Performance Ratio and Degradation Rate Analysis of 10-Year Field Exposed Residential Photovoltaic Installations in the UK and Ireland

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Abstract: As photovoltaic (PV) penetration of the power grid increases, accurate predictions of return on investment require accurate analysis of decreased operational power output over time. The degradation rate in PV module performance must be known in order to predict power delivery. This article presents the degradation rates over 10 years for seven different PV systems located in England, Scotland, and Ireland. The lowest PV degradation rates of $-0.4\%$ to $-0.6\%/\text{year}$ were obtained at the Irish PV sites. Higher PV degradation rates of $-0.7\%$ to $-0.9\%/\text{year}$ were found in England, whereas the highest degradation rate of $-1.0\%/\text{year}$ was observed in relatively cold areas including Aberdeen and Glasgow, located in Scotland. The main reason that the PV systems affected by cold climate conditions had the highest degradation rates was the frequent hoarfrost and heavy snow affecting these PV systems, which considerably affected the reliability and durability of the PV modules and their performance. Additionally, in this article, we analyse the monthly mean performance ratio (PR) for all examined PV systems. It was found that PV systems located in Ireland and England were more reliable compared to those located in Scotland.

Keywords: renewable energy; photovoltaics; degradation; reliability analysis

1. Introduction

The ability to precisely predict output power delivery over time is of vital importance to the growth of the photovoltaic (PV) industry. Two key cost drivers are the efficiency with which sunlight is converted into actual energy and how this relationship fluctuates over time. Accurate quantification of power output decay over time, also known as the degradation rate [1], is critical to all stakeholders/utility companies, investors, integrators, and researchers alike. Economically, PV modules’ degradation rates are equally important, because a higher degradation rate interprets directly into reduced output power produced by the system, thus reducing future cash flows [2].

Inaccuracies in determining degradation rates amplify financial risks in the PV sector. Technically, it is essential that degradation mechanisms are understand because they could ultimately lead to PV system failures [3]. Typically, a $10\%$ decline is considered a failure; however, while there is no compromise on the definition of failure [4] it should be noted that a high-efficiency module degraded by $50\%$ may still have a higher efficiency than a non-degraded module from a less efficient technology.

Documentation of the degradation mechanisms through modelling and experiments in principle directly leads to lifetime improvements of PV modules, as suggested by S. Kawai et al. [5]. Outdoor field-testing has played a significant role in measuring long-term lifetime and behaviour for at least two reasons: it is the typical functioning environment for PV installations, and it is the only way to correlate indoor testing apparatuses to outdoor results to forecast field performance.

To date, there is a lack of published work found in the literature which represents analysis of PV degradation rates across the United Kingdom. Therefore, in this article, the degradation rates of seven
PV systems installed in various locations in the UK were examined and comprehensively compared over a period of ten years (2008 to 2017). Before moving to the methodology section, it is important to present an overview of the degradation rates across different regions in the world, summarised as follows:

United States of America (USA): the USA is among the top five countries leading development of PV technology worldwide [6]. In 1977, the Department of Energy established the Solar Energy Research Institute in Golden, Colorado. Outdoor testing of modules and sub-modules started at the Solar Energy Research Institute in 1982. When amorphous silicon (a-Si) modules first became commercially available, national renewable energy laboratory (NREL) began to report a degradation rate that was considerably higher than $-1.0\%$/year [7]. In other reports [8,9], similar results of PV degradation were found in small (<10 kWp) PV installations, followed by a yearly degradation rate of approximately $-0.8\%$ to $-1.25\%$/year.

Europe: the terrestrial focus of the PV industry in Europe can be traced to the oil crisis of the 1970s. The development and installation of PV sites can be classified into publicly and privately funded projects. The publicly-funded part in Europe can be additionally classified into the umbrella organisation of the Commission of the European Communities and individual national programmes. Nevertheless, various references indicate that the annual degradation rate in Spain and Italy is between $-0.8\%$ and $-1.1\%$/year [10–12], in Germany between $-0.5\%$ and $-0.7\%$/year [13,14], in Cyprus between $-0.8\%$ and $-1.1\%$/year [15], in Greece between $-0.9\%$ and $-1.13\%$/year [16], and finally in Poland it is always higher than $-0.9\%$/year [17].

Asia: Chandel et al. [18] studied the degradation rate in India based on a PV system operated for a period of 28 years. Based on their analysis, it was found that the degradation rate was equal to $-1.4\%$/year. Similar results were found by Dubey et al. [19], where the degradation rate in southern India was observed at $-1.25\%$/year. Furthermore, in Thailand, the degradation rate was widely different, ranging between $-0.5\%$ and $-4.9\%$/year [20]. However, Dechthummarong et al. [21] found that the degradation rate based on 15 years of PV operation in northern Thailand was equal to $-1.5\%$/year. Other reports found the PV degradation rate was equal to $-1.2\%$/year in Japan [22], $-2.0\%$/year in Singapore [23], and $-1.3\%$/year in the Republic of Korea [24].

In summary, from a global point of view, the PV degradation rate varies from $-0.2\%$ to $-2.0\%$/year. Yet there is not enough evidence on the annual PV degradation rate in the region of the UK and Ireland. Therefore, this study aimed to fill in this gap of knowledge by evaluating seven different PV systems located in various locations (England, Scotland, and Ireland). It was found that the average annual degradation rates of the PV installations varied between $-0.4\%$ and $-1.16\%$/year, contingent on the environmental conditions.

2. Methodology

2.1. Description of the Examined PV Systems

In this work, seven different PV installations were examined. The geographical distribution of the PV systems is shown in Figure 1a and summarised in Table 1. Figure 1b presents a real picture of the examined PV system located at Huddersfield (PV site C). All examined PV systems had an identical configuration which is demonstrated in Figure 1c, as well as identical azimuth ($-3^\circ$ due to South), and tilt angle of (39°). The PV installations comprised crystalline silicon PV modules with peak power of 220 W, and they were configured in 2 PV strings connected in parallel, each comprising 9 PV modules connected in series. All had the same PV capacity of 3960 W. The electrical characteristics, including the peak power, voltage, and current at maximum power point for the examined PV modules, are shown in Table 2.
Figure 1. Examined photovoltaic (PV) systems’ configuration and geographical representation: (a) geographical distribution of the examined PV installations in the United Kingdom including the average irradiance (G) and temperature (T) over the last 30 years; (b) real picture of the examined PV system installed at Huddersfield site—PV site C; (c) and PV sites’ configuration, which comprised two parallel PV strings each consisting of nine series-connected PV modules.

Table 1. Distribution of the Examined PV Systems.

| PV Site | Location          | UK   | Ireland |
|---------|-------------------|------|---------|
| A       | Plymouth, England | ✓    | -       |
| B       | London, England   | ✓    | -       |
| C       | Huddersfield, England | ✓ | -       |
| D       | Glasgow, Scotland | ✓    | -       |
| E       | Aberdeen, Scotland | ✓    | -       |
| F       | Dublin, Ireland   | -    | ✓       |
| G       | Sligo, Ireland    | -    | ✓       |
In the UK and Ireland, the dominant PV installations are made of crystalline silicon. For that reason, in this study, we aimed to analyse the performance of crystalline silicon PV installations made of the same configuration, manufacture, and connected via similar electrical components.

Furthermore, all observed PV systems were fitted with an ICONICA maximum power point tracking (MPPT) unit. This device has the capability of enhancing the output power during partial shading conditions, the MPPT efficiency ranging from 97.5% to 99.2%. The MPPT unit was connected to a hybrid, pure sine wave inverter linked to the grid, and the inverter efficiency ranged from 90% to 94%.

The tested PV systems were categorised into three main groups: the first group contained PV sites A, B, and C (located in England); the second group comprised PV sites E and F (located in Scotland); the last group consisted of two PV sites, F and G (located in Ireland).

Solar irradiance (G) and ambient temperature (T) play a significant role in the performance and annual energy production of PV modules. Since the examined PV sites were in different locations, it is worth addressing the locations’ weather and ambient temperature data. The average values of the irradiance and ambient temperature in all studied locations between the years 1981–2010 were taken from [25] and are presented in Figure 1a.

All examined PV systems were sited with a weather station. The weather station measured the ambient temperature, wind speed, humidity, and solar irradiation. Onsite measurements of DC voltage and current were recorded by the maximum power point (MPPT) units, and at the inverter input sampled every 5 min; thus, the number of samples collected in each year was equal to 52,560 samples. The comparison between degradation rates of the PV systems was observed over a period of 10 years; 2008 to 2017.

2.2. Power-Irradiance Analysis Technique

The power-irradiance technique is a method which compares the output measured power of a PV system with a corresponding irradiance level; usually full spectrum 0 to 1000 W/m². This technique depends on the measured and simulated/theoretical output power of the examined PV system in order to visualise the degradation rates of the PV systems. It is worth noting that partial shading, hot spots, micro-cracks, and other environmental factors were not considered while estimating the theoretical output power.

The calculation of the theoretical power of the PV installations $P_{dc,\text{theoretical}}$ was determined using Equations (1)–(3), where the theoretical power depended on the measured plane-of-array irradiance $G$, and the PV module temperature $T_c$.

The results of the irradiance vs output power are presented using a full spectrum of the irradiance; 0 to 1000 W/m². However, in the analysis of the degradation rates, mainly using Equation (2), only irradiance from 250 W/m² to 1000 W/m² was considered. This was because during the determination of the degradation rates, which will be discussed later in the results section, at low irradiance values, the slope of the power-irradiance would be expected to deviate, hence resulting in inaccurate analysis of the degradation rates.

\[
P_{dc,\text{theoretical}} = N_{am} \cdot N_{pm} \cdot P_{m,\text{theo}} \cdot G_{eff} \cdot (1 + K_v \cdot \Delta T) \cdot (1 - K_i \cdot \Delta T)
\]

(1)

\[
G_{eff} = \frac{G}{G_n}
\]

(2)
\[ \Delta T = T_c - T_n \]  
(3)

where \( N_{sm} \) and \( N_{pm} \) are the number of PV modules connected in series and parallel respectively, the \( P_{\text{Mtheo}} \) is the measured peak power of the PV module under standard test conditions (STC), and \( K_v \) and \( K_i \) are the voltage and current temperature coefficients respectively; these coefficients are provided in the PV modules’ manufacturer datasheets. The last parameters, \( G_n \) and \( T_n \) are the reference irradiance and PV module temperature under STC (\( G: 1000 \text{ W/m}^2 \), and \( T: 25 \degree \text{C} \)).

Linear regression equations were obtained using a linear correlation approach (LCA) from the actual PV array DC output-measured power for each year described by the following empirical Equation (4).

\[ P_{\text{dc measured}} = A_{Gr} G + C \]  
(4)

where \( P_{\text{dc measured}} \) is the actual PV installation’s DC output-measured power, \( A_{Gr} \) is the gradient, \( G \) is the plane of-array irradiance measured by the weather station, and \( C \) is the ordinate value of the \( P_{\text{dc measured}} \) at \( G = 1000 \text{ W/m}^2 \).

3. Results

3.1. Degradation Rates in England

The power-irradiance technique was applied to evaluate the degradation rates of the examined PV systems based on their DC output power. Figure 2 shows the power-irradiance profiles in three different years: 2008, 2013, and 2017. The blue points present the theoretical DC power obtained from Equations (1)–(3), whereas the orange points present the actual measured DC power.

Table 3 summarises the yearly and total degradation rates of the examined PV systems. It was found that PV systems A and C had the highest degradation rates during the first year of operation; in 2008, whereas PV site B, located in London, had the highest yearly degradation rate of \(-0.95\%\) in 2012.

### Table 3. England PV systems’ Degradation Rates.

| Year | Plymouth Site A | London Site B | Huddersfield Site C |
|------|-----------------|---------------|---------------------|
|      | Yearly Cumulative | Yearly Cumulative | Yearly Cumulative |
| 2008 | -0.91 | -0.91 | -0.87 | -0.87 | -0.73 | -0.73 |
| 2009 | -0.71 | -1.62 | -0.85 | -1.72 | -0.55 | -1.28 |
| 2010 | -0.72 | -2.34 | -0.88 | -2.6 | -0.42 | -1.7 |
| 2011 | -0.73 | -3.07 | -0.80 | -3.4 | -0.58 | -2.28 |
| 2012 | -0.77 | -3.84 | -0.95 | -4.35 | -0.55 | -2.83 |
| 2013 | -0.73 | -4.57 | -0.92 | -5.27 | -0.47 | -3.3 |
| 2014 | -0.71 | -5.28 | -0.88 | -6.15 | -0.53 | -3.83 |
| 2015 | -0.73 | -6.01 | -0.85 | -7.0 | -0.43 | -4.26 |
| 2016 | -0.69 | -6.7 | -0.87 | -7.87 | -0.53 | -4.79 |
| 2017 | -0.75 | -7.45 | -0.93 | -8.8 | -0.51 | -5.3 |
| Average | -0.74%/year | -0.88%/year | -0.53%/year |

As can be noticed in Figure 2 and Table 3, there was almost a linear degradation rate for PV site A. The average degradation rate over the last ten years was equal to \(-0.74\%/\text{year}\). The highest average degradation rate was observed in site B at \(-0.88\%/\text{year}\). The PV system installed in Huddersfield (PV site C) had a minimum degradation rate compared to PV sites A and B; its annual degradation rate was equal to \(-0.53\%/\text{year}\).

Another interesting observation from the reported results in Table 3 is that PV systems A and B, which were located in areas with relatively hot weather conditions, had higher degradation rates compared to the PV system installed in Huddersfield, a relatively cold area. On the other hand, in order to study the correlation between the degradation rates vs the environmental conditions, the next
The sub-section will evaluate the degradation rates of two different PV installations located in cold weather conditions (sited in Scotland).

![Graphs showing DC array power for different years (2008, 2013, 2017) with theoretical and measured power.]  

**Figure 2.** Cumulative degradation rates for PV systems A, B, and C in 2008, 2013, and 2017: (a) PV site A—Plymouth; (b) PV site B—London; (c) PV site C—Huddersfield.

### 3.2. Degradation Rates in Scotland

The annual and cumulative degradation rates from 2008 to 2017 for both sites D and E are presented in Table 4. It is evident that both PV sites had a maximum degradation rate in their first year of operation, 2008, when the degradation rates were equal to −1.23% and −1.33% for sites D, and E, respectively. The power-irradiance profiles in 2008, 2013, and 2017 for both PV systems are shown in Figure 3. The degradation rates for the PV modules increased over the years. For example, at site D, the accumulative degradation rate increased from −1.23% to −10.59% from 2008 to 2017. However, there was a further reduction in the annual output power in Aberdeen compared to Glasgow. The degradation rate for the Aberdeen PV system in 2008 was equal to −1.33%, and it increased to an accumulative of −11.62% in 2017.
Table 4. Scotland PV systems’ Degradation Rate Analysis.

| Year | Yearly | Cumulative | Yearly | Cumulative |
|------|--------|------------|--------|------------|
| 2008 | -1.23  | -1.23      | -1.33  | -1.33      |
| 2009 | -1.15  | -2.38      | -1.19  | -2.52      |
| 2010 | -1.12  | -3.5       | -1.15  | -3.67      |
| 2011 | -1.08  | -4.58      | -1.22  | -4.89      |
| 2012 | -1.11  | -5.69      | -1.12  | -6.01      |
| 2013 | -0.93  | -6.62      | -1.05  | -7.06      |
| 2014 | -1.02  | -7.64      | -1.16  | -8.22      |
| 2015 | -0.92  | -8.56      | -1.15  | -9.37      |
| 2016 | -0.95  | -9.51      | -1.08  | -10.45     |
| 2017 | -1.08  | -10.59     | -1.17  | -11.62     |

Average -1.05%/year -1.16%/year

Remarkably, it was found that the yearly average degradation rates for Glasgow and Aberdeen PV installations were equal to −1.05% and −1.16%/year, respectively. These high degradation rates were related to the fact that both PV sites are in cold areas. The increase in the degradation rates was due to the effect of the heavy snow, rain, and high wind speed on the surface of the PV modules; thus there was a higher risk of PV hot spots [25], micro cracks [26,27], and damage in the surface of the PV modules. Figure 4a shows an actual image of broken glass on a PV module located in Aberdeen site due to hoarfrost (this image was captured in February 2018), whereas in Figure 3b two hot spots were observed in the Glasgow PV system (these images were captured in June 2018). Therefore, in comparison to the degradation rates observed in the PV systems located in England, the PV systems located in Scotland had a higher degradation rate over the studied period.
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UK-based average climate conditions: Huddersfield, Dublin, and Sligo PV systems. The yearly average PV degradation rate was between −0.69% and −0.72%, respectively. The power-irradiance profiles in 2008, 2013, and 2017 for both PV sites are shown in Figure 5. The degradation rates for the PV modules increased over the years. For example, at site F, the accumulative degradation rate increased from −0.69% to −5.58% from 2008 to 2017. However, there was more loss in the annual output power in the PV systems located in Sligo, where the degradation rate in 2008 was equal to −0.72%, and it increased to an accumulative rate of −5.8% in 2017.

Table 5. Ireland PV systems’ Degradation Rates.

| Year | Dublin Site F | Sligo Site G |
|------|---------------|--------------|
|      | Yearly | Cumulative | Yearly | Cumulative |
| 2008 | −0.69  | −0.69      | −0.72  | −0.72      |
| 2009 | −0.55  | −1.24      | −0.58  | −1.3       |
| 2010 | −0.52  | −1.76      | −0.57  | −1.87      |
| 2011 | −0.53  | −2.29      | −0.57  | −2.44      |
| 2012 | −0.61  | −2.9       | −0.57  | −3.01      |
| 2013 | −0.62  | −3.52      | −0.55  | −3.56      |
| 2014 | −0.53  | −4.05      | −0.53  | −4.09      |
| 2015 | −0.48  | −4.53      | −0.53  | −4.62      |
| 2016 | −0.54  | −5.07      | −0.59  | −5.21      |
| 2017 | −0.51  | −5.58      | −0.62  | −5.83      |
| Average | −0.56%/year | −0.58%/year |

The yearly average degradation rates for both Irish PV installations were equal to −0.56% and −0.58%/year, respectively. Remarkably, the average yearly degradation rates for PV sites F and G over the last ten years were almost equal to those of PV site C (located in Huddersfield). This result indicates that the weather conditions played a significant role in the degradation rates for PV modules. For example, PV systems located in Huddersfield, Dublin, and Sligo relatively had the same degradation rate over the last ten years, where these locations are affected by the same irradiance and ambient temperature. By contrast with this result, it is possible to divide the cumulative degradation rates of all examined PV sites based on the weather conditions as follows:

- UK-based hot climate conditions: Plymouth and London PV systems. The yearly average PV degradation rate was between −0.70% and −0.9%/year.
- UK-based average climate conditions: Huddersfield, Dublin, and Sligo PV systems. The yearly average PV degradation rate was between −0.4% and −0.6%/year.
• UK-based cold climate conditions: Glasgow and Aberdeen PV systems. The yearly average PV degradation rate was always higher than −1.0%/year.

According to the literature review summary on page 2, our results indicate that PV installations in the UK and Ireland have relatively identical degradation rates compared to other counties affected by similar climate conditions. For example, in Germany [13] and Poland [17], the PV degradation rates are in the range of −0.5% to −1.5%/year, compared with our PV degradation results of −0.4% to −1.16%/year.

According to Figure 6, the total number of samples is equal to 120 per location (twelve months × incident in the plant of the PV array (kWh)). The shape of the obtained results is categorised by a normal distribution function, whereas the mean corresponds to the monthly mean of the PR over the studied period.

Figure 5. Cumulative degradation rates for PV systems F and G in 2008, 2013, and 2017: (a) PV site F—Dublin; (b) PV site G—Sligo.

4. Monthly Performance Ratio (PR) Analysis

In this section, the evaluation of the examined PV installations will be assessed using performance ratio (PR) analysis. The PR is a widely used metric for comparing the relative performance of PV installations whose technology, capacity, design, and location differ [28,29]. The PR was calculated using Equation (5).

\[ PR = \frac{\eta_{\text{measured}}}{\eta_{\text{theoretical}}} = \frac{E}{G} \]  

where \( \eta_{\text{measured}} \) and \( \eta_{\text{theoretical}} \) are the actual measured efficiency and theoretical output efficiency of the examined PV installations, \( E \) is the output energy of the PV system (kWh), and \( G \) is the solar irradiance incident in the plant of the PV array (kWh).

The normal distribution graphs of the monthly PR for all examined PV systems are shown in Figure 6. The total number of samples is equal to 120 per location (twelve months × ten years of PV operation). The shape of the obtained results is categorised by a normal distribution function, whereas the mean corresponds to the monthly mean of the PR over the studied period.
Figure 6. Performance ratio (PR) analysis for all examined PV systems: (a) PV systems installed in England; (b) PV systems installed in Scotland; (c) PV systems installed in Ireland.

Figure 6a presents the PR of the PV systems installed in England. The mean PR values were equal to 88.91%, 87.96%, and 87% for PV systems installed in Huddersfield, Plymouth, and London, respectively. This result is consistent with the results obtained by the power-irradiance technique described earlier in Section 3.1. Huddersfield PV system had the lowest annual degradation rate of...
−5.03%/year, while the highest PV degradation rate of −0.88%/year was observed for the PV system located in London.

According to Figure 6b, PV systems in Scotland had the lowest PR values compared to all other examined PV systems; the monthly mean PR were equal to 86.15% and 85.46% for Glasgow and Aberdeen, respectively. This result was due to the high degradation rates of these PV systems; their annual degradation rates were always higher than −1.0%/year. This result also confirmed that PV hot spotting, heavy snow, and hoarfrost affected the PR values of all PV systems installed in cold areas [30].

In the previous sections, we have demonstrated that the PV systems installed in Huddersfield, Dublin, and Sligo had almost identical annual degradation rates, varying from −0.53%/year in Huddersfield to −0.56%/year in Dublin and −0.58%/year in Sligo. Consequently, according to results shown in Figure 6a,c, the PV systems had nearly identical monthly mean PR values. In Huddersfield, the PR was equal to 88.91%, while in Dublin and Sligo, the monthly mean PR were equal to 88.78% and 88.57%, respectively.

In summary, this section confirms that the PV systems located in Ireland and England had better performance compared to both PV systems located in Scotland. Based on the technical report done by Leloux et al. [31], it was found that the monthly mean PR value of 5835 rooftop PV systems located in the UK ranged from 81% to 83%. While, according to our findings, the monthly mean PR was always higher than 85%, there are two critical features of the higher rate of the PR observed in our study:

- All examined PV systems were fitted with efficient MPPT units. As is shown in Figure 1c, these MPPT units have tracking efficiency ranging from 99.2% to 97.5%. Hence, the MPPT increases the annual yielded energy of the PV systems [32], particularly during partial shading scenarios, resulting in a higher PR value.
- One of the leading causes of output power loss in the PV systems was the conversion ratio of the DC–AC inverters, since they usually operate at low conversion limits, varying from 70% to 95% [33]. This was not a problem in our examined PV installations, since as noted earlier in Figure 1c, the PV systems were fitted with an efficient DC–AC inverter, with a conversion ratio always higher than 90%.

5. Summary of Contributions

In this article, we presented a fundamental and straightforward approach to estimate the degradation rate in a typical PV installation. In order to compare the novelty and simplicity of our approach, the results of the degradation rate of an installation at Plymouth city were validated via the different, widely used degradation estimation technology of RdTool [34] developed by the National Renewable Energy Laboratory (NREL).

This tool requires not only the temperature variance of the PV site, as our technique does, but also requires the following steps: data normalisation, filtering row data, and aggregation. Therefore, the data analytics of the degradation rate estimation strongly depend on the actual data available on the PV site; hence, more data available with time stamps (data captured using 1 min resolution or less) would typically result in an accurate prediction of the degradation rate. However, as recommended by [35], the estimation of PV degradation is more accurate if the data aggregation is of 1-week to 1-month resolution. Therefore, both aggregation processes were used to analyse our available dataset from the Plymouth site.

The results of the degradation rate testing using the RdTool are shown in Figure 7. As can be seen in Figure 7a, the degradation rate of the PV site was equal to −1.176%/year without any data filtration; this means that all aggregated data of the PV site were used for this analysis, while any missing data or inaccurate data has been considered. After the filtration process, which typically takes considerable time, the degradation rate was as accurate as −7.77%/year, close to our previous findings of −0.74%/year, as shown in Figure 2a. The results of 1-month resolution without any data filtration are shown in Figure 7b; the estimated degradation was −1.057%/year, while the degradation was estimated at −0.69%/year after filtering the data samples.
Figure 7. Degradation rate analysis for Plymouth city using RdTool [34]: (a) 1-week data resolution; (b) 1-month data resolution.

In contrast with the above-mentioned results, the commonly used RdTool requires a significant effort involving data filtration and aggregation in order to estimate as accurately as possible the degradation rates of PV installations. However, our proposed technique does not require this substantial amount of filtration of the missing data samples, which makes the power-irradiance technique easy to adapt and simple to implement practically.

6. Conclusions

This article presents an analysis of the degradation rates of seven different PV systems installed in various locations across England, Scotland, and Ireland. It was found that the lowest PV degradation rates of $-0.4\%$ to $-0.6\%/year$ were obtained at the Irish PV sites. Higher PV degradation rates of $-0.7\%$ to $-0.9\%/year$ were observed at the PV sites located in England. The highest PV degradation rate of $-1.0\%/year$ was observed in cold areas such as Aberdeen and Glasgow, located in Scotland. The main reason that the PV systems located in cold areas had the highest degradation rates is due to the frequent hoarfrost and heavy snow affecting these PV systems, resulting in reliability and durability problems in the affected PV modules.

Furthermore, in this article, we have analysed the performance ratio (PR) for all examined PV systems, and found that the monthly mean PR for the PV systems located in Ireland and England was always higher than 87%, whereas PV systems located in Scotland had the lowest monthly mean PR in the range of 85% to 86%. In future, it is intended to compare our observations with those of various PV systems installed in diverse locations across the globe, therefore enabling us to analyse the degradation rates of PV systems affected by different weather conditions.

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