Analysis of measured photovoltaic module performance for Florida, Oregon, and Colorado locations

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Abstract

A study was conducted to determine and compare the measured energy production of photovoltaic (PV) modules for three climatically diverse locations: Cocoa, Florida; Eugene, Oregon; and Golden, Colorado. The PV modules were 2010 vintage and included single-crystalline silicon (x-Si), multi-crystalline silicon (m-Si), cadmium telluride (CdTe), copper indium gallium selenide (CIGS), amorphous silicon (a-Si) tandem and triple-junction, amorphous silicon/crystalline silicon or heterojunction with intrinsic thin-layer (HIT), and amorphous silicon/microcrystalline silicon (a-Si/ μ x-Si). Annual performance metrics for reference yield, final PV yield, performance ratio, and the losses associated with angle-of-incidence (AOI), PV module temperature, and low light or irradiance level were determined.

Results showed considerable variation in energy production because of both the site-to-site differences in reference yield and the PV module characteristics; for example, the best-performing PV modules in Cocoa had final PV yield values nearly 60% greater than the lowest performing PV module in Eugene. In Cocoa, the final PV yield of the a-Si/ μ x-Si PV module was greater, after considering measurement uncertainty, than other PV modules in Cocoa, except for the CdTe PV module. In Eugene, more PV modules performed more similarly to each other. The final PV yield values for the a-Si/ μ x-Si and CdTe PV modules were not measurably greater than the final PV yield values for the HIT and a-Si PV modules. In Golden, the final PV yield values of the PV modules varied the least, within measurement uncertainty, except for one PV module.

Losses from AOI effects were from 2½% to 3%; losses from PV module temperature were from 2.3% to 10.8%; and low-light-level effects ranged from a loss of 7.4% for a CIGS PV module deployed in Eugene to a gain of 0.3% for a CdTe PV module deployed in Cocoa. Spectral effects also appeared to be present, with increased performance of the CdTe modules and a-Si PV module in Cocoa and decreased performance in Golden.

Key words: photovoltaic; yield; performance; angle-of-incidence; irradiance.

1. Introduction

Demonstrated field performance provides buyers and sellers of PV systems information needed to understand the expected performance and benefits. Considerable PV system performance data exists in the literature, but usually the information is for a single PV technology and location; thus, comparing data for one PV technology and location to another is subject to the uncertainties associated with differences in how the data were measured and reported by the different organizations. Side-by-side testing of different PV technologies at the same location is the best method to demonstrate site-specific performance differences in PV technology. Some information of this type is available, notably: Ismail et al. (2013) compared the performance of six 200-kWp PV systems in Brunei Darussalam; Zinber et al. (2010) compared the performance of 24 1-kWp PV systems in Stuttgart, Germany, and Nicosia, Cyprus; and Friesen et al. (2011) compared the performance of 13 PV modules in Canobbio, Switzerland. Comparing PV module data provides potentially lower uncertainty in results, because PV module power ratings and coefficients can be more accurately determined than those for PV systems.

To provide comparative data for locations in the United States, this work compared the performance of PV modules of different technologies for three climatically diverse locations: Cocoa, Florida; Eugene, Oregon; and Golden, Colorado. The departure of the annual efficiency from the efficiency at standard test conditions (STC) was analyzed and quantified with respect to the losses resulting from AOI, operating temperature, and low-light-level performance. This provides information about PV module characteristics that is important for achieving the maximum energy production for a particular location or one with a similar climate.

We used public data that were measured previously for PV modules representing all technologies available in 2010, when the work began (Marion et al., 2014a). (If interested, the publicly available data may be obtained by contacting the corresponding author.) The PV modules included x-Si PV modules, m-Si PV modules, CdTe PV modules, CIGS PV modules, a-Si tandem and

triple-junction PV modules, HIT PV modules, and a-Si/ μ x-Si PV modules. In general, one or two of each PV module technology was deployed at each location.

The purpose of the previous work was to provide a publicly available data set for use in validating models that estimate the performance of flat-plate PV modules. A user's manual is included with the data set that describes the data and format, measurement equipment and station operations, data-quality assessment and uncertainties, and participating organizations (Marion et al., 2014b). The National Renewable Energy Laboratory (NREL) performed PV module current-voltage (I-V) curve and meteorological data measurements at its location in Golden, Colorado, which is considered a semiarid climate. Measurements in Cocoa, Florida (subtropical climate) were performed by the Florida Solar Energy Center. Measurements in Eugene, Oregon (marine west coast climate) were performed by the University of Oregon.

The same makes and models of the PV modules were tested at all locations, common data-acquisition systems were used, and calibrations were performed at NREL. The PV modules were deployed on south-facing racks and tilted from the horizontal at an angle equal to each site's latitude. For use in determining model parameters and coefficients, post-deployment measurements were performed. NREL measured PV module performance under STC per International Electrotechnical Commission (IEC) standards 61215 (IEC 2005) and 61646 (IEC 2008). The CFV Solar Test Laboratory, in Albuquerque, New Mexico, measured the irradiance-temperature characteristics per IEC 61853 (IEC 2011a) and the temperature coefficients per IEC 61215 and IEC 61646. Sandia National Laboratories measured coefficients and parameters for use with the Sandia array performance model (King et al., 2004).

2. Data Analysis

Metrics describing energy quantities for PV systems have been established and are described in IEC 61724 (IEC, 1998). Three of these metrics are useful for defining the PV module performance with respect to the energy production, solar resource, and overall effect of losses: final PV yield, reference yield, and performance ratio. Compared to PV systems, PV modules have greater PV yield and performance ratio metrics, because system-related losses (inverter, wiring, and mismatch losses, etc.) are not present.

Data were analyzed for one-year periods. This included data from March 1, 2011, through February 29, 2012, for Cocoa, Florida; data from January 1, 2013, through December 31, 2013, for Eugene, Oregon; and data from September 1, 2012, through August 31, 2013, for Golden, Colorado. To meet financial constraints, the same equipment and PV modules were first deployed in Cocoa and then later deployed in Eugene. Additional equipment and PV modules were deployed in Golden.

Before and after each deployment, PV module performance was measured under STC by NREL to check for PV module failures during deployment or as a result of transportation. Erratic performance of the x-Si PV module in Golden was detected, and follow-on electroluminescence testing indicated cracked cells. Consequently, the performance of this PV module is not reported for this work.

For Eugene and Golden, days were excluded when PV modules were covered or partially covered with snow or ice; 20 days were excluded for Eugene, and 49 days were excluded for Golden. To minimize the impact of excluded days, yield totals for non-excluded days in a month were used to determine average daily totals. These were then multiplied by the number of calendar days for the month to determine the annual metrics. This provided representative annual metrics, which showed that the reference yields were within 2.5% of the 30-year average for the locations and well within their reference yield interannual variability of $\pm 9\%$ from Marion and Wilcox (1994).

Data were also corrected for the effects of soiling by applying a daily PV module soiling derate value that is included with the data. The PV module soiling derate values were determined by comparing the performance of two identical PV modules, one that was cleaned each workday and another that was not cleaned (Marion et al., 2014b). In general, the soiling effects for the sites were minor. At the Cocoa site, the average daily PV module soiling derate was 0.999 and the minimum was 0.985. At the Eugene site, the average daily PV module soiling derate was 0.997 and the minimum was 0.964. At the Golden site, the average daily PV module soiling derate was 0.997 and the minimum was 0.977.

PV module performances were measured at each location using a Daystar MT5 Multi-Tracer. During the day, I-V curves were measured at either 5-minute (Cocoa and Eugene) or 15-minute (Golden) intervals. Between I-V curve measurements, the PV modules were operated at their peak power. The resulting average power, in-plane irradiance, and PV module temperature were measured based on 1-second samples. Meteorological data were also measured and included direct normal irradiance, global horizontal irradiance, diffuse horizontal irradiance, dry bulb temperature, relative humidity, atmospheric pressure, wind speed, and wind direction. These 5- and 15-minute averages were used in this work to determine the performance metrics. (The I-V curve data were also used to characterize low-light-level performance, as described in Section 2.6.) The following sections describe the procedures used to determine the final PV yields, reference yields, performance ratios, and losses associated with AOI, operating temperature, and low light levels.

2.1 Final PV yield

The final PV yield, Y_f , is the energy output, E , divided by the rated power, P_0 . It represents the number of hours that the PV module would need to operate at its rated power to provide the same energy. The units are hours or kWh/kW. The Y_f normalizes the energy produced with respect to the PV module size; consequently, it is a convenient way to compare the energy produced by PV modules of differing size.

$$Y_f = E / P_0 \quad (1)$$

The energy output is determined by numerically integrating the measured power over time.

$$E = t \sum P_i \quad (2)$$

where t is the averaging interval, hours; P is the measured average power, W/m²; and i is the index for the individual measurement within the period of evaluation.

Values used for P_0 were based on the post-deployment STC rating performed at NREL rather than the manufacturers' ratings. This was to not bias the results in case of an inaccurate manufacturer nameplate rating or in case of performance degradation that may have been present for some of the PV modules that had been in service for several years prior to deployment for this work. Additionally, the NREL post-deployment STC ratings were increased for the PV modules that degraded during their deployments (Marion et al., 2014b) to reflect an average during their deployment. This was to nullify the effects of degradation, which may have been specific to their manufacture rather than their technology. If studying the effects of degradation is desired, Jordan and Kurtz (2013) analyzed nearly 2,000 published values, and the results of their analysis may be used to adjust results.

2.2 Reference yield

The reference yield, Y_r , is the total in-plane irradiance, H , divided by the PV module's reference irradiance, G , for its rating conditions. It represents an equivalent number of hours at the reference irradiance. The PV modules were all rated for a reference irradiance of 1,000 W/m²; consequently, Y_r is the number of peak sun hours. The Y_r defines the solar radiation resource for the PV module. It is a function of the location, orientation of the PV module, and year-to-year variability.

$$Y_r = H / G \quad (3)$$

where the total in-plane irradiance is determined by numerically integrating the measured in-plane irradiance I over time.

$$H = t \sum I_i \quad (4)$$

2.3 Performance ratio

The performance ratio PR is the Y_f divided by the Y_r . Normalizing it with respect to irradiance quantifies the overall effect of losses on the rated output. The PR is dimensionless; a value of one indicates that no losses are present.

$$PR = Y_f / Y_r \quad (5)$$

2.4 AOI losses

Losses associated with AOI represent the reduction in irradiance transmitted to the PV cell relative to normal incidence. These losses were determined using the air-glass model developed by Sjerps-Koomen et al. (1997). The air-glass model resulted from studies that showed that the air-glass interface dominates the transmittance of radiation, relative to normal incidence, and that considering only the air-glass interface provides essentially the same results when compared to using more complex models that consider transmittance and reflectance of other PV module materials and interfaces (glass, EVA, and cell anti-reflective coatings). Snell's law was used to determine the angle of refraction in the glass, and Fresnel equations were used to determine the reflection from the glass surface.

Fig. 1 represents the air-glass model for two front-cover materials: glass with an index of refraction of 1.526 and Tefzel with an index of refraction of 1.4. The a-Si tandem and triple-junction PV modules use a Tefzel front cover; the remaining PV modules

use a glass front cover without any anti-reflective coating. AOI losses occur for AOIs greater than 40° (correction factors less than one); the Tefzel front cover provides slightly lower losses because of its lower index of refraction.

The in-plane irradiance consists of both beam and diffuse radiation, which require separate treating because of their differing AOIs. Additionally, the diffuse radiation consists of components that have different AOIs. We used the model of Perez et al. (1990) to determine the values of the in-plane irradiance components: beam, circumsolar diffuse, isotropic sky diffuse, horizon diffuse, and ground-reflected isotropic diffuse. The inputs to the Perez model included sun zenith angle, PV module tilt angle from horizontal, incident angle of beam radiation to the PV module, direct normal irradiance, diffuse horizontal irradiance, and surface albedo. We used a surface albedo of 0.2 to represent vegetation in Cocoa and Eugene, and we used measured values from NREL's Solar Radiation Research Laboratory in Golden to account for a changing albedo from snow.

We applied individual AOI correction factors to determine the useful in-plane irradiance H_u after AOI losses.

$$H_u = t \sum (I_{b,i} \cdot F_{b,i} + I_{cs,i} \cdot F_{cs,i} + I_{sky,i} \cdot F_{sky} + I_{hor,i} \cdot F_{hor} + I_{grd,i} \cdot F_{grd}) \quad (6)$$

where F is the AOI correction factor, subscript b denotes the beam irradiance, subscript cs denotes circumsolar diffuse irradiance, subscript sky denotes isotropic sky diffuse, subscript hor denotes horizon diffuse irradiance, and subscript grd denotes ground-reflected isotropic diffuse irradiance.

Because the PV modules are fixed and their view factor of the sky, horizon, and ground is constant, the AOI correction factors for the isotropic sky diffuse, horizon diffuse, and ground-reflected isotropic diffuse irradiances were also constants. These can be determined by the method of Brandemuehl and Beckman (1980). This method calculates AOI correction factors for all view angles of the sky, horizon, or ground and determines a single effective angle and AOI correction factor. The results of using this method for the PV modules in this work are shown in Table 1. For the glass front cover, the isotropic sky diffuse irradiance loss was approximately 4%, the horizon diffuse irradiance loss was between 9% and 22%, and the ground-reflected diffuse irradiance loss was between 24% and 43%, with the larger losses for the small PV module tilt angles. For the Tefzel front cover, the AOI losses were slightly less.

The AOI correction factors for the beam and circumsolar diffuse radiation change with changing sun angles; consequently, the air-glass model was used for each data time to determine the correction factors based on a calculated incidence angle of the direct beam radiation to the PV module front cover.

We used Eqn. 7 to determine the loss from AOI, L_{aoi} . Similar to the PR , it is dimensionless and represents a fractional loss of the available solar radiation.

$$L_{aoi} = (H_m - H_u) / H_m \quad (7)$$

where H_m is the Perez modeled total in-plane irradiance without accounting for AOI losses, which is essentially the same as Eqn. 6 but with the AOI correction factors equal to one. The use of a model introduces uncertainty, but we expected it to be quite small considering the small mean-bias errors (MBEs) and root-mean-square errors (RMSE) observed when comparing the Perez-modeled in-plane irradiances to those measured for the three locations. For Cocoa, the MBE was -1.9 W/m², or -0.6% of the average in-plane irradiance, and the RMSE was 12.5 W/m², or 2.7% of the average in-plane irradiance. For Eugene, the MBE was 0.6 W/m², or 0.2% of the average in-plane irradiance, and the RMSE was 13.9 W/m², or 4.0% of the average in-plane irradiance. For Golden, the MBE was 5.2 W/m², or 1.2% of the average in-plane irradiance, and the RMSE was 18.4 W/m², or 4.2% of the average in-plane irradiance.

2.5 Operating temperature losses

PV module efficiency decreases with increasing temperature. For most locations, the overall PV module temperatures during operation were greater than their rating temperature of 25°C; thus, there was a loss in energy production. To determine the loss, we first used Eqn. 8 to temperature correct the measured power values to performance at 25°C.

$$P_{tc} = P / [1 + \gamma \cdot (T - 25)] \quad (8)$$

where T is the PV module temperature, °C, and γ is the power correction factor for temperature, °C⁻¹. This temperature correction method dates to the linear expression for efficiency by Evans and Florschuetz (1977). Next, the P_{tc} values were used to determine the energy production, E_{tc} , for a hypothetical situation in which PV module temperatures remain at 25°C.

$$E_{tc} = t \sum P_{tc,i} \quad (9)$$

Finally, we used Eqn. 10 to determine the loss caused by temperature, L_t . Similar to the PR , it is dimensionless, and it represents a fractional loss of energy production from temperature effects.

$$L_t = (E_{tc} / P_0 - Y_f) / Y_r \quad (10)$$

2.6 Low-light-level losses

A decreased PV module efficiency at low light levels is generally associated with the PV module having a low shunt resistance. Increasing the shunt resistance improves both the low-light-level efficiency and the efficiency at STC. Increasing the series resistance also increases the low-light-level efficiency, but it does so at the expense of the efficiency at STC (Grunow et al., 2004).

We characterized low-light-level performance by using the I-V curve data for the year to perform a least-squares fit to provide an equation of the following form:

$$P_{tc}(I_e) = a_0 + a_1 \cdot I_e + a_2 \cdot I_e^2 + a_3 \cdot I_e^3 + a_4 \cdot I_e^4 \quad (11)$$

where the a values are the polynomial curve-fit coefficients, and I_e is the effective irradiance, W/m^2 (King et al., 2004), otherwise referred to as the self-reference irradiance (IEC, 2011b). The I_e quantifies the portion of the incident irradiance effectively used by the PV cells, thereby accounting for losses associated with soiling, AOI, and solar spectrum variations. Eqn. 12 is the expression for I_e .

$$I_e = 1000 \cdot I_{sc} / I_{sc0} / [1 + \alpha \cdot (T - 25)] \quad (12)$$

where I_{sc} is the I-V curve's short-circuit current, A; I_{sc0} is the short-circuit current at STC, A; and α is the short-circuit current correction factor for temperature, $^{\circ}\text{C}^{-1}$.

If the curve fit results in a straight line through the origin, a constant efficiency as a function of irradiance level is indicated, because P_{tc} is directly proportional to I_e . Fig. 2 provides the curve fits for representative modules. Departures of the curve fits below the diagonal indicate a decreased efficiency and low-light-level losses. The RMSE of the curve fits was quite good: 0.6% of the average P_{tc} or less for half of the PV modules; within 2.8% for all except one of the remaining modules, which included a-Si PV modules subject to seasonal changes in efficiency and PV modules that degraded up to 7% during their deployments; and 6.2% for a PV module that degraded by 13%.

The energy metrics are based on the 5-minute and 15-minute averaged data in which the module is operated at peak power; consequently, no I_{sc} data are present to determine the I_e . However, knowing the value of P_{tc} , we can solve Eqn. 11 for I_e by rearranging terms into an $F(x) = 0$ format and solving for I_e using an iterative bisection algorithm such as that presented by Burden and Faires (1985). After I_e was determined, we determined the power, P_{tic} , corrected for both temperature and low irradiance effects, by using Eqn. 13.

$$P_{tic} = P_{tc}(1000) \cdot I_e / 1000 \quad (13)$$

where $P_{tc}(1000)$ is Eqn. 11 evaluated for an I_e of 1000 W/m^2 . The P_{tic} values were then used to determine the energy production, E_{tic} , corrected for both temperature and low-light-level effects.

$$E_{tic} = t \sum P_{tic,i} \quad (14)$$

Finally, we used Eqn. 15 to determine the loss caused by irradiance level, L_i . Similar to the PR , it is dimensionless, and it represents a fractional loss of energy production from irradiance or low-light-level effects.

$$L_i = (E_{tic} - E_{tc}) / P_0 / Y_r \quad (15)$$

3. Results and Discussion

The results of the data analysis are shown in Table 2 and Fig. 3. Uncertainty values for measured and calculated parameters, with a coverage factor of 2, are provided in Table 3. For each PV module and location, Table 2 provides the annual performance metrics and the calculated losses associated with AOI, PV module temperature, and low light or irradiance level. The same set of PV modules were first deployed in Cocoa and then redeployed later in Eugene. A second set of PV modules were deployed in

Golden. Although for the same PV modules, the P_0 values for Cocoa and Eugene as shown in Table 2 may differ because we accounted for degradation by using average P_0 values for the deployments.

For the different locations and PV modules, considerable variation in energy production is shown. The best-performing PV modules at Cocoa, a-Si/ μ x-Si and CdTe, had Y_f values nearly 60% greater than the lowest performing PV module at Eugene, CIGS. The Y_f values for all the PV modules at Eugene were less than the other locations, primarily because the Y_r values were approximately 30% greater at the other two locations. The solar resource is a dominant factor in determining the PV energy produced.

Meaningful comparisons of Y_f values for a given location should consider their uncertainty. As shown in Table 3, the uncertainty of Y_f is 3.5%. When comparing two Y_f values, the uncertainty of the comparison is $(3.5^2 + 3.5^2)^{1/2} = 5\%$; consequently, Y_f values need to differ by more than 5% for the difference to be significant or measurable. For Cocoa, the Y_f of the a-Si/ μ x-Si PV module was measurably greater than that of all other PV modules, except for the CdTe PV module. The Y_f values of the x-Si and m-Si PV modules were not measurably greater than the Y_f value for the lower performing CIGS PV module, but the Y_f values for the HIT and a-Si PV modules were measurably greater.

For Eugene, more PV modules were within the uncertainty of the best performers. The Y_f values for the a-Si/ μ x-Si and CdTe PV modules were not measurably greater than the Y_f values for the HIT and a-Si PV modules. The Y_f values of the x-Si and m-Si PV modules were not measurably greater than the Y_f value for the better performing CIGS PV module, but they were measurably greater than the Y_f value for the lower performing CIGS PV module.

For Golden, the Y_f values varied the least. All the PV module Y_f values were within 5%, except for one CIGS PV module's Y_f value that increased the range to 5.7%.

The PR normalizes output with respect to the solar resource, and it identifies the extent of losses or other factors present. The a-Si/ μ x-Si and CdTe PV modules in both Cocoa and Eugene had the largest PR s; whereas the CIGS PV modules in all locations had the smallest PR s. The CIGS PV module PR s were less because of greater losses associated with low light level and operating temperature. Low-light-level performance of crystalline silicon PV modules has improved in recent years (Ransome, 2014); therefore, it is likely that as the CIGS technology matures, its low-light-level performance will be improved, primarily by increasing the shunt resistance of its cells through improved design and manufacturing processes.

For the PV modules with glass front covers, the L_{aoi} was approximately 3% (0.03). The L_{aoi} for PV modules with a Tefzel front cover was approximately 2.5%. Approximately 40% (relative) of the total L_{aoi} is associated with the beam irradiance; the remaining 60% is associated with the diffuse irradiance.

Values of L_i ranged from a low of 2.3% for a CdTe PV module deployed at Eugene to 10.8% for a CIGS PV module deployed at Cocoa. Increased operating temperatures and large negative power temperature coefficients increase L_i . PV modules with smaller temperature coefficients have smaller values of L_i for warm and temperate climates; but in cool and cloudy climates such as Eugene's, the losses were less significant and on the order of the L_{aoi} . In cool and cloudy climates, PV modules with good low-light-level performance may be the more important criterion.

Values of L_i ranged from a loss of 7.4% for a CIGS PV module deployed at Eugene to a gain of 0.3% (-0.003) for a CdTe PV module deployed at Cocoa. A gain was realized for the CdTe PV module because of a slight increase in efficiency for mid-level irradiance values (refer to Fig. 2). The CIGS PV module performed poorly because of its drop in efficiency for the low light levels of Eugene's cloudy climate. By analyzing the low-light-level losses for the PV modules, we developed a rule-of-thumb estimate of a PV module's low-light-level loss by using manufacturer or laboratory data for a PV module's decrease in efficiency from operation at 1,000 W/m² irradiance to operation at 200 W/m² irradiance. In sunny climates (Cocoa and Golden), the low-light-level loss was approximately one-quarter of the relative decrease in efficiency, from 1,000 W/m² irradiance to 200 W/m² irradiance. In cloudy climates (Eugene), the low-light level loss was approximately one-third of the relative decrease in efficiency. For example, the decrease in efficiency from 1,000 W/m² irradiance to 200 W/m² irradiance for the PV module mSi0166 was 12% (relative). For this PV module, the rule-of-thumb estimate provides a L_i of 3% (0.030) for sunny climates and a L_i of 4% (0.040) for cloudy climates.

Fig. 3 shows a stacked-bar chart of the PR s and the calculated losses associated with AOI, PV module temperature, and low light level. If there were no measurement errors and all losses and effects were included, the stacked values should equal one. Within measurement error, the stacked values should be within the plus or minus uncertainty represented by the dashed lines in Fig. 3. This was shown to be true except for a few thin-film PV modules. The stacked value for the PV module CIGS39013 is greater than the upper uncertainty boundary. We suspect that the uncertainty of the measurement of P_0 for this module was greater than our estimate because of CIGS metastabilities associated with the light/dark exposure of the PV module prior to the performance measurement with the solar simulator. Work is being performed to address thin-film PV metastabilities (Deline et al., 2012; Silverman et al., 2014) to provide more accurate measurements of P_0 in the future.

Departures of stacked-bar values from one for the a-Si and CdTe PV modules are consistent with previous work in which the sensitivity of PV performance to variations in atmosphere for days with clear skies was studied (Marion, 2012). The extent of attenuation of solar radiation by the atmosphere is determined primarily by the mass of air and the amounts of water vapor, aerosols, and ozone. Because these constituents selectively absorb and scatter radiation, their impact on PV performance is sensitive to the spectral response of the PV module, with increased sensitivity for CdTe and a-Si PV modules that respond to a

narrower wavelength range than other technologies. Most of their variations in performance caused by the solar spectrum are a consequence of the amount of water vapor, which absorbs radiation at wavelengths primarily outside their response range. Increasing the amount of water vapor increases performance relative to the pyranometer measurement; conversely, decreasing the amount of water vapor decreases performance relative to the pyranometer measurement. Although the stacked-bar values do not include a correction for spectrum, the CdTe and a-Si values shown in Fig. 3 indicate that spectral effects were present, with the larger values for the location with the most water vapor (Cocoa), the smallest values for the location with the least water vapor (Golden), and values in between for the Eugene location which has water vapor values less than those in Cocoa and greater than those in Golden.

Nelson et al. (2013) developed a spectral shift factor for CdTe PV modules as an exponential of precipitable water vapor that provides similar trends to our results: for Miami, a spectral effect of +2.6%; and for Albuquerque, a spectral effect of -1.1%. If these spectral effects were included for Cocoa and Golden, respectively, the CdTe stacked bars would be within 3% of one.

Besides spectral effects, the a-Si tandem and triple-junction PV modules may also undergo seasonal changes in efficiency based on their previous light exposure and operating temperatures (Ruther et al., 2008, and Virtuani and Fanni, 2014) because of the well-known Staebler-Wronski effect (1977). Except for the aSiTriple28324 PV module deployed at Cocoa, the PV modules did not experience the typical first-year degradation during their deployments, because the PV modules had been previously light-exposed for a year or longer. The aSiTriple28324 PV module deployed at Cocoa had been previously light-exposed for approximately two months.

4. Summary

The annual performance metrics, Y_r , Y_f , and PR , and the losses associated with AOI, PV module temperature, and low light or irradiance level, were determined using measured data for three climatically diverse locations and for PV modules representing all PV module technologies available in 2010: x-Si, m-Si, CdTe, CIGS, a-Si tandem and triple-junction, HIT, and a-Si/ μ x-Si. The PV modules were deployed on south-facing racks and with a tilt angle from the horizontal equal to each location's latitude.

Considerable variation in energy production was shown as a result of both the site-to-site differences in Y_r and the PV module characteristics. The best-performing PV modules at Cocoa, a-Si/ μ x-Si and CdTe, had Y_f values nearly 60% greater than the lowest performing CIGS PV module at Eugene.

For the PV modules at Cocoa, the Y_f of the a-Si/ μ x-Si PV module was measurably greater than all other PV modules, except for the CdTe PV module. For Eugene, more PV modules were within the uncertainty of the best performers. The Y_f values for the a-Si/ μ x-Si and CdTe PV modules were not measurably greater than the Y_f values for the HIT and a-Si PV modules. For Golden, the Y_f values varied the least. All the PV module Y_f values were within 5%, except for one CIGS PV module for which its Y_f value increased the range to 5.7%.

Losses from AOI were determined using the air-glass model and by treating the diffuse irradiance components separately, each with its own effective incident angle. The L_{aoi} for the PV modules with glass front covers was determined to be 3%, and it was determined to be approximately 2½% for the PV modules with Tefzel front covers. Approximately 40% (relative) of the total L_{aoi} is associated with the beam irradiance; the remaining 60% is associated with the diffuse irradiance. Consequently, it is important that performance models calculate AOI losses for both beam and diffuse irradiance.

Losses from PV module temperature were determined by correcting measured values of P to 25°C and calculating the differences of the sums of the measured and the temperature-corrected P . Values of L_t ranged from a low of 2.3% for a CdTe PV module deployed at Eugene to 10.8% for a CIGS PV module deployed at Cocoa.

The effects of low light or irradiance level were evaluated by parameterizing the temperature corrected P versus the effective irradiance. An effective irradiance was used to remove spectral effects usually present with low light levels. Values of L_i ranged from a loss of 7.4% for a CIGS PV module deployed at Eugene to a gain of 0.3% for a CdTe PV module deployed at Cocoa. A gain was realized for the CdTe PV module because of a slight increase in efficiency for mid-level irradiance values. The CIGS PV module performed poorly because of its drop in efficiency for the low light levels of Eugene's cloudy climate. A rule-of-thumb method was also presented to determine low-light-level losses by using manufacturer or laboratory data for a PV module's decrease in efficiency from operation at 1,000 W/m² irradiance to operation at 200 W/m² irradiance.

A stacked-bar chart analysis of the PR s and the calculated losses was used to check the reasonableness of the results. The analysis indicated possible errors in the P_0 value for a CIGS PV module, perhaps because of CIGS metastabilities. Spectral effects also appeared to be present, with increased performance of the CdTe and a-Si PV modules at Cocoa and decreased performance at Golden.

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Figure Captions

Fig. 1. Air-glass model correction factors versus AOI for two front-cover materials: glass with an index of refraction of 1.526 and Tefzel with an index of refraction of 1.4.

Fig. 2. Polynomial curve fits of the temperature corrected power, P_{tc} , versus the effective irradiance, I_e , for representative PV modules. The diagonal through the origin is a line of constant efficiency with no losses associated with low light levels.

Fig. 3. Stacked-bar chart of the PRs and the calculated losses associated with AOI, PV module temperature, and low light level. If there were no measurement error and all losses and effects were included, the stacked values should equal one. Uncertainty in stacked value, $U = 0.045$, shown by the dashed lines.

Figure 1

Figure 2

Figure3

Table 1

Effective incident angles and AOI correction factors for glass and Tefzel PV module front covers

Location/Tilt	Diffuse Component	Glass	AOI Factor	Tefzel	AOI Factor
		Angle (°)		Angle (°)	
Cocoa/28.5°	Sky	57.7	0.958	57.6	0.965
	Horizon	74.6	0.784	74.4	0.802
	Ground-reflected	81.8	0.567	81.6	0.587
Golden/40.0°	Sky	57.0	0.961	56.8	0.967
	Horizon	67.7	0.889	67.6	0.902
	Ground-reflected	77.4	0.719	77.2	0.738
Eugene/44.0°	Sky	56.9	0.962	56.8	0.968
	Horizon	65.6	0.910	65.4	0.921
	Ground-reflected	75.8	0.757	75.7	0.776

Table 2

Annual performance metrics and calculated losses caused by AOI, temperature, and irradiance level

Location	PV Module	Technology	P_0 (W)	γ (°C ⁻¹)	Y_r (h)	Y_f (h)	PR	L_{aoi}	L_t	L_i
Cocoa	aSiMicro03036	a-Si/ μ x-Si	105.0	-0.0024	2027	2019	0.996	0.030	0.045	0.017
	aSiTandem72-46	a-Si/a-Si:Ge	39.5	-0.0025	2027	1917	0.946	0.026	0.052	0.011
	aSiTriple28324	a-Si/a-Si/a-Si:Ge	65.0	-0.0029	2027	1904	0.939	0.026	0.063	0.010
	CdTe75638	CdTe	64.5	-0.0021	2027	1986	0.980	0.030	0.043	-0.003
	CIGS39017	CIGS	146.7	-0.0054	2027	1740	0.859	0.030	0.108	0.049
	CIGS8-001	CIGS	73.9	-0.0038	2027	1716	0.847	0.030	0.069	0.050
	HIT05667	HIT	213.9	-0.0035	2027	1855	0.916	0.030	0.064	0.011
	mSi0166	m-Si	46.1	-0.0041	2027	1762	0.869	0.030	0.067	0.032
	mSi0188	m-Si	45.8	-0.0041	2027	1769	0.873	0.030	0.067	0.029
	mSi460A8	m-Si	79.8	-0.0042	2027	1806	0.891	0.030	0.072	0.022
Eugene	xSi12922	x-Si	83.0	-0.0042	2027	1800	0.888	0.030	0.076	0.005
	aSiMicro03036	a-Si/ μ x-Si	103.0	-0.0024	1536	1482	0.965	0.030	0.024	0.022
	aSiTandem72-46	a-Si/a-Si:Ge	38.5	-0.0025	1536	1430	0.931	0.027	0.028	0.015
	aSiTriple28324	a-Si/a-Si/a-Si:Ge	62.9	-0.0029	1536	1436	0.935	0.027	0.032	0.010
	CdTe75638	CdTe	63.9	-0.0021	1536	1482	0.966	0.030	0.023	0.002
	CIGS39017	CIGS	143.1	-0.0054	1536	1344	0.875	0.030	0.060	0.063
	CIGS8-001	CIGS	69.0	-0.0038	1536	1270	0.827	0.030	0.037	0.074
	HIT05667	HIT	212.4	-0.0035	1536	1434	0.934	0.030	0.030	0.012
	mSi0166	m-Si	46.1	-0.0041	1536	1362	0.887	0.030	0.036	0.038
	mSi0188	m-Si	45.8	-0.0041	1536	1378	0.897	0.030	0.030	0.035
Golden	mSi460A8	m-Si	79.8	-0.0042	1536	1403	0.914	0.030	0.041	0.030
	xSi12922	x-Si	83.0	-0.0042	1536	1406	0.916	0.030	0.040	0.008
	aSiMicro03038	a-Si/ μ x-Si	107.3	-0.0024	2034	1799	0.884	0.029	0.037	0.015
	aSiTandem90-31	a-Si/a-Si:Ge	41.1	-0.0022	2034	1790	0.880	0.025	0.034	0.014
	aSiTriple28325	a-Si/a-Si/a-Si:Ge	63.6	-0.0029	2034	1783	0.876	0.025	0.039	0.008
	CdTe75669	CdTe	65.8	-0.0021	2034	1868	0.918	0.029	0.034	-0.001
	CIGS39013	CIGS	129.7	-0.0051	2034	1762	0.867	0.029	0.099	0.067
	CIGS1-001	CIGS	77.4	-0.0039	2034	1786	0.878	0.029	0.055	0.031
	HIT05662	HIT	217.5	-0.0033	2034	1857	0.913	0.029	0.052	0.011
	mSi0247	m-Si	45.2	-0.0041	2034	1812	0.890	0.029	0.065	0.035
	mSi0251	m-Si	44.8	-0.0042	2034	1811	0.890	0.029	0.066	0.032
	mSi460BB	m-Si	79.6	-0.0042	2034	1857	0.913	0.029	0.056	0.017

Table 3

Uncertainty values for measured and calculated parameters with a coverage factor of 2. Expressed as a percentage for parameters with engineering units and dimensionless for dimensionless parameters

Parameter	Uncertainty
P_0	3.4%
E	0.6%
Y_r	2.6%
Y_f	3.5%
PR	0.043
L_{aoi}	0.005
L_t	0.009
L_i	0.010
$PR + L_{aoi} + L_t + L_i$	0.045