Assessment of a Solar PV Re-Powering Project in Sweden Using Measured and Simulated Data
Abstract

Re-powering solar PV plants is an upcoming discussion on the global stage. Although the respective component warranties indicate the time to change the system machinery, the methodology and justification for carrying this out are two aspects that need further study.

The rooftop solar PV system on top of Dalarna University was re-positioned in 2014. Prior to installing the system in its new position, the system arrays were reconfigured and new inverters were installed.

This thesis aimed to compare and analyze two sections of the solar power plant to understand which amongst them performs better. Graphs depicting energy, current, voltage and other parameters were formulated to ascertain the efficacy of the array configurations for this Nordic latitude.

Thereafter, PVsyst and SAM were used to compare the simulated results with the actual output from the system.

It was found that the measured energy output from one section of the solar power plant was higher than that of the other during 2014. On an annual basis, this difference was 21.5 kWh or 2%. On closer inspection, this contrast was attributed to a difference in yield early in the morning.

Further, PVsyst simulated the annual energy with a deviation of less than 1% than what was measured, whereas SAM measured a deviation in energy measurement of 2.5% higher than the actual measured energy. These values were obtained using the detailed design options for both softwares. A point to keep in mind is that prior experience of working with both these softwares is recommended prior to carrying out the simulations on these softwares.

An underlying point to note in this study is its limitations. This study is valid in the northern latitudes, such as the Nordic climates, since other regions would not have such low (sub-zero) temperatures to account for while sizing the inverter. In regions of high irradiance, a system re-powered in a way such as the system in this case would have higher clipping losses.

Relevant previous studies and related topics have been visited, summarized and cited.
Acknowledgment

First and foremost, I would like to truly thank Marco Hernandez Velasco, under whose supervision I have undertaken this project. I am extremely grateful that he accepted me to work under him. Without his advice, guidance and patience, it would have been difficult to give shape to this thesis. Next, I would like to express my humble appreciation to Désirée Kroner for helping me shortlist the subject of my thesis. I am very thankful for her continuous support throughout my year at Dalarna University.

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Contents

1 Introduction ................................................................................................................. 6
  1.1 Solar PV .................................................................................................................... 6
  1.2 Motivation for undertaking this thesis ................................................................. 6
    1.2.1 Repowering ........................................................................................................ 7
    1.2.2 Sub-string configuration ................................................................................. 7
  1.3 Aim ............................................................................................................................ 8
  1.4 Need for a software to repower a solar PV plant .................................................. 8

2 Background .................................................................................................................. 9
  2.1 Previous work ......................................................................................................... 9
  2.2 PVsyst ..................................................................................................................... 10
  2.3 SAM ....................................................................................................................... 10
  2.4 The reference power plant - DU PV system and its evolution ............................ 12
  2.5 Reference yield (Y_r) vs final PV system yield (Y_f) .............................................. 14

3 Methodology ................................................................................................................. 15
  3.1 Key software input parameters .............................................................................. 15
    3.1.1 Location and weather data ............................................................................. 15
    3.1.2 Inverter ............................................................................................................. 16
    3.1.3 System losses .................................................................................................. 16
    3.1.4 Shading .......................................................................................................... 17
    3.1.5 System design .................................................................................................. 17
  3.2 PV Module .............................................................................................................. 18

4 Results .......................................................................................................................... 20
  4.1 PVsyst vs SAM ...................................................................................................... 20
    4.1.1 Energy comparison ......................................................................................... 20
    4.1.2 Hays and Davies Model vs Perez-Ineichen model ........................................ 23
    4.1.3 Simulation summary ..................................................................................... 25
  4.2 Array 1 vs Array 2 .................................................................................................. 25
    4.2.1 Energy analysis ............................................................................................... 25
    4.2.2 I-V curve .......................................................................................................... 28
    4.2.3 Irradiance vs module temperature and wind speed ....................................... 29
    4.2.4 MPP voltage versus DC power ..................................................................... 30
    4.2.5 AC power versus inverter efficiency .............................................................. 31
    4.2.6 Reference yield (Y_r) vs final PV system yield (Y_f) ....................................... 32
  4.3 Uncertainty and error analysis .............................................................................. 33
    4.3.1 Input errors ...................................................................................................... 33
    4.3.2 Data-acquisition (measurement) errors ......................................................... 34
    4.3.3 Data processing errors .................................................................................. 35

5 Discussions and conclusion ......................................................................................... 37

6 Future Work ................................................................................................................. 38

Appendices ....................................................................................................................... 41
  Appendix 1 .................................................................................................................... 41
  Appendix 2 .................................................................................................................... 42
  PVsyst inputs ............................................................................................................. 42
  Appendix 3 .................................................................................................................... 48
  SAM inputs ................................................................................................................ 48
  Appendix 4 .................................................................................................................... 52
  Hays versus Perez model comparison ..................................................................... 52
  Appendix 5 .................................................................................................................... 53
  Inverter datasheet ..................................................................................................... 53
  Appendix 6 .................................................................................................................... 55
  PVsyst simulation reports ......................................................................................... 55
Appendix 7

SAM simulation reports
# Nomenclature

<table>
<thead>
<tr>
<th>Abbreviations</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Array 1</strong></td>
<td>Array 1 of DU's solar PV system</td>
</tr>
<tr>
<td><strong>Array 2</strong></td>
<td>Array 2 of DU's solar PV system</td>
</tr>
<tr>
<td><strong>GPVM</strong></td>
<td>Gallivare PhotoVoltaic AB, PV module manufacturer in Scandinavia</td>
</tr>
<tr>
<td><strong>DU</strong></td>
<td>Dalarna University, Borlänge Campus</td>
</tr>
<tr>
<td><strong>IEA</strong></td>
<td>International Energy Agency</td>
</tr>
<tr>
<td><strong>I_{mpp}</strong></td>
<td>Current at maximum power point</td>
</tr>
<tr>
<td><strong>I_{sc}</strong></td>
<td>Short circuit current</td>
</tr>
<tr>
<td><strong>ISO</strong></td>
<td>International Organization for Standardization</td>
</tr>
<tr>
<td><strong>LCOE</strong></td>
<td>Levelized Cost of Electricity</td>
</tr>
<tr>
<td><strong>MPP</strong></td>
<td>Maximum Power Point</td>
</tr>
<tr>
<td><strong>P_{max}</strong></td>
<td>Maximum power point</td>
</tr>
<tr>
<td><strong>POA</strong></td>
<td>Plane of Array</td>
</tr>
<tr>
<td><strong>PR</strong></td>
<td>Performance Ratio</td>
</tr>
<tr>
<td><strong>PV</strong></td>
<td>Photovoltaic</td>
</tr>
<tr>
<td><strong>PVsyst</strong></td>
<td>Simulation software</td>
</tr>
<tr>
<td><strong>SAM</strong></td>
<td>National Renewable Energy Laboratory’s (NREL) System Advisory Model</td>
</tr>
<tr>
<td><strong>STC</strong></td>
<td>Standard Test Conditions</td>
</tr>
<tr>
<td><strong>VAT</strong></td>
<td>Value Added Tax</td>
</tr>
<tr>
<td><strong>V_{mpp}</strong></td>
<td>Voltage at Maximum Power Point</td>
</tr>
<tr>
<td><strong>V_{oc}</strong></td>
<td>Open circuit voltage</td>
</tr>
</tbody>
</table>
1 Introduction

1.1 Solar PV

It is an established fact that the sun’s energy creates heat and light. However, in addition, it can also be used to generate electricity. This electricity that is derived from the rays of the sun is referred to as solar energy.

One of the technologies used to convert the sun’s energy to electricity is called solar photovoltaics, commonly called solar PV. [1]

The term PV gets its name from the PV effect, which is the process of converting light (photons) to electricity (voltage). The PV effect was discovered in 1954 when scientists at Bell Telephone discovered that silicon (an element found in sand) created an electric charge when exposed to sunlight. This led to the birth of solar PV technology that in present day uses solar PV panels to convert the sun’s rays into usable electricity. [2]

1.2 Motivation for undertaking this thesis

The Swedish Energy Agency expects solar PV to contribute 4TWh in 2020, scaling up to 32TWh of energy by 2050. [3]

According to [4] a total of 47.4MWp of solar PV capacity was installed as of 2015, a growth of 31% as compared to the previous year. This then put the cumulative grid-connected capacity at 115.7MWp, at the end of the year 2015. In a nutshell, a total number of 126.8MWp was achieved considering both the off-grid and grid-connected capacities. This increase in capacity was attributed to declining system prices and availability of a capital subsidy among other reasons.

An interesting investment parameter to look at for this scenario is the levelized cost of electricity (LCOE). Inclusive of the Swedish value added tax (VAT) of 25%, the investment cost was about 18.75 SEK/W for a typical residential installation at the end of 2015. This led to an LCOE of 1.09 SEK/kWh. This number is of interest since it is comparable to the variable part of the consumer electricity price and compensation of excess electricity in Sweden. [4]

The global PV market, on the other hand, broke several records in 2015. The cumulative PV installed capacity grew by 25% at 50 GW. The Chinese market grew to 15.2GW while Japan reached 11GW. India’s installed PV base was hovering around the 2GW mark whereas Turkey was at 208MW. The European PV market propelled thanks to the United Kingdom that installed 3.5GW in 2015. The other top markets were Germany at 1.5GW, France at 0.9GW and Italy installed 300MW in 2015. [5]

In general terminology, solar plants have a lifetime of twenty-five to thirty years. However, this is not the entire truth. Different components of a solar PV plant have different life spans. PV modules are generally accepted to perform for twenty-five to thirty years while inverters may need to be changed once every six to nine years.

In the early 1990s, commercial solar installations took off with the 500kWp solar PV installation in California, USA by Pacific Gas & Electric, which was one of the first grid-connected PV installation. Since then, many solar PV plant components have gone past or are nearing the end of their effectiveness. Therefore, the global solar installation boom and the end-of-life of many solar plants that have already been installed, makes this thesis work relevant. [6]
1.2.1 Repowering

Repowering of a solar PV plant refers to replacing the inverters, adding DC-DC optimizers or in certain cases replacing the PV panels of your solar plant. Repowering may be done when the life of the components mentioned above is towards the end of its warranty tenure. Alternately this could also be a necessity because of faulty components. The theoretical advantages of replacing the equipment include increase in energy yield due to better tracking of your IV array input values. [7]

Since the solar energy boom began in Sweden in the early 2000’s, this year and the time going forward will require a repowering decision for an increasing number of solar PV plants. However, with solar modules still functional the practical approach might be to retrofit the equipment and keep the plant working.

1.2.2 Sub-string configuration

1.2.2.1 Sub-string

A set of solar cells or PV modules connected in series is called a ‘string’ [8]. The discussion regarding solar PV plants on a string level can be referred to as the discussion on a sub-string level.

The importance of this examination is crucial since the arrangement of modules within strings decides the string voltage or the string current. More specifically, the number of modules in series decides the string current, while the number of strings connected in parallel decides the voltage of that array.

1.2.2.2 Inverter sizing

The power rating and total number of inverters are determined by the overall power of the solar PV array. The solar array has to be optimally matched to the corresponding inverter(s), specifically to each other’s output values. It is suggested that the nominal power of the inverter be at ±20% of the PV array output (under STC). This is also dependent on the module technology, the inverter selected, the local irradiation values, and orientation of the PV modules. [9]

One point to keep in mind is that the maximum connectable PV power as stated by the inverter manufacturer should not necessarily be trusted. Experience suggests that very high values are stated resulting in the inverter operating in the overload range. Avoidable overload energy losses are the result due to the limitation and eventually premature aging of the components. The inverter’s nominal AC power is the power it can continuously feed into the grid without cutting out at an ambient temperature of 25°C. When optimizing the performance and enabling grid management functions, such as idle power production, a sizing ratio of 1:1.1 can be recommended.

The ratio of PV array power rating (W_p) to the inverter’s nominal AC power is known as the inverter sizing factor. [9]

\[
SR_{AC} = \frac{P_{PV}}{P_{INV_{AC}}} 
\]

Equation 1.1

The inverter’s capacity utilization is expressed using this sizing factor. A range from 0.83 to 1.25 (not including those numbers) is a typical sizing factor. Although a recommended \( SR_{AC} \)
is 0.9. Furthermore, studies have shown that $SR_{AC}$ of 1.1 to 1.2 leads to additional losses of 0.5% to 1% compared to a sizing of 1:1. The reason for these losses is because the inverter switches off during instances of low irradiance. Sizing factors of 1.2 to 1.3 resulted in additional losses ranging between 1% and 3%. [9]

1.3 Aim

The aim of this thesis is to assess Dalarna University’s (DU) two solar PV arrays (Array 1 and Array 2) and ascertain which repowered configuration performs best in this specific latitude.

To achieve the above objective, first, simulations will have to be carried out using two softwares, PVsyst (version 6.5.3) [10] and NREL’s SAM (version 2016.3.14) [11].

Thereafter, measured electrical system values for the one-year duration from April 2014 to March 2015 will be studied and compared for Array 1 and Array 2.

1.4 Need for a software to repower a solar PV plant

A brief explanation could be to optimize the future performance of a solar power plant to generate maximum financial returns.

Considering the economical aspect, it is expected that the cost of commercial solar power installations will be at 1.00 to 1.50 $/W by the end of 2017 [12]. Because of the capital-intensive nature of this technology, thorough research is required prior to investment in such a project. Moreover, in case of involvement of financial institutions, it is mandated that a due diligence study of a renewable project is carried out before financial approval. The reports preferred in this case are those generated by simulation softwares such as PVsyst and SAM.

On a secondary level, simulation softwares also readily and quickly forecast energy output of one solar plant with that of similar solar PV plants. Such benchmarking is key information for company investors and is another one of the uses of a simulation software in the solar industry.

A power plant involves multiple components put together. These numerous parts need to be fused together seamlessly to get satisfactory results. To add, optimum land use is also a criterion in most projects and suddenly one has a composite design to be considered. Simulation softwares make such a complex sizing procedure relatively convenient and more importantly quickly return results for the user. As a result, undesirable developments are significantly reduced.

To add, technological advancement through the years results in better system components, innovative inverters and more efficient modules which require modification of the original configuration. Using simulation softwares, therefore, enables an optimal solution in the shortest duration.

The softwares proposed to be used in this thesis work are PVsyst and NREL’s System Advisory Model (SAM).

To better understand which configuration is suitable, two simulation softwares, PVsyst and SAM were used and the system used for the simulations was the solar PV system at DU.
2 Background

2.1 Previous work

Reconfiguration of PV modules is an area of study that has held literary interest. Balato et al. [13], studied how best to maximize the energy output of a PV module across its lifetime by minimizing the severe thermal stresses within it. It was suggested to limit or avoid localized heating phenomena associated with bypass diodes conduction and/or reverse bias operation of PV cells. This was done by reigning in the controllable factors impacting the distribution of operating temperature within the PV module. The controllable factors included the operating voltage and the corresponding operating current. In summary the research states that the lower the localized thermal stresses, the slower the power derating due to aging and therefore the higher the corresponding energy production. In conclusion, by means of reconfiguration of the PV modules’ connections and with the help of an apt objective function, it is possible to identify the optimal configuration and the optimal operating point in any operating condition. [13]

Vazquez et al. [14] presented a degradation model for PV modules to find out the PV module reliability. It was suggested that among other module reliability parameters, the warranty period can be assessed based on PV module degradation in the field. The study goes on to suggest some findings about IEC 61215, which is the standard most commercial crystalline silicon PV modules are qualified with. The study adds that IEC 61215 tests are not reliability tests but can provide some information on reliability. In conclusion is was said that the annual degradation rate for crystalline silicon PV modules ranges from 0.3 to 3% and seems to be constant during the wear out period. [14]

One of the longest operational solar PV plants in Sweden was commissioned in 1984 in Huvudsta, Stockholm. This 2.1 kWp installation consists of 48 polycrystalline Kyocera modules. Palmblad et al. [15] evaluated the degradation of these modules. On visual inspection, it was observed that even after twenty-three years of operation, these modules displayed no visual signs of defects. Measurements conducted on the system concluded that the array showed a 2% reduction in peak power compared to measured values during installation. [15]

Janssen [16] analyzed the two sub-systems (Solvex and Sunways) independently so as to compare their performance. It was estimated that the power degradation of the PV modules in the system was less than 10%. Further, the degradation in short circuit current was known more accurately to be near 7%. In parallel, I-V curves of two PV modules were compared. The first was a single PV module from one of the sub-systems while the second was a reference module from the same model and manufacture year which had only received light use. No notable difference was observed between the two modules.

In the early 2013, the DU system was reconfigured. The earlier sub-systems of 1.8 kWp (Solvex) and 1.4 kWp (Sunways) were reconfigured into identical arrays of 1.6 kWp each. The new arrays were called Array 1 and Array 2. The two inverters were replaced by two identical 1.2 kW rated SMA Sunnyboy 1200 inverters. Further, the system was repositioned because of the shadow from the newly constructed wing of the university that was falling onto the arrays.

Khan [17] and Khajehalijani [18] conducted studies on the newly configured system. Khan [17] found that the average daily value of degradation was 11.5%. This value was in contrast to the value suggested in previous thesis work in 2010 which was less than 10%. In addition, the average daily system efficiency was found to be 6.8% and for Array 1 while it was 7.2%
for Array 2. In comparison to the old system, the average daily system efficiency was 7.1% for Sunways subsystem and 6.5% for Solwex's subsystem.

Khajehalijani [18] evaluated an I-V curve tracer by measuring performance of PV systems in Sweden. DU system was one of the systems measured wherein I-V curves of each string were analyzed. It was further observed that possible defects and common failures such as short-circuited bypass diodes, burnt solar cells, mismatch losses, and hotspot etc. can be recognized from the form of I-V curves. Further, the degraded electrical parameters of the PV modules were measured and tabled.

Baranger [19] analyzed and compared the performance of DU’s grid-connected solar PV system to previous configurations. The objective of the study was also to ascertain the benefit of the system, re-configured in 2014, under low irradiance conditions. Further, under low irradiance (0 to 200 W/m²), it was observed that inverter of Array 1 begins operating at 37 W/m² on a daily average in March and April 2014, whereas the inverter of Array 2 begins operating at an irradiance level of 126 W/m². Since the performance ratio can be said to be a measure of the efficiency of a PV system, for 2014, it was found that Array 1 performed slightly better than Array 2 below 500 W/m². Whereas Array 2's performance ratio was higher at irradiance values above 600 W/m². It was concluded, first, that Array 1 produces 1% more energy at irradiance level of less than 200 W/m². Second, that the efficiency of inverter of Array 1 is 2% higher than that of the inverter of Array 2 as is expected. This is because the voltage of Array 1 is half that of Array 2. [19]

Tesfay [20] evaluated the power degradation of 53 PV modules at DU. The study found an average global power degradation of 11.9%. Similarly, the average short circuit current degradation was found to be 6.4% whereas the average open circuit voltage degradation was found to be 2.5%. The annual median degradation rate of PV modules was calculated to be 0.6% as compared to a related study which indicated a median degradation rate of 0.46% per year. The reason for higher median degradation in modules installed at DU was attributed to possible causes of parasitic resistances, mismatch, ageing, loss of transparency of encapsulant. [20]

2.2 PVsyst

PVsyst is a software used to study and simulate solar PV power plants [21]. Founded by André Mermoud and Michel Villoz and released in the mid-nineties, the software was entirely rewritten in 1999 using the Borland DELPHI 3 platform instead of the older Borland Pascal 7. This helped the software gain in graphical user interface quality, reliability and compatibility with most recent versions of the widely used Windows operating system. [22]

The software was coded to enable the development of PV technology in an optimal and reliable way. In short, it is a tool that allows its user to accurately analyze different configurations and evaluate the results and in the end identify the best possible solution. [21]

2.3 SAM

SAM is a model that focuses on the performance and financial aspects of a renewable project to facilitate decision making. [2]

Originally developed by the NREL in collaboration with Sandia National Laboratories in 2005, SAM was at first utilized by the US Department of Energy’s Solar Energy Technologies Program for solar technology improvement for their internal programs. [23]
<table>
<thead>
<tr>
<th>SN</th>
<th>Parameters</th>
<th>PVsyst</th>
<th>NREL, SAM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Software availability</td>
<td>For purchase/license only (30 day free full evaluation).</td>
<td>Free and accessible to anyone in the world.</td>
</tr>
<tr>
<td>2</td>
<td>Systems that can be simulated / sized</td>
<td>Grid-tie, off-grid, and DC grid. No hybrid grid-tie + standalone.</td>
<td>Grid-tie only for residential, commercial, commercial PPA, Utility Power Producer, No off-grid or hybrid.</td>
</tr>
<tr>
<td>3</td>
<td>Weather data Source</td>
<td>TMY2, TMY3, Meteonorm, ISM-EMPA, Helioclim-1 and -3, NASA-SSE, WRDC, PVGIS-ESRA and RETScreen; user can import custom data in a CSV file.</td>
<td>TMY2, TMY3, EPW, Meteronorm.</td>
</tr>
<tr>
<td>4</td>
<td>Irradiance model</td>
<td>Hay and Davies model (default), Perez et al. model (option).</td>
<td>Perez et al. model (default); Isotropc Sky Model, Hay and Davies model, Reindl model (options); total and beam (default), beam and diffuse (option).</td>
</tr>
<tr>
<td>5</td>
<td>Production-estimating model: Module</td>
<td>Shockley’s one-diode model for crystalline silicon; modified one diode model for thin film.</td>
<td>Sandia model, CEC model, PVWatts model.</td>
</tr>
<tr>
<td>6</td>
<td>Production-estimating model: Inverter</td>
<td>Inverter profile and efficiency curve generated from measured data.</td>
<td>Single efficiency derate factor, Sandia Model for grid-connected inverters.</td>
</tr>
<tr>
<td>7</td>
<td>Simulation frequency</td>
<td>Hourly</td>
<td>Hourly</td>
</tr>
<tr>
<td>8</td>
<td>Tilt</td>
<td>Manual input</td>
<td>Manual input</td>
</tr>
<tr>
<td>9</td>
<td>Orientation</td>
<td>Manual input</td>
<td>Manual input</td>
</tr>
<tr>
<td>10</td>
<td>Derate factors</td>
<td>Field thermal loss, standard NOCT factor, Ohmic losses, module quality, mismatch, soiling (annual or monthly), IAM losses</td>
<td>Mismatch, diodes and connections, dc wiring, soiling, sun tracking, AC wiring, transformer.</td>
</tr>
<tr>
<td>11</td>
<td>Economic financial modelling</td>
<td>Difficult to understand economic modeling</td>
<td>Very powerful, easy-to-use and easy-to understand economic modeling</td>
</tr>
</tbody>
</table>
2.4 The reference power plant - DU PV system and its evolution

Dalarna University’s 3.24kWp [19] solar PV power plant was taken as the reference system for the purpose of this thesis. The system was installed in the year 1994 [19] and has since undergone a few changes for research as also to keep it relevant in today’s changing times.

The below table gives a brief overview of how the power plant has evolved over the years.

| Table 2 Evolution of DU’s solar PV power plant over the years [19] |
|-----------------|-----------------|-----------------|-----------------|-----------------|
| **Array 1**     |                 |                 |                 | 36              |          |
| Modules         | 40              | 32              |                 |                 |          |
| Parallel strings| 10              | 2               |                 |                 |          |
| Modules per string| 4               | 16              |                 |                 |          |
| Inverter 1      | NEG 1600        | Sunways NT 1800 |                 |                 |          |
| **Array 2**     |                 |                 |                 | Sunnyboy 1200   |          |
| Modules         | 32              | 40              |                 |                 |          |
| Parallel strings| 2               | 4               |                 |                 |          |
| Modules per string| 16             | 10              |                 |                 |          |
| Inverter 1      | Solwex 2065     |                 |                 |                 |          |
| Orientation     | 30° E to S      |                 |                 | Sunnyboy 1200   |          |
| Tilt            | 60°             |                 |                 |                 |          |
| Height          | Same height     |                 |                 | Array 2 placed 1m lower | Array 2 placed 3m closer to forecourt |
| Place of arrays | Same place      |                 |                 |                 |          |
From the above depiction of the system it can be seen that the values are measured by SMA’s inbuilt data logger. The data logger stores the data values locally on a SD card within the Sunny WebBox and also stores it on the internet on the Sunny web portal. The SMA data logger has one PV cell (a-Si type technology) based irradiation sensor with an accuracy of ±8%. It also has a PV module temperature sensor with an accuracy of ±0.5°C. [17]
Figure 3. Array 1 voltage sizing: Modules in series: 9; Number of strings: 4 [10]

Figure 4. Array 2 voltage sizing: Modules in series: 18; Number of strings: 2 [10]

From the above IV curve graphs (taken from PVsyst), it can be seen that the MPP points of the two arrays vary significantly. Therefore, the decision on how to arrange the array configuration will depend on where it is desired to operate the inverter MPP point at. This decision will depend upon the irradiance levels received at the location, the minimum and maximum temperatures and soiling.

2.5 Reference yield ($Y_r$) vs final PV system yield ($Y_f$)

One of the objectives of the International Energy Agency (IEA) Photovoltaic Power Systems Program’s Task 2 is to collect and analyze performance and reliability of photovoltaic power systems [25]. The parameters describing energy quantities for these photovoltaic power systems have been established by the program and are described in the IEC standard 61724 [26] [27].

More specifically, three of the IEC 61724 performance parameters, mentioned above, may be used to define the overall system performance. These parameters are the final PV system yield ($Y_f$), the reference yield ($Y_r$) and the performance ratio [27].

The final PV system yield ($Y_f$) is the net energy output ($E$) divided by the solar photovoltaic system’s nameplate DC power ($P_o$). The resulting number is a representation of the number of hours that the PV array would need to operate at its rated power to provide the same energy.

$$Y_f = \frac{E}{P_o} \quad \text{Equation } 2.1$$

The unit for $Y_f$ in the above equation will be either $\frac{kWh}{kW}$ or $\text{hours}$.

On the other hand, the reference yield ($Y_r$) is the total plane of array (POA) irradiance ($H$) divided by the reference irradiance ($G$). The resultant value is a representation of an equivalent number of hours at the reference irradiance. As an illustration, if $G$ equals 1 kW/m², then $Y_r$ is the number of peak sun hours or the solar irradiation in kWh/m² [27].

$$Y_r = \frac{H}{G} \quad \text{Equation } 2.2$$

The unit for $Y_r$ above is $\text{hours}$.
3 Methodology

1. Collate measurement data for DU’s Array 1 and Array 2 for the year 2014-2015.
2. Perform sanity check of the data to ascertain the homogeneity of the measured values.
3. Create hourly values from the available five-minute values for both arrays and tabulation of the data in excel.
4. Create graphs for comparison of annual energy produced, I-V plot and others.
5. Understand the working of PVsyst and SAM.
6. Define electrical parameters for a degraded PV module. The parameters for this PV module will contain the degraded values of the original installed DU module.
7. Identify the other input parameters and boundary conditions for the two softwares.
8. Perform the simulations and tabulate hourly and monthly data for both arrays for both softwares.
9. Analyze the simulated data by plotting it in graphs and tables and compare against measured data.

3.1 Key software input parameters

Both simulation softwares, PVsyst and SAM, require a defined set of module and inverter parameters to process data.

Before beginning the simulations, the simulation year also had to be decided. Although measured system data (energy, current, voltage, module temperature, etc.) from the inverter data logger was available for 2014-2015, 2015-2016 and 2016-2017 (April to March for all years), homogenous measured data for the entire year was only available for the year April 2014 to March 2015. Therefore, the focus of the simulations was for the duration April 2014 to March 2015.

3.1.1 Location and weather data

The weather data was procured from Meteonorm (version 7.2.2). The file format that was used was a TMY2 file. This file, called as the typical meteorological year file, contains one year of hourly solar radiation, illuminance, wind speed, temperature and snow depth. The data represented in the file is for one year and is averaged from the years 1991 to 2010. [28]

3.1.1.1 Albedo values
PVsyst suggests standard albedo values for certain standard surroundings. For the simulations it was decided to use standard albedo value suggested in PVsyst for the ‘urban situation’ which was 0.2. For simplification, this value was chosen for all the months of the year.

3.1.1.2 Absolute temperature value
The ’Lower temperature for Absolute Voltage limit’ was chosen as -5°C. In this field, the lowest forecasted module temperature during daylight needs to be input [10]. From studies conducted in Germany, in the early morning during the winter months, the air temperature drops to -10°C to -15°C. The absolute voltage value is also expected to be encountered in the early morning in the winter months. However, the lowest value accepted by PVsyst was -5°C. For any value lower than this, PVsyst returned an error stating that the array voltage is exceeding the inverter voltage. Since this error does not let the simulation proceed the minimum temperature was retained at -5°C. [9:211]
In PVsyst, the inverter sizing is based on a tolerable loss during the year. This parameter, defined under the 'limit overload loss for design in Figure 5', permits to increase this limit to accommodate highly oversized PV arrays in reference to the inverter. For the simulation, the default value of 3% was selected. [29]

3.1.2 Inverter
Both inverters installed in DU’s solar PV system are the SMA Sunny Boy 1200. The parameters for the same were available within PVsyst’s inverter database and the same file was used for the simulations.

The inverter datasheet stated that the night time consumption of the inverter could be taken as 0.1W. Since this value was taken as ‘zero’ in the original PVsyst database, the value was updated as per the inverter datasheet.

In SAM, the Sandia model for grid-connected PV inverters has been applied to enact the inverter datasheet model. This model comprises of certain equations that SAM utilizes to calculate the hourly AC output of the inverter based on the DC input. The inverter data sheet model permits the user to enter data from the manufacturer’s data sheet to model the inverter.[11] [30]

3.1.3 System losses

3.1.3.1 Thermal parameters
[10]

\[ U = U_C + U_V \times W_V \]  

Equation 3.1

where,
\( U = \text{thermal loss factor} \)
\( U_C = \text{constant loss factor} = 29 \text{ W/m}^2\text{K} \)
\( U_V = \text{wind loss factor} = 0 \)
\[ \dot{W}_V = wind \ velocity \]

### 3.1.3.2 Ohmic losses

The ohmic losses were calculated from the wiring layout. The lengths of the 4mm\(^2\) and 16mm\(^2\) cables were measured to be approximately 4 m/circuit and 23 m/circuit respectively. PVsys in turn calculated the ‘global wiring resistance’ to be 31.7m\(\Omega\) or ‘in loss fraction’ at STC to be 0.22%.

### 3.1.3.3 Module quality LID mismatch

The module efficiency loss was taken as 0.1% per year, which was the default value recommended by PVsyst.

Khajehalijani [18] measured a drop in the output power of each string in DU’s solar PV system as a percentage. For the purpose of this study an average of the four percentage values was calculated which came to be 14.3%. Considering a power reduction due to aging of 10% over 20 years (0.5% each year for crystalline PV modules), 4.3% losses remain and can be attributed to series losses and mismatch losses [18]. Since this study indicated a value for mismatch losses around 4.3%, 3.5% mismatch losses were chosen for the purpose of simulation.

### 3.1.3.4 Soiling Loss

Particulate matter on the surface of a PV module hampers the amount of solar irradiance reaching the PV cells. This accumulation of foreign matter impacts the performance output of a PV module. This dust on top of PV modules is commonly referred to as PV ‘soiling loss’. Since dependent on particles in the atmosphere, PV soiling losses are location specific and bear a relation to module tilt and additional other factors. [31]

Soiling loss for January and December was considered as 10%, for February it was taken as 5% while for the other ten months it was considered to be 2%. PVsys has no snow model, hence it is considered that 10% of the time in December and January there is snow on the modules while the estimation is 5% for February. For the rest of the months it was assumed that for 2% of the time dust accumulates on the PV modules.

### 3.1.4 Shading

In PVsys, the default horizon shading for the location was chosen for this simulation. No shading was considered for SAM.

In SAM, it is suggested that the snow cover model is apt for PV systems with a tilt between 10\(^\circ\) and 45\(^\circ\). The snow loss estimates for tilt angles outside this boundary condition may not return accurate results. [11] Therefore, the snow cover model was not utilized during the simulation.

### 3.1.5 System design

The PV system’s tilt of 60\(^\circ\), azimuth of 33\(^\circ\) and fixed tilt structure were taken as inputs as per the factual information.
3.2 PV Module

A new PV module was defined for the purpose of the simulations. In essence, this new PV module had degraded parameters as compared to the parameters of the module when it was first installed in 1994. The new electrical PV module parameters defined were essentially degraded parameters that were arrived at by analyzing measured parameters referenced from previous thesis work. Degradation study for the PV modules and the system was carried out during previous thesis work by [19], [20] and [18]. The data from these studies was analyzed to model the new PV module parameters.

Tesfay [20] carried out the current, voltage and power measurements of the installed modules and tabled his results for $I_{SC}$, $I_{MPP}$, $V_{OC}$, $V_{MPP}$ and $P_{MAX}$. It was also decided to use the same definition of module parameters for Array 1 and Array 2. Since the software requires one value per parameter the question was which value to select from the values available from [20]. The values were therefore analyzed and three cases were modelled and tabled as under.

In Table 3, case one was where average current and average voltage values were calculated and tabled. For case two, average voltage and minimum current values were calculated. Whereas for the last one, case three, minimum voltage and minimum current values were calculated and listed. In addition, the tolerances for each case were also calculated and appended to their respective standard values.

The values for power ($P_{max}$) were calculated by multiplying the MPP current and MPP voltage.

One point to note is the anomaly that may be noticed in the value of MPP voltage for all three cases. MPP voltage for all three cases was independently calculated but could not be used as inputs into PVsyst. This was because the software requires each cell with the module to have a $V_{mpp}$ between 0.45 V and 0.64 V. Since, 16.21 V divided by the number of cells that are in each module in this installation (36 cells) gives 0.45 V, the MPP voltage value for all three cases was considered to be 16.21 V. This assumption could be one of the errors of the study.
Table 3. Definition of degraded PV module for simulation purposes

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Nominal values during installation</th>
<th>Extrapolated to STC in 2014</th>
<th>Tolerance</th>
<th>Case One</th>
<th>Case Two</th>
<th>Case Three</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min</td>
<td>Max</td>
<td>Avg</td>
<td>Min</td>
<td>Max</td>
<td>Avg</td>
</tr>
<tr>
<td>$V_{oc}$ (V)</td>
<td>20.51</td>
<td>21.04</td>
<td>20.75</td>
<td>20.01</td>
<td>20.67</td>
<td>20.24</td>
</tr>
<tr>
<td>$I_{sc}$ (A)</td>
<td>2.85</td>
<td>3.03</td>
<td>2.96</td>
<td>2.65</td>
<td>2.88</td>
<td>2.77</td>
</tr>
<tr>
<td>$I_{mpp}$ (A)</td>
<td>2.44</td>
<td>2.72</td>
<td>2.55</td>
<td>2.33</td>
<td>2.56</td>
<td>2.43</td>
</tr>
<tr>
<td>$V_{mpp}$ (V)</td>
<td>16.55</td>
<td>17.63</td>
<td>17.20</td>
<td>15.44</td>
<td>16.46</td>
<td>15.92</td>
</tr>
<tr>
<td>$P_{max}$ (W)</td>
<td>42.05</td>
<td>47.14</td>
<td>43.88</td>
<td>36.85</td>
<td>40.7</td>
<td>38.66</td>
</tr>
<tr>
<td>$\mu V_{oc}$ (%/K)</td>
<td>-0.30</td>
<td>-0.50</td>
<td>-0.40</td>
<td>-0.38</td>
<td>-0.38</td>
<td>-0.38</td>
</tr>
<tr>
<td>$\mu I_{sc}$ (%/K)</td>
<td>0.02</td>
<td>0.08</td>
<td>0.02</td>
<td>0.02</td>
<td>0.02</td>
<td>0.02</td>
</tr>
<tr>
<td>$\mu P_{mpp}$ (%/K)</td>
<td>-0.37</td>
<td>-0.52</td>
<td>-0.37</td>
<td>-0.37</td>
<td>-0.37</td>
<td>-0.37</td>
</tr>
<tr>
<td>$R_{series}$</td>
<td>0.645</td>
<td>0.645</td>
<td>0.645</td>
<td>0.645</td>
<td>0.645</td>
<td>0.645</td>
</tr>
<tr>
<td>$R_{shunt}$</td>
<td>450</td>
<td>450</td>
<td>450</td>
<td>450</td>
<td>450</td>
<td>450</td>
</tr>
</tbody>
</table>

1 Indicates the negative tolerance of the parameter.
2 The values that were entered into both the softwares have been tabulated in the ‘SW input’ columns.
3 Indicates the positive tolerance of the parameter.
4 Calculated average was 15.9. However, PVsyst requires each cell to have an MPP voltage between 0.45 V and 0.64 V. Therefore, $(16.21\text{ V})/(36\text{ cells})$ gives 0.4502 V which was the minimum value acceptable. Therefore, this value was chosen for all the three cases.
5 $P_{max}$ was calculated by multiplying, $I_{mpp}$ and $V_{mpp}$.
6 As mentioned by previous module definitions within PVsyst for GPVM module.
7 As mentioned by previous module definitions within PVsyst for GPVM module.
4 Results

The first step in the assessment of the solar plant was the software simulation. The software input parameters mentioned in the preceding sections were entered into the two softwares. The size of the systems used in the simulations was the same as the capacity of the solar system installed on the roof of DU.

4.1 PVsyst vs SAM

4.1.1 Energy comparison

4.1.1.1 Cumulative annual

Energy generated, among other electrical parameters, is a ready reckoner when it comes to the efficacy of an energy system and hence this parameter was the first to be plotted.

Since solar energy is most conveniently visualized in relation to time, a bar graph was plotted wherein the twelve months of the year (plotted on x-axis) were compared to the solar energy generated by each software in that duration. Values (in kWh) for both, PVsyst and SAM were plotted distinctly so that a contrast, if any, could be observed and analyzed.

![Figure 6. Monthly energy - as simulated in PVsyst and SAM compared to actual measured energy](image)

Figure 6 shows the simulated yield comparison between PVsyst and SAM for December. The blue bar graphs (abbreviated ‘Sum of InvEn_Pvsyst’) and orange bar graphs (abbreviated ‘Sum of InvEn_SAM’) in the graph legend indicate the sum of all yield (in kWh) for the corresponding month for PVsyst and Sam respectively.

The numbers from 1 to 12 on the x-axis above represent the months from January to December respectively. The graph shows how the two softwares vary in their energy simulation month on month. It can be seen from the graph that while for most part of the year SAM overestimates the energy as compared to PVsyst, they are both very close in the energy estimates for November and December.

Another marker on the above graph is the grey line which represents the actual measured energy generated by the entire system during each month. It can be seen that June, August and December are the months when the softwares have simulated a value comparable to the measured data whereas in the other months there is a deviation.
Next, it was desired to analyze how the modelling softwares simulate energy generated across two very diverse seasons, winter and summer.

4.1.1.2 Winter simulation

According to [32], the performance ratio (PR) of a solar PV system is closely related to the way the PV modules perform in different seasons. This is primarily because the module temperature plays a key role in the behavior. In the study performed in Bangalore, India, during winter, the PV modules attain maximum efficiency at a module temperature of 55°C without significant loss of efficiency.

Next, December 2014 was chosen as the month to represent winter. To extract a true picture for the simulation, all the days in the month were scanned to find out the hours between which the system was generating energy. Once these hours were identified across the entire month, the energy simulated for each of these hours across the entire month was summed up and tabulated. In Figure 7, the blue bar graphs (abbreviated ‘Sum of InvEn1_Pvsyst’) represented energy simulated by PVsyst for Array 1, orange bar graphs (abbreviated ‘Sum of InvEn1_SAM’) represented energy simulated by SAM for Array 1, grey bar graph (abbreviated ‘Sum of InvEn2_Pvsyst’) represented energy simulated by Pvsyst for Array 2 and yellow bar graph (abbreviated ‘Sum of InvEn2_SAM’) represented energy simulated by SAM for Array 2.

The hours not producing any energy (hours according to both, the software simulation and the measured energy) were omitted from the graph.

![Figure 7. Energy simulation for December 2014 - a representation of winter simulation of PVsyst and SAM](image)

Beginning with PVsyst, it can be said from Figure 7 that Array 1 seems to be outperforming the energy generated by Array 2. One inference that could be made is that for most days in the month the blue bar graph (Array 1) generates more than the grey one (Array 2).

The bar graphs for SAM (orange for Array 1 and yellow for Array 2) on the other hand, indicate the same energy production (for both the arrays) for the entire month for most days.
Since both the softwares utilize the same weather files, for this particular month, it seems as if PVsyst takes into account the difference in array configuration whereas SAM does not seem to be taking this aspect into consideration.

Two other line markers, blue (abbreviated ‘Sum of InvEn1_Actual’ in the graph) for measured energy for Array 1 and green (abbreviated ‘Sum of InvEn2_Actual’ in the graph) for measured energy for Array 2, present additional information in the above graph. It can be observed that the measured energy for Array 1 is always more than the energy measured for Array 2.

4.1.1.3 Summer simulation

According to [32], in summer, for module temperature greater than 45°C, the module efficiency reduces by 0.08% per degree rise in temperature. Therefore, it was imperative that a comparison be conducted similar to the one explained in the earlier section and similar to the one depicted in Figure 7.

In Figure 8, the blue bar graphs (abbreviated ‘Sum of InvEn1_Pvsyst’) represented energy simulated by PVsyst for Array 1, orange bar graphs (abbreviated ‘Sum of InvEn1_SAM’) represented energy simulated by SAM for Array 1, grey bar graph (abbreviated ‘Sum of InvEn2_Pvsyst’) represented energy simulated by PVsyst for Array 2 and yellow bar graph (abbreviated ‘Sum of InvEn2_SAM’) represented energy simulated by SAM for Array 2.

The graph for May 2014 above displays a similar pattern to the one for December. For PVsyst, Array 1 seems to be generating more energy as compared to Array 2 for most hours of the month. The simulation result from SAM, on the other hand, depicts both arrays to be generating the same amount of energy.

One thing to note about the actual measured data in the above graph is the difference in the Array 1 and Array 2 energy production. From 05:00hr to 08:00hr Array 1 is producing more energy than Array 2 even though both the arrays have the same installed DC power. Also for the rest of the day (from 09:00hr to 20:00hr) the generation is very close for both arrays.

One inference that we can draw about the software versus actual comparison here is that for this month the total actual measured energy generated in the first half of the day was
lower than that simulated by both softwares. The reason for this anomaly could be attributed to a few reasons. The most important of them could be the variation in actual weather data with respect to the weather data used in the simulations.

4.1.2 Hays and Davies Model vs Perez-Ineichen model

There exist models to estimate the plane of array (POA) irradiance from the standard components (GHI, DNI and DHI). The POA irradiance had three components, namely, POA beam, POA ground reflected and POA sky diffuse.

According to [33] diffuse radiation is divided into certain elements as mentioned under.
- The uniform irradiance from the sky referred to as the isotropic element.
- Forward scattering of radiation concentrated in the area immediately surrounding the sun referred to as the circumsolar diffuse component.
- Horizontal brightening component.

Out of the models that are used to interpret the POA irradiance, the simulation results from Hays and Davies and the Perez sky diffuse models are discussed here since these two are common to both softwares, PVsyst and SAM. Transposition in both models is separately calculated for each irradiance component. The beam component is translated using a purely geometrical transformation, which does not involve any physical assumption. [34]

In the Hays and Davies model the POA sky diffuse component \( E_d \) is given the following formula.

\[
E_d = DHI \times \left[ A_i \frac{\cos(\theta)}{\cos(\theta_z)} + (1 - A_i) \frac{1 + \cos \beta}{2} \right]
\]

Equation 4.1

In the above equation, \( DHI \) is the diffused horizontal irradiance while \( A_i \) is the ratio of the direct normal irradiance (DNI) to the extraterestrial radiation. The term \( \frac{\cos(\theta)}{\cos(\theta_z)} \) is the ratio of beam irradiance on tilted surface to the beam irradiance on horizontal surface. This ratio is also referred to as \( R_b \) or the geometric factor. Meanwhile, the symbol \( \theta \) is the angle of incidence of the irradiance while \( \theta_z \), called the zenith angle, is the angle between the vertical and the line to the sun. This can also be referred to as the angle of incidence of beam radiation on a horizontal surface. The other angle in the equation is \( \beta \) which is the tilt angle of the solar array with respect to the horizontal. The geometry is also depicted in Figure 9 nedan. [35]

\[G_{bn}\]
\[G_b\]
\[\theta_z\]

Horizontal surface

\[G_{bn}\]
\[G_{on}\]
\[\theta\]
\[\beta\]

Horizontal surface

Figure 9. Solar geometric angles [35]

Equation 4.2 nedan represents the Perez- Ineichen sky diffuse model.
\[ E_d = DHI \times \left[ (1 - F_1) \left( \frac{1 + \cos \beta}{2} \right) + F_1 \left( \frac{a}{b} \right) + F_2 \sin \beta \right] \]

Equation 4.2

In the above equation \( F_1 \) and \( F_2 \) are coefficients that describe circumsolar and horizon brightness respectively. The terms \( a \) and \( b \) in the equation account for the incidence angles on the tilted and horizontal surfaces of the circumsolar radiation cone. Here the origin of the circumsolar radiation from the sun is considered to be a point source. [35][36]

4.1.2.1 PVsyst

As per [34] the beam radiation component is calculated by both the models using the geometric models and therefore is the same for both models. The diffused component, is tabulated below for Array 1 and Array 2.

<table>
<thead>
<tr>
<th>Months</th>
<th>GHI kWh/m²</th>
<th>AC Energy 1 kWh</th>
<th>Global POA kWh/m²</th>
<th>Diffused POA kWh/m²</th>
<th>AC Energy 2 kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>May</td>
<td>153</td>
<td>156</td>
<td>145</td>
<td>64</td>
<td>154</td>
</tr>
<tr>
<td>December</td>
<td>5</td>
<td>21</td>
<td>20</td>
<td>7</td>
<td>20</td>
</tr>
<tr>
<td>Yearly total</td>
<td>932</td>
<td>1188</td>
<td>1098</td>
<td>434</td>
<td>1168</td>
</tr>
</tbody>
</table>

Although the electricity generated is the key parameter of a system, the crucial aspect in the above synopsis is the diffused radiation in the plane of array. In May, the diffused POA acquired in the Hay’s model is 8% lower than the value obtained using the Perez model. Applying the same methodology for the values in December, the diffused POA from the Hay’s model was calculated to be 14% lesser than Perez.

4.1.2.2 SAM

The same approach was applied for SAM and the values were tabulated as under.

<table>
<thead>
<tr>
<th>Months</th>
<th>GHI kWh/m²</th>
<th>AC Energy 1 kWh</th>
<th>Global POA kWh/m²</th>
<th>Diffused POA kWh/m²</th>
<th>AC Energy 2 kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>May</td>
<td>153</td>
<td>157</td>
<td>146</td>
<td>71</td>
<td>158</td>
</tr>
<tr>
<td>December</td>
<td>5</td>
<td>19</td>
<td>20</td>
<td>7</td>
<td>19</td>
</tr>
<tr>
<td>Yearly total</td>
<td>932</td>
<td>1199</td>
<td>1104</td>
<td>481</td>
<td>1201</td>
</tr>
</tbody>
</table>

From both tables above, the interesting aspect to note is the yearly values of diffused POA. Although the weather file in both the softwares was alike, the yearly values have turned out to be different for both the models. The answer to this was not found and this query could be further investigated. A little discussion for the uncertainty analysis of the Hay’s and Perez model is discussed under the section ‘Uncertainty and error analysis’. A detailed table for all the months for both softwares has been appended under Appendix 4.
4.1.3 Simulation summary

Table 6. Simulation summary

<table>
<thead>
<tr>
<th></th>
<th>Array 1</th>
<th>SAM</th>
<th>PVsyst</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal power</td>
<td>1.36 kW&lt;sub&gt;p&lt;/sub&gt;</td>
<td>1.36 kW&lt;sub&gt;p&lt;/sub&gt;</td>
<td></td>
</tr>
<tr>
<td>System production</td>
<td>1171 kWh/year</td>
<td>1154 kWh/year</td>
<td></td>
</tr>
<tr>
<td>Normalized production (kWh/kW&lt;sub&gt;p&lt;/sub&gt;/year)</td>
<td>2.36</td>
<td>2.32</td>
<td></td>
</tr>
<tr>
<td>Specific production (kWh/kW&lt;sub&gt;p&lt;/sub&gt;/day)</td>
<td>861</td>
<td>848</td>
<td></td>
</tr>
<tr>
<td>Performance Ratio</td>
<td>79.8%</td>
<td>79.5%</td>
<td></td>
</tr>
</tbody>
</table>

Array 2

<table>
<thead>
<tr>
<th></th>
<th>Array 1</th>
<th>SAM</th>
<th>PVsyst</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal power</td>
<td>1.36 kW&lt;sub&gt;p&lt;/sub&gt;</td>
<td>1.36 kW&lt;sub&gt;p&lt;/sub&gt;</td>
<td></td>
</tr>
<tr>
<td>System production</td>
<td>1172 kWh/year</td>
<td>1134 kWh/year</td>
<td></td>
</tr>
<tr>
<td>Normalized production (kWh/kW&lt;sub&gt;p&lt;/sub&gt;/day)</td>
<td>2.36</td>
<td>2.28</td>
<td></td>
</tr>
<tr>
<td>Specific production (kWh/kW&lt;sub&gt;p&lt;/sub&gt;/year)</td>
<td>862</td>
<td>834</td>
<td></td>
</tr>
<tr>
<td>Performance Ratio</td>
<td>79.9%</td>
<td>78.2%</td>
<td></td>
</tr>
</tbody>
</table>

PVsyst makes a clear distinction between the performance ratios of the two arrays. The software calculates the Array 2 to have a PR of 1.3% lower than that of Array 1.

4.2 Array 1 vs Array 2

With a solar PV system, there lies an opportunity to analyze a broad variety of measured values. In most cases, the level of details into which the PV monitoring data is studied is determined by the desired aim. For time bound reasons, the detailed analysis of data also depends on the correctness of the measured data and the effort considered suitable to achieve the intended outcome. [37]

One of the easiest way to gain first insights is to visualize the recorded parameters as a function of time. Once such example is given in Figure 10, Figure 11 and Figure 12.

4.2.1 Energy analysis

4.2.1.1 Yearly energy analysis

Table 7. Energy production for the years 2014 to 2017 (beginning April and ending March)

<table>
<thead>
<tr>
<th>Year</th>
<th>Array 1 (kWh)</th>
<th>Array 2 (kWh)</th>
<th>Difference (kWh)</th>
<th>Percentage difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014-2015</td>
<td>1153.5</td>
<td>1132.0</td>
<td>21.5</td>
<td>1.9%</td>
</tr>
<tr>
<td>2015-2016</td>
<td>1149.6</td>
<td>1124.7</td>
<td>24.9</td>
<td>2.2%</td>
</tr>
<tr>
<td>2016-2017</td>
<td>1122.2</td>
<td>1099.3</td>
<td>22.9</td>
<td>2.0%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>3425.31</td>
<td>3356.02</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

During the year 2016-2017, there were times when the temperature sensors were not functional. Since the sensors are located within a box, there can also be doubts raised on the efficacy of the sensor data for this year.

From 14<sup>th</sup> December 2015 to 11<sup>th</sup> January 2016 the logged values for the PV system were found to be missing. This may have been the time during which measurements were being carried out for thesis work.
The year 2014-2015 was found to be the most complete year in terms of data and therefore this year was identified to analyze the energy performance of the solar PV system.

### 4.2.1.2 Approach

April, August and December were the months chosen to represent the seasons spring, autumn and winter respectively. Energy values for each hour across all days in a month were summed up. For example, energy generated from 08:00 hr to 09:00 hr across all days in December was added and tabled under 08:00 hr. This was done for each array separately. Thereafter, the resultant summed up energy values were tabulated against the respective hour for each of the two arrays.

In Figure 10 the blue graphs represent the yield of Array 1 while the orange graphs represent the yield for Array 2.

![Figure 10. Hourly energy comparison for Array 1 and Array 2 for April 2014](image)

Figure 10 is a graph of the hour number in the day (x-axis) versus the sum of total energy generated in that hour for the entire month (y-axis). From the graph it can be seen that Array 1 is producing more energy from 06:00 hr to 09:00 hr and also from 17:00 hr to 19:00 hr.

Similar graphs have been depicted for August and December in Figure 11 and Figure 12 respectively. In Figure 11 the blue graphs represent the yield of Array 1 while the orange graphs represent the yield for Array 2.

![Figure 11. Hourly energy comparison for Array 1 (in blue) and Array 2 (in orange) for August 2014](image)

Figure 11 also conveys that Array 1 produces more energy than Array 2 between 06:00 hr and 09:00 hr.
Figure 12. Hourly energy comparison for Array 1 (in blue) and Array 2 (in orange) for December 2014

Figure 12 also conveys a similar pattern to the earlier two months above. In this graph Array 1 produces more energy through the entire duration the plant is functioning.

Figure 13. Average module temperature (in °C) for each hour in the month vs respective hour

Figure 13 is a graph of the hour (x-axis) versus the average PV module temperature for a particular month for the respective hour. In the legend above, number 4 (blue graphs) indicates the average PV module temperature for April, number 8 (orange graphs) indicates for August and number 12 (grey graphs) indicates for December.

From the above three figures (Figure 10, Figure 11 and Figure 12) it can be seen that Array 1 outperforms Array 2 in energy production from 06:00 hr to 09:00 hr.

Beginning with August, a significant difference in energy production (between Array 1 and Array 2) is observed from 06:00 hr to 08:00 hr wherein the average module temperature is below 17°C.

Moving to the month of April, a visible power production difference between the two arrays is observed between 06:00 hr to 09:00 hr. In this instance, the average module temperature does not exceed 8.5°C.

Interestingly, in December, Array 1 outperforms Array 2 throughout the day wherein the average module temperature varies between -5.5°C and 1.5°C throughout the day.

This trend across the three seasons points towards a possible impact of module temperature in the energy performance of an array’s string configuration.
4.2.2 I-V curve

4.2.2.1 Approach
Like the above figures, many measured values can be compared to each other by plotting them against varied time steps. One of the methods that may reveal additional perspective is a scatter plot between two measured parameters as against plotting against time steps as suggested by Woyte et al.[37].

Figure 14 to Figure 18 have been plotted using values measured over three years as under.
- April 2014 to March 2015
- April 2015 to March 2016
- April 2016 to March 2017

![Figure 14. I-V curve for three years (Apr 14-Mar 15, Apr 15-Mar 16, Apr 16-Mar 17) for Array 1 and Array 2 inclusive of module temperature](image-url)
Figure 15 shows the I-V curve for Array 1 and Array 2. The scatter plot on the left of the graph with a maximum current just above 10A represents Array 1 while the set of points on the right side of the graph represents Array 2.

The vertical red line at 400V represents the maximum permissible input voltage for the inverter.

The plot representing Array 2 is close to the maximum permissible input voltage of 400 V. Extreme temperatures might sway the voltage limit closer to the threshold and might be a concern. However, this has not been the case since the system was re-powered in 2014.

The original configuration of each array prior to 2014 was 18 modules in each string and two strings then in parallel.

Prior to installation of Array 1, it was envisaged that there might be excess clipping losses due to the high current within the array. In addition, there was the concern of higher temperature which might warm up the inverter. However, it can be seen from Figure 15 that the clipping losses for Array 1 are not that excessive which could also translate to little or no impact of increased temperature on inverter performance.

For Array 2 it was expected to have little or no clipping losses but in real-world performance this configuration does undergo loss of power.

4.2.3 Irradiance vs module temperature and wind speed

Module temperature is crucial to the value of the MPP voltage of a solar PV system. In the above figure, it might be interesting to observe the location of points on the graph for low wind speed (blue color dots representing by 2 to 5 m/s) and high wind speed (yellow color dots representing 8 to 11 m/s). On visual observation, for a plane of array irradiance of 600
to 1000 W/m² the yellow dots seem to have an average module temperature of a few degrees centigrade lower than that for the blue dots. However, further analysis would be required to quantify the effects of wind speed.

![Figure 16. Plot of irradiance (POA) versus module temperature with wind speed](image)

### 4.2.4 MPP voltage versus DC power

The Array 1 plot on the left side of Figure 17 indicates a shorter variation of voltage limits. Whereas, for Array 2 the plot is closer to the 400 V maximum input voltage of the inverter. During extreme low temperatures, there might be reason to monitor Array 2 to avoid the voltage inching closer to the threshold limit.

![Figure 17. MPP voltage of the system versus DC power of the system](image)
4.2.5 AC power versus inverter efficiency

To further compare the performance of the two PV arrays, it was required to address the efficiency of the inverter. This was done using the ratio between the power output from the inverter (AC) to the power input from the PV-arrays (DC). The ratio mentioned herein is called the conversion efficiency. The losses inherent while converting the DC power to the AC power are described by the conversion efficiency. [9:127]

Figure 18. AC power versus inverter efficiency. Plot for Array 1 is on the left while the plot on the right is for Array 2.

Figure 18 is a graph of the system’s AC power plotted against the inverter’s efficiency. The inverter’s efficiency in this case has been calculated as the ratio of the DC input power into the inverter and the AC output power. In the figure above, the plot to the left is of Array 1 while that to the right is of Array 2.
Table 8 Inverter efficiency at low AC power (0 to 400 W)

<table>
<thead>
<tr>
<th>AC power (W)</th>
<th>Array 1’s inverter efficiency⁸</th>
<th>Array 2’s inverter efficiency</th>
<th>Range of irradiance observed</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 to 50</td>
<td>0.22 to 0.79</td>
<td>0.12 to 0.72</td>
<td>50 to 150 W/m²</td>
</tr>
<tr>
<td>50 to 100</td>
<td>0.79 to 0.88</td>
<td>0.72 to 0.80</td>
<td>50 to 200 W/m²</td>
</tr>
<tr>
<td>100 to 150</td>
<td>0.88 to 0.91</td>
<td>0.80 to 0.85</td>
<td>50 to 200 W/m²</td>
</tr>
<tr>
<td>150 to 200</td>
<td>0.91 to 0.92</td>
<td>0.85 to 0.88</td>
<td>100 to 250 W/m²</td>
</tr>
<tr>
<td>200 to 400</td>
<td>0.92⁹</td>
<td>0.90¹⁰</td>
<td>150 to 300 W/m²</td>
</tr>
</tbody>
</table>

Efficiency values from the table Table 8 suggest that at low irradiance the inverter connected to Array 1 seems to have a higher efficiency as compared to the inverter of Array 2.

Further, the plot also communicates that inverter 1 (inverter of Array 1) has a wider range of efficiencies (0.88 to 0.98) in the power range of 200W to 400W. In the same region inverter 2 has an efficiency range from 0.88 to 0.92.

At low irradiance, it can be interpreted that AC power output is much lower than the generated DC power in the system. This happens because of the power consumption of the inverter itself which makes the efficiency drop. [37]

4.2.6 Reference yield \( (Y_r) \) vs final PV system yield \( (Y_f) \)

4.2.6.1 Approach
As mentioned in section 2.5 the performance ratio (PR) is a ratio of \( Y_f \) over \( Y_r \).

Figure 19. Reference yield \( (Y_r) \) versus final PV system yield \( (Y_f) \)

⁸ Lower value of range corresponds to lower limit of corresponding AC power. Similarly, higher value of range corresponds to higher limit of AC power.
⁹ This is the mean value that was considered on visual observation of the plot
¹⁰ This is the mean value that was considered on visual observation of the plot
In the graph above it can be seen that $Y_r$ and $Y_f$ are in magnitude of 0.0x instead of 0.x. The main reasons for this are that the values dealt with in this study are in very small time steps. Here, the numerator in the formula for $Y_r$ is the irradiation received per meter square in a five-minute interval. Therefore, the graph has $\frac{1}{12}$ of what would arrive in a complete hour. The denominator in this case is the irradiation at STC (1kW/m²). [38]

$$Y_r = \frac{H}{12G_{STC}}$$  \hspace{1cm} Equation 4.3

Similarly, for $Y_f$, the numerator is the yield generated during a five-minute interval.

$$Y_f = \frac{E_{PV}/12}{P_0}$$  \hspace{1cm} Equation 4.4

$Y_f$ is capped for reference yields at approximately 0.75 for both array 1 and array 2. This power throttling indicates the under-sizing of inverters which is common indication of sizing in northern Europe [37].

The relationship between $Y_f$ and $Y_r$ can be said to indicate the overall conversion efficiency of the installation. Although this relationship can indicate phenomena such as defective strings or inverters and inverter under-sizing (power limitation), for the DU system both arrays seem to be performing as expected.

A linear relation ($Y_r = Y_f$) can be seen in Figure 19. Many points or values of performance ratios vary around one. These values for PR appear to be relatively high even for instantaneous values. The reason for this is presently not known. Temperature of the module, solar spectrum, irradiance measuring device and precision of data logger are factors influencing the performance ratio. [37]

4.3 Uncertainty and error analysis

Errors encountered during the study were categorized under three sections - as input errors, data acquisition errors and data processing errors.

4.3.1 Input errors

Errors associated with parameters that were not measured nor that were processed directly were included in this section. These included weather data and errors associated with degradation data.

A significant impact was noticed in the uncertainty contributed by Meteonorm. This weather software has a data variation of 5% from year to year. To add to that, the recorded values hold an uncertainty of 4%. [28]. Since the uncertainty values were directly available, the combined uncertainty from Meteonorm was calculated by squaring the variation percentage (5%) and the uncertainty percentage (4%) and then taking the square root of the resultant value.

The second part, which was the uncertainty of the degraded data was not calculated. Analyzing degraded data was envisaged to take time longer than the time scope available for this thesis. Therefore, for the purpose of this analysis the uncertainty for degraded data values was assumed to contain negligible error.
4.3.2 Data-acquisition (measurement) errors

This type of error was further considered to have two parts. First part was the variation induced due to the errors in the instruments while the second was the human aspect of calculations.

For the human aspect, it was assumed that best effort was put forth to analyze and gather the results. Furthermore, there was no bias towards any specific method, quantity or pre-defined conclusion. Lastly, no effort was made to influence the results in any way. Therefore, a negligible error was assumed in this case.

For the first part, the data-acquisition or measurement errors, method within the Guide to the Expression of Uncertainty in Measurement (GUM) was referred to. The Joint Committee for Guides in Metrology (JCGM) in its GUM defines uncertainty of measurement as a parameter, associated with the result of a measurement, that characterizes the dispersion of the values that could reasonably be attributed to the measurand. [39]

A sure way to ascertain weakness in the process of measurement is to have a definite hold of the uncertainty at each step of the measurement process. A standard of this analysis of uncertainty is contained in the GUM, which is an International Organization for Standardization (ISO) standard.

The methods to analyze uncertainty in the GUM are estimated through two methods – statistics and other methods. To distinguish between these two, uncertainties in the GUM are defined as Type A (ascertained through statistical methods) and Type B (ascertained through other means) uncertainties.

It is only apt to explain the difference between the uncertainties, Type A and Type B, further. By understanding, an uncertainty is broadly a dispersion of measured values around the true value of a parameter. This dispersion is influenced by a certain number of elements. By conducting multiple measurements, the dispersion can be characterized through a standard deviation calculation (Type A). A single measurement on the other hand, may imply a dispersion that can be quantified if the instrument’s calibration and tolerance (or accuracy) are known (Type B). To grasp the holistic dispersion of a measurement, analysis of Type A and Type B uncertainties of a few instrument measurements might yield a quantifiable result.[40]

According to [40], a coverage factor is then applied to the above to incorporate a level of confidence to the combination of the two types of uncertainty to give the total expanded uncertainty for PV module measurement.

Type B elements of uncertainty appear from instruments used in a measurement and their respective calibration histories. As one of its definition, Type B analysis is an estimation of the uncertainty of a variable that has not been obtained from repeated measurement [40].

Fractional uncertainties as defined by [41], which were available through component data sheets, of the measuring instruments were used in calculating the uncertainty in measurement.

According to [40] the steps in calculating uncertainty are as under.

1. List the components of uncertainty arising from random effects. For example, instrument uncertainties.
2. For the respective variable, assume uncertainty component probability distribution. This information could come from a manufacturer’s data sheet or calibration history.
3. Calculate the individual component uncertainty, $u_i$.
4. Calculate the combined standard uncertainty, $u_c$.

The individual component uncertainty ($u_i$) is the calculated by dividing the uncertainty interval by the probability distribution factor. $u_{c,measured}$ is found out by squaring the individual component uncertainties and then taking their square root.

$U_X$ is the expanded combined uncertainty that is arrived at by multiplying the combined standard uncertainty ($u_{c,measured}$) by the coverage factor applicable ($c$). This coverage factor is related to the normal distribution. When a level of confidence of 95% is used, the coverage factor takes the value of $c=2$. [42]

Furthermore, the expanded combined uncertainties are combined by adding their squares and then taking their square root. This gives the combined total uncertainty ($U_{95,Total}$).

### Table 9: Uncertainty calculation

<table>
<thead>
<tr>
<th>Row Number</th>
<th>Measuring equipment</th>
<th>Uncertainty ($u_i$)</th>
<th>Uncertainty density function</th>
<th>Divisor</th>
<th>Component uncertainty</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Data-acquisition (measurement) errors</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Inverter</td>
<td>3.0%</td>
<td>Rectangular</td>
<td>√3</td>
<td>1.7%</td>
</tr>
<tr>
<td>3</td>
<td>AC line losses in inverter</td>
<td>1.0%</td>
<td>Assumed normal</td>
<td>3</td>
<td>0.3%</td>
</tr>
<tr>
<td>4</td>
<td>SMA PV (aSi) cell</td>
<td>8.0%</td>
<td>Assumed normal</td>
<td>3</td>
<td>2.7%</td>
</tr>
<tr>
<td>5</td>
<td>Sunny Web box (SMA data logger)</td>
<td>4.0%</td>
<td>Assumed normal</td>
<td>3</td>
<td>1.3%</td>
</tr>
<tr>
<td>6</td>
<td>Meteonorm weather data variation (software variation)</td>
<td>5.0%</td>
<td>Rectangular</td>
<td>√3</td>
<td>2.9%</td>
</tr>
<tr>
<td>7</td>
<td>Combined standard uncertainty ($u_{c,measured}$)</td>
<td>(Root sum square)</td>
<td></td>
<td></td>
<td>4.5%</td>
</tr>
<tr>
<td>8</td>
<td>Expanded Combined Uncertainty from Measurements ($U_{95,measured}$)</td>
<td>Coverage factor=2</td>
<td></td>
<td></td>
<td>9.0%</td>
</tr>
<tr>
<td>9</td>
<td>Degradation measurement with AMPROBE (Solar-4000) I-V curve tracer</td>
<td>5.0%</td>
<td>Assumed normal</td>
<td>3</td>
<td>1.7%</td>
</tr>
<tr>
<td>10</td>
<td>Expanded Combined Uncertainty from IV tracer ($U_{95,IV tracer}$)</td>
<td>Coverage factor=2</td>
<td></td>
<td></td>
<td>3.3%</td>
</tr>
<tr>
<td>11</td>
<td>Combined Total Uncertainty ($U_{95,Total}$)</td>
<td>$\sqrt{(U_{95,measured})^2 + (U_{95,IV tracer})^2}$</td>
<td></td>
<td></td>
<td>9.6%</td>
</tr>
</tbody>
</table>

Table 9 depicts the uncertainty budget for the measurements conducted for the solar PV system. First, the relevant individual uncertainties affecting the measurement process are listed from row one to row five. Second, as described in the preceding section, the individual component uncertainty is calculated against the respective value. This is followed by combining the extended combined uncertainty of the IV tracer and of the measurements to give a combined total uncertainty.

### 4.3.3 Data processing errors

The occurrence of data processing errors can be ascribed to the models used in the simulation or to the formulas used to interpret measured values. First among data processing errors is the error arisen from comparing the simulated energy values to the actual measured energy values. To carry on this discussion the terms accuracy and precision need to be referred to.

Accuracy is defined as the closeness of a measured value to a standard or known value. Precision refers to the closeness of two or more measurements to each other. A brief example to understand accuracy and precision is a football player trying to score a goal. If the footballer kicks with accuracy her aim will always take the ball close to or into the back
of the goal. However, if the player is precise with shooting the ball, her aim will always take the ball to the same location which may or may not be close to the goal post. \cite{43}

Precision is at times segregated into repeatability and reproducibility. Repeatability is when the conditions are kept constant while using the same instruments and operator and repeating the measurements in a short time interval. Reproducibility is the variation assessed over a long period of time using different instruments and operators of the same measurement process. \cite{44}

Meanwhile, error analysis according to \cite{41} is the study and evaluation of uncertainty in measurement.

It is important to note the relation among accuracy, precision and error. A random error will be lesser in magnitude if measured with an instrument that is accurate and with more reproducibility and repeatability (precision). More experiments will bring a closer true value. Therefore, with multiple measurements, the precision of the result can be ascertained. Following this, an estimation of how close the mean value is to the true value can be made in case there was no error involved. It can be said that there is less deviation of the mean from the true value as the number of measurements increase. \cite{44}

A variation between the modelled values and measured values is essential in improving future models. Root mean square error (RMSE), mean bias error (MBE) and mean absolute error (MAE) are tools that could be utilized to ascertain the deviation in measurements. \cite{45}

RMSE values give information on the variation between the modelled values and measured values, MBE values provide the average deviation between the modelled values and measured values while MAE values provide the average absolute deviation of the modelled values from the measured values. RMSE and MAE values are always positive whereas MBE can be either negative or positive. \cite{45}

\begin{equation}
\text{RMSE} = 100\% \times \left( \frac{1}{n} \sum_{i=1}^{n} (y_i - x_i)^2 \right)^{1/2} \div \left( \frac{1}{n} \sum_{i=1}^{n} x_i \right) \quad \text{Equation 4.5}
\end{equation}

\begin{equation}
\text{MBE} = 100\% \times \left( \frac{1}{n} \sum_{i=1}^{n} (y_i - x_i) \right) \div \left( \frac{1}{n} \sum_{i=1}^{n} x_i \right) \quad \text{Equation 4.6}
\end{equation}

\begin{equation}
\text{MAE} = 100\% \times \left( \frac{1}{n} \sum_{i=1}^{n} |y_i - x_i| \right) \div \left( \frac{1}{n} \sum_{i=1}^{n} x_i \right) \quad \text{Equation 4.7}
\end{equation}

where

- $y_i$ = the $i$th modelled value
- $x_i$ = the $i$th measured value
- $n$ = the number of measured or modelled values

Willmott et al. \cite{46} suggests that RMSE is not appropriate because of its variability within the distribution of error magnitudes and with the square root of the number of errors. It is further stated that RMSE is a function of MAE, the squared errors (in other words the dispersal of error magnitudes) and the square root of the number of data points and hence is not a description of average error alone. Nevertheless, considering the limited duration for this study, it was decided to analyse using only the MBE function.
Table 10 PVsyst and SAM MBE values

<table>
<thead>
<tr>
<th>Array Number</th>
<th>Number of data points</th>
<th>PVsyst_MBE</th>
<th>SAM_MBE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Array 1</td>
<td>8760</td>
<td>2.8%</td>
<td>1.7%</td>
</tr>
<tr>
<td>Array 2</td>
<td>8760</td>
<td>3.0%</td>
<td>3.7%</td>
</tr>
</tbody>
</table>

Table 10 displays error analysis of simulated data. The variation or error in yield output forecasted by PVsyst and SAM was compared against the measured data energy generated. For both softwares the error increases from the value for Array 1 to the value for Array 2.

The second part of the data processing errors is the uncertainty in the two models used to calculate diffused radiation on the plane of array. A difference in POA diffused irradiation values can be observed in Table 4 and Table 5. However, this variation could be attributed to both these models’ respective MBE variations, which from measurements carried out by other studies has depicted a systematic difference of 1.8% to 2.2%. It appears that the Perez model is more sensitive of the diffuse radiation and is often not justified in PVsyst except when measured hourly data is available [34].

5 Discussions and conclusion

The focus of this study was to assess the two re-powered arrays of the DU solar PV system and ascertain which among them was generating a higher yield.

The layout of this section involves a discussion about the challenges faced during the assessment, then there is a discussion about the uncertainty in measurements and finally a short note on the findings of the thesis.

There were three challenges that were central during this study - identification of the boundary conditions for this research, selection of the input parameters for the softwares and comparison between real world parameters and simulated parameters for Array 1 and Array 2.

First, the identification of boundary conditions or limitations proved to be a difficult task. Measured data for DU’s solar PV system was available in five-minute intervals. This had to be converted into hourly values. Prior to conversion, this data had to be checked for uniformity and therefore a visual check was carried out for each line item for three years of data from 2014 to 2017 (a year beginning April and ending March). Although the check was performed thoroughly, a possibility exists that the year finally chosen for study (April 2014 to March 2015) could have a false reading(437,795),(563,818) [34].

The second challenge was regarding the selection of software inputs. Since the PV modules were installed in 1994, not all of its electrical parameters were readily available. Moreover, inherent power losses indicated that degradation had taken place and therefore the original electrical parameters of the modules could not be used. Hence, previous thesis studies and PV module literature were studied to ascertain the most apt approach to define parameters for a new PV module. This new PV module was essentially a degraded version of the original installed PV module and was utilized as input for the simulation softwares.

The third challenge was the comparability between the real-world values and the values forecasted by the simulation softwares. The real-world system contained degraded PV modules and the newly installed inverters, whereas it is expected that the softwares treated
all the component input values as applicable for a recently installed (new) system. The software is designed to work with nominal values (plus tolerances) but not with old equipment. In this case it was pertinent to create a new model that represented the conditions of the equipment. However, this approach contributes more uncertainty (as shown in earlier sections). Furthermore, there will be more variation from module to module after 20 years of use as compared to the variation after manufacturing. Hence, the tolerances suggested could be even higher than suggested in this thesis.

Moving onto the results, PVsyst took into account the different configuration of Array 1 and Array 2 and predicted the yield to vary for the two array configurations. SAM on the other hand made no distinction in the output generation of the two arrays throughout the year and this was one of its drawbacks.

It is also pertinent to further discuss the efficacy of PVsyst. Considering the degradation, the system yield was within the expected production probability forecast of P50. Also called the average level of generation, this means that this output will be surpassed 50% of the time. Even the P90 level of PVsyst was 2047 kWh (1032 kWh + 1015 kWh), 12% lower than the actual measured annual output for the whole PV system.

Moving onto the measured data, the data values returned contained interesting results. Inverter of Array 1 seemed to be starting earlier than Array 2 during early mornings. During April and August 2014, Array 1 performed better from 06:00 hr to 09:00 hr and generated more electricity. In the winter month of December 2014, Array 1 performed better right throughout the day.

A point of improvement in the assessment could be in the area of uncertainty in the measurement and calculation process. Inherent instrument tolerances were taken into account and an uncertainty in measurement was calculated to be 10%. Further, the uncertainty within the models of the simulation softwares was also incorporated. However, the uncertainty in degradation data was not calculated and assumed to be negligible. This is one area that could be studied further.

The weather data procured from the software Meteonorm specifies that there is a 5% variability in weather data values in comparison to the actual weather from one year to the next. Another crucial value is the 4% uncertainty in this weather data itself. This means that from one year to the next, the weather data might undergo a variation of close to 6%. [28]

Two statements could be shared as a summary observation of the above work. First, is that Array 1 seems to be performing better than Array 2 in this specific Nordic climate, from the total output that is measured in kWh. Specifically Array 1 was found to be 2% better performing than Array 2. The second summary observation is concerning the softwares. PVsyst seems to be treating the two arrays as different as can be seen from the energy simulations. While SAM seems to be making no distinction in this regard.

### 6 Future Work

In the analysis of a PV system there is a time early in the morning when the first irradiance strikes the PV module. At a certain minimum irradiance, the inverter starts up and yield is generated. It was observed during the study that there might be a point of minimum current (corresponding to minimum voltage of 100 V since that is the minimum start voltage of the inverter) at which the inverter starts and a yield is detected. It was observed that the start up current was around 0.03 A for a few days in January 2014. However, a definite insight would be obtained by an in depth study and measurements over a significant duration of time.
Bibliography


[33] “PV Performance Modeling Collaborative | POA Sky Diffuse.”


Appendices

Appendix 1

Original datasheet parameters of PV module, GPVM 50 at installation as per [16]

<table>
<thead>
<tr>
<th>SN</th>
<th>Parameter</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Output power</td>
<td>W_p</td>
<td>44.72</td>
</tr>
<tr>
<td>2.</td>
<td>Number of cells</td>
<td>-</td>
<td>36</td>
</tr>
<tr>
<td>3.</td>
<td>Open circuit voltage ($V_{oc}$)</td>
<td>V</td>
<td>20.90</td>
</tr>
<tr>
<td>4.</td>
<td>Short circuit current ($I_{sc}$)</td>
<td>A</td>
<td>2.98</td>
</tr>
<tr>
<td>5.</td>
<td>Current at MPP ($I_{MPP}$)</td>
<td>A</td>
<td>2.54</td>
</tr>
<tr>
<td>6.</td>
<td>Voltage at MPP ($V_{MPP}$)</td>
<td>V</td>
<td>17.62</td>
</tr>
<tr>
<td>7.</td>
<td>Module efficiency</td>
<td>%</td>
<td>10.80</td>
</tr>
<tr>
<td>8.</td>
<td>Gross area</td>
<td>m²</td>
<td>0.415</td>
</tr>
<tr>
<td>9.</td>
<td>Fill factor</td>
<td>%</td>
<td>71.70</td>
</tr>
<tr>
<td>10.</td>
<td>Series resistance</td>
<td>mΩ</td>
<td>549</td>
</tr>
</tbody>
</table>
Appendix 2

PVsyst inputs

System design for Array 1 in PVsyst
System design for Array 2 in PVsyst
System losses for PVsyst
**Inverter input for PVsyst**
PV module input for PVsyst
Appendix 3

SAM inputs

System Design for Array 1

System Sizing

- Specify desired array size
  - Desired array size: 200 kWdc
  - DC to AC ratio: 1.10

- Specify modules and inverters
  - Modules per string: 9
  - Strings in parallel: 4
  - Number of inverters: 1

Configuration at Reference Conditions

Modules

- Nominal capacity: 1.362 kWdc
- Number of modules: 36
- Modules per string: 9
- Strings in parallel: 4
- Total module area: 150 m²
- String Voc: 182.2 V
- String Vmp: 145.9 V

Inverters

- Total capacity: 1.200 kWac
- Total capacity: 1.321 kWdc
- Number of inverters: 1
- Maximum DC voltage: 410.0 Vdc
- Minimum MPPT voltage: 100.0 Vdc
- Maximum MPPT voltage: 320.0 Vdc

Sliding messages (see Help for details):
- Actual DC to AC ratio is 1.14.

DC Subarrays

To model a system with one array, specify properties for Subarray 1 and disable Subarrays 2, 3, and 4. To model a system with up to four subarrays connected in parallel to a single bank of inverters, for each subarray, check Enable and specify a number of strings and other properties.

String Configuration

- Subarray 1
  - Strings in array: 4 (always enabled)
  - Strings allocated to subarray: 1
- Subarray 2
  - Enable
- Subarray 3
  - Enable
- Subarray 4
  - Enable

Tracking & Orientation

- Azimuth: Fixed
- Tilt: Fixed
- 1 Axis
- 2 Axis
- Azimuth Axis
- Tilt-axis
- Tilt latitude: 60
- Azimuth (deg): 213
- Ground coverage ratio (GRC): 0.3
- Tracker rotation limit (deg): 45
- Backtracking: Enable

Ground coverage ratio is used (1) to determine when a one-axis tracking system will backtrack, (2) in self-shading calculations for fixed tilt or one-axis tracking systems on the Shading page, and (3) in the total land area calculation. See Help for details.

Estimate of Overall Land Usage

- Total module area: 150 m²
- Total land area: 0.0 acres

SAM uses the total land area only when you specify a $/acre cost on the System Costs page: Total land area = total module area * GCR * $/acre = 0.0002471 (1 m² = 0.0002471 acre)

PV Subarray Voltage Mismatch

Subarray Voltage Mismatch Calculation

When subarrays have different orientations, modules in each subarray are exposed to different levels of solar radiation and wind speed, which results in different subarray cell temperatures and maximum power point voltages (Vmp). The voltage mismatch causes electrical losses and an inverter input voltage less than Vmp. By default, SAM estimates the inverter input voltage by averaging the subarray Vmp values.

If you are using the CEC or IEC 61724 module model, SAM can more accurately estimate the inverter input voltage. This option requires longer simulation times to calculate mismatch losses. This more accurate method generally results in lower system output than the default method. See Help for details.

- Calculate maximum power voltage for array and associated losses due to subarray mismatch (CEC and IEC 61724 models only)
System Design for Array 2

**System Sizing**
- Desired array size: 200 kWdc
- DC to AC ratio: 1.10

**Configuration at Reference Conditions**
- Nameplate capacity: 1.362 kWdc
- Number of modules: 36
- Modules per string: 18
- Strings in parallel: 2
- Total module area: 15.9 m²
- String Voc: 364.3 V
- String Vmp: 291.8 V
- Total capacity: 1.200 kWdc
- Number of inverters: 1
- Maximum DC voltage: 418.0 Vdc
- Maximum MPPT voltage: 328.0 Vdc

**DC Subarrays**
To model a system with one array, specify properties for Subarray 1 and disable Subarrays 2, 3, and 4. To model a system with up to four subarrays connected in parallel to a single bank of inverters, for each subarray, check Enable and specify a number of strings and other properties.

**String Configuration**
- Subarray 1: Strings in array: 2, Strings allocated to subarray: 1 (enabled)
- Subarray 2: Strings in array: 2, Strings allocated to subarray: 1 (enabled)
- Subarray 3: Strings in array: 2, Strings allocated to subarray: 1 (enabled)
- Subarray 4: Strings in array: 2, Strings allocated to subarray: 1 (enabled)

**Tracking & Orientation**
- Tilt (deg): 60, 60, 60, 60
- Azimuth (deg): 213, 213, 213, 213
- Ground coverage ratio (GCR): 0.3, 0.3, 0.3, 0.3
- Tracker rotation limit (deg): 45, 45, 45, 45

**Estimate of Overall Land Usage**
- Total module area: 15.0 m²
- Total land area: 0.0 acres

**PV Subarray Voltage Mismatch**

**Subarray Voltage Mismatch Calculation**
When subarrays have different orientations, modules in each subarray are exposed to different levels of solar radiation and wind speed, which results in different subarray cell temperatures and maximum power point voltages (Vmp). The voltage mismatch causes electrical losses and an inverter input voltage less than Vmp. By default, SAM estimates the inverter input voltage by averaging the subarray Vmp values.

If you are using the CEC or IEC 61724 module model, SAM can more accurately estimate the inverter input voltage. This option requires longer simulation times to calculate mismatch losses. This more accurate method generally results in lower system output than the default method. See Help for details.

- Calculate maximum power voltage for array and associated losses due to subarray mismatch (CEC and IEC 61724 models only)
### System losses for Array 1

**Irradiance Losses**
Soiling losses apply to the total solar irradiance incident on each subarray. SAM applies these losses in addition to any losses on the Shading and Snow page.

<table>
<thead>
<tr>
<th>Subarray</th>
<th>Monthly soiling loss</th>
<th>Average annual soiling loss</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Edit values...</td>
<td>3.58333</td>
</tr>
<tr>
<td>2</td>
<td>Edit values...</td>
<td>3.58333</td>
</tr>
<tr>
<td>3</td>
<td>Edit values...</td>
<td>3.58333</td>
</tr>
<tr>
<td>4</td>
<td>Edit values...</td>
<td>3.58333</td>
</tr>
</tbody>
</table>

**DC Losses**
DC losses apply to the electrical output of each subarray and account for losses not calculated by the module performance model.

<table>
<thead>
<tr>
<th>Module mismatch (%)</th>
<th>3.5</th>
<th>3.5</th>
<th>3.5</th>
<th>3.5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diodes and connections (%)</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>DC wiring (%)</td>
<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
</tr>
<tr>
<td>Tracking error (%)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nameplate (%)</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>DC power optimizer loss (%)</td>
<td>0</td>
<td>All four subarrays are subject to the same DC power optimizer loss.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total DC power loss (%)</td>
<td>8.035</td>
<td>8.035</td>
<td>8.035</td>
<td>8.035</td>
</tr>
</tbody>
</table>

**Default DC Losses**
Apply default losses to replace DC losses for all subarrays with default values.

Apply default losses for:
- String inverters
- Microinverters
- DC optimizers

**AC Losses**
AC losses apply to the electrical output of the inverter and account for losses not calculated by the inverter performance model.

| AC wiring (%) | 0 % |
| Step-up transformer (%) | 0 % |
| Total AC power loss (%) | 0 % |

### System losses for Array 2

**Irradiance Losses**
Soiling losses apply to the total solar irradiance incident on each subarray. SAM applies these losses in addition to any losses on the Shading and Snow page.

<table>
<thead>
<tr>
<th>Subarray</th>
<th>Monthly soiling loss</th>
<th>Average annual soiling loss</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Edit values...</td>
<td>3.58333</td>
</tr>
<tr>
<td>2</td>
<td>Edit values...</td>
<td>3.58333</td>
</tr>
<tr>
<td>3</td>
<td>Edit values...</td>
<td>5</td>
</tr>
<tr>
<td>4</td>
<td>Edit values...</td>
<td>5</td>
</tr>
</tbody>
</table>

**DC Losses**
DC losses apply to the electrical output of each subarray and account for losses not calculated by the module performance model.

<table>
<thead>
<tr>
<th>Module mismatch (%)</th>
<th>3.5</th>
<th>3.5</th>
<th>2</th>
<th>2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diodes and connections (%)</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>DC wiring (%)</td>
<td>0.07</td>
<td>0.07</td>
<td>2</td>
<td>2</td>
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<tr>
<td>Tracking error (%)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nameplate (%)</td>
<td>4</td>
<td>4</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>DC power optimizer loss (%)</td>
<td>0</td>
<td>All four subarrays are subject to the same DC power optimizer loss.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total DC power loss (%)</td>
<td>7.888</td>
<td>7.888</td>
<td>4.440</td>
<td>4.440</td>
</tr>
</tbody>
</table>

**Default DC Losses**
Apply default losses to replace DC losses for all subarrays with default values.

Apply default losses for:
- String inverters
- Microinverters
- DC optimizers

**AC Losses**
AC losses apply to the electrical output of the inverter and account for losses not calculated by the inverter performance model.

| AC wiring (%) | 0 % |
| Step-up transformer (%) | 0 % |
| Total AC power loss (%) | 0 % |
Inverter input for SAM

PV module input for SAM
Appendix 4
Hays versus Perez model comparison

**PVsyst**

<table>
<thead>
<tr>
<th>Month</th>
<th>GHI kWh/m²</th>
<th>AC Energy (A1) kWh</th>
<th>Global&lt;sub&gt;POA&lt;/sub&gt; kWh/m²</th>
<th>Diffused&lt;sub&gt;POA&lt;/sub&gt; kWh/m²</th>
<th>AC Energy (A2) kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>10</td>
<td>35</td>
<td>33</td>
<td>9</td>
<td>35</td>
</tr>
<tr>
<td>February</td>
<td>28</td>
<td>68</td>
<td>59</td>
<td>20</td>
<td>66</td>
</tr>
<tr>
<td>March</td>
<td>68</td>
<td>127</td>
<td>111</td>
<td>32</td>
<td>125</td>
</tr>
<tr>
<td>April</td>
<td>108</td>
<td>140</td>
<td>125</td>
<td>52</td>
<td>138</td>
</tr>
<tr>
<td>May</td>
<td>153</td>
<td>156</td>
<td>145</td>
<td>64</td>
<td>154</td>
</tr>
<tr>
<td>June</td>
<td>162</td>
<td>151</td>
<td>143</td>
<td>65</td>
<td>149</td>
</tr>
<tr>
<td>July</td>
<td>160</td>
<td>152</td>
<td>147</td>
<td>55</td>
<td>146</td>
</tr>
<tr>
<td>August</td>
<td>122</td>
<td>139</td>
<td>131</td>
<td>62</td>
<td>137</td>
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<tr>
<td>September</td>
<td>73</td>
<td>111</td>
<td>103</td>
<td>34</td>
<td>109</td>
</tr>
<tr>
<td>October</td>
<td>33</td>
<td>58</td>
<td>53</td>
<td>22</td>
<td>57</td>
</tr>
<tr>
<td>November</td>
<td>11</td>
<td>30</td>
<td>27</td>
<td>9</td>
<td>29</td>
</tr>
<tr>
<td>December</td>
<td>5</td>
<td>21</td>
<td>20</td>
<td>7</td>
<td>20</td>
</tr>
<tr>
<td>Yearly total</td>
<td>932</td>
<td>1188</td>
<td>1154</td>
<td>1098</td>
<td>1168</td>
</tr>
</tbody>
</table>

**SAM**

<table>
<thead>
<tr>
<th>Month</th>
<th>GHI kWh/m²</th>
<th>AC Energy (A1) kWh</th>
<th>Global&lt;sub&gt;POA&lt;/sub&gt; kWh/m²</th>
<th>Diffused&lt;sub&gt;POA&lt;/sub&gt; kWh/m²</th>
<th>AC Energy (A2) kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>10</td>
<td>35</td>
<td>34</td>
<td>10</td>
<td>35</td>
</tr>
<tr>
<td>February</td>
<td>28</td>
<td>69</td>
<td>61</td>
<td>22</td>
<td>69</td>
</tr>
<tr>
<td>March</td>
<td>68</td>
<td>130</td>
<td>112</td>
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<tr>
<td>April</td>
<td>108</td>
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<td>126</td>
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<td>141</td>
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<tr>
<td>May</td>
<td>153</td>
<td>157</td>
<td>146</td>
<td>71</td>
<td>158</td>
</tr>
<tr>
<td>June</td>
<td>162</td>
<td>152</td>
<td>144</td>
<td>73</td>
<td>153</td>
</tr>
<tr>
<td>July</td>
<td>160</td>
<td>154</td>
<td>147</td>
<td>66</td>
<td>154</td>
</tr>
<tr>
<td>August</td>
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<td>132</td>
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<td>140</td>
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<td>September</td>
<td>73</td>
<td>112</td>
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<td>October</td>
<td>33</td>
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<td>November</td>
<td>11</td>
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<td>10</td>
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</tr>
<tr>
<td>December</td>
<td>5</td>
<td>19</td>
<td>20</td>
<td>7</td>
<td>19</td>
</tr>
<tr>
<td>Yearly total</td>
<td>932</td>
<td>1199</td>
<td>1104</td>
<td>1077</td>
<td>1201</td>
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</tbody>
</table>
Appendix 5

Inverter datasheet

SB 1200 / SB 1700

Safe
- Integrated ESS DC load-disconnecting unit
- Galvanic isolation

Universal
- For indoor and outdoor installation
- Suitable for generator grounding

Reliable
- Tried and tested technology
- Maintenance free, thanks to convection cooling

SUNNY BOY 1200 / 1700
Proven technology for secure investments

Universally applicable, the Sunny Boy inverters 1200 and 1700 are used in the most diverse AC grids thanks to their galvanic isolation. In addition, the devices are suitable for the simple grounding of the generator. Their integrated ESS DC load-disconnecting unit simplifies installation and reduces its cost at the same time. Equipped with the OpitTrac MPP tracking process, it will always find the optimal working point, even under dynamic weather conditions. In this way, it reliably converts solar energy into solar earnings.
## Technical Data
### SUNNY BOY 1200 / 1700

<table>
<thead>
<tr>
<th>Input (DC)</th>
<th>SB 1200</th>
<th>SB 1700</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max. DC power</td>
<td>1220 W</td>
<td>1850 W</td>
</tr>
<tr>
<td>Max. DC voltage</td>
<td>400 V</td>
<td>400 V</td>
</tr>
<tr>
<td>PV-voltage range, MPPT</td>
<td>100 V – 320 V</td>
<td>139 V – 320 V</td>
</tr>
<tr>
<td>Max. input current</td>
<td>12.6 A</td>
<td>12.6 A</td>
</tr>
<tr>
<td>Number of MPP trackers</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Max. number of strings (optional)</td>
<td>2</td>
<td>2</td>
</tr>
</tbody>
</table>

### Output (AC)

<table>
<thead>
<tr>
<th>Nominal AC input</th>
<th>SB 1200</th>
<th>SB 1700</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max. AC power</td>
<td>1200 W</td>
<td>1550 W</td>
</tr>
<tr>
<td>Max. output current</td>
<td>6.1 A</td>
<td>6.1 A</td>
</tr>
<tr>
<td>AC grid frequency (without stop) / range</td>
<td>50 Hz / 60 Hz / ± 4.5 Hz</td>
<td>50 Hz / 60 Hz / ± 4.5 Hz</td>
</tr>
<tr>
<td>Phase shift (cos φ)</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

### Protection devices

<table>
<thead>
<tr>
<th>Protection devices</th>
<th>SB 1200</th>
<th>SB 1700</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC reverse polarity protection</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>RS-485, load disconnecting switch</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>AC circuit breaker</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Ground fault monitoring</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Grid monitoring (SMA Grid Guard)</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Galvanically isolated</td>
<td>•</td>
<td>•</td>
</tr>
</tbody>
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### General Data

<table>
<thead>
<tr>
<th>Dimensions</th>
<th>SB 1200</th>
<th>SB 1700</th>
</tr>
</thead>
<tbody>
<tr>
<td>H / D (in mm)</td>
<td>440 / 339 / 214</td>
<td>440 / 339 / 214</td>
</tr>
<tr>
<td>Weight</td>
<td>23 kg</td>
<td>25 kg</td>
</tr>
<tr>
<td>Operating temperature range</td>
<td>-25 °C – +60 °C</td>
<td>-25 °C – +60 °C</td>
</tr>
<tr>
<td>Noise emission (typical)</td>
<td>≤ 41 dB(A)</td>
<td>≤ 46 dB(A)</td>
</tr>
<tr>
<td>Consumption (night)</td>
<td>0.1 W</td>
<td>0.1 W</td>
</tr>
<tr>
<td>Topology</td>
<td>1P transformer</td>
<td>1P transformer</td>
</tr>
<tr>
<td>Mounting location</td>
<td>indoors / outdoors (IP65)</td>
<td>indoors / outdoors (IP65)</td>
</tr>
</tbody>
</table>

### Features

<table>
<thead>
<tr>
<th>Features</th>
<th>SB 1200</th>
<th>SB 1700</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC connection, MCT / MSA / Tyco</td>
<td>• / • / •</td>
<td>• / • / •</td>
</tr>
<tr>
<td>AC connection, plug connector</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>LCD</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Interfaces, Bluetooth / RS485</td>
<td>• / •</td>
<td>• / •</td>
</tr>
<tr>
<td>Warranty, 5 years / 10 years / 15 years / 20 years / 25 years</td>
<td>• / • / • / • / •</td>
<td>• / • / • / • / •</td>
</tr>
</tbody>
</table>

### Certificates and Approvals
- www.SMA.de
- www.SMA.de

### Accessories

- SMA Solar Technology AG

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www.SMA.de
Appendix 6

PVsyst simulation reports

Array 1 simulation report

<table>
<thead>
<tr>
<th>PVsyst V6.53</th>
<th>06/09/17</th>
<th>Page 1/4</th>
</tr>
</thead>
</table>

### Grid-Connected System: Simulation parameters

<table>
<thead>
<tr>
<th>Project:</th>
<th>Borlaenge add</th>
<th>Country:</th>
<th>Sweden</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geographical Site:</td>
<td>Borlaenge add</td>
<td>Latitude:</td>
<td>60.43° N</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Longitude:</td>
<td>15.50° E</td>
</tr>
<tr>
<td>Albedo:</td>
<td>0.20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Meteo data:</td>
<td>Borlaenge add</td>
<td>MeteoNorm file - Synthetic</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Simulation variant:</th>
<th>Case 2 - Array 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simulation date:</td>
<td>06/09/17 10h46</td>
</tr>
</tbody>
</table>

#### Simulation parameters

<table>
<thead>
<tr>
<th>Collector Plane Orientation</th>
<th>Tilt: 60°</th>
<th>Azimuth: 33°</th>
</tr>
</thead>
<tbody>
<tr>
<td>Models used:</td>
<td>Transposition: Hay</td>
<td>Diffuse: Perez, Meteonorm</td>
</tr>
<tr>
<td>Horizon:</td>
<td>Free Horizon</td>
<td></td>
</tr>
<tr>
<td>Near Shadings:</td>
<td>No Shadings</td>
<td></td>
</tr>
</tbody>
</table>

#### PV Array Characteristics

<table>
<thead>
<tr>
<th>PV module</th>
<th>Si-mono</th>
<th>Model: GPVM 50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Custom parameters definition</td>
<td>Manufacturer: GPVM</td>
<td></td>
</tr>
<tr>
<td>Number of PV modules</td>
<td>In series: 9 modules</td>
<td></td>
</tr>
<tr>
<td>Total number of PV modules</td>
<td>Nb. modules: 36</td>
<td></td>
</tr>
<tr>
<td>Array global power</td>
<td>Nominal (STC): 1361 Wp</td>
<td></td>
</tr>
<tr>
<td>Array operating characteristics (50°C)</td>
<td>Unit Nom. Power: 37.8 Wp</td>
<td></td>
</tr>
<tr>
<td>Total area</td>
<td>U mpp: 131 V</td>
<td></td>
</tr>
<tr>
<td>Inverter</td>
<td>Model: Sunny Boy 1200</td>
<td></td>
</tr>
<tr>
<td>Inverter pack</td>
<td>Nb. of inverters: 1 units</td>
<td></td>
</tr>
<tr>
<td>Inverter characteristics</td>
<td>Operating Voltage: 100-320 V</td>
<td></td>
</tr>
<tr>
<td>Inverter parameters</td>
<td>Total Nom. Power: 1.20 kWac</td>
<td></td>
</tr>
</tbody>
</table>

#### PV Array loss factors

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>10.0%</td>
<td>5.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>2.0%</td>
<td>10.0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Thermal Loss factor</th>
<th>Uc (const)</th>
<th>29.0 W/m²K</th>
<th>Uv (wind)</th>
<th>0.0 W/m²K / m/s</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wiring Ohmic Loss</td>
<td>Global array.</td>
<td>32 mOhm</td>
<td>Loss Fraction</td>
<td>0.2 % at STC</td>
</tr>
<tr>
<td>Serie Diode Loss</td>
<td>Voltage Drop</td>
<td>0.7 V</td>
<td>Loss Fraction</td>
<td>0.5 % at STC</td>
</tr>
<tr>
<td>Module Quality Loss</td>
<td>Loss Fraction</td>
<td>0.1 %</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Module Mismatch Losses</td>
<td>Loss Fraction</td>
<td>3.5 % at MPP</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Incidence effect, ASHRAE parametrization</td>
<td>IAM = 1 - bo (1/cos i - 1)</td>
<td>bo Param.</td>
<td>0.05</td>
<td></td>
</tr>
</tbody>
</table>

#### User’s needs:

Unlimited load (grid)
Grid-Connected System: Main results

**Project:** Borlaenge add

**Simulation variant:** Case 2 - Array 1

### Main system parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV Field Orientation</td>
<td>tilt</td>
</tr>
<tr>
<td>PV modules</td>
<td>Model</td>
</tr>
<tr>
<td>PV Array</td>
<td>Nb. of modules</td>
</tr>
<tr>
<td>Inverter</td>
<td>Model</td>
</tr>
<tr>
<td>User's needs</td>
<td>Unlimited load (grid)</td>
</tr>
</tbody>
</table>

### Grid-Connected

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>tilt</td>
<td>60°</td>
</tr>
<tr>
<td>azimuth</td>
<td>33°</td>
</tr>
<tr>
<td>Nominal power</td>
<td>1381 Wp</td>
</tr>
<tr>
<td>Nominal power</td>
<td>1200 W ac</td>
</tr>
</tbody>
</table>

### Main simulation results

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Produced Energy</td>
<td>1184 kWh/year</td>
</tr>
<tr>
<td>Performance Ratio PR</td>
<td>79.50 %</td>
</tr>
<tr>
<td>Specific prod.</td>
<td>848 kWh/kWp/year</td>
</tr>
</tbody>
</table>

### Normalized productions (per installed kWp): Nominal power 1381 Wp

#### Performance Ratio PR

### Balances and main results

<table>
<thead>
<tr>
<th>Month</th>
<th>GlobHor kWh/m²</th>
<th>DiffHor kWh/m²</th>
<th>T Amb °C</th>
<th>GlobInc kWh/m²</th>
<th>GlobEff kWh/m²</th>
<th>EArray kWh</th>
<th>E_Grid kWh</th>
<th>PR</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>8.6</td>
<td>5.39</td>
<td>-2.95</td>
<td>32.0</td>
<td>27.9</td>
<td>37.8</td>
<td>34.2</td>
<td>0.785</td>
</tr>
<tr>
<td>February</td>
<td>27.8</td>
<td>15.28</td>
<td>-3.86</td>
<td>56.7</td>
<td>52.4</td>
<td>71.4</td>
<td>64.5</td>
<td>0.836</td>
</tr>
<tr>
<td>March</td>
<td>67.6</td>
<td>28.40</td>
<td>-0.44</td>
<td>108.6</td>
<td>103.8</td>
<td>137.2</td>
<td>124.2</td>
<td>0.840</td>
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<tr>
<td>April</td>
<td>108.0</td>
<td>56.55</td>
<td>4.44</td>
<td>161.6</td>
<td>151.7</td>
<td>140.9</td>
<td>135.7</td>
<td>0.820</td>
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<tr>
<td>May</td>
<td>152.7</td>
<td>74.10</td>
<td>10.72</td>
<td>140.4</td>
<td>133.1</td>
<td>167.3</td>
<td>151.3</td>
<td>0.792</td>
</tr>
<tr>
<td>June</td>
<td>162.4</td>
<td>77.59</td>
<td>14.50</td>
<td>139.3</td>
<td>132.1</td>
<td>163.1</td>
<td>147.7</td>
<td>0.773</td>
</tr>
<tr>
<td>July</td>
<td>159.9</td>
<td>68.87</td>
<td>16.98</td>
<td>143.0</td>
<td>135.4</td>
<td>164.1</td>
<td>148.2</td>
<td>0.762</td>
</tr>
<tr>
<td>August</td>
<td>122.0</td>
<td>69.09</td>
<td>15.76</td>
<td>126.7</td>
<td>120.4</td>
<td>146.1</td>
<td>134.1</td>
<td>0.778</td>
</tr>
<tr>
<td>September</td>
<td>73.0</td>
<td>34.14</td>
<td>11.04</td>
<td>101.0</td>
<td>96.5</td>
<td>120.5</td>
<td>108.7</td>
<td>0.791</td>
</tr>
<tr>
<td>October</td>
<td>33.1</td>
<td>21.46</td>
<td>5.54</td>
<td>51.7</td>
<td>49.2</td>
<td>63.3</td>
<td>55.6</td>
<td>0.805</td>
</tr>
<tr>
<td>November</td>
<td>10.8</td>
<td>7.28</td>
<td>1.32</td>
<td>26.3</td>
<td>25.0</td>
<td>32.7</td>
<td>26.2</td>
<td>0.814</td>
</tr>
<tr>
<td>December</td>
<td>5.4</td>
<td>3.79</td>
<td>-1.83</td>
<td>18.9</td>
<td>16.4</td>
<td>21.9</td>
<td>19.6</td>
<td>0.761</td>
</tr>
</tbody>
</table>

**Year**

| Year       | 932.4          | 481.98         | 6.10    | 1068.3         | 1008.1         | 1277.4     | 1153.5    | 0.795       |

**Legends:**

- GlobHor: Horizontal global irradiation
- DiffHor: Diffuse irradiation
- T Amb: Ambient Temperature
- GlobInc: Global incident on coll. plane
- GlobEff: Effective Global, corr. for IAM and shadings
- EArray: Effective energy at the output of the array
- E_Grid: Energy injected into grid
- PR: Performance Ratio
Grid-Connected System: Loss diagram

Project: Borlaenge add
Simulation variant: Case 2 - Array 1

<table>
<thead>
<tr>
<th>Main system parameters</th>
<th>System type</th>
<th>Grid-Connected</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV Field Orientation</td>
<td>tilt</td>
<td>azimuth 33°</td>
</tr>
<tr>
<td>PV modules</td>
<td>Model</td>
<td>36 Wp</td>
</tr>
<tr>
<td>PV Array</td>
<td>Nb. of modules</td>
<td>Sunny Boy 1200</td>
</tr>
<tr>
<td>Inverter</td>
<td>Model</td>
<td>Phom total 1361 Wp</td>
</tr>
<tr>
<td>User's needs</td>
<td></td>
<td>Phom 1200 W ac</td>
</tr>
</tbody>
</table>

Loss diagram over the whole year

- Horizontal global irradiation
- Global incident in coll. plane
- IAM factor on global
- Soiling loss factor
- Effective irradiance on collectors
- PV conversion
- Array nominal energy (at STC effic.)
- PV loss due to irradiance level
- PV loss due to temperature
- Module quality loss
- Module array mismatch loss
- Ohmic string loss
- Array virtual energy at MPP
- Inverter Loss during operation (efficiency)
- Inverter Loss over nominal inv. power
- Inverter Loss due to power threshold
- Inverter Loss over nominal inv. voltage
- Inverter Loss due to voltage threshold
- Night consumption
- Available Energy at Inverter Output
- Energy injected into grid
Grid-Connected System: P50 - P90 evaluation

**Project:** Borlaenge add  
**Simulation variant:** Case 2 - Array 1

<table>
<thead>
<tr>
<th>Main system parameters</th>
<th>Grid-Connected</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV Field Orientation</td>
<td>tilt 60°</td>
</tr>
<tr>
<td>PV modules</td>
<td>GPVM 50</td>
</tr>
<tr>
<td>PV Array</td>
<td>Nb. of modules 36</td>
</tr>
<tr>
<td>Inverter</td>
<td>Model Sunny Boy 1200</td>
</tr>
<tr>
<td>User's needs</td>
<td>Unlimited load (grid)</td>
</tr>
</tbody>
</table>

**Evaluation of the Production probability forecast**

The probability distribution of the system production forecast for different years is mainly dependent on the meteo data used for the simulation, and depends on the following choices:

- **Meteo data source:** MetroNorm file
- **Meteo data kind:** TMY, multi-year
- **Specified Deviation:** Climate change 0.0 %
- **Year-to-year variability Variance:** 7.8 %

The probability distribution variance is also depending on some system parameters uncertainties:

- Specified Deviation:
  - PV module modelling/parameters 2.0 %
  - Inverter efficiency uncertainty 0.5 %
  - Soiling and mismatch uncertainties 1.0 %
  - Degradation uncertainty 1.0 %

**Global variability (meteo + system) Variance:** 8.2 % (quadratic sum)

**Annual production probability**

- **Variability:** 94 kWh
  - P50 1154 kWh
  - P90 1032 kWh
  - P95 998 kWh

**Probability distribution**

![Probability distribution graph](image)
Array 2 simulation report

Grid-Connected System: Simulation parameters

<table>
<thead>
<tr>
<th>Project</th>
<th>Borlaenge add</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geographical Site</td>
<td>Borlaenge add</td>
</tr>
<tr>
<td>Situation</td>
<td>Latitude 60.43° N</td>
</tr>
<tr>
<td></td>
<td>Longitude 15.50° E</td>
</tr>
<tr>
<td></td>
<td>Time zone UT+1</td>
</tr>
<tr>
<td></td>
<td>Albedo 0.20</td>
</tr>
<tr>
<td>Meteo data:</td>
<td>Borlaenge add</td>
</tr>
<tr>
<td></td>
<td>MeteNorm file - Synthetic</td>
</tr>
</tbody>
</table>

Simulation variant: Case 2 - Array 2

Simulation date: 06/09/17 10h44

Simulation parameters

<table>
<thead>
<tr>
<th>Collector Plane Orientation</th>
<th>Tilt 60°</th>
<th>Azimuth 33°</th>
</tr>
</thead>
<tbody>
<tr>
<td>Models used</td>
<td>Transposition Hay Diffuse Perez, MeteNorm</td>
<td></td>
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<tr>
<td>Horizon</td>
<td>Free Horizon</td>
<td></td>
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<tr>
<td>Near Shadings</td>
<td>No Shadings</td>
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PV Array Characteristics

<table>
<thead>
<tr>
<th>PV module</th>
<th>Si-mono Model GPVM 50</th>
</tr>
</thead>
<tbody>
<tr>
<td>Custom parameters definition</td>
<td>GPVM</td>
</tr>
<tr>
<td>Number of PV modules</td>
<td>18 modules</td>
</tr>
<tr>
<td>Total number of PV modules</td>
<td>36</td>
</tr>
<tr>
<td>Array global power</td>
<td>Nominal (STC) 1361 Wp At operating cond. 1276 Wp (40°C)</td>
</tr>
<tr>
<td>Array operating characteristics (50°C)</td>
<td>U mpp 262 V I mpp 4.9 A</td>
</tr>
<tr>
<td>Total area</td>
<td>Module area 15.0 m² Cell area 12.1 m²</td>
</tr>
</tbody>
</table>

Inverter

<table>
<thead>
<tr>
<th>Inverter</th>
<th>Model Sunny Boy 1200</th>
</tr>
</thead>
<tbody>
<tr>
<td>Custom parameters definition</td>
<td>SMA</td>
</tr>
<tr>
<td>Characteristics</td>
<td>Operating Voltage 100-320 V</td>
</tr>
<tr>
<td>Inverter pack</td>
<td>Nb. of inverters 1 units</td>
</tr>
<tr>
<td></td>
<td>Total Power 1.2 kWac</td>
</tr>
</tbody>
</table>

PV Array loss factors

<table>
<thead>
<tr>
<th>Array Soiling Losses</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.0%</td>
</tr>
</tbody>
</table>

Thermal Loss factor | Uc (const) 29.0 W/m²K |
Wiring Ohmic Loss | Global array res. 36 mΩ |
Series Diode Loss | Voltage Drop 0.7 V |
Module Loss | Loss Fraction 0.1% at STC 0.2% at STC 0.1% |
Module Mismatch Losses | Loss Fraction 3.5% at MPP |
Incidence effect, ASHRAE parametrisation | IAM = 1 - bo (1/cos i - 1) bo Param. 0.05 |
User's needs: Unlimited load (grid)
Grid-Connected System: Main results

Project: Borlaenge add
Simulation variant: Case 2 - Array 2

Main system parameters
- System type: Grid-Connected
- Tilt: 60°
- Azimuth: 33°
- PV modules: 36
- Model: GPVM 50
- Nb. of modules: 36
- Model: Sunny Boy 1200
- User’s needs: Unlimited load (grid)

Main simulation results
- Produced Energy: 1134 kWh/yr
- Performance Ratio PR: 76.14 %
- Specific prod: 833 kWh/kWp/yr

Normalized productions (per installed kWp): Nominal power 1381 Wp

Performance Ratio PR

Case 2 - Array 2
Balances and main results

<table>
<thead>
<tr>
<th></th>
<th>GlobHor kWh/m²</th>
<th>DiffHor kWh/m²</th>
<th>T Amb °C</th>
<th>GlobInc kWh/m²</th>
<th>GlobEff kWh/m²</th>
<th>EArray kWh</th>
<th>E_Grid kWh</th>
<th>PR</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>9.6</td>
<td>5.39</td>
<td>-2.95</td>
<td>32.9</td>
<td>27.9</td>
<td>34.4</td>
<td>0.768</td>
<td></td>
</tr>
<tr>
<td>February</td>
<td>27.8</td>
<td>15.28</td>
<td>-3.96</td>
<td>56.7</td>
<td>52.4</td>
<td>71.6</td>
<td>63.2</td>
<td>0.819</td>
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<td>March</td>
<td>67.6</td>
<td>28.40</td>
<td>-4.64</td>
<td>138.6</td>
<td>103.8</td>
<td>137.7</td>
<td>122.3</td>
<td>0.827</td>
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<td>April</td>
<td>108.0</td>
<td>56.55</td>
<td>5.44</td>
<td>212.6</td>
<td>115.7</td>
<td>150.4</td>
<td>133.4</td>
<td>0.806</td>
</tr>
<tr>
<td>May</td>
<td>152.7</td>
<td>74.10</td>
<td>10.72</td>
<td>240.4</td>
<td>133.1</td>
<td>167.9</td>
<td>148.8</td>
<td>0.779</td>
</tr>
<tr>
<td>June</td>
<td>162.4</td>
<td>77.59</td>
<td>14.50</td>
<td>133.3</td>
<td>132.1</td>
<td>183.7</td>
<td>144.9</td>
<td>0.764</td>
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<tr>
<td>July</td>
<td>159.9</td>
<td>88.87</td>
<td>18.9</td>
<td>143.0</td>
<td>135.4</td>
<td>184.7</td>
<td>145.9</td>
<td>0.750</td>
</tr>
<tr>
<td>August</td>
<td>122.0</td>
<td>69.09</td>
<td>15.76</td>
<td>120.7</td>
<td>122.4</td>
<td>148.7</td>
<td>131.9</td>
<td>0.765</td>
</tr>
<tr>
<td>September</td>
<td>73.0</td>
<td>34.14</td>
<td>11.04</td>
<td>101.0</td>
<td>96.5</td>
<td>120.9</td>
<td>107.1</td>
<td>0.779</td>
</tr>
<tr>
<td>October</td>
<td>33.1</td>
<td>21.46</td>
<td>5.54</td>
<td>51.7</td>
<td>49.2</td>
<td>63.5</td>
<td>55.4</td>
<td>0.788</td>
</tr>
<tr>
<td>November</td>
<td>10.8</td>
<td>7.28</td>
<td>1.32</td>
<td>26.3</td>
<td>25.0</td>
<td>32.8</td>
<td>28.0</td>
<td>0.797</td>
</tr>
<tr>
<td>December</td>
<td>5.4</td>
<td>3.79</td>
<td>-1.83</td>
<td>18.9</td>
<td>16.4</td>
<td>22.0</td>
<td>19.1</td>
<td>0.741</td>
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<tr>
<td>Year</td>
<td>932.4</td>
<td>481.96</td>
<td>6.10</td>
<td>1086.3</td>
<td>1008.1</td>
<td>1281.7</td>
<td>1133.8</td>
<td>0.781</td>
</tr>
</tbody>
</table>

Legends: GlobHor: Horizontal global irradiation
         DiffHor: Horizontal diffuse irradiation
         T Amb: Ambient Temperature
         GlobInc: Global irradiation in coll. plane
         GlobEff: Effective Global corr. for IAE and shadings
         EArray: Effective energy at the output of the array
         E_Grid: Energy injected into grid
         PR: Performance Ratio
Grid-Connected System: Loss diagram

Project: Borlaenge add
Simulation variant: Case 2 - Array 2

<table>
<thead>
<tr>
<th>Main system parameters</th>
<th>System type</th>
<th>Grid-Connected</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV Field Orientation</td>
<td>tilt 60°</td>
<td>azimuth 33°</td>
</tr>
<tr>
<td>PV modules</td>
<td>Model GPVM 50</td>
<td>Pnom 36 Wp</td>
</tr>
<tr>
<td>PV Array</td>
<td>Nb. of modules 36</td>
<td>Pnom total 1361 Wp</td>
</tr>
<tr>
<td>Inverter</td>
<td>Model Sunny Boy 1200</td>
<td>Pnom 1200 W ac</td>
</tr>
<tr>
<td>User's needs</td>
<td>Unlimited load (grid)</td>
<td></td>
</tr>
</tbody>
</table>

Loss diagram over the whole year

- Horizontal global irradiation
- Global incident in coll. plane
- -14.4%
- -3.0%
- -2.5%
- IAM factor on global
- Soiling loss factor
- Effective irradiance on collectors
- PV conversion

Array nominal energy (at STC effic.)
- PV loss due to irradiance level
- PV loss due to temperature
- Module quality loss
- Module array mismatch loss
- Ohmic wiring loss

Array virtual energy at MPP
- Inverter Loss during operation (efficiency)
- Inverter Loss over nominal inv. power
- Inverter Loss due to power threshold
- Inverter Loss over nominal inv. voltage
- Inverter Loss due to voltage threshold
- Night consumption

Available Energy at Inverter Output
- Energy injected into grid
Grid-Connected System: P50 - P90 evaluation

Project: Borlaenge add
Simulation variant: Case 2 - Array 2

Main system parameters
- System type: Grid-Connected
- Tilt: 60°
- Azimuth: 33°
- PV modules: GPV/M 50
- Pv total: 36 Wp
- Inverter: Sunny Boy 1200
- Nom total: 1361 Wp
- User's needs: Unlimited load (grid)

Evaluation of the Production probability forecast

The probability distribution of the system production forecast for different years is mainly dependent on the meteo data used for the simulation, and depends on the following choices:

- Meteo data source: MeteoNorm file
- Kind: TMY, multi-year
- Specified Deviation: Climate change 0.0 %
- Year-to-year variability: Variance 7.8 %

The probability distribution variance is also depending on some system parameters uncertainties

- Specified Deviation: PV module modelling/parameters 2.0 %
- Inverter efficiency uncertainty 0.5 %
- Soiling and mismatch uncertainties 1.0 %
- Degradation uncertainty 1.0 %
- Global variability (meteo + system) Variance 8.2 % (quadratic sum)

Annual production probability

- Variability: 93 kWh
- P50: 1134 kWh
- P90: 1015 kWh
- P95: 981 kWh

Probability distribution

- E_Grid system production kWh
- P50 = 1134 kWh
- E_Grid simul = 1134 kWh
- P90 = 1015 kWh
- P95 = 981 kWh
## Appendix 7

### SAM simulation reports

#### Array 1

**System Advisor Model Report**

- **Photovoltaic System**: 1.36 kW Nameplate
- **Location**: Borlaenge, None
- **Installed Cost**: $0.00/W
- **Time Zone**: 60.43 N, 15.5 E, GMT +1

### Performance Model

<table>
<thead>
<tr>
<th>Modules</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>User-specified parameters</td>
<td>monoSi</td>
</tr>
<tr>
<td>Cell material</td>
<td></td>
</tr>
<tr>
<td>Module area</td>
<td>0.4 m²</td>
</tr>
<tr>
<td>Module capacity</td>
<td>37.8 DC Watts</td>
</tr>
<tr>
<td>Quantity</td>
<td>36</td>
</tr>
<tr>
<td>Total capacity</td>
<td>1.4 DC kW</td>
</tr>
<tr>
<td>Total area</td>
<td>14 m²</td>
</tr>
</tbody>
</table>

### Inverters

<table>
<thead>
<tr>
<th>Custom (Inverter Datasheet Model)</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit capacity</td>
<td>1.2 AC kW</td>
</tr>
<tr>
<td>Input voltage</td>
<td>210 DC V</td>
</tr>
<tr>
<td>Quantity</td>
<td>1</td>
</tr>
<tr>
<td>Total capacity</td>
<td>1.2 AC kW</td>
</tr>
<tr>
<td>DC to AC Capacity Ratio</td>
<td>1.14</td>
</tr>
<tr>
<td>AC losses (%)</td>
<td>0.0</td>
</tr>
</tbody>
</table>

### Four subarrays:

<table>
<thead>
<tr>
<th>Strings</th>
<th>Modules per string</th>
<th>String voltage (DC V)</th>
<th>Tilt (deg from horizontal)</th>
<th>Azimuth (deg E of N)</th>
<th>Tracking</th>
<th>Self shading</th>
<th>Rotation limit (deg)</th>
<th>Shading</th>
<th>Snow</th>
<th>Soiling</th>
<th>DC losses (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>145.9</td>
<td>60.0</td>
<td>213</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>yes</td>
<td>8.0</td>
</tr>
<tr>
<td>2</td>
<td>9</td>
<td>145.9</td>
<td>60.0</td>
<td>213</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>yes</td>
<td>8.0</td>
</tr>
<tr>
<td>3</td>
<td>9</td>
<td>145.9</td>
<td>60.0</td>
<td>213</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>yes</td>
<td>8.0</td>
</tr>
<tr>
<td>4</td>
<td>9</td>
<td>145.9</td>
<td>60.0</td>
<td>213</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>no</td>
<td>yes</td>
<td>8.0</td>
</tr>
</tbody>
</table>

### Performance Adjustments

- **Availability/Curtailment**: none
- **Degradation**: none
- **Hourly or custom losses**: none

### Annual Results (in Year 1)

<table>
<thead>
<tr>
<th>GHC kW/m²/day</th>
<th>PQA kW/m²/day</th>
<th>Net to inverter</th>
<th>Net to grid</th>
<th>Capacity factor</th>
<th>Performance ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.6</td>
<td>2.6</td>
<td>1,280 DC kWh</td>
<td>1,170 AC kWh</td>
<td>9.81</td>
<td>0.8</td>
</tr>
</tbody>
</table>
No Financial model.
Photovoltaic System: None

1.36 kW Nameplate
Borlaenge, 60.43 N, 15.5 E GMT +1

Nominal POA (kWh)
16.134

Nominal DC energy (kWh)
1,430

Net DC energy (kWh)
1,289

Gross AC energy (kWh)
1,171

Annual energy (kWh)
1,171
Array 2

### System Advisor Model Report

**Photovoltaic System**
- Nameplate: 1.36 kW
- Installed Cost: $0.00/W
- Location: Bolaenge, 60.43 N, 15.5 E GMT +1

### Performance Model

#### Modules
- User-specified parameters
- Cell material: monoSi
- Module area: 0.4 m²
- Module capacity: 37.6 DC Watts
- Quantity: 36
- Total capacity: 1.4 DC kW
- Total area: 14 m²

#### Inverters
- Custom (Inverter Datasheet Model)
- Unit capacity: 1.2 AC kW
- Input voltage: 210 DC V
- Quantity: 1
- Total capacity: 1.2 AC kW
- DC to AC Capacity Ratio: 1.14
- AC losses (%): 0.0

#### Two subarrays:
<table>
<thead>
<tr>
<th></th>
<th>1</th>
<th>2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Strings</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Modules per string</td>
<td>18</td>
<td>18</td>
</tr>
<tr>
<td>String voltage (DC V)</td>
<td>291.8</td>
<td>291.8</td>
</tr>
<tr>
<td>Tilt (deg from horizontal)</td>
<td>60.0</td>
<td>60.0</td>
</tr>
<tr>
<td>Azimuth (deg E of N)</td>
<td>213</td>
<td>213</td>
</tr>
<tr>
<td>Tracking</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>Backtracking</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Self shading</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>Rotation limit (deg)</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Shading</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>Snow</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>Soiling</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>DC losses (%)</td>
<td>7.9</td>
<td>7.9</td>
</tr>
</tbody>
</table>

### Performance Adjustments
- Availability/Curtailment: none
- Degradation: none
- Hourly or custom losses: none

### Annual Results (in Year 1)

| GHI kWm²/day | 2.8 | 2.8 |
| POA kWm²/day | 2.0 | 2.0 |
| Net to inverter | 1,290 DC kWh |
| Net to grid | 1,170 AC kWh |
| Capacity factor | 9.82 |
| Performance ratio | 0.8 |

No Financial model.
No Financial model.
Photovoltaic System

Nominal POA (kWh)
18.134

Nominal DC energy (kWh)
1.435

Net DC energy (kWh)
1.286

Gross AC energy (kWh)
1.172

Annual energy (kWh)
1.172

Boraenge,
60.43 N, 15.5 E, GMT +1

1.36 kW Nameplate
$0.00/W Installed Cost