

Background

Wood was contracted to perform a capacity test for a utility scale solar PV plant in USA. A capacity test is a method to verify the performance of a PV plant and is typically conducted for substantial completion. The capacity test result is calculated as the ratio of modeled system power vs the measured system power at defined reporting conditions. A typical passing result is 97% and represents 100% minus some uncertainty. While the method for calculating the test result is fairly well defined in the ASTM E2848-13 standard (which is typically used for capacity tests in USA), the process can be much more challenging. The challenges for this project included using both bifacial and monofacial modules, varying azimuths, limited weather stations, near shading, rolling terrain, and a high DC/AC ratio making collecting data difficult. This case study will outline how Wood overcame these challenges, the key lessons learned, and best practices for conducting a successful performance test.

Test Methodology

There are two standardized methods for verifying the capacity of PV plants, ASTM E2848-13 and IEC 61724-2. While ASTM E2848-13 uses multi-linear regression to calculate power at the reporting conditions, IEC 61724-2 is a simpler method directly comparing modelled and measured power at the test conditions. Given the ASTM E2848 method was adopted for this project the methodology is summarized below.

ASTM E2848-13 presents a methodology for calculating the capacity of a PV system using multiple linear regression to fit collected data, PV system power (P), plane of array irradiance (E_{POA}), ambient temperature (T_{amb}), and wind speed (V_{ws}) to a performance equation:

$$P = E_{POA}(a_1 + [a_2 * E_{POA}] + [a_3 * T_{amb}] + [a_4 * V_{ws}])$$

Substitution of filtered modelled data (i.e. from PVSyst) into this equation allows for derivation of the modelled coefficients (a_{1_mod} , a_{2_mod} , a_{3_mod} , a_{4_mod}), and likewise with filtered measured data (a_{1_meas} , a_{2_meas} , a_{3_meas} , a_{4_meas}). Typically, one month of modelled data is used corresponding to the month the test is conducted. For measured data, the ASTM standard requires a minimum of 50 data points with 15-minute average interval. This is equivalent to 750 minutes or 12.5 hours. The ASTM standard allows for a collection period of at least three (3) days to at most four (4) weeks.

The PV system capacity is reported with respect to a specific set of reporting conditions (RC) which can be based on the measured or modelled filtered datasets and is calculated based on the average value of each parameter (E_{POA_RC} , T_{amb_RC} , V_{ws_RC}). Using the measured and modelled coefficients the measured and expected power are calculated at the reporting conditions respectively with the following equations:

$$P_{Expected} = E_{POA_RC}(a_{1_mod} + [a_{2_mod} * E_{POA_RC}] + [a_{3_mod} * T_{amb_RC}] + [a_{4_mod} * V_{ws_RC}])$$

$$P_{Measured} = E_{POA_RC}(a_{1_meas} + [a_{2_meas} * E_{POA_RC}] + [a_{3_meas} * T_{amb_RC}] + [a_{4_meas} * V_{ws_RC}])$$

The capacity test result is calculated as follows:

$$Test\ Result = \frac{Power_{Measured}}{Power_{Expected}}$$

A typical passing test result is 100% minus some uncertainty, ~97%.

Challenges

Bifacial and monofacial panels

The ASTM E2848-13 standard only presents a methodology for calculation of PV system capacity with monofacial modules, and this project has both monofacial and bifacial modules. NREL's Conference Paper (NREL/CP-5K00-73982) "Suggested Modifications for Bifacial Capacity Testing" includes a method for adapting the ASTM E2848-13 standard for bifacial modules. This is done by substitution E_{POA} with E_{Total} which is calculated with the following equation:

$$E_{Total} = E_{POA} + E_{Rear} * \varphi$$

where E_{POA} is the front-side POA irradiance, E_{Rear} is the rear-side back-of-module irradiance, and φ is the specified bifaciality factor from the module spec sheet. E_{Rear} can be measured directly or modelled if necessary.

Given the project has a mixture of monofacial and bifacial panels, the test needed to be subdivided into two separate tests and test result formula modified as follows:

$$Test\ Result = \frac{(P_{Measure_mono} + P_{Measured_bifacial}) * \eta}{P_{Expected_mono} + P_{Expected_bifacial}}$$

where $P_{Measure_mono}$ and $P_{Measured_bifacial}$ are measured at the inverter level and η is the electrical efficiency and calculated as follows:

$$\eta = \frac{\sum Inverter\ power}{\sum PV\ system\ power}$$

where inverter power is the power measured at the inverters and PV system power is normally measured at the point of interconnection, and both are calculated with consistent filtered timestamped data. Note, the η can be excluded from the test result but the PVSyst model used for calculating the expected capacity needs to be modified to exclude AC wiring losses, and the capacity test will be less comprehensive as the performance of the AC side of the plant is excluded.

Varying azimuths & Limited Weather Stations

The project consists of six arrays; four bifacial arrays, and two monofacial arrays. All arrays are fixed tilt and face south (180°) except for one monofacial array which faces south-east (~145°). The project has two weather stations located in the bifacial arrays and no weather station in either monofacial arrays. Each weather station consists of one global horizontal irradiance (GHI) sensor, one front plane of array (POA), three rear plane of array (RPOA) irradiance sensors, two back of module temperature sensors, and one weather sensor for ambient temperature, relative humidity, wind speed, and direction.

Given there are both monofacial and bifacial modules, it is more important that the weather stations are installed in the bifacial arrays such that the RPOA is measured properly; however, the monofacial array, which is not facing directly south, should have its own weather station, as its irradiance will vary significantly from the other arrays facing directly south. Given this circumstance there were a few options for the project:

- a weather station is installed in this array.
- the POA irradiance is modeled based on the GHI.
- the array is excluded from the capacity test.

While installing a weather station would be the best option for accuracy of the performance test, the client chose to model the POA irradiance for the SE facing array based on the GHI. This typically adds uncertainty to the test but is still ultimately better than excluding the array from the capacity test. For this case, Wood recommends both the Hay's and Perez transposition models are tested with GHI data to confirm which model best predicts POA. This can be done by comparing predicted POA irradiance with measured POA irradiance from the south facing arrays.

The ASTM standard does not specify a minimum number of weather stations however IEC 61724-1 does specify a minimum of two for projects <40 MW, which this project is. Given this project has two weather stations it technically meets the IEC requirement; however, given there are two module types and varying azimuths, Wood opines the number of weather stations should be increased to take this situation into account.

Irradiance Sensor Position

The ASTM E2848-13 standard does not have requirements for the amount or positioning of POA or RPOA sensors for capacity testing. The IEC 61724-1 standard does have recommendations for the amount of weather stations per project and does specify one (1) POA sensor and three (3) RPOA irradiance sensors per weather station, however, it does not provide recommended mounting positions. Wood recommends the following sensor positioning and mounting for trackers in accordance with recent industry publications:

- POA/RPOA sensor: on interior rows, not in most east or west row, and at least 5 modules in from north or south edge (as shown in Figure 1).
- RPOA sensor: for 1P trackers, 50% of the distance between the torque tube and east and west edges. For 2P trackers, 40-50% of the distance from the east/west edges to the torque tube (as shown in Figure 2).
- IEA PVPS Task 13's report for Bifacial Tracking notes that torque tube mounting (which is common practice) results in ~7% annual error in the RPOA irradiance while E/W mounting at 50% of edges results in ~2% error (as shown in Figure 3).

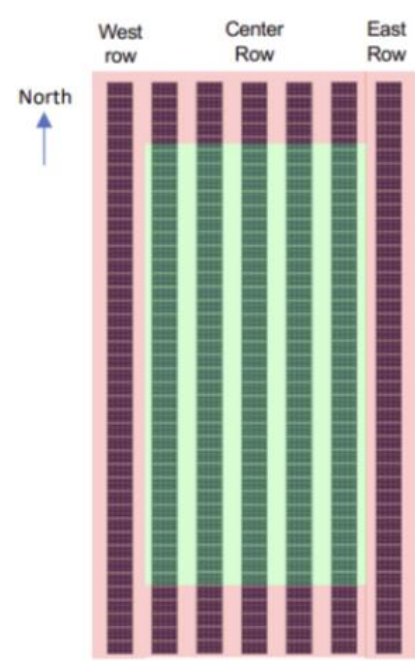


Figure 1: POA/RPOA Positioning (https://pvpmc.sandia.gov/download/7681/?tmstvt=1745425887)

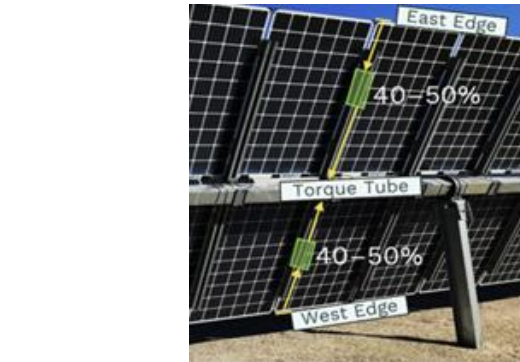
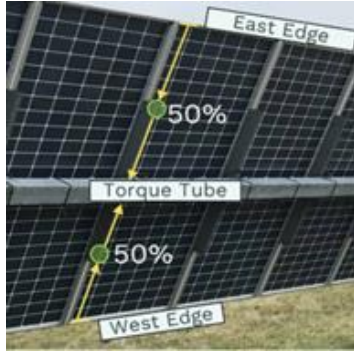


Figure 2: RPOA Positioning (https://iea-pvps.org/wp-content/uploads/2024/08/18_IEAPVPS-bifacial-tracking-1.pdf)

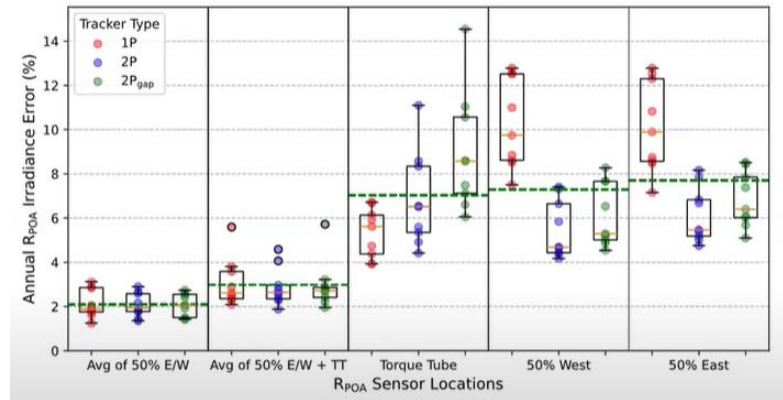


Figure 3: Annual RPOA Irradiance Error (https://www.youtube.com/watch?v=T4O_d3w8mU8)

Near Shading

According to the ASTM E2828-13 standard averaging intervals in which either the irradiance measurement device or the system is shaded or obstructed by snow, frost, or other environmental debris shall be excluded from the test.

This project is surrounded by trees, therefore all-time intervals that are affected by shading must be excluded from the test, which is not straightforward for a heavily forested site. If a detailed shading model is constructed in PVSyst with nearby tree and elevations data or canopy height data, the ShdLoss hourly output can inform shading times, which will vary significantly by time of year. For this project, the EPC initially wanted to conduct the capacity test in November, which PVSyst predicted shading up until mid morning on some arrays as shown in Figure 4. However, through timeseries analysis (Figure 5) of inverter production and site investigation, it was determined that shading continued until noon on select areas of the project.

Therefore, it is critical that shading times are verified on site and documented with timestamped photographs. Wood recommends considering shading for informing the time of year for capacity testing and not conducting capacity tests for shaded sites in winter.

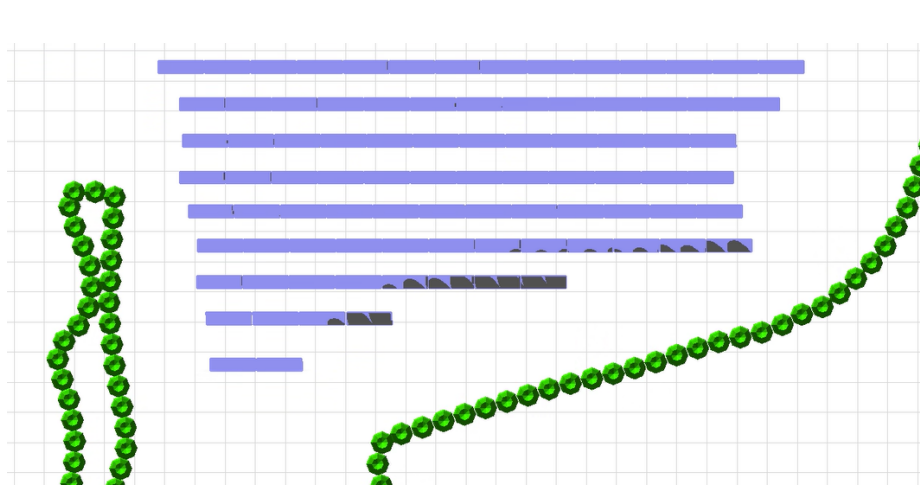


Figure 4: PVSyst Shading Model (mid morning)

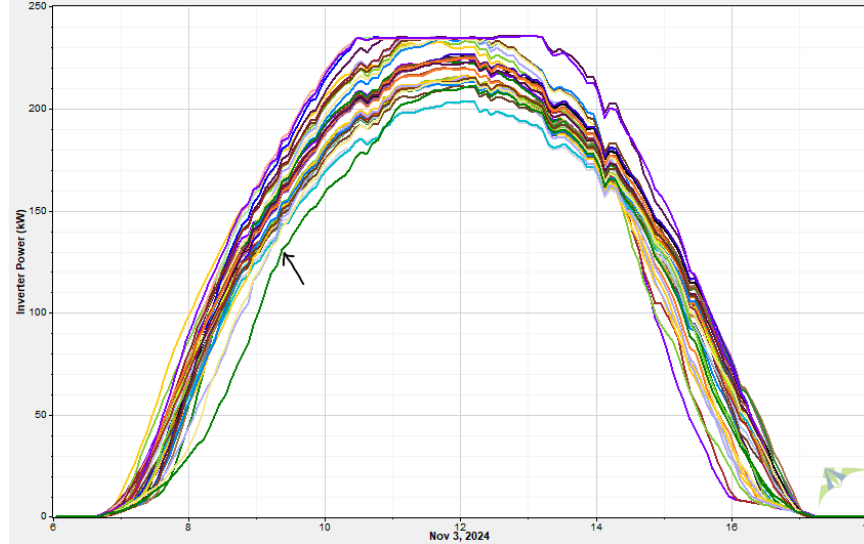


Figure 5: Inverter Power Timeseries Analysis with shading until noon

Back Shading

With the introduction of bifacial modules, back shading of the PV modules is often a forgotten consideration for calculation of the RPOA in EPC exhibits. While front shading is excluded from capacity tests, back shading cannot be excluded since it is due to the module racking. Back shading is primarily due to the torque tube but can also be due to purlins and structural supports of the racking system and results in lower RPOA irradiance.

The amount of torque tube shading is highly dependent on the configuration (1P, 2P) and the spacing between the panels for 2P configuration. For this project, the PVsyst model calculated back shading to be a 5% uniform loss while industry research has shown it varies diurnally throughout the day.

Back shading loss is incorporated into the RPOA irradiance in PVSyst, however back shading is not inherent in the RPOA measurements on site, therefore back shading must be either removed from the modelled RPOA irradiance or applied to the measured RPOA irradiance for like-for-like comparison. It is easier to account for back shading in modeled data rather than measured data, and is inconsequential if applied as a uniform loss, but if modelled with diurnal profile, Wood recommends it is applied to the measured POA irradiance to maintain linearity between power and irradiance. Incorporation of back shading makes capacity testing more accurate and easier to pass.

Rolling Terrain

Conducting capacity tests in rolling or complex terrain is more difficult and adds uncertainty to the test. It is more critical that high resolution terrain data is inputted into your energy model, and the terrain data reflects the as built ground conditions. Inspection for inter-row shading should be conducted on north-south slopes and inter-array shading for east-west slopes. It is also critical that POA and RPOA sensors are installed in representative locations of the terrain. The average azimuth and tilt of each sensor should align with the average conditions of the shading model. This should be verified by measurements on site and can sometimes detected by comparison of output between the various sensors via a timeseries analysis.

Clipping

The ASTM E2828-13 standard requires averaging intervals in which the inverter limits the production of the PV array to be excluded. This is because clipping hides performance issues and the relationship between irradiance and power becomes non-linear. For high DC/AC ratio plants (> 1.2) the amount of midday clipping can become substantial, especially in summer. Also, when combined with a minimum irradiance threshold of 200-400 W/m² which can be imposed in EPC exhibits due to non-linearities at low irradiances, collecting data for a capacity test can be difficult. Wood recommends considering clipping to inform the time of year to conduct the test. Due to possible shading in the winter and high levels of clipping in the summer, spring and fall can be optimum times to conduct capacity tests.

Lessons Learned

- Early engagement with the EPC is encouraged to ensure the weather stations are suitable for capacity testing in terms of the quantity, instruments specified, positioning, and mounting.
- A comprehensive test plan is recommended detailing the methodology and providing clarity where the EPC exhibit may be ambiguous.
- Shading and clipping should be considered to inform scheduling of the Capacity Test.
- The PVSyst model must be up to date and reflect the as-built conditions of the plant.

Conclusions

Solar performance testing has become increasingly difficult with the introduction of bifacial systems, high AC/DC ratios, and the movement of solar PV plants from flat to complex and forested terrain. Many of these factors increase the uncertainty of the test and increase the difficulty to pass, while the plant may be performing exactly as expected. It is of the utmost importance that plant is modelled as accurately as possible, and care is given to the uncertainty of the test when choosing the performance guarantee.