.1.1:2017*** Table 4.

TABLE 4 *(continued)*

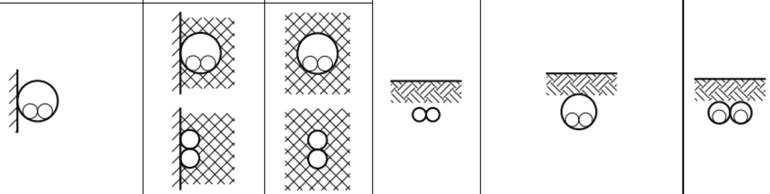
14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Conductor size	Current-carrying capacity, A													
	Enclosed			Thermal insulation				Buried direct		Underground wiring enclosure				
	Wiring enclosure in air			Partially surrounded by thermal insulation		Completely surrounded by thermal insulation								
														
	Cu									Cu				
mm²	Solid/ Stranded	Flexible	Al	Cu	Al	Cu	Al	Cu	Al	Solid/ Stranded	Flexible	Al	Cu	Al
1	13	14	—	11	—	6	—	18	—	18	19	—	21	—
1.5	18	18	—	14	—	8	—	23	—	23	23	—	26	—
2.5	24	24	—	20	—	12	—	32	—	32	31	—	36	—
4	32	31	—	25	—	16	—	41	—	41	40	—	47	—
6	41	40	—	33	—	20	—	52	—	52	50	—	58	—
10	54	54	—	44	—	27	—	69	—	69	68	—	77	—
16	70	69	54	56	43	36	28	122	95	89	87	69	99	77
25	94	91	73	75	58	48	37	158	123	116	112	90	129	100
35	112	110	87	90	70	59	46	190	147	139	136	108	155	120
50	138	139	107	110	86	—	—	225	174	168	168	130	186	145
70	170	169	132	136	105	—	—	277	215	206	205	160	228	177
95	212	206	164	169	131	—	—	332	257	252	244	195	278	215
120	242	237	188	193	150	—	—	378	294	287	282	223	316	245
150	282	278	219	225	175	—	—	424	329	329	324	255	354	274
185	320	312	249	256	199	—	—	480	374	373	363	291	408	317
240	381	373	298	305	238	—	—	556	434	438	429	342	472	368
300	—	—	—	—	—	—	—	628	491	496	493	388	546	425
400	—	—	—	—	—	—	—	713	564	575	572	454	621	487
500	—	—	—	—	—	—	—	805	644	649	663	520	721	570
630	—	—	—	—	—	—	—	904	737	750	754	611	816	652

Figure 21.9: *Current-carrying capacities of two single-core cables with thermoplastic insulation, 75°C maximum conductor temperature, 40°C ambient air temperature and 25°C ambient ground temperature.*

(Source: AS/NZS 3008.1.1:2017)

REMEMBER

As mentioned in Chapter 16, multiply the three-phase V_C value by 1.155 to convert to single-phase (which can be used for voltage drop in DC circuits according to ***AS/NZS 4509.2:2010***).

AUSTRALIAN STANDARDS

The value 1.58 mV/Am has been obtained from ***AS/NZS 3008.1.1:2017*** Table 47 using a conductor temperator of 60°C, max power factor and 25 mm² CSA.

When selecting cable sizes, allowable voltage drops must also be taken into account. For the cable selected on the basis of CCC, the voltage drop for the 2.5 m length cable and current per battery of 60 A is given by:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{2.5 \times 60 \times (1.58 \times 1.155)}{1{,}000} = 0.27\ V$$

NOTE

60 A has been used in this equation, however the maximum 30-minute discharge current by the inverter is 228.88 A. With 17 batteries in parallel this is only 13.5 A discharge per battery, and the voltage drop would be approximately 0.1%.

Based on nominal battery voltage of 51.2 V this represents a 0.5% voltage drop. Total voltage drop between battery bank and inverter-charger should be less than 5%, so this is well below the recommended limit.

The short circuit current of the battery is given by the manufacturer as 1,260 A. Reaction/activation time of the fault protection device must also be taken into account for the time dependent current carrying capacity of the cable. This example uses one second to determine the minimum area of the cable, also referred to as cross-sectional area (CSA):

$$A = \frac{\sqrt{I_{SC}^2 \times t}}{K} = \frac{\sqrt{1{,}260^2 \times 1}}{122} = 10.33\ mm^2$$

AUSTRALIAN STANDARDS

'K' is obtained from Table 54 in ***AS/NZS 3008.1.1:2017***, however it should also be available from manufacturers or local standards.

Being of larger CSA than required, the 25 mm² cable determined above is sufficient to meet the requirements due to the potential fault current from the battery.

Battery Bus Bar to Battery Switch Fuse

The maximum discharge current to be met by this cable is the maximum discharge current by the inverter of 228.88 A. The maximum charge current is the sum of the rated currents from the charge controllers (from Figure 21.7, this is 60 A each) and the battery inverter (from Figure 21.2 this is 156 A). The maximum continuous current this cable must be able to carry is therefore 60 + 60 + 156 = 276 A.

The battery cables connecting the battery bus bar to battery switch fuse would be enclosed in air for mechanical protection. 150 mm² cable mounted in this way can carry 278 A (Figure 21.9) and hence would be selected as the cable between the battery and the battery bus bar link on the basis of CCC.

The distance between battery bus bar and the switch fuse is one metre. The voltage drop in 1 metre long cables with a maximum 30 minute discharge current of 228.88 A is given by:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{1 \times 228.88 \times (0.316 \times 1.155)}{1{,}000} = 0.084\ V$$

Based on a nominal battery voltage of 51.2 V, this represents a 0.16% voltage drop.

The short circuit current of each battery is 1,260 A, so this represents 17 × 1,260 = 21,420 A for the entire battery bank. Again, assuming the fault protection clears the short circuit in one second, the minimum cable CSA is given by:

$$A = \frac{\sqrt{I_{SC}^2 \times t}}{K} = \frac{\sqrt{21{,}420^2 \times 1}}{122} = 175\ mm^2$$

From the cable sizes available (Figure 21.9), the first cable that meets or exceeds this value is 185 mm². This is larger than the requirement for CCC (150 mm²), so 185 mm² cabling is selected between the bus bar and switch fuse in order to meet both the CCC and fault current requirements. This cable size has a V_c of 0.279, resulting in a reduction of the voltage drop to 0.074 V (0.14%).

For selecting the size of the fuse, the three relevant discharge currents are:

- Continuous current = 152.59 A
- Maximum demand (30 minutes) = 228.88 A
- Surge current = 366.21 A

In addition, the fuse must carry the maximum charge current of 276 A. From Figure 21.10, a 200 A fuse is suitable to meet these four requirements.

AUSTRALIAN STANDARDS

The value 0.316 mV/Am has been obtained from ***AS/NZS 3008.1.1:2017*** Table 47 using a conductor temperator of 60°C, max power factor and 150 mm² CSA.

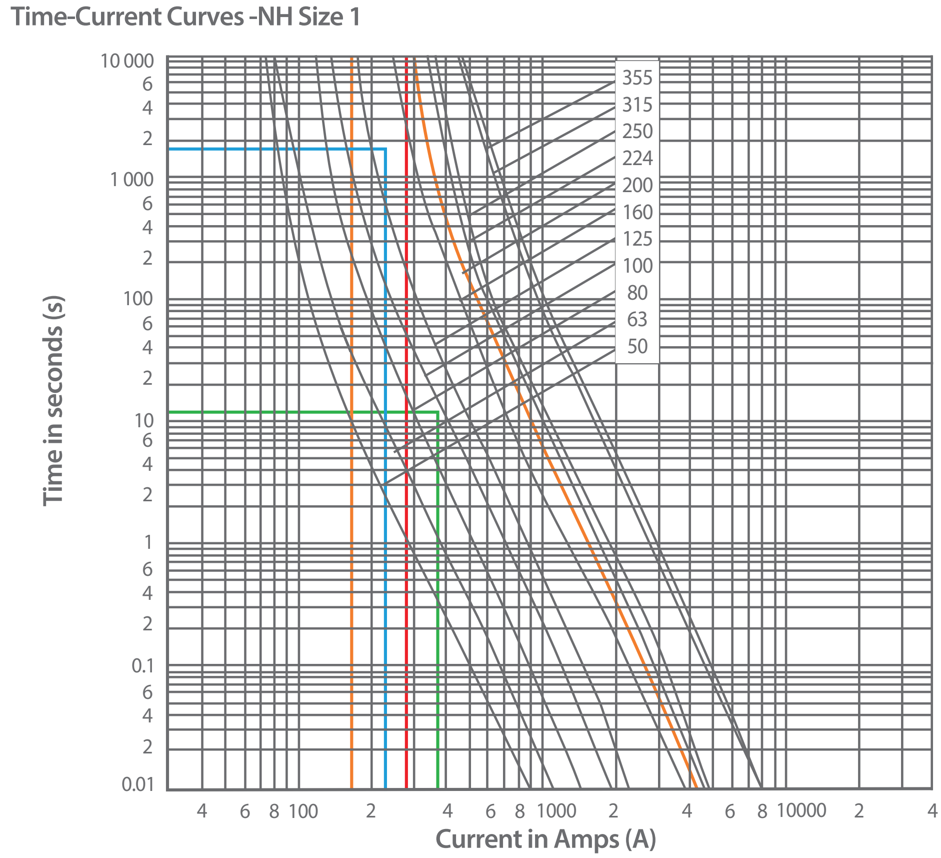


Figure 21.10: *Fuse time-current curves with system currents overlaid.*
(Source: Bussmann)

However, these currents (apart from the maximum charge current) are at the battery nominal voltage of 51.2 V. Li-ion batteries can drop further in voltage during discharge compared to lead acid batteries. In this design, the battery cut-off voltage is 46.9 V, so the continuous, maximum demand, and surge currents could potentially be 9% higher. In this case, the 200 A fuse will still be suitable for all currents, and due to battery short circuit current calculations, all cables selected can carry the increased currents at minimum battery voltage.

Battery Switch Fuse to DC Bus

From the previous sub-section, 185 mm^2 cable has been selected to meet the potential battery fault current with a voltage drop of 0.074 V over one metre at the maximum 30 minute demand current of 228.88 A. 185 mm^2 cable will also be used for the one metre distance between the battery switch fuse and the DC bus and hence has the same voltage drop of 0.074 V.

DC Bus to Inverter

The cable between the DC bus and inverter would be the same size as that between the battery bus bar and DC bus: 185 mm^2, capable of carrying 312 A continuously. This is sufficient for the maximum current that will be carried by this cable, equal to that of the maximum demand of the inverter: 228.88 A.

It is recommended that there is a DC isolator between the DC bus and the inverter so that the batteries can be charged by the solar array while the inverter is isolated. This does not necessarily need to include protection, because the switch fuse between the battery bus bar and DC bus will protect the cable between the DC bus and inverter. However, an additional 200 A switch fuse is the cheapest option.

A final voltage drop check between the batteries and the inverter is required using the maximum 30 minute demand current.

The voltage drop between the batteries and battery bus bar, where the 228.88 A current is shared across 17 parallel batteries, is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{2.5 \times (228.88/17) \times (1.58 \times 1.155)}{1{,}000} = 0.061\ V$$

The voltage drop between the battery bus bar and battery switch fuse is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{1 \times 228.88 \times (0.279 \times 1.155)}{1{,}000} = 0.074\ V$$

AUSTRALIAN STANDARDS

The value 0.279 mV/Am has been obtained from ***AS/NZS 3008.1.1:2017*** Table 47 using a conductor temperator of 60°C, max power factor and 185 mm² CSA.

The voltage drop over the one metre between the battery switch fuse and DC bus is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{1 \times 228.88 \times (0.279 \times 1.155)}{1{,}000} = 0.074\ V$$

Assuming a distance of one metre, the voltage drop between the DC bus and inverter is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{1 \times 228.88 \times (0.279 \times 1.155)}{1{,}000} = 0.074\ V$$

Therefore, the total voltage drop between batteries and battery inverter is equal to 0.283 V.

As a percentage:

$$\frac{V_d}{V_{DC}} = \frac{0.283\ V}{51.2\ V} = 0.006 = 0.6\%$$

This meets the maximum 5% voltage drop requirement between battery bank and inverter.

Solar Array 1 to Combiner Box 1

There are four strings in parallel. The I_{SC} of each module is 9.34 A while the maximum fuse rating is 15 A (Figure 21.5).

From Section 16.2.3, overcurrent protection is required in string cables if:

$$I_{MOD\ MAX\ OCPR} < I_{SC\ MOD} \times (N_P - 1)$$

Since three (4 – 1) parallel strings would have a total I_{SC} of 28.02 A, greater than the maximum fuse rating, string fuses are required in the combiner box.

Overcurrent protection for PV string cables, if required, must be sized as follows:

$$1.5 \times I_{SC\ MOD} < I_{TRIP} < 2.4 \times I_{SC\ MOD}$$

AND

$$I_{TRIP} \sim I_{MOD\ MAX\ OCPR}$$

So in this case the string fuse shall be rated between 1.5 × 9.34 A = 14.01 A and 2.4 × 9.34 A = 22.42 according to the first formula, and less than or equal to 15 A to conform to the second formula. A 15 A fuse meets both these requirements. As the array is LV, these fuses must be located in the positive and negative cables of each of the four strings.

Since HRC fuses will be used as string protection, the string cables' minimum current carrying capacity is 15 A ÷ 0.9 = 16.7 A. Based on Table 16.6, the smallest cable to meet the CCC is 2.5 mm², however 4 mm² is recommended to reduce voltage drop and thus energy losses.

AUSTRALIAN STANDARDS

The value 10.9 mV/Am has been obtained from ***AS/NZS 3008.1.1:2017*** Table 47 using a conductor temperator of 90°C, max power factor and 4 mm² CSA.

Assuming the string cables are six metres in length between the furthest string and the DC combiner box (total 12 m string route length), the voltage drop in the string cables is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{6 \times 9.34 \times (10.9 \times 1.155)}{1{,}000} = 0.706\ V$$

The V_{MP} of each string equals 3 × 31.4 V = 94.2 V.

As a percentage:

$$\frac{V_d}{V_{MP}} = \frac{0.706\ V}{94.2\ V} = 0.0075 = 0.75\%$$

Combiner Box 1 to MPPT 1

The array cable overcurrent protection is sized as follows:

$$1.25 \times I_{SC\ ARRAY}\ \tilde{}\ I_{\ TRIP}\ \tilde{}\ 2\ .4 \times I_{SC\ ARRAY}$$

Now:

$$I_{SC\ ARRAY} = 4 \times 9.34\ \text{A} = 37.36\ A$$

Therefore:

$$I_{TRIP\ MINIMUM} = 1.25 \times 37.36\ \text{A} = 46.70\ A$$

$$I_{TRIP\ MAXIMUM} = 2.4 \times 37.36\ \text{A} = 89.66\ A$$

Figure 21.11 shows the available non-polarised circuit breakers from ABB.

I_{cu} [kA]	Rated current [A]	Type designation	Product number	EAN number 76122712	Weight [kg]	Pack. unit
5	10	S802PV-S10	2CCP842001R1109	10939	0.49	1
5	13	S802PV-S13	2CCP842001R1139	10946	0.49	1
5	16	S802PV-S16	2CCP842001R1169	10953	0.49	1
5	20	S802PV-S20	2CCP842001R1209	10960	0.49	1
5	25	S802PV-S25	2CCP842001R1259	10977	0.49	1
5	32	S802PV-S32	2CCP842001R1329	10984	0.49	1
5	40	S802PV-S40	2CCP842001R1409	10991	0.49	1
5	50	S802PV-S50	2CCP842001R1509	11004	0.49	1
5	63	S802PV-S63	2CCP842001R1639	11011	0.49	1
5	80	S802PV-S80	2CCP842001R1809	11028	0.49	1
5	100	S802PV-S100	2CCP842001R1829	14968	0.49	1
5	125	S802PV-S125	2CCP842001R1849	14999	0.49	1

Figure 21.11: *Non-polarised circuit breaker data.*
(Source: ABB)

AUSTRALIAN STANDARDS

Figure 21.12 makes up a part of ***AS/NZS 3008.1.1:2017*** Table 5.

Based on the calculations and the datasheet, the 50 A rated circuit breaker is recommended.

The cable, which will have XLPE insulation rather than the thermoplastic used for the battery cables, must have a minimum current rating equal to that of the protection device (i.e. 50 A). As shown in Figure 21.12, 10 mm² cable has a rating of only 48 A exposed to sun while 16 mm² has a 63 A rating, so 16 mm² cable would be selected. However, if the cable is not exposed to the sun then a 10 mm² cable (“Touching” CCC of 64 A) would suffice.

1	2	3	4	5	6	7	8	9	10	11	12	13
Conductor size	Current-carrying capacity, A											
	Unenclosed											
	Spaced			Spaced from surface			Touching			Exposed to sun		
	Cu		Al	Cu		Al	Cu		Al	Cu		Al
mm²	Solid/ Stranded	Flexible		Solid/ Stranded	Flexible		Solid/ Stranded	Flexible		Solid/ Stranded	Flexible	
1	20	21	—	20	21	—	16	16	—	12	13	—
1.5	26	26	—	25	26	—	20	20	—	15	16	—
2.5	36	35	—	36	34	—	28	27	—	21	21	—
4	48	46	—	47	46	—	37	36	—	28	27	—
6	61	59	—	60	58	—	47	46	—	36	34	—
10	84	83	—	82	81	—	65	64	—	48	48	—
16	112	110	87	108	106	84	86	85	67	64	63	50
25	151	147	117	145	141	112	117	114	91	86	83	66
35	186	183	144	177	174	137	144	141	111	105	103	81
50	228	231	177	216	218	167	176	178	136	127	128	99
70	291	292	226	273	274	212	224	225	174	160	161	124
95	361	351	280	338	328	262	278	271	216	197	192	153
120	422	418	328	393	389	305	325	322	253	229	226	178
150	486	483	377	451	448	350	375	373	291	262	260	204
185	565	555	439	522	512	406	436	428	340	303	296	236
240	678	668	527	622	613	485	522	515	408	359	353	280
300	787	772	612	718	705	562	605	594	473	413	404	323
400	923	933	723	836	843	660	708	715	559	478	480	377
500	1078	1090	850	966	975	772	821	830	656	550	552	439
630	1261	1288	1003	1113	1135	904	950	969	772	629	639	511

Figure 21.12: Current-carrying capacities of two single-core cables with X-90 insulation, 90°C maximum conductor temperature, 40°C ambient air temperature and 25°C ambient ground temperature.

(Source: AS/NZS 3008.1.1:2017)

Assuming the distance from the combiner box to the MPPT is 10 metres and 10 mm² cable is able to be used, then the voltage drop is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{10 \times 37.36 \times (4.22 \times 1.155)}{1{,}000} = 1.82\ V$$

As a percentage of array voltage (3 × 31.4 = 94.2 V):

$$\frac{V_d}{V_{MP}} = \frac{1.82\ V}{94.2\ V} = 0.019 = 1.9\%$$

This is a total of 2.6% when voltage drop in the string cables is included. Recommended maximum voltage drop between the PV array and PCE is 3%, so these cable sizes are acceptable.

AUSTRALIAN STANDARDS

The value 4.22 mV/Am has been obtained from ***AS/NZS 3008.1.1:2017*** Table 47 using a conductor temperator of 90°C, max power factor and 10 mm² CSA.

MPPT 1 to DC Bus

Assume the distance between the MPPT and the DC bus is two metres. Array 1 comprises 12 modules each with a rated output of 280 W and de-rated output of 254 W (Section 21.1.8). To be conservative, the following calculations will be based on the **rated** array power of 12 × 280 = 3,360 W. The voltage drop is 2.6% (97.4% cable efficiency) and the MPPT is 96% efficient. Therefore, current output of the MPPT at nominal battery voltage of 51.2 V is:

$$\frac{0.974 \times 0.96 \times 3{,}360\ W}{51.2\ V} = 61.4\ A$$

AUSTRALIAN STANDARDS

The value 1.58 mV/Am has been obtained from ***AS/NZS 3008.1.1:2017*** Table 47 using a conductor temperator of 60°C, max power factor and 25 mm² CSA.

The cables between the MPPT and the DC bus, which will use thermoplastic insulation and be enclosed in air for mechanical protection, should be rated with a safety margin of 1.25. Cable CCC is then a minimum of 1.25 × 61.4 A = 76.75 A. From Figure 21.9, 25 mm² cable mounted in this way can carry 91 A.

The voltage drop in this cable, based on a current of 61.4 A, would be:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{2 \times 61.3 \times (1.58 \times 1.155)}{1{,}000} = 0.224\ V$$

As a percentage:

$$\frac{V_d}{V_{DC}} = \frac{0.224\ V}{51.2\ V} = 0.004 = 0.4\%$$

Therefore, the voltage drop from the first PV array to the DC bus is in total 3.0%.

Solar Array 2 to Combiner Box 2

There are three strings in parallel. The I_{SC} of each module is 9.34 A while the maximum fuse rating is 15 A (Figure 21.5).

From Section 16.2.3, overcurrent protection is required in string cables if:

$$I_{MOD\ MAX\ OCPR} < I_{SC\ MOD} \times (N_P - 1)$$

Since two (3 – 1) parallel strings would have a total I_{SC} of 18.68 A, greater than the maximum fuse rating, string fuses are required in the combiner box.

Overcurrent protection for PV string cables, if required, must be sized as follows:

$$1.5 \times I_{SC\ MOD} < I_{TRIP} < 2.4 \times I_{SC\ MOD}$$

AND

$$I_{TRIP} \,\tilde{}\, I_{MOD\ MAX\ OCPR}$$

In this case:

$$1.5 \times 9.34 = 14.01\ A < I_{TRIP} < 2.4 \times 9.34 = 22.42\ A$$

and

$$I_{TRIP} \,\tilde{}\, 15\ A$$

A 15 A fuse meets these requirements, and will be required in both the positive and negative cables in each of the four strings since the array is LV.

Since HRC fuses will be used as string protection, the string cables' minimum CCC is 15 A ÷ 0.9 = 16.7 A. As for Array 1, 4 mm² cable will be used to meet this requirement, for a total voltage drop in the string cables of 0.706 V or 0.75%.

Combiner Box 2 to MPPT 2

The array cable overcurrent protection is sized as follows:

$$1.25 \times I_{SC\ ARRAY} \,\tilde{}\, I_{TRIP} \,\tilde{}\, 2.4 \times I_{SC\ ARRAY}$$

Now:

$$I_{SC\ ARRAY} = 3 \times 9.34\ A = 28.02\ A$$

Therefore:

$$I_{TRIP\ MINIMUM} = 1.25 \times 28.02\ A = 35.03\ A$$

$$I_{TRIP\ MAXIMUM} = 2.4 \times 28.02\ A = 67.25\ A$$

To maintain consistency between the arrays, a 50 A circuit breaker would be selected (Figure 21.11).

As for Array 1, 16 mm² cable (with XLPE insulation) is required if exposed to the sun, and 10 mm² suffices if not (Figure 21.12).

Assuming the distance from the combiner box to the MPPT is 10 metres and 10 mm² cable is able to be used then the voltage drop is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{10 \times 28.02 \times (4.22 \times 1.155)}{1{,}000} = 1.37\ V$$

As a percentage of array voltage:

$$\frac{V_d}{V_{MP}} = \frac{1.37\ V}{94.2\ V} = 0.015 = 1.5\%$$

This is a total of 2.3% when string cables are included. Recommended maximum voltage drop between array and PCE is 3%, so these cables are acceptable.

MPPT 2 to DC Bus

Assume the distance between the MPPT and the DC bus is two metres. Array 2 comprises 9 modules each with a rated output of 280 W and de-rated output of 254 W. To be conservative, calculations will be based on the **rated** array power of 9 × 280 = 2,520 W_p. The voltage drop is 2.3% (97.7% cable efficiency) and the MPPT is 96% efficient. Therefore current output of the MPPT at nominal battery voltage of 51.2 V is

$$\frac{0.977 \times 0.96 \times 2{,}520\ W}{51.2\ V} = 46.2\ A$$

The cables between the MPPT and the DC bus, which will be enclosed in air for mechanical protection, should be rated with a safety margin of 1.25. Cable CCC is then a minimum of 1.25 × 46.2 A = 57.8 A. From Figure 21.9, 16 mm² cable enclosed in air can carry 69 A. However, it would be more convenient to use the same size cable as Array 1, so 25 mm² cable will be selected.

The voltage drop in this cable, based on a current of 46.2 A, would be:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{2 \times 46.2 \times (1.58 \times 1.155)}{1{,}000} = 0.169\ V$$

As a percentage:

$$\frac{V_d}{V_{DC}} = \frac{0.169\ V}{51.2\ V} = 0.003 = 0.3\%$$

Therefore, the voltage drop from the second PV array to the DC bus is in total 2.9%.

Voltage Drop from Array to Batteries

It is recommended that the total voltage drop between the array and battery bank is no more than 5%; this includes the voltage drop between the array and DC bus as well as the voltage drop between the DC bus and the batteries.

The maximum voltage drop between the array and the DC bus occurs in Array 1, with a total 3.0% as previously calculated.

The worst case scenario for voltage drop between the DC bus and the batteries is that I_{SC} is coming from the two arrays (61.3 + 46.2 = 107.5 A) in addition to full charge current from the inverter (156 A). In this case, current between the DC bus and the battery bus bar would be 107.5 + 156 = 263.5 A.

NOTE

This is not greater than the 510 A which is the maximum charge current that battery bank would accept.

The cable between the DC bus and battery bus bar is 185 mm² and the physical distance is two metres (one metre from the bus bar to the battery switch fuse, and one metre from the switch fuse to the DC bus), so maximum voltage drop from the DC bus to the battery bus bar is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{2 \times 263.5 \times (0.279 \times 1.155)}{1{,}000} = 0.170\ V$$

The 263.5 A maximum charge current represents 15.5 A per battery. The cable between the battery bus bar and battery is 25 mm^2 and the cable length is 2.5 metres, so voltage drop from the battery bus bar to the batteries is:

$$V_d = \frac{L \times I \times V_C}{1{,}000} = \frac{2.5 \times 15.5 \times (1.58 \times 1.155)}{1{,}000} = 0.071\ V$$

Therefore, the total voltage drop from batteries to DC bus is 0.170 + 0.071 = 0.218 V. As a percentage:

$$\frac{V_d}{V_{DC}} = \frac{0.218\ V}{51.2\ V} = 0.004 = 0.4\%$$

The total maximum voltage drop between a PV array and the batteries is therefore:

$$3.1\% + 0.4\% = 3.5\%$$

This is much less than the 5% recommendation.

21.2 AC Bus System

21.2.1 Customer Requirements

- Customer wants to take their boarding house off-grid to improve their "green" credentials, to minimise business interruptions due to frequent, extended blackouts, and as a personal statement.
- Three days of autonomy without needing to run the genset in the event of bad weather (don't want to disturb guests who are primarily there on the summer weekends).
- 10 years minimum to battery replacement.
- Minimal maintenance requirements wherever possible.

21.2.2 Site Description

Site is a double storey building with Colorbond roof and lightweight construction. It is a former country pub in the village of The Channon, near Lismore NSW.

- Latitude 28.67°S
- Town water and sewage facilities
- Occupants: 4 adults full-time (2 owners + 2 staff), with 4 guest rooms for up to 12 guests
- Currently connected to the grid supply
- LPG for cooking (and instantaneous boost for domestic hot water)
- Domestic hot water will be via evacuated tube with LPG boost – heating elements in water tanks can be used as dump loads for PV if desired
- Heating via slow combustion stoves in rooms (rarely required due to climatic conditions)
- Possible locations for equipment include building a dedicated shed, or installing equipment in a container at rear of the premises
- Large available roof facing NE, smaller roof facing NW, both pitched at 22 degrees – suitable for PV installation with roofing battens spaced approximately 1100 mm vertically and rafters 600 mm apart.

thermal mass and are unlikely to cool to the minimum temperature; additionally, battery operation will generate internal heat.

- Since a conservative 'typical' discharge rate is at C_{24}, the actual capacity of the two parallel strings is actually between 5,692 Ah at C_{24} and 6,830 Ah at C_{48}.
- They will be less expensive.

Check Battery Discharge Characteristics against Inverter Requirements

It is recommended that:

- The C_5 discharge current of the battery is greater than or equal to the half-hour rating of the battery inverter.
- The C_1 discharge current is greater than or equal to the surge rating of the battery inverter.

The C_5 capacity of the A602/3270 is 2,227 Ah. Therefore:

$$I_{STRING\ MAX\ DEMAND} = \frac{2{,}227\ Ah}{5\ h} = 445.4\ A$$

Two strings in parallel will provide a combined discharge current of $I_{BATT\ MAX\ DEMAND}$ = 890.8 A.

The C_1 capacity of the A602/3270 is 1,309 Ah. Therefore:

$$I_{STRING\ SURGE} = \frac{1{,}309\ Ah}{1\ h} = 1{,}309\ A$$

Two strings in parallel will provide a combined discharge current of $I_{BATT\ SURGE}$ = 2,618 A.

The maximum current that can be drawn by the three AC bus interactive inverters set up in 3-phase mode, based on nominal battery voltage, are as follows (see Figure 21.16 for relevant data):

$$I_{MAX\ DEMAND} = \frac{Maximum\ demand}{V_{DC} \times \eta_{INV}} = \frac{3 \times 8{,}000\ W}{48\ \mathrm{V} \times 0.96} = 521\ A$$

$$I_{SURGE} = \frac{Surge\ demand}{V_{DC} \times \eta_{INV}} = \frac{3 \times 11{,}000\ \mathrm{W}}{48\ \mathrm{V} \times 0.96} = 716\ A$$

Notes:

1. Calculations assume power factor of 1.
2. The actual inverter ratings have been used; these are greater than the estimated maximum demand (16.6 kVA) and surge demand (22.1 kVA) calculated previously for the site. This has been done to ensure if loads do increase at the site such that the full inverter capacity is used, the battery bank can still provide the required currents.

The C_5 discharge current of the battery bank is greater than the required maximum demand current of the inverter, and the C_1 discharge current of the battery bank is greater than the required surge current of the inverter. Therefore the battery bank and inverter are matched in accordance with the required discharge currents.

Check Battery Charge Characteristics against Inverter Charging Capability

The maximum current that can be supplied by the three AC bus interactive inverters setup in 3-phase mode is 3 × 140 A = 420 A (see Figure 21.16).

The maximum charge current that can be accepted by a lead acid battery is typically 10% of the C_{10} capacity. The C_{10} capacity rating of the A602/3270 battery is 2,530 Ah so the maximum charge current is 2,530 Ah ÷ 10 h = 253 A. Two strings of batteries in parallel will thus accept a maximum charge current of 506 A, which is greater than the maximum charge current available from the inverter. Therefore the battery bank and inverter are matched in accordance with the allowed charge current. Also note that since there are two parallel strings, the selected battery capacity is 2 × 2,530 Ah = 5,060 Ah.

Cycle Life

The average daily depth of discharge is calculated using:

$$DOD_{DAILY} = \frac{E_{TOT} \times 100\%}{V_{DC} \times \text{Selected battery capacity}} = \frac{57{,}917\ \text{Wh} \times 100\%}{48\ \text{V} \times 5{,}060\ \text{Ah}} = 23.8\%$$

Based on the life cycle curve displayed in Figure 21.19 the selected battery will have a cycle life of over 6,500 cycles at this depth of discharge. This represents a minimum 17 year life-time:

$$\frac{6{,}500\ \text{cycles}}{1\ \text{cycle/day} \times 365\ \text{days/year}} = 17.8\ \text{years}$$

In reality, the effects of temperature, etc., will reduce the actual lifetime to less than 17 years. However, the batteries should still last a full 10 years before replacement.

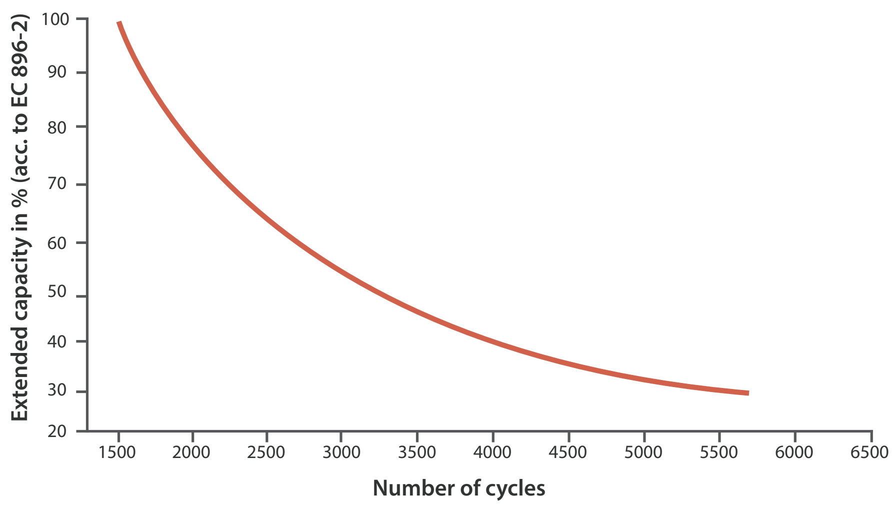


Figure 21.19: Sonnenschein A602/3270 cycle life.
(Source: Sonnenschein)

21.2.8 Sizing the PV Array

Based on the load profile, the load between 9am and 3pm is 22,900 Wh and on a sunny day some or all of the load could be directly supplied from the PV system to the AC bus and thus to the loads. This direct supply component is $E_{PV\text{-}AC}$.

The remaining $E_{PV\text{-}BATT}$ = 32,700 Wh/day would have to be supplied from energy stored in the battery. Accordingly, the relevant system efficiencies for direct supply

21.2.10 Sizing the Genset

The genset is mainly being used for back-up; however, it may be required to operate for a small period of time in the design month because an array of 56 modules was selected where 56.5 modules were required.

The genset should therefore be sized to meet both the following formulae:

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

and

$$S_{GEN} = \frac{(S_{BC} + S_{SUR\_CHG}) \times F_{GO}}{ALT\ SURGE\ RATIO}$$

S_{BC} is the demand when inverter is charging the battery at the maximum of 3 × 140 A × 48 V = 20,160 VA (unity power factor). S_{MAX_CHG} is the maximum demand that is required to be met by the genset when it is operating and for this example it is assumed to be the maximum demand as determined in Section 21.2.6 (i.e. 16.6 kVA). S_{SUR_CHG} is the surge demand that is required to be met by the genset when it is operating and for this example it is assumed to be the maximum demand as determined in Section 21.2.6 (i.e. 22.1 kVA).

The genset brand has not been selected, however any good 1500 RPM diesel genset will have an Alt (Alternator) Surge Ratio of at least 2.

Using a diesel genset and an oversize factor of 10%:

$$S_{GEN} = (S_{BC} + S_{MAX\_CHG}) \times F_{GO} = (20.16 + 16.6) \times 1.1 = 40.4\ kVA$$

and

$$S_{GEN} = \frac{(S_{BC} + S_{SUR\_CHG}) \times F_{GO}}{ALT\ SURGE\ RATIO} = \frac{(20.16 + 22.1) \times 1.1}{2} = 23.2\ kVA$$

The minimum genset to meet the requirements is 40.4 kVA. However, the genset will also need to be de-rated for temperature, humidity and altitude.

From Table 21.5, the maximum temperature is 43.4°C, maximum humidity is 81% and altitude is 55 metres. Applying the typical deratings from Table 15.8:

- $De\text{-}rating\ due\ to\ temperature = \frac{(43.4\text{-}25)}{5} \times 2.5\% = 9.2\%$
- $De\text{-}rating\ due\ to\ humidity = \frac{(81\text{-}60)}{10} \times 1\% = 2.1\%$
- $De\text{-}rating\ due\ to\ altitude = \frac{(55\text{-}300)}{300} \times 3\% = 0\%$

Total de-rating of the genset = 0.908 × 0.979 × 1.00 = 0.889, equivalent to an efficiency of 88.9%. Therefore the required genset rating = 40.4 kVA ÷ 0.889 = 45.4 kVA.

Notes:

1. The maximum genset rating for each inverter is 11.5 kW which for the three inverters in 3-phase mode is 34.5 kW. At 0.8 power factor (standard rating of inverters), this would allow a 43.1 kVA genset. It is recommended to check with the manufacturer if this is acceptable.
2. In reality, a smaller genset might be selected because of the cost in running a genset of this size. The decision might be that genset is only run to charge the batteries when the demand is low, so the genset is not required to meet the 16.6 kVA peak demand.

