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Insights on the Degradation and Performance of 3000 PV Installations of Various Technologies Across the UK

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***Abstract*—This article presents the degradation rates over eight years for 3000 PV installations distributed across the UK. The study considers three PV cell technologies, namely, monocrystalline silicon (Mono-Si), polycrystalline silicon (Poly-Si), and thin-film Cadmium Telluride (CdTe). The available raw data undergoes three key stages: normalization, filtering, and aggregation, before the degradation analysis of the considered installations. This algorithm can be considered as one of the paper contributions. Results show that a maximum degradation rate of -1.43%/year is observed for the CdTe type, whereas Poly-Si and Mono-Si PVs have annual degradation rates of -0.94% and -0.81% respectively. Moreover, this article exploits the monthly mean performance ratio (PR) for all the examined PV sites. The highest PR value of 87.97% is calculated for the Mono-Si PV installations, while 85.08% and 83.55% is calculated for Poly-Si and CdTe installations, respectively.**

***Index Terms*—Photovoltaic Systems; Degradation Rate; Performance Analysis; PV Technologies, CDF function.**

I. INTRODUCTION

Precise prediction of the power output from PV installations over their lifetime is crucial for the accurate estimation of the levelised cost of energy (LCOE), which is the main driver for the market success of the PV technology. In order to precisely predict the energy yield of a particular PV system, power degradation rates (i.e. power decline over time [1]) need to be quantified and taken into account. Such information is critical to all stakeholder's/utility companies, investors, integrators, and researchers alike because higher degradation rates reflect reduced output power, and hence economic losses [2].

Inaccurate degradation rate estimation could amplify the financial risks in the PV sector [3]. Typically, a 10% degradation is considered a failure. However, there is no compromise on the definition of failure [4], because a high-efficiency module degraded by 50% may still have a higher efficiency than a non-degraded module of a less efficient technology.

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The modelling of the degradation mechanisms through simulations and experiments in principle directly leads to lifetime improvements in PV modules [5]. Outdoor field-testing has played a significant role in measuring the lifetime and behaviour for two key reasons: (i) it is the typical functioning environment for PV installations, and (ii) it is the only way to correlate between the indoor testing apparatuses and the outdoor results to forecast the actual performance.

Although there are various research efforts that focus on the degradation rate of PV systems worldwide [10-24], there is lack of references describing the behaviour and degradation analysis of existing PV systems in the United Kingdom (temperate maritime climate). Therefore, in this paper, the data of 3000 PV installations across the UK are refined, and the extracted degradation rates are analyzed over a period of ten years (2008 to 2017). In this context, the following part provides an overview of the degradation rates worldwide:

United States of America (USA): When amorphous silicon (a-Si) modules first became commercially available, the National Renewable Energy Laboratory (NREL) reported degradation rates higher than -1.0%/year [7]. In [8] and [9], similar results of the PV degradation were found in small (<10 kW) size PV installations exhibiting an annual degradation rate of approximately -0.8% to -1.25 %/year.

Europe: A number of studies in Spain and Italy indicated degradation rates between -0.8% to -1.1%/year [10-12], while in other EU countries such as Germany, Cyprus, Greece and Poland, the reported rates were between -0.5% to -0.7%/year [13], [14], -0.8% to -1.1%/year [15], -0.9% to -1.13%/year [16], and greater than -0.9%/year [17], respectively.

Asia: authors in [18] studied the degradation rate in India based on a field exposure of mono-crystalline PV modules where the degradation rate was found to be -1.4%/year. Similar results were reported by [19] where the degradation rate in southern India was observed at -1.3%/year. Furthermore, in Thailand, the degradation rates were widely different, ranging from -0.5% to -4.9%/year [20]. A study conducted by [21] found that the PV degradation rate based on the long term of outdoor exposure in northern Thailand was equal to -1.5%/year. The degradation rates of PV modules in Japan, Singapore, and the Republic of Korea were reported equal to -1.15%/year [22], -2.0%/year [23], and -1.3%/year [24], respectively.

It is also worth mentioning that these degradation rates are also strongly dependent on the geographical locations of the considered PV installations along with the used technologies.

As this article describes the degradation estimation of PV systems; hence, an overview of existing PV degradation estimation methods are classified into two main categories:

1) Mathematical/statistical-based methods such as in [6, 7, 22, and 25], use a comparative analysis "mathematically/statistically" to observe the performance ratio of the PV modules over a definite period (usually one week). These methods tend to be the optimum to use in determining the degradation rate of PV systems that are operating over a long period. The foremost disadvantage of these methods that they demand precise measurements of the solar irradiance, ambient temperature as well as the output power, and in some cases [26] requires the PV modules/systems current-voltage (I-V) curve.
2) Power-Irradiance method: this method has been used widely used in the literature [10, 27 and 28] to estimate the degradation of PV systems. This method entails the analysis of the power versus the solar irradiance of the examined PV system throughout (preferably) one-month. The most significant advantage of this method is that it is uncomplicated to perform as only two parameters are required, i.e. power and solar irradiance. However, the accuracy of estimating PV degradation is considerably lower compared with the mathematical/statistical-based methods.

In summary, from a worldwide point of view, the reported PV degradation rates vary between -0.2% to -2.0%/year, although from the authors' knowledge, there is no enough evidence of the annual degradation rates of PV modules with different technologies across the UK. Therefore, this paper aims to fill in this gap by assessing and analyzing the degradation rates of 3000 PV installations located in various locations across the UK, considering three PV technologies: Monocrystalline Silicon (Mono-Si), Polycrystalline Silicon (Poly-Si) and Thin-film Cadmium Telluride (CdTe).

II. Methodology: PV Degradation Rate Analysis

In this section, the algorithm to refine the available huge amount of measured data, and subsequent, mathematical analysis to determine the PV degradation rates are proposed. The data refining and degradation rates evaluations, using the time-series of the PV installations, proceeds through four key stages: normalization, data filtering, data aggregation, and degradation estimation.

A. Normalization

This step calculates a unit-less performance ratio (PR) metric with a reduced amount of variability than the raw power production data gathered for a particular PV system. The PR is typically based on the rated power of the system. While the optimum PR metric is analysed with respect to the ambient temperature of the PV installation using (1).

$$PR = \frac{P}{P_{STC,rated}\,\frac{G_{poa}}{G_{ref}}\left(1+\gamma\left(T_{PV}-T_{ref}\right)\right)} \quad (1)$$

where P is the measured dc or ac power of the PV systems in watts, $P_{STC,rated}$ is the rated dc or ac power of the PV system in watts, G_{poa} is the plane-of-array irradiance, G_{ref} is the reference irradiance 1000 W/m^2, γ is the maximum power temperature coefficient in relative %/°C, T_{PV} is the PV system temperature in °C, and T_{ref} is the PV system reference temperature which assumed to be 25 °C in this paper.

Since the value of the temperature T_{PV} of a typical PV system is not available in most PV installations database, and in order to measure the accurate value of T_{PV}, the clear-sky ambient temperature model estimates the ambient temperature (T_{amb}). This model is based on each examined PV site location as well as monthly average day-time and night-time temperatures. The value of the temperature for all examined PV systems was found using the open-access database of the high-resolution dataset from the UK Met-Office with a spatial resolution of 0.05 °C. The ambient temperature, T_{amb}, is then assessed using (2).

$$T_{amb} = \left[\frac{\left(T_{Day} - T_{Night}\right)}{2}\cos\left(\frac{h+8}{24}\,2\pi\right)\right] + \frac{\left(T_{Day} - T_{Night}\right)}{2} \quad (2)$$

where T_{Day} is the average monthly day temperature in °C, T_{Night} is the average monthly night temperature in °C, and h is the time since midnight in hours. The value 8 is an empirical factor taking into account the daily lag between the peak temperature and irradiance [2], while 24 is the number of hours per day. Having defined T_{amb}, the next step is to calculate the value of T_{PV} using (3).

$$T_{PV} = T_{amb} + \left(G_{poa}\; e^{-3.56}\right) + \frac{G_{poa}}{333} \quad (3)$$

where, G_{poa} is the plane-of-array irradiance affecting a particular PV installation.

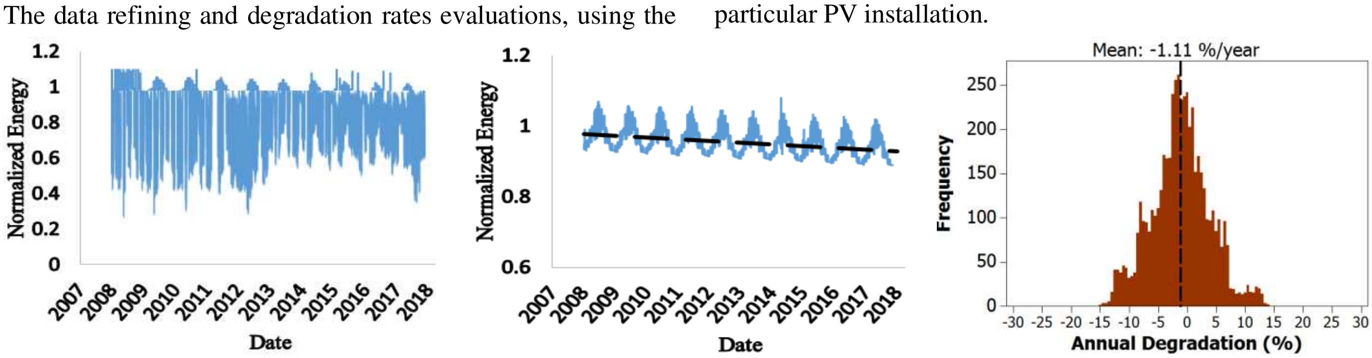


Fig. 1. Example of the YOY degradation process. **(a)** Data filtering, **(b)** Aggregation process, **(c)** Output degradation analysis.

B. Data Filtering

The data filtering step removes data collected during periods of the variable/poor solar resource conditions (i.e. during cloudy and overcasting conditions) in addition to any source of data biasing or no representative datasets such as data captured during nigh-times. Low irradiance conditions are often associated with night-time data or with errors due to dc/ac inverters or the maximum power point (MPPT) tracking units' start-up duration. To exclude these start-up issues associated with the data collection, the cut-off irradiance is, as a rule of thumb, taken to be below 200 W/m^2. This then results in an accurate estimation of the PV annual degradation. An example of the data filtering output is shown in **Fig. 1(a)**.

C. Aggregation Process

Raw data is gathered and expressed in a summary for statistical analysis. For example, the primary purpose of aggregating the output power data for a PV system is to outline the average, minimum, maximum and allocate any disparities in the collected output powers, hence to avoid incorrect analysis of the yielded energy.

The PV systems data are aggregated according to irradiance and temperature weighted average. This step reduces the impact of high-error data points in the morning and evening time. The aggregation time-period is a one-day period, i.e., the final yield data has a resolution of one day. An example of the output aggregation process is shown in **Fig. 1(b)**.

The normalized energy profile reveals a power peak during summertime, and the lowest normalized energy is observed during four months from November, until February. This is expected, as the actual solar irradiance is naturally low in the UK during the winter season [29]. In contrast, the normalized energy of the aggregation process would be expected to diverge dependent on the actual weighted temperature and the solar irradiance at the examined PV installation.

D. Degradation analysis

The degradation analysis uses the data obtained after the three previous stages to compute a degradation rate based on year-on-year method. The rate of change is calculated between two points at the same time in subsequence years. Calculating such a rate of change for all data points and all years results in a histogram of rates of change, as shown in **Fig. 1(c)**. The central tendency of the histogram represents the overall system performance, while negative mean represents a decrease in the PV annual performance.

III. Examined PV Systems

In this article, the data of more than 10,000 PV installations were collected via the solar UK database [30]. The PV panel technologies are either Mono-Si, Poly-Si, or CdTe. In order to enhance the data analysis and PV degradation results, all the PV installations are subjected to filtration process, leading to the selection of only 1000 PV systems per PV technology. A summary of the set of requirements applied during the filtration process of the suitable PV installations are as follows:

1) PV systems azimuth angle in the range of ±10 degrees.
2) Only considering residential PV systems with a capacity between 2.2 kWp and 4.0 kWp.
3) PV systems tilt angle is ranging from 20 to 55 degrees.
4) The considered PV system has to be installed within 2010 - 2011.

A. Examined PV Technologies Functionality

The examined PV technologies and their working principles are presented as follows:

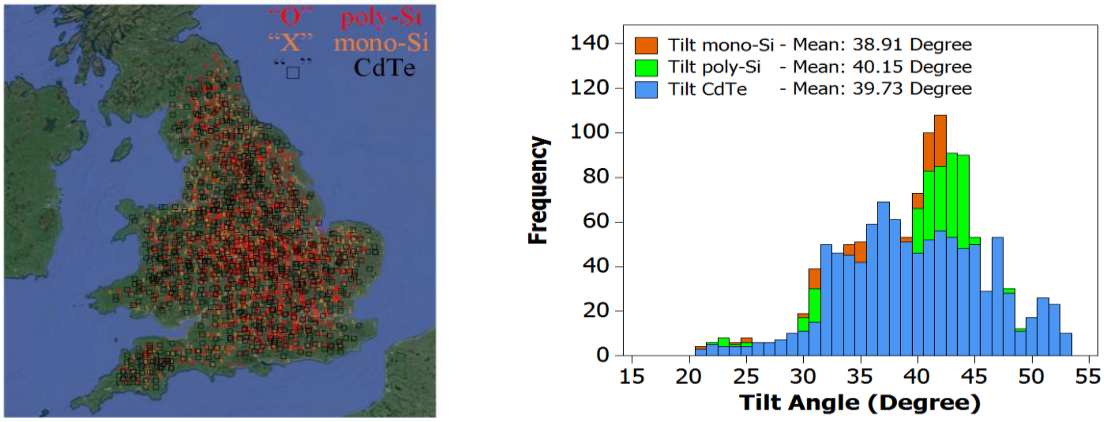
Mono-Si solar cells are made out of silicon ingots, which are cylindrical in nature. To optimize the efficiency and lower costs of a sole Mono-Si cell, four sides are cut out of the cylindrical ingots to create the silicon wafer [31]. The most significant advantage of this technology is that Mono-Si PV modules demonstrate the longest life, according to most solar panel manufacturers. However, Mono-Si solar panels have two key drawbacks including **(i)** the Czochralski process is used to produce the Mono-Si, resulting in a cut in the cylindrical ingots, where a substantial amount of the original silicon ends up as waste, and **(ii)** the performance of the Mono-Si suffers while the temperature goes up.

The second considered PV technology, Poly-Si, is made of a raw silicon material, melted, and poured into a square mould, which is cooled and cut into perfectly square wafers [32]. The main advantage of this technology is that the procedure to manufacture Poly-Si is more straightforward and cost-effective, and it tends to have slightly lower heat tolerance compared to Mono-Si and CdTe. However, Poly-Si has a typical efficiency ranging from 13% to 19%, because of the lower silicon purity, whereas Mono-Si and CdTe have higher efficiency ratings, evidenced by V. Komoni *et al.* [33].

CdTe solar panels are made of cadmium telluride, a thin semiconductor material [34]. This technology is cheaper to manufacture than crystalline-based solar cells. In addition, low temperature and shading have less impact on the CdTe solar panels performance. While this technology has several drawbacks such as **(i)** CdTe panels necessitate a lot of installation space, but crystalline-based PV panels could produce up to three times the amount of energy as CdTe panels for the same amount of space [35], and **(ii)** CdTe PV modules tend to degrade quicker than Mono-Si and Poly-Si solar panels, which is why they typically come with a shorter warranty ranging from 10 to 18 years [36].

(a) **(b)** **(c)**

Fig. 2. The appearance of different examined PV technology. **(a)** Mono-Si, **(b)** Poly-Si, **(c)** CdTe.



(a) (b)

Fig. 3. (a) Geographical distribution of all examined PV installations, (b) Tilt angle ranges for all considered PV sites.

B. Distribution of the Examined PV Systems

The map in **Fig. 3(a)** shows the distribution of the examined PV installations. The total number of examined PV systems is equal to 3000, while as discussed earlier, 1000 PV systems were selected per PV technology. All PV systems were installed from 2010 to 2012 (i.e. the data roughly represent six to eight years in service). The distribution of the PV systems is fairly the same, where all the examined PV technologies are affected by various weather conditions and scattered across the UK, including northern sites (generally colder weather conditions), the midlands, and the southern site (warmer weather conditions) such as London and Plymouth.

C. Tilt-Angle, Azimuth-Angle, and Annual Energy Disparities

The tilt angle is the inclination angle of the PV module from the horizontal plane. The tilt angles are obtained for all the considered PV systems, where all of them have fixed (non-tracking) mounting. The tilt angles are in the range between 21 to 53 degrees, as shown in **Fig. 3(b)**. The mean tilt angle for the PV systems based on their PV technology is equal to 35.7º, 34.9º, 35.2º obtained for Mono-Si, Poly-Si and CdTe, respectively. On the other hand, the azimuth angle is the angle of the PV module relative to the direction due south (-90° is east, 0° is south, and +90° is west). The azimuth angles are in the range of ±10 degrees.

The tilt and azimuth angle variations play a vital role in PV production since different tilt or azimuth angles affect PV energy production [37]. In fact, the proposed method for degradation analysis and the PR consider this uncertainly in the data processing, since the standard test conditions at certain tilt and azimuth angle will be compared to the actual energy production. Hence, the analysis only considers the actual annual energy production, degradation rate, location, and other environmental conditions such as partial shading. Therefore, the analysis of the tilt and azimuth angle does not skew the calculated PR for the tested PV systems. Hence, this would increase the consistency and reliability of the obtained results. Furthermore, all PV installations have a capacity varying from 2.2 kWp to 4.0 kWp. However, the disparities in the amount of the energy production per PV installation would not impact the degradation analysis due to the applied normalization to ensure that PV energy yield is dimensionless, and within a range of 0 to 1.0.

According to **Fig. 4**, the distribution of the examined PV installations based on their capacity shows that most of the PV systems typically range from 3.1 to 3.9 kWp. While there is only a small share of the PV systems that have a capacity below 2.5 kWp, this consistency indeed ensures minimal inequalities the degradation rate analysis.

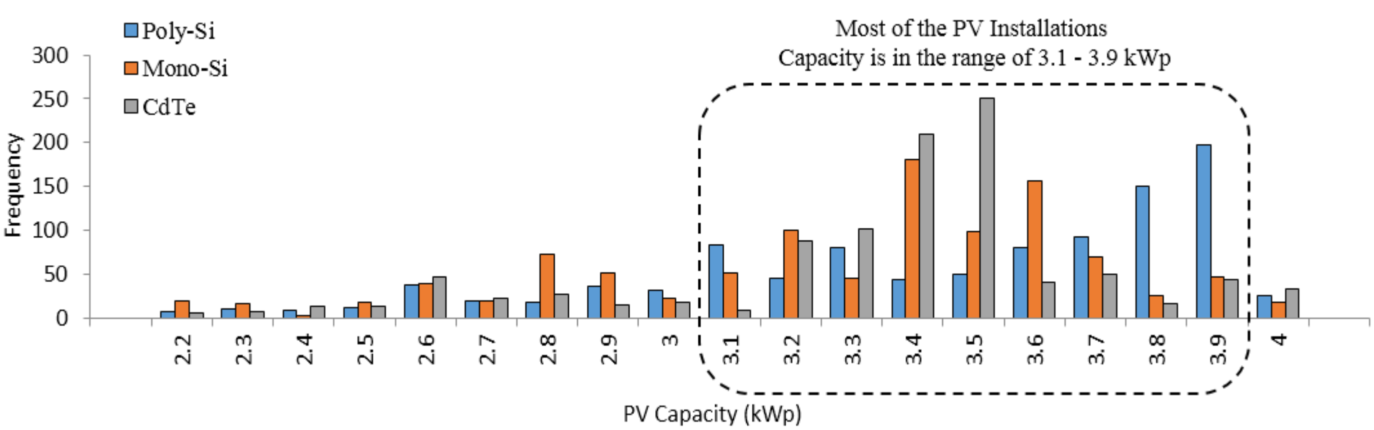


Fig. 4. Distribution of the PV installations capacity.

IV. Results

In this section, the obtained results of the annual PV degradation rate as well as the analysis of the PR of all examined PV systems will be presented.

A. Annual PV Degradation Rate Analysis

The annual degradation rates of all the examined PV systems are presented in **Fig. 5**, and summarized in **Table I**. The annual degradation rate of the Mono-Si is the lowest at a rate of -0.81%/year, while the highest is observed for the CdTe PV systems which are equal to -1.43%/year. According to the literature, this result was expected since CdTe PV modules degrade in higher rates compared to Mono-Si and Poly-Si, particularly in hot regions such as the southern UK. Though, it would be expected that the CdTe modules perform differently based on the geographical location of the PV installation. Both Mono-Si and Poly-Si degrade in fewer rates, as these PV technologies have better performance compared to the CdTe.

One of the decisive reasons that CdTe have a higher degradation rate compared to Poly-Si and Mono-Si PV installations is the inconsistencies of the ambient temperature, which strongly fluctuate the performance (output power) of this technology. This remark will be discussed in more details through the following observations.

Since CdTe has the highest degradation rate compared to the other PV technologies, it would be useful to examine the performance of this PV technology based on geographical distribution. Hence, all the examined CdTe installations are studied in three different regions, including north, middle, and south UK; **Fig. 6** maps the location of each region. The three

Table I Summary of the annual degradation rate per PV technology

PV technology	Annual measured degradation rate (%/year)	Degradation rate confidence interval (%/year)	
		Minimum	Maximum
Mono-Si	-0.81	-0.78	-0.83
Poly-Si	-0.94	-0.92	-0.95
CdTe	-1.43	-1.41	-1.45

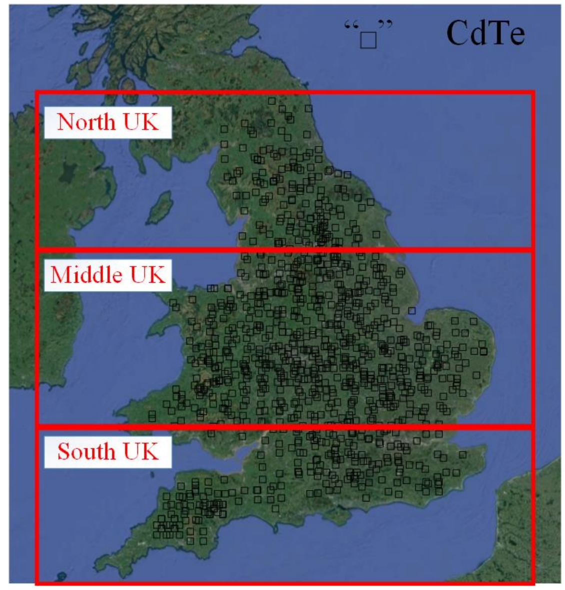


Fig. 6. Geographical distribution of all examined PV installations of CdTe technology.

regions are affected by different weather conditions, where the northern UK is affected by cold weather conditions, and the southern UK is the hottest. There are 213 examined installations in the north UK, 527 installations is in the middle sector, and 260 in the southern sector.

According to **Fig. 7(a)**, PV installations located in the north has the lowest annual degradation rate of -1.08 %/year; while in **Figs. 7(b) and (c)**, PV installations located in the middle and south of the UK has an annual degradation of -1.37 %/year and -1.84 %/year, respectively. The variation of the degradation rate is due to several reasons including, the relatively hotter weather in the southern UK and day-to-day unstable temperature. In addition, the humidity in the south is higher compared to middle and northern regions. In principle, these factors increase the water vapour in the air, hence increases the heat-conductivity of the solar cell, reducing its performance and the output power. Thus, PV installations located in the south are expected to suffer worse degradation.

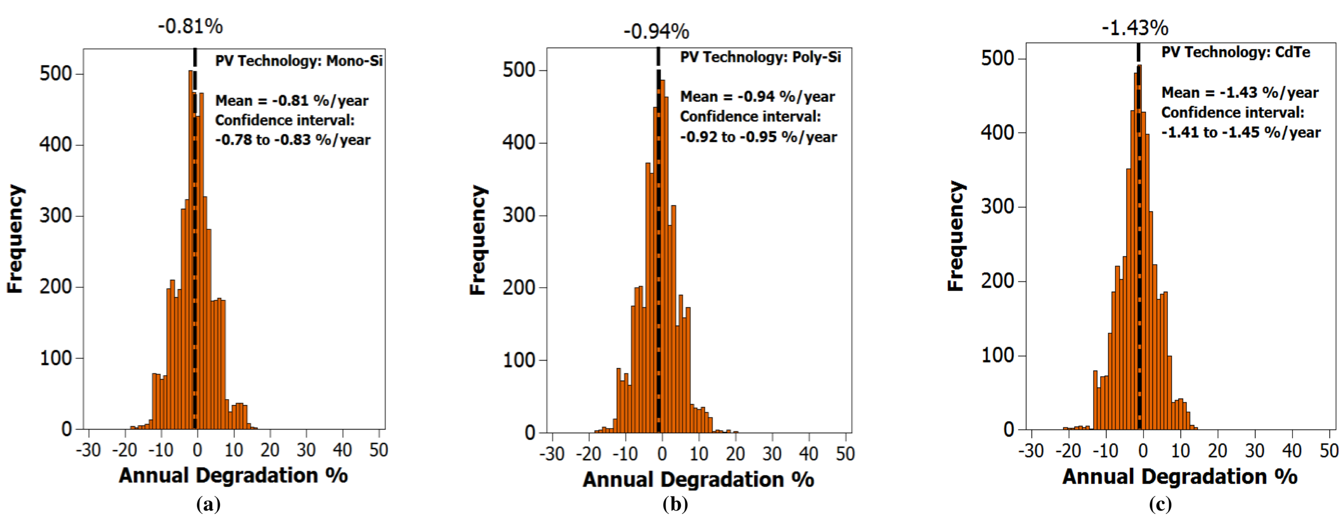


Fig. 5. The annual degradation rate of all examined PV installations. **(a)** Mono-Si, **(b)** Poly-Si, **(c)** CdTe.

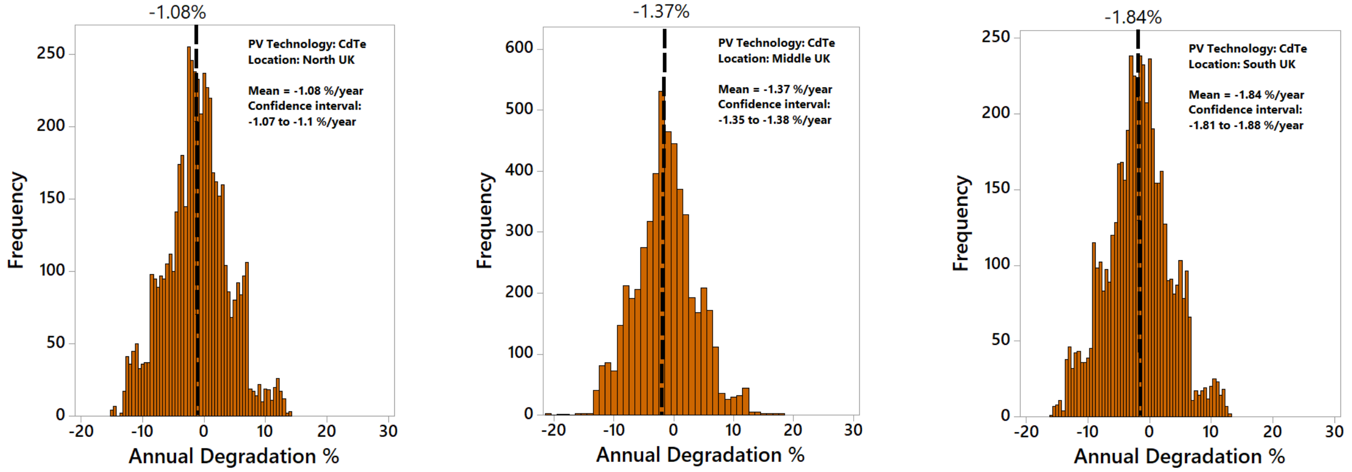


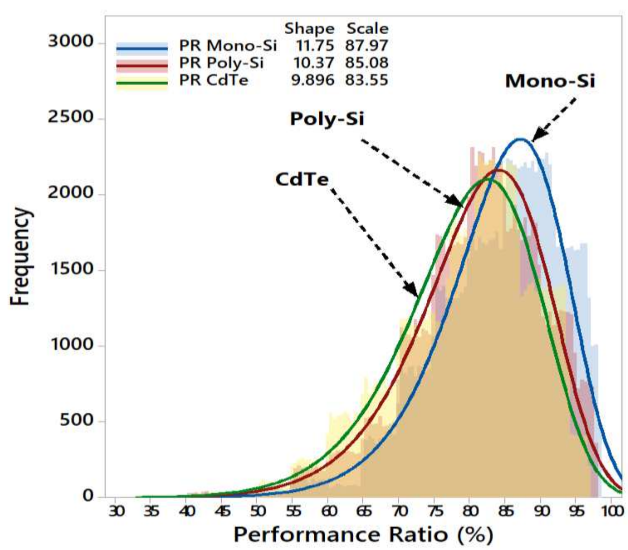
Fig. 7. Analysing the annual degradation rate for CdTe based on location. **(a)** North UK, **(b)** Middle UK **(c)** South UK.

B. *Performance Ratio (PR) Analysis*

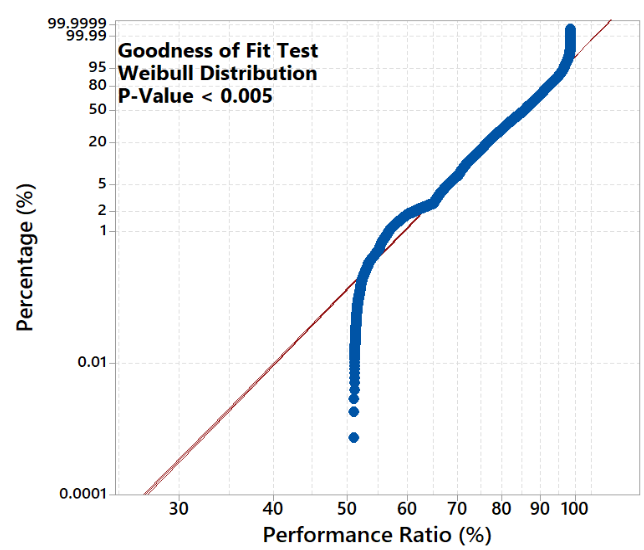
The analysis of the degradation rate could have uncertainties, as almost all PV systems suffer different kinds of faults, such as problems associated with dc/ac inverters, electrical installation mismatching (i.e. fuses and wiring), output power limitation and grid perturbations (i.e. voltage limitations and power factor), and the installation infrastructure (i.e. size, tilt and azimuth angles). Therefore, the PR is analysed as an insightful indicator. PR is a widely used metric for comparing the relative performance of PV systems whose design, technology, capacity and location differ.

The monthly integrated PR has been calculated for all PV systems, within 96 months (January 2010 – December 2017). **Fig. 8(a)** shows the distribution of the monthly integrated PR. The distribution does not follow a standard (or Gaussian) function, because a fraction of the PV systems show an overall performance lower than the average (below 60%). In view of that, the distribution of the PR is better explained with a Weibull distribution, which frequently arises when the range of deviation of the sampled population is substantially limited at one extremity, but not at the other. It is usually challenging to produce PR higher than 95%, because of PV modules problems such as partial shading conditions, line-to-line and line-to-ground faults, hot-spotting, and micro-cracks.

Prior to using the Weibull distribution, the probability of the error has been estimated using all samples of the PV installations. **Fig. 8(b)** shows that the probability error is less than 0.005; noted as P-Value < 0.005. The P-Value is defined as the probability of the results "in this case, the PR ratio of the PV installations" statistically significant if the threshold is less than 0.005 [38]. By contrast with this definition, the Weibull distribution could be used to analyse the performance of the PV systems data. In addition, it is worth noting that there is a large deviation of the curve at lower PR ratios (less than 55%). This large deviation has a probability ranging from 0.01% to 1%. Therefore, a minimal skew of the Weibull distribution function over all other considered PR ratios is assured. Hence, the prediction of the mean (scale) of the PR would be expected to have a high rate of accuracy.



(a)



(b)

Fig. 8. **(a)** PR ratio analysis for all examined PV systems, **(b)** Goodness of Weibull distribution function.

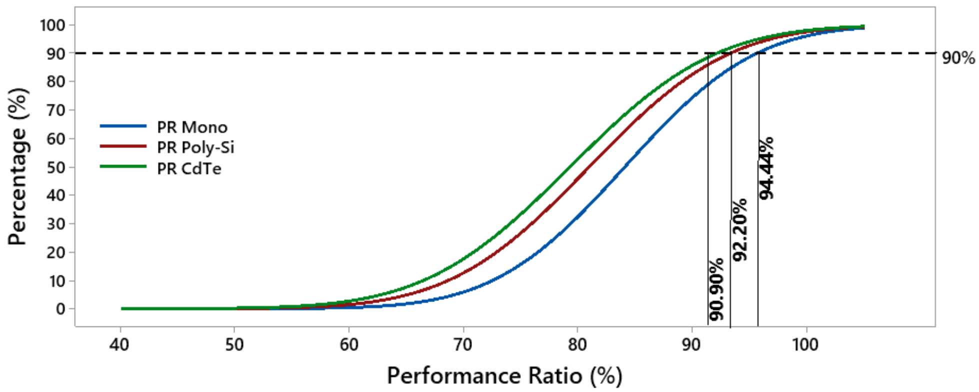


Fig. 9. Cumulative Density Function (CDF) profile for all examined PV installations.

The monthly integrated PR for all examined PV systems is shown in **Fig. 8(a)**; the highest PR value (scale) of 87.97% is obtained for the Mono-Si PV installations, while 85.08% and 83.55% is obtained for Poly-Si and CdTe, respectively. Clearly, this result confirms that Mono-Si PV installations are the optimum in terms of the monthly energy production compared to Poly-Si and the CdTe. While CdTe PV technology remains the lowest in the monthly energy production and the highest in the annual degradation rate as discussed earlier in the previous section.

The study also analyses the data of the PV installations using the cumulative density function (CDF). The CDF is the probability that the variable takes a value less than or equal to the PR ratio of the PV systems. A typical output of the CDF profile is shown in Fig. 9; the horizontal axis corresponds to the PR ratio, whereas the vertical axis is the percentage of the occurrence.

The presented study takes into account the 90% threshold to analyse the PR for examined PV technologies. It was found that 90.90% of the CdTe PV systems have a monthly PR greater than 90%. Likewise, 92.20% of the Poly-Si PV installations have a monthly PR higher than 90%. The uppermost percentage of the PV systems that would generate a monthly PR higher than 90% is observed for the optimum PV technology, Mono-Si.

V. Conclusion

This paper presents the analysis of 3000 PV installations comprising three different PV technologies: Mono-Si, Poly-Si, and CdTe. Results show that a maximum degradation rate of -1.43%/year is observed for the CdTe PV sites, whereas Poly-Si and Mono-Si photovoltaic systems recorded degradation rates of -0.94%/year and -0.81%/year, respectively. The location of the PV system plays a significant role in the variance of the degradation rate, as concluded through the analysis of CdTe installations in three regions of the UK. It was found that the degradation depended on the location of the PV systems, ranging from -1.08%/year to -1.84%/year. In addition, the paper analysed the monthly average of the PR ratio for all the examined PV installations. The highest PR of 87.97% was obtained for the Mono-Si PV installations, while 85.08% and 83.55% were observed for Poly-Si and CdTe, respectively. In addition, it was found using the analysis of the CDF function that 94.44% of the Mono-Si PV systems have a monthly PR higher than 90%. Likewise, 92.20% and 90.90% of the Poly-Si and CdTe PV installations have a monthly PR higher than 90%.

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