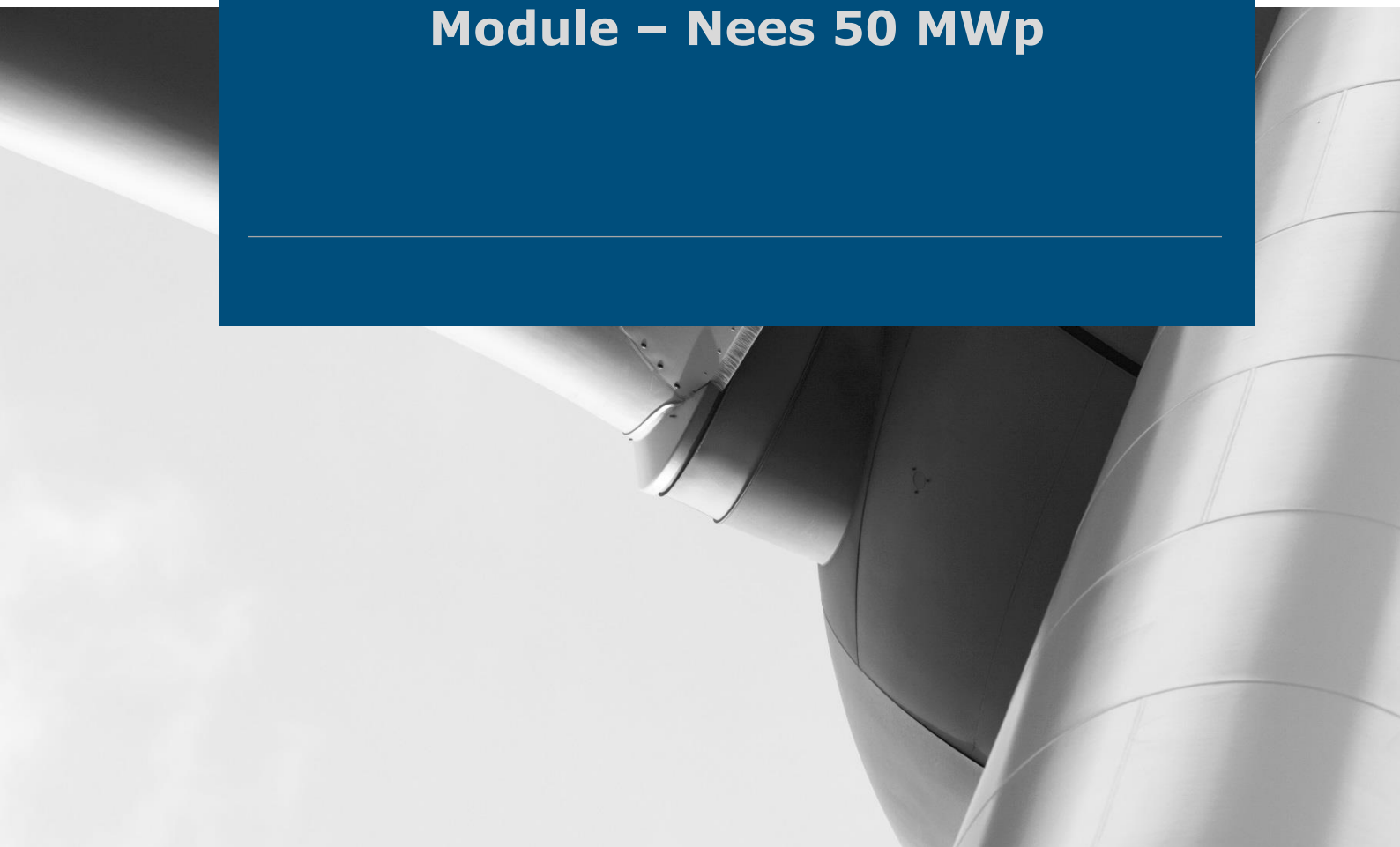
# Technical Note:

## Validation of windPRO SOLAR PV Module – Nees 50 MWp



DATE

22 June 2020

PREPARED BY

EMD International A/S
Niels Jernes Vej 10
DK- 9220 Aalborg
T: + 45 96 35 44 44
E: emd@emd.dk

AUTHOR

Per Nielsen
EMD International A/S
pn@emd.dk

CONTRIBUTORS

Leif Holm Tambjerg

REVIEW

Anders N. Andersen.

EDITION

1.0

# Contents

# Executive Summary

Using the Nees 35 MW AC, 50 MW DC project it is validated that the windPRO Solar-PV module in windPRO 3.4 is capable of reproducing real-world measurements with predictions within +/-2% for each panel group tested in the following situations:

1. Array shading only
2. Obstacle shading
3. WTG shading

The entire plant is also modelled by subdividing into three inverter sections. This is predicted accurately (within 0.2%) compared to actual measurements for all three sections when corrected for data and availability losses.

In all three detailed validation cases, the comparisons are performed by comparing concurrent measured and calculated time series. Availability issues and gaps in measured data have been filtered out.

The calculations are initially based on two data sets:

1. Local tilted (20°) solar irradiation measurements (15-minute time resolution)
2. Heliosat (SARAH) model data based on satellite obtained cloud coverage (30-minute time resolution)

Having the local measurements tilted (20° matching the panels) conflicts with normal solar irradiation measurement procedures, where irradiation is measured on a horizontal plane. This is handled by "un-tilting" the data and using these as if they were on horizontal plane.

Calculating the full plant with Heliosat data gives an exact match to measurements when these are corrected for availability losses found in the time series. The availability losses account for 3.5%, which seems high. However, the availability concerns both the measurement system and the production units. Some of the availability losses might just be missing data, not missing production.

Overall, the results of this note show that with care and attention, the windPRO Solar-PV module can produce accurate results.

# 1 The test project


*Figure 1 The Nees project in North West Jutland.*

This note concerns the validation of windPRO's Solar-PV module using the Nees PV project. The Nees project is located in North West Jutland, approximately 10km west of Holstebro. The project has been in operation since 2017 and consists of 50MWp of PV. In addition, there is a single 500 kW wind turbine located within the array (Vestas V39, 40.5m hub height).

Of importance for a thorough validation is that there is obstacle shading as well as WTG shading – and of course panel shading. The three shading types will be validated by selection of suitable panels.

## 1.1 String configuration

*Figure 2 The string layout showing how measurements are arranged.*

The panels are arranged with 20 panels on each inverter string, where measurements are available for each of the 8 strings connected to one inverter.

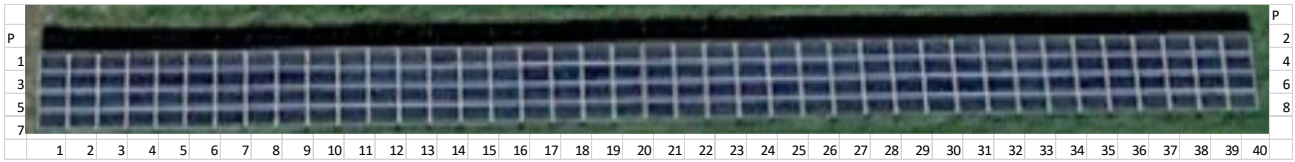



*Figure 3 The "real view" of the panels corresponding to string layout.*

The upper left 20 panels are named P1, Upper right 20 panels P2 etc.

## 1.2 The measurements

The measurements used come from a variety of sources; inverter measurements, irradiation measurement stations, collected power for inverter sections. The first mentioned are described here.

*Table 1 Data files, inverter measurements.*

15-min values, one file for each inverter and month:

| **Column header** | **1. data line:** |
|---|---|
| Generated On | 2019-01-01 00:00:00 |
| Device Status | Idle: No irradiation |
| Daily Energy (kWh) | 0.00 |
| Inv. Efficiency (%) | 0.00 |
| Lifetime Energy (kWh) | 50356.05 |
| Input Power(kW) | 0.000 |
| Active Power (kW) | 0.000 |
| Reactive Power (kVar) | 0.000 |
| Power Factor | 0.000 |
| Grid Frequency (Hz) | 0.00 |
| Grid A Current (A) | 0.0 |
| Grid B Current (A) | 0.0 |
| Grid C Current (A) | 0.0 |
| Grid AB Line Voltage (V) | 0.0 |
| Grid BC Line Voltage (V) | 0.0 |
| Grid CA Line Voltage (V) | 0.0 |
| PV1 Input Current (A) | 0.00 |
| PV2 Input Current (A) | 0.00 |
| PV3 Input Current (A) | 0.00 |
| PV4 Input Current (A) | 0.00 |
| PV5 Input Current (A) | 0.00 |
| PV6 Input Current (A) | 0.00 |

| | |
|---|---|
| PV7 Input Current (A) | 0.00 |
| PV8 Input Current (A) | 0.00 |
| PV1 Input Voltage (V) | 0.0 |
| PV2 Input Voltage (V) | 0.0 |
| PV3 Input Voltage (V) | 0.0 |
| PV4 Input Voltage (V) | 0.0 |
| PV5 Input Voltage (V) | 0.0 |
| PV6 Input Voltage (V) | 0.0 |
| PV7 Input Voltage (V) | 0.0 |
| PV8 Input Voltage (V) | 0.0 |
| Cabinet Temperature (°C) | 23.8 |

The parameters used for the validation calculations are the inverter efficiency and the voltage and current for each panel string (20 panels).

The data for selected inverters for the validation is loaded in a windPRO meteo object, where two import filters are used so the daylight-saving adjustment is taken out and all data is in time zone UTC+1.

The data are then copied from meteo objects to Excel, where measured active power is calculated for each time stamp for each panel string as A (ampere) x V(volt) x Inv. Eff. Using this method, totals for all 8 panel strings are compared to the data column "Active power" and found to match well.

In this way, active power is available for each sub string, which is important especially for validating the panel shading calculation, which differs significantly between the lower and higher vertical placed panel strings.

## 1.3 The Panels

The panels are "Tata Power Solar", the TP300 series. The panels installed range from 310 W to 325 W, based on what the manufacturer could deliver at the time of installation. See 5.1 for the arrangement of the different sizes. Figures 4 & 5 show the 325 W variant as input in windPRO:

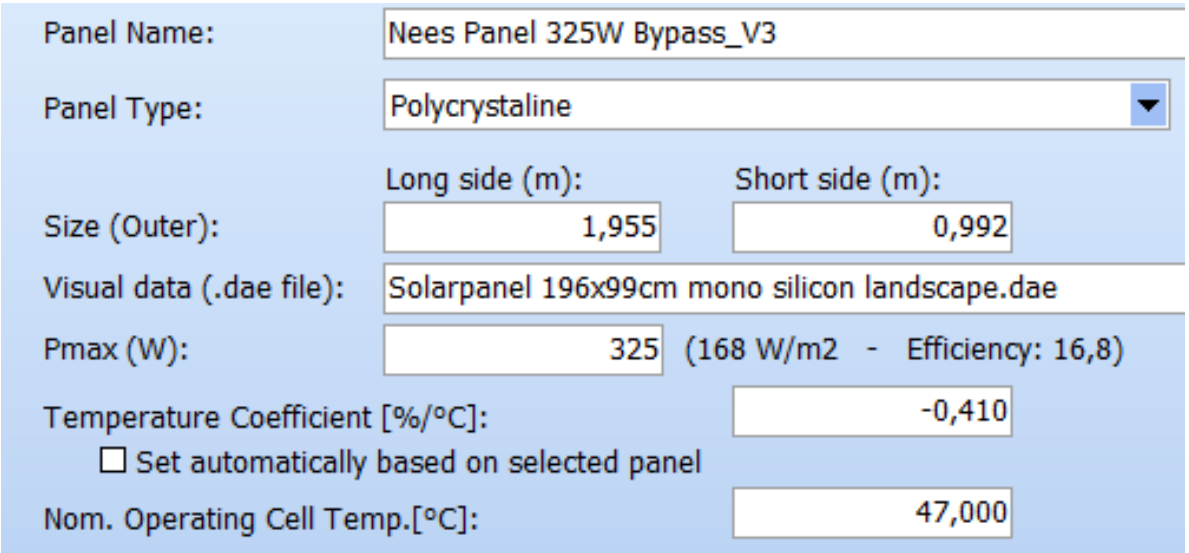



*Figure 4 General panel specifications.*

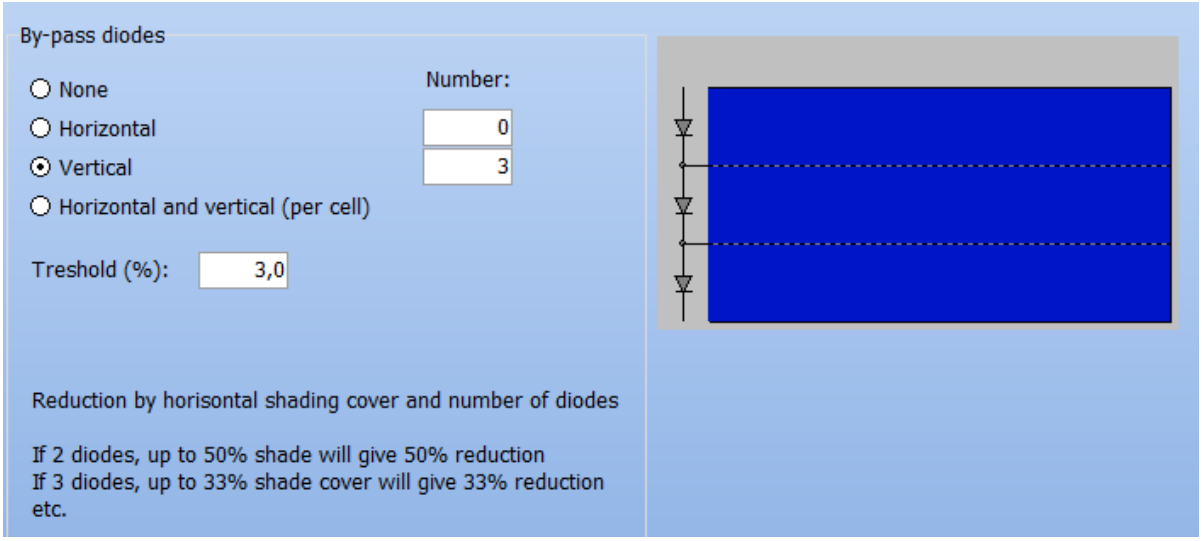



*Figure 5 Bypass diodes within panels.*

The bypass diodes mean that horizontal shading (e.g. array shading) will give limited losses, while vertical shading (e.g. WTG tower) will remove the direct irradiation for the entire panel even if just a small part of the panel is shaded. Apart from shading reduction of direct irradiation, the diffuse irradiation will be reduced by the panel arrangement. Panels with 0° tilt angle will have no diffuse reduction (facing 180°), while tilted panels will be reduced partly by the tilt angle reducing the 180° view, partly by further reduction from the panel in front.

## 1.4 Validation setup

The measurements are compared to calculations, where neither measurements, nor calculations are reduced for internal grid loss. In the detailed tests concurrent measured and calculated data where all substrings have >0 active power are compared in order to eliminate the problems of availability.

A part of the test is detailed visualization of the calculations and measurements, see Figure 6:

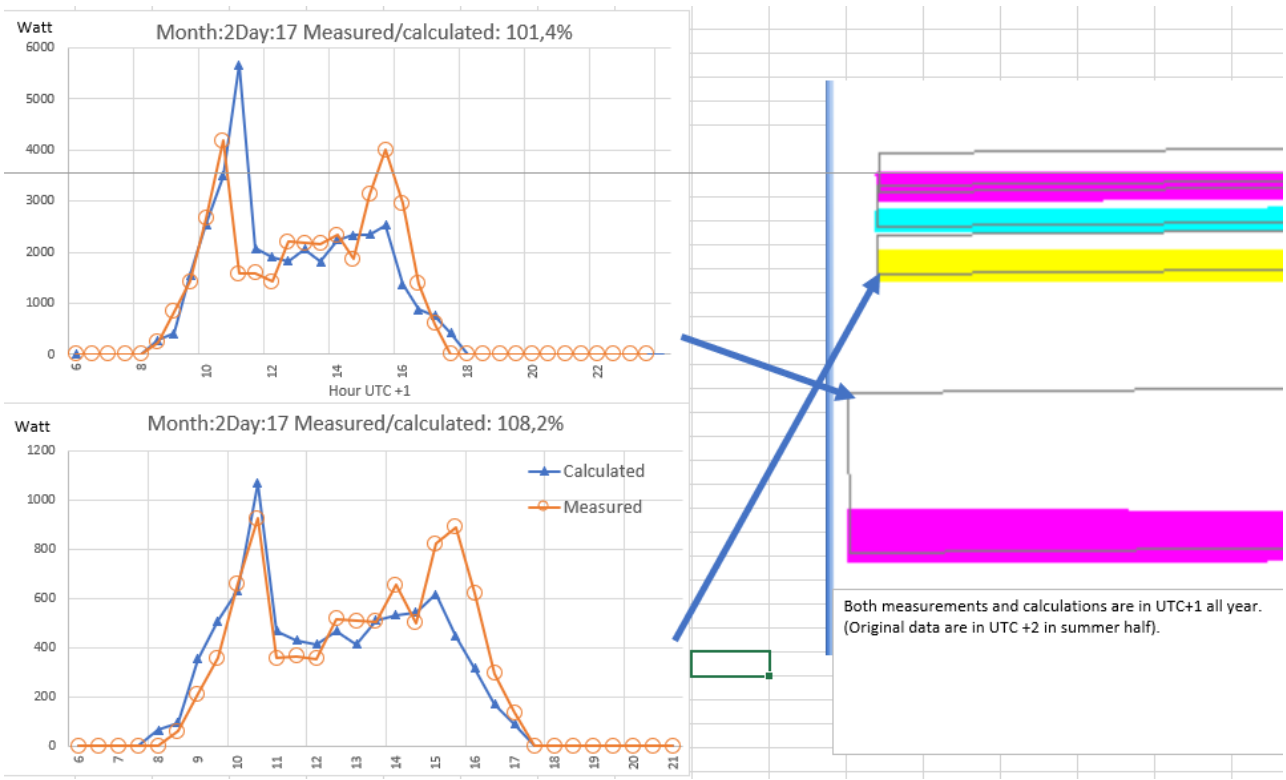



*Figure 6 Comparing measured and calculated values on a ½ hour basis for selected panel groups for a specific day.*

The detailed comparisons are to see if calculations work as expected. The main evaluations are based on annual and monthly values. To the right the panel arrangement is seen. The lower one is a full table with 4 panel rows. In the upper, the panel rows are established individually in the calculation setup.

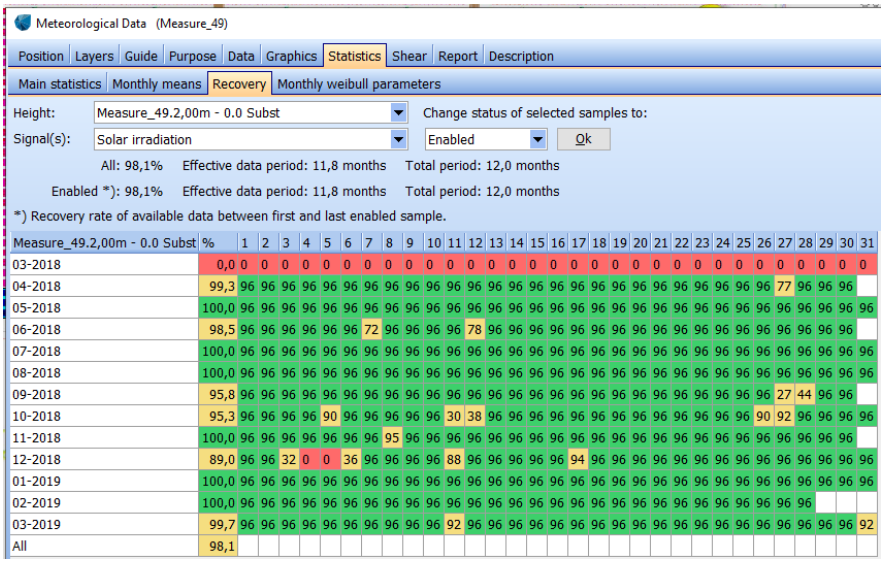
## 1.5 Meteorological data for calculation

There are local measurements of solar irradiation at five locations.


*Figure 7 Three of the five measurement locations shown in yellow, and their locations within the arrays.*

Apart from the three measurement locations marked above, there is one further north and one further south. Our three detailed test calculation areas are shown with blue markings:

1. Panel array shading only
2. Obstacle shading
3. WTG shading



Meteorological Data (Measure_49)

Position | Layers | Guide | Purpose | Data | Graphics | Statistics | Shear | Report | Description

Main statistics | Monthly means | Recovery | Monthly weibull parameters

Height: Measure_49.2,00m - 0.0 Subst — Change status of selected samples to:

Signal(s): Solar irradiation — Enabled — Ok

All: 98,1% Effective data period: 11,8 months Total period: 12,0 months

Enabled *): 98,1% Effective data period: 11,8 months Total period: 12,0 months

*) Recovery rate of available data between first and last enabled sample.

| Measure_49.2,00m - 0.0 Subst | % | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 03-2018 | 0,0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 04-2018 | 99,3 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 77 | 96 | 96 | 96 | |
| 05-2018 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 06-2018 | 98,5 | 96 | 96 | 96 | 96 | 96 | 96 | 72 | 96 | 96 | 96 | 96 | 78 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | |
| 07-2018 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 08-2018 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 09-2018 | 95,8 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 27 | 44 | 96 | 96 | |
| 10-2018 | 95,3 | 96 | 96 | 96 | 96 | 90 | 96 | 96 | 96 | 96 | 96 | 30 | 38 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 90 | 92 | 96 | 96 | 96 | 96 |
| 11-2018 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 95 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | |
| 12-2018 | 89,0 | 96 | 96 | 32 | 0 | 0 | 36 | 96 | 96 | 96 | 96 | 88 | 96 | 96 | 96 | 96 | 96 | 94 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 01-2019 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 02-2019 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | | | |
| 03-2019 | 99,7 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 92 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 92 |
| All | 98,1 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

*Figure 8 Local measurements from measure point 49 (at inverter area 49)*

Substitutions were made in the data from measure point 1 where data were missing. Data at 15 min. resolution was available for the period 01.04.2018-31.03.2019 with 98.1% recovery rate.

The local measurements are compared to Heliosat[1] data and Høvsøre measurements operated by DTU/Risø just 7 km NW of the Nees location. The Local measurements were recorded with a 20° tilt (to match the panel tilt) and therefore need to be converted to the horizontal, to match the other data sources. This is done by calculating with Heliosat data and establish the ratio between local irradiation with 20° tilt and the 0° data:

| Average of Tilted/horisontal | Column Labels | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Row Labels | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Grand Total |
| 0 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 1 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 2 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | - | - | - | - | 0,09 | 0,63 | 0,09 | - | - | - | - | - | 0,07 |
| 5 | - | - | - | 0,11 | 0,71 | 0,85 | 0,79 | 0,35 | - | - | - | - | 0,24 |
| 6 | - | - | 0,08 | 0,69 | 0,90 | 0,90 | 0,91 | 0,87 | 0,54 | 0,07 | - | - | 0,42 |
| 7 | - | 0,12 | 0,91 | 1,01 | 0,99 | 0,97 | 0,97 | 0,99 | 1,04 | 1,40 | 0,10 | - | 0,71 |
| 8 | 0,07 | 1,06 | 1,11 | 1,06 | 1,06 | 1,02 | 1,02 | 1,04 | 1,08 | 1,25 | 1,01 | - | 0,90 |
| 9 | 1,54 | 1,28 | 1,14 | 1,10 | 1,10 | 1,05 | 1,06 | 1,06 | 1,12 | 1,30 | 1,18 | 1,21 | 1,18 |
| 10 | 1,33 | 1,29 | 1,14 | 1,10 | 1,12 | 1,07 | 1,08 | 1,08 | 1,12 | 1,24 | 1,17 | 1,21 | 1,16 |
| 11 | 1,29 | 1,25 | 1,17 | 1,11 | 1,14 | 1,08 | 1,10 | 1,09 | 1,14 | 1,25 | 1,16 | 1,18 | 1,16 |
| 12 | 1,34 | 1,23 | 1,19 | 1,12 | 1,13 | 1,08 | 1,10 | 1,11 | 1,11 | 1,21 | 1,25 | 1,25 | 1,18 |
| 13 | 1,42 | 1,22 | 1,18 | 1,12 | 1,11 | 1,08 | 1,10 | 1,10 | 1,11 | 1,23 | 1,29 | 1,34 | 1,19 |
| 14 | 1,37 | 1,23 | 1,18 | 1,09 | 1,10 | 1,06 | 1,08 | 1,09 | 1,12 | 1,30 | 1,31 | 1,28 | 1,18 |
| 15 | 2,00 | 1,37 | 1,18 | 1,07 | 1,08 | 1,04 | 1,06 | 1,06 | 1,10 | 1,33 | 2,23 | 4,65 | 1,60 |
| 16 | 1,31 | 1,73 | 1,20 | 1,07 | 1,04 | 1,00 | 1,02 | 1,03 | 1,10 | 2,21 | 1,84 | - | 1,21 |
| 17 | - | 1,70 | 1,23 | 1,01 | 0,94 | 0,94 | 0,95 | 0,99 | 1,12 | 0,96 | - | - | 0,81 |
| 18 | - | - | 0,22 | 0,87 | 0,77 | 0,85 | 0,82 | 0,87 | 0,40 | - | - | - | 0,40 |
| 19 | - | - | - | 0,22 | 0,60 | 0,69 | 0,66 | 0,56 | - | - | - | - | 0,23 |
| 20 | - | - | - | - | 0,20 | 0,70 | 0,55 | 0,01 | - | - | - | - | 0,12 |
| 21 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 22 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 23 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Grand Total** | **0,49** | **0,56** | **0,54** | **0,57** | **0,63** | **0,67** | **0,64** | **0,60** | **0,55** | **0,61** | **0,52** | **0,51** | **0,57** |

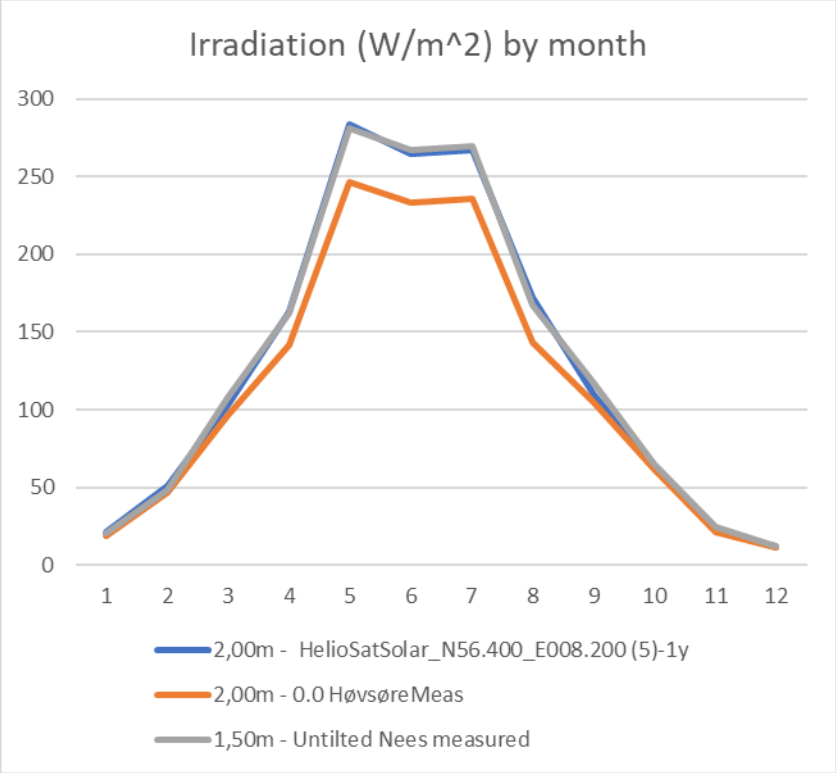
*Figure 9 Calculated ratio 20° irradiation tilted to horizontal by month and hour.*

The ratio is highest around mid-day in winter months and lowest in the morning and evening. With these month/hours values, the Nees tilted data are processed for each time step, to create an untilted data set.

The results of the adjustment can be seen in Figure 10, where good matches are seen between the adjusted Nees data and the Heliosat data.

[1] "Heliosat (SARAH)" is a satellite-based surface solar irradiance dataset: The raw data are produced and delivered by EUMETSAT

http://help.emd.dk/mediawiki/index.php?title=Heliosat_(SARAH)




The measurements at Nees is very close to Heliosat data for the concurrent year.

The reason for Høvsøre being lower than Nees as well as Heliosat is due to shading, mostly, but not only, in the afternoon, from the measurement mast where the measurement device is mounted. This makes this source poor for comparison. Although for some parts of the day which are without shade, there is a very fine match to the Nees measurements.

The local Nees measurements show round 1% higher global radiation than Heliosat.

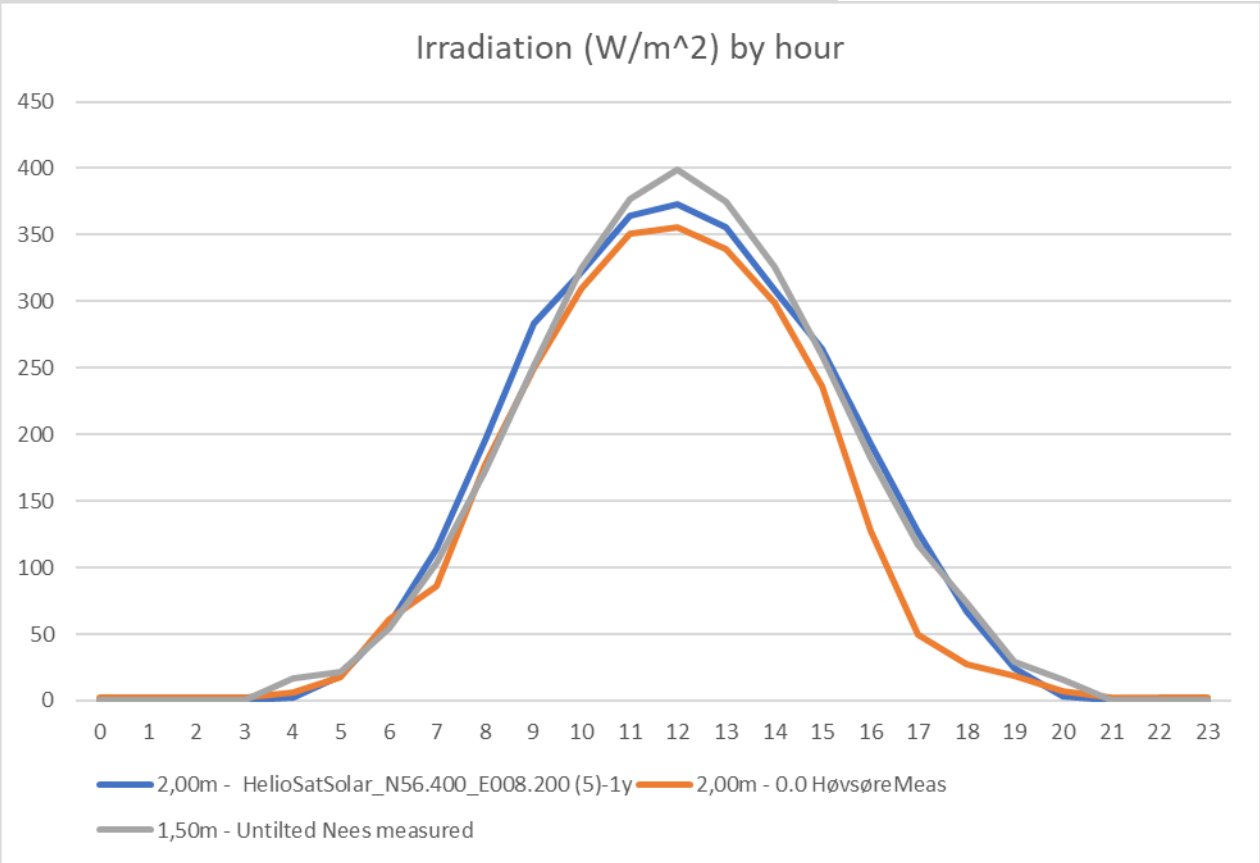



*Figure 10 Solar irradiation data comparisons by month (upper) and by hour (lower).*

In our validations, we calculate with local measurements as well as with Heliosat data to test the sensitivity of the difference in radiation as well as time resolution. Heliosat data is half-hourly, Nees quarter-hourly.

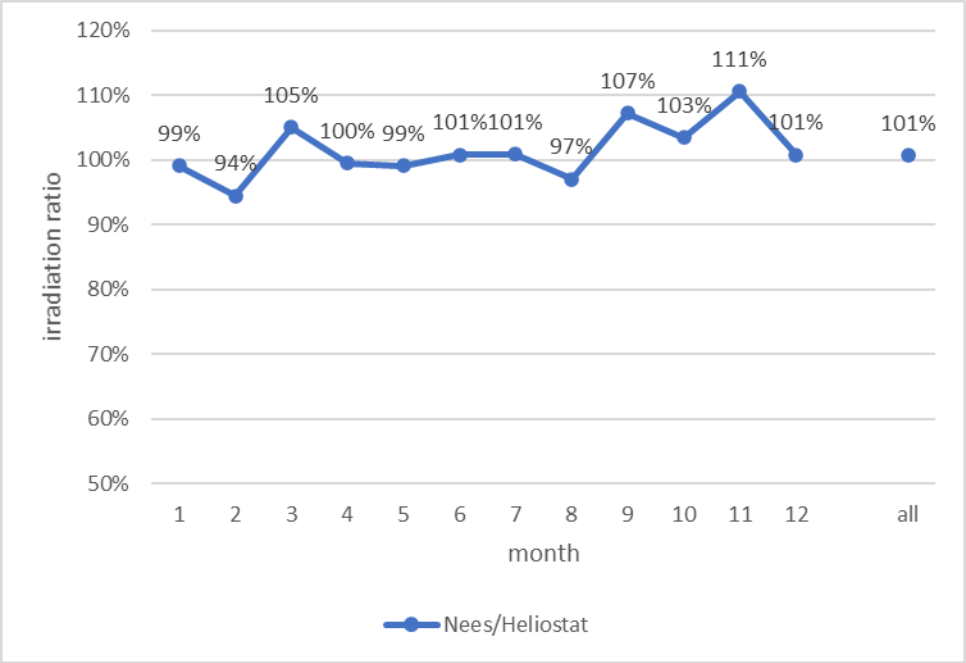



*Figure 11 The local measurements have some deviations to the Heliosat data by month.*

## 1.6 windPRO's meteorological data handling

When using windPRO, the recovery rate becomes less problematic. There is a built-in advanced gap-filling function, which uses nearest-neighbor samples to gap-fill based on the ratio between the top of atmosphere radiation at the specific location and the local data. This method therefore assumes the same cloudiness in the missing samples as is the case for the nearest-neighbor samples.

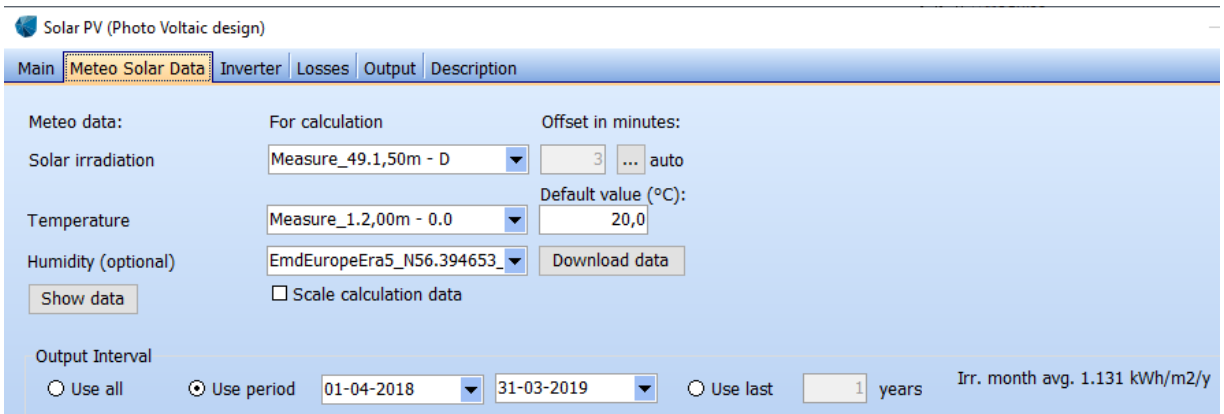



*Figure 12 Setting up the Meteo data for calculation.*

Figure 12 shows an example of the setup of the Meteo data, here based on the local measurements loaded in a Meteo object. Humidity data are taken from EmdEuropeEra5 dataset (this data set require subscription, but also free data sets like ERA5 includes humidity). Humidity is used for separating the global irradiation into direct and diffuse

irradiation. If no humidity data are loaded, a simplified model is implemented. Data must be loaded into Meteo objects.

windPRO users have access to an online data service, where, for example, the Heliosat (SARAH) data are available. A simple download service is established, which loads nearest Heliosat (if the project site lies within the coverage area) and the nearest ERA5-T data set (global coverage). There will always be one Irradiation, Temperature and Humidity signal from ERA5-T model data and, probably the best model data set, Heliosat. The Heliosat data will be used as an alternative to the local measurements in the validations. The Heliosat data are available for a quite large area, see coverage below. Heliosat data are created by utilizing satellite images of cloud coverage with 30 min. resolution in time and ~5 km spatial resolution. There are two data sets:

West (half-hourly values, updated monthly):

http://help.emd.dk/mediawiki/index.php?title=Heliosat_(SARAH)

East (one hour values, not updated regularly):
http://help.emd.dk/mediawiki/index.php?title=Heliosat_(SARAH)_East

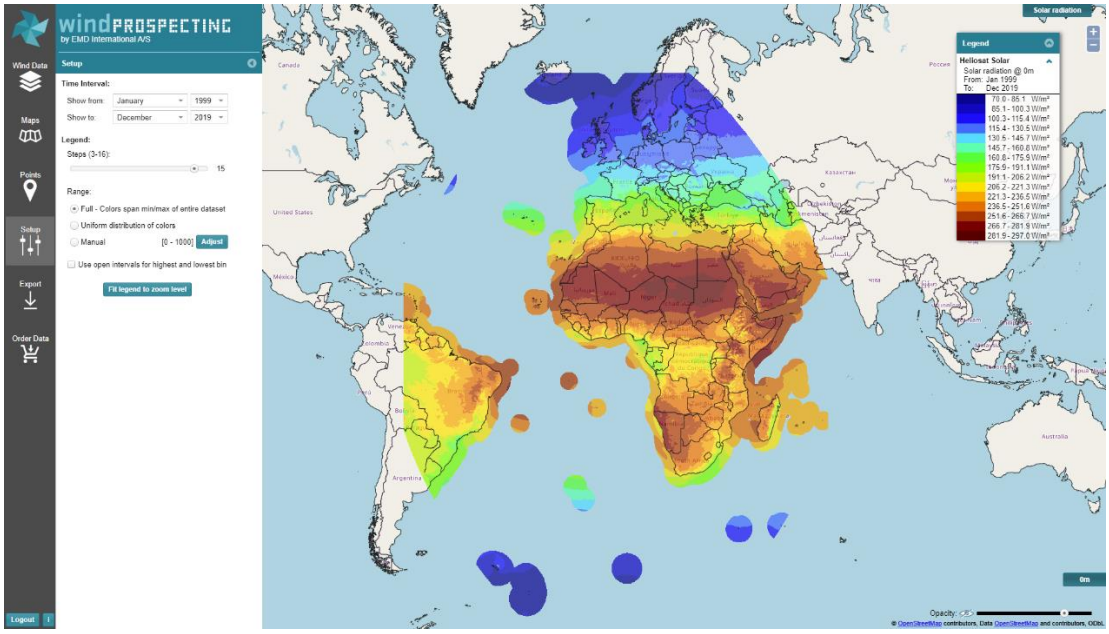



*Figure 13 Heliosat West data Europe/Africa/part of South America coverage.*

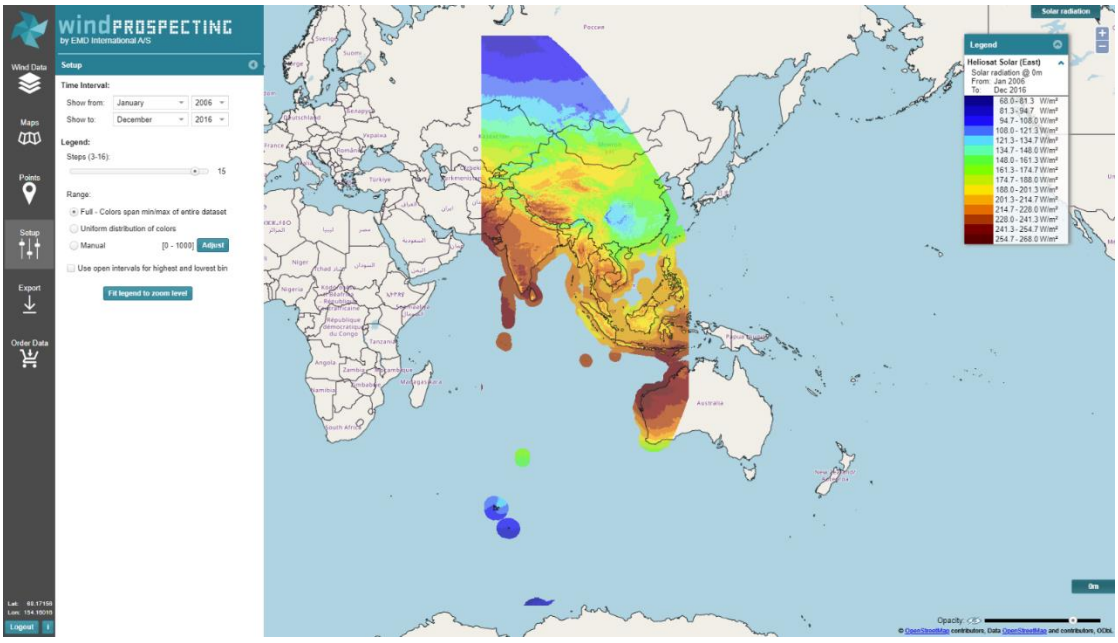



*Figure 14 Heliosat East data part of Asia/Australia coverage.*

The Heliosat data are included when purchasing the Solar-PV module for windPRO. This adds essential value to the module as obtaining Heliosat data from other vendors can cost €1000 for just one data series. With the Solar-PV module, the data are freely available with a Solar-PV module in service.

# 2 Validation of Array shading calculation

An unrestricted panel, with no shading except from neighbour panel shading is identified. The measured and calculated production, and indirectly the shading loss, are compared.

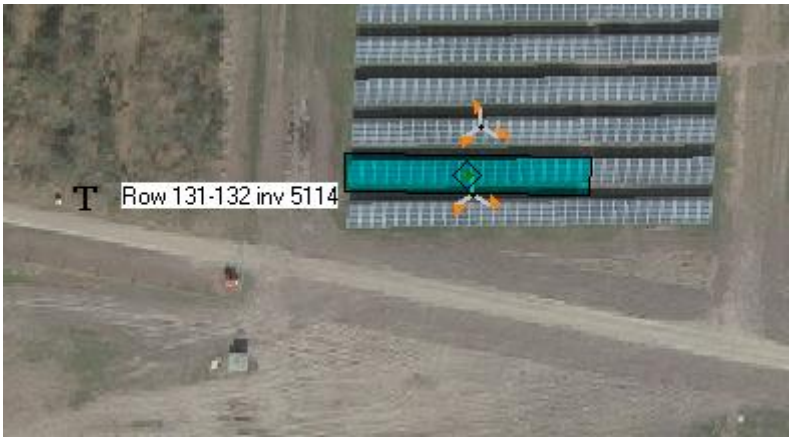



Figure 15. Close-up of single panel example.

The unrestricted panel is south-most in Figure 15. The second string of panels, marked blue, is investigated, where we look at the four horizontal strings from inverter 5113.

| | | | |
|---|---|---|---|
| 315 W | 5113 | | |
| | Row 131 | 0% | P1-13 |
| | | 2% | P3-13 |
| | | 5% | P5-13 |
| | | 9% | P7-13 |
| | 5114 | | |
| | Row 132 | 1% | P2-14 |
| | | 2% | P4-14 |
| | | 1% | P6-14 |
| | | 3% | P8-14 |

*Figure 16. Loss figures by panel.*

These are the "raw" loss figures, where a loss is defined as production relative to the best producing panel string consisting of 20 panels. In the analyses, we extract concurrent data where all panel strings are in operation, so availability issues do not distort the analyses.

The measurements clearly show that the lowest string, P7, has more array shading. The magnitude is 7-8% more loss than the unrestricted string at the front of the table, but 9% more than the top string at the shaded table.

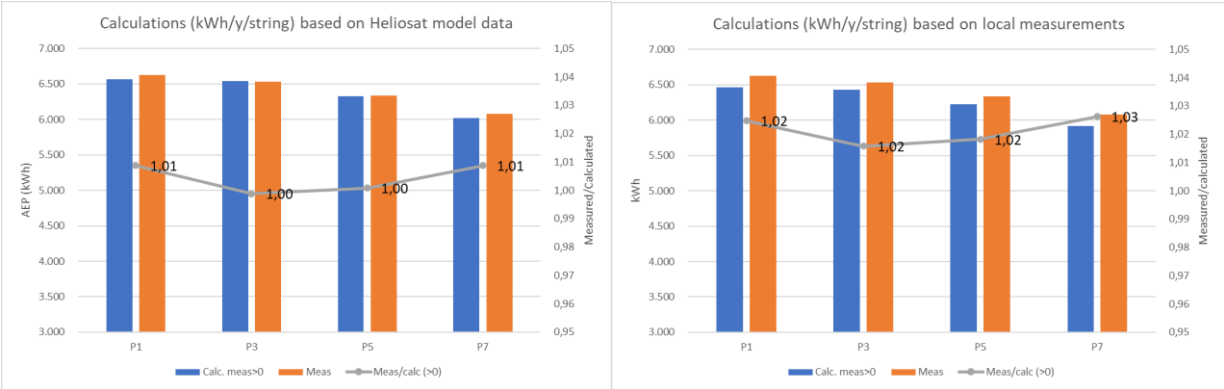



*Figure 17 Measured and calculated output (concurrent to measurements) for the two different irradiation data sets.*

The overall results show very accurate predictions. Output is slightly under predicted by both data sources, but panel string by panel string in both cases are handled very well, with results within +/-1% between measurements and calculations for each panel string on an annual basis.

The P1 string was tested on a monthly basis: (kWh/month) for one string of 20 panels, 6.3 kW DC, 4.5 kW AC.

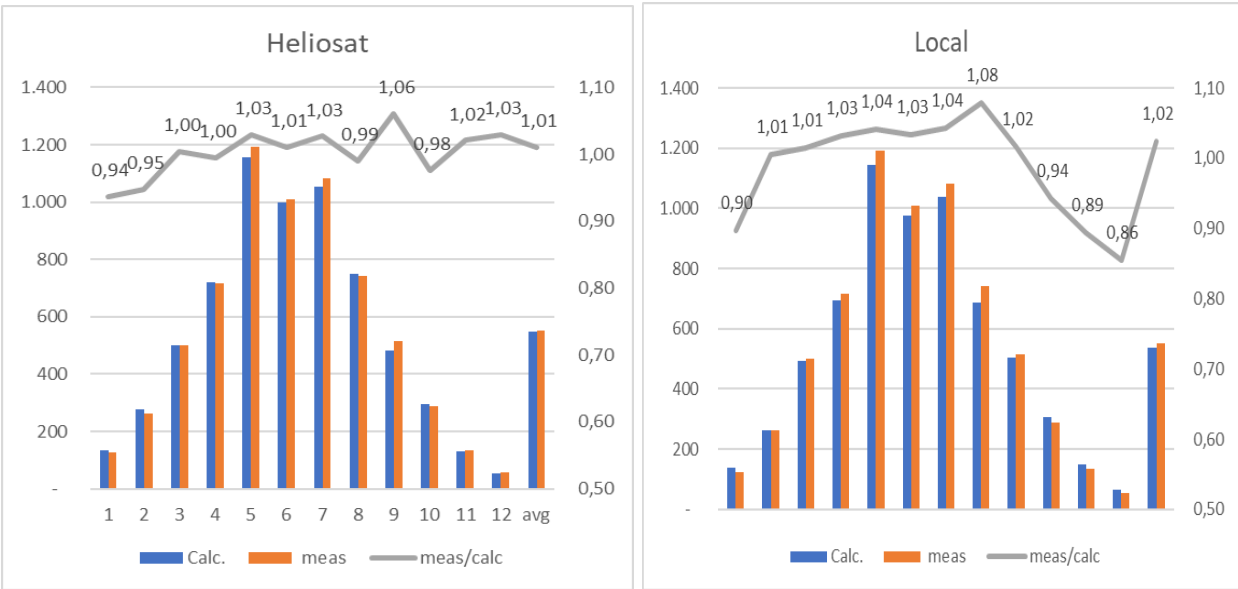



*Figure 18. Monthly variations in measured and predicted output using Heliosat and local data.*

Here the use of local irradiation measurements (right) makes a poorer match than the use of Heliosat model data (left). The local data under-predicts production in the summer and over-predicts in the winter. The Heliosat data predicts month-by-month mostly within +/- 5%.

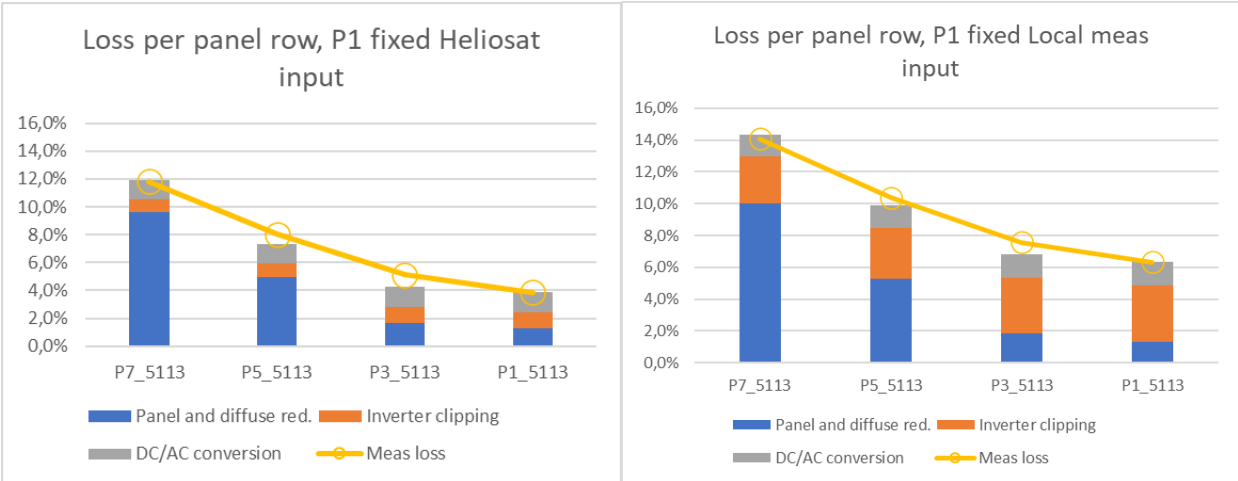



*Figure 15 Losses by panel string subdivided by loss type. "Measured" loss is scaled so P1 is assumed to be calculated correctly.*

Further details of the loss calculation are shown in Figure 19. The measured loss is obtained by assuming the unrestricted panel string P1 is correctly calculated, where the loss-free panel string production is found and used for estimation of the "measured" loss for each panel string. This illustrates the difference having different solar irradiation input. The local measurements give much higher inverter clipping losses. The reason is partly the higher time resolution, but mostly the higher mid-day irradiation values.

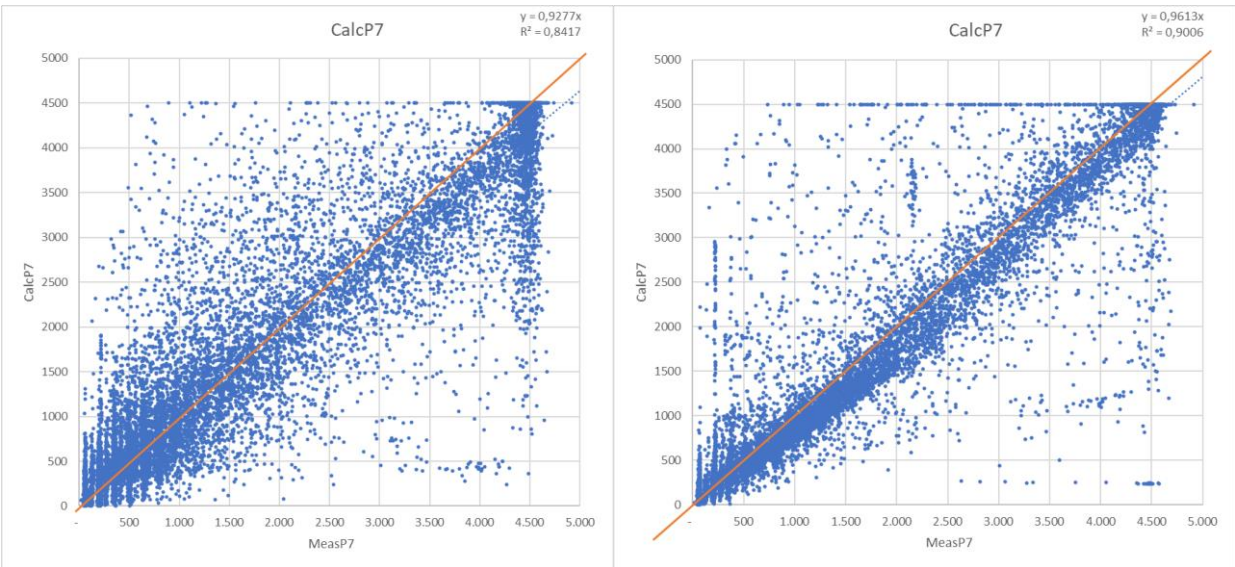



*Figure 20 Scatterplot, calculated vs. measured for the string with most array shading. Left Heliosat, 30 min, right local measurements, 15 min.*

The advantage of having high resolution local data is clear when the match by each time step is tested. It will be shown later, however, that this does not necessarily lead to more precise results. The scatter plot based on calculations from local measurements shows a good reasonable linear relation, but also that there are several calculation values with maximum production, where the actual measurement is lower.

A final test is to subdivide losses into diffuse and direct irradiation.

| Heliosat | All data | Diffuse | Direct |
|---|---|---|---|
| Measured | 8,3% | 3,3% | 5,3% |
| Calculated | 8,3% | 3,2% | 5,1% |
| Meas - calc. | 0,0% | 0,1% | 0,2% |

| Local meas. | All data | Diffuse | Direct |
|---|---|---|---|
| Measured | 8,3% | 3,3% | 5,1% |
| Calculated | 8,5% | 3,3% | 5,2% |
| Meas - calc. | -0,2% | 0,1% | -0,1% |

*Figure 21. Division of losses into diffuse and direct irradiation parts.*

The loss is here defined as difference between P1 and P7 strings (upper and lower). We can subdivide the loss into diffuse and direct irradiation, by assuming the calculations make this separation correct. This is done by establishing the loss (measured and calculated) for each time step and using the calculation ratio between diffuse and direct irradiation to separate the loss in the direct and diffuse parts.

For both data sources this works well.

# 3 Validation of Obstacle shading calculation

The panels tested are shown below. For the lower row (south), panels are subdivided in left and right, for the middle row only the left part is used, but subdivided in four strings vertically. The top row also just uses the left part, but only as one table.

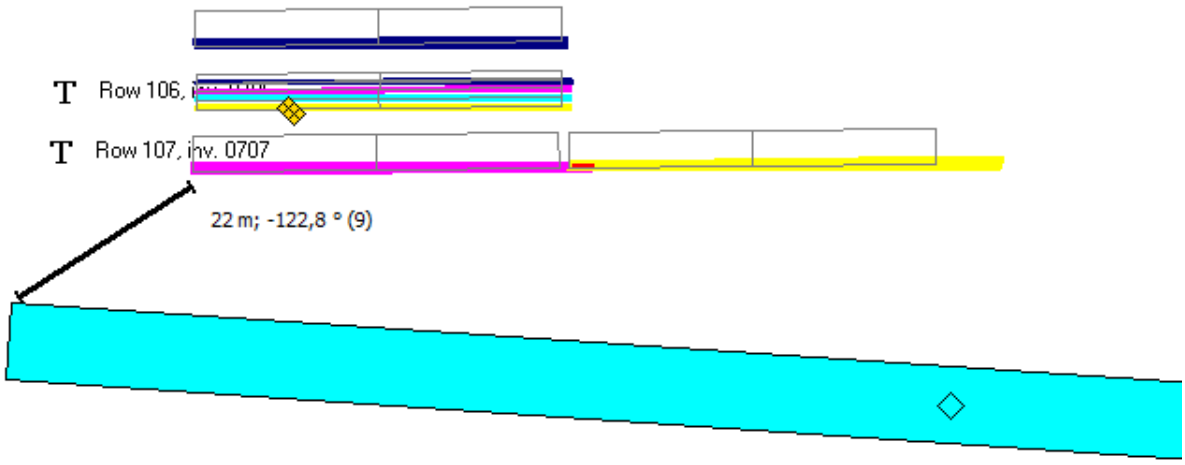



*Figure 22 panel and obstacle arrangement.*

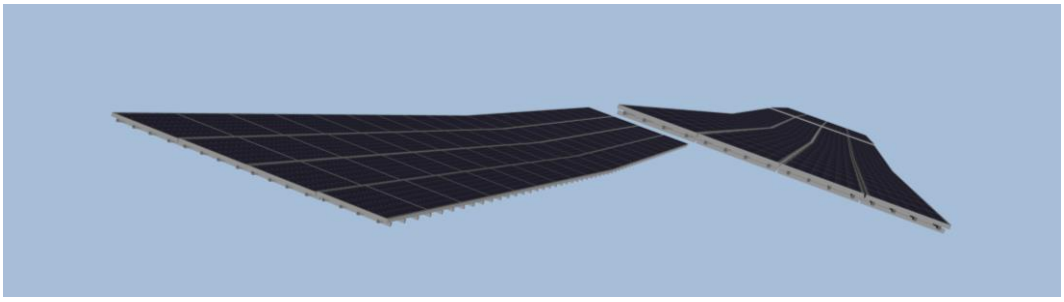


*Figure 16 Visualization of the panel arrangement.*

A simple visualization of the two front (south) tables, where the left panel is "constructed" as 4 areas, with individual offset from ground found by this table:

*Table 2 Illustration of how to calculate ground offset for setting up panel positions.*

| | | |
|---|---|---|
| Panel height | 0,992 | radians: |
| Angle | 20 | 0,34906585 |
| Lower bottom | 0,4 | |
| Offset | 0,33 | multiplier |
| Second | 0,73 | 1 |
| Third | 1,07 | 2 |
| Fourth | 1,40 | 3 |

The Arctangent function is used to find the vertical offset between the panel strings to be able to vertically position the panels correctly in the calculations.

The raw measurements give these relations between the different panel strings, where the percentage shown is the reduction relative to best-producing panel based on concurrent operation of all strings.

| | | | | |
|---|---|---|---|---|
| 325 W | 705 | | | |
| | P1 | 0% | 3% | P2 |
| | P3 | 2% | 2% | P4 |
| | P5 | 4% | 4% | P6 |
| | P7 | 9% | 8% | P8 |
| | 706 | | | |
| | P1 | 1% | 0% | P2 |
| | P3 | 2% | 2% | P4 |
| | P5 | 5% | 3% | P6 |
| | P7 | 9% | 9% | P8 |
| | 707 | | | |
| | P1 | 3% | 2% | P2 |
| | P3 | 4% | 2% | P4 |
| | P5 | 6% | 3% | P6 |
| | P7 | 4% | 3% | P8 |

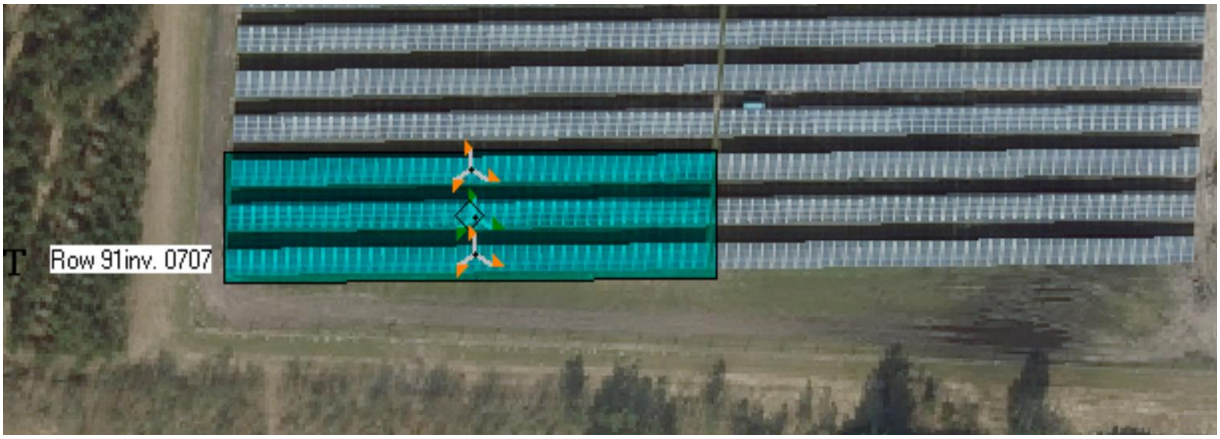



*Figure 24 Shading losses from an obstacle across the test panels.*

The obstacle (a row of trees) is closer to the left panels than the right panels, which also are reflected in the measured losses. Shading losses are seen in almost all panels.

## 3.1 Measuring the obstacle


*Figure 25 Measuring the shadow length of an obstacle on Google Earth™.*

On Google Earth™, the measure tool is used for measuring the shadow length as illustrated in Figures 25 and 26.


*Figure 26 Measuring shading length of obstacle on Google Earth (2).*

Measuring the shadow length from trees is difficult, as it is very sensitive to where we assume the treetop is located. the two attempts shown in Figures 25 and 26 produce results of 5.78 and 6.14m respectively. So, the shadow length is close to 6 m in both cases.

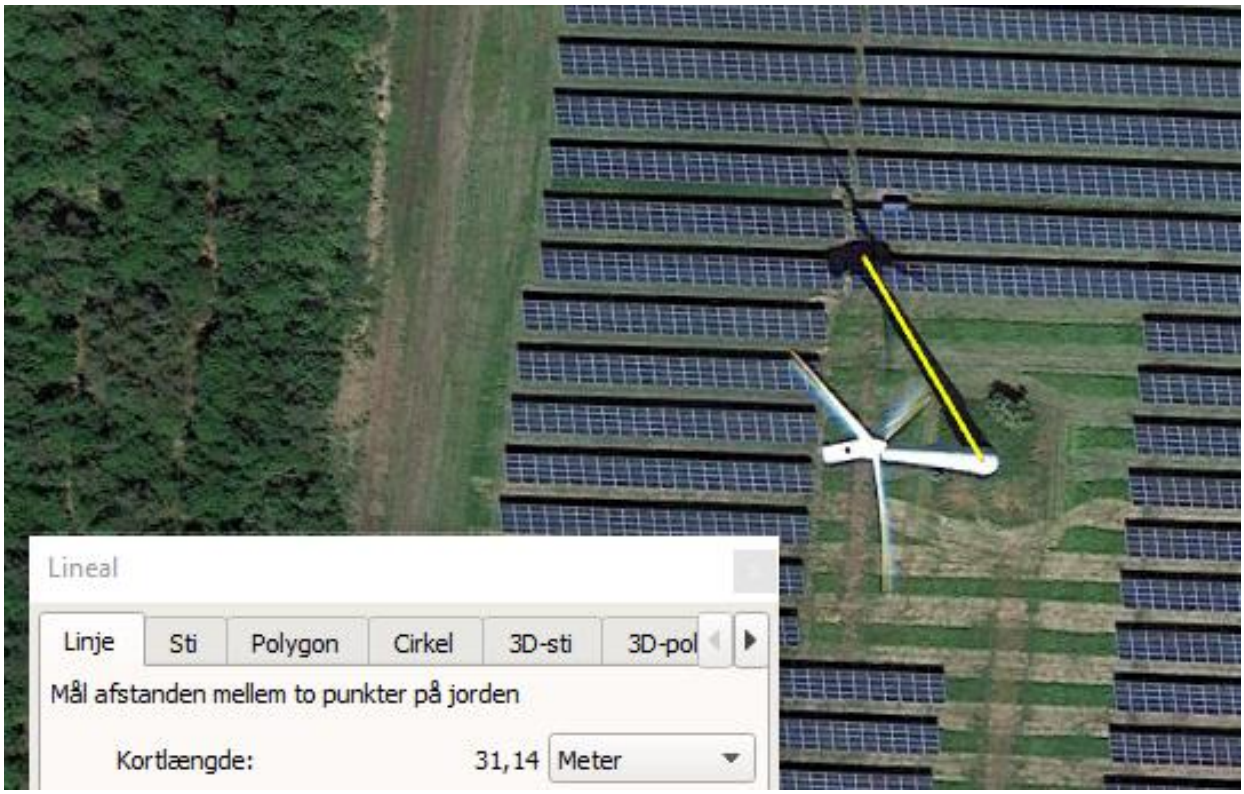



*Figure 27 Measuring shading length for turbine on Google Earth™.*

The shadow length is here measured quite precise for the WTG to 31,1 m. The actual hub height is 40.5 m. We can then calculate the tree height in the obstacle row:

| | Height m | Shadow length |
|---|---|---|
| WTG hub height: | 40,5 | 31,1 |
| Obstacle height: | 7,5 | 6 |

Using the implied ratio from the WTG, the obstacle height of the trees is estimated to be 7.5m. However, it is not that simple. The obstacle is not of a similar height all the shadow lengths, and there are probably less obstacle effects in winter as the trees will lose their leaves. Different heights around the 7.5 m should be tested to fine-tune the assumption.

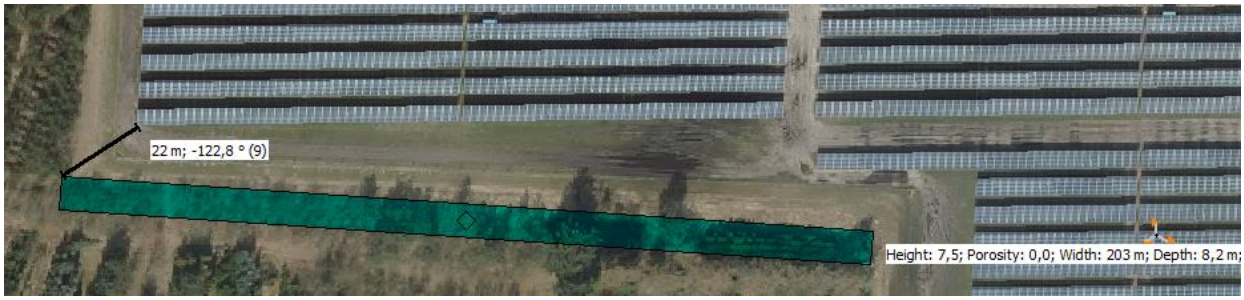



*Figure 28 Establishment of an obstacle in windPRO.*

The obstacle is established with the windPRO standard obstacle object as shown above. The background map shown here is not showing the tree row as clearly as the Google Earth™ screen shots shown previously.

## 3.2 Calculation results with obstacle shading

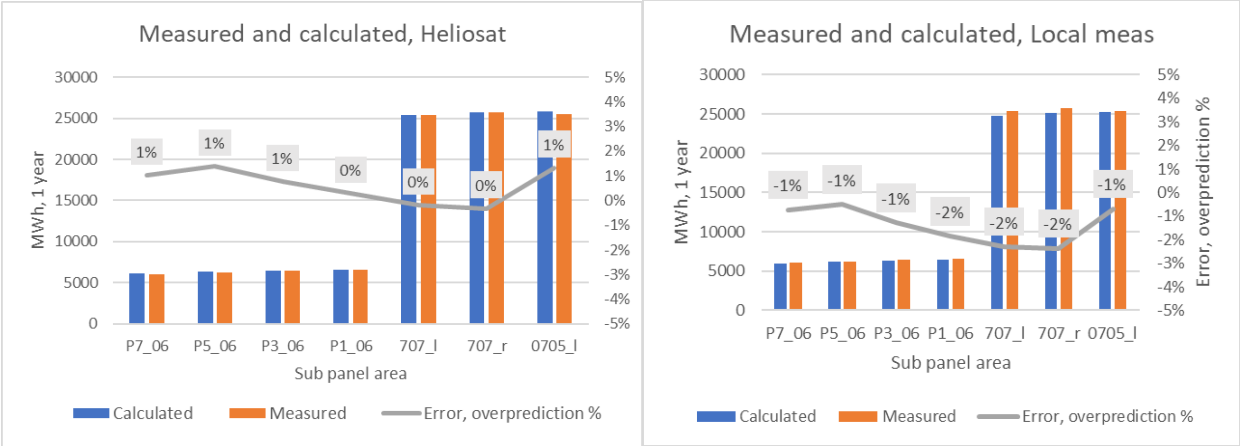



*Figure 29 Overall calculation results compared to concurrent measurements with 8m obstacle height.*

As shown in Figure 29 most panel groups is calculated within +/- 1% of measured values, with a slight under-prediction based on local measurements, which match the first test case without obstacles, where panel shading was tested.

Calculations are filtered, so only concurrent time stamps with measured values > 0 are included. This reduces the calculated production by approximately 4% (due to availability loss and gaps in measurements).

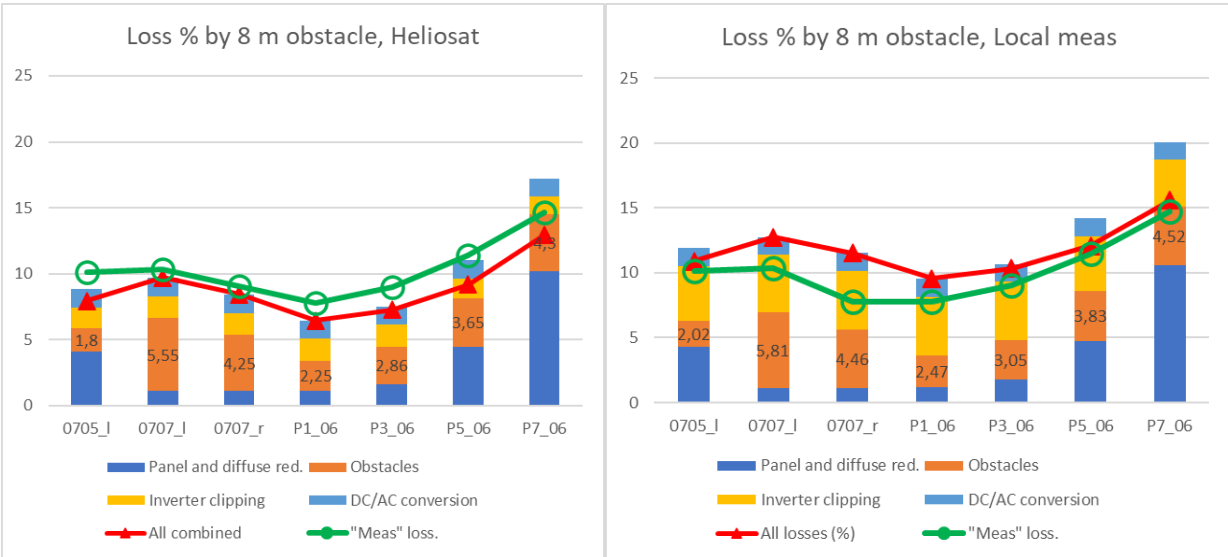



*Figure 30 Loss composition where an obstacle is included. The "Meas" loss must be compared to "All combined", not the stacked graph.*

Concentrating on the losses, Figure 30 shows the results produced by the two different datasets are diffeent. The results derived from local measurements show higher inverter clipping losses. What we cannot know for sure is the real level of the measured loss, and

therefore which of the two data sets produces a result that is closest to correct. There is no doubt that the obstacle creates loss, and this is calculated in the right order of magnitude.

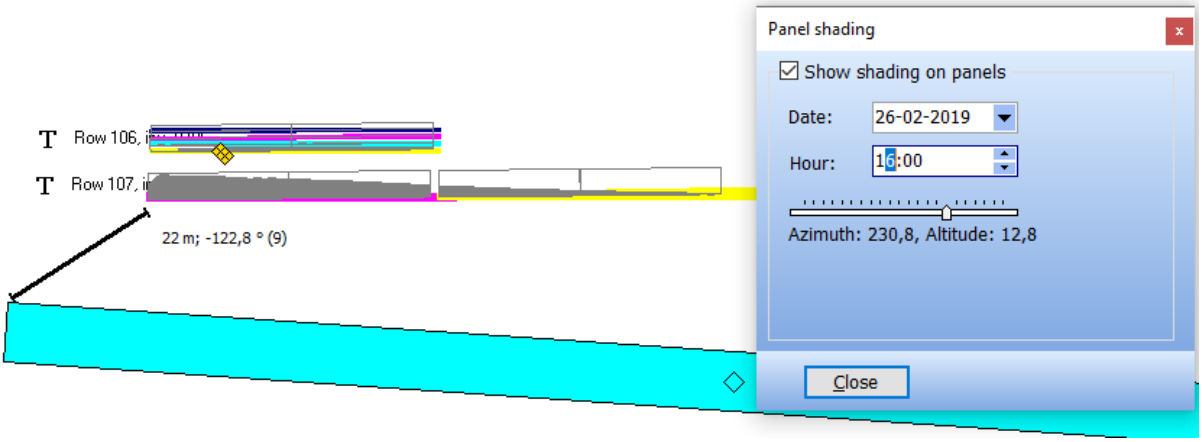



*Figure 31 Visualization of the shading from an obstacle at a specific data-time.*

It is possible to visualize the shading from the obstacle (as well as other shading elements). Figure 31 shows how most of the front left panel is covered at 16:00 on February 26th, where the Sun altitude is 12.8°. The shadow seen on the Row 106 is from the Row 107 panels.

# 4 Validation of wind turbine shading calculation

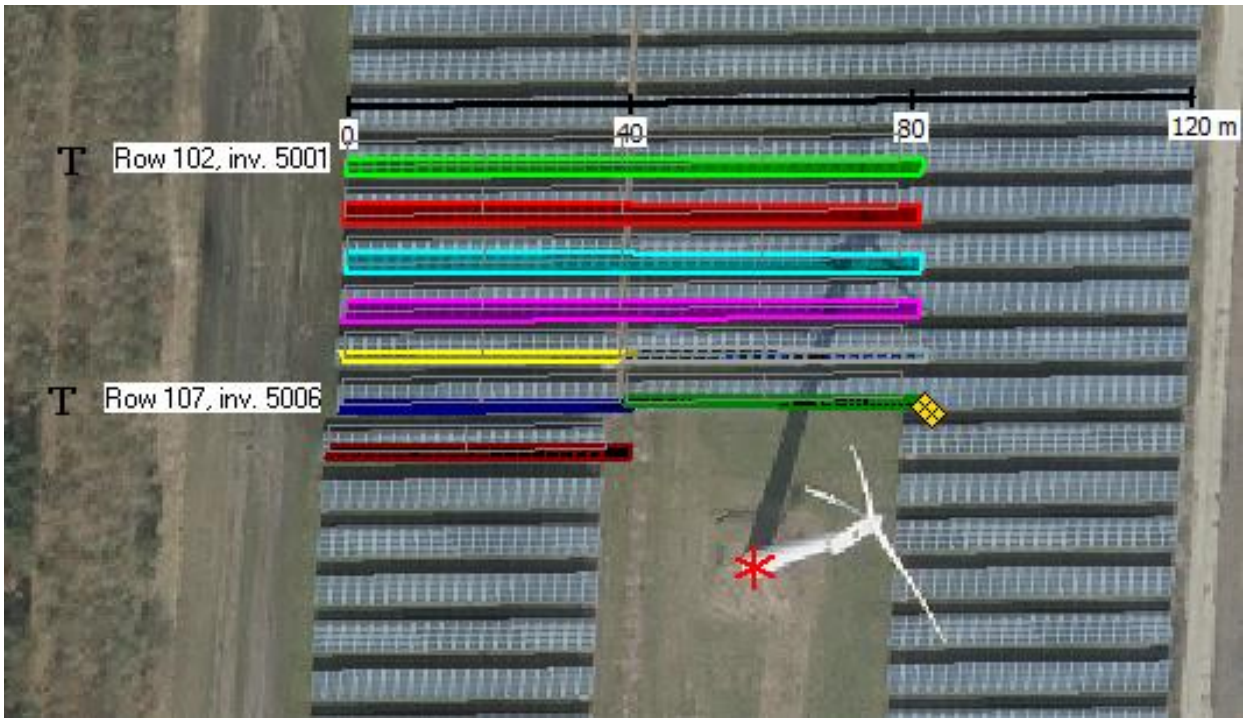



*Figure 32 The calculation setup with panels and WTG.*

The Nees project includes a single turbine within the solar array. The WTG is a Vestas V39 500 kW with 40.5m hub height.

Figure 32 shows the location of the turbine and the nearest neighbour panel rows. The calculation concentrates on the four northerly panels which share one inverter. The next two panels are subdivided into left and right to be able to evaluate the effects of the WTG shading in a more detailed way.

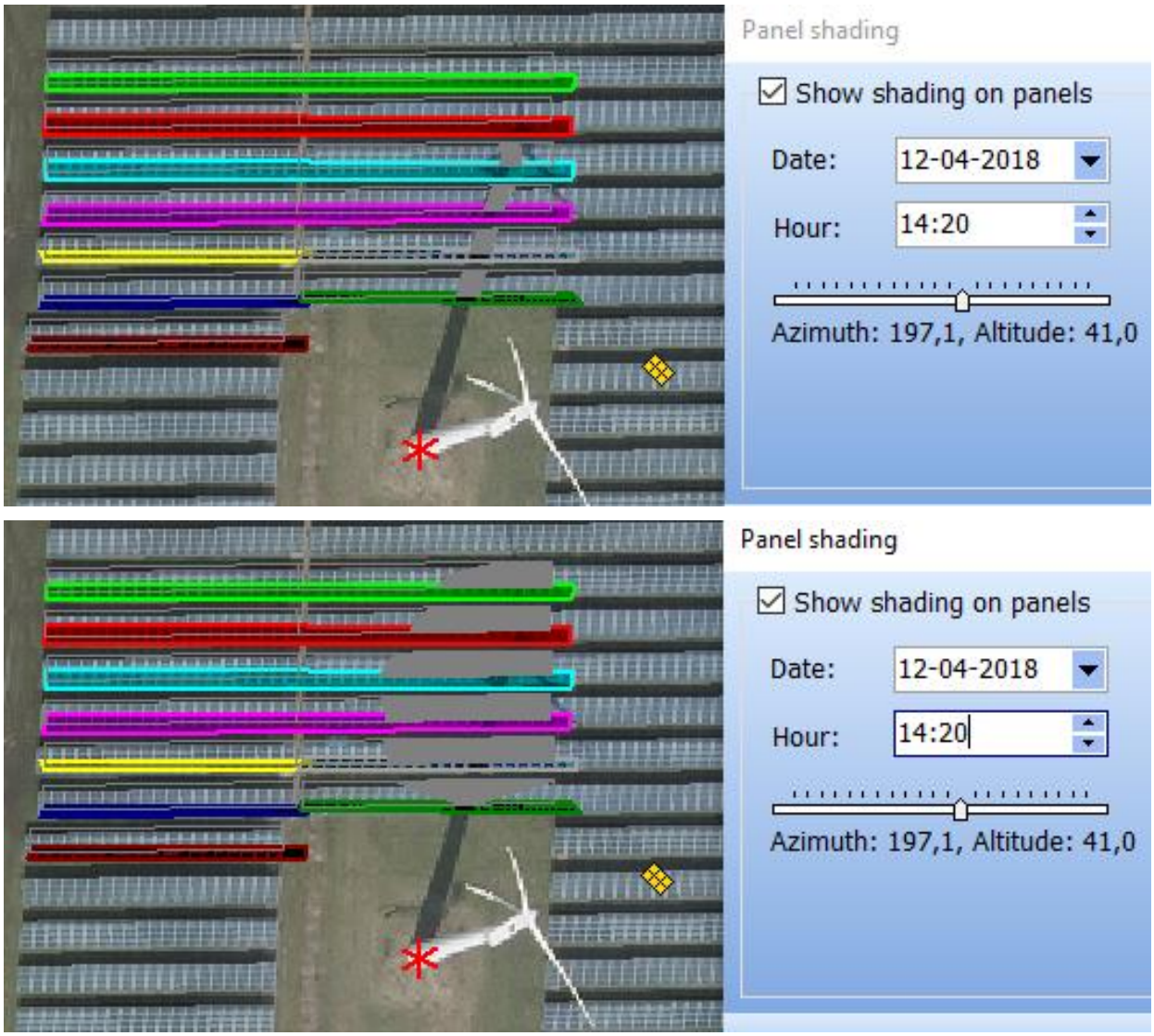



*Figure 33 Illustration of shading calculation capabilities. Shade is only seen where there are panels.*

The shadows are calculated very precisely for each time step, shown in Figure 33, firstly with 100% rotor area reduction, secondly without rotor area reduction. While windPRO always assume the nacelle direction is towards south, the alignment of the shadow compared to the ortho photo is not completely the same. It will be considered to include the actual wind direction by time step in future improvement.

## 4.1 The measurements

| Measured reduction relative to best producing group | | | |
|---|---|---|---|
| 5001 | | | |
| P1 | 2% | 2% | P2 |
| P3 | 4% | 4% | P4 |
| P5 | 6% | 7% | P6 |
| P7 | 10% | 11% | P8 |
| 5002 | | | |
| P1 | 1% | 3% | P2 |
| P3 | 3% | 5% | P4 |
| P5 | 5% | 7% | P6 |
| P7 | 10% | 13% | P8 |
| 5003 | | | |
| P1 | 1% | 4% | P2 |
| P3 | 3% | 6% | P4 |
| P5 | 5% | 9% | P6 |
| P7 | 10% | 15% | P8 |
| 5004 | | | |
| P1 | 0% | 5% | P2 |
| P3 | 2% | 8% | P4 |
| P5 | 6% | 9% | P6 |
| P7 | 9% | 17% | P8 |
| 5005 | | | |
| P1 | 0% | 7% | P2 |
| P3 | 2% | 9% | P4 |
| P5 | 5% | 10% | P6 |
| P7 | 10% | 16% | P8 |
| 5006 | | | |
| P1 | 2% | 10% | P2 |
| P3 | 4% | 8% | P4 |
| P5 | 7% | 10% | P6 |
| P7 | 11% | 9% | P8 |

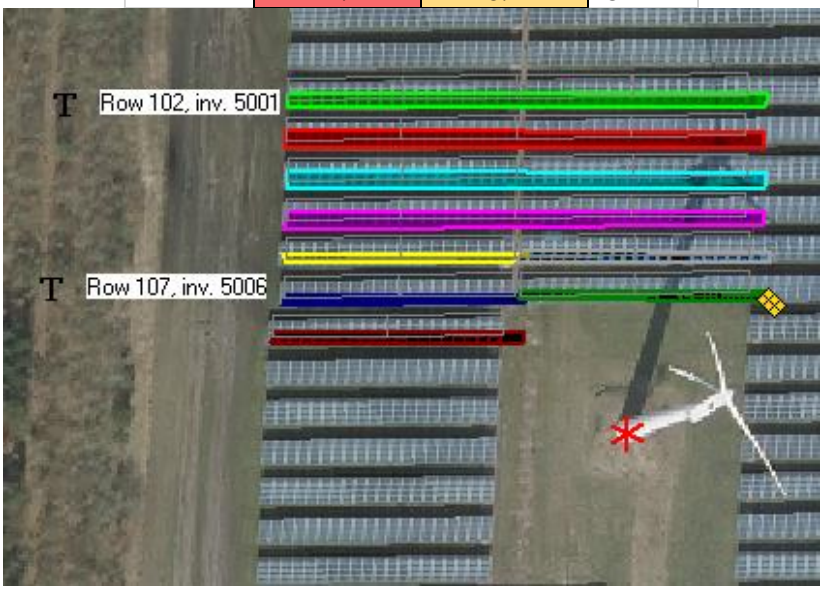



*Figure 34 Measurements shown together with panel arrangement.*

Figure 34 shows the relative measurements (all concurrent), showing the reductions relative to the best-producing string for one year. The WTG shading reduces the yield of the righthand part and the array shading reduces the yield of the lower panel rows. The WTG shading is seen to give significant losses at the nearest 4-5 rows north of the turbine.

## 4.2 Calculation of WTG shading

In the loss setup, there are options to reduce the rotor area used in calculations, where handling the rotor as a full disk will create too large a loss in the calculation.

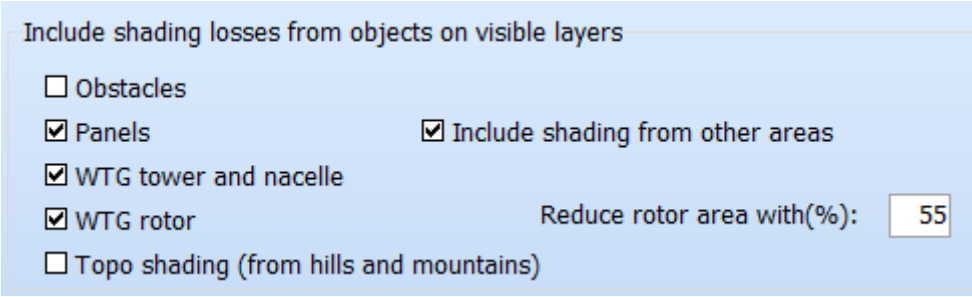
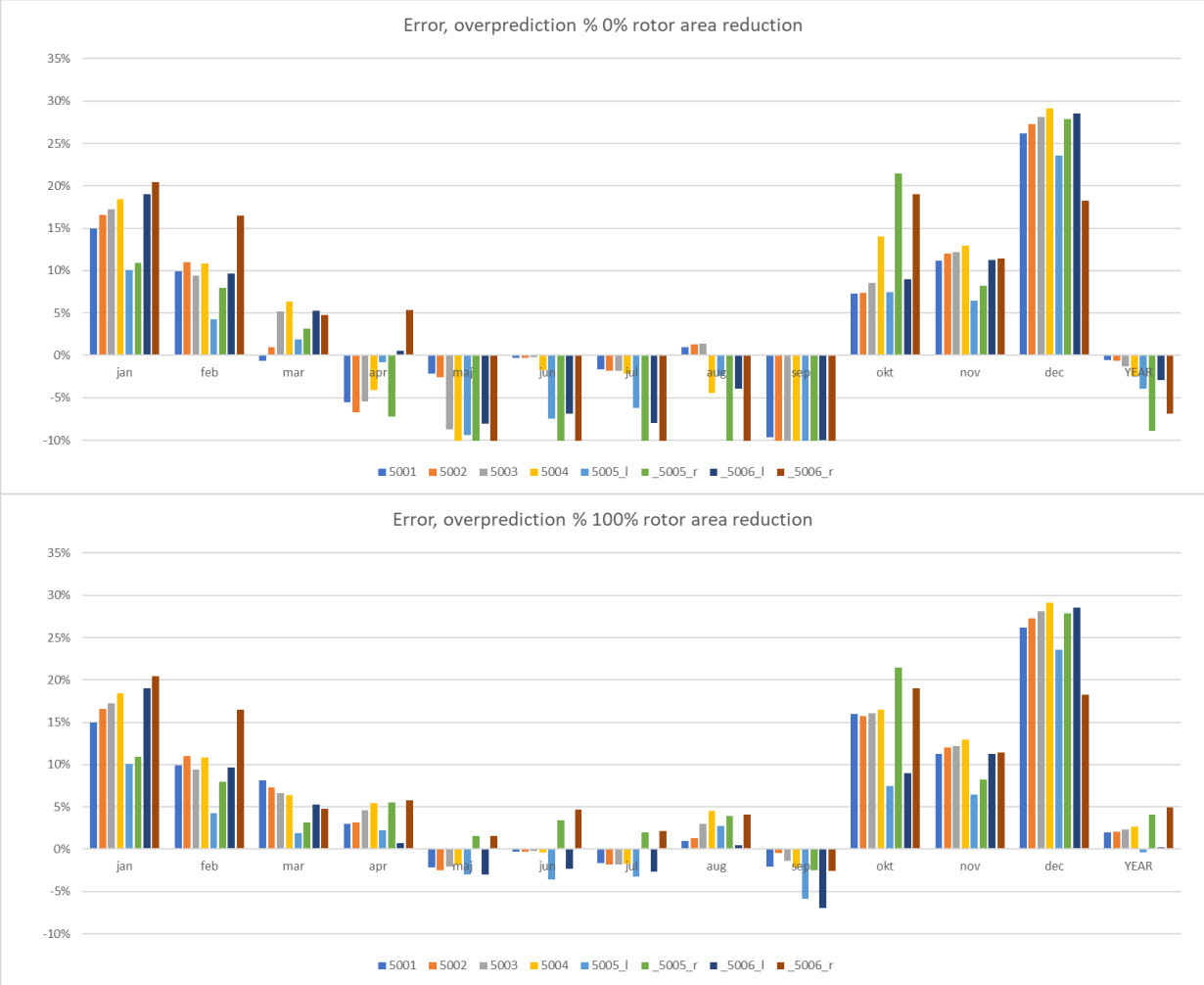



*Figure 35 Shading loss setup.*

First, we set up a calculation with no reduction and then another with 100% reduction of the rotor area, to see how much this affects the results. Finally, we adjust the reduction factor. All WTG shading validation calculations are based on Heliosat data.



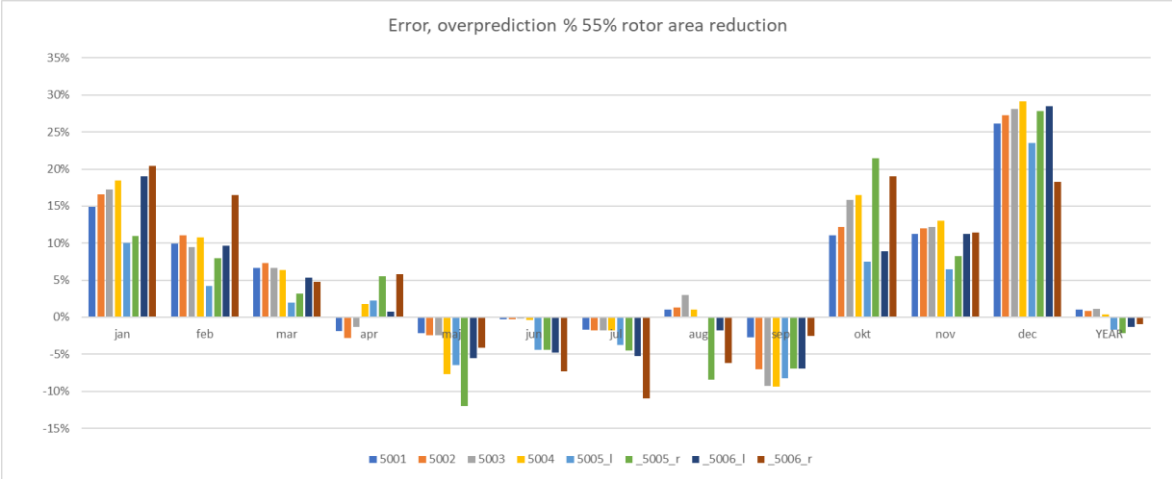
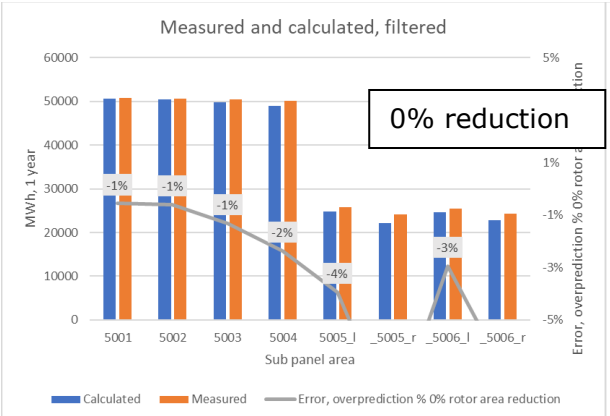
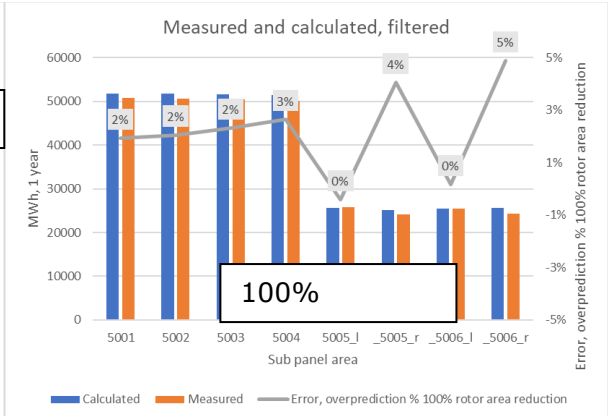
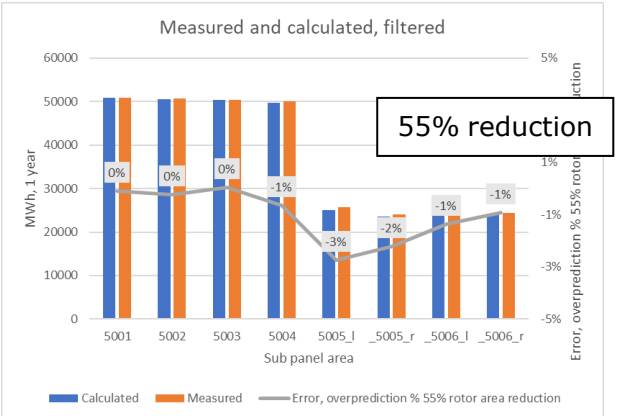



*Figure 36 The three calculations with zero, 100% and adjusted (55%) rotor area reduction.*

Looking at the monthly calculation performance, Figure 36 shows that the winter months are over-predicted (too little calculated shading loss), while the summer months are under-predicted. This problem is not solved by adjusting the reduction of rotor area. **NOTE: In the last chapter, a comparison between logger data and meter data showed that the logger data used here probably has a bias. To some extent, that may explain the season bias.**

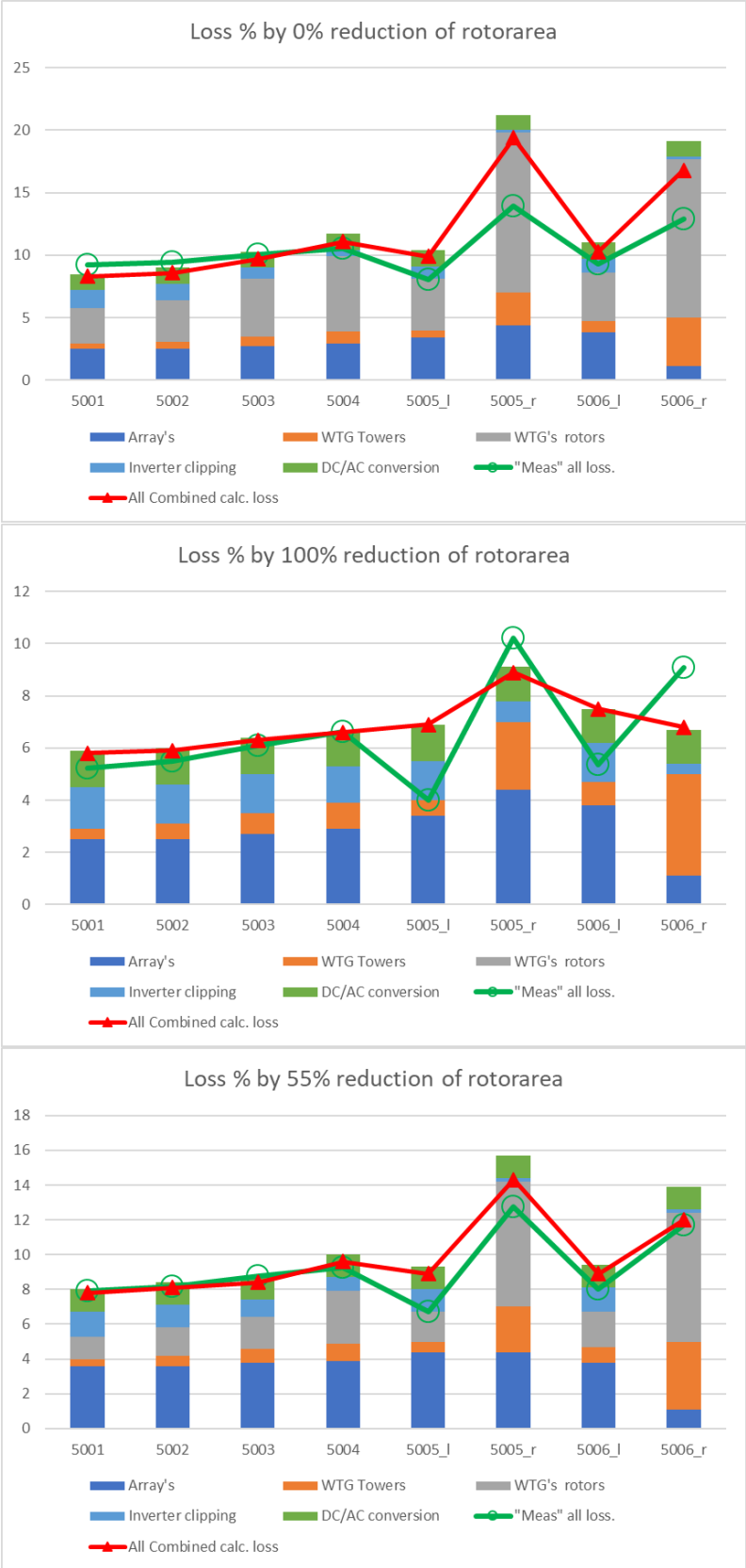



Not being able to handle the seasonal variations, it is possible to tune the calculation, so the annual results match the measurements well. To the left with 55% rotor area reduction, most panel groups are reproduced within +/-1.5%, although with some bias. The panel groups closest to the turbine are under-predicted (slightly too high losses are calculated). Although these results are in line with previous tests, when based on the Heliosat data an under-estimation of a few percent must be expected.

*Figure 37 Comparison of measured and calculated with WTG shading with different rotor area reductions.*




The losses by different rotor area reductions. Note the measured losses cannot be identified precisely in the data, and are therefore adjusted to match reasonable levels on average for all panel groups, to visualize the impact of different rotor area reductions. It is clear that the best match panel area to panel area is to find in-between 0% and 100% reduction of rotor area, where 55% is found as best match.

*Figure 38 Calculated loss by panel group compared to "measured".*

The rotor seems to have some influence on the shading loss but handled as a solid circle will, as expected, create too high loss calculation. A 55% reduction on annual basis will give a good representation, but this is not the full truth. Looking at monthly reproduction there is more to understand.

To try to find out what is going on, some shading visualizations:

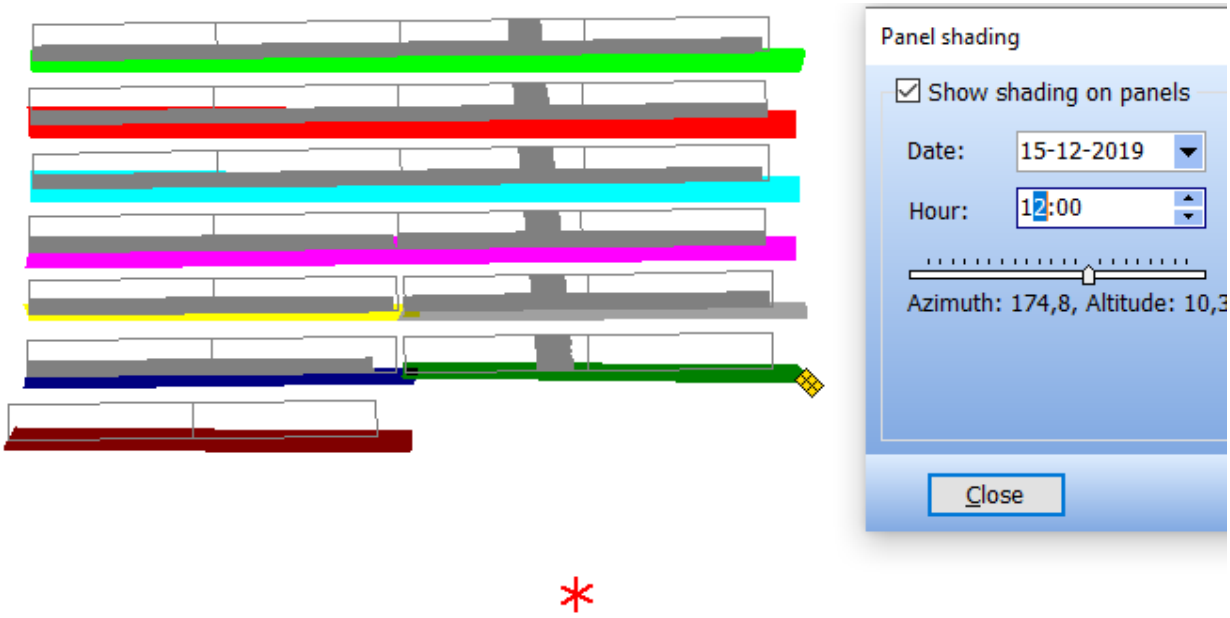



*Figure 39 Shading on the tested panels in a winter month. As well as turbine shading, panel shading is seen in the grey coloring.*

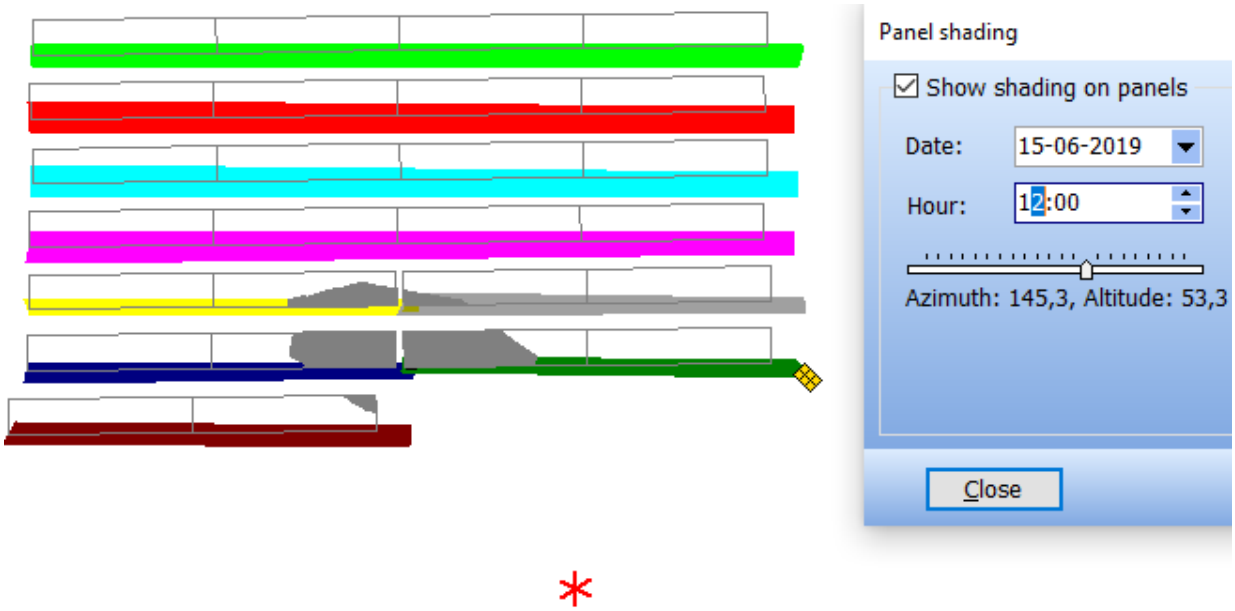



*Figure 40 Shading from turbine on a summer day at noon with 55% area reduced rotor.*

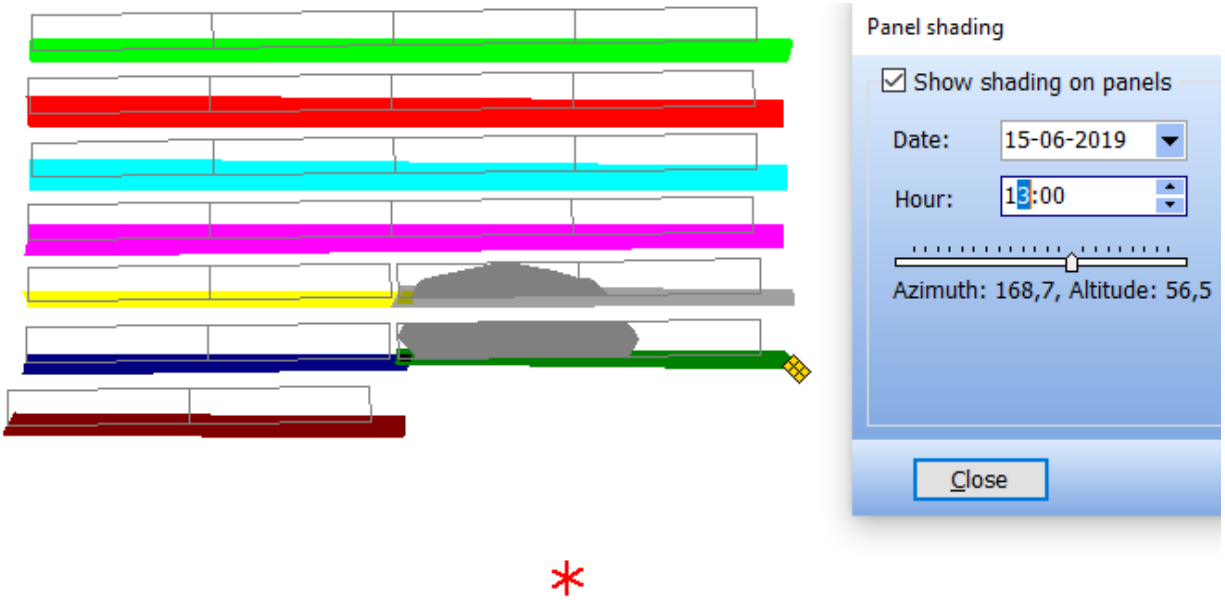



*Figure 41 As for Figure 40, one hour later, the rotor movement is observed, and it now covers most of panel group 5006_r.*

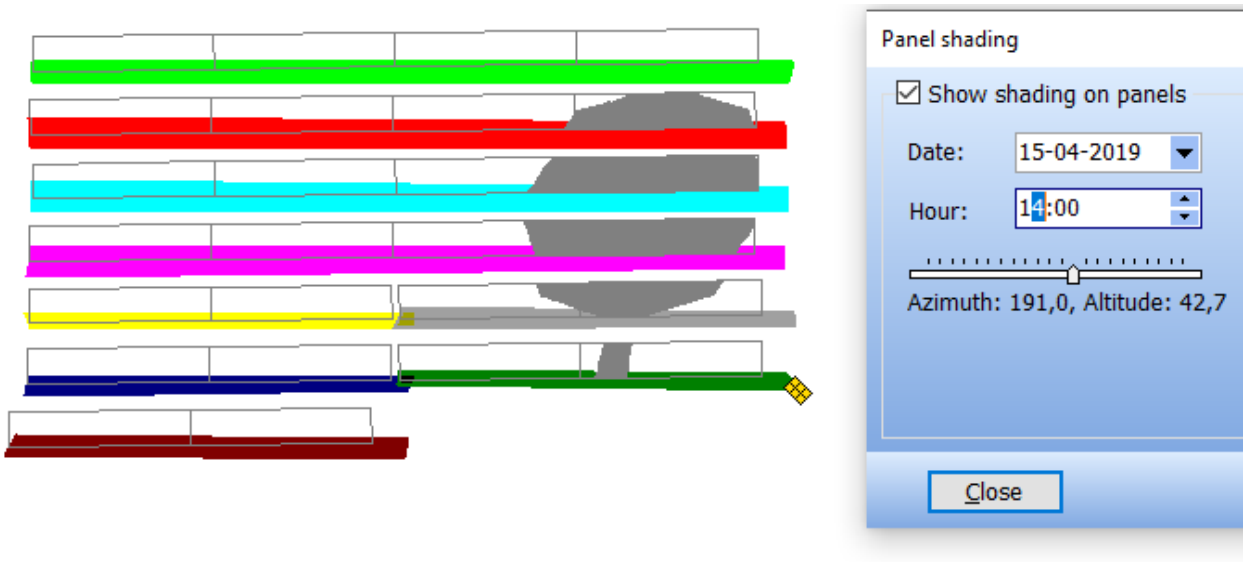



*Figure 42 In April at 14:00 the rotor shading is above the first panel group 5506_r when reduced by 55%.*

In winter months, the tower shading is dominating while in summer months it is the rotor shading, when looking at midday with the highest irradiation.

By replacing the individual panels with "wide panels", where ten panels are replaced with one wide panel, the result suggests that the tower shading is calculated higher. This is due to a vertical shading that leads to a full reduction of direct radiation for the entire panel. The rotor area must then be reduced even more to get a matching measured/calculated ratio. Figure 43 shows that for a 100% reduction of the rotor area, only tower shading is happening. An alternative with five panels in series is tested, where an 80% reduction of the rotor area is found to give the best reproduction of the measurements on an annual basis.

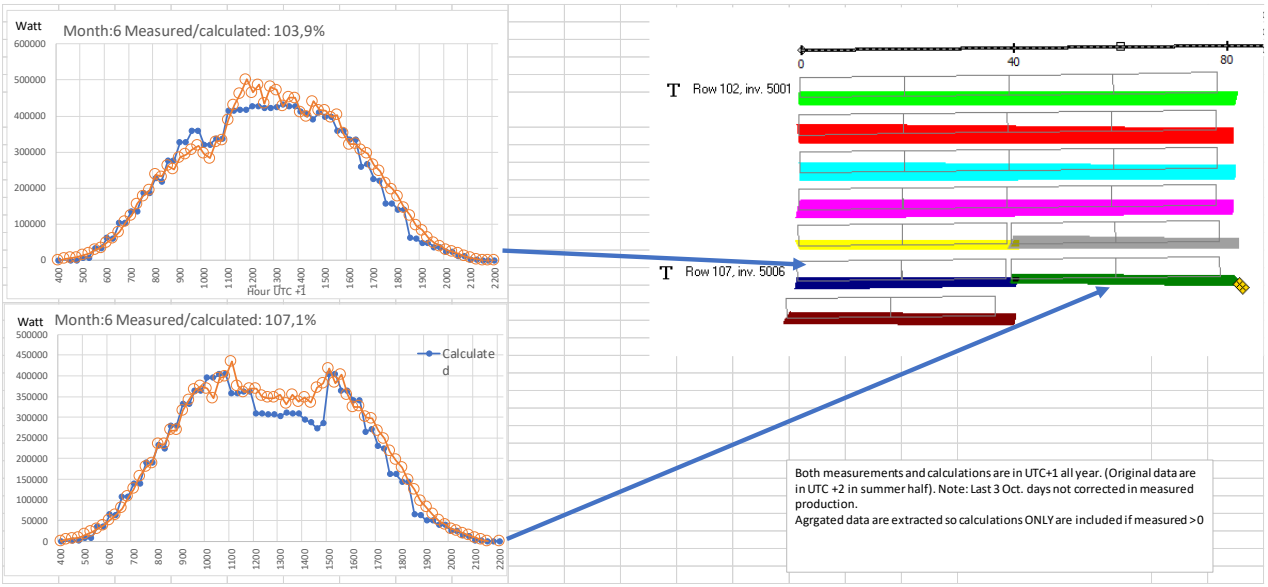



*Figure 43 The test setup, where specific panel groups are tested. The shading reduction in calculations is clearly visible.*

Figure 44 shows the two graphs from Figure 43 merged into one and it is tested how the "base calibration" with individual panels and 55% rotor area reduction is reproduced compared to the calculation where ten panels on a horizontal alignment are replaced by one wide panel (corresponding to ten series connected panels). The alternative five panels are in series. Tower shading on just one panel will set the direct irradiation to zero for all the series panels.

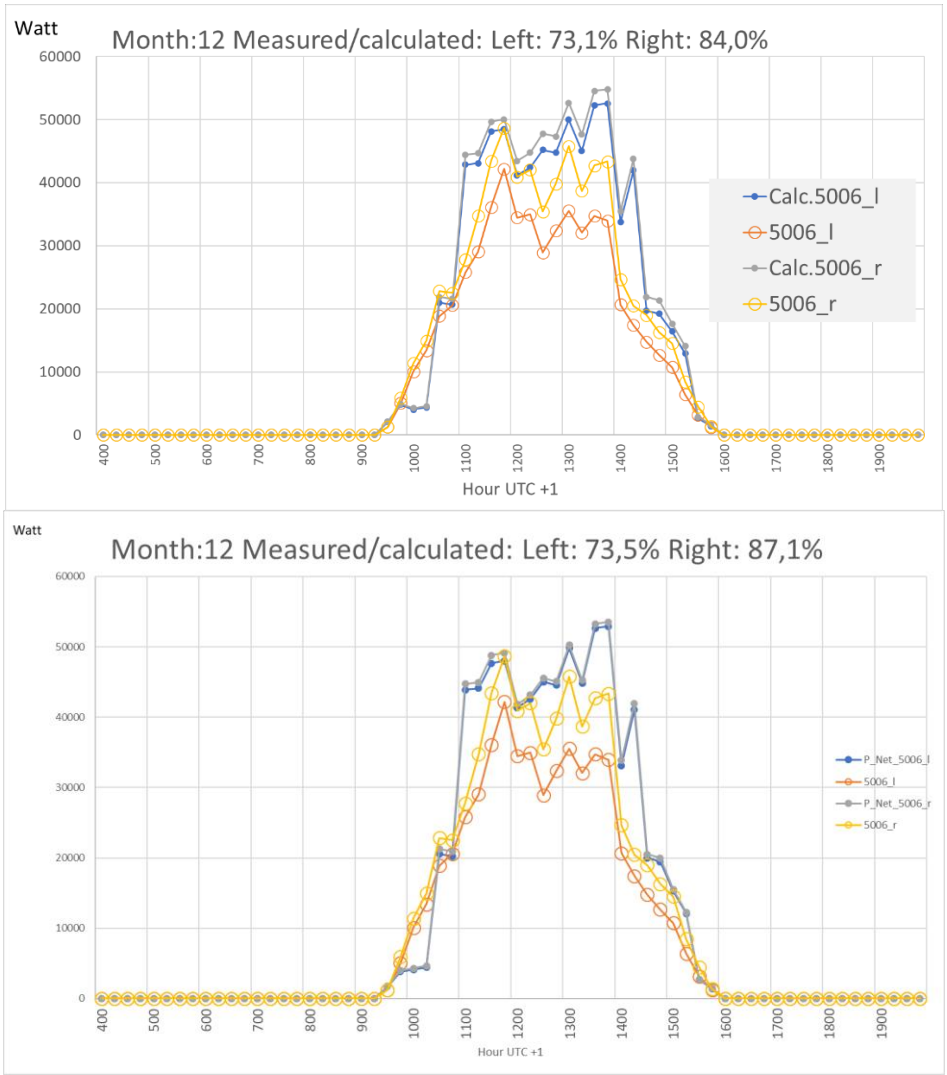



*Figure 44 Upper with 55% reduction of rotor area, lower with 100% reduction AND serial connection of ten panels.*

In a winter month, where the calculation over-predicts production, a small improvement is seen by increasing the tower shading and removing the rotor shading from the calculation. However, this does not fully solve the issue. The reason is probably that only the direct irradiation is reduced by the WTG shading calculation, where also the diffuse irradiation will be affected. Another issue for over-prediction might be that the inverter has difficulties finding the optimum operation point due to the flickering shadow.

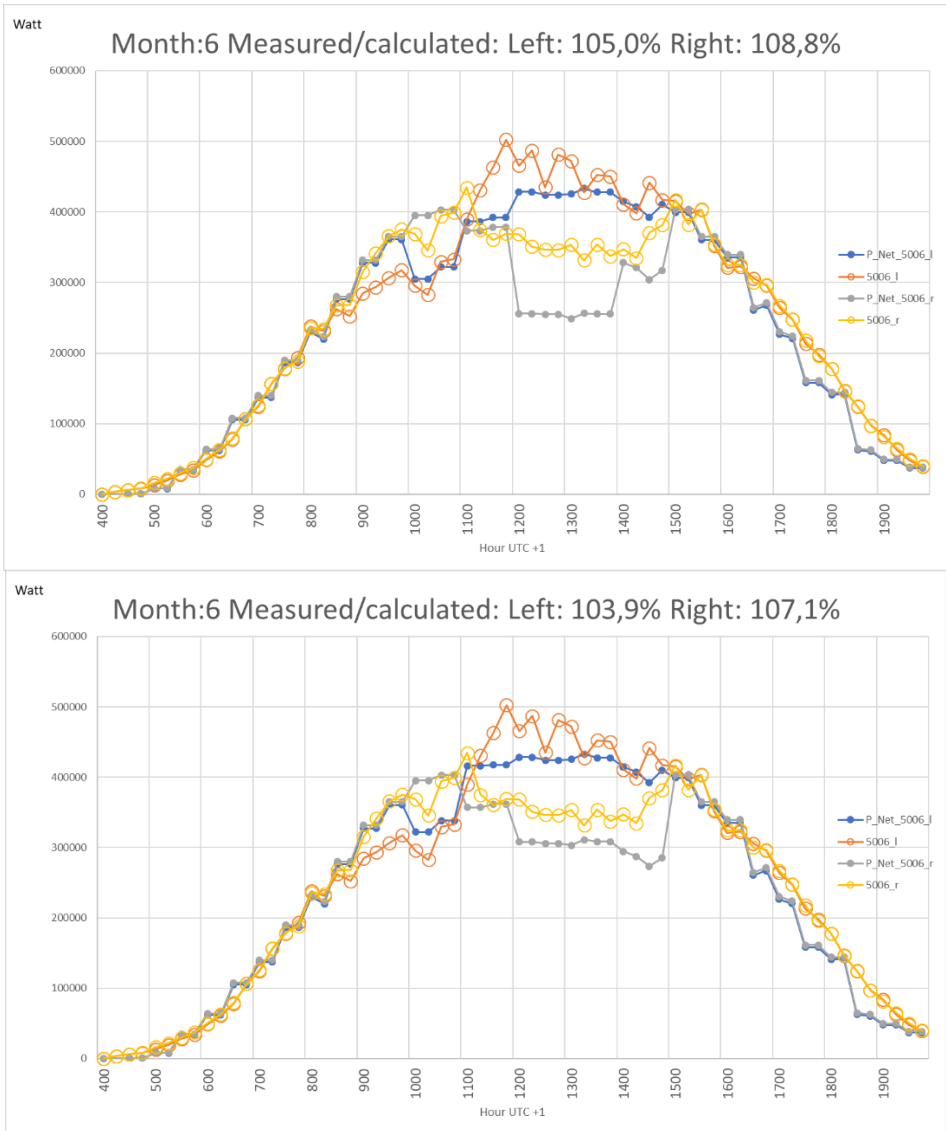



*Figure 45 As previous graphs, but summer month.*

For a summer month, a larger improvement is seen. Shading reduction is still calculated too high, but it moves into the right direction by converting rotor reduction to tower reduction. Overall, although deviations are small, on annual basis this doesn't make the reproduction of measurements dramatically better. Overall, the basic setup with approximately 50% reduction of rotor area works fine, and further tuning by rearrangement of panels does not seem to be worth the effort, see Figure 46.


*Figure 46 Testing the three different calculation setups on annual basis.*

For all variants, production is calculated slightly too low for the most shaded panels compared to the less shaded. The shading loss therefore seems to be predicted a little too high for the panels nearest the turbine compared to the more remote ones. However, this only happens in summer months. In winter months, shading loss is predicted to be too low. The main reason is probably that the WTG shading only reduces the direct irradiation, not the diffuse, while most of the winter production is diffuse-based. This is an issue to be handled in a later version of the module. It is important to mention that the deviations are in the order of +/-2% in AEP between more and less shaded panel groups. In general, the overall AEP calculation must be considered very precise.

## 4.3 Conclusion on turbine shading calculation

**The recommendation for calculation of WTG shading with present version of windPRO Solar-PV module will be to include 50% reduction of rotor area with a standard calculation setup.**

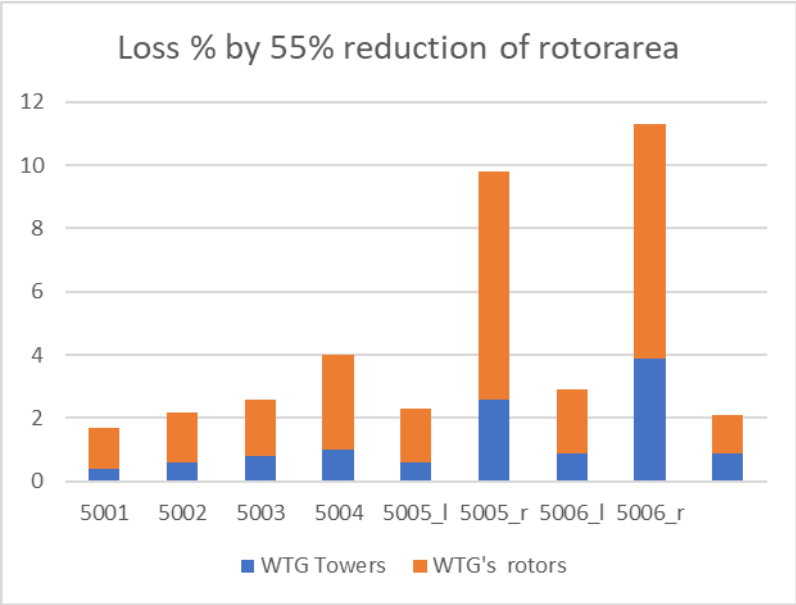



*Figure 47 Shading loss from turbine divided into tower/nacelle and rotor elements based on experimental calibration against measurements.*

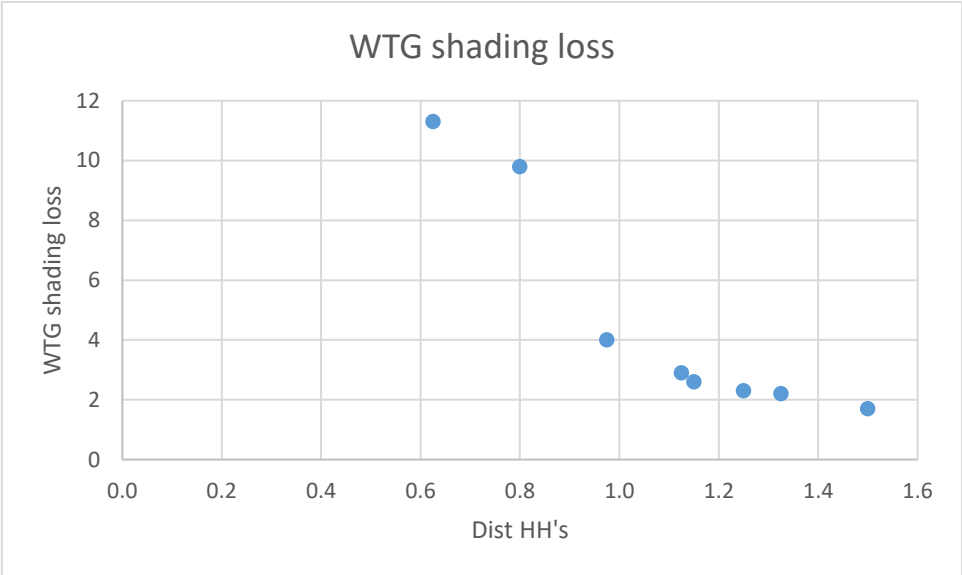



*Figure 48 Shading loss vs distance measured in hub heights.*

The two highest points in Figure 48 are for panels directly north of the turbine. The other points are either are in north-westerly direction or panels that cover north as north-west directions as well. This graph is based on a 40.5 m hub height turbine with 39 m rotor diameter. It can be concluded that with WTGs closer than their hub height from panels, WTG shading losses start to become quite large, is the order of 10% of annual production.

# 5 Full plant calculation validation

## 5.1 The plant configuration

As seen, there are different panel sizes within the different areas. Therefore, the plant is created by 28 different areas where each area is within an inverter section and has same panel power.

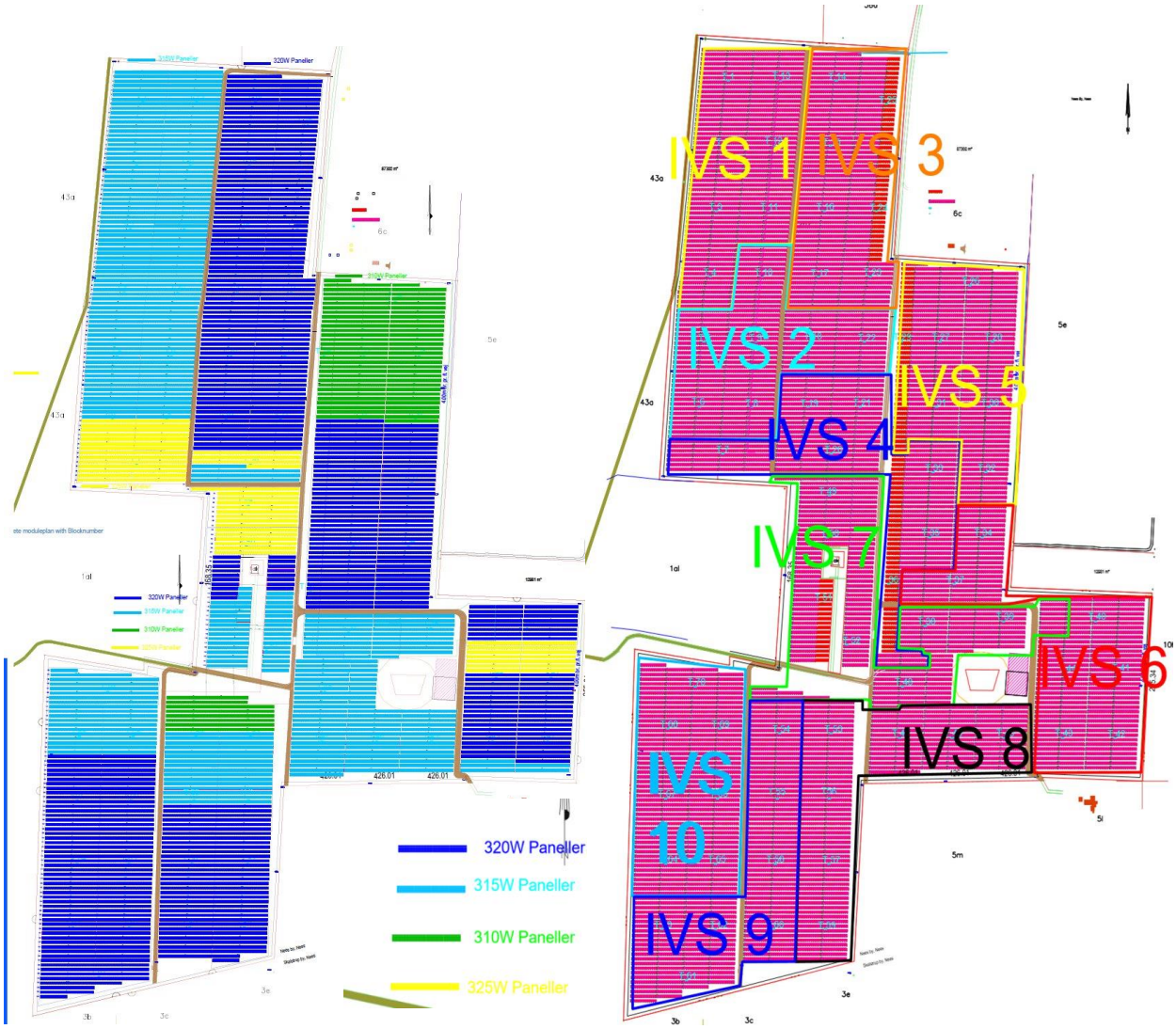



*Figure 49 The panel power areas (left), from 310-325W, and the Inverter Sections (right).*

The two maps shown must be combined to create calculations for each of the three inverter sections (where 1-3 are grouped, etc.) with aggregated measurements, and at the same time use the correct panel power values. This results in a total of 28 areas, see Figure 50. Note the panel power map above is not fully correct according to the detailed specifications received in Excel sheet.

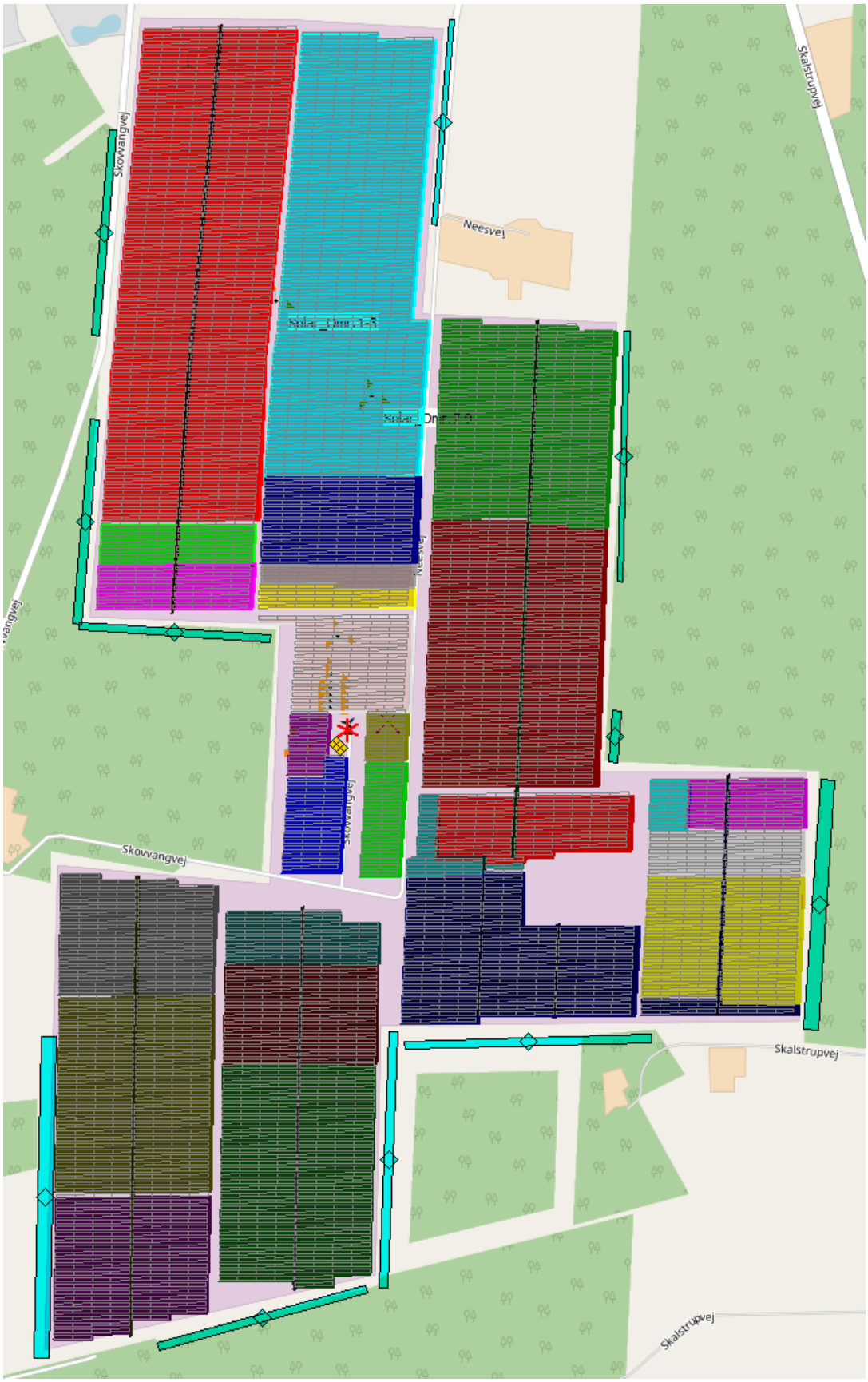



*Figure 50 The plant created in windPRO with 28 areas. The WTG and Obstacles are shown.*

The full plant with the 28 areas aggregated by Inverter sections and panel power consists of following panels and inverters:

| Row Labels | Sum of Inverters | Sum of Panels | Sum of DC Capacity (kW |
|---|---|---|---|
| **IVS10** | **98** | **15680** | **4988,8** |
| 315 | 35,5 | 5760 | 1814,4 |
| 320 | 62,5 | 9920 | 3174,4 |
| **IVS1-3** | **294** | **47040** | **14940,8** |
| 315 | 154 | 24640 | 7761,6 |
| 320 | 126 | 20160 | 6451,2 |
| 325 | 14 | 2240 | 728 |
| **IVS4-6** | **294** | **47040** | **14956** |
| 310 | 69 | 11040 | 3422,4 |
| 315 | 18 | 2880 | 907,2 |
| 320 | 172 | 27520 | 8806,4 |
| 325 | 35 | 5600 | 1820 |
| **IVS7-9** | **294** | **47040** | **14985,2** |
| 310 | 15 | 2400 | 744 |
| 315 | 77,5 | 12400 | 3906 |
| 320 | 178,5 | 28560 | 9139,2 |
| 325 | 23 | 3680 | 1196 |
| **Grand Total** | **980** | **156800** | **49870,8** |
| | | | |
| Nees IVS 1-9 | 882 | 141120 | 44.882 |

*Figure 51 The full project, we do not have measurements for IVS_10.*

| Array/Subarray Name | Azimuth deg. from N | tilt angle deg. | inverter type | inverter number | module type | module number | area m2 | DC power kWp |
|---|---|---|---|---|---|---|---|---|
| **IVS 1-3** | | | | | | | | |
| 315 | 180 | 20 | SUN2000 36KTL | 154 | Tata TP315 | 24.640 | 47.785,83 | 7.761,60 |
| 320 | 180 | 20 | SUN2000 36KTL | 126 | Tata TP320 | 20.160 | 39.097,50 | 6.451,20 |
| 325 | 180 | 20 | SUN2000 36KTL | 14 | Tata TP325 | 2.240 | 4.344,17 | 728,00 |
| **IVS 1-3** | | | | **294** | | **47.040** | **91.227** | **14.940,80** |
| **IVS 4-6** | | | | | | | | |
| 310 | 180 | 20 | SUN2000 36KTL | 69 | Tata TP310 | 11.040 | 21.410,53 | 3.422,40 |
| 315 | 180 | 20 | SUN2000 36KTL | 13 | Tata TP315 | 2.080 | 4.033,87 | 655,20 |
| 320 | 180 | 20 | SUN2000 36KTL | 177 | Tata TP320 | 28.320 | 54.922,68 | 9.062,40 |
| 325 | 180 | 20 | SUN2000 36KTL | 35 | Tata TP325 | 5.600 | 10.860,42 | 1.820,00 |
| **IVS 4-6** | | | | **294** | | **47.040** | **91.227** | **14.960,00** |
| **IVS 7-9** | | | | | | | | |
| 310 | 180 | 20 | SUN2000 36KTL | 15 | Tata TP310 | 2.400 | 4.654,46 | 744,00 |
| 315 | 180 | 20 | SUN2000 36KTL | 133 | Tata TP315 | 21.280 | 41.269,58 | 6.703,20 |
| 320 | 180 | 20 | SUN2000 36KTL | 123 | Tata TP320 | 19.680 | 38.166,60 | 6.297,60 |
| 325 | 180 | 20 | SUN2000 36KTL | 23 | Tata TP325 | 3.680 | 7.136,84 | 1.196,00 |
| **IVS 7-9** | | | | **294** | | **47.040** | **91.227** | **14.940,80** |
| | | | | | | | | |
| **NEES IVS 1-9** | | | | **882** | | **141.120** | **273.682** | **44.841,60** |

*Figure 52 Specifications from external consultant's calculation report used to check the panel setup in windPRO.*

There is a match on totals between the windPRO project setup and the external consultant's setup, but smaller differences within the individual inverter sections/panel power values. The reason for this is probably that the project design has been slightly modified when constructed. In the windPRO design, an Excel sheet describes which panel power is used for each inverter and how the inverter is located.

## 5.2 Inverter setup

The inverters are defined as "half size" (18 kW, where the real inverters are 36 kW). The reason for this is that the windPRO software will not share inverters from one area to another. By having areas with different panel power and areas that must belong to specific inverter sections, the areas will in reality share inverters in some parts. This is made possible by halving the inverter size. Then for each area the AC/DC ratio is fine-tuned to make the number of inverters match each area from the specification documents.

Inverter setup: Save as default | Load EMD defaults

| Areas | AC/DC spec. | DC-power (kW) | Inv. Size (kW) | No. Of inverters | AC power (kW | AC/DC realized | |
|---|---|---|---|---|---|---|---|
| **Edit all** | | | **18,0** | | | | **Edit inv.** |
| 1-3_325W | 0,690 | 728 | 18,0 | 28 | 504 | 0,69 | Edit inv. |
| 1-3_315W | 0,712 | 7.762 | 18,0 | 308 | 5.544 | 0,71 | Edit inv. |
| 1-3_320W | 0,703 | 6.451 | 18,0 | 252 | 4.536 | 0,70 | Edit inv. |
| 4-6_325W_ | 0,690 | 728 | 18,0 | 28 | 504 | 0,69 | Edit inv. |
| 4-6_315W | 0,710 | 353 | 18,0 | 14 | 252 | 0,71 | Edit inv. |
| 4-6_325W_a | 0,690 | 364 | 18,0 | 14 | 252 | 0,69 | Edit inv. |
| 4-6_320W_x | 0,695 | 1.434 | 18,0 | 56 | 1.008 | 0,70 | Edit inv. |
| 4-6_310W | 0,725 | 3.422 | 18,0 | 138 | 2.484 | 0,73 | Edit inv. |
| 4-6_320W_a | 0,700 | 4.762 | 18,0 | 186 | 3.348 | 0,70 | Edit inv. |
| 4-6_315W_a | 0,700 | 302 | 18,0 | 12 | 216 | 0,71 | Edit inv. |
| 7-9_320W_a | 0,700 | 256 | 18,0 | 10 | 180 | 0,70 | Edit inv. |
| 7-9_320W_b | 0,703 | 205 | 18,0 | 8 | 144 | 0,70 | Edit inv. |
| 7-9_325W | 0,690 | 1.196 | 18,0 | 46 | 828 | 0,69 | Edit inv. |
| 7-9_315W_a | 0,690 | 605 | 18,0 | 24 | 432 | 0,71 | Edit inv. |
| 7-9_315W_b | 0,704 | 454 | 18,0 | 18 | 324 | 0,71 | Edit inv. |
| 7-9_315W_aa | 0,708 | 1.235 | 18,0 | 49 | 882 | 0,71 | Edit inv. |
| 7-9_320W_c | 0,703 | 205 | 18,0 | 8 | 144 | 0,70 | Edit inv. |

*Figure 53Inverters are defined by the specified AC/DC ratio.*

When giving the AC/DC ratio, number of inverters that fulfil this is auto calculated, getting as close as possible to the specified ratio, but not below.

| | Output |
|---|---|
| Rated AC Active Power | 36,000 W |
| Max. AC Apparent Power | 40,000 VA |
| Max. AC Active Power (cosϕ=1) | Default 40,000W; 36,000W optional in settings |
| Rated Output Voltage | 220V / 380V, 230V / 400V, default 3W+N+PE; 3W+PE optional in settings 277V/480V, 3W+PE |
| Rated AC Grid Frequency | 50 Hz / 60 Hz |
| Max. Output Current(@380V/400V/480V) | 60.8 A/57.8A/48.2A |
| Adjustable Power Factor | 0.8 LG ... 0.8 LD |
| Max. Total Harmonic Distortion | < 3% |

*Figure 54 Inverter specification.*

There is a little doubt on the inverter power; EMD has chosen 36 kW, where it seems the external consultant has chosen 40 kW, which require cos(Φ) of 1.0. Checking the maximum measured power for the three Inverter sections confirm that 36 kW per inverter is the correct figure.

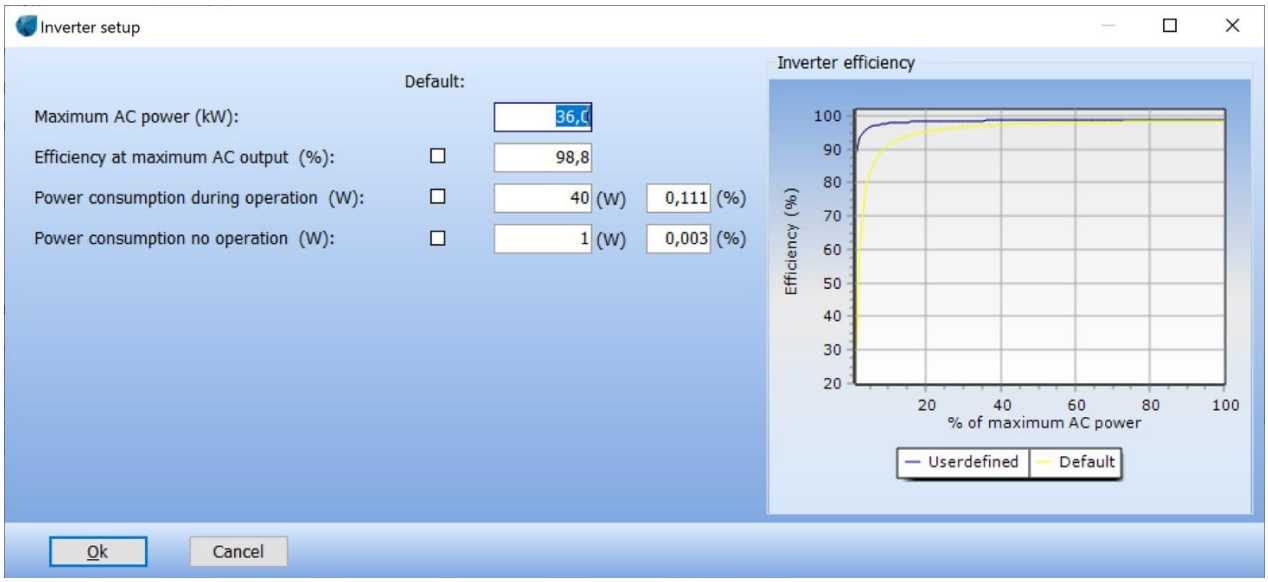
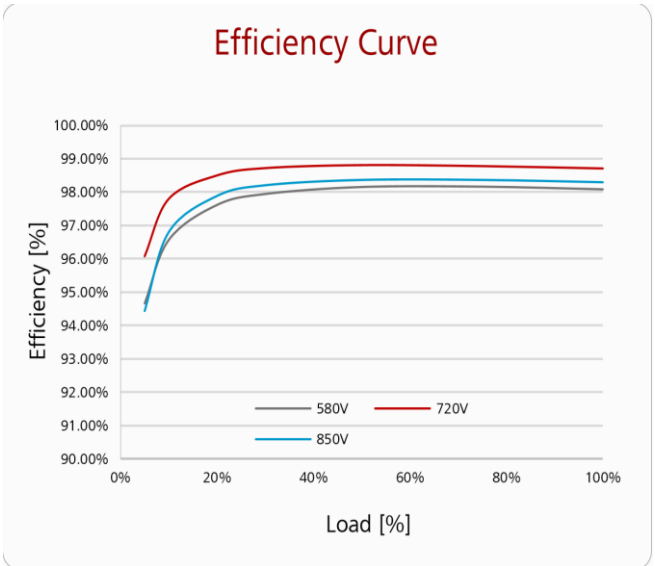



*Figure 55 Inverter specification.*




The inverter is seen (by visualizing the data) to operate most of the time close to 720 V. Therefore, the efficiency curve for 720 V is used and is reproduced by adjusting the maximum efficiency and the power consumption during operation as seen in Figure 55.

The inverter size is later halved to make the inverter assignment to the areas more flexible.

*Figure 56 Efficiency curve from inverter data sheet.*

## 5.3 The measurements

*Table 3 The measurements for each of three inverter Sections on 15-minute resolution available as .csv files.*

| | |
|---|---|
| Generated On | 2018-04-01 10:15:00 |
| Daily Energy (kWh) | 6351,73 |
| Active Power (kW) | 6499,848 |
| Total Irradiance (W/m²) | 455 |

| | |
|---|---|
| Daily Irradiation Amount (kWh/m²) | 0,45 |
| PV Module Temp (°C) | - |
| Ambient Temp (°C) | 5,2 |

The measurements are loaded in Excel for further evaluations. Be aware that data are in local time, including daylight saving time. This is corrected in Excel while calculations are in UTC+1 for the whole year. In windPRO Solar-PV it is necessary to have solar data in the same time zone for the whole year, while the data are time-aligned with Top of Atmosphere radiation. This will not work correctly if half the data are shifted by one hour.

The registrations in data files with **Active power** and **Daily energy** are checked to ensure that they match very close. The Daily energy (accumulated production during each day) has some spikes where the counter sometimes "jumps" (data error), so the Active power column is used.

## 5.4 Calculations compared to measurements

Aggregating the calculation results for the three **I**n**V**erter **S**ections (IVS) with aggregated measurements gives the following results, looking at concurrent data (calculations only included for time stamps where measurements >0):

Concurrent data, no loss reduction in calc. apart from shading and inverter

| Inverter sections | _IVS1-3 | _IVS4-6 | _IVS7-9 | Sum |
|---|---|---|---|---|
| Calculated (MWh) | 15.367 | 15.362 | 15.432 | 46.160 |
| Measured (MWh) | 15.146 | 15.060 | 15.170 | 45.376 |
| Measured/Calculated | 99% | 98% | 98% | 98% |

*Table 4 Main results calculating 50 MW dc plant, concurrent data, based on Heliosat data.*

NOTE: Concurrency means something different here than in the previous test. Having data from many inverters summarized will not reveal if some inverters have been out of operation.

Therefore, the measured availability data for each Block (there are 63 blocks for IVS 1-9) must be examined in order to better define the availability losses.

Unfortunately, it turns out, that the availability registrations do not give a correct picture of the real availability, see examples in Figure 57:

| | Availability by IVS | | | | Meas/calc | | |
|---|---|---|---|---|---|---|---|
| | IVS1-3 | IVS4-6 | IVS7-9 | | IVS1-3 | IVS4-6 | IVS7-9 |
| Avg.if >0 | 100,0 | 99,8 | 99,9 | | 0,91 | 0,88 | 0,86 |
| avg. Avail. | 94,5 | 92,7 | 93,6 | check | 0,89 | 0,86 | 0,85 |
| 25-10-2018 | 100,0 | 99,7 | 99,7 | | 1,10 | 0,95 | 0,91 |
| 26-10-2018 | 100,0 | 100,0 | 99,9 | check | 0,04 | 0,03 | 0,03 |
| 27-10-2018 | 100,0 | - | - | | 0,01 | 0,00 | 0,02 |

*Figure 57 Availability info test.*

In Figure 57, three days with different measured average block availability aggregated on inverter sections are shown.

Data from October 25th looks reasonable. IVS 1-3 has 100% availability, meas/calc is 1,1. For the two other dates, availability is just 0.3% below 100%, but meas/calc. is more than 15% below the first IVS. This does not seem plausible. A possible cause can be that the availability

is high most of the time, just not the sunniest time. Therefore availability does not show real loss expectations.

For the next day, October 26th, the production is just 3-4% of calculated, but availability measurements are almost100%. This also seems unrealistic. On the third day, IVS_1-3 has 100% availability, the two other 0%, but all three measurements are close to zero.

The availability figures cannot be considered as reliable when taken from these measurements. Therefore, we create our own availability calculation. This is based on using the availability as the measurements; if the ratio measured/calculated is above a threshold of 75% and the availability not is zero. If the measured/calculated ratio is below the threshold, we use this as availability. With this setup, we calculate energy availability loss for each day. Note this can be negative if the measured production is higher than calculated. Then we sum for the year:

| | Manual availability (%) | | | Energy availability loss (kWh) - 1 year | | |
|---|---|---|---|---|---|---|
| | Treshold: | 0,75 | | | | |
| | IVS1-3 | IVS4-6 | IVS7-9 | IVS1-3 | IVS4-6 | IVS7-9 |
| Avg.if >0 | 91,74 | 90,00 | 90,80 | 2,8% | 4,1% | 3,4% |
| avg. Avail. | 89,73 | 88,02 | 89,31 | 436.046 | 644.709 | 528.930 |
| 25-10-2018 | 110,22 | 99,71 | 99,72 | - 1.326 | 38 | 37 |
| 26-10-2018 | 3,70 | 2,99 | 3,21 | 22.993 | 23.187 | 23.103 |
| 27-10-2018 | 0,85 | 0,25 | 2,30 | 43.231 | 43.540 | 42.543 |

*Figure 58 Illustration of the availability loss calculation.*

The same three days are presented in Figure 58. On the first day, IVS_1-3 shows a negative availability loss, which "compensates" the method, which would calculate too high availability losses if only the days where calculation is higher than measured were given availability loss.

With the availability losses as defined, the following table gives the totals for the three inverter sections:

| All data, no loss reduction in calc. apart from shading and inverter | | | | |
|---|---|---|---|---|
| Inverter Section | _IVS1-3 | _IVS4-6 | _IVS7-9 | Sum |
| Calculated (MWh) | 15.713 | 15.706 | 15.712 | 47.132 |
| Measured (MWh) | 15.146 | 15.060 | 15.170 | 45.376 |
| Measured/Calculated | 96% | 96% | 97% | 96% |
| Availability corrected *) | | | | |
| Availability loss | 3,1% | 3,9% | 3,5% | 3,5% |
| Measured/Calculated | 99,5% | 99,8% | 100,0% | 99,8% |

*) Based on advanced loss-based availability calculation method.

*Table 5 Heliosat calculations vs measurements with availability correction.*

As seen, calculations show 4% higher values for the full year than the measurements. This can all be explained as availability losses. Although it might not be "out of order", it can also cover gaps in the data collection, see next paragraph.

The conclusion is that based on Heliosat data, calculation is precise as measurements on annual basis, but with some summer-winter bias, where the model calculations over-predict in winter and under-predict slightly in summer, see next section. This could be a bias in Heliosat data, or it could be due to lack of diffuse reduction in winter from obstacles and WTG, indicated in the detail evaluations.

Meteorological Data (Solar_Omr.1-3)

Position | Layers | Guide | Purpose | Data | Graphics | Statistics | Shear | Report | Description

Main statistics | Monthly means | Recovery | Monthly weibull parameters

Height: 2,00m -

Signal(s): Solar irradiation

Change status of selected samples to: Enabled Ok

All: 98,1% Effective data period: 11,8 months Total period: 12,0 months

Enabled *): 98,1% Effective data period: 11,8 months Total period: 12,0 months

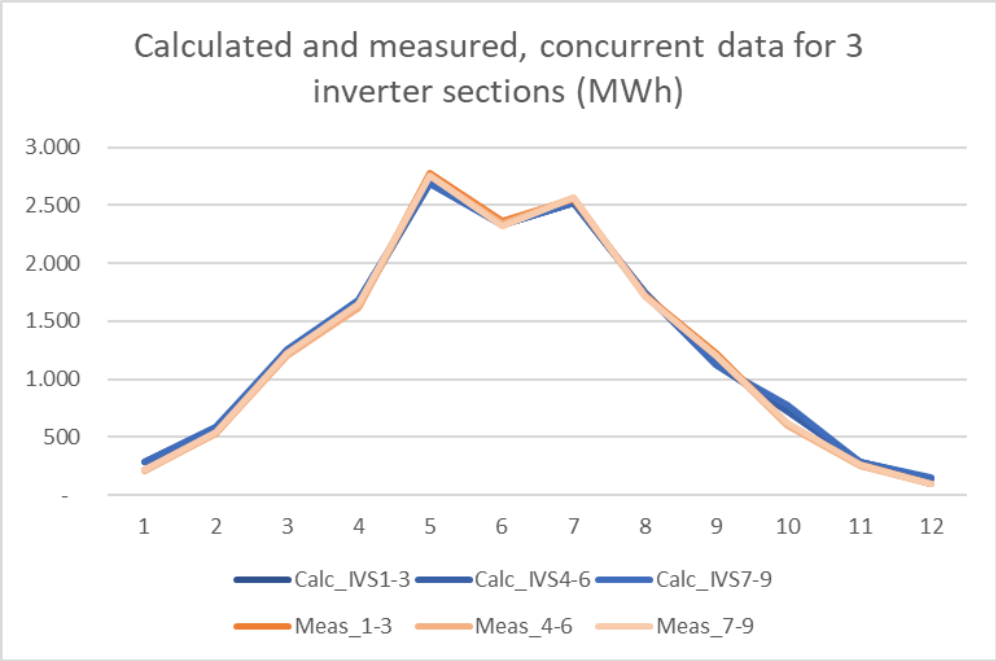
*) Recovery rate of available data between first and last enabled sample.

| 2,00m - | % | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 04-2018 | 98,5 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 86 | 96 | 64 | 96 | 96 | 96 | |
| 05-2018 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 06-2018 | 98,5 | 96 | 96 | 96 | 96 | 96 | 96 | 72 | 96 | 96 | 96 | 96 | 78 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | |
| 07-2018 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 08-2018 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 09-2018 | 95,8 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 31 | 40 | 96 | 96 | |
| 10-2018 | 95,3 | 96 | 96 | 96 | 96 | 90 | 96 | 96 | 96 | 96 | 96 | 34 | 34 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 95 | 96 | 88 | 96 | 96 | 96 | 96 | 96 |
| 11-2018 | 99,8 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 93 | 94 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | |
| 12-2018 | 89,0 | 96 | 96 | 32 | 0 | 0 | 36 | 96 | 96 | 96 | 96 | 88 | 96 | 96 | 96 | 96 | 96 | 94 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 01-2019 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| 02-2019 | 100,0 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | | | |
| 03-2019 | 99,7 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 92 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 92 |
| All | 98,1 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

*Figure 59 Data recovery for IVS 1-3 measurements. 2% is missing.*

Figure 59 shows 2% of data are missing for IVS_1-3. Although mostly occurring in winter months, it indicates the full availability loss is not due to data gaps.

In the Figures 60-62, the inverter section calculations are compared to measurements on annual basis, aggregated by month and hour.



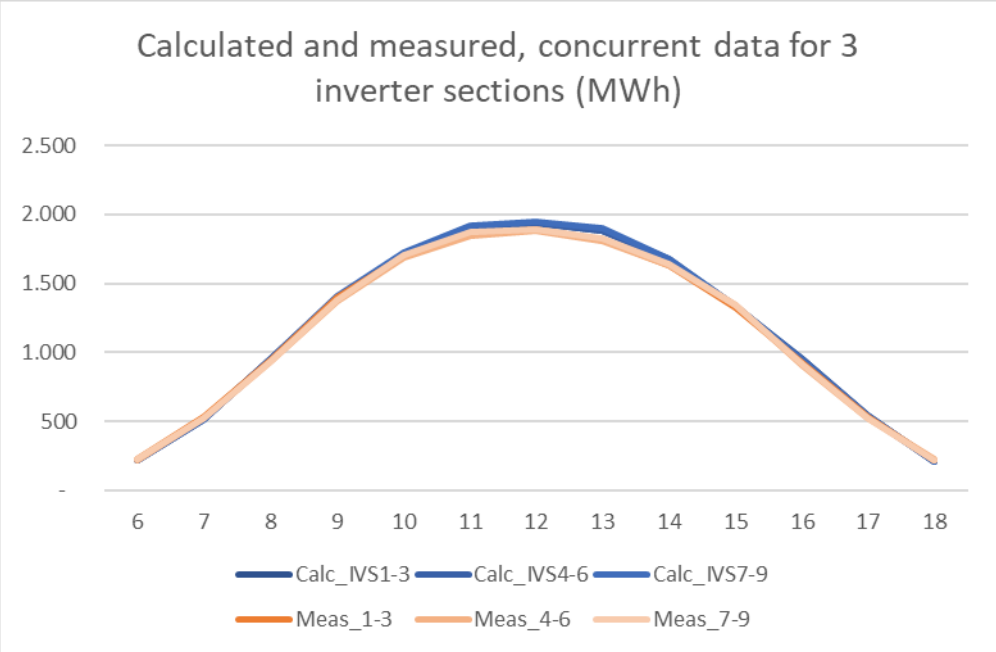




*Figure 60 Monthly (upper) and hourly (lower) comparisons of measured and calculated.*

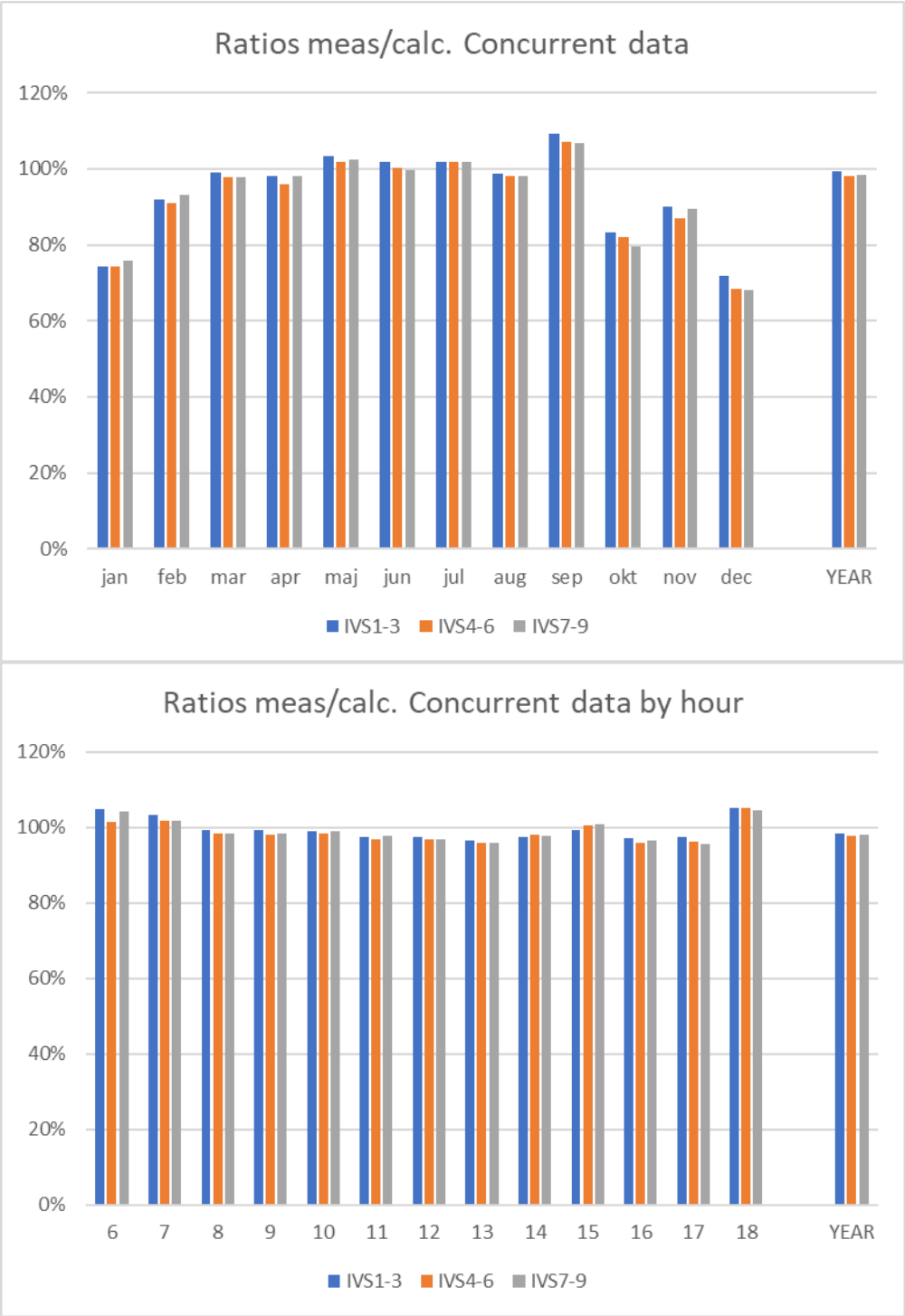



*Figure 61 Monthly (upper) and hourly (lower) comparisons of ratios measured/calculated (Heliosat)*

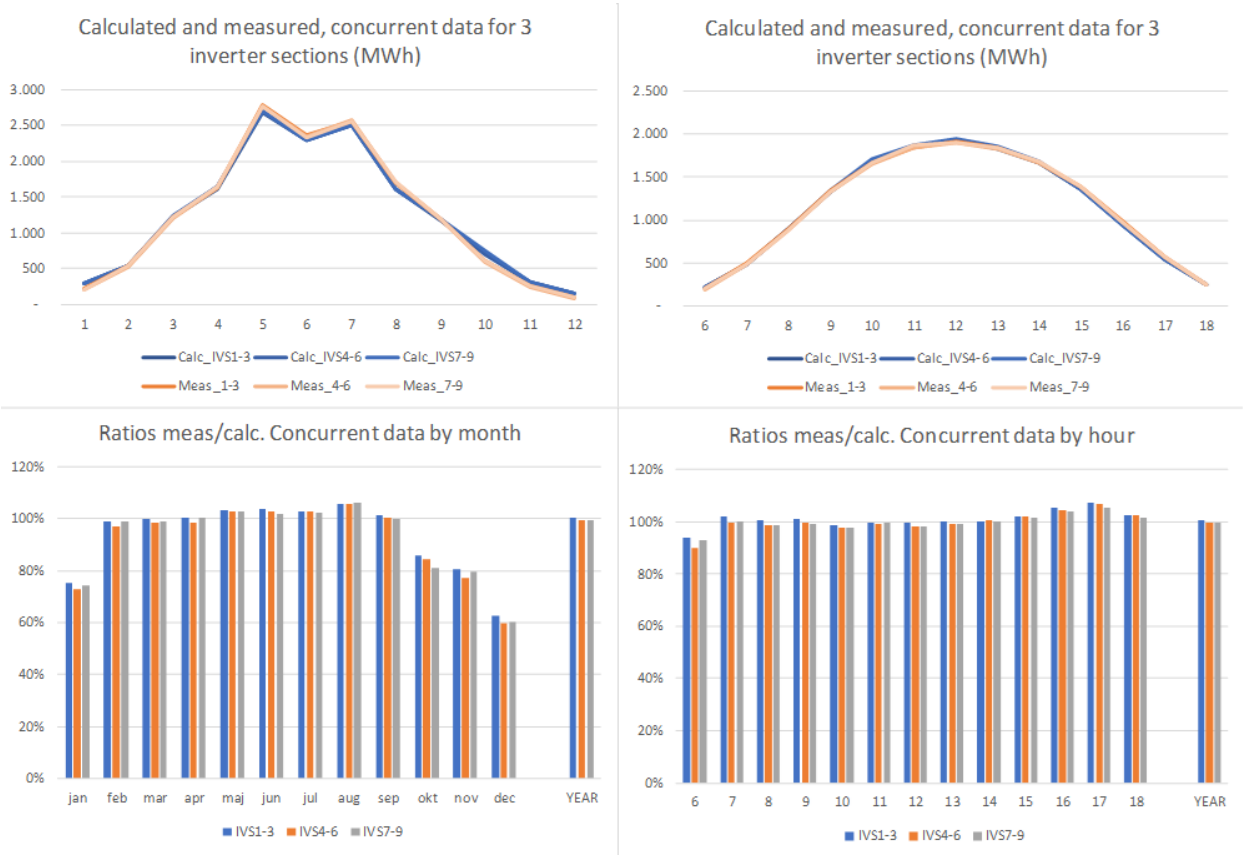



*Figure 62 Graphs based on local measurements.*

Calculations based on local measurements show higher over-predictions in winter months than Heliosat data, but due to slightly under-prediction in summer months, there is an exact match on the annual totals. This means a small under-estimation, whilst it can clearly be seen that there are availability losses in the measurements.

## 5.5 Loss details

It is possible to evaluate losses in more detail.

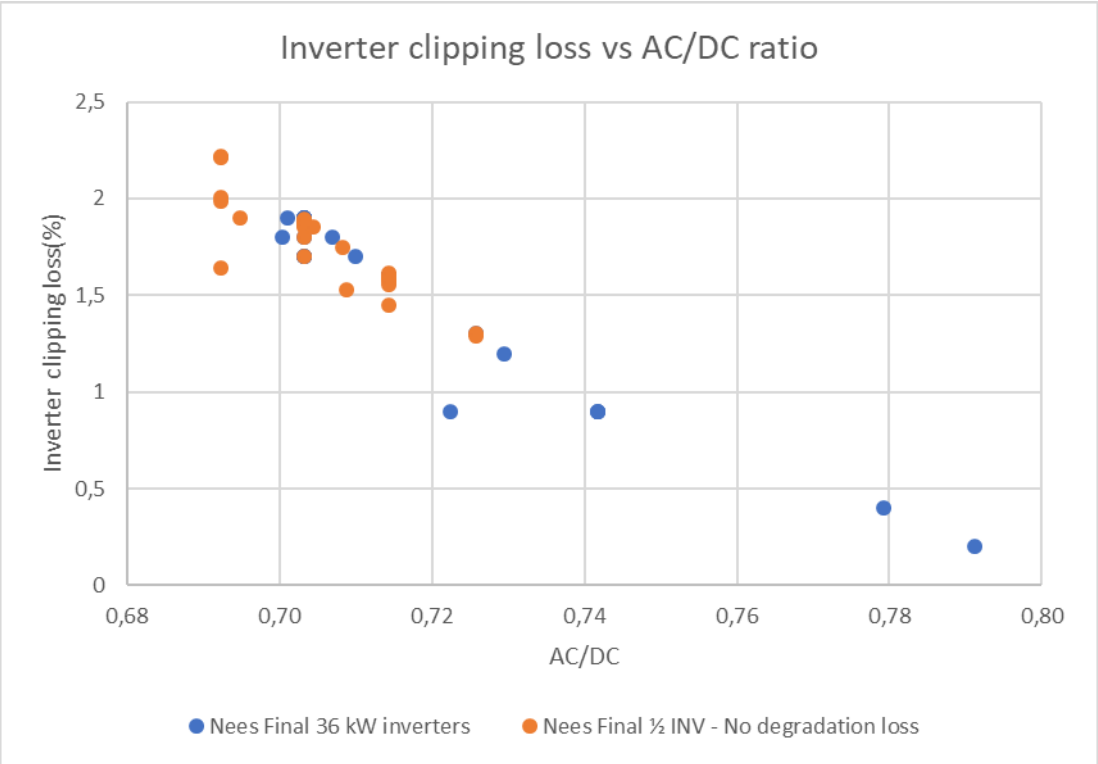



*Figure 63 Inverter clipping loss vs AC/DC ratio.*

Figure 63 shows how a smaller inverter size narrows the AC/DC ratio while the software only allows for using an integer number of inverters for each area. If the project, as in this example consists of many areas due to different panel sizes (power), this limitation does not match the reality. Some inverters are connected across multiple areas. This setup problem can be solved by reducing the inverter size used in calculation. The AC/DC ratios will still differ a little due to the differences in panel power.

*Table 6 Inverter clipping loss by inverter size in calculations.*

| | All sections | Unit |
|---|---|---|
| Inverter clipping loss, 36 kW | 956,8 | MWh/y |
| Inverter clipping loss, 18 kW | 948,9 | MWh/y |
| Change | 7,9 | MWh/y |
| Change % | 0,8 | % |

The result of calculating with the inverter setup that reflects the real wiring more accurately is a 0.8% lower calculated inverter clipping loss.

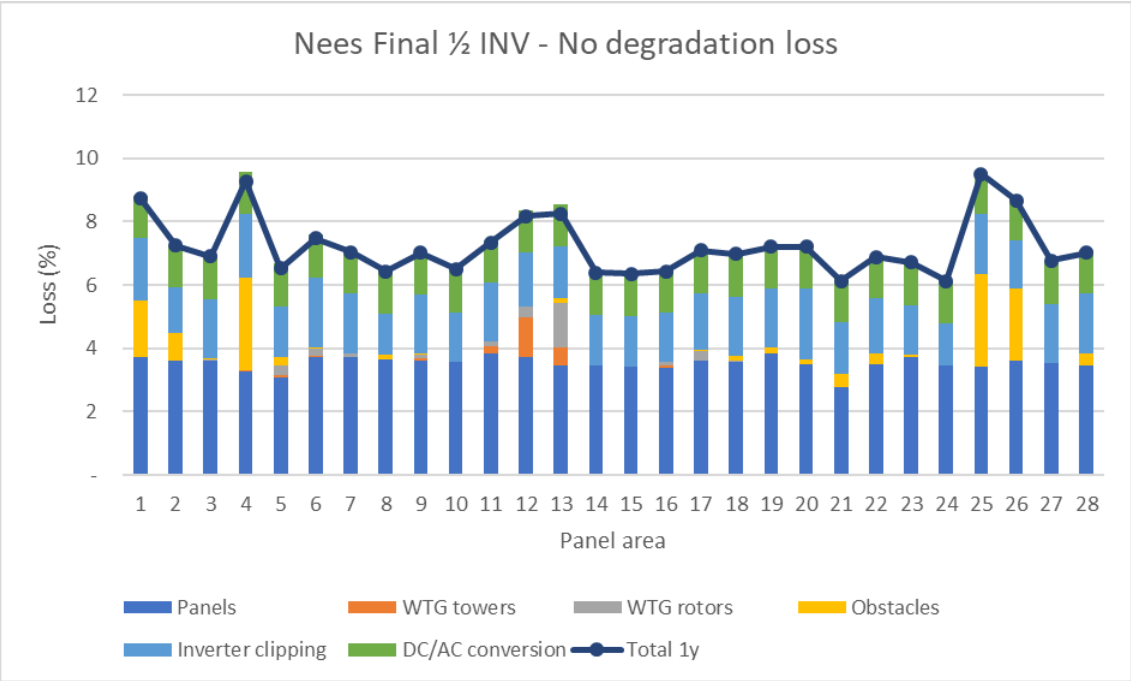



*Figure 64 All areas with calculated losses.*

The calculated losses per sub-area vary from 6.1% to 9.5%. Obstacles especially make a difference, but also the WTG is seen to increase the losses significantly for the areas around this (12-13).

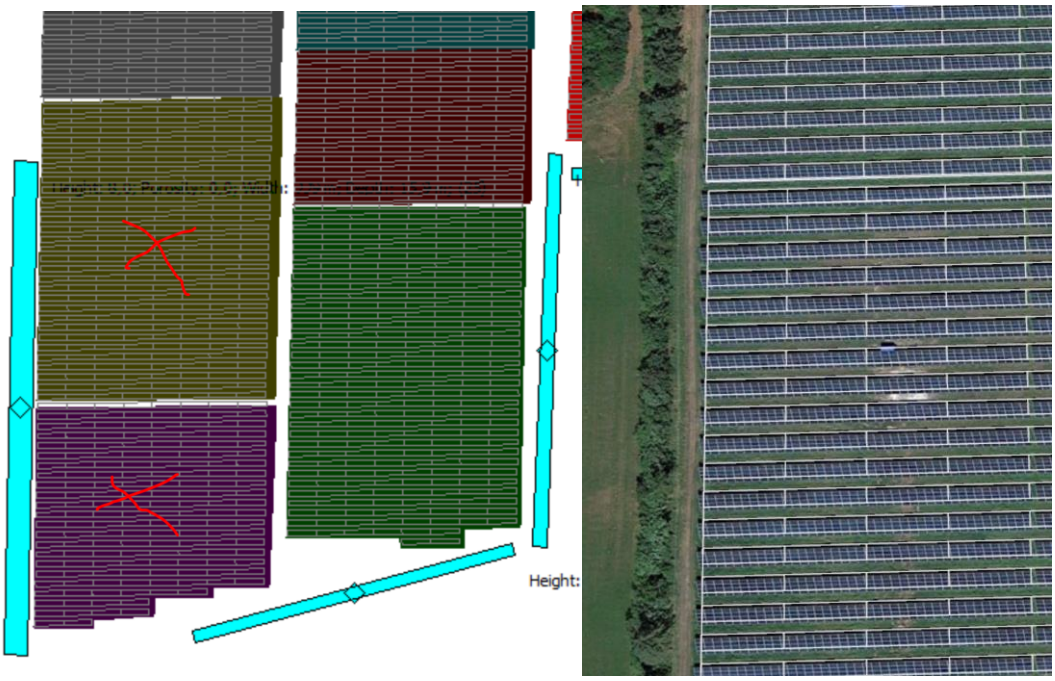



*Figure 65 Areas 25 and 26 marked with red X, where obstacle shading loss is large. To the right panels on Google Earth™.*

Figure 65 shows the obstacle seen to the left of the panel areas, that causes a reduction in yield for Area 25 (lower, part of IVS 7-9) and Area 26 (upper, part of IVS 10). Note that the loss from this obstacle is calculated to be almost 3% for each of the marked areas. So it matters to keep distance to trees or keep the height of the trees low.

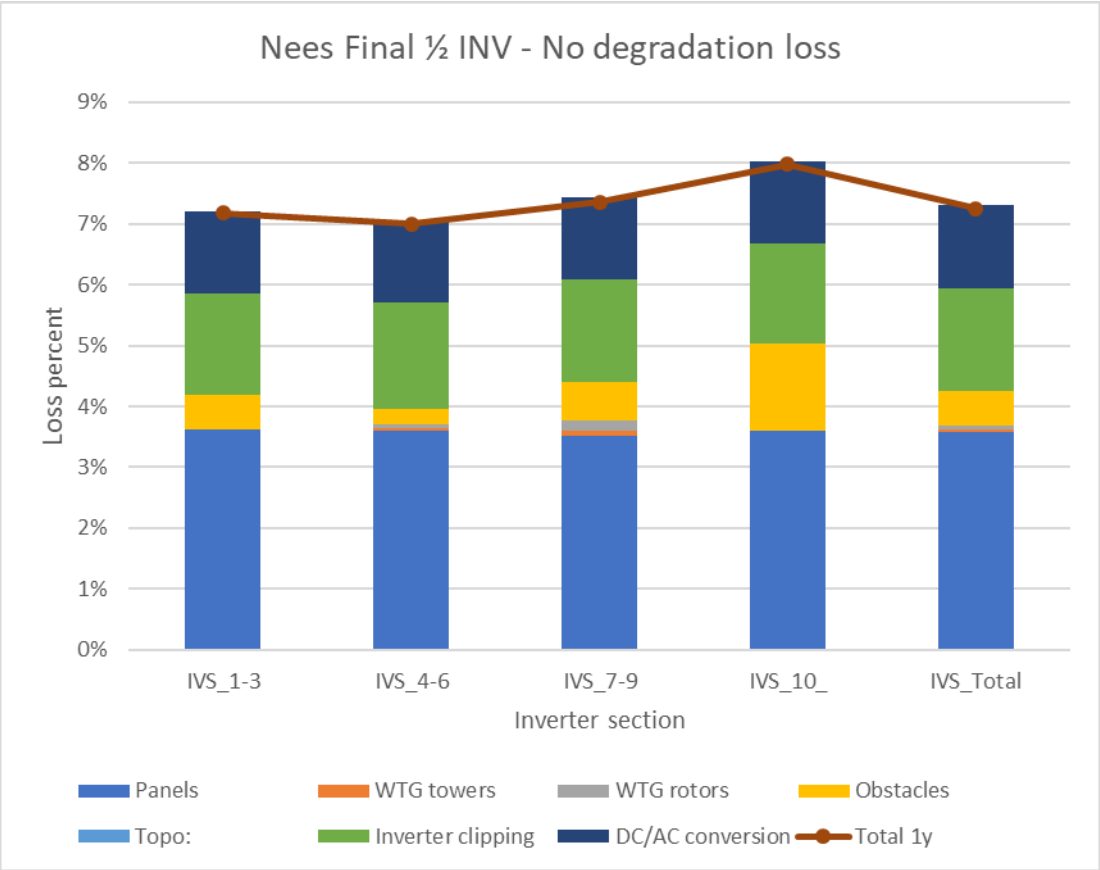



*Figure 66 The calculated loss by inverter section.*

By inverter section, there are small differences between the predicted losses as shown in Figure 66. IVS_10 has some higher calculated obstacle losses giving round 1% more loss than for the other areas. With only one WTG (and a smaller one), this only invokes the loss for the full plant marginally. Nevertheless, building PV plants within wind parks (or installing PV plants around wind farms), can give significant losses from the WTG shading, making this calculation extremely important.

## 5.6 Panel power influence on production and costs

From the home page of the panel manufacturer the costs for different panel powers can be seen. With these it can be analyzed to see if there is a benefit of using 325 W panels vs. 315 W panels.

*Table 7 Cost of panels by panel power (costs correct as of 2020).*

| Model | Price (Rs) | Per watt(Rs) | DKK/panel | DKK/kW | Relative to 325W | |
|---|---|---|---|---|---|---|
| Tata Solar Panel 315 Watt | 9450 | 30 | 892 | 2.832 | 96,9% | -3,1% |
| Tata Solar Panel 320 Watt | 9600 | 30 | 906 | 2.832 | 98,5% | -1,5% |
| Tata Solar Panel 325 Watt | 9750 | 30 | 920 | 2.832 | 100,0% | 0,0% |
| Tata Solar Panel 330 Watt | 9900 | 30 | 934 | 2.832 | 101,5% | 1,5% |

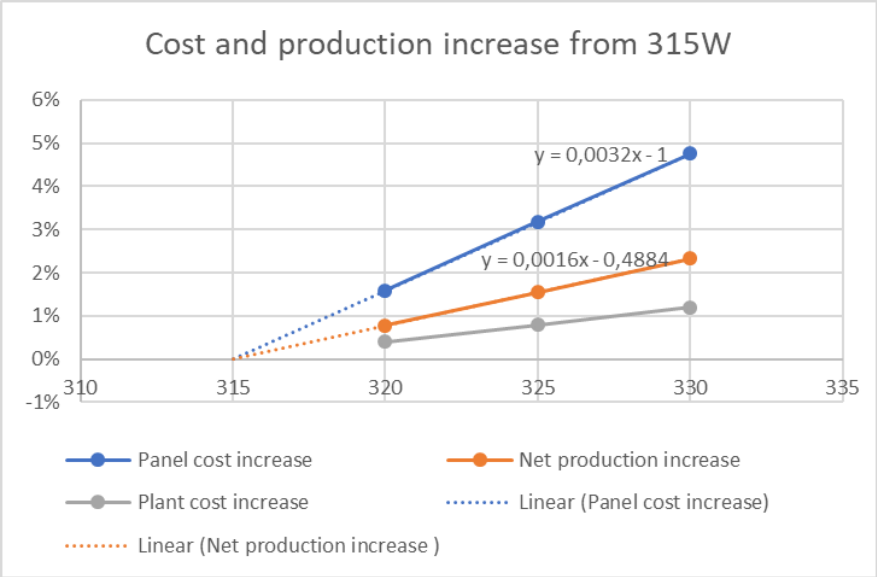



*Figure 67 Cost and production increase by panel power.*

Figure 67 shows that the cost of panels within the 315 to 330 W range, increases linearly with rating. Production increases similarly, but with a lower slope. Assuming the panel costs are 25% of the entire plant costs, the plant cost increase will be lower than the production increase. Therefore it can be concluded that using panels of higher power will be feasible for the project in this case.

## 5.7 Long term expectations

To get to the long-term expectations, the solar irradiation in the Nees data period 01.04.2018-31.03.2019 is evaluated.

Three different data sources are used for calculation of a solar index, simply by taking the annual global irradiation on horizontal plane and divide with the full period for the different data sources.

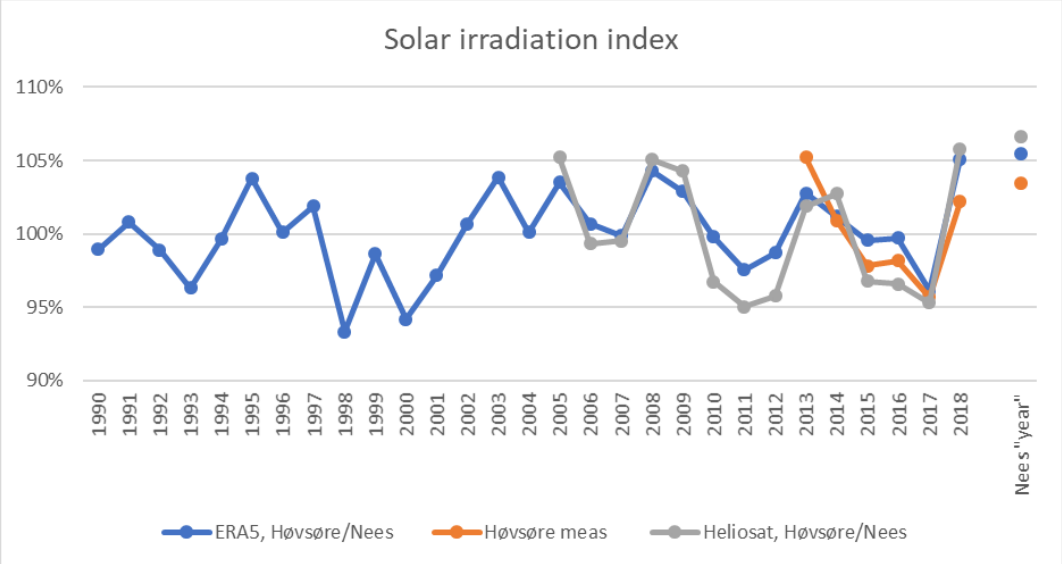



*Figure 68 Solar irradiation index.*

There is some increased interannual variation in Heliosat compared to ERA5 irradiation data. This is probably closer to the truth, while ERA5 is more smoothed data than Heliosat due to more details about cloud coverage, it nevertheless catches the dynamic behavior of the irradiation better. The Høvsøre measurements are not complete, which affects the accuracy:

| Average of % | Column Labels | | | | | | |
|---|---|---|---|---|---|---|---|
| Row Labels | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Grand Total |
| 1 | 100,0 | 99,7 | 99,8 | 99,8 | 99,8 | 99,8 | 99,8 |
| 2 | 90,2 | 99,9 | 99,6 | 99,8 | 98,9 | 99,8 | 98,0 |
| 3 | 87,5 | 99,9 | 99,7 | 99,7 | 99,6 | 99,8 | 97,7 |
| 4 | 100,0 | 100,0 | 99,7 | 99,6 | 99,6 | 99,5 | 99,7 |
| 5 | 99,9 | 99,9 | 99,6 | 96,4 | 98,7 | 99,7 | 99,0 |
| 6 | 99,8 | 99,9 | 99,6 | 99,6 | 99,7 | 99,5 | 99,7 |
| 7 | 99,9 | 100,0 | 99,8 | 99,8 | 99,6 | 99,8 | 99,8 |
| 8 | 87,7 | 100,0 | 97,7 | 99,6 | 99,7 | 99,6 | 97,4 |
| 9 | 96,2 | 99,9 | 99,7 | 99,7 | 99,5 | 99,7 | 99,1 |
| 10 | 99,9 | 97,1 | 99,7 | 99,7 | 99,8 | 99,8 | 99,3 |
| 11 | 100,0 | 99,8 | 98,6 | 98,1 | 99,8 | 99,4 | 99,3 |
| 12 | 99,5 | 99,2 | 99,6 | 99,2 | 99,2 | 99,7 | 99,4 |
| **Grand Total** | **96,7** | **99,6** | **99,4** | **99,3** | **99,5** | **99,7** | **99,0** |

*Figure 69 Høvsøre data recovery.*

In 2013 there are many missing data in winter months, which probably explains the higher 2013 year index value compared to the other data sources. This will also push down the other years, since these are normalized against the average of all the years.

For the "Nees year"(Apr.18-Mar.19), the average of the two-model data set is 106%, which is probably what shall be divided into the calculation results for the Nees year with measurements. The calculated long-term expectations will be 47.1/106% = 44.4 GWh/y for the nine inverter sections IVS1-9. The external consultancy report estimates 44.3 GWh/y.

Not included in these figures are the expected annual linear panel degradation of 0.24%, as well as availability losses and other potential losses not included in calculation, e.g. growing trees, soiling, snow etc.

## 5.8 Validation of IVS measurements (data logger) against metering.

| | Metered | IVS measured | IVS/Meter |
|---|---|---|---|
| jan-19 | 652.132 | 654.172 | 100% |
| feb-19 | 1.587.811 | 1.625.498 | 102% |
| mar-19 | 3.545.960 | 3.663.499 | 103% |
| apr-18 | 4.813.998 | 4.899.166 | 102% |
| maj-18 | 8.036.041 | 8.315.693 | 103% |
| jun-18 | 6.863.618 | 7.064.367 | 103% |
| jul-18 | 7.447.275 | 7.705.201 | 103% |
| aug-18 | 4.983.520 | 5.064.733 | 102% |
| sep-18 | 3.483.074 | 3.511.712 | 101% |
| okt-18 | 1.825.141 | 1.832.996 | 100% |
| nov-18 | 751.557 | 749.135 | 100% |
| dec-18 | 294.198 | 289.424 | 98% |
| SUM | 44.284.325 | 45.375.596 | 102,5% |

The metered data are 2.5% lower than the logger data.

*Table 8 The metered data compared to the data logger data.*

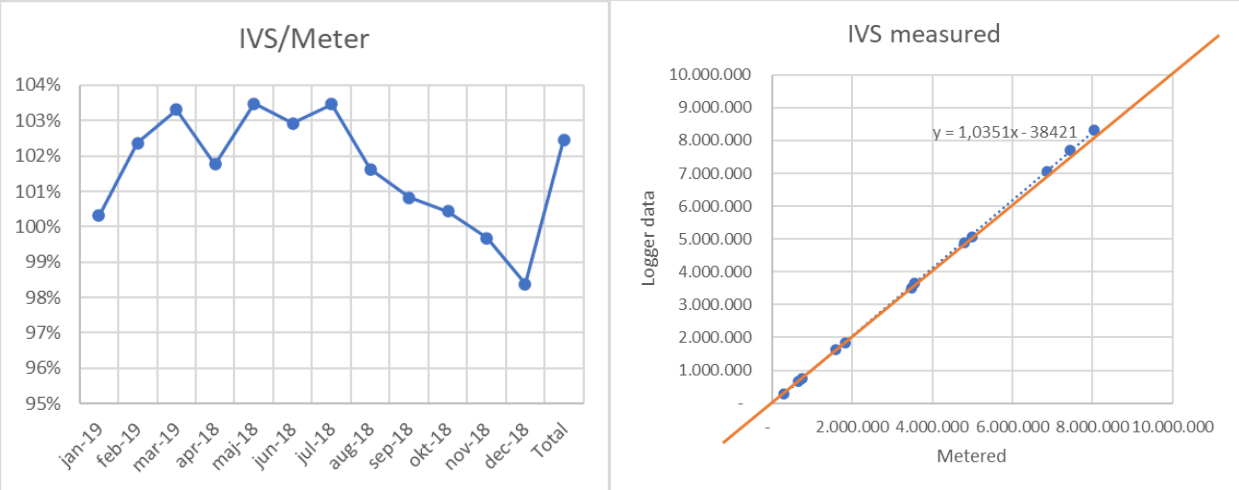



*Figure 70 The ratio between data logger measurements and meter data.*

There is a clear trend that the logger data show higher values than the meter data when production is high. This could indicate a calibration issue, that the logger data tends to show too high a production when this is high and too low when it is low. This could explain why calculations seem to under-predict summer and over-predict winter – that the real reason for this is a bias in logger data.

That the logger data seem to show too high values (2.5%) might also explain that the validation calculations in general come out with an "exact match", whereas it might be expected that the calculations should be slightly higher than measurements, due to losses, partly in local cabling, partly due to "non-perfect" operation. The detailed validation cases show typically round 2% under-prediction, which seems well-explained by the bias between metered and logger data.

# 6 Acknowledgements

Data from the Ness PV solar plant provided by NRGi Renewables A/S, Dusager 22, DK-8200 Aarhus, represented by Asset manager Kasper Hausted Svendsen, has supported EMD with comprehensive measurements for one year (01.04.2018 - 31.03.2019) and has been of great help in clarifying and discussing the results.