Assets Planning and Delivery Group
Engineering

DESIGN STANDARD DS 25

Solar Energy Systems

VERSION 1
REVISION 1

DECEMBER 2022

FOREWORD

The intent of Design Standards is to specify requirements that assure effective design and delivery of fit for purpose Water Corporation infrastructure assets for best whole-of-life value with least risk to Corporation service standards and safety. Design standards are also intended to promote uniformity of approach by asset designers, drafters and constructors to the design, construction, commissioning and delivery of water infrastructure and to the compatibility of new infrastructure with existing like infrastructure.

Design Standards draw on the asset design, management and field operational experience gained and documented by the Corporation and by the water industry generally over time. They are intended for application by Corporation staff, designers, constructors and land developers to the planning, design, construction and commissioning of Corporation infrastructure including water services provided by land developers for takeover by the Corporation.

Nothing in this Design Standard diminishes the responsibility of designers and constructors for applying the requirements of the Western Australia's Work Health and Safety (General) Regulations 2022 to the delivery of Corporation assets. Information on these statutory requirements may be viewed at the following web site location:

[Overview of Western Australia's Work Health and Safety (General) Regulations 2022 (dmirs.wa.gov.au)](dmirs.wa.gov.au)

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Head of Engineering

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REVISION STATUS

The revision status of this standard is shown section by section below.

				REVISION STATUS		
SECT.	**VER./ REV.**	**DATE**	**PAGES REVISED**	**REVISION DESCRIPTION (Section, Clause, Sub-Clause)**	**RVWD.**	**APRV.**
All	1/0	25/07/18	All	New	NHJ	MSP
All	**1/1**	**23/12/22**	**NA**	**Scheduled review, no changes required at this stage**	**RR**	**RR**

DESIGN STANDARD DS 25
Solar Energy Systems

CONTENTS

Section *Page*

1. Introduction

1.1 Purpose

(a) The Water Corporation has adopted a policy of out sourcing most of the electrical engineering and electrical detail design associated with the procurement of its assets. The resulting assets need to be in accordance with the Corporation's operational needs and standard practices.

(b) This design standard (i.e. Electrical Design Standard DS25) sets out design standards and engineering practice which shall be followed in respect to the design and specification of solar powered systems being acquired by the Corporation. This design manual does not address all issues that will need to be considered by the Designer in respect to a particular solar powered system.

(c) It is the Water Corporation's objective that its assets will be designed so that these have a minimum long term cost and are convenient to operate and maintain. In respect to matters not covered specifically in this manual, the Designer shall aim his/her designs and specifications at achieving this objective.

(d) This design standard is intended for the guidance of electrical system Designers and shall not be quoted in specifications for the purpose of purchasing electrical equipment or electrical installations except as part of the prime specification for a major design and construct (D&C) contract.

1.2 Scope

(a) Eventually this Design Standard (DS25) will cover the requirements for the following types of solar energy system:

    (i) isolated borehole pump drive systems without battery support,

    (ii) isolated pump drive systems with battery support,

    (iii) grid connected solar energy recovery systems.

(b) This edition of this Design Standard is limited to isolated borehole pump drive systems without battery support.

(c) Sections 2 to 9 of the Design Standard have general application whereas sections 10 to 12 relate to isolated borehole pump drive systems without battery support.

2. Definitions

2.1 General

The meaning of various terms and abbreviations used in this Design Standard shall be as defined hereunder.

(a) Irradiance (P_{ir}) = instantaneous solar radiation power per unit area = kW/m^2

(b) Irradiation (Q_{ir}) = solar radiation energy per unit area per unit time

= $kWh/m^2/day$

(c) MPPT = maximum power point tracker

= a control algorithm within the PCE which varies the load so that the product of voltage and current taken is maximised

(d) NOCT = "normal" operating cell temperature = 45 deg. C

(temperature coefficients are sometimes quoted against NOCT)

(e) PCE = power conversion equipment

(f) PV array = an assembly of electrically interconnected PV strings or PV sub-arrays comprising all components up to the D.C. input terminals of power conversion equipment or D.C. load

(g) PV module = smallest complete environmentally protected assembly of interconnected PV cells

(h) PV module conversion efficiency - commonly termed "module efficiency"

= ratio of output energy/input energy under standard test conditions

PV module efficiency is a measure of power output per unit area of PV array

(i) PV module rated power = power produced by module at STC

(j) PV = photovoltaic

(k) PV string = a circuit of series connected PV modules

(l) P_{SH} = peak sun hours = area under the daily radiation curve with maximum irradiance of 1 kW/m^2

$$1 * P_{SH} = 1 * kWh/m^2 = 3.6 \, MJ/m^2$$

(m) Solar angle (ϑ_{sa}) = angle of solar radiation from the centre of the sun to the horizontal plane for particular month. (Figure 2.1 refers)

This angle is always between 0° and 90°.

(n) Solar azimuth (in the Southern hemisphere) = The angle between North and the point on the compass where the sun is positioned on a horizon plane. (Figure 2.1 refers.)

The solar azimuth angle varies as the sun moves from East to West across the sky throughout the day.

In general, azimuth is measured clockwise from 0° (true North) to 359°.

(o) Solar pump inverter = variable speed pump motor drive unit consisting of variable speed controller with selectable varying voltage input D.C. supply or fixed 3 phase A.C, input power supply.

(p)   STC = PV module radiation standard test conditions   = 1 kW/m^2 at 25 deg. C

h = elevation angle, measured up from horizon

z = zenith angle, measured from vertical

A = Azimuth angle, measured clockwise from North
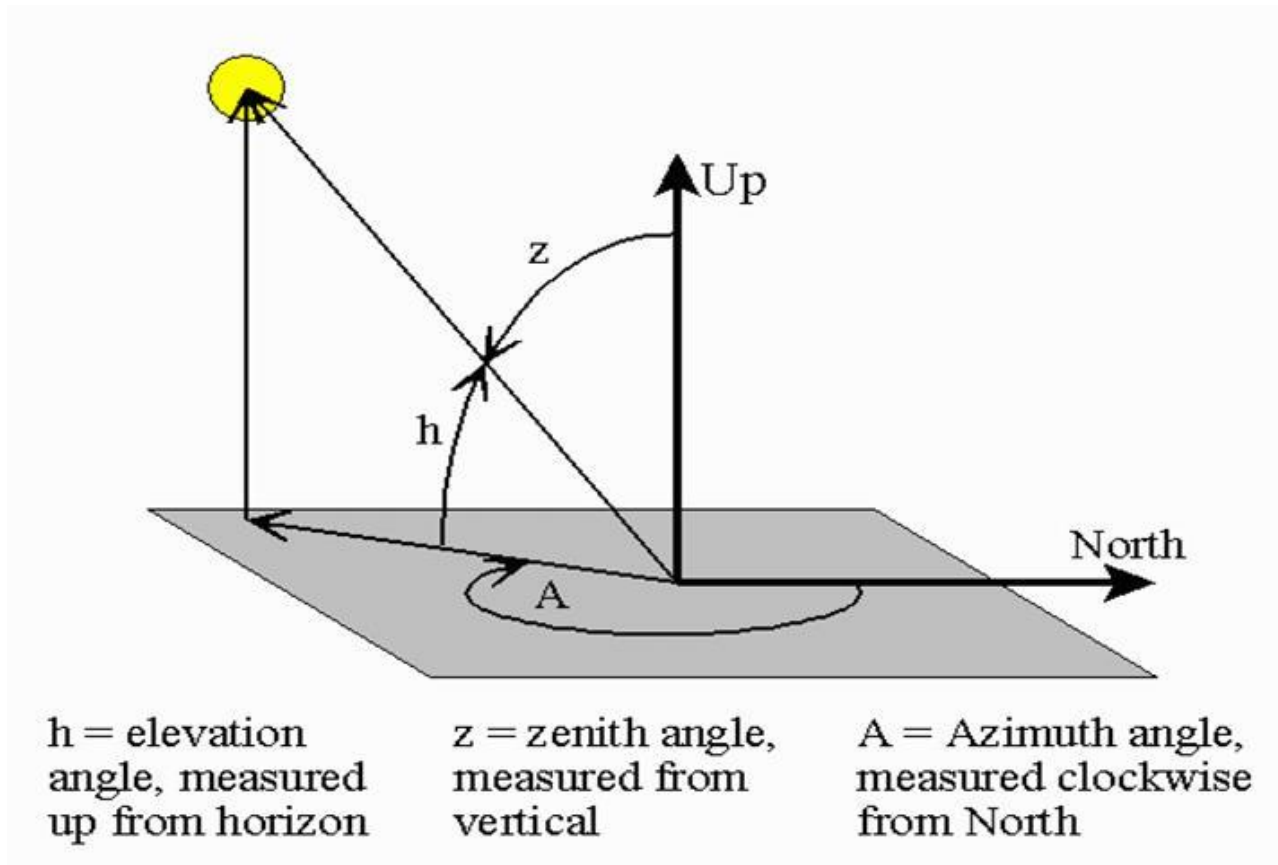
Figure 2.1

2.2   PV Module

(a) $I_{sc\ mod}$ = PV module short circuit current at STC

(b) $I_{mod\ max\ ocpr}$ = PV module maximum protection equipment current setting

(c) I_{mpp} = current at maximum power point of PV module under STC

(d) P_{mpp} = power at maximum power point of PV module under STC

(e) T_{mod} = module operating temperature

(f) T_{amb} = shade ambient temperature

(g) V_{mpp} = voltage at maximum power point of PV module under STC

(h) V_{ocmod} = open circuit voltage of PV module

(i) α = temperature coefficient of $I_{sc\ mod}$ % per deg. C above STC

(j) β = temperature coefficient of $V_{oc\ mod}$ % per deg. C above STC

(k) γ = temperature coefficient of P_{mpp} % per deg. C above STC

(l) η = efficiency % at maximum power point of PV module under STC

(m) ϑ_{tov} = module optimum tilt angle to the vertical for particular month
= ϑ_{sa} (solar angle)

(n) ϑ_{toh} = module optimum tilt angle to the horizontal for particular month   =
(90- ϑ_{sa})

2.3 PV Array

(a) I_n = over current rating of PV string protective device

(b) $I_{sc\ array}$ = I_{mod} * S_{sa} = short circuit strength of PV array at STC

(c) M = number of series connected modules in any PV string of a PV array

(d) N_g = lightning flash density (AS/NZS 5033-2012 Appendix G)

(e) S_a = number of parallel connected PV strings in PV array

(f) T_{min} = expected minimum daily PV cell temperature, deg. C

(g) T_{STC} = PV cell temperature at STC, deg. C

(h) $V_{oc\ array}$ = $V_{os\ mod}$*M = PV array open circuit voltage

(i) $V_{mpp\ array}$ = V_{mpp} *M = PV array maximum power point voltage

3. Solar Radiation

3.1 General

(a) The amount of solar radiation received at any particular site onto a horizontal surface varies with:

(i) the time of day,

(ii) the season of the year, and

(iii) the amount of cloud cover.

(b) The amount of solar radiation received onto a horizontal surface also depends on the latitude of the site.

(c) In addition, the level of irradiance (kW/m^2) onto a tilted surface varies with the angle of tilt of the surface from the horizontal and the direction in which the surface is pointing.

(d) For fixed tilt PV arrays in the Southern Hemisphere,   maximum solar energy captured per annum is achieved if the PV modules face North and the PV module tilt is set at the March optimum value.

However, if there is a need to minimise the differences in irradiance levels over the year, the PV module tilt will need to be set at the June optimum value.

(e)   Figure 3.1 hereunder indicates the average hourly irradiance (kW/m^2) onto horizontal surfaces for the months of December and June at Wagga Wagga which is located at latitude 34.5° South.

The area under the daily irradiance curve represents the received irradiation (kWh/m^2/day), i.e. the daily received energy.

Daily Variation of Irradiance
at Wagga Wagga

Figure 3.1
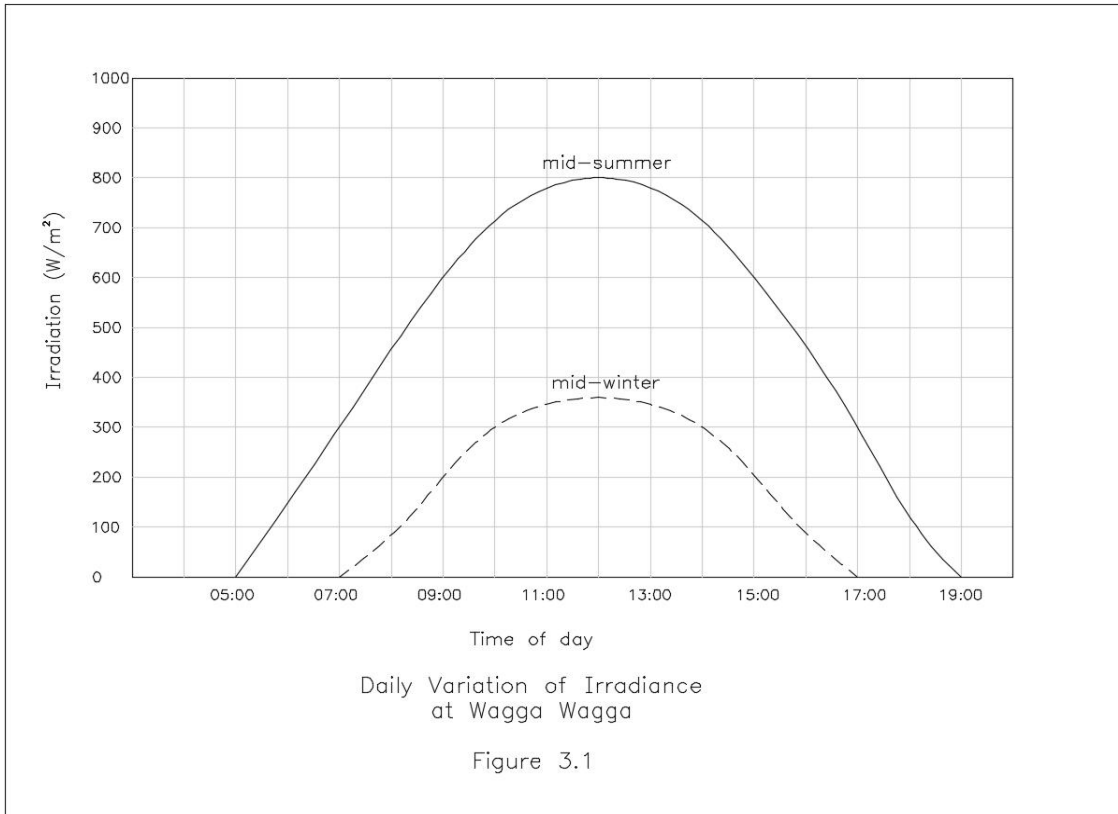
3.2   AUSOLRAD Irradiance Calculation Software

The Australian Solar Radiation Software (AUSOLRAD) provides, for a limited range of Australian cities and towns, a method of calculating for each month the:

(a)   average hourly irradiance (W/m^2) onto a horizontal surface

(b)   average daily irradiation (kWh/m^2/day) onto a horizontal surface

(c)   average hourly irradiance (W/m^2) onto a surface tilted at the site latitude degree,

(d)   average daily irradiation (kWh/m^2/day) onto a surface tilted at the site latitude degree.

3.3 NASA Solar Radiation Software

(a) The NASA web site "esoweb.larc.nasa.gov/sse/" provides a method of calculating monthly 22 year averaged midday irradiance incident onto a horizontal surface (kW/m^2) for any site on the basis of site latitude and longitude.

(b) The above NASA web site also generates for the same site:

   (i) monthly 22 year averaged irradiation incident on a horizontal surface (kWh/m^2/day),

   (ii) monthly 22 year averaged clear sky irradiation incident on a horizontal surface (kWh/m^2/day),

   (iii) monthly averaged clear sky days (days per month)

(c) The term "irradiance" is defined in AS/NZS 5033 and in this Design Standard (at para. 2.1) as being the "radiant solar power incident upon unit area of surface, measured in watts per square metre".

   However the above NASA web site quotes incident radiant solar <u>power</u> as "insolation kW/m^2".

(d) At para. 2.1 of this Design Standard the term "irradiation" is defined as being the "radiant solar energy incident upon unit area of surface, measured in watt hours per square metre per day."

   However the above NASA web site quotes incident radiant solar <u>energy</u> as "insolation kW/m^2/ day".

3.4 Solar Electricity Handbook Solar-Irradiance

(a) The software at "solarelectricityhandbook.com/solar-irradiance.html" web site provides, for a limited range of Australian cities and towns, a method of calculating for each month, the:

   (i) average daily irradiation (kWh/m^2/day) onto a horizontal surface,

   (ii) average daily irradiation (kWh/m^2/day) onto a surface tilted at the site latitude degree,

   (iii) average daily irradiation (kWh/m^2/day) onto a surface tilted to provide the best summer performance,

   (iv) average daily irradiation (kWh/m^2/day) onto a surface tilted to provide the best winter performance.

(b) This web site quotes incident radiant solar energy as both "insolation kW/m^2/day" and as "irradiance kW/m^2/day" (neither of which complies with this Design Standard definition).

3.5 Solar Electricity Handbook, Solar- Angle-Calculator

(a) The software at "solarelectricityhandbook.com/solar-angle-calculator.html" web site provides, for a limited range of Australian cities and towns, a method of calculating for each month, the solar angle at noon.

(b) This software provides the optimum PV module surface tilt angle to the vertical (ϑ_{tov}) which equals the solar angle (ϑ_{sa}) to the horizontal.

(c) As per para. 2.2, the optimum PV module surface tilt angle to the horizontal $\vartheta_{toh} = (90- \vartheta_{tov})$

3.6 Calculation of Irradiance on Tilted Surfaces

(a) For a North facing tilted surface, the optimum surface irradiance level at noon (P_{irto}) can be calculated as follows:

$$P_{irto} = P_{irh}/cos(\vartheta_{taho})$$

where

P_{irto} = irradiance on surface with optimum horizontal tilt angle ϑ_{taho}

P_{irh} = irradiance on horizontal surface for the particular month

ϑ_{taho} = optimum PV module tilt angle to the horizontal,

   for the particular month.

(b) For example, if the PV module tilt is set at the optimum value for March, the noon irradiance level in December can be calculated as follows:

$$P_{irtd} = P_{irhd}*sin(\vartheta_{sasd}) /cos(\vartheta_{tahm})$$

where

P_{irtd} = irradiance in December onto surface with tilt angle to horizontal of ϑ_{tom}

P_{irhd} = irradiance on horizontal surface for December

ϑ_{tahm}= optimum PV module tilt angle to the horizontal,

   for March

ϑ_{sasd} = angle between December solar angle and module surface

= $\vartheta_{tahm} +\vartheta_{savd}$

ϑ_{savd} = solar angle from vertical for December

(c) The monthly optimum PV module tilt angle from the vertical (ϑ_{tav}) can be obtained, for various towns, from the Solar Electricity Handbook software.

PV module optimum tilt angles depend on site latitude, so the town used for calculation by the above software should be one at a similar latitude to the site under consideration.

(d)   However the best year round performance will be achieved if the PV module tilt angle from the horizontal is set at the site latitude angle, i.e. the March angle.

(e)   The site irradiance on a horizontal surface at the site under consideration can be obtained from the above NASA software on the basis of site latitude and longitude.

(f)   A spreadsheet print out of typical irradiance calculations is shown at Table 3.1.

Site	Latitude	Month	Module Tilt Angle	Solar Angle from module surface	Irradiance onto horizontal surface at noon	Irradiance onto module surface at noon	Irradiation on horizontal surface
	deg. South		deg.	deg.	kW/m²	kW/ m²	kWh/day/ m²
Esperance	33.5	March	34	90	0.59	0.71	4.91
Esperance	33.5	December	34	66	0.75	0.82	6.94
Esperance	33.5	June	34	114	0.39	0.43	2.52
Wagga Wagga	34.5	March	35	90	0.68	0.83	6.02
Wagga Wagga	34.5	December	35	67	0.77	0.87	8.5
Wagga Wagga	34.5	June	35	113	0.36	0.40	2.66
Perth	31.5	March	32	90	0.7	0.83	6.53
Perth	31.5	December	32	66	0.91	0.98	8.5
Perth	31.5	June	32	114	0.37	0.40	3.89
Roebourne	20.5	March	21	90	0.82	0.88	6.75
Roebourne	20.5	December	21	67	0.96	0.95	8.23
Roebourne	20.5	June	21	113	0.57	0.56	4.28

Results of Typical Irradiance Calculations

Table 3.1

4.   Standards Requirements for PV Modules

4.1   International Standards

The relevant International Standards for PV modules are as listed hereunder:

IEC 61215-1   Terrestrial photovoltaic (PV) modules - Design qualification and type approval - Part 1: Test requirements

IEC 61701   Salt mist corrosion testing of photovoltaic(PV) modules

IEC 61730-1   Photovoltaic (PV) module safety qualification-

Part 1: Requirements for construction

IEC 61730-2   Photovoltaic (PV) module safety qualification-

Part 2 : Requirements for testing

IEC 62716   Photovoltaic (PV) modules - Ammonia corrosion testing

4.2   Minimum Compliance Requirements

(a) PV modules used in all project shall be certified for compliance with IEC 61215-1, IEC 61730-1 and IEC 61730- 2.

(b) PV modules used at sites located within 20 km of the sea coast shall be certified for compliance with IEC 61701.

(c) PV modules used at sites close to sewage treatment plants shall be certified for compliance with IEC 62716.Standard Test Conditions

4.3   Standard Test Conditions

Standard test conditions for PV modules are an irradiance level of 1000 watt/m^2 and an ambient temperature of 25°C.

The performance characteristics of PV modules are quoted by manufacturers on the above basis together with temperature coefficients for voltage, current and power, to allow characteristics to be determined under actual operating conditions.

5.   Types of PV Modules

5.1   General

(a) The three types of PV modules generally available are:

(i) monocrystalline type,

(ii) polycrystalline type, and

(iii) thin film type.

(b) The monocrystalline modules are the best performing type, but also the most expensive. Because these modules are the most efficient, these require less surface area than the other types to produce the same power. For that reason monocrystalline modules should be favoured if module mounting space is limited.

(c) Thin film modules are the least efficient type, but have marginally better over temperature performance.

(d) Performance specifications vary between makes and models and this variation needs to be taken into account when preparing project designs.

5.2 Monocrystalline Type

The typical performance specifications of a monocrystalline PV module at standard test conditions (STC) are as follows:

(a) example = LG MonoX Plus 300 W(made in South Korea)

(b) V_{ocmod} = 38.9 volts

(c) $I_{sc\ mod}$ = 10.07 amps

(d) $I_{mod\ max\ ocpr}$ = 20 amps

(e) V_{mpp} = 31.7 volts

(f) I_{mpp} = 9.47 amps

(g) P_{mpp} = 300 watts

(h) η = 17.5 %

(i) α = +0.03 % per deg. C

(j) β = -0.30 % per deg. C

(k) g = -0.41 % per deg. C

(l) temperature range = -40 deg. C to + 90 deg. C

(m) 25 year power output = 84.8 % of initial rating

(n) wind load rating = 6000 Pa on front, 5400 Pa on rear

(o) reverse diodes - fitted

(p) IEC 61730-1/2 - certified

(q) IEC 61215-1 - certified

(r) IEC 61701 - certified

(s) IEC 62716 - certified

5.3 Polycrystalline Type

The typical performance specifications of a polycrystalline PV module are as follows:

(a)   example = Q.PRO-G2 (made in Europe)

(b) V_{ocmod} =   37.78 volts

(c) $I_{sc\ mod}$ = 8.94 amps

(d) $I_{mod\ max\ ocpr}$ not specified on standard data sheet

(e) V_{mpp} = 29.89 volts

(f) I_{mpp} = 8.45 amps

(g) P_{mpp} = 252.5 watts

(h) η = 15.0 %

(i) α =   +0.04% per deg. C

(j) β =   -0.33 % per deg. C

(k) γ =   -0.43 % per deg. C

(l)   temperature range = - 40 deg. C to +85 deg. C

(m)   25 year power output = 83% of initial rating

(n)   wind load rating =   5400 Pa

(o)   reverse diodes - fitted

(p)   IEC 61730-1/2 - certified

(q)   IEC 61215-1 - certified

(r)   IEC 61701 - not certified

(s)   IEC 62716 - not certified

5.4 Thin Film Type

The typical performance specifications of a thin film PV module are as follows:

(a)   example = First Solar Series 4TM

(b) V_{ocmod} = 86.0 volts

(c) $I_{sc\ mod}$ = 1.74 amps

(d) $I_{mod\ max\ ocpr}$ = 4 amps

(e) V_{mpp} = 67.8 volts

(f) I_{mpp} = 1.55 amps

(g) P_{mpp} = 105 watts

(h) η = 14 %

(i) α =   +0.04 % per deg. C

(j)   β = -0.29 % per deg. C

(k)   γ =   -0.34 % per deg. C

(l)   temperature range = - 40 deg. C to +85 deg. C

(m)   25 year power output = 80   % of initial rating

(n)   wind load rating = 2400 Pa higher ratings possible but not tested

(o)   reverse diodes -   not fitted

(p)   IEC 61730-1/2 - certified

(q)   IEC 61215-1 - not certified

(r)   IEC 61701 - certified

(s)   IEC 62716 - not certified

5.5   PV Module Characteristics

(a)   Figure 5.1 shows the current versus voltage and available power versus voltage relationship for a PV module at a defined temperature and irradiance level.

The maximum available output power will occur when the current taken is such that the product of voltage and current is at the maximum.

For monocrystalline and polycrystalline PV modules, the maximum available power occurs typically at a current approximately 95 % of the maximum current. This current is termed the maximum power point current.

Similarly the voltage at the maximum power point current level is termed the maximum power point voltage.

Consequently the power conversion equipment needs include an algorithm (MPPT) which adjusts the load so that the product of PV module output voltage and output current is maximised.

PV Module Current versus Voltage and Current
versus Power Charateristics
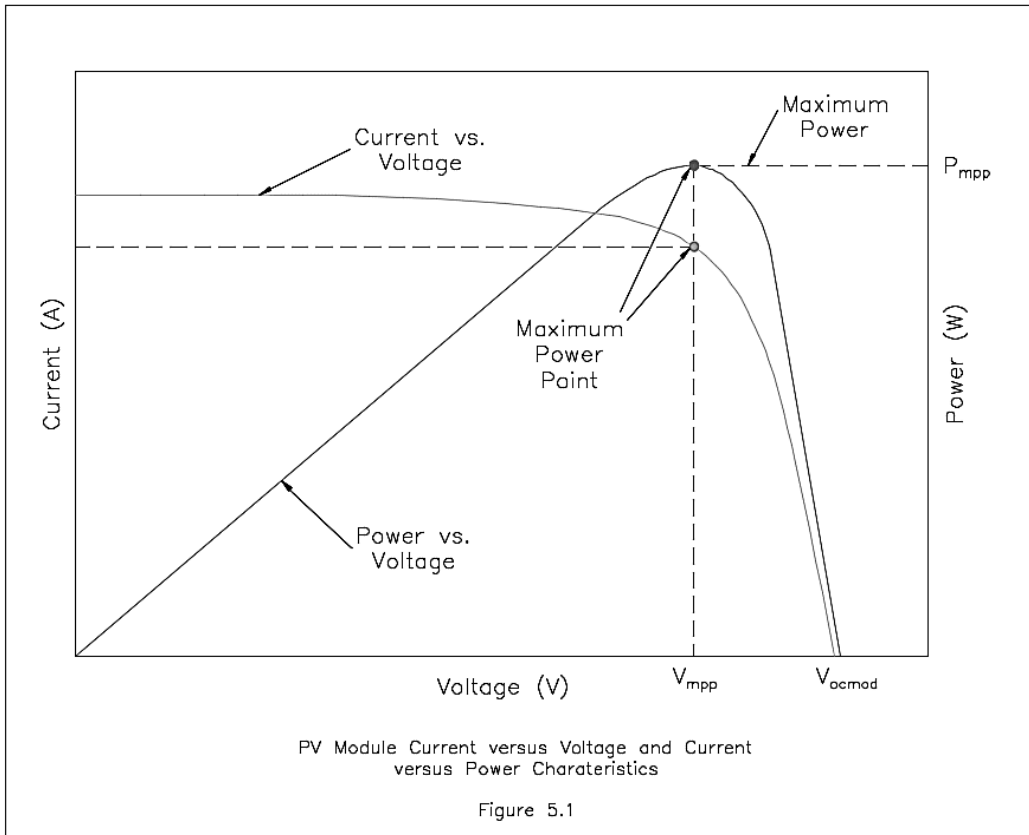
Figure 5.1

(b)   Figure 5.1 is diagrammatic only and is not drawn to scale.

In respect to currently available PV modules, the rate of current decline at higher voltage levels is much sharper, as can be seen on Figure 5.2

(c)   Figure 5.2 is drawn for the monocrystalline module specified at para. 5.2 above and shows current versus voltage curves for various levels of irradiance under standard temperature test conditions.

In this PV module the maximum power point occurs at 9.47 amps with an irradiance level of 1000 watt/m^2, i.e. $100*9.47/10.07 = 94$ % of the short circuit current ($I_{sc\ mod}$).

The short circuit current is directly proportional to the irradiance level.

(d)   Up until the knee point of its current versus voltage curve, the PV module is a current source with the current being directly proportional to the irradiance level.

(e)   PV module output voltage, output current and output power are all affected by temperature as is shown in Figure 5.3.

Typical PV Modules Current vs Voltage characteristic for
various irradiance levels at defined temperature

Figure 5.2

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Voltage, Current and Power Temperature Coefficients for Typical Monocrystalline PV Module.

Figure 5.3
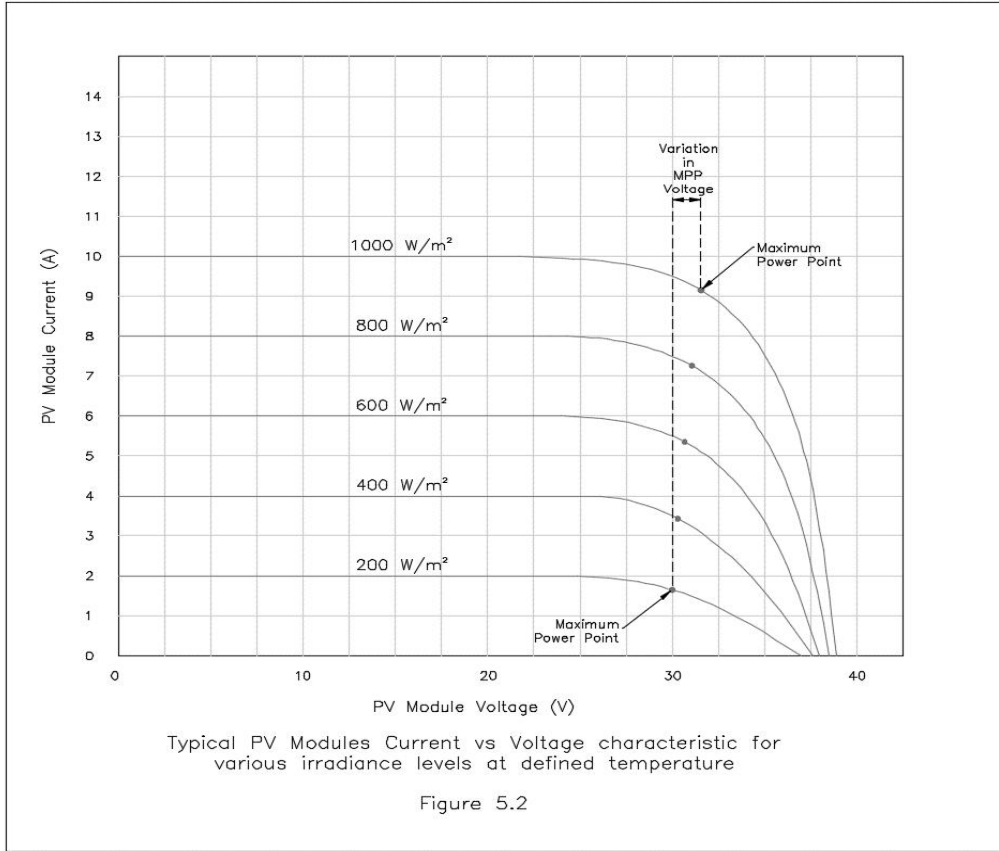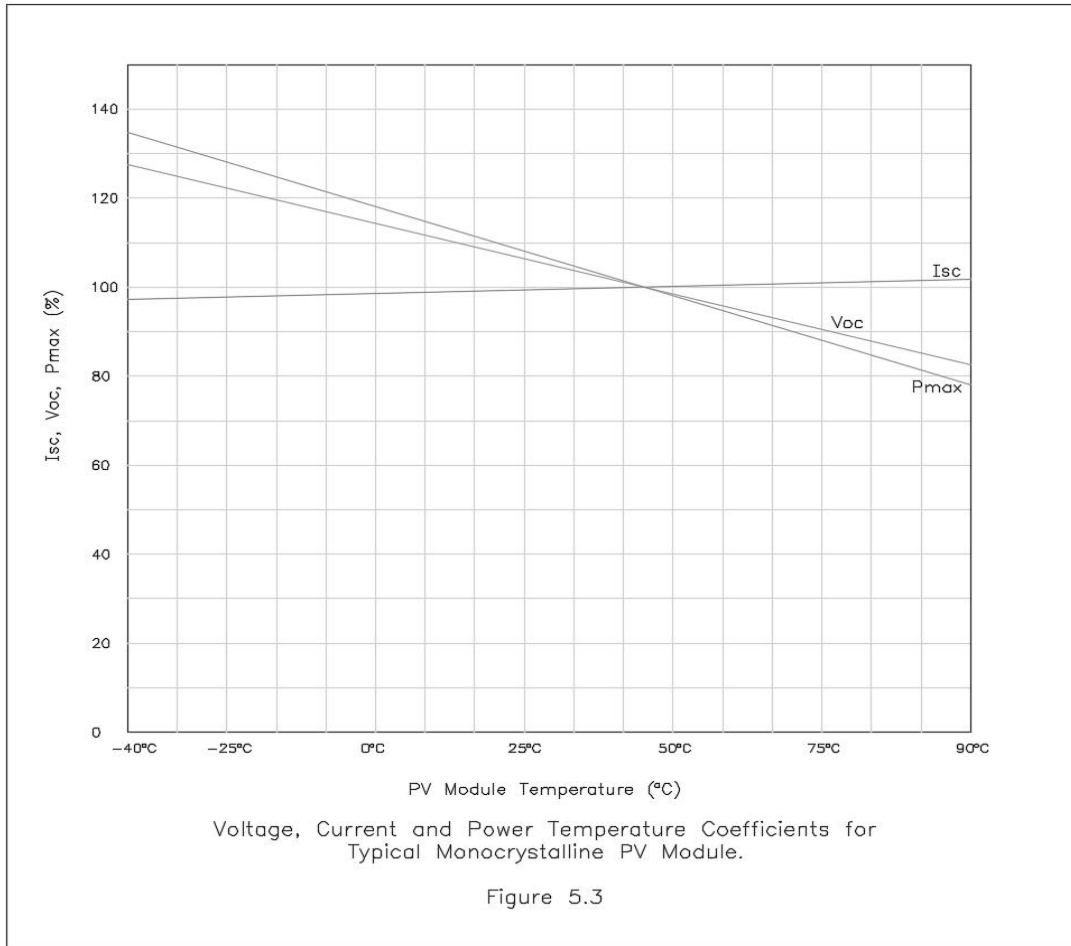
6. PV Module Operating Conditions.

6.1 PV Module Operating Temperature

(a) PV module operating temperature depends on the shade ambient temperature (T_{amb}) and how close the module is to anything that may trap heat, such as a roof top.

(b) Designs in accordance with this Design Standard (DS25) shall be prepared on the assumption that the module operating temperature (T_{mod}) will be as follows:

   (i) less than 150 mm from roof surface T_{mod} = T_{amb} +35 deg. C

   (ii) more than 150 mm from roof surface T_{mod} = T_{amb} +30 deg. C

   (iii) PV array on elevated ground mount T_{mod} = T_{amb} +25 deg. C

6.2 Maximum Voltage versus Temperature

(a) PV modules "wake up" at first light. At this time the sun light will not be falling on the PV module face directly, so that the PV module will not produce any current, but nevertheless will go the open circuit voltage i.e. V_{oc}.

At this time the PV module becomes a high impedance voltage source so that if disconnected from the load, the voltage at the source side of the disconnection point will become V_{oc}.

Once connected to the load, and as the received solar irradiation increases, the PV module will revert progressively to being a current source at situations above the knee point on the PV module current versus voltage curve.

At first light it can be assumed that the PV modules are at the minimum overnight temperature, so that at this time the open circuit voltage will be at the maximum.

For safety reasons and for equipment voltage rating reasons, the installation shall be designed on the basis the installation maximum voltage being the PV array open circuit voltage at minimum daylight temperature.

(b)   As an example consider a LG MonoX plus PV module

At STC V_{ocmod} = 38.9 volts, temp. = 25 deg. C

β = -0.33 % per deg. C

Assume first light temperature = 5 deg. C

Then at first light V_{oc} = 38.9*[1+20*0.33/100] = 41.47 volts

6.3   Minimum Voltage versus Temperature

(a)   As shown in Figure 5.3, the PV module output voltage decreases significantly with increase in PV module operating temperature.

It is important to calculate the PV module minimum output voltage because generally power conversion equipment (PCE) has a   limited acceptable range of input voltage,

(b)   Consider the following example

(i) V_{mpp} = 31.7 volts

(ii) β = -0.41   % per deg. C.

Then at 70 deg. C, voltage at maximum available power point

= 31.7*volts *[1-0.0041*(70-25)] = 25.9 volts

Since PV module voltage does decline a little with reduced irradiance as shown Figure 2, this value should be reduced by a factor of 0.95

Hence minimum PV module output voltage maximum power point operating voltage at a PV module operating temperature of   70 deg. C = 25 volts.

6.4   Factors Effecting Available Power

(a)   The maximum power available from a PV module depends on:

(i)   the level of irradiance onto the PV module,

      (ii) the operating temperature of PV module, and

      (iii) the age of the PV module.

(b)   The maximum level of irradiance at a particular site shall be determined as discussed at para. 3.6.

       The level of irradiance under STC is 1000 watt/ m^2 (at 25 deg. C)

(c)   As the PV module operating temperature increases during the day the power available from the PV module decreases in proportion to the power temperature coefficient γ and the operating temperature rise.

(d)   The maximum power available from the PV module decreases linearly over the module's life.

       For the monocrystalline PV module quoted para. 5.2(a) above the modules rated life is 25 years at which time the available power will have decreased by a factor of 0.848.

(e)   Consider the following example:

      (i) site maximum irradiance level = 900 watts/m^2

      (ii) PV module type = LG MonoX Plus 300 W module

      (iii) STC irradiance = 1 kW/m^2

      (iv) STC operating temperature = 25 deg. C

      (v) P_{mmp} = 300 watts at STC

      (vi) γ = -0.41   % per deg. C.

      (vii) PV module operating temperature at site = 70 deg. C

      (viii) age of PV module = 12 years

      (ix)derating factor at 25 years = 0.848

      Then maximum power available from the module

      = 300*watts*[1-0.0041*(70-25)]*(900/1000)*[1+0.848]*12/25

      = 195 watts

6.5   Orientation and Tilt Angle

(a)   The amount of solar energy which can be collected from a PV module depends on the radiation level and the combination of PV module tilt angle and PV array orientation (para. 3.6 refers).

(b)   PV module tilt angle from the horizontal should be greater than 11 degrees to enable dirt build up on modules to be washed off with rain, or easily washed off manually.

(c)   The annual amount of solar energy collected is maximised if the PV module tilt angle from the horizontal is the same as the latitude of the site, (but not less than 11 degrees).

(d)   In the Southern Hemisphere, increasing the tilt angle will increase the amount of solar energy received in June while reducing it will increase the amount solar energy received in January.

(e)   A typical example of the monthly variations of solar radiation (kWh/day/m^2 for three different tilt angles is shown at Figure 6.1 for a site with a latitude of 31 deg., (e.g. Perth) and with a due North orientation,

(f)   Table 6.1 shows the relevant monthly solar radiation levels (PSH) at the same site. (Note 1 P_{SH} = 1 kWh/m^2/day)

(g)   As can be seen from the above, the optimum PV module tilt angle depends on when the maximum PV module power output is required.

Variation in Irradiance with changes in PV Module Tilt Angle for site at Latitude 31°

Figure 6.1
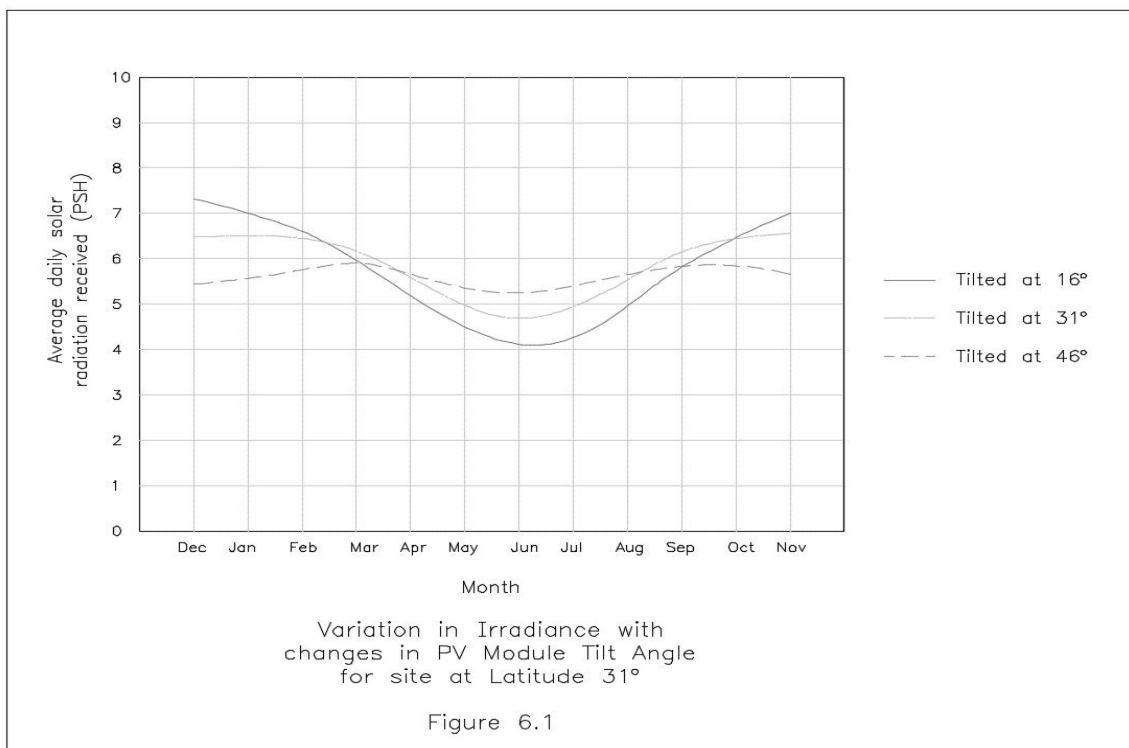
Month	tilt angle 16° P_{SH}	tilt angle 31°. P_{SH}	tilt angle 46° P_{SH}
December	7.25	6.62	5.63
January	7.18	6.63	5.71

February	6.70	6.43	5.80
March	6.16	6.24	6.00
April	5.22	5.63	5.76
May	4.22	4.77	5.11
June	3.87	4.51	4.96
July	4.06	4.67	5.07
August	4.92	5.43	5.54
September	5.98	6.21	6.12
October	6.49	6.35	5.87
November	6.98	6.50	5.67
Average daily for year	5.75	5.83	5.60
Average annual for year	2098	2128	2045

Table 6.1

6.6 Shading

As further discussed in para. 7.2, if a PV module is shaded in any way the module power output is reduced.

If there is continuous shading at the same position on a PV module, the module can develop "hot spots" leading to permanent damage.

7. PV Arrays

7.1 PV Strings

(a) PV modules are connected in series as PV strings in order to produce the required input voltage at the power conversion equipment (PCE).

(b) PV strings are connected in parallel in order to produce the required power outputs.

7.2 PV Array Shading

(a) As mentioned in para 6.6, if a PV array is shaded in any way the power output is reduced.

If there is continuous shading at the same position on solar modules, the modules can develop "hot spots" leading to permanent damage.

(b) Possible sources of shading include:

(i) vegetation (e.g. trees, bushes, long grass)

(ii) structures (e.g. buildings, shelters, fences, poles,)

(iii) overhead power lines

(iv) land (e.g. hills, rocks)

(v) the PV array itself (e.g. insufficient row spacing)

(c) Solar arrays shall be positioned so that between the hours of 9.00 am and 3.00 pm local time, at the shortest day of the year, no part of any PV module in a PV array is shaded.

(d) Shadow lengths increase with site latitude. Various software tools are available to allow winter solstice shadow lengths to be calculated at particular site locations, e.g. Solar Pathfinder and Solometric Suneye.

Table 7.1 shows the shadow length of a 1 metre high pole in various Australian towns at various times of the day.

Table 7.1 can be used to provide a reasonable first estimate of shadow positioning.

Time	Jabiru NT (Latitude 12.6667°) Shadow Length	Jabiru NT (Latitude 12.6667°) Shadow Direction	Townsville QLD (Latitude 19.2564°) Shadow Length	Townsville QLD (Latitude 19.2564°) Shadow Direction	Newman WA (Latitude 23.3539°) Shadow Length	Newman WA (Latitude 23.3539°) Shadow Direction	Port Augusta SA (Latitude 32.4833°) Shadow Length	Port Augusta SA (Latitude 32.4833°) Shadow Direction	Ballarat VIC (Latitude 37.55°) Shadow Length	Ballarat VIC (Latitude 37.55°) Shadow Direction	St Helens TAS (Latitude 41.32°) Shadow Length	St Helens TAS (Latitude 41.32°) Shadow Direction
0800	2.59m	S 1.36m W 2.21m	3.16m	S 1.75m W 2.63m	3.66m	S 2.08m W 3.02m	5.69m	S 3.36m W 4.59m	8.19m	S 4.91m W 6.56m	12.19m	S 7.36m W 9.72m
0900	1.54m	S 0.97m W 1.19m	1.82m	S 1.23m W 1.35m	2.05m	S 1.42m W 1.48m	2.83m	S 2.05m W 1.95m	3.54m	S 2.62m W 2.39m	4.34m	S 3.24m W 2.89m
1000	1.06m	S 0.82m W 0.67m	1.27m	S 1.03m W 0.74m	1.44m	S1.19m W 0.8m	1.95m	S 1.67m W 1.00m	2.38m	S 2.06m W 1.18m	2.82m	S 2.47m W 1.37m
1100	0.81m	S 0.75m W 0.31m	1.01m	S 0.95m W 0.34m	1.15m	S 1.09m W 0.36m	1.58m	S 1.52m W 0.44m	1.93m	S 1.86m W 0.52m	2.27m	S 2.19m W 0.59m
1200	0.73m	S 0.73m E 0m	0.92m	S 0.92m E 0m	1.07m	S 1.07m E 0m	1.48m	S 1.48m E 0m	1.80m	S 1.8m E 0m	2.12m	S 2.12m E 0m
1300	0.81m	S 0.75m E 0.31m	1.01m	S 0.95m E 0.34m	1.15m	S 1.09m E 0.36m	1.58m	S 1.52m E 0.44m	1.93m	S 1.86m E 0.52m	2.27m	S 2.19m E 0.59m
1400	1.06m	S 0.82m E 0.67m	1.27m	S 1.03m E 0.74m	1.44m	S 1.19m E 0.8m	1.95m	S 1.67m E 1.00m	2.38m	S 2.06m E 1.18m	2.87m	S 2.47m E 1.37m
1500	1.54m	S 0.97m E 1.19m	1.82m	S 1.23m E 1.35m	2.05m	S 1.42m E 1.48m	2.83m	S 2.05m E 1.95m	3.54m	S 2.62m E 2.39m	4.34m	S 3.24m E 2.89m
1600	2.59m	S 1.36m E2.21m	3.16m	S 1.75m E 2.63m	3.66m	S 2.08m E 3.02m	5.69m	S 3.36m E 4.59m	8.19m	S 4.91m E 6.56m	12.19m	S 7.36m E 9.72m

June Shadow Lengths of a 1-meter vertical pole for various Australian Locations

Table 7.1

> (e) As can be seen from Table 7.1, fence to PV array separations will need to be greater at sites located at lower latitudes.
>
> (f) The greater the height of the fence compared to the height of the bottom of the of the PV modules in the PV array, the greater the required separation between the fence and the PV array.
>
> (g) As an example, consider a PV array located at Norseman mounted so that the lower end of the solar panels is 0.5 metre above ground and surrounded by a 2.4 metre high security fence directly North of a PV array located on an East -West alignment.
>
> Norseman is located at latitude 32.20° South.
>
> From Table 7.1 Port Augusta is located at latitude 32.48° South, which is further South than Norseman, so that Port Augusta shadow lengths can be used safely to calculate minimum clearances at Norseman
>
> From Table 7.1, at 10.00 am local time (i.e. 2 hours before the sun is at its zenith) a 1 metre pole will throw a shadow 1.67 metres South.
>
> In such a case the separation between the Northerly fence and the PV array would need to be more than:
>
> (2.4-0.5)*1.67 = 3.17 metres
>
> From Table 7.1, at 10.00 am local time (i.e. 2 hours before the sun is at its zenith) a 1 metre pole will throw a shadow 1.00 metres West.

In such a case the separation between the side   fences and the PV array would need to be more than:

(2.4-0.5)*1.0 = 1.9 metres

7.3   PV Module Row Separation

(a)   As per para. 7.2 spacing needs to be provided between PV module rows so that between the hours of 9.00 a.m. to 3.00 p.m. local time, at the shortest day of the year, the Southerly solar modules are not shaded by the Northerly solar modules

(b)   The required spacing is dependent on the site solar winter solstice 9.00 a.m. and 3.00 p.m. solar altitude and azimuth angles.

(c)   The altitude angle is defined as the angular height of the sun in the sky measured from the horizontal.

(d)   The azimuth angle is defined as the horizontal angle measured clockwise from a North base line.

(e)   Calculation of solar panel row spacing shall be determined in accordance with Figure 7.1 where:

X = height of top edge of the PV module above bottom edge

Y = minimum separation required.

(f)   Altitude angles and azimuth angles depend on site latitude and can be determined from Table 7.2.

$$X = \sin(Tilt°) \times Length$$

$$Y = X \times \frac{\cos(azimuth\ angle)}{\tan(altitude\ angle)}$$

Calculating the minimum distance between rows.

Figure 7.1
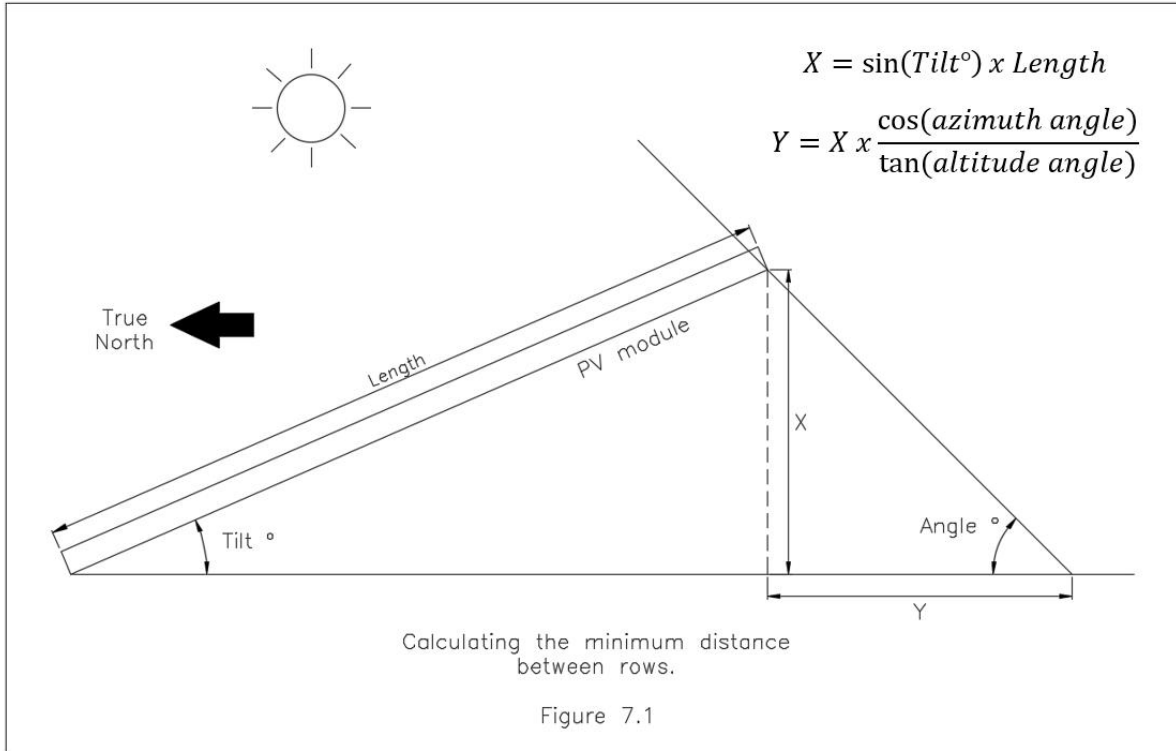
10 AM			2 PM		
Latitude (° South)	Azimuth (°)	Altitude (°)	Latitude (° South)	Azimuth (°)	Altitude (°)
11	40	45	28	32	31
12	40	44	29	32	30
13	39	43	30	32	29
14	38	42	31	31	28
15	38	42	32	31	28
16	37	41	33	31	27
17	37	40	34	31	26
18	36	39	35	30	25
19	36	38	36	30	24
20	35	38	37	30	23
21	35	37	38	30	22
22	35	36	39	-	-
23	34	35	40	29	21
24	34	34	41	29	20
25	33	33	42	29	19
26	33	33	43	29	18
27	33	32			

Solar Azimuth and Altitude at 10pm and 2pm on the Winter Solstice (June 22)

Table 7.2

7.4 Bird Spikes

(a) Bird spikes are sets of vertical metal spikes which can be mounted along the top edge of PV modules in order to prevent birds perching there and soiling the face of PV module with bird droppings.

(b) If bird spikes are fitted to PV modules, the module row spacing will have to be increased significantly because of the shadows thrown by such devices.

(c) The possible benefits of fitting bird spikes at a particular location need to be weighed against the disadvantages of doing so, before a decision is made to fit such devices.

7.5 Support Structures

(a) Structures supporting solar arrays shall be designed so that solar arrays and the associated supporting structures are immune to damage during worst case environmental conditions (i.e. wind or flooding).

PV module frames and casings shall be designed and certified for front and rear wind loadings of not less than 5.5 kPa.

(b) Structures supporting solar arrays shall be designed so that sufficient space is provided under to solar modules to permit convenient clearing of grass or other vegetation.

(c) Support structures shall be of galvanised steel.

All bolts, nuts and fasteners shall be stainless steel. Care shall be taken to prevent corrosion between electrochemical dissimilar metal surfaces, e.g. by use of nylon washers.

8. PV Array Ratings

8.1 PV Array Voltage Rating

(a) AS/NZS 5033 Clause 3.1 requires that the PV array voltage level not exceed 600 VDC unless access to the entire PV array and associated wiring and protection equipment is restricted to authorised persons.

(b) Use of the highest practical PV array voltage has significant advantages in respect to reduction in the amount of switching and protection equipment required as well as minimising cable costs.

(c) If the PV array maximum allowable open circuit voltage is 800 VDC and, as determined at para. 6.2, the LG Mono X Plus PV module maximum open circuit voltage is 41.47 volts , then the maximum number of these PV modules per PV string will be 800/41.47 = 19 assuming that access to the PV array is limited to authorised persons.

(d) If access to the PV array is not limited to authorised persons, the maximum number PV modules per PV string becomes 600/41.47 = 14

(e) However some types and brands of power conversion equipment (PCE) require a particular upper limit on the operating input D.C. voltage and this will determine the required PV array voltage.

(f) In the case of the PCE being a solar pumping inverter as defined para. 2 (i.e. suitable for powering pumps directly without use of batteries), the D.C, input operating voltage is required to be 1.41 times the motor rated three phase input voltage, i.e. for a 415 VAC motor, the required operating D.C. input voltage to the PCE needs to be 587 volts

(g) IEC 60034-1 Clause 7.3 specifies the voltage limits for electric motors as the rated voltage plus or minus 5 % continuously and plus and minus 10 % for limited periods of time. Consequently a motor rated at 400 VAC may be run continuously at 415 VAC or at 380 VAC.

(h) If the motor nameplate specifies a range of voltage ratings, the PV array voltage rating and solar pumping inverter settings shall be based on the average voltage of the rated voltage range.

(i) As per AS/NZS 5033 under maximum load conditions the voltage drop from the most remote PV module to the input terminals of the PCE shall not exceed 3 % of the Vmpp voltage (at STC) for LV PV arrays.

Further at full load the difference in voltage drop in PV string cables and in PV sub-array cables at the point(s) of common coupling shall not exceed 1% of the V_{mpp} voltage (at STC) for LV PV arrays.

(j) However various voltage drops due to varying loads and operating conditions will occur in a practical solar pumping system, such as the following:
(i) voltage drop due to PV module temperature variation (20 % max.)

(ii) voltage drop in PV array cabling (3 % max. as per AS/NZS 5033)

(iii) voltage drop in PCE

(iv) voltage drop in PCE output filters

(v) voltage drop in supply cables to load (5% max.)

(k)   Not all voltage drops will occur concurrently, but nevertheless the PV array voltage ratings and solar pumping inverter settings shall be based on the motor's nameplate voltage rating.

(l)   If the LG Mono X Plus PV module operating voltage rating is 31.7 volts then the number of PV modules required per PV string for a 415 VAC motor will be 587*1.03 /31.7 = 19 which meets the requirements of sub-para. (c), above.

8.2   PV Array Power Output Rating

(a)   The required maximum power output from the PV array shall be determined taking into account:

(i) the season of the year during maximum pumping is required, and

(ii) the hourly irradiance profile on the PV module when maximum pumping is required.

(b)   The number PV modules required in the PV array shall be calculated assuming:

(i) the module operating temperature is at the annual maximum, and

(ii) the PV array modules are 25 years old

(c)   As an example consider a PV array required to power a 22 kW submersible bore hole pumping unit.

(i) Assuming a motor efficiency of 83 %, a solar drive efficiency of 95%, a harmonic filter power efficiency of 95 %, D.C. cable losses of 1% and motor cable power losses of 5%, the required PV array load would be:

22*kW/(0.83*0.95*0.95*0.99*0.95) = 31.2* kW

(ii) For the module and operating conditions detailed in para. 6.4(e), the available power per module = 195 *watts

(iii) Hence the minimum number of PV modules required

= 31.2/0.195 = 160

(iv) If the associated PCE requires 19 modules per string, the number of PV strings required would be 160/19 = 8.4 say 9.

(All PV strings must contain the same number of modules.)

8.3 Ground Area Requirements

The dimensions of LG Mono X Plus PV module are 1.016 m by 1.686 m, so that the surface area if the above PV array will be approximately

$$1.7*160 = 272 \text{ m}^2.$$

In the above example, after allowing for the required spaces between rows of PV arrays and between PV arrays and the external fencing, the total area required would be the size of a residential housing block.

8.4 Variation in Irradiance Levels

(a) PV modules have a nominal irradiance level working range of 1000 W/m^2 to 200 W/m^2.

However after allowing for power conversion equipment (PCE) start-up margins, the practical working range is 1000 W/m^2 to 250 W/m^2.

(b) The effect of variations in the irradiation level on PV module output current and voltage is shown at Figure 5.2.

It can be seen that the range of maximum power point voltages is relatively small so that the output power varies approximately in proportion to the irradiance level received on the surface of the PV modules.

(c) As can be seen from Figure 3.1 and Table 3.1 the received irradiance level varies significantly during the day and from summer to winter.

It also can be seen that, the greater the site latitude, the greater the difference between the summer and winter irradiance levels.

(d) The irradiance level on the PV module face will vary with the angle of tilt of the PV module.

Table 3.1 has been calculated for the optimum year round PV module tilt, and with the PV modules facing North, so as to maximise the yearly the solar energy captured.

(e) As can be seen from Table 3.1, in Roebourne the June noon irradiance level on the surface of the PV modules will be approximately 560 W/m^2.

On the other hand in Roebourne with the above tilt settings the December noon irradiance level on the surface of the PV modules will be approximately 880 W/m^2.

This value is lower than the Perth December irradiance value which is due to greater cloud cover in Roebourne during the "wet" season".

However on the relatively rare clear days the December irradiance level in Roebourne can be expected to be approximately 6 % higher.

(f) The solar power generated by a PV array is proportional to the level of irradiance, so that the range of usable solar irradiance is proportional to the allowable range of pump power demand.

9. Electrical Installation of PV Arrays

9.1 Standards

The electrical installation of photovoltaic arrays shall be in accordance with the following standards:

(a) AS/NZS 3000: Electrical Installation

(b) AA 4509: Standalone power systems for renewable energy power systems

(c) AS/NZS 5033: Installation and safety requirements for photovoltaic (PV) arrays

(d) IEC 62305-3: Lightning protection - Physical damage to structures and life hazard

9.2 Scope of AS/NZS 5033

(a) Like standard AS/NZS 3000, standard AS/NZS 5033 is a very prescriptive document and could best be described as a standard specification

Currently the W.A Electrical Requirements issued by Energy Safety W.A. requires compliance with AS/NZS 5033. Consequently care shall be taken to ensure that the design of PV arrays complies completely with AS/NZS 5033 as well as the additional requirements specified hereunder.

(b) AS/NZS 5033 contains various options covering a wide range of applications. This Design Standard covers specifically the additional requirements for solar pumping applications.

(c) AS/NZS 5033 clause 3.4.3 requires PV arrays sites to have some form of communication link to the system operators.

(d) AS/NZS 5033 is a relatively large document and its contents would not have been included in past electrical contractor or past electrician training. Consequently electrical contractors undertaking electrical installation of PV arrays shall be accredited by the Clean Energy Council to undertake such work.

9.3 PV Array Configuration

(a) The solar array configuration shall conform to one of the configurations shown in AS/NZS 5033.

(b) In particular Water Corporation solar pumping PV installations shall be designed in accordance with Figure 9.1, unless approved otherwise by the Senior Principal Engineer.

(c) Figure 9.1 is drawn for only 3 PV strings, but PV string combiner boxes are available for up to 24 parallel strings as discussed hereunder.

(d) Figure 9.1 hereunder is based on AS/NZS 5033 Figure 2.3 and the Notes at AS/NZS 5033 Table 4.3.

PV Array Connections

Figure 9.1
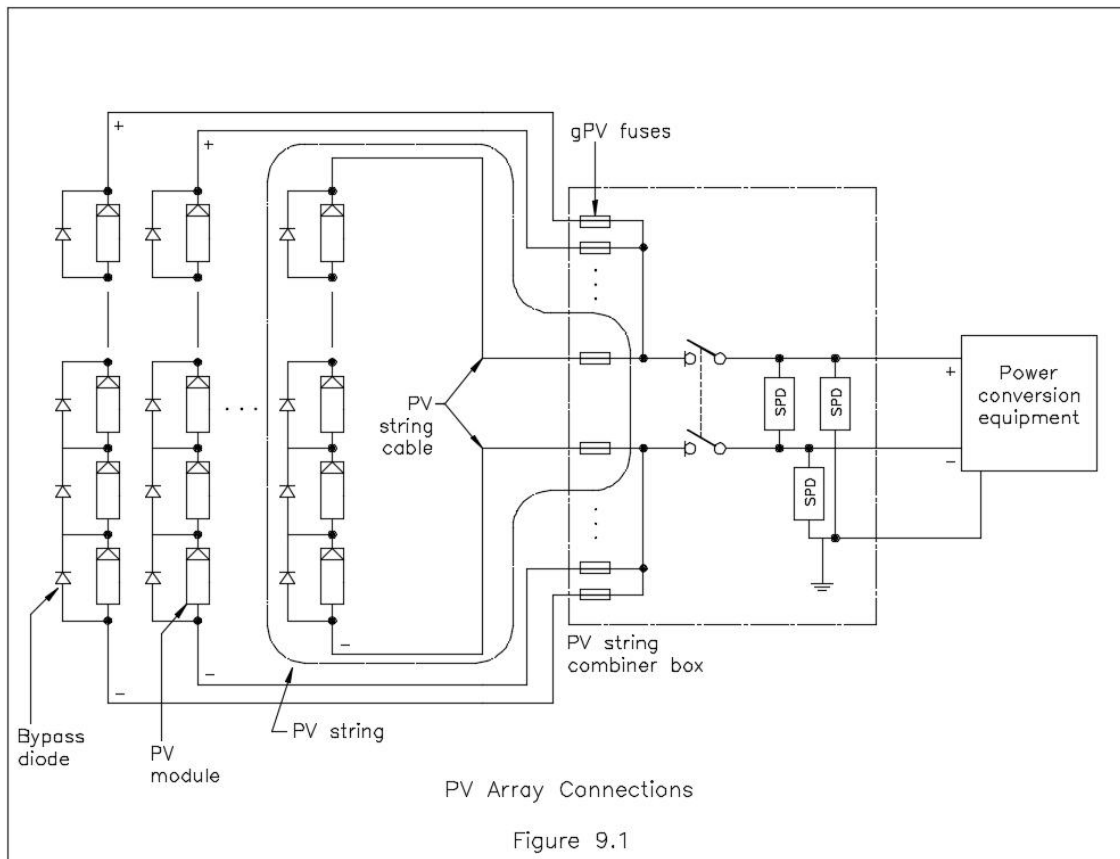
9.4 PV String Combiner Box

(a) Apart from the requirement at the note attached to AS/NZS 5033 Table 4.4 AS/NZS 5033 does not require specifically that a degree of protection of IP2X be provided in the PV string combiner box.

Nevertheless it shall be a requirement of this Design Standard that the above is the case.

[PV string combiner boxes in the "IPD Photovoltaic PVDC Basic" range of PV string combiner provide an internal degree of protection of IP2X.]

(b) Since some equipment housed in PV combiner boxes requires derating with increased temperature, PV string combiner boxes shall be installed in permanent shade

(c) PV string combiner boxes shall be provided with an external degree of protection of IP65.

9.5　　D.C. Fuses and Fuse Holders

(a)　Fuses should be Type gPV in accordance with IEC 6029-6 with a fault maximum breaking capacity of 10 kA.

(b)　Fuse holders shall provide a degree of protection of IP2X with the fuse carrier in place and with the fuse carrier withdrawn.

(c)　PV string fuse holders shall be single pole and shall be fitted with blown fuse indicators.

(d)　PV string fuse/fuse holder sets shall comply with the following:

　　(i)　line to line voltage - 1000 VDC

　　(ii)　line to ground voltage - 1000 VDC [see sub-para (f) below]

　　(iii)　fuse holder maximum current - 32 amps

　　(iv)　fuse In range - 1 amps to 30 amps

　　(v)　operating temperature range - 5 deg. C to 60 deg. C

　　(vi)　fuse In derating factor at 60 deg. C - 0.8

　　(vii)　utilisation category - IEC 60947 DS2B

(e)　DF Electric fuses reference 491635 and DF Electric fuse holders reference 485152 meet the above requirements.

9.6　　PV String Fuse Rating

(a)　As per AS/NZS 5033 clause 3.3.4, PV string over current protection required if:

$$[(S_a - 1)*I_{sc\ mod}] > I_{mod\ max\ ocpr}\quad \text{where:}$$

S_a = number of parallel connected PV strings in PV array

$I_{sc\ mod}$ = PV module short circuit current at STC

$I_{mod\ max\ ocpr}$ = PV module maximum protection current rating

(b)　For the typical monocrystalline PV module described at para. 5.2:

$I_{sc\ mod}$ = 8.1 amps

$I_{mod\ max\ ocpr}$ = 20 amps

If S_a = 3, $(S_a - 1)*I_{sc\ mod}$ = 2*8.1 = 16.2 amps i.e. not greater than 20 amps

So using the typical monocrystalline modules, no more than 3 PV strings may be connected in parallel without overcurrent protection.

(c)　As per AS/NZS 5033 clause 3.3.5.1 (a) , if PV string overcurrent protection is required and In = over current rating of PV string protective device

(i.e. I_n = rating of the fuse),

then I_n must satisfy the following:

$I_n > 1.5 * I_{sc\ mod}$ &

$I_n < 2.4 * I_{sc\ mod}$ &

$I_n \leq I_{mod\ max\ ocpr}$

(d) For the typical monocrystalline PV module described at para. 5.2:

If $I_n = 16$ amp

$1.5 * I_{sc\ mod} = 1.5 * 8.1 = 12.15$ amps i.e. $< I_n$

$2.4 * I_{sc\ mod} = 2.4 * 8.1 = 19.44$ amps i.e. $> I_n$

$I_{mod\ max\ ocpr} = 20$ amps, i.e. $> I_n$

Hence in this example a 16 amp PV string fuse would be suitable.

(e) No more than one PV string shall be connected under the protection of one fuse despite this being allowed under certain conditions specified at AS/NZS 5033 clause 3.3.5.1(b).

9.7 PV Array Isolating Switches

(a) As shown on Figure 8.1, PV array isolating switches shall be provided in the PV combiner box and at the PCE (i.e. adjacent to the solar pump inverter).

(b) PV array isolating switches shall comply with the requirements of IEC 60947-3 DS21B and shall have been type tested accordingly.

(c) PV isolating switches shall be load breaking double pole multiple break switches with an onsite maximum rated current of not less than the onsite maximum temperature current rating of the associated PV array cables.

(d) PV array isolating switches shall interrupt all live conductors simultaneous and each switch pole shall be rated to open the full PV array voltage, i.e. V_{oc} array.

(e) Telergon model S6N0160MQS0 DC isolators meet the above requirements for PV arrays within the scope of this Design Standard.

9.8 Surge Protective Devices

(a) Surge protective devices shall comply with IEC 61643-32 and with the following:

(i) Rated system voltage - 1000 VDC

(ii) IEC 61643 protection type - T1 & T2

(iii) 8/20μs discharge current - 15 kA

(iv) 10/350 μs discharge current - 12.5 kA

(v) voltage protection level - 2.5 kV

(b) DEHN Type DCBYPVSCI1000 Lightning Current and Surge Arrestors meet the above requirements.

9.9 Cabling

9.9.1. Voltage Drop in PV Cables General

Cable sizes shall be selected so that under maximum load conditions the voltage drop from the most remote PV module in the PV array to the input of the PV string combiner does not exceed 1.5 % of V_{mpp} where:

V_{mpp} = voltage at maximum power point of PV module under STC

9.9.2. PV Array Cables

The PV array cable on site maximum temperature current rating shall be not less than $1.25*I_{sc\ array}$ where:

$I_{sc\ array} = I_{sc\ mod} * S_{sa}$ = short circuit strength of PV array at STC

$I_{sc\ mod}$ = PV module short circuit current at STC

S_{sa} = number of parallel PV strings in the PV array

9.9.3. PV String Cables

The PV string on site maximum temperature current rating of PV string cables shall be not less than the current rating of the associated fuse determined as per para. 8.6 (c) above.

9.9.4. PV String Cable Connectors

(a) All connections to and from PV string cables, including connections into the PV string combiner box, shall be made with single pole PV connectors complying with the requirements of AS/NZS 5033 clause 4.3.7 and with the following:

   i. rated voltage - 1000 VDC TUV

   ii. contact resistance ≤ 5 milliohm

   iii. degree of protection - IP67

   iv. temperature range = - 40 deg. C to +85 deg. C

(b) COYO brand PV connectors meet the above requirements.

9.10 PV Array Functional Earthing

(a) Unless approved otherwise by the Senior Principal Engineer, the inverter in the PCE shall be "non- separated type" so that earthing of the PV array output will be within the PCE itself and no external earthing is appropriate as shown Figure 9.2,

(b) Depending on the make of PCE, the PCE output neutral will connected internally to:

   (i) to the PV output positive, or

(ii) to the PV output negative, or alternately

(iii) may be rapidly switched between the two.

PV Array Earthing Connection

Figure 9.2
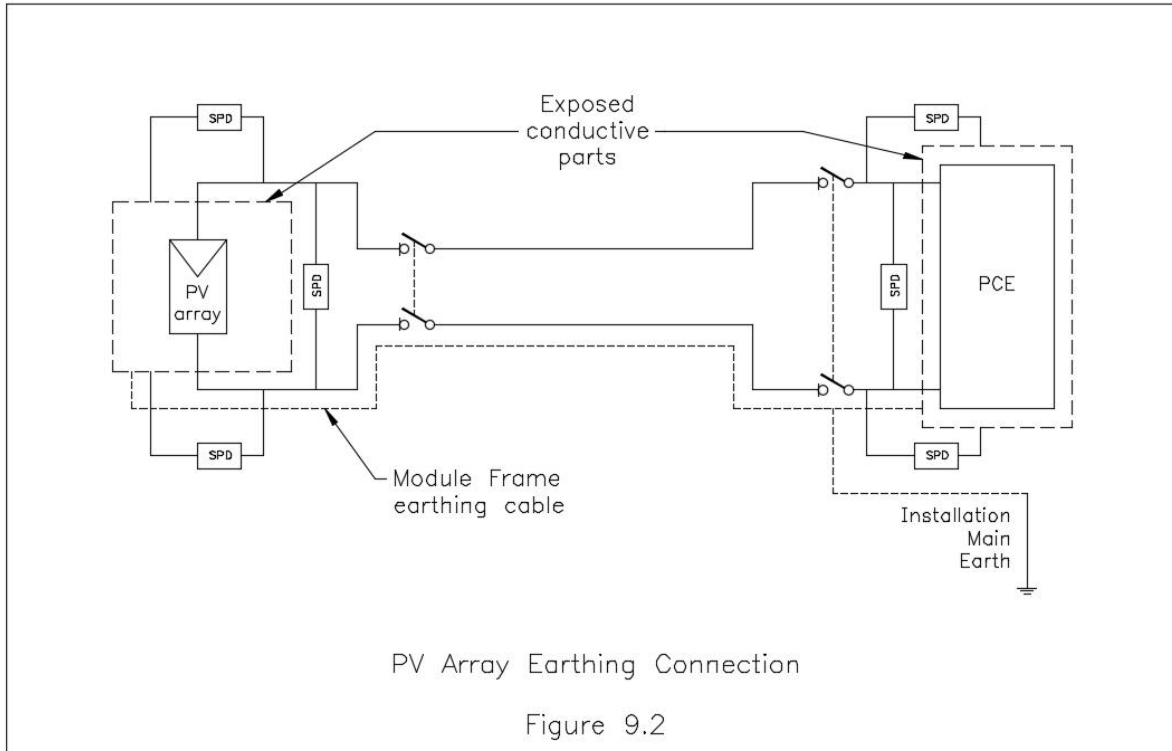
9.11 PV Array Lightning Protection

9.11.1. Lightning Protection Systems (LPS)

(a) The risk of damage from a lightning strike shall be determined early in the design stage because, among other things, it will influence the layout of the PV strings.

(b) The risk shall be determined according to IEC 62305-2.

Suitable risk analysis software is available for this purpose, e.g. "DEHNsupport" and Furse "StrikeRisk".

(c) IEC 62305-1 defines four lightning protection levels, i.e. LPL I to LPL IV with LPL IV being the most severe.

The required class of lightning protection system is defined similarly with LPS IV being required for the most severe lightning situation.

(d) Two type of LPS are defined i.e. "isolated" and "non-isolated".

An isolated LPS is required if the structure is constructed of flammable material or there is danger of fire or explosion. Otherwise the simpler non-isolated LPS is satisfactory.

In respect to DS25, a non-isolated LPS will be adequate.

(e)   The three basic elements to a LPS are:

    (i)   the air termination system,

    (ii)   the down conductor system, and

    (iii)   the earth termination system.
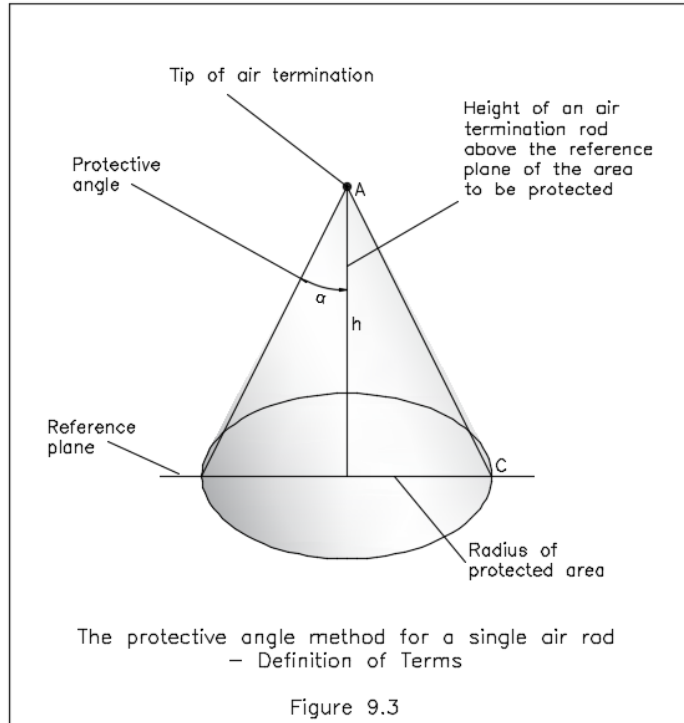
9.11.2.   Air Termination System

(a)   For "free field" PV systems such as proposed for solar pumping applications as specified in DS25, the air termination system shall be based on air "finials" (or air termination rods).

(b)   These finials may be on free standing masts or may be "air termination rods" supported off the PV array structure by insulated isolating spacers (e.g. DEHNiso spacers) as shown Figure 9.6.

(c)   The finials shall be mounted immediately behind the associated PV string support structure separated by a specified "finial separation distance".

9.11.3.   Finial Separation Distance

(a)   The required separation distance depends on:

    (i)   the selected class of LPS,

    (ii)   the insulating material between the finial and the adjacent conductor,

    (iii)   the lightning flowing in the finial,

    (iv)   the distance from the end of the finial to the point of separation.

(b)   IEC 62305-3 defines how the required finial separation distance shall be calculated.

DEHN can provide software to assist this calculation, i.e. DEHN Distance Tool software.

9.11.4.   Zone of Protection

(a)   The area protected by a single air termination can be calculated by the "protective angle method" as shown by Figure 9.3

Tip of air termination

Height of an air termination rod above the reference plane of the area to be protected

Protective angle

A

α

h

Reference plane

C

Radius of protected area

The protective angle method for a single air rod
— Definition of Terms

Figure 9.3

(b)   As illustrated at Figure 9.4, the protective angle afforded by an air rod is a three dimensional concept whereby the rod is assigned a cone of protection by sweeping the line AC at the angle of protection a full 360 degrees around the air rod.

The protective angle differs with varying height of the air rod and the class of LPS.

α°

h(m)

Note 1   Not applicable beyond values marked with °
          Only rolling sphere and mesh methods apply in these cases
Note 2   h is the height of air-termination above the reference
          plane of the area protected
Note 3   The angle will not change for values of h below 2m

Determination of the protective angle
(IEC 62305-3 Table 2)
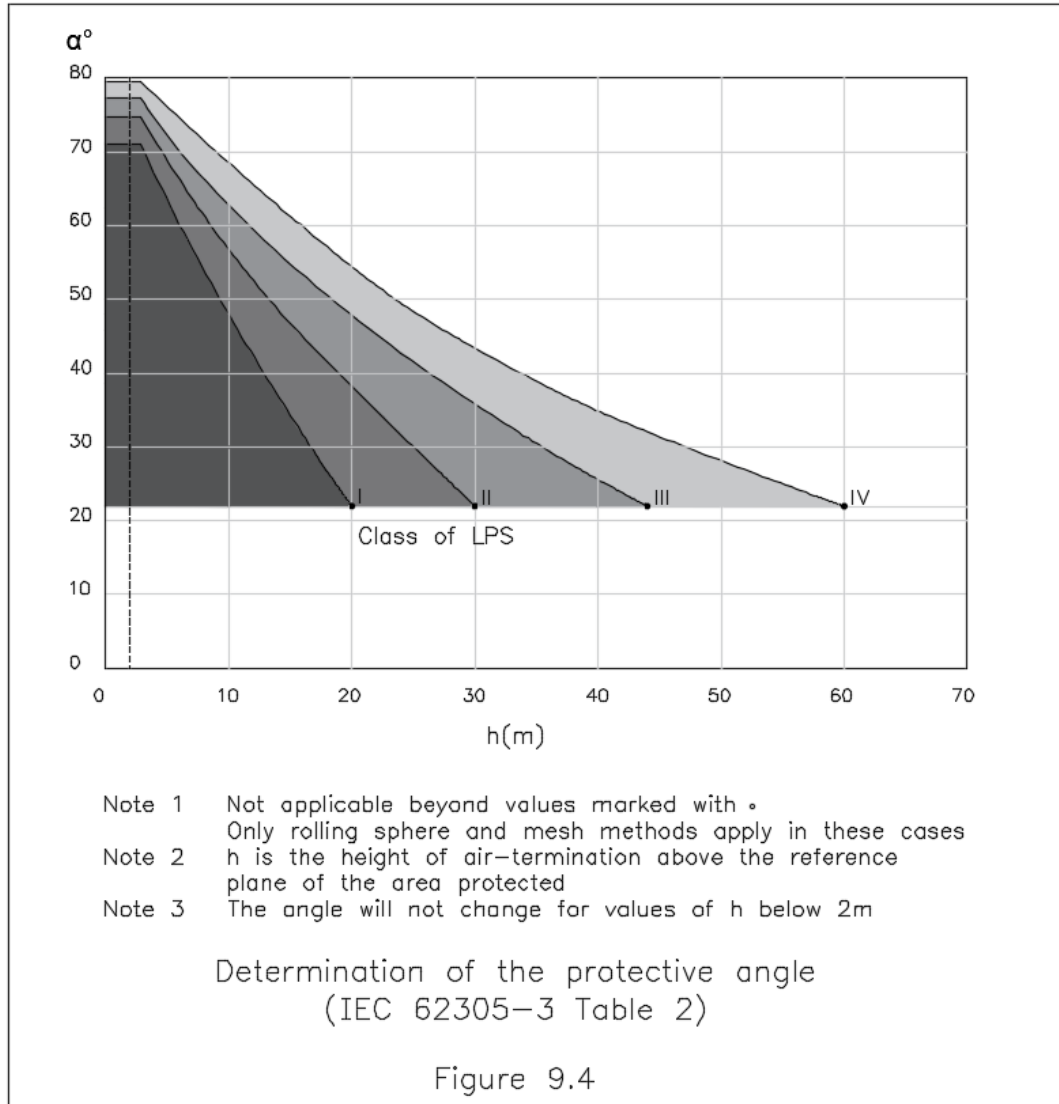
Figure 9.4

(c)   As further illustrated at Figure 9.5 the protective angle varies with the distance from the tip of the air termination to the reference plane.

Effect of height of the reference plane on the protection angle as per IEC 62305—3 Table 2

Figure 9.5
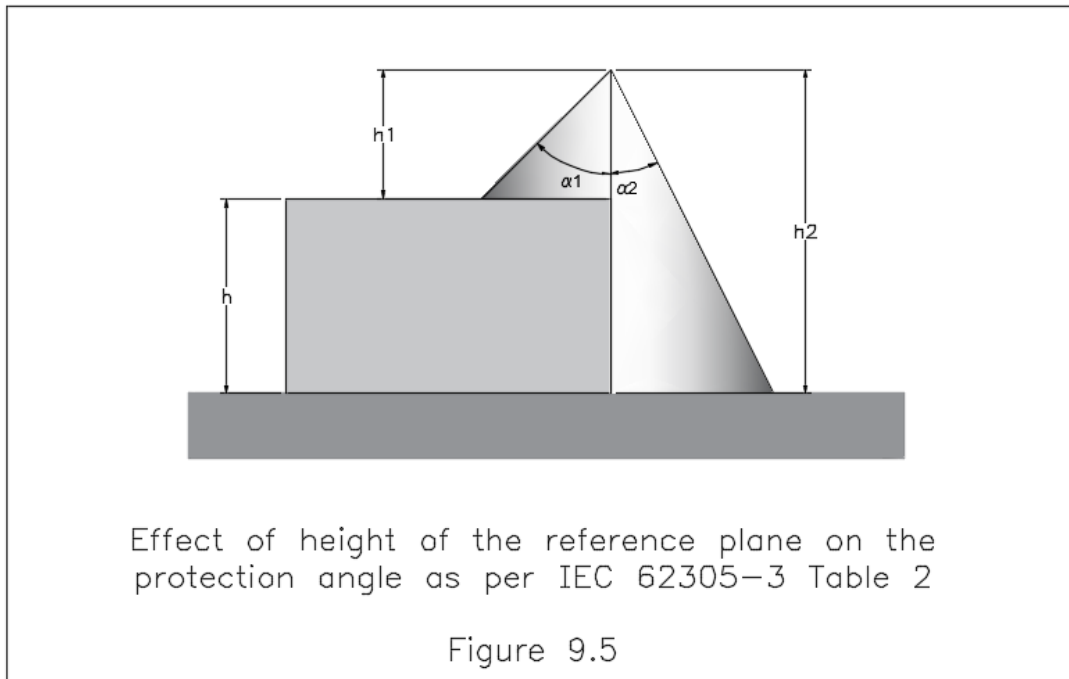
(d) The required length of air-termination rods depends on the spacing, the shorter the air-termination rod the shorter the required minimum distance between rods.

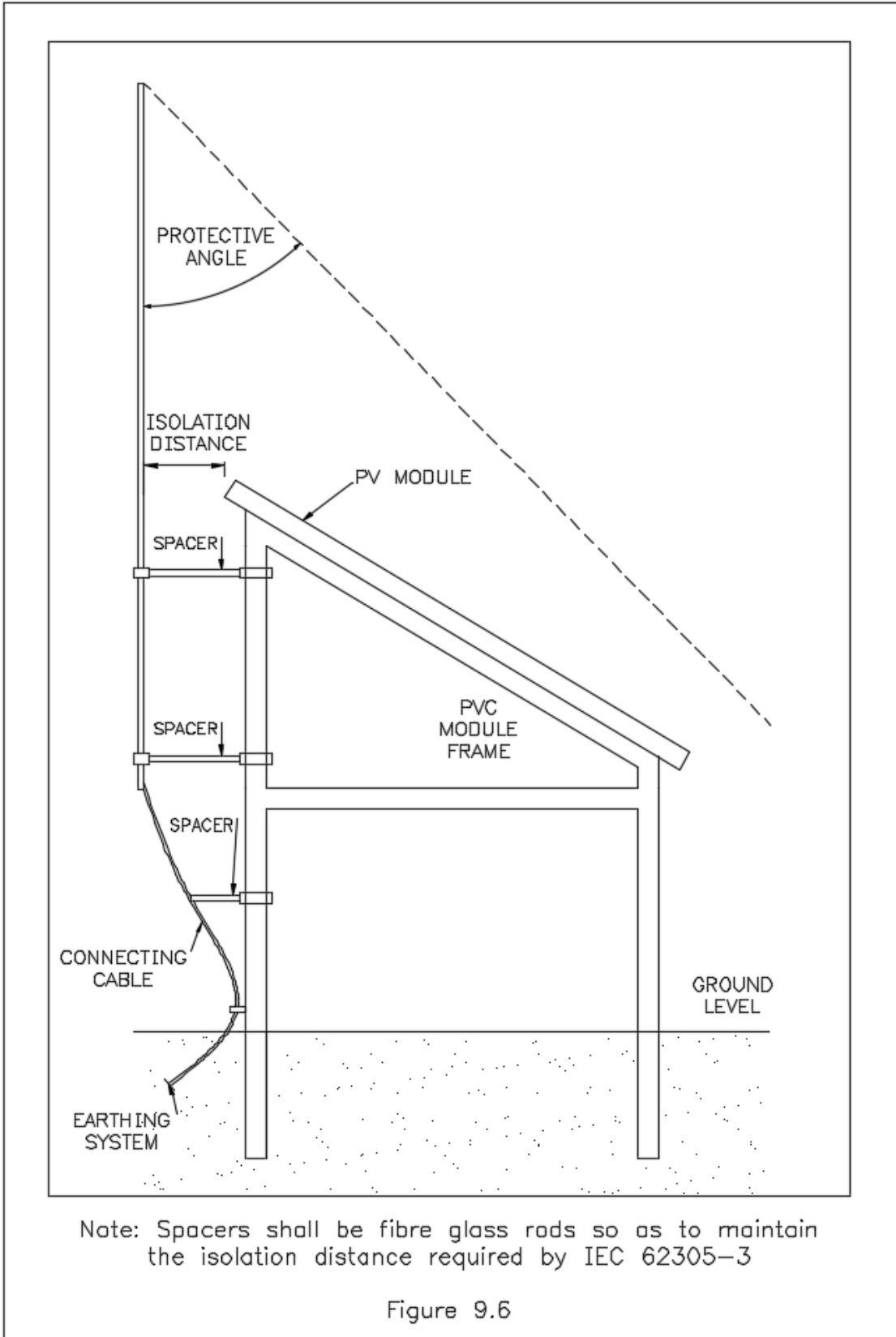The DEHN Air-Termination Tool software is available to calculate the air-termination rod length required for specific distances between air-termination rods.

(e) As for bird spikes (para. 6.4), air-termination rods will throw a shadow, so that the higher the air-termination rods are made, the greater the spacing between PV module rows in the PV array must be made.

9.11.5. Down Conductor Separation

As per IEC 62305-3, the separation of down conductors from the air termination system to the earth termination depends on the class of lightning protection system (LPS) and for classes I and II shall not exceed 10 metres, for class III shall not exceed 15 metres and for class IV shall not exceed 20 metres.

PROTECTIVE ANGLE

ISOLATION DISTANCE

PV MODULE

SPACER

SPACER

PVC MODULE FRAME

SPACER

CONNECTING CABLE

GROUND LEVEL

EARTHING SYSTEM

Note: Spacers shall be fibre glass rods so as to maintain the isolation distance required by IEC 62305-3

Figure 9.6

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9.11.6. PV Array Structure Earthing

(a) Exposed parts of PV modules shall be electrically bonded to the associated metal support structure, the various components of which shall be electrically bonded together.

(b) The PV array structure shall be connected to the LPS earthing system at a location close to each air-termination rod and the air-termination rod shall be connected to the LPS earthing system at the same point (since the LPS is to be "non-isolated").

(c) The earth resistance value of the whole of the interconnected LPS earthing system before bonding to services which do not form part of the LPS shall not be more than 10 ohms.

(d) The design of the LPS earthing system shall be such as to minimise step and touch potentials in the event of a lightning strike.

(e) The design of the LPS earthing system shall be carried out by a specialist earthing design engineer and shall be carried out in conjunction with the electrical engineer responsible for the remainder of the electrical installation.

10.   Isolated Borehole Pump Drives without Battery Support

10.1   General

(a)   The typical installation covered by this Design Standard will consist of an electrically powered borehole pump located some distance from its associated large storage tank and pumping directly into it.

(b)   The use of solar energy at a particular bore site will have been determined as being viable because the borehole pump is relatively small, the estimated cost of providing an electrical power connection between the storage tank is relatively high and the capacity of the storage tank is such that in most times the pump can deliver water to the tank whenever there is sufficient solar energy to do so.

(c)   Electrical equipment and circuits in pump stations shall be deemed to consist of the following separate systems:

   (i) the D.C. power generation system,

   (ii) the electric drive system,

   (iii) the energy storage system (if required) and

   (iv) the plant control system

(d)   Generally facilities will be provided to allow a standby supply from a diesel powered A.C. generator.

(e)   In rare cases provision may also be made for an auxiliary supply from an associated A.C. grid power supply.

10.2   D.C. Power Generation System

(a)   The solar D.C. power generation system shall consist of:

   (i) the PV modules

   (ii) the support frames on which the PV modules are mounted.

   (iii) the electrical installation between the PV modules and the input terminals of the system power conversion equipment (PCE).

(b)   The principal function of the D.C. power generation system shall be to harness solar power for use by the drive system.

(c)   The power available from the D.C. power generation system will vary with the time of the day, the season of the year and the cloud cover.

(d)   In addition the power available from the D.C. power generation system will vary with the received irradiance level, the operating temperature of the PV modules and the age of the PV modules.

10.3 Electric Drive System

(a) The solar power generation system shall be connected directly to the electric drive system so as to power the latter without the need for battery storage.

The power conversion equipment shall consist of a special D.C. to A.C. variable speed controller which incorporates a maximum power point tracking algorithm which varies the speed of the driven motor so that the motor load matches the power available from the D.C. power supply.

(b) The variable speed controller shall be provided with input supply facilities which allow supply from a standby A.C. generating set.

10.4 Plant Control System

(a) Plant control system (PCS) shall be deemed to include:

(i) the remote terminal device (RTU) connected to a remote central hydraulic system control centre (if required).

(ii) any instrumentation measuring hydraulic system parameters directly,

(iii) the solar PV system and supporting batteries required to power the above RTU and instrumentation system including the associated electrical installation.

(b) Plant control system requirements are not included in the scope of this Design Standard.

11. Solar Powered Pumps without Batteries - Speed Control

11.1 Positive Displacement Pump Characteristics

(a) With a true positive displacement (PD) pump, the torque demand is constant over the complete flow rate range   when pumping against a fixed head. Since power demand is torque multiplied by speed, and in a true PD pump flow rate is directly proportional to speed, there will be no power demand before flow commences.

(b) The power demand versus speed characteristic of a positive displacement pump is shown on Figure 11.3

(c) However Mono Pumps advise their borehole pumps are not true positive displacement pumps in that   there will be almost no flow at less than 50 % speed, i.e. the usable flow rate range will be approximately 2:1.

Mono Pumps further advise that no harm will come to the pump if operated below half speed for significant time, i.e. Mono borehole pumps are less prone to no flow damage than are centrifugal pumps.

(d) The largest submersible motor driven PD borehole pump available currently is rated at only 2 kW. However line shaft driven PD borehole pumps are available rated up to 10 kW.

11.2 Centrifugal Pump Characteristics

(a) The characteristics of a typical centrifugal pump are shown at Figure 11.1.


Hydraulic resistance characteristic

Figure 11.1
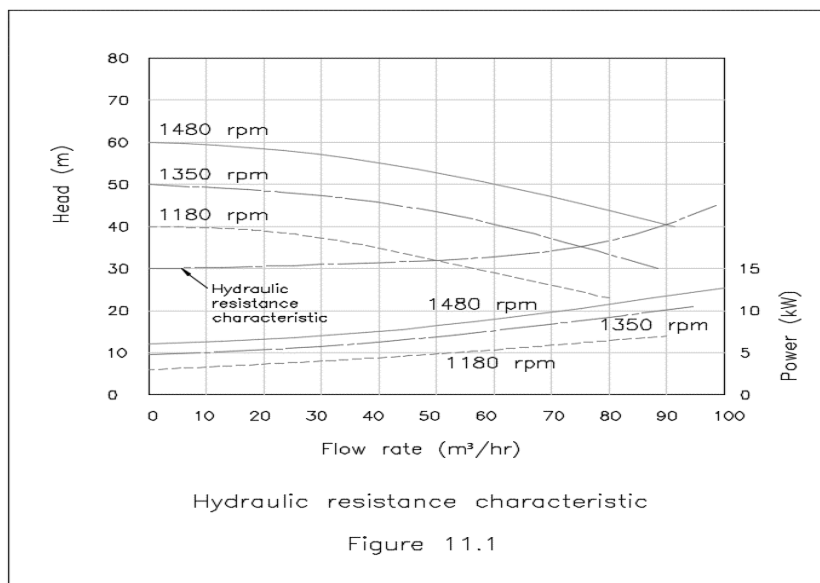
(b) The most common application of solar pumping will be borehole pumps pumping to a collection tank. In such applications the static head on the pump may be a major

part of the total pumping head. Such a hydraulic resistance characteristic is shown on Figure 11.1

(c)   In the example shown at Figure 11.1, a power input of approximately 2.5 kW will be required before pumped flow commences, i.e. the pump speed will need to be increased above 1050 rpm before flow commences.

Hence in this example, the pump should not be permitted to operate at speeds less than 1100 rpm.

(d)   It should be further noted from Figure 11.1, that the full load power demand will be approximately 12.5 kW.

(e)   Figure 11.2 shows the power demand versus flow rate characteristic for a centrifugal pump having the characteristics shown at Figure 11.1 pumping against the hydraulic resistance characteristic shown in Figure 11.1

(f)   Figure 11.3 shows the power demand versus speed characteristic for a centrifugal pump having the characteristics shown at Figure 11.1 pumping against the hydraulic resistance characteristic shown in Figure 11.1.
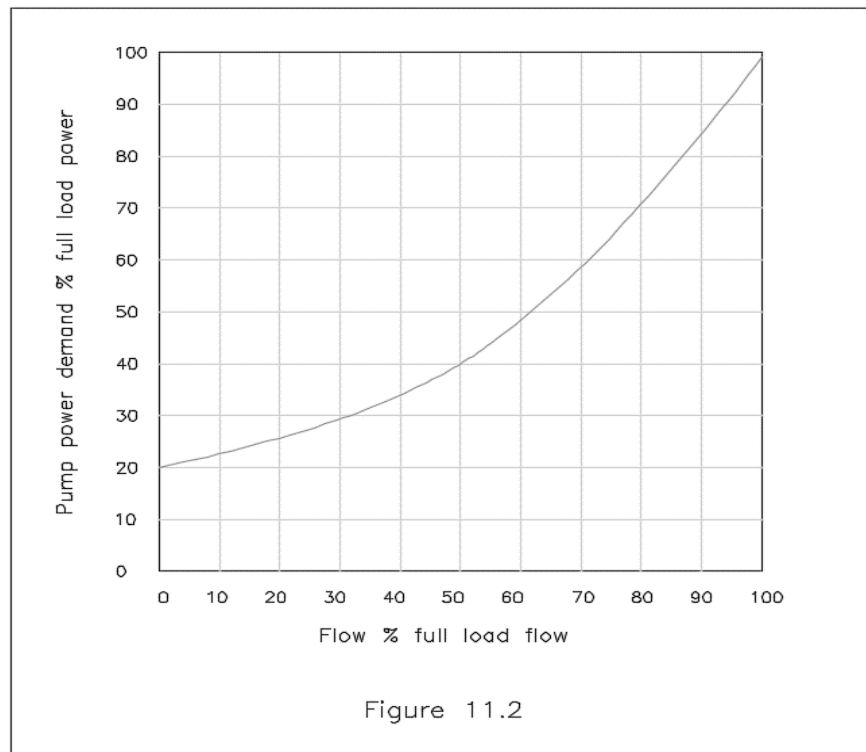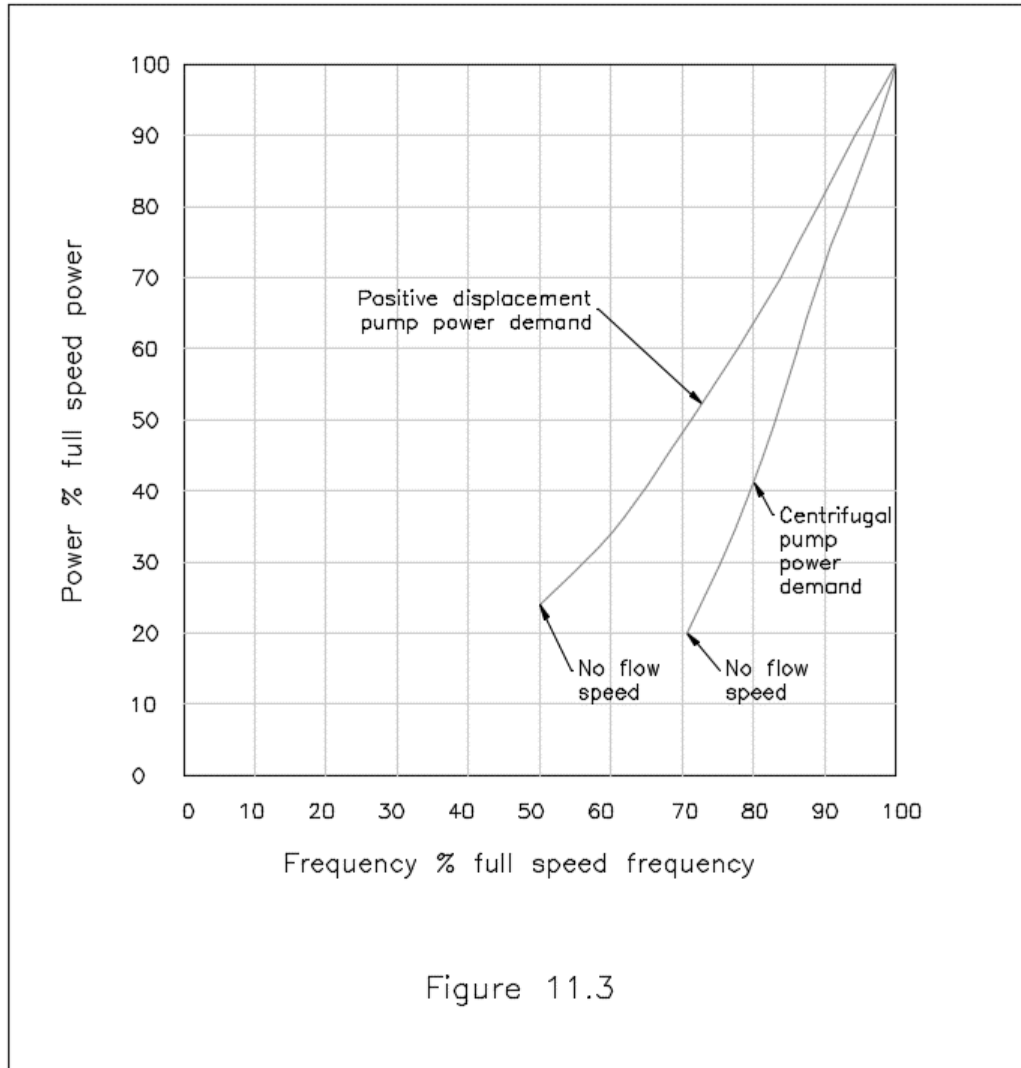

Figure 11.2

Figure 11.3

(g) For a centrifugal pump pumping against a relatively low static head the power demand versus speed characteristic will be cubic. (para. 11.9 refers).

However, as can be seen from Figure 11.3, with a larger static head the power demand versus speed drops below the cubic characteristic due to the power requirement prior to flow commencing.

11.3   Basic Function of Power Conversion Equipment

(a)   In a solar powered pumping system without batteries the basic function of the power conversion equipment (PCE) is to convert the D.C. electrical energy received from the PV array into electrical energy to drive the pump motor.

Such PCEs are commonly known as "solar pumping inverters".

(b)   The solar pumping inverter shall include a maximum power point tracker (MPPT) function which shall operate the PV modules at the maximum power point voltage applicable to the irradiance level received.

If the motor load is less than the maximum power available from the PV array, the PV module will operate at a lower current and a slightly higher voltage, i.e. the PV array current level will fall much faster than the PV array voltage level rises, as indicated Figure 5.1.

(c)   The maximum rating of the solar pumping inverter shall be matched to the full load rating of the motor.

(d)   The solar pumping inverter shall vary the speed of the motor by varying the voltage and frequency of the 3 phase A.C. supply to the motor so that motor's rated power versus speed characteristic matches the available power versus irradiance characteristic.

This control will be open loop, so that if the motor load at any particular speed is less than motor rated load at that speed, the PV array will operate off the maximum power point level, i.e. the system will operate inefficiently.

(e)   The solar pumping inverter shall incorporate a control system which, as closely as is practical, shall match the pump load characteristic with the PV array power supply characteristic.

11.4   Incoming D.C. Voltage

(a)   As per para. 8.1(g), the ratio of the PV array voltage to motor nominal 3 phase A.C. voltage shall be 1.41.

(b)   The motor nominal A.C. voltage shall be taken to be the motor nameplate voltage.

If the motor name plate specifies an acceptable range of voltages, the nominal voltage shall be taken to be the average.

(c)   Consequently the number of PV modules per PV string shall be such that, for   a system powering a 3 phase 415 VAC motor, the PV array maximum power point voltage (V_{mpp} array) shall be 580 VDC at the site mid-summer noon irradiance level, at full load and at maximum PV module temperature (paras. 6.3 and 8.1 refer).

11.5   PV Array Voltage versus Irradiance Level Relationship

(a)   For a constant voltage source, the power output is proportional to the current taken. Similarly for a constant current source, the power output is proportional to the output voltage generated.

(b)   At a particular irradiance level and at output voltages below the current versus voltage knee point, the PV array is approximately a current source.

(c)   As indicated on Figure 5.2, up until the knee point in the PV module current versus voltage characteristic, the module current is proportional to the irradiance level.

As indicated on Figure 5.1, for a particular level of irradiation, up until the knee point of the power versus voltage curve the power is almost proportional to the voltage.

Hence at voltages less than 85% of the power versus voltage curve knee point voltage, the incoming voltage may be used as an indication of available power

Thus the incoming D.C. voltage may be used for starting and stopping control of the drive.

(d)   However at voltages above the knee point in the PV module power versus voltage characteristic, the current declines sharply whereas the voltage increases more slowly.

(e)   PV module output voltage, output current and output power are all affected by temperature as is shown in Figure 5.3.

11.6   Solar Pumping Inverter - Mode of Starting and Stopping Control

(a)   The solar pumping inverter shall include a low conductance incoming D.C. voltage monitoring module which shall be connected permanently to the incoming D.C. supply.

(b)   The prime function of the D.C. voltage monitoring function is to detect the presence of irradiance at a level sufficient to start the pump but not necessarily at a level to run the pump at the level required to run the pump at the required minimum speed.

(c)   At voltages up until 90 % of the maximum power point voltage, the PV array will behave like as current source, to that voltage across the above monitoring module will indicate the level of solar irradiance.

When this incoming D.C. voltage reaches voltage V2 as defined hereunder the solar pumping inverter shall commence to modulate and the pump shall be started.

(d)   However with settings as described hereunder the pump may not reach the set minimum speed within the set start time T_f and if so the pump shall be shut down accordingly.

(e) Provided that the incoming D.C. remains above V_2, the solar pumping inverter shall attempt another start after a set restart time T_r.

(f) If the D.C. incoming voltage falls below voltage V_1 as defined hereunder the solar pumping inverter shall stop the pump immediately.

(g) The motor start voltage V_2 should be set at 85 % of PV array MPP voltage versus ambient temperature with the PV modules at maximum ambient temperature,

i.e. for a 415 VAC motor V_2 should as follows:

$V_2 = 0.85*31.7*19*(1-25*0.33/100) = 469.7$ volts, say 470 volts.

(h) In some makes of solar pumping inverter voltages V_1 and V_2 are programmable separately, whereas in other makes only a single "run" voltage is programmable, i.e. the hysteresis between V_1 and V_2 is fixed (typically at 5 %).

(i) In some makes of solar pumping inverter T_r may be increased automatically depending on the number of recent unsuccessful continuous run attempts.

(j) Voltage V_1 should be set at the inverter's minimum voltage setting or at 400 volts, whichever is the greater.

(k) The solar pumping inverter shall utilise a two stage start process i.e. when the incoming D.C, voltage reaches voltage V_3 the modulator's main power supply shall be energised and when the incoming D.C. voltage falls below V_4 the modulator's main power supply shall be shut down.

In such solar pumping inverters voltages V_3 and V_4 **may** have fixed settings, so care shall be taken to ensure that voltages V_2 and V_1 are both set above voltage V_3.

(l) The minimum continuous operating speed shall be set to be above the no flow speed, e.g. for the example shown in Figure 11.3 an appropriate minimum speed setting would be 75 % of full speed.

11.7 Solar Pumping Inverter - Positive Displacement Pump

(a) Motor torque is proportional to motor field strength which in turn is proportional to motor voltage.

(b) At any particular speed and at rated full load current, motor power is proportional to motor voltage.

(c) Motor speed is proportional to the supply 3 phase A.C. voltage frequency

(d) Motor torque is power per unit speed i.e. $T = P/s$

Where: T = motor output torque

P = motor output power

s = motor speed

(e) Since a positive displacement pump has a constant torque requirement regardless of pump speed, a solar pumping inverter controlling the speed of this type of pump

so as to maintain motor rated full load current, must vary the 3 phase A.C. voltage so as to maintain a constant voltage to frequency ratio V/f, i.e. $V = K*f$

Where: V = motor supply voltage

f = motor supply voltage frequency

K = project specific constant

(f) Thus the voltage versus frequency and the torque versus speed characteristics both will be linear, i.e. the controller's voltage versus frequency characteristic will match the torque versus speed characteristic of a positive displacement pump.

(g) Since power is the product of torque and speed, the resulting power to frequency characteristic of the solar pumping inverter and the power to speed characteristic of positive displacement pump both will be quadratic.

(h) The available power to frequency of a solar pumping inverter with a constant V/f characteristic is shown on Figure 11.4.

11.8 Solar Pumping Inverter - Centrifugal Pump with Low Static Head

(a) Unlike the positive displacement pump discussed above, which has a constant torque requirement, a centrifugal pump pumping against a low static head has a torque requirement proportional to the pump speed.

(b) Consequently in order to provide, at motor rated current, a motor output torque which matches the torque input requirement of such a pump the voltage versus frequency characteristic described at para. 11.7 (e) above needs to be modified so as to maintain a constant voltage to frequency squared ratio V/f^2

i.e. $V = K*f^2$

where: V = motor supply voltage

f = motor supply voltage frequency

K = project specific constant

(c) Thus the voltage versus frequency and the torque versus speed characteristics both will be quadratic, i.e. the controller's voltage versus frequency characteristic will match the torque versus speed characteristic of a centrifugal pumping against a low static head

(d) Since power is the product of torque and speed, the resulting power to frequency characteristic of the solar pumping inverter and the power to speed characteristic of centrifugal pump pumping against a small static head pump both will be cubic.

(e) The available power to frequency of a solar pumping inverter with a constant V/f^2 characteristic is shown on Figure 11.4.

11.9 Solar Pumping Inverter - Centrifugal Pump with High Static Head

(a) As can be seen from Figure 11.3 neither the V/f nor the V/f^2 available power versus frequency characteristic matches the power to speed characteristic of the example centrifugal pump described at Figure 11.1 when pumping against a relatively high static head.

However the V/f^2 available power versus frequency characteristic is a closer match.

(b) The area between the V/f and V/f^2 available power curves and the centrifugal pump power demand curve is a measure of the wasted available power.
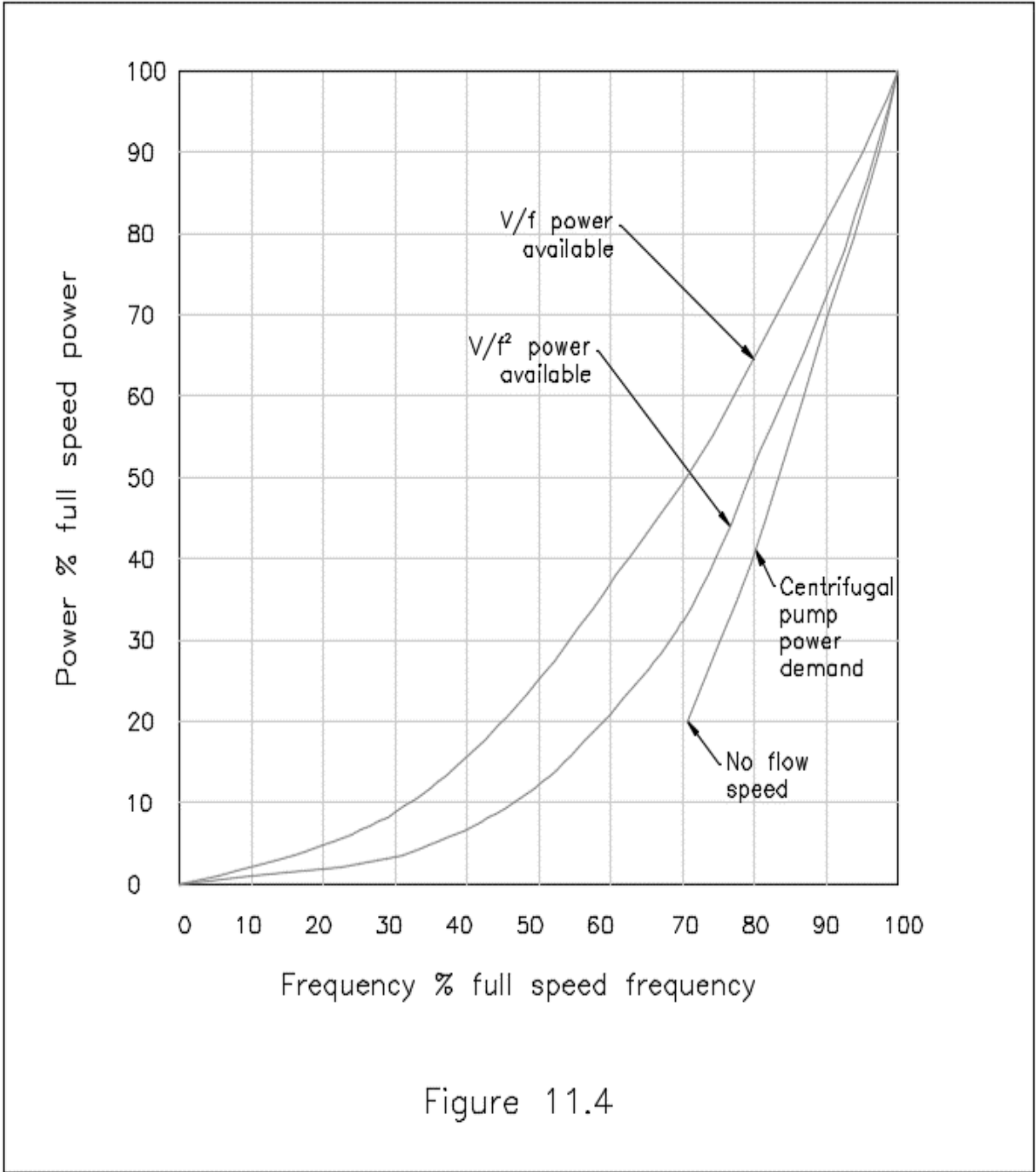
Figure 11.4

(c)   It should be noted that if a V/f characteristic inverter was used with centrifugal pump described at Figure 11.1, pumping would not commence until the irradiance power level had reached 50 % of the required maximum.

(d)   Similarly if a V/f^2 characteristic inverter was used with centrifugal pump described at Figure 11.1, pumping would not commence until the irradiance power level had reached 35 % of the required maximum.

(e)   In the case of a borehole pump pumping into the bottom of a relatively large tank the static head on the pump will vary considerably and therefore so will the pump's power versus speed demand characteristic.

(f)   In view of the above solar pumping inverters controlling centrifugal pumps shall incorporate a V/f^2 output voltage characteristic.

11.10   Effect of Variation in Irradiance Levels

(a)   As shown in Figure 3.1, the ratio of summer to winter noon horizontal surface irradiance levels can be of the order of 2:1 and the summer to winter daily horizontal surface irradiation variations can be of the order of 3:1.

(b)   The variation between tilted PV module surface summer to winter noon irradiance levels can be minimised by increasing the tilt angle to the June optimum value.

(c)   As discussed in para. 6 using the June optimum PV tilt angle will result in an annual irradiation being less than if the March tilt angle is used. However this reduction in irradiation level is relatively small as shown in Table 6.1.

(d)   Even with the solar pumping inverter programmed with the V/f^2 characteristic as discussed above, borehole centrifugal pumps will not start pumping until the incoming D.C. power level has reached approximately 35 % of the pump maximum demand power level.

(e)   Consequently for systems incorporating solar pumping inverters without batteries and requiring to operate year round, the winter optimum PV module tilt angle shall be used.

11.11   Solar Pumping Inverter - Dry Run Protection

(a)   Dry run protection (i.e. no flow protection) shall be provided, but shall be bypassed during motor starting periods.

(b)   A dry run situation can be detected by the load power being below a set minimum power level, i.e. the power level required to enable the driven centrifugal to overcome the static head and generate minimum flow.

(c)   However the inverter's control system aims to run the motor at a voltage and frequency which will result in motor full load current. Thus a dry run situation can be detected by the current being below a specified minimum current for a specified time.

(d)   Care shall be taken to ensure that underload protection settings are such that, as far as is practical, the underload protection will trip prior to input D.C. undervoltage protection tripping.

11.12   Solar Pumping Inverter - Standby Power Supply

(a)   The solar pumping inverter shall have an auxiliary 3 phase power input facility to allow the motor to be run at full speed at times when the D.C. power supply from the PV array is not available.

(b)   The selection of either D.C. input supply from the PV array or three phase A.C. from a standby generator shall be by a special manual changeover switch.

The changeover switch shall switch all three phases of the A.C. supply coming from the generator and both positive and negative of the D.C. supply coming from the PV array.

11.13   Solar Pumping Inverter - Output Filtering

Whether or not A.C. output voltage filtering will depend on motor characteristics and length of motor cable. Reference shall be made to Design Standard DS22 in this regard.

11.14   Solar Pumping Inverter - Ambient Temperature

(a)   The solar pumping inverter is an electronic device and thus will need to be derated for the ambient temperatures expected at most solar powered pumping system sites.

(b)   Consequently solar pumping inverters shall be positioned in well ventilated and permanently shaded locations.

11.15   Solar Pumping Inverter - D.C. Earth Fault Alarm

(a)   AS/NZS 5033 clause 3.4.1 requires PV arrays connected to grid interactive inverters to comply with IEC 62109-2. Such inverters are required to include D.C. earth fault detection and alarm facilities.

(b)   However solar pumping inverters are not interactively connected to the grid, so that there is no requirement for D.C. earth fault alarm facilities as specified AS/NZS 5033 clause 3.4.3.

11.16   Solar Pumping Inverter - Power Connections

(a)   The required power connections to the solar pumping inverter are shown in Figure 11.5.

(b)   Solar pumping inverters are commonly standard variable speed controllers with the firmware altered in order to facilitate their use as solar pumping inverters. The block diagram shown at Figure 11.5 is drawn for such a solar pumping inverter.

In this example the firmware in the standard variable speed controller has been modified so that the brake chopper is closed permanently thus allowing the brake chopper output to be used as the D.C. power input. Nevertheless the brake chopper hardware remains in place.

Connections for Typical Solar Pumping PCE
without batteries

Figure 11.5
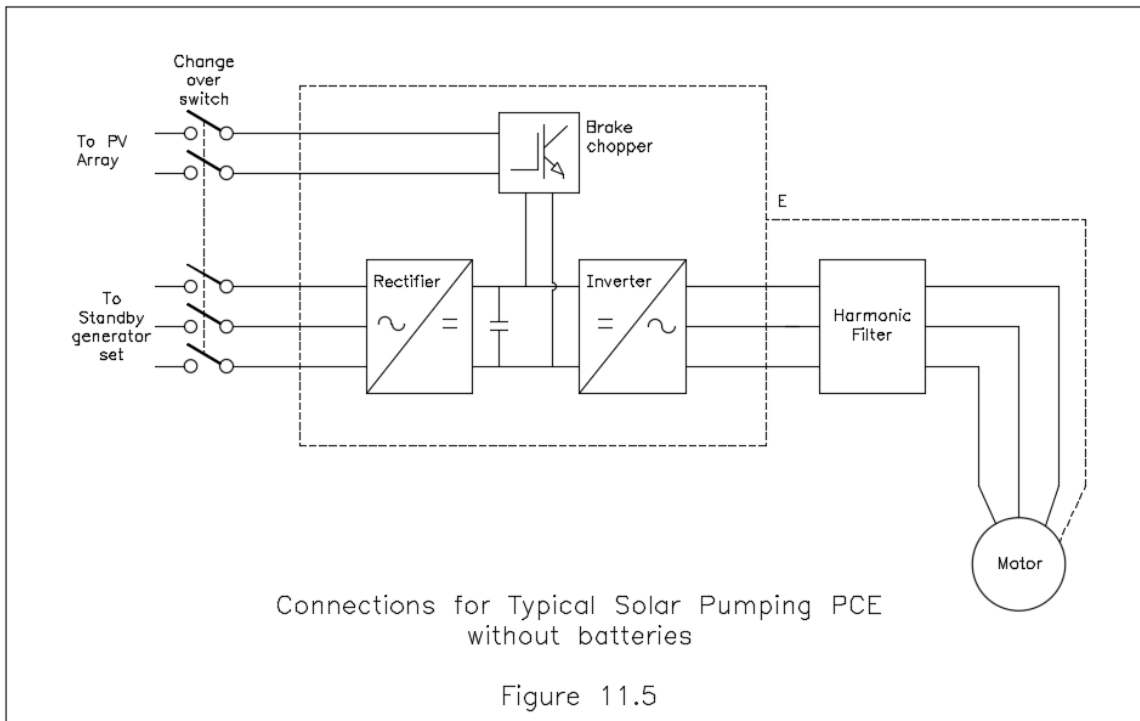
11.17 Solar Pumping Inverter - PID Control

(a) There may be applications where it is necessary for a solar pumping inverter to control the associated pump so that pumping occurs only within a narrow range of output pressures.

(b) Solar pumping inverters for use in the above application shall be equipped with V/f and V/f^2 control functions as well as a subsidiary PID function.

Such inverters shall include a facility to connect a pressure transducer which can be used in conjunction with the PID function so as to maintain the pump output pressure at a set value.

(c) The implementation of the PID function shall be optional, and if it is implemented it shall be capable of being implemented in conjunction with either the V/f control function or the V/f^2 control whichever is selected and the system operation shall be as follows:

(i) As the sun rises and the received solar energy increases the motor shall be started and shall be accelerated in accordance with the selected V-f control function.

(ii) When the pump speed has increased to the level sufficient to generate the set pressure level, the PID function shall take control and maintain the pressure at the set value regardless of flow rate.

(iii) Provided that the level of incoming solar energy remains high enough to generate the pump output pressure at the set level, the PID function shall maintain the pump output pressure at the set level.

(iv) Once the level of incoming solar energy falls below the level required to maintain the set pressure level, the selected V-f function shall take control and reduce the pump speed and output pressure accordingly.

(v) Once the speed falls to the set minimum level, the pump shall be stopped in the normal manner.

(vi) Thus, the upper limit of the controlled pressure range shall be the PID pressure set point and the lower limit of the controlled pressure range shall be determined by the minimum speed set point.

(d) It should be noted that incoming solar energy in excess of the level needed to maintain the PID set point pressure will be wasted.

12. Design Process for Solar Powered Drives without Batteries

The following outlines the design process which shall be followed when designing solar powered pumping systems which do not include batteries between the pump drive inverter and the solar array.

12.1 Load Requirements

(a) Determine maximum and minimum pump power demand.

(b) Determine distance from PV array to power conversion equipment (PCE) and from PCE to motor terminals.

(c) Determine motor compliance with IEC 60034.17 and thus determine whether motor power input filtering will be required and, if so, what type, as per DS22.

(d) Estimate the likely required power output from the PV array.

(e) Obtain from the Mechanical Design Engineer a graph showing the power versus speed relationships for the specified pump to be used for pumping under site lowest static head and site highest hydraulic conditions.

(f) Determine the required control voltage-frequency characteristic

(g) Select a type and make of solar pumping inverter.

(h) Determine the inverter withstand voltage and confirm the input D.C. operating voltage which is necessary to be able to generate motor rated full speed power output at rated motor voltage.

12.2 Site Conditions

(a) Determine site maximum and minimum shade ambient temperatures.

(b) Determine the site maximum wind speed.

(c)   Determine whether the site is susceptible to salt or ammonia pollution.

(d)   Confirm that the site can provide a North facing area free of vegetation and shade on which to house the proposed PV array, as per para. 8.4

(The further South the site is located, the larger the area required.)

For example, a site near Roebourne may require an area of approximately 500 square metres whereas a site near Esperance may require an area of approximately 600 square metres.)

(e)   Determine the site solar angle as per para. 3.5. This solar angle calculator refers to a fairly wide range of cities and towns. If (as is likely) the site is not located at one of the nominated cities or towns, solar angles should be calculated for the nominated Southern Hemisphere city or town on approximately the same latitude.

(f)   Calculate the optimum PV module tilt angle as per para. 3.6.

(g)   Determine average maximum and minimum irradiation levels on PV modules installed at site for year round optimum tilt in December, March and June, as per para. 3.6.

(h)   Determine PV module operating ambient temperature, as per para. 6.1.

12.3   PV Modules

(a)   Select the type, make and module of PV module to be used, as per para. 5.

(b)   Determine PV module minimum temperature open circuit voltage V_{ocmod} as per para. 6.2

(c)   Determine PV module maximum temperature operating voltage V_{mpp} as per para. 6.3.

(d)   Calculate the power per module available at noon in December and in June on the basis of irradiance levels calculated as per para. 12.2(g) above assuming maximum ambient temperature occurs at noon, as per para. 6.4.

12.4   PV Array General

(a)   Calculate the number of PV modules required to the meet the maximum load as calculated as per para.12.1 (d).

(b)   Calculate the number of PV modules required in series to meet the solar pumping inverter operating D.C. input voltage, as per paras. 8.1 and 12.1 (g).

(c)   Check that at minimum temperature the above number of PV modules in series will not generate an open circuit voltage exceeding the maximum rating of the solar pumping inverter.

(d)   Determine the required number of PV modules required per PV string and the required number of PV strings as per paras.8.1 and 8.2.

(Note that all PV strings which are connected parallel as per Figure 9.1 must have the same number of PV modules.)

12.5 PV Array Structural

(a) Determine the physical arrangement of the PV arrange taking into account the following:

    (i) the orientation of PV modules (usually Northerly),

    (ii) the need for bird spikes, as per para. 7.4,

    (iii) the need to avoid PV module shading as per para. 7.2,

    (iv) the need for safe personnel access between PV string rows,

    (v) fencing and security of access to restrict access to authorised persons,

    (vi) positioning of PV strings so that the differences in cable run lengths from PV strings to PV combiner boxes is minimised,

    (vii) the need to provide shaded locations for PV string combiner box(es).

(b) Design the PV module support structures so that these and the PV modules mounted thereon will be able to withstand the maximum wind velocities recorded at the site, as per para. 7.5.

12.6 PV Array Electrical

(a) Design the PV array electrical system in accordance with Figure 9.1.

(b) As part of the electrical design of the PV system specify the following:

    (i) type and size of cables running within PV strings and from individual strings to the PV combiner box, as per para. 9.9. [Cable sizing shall be such that, at full load current the voltage difference between individual PV string cables at the terminals of the PV combiner box shall be not more than 1%]

    (ii) type and size of cables running from box to the solar pumping inverter, as per para, 9.9. [Cable sizing shall be such that the full load current voltage drop from PV module terminals to solar pumping inverter terminals shall be not more than 3%, preferably less than 1.5%]

    (iii) D.C. fuses and fuse holders, as per paras. 9.5 and 9.6,

    (iv) PV array isolating switches, as per para. 9.7,

    (v) surge protective devices , as per para. 9.8,

    (vi) functional earthing as per para. 9.10.

(c) Review the completed PV array electrical design to verify conformance with relative sections of AS/NZS 5033.

12.7 PV Array Lightning Protection

(a) Determine the lightning risk at the site of the PV array, as per para. 9.11.1,

(b) Design the air termination system, as per paras. 9.11.2, 9.11.3 and 9.11.4,

(c) Design lightning protection down conductor system, as per para. 9.11.5

(d)   Design PV array lightning protection earthing system, as per 9.11.6.

12.8   Solar Pumping Inverter

(a)   Determine ambient conditions in which the solar pumping inverter will be required to operate, as per para. 11.14. The solar pumping inverter will contain power electronic equipment and can be expected to be subject to considerable ambient temperature derating.

(b)   Include in the overall system design a fully shaded well ventilated location in which to locate the solar pumping inverter.

(c)   Determine solar pumping inverter starting and stopping voltage set points as per para. 11.6

(d)   On the basis of the pump power versus speed supplied as per para. 12.1(e) determine the type of V- f characteristic required.

(e)   Determine the minimum allowable pump operating speed and thus the minimum continuous operating load as per para. 11.8 and determine the time permitted for operation below this value and the minimum time before restarting is permitted.

(f)   Determine and specify any required solar pumping inverter read out parameters.

(g)   Specify the required features of the solar pumping inverter and select a suitable brand and model.

12.9   Connection from Solar Pumping Inverter to Motor

(a)   The output voltage from the solar pumping inverter will be 3 phase pulse width modulated and may require filtering.

Hence determine what type of filtering, if any, is required, as per DS22.

(b)   Determine the length, size and type of cable to be run from the solar pumping inverter to the motor.

12.10   Review

Review the PV system design to verify that the various power assumptions made in the development of the design remain consistent with the final outcome.

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