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Irradiation and PV array energy output, cost, and optimal positioning estimation for South Africa

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Abstract
Simulation results of an irradiation and PV array performance software package (SunSim) are presented. South African irradiation data availability is discussed, an irradiation data classification system proposed, and the estimation of diffuse irradiation on tilted surfaces analysed. Estimation of PV array energy output using King's performance model is explained, and the influence of the irradiation and temperature data set measurement interval on PV energy output estimation investigated. Simulation results are presented, aimed at identifying optimal fixed PV panel tilt angles and solar-tracking configurations for different locations in South Africa. Lastly, the cost of PV-based generation in South Africa is investigated.

Keywords: irradiation, PV, tilt, diffuse, tracking, measurement interval

1. Introduction

Project decisions based on incorrect data seldom result in successful projects. This statement holds true within the context of rural electrification in South Africa utilizing photovoltaic (PV) generation due to the high cost associated with PV technology, decisions based on incorrect data (e.g. solar irradiation at the site) that can lead to under/over-designed systems that either fail to address the needs of the community, or are unnecessarily expensive.

This paper presents the results of a selection of solar irradiation and PV array simulations aimed at increasing the quality of scientific and financial data available to rural electrification decision makers in South Africa.

A number of PV array simulation packages already exist, e.g. RETScreen (Canada's Natural Resources 2006), POWACOST/SOLATILT (Cowan et al 1992) and PV-DesignPro (Maui Solar Energy Software Corporation 2006). SunSim, the simulation package used in this paper (the user interface of SunSim is shown in Figure 1), was not developed to replace these packages, but rather focused on answering the following research questions:

- What irradiation data is available in South Africa on which to base PV array energy output estimations?
- How accurate is the satellite-derived irradiation data used by software like RETScreen?
- What influence does the use of long-term rather than 5-minute or hourly irradiation and temperature data sets have on PV array energy output estimation?
- Is the rule-of-thumb of positioning a fixed PV panel at an elevation angle of latitude plus 10-15° for highest minimum daily energy through the year, and an azimuth angle of 0°, (as recommended in e.g. (Cowan et al. 1992) valid for South African irradiation conditions?
- What influence does the array solar-tracking configuration have on PV array energy output and energy cost in South Africa?
- What influence does the PV material e.g. mono- vs. poly-crystalline silicon have on the PV array energy output and energy cost in South Africa?

2. Irradiation on tilted surfaces in South Africa

2.1 South African irradiation data availability and classification

Data describing the solar resource at a specific location in South Africa is typically available from one or more of the following sources:

1. *Ground station measurements from pyranometers*. The accuracy of the resulting global and diffuse irradiation data is a function of the accuracy of the instrument, its calibration and its spectral sensitivity.
2. *Ground station measurements of sunshine hours*. The percentage of sunshine measured during an hour can be used to estimate the global irradiation at a given location. Diffuse radiation requires further estimations, e.g. by using

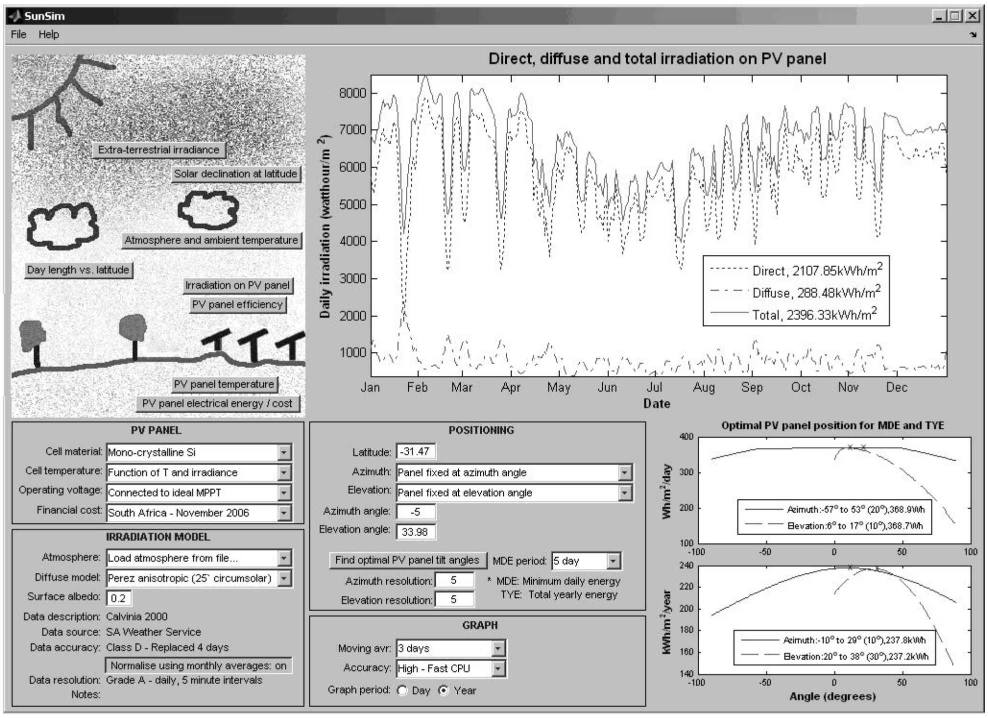


Figure 1: SunSim irradiation and PV energy simulation package

sky clearness indices, with an associated increase in inaccuracy.

3. *Satellite irradiation measurements.* Satellite observations are unable to take the effect of the microclimate at the measurement location into account, but are useful for locations where no ground measurements are available.

The resolution of the irradiation data available from the above sources varies from measurements every 5 minutes to only monthly averages.

These variations in accuracy and resolution among irradiation data sources necessitate the development of a classification system by which the simulation results based on these sources can be differentiated.

The classification system proposed in this paper identifies the accuracy and resolution of the irradiation data using accuracy grades between A and D, as shown in Table 1. For example, satellite-sourced monthly average only irradiation data is classified as grade C:D using this system.

SunSim's simulation results were based on irradiation data from the locations in South Africa, shown in Figure 2.

The South African Weather Service (SAWS) is the main source of ground measurement irradiation data in South Africa. Sun hour measurements are available for a number of locations, while high accuracy pyranometers are used in the bigger cities of South Africa. A number of these pyranometers however, appear to be calibrated less often than the manufacturers recommend, if at all (SAWS 2006); a convincing reason for the inaccuracies found in some of the 5-minute irradiation data sets made available by the SAWS, e.g. Cape Town 2001 (Figure 3).

Eberhard et al. (1990) published solar radiation data for South Africa, based on SAWS measurements over two decades. These data sets are used in SunSim for normalization purposes.

The third source of South African irradiation data is satellite-based data, e.g. from NASA's Surface Meteorology and Solar Energy (SSE) program. The SSE program uses 3-hourly satellite observations over 10 years with a resolution of 1° by 1°, and a measurement accuracy of more than 85% (NASA 2006).

Table 1: Accuracy and resolution classification system for South African irradiation data

Accuracy	*Grading*	*Resolution*
Regularly calibrated ground measurement stations, pyranometer accuracy < 1%, data accuracy < 10%	A	Daily measurements, 5- or 10-minute intervals
Estimates from hourly sunshine hour measurements	B	Daily measurements, 1-hour intervals
Satellite measurements	C	Monthly average, 1-hour intervals
Non-calibrated pyranometers or silicon-based irradiance meters	D	Daily or monthly average only

Note: The data grade is written as accuracy: resolution, e.g. sunshine hour derived 5-minute interval data will be classified as B:A

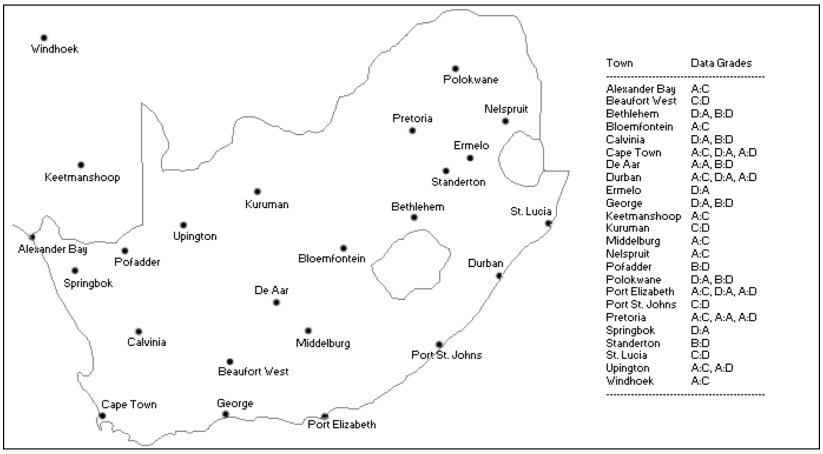
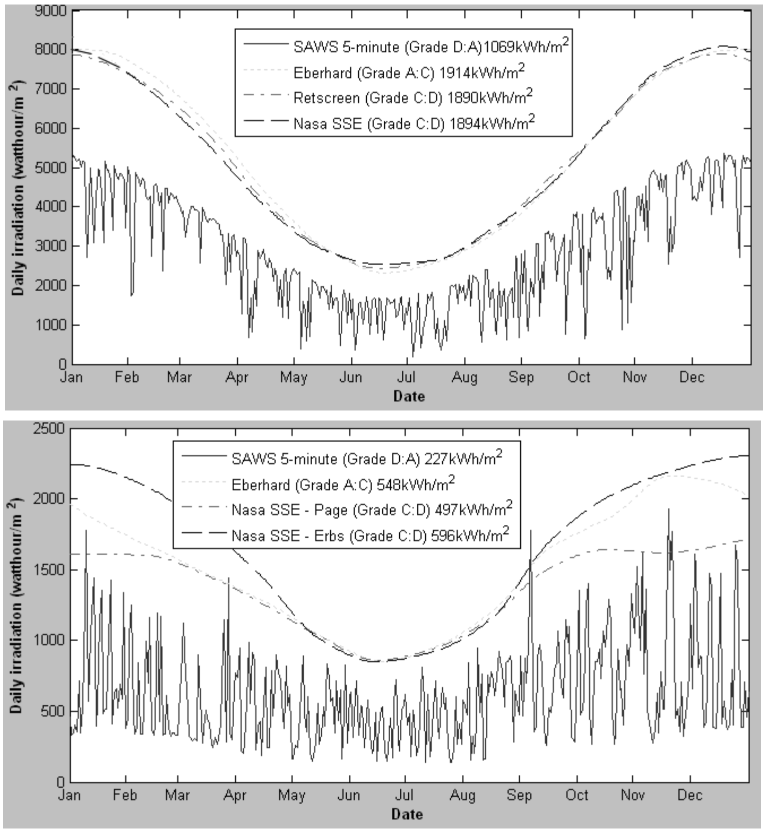


Figure 2: SunSim irradiation data locations, with the accuracy: resolution classification of the data available at each location



Note: The 5-minute data is for Cape Town, 2001. Eberhard's data is based on 19 years of ground irradiation measurements, while Retscreen and NASA's data is based on satellite measurements from 1983-1993.

Figure 3: Different data sources of global and diffuse irradiation on horizontal surfaces, for Cape Town

2.2 Normalization of Grade D accuracy irradiation data

Grade A or B resolution data, i.e. measured daily at 5-minute or hourly intervals, is required for accurate estimations of the optimal PV panel azimuth angle.

Unfortunately, most of the Grade A resolution data made available by SAWS had an accuracy of grade D, as previously illustrated in Figure 3.

In order to make the grade D:A data usable, an algorithm was included in SunSim, where a 30-day moving-average representation of the grade D:A data was normalized against grade A:D data from Eberhard, resulting in data shown in Figure 4.

2.3 Estimation of diffuse radiation on tilted surfaces

Irradiation data for a specific location is typically

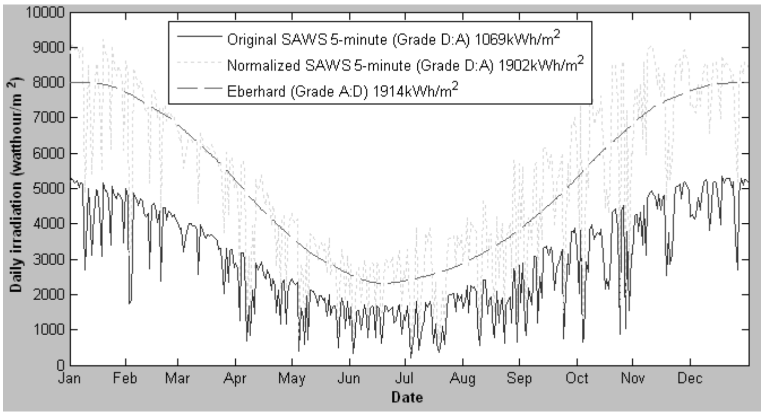


Figure 4: Normalized versus original grade D:A global irradiation data for Cape Town 2001

available as global and diffuse irradiation on a horizontal surface. From these data sets, the beam horizontal irradiation component can easily be found by subtracting the diffuse component from the global component.

Beam radiation on a tilted plane is again easily calculated, using equation 1.

$$G_f = \frac{\cos(I)}{\sin\,(90° - Z)} \qquad \textit{Equation 1}$$

where G_f is the geometric factor, i.e. the ratio of tilted versus horizontal beam irradiation, I is the incidence angle and Z is the sun's zenith angle (Vartiaimen 2000).

Diffuse irradiation on a tilted surface is, however, more problematic. The assumption is not accurate that the diffuse irradiation sources are distributed uniformly across the sky dome (isotropic), and a number of anisotropic measurement-based models exist to estimate diffuse irradiation more accurately.

SunSim uses the 25° circumsolar version of the Perez model (Perez et al. 1988) to estimate diffuse radiation on tilted planes, based on recommendations in Eberhard et al. (1990), Vartiaimen (2000), and Perez et al. (1988).

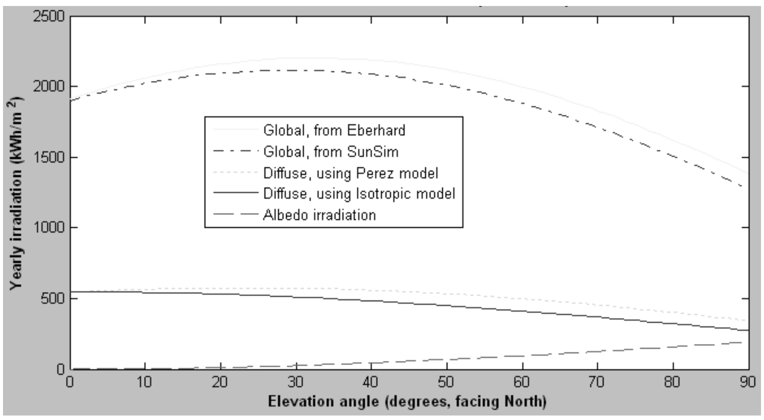
Popular simulation software like RETScreen, however, calculates horizontal diffuse irradiation from satellite data using the Erbs et al. (1982) method (see Figure 2), and diffuse irradiation on a tilted plane using a more generally applicable isotropic model (NASA 2006).

As can be seen from Figures 5 and 6, the use of this isotropic model by RETScreen ultimately underestimates the global radiation on a tilted plane by between 6 and 8% compared to SunSim's Perez model.

3. Estimation of PV array energy output

3.1 SunSim's PV array performance model

SunSim uses King's PV array performance model developed and validated by Sandia National Laboratories (King et al. 2004), which includes the



Note: The differences in global irradiation estimation between Eberhard and SunSim is caused by Eberhard's assumption of equal length months when summing monthly irradiation to yearly values.

Figure 5: Diffuse and albedo irradiation on a tilted plane using normalized Cape Town 2001 data as a function of the elevation angle

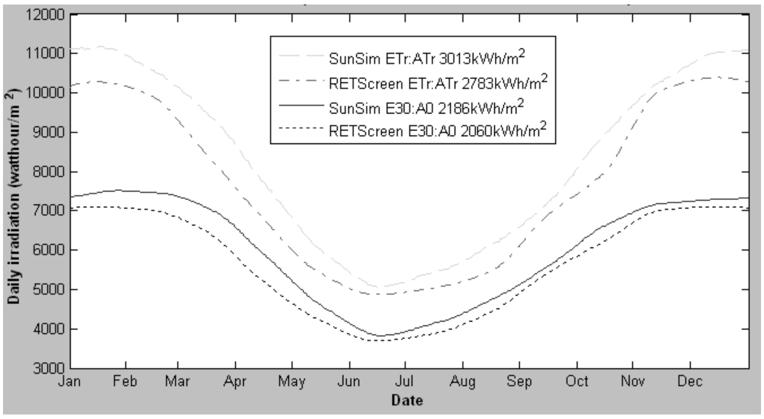


Figure 6: Comparison of the global irradiation falling on a tilted plane between SunSim and RETScreen, for two cases: the elevation and azimuth angles tracking the sun, and the elevation angle fixed at 30° and the azimuth angle fixed at 0°

electrical, optical and thermal characteristics of a variety of PV panel materials. Certain interesting aspects of the model are highlighted in the next paragraphs.

The spectral content of beam irradiance is changed as it moves through the atmosphere, due to selective absorption by atmospheric gases. As the air mass between the PV panel and the sun increases as the sun moves closer to the horizon, so does the spectral absorption, altering the spectral distribution of the irradiance incident on the panel. The air mass modifier in King's model compensates for this effect as shown in Figure 7, for a variety of PV materials with different spectral sensitivities.

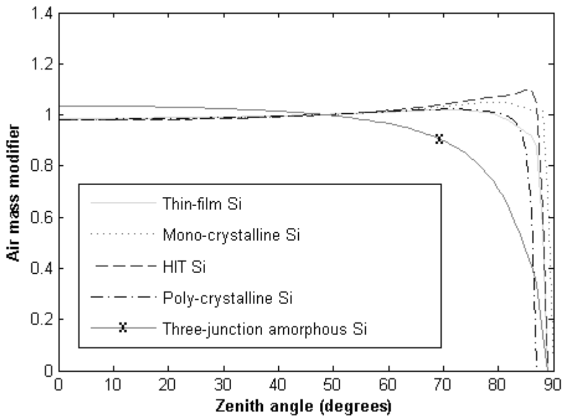


Figure 7: The air mass modifier for various PV materials as a function of the zenith angle of the sun (0°: overhead, 90°: horizon)
Adapted from de Soto et al (2006)

The incidence angle modifier used in King's model, as shown in Figure 8, accounts for losses through reflection of incident irradiance off the glass surface of the PV panel.

The way in which King's model relates the electrical characteristics of a PV panel to incident irradiance and panel temperature is clearly indicated in Figure 9. The model supplies five data points for a given ambient temperature, irradiance, PV material, zenith and incidence angle.

In calculating the PV array energy output, SunSim assumes a 4% loss of energy due to array mismatches, resistive losses and panel soiling, and a 5% loss of energy due to inverter inefficiencies.

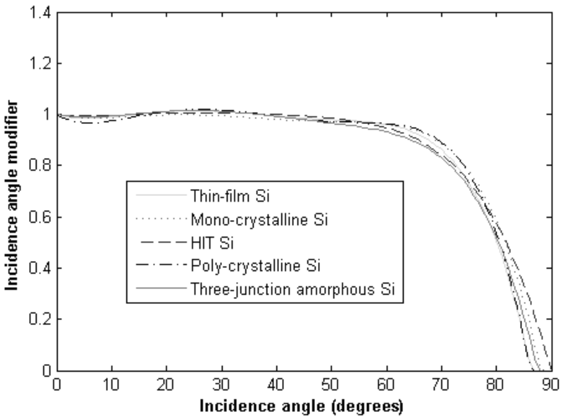


Figure 8: The incidence angle modifier for various PV materials versus the incidence angle of the sun (0°: right angle with surface)
Adapted from de Soto et al (2006)

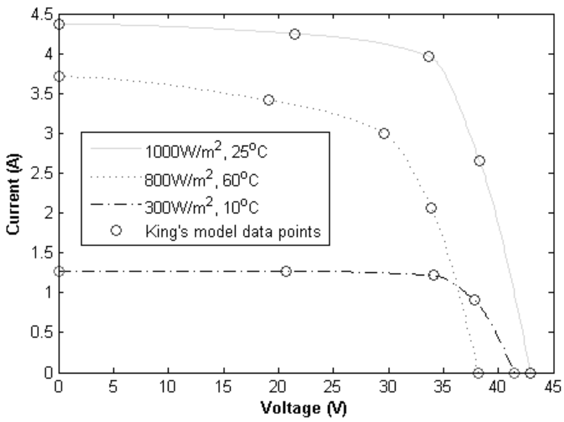


Figure 9: Electrical characteristics of a mono-crystalline Si panel according to King's model. (Incidence and zenith angles = 0°)
Adapted from de Soto et al (2006)

3.2 Influence of data set measurement interval on PV array energy output estimation

The energy output of a PV array responds quickly and in a non-linear fashion to changes in ambient temperature and incident irradiance, as shown in Figure 9. Due to this fast and non-linear response, the use of long-term averaged instead of 5-minute or hourly irradiation and ambient temperature data sets to estimate PV array energy output, should introduce over- or under-estimation errors.

Simulations were done in SunSim to verify this, using 5-minute data sets converted into hourly and month-hourly data sets.

From Table 2 it can be seen that for non-maximum power point tracker (MPPT) PV arrays, the use of long-term instead of 5-minute interval data sets over-estimates PV array energy output by, on average, 16% for the locations simulated. Where MPPTs were included in the system, the mean over-estimation decreased to 3%.

Table 2: The influence of the irradiation and ambient temperature data set measurement interval on the PV array energy output estimation, for an optimally positioned fixed array

Location (normalized grade D:A data sets)	*5-min data set*	*Hourly data set*	*Long-term data set*
Calvinia 2001	161.2	167.3 (3.7%)	187.5 16.3%)
Cape Town 2001	150.8	155.4 (3%)	177.6 17.8%)
De Aar 2001	176.2	181.5 (3%)	198.5 (12.7%)
Durban 2001	136.5	139.7 (2.4%)	162.7 (19.2%)
P Elizabeth 2001	160.2	163.7 (2.2%)	185.6 (15.6%)
Polokwane 2001	162.6	170.3 (4.7%)	191.7 (17.9%)
Pretoria 2003	169.9	175.6 (3.4%)	189.0 (11.2%)
Mean overestimation		3.2%	15.8%

Note: All values are in kWh/m^2/year or percent. Long-term data sets are in monthly-hourly format. The PV array was connected directly to a 12V battery without a MPPT.

4. Estimation of optimal fixed PV array tilt angles

Fixed PV arrays (i.e. the panels are fixed into position for the whole year) are typically installed with one of two requirements in mind: either to deliver the highest yearly energy (HYE) e.g. grid-connected PV arrays, or to deliver the highest minimum daily energy (HMDE) through the year e.g. for battery charging purposes.

The differences in PV array energy output through the year for these different requirements are shown in Figure 10 (overleaf). It can be seen that for the HMDE configuration, a higher daily energy is received in the lowest irradiation period in July compared to the HYE, at the cost of a lower total yearly energy.

SunSim estimated the optimal elevation and azimuth angles for fixed PV arrays at HYE and HMDE for different locations, as shown in Table 3. For HMDE calculations a 5-day period moving average filter was applied to the irradiation data set, to simulate a system where batteries would be able to supply the load for 5 days with minimum recharging.

Table 3: Optimal elevation and azimuth tilt angles for a fixed PV array at various locations (latitude South as shown)

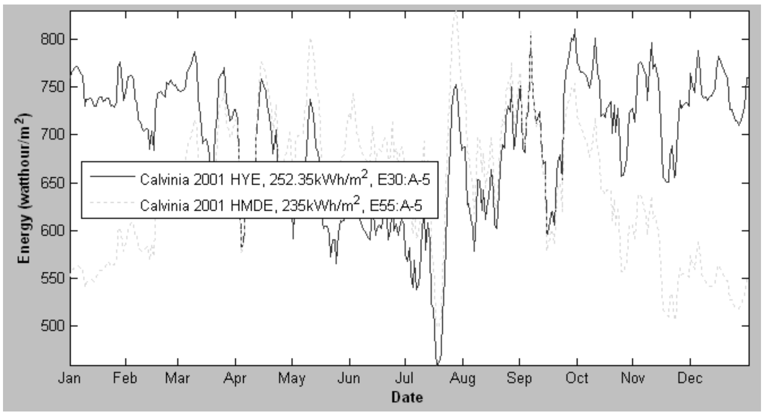
Data set	*Latitude (S)*	*HYE optimal eleva.*	*HYE optimal azim.*	*HMDE optimal eleva.*	*HMDE optimal azim.*
Calvinia 2001	31.5°	30°	-5°	55°	-5°
Cape Town 2001	34.0°	30°	-35°	40°	5°
De Aar 2001	30.7°	30°	10°	40°	5°
Durban 2001	30.0°	30°	10°	20°	30°
P Elizabeth 2001	34.0°	35°	-15°	35°	0°
Polokwane 2001	23.9°	25°	5°	15°	25°
Pretoria 2003	25.7°	30°	10°	10°	20°

Note: Negative azimuth angles imply that the PV array is tilted towards the West.

The results summarized in Table 3 show that the HYE elevation angle can indeed be set to the latitude of the location with reasonable accuracy (the variation in PV array energy output between using latitude or HYE optimal as elevation angle is less than 0.2% for all data sets in Table 3).

From the simulation results, a similar rule-of-thumb appears to apply to the HYE optimal azimuth angle: for locations in South Africa exposed to frontal weather systems (e.g. Cape Town and Port Elizabeth) the azimuth angle can be adjusted towards the West, while for locations exposed to convective precipitation (e.g. Pretoria and Polokwane) the azimuth angle can be adjusted towards the East/morning (thunderstorms tend to build up during the afternoon, with associated loss in irradiation).

However, adjustment of the azimuth from 0° at best resulted in only a 3.6% increase in energy



Note: For HYE/HMDE the optimal fixed tilt angles are elevation = 30/55 and azimuth = -5/-5. HMDE period = 5 days.

Figure 10: Daily electrical energy from PV array for Calvinia 2001, for two requirements: HYE and HMDE

(Cape Town HYE), with less than 0.5% increase for most of the data sets, and are therefore, not of much practical use.

Finally, no trends could be found from the HMDE elevation angle results for different locations in South Africa, disproving the general wisdom that the elevation angle should be tilted a further few degrees from latitude towards vertical for HMDE, as recommended in e.g. Cowan et al. (1992).

5. Comparison of different array solar-tracking configurations

Simulations compared the PV array energy output between the following solar-tracking setups:

- E0:A0 - Fixed horizontally. All PV array output energies are compared to this baseline.
- Eopt:Aopt – Fixed at optimal HYE tilt angles.
- Eadj:Aopt – Elevation angle is adjusted twice yearly at equinox (20 March and 23 September) to compensate for the change in solar declination angle (23°/-23°). Azimuth fixed at optimal HYE.
- Etrd:Aopt – Elevation angle tracks the declination angle of the sun through the year (note: not the zenith angle. Declination = noon zenith angle). Azimuth fixed at optimal HYE.
- Etr:Aopt – Elevation angle tracks the zenith angle of the sun through the day. Azimuth fixed at HYE.
- Etr:Atr – Both the elevation and azimuth angles track the sun through the day and year.

The results of the simulations are shown in Table 4, and clearly illustrate the impact of different solar-tracking configurations on PV array energy output compared to the fixed horizontal baseline.

Of special interest is the fact that, while adjusting the elevation angle of an already optimally fixed PV panel twice yearly increases the energy output by almost 5%, further daily adjustments to the elevation angle only increase the energy output by another 1%.

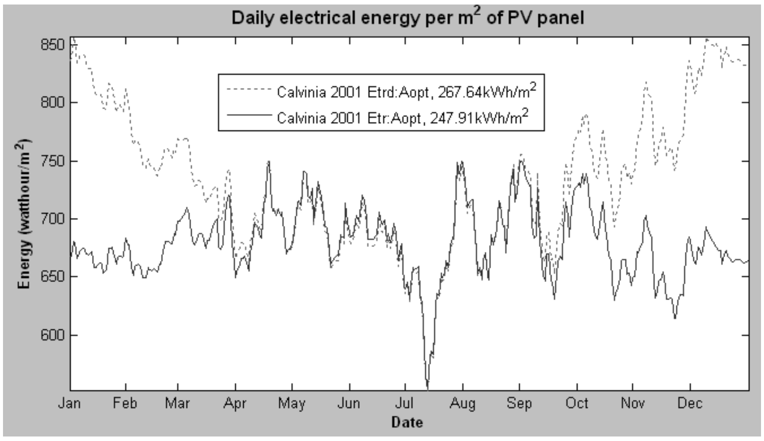
Table 4: Comparison of the PV array energy outputs for different array solar-tracking configurations, using mono-crystalline Si PV panels with MPPT

Data set	*Eopt: Aopt:*	*Eadj Aopt*	*Etrd: Aopt*	*Etr: Aopt*	*Etr: Atr*
Calvinia 2001	252 12.7%	266 19%	268 19.6%	248 10.7%	353 57.6%
C Town 2001	236 14.7%	238 15.9%	242 17.9%	238 15.7%	300 46.2%
De Aar 2001	262 13.9%	277 20.4%	278 21%	259 12.5%	331 43.9%
Durban 2001	198 13.4%	206 18%	207 18.9%	197 13.1%	232 33.2%
P Elizabeth 2001	226 15.2%	235 19.9%	237 20.8%	225 14.8%	274 39.6%
Polokwane 2001	1235 9.8%	247 15.7%	249 16.3%	230 7.6%	322 50.9%
Pretoria 2003	238 11.1%	249 16.1%	250 16.9%	235 9.5%	313 46.2%
Mean %	13%	17.9%	18.8%	12%	48.3%

Note: All values are in kWh/m^2/year or percent. Percentage values indicate the increase of energy using the specific tracking configuration compared to a fixed E0:A0 panel.

The result showing that declination elevation tracking gives almost 7% more energy than zenith elevation tracking is at first glance counter-intuitive, and was investigated in more detail.

As shown in Figure 11, zenith tracking contributes slightly more energy towards the yearly total than declination tracking in winter, but significantly less in summer. The explanation for this is found in Figure 12, which plots the incidence angle of the



Note: The graphs were smoothed with a 9-day moving average filter.

Figure 11: Daily electrical energy for elevation tracking of the declination and zenith angles, with azimuth fixed at HYE optimal

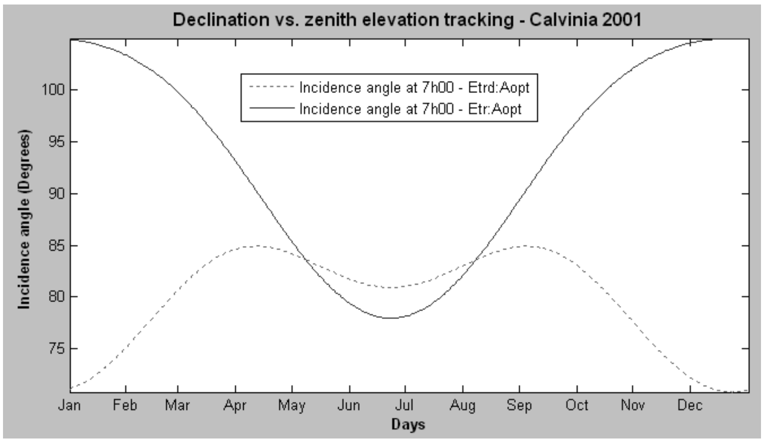


Figure 12: The incidence angle at which irradiance falls on the PV panel at 7h00 daily, for elevation tracking of the declination and zenith angles, with azimuth fixed at HYE optimal

sun's irradiance on the panel, increasing dramatically in summer using zenith instead of declination tracking.

6. Estimation of PV array energy costs

Accurate estimation of the yearly energy available from PV panels makes it possible to estimate the lifecycle cost of PV energy. For the lifecycle energy cost (Rands per kWh) estimations presented in this section, typical 2006 South African PV system costs (assuming a $10kW_{peak}$ system for economy of scale) were used, shown in Table 5 below. A net discount rate of 8%, a life cycle period of 20 years, monocrystalline PV panels and MPPT inverters were assumed unless otherwise stated. Furthermore, it was assumed that inverters would be replaced every 10 years.

The estimated Rand per kWh costs shown in Table 6 for a variety of locations in South Africa were calculated by converting all costs during the lifecycle of the system to their present values, and dividing the resulting present value cost by the amount of energy generated during the lifecycle period.

From Table 6, it is clear that the solar-tracking configuration of the PV array does not have a profound influence on the cost of energy produced by the array, as the higher energy output of a solar-tracking array appears to be balanced out by the additional structural and O&M costs.

The overestimation of yearly energy output when using long-term data sets, discussed in section 3.2, offers a potential explanation of the difference in costs (4 to 12%) between Cape Town 2001 (five-minute data set) and Cape Town long-term.

As can be seen in Table 7, the discount rate used over a 20-year life-cycle period does not significantly influence the estimated PV energy generation cost. This result is to be expected, given that the initial capital investment far exceeds the recurring expenditure for a typical PV array.

Table 5: Description of costs used in the SunSim simulations

Description	*Cost per kW_{peak}*
Panel cost (thin film)	R31300
Panel cost (mono-crystalline)	R36000
Panel cost (Sanyo HIT)	R38000
Panel cost (poly-crystalline)	R35100
Panel cost (3-junction amorphous)	R33100
Transport and installation	R4000
Structure (Eopt:Aopt)	R500
Structure (Eadj:Aopt)	R2000
Structure (Etr:Aopt)	R4000
Structure (Eopt:Atr)	R5000
Structure (Eadj:Atr)	R6000
Structure (Etr:Atr)	R9000
O&M (Eopt:Aopt)	R2600 per year
O&M (Eadj:Aopt)	R2600 per year
O&M (Etr:Aopt)	R2600 per year
O&M (Eopt:Atr)	R4600 per year
O&M (Eadj:Atr)	R4600 per year
O&M (Etr:Atr)	R4600 per year
Wiring, fuses etc.	R1000
Basic inverter	R4000
MPPT inverter	R8000

Table 6: Rand per kWh costs of PV energy for a variety of locations in South Africa

Data set	*Eopt: Aopt MPPT (R)*	*Eopt: Aopt no MPPT (R)*	*Eadj: Aopt (R)*	*Etr: Atr (R)*
Calvinia 2001	1.79	2.56	1.72	1.72
Cape Town 2001	1.91	2.74	1.93	2.02
De Aar 2001	1.72	2.34	1.66	1.66
Durban 2001	2.28	3.03	2.23	2.45
P Elizabeth 2001	1.99	2.58	1.95	2.05
Polokwane 2001	1.92	2.54	1.86	1.89
Pretoria 2003	1.89	2.43	1.85	1.94
Upington long-term	1.68	2.36	1.62	1.62
C Town long-term	1.82	2.19	1.78	1.77

Note: O&M represents the operations and maintenance costs. A net discount rate of 8%, a life cycle period of 20 years, mono-crystalline PV panels and MPPT inverters were assumed.

Table 7: The influence of change in discount rate on PV energy generation costs per kWh

Data set	*Net discount rate = 4%*	*Net discount rate = 8%*	*Net discount rate = 12%*
De Aar 2001	R2.01	R1.72	R1.55

Note: Simulated using the De Aar 2001 data, a life cycle period of 20 years, mono-crystalline PV panels and MPPT inverters.

If PV arrays are stolen, the lifecycle period decreases, which in turn, increase the PV energy generation cost drastically. This is shown in Figure 13.

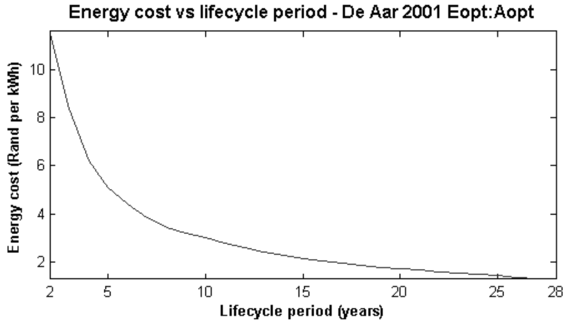


Figure 13: PV energy generation cost as a function of the lifecycle period, simulated using the De Aar 2001 data, a discount rate of 8%, mono-crystalline PV panels and MPPT inverters

The simulation results in Figure 14 indicated that of the five different silicon-based PV panel technologies compared, thin-film silicon offers the lowest cost per unit of energy generated.

It should be noted, though, that the simulation assumed that the power output of all five technologies would not degrade over the 20-year period simulated. The accuracy of this assumption is debatable, e.g. in the case of amorphous silicon PV panels.

7 Conclusions

SunSim was developed to answer a number of research questions posed in the Introduction of this paper. All of these questions were answered, with the following results deserving attention:

- The accuracy and resolution of South African irradiation data varies significantly, necessitating an irradiation data classification system. Such a system was proposed in this paper.
- Recent 5-minute interval irradiation data from the SAWS appears to be inaccurate, and needs to be normalized to existing accurate long-term data before use.
- Although the satellite-derived irradiation data used by the popular RETScreen package is accurate, RETScreen underestimates the global radiation on a tilted plane by between 6 and 8% compared to SunSim. This is due to the use of a basic isotropic diffuse model instead of the more accurate Perez model.
- For non-MPPT PV arrays, the use of long-term instead of 5-minute interval data sets over-estimate PV array energy output by on average 16%. This decreases to 3% where MPPTs were included in the system.
- No trends could be found from the highest minimum daily energy (HMDE) through the year elevation angle results, disproving the general

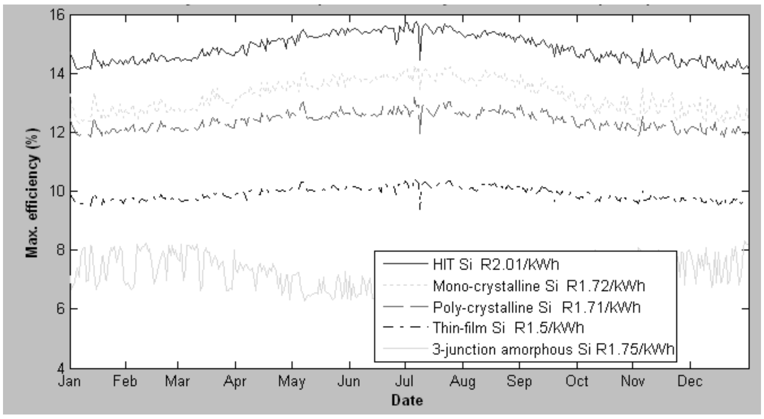


Figure 14: Daily maximum PV panel efficiency through the year for a fixed PV array using De Aar 2001 data, for five different silicon PV panel technologies

wisdom that the elevation angle should be tilted a further few degrees from latitude towards vertical for HMDE.

- PV energy costs for PV arrays fixed at optimal tilt angles, excluding battery costs, varied from R1.72 to R2.28 per kWh (De Aar 2001 and Durban 2001 data), and are relatively insensitive to different discount rates.
- If a PV array's lifecycle period is decreased, e.g. due to theft, the energy cost increased dramatically (R6 per kWh for a 4-year lifecycle period)
- Silicon thin-film appears to be the most cost effective PV panel technology, and HIT silicon panels the least.

The simulation results contained in this paper have the potential to contribute towards increasing the quality of scientific and financial data available to rural electrification decision makers in South Africa, thereby satisfying the aims for which the SunSim simulation package was developed.

Acknowledgements

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