How accurate can PV energy yield simulations be?

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Introduction

Commercially available sizing programs use a variety of algorithms to estimate the energy yield of a solar array at a given site with defined orientation and which contains specified types and numbers of PV modules and balance of systems components [1].

The programmes use many user-defined inputs such as dirt loss factor, wiring resistance, thin film degradation factor etc. that rely on either site knowledge, the experience of the designer with the different components or just best guesses.

These sizing programmes will usually calculate hourly weather data series, dc PV performance, inverter and BOS losses and finally give a yearly sum of ac final yield kWh/kWp (YF) and performance ratio (PR) where PR = YF/YR where YR = insolation.

Often the measured PR data comes close to the predicted values. But do the programs model everything correctly? Or are there so many unknowns that the predictions and output happen by chance to coincide to within a few %?

This paper lists and estimates some of the errors and unknowns in many of the different variables and shows how they impact on the kWh/kWp predictions. Models are compared with field data and suggestions made on how to improve their usage.

Array kWh

The kWh produced by an outdoor array is calculated as the sum of instantaneous power (ideally measured at least several times an hour) or by a cumulative energy counter over a period usually of a year.

The instantaneous power will depend on many parameters including: -

- actual Pmax of the array (W)
- plane of array (POA) irradiance Gi (kW/m²)
- module temperature Tmod (C)
- inverter efficiency
- max power point tracking losses
- dc, BOS and other losses

Weather and electrical measurements

The irradiance should be measured in the plane of array by pyranometers or reference cells. Pyranometers have a flatter spectral response than PV cells and therefore the array efficiency may appear to have a spectral sensitivity, they may also have different angle of incidence effects. If irradiance is measured with reference cells then these will need to be calibrated. For thin film (TF) devices (often with stability and annealing effects) it is more usual to calibrate a crystalline Si cell filtered to mimic the spectral response (SR) of the TF module.

If the light levels are only measured in the horizontal plane then there are complicated calculations to estimate the POA irradiance, some sites also only use the nearest meteorological site which could be many km away and therefore could have quite different weather patterns.

Temperatures will be measured by thermocouples either shaded behind the module as ambient temperature (Tamb) or fixed to the back of the module as module temperature (Tmod).

It is useful to check the MPP tracking by monitoring the DC string voltage (but this is rarely done).

The inverter output will give the instantaneous AC power or will be some form of cumulative energy value.

Calculation steps in sizing programs

Most sizing programs use calculation steps as described below [1]: -

- Locate nearest meteorological data in its database (usually horizontal plane monthly insolation averages)
- Use stochastic Markov transition matrices to generate a pseudo random horizontal plane irradiance chains with time Gh(t).
- Calculate clearness index kT = Gh(t)/Xh(t) where Gh(t) = horizontal irradiance and Xh(t) = irradiance expected from solar

geometry assuming no atmospheric attenuation and scattering
- Use a lookup function to estimate the irradiance fraction direct = Bh(t) and scattered/diffuse = Dh(t) light.
- Estimate tilted plane irradiance Gi(t) from the angle of incidence of the tilted modules with the sun and the diffuse part of the sky
- Lookup nominal PV parameters (e.g. Imax, Vmax, NOCT, temperature derating factors etc. from a module database)
- From the PV mounting method estimate the module temperature Tm(t) (from ambient, POA irradiance and wind cooling)
- Generate the Imax and Vmax expected of the PV from the irradiance and module temperature.
- Calculate DC losses (from dirt, wiring, shading etc.)
- Estimate AC losses (Vmpp mistracking, limits, turn on, inverter efficiency etc.)
- Generate AC Output power values
- Sum over the year to give the kWh/y

Unknowns

The weather data may well be different from the site in the reference database (particularly if it is not very close), also there will be variability of yearly weather data year to year (often found to be ±4% from NREL 30 year data) and drift in the calibration of the reference sensors which in any case are normally ~±3% accuracy.

PV calibration laboratories only guarantee their reference module measurements (which manufacturers often use to calibrate their flash testers) to ~ ± 2%.

Manufacturers usually supply PV modules in ~10Wp bin widths (e.g. a variation in Pmax might be from 200-210Wp) meaning that there can be a variation between the best and worst modules in a band of ±2.5%.

There will also be degradation and annealing to consider, most manufacturers guarantee Pmax to something like 80% of initial Pmax after 20 years (i.e. 1% loss per year) – thin films will often degrade and anneal somewhat with the seasons making it impossible to know the exact Pmax of an array.

With long lifetimes of arrays expected of 25 years plus there can be loss due to vandalism, theft, hailstorms, wind damage or falling debris and so replacement modules will need be added – it is unlikely after several years that the manufacturers will be able to make identical replacements as they may have improved their efficiencies and increased their module sizes so step changes in performance will be seen when parts of the array are changed.

Inverters are modelled using their spec sheet values (i.e. mpp voltage limits, efficiency vs. Pin) but these do not yet characterise all of their sensitivities – for example efficiency vs. input voltage [3] and Inverter temperature [4] and therefore these are not modelled correctly.

Real data examples

There are many freely available measurements from data logged arrays around the world on the internet.

Two examples from the USA are shown in Fig 1 (seven years of a thin film 2J a-Si) and Fig 2 (three complete years for a sc-Si array).

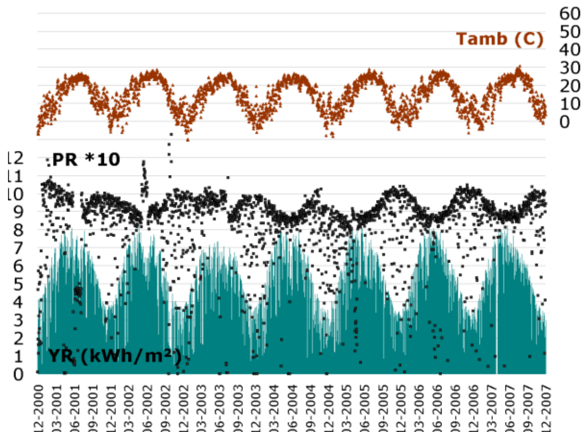

Fig 1: Seven years of daily performance of a thin film array in the USA.

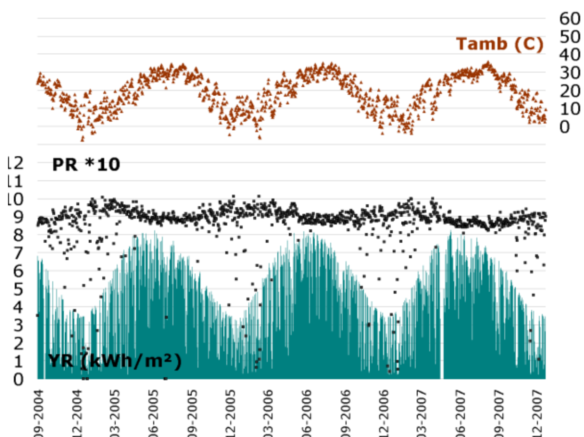

Fig 2: Three complete years of daily performance of a c-Si array in the USA.

Tamb plotted (right y-axis) is the daily average ambient temperature (from dawn to dusk), YR is the daily sum POA irradiance Gi in kWh/m²/d. PR*10 shows the performance ratio PR (which is just scaled by 10 to fit the graph).

Both graphs clearly show the repeating seasonal changes in temperature and insolation with maximum winter values of 3 peak hours and summer nearer 7, Tambient varies from 0C to 30C.

The daily performance ratios for the thin film site according to the data appear to vary from 85%(summer) to 100% (winter). For the crystalline array the performance ratio is almost constant at 90% for the first two years. (Note that PR for a well performing array with correct Pmax declarations will more usually be in the range 75-85% indicating some possible inconsistency in these measurements.)

As this is 3rd party data from the internet the calibrations used, types of irradiance sensors, accuracy of electrical measurements etc. are unknown. However it is an example of the measurements that might be compared with sizing program outputs.

Fig 1 shows a slightly falling minimum summer PR with approximately constant maximum winter PR – perhaps there is some stabilisation, worsening the winter performance.

Although most of the PR values are on a narrow band there are quite a few well outside this range, some can be due to snow coverage; clumps of points (45% for Fig 1) indicate a partial failure of the system (perhaps some of the strings or inverters being down that then was corrected) and a time of above average performance (100-120%), perhaps there was a problem with the irradiance sensor.

Fig 3 gives the sums of the yearly data for the two arrays showing the variability of YR, YF and PR.

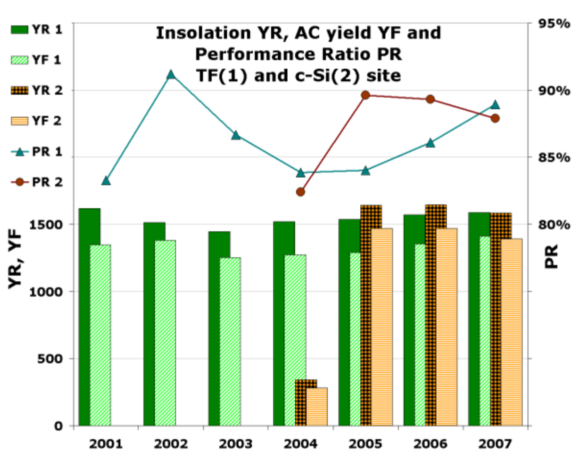

Fig 3: Yearly data from the arrays in Figs 1 and 2.

The variability in the yearly data implies that we can't just take simple sums of kWh produced to compare with models and that every data point needs to be checked for accuracy and then removed or corrected if thought to be wrong – even then there will be yearly variations.

Sensitivity to measurement frequency

Hourly weather predictions usually overestimate the importance of low light level radiation as there are often periods of erratic weather of bright and dull periods, which would be averaged together in hourly data [2]. During erratic weather the PV performance is dominated by the bright periods (where irradiance can be 20% or more above the value expected in clear skies due to extra reflections by bright clouds – called the "edge of cloud effect") whereas the PV temperature will be up to 10C lower than expected as the modules cool when under low irradiance in diffuse conditions.

PV efficiency vs irradiance

Most simulation programs have an "efficiency vs irradiance" curve for each module type [1]. (Efficiencies are usually measured under flash simulators under STC conditions i.e. normal angle of incidence irradiance, AM1.5, 100% direct beam and at 25C.) The following are examples of efficiency vs irradiance curves that are used in different sizing program models.

A lookup table often from a module spec sheet with efficiencies at different light levels from 200-800W/m².

Values of Vmax and Imax at "high" and "low" light levels and then interpolate a curve between just two points (although at least 3 points are required for a curve)

An equivalent circuit model. A 2-diode model is needed for best accuracy (modelling recombination at the junction and in the bulk). The second diode usually reduces the current at the Pmax point, meaning that a 1-diode model will not be able to reproduce the shape of the IV curve.

Measurements on crystalline modules often show better performance under low light real conditions than these programs suggest [1].

Comparing correlation of input variables

In reality modules are almost never at normal irradiance, usually Air Mass AM is >1.5, there is always a diffuse component and the temperature is above 25C for the majority of the time.

Indoor tests try to characterise performance by separating the effects of temperature and irradiance (for example measuring efficiency vs. irradiance at a constant temperature, then efficiency vs. temperature at a given irradiance). However under real conditions all meteorological parameters are correlated. For example when the irradiance is very high then the temperature will tend to be high as well, also the angle of incidence of the sun will tend to be near normal, the sky will be blue and the diffuse irradiance component low.

This means that any attempt to understand the outdoor performance versus one of these parameters will necessarily involve the others.

Programs cannot be validated just on their kWh/kWp predictions; there are many different unknown input variables that can compensate for each other.

Variabilities in kWh/kWp

The definition of PR is

$$PR = \frac{YF}{YR} = \frac{\text{AC yield}}{\text{POA insolation}} = \frac{kWh/kWp}{kWh/m^2}$$

e.g. if the Insolation YR was 1000kWh/m² and the final yield YF was 780kWh/kWp then PR = 780/1000 = 78%. Note all other units for efficiency, area etc. cancel out as lower efficiency modules have larger areas to collect light for the same nominal maximum power.

We can simply rearrange equation <1> to be

$$kWh = PR * (YR) * (kWp) \qquad <2>$$

Where some of the errors mentioned are given below: -

{1} PR: unknown downtime, ±1% dirt (but may affect sensor too and will be worst in best weather)
{2} YR: ±2% pyranometer calibration, ±4% year-by-year variance,
{3} Pmax: ±2% reference module calibration, ±2.5% module band, ~-1%/year degradation

Even correcting for the 4% year by year variation and setting the dirt to 0% there is still a possible 2+2+2.5=±6.5% variation due to measurement inaccuracy alone.

Conclusions

Several large unknowns have been identified explaining some variabilities in array performance.

Comparisons of ac logged data with commercial sizing programs show inaccuracies in the way the sizing programs determine hourly POA irradiance and poor modelling of PV modules performance particularly in low light level response.

Sizing programs should be used more to design and check monitored systems to not have large avoidable losses. The accuracy of sizing program predictions depends on each modelling stage and will never be better than the unknown input variables.

References

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[3] MPP Voltage Monitoring to Optimise Grid Connected System Design Rules http://www.ntb.ch/Pubs/sensordemo/pv/2004_06_mppv_baumgartner_paris.pdf

[4] “Sicherheitsaspekte bei dezentralen netzgekoppelten Energieerzeugungsanlagen - SIDENA - Abschlussbericht - Wissenschaftliche und technische Projektergebnisse”

Acknowledgedements

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