UNIVERSIDAD POLITÉCNICA DE MADRID

**ESCUELA TÉCNICA SUPERIOR
DE INGENIEROS DE TELECOMUNICACIÓN**

TESIS DOCTORAL

**CONTRIBUTIONS TO UNCERTAINTY REDUCTION IN
THE ESTIMATION OF PV PLANTS PERFORMANCE**

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UNIVERSIDAD POLITÉCNICA DE MADRID

Instituto de Energía Solar

Departamento de Electrónica Física

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TESIS DOCTORAL

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RESUMEN

Esta tesis doctoral presenta un procedimiento integral de control de calidad en centrales fotovoltaicas, que comprende desde la fase inicial de estimación de las expectativas de producción hasta la vigilancia del funcionamiento de la instalación una vez en operación, y que permite reducir la incertidumbre asociada su comportamiento y aumentar su fiabilidad a largo plazo, optimizando su funcionamiento.

La coyuntura de la tecnología fotovoltaica ha evolucionado enormemente en los últimos años, haciendo que las centrales fotovoltaicas sean capaces de producir energía a unos precios totalmente competitivos en relación con otras fuentes de energía. Esto hace que aumente la exigencia sobre el funcionamiento y la fiabilidad de estas instalaciones. Para cumplir con dicha exigencia, es necesaria la adecuación de los procedimientos de control de calidad aplicados, así como el desarrollo de nuevos métodos que deriven en un conocimiento más completo del estado de las centrales, y que permitan mantener la vigilancia sobre las mismas a lo largo del tiempo. Además, los ajustados márgenes de explotación actuales requieren que durante la fase de diseño se disponga de métodos de estimación de la producción que comporten la menor incertidumbre posible.

La propuesta de control de calidad presentada en este trabajo parte de protocolos anteriores orientados a la fase de puesta en marcha de una instalación fotovoltaica, y las complementa con métodos aplicables a la fase de operación, prestando especial atención a los principales problemas que aparecen en las centrales a lo largo de su vida útil (puntos calientes, impacto de la suciedad, envejecimiento...). Además, incorpora un protocolo de vigilancia y análisis del funcionamiento de las instalaciones a partir de sus datos de monitorización, que incluye desde la comprobación de la validez de los propios datos registrados hasta la detección y el diagnóstico de fallos, y que permite un conocimiento automatizado y detallado de las plantas. Dicho procedimiento está orientado a facilitar las tareas de operación y mantenimiento, de manera que se garantice una alta disponibilidad de funcionamiento de la instalación. De vuelta a la fase inicial de cálculo de las expectativas de producción, se utilizan los datos registrados en las centrales para llevar a cabo una mejora de los métodos de estimación de la radiación, que es la componente que más incertidumbre añade al proceso de modelado.

El desarrollo y la aplicación de este procedimiento de control de calidad se han llevado a cabo en 39 grandes centrales fotovoltaicas, que totalizan una potencia de 250 MW, distribuidas por varios países de Europa y América Latina.

ABSTRACT

This thesis presents a comprehensive quality control procedure to be applied in photovoltaic plants, which covers from the initial phase of energy production estimation to the monitoring of the installation performance, once it is in operation. This protocol allows reducing the uncertainty associated to the photovoltaic plants behaviour and increases their long term reliability, therefore optimizing their performance.

The situation of photovoltaic technology has drastically evolved in recent years, making photovoltaic plants capable of producing energy at fully competitive prices, in relation to other energy sources. This fact increases the requirements on the performance and reliability of these facilities. To meet this demand, it is necessary to adapt the quality control procedures and to develop new methods able to provide a more complete knowledge of the state of health of the plants, and able to maintain surveillance on them over time. In addition, the current meagre margins in which these installations operate require procedures capable of estimating energy production with the lower possible uncertainty during the design phase.

The quality control procedure presented in this work starts from previous protocols oriented to the commissioning phase of a photovoltaic system, and complete them with procedures for the operation phase, paying particular attention to the major problems that arise in photovoltaic plants during their lifetime (hot spots, dust impact, ageing...). It also incorporates a protocol to control and analyse the installation performance directly from its monitoring data, which comprises from checking the validity of the recorded data itself to the detection and diagnosis of failures, and which allows an automated and detailed knowledge of the PV plant performance that can be oriented to facilitate the operation and maintenance of the installation, so as to ensure a high operation availability of the system. Back to the initial stage of calculating production expectations, the data recorded in the photovoltaic plants is used to improved methods for estimating the incident irradiation, which is the component that adds more uncertainty to the modelling process.

The development and implementation of the presented quality control procedure has been carried out in 39 large photovoltaic plants, with a total power of 250 MW, located in different European and Latin-American countries.

Index

1	Introduction	1
1.1	Energy at the crossroads	1
1.2	The PV momentum	3
1.3	State of the art and objectives	6
1.4	PV plants database	7
2	Quality control in PV plants	9
2.1	Quality control procedure	12
2.2	Energy yield forecasting	13
2.3	On-site solar radiation measuring campaigns	15
2.4	Laboratory testing of PV module samples	17
2.5	Measuring conditions in the field	17
2.5.1	Ambient conditions	17
2.5.2	Operating conditions	20
2.6	On-site characterization of PV plants	25
2.6.1	In-depth characterization of PV generators	27
2.6.2	Visual and infrared inspection	33
2.6.3	STC power of individual PV modules	33
2.7	Uncertainty in quality control procedures	35
3	Measurement contributions	43
3.1	I-V curve of large PV generators	43
3.1.1	A 500 kW <i>I-V</i> curve	43
3.1.2	Other large PV generators I-V curves	48
3.2	Dealing with hot-spots	51
3.2.1	Fundamentals of hot-spots	53
3.2.2	Experimental data	59
3.2.3	Method	59
3.2.4	Results	61
3.2.5	Discussion	67
3.2.6	Proposal	68
3.3	Dust as a hot-spot source	70

3.3.1	In-field measurements	71
3.3.2	Discussion	76
3.4	Long-term durability	76
3.4.1	Visual defects	78
3.4.2	Electrical performance	79
3.4.3	Electrical insulation	82
3.4.4	Discussion	83
4	Operation surveillance	85
4.1	Looking for simplicity	85
4.2	Looking for accuracy	86
4.3	Data consistency	89
4.4	Anomalies and availability	93
4.5	PV plants under operation	97
4.5.1	From provisional to final acceptance	97
4.5.2	Operational results	99
4.6	PV evaluation tool: a software contribution	103
4.6.1	Software design	104
4.6.2	Application results	105
5	Back to modelling: the irradiance case	113
5.1	Modelling from hourly values	113
5.1.1	Decomposition models	114
5.1.2	Transposition models	115
5.1.3	Angular and spectral corrections	117
5.2	Modelling from monthly average of daily irradiation	118
5.3	Experimental database	122
5.4	Model evaluation	123
5.5	Results	125
5.5.1	Modelling from hourly irradiation data	125
5.5.2	Modelling from monthly averages of daily irradiation	130
5.6	Discussion	133
6	Conclusions	135
6.1	Quality control procedure	135

6.2	Measurement contributions	136
6.3	Operating results	137
6.4	Back to modelling	137
7	Future research	139
	Annex 1: Results of the ANOVA test for irradiation modelling	141

List of figures

Figure 1. Accumulated PV power installed in the world, from 2000 to 2014.	3
Figure 2. New PV capacity installed year by year, from 2000 to 2014.	3
Figure 3. Yearly installed power in Europe by country, from 2000 to 2014.	4
Figure 4. General electrical scheme of a PV plant.	7
Figure 5. Geographic distribution of the PV plants.	9
Figure 6. Daily broadband horizontal irradiation for Valladolid.	16
Figure 7. Reference modules installed to measure operating conditions.	20
Figure 8. Operated reference module.	21
Figure 9. Reference module versus reference cells.	22
Figure 10. Reference module vs thermocouples.	25
Figure 11. Weekly PR at the Cuenca PV plant.	26
Figure 12. Weekly evolution of PR and PR_{STC} at the Madrid PV installation.	27
Figure 13. Details of the power analyser connection at the Málaga-1 PV plant.	28
Figure 14. DC power versus irradiance observed at the Moquegua PV plant.	30
Figure 15. DC power versus irradiance observed at the Toledo-2 PV plant.	31
Figure 16. Inverter efficiency versus load factor at the Moquegua PV plant.	32
Figure 17. Inverter efficiency versus load factor observed at the Málaga PV plant.	32
Figure 18. Measured power versus declared power for individual modules of the Cuenca-1 PV plant.	34
Figure 19. Frequency distribution of the difference between the in-field measured power and the declared power for individual modules of the Cuenca-1 PV plant.	34
Figure 20. PV modules order at the Cuenca PV plant.	35
Figure 21. Statistical distribution of the yearly production estimation of a PV plant.	37
Figure 22. Probability function evolution during the quality control process.	41
Figure 23. I - V tracer connection to the entrance of an inverter,	44
Figure 24. Simplified circuit design of the I - V tracer.	45
Figure 25. Reference PV modules at the Murcia-5 PV plant.	45
Figure 26. Evolution of I and V during the charging process, at the Murcia-5 PV plant.	46
Figure 27. Measured I - V curve and extrapolation to STC , at the Murcia-5 PV plant.	47
Figure 28. Reference PV modules at the Zamora-1 PV plant.	49
Figure 29. Evolution of I and V during the charging process, at the Zamora -1 PV plant.	49
Figure 30. Measured I - V curve and extrapolation to STC , at the Zamora -1 PV plant.	50
Figure 31. IR images of hot-spots.	52
Figure 32. Fundamental of hot-spots in a solar cell.	54
Figure 33. Second quadrant I - V characteristics of 7 individual cells of a PV module.	54
Figure 34. Fundamental of hot-spots in a PV module.	55
Figure 35. Fundamental of hot-spots in a PV array.	56
Figure 36. Operating point oscillation at a non-defective and at a defective PV module.	56
Figure 37. Operating voltage losses of a defective PV module respect to a non- defective one, versus hot-spot temperature.	57

Figure 38. Evolution of the operating voltage of three modules in the same string, with different hot-spot affection degrees.....	58
Figure 39. Hot-spots from by-pass diodes.....	59
Figure 40. Examples of visible defects related to hot-spots.....	61
Figure 41. Frequency distribution of the hot-spot temperature at the Cuenca PV plant	62
Figure 42. Hot-spot temperature evolution at the Badajoz-2 and the Cuenca PV plants	63
Figure 43. Electroluminescence relation with hot-spots	64
Figure 44. Normalized hot-spot temperature versus area of a cell isolated by a crack	65
Figure 45. Relation between electrical parameters and hot-spot incidence	66
Figure 46. Normalized hot-spot temperature versus operating voltage loss.....	67
Figure 47. Annual frequency distribution of the operating temperature at the Cuenca PV plant.....	68
Figure 48. Application of the proposed hot-spot classification criteria.....	69
Figure 49. Non-uniform dust patterns spontaneously formed on PV modules and array surfaces.....	71
Figure 50. PV module layout.....	71
Figure 51. <i>IR</i> images PV modules showing hot-spots derived from dust accumulation.....	72
Figure 52. <i>I-V</i> curves of PV modules with hot-spots derived from dust accumulation. Modules still dusty.....	74
Figure 53. Close-up view of the MPP region of the <i>I-V</i> curves presented in figure 52.....	74
Figure 54. <i>I-V</i> curves of PV modules with hot-spots derived from dust accumulation. Modules have been cleaned.....	75
Figure 55. Close-up view of the MPP region of the <i>I-V</i> curves presented in figure 54.....	75
Figure 56. Madrid PV installation	77
Figure 57. Cracks in terminal boxes appeared during the first 13 years of operation.	78
Figure 58. Backsheet delamination appeared after the first 17 years of operation	79
Figure 59. Cracks and moss in the frame appeared after the first 17 years of operation	79
Figure 60. Short circuit current distribution before and after 17 years of outdoor exposition.....	81
Figure 61. Open circuit voltage distribution before and after 17 years of outdoor exposition.....	81
Figure 62. Fill factor distribution before and after 17 years of outdoor exposition.....	81
Figure 63. Maximum power distribution before and after 17 years of outdoor exposition.....	82
Figure 64. Degradation rate distribution.....	82
Figure 65. Wet leakage test.....	83
Figure 66. Power production process in a PV system	86
Figure 67. Yearly frequency distributions of weather and operating conditions at the Cádiz-2 PV plant in 2012.....	91
Figure 68. $T_C - T_A$ versus G_{eff}	92
Figure 69. Daily irradiation gain, $G_d(I)/G_d(0)$ in function of the daily horizontal irradiation, $G_d(0)$	93
Figure 70. Normalized daily yields of the strings of the Moquegua PV.....	96
Figure 71. Ordered normalized daily yield for the string of the Moquegua PV plant	97
Figure 72. Estimated yield versus experimental yield.	98

Figure 73. Final yield and <i>PR</i> frequency distributions for PV plants with different tracking strategies.....	102
Figure 74. Flow chart of the PVET software	105
Figure 75. 15-minute evolution of the ambient and the operating temperature during the month of June 2013 in the Palermo-3 PV plant.....	105
Figure 76. 15-minute evolution of temperature and low irradiance losses during the month of June 2013 in the Palermo-3 PV plant.....	106
Figure 77. Sankey diagram of the energy generation process during the month of November 2013 in the Caltanissetta-2 PV plant.....	106
Figure 78. String pair power evolution showing PID recovery.	107
Figure 79. Hot-spots derived from a bad connection between the plate and the bus-bar coming from the cells at the Moquegua PV plant.	108
Figure 80. Normalized relative daily yield of the 1982 string pairs of the Moquegua PV plant, for the 4 th of May, 2015.....	109
Figure 81. Normalized relative daily yield evolution over the analyzed period for different string pairs of the Moquegua PV plant.....	110
Figure 82. Normalized relative daily yield for the 1982 string pairs of the Moquegua PV plant, the 19 th of February 2015. Differences.....	111
Figure 83. Modelling process when starting from hourly irradiation data	113
Figure 84. Modelling scheme when starting from monthly irradiation values and using monthly average profiles.....	118
Figure 85. Frequency distribution of the experimental and simulated hourly irradiances in a two-axis tracking system	120
Figure 86. Modelling scheme when starting from monthly irradiation values and using synthetic series generation profiles.....	120
Figure 87. Modelling scheme when starting from monthly irradiation values and using synthetic series generation profiles.....	122
Figure 88. Geographic distribution of the PV plants of the modelling exercise.....	123
Figure 89. Experimental versus simulated hourly irradiances	125
Figure 90. Experimental versus simulated daily irradiances.....	125
Figure 91. Irradiance frequency distributions between experimental and modeled values, and frequency distribution differences	126
Figure 92. ANOVA analysis applied to the CWE of the hourly irradiances results.....	127
Figure 93. Experimental versus simulated yearly irradiances.....	128
Figure 94. ANOVA analysis applied to the CWE of the yearly irradiances results, calculated from hourly irradiances.....	Error! Marcador no definido.
Figure 95. ANOVA analysis applied to the CWE of the yearly irradiation results, calculated from monthly irradiances, for each of the decomposition models..	131
Figure 96. ANOVA analysis applied to the CWE of the yearly irradiation results, calculated from monthly irradiances, for each of the irradiance distribution, transposition and spectrum models.	132

1 Introduction

1.1 Energy at the crossroads

After years of reluctance, the International Energy Agency acknowledged in 2010 that the crude oil output reached its maximum value, commonly known as peak oil, in 2006 (Birol, 2010). Other authors predict global natural gas production will peak around or even before the year 2020 (Zittel, 2013). Considering that these energy sources account for 52.7% of the total world energy supply (IEA, 2007), and that global energy consumption grows steadily year by year, the arrival of a crisis in the energy system, understood as a deep change with important consequences, seems evident. This energy crisis has been widely commented and there are plenty of theories about how will it be, when will it happen and how will it impact the human society (Tverberg, 2012) (Murphy, 2011) (Murphy, 2011) (Fernández, 2014). All of them agree in foreseeing that the upcoming energetic, and therefore, economic and social systems will not be similar to the actual ones.

The current energetic system is characterized by a huge and growing complexity. As an example, every crude oil barrel went over an average sailing distance of 13,900 km in 2013, roughly a third of the distance around the globe, and accounting for a 9% increase since 2010 (Yep, 2014). The correct functioning of this system implies the construction of large infrastructures, such as oil and gas pipelines, refineries, regasification stations... which, in turn, require the leveraging of big amounts of money. Therefore, a full involvement in the energetic system is only available to entities with large financial capacities, essentially big companies or rich countries. Moreover, as fossil fuels are non-homogenously distributed around the world, their possession has historically derived in the so-called “resource wars” (Klare, 2001) (Klare, 2009), not only between countries but also between companies and local population (Klare, 2007), passing the idea over of a non-democratic, unequal and unfair system. These stresses, together with the external energetic dependence of most of the countries point out the low resilience of the energetic system and its vulnerability in the long-term, even more in a depletion resources scenario. However, and being all these aspects of fundamental importance (so as to condition geopolitics all around the world), there are two main characteristics that, in the opinion of the authors, lead the necessity of a model change.

On the one hand, this energetic system is deeply inefficient, if we consider the wellbeing of the majority of the population. 1.2 billion people are still without access to electricity in 2014 and energy poverty is still looming and remains unsolved in several poor regions. Nevertheless, when referring to energy poverty, it is usual to think only in non-developed countries, but the problem is much more spread. For example, in 2012, more than 7,000 deaths in Spain were due to energy poverty, which affected over 7 million people (a 15% of the country population) (Tirado Herrero, 2012). Also in that year, over a million Californian households risked from energy poverty, more than a 15% in some counties (Lesser, 2015). As we will see below, this situation is inefficient not only in social terms but also in economic ones, as there are cheaper alternatives.

On the other hand, this energetic system is not useful to tackle climate change. A recent publication demonstrates that a third of the known oil reserves, half of gas reserves and

over 80% of coal reserves should remain unused from 2010 to 2050 in order to meet the target of keeping warming below 2°C throughout the 21st century (McGlade, 2015). The current fossil fuel based system is completely unsustainable in the long term for environmental, but also economic reasons, as a business as usual scenario could lead to a 20% economy constriction (Stern, 2006).

Regarding the resources depletion, some voices defend that unconventional fossil fuels could compensate the conventional fuels decrease in order to maintain the current model. Despite the considerable boom experienced by these technologies in the last years, they do not face many of the problems presented in the previous paragraphs, and only could be considered as a short-lived complement that would delay the change of system some years, while would worsen the conditions in which the system change decision will be adopted. In addition to the several environmental and social aspects that discourage the use of unconventional sources, the high decline output rates and the need for continuous inputs of capital¹ have made of unconventional fuels a ruinous business in the actual low price context². In fact, some authors think that its enormous growth has had more to do with a financial bubble than with a real introduction as alternative sources³.

On the contrary, renewable energies have reached a maturity degree and an economic competitiveness that makes them a powerful alternative for the electric share of the future energetic system. Obviously, they do not emit greenhouse gases and due to their more homogenous and distributed character, increase the energetic autonomy of countries, erasing one of the main sources of conflicts and geopolitical strain. In addition, renewables move resource, generation and consumption closer, what increases the system efficiency. This fact derives also in a simplification of the system itself and reduces the need for large infrastructures. Other important characteristic of some renewables is their modularity, especially remarkable for photovoltaic (PV) energy. It allows accomplishing from a large PV plant to a small solar home system without much complexity addition. This characteristic drives to a more spread and democratic generation model, much lower in capital intensity, in which the possession of the energy production means is divided, allowing replication schemes in completely different regions. This is the most important contribution of solar energy to the energy system change. As declared by the American utilities, PV technology supposes a disruptive challenge able to create a paradigm shift in the model (Kind, 2013).

However, despite accepting the need of a change and the availability of economically competitive alternatives, those energy sources able to play an important role need to guarantee high reliability and low performance uncertainty. These aspects are critical to minimize investing risks and maximize profitability for the owner, and to carry out

¹ In the USA, the capital inputs needed in order to maintain shale production are estimated at €48 billion per year to drill more than 8,600 wells. In comparison, the value of shale gas produced in 2012 was just €33 billion.

² Always in the USA, shale companies' debt has almost doubled over the last four years while revenue has gained just 5.6 % (Loder, 2014). In fact, the businessmen themselves declare the lack of profitability: Rex W. Tillerson, Exxon Chief Executive: "We are all losing our shirts today". "We're making no money. It's all in the red." (Jerry A. Dicolo, 2012) (Wethe, 2015)

³ Potential reserves have been systematically swelled. As a paradigmatic example, the USA federal energy authorities slashed by 96% the previous estimated amount of recoverable oil buried in California's vast Monterey Shale deposits, until then considered as the most promising area of the country.

accurate production predictions on the grid management side that allow high penetration rates.

1.2 The PV momentum

This thesis begins in 2008, a time when the situation of photovoltaic solar energy was totally different from today: during the development of this work we have been fortunate to see this technology evolve from a promising childhood to a relatively consolidated maturity. Two snapshots of the sector situation in the initial and final moments of this work testify that evolution. Figure 1 and Figure 2 present the year to year evolution of the total PV capacity and the new installed power, from 2000 to 2014 (EPIA, 2015).

Figure 1. Accumulated PV power installed in the world, from 2000 to 2014. Source EPIA.

Figure 2. New PV capacity installed year by year, from 2000 to 2014. Source EPIA

As it can be observed, the first PV plant installation boom was centred in 2008, supported mainly by the development of the German and Spanish markets, due to the implementation in these countries of attractive feed-in tariff regulations. The worldwide installed capacity increased from around 1 GW per year between 2004 and 2006 to 2.5 GW in 2007 and to 6.7 GW the following year (over a 75% installed in the two mentioned

countries), as can be observed in . At that time, the bulk of the market and the leading promoting and manufacturing companies were European; installations were divided into domestic and commercial rooftops in Germany, and on-ground PV plants in Spain; and the standard cost was around 7.5 €/Wp for the small installations and around 5 €/Wp for PV plants with static structures, raising to 6 €/Wp when tracking was incorporated (IEA, 2009). Due to the characteristics of the Spanish legislation, most of the PV plants were composed of several 100 kW units, contributing to a total power that usually ranged from 1 up to 5 MW, although there were also PV plants of up to 50 MW (as the here considered Cuenca and Alentejo PV plants). The 2007-2008 expansion allowed a remarkable price decrease, which, in turn, led to further development of PV installations with a similar trend until 2011 (more than 60 GW were installed in the period), mainly in Europe but also in Japan, China and the United States. By the end of 2011, the average PV module price had declined from 3 €/Wp in 2008 to around 1 €/Wp while the whole system cost for PV plants reached around 2.2 €/Wp (IEA, 2012). This drop was due to, on the one hand, the economies of scale and the technology improvements derived from the increased installed power and the consequent equipment demand and, on the other hand, to the substitution of European manufacturers by Asiatic ones, and to the factories offshoring in the Asiatic countries.

After 2011, the global installed capacity experienced a certain downturn, mainly due to the variation of the feed-in tariff policies in some European countries: Spain (2009), Czech Republic (2010), Italy (2012), Bulgaria (2013) or Germany (2013). The reduction of PV incentives affected sequentially the added capacity, as it is observed in Figure 3 (EPIA, 2015).

Figure 3. Yearly installed power in Europe by country, from 2000 to 2014. Source EPIA

The reasons for this change in governmental programmes were varied, including non-optimum design of some of the incentive policies themselves, which did not foresee the outstanding PV installation increase. As a general rule, these policies assured a common feed-in tariff for all the systems connected within a certain period, what derived in a boom of new installations but also implied large remunerations to be paid, that could not be maintained in the long term. Another influence factor could be the negative impact

derived from discredit campaigns carried out by the traditional electric sector companies, which transmitted the idea of renewables in general, and PV in particular, as expensive technologies. Although the details of these regulation changes are out of the scope of this work, it is worth mentioning, on the one hand, that PV currently receives less incentives than other classical technologies⁴ and, on the other hand, that as a counter-effect, the savings generated by renewables in the electricity market, through clearing price decrease, overtake the incentives received⁵ (Gallego-Castillo, 2015). In any case, these legislative fluctuations supposed a harsh impact on the European PV industry, causing the disappearance of many companies and the business model change of many others.

After the 2012 parenthesis, PV continued to growth intensely, with more than 40 GW installed in 2014. On average, PV has grown 50% annually since 2008, which are typical values of the early stages of development of a technology. The European market is no longer dominant (only contributed with 6.6 GW in 2014, a 16% of the total power) and has been moved by the Asian market (10.6 GW in China and 9.7 GW in Japan for a total of 22.6 GW) and the American one (6.2 GW in the USA for a total of 7.1 GW). Half of the capacity was installed in rooftops and the other half as large scale PV plants, with standard powers between 10-60 MW (although there are numerous facilities over 100 MW), composed of generation units between 500 kW and 1.2 MW and mounted over static or horizontal axis structures.

An overall price decline of almost 75% has been experienced in this period. In particular, the cost of the PV module (formerly the most important part of the investment) has been drastically reduced from 3 €/Wp to less than 0.7 €/Wp, contributing to a total installation price under 1 €/Wp. These construction prices drive to a levelized cost of energy (LCOE) between 61 and 73 €/MWh, which positions PV as a fully competitive technology, as it has been already recognized by several institutions (Lazard, 2014). In fact, PV installations are now usually accomplished in the framework of really competitive call for tenders. Even when considering small domestic installations rooftops, the cost is low enough to exceed grid parity in many countries. In such contexts, the cost of capital becomes an essential part of the inversion and the precision in the estimations about how much energy will an installation produce become of crucial importance. These two aspects will be discussed in detail in following chapters.

In the previous section we said that PV, due to its simplicity and distributed nature, can make a decisive contribution not only to a technological paradigm shift in the energy system but also to a shift in the possession of it. PV plants have constituted the experimental field for this thesis. Obviously, this type of installations is more related to the technological shift than to the possession one, as they require a considerable capital

⁴ The British Government assured a fix retribution of 127 €/MWh during 35 years to the incipient Hinkley Point C nuclear reactor (Iván Calvo, 2013) (Roca, 2015). PV energy, including storing and other flexibility structures would require half of the incentives. Along the same lines, if Britain had invested in wind turbines the same amount of money that it is going to invest in the Hinkley nuclear reactor, it could have a generating capacity six times larger.

⁵ In addition to the merely economic evaluation, PV installation generates other well-known contributions: creation of a high added value local industry; energy dependence decrease; improvement in the balance of payments; reduction of greenhouse gases emissions; increase of the competitiveness of the industrial activities by the addition of self-sufficiency...

accumulation, only available to big companies. However, they contribute with a remarkable accumulation of casuistry and an extensive test field, constituting an excellent opportunity to learn. Many of the interventions made in PV plants are carried out just because of their economies of scale (as detailed monitoring), and would be difficult to implement in small installations. Although being derived from work in PV plants, the conclusions of this thesis can be applied to any type of PV facility, and are oriented to increase the reliability not only of large installations but the whole PV technology.

1.3 State of the art and objectives

PV plants built between 2008 and 2014 have been mainly carried out using project finance procedures, where the installation itself acts as payment guarantee. In this scheme, it is typically required the completion of a due diligence to ensure the technical quality of the plant. Quality controls, very common and established for other technologies, were, before the 2008 boom, restricted to the peak power measurement of PV modules in specialized laboratories. However, such a procedure did not prevent problems to appear. As an example, the PV generators of a representative sample of a 10% of the first boom Spanish installations presented a peak power value 6% lower than the nominal value, with almost a 25% of the installations below 10% (Martínez, 2012). The shift from small-scale off-grid environments to the promotion of big installations in fully commercial markets required an adaptation process for the PV companies but also the development of new quality standards and methods.

In this framework, one of the main activities of the PV systems research group of the IES-UPM during these years has been the provision of services to PV companies and, among this, the accomplishment of the technical due-diligences of many PV projects. The IES-UPM played the role of independent experts at different stages of the projects: defining the initial production expectation, measuring PV modules and preparing some of them to act as reference modules in the field (to measure the operating conditions), and accomplishing the in-field measurements during the commissioning of the plant. Taking advantage of the previous IES-UPM knowledge and of this in-field work accomplished in the Spanish PV plants, numerous studies were published, facing the improvement of measurement procedures, the detection of early degradation phenomena and the development of proper indexes and methods to evaluate the initial state of health of PV installations (García, 2014) (Martínez-Moreno, 2012) (Martínez-Moreno, 2010).

After the first boom of installations, the importance of knowing the performance of PV plants started to grow. However, as casuistry had been limited, the available analyses were restricted to specific pioneer facilities, leaving some relevant questions unanswered: how do PV systems really work over time? How much energy can be expected to be produced? What are the main problems that threaten their long-term performance? How can their behaviour be predicted? How can be their reliability improved and the uncertainty in their performance reduced?

The favourable economic scenarios in the first years of development led to sensible returns, even in PV plants with low peak power or performance problems, what did not reinforce the need of improving the quality control procedures. However, this situation is no longer true in recently installed PV plants. In a very competitive context, with retribution prices as low as 60 €/MWh, there is no room for 6% deviations from nominal

power. Moreover, it is usual to guarantee energy production with very narrow deviation ranges, under penalty of fines. This leaves no room for estimation uncertainties of 6-8% either. This new situation, characteristic of mature technologies, requires, again, the improvement of both installations and quality control methods.

The objective of this thesis is to contribute to a better understanding of PV plants performance and to the improvement of their reliability. The work was temporally divided in three stages. As a first period, several in-field measurements and performance analyses were accomplished, between 2008 and 2012. Then, starting from the results obtained and coinciding with the downturn of PV installation, some theoretical studies and procedures were developed. Then, as a final phase, the resulting contributions were tested in the recently installed PV plants.

1.4 PV plants database

This thesis is based on the experimental background provided by the in-field work accomplished by the IES-UPM in the last decade. This experience includes on-site measurements and performance analysis in more than 70 large-scale PV plants connected to the grid, totalizing more than 350 MW. In this work, 39 PV plants have been considered, totalling more than 200 MW. These installations are mainly located in Europe, but also in Latin America; include static structures, single-axis tracking (horizontal and azimuthal) and double-axis tracking (with horizontal and vertical primary axis)⁶; and are composed of PV modules of different materials, as mono and poly-crystalline silicon (m-Si and p-Si) and cadmium-telluride (CdTe), gathered in generators that go from 3 kW up to 800 kW. In general, all the installations follow the electric layout presented in Figure 4.

Figure 4. General electrical scheme of the PV plants considered in this thesis, made up of several PV generators. Each of them feeds an inverter and then a low-to-medium voltage transformer; and is controlled by means of an energymeter. A final energymeter in the medium voltage side is usually included.

For each of the installations, depending on the quality control steps the IES-UPM has been involved in, from one up to four years of performance data are available, in addition to the initial production estimation and the characterization measurements. As a part of the characterization tests, every installation is equipped with reference modules for measuring the operating conditions, G^{ef} and T_C . These modules were previously stabilized and calibrated at the IES-UPM facilities, and their traceability is referred to the CIEMAT. Further details are given in section 2.5.

⁶ The primary axis is the one directly linked to the foundation of the tracker while the secondary is the one linked to the primary.

Table 1 presents the main PV plants characteristics while Figure 5 shows the geographical distribution of the Spanish installations.

Plant	Country	Latitude (°)	Longitude (°)	PV module material	Configuration	Power (MW)
Albacete-1	Spain	38,96	-1,74	m-Si	2xhv	3.2
Albacete-2	Spain	38,96	-1,74	m-Si	2xhv	2.2
Alentejo	Portugal	38,19	-7,22	p-Si	1xa	45.8
Badajoz-1	Spain	38,33	-6,69	m-Si	2xvh	11.3
Badajoz-2	Spain	38,79	-6,33	m-Si/p-Si	1xa	8
Cáceres-1	Spain	39,97	-6,11	p-Si	2xvh	2.1
Cáceres-2	Spain	39,40	-5,98	p-Si	2xvh	0.5
Cádiz-1	Spain	36,70	-6,28	p-Si	2xvh	3.8
Cádiz-2	Spain	36,76	-6,32	p-Si	2xvh	1.9
Caltanissetta-1	Italy	37,04	14,41	p-Si	St	4.5
Caltanissetta-2	Italy	36,99	14,44	p-Si	St	1
Ciudad Real-1	Spain	39,01	-3,41	m-Si	2xvh	2.0
Ciudad Real-2	Spain	39,09	-3,28	m-Si	2xvh	2.0
Córdoba	Spain	37,60	-4,69	p-Si	2xvh	4.5
Cuenca	Spain	39,64	-2,09	p-Si	St	60
Granada-1	Spain	37,35	-3,27	m-Si	2xhv	3.0
Granada-2	Spain	37,23	-4,15	m-Si	St	1.6
Huelva	Spain	37,15	-6,50	m-Si	2xvh	3.4
Latina	Italy	41,40	13,03	p-Si	St	6
Madrid	Spain	40,45	-3,73	m-Si	St	0.1
Málaga	Spain	37,05	-4,89	m-Si	St	2.1
Moquegua	Peru	-17,54	-71,04	p-Si	1xh	20
Murcia-1	Spain	37,78	-1,65	m-Si	2xhv	2.1
Murcia-2	Spain	37,93	-2,17	m-Si	2xvh	1.6
Murcia-3	Spain	37,54	-1,75	p-Si	St	2
Murcia-4	Spain	37,65	-1,07	p-Si	St	3
Murcia-5	Spain	37,60	-1,75	p-Si	St	4
Palermo-1	Italy	37,88	13,06	p-Si	St	1.5
Palermo-2	Italy	37,92	13,35	p-Si	St	5.9
Palermo-3	Italy	37,95	13,26	p-Si	St	5
Palermo-4	Italy	37,91	13,30	p-Si	2xvh	2.4
Sevilla-1	Spain	37,63	-5,13	m-Si	2xhv	1.5
Sevilla-2	Spain	36,97	-6,03	p-Si	2xvh	3.7
Sevilla-3	Spain	37,39	-5,95	m-Si	St	1.8
Toledo-1	Spain	39,29	-3,46	m-Si	2xvh	3.5
Toledo-2	Spain	39,69	-3,00	p-Si	2xhv	2
Valladolid-1	Spain	41,65	-4,82	p-Si	2xvh	9.5
Valladolid-2	Spain	42,09	-5,22	p-Si	2xvh	0.1
Zamora	Spain	41,46	-5,82	CdTe	St	10

Table 1. Main characteristics of the 39 PV plants considered in this thesis. For each of them, location, country, coordinates, type of structure and power are specified.

Figure 5. Geographic distribution of the Spanish PV plants considered in this thesis. Squares represent static configuration installations; triangles, one-axis tracking configuration, diamonds, double-axis tracking configuration with horizontal primary axis; and circles, double-axis tracking configuration with vertical primary axis. The size of the plant is proportional to the symbol area.

2 Quality control in PV plants

The main objective of a quality control process is to ensure that a PV plant performs accordingly to a set of previously defined criteria. The installation is generally evaluated in terms of its corresponding yearly energy yield or of some performance indexes. At the beginning of the project, an initial estimation set the production expectation that should be fulfilled along the installation lifetime. Then, the quality control process determines how much the real energy production capability will match this expectation. Quality control procedures are usually accomplished: as a part of the commissioning tests, in relation with a buying and selling of the PV plant or due to a suspicion of underperformance. The conclusions of it should derive not only in a better knowing of the installation itself, but also in the allocation of the responsibilities for any possible underperformance, among the different involved actors.

As an independent laboratory, the IES-UPM has been involved in the quality assurance process of tens of PV plants. Most of its experience was acquired in the frame of the technical “due-diligence” process associated to the project financing. This scheme was the prevailing option during the Spanish PV boom, between 2008 and 2009, where most of the here-concerned installations were built up.

Back then, large PV plants were a novelty and there were not a widely accepted technical standard for controlling them. In this absence, a general energy standard was adopted: to combine a power test with a performance test during the initial commissioning; and to rely on an energy/resource ratio, for operation guaranties. Power checking was restricted to laboratory testing of samples of PV modules before their installation; performance checking was usually controlled by means of the so called Performance Ratio (*PR*), a relation, during a certain period, between the final yield of the installation, Y_F , and a reference yield, Y_R , obtained from the effective in-plane irradiation. More in detail, this index is defined in IEC-61724 (IEC, 1998) as:

$$PR_t = \frac{Y_F}{Y_R} = \frac{E_{AC,t} \times G^*}{G_t^{ef} \times P_{NOM}^*}$$

Equation 1. Performance Ratio for a period t .

where $*$ stands for Standard Test Conditions (STC), $E_{AC,t}$ is the energy delivered to the grid during the period t , P_{NOM}^* is the nominal power of the PV generator, understood as the sum of the datasheet STC power of the modules, and G_t^{ef} is the effective in-plane irradiation during that period.

The *PR* has the advantage of being simple: it can be directly calculated without any kind of modelling, just from the data coming from the energy meters, the PV manufacturer datasheet and an irradiance sensor. It can be adequate for qualifying technical quality when considering yearly periods: for a given PV plant and site, it tends to be constant along the years, as much as the climatic conditions tend to repeat. This way, contractual management of the *PR* only requires an agreement on the guaranteed value (derived from the initial yield simulation exercise and a safety margin agreed among the parties involved in the project), on the solar radiation measuring device (further discussed on section 2.5)

and on the long-term degradation effects. Nevertheless, it has some important disadvantages, among which, to not differentiate between avoidable and unavoidable losses. The first ones come from technical imperfections deriving on real performance below the nominal characteristics announced by the engineering procurement and construction companies (EPCC) or by the equipment manufacturers (underrating, mismatching, low efficiency, etc.), while the second ones are intrinsic to the performance (thermal and irradiance efficiency losses) or to the design (shades and inverter saturation) of the installation. What it is important to understand is that only avoidable losses are really related to the technical quality of the PV plant and, therefore, that the *PR* is not an advisable index for quality control. More inconveniences have also arisen in other phases of the quality control processes carried out in the pioneering large PV plants: for example, the originally planned power test, consisting on the testing of PV modules samples in laboratories before their in-field installation did not avoid the further appearance of undesirable degradation phenomena, induced by light, polarization, micro-cracks... At the lights of this experience, the establishment of an accurate, robust and clear quality control procedure is required.

In this chapter, we explain the main characteristics and steps of our proposal for the quality control of PV plants. Then we expound on two key points: the operating conditions measurement with reference modules and the uncertainty evolution during the process. Finally, we present the quality control results of the ensemble of PV plants considered in this work.

2.1 Quality control procedure

PV project design requires estimating, both, profitability and risks. Profitability is addressed by calculating the most probable value of the yearly energy production, which is a key parameter for the baseline economic scenario. This initial estimation is typically the direct result of a forecast simulation exercise relying on:

- A local climate scenario coming from an available solar radiation database.
- A PV plant characteristics set, described by the technical information provided by the equipment manufacturers (PV module, inverter and transformer datasheets).
- An energy losses scenario made up by the conjunction of all the unavoidable losses.

Risks derive from the fact that such an exercise relies on a set of suppositions that will not necessarily be matched by later realities. Differences between initial suppositions and further realities are denoted as uncertainties and are obviously unknown at the beginning of the project. In practice, the information used in the energy production simulation is affected by uncertainty coming from several sources: low spatial resolution in the satellite data could derive in solar radiation differences for a specific site, future radiation could evolve in a different way than what expected according to past records, real equipment efficiency could differ from manufacturer statements, ageing could affect more or less than what predicted... In order to address this uncertainty, some specific tests are accomplished along the construction of the PV plant:

- Equipment production surveillance directly at the factories
- On-site solar radiation measurements
- Testing of PV module samples at independent laboratories
- On-site efficiency measurements and characterization
- Performance evolution surveillance
- Thermographic revisions

In this context, a quality control process can be understood as a progressive uncertainty reduction path: each particular step adds information related to a concrete issue that has an impact on the yield estimation, obviously reducing the associated risk. Some of these steps, as the equipment at the factories, the laboratory testing or the on-site characterization, have been already analysed in the literature and are the main subjects of previous works [REF]. In the following sections we will make a brief overview on them and then focus on those steps related to the operation of the PV plants. As this quality control process is oriented to be applied directly in commercial frameworks, it is worth remembering the importance of distinguishing between avoidable and unavoidable losses and to clearly preserve the responsibility chain.

2.2 Energy yield forecasting

The energy production estimation represents the first step of a quality control process. Once defined the location, the technical characteristics of the PV plant and the allowable losses scenario, the estimation is obtained from a simulation exercise based on a performance model that describes the relation between the ambient conditions (basically solar radiation and ambient temperature) and the PV plant response (delivered power). Such an exercise is usually performed by means of commercially available software packages (www.pvresources.com) and includes three different steps:

- a) *Estimating meteorological conditions*, that is, broadband horizontal irradiance and ambient temperature. Current solar radiation databases provide broadband horizontal irradiation data based on satellite observations obtained during a minimum period of 10 years. Each location is covered by a certain pixel of the satellite's picture. Solar radiation is then derived from the picture colour intensity at different wavelengths by means of different mathematical models. Those models are adjusted to minimize deviations with respect to on-ground measurements at some reference meteorological stations. Ambient temperature is obtained directly from the records of on-ground meteorological stations using interpolation procedures to derive from them the data corresponding to any other location.
- b) *Estimating operating conditions*, understood as the effective in-plane irradiance and the PV module operating temperature. The calculation of the effective in-plane irradiance from the broadband horizontal one is done using several mathematical models and entails, at least, three different steps: the decomposition of the broadband horizontal irradiation into its direct and diffuse components; the transposition of each of this components to the tilted plane, in which it is of particular importance the angular distribution of the diffuse irradiation in the sky;

and the angular and spectral responses of the PV modules. Again, these models are adjusted to minimize errors according to the measurements performed at some locations and at some particular orientations (mainly at research institutions and at tilt angles equal to latitude). Estimating the operating cell temperature from the ambient temperature is also achieved following mathematical models. Both processes and their modelling possibilities are subjected to a deeper study in chapter 5.

- c) *Estimating the electric response of the PV system.* The electric response of a PV plant to the operating conditions is calculated assuming that all the components are free from anomalies and that their performance matches the datasheet specifications.

Some of the most widespread yield forecasting software packages describe the PV module behaviour by means of the so-called five parameters one diode model equation. Required input data for this model (series and shunt resistance, photocurrent, saturation current and diode quality factor) are not found at the PV manufacturer datasheets. Instead, they are derived from certain software authors assumptions obtained from I - V curves measured on particular specimens at independent testing organizations. The use of this model entails a risk of breaking-off the responsibility chain when founding a discrepancy between measured and declared values. Other software possibilities overcome this problem turning to PV performance models that rely only on datasheet information. Equation 2 is particularly suitable in this case:

$$\eta_{PVmod}(G^{ef}, T_C) = \eta_{PVmod}^* \times [1 + \gamma(T_C - T_C^*)] \times \left(a + b \frac{G^{ef}}{G^*} + c \ln \frac{G^{ef}}{G^*} \right)$$

Equation 2. PV module efficiency, as a function of irradiance and temperature.

where η_{PVmod} is the PV module efficiency and * stands for STC. This model describes thermal losses by means of the coefficient of power variation with temperature, γ , which is always found at manufacturer datasheets. Moreover, the a , b and c parameters describing the efficiency dependence on irradiance are obtained from power values corresponding to different irradiance values, which must also be found at datasheets, providing they comply with EN-50380 (according to this norm, in addition to the STC values, the power at $G = 200 \text{ W/m}^2$ and at some other intermediate irradiance must be provided) (UNE, 2003).

Then, the inverter efficiency is usually modelled as:

$$\eta_{INV}(P_{DC}) = P_{INV} \times \frac{-(1 + k_{i1}) + \sqrt{(1 + k_{i1})^2 - 4k_{i2} \left(k_{i0} - \frac{P_{DC}}{P_{INV}} \right)}}{2k_{i2}P_{DC}}$$

Equation 3. Inverter efficiency, as a function of the load factor.

where η_{INV} is the inverter efficiency, P_{DC} is the DC power at the inverter entry, P_{INV} is the nominal power of the inverter and k_{i0} , k_{i1} and k_{i2} are three dimensionless parameters that can be physically associated to the vacuum, linear (commutation losses due to semiconductor voltage drops) and quadratic (Joule

effect losses in the resistive elements) losses, respectively. The three of them can be derived from the efficiency curve included at the inverter datasheet. In an analogous way, the transformer efficiency is modelled according to:

$$\eta_{TRA}(P_{AC}) = P_{TRA} \times \frac{-1 + \sqrt{1 - 4k_{t2} \left(k_{t0} - \frac{P_{AC}}{P_{TRA}} \right)}}{2k_{t2}P_{AC}}$$

Equation 4. Transformer efficiency, as a function of the load factor.

where η_{TRA} is the transformer efficiency, P_{AC} is the AC power at the transformer entry, P_{TRA} is the nominal power of the transformer and k_{t0} and k_{t2} are, respectively, the vacuum and quadratic losses of the transformer, which are also included in the transformer datasheet.

As previously mentioned, some tests are performed along the quality control process in order to progressively reduce the estimation uncertainty. Therefore, it is important to use a calculation model adaptable to the obtained experimental results. This is not easy with current commercial software and is the reason why specialized laboratories often prefer to use their own software to have greater flexibility.

In the case of IES-UPM, we use SISIFO, a free access and open source simulation tool developed on a broad experimental basis. This software incorporates the previously mentioned power response modelling possibilities as well as some others regarding PV structures configuration or radiation treatment, as well as economic scenarios and application options. For the same hypothesis of solar radiation and modelling, SISIFO estimations are very similar to those of commercial software (for example, PVSYST). For example, a recent simulation exercise of yearly production for a 14.8 kW PV system connected to the grid in Genoa (Italy) resulted in 17,858 kWh and 17,735 kWh with SISIFO and PVSYST, respectively. However, the models applied in SISIFO only use parameters defined in the manufacturer's datasheets, allowing maintaining the responsibility chain in the estimation. Moreover, SISIFO is supported by detailed comparison of simulated and monitored results at more than 300 MW of large PV plants. We have used this software for all the energy yield calculations of this work.

2.3 On-site solar radiation measuring campaigns

One of the largest uncertainty sources in yield estimation exercises is the one derived from initial solar radiation data. An obvious procedure for reducing such uncertainty consists in performing a measuring campaign directly at the site and long enough to provide a statistically significant correction for the model at the back of the database. That can be achieved, for example, by comparing model estimations and ground measurements in terms of daily irradiation along a full year. Then, a simple linear fit provides a correction factor, which is finally applied to the database content, thus removing any possible bias in the long-term modelled data. Figure 6 presents an example for the Valladolid-2 PV plant between February 2008 and February 2009. On-ground data come from a meteorological station that belongs to the National Meteorological Institute of Spain. The spread around

the trend is relatively small ($R^2 = 0.96$)⁷. The regression coefficient shows a systematic 7% difference between satellite and on-ground data. Such a difference can be caused by a defective satellite approach that can be corrected after the measuring campaign. In this example, part of the difference could come also from a defective maintenance of the meteorological station, as it was not specifically installed for this purpose and a correct maintenance was not assured. In this sense, it is important to keep the station clean and free from failures during the measuring campaign, in order to avoid from on-ground failures that could affect the results.

Figure 6. Comparison between the values of daily broadband horizontal irradiation for Valladolid, coming from an on-ground meteorological station and from satellite data.

In general, the IES-UPM experience has been to find good correlations in regions with flat or regular orographies. On the contrary, in mountainous or high gradients regions, on-ground and satellite measurements tend to differ.

On the other hand, the broadband horizontal radiation is not the direct input of the PV system but the effective in-plane radiation. It is an appealing possibility for minimizing modelling uncertainty to measure also the latter by means of reference PV modules with the same orientation as the future PV array. This option allows assessing the effect of soiling: for example, by installing a PV module in vertical position and another one in horizontal position, or analysing independently each of the three different substrings of the PV module delimited by a by-pass diode. We will further go into these aspects in section 2.5.

⁷ Some uncertainty is inherent to this comparison, derived from the random character of cloud formation and evolution, as satellites only make five punctual observations along the day. Taking this consideration into account, the obtained spread can be considered as reasonably small.

2.4 Laboratory testing of PV module samples

Testing representative PV module samples at independent laboratories is a common practice for controlling the power delivered by the PV manufacturers. However, even assuming perfect coincidence between the laboratory results and the values declared by the manufacturer, some uncertainty on PV module performance still persists.

On the one hand, c-Si modules, which are the most used in commercial PV plants and represent more than a 97 % of the analysed plants, are somewhat affected by Light Induced Degradation (LID), which consists of a sudden decrease in efficiency after the first few days of outdoor exposure. Manufacturers use to provide positive tolerance for the power rating of the modules and also guarantee that it will remain above 97% of the nominal value after the first year of exposure. Despite this guarantee represents a formal protection against excessive LID and other possible initial failures, it is strongly recommended to test the modules sample not only “as received” but also after their exposure to more than 60 kWh/m² of irradiation, what provides information for estimating real LID rates. On the other hand, PV efficiency varies with irradiance and temperature. Related information is usually provided at manufacturers’ datasheets, in terms of temperature coefficients and efficiency reduction from STC to 200 W/m². However, experience shows this information is sometimes of doubtful representativeness. Therefore, it is also recommended testing the irradiance and temperature performance of the modules sample, what allows detecting possible performance irregularities before PV modules reach the field. At this point, the energy production estimation exercise can be refreshed with this new data inputs, and warnings can be issued in case of significant differences (above 2%) with initial results.

Along other lines, it is worth considering testing also PV modules propensity to the so-called Potential Induced Degradation, PID. This is a medium-term degradation phenomenon sometimes observed after a few months of exposure. PID is still not considered at the current version of IEC-61215 qualification standard (IEC, 2006). Meanwhile, propensity for PID can be quickly tested (it takes about a week) and preventive measures, like PV array grounding, can be adopted in case of positive results.

Finally, it is worth taking advantage of laboratory testing to prepare reference PV modules for further use as operation conditions sensors at the PV plant, as we will see in detail in the following section.

2.5 Measuring conditions in the field

2.5.1 Ambient conditions

Measuring weather conditions is a common practice in many fields of science and engineering, so the concerned technology is nowadays sufficiently standard. In fact, the installation of meteorological stations, equipped with pyranometers, thermometers and anemometers, is a widespread habit for irrigation control, weather forecasting, air traffic management, environmental preservation and also power generation. Another widely known source of meteorological data are satellites, from whose observations can be derived the solar radiation for a certain location. The reliability of these of data has improved in the last years and they can sometimes be provided with a special resolution

as low as $1 \times 1 \text{ km}^2$. However, it is still advisable to cross-check their results with on-ground measurements coming from meteorological stations, as we have mentioned in section 2.3.

Recurring to external data sources, whatever they come from satellite or on-ground observations, is usually the case for small PV installations, which cannot afford the economic effort of including own sensors. In these cases, radiation data is usually applied to production checking in monthly terms, as higher frequency analyses are very conditioned by the increasing uncertainty related to the determination of the incident irradiation. If the PV system is large enough, as it is the case of PV plants, it is common to have own meteorological stations, what allows verifying the in-field conditions or applying safety considerations: for example, wind speed measurement allows protecting the trackers against dangerous wind gusts. As the common meteorological stations, those installed in PV plants include the measure of the broadband horizontal irradiation, the ambient temperature and the wind speed.

Thermoelectric pyranometers are the most common and advisable option for measuring broadband horizontal radiation. They have a flat spectral and angular response due to their black sensor and their hemispherical dome, respectively. The most widespread devices are those of Class-II, according to the ISO-9060 norm, which present a good performance in the $0.3\text{-}2.8 \text{ }\mu\text{m}$ wavelength range and for incident angles below 75°C . When providing a reasonable calibration frequency (biannually, for example), they allow measuring horizontal radiation with a $\pm 3\%$ uncertainty.

Class II thermoelectric pyranometers are also the device used by meteorological services, and from them come the bulk of measurements used in the current solar radiation databases (H-World, PVGIS, Meteonorm, NASA...), including those who rely on satellite observations, since their calibration is verified using the on-ground pyranometer measurements. The reference radiation for designing any PV project is precisely the one coming from pyranometers; hence the desirability of using them for horizontal radiation measurement.

Pyranometers outperform other devices (solar cells or modules) for another reason: dust and dirtiness accumulation are strongly dependent on the slope of the surfaces, being prone to more affection in the horizontal ones. This makes necessary a frequently cleaning for those sensors with flat cover, as solar cells and modules (otherwise, measurements will end up being much lower than the real radiation). The hemispherical shape of pyranometers allows self-cleaning, what reduces uncertainty and increases the measure representativeness.

Month	Mean of daily horizontal irradiation, $G_{d,m}(0)$ (Wh/m^2)				Comparison (%)		
	PV plant	External station	SoDa	PVGIS	SIAR vs PV plant	SoDa vs PV plant	PVGIS vs PV plant
January	1,465	1,565	1,800	1,731	-6.4	-18.6	18.1
February	3,367	3,363	3,281	2,578	0.1	2.6	-23.4
March	5,102	5,106	5,086	4,156	-0.1	0.3	-18.5
April	5,750	5,966	6,158	4,892	-3.6	-6.6	-14.9
May	7,223	7,605	7,414	6,041	-5.0	-2.6	-16.4
June	7,191	7,806	7,466	6,908	-7.9	-3.7	-3.9

July	7,895	8,597	7,774	7,036	-8.2	1.6	-10.9
August	6,851	6,886	6,530	6,230	-0.5	4.9	-9.1
September	5,258	5,231	5,105	4,751	0.5	3.0	-9.6
October	3,549	3,523	3,454	3,195	0.7	2.8	-10.0
November	2,022	1,955	2,047	1,926	3.5	-1.2	-4.8
December	1,471	1,359	1,608	1,321	8.3	-8.5	-10.2
Year	4,770	4,923	4,819	4,240	3.2	1.0	-11.1

Table 2 presents the monthly means of daily broadband horizontal irradiation, registered at the Valladolid-1 PV plant along 2009. It presents also the corresponding values obtained at a nearby meteorological station⁸ as well as those given by SoDa. The difference between the two meteorological stations is a 3.2% at yearly level, although some months it reaches an 8.3%. The comparison with satellite data shows a 1.0% yearly difference that, in some months reaches the 18.6%. The yearly discrepancies are of the same order of magnitude as the measure uncertainty, so that the PV plant measurements are validated. The higher differences arisen at monthly levels reinforce the convenience of using external data as a contrast.

Month	Mean of daily horizontal irradiation, $G_{d,m}$ (0) (Wh/m ²)				Comparison (%)		
	PV plant	External station	SoDa	PVGIS	SIAR vs PV plant	SoDa vs PV plant	PVGIS vs PV plant
January	1,465	1,565	1,800	1,731	-6.4	-18.6	18.1
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May	7,223	7,605	7,414	6,041	-5.0	-2.6	-16.4
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July	7,895	8,597	7,774	7,036	-8.2	1.6	-10.9
August	6,851	6,886	6,530	6,230	-0.5	4.9	-9.1
September	5,258	5,231	5,105	4,751	0.5	3.0	-9.6
October	3,549	3,523	3,454	3,195	0.7	2.8	-10.0
November	2,022	1,955	2,047	1,926	3.5	-1.2	-4.8
December	1,471	1,359	1,608	1,321	8.3	-8.5	-10.2
Year	4,770	4,923	4,819	4,240	3.2	1.0	-11.1

Table 2. Monthly mean of daily horizontal irradiation measured at the Valladolid-1 PV plant, at a nearby meteorological station; given by SoDa and PVGIS; and comparisons between them.

In another vein, the irradiation measured in 2009 was clearly above (11.1%) the mean of the last 20 years, given by PVGIS. This phenomenon seems to be common in Europe and has been revealed in many observations. The probable cause is the decrease in the aerosol concentration in the atmosphere, as a result of the application of laws for the reduction of acid rain generating gases emission (SO_x y NO_x). As a consequence, some of the available

⁸ This meteorological station belongs to the Spanish Agroclimatic Information System for Irrigation and is supposed to be maintained correctly. It is located 9 km away from the PV plant and at an altitude 100 meters lower, what can lead to irradiation differences with the meteorological station located in the PV plant due to the frequent fogs affecting the area.

satellite databases have created a second radiation reference based only in the last 10 years, which provide more accurate results.

Regarding temperature and wind speed measurement, conventional instrumentation in both cases provide enough accuracy for photovoltaic purposes, typically better than 0.3 °C in temperature and 0.2 m/s in wind speed.

However, the measure of the ambient conditions is not sufficient for making an acceptable evaluation of the performance of a PV plant. Back in 2008, the horizontal irradiation was sometimes considered as the reference for calculating the *PR*. Nevertheless, this procedure was soon disregarded due to the non-linearity relation between horizontal and in-plane irradiation, which is the proper reference for *PR* calculation. In medium and large installations, it is appealing to measure, in addition, the operating conditions.

2.5.2 Operating conditions

In recent years, the development of the PV technology has brought along the availability of dedicated devices for measuring the operating conditions: effective in-plane irradiance and operating temperature, by means of reference PV cells and modules. Moreover, the spectacular development of data acquisition systems has promoted the installation and coexistence of several measuring instruments in PV plants. The negative side of this redundancy is that different devices can lead to different results, which adds a considerable uncertainty. Obviously, this affects to the calculation of the different performance indexes and, therefore, to the PV system qualification, which varies depending on the selected irradiation source. In order to assure a correct measurement, it is worth taking some precautions: on the one hand, not only the measuring devices but also the associated electronics must be properly calibrated. For example, the sometimes used voltage-current (4-20 mA) converters must guarantee a proper performance for the wide temperature and humidity ranges reached in the field. On the other hand, dust and dirtiness deposition of must be watched, especially in arid climates or when there are nearby sources of dust (crops, unpaved roads, quarries...).

As we will see in the next sections, the most advisable devices for measuring operating conditions are reference modules. They are usually modules of the same manufacturer, type and batches as those constituting the PV generator, but previously stabilized (exposed to more than 60 kWh/m²) and carefully calibrated at an independent laboratory. In practical terms, it is useful to install two modules: one for measuring effective in-plane irradiance and another one to measure operating cell temperature. Figure 7 shows an example of the installation of reference modules in two PV plants (Cuenca-1 and Palermo-4) with static structure and two-axis tracking, respectively.

Figure 7. Reference modules installed (a) in a static structure at the Cuenca-1 PV plant and (b) in a two-axis tracker in the Palermo-4 PV plants. One of the modules measures the effective in-plane irradiance through the short-circuit current, while the other measures the operating cell temperature through the open-circuit voltage.

In some occasions, mainly due to structural reasons in trackers, it is not possible to install two reference modules. This difficulty can be overcome using the intermediate electrical contacts of the PV module to divide it into two sections, short-circuiting one of them to measure irradiance and leaving the other one in open-circuit to measure cell temperature. Figure 8 shows two examples of operated PV modules at the Cádiz-1 and Granada-1 PV plants, both of them with double-axis tracking systems, with vertical and horizontal primary axis, respectively.

Figure 8. Reference module operated and divided in two sections to measure simultaneously the effective in-plane irradiance and the cell operating cell temperature at a two double-axis tracking PV plants: (a) Cádiz-2 vertical primary axis system and (b) Granada-1 horizontal primary axis system.

2.5.2.1 Effective in-plane irradiance

Calibrated solar cells and reference modules are both constituted by solar cells of the same technology as those forming the generator. Therefore, they offer the advantage of having the same thermal, spectral and angular response as the PV generators, leading to more accurate and repeatable results. Both devices are forced to work near in the short-circuit condition, where the current is almost linear with the incident irradiance. In practice, this is achieved by connecting the solar device to a very small resistance, R_{shunt} , so that the operating voltage is low enough to make the device work in a region, where current is

almost independent from voltage. In some cases, solar cells are encapsulated surrounded by other solar cells, to assure the same reflection behaviour as PV modules. Both in calibrated solar cells and reference modules, the effective in-plane irradiance is calculated as:

$$G^{ef} = G^* \times \frac{I_{SC}}{I_{SC}^*} \times \frac{1}{1 + \alpha(T_c - T_c^*)}$$

Equation 5. Effective in-plane irradiance, calculated from the short-circuit current of a PV module, and having into account the temperature effect.

where I_{SC} is the short-circuit current, * stands for STC and α is the temperature variation coefficient of the short-circuit current. Many of the commercial solar cells also include the measurement of the operating temperature, usually by means of thermocouples. This temperature measurement is disregarded because of its low representativeness, as heat dissipation mechanisms of solar cells are different from those of PV modules (e.g., the perimeter/area ratio is higher in the cells, what makes them to be cooler than modules).

The main advantage of PV modules with respect to solar cells is its robustness against dirtiness, which generally consists of two components: a fine homogenous cover and some located elements. Homogenous dust covers derive in a decrease of the output power of PV modules proportional to the effective in-plane irradiance reduction. Located elements (as sand accumulation, bird droppings, mud...) are usually not homogeneously distributed, and, except in cases of extreme dirt, do not have a very significant effect on the generated power. The short-circuit current of a PV module is only affected by the first of these components (located dirt create steps in the I-V curve, but do not affect short-circuit current). Besides, the distribution of dust in the reference module should be like in any other module. However, neither of these two things is assured for a reference cell: its short-circuit current is directly affected by any dirt, localized or not, and its size, much smaller than that of PV modules, can make its dust distribution different from that of PV modules. Moreover, the response of a PV module is more stable and repeatable than that of other sensors (Caamaño-Martín, 2002).

Finally, reference PV modules are manufactured, as the rest of PV modules, following strict quality standards that guarantee their long term durability in the field, which is not the case for solar cells. As an example of early degradation of reference cells, Figure 9 shows the relation between the irradiances measured by a reference module and two reference cells, in 15-minutes mean values, at the Moquegua PV plant between the 2nd and the 3rd of June, 2015. This test was carried out during the quality control procedure of the installation and consisted of verifying the calibration of two reference cells installed in the PV plant at the beginning of its operation, two years early. For this test, a calibrated PV module and a secondary reference cell of the IES-UPM were used as references. The latter had recently been calibrated at a European round robin of solar radiation sensors. Table 3 summarizes the accumulated irradiation measured at each of the devices: the difference between the secondary cell and the PV module was as low as 0.6% while the cells installed in the field registered 4.6% and 5.1% less irradiation than the secondary cell, respectively. This result pointed out a calibration loss in the reference cells after two years of in the field.

Figure 9. Reference module versus reference cells. Each point coming from the analysed cells represents the 15-minutes mean irradiance during the afternoon of the 2nd of May, 2015. For the reference module and the secondary reference cell, data is recorded each minute during the same period.

	Measured irradiation (kWh/m ²)	Difference (%)
IES-UPM secondary cell	2,065	-
Reference module	2,052	0.6
Cell 1	1,961	5.1
Cell 2	1,970	4.6

Table 3. Irradiation measured by the reference cells from the 29th of May to the 6th of June and comparison with the reference module and the secondary reference cell.

Analogous recalibration experiments were accomplished in 10 PV plants in Spain equipped with the corresponding reference PV modules, after 5 years of in-field exposure.

PV plant	Calibration difference (%)	
	Irradiation	Temperature
Badajoz-1	0.19	0.09
Cáceres-1	-0.19	0.04
Cáceres-2	0.19	0.12
Cádiz-1	0.00	0.20
Cádiz-2	0.00	-0.06
Córdoba	0.12	0.02
Huelva-1	-0.17	0.32
Sevilla-2	0.00	0.05
Sevilla-3	-0.92	0.00
Valladolid-1	-1.22	-0.91

Table 4 summarizes the results obtained. The maximum deviation found is 1.2%, below the measurement uncertainty, and in 8 cases the difference is lower than 0.2%, what gives an idea of the stability of PV modules and their calibration.

PV plant	Calibration difference (%)	
	Irradiation	Temperature
Badajoz-1	0.19	0.09
Cáceres-1	-0.19	0.04
Cáceres-2	0.19	0.12
Cádiz-1	0.00	0.20
Cádiz-2	0.00	-0.06
Córdoba	0.12	0.02
Huelva-1	-0.17	0.32
Sevilla-2	0.00	0.05
Sevilla-3	-0.92	0.00
Valladolid-1	-1.22	-0.91

Table 4. Calibration differences found at the reference modules installed at 10 PV plants in Spain, after 5 years of in-field exposure. All the modules were operated to measure irradiance and cell temperature at the same time; the results of both parts are presented.

2.5.2.2 Operating cell temperature

The operating cell temperature of a PV module is obtained from its open-circuit voltage by means of:

$$T_c = \frac{V_{OC} - V_{OC}^* + \beta \times N_s \times T_c^*}{N_s \times \left(\beta + \frac{m \times k}{q} \times \ln \frac{G^{ef}}{G^*} \right)} - \frac{NOCT - 20}{800} \times G^{ef} \times \eta_{PVmod}(G^{ef}, T_c)$$

Equation 6. Operating cell temperature, calculated from the open-circuit voltage of a PV module, including the correction for not being in operation.

where β is the temperature variation coefficient of the open-circuit voltage, N_s is the number of cell in series in the PV module, m is the diode linearity factor, k is the Boltzmann constant q the electron charge and $NOCT$ the nominal operating cell temperature, given by the manufacturer. This equation includes the secondary effect of irradiance in the PV module efficiency and the cooling effect derived from the fact that PV modules are in operation and, therefore, only have to dissipate as heat the difference between the incident irradiance and the delivered power. This is an implicit equation, but results are almost invariable after two iterations.

Another widespread possibility for measuring the operating cell temperature is using thermocouples attached to the rear part of the PV module. Nevertheless, it is strongly preferable to use reference modules, due to the following reasons:

- The V_{OC} value can be interpreted as an equivalent temperature of the whole module, thus representing the average temperature of the ensemble of cells. Even in normal operation and depending on the module size, it is common to find

temperature differences between cells ranging from 4°C to 10°C⁹. Then, it is understood that an equivalent temperature of the ensemble of cells is more representative than any measure taken only at a single point (which is the case of thermocouples).

- Along the same lines, thermocouples measure the temperature of the rear surface of the PV module, which is not necessarily the same as the internal working temperature of the cells. The application of correction coefficients, based on specific experimental cases, entails some additional uncertainty. As V_{oc} is directly shaped by the effective operating temperature, it avoids any of this uncertainty.
- Thermocouples measurement stability in the field is doubtful. It is very common to find detached specimen after some months of installation. Even if they remain attached, the thermal excursions to which PV modules are subject to, can provoke contact deterioration in the module-thermocouple interface, which translates in a defective registered temperature.
- Previous studies have shown that temperature measurement dispersion is much lower when using reference modules than when using thermocouples (Caamaño-Martín, 2002), (Alonso, 2000).
- The signal amplitude when using reference PV modules is in the range of volts (from 10 V if the module has been operated and between 30-40 V otherwise) while the signal amplitude of thermocouples is in the range of millivolts. Therefore, recording is sturdier when using the open-circuit voltage, as thermocouple value can be distorted by the noise associated to the signal transmission.

As an example of the better performance of PV modules for measuring T_c , Figure 10 presents the relation between the operating temperatures measured by a reference PV module and three thermocouples at the Moquegua PV plant, between the 29th of May and the 6th of June, 2015. It includes also the T_c measurement from a second reference module. Table 5 presents the corresponding results in terms of daily equivalent temperature, calculated as a weighted mean of the operating cell temperature by the effective in-plane irradiance.

⁹ According to the IES-UPM experience, this temperature difference can be divided into 4 °C due to voltage variations and 6 °C due to dissipation differences between cells, and is not related to any defective performance, as we will see in section 3.2.

Figure 10. Comparison between the operating cell temperature measured by a reference module and that obtained from three thermocouples (red, blue and green dots) at the Moquegua PV plant, between the 29th of May and the 6th of June, 2015. The figure includes also the comparison with a second reference PV module (grey dots).

Measure	Ref. module 1	Ref. module 2	Therm. 1	Therm. 2	Therm. 3
Eq. temperature (°C)	38.7	38.8	35.3	36.8	42.1
Difference (%)	-	-0.3	-8.7	-4.4	8.7

Table 5. Daily equivalent temperature measured by two reference modules and three thermocouples. High coincidence can be observed between the modules, while thermocouples results are much more dispersed.

High coincidence is observed between the reference PV modules (only a 0.3% difference between them) while significant differences are found with respect to the thermocouples (up to 8.7% and not lower than 4%), although they were perfectly attached to the module.

2.6 On-site characterization of PV plants

A major milestone in a quality control process is the on-site evaluation of the PV plant, usually performed during the commissioning tests. It represents a great chance for assuring that the PV system, already in operation, fulfils its specifications and is free from threats that could affect its lifetime. Initially, this step was composed of some power and performance tests, mainly based on the *PR* analyses of the PV plant during a week. One of the main issues to tackle when accomplishing such a process is to make a global evaluation on the basis of an analysis restricted to a short and particular period. In order to get a reliable result, both the application period and the selected evaluation index should be as representative as possible of the climatic characteristics of the whole year and the mean behaviour of the plant, respectively. In order to guarantee the representativeness of the period, it is usual to turn to the frequency distributions of the effective in-plane irradiance

and the operating temperature and compare them with those obtained for the whole year, looking for the most similar periods.

Regarding the evaluation indexes, we have already seen the inconvenience of using the PR due to the impossibility of distinguishing between avoidable and unavoidable losses. Another disadvantage of this index is its large variability for short periods of time: as the PR is not corrected in temperature, it is far from being constant along the year. Figure 11 shows an example of the weekly PR evolution along the year 2010 in a PV generator of the Cuenca PV plant. The main values for the whole period are $PR_{\text{mean}} = 84.2\%$, $PR_{\text{max}} = 93.3\%$ and $PR_{\text{min}} = 68.8\%$, what results in more than a $\pm 10\%$ excursion along the year. Even if we restrict the analysed period to a month (red square in the figure) we find a $\pm 7\%$ variation ($PR_{\text{mean}} = 78.0\%$, $PR_{\text{max}} = 83.9\%$ and $PR_{\text{min}} = 70.8\%$). As a consequence of being temperature dependent, the PR results are, in addition, somehow contrary to what our intuition indicates. For example, the PR of an installation with the same quality qualification will be lower if it is located in the southern Spain than if it is located in the northern Germany, despite the former is a place with a significantly higher solar radiation. For all of this, it is not appealing to use the PR as an evaluation index.

Figure 11. Weekly PR of a generation unit of the Cuenca PV plant during 2010. Up to $\pm 10\%$ variability can be observed along the year. Even within a month, a $\pm 7\%$ variation occurs.

A better option consists of eliminating the operating conditions influence in the PR by correcting it to the Standard Test Conditions, reaching the so-called PR_{STC} :

$$PR_{\text{STC}} = \frac{PR}{(1 - \Delta E_{T_c})(1 - \Delta E_{G < G^*})}$$

Equation 7. Performance index corrected to the Standard Test Conditions

where ΔE_{T_C} stands for the thermal losses and $\Delta E_{G < G^*}$ for the efficiency losses due to low irradiance levels. Figure 12 shows the evolution of the PR_{STC} and its comparison with the PR for the Madrid PV generator. The PR_{STC} excursion is restricted to a $\pm 4\%$ along the year and a $\pm 11\%$ within a month, what proves its better representativeness. The outstanding benefit for the rather low added complexity of measuring the cell operating temperature is that the PR_{STC} is neither time nor site dependent, allowing more precise qualification of the technical quality of a PV installation.

Figure 12. Weekly evolution of PR and PR_{STC} , at the Madrid PV installation during 2010. The higher stability of the PR_{STC} is clearly observable.

However, the PR_{STC} still lumps together the performance of all the elements of a generation unit: PV array, inverter and transformer. So, it is appealing not to evaluate a PV installation quality only by means of a PR_{STC} value during a week, but to take advantage of the commissioning tests to make more in-depth characterization of the PV plant performance, what will provide the grounds for making detailed energy losses analyses and careful operation surveillance. In this sense, it is useful to consider the characterization of PV generators, the visual and infrared analysis of the PV plant and the STC power measurements of individual modules. All of these tests have been widely described in previous works (Martínez, 2012) (Martínez-Moreno, 2012). In the following sections, some particular examples of the application of this tests to the PV installations considered in this thesis will be shown.

2.6.1 In-depth characterization of PV generators

In-depth characterization of PV generators can be done at the price of measuring not only irradiance, as for the simple PR , and operating temperature, as for the PR_{STC} , but also measuring the DC and AC power responses of the system, P_{DC} and P_{AC} , at the entrance and at the exit of the inverter, respectively. That must be done with highly accurate power analysers and paying particular attention to DC current measurements. Then, the analysis

of (G, T_C, P_{DC}) values allows deducing the STC power of the PV generator, and the analysis of (P_{DC}, P_{AC}) values leads to know the efficiency curve of the inverter as a function of the load factor. The corresponding benefit is, therefore, to clearly distinguish between the performance characteristics of the PV system components and also to observe the PV system behaviour both in normal and abnormal operation. In the first case, for example, it can be paid attention to the efficiency dependence on temperature and irradiance or to the maximum power point tracking; while, in the second, shadings, inverter saturation, partial clouding,..., can be detected and quantified. In this sense, it is advisable to characterize PV generators using wattmeters instead of I - V curve measurements, as the former allows making a continuous evaluation through different working conditions while the latter only reflects the behaviour at an instantaneous moment. Anyway, as we will see below, both tools are complementary, and their combination allows obtaining a more in-depth analysis. Figure 13 shows an example of the connection of the power analyser at a 125 kW inverter of the Málaga PV plant. It is worth observing the clamps for measuring the AC current and the calibrated shunt resistor for measuring the DC current.

Figure 13. Details of the power analyser connection at a 125 kW inverter of the Málaga-1 PV plant. (a) Wattmeter and computer used to store the collected data. (b) Connections at the AC side: crocodile clips are used for the measure of the AC voltage and current clamps for the AC current. (c) Connections at the DC side: again, crocodile clips for the DC voltage measure but, in this case, a high accuracy shunt resistor (300A/150mV) is used for the measure of the DC current.

Figure 14(a) shows the P_{DC} versus G values, recorded with a 30 seconds sampling period, measured at the entrance of a 630 kW inverter of the Moquegua PV plant, once P_{DC} values have been corrected to 25 °C using the following equation:

$$P_{DC}(25) = \frac{P_{DC}}{1 + \gamma(T_C - T_C^*)}$$

Equation 8. DC power measured at the entrance of the inverter, corrected to 25 °C.

being γ the coefficient of PV modules power variation with temperature. Some different situations can be observed. On the one hand, the scattered points above the trend (region 1) correspond to those moments with clouds over the irradiance sensor that do not affect in the same way the whole PV generator. This situation is usual in large PV plants, where PV generators can take up more than one hectare. The opposite occurs for points in region 2, where clouds affect the generator to a greater extent than the irradiance sensor. Points below and above the trending line for irradiances below 650 W/m² (region 3) are mainly a consequence of a misaligning in the position of the trackers of the generator when applying backtracking strategies (the movement of the trackers is arranged in sequence in order to avoid power consumption peaks, leading to different tracking positions). The real STC power of the PV array is obtained by disregarding all the anomalous situations and by restricting the irradiance range to $G > 800$ W/m², as it is presented in Figure 14(b).

Figure 14. DC power versus irradiance observed at the entrance of a 630 kW inverter of the Moquegua PV plant, (a) once P_{dc} values have been corrected to 25 °C. Some anomalous situations can be observed. (b) Values corresponding to normal operation and stable irradiances larger than 800 W/m².

Figure 15 shows an analogous example, this time obtained at a 125 kW inverter of the Toledo-2 PV plant. An anomalous performance can be observed in region 1. It is caused by a voltage restriction in the inverter that leads to a deviation from the maximum power point.

Figure 15. DC power versus irradiance observed at the entrance of a 125 kW inverter of the Toledo-2 PV plant, once P_{DC} values have been corrected to 25 °C. The inverter saturation can be observed at high irradiance levels (region 1).

Moreover, Figure 16 shows the relation between the inverter efficiency (P_{AC}/P_{DC}) (left axis) and the load factor (P_{AC}/P_{INV}) as well as between the DC voltage (right axis) and the load factor, obtained at the 125 kW inverter associated to the PV generator presented in Figure 15. Triangles represent the efficiency values derived from the manufacturer's datasheet. It can be observed the existence of a lower limit in the voltage excursion (regions 1 and 2) that makes the inverter losing the maximum power point tracking, causing an efficiency loss in the system. The hysteresis observed in the DC voltage curve is caused by the different operating temperature of the PV modules in the morning and in the afternoon, given a common irradiance level.

Figure 16. Inverter efficiency versus load factor observed a 630 kW inverter of the Moquegua PV plant (blue dots). In grey, it is shown the DC voltage evolution in function of load factor. Yellow triangles represent the theoretical efficiency, as given by the manufacturer. The voltage limitation can be clearly observed in regions 1 and 2.

An analogous case is presented in Figure 17 at a 100 kW inverter of the Málaga PV plant. Here, low inverter efficiency can be observed for load factors below 50%. Possibly, this discrepancy with the declared values is related to the inverter internal consumption, mainly due to refrigerating fans.

Figure 17. Inverter efficiency versus load factor observed at a 100 kW inverter of the Málaga PV plant (blue dots). In grey, it is shown the DC voltage evolution in function of the load factor. Yellow triangles represent the theoretical efficiency, as given by the manufacturer. Low efficiency is observed in region 1 for low load factors, due to internal refrigerating fans consumption.

2.6.2 Visual and infrared inspection

In addition to the evaluation of the electric performance of a PV plant, there are some issues that can affect the reliability of the installation, cause an operation availability reduction, or suppose a threat for the durability of some of the PV components. In particular, it is appealing to accomplish a visual inspection of the installation, paying attention to the appearance of rusting in the structures; the air and water tightness of the connection boxes; the disposal of wiring to avoid damages or knots; the appearance of yellowing, snail-tracks, burn metallization, faulty terminals, bubbles or any other observable defect at the PV modules; and, in general, the state of the grounding cables, the subterranean wiring chests or the foundations. Besides, it is worth attending the affection of dust and the condition of the vegetation, to avoid unnecessary shadowing over the PV modules.

Nevertheless, some other anomalies can go unnoticed after a visual inspection, especially if related to internal problems of the components. Fortunately, PV modules and other electric equipment develop the so-called hot-spots as a general response to this kind of anomalies (micro-cracks, defective soldering, bad contacts...), making them easily detectable through infrared inspections. Further investigation on this issue will be presented in section 3.2.

2.6.3 STC power of individual PV modules

I-V curve measurement of individual specimens is also a suitable tool for assessing the quality of PV modules. It can be made without removing the selected modules from their definitive installation site and, if measuring simultaneously the *I-V* curves of the concerned PV device and of a reference module located close to it, accuracy better than 3% is obtained. As an in-field example, the quality control process performed at the 12 MW Cuenca-1 PV plant is presented, where more than 2,800 individual PV modules were measured. The objective was, on the one hand, to verify the PV module average power delivered by the manufacturer and, on the other hand, to analyse if an in-field classification of the PV modules according to their datasheet values could reduce the current and voltage mismatching losses. Experimental repeatability in the power measures resulted better than 2%.

Figure 18 shows the comparison between the measured power of the modules and the power declared in the flash-list of the manufacturer. Tolerance, established at 3%, is delimited by the two red lines. Mean power is slightly over the nominal value, validating the sample. It is also possible to notice a higher dispersion when measuring in the field, as there are units out of tolerance that were not detected when measuring at the manufacturer's factory. Figure 19 presents the frequency distribution of the difference between measured and declared power.

Figure 18. Measured power versus declared power for 2,817 modules of the Cuenca-1 PV plant. Red lines delimit the $\pm 3\%$ tolerance margin around the nominal power.

Figure 19. Frequency distribution of the difference between the in-field measured power and the declared power for 2,817 PV modules of the Cuenca-1 PV plant.

The data distribution fits a Gaussian, typical of random phenomena, with an average value of 0.43% and a standard deviation $\sigma = 2.18\%$. The mean value indicates the difference between the manufacturer solar simulator and flash used for the characterization of the reference modules used in the in-field measurements and is really small.

Considering the in-field power result as reference, the uncertainty associated to the measure of a single module is $\pm 4.36\%$, assuming a 95% confidence interval. This range is significantly larger than the width of the intervals in which the classification processes pretend to differentiate the modules (usually $\pm 1\%$), so it was derived that any classification made on the basis of flash measurements resulted irrelevant. In fact, to achieve a positive feedback of module classification, in terms of improving the total efficiency of the PV generator, the result of ordering the modules according to flash values (for example, from larger to lower power) should be sensibly similar to the ordering according to in-field results. Figure 20 shows a very different reality. The same result is obtained for other classification indexes as the maximum power point current, I_M^* .

Figure 20. PV modules order from larger to lower power at the Cuenca PV plant: according to in-field measurement versus according to flash results.

2.7 Uncertainty in quality control procedures

The main result of a productivity simulation exercise is the expected yearly production. In project financing, this value is typically denoted as $E_{P_{50}}$, where E stands for yearly energy and P_{50} means that this value is just at the middle of the probability range. In other words, the probability of real energy production exceeding this value equals the probability of being below it. In statistical terms, this is the most probable value.

However, the occurrence of this production is conditioned by the existence of different sources of uncertainty, as we introduced in section 2.1. As these uncertainties are unknown at the beginning of the project, they are treated as random variables, each defined by its corresponding mean and standard deviation values, ε and σ , respectively. Assuming the uncertainty sources are independent each other, the expected yearly energy

production is properly described by means of a Gaussian distribution with a standard deviation, σ_{total} , given by:

$$\sigma_{total} = \sqrt{\sum_{i=1}^N \sigma_i^2}$$

Equation 9. Standard deviation associated to the total uncertainty, calculated as the combination of N statistically independent uncertainty sources, each of them with its corresponding standard deviation.

where i extends to the N identified uncertainty sources. Table 6 summarizes the main sources of uncertainty at the beginning of a PV project.

Uncertainty source	First year	20 years
Database	6%	N.A.
Long term trend	N.A.	2%
Modelling	2% static systems 4% tracking systems	
Dust	1.5%	N.A.
Operating temperature determination	2%	N.A.
Electric power response	2%	N.A.
Initial STC power of the PV modules	2%	N.A.
Ageing	N.A.	2%
Total	7.9 % static systems 8.6 % tracking systems	

Table 6. Main sources of uncertainty that affect the energy estimation of a PV project, at the beginning of it.

Then, probability distributions theory allows quantifying the risk associated to the project, linking expected production and occurrence probability values. For example, the E_{P90} , which is the energy production value having 90% probability of being exceeded by real production is given by:

$$E_{P90} = E_{P50} - 1.28 \times \sigma_{total}$$

Equation 10. Relation between the P_{90} value and the P_{50} value, as a function of the standard deviation.

Along the same lines,

$$E_{P95} = E_{P50} - 2 \times \sigma_{total}$$

Equation 11. Relation between the P_{95} value and the P_{50} value, as a function of the standard deviation.

Figure 21 presents an example of the yearly energy estimation probability function for a static PV plant, which most probable production value is 1,500 kWh/kWp. The E_{P90} (1,348 kWh/kWp) and E_{P95} (1,263 kWh/kWp) values are also plotted in the figure.

Figure 21. Statistical distribution of the yearly energy production estimation of a PV plant. Blue, violet and red lines represent the $E_{P_{50}}$, $E_{P_{90}}$ and $E_{P_{95}}$ values, respectively

These values are especially relevant as are those to which is usually linked the PV project financing. While the $E_{P_{50}}$ represents the expected result, the difference between $E_{P_{50}}$ and $E_{P_{90}}$ can be understood as the risk of the project, which is obviously interesting to minimize. In the presented case, uncertainty derives in differences between $E_{P_{50}}$ and $E_{P_{90}}$ larger than 10%, which, in terms, directly translates to the financial conditions. Hence the importance of reducing uncertainty by implementing quality control processes. In the following parts, this reduction is tracked throughout different phases of the quality control process.

1) Solar radiation estimation

As we have previously stated, satellite models try to adjust their databases according to in-field measurements. Nevertheless, a 6% related uncertainty is expected in this data. After accomplishing an on-site broadband horizontal solar irradiation measuring campaign (section 2.3), this uncertainty is reduced to 2-3%, which mainly corresponds to pyranometer tolerance. This step allows reducing the standard deviation a 2% of total value, or a relative 25%, as presented in Table 7.

Uncertainty source	First year	20 years
Radiation measurement	3%	N.A.
Long term trend	N.A.	2%
Modelling	2% static systems 4% tracking systems	
Dust	1.5%	N.A.
Operating temperature determination	2%	N.A.
Electric power response	2%	N.A.
Initial STC power of the PV modules	2%	N.A.
Ageing	N.A.	2%
Total	5.9% static systems 6.9% tracking systems	

Table 7. Main sources of uncertainty that affect the energy estimation of a PV project, after accomplishing a broadband horizontal solar radiation campaign in the field.

2) Operating conditions estimation

The inclusion of reference PV modules during the on-site measuring campaigns allows removing the modelling and dust uncertainties and reducing the operating temperature determination and the radiation measurement uncertainties, leading to a total standard deviation decrease of 1.3% for static systems and a 2.3% for tracking systems (22% and 33%, respectively, in relative terms). Table 8 updates the uncertainty values.

Uncertainty source	First year	20 years
Radiation measurement	2%	N.A.
Long term trend	N.A.	2%
Operating temperature determination	1%	N.A.
Electric power response	2%	N.A.
Initial STC power of the PV modules	2%	N.A.
Ageing	N.A.	2%
Total	4.6%	

Table 8. Main sources of uncertainty that affect the energy estimation of a PV project, after accomplishing a effective in-plane solar radiation campaign in the field.

3) PV modules power response

As already introduced in section 2.2, PV modules operate in a wide range of (G, T_c) values, and dealing with them requires not only the rated power values but also information related with the efficiency variation with irradiance and temperature.

On the one hand, datasheets content is often not fully coherent. For example, there are two ways of deriving P^* values from measured I - V curves. The one is to extrapolate the full I - V curve to STC in accordance with IEC-60891, using α and β . The other consist of, first, obtaining the maximum power of the measured curve and, second, extrapolating only this value to STC, using γ . Ideally, both results should fully coincide. However, they usually

differ in about 2-3%, and the IES-UPM experience includes differences up to 5%. This can be a consequence of a certain spread in the individual PV module characteristics. In fact, module to module parameter variations has been pointed out as a significant source of uncertainty (Allet, 2011) (Stein, 2013). As a representative example, the flash-list observed dispersion in 126 crystalline silicon PV modules recently received at our laboratory are 3% for P^* (which corresponds to a common market tolerance), 6.4 % for I_{SC}^* , 1.2% for V_{OC}^* , 5.2% for I_M^* and 5.4% for V_M^* (Martínez, 2015).

On the other hand, nowadays standard guarantees are restricted to the P^* value, while the rest of the datasheet content is not particularly intended to support efficiency quality controls. Because of that, guarantees beyond the P^* value must be agreed with the PV manufacturer, prior to the PV modules supply. The IES-UPM experience on the quality control of large PV plants includes several cases of PV manufactures providing guarantees also on γ values. This is important because thermal losses (due to operating temperatures different to T_c^*) use to be particularly relevant at the energy balance of a PV plant.

Both, datasheet limitations and doubtful representativeness of data from particular specimens, represent uncertainty sources for energy yield forecasting. The accomplishment of specific laboratory testing of samples of PV modules prior the PV plant installation (described in section 2.4) further reduces the associated uncertainty a 0.7% (a 15% in relative terms). However, the maintenance of the responsibility chain in this quality control steps requires enlarging the PV manufacturers' commitment to also give guarantees on other than P^* values. This is likely easier when such values are directly obtained from datasheets (for example, the *NOCT* and temperature coefficients) than when they are not extracted from PV manufacturers information (for example, the value of the parallel resistance obtained from a *I-V* curve measured on a particular specimen at an independent organization). Table 9 presents the resulting uncertainty values.

Uncertainty source	First year	20 years
Radiation measurement	2%	N.A.
Long term trend	N.A.	2%
Operating temperature determination	1%	N.A.
Electric power response	1%	N.A.
Initial STC power of the PV modules	2%	N.A.
Ageing	N.A.	1%
Total	3.9%	

Table 9. Main sources of uncertainty that affect the energy estimation of a PV project, after laboratory testing of samples of PV modules.

4) PV system electrical response

Uncertainty can be further reduced by fitting the performance model with data directly measured at the concerned PV array. Regarding PV generators, the difference between the nominal and the real STC value is derived from manufacturing tolerance, initial degradation, characteristic mismatching and voltage drops in the wiring. Regarding inverters, differences between the real and theoretical efficiency is derived from auxiliary

equipment consumption, mainly fans, which is not included in the datasheet efficiency curves and which can represent up to 2% of the total energy produced. Both PV generator response and inverter efficiency are addressed during the on-site characterization, as presented in section 2.6. This allows reducing uncertainty in energy estimation to a final 3.2%, 0.7% lower than in the previous step (an 18% relative reduction), as shown in Table 10.

Uncertainty source	First year	20 years
Radiation measurement	2%	N.A.
Long term trend	N.A.	2%
Operating temperature determination	1%	N.A.
Ageing	N.A.	1%
Total	3.2%	

Table 10. Main sources of uncertainty that affect the energy estimation of a PV project, after the on-site characterization campaign.

Overall, the application of a quality control process during the design, installation and start-up phases of a PV project reduces the energy estimation uncertainty in almost a 60%, what leads to a 6.8% improvement in the $E_{P_{90}}$ value and to an 11.2% increase in the $E_{P_{95}}$ value, as summarized in Table 11. For the case presented in Figure 21 Table 11, these values rise from 1,348 to 1,439 kWh/kWp and from 1,263 to 1,404 kWh/kWp, respectively.

Parameter	Initial	After quality control
Uncertainty (%)	7.9 (static systems) 8.6 (tracking systems)	3.2
Uncertainty improvement (%)	59.5 (static systems) 62.8 (tracking systems)	
$E_{P_{90}}$ improvement (%)	6.8	
$E_{P_{95}}$ improvement (%)	11.2	

Table 11. Uncertainty reduction and energy estimation improvement after accomplishing the overall quality control process.

Figure 22 shows the evolution of the probability function presented in Figure 21 along the different steps of the quality control. As it can be observed, the narrowing of the curve leads to an increase of the occurrence probability of the mean value, as well as to an approach of the different probability ranges.

Figure 22. Probability function evolution during the quality control process. A narrowing of the curve can be observed, which leads to an increase in the probability of occurrence of the mean value, and to an approach of the different probability ranges.

Finally, it is worth mentioning that uncertainty becomes reduced not only by adopting technical precautions when testing but also by making appropriate decisions at the initial negotiation phase. For example, giving contractual priority to a particular solar radiation sensor (pyranometer, reference cell or reference module) and to a particular calibration laboratory significantly reduces uncertainty on solar radiation measurements and, therefore, on derived performance parameters.

3 Measurement contributions

In this chapter, some lessons learned during on-site measurement of PV plants are presented. First, *I-V* curve measurement of large PV generators is addressed, as a complementary tool to wattmeter analysis, when characterizing PV generators. Then, the hot-spot problem, which is the most common issue that affect PV plants under operation, is analysed and a proposal for dealing with it in the field is presented. Moreover, the dust effect on PV modules is examined, as a specific hot-spot source. Finally, the evolution of PV power over time is studied, taking advantage of the Madrid installation, which has been in operation for 17 years.

3.1 *I-V* curve of large PV generators

On-site *I-V* curves of PV generators are a useful tool for assessing not only the effective peak power but also for diagnosing possible performance anomalies (shadows, hot-spots, polarization, connection failures...). Nevertheless, current state-of-art is restricted to relatively low powers, typically below 100 kW, which is likely due to the practical difficulties of dealing with large currents. In fact, as far as we know, commercial *I-V* tracers are limited to 100 A. Nowadays, however, generators of up to 1.2 MW are found in PV installations, which implies currents above 1000 A.

In this section, the *I-V* curve of a 500 kW generator is presented. It was obtained by means of an own-made capacitive load. Once obtained, the *I-V* characteristics were extrapolated to *STC* according to IEC-60891 using the effective in-plane incident irradiance, G^{ef} , and the cell operating temperature, T_c , registered by means of two reference modules. Afterwards, the *I-V* curve measurements of 760 kW and 800 kW PV generators are also presented. As far as we know, these have consecutively been the largest *I-V* curves measured so far.

3.1.1 A 500 kW *I-V* curve

3.1.1.1 The PV generators

The measurement took place in the Murcia-5 PV plant, the 18th of January of 2012. This PV plant is formed by four 500 kW generators connected to their respective inverters. Each generator consists of 93 parallel connected strings, each of which is composed of the series connection of 23 monocrystalline silicon modules of 250 W. The nominal values of the PV generator, resulting from the flash-list information given by the manufacturer, are: $I_{SC}^* = 810$ A, $V_{OC}^* = 876$ V and $P_{peak}^* = 535,924$ W.

Every inverter had 9 bipolar entries, able to accommodate the cables coming from an equal number of DC boxes in the field. These entries were paralleled inside the inverter. The here concerned PV generator included 6 DC boxes (3 with 15 parallel connected strings and another 3 with 16 parallel connected strings), and therefore 3 inverter entries were free. We took advantage of this circumstance by simply connecting our *I-V* tracer to one of these free entries (Figure 23). It is worth noting that, this way, the measurement is done just at the inverter entry. In other words, corresponding results include all the losses until that point (possible early degradation, module mismatching, DC wiring...).

Figure 23. Connection of the *I-V* tracer to the entrance of the measured inverter, following a four wire configuration. It can be observed the *I-V* tracer in the background, the six cables from the DC boxes on the right and the *I-V* tracer connection in a free entry in the foreground.

3.1.1.2 The *I-V* tracer

We used an up-scaled own-made capacitive load based on insulated gate bipolar transistors (IGBT) that has been described in previous publications (Muñoz, 2006). Figure 24 presents a simplified scheme. Key features are:

- An 800 V/16.7 mF capacitor. Roughly, the capacitor charging process is described in terms of a time constant $\tau = RC$, with C being the capacitance and R being the resistance determined by the open circuit voltage (V_{oc}) and the short circuit current (I_{sc}) of the generator ($R = V_{oc}/I_{sc}$). Here $\tau = 18.1$ ms, which leads to charging times of about 30 ms, large enough to avoid transient effects influence.
- A 400 A/1200 V IGBT. In this case, the current measured nearly doubled the limit of the continuous IGBT current (700 A), but due to the very low charging times it caused no damage to the transistor.
- An 500 A/ 150 mV 0.5 class (uncertainty of $\pm 0.5\%$) shunt resistance for measuring the current at the entrance of the load.
- A four wire connection configuration, with the voltage taken in the connection point, to avoid considering any voltage drop in the *I-V* tracer cables.
- A negative voltage capacitor pre-charge, using a battery, for assuring the capacitor to pass through the short-circuit point. Because of the large current value, there was a voltage loss in the *I-V* tracer cables of about 24 V between the connection point and the entrance to the load. A 30 V negative voltage pre-charge compensated this fact.

Figure 24. Simplified circuit design of the I - V tracer. Both IGBTs function as switchers, R_D is the capacitors discharge resistance, V_{PRE} the pre-charge battery (acted by switcher P) and C the capacitor.

In order to minimize the noise/signal relation, we used a four isolated channel oscilloscope (Metrix Scopix OX7104-c) for acquiring the current and voltage signals, coming from the generator, and $G_{ef}(I)$ and T_C , coming from the reference modules.

3.1.1.3 Measuring conditions

Measuring operating conditions were registered (through I_{SC} and V_{OC}) from two reference modules, previously stabilized and calibrated outdoors at the IES-UPM facilities, as explained in previous chapters. The calibration traceability is referred to the CIEMAT. The corresponding uncertainty for these modules is $\pm 2.0\%$ in I_{SC} , $\pm 1.0\%$ in V_{OC} and $\pm 2.5\%$ in P_M . These modules were from the same batches, and therefore, of the same type, as those that make up the generator. As we have presented in previous chapters, the use of reference modules is the best option when trying to reduce the uncertainty associated to spectral, angular and thermal responses. They were installed in the generator's structure in a position free from shadows, as can be observed in Figure 25. Just as a precaution to prevent the uncertainty associated with the effect of dust in the measurements, the reference modules were installed more than 15 days in advance, thus guaranteeing similar dust coverage.

Figure 25. View of the reference modules installation at the Murcia-5 PV plant. They are located above the generator and no appreciable dirtiness differences are observed.

The main source of uncertainty when measuring the I - V curve of large PV generators on-site is that associated to the T_c determination. The bigger the generator and the higher the wind speed, the larger the T_c spread among the generator and, therefore, the less representative the value given by a single reference module. To limit the corresponding uncertainty, it is worth guaranteeing the following: charging times of around 20 ms, incident irradiance of more than 800 W/m², diffuse/global irradiance proportion (D/G) lower than 20%, and wind speed lower than 3 m/s. As presented in Table 12, weather conditions easily fulfilled these requirements. In any case, a thermographic inspection of the installation showed mean temperature differences between the reference module and the modules forming the generator lower than 2 °C.

3.1.1.4 Results

Figure 26 presents the evolution of the current (blue line) and the voltage (orange line) during the charging process. As it can be observed, the charging time is larger than 20 ms, which allows avoiding fill factor errors in the measurement. Despite it is not relevant for the final results, it is interesting to note the acute current peak (≈ 1400 A), at the beginning of the capacitor charging process. It occurs due to the displacement of majority carriers, inside both p and n zones, required to adapt the length of the depletion zone of the p-n junction to the solar cell applied voltage. Switching the capacitor on implies the PV generator suddenly changing from open circuit to short circuit conditions. Hence, the length of the depletion zone must sharply reduce. This process lasts typically for less than 0.2 ms and does not affect the measurement. In fact, it only appears in I - V curves when they are captured with a relatively high sampling frequency. Here, we have used 12.5 kHz. On the other hand, as a precaution to prevent any difference between the voltage reached at the capacitor terminals and the real open circuit voltage, the latter is also measured just before the charging process.

Figure 26. Evolution of I and V during the charging process of the 500 kW PV generator I - V curve. The displacement current peak can be observed at $t=0$.

Once obtained, the curve was extrapolated to STC in accordance with IEC-60891 (procedure 1) using the current and voltage temperature coefficients given by the manufacturer, which are $\alpha = 0.04$ %/°C and $\beta = -0.33$ %/°C, respectively. V_{oc}^* and I_{sc}^* have

been calculated by linear extrapolation from the points around them. The series resistance (R_s) was supposed constant through all the operating conditions and estimated assuming a variable fill factor, following the equations proposed by Green (Green, 1982). This method has been demonstrated a good approximation (Polverini D., 2012). The curve correction factor (κ) was fixed at $1.25 \times 10^{-3} \Omega/^\circ C$, which is a typical value for crystalline silicon cells. Figure 27 shows the I - V curve under real operation conditions (blue line) and once extrapolated to STC (orange line). Table 12 presents the operating conditions and the main characteristics of one of the I - V curves while Table 13 summarizes the mean values obtained after six measurements together with the corresponding uncertainty, calculated considering a 5% significance level. The average maximum power of the PV generator resulted $P_{M,IEC-60891}^* = 502,761 W$.

It is worth mentioning that the uncertainty of the measured power in one curve is lower than 1.4% and that of the extrapolated power is lower than 3.6%. These values have been calculated following a type B evaluation as established by the “Guide to the expression of the uncertainty in measurement” (IEC, 2008). The main uncertainty factors have been the calibration of the reference modules and the temperature coefficients.

Figure 27. I - V curve measured (blue line) and extrapolated to STC (orange line) of a 500 kW PV generator at the Murcia-5 PV plant.

Another way of obtaining the maximum power at STC is to calculate the maximum power from the measured curve and then translate it by using Equation 12:

$$P_M^* = P_M \times \frac{G^*}{G_M} \times \frac{1}{1 + \gamma(T_C - T^*)}$$

Equation 12. Maximum power corrected to Standard Test Conditions.

where subscript M means measured, superscript $*$ means STC and $\gamma = -0.45 \text{ } \%/^\circ C$ is the power temperature coefficient given by the manufacturer. Despite its simplicity, there is experimental evidence of this equation being as good as more complex ones. This way, the average maximum power resulted $P_{M,\gamma}^* = 492,182 W$. The difference between both

extrapolation methods (2.1%) is small and gives an idea of the uncertainty associated with these procedures and of the coherence of the temperature coefficients.

			Measured values	STC values
PV plant	Murcia-5	I_{SC} [A]	709.0	791.5
Date	18 th of January, 2012	V_{OC} [V]	780.0	846.1
Hour	13:24	I_M [A]	650.0	731.8
G [W/m ²]	899	V_M [V]	614.4	687.6
D [W/m ²]	70	$P_{M, IEC-60891}$ [W]	400,550	503,216
T_C [°C]	47.2	FF	0.724	0.751
Wind speed [m/s]	<1.5	$P_{M, \delta}^*$ [W]	400,550	495,133
Air mass	1.98	κ [°C]	1.25×10^{-3}	1.25×10^{-3}
t_{CHARGE} [ms]	26.2	R_S [Ω]	0.091	0.071

Table 12. Operating conditions and main parameters of one of the I - V curves obtained at a 500 kW PV generator of the Murcia-5 PV plant.

Mean $\pm \Delta$			
I_{SC}^* [A]	797.2	$\pm$	5.1
V_{OC}^* [V]	841.4	$\pm$	5.6
I_M^* [A]	737.1	$\pm$	13.7
V_M^* [V]	682.1	$\pm$	4.9
$P_{M, IEC-60891}^*$ [W]	502,761	$\pm$	12,692
FF^*	0.750	$\pm$	0.010
$P_{M, \delta}^*$ [W]	492,182	$\pm$	12,497

Table 13. Mean and standard deviation values of the I - V curves obtained at a 500 kW PV generator of the Murcia-5 PV plant.

As it has been presented in previous works, I - V curve measurements can be compared with the ones made using a wattmeter. For this PV generator, the analysis with the wattmeter resulted in an extrapolated maximum power of $P_{M, Watt}^* = 501,407$ W. The small difference between both procedures (0.3%) indicates coherence and validates the results obtained.

3.1.2 Other large PV generators I - V curves

I - V curves larger than 500 kW were obtained during the development of this thesis in the Zamora PV plant, on June 2012. This installation consists of twelve generators ranging from 500 kW to 800 kW, each of them made up of up to 712 parallel connected strings, composed of the series connection of 14 cadmium telluride modules of 80 W. Their nominal values reach $I_{SC}^* = 1,350$ A, $V_{OC}^* = 850$ V and $P_{peak}^* = 804$ kW.

In order to accomplish such measurements, the already presented I - V tracer was upgraded in the following parts:

- A new IGBT of 900 A/1200 V and a 1,000 A/150 mV 0.5 class (uncertainty of $\pm 0.5\%$) shunt resistance were incorporated for adapting the tracer to larger current measurements.
- The negative pre-charge was increased to 48 V.

The new characteristics drove to a time constant $\tau = 10.5$ ms, which led to charging times of about 20 ms, still large enough to avoid transient influences.

Operating conditions were measured using two reference PV modules shown in Figure 28. Due to technological factors, the corresponding uncertainty for these modules is higher than for crystalline silicon modules: 5.0% in I_{SC} , V_{OC} and P_M , what derives in an extrapolated power uncertainty of 5.0%, although the measured power uncertainty is still as low as 1.5%.

Figure 28. View of the reference PV modules used for measuring the operating conditions in the Zamora-1 PV plant.

Figure 29 shows the evolution of current and voltage in the measure of the 800 kW I-V curve, and Figure 30 presents the measured and corrected I - V curves.

Figure 29. Evolution of I and V during the charging process of the 800 kW PV generator I-V curve. A displacement current peak of up to 1600 A can be observed at $t=0$.

Figure 30. I - V curve measured (blue line) and extrapolated to STC (orange line) of an 800 kW PV generator at the Zamora PV plant.

Table 14 shows the main operating conditions and measured and extrapolated parameters obtained in one I - V curve and Table 15 presents the mean values of the set of measurements, with their corresponding uncertainty. In this case, the difference between the two extrapolation methods is 5.5%, larger than in the previous section, and it is probably derived from incoherencies between the temperature coefficients. In fact, this difference is constant for all the generators measured in the Zamora PV plant, as detailed in Table 16. On the other hand, the analysis with the wattmeter results in a extrapolated maximum power of $P_{M,Watt}^* = 757,811$ W. The difference between both procedures (2.0%) is within the uncertainty range, what, again, indicates coherence and validates the conclusions obtained.

			Measured values	STC values
PV plant	Zamora	I_{SC} [A]	1225.7	1237.0
Date	15 th of June, 2012	V_{OC} [V]	820.2	860.3
Hour	15:37	I_M [A]	1095.4	1114.8
G [W/m^2]	992	V_M [V]	641.7	699.0
D [W/m^2]	112	$P_{M, IEC-60891}$ [W]	702872	779267
T_C [$^{\circ}C$]	42.5	FF	0.699	0.732
Wind speed [m/s]	<2.0	$P_{M, \delta}^*$ [W]	702872	740617
Air mass	1.17	κ [$\Omega/^{\circ}C$]	1.25×10^{-3}	1.25×10^{-3}
t_{CHARGE} [ms]	18.6	R_S [Ω]	0.114	0.097

Table 14. Operating conditions and main parameters of the I - V curve measurement obtained in an 800 kW PV generator of the Zamora PV plant.

	Mean $\pm \Delta$		
I_{SC}^* [A]	1,240.0	$\pm$	6.4
V_{OC}^* [V]	862.3	$\pm$	5.1
I_M^* [A]	1,114.6	$\pm$	4.2
V_M^* [V]	703.4	$\pm$	10.6
$P_{M, IEC-60891}^*$ [W]	784,044	$\pm$	11,067
FF^*	0.733	$\pm$	0.003
$P_{M, \delta}^*$ [W]	742,728	$\pm$	4,894

Table 15. Mean and standard deviation values of the I-V curves obtained at an 800 kW PV generator of the Zamora PV plant.

PV generator (kW)	P_{Peak}^* (W)	$P_{IEC60891}^*$ (W)	$P_{M, \gamma}^*$ (W)	$P_{IEC60891}^*$ vs P_{Peak}^* (%)	$P_{IEC60891}^*$ vs $P_{M, \gamma}^*$ (%)
500	501.8	500.4	473.5	-0.3	-5,6
760	748.4	747.4	693.1	-0.1	-7,4
800	803.9	784.0	742.7	-2.5	-7,6

Table 16. Main results obtained in three PV generators of the Zamora PV plant. As it can be observed, differences between the corrected power, depending on the extrapolation method, are around 5% in all the cases.

3.2 Dealing with hot-spots

A hot-spot consists of a localized overheating in a PV module. It appears when, due to some anomaly, the short circuit current of the affected cell becomes lower than the operating current of the whole, giving rise to reverse biasing, thus dissipating the power generated by other cells as heat. Figure 31 shows two IR images of hot-spots. The anomalies that cause hot-spots can be external to the PV module: shading (Alonso-García et al., 2003; Herrmann et al., 1997; Molenbroek et al., 1991) or dust¹⁰ (Lorenzo et al., 2014); or internal: micro-cracks (Brun and Melkote, 2009; Buerhop et al., 2012; García et al., 2013; Grunow et al., 2005; Paggi and Sapor, 2013, Paggi et al., 2013), defective soldering (Buerhop et al., 2012; Chaturvedi et al., 2013; Gabor et al., 2006; García et al., 2013; Muñoz J. et al. 2008), potential induced degradation (Berghold et al., 2013; Hacke et al., 2010), material imperfections (Vasko et al., 2014)... In general, a hot-spot entails a decrease of the operational efficiency of the PV module. Moreover, when a hot-spot persists over time, it entails a risk for the PV module's lifetime (Buerhop et al., 2012; García M et al., 2013; Muñoz M. A. et al., 2011; Osterwald and McMahon, 2009; Radziemska, 2003; Simon and Meyer, 2010; Solórzano and Egido, 2014).

¹⁰ We will address this particular case in the following section.

Figure 31. IR images of hot-spots. (a) General view of a PV array with hot-spots caused by potential induced degradation (suggested by the appearance of a regular pattern). (b) Hot-spot in a PV module caused by micro-cracks. The operating temperature at the hot-spot is 87 °C while the mean temperature of the rest of the module is 53 °C, which represents a temperature difference of 34 °C.

Hot-spots are relatively frequent in current PV generators and this situation will likely persist as the PV module technology is evolving to thinner wafers, which are prone to developing micro-cracks during the manipulation processes (manufacturing, transport, installation, etc.) (Chaturvedi et al., 2013; Gabor et al., 2006; Grunow et al., 2005; Kajari-Schröder et al., 2011; Köntges et al., 2011). Fortunately, they can be easily detected through IR inspection, which has become a common practice in current PV installations (Auer et al., 2007; Botsaris and Tsanakas, 2010; Buerhop et al., 2011b; Buerhop et al., 2012; Hoyer and Buerhop, 2008; Kasemann et al., 2009; King et al., 2000; Muñoz M. A. et al., 2011;). However, the impacts of hot-spots on operational efficiency and lifetime have been scarcely addressed, which helps to explain why there is a lack of widely accepted procedures for dealing with hot-spots in practice as well as specific criteria referring to the acceptance or rejection of affected PV modules in commercial frameworks. For example, the hot-spot resistance test included in IEC-61215 (Crystalline silicon terrestrial photovoltaic modules. Design qualification and type approval) is successfully passed if the module resists the hot-spot condition for a period of 5 hours, which suggests that this standard addresses transitory hot-spots, as those caused by also transitory shading, but not permanent ones, caused by internal module defects (IEC, 1995). Along the same lines, the IEC-62446 (Grid connected photovoltaic systems. Minimum requirements for system documentation, commissioning tests and inspection) only states: “A hot-spot elsewhere in a module usually indicates an electric problem [...] In any case investigate the performance of all modules that show significant hot-spots” (IEC, 2009). Furthermore, a draft of the IES-60904-12 (Photovoltaic devices: infrared thermography of photovoltaic modules) clearly establishes how to capture, process and analyse the IR images, but still does not set out any PV module acceptance/rejection criteria (IEC, 2014). The Instituto de Energía Solar – Universidad Politécnica de Madrid (IES-UPM) experience includes many cases of actors in the PV sector, mainly module manufacturers and engineering, procurement and construction companies (EPCC), requesting advice on how to proceed with collections of IR images of affected modules, and whose corresponding contracts lacked the foresight to pose a relevant question: which ones of the affected PV modules should be replaced under the PV manufacturer’s responsibility?

The purpose of this section is to suggest a protocol for the effective treatment of hot-spots in the field, addressing both the lifetime and the operational efficiency of the PV modules. Starting from the observations of 200 affected modules of the Cuenca and Badajoz-2 PV plants as experimental support, hot-spot observation procedures and well defined acceptance/rejection criteria are proposed, oriented to their possible application in contractual frameworks.

3.2.1 Fundamentals of hot-spots

For explanation purposes, we first consider the case of a group of n identical solar cells, associated in series and protected by a by-pass diode (Figure 32-a). The operating conditions: incident irradiance, G , operating cell temperature, T_c , and polarization voltage, V , are such that a certain current, I_c , is circulating through these cells. A hot-spot appears in a cell (Figure 32-b) when some defect (micro-crack, shade, etc.) reduces its corresponding short circuit current, $I_{SC,D}$, so that

$$I_{SC,D} < I_c$$

Equation 13. Hot-spot appearance condition in a defective cell.

which forces the cell to operate at a negative voltage,

$$V_D = -(n - 1)V_{ND} + V$$

Equation 14. Negative voltage to which a defective cell is forced to operate when working in association with other cells.

where subscripts “ D ” and “ ND ” refer, respectively, to defective and non-defective cells. Consequent power dissipation heats the defective cell, giving rise to a hot-spot, characterized by the temperature increase of this cell in relation to the non-defective ones, ΔT_{HS} . In what follows, we will refer to this value as the “hot-spot temperature”. The by-pass diode assures $V \geq 0$, thus limiting the negative biasing and the power dissipation in this cell. Obviously, the maximum hot-spot temperature is then attained when the group is short-circuited or, which is nearly the same, when the bypass-diode is ON. Note that ΔT_{HS} is directly related to the product $I_c \times V_D$. In other words, hot-spot temperature mainly depends on the operating voltage and incident irradiance (which modulates I_c), on the defect gravity (which determines $I_{SC,D}$) and on the second quadrant I - V characteristic of the defective cell (which modulates V_D). As this characteristic can substantially differ from one cell to another, even within the same PV module (Alonso-García and Ruiz, 2006), the hot-spot temperature also depends on the particular defective cell. As a representative example, Figure 33 shows the second quadrant I - V curves of 7 individual solar cells of a same PV module measured by Alonso-García and Ruiz (Alonso-García and Ruiz, 2006). It can be observed that power dissipation at a hot-spot can vary nearly an order of magnitude depending on the defective cell (Alonso-García and Ruiz, 2006; Alonso-García et al., 2003; Herrmann et al., 1997; Herrmann et al., 1998; Muñoz M. A. et al., 2011).

Figure 32. Fundamentals of hot-spots in a solar cell: (a) Electrical connection of n originally identical cells protected by a by-pass diode. One of the cells is affected by dust, shading or any internal defect that limits its short-circuit current. (b) I-V curves of the affected cell and a non-affected one. The current imposed by the non-defective cells makes the defective cell work in the second quadrant, thus dissipating power and generating a hot-spot.

Figure 33. Second quadrant I-V characteristics of 7 individual cells of a PV module (Alonso, et al. 2006). The great dispersion in the second quadrant behaviour is notorious. If any of these cells were defective, and considering the value indicated by the horizontal continuous line as the operating current (imposed by the non-defective cells), it can be observed that the derived dissipated power varies about one order of magnitude depending on the particular affected cell.

The hot-spot temperature can be easily estimated on the assumptions that $n \gg 1$ and that heat is homogeneously dissipated over the solar cell surface. Then, it is rather straightforward to deduce that

$$\Delta T_{HS} \approx C_T \times \frac{I_C \times V_D}{S}$$

Equation 15. Hot-spot temperature, as a function of the operating conditions.

where S is the solar cell surface and C_T a thermal dissipation coefficient that can be estimated from the Nominal Operation Cell Temperature ($NOCT$):

$$C_T = \frac{NOCT(^{\circ}C) - 20}{800 \text{ W/m}^2}$$

Equation 16. Thermal dissipation coefficient, derived from the $NOCT$.

For example, $NOCT = 47^{\circ}C$, $S = 225 \text{ cm}^2$, $I_c = 6 \text{ A}$ and $V_D = 10 \text{ V}$ lead to $C_T = 0.036^{\circ} \frac{C}{W/m^2}$ and $\Delta T_{HS} = 96^{\circ}C$.

However, this is of scarce practical value because heat dissipation is rarely homogeneous over the cell surface, as can be clearly observed in Figure 31(b). Obviously, any non-homogeneity translates into ΔT_{HS} increase, thus worsening the case. More detailed explanations on the relation between power and temperature are found in the literature (Buerhop et al., 2011b; Hoyer et al., 2009).

Now, let us consider the case of a PV module made up of three series associated groups, each made up of n cells and a bypass diode (Figure 34-a). Note that many currently commercial PV modules respond to this configuration, with n ranging typically from 18 to 24. A defective cell like the one described above does not reduce now the PV module short-circuit current but becomes an anomalous step in the first quadrant of the I - V and P - V curves (Figure 34-b).

Figure 34. Fundamental of hot-spots in a PV module (a)Electrical scheme of a PV module with 3 groups, each of them made up of n cells and a by-pass diode. (b) I - V and P - V curves of a non-defective (blue) and a defective (red) module. The difference in the current at the maximum power point between the defective module, $I_{M,D}$, and the non-defective module, $I_{M,ND}$, can be observed.

Again, ΔT_{HS} depends on the operating voltage of the concerned group, which, in turn, depends on the operating voltage of the PV module. The voltage at the step marks the bypass diode turning ON, and ΔT_{HS} reaches its maximum for the voltage range below this step. Figure 35 shows examples of I - V curves of real modules affected by hot-spots. It is worth noting that current at the maximum power point of the defective module, $I_{M,D}$, is always lower than that corresponding to the non-defective ones, $I_{M,ND}$: $I_{M,D} < I_{M,ND}$.

Figure 35. Fundamental of hot-spots in a PV array (a) I - V and P - V curves of a non-defective (blue and green) module and of a defective module (red and black) affected by a fill-factor loss (b) I - V and P - V curves of a non-defective (blue and green) module and of a defective (red and black) module with a “step” anomaly.

Furthermore, if a module like these is connected in series with many other modules (often between 20 and 30 modules) and the resulting string is connected to an inverter able to impose the Maximum Power Point (MPP), the operating current of the group must range from $I_{M,ND}$ and $I_{M,D}$. Then, the larger the number of modules in the series, the closer the operating current will be to $I_{M,ND}$. In this situation, the operating voltage of the defective module is well below that corresponding to its MPP. The important thing to remember is that the power loss of a defective PV module is much larger when it works associated to other non-defective modules than when it works alone. A practical consequence of the latter is that this module could pass the standard warranty conditions (referring to the maximum power of the module alone) while failing to deliver the power in practice.

Figure 36. I - V curves of a non-defective (blue) and a defective (red) module. The maximum power points are marked for each module. It is assumed that the defective module is connected in series with a large number of non-defective ones and the resulting string is connected to an inverter able to impose the maximum power point. Because of the disproportion between the number of defective and non-defective modules, the operation current of the whole string is close to that corresponding to the maximum power of a non-defective module. Sinusoidal signal (1) represents the current oscillations around this value due to the MPP tracking strategy of the inverter. Sinusoidal signal (2) and (3) represent the corresponding voltage oscillations at a non-defective and at the defective modules. Voltage excursions are clearly greater in the defective module. The defective module does not only produce less power but also fluctuates more in operating voltage.

Figure 36 helps us to understand a hot-spot derived phenomenon related to the operating voltage of the PV modules. This fact results from the typical slight current excursion caused by the inverter MPP tracking algorithm, when a defective PV module is integrated into a string with a large number of non-defective ones. Associated voltage excursions in the defective module are much larger than that corresponding to the non-defective ones. Note that the operating voltage differences between defective and non-defective modules, ΔV_{HS} , also fluctuate following the MPP search. It is worth mentioning that such voltage differences can be easily understood as direct power losses, as the current is common to all the modules in the string.

In turn, these voltage fluctuations translate into ΔT_{HS} fluctuations. This is visible in Figure 37, which shows the records, every 5 seconds, of ΔV_{HS} versus ΔT_{HS} for one particular defective module at the Badajoz-2 PV plant (measurement details are explained below) over a period of one day. Black dots represent the moments with high and stable irradiance, while grey diamonds refer to unstable or low irradiance periods. Large instability is observed during low and variable irradiance moments (which is obviously also associated to the low ΔT_{HS} region, below 20 °C) when the MPP algorithms are prone to instability. However, the relationship between ΔV_{HS} and ΔT_{HS} becomes essentially stable in the high irradiance (and so, high ΔT_{HS}) region, where most of the energy is generated.

Figure 37. Operating voltage losses of a defective PV module with respect to a non-defective one, ΔV_{HS} , versus the corresponding hot-spot temperature, ΔT_{HS} . The MPP tracking algorithm makes ΔV_{HS} fluctuate at low irradiance.

These phenomena can also be observed in Figure 38, which shows the simultaneous records of the in-plane irradiance (black line) and the operating voltages of 3 modules of the same string (one non-defective, blue dots; and two defective, red and yellow dots). Large voltage excursions in the defective modules become evident. This observation was made at the Badajoz-2 PV plant, at a system with one-axis azimuthal tracking affected by clouds, what explains the evolution of the incident irradiance. The considered string was

composed of 22 PV modules associated in series. Two of these modules were affected by hot-spots while the others were not.

Figure 38. Evolution of the operating voltage of three modules in the same string. From top to bottom: a reference non-defective module (blue) and two modules (red and yellow) with hot-spots of, respectively, medium and severe gravity. In black, the corresponding evolution of the incident irradiance.

Finally, not only defective cells but also defective by-pass diodes can bring about hot-spots. In the latter case, short-circuited diodes give rise to an easily recognizable thermal pattern, consisting of an anomalous hotter band, somewhat like a brushstroke extended over the cells protected by the affected diode, with several cells exhibiting temperature differences of about 5 °C (as these cells are short-circuited, they do not deliver any electrical power, having to dissipate the corresponding power as heat) (Buerhop, 2011b). Furthermore, temperature dispersion between these cells is also expected. This behaviour occurs because the solar cells that make up real PV modules are not completely identical, but have a certain electrical characteristic mismatch that becomes a dispersion of voltage. At the short-circuit condition imposed by the defective diode, the sum of the voltage of all the cells protected by it is null, leading some cells becoming positive biased and others becoming negative biased. In this situation, the latter are slightly hotter than the former. Figure 39 shows an example of a PV module with a conducting by-pass diode measured at the IES-UPM facilities. Obviously, despite the temperature difference remaining low, such a module loses effective power, at a ratio equal to the number of defective diodes divided by the total number of diodes.

Figure 39. Hots-spots from by-pass diodes: (a) View of a PV module with a defective (short-circuited) by-pass diode. The cells protected by this diode are 5 °C hotter than the rest of the cells. (b) Close view of the connection box. The affected diode is at 110 °C while the others are working at 60 °C.

3.2.2 Experimental data

In this work, we have analysed a sample of 200 defective PV modules from the Cuenca and Badajoz-2 PV plants: respectively, 122 poly-crystalline silicon modules from one single manufacturer (p-Si1) and 78 mono and poly-crystalline silicon modules from two manufacturers (m-Si and p-Si2). These defective modules were selected on the basis of a previous *IR* report made by the maintenance personnel of the PV plants. Then, we carried out the following tests: visual inspection, *IR* inspection, electroluminescence (EL), peak power and operating voltage. The Cuenca PV plant (12 MW) has been in operation since September 2011. Hot-spots soon appeared, but the module manufacturer agreed to substitute all the modules exhibiting a hot-spot temperature greater than 30 °C on March 2013. The *IR* inspection that led to the selection of the sample of defective modules analysed in this article was carried out on June 2013 and the tests performed by the IES-UPM on January 2014. The process was similar for the Badajoz-2 PV plant (8 MW). The operation start-up was in September 2008 and the modules with hot-spot temperature larger than 30 °C were first substituted on June 2010. Then, a new *IR* inspection lead to the detection of the 78 defective modules on July 2012 and, finally, the complete IES-UPM tests were carried out on May 2013. It is worth noting that, in the case of the Cuenca PV plant, the initial *IR* inspection was made in summer while the tests were carried out the following winter, while in the case of the Badajoz-2 PV plant both inspections took place near the summer months. We will later discuss the consequences of these differences.

3.2.3 Method

3.2.3.1 Visual inspection

A detailed visual check was performed to all the concerned PV modules in order to find observable defects.

3.2.3.2 Infrared inspection

The *IR* images were obtained by means of an infrared camera (FLIR-Infracam, 7.5-13 μm), directly in the field, during normal operation and respecting the conditions suggested by the IEA-PVPS-Task 13 experts (IEA,2014): sunny cloudless days, a minimum incident irradiance of 700 W/m² and an angle of view to the module glass plane not lower than 60 °. As the relevant parameter in this test is more the temperature difference than the

absolute temperature value, imaging can be done at either the front or the back of the module. Just for convenience, we did all of them at the rear. Because of the aforementioned dependence on ΔT_{HS} with irradiance, it is appropriate to characterize hot-spots through a value normalized to the standard irradiance, $G^* = 1000 \text{ W/m}^2$:

$$\Delta T_{HS}^* = \Delta T_{HS} \frac{G^*}{G}$$

Equation 17. Normalized hot-spot temperature.

where * stands for the Standard Test Conditions (STC). Up to now, there has not been a widely accepted correlation for considering this effect on the heating of PV modules (IEC, 2014). Nevertheless, we think that there is a certain advantage of assuming that the hot-spot temperature is proportional to the incident irradiance. Non-linearity in the $\Delta T_{HS} - G$ relationship is likely to be small for the relatively narrow irradiance range defined by $G > 700 \text{ W/m}^2$, which is the condition that imposed on our *IR* images.

3.2.3.3 Electroluminescence

The objective of this test is to analyse the correlation between the portion of isolated area of a cell affected by micro-cracks and the magnitude of hot-spots. The analyses were carried out directly in the field during night using an EL camera (pco.1300 solar, $1.3 \mu\text{m}$) and a power source (TTi EX752M). Each module was polarized in the fourth quadrant at 25% of the STC rated short circuit current. The experiment was carried out in January 2014 and applied only to a smaller sample of 35 PV modules in the Cuenca PV plant, due to the difficulties of implementing this test on site. We have followed the crack type classification proposed by Köntges et al. (Köntges et al., 2011), dividing the affected cells into C-type (those exhibiting only background noise for the inactive cell part) and B-type (those exhibiting a reduced intensity but higher than the background noise).

3.2.3.4 Electrical inspection: power rating

The individual I-V curves of the affected PV modules were obtained with a commercial I-V tracer (Tritec Tri-ka) and extrapolated to STC in accordance with the IEC-60891 (procedure 1), using the current and voltage temperature coefficients given by the manufacturer. The incident irradiance and the operating cell temperature were measured by means of a previously calibrated module of the same technology, used as reference.

3.2.3.5 Electrical inspection: operating voltage

The operating voltage of the PV module, when working within the PV array, was measured by simply inserting “T” connectors into the module output wires. Then, it was possible to compare the voltage at which the different modules (affected and not affected by hot-spots) were working, as shown in Figure 37 and Figure 38. The voltage losses as regards the non-defective modules can be understood directly as power losses, as the current is common for all the modules connected in series.

3.2.4 Results

3.2.4.1 Visual inspection

Figure 40 shows examples of visible defects, where micro-cracks cause a current drift and a corresponding heat that leads to the burning of the metallization fingers and to bubbles at the rear of the modules. However, we found observable defects in only a 19% of the concerned PV modules, which is a too weak correlation for considering visual defects as a basis for dealing with hot-spots.

Figure 40. Examples of visible defects related to hot-spots (a) Burnt metallization fingers caused by micro-cracks (b) Bubbles at the rear part of a PV module affected by hot-spots.

3.2.4.2 Infrared inspection

Figure 41 shows the frequency distribution of ΔT_{HS}^* derived from the IR inspection performed in the Cuenca PV plant in January 2014. It must be noted that it does not reflect the total hot-spot occurrence in the PV plant, but only the hot-spots observed some months after the substitution, mentioned above, of all the modules with $\Delta T_{HS}^* > 30^\circ\text{C}$. Hence, as the distribution just after this substitution was supposed to have no elements beyond this value, the appearance of a tail in the distribution is a clear symptom of hot-spot evolution over time (it reflects those modules with $\Delta T_{HS}^* < 30^\circ\text{C}$ in March 2013 which have moved to the region beyond 30°C some months later).

On the other hand, we did not observe any PID phenomena (which, as observed in Figure 31-a), typically lead to a recognizable spatial pattern), thus hot-spots were likely to be caused by internal defects, mostly micro-cracks. In this case, the hot-spot temperature depends on the temperature of the module, as the thermal stress affects the contact resistance between the two sides of the crack. Hence, an evolution of ΔT_{HS}^* is to be expected over the year, being larger in summer than in winter, due to a larger expansion. This thermal cycling, also occurring at a daily level, typically entails degeneration, what leads to a probable worsening of hot-spots over time, as it is observed in the figure. However, these are not absolute rules. Each micro-crack is somewhat unique and even an improvement with thermal cycling can be observed (Köntges et al., 2011).

Figure 41. Frequency distribution of the hot-spot temperature for affected PV modules of the Cuenca PV plant in January 2014. Modules with $\Delta T_{HS}^* > 30^\circ\text{C}$ were first replaced in March 2013. Hence, the tail of the distribution reflects those modules with $\Delta T_{HS}^* < 30^\circ\text{C}$ in March 2013 which, due to the hot-spot evolution, have moved to the region beyond 30°C a year later. This is a clear example of hot-spot worsening over time.

Figure 42 shows the combined result of these effects. Each point in the graph describes the observed ΔT_{HS}^* at two different moments. Figure 42-a shows the evolution at the Badajoz-2 PV plant between July 2012 (average ambient temperature, $T_A = 34^\circ\text{C}$) and May 2013 ($T_A = 25^\circ\text{C}$). All the modules showing $\Delta T_{HS}^* > 5^\circ\text{C}$ in July have been considered. Despite the dispersion being high, on average, ΔT_{HS}^* has increased 11%. Figure 42-b shows the case at the Cuenca PV plant between June 2013 ($T_A = 28^\circ\text{C}$) and January 2014 ($T_A = 10^\circ\text{C}$). Only those modules with $\Delta T_{HS}^* > 15^\circ\text{C}$ in June have been considered on this occasion. Here, the average ΔT_{HS}^* has decreased by 22%, in an example of seasonal effects overcoming the degradation over time.

Figure 42. Hot-spot temperature evolution for (a) the Badajoz-2 PV plant and (b) the Cuenca PV plant. Each point corresponds to a particular module and represents the measure of ΔT_{HS}^* at the beginning and at the end of the experimental period. At the Badajoz-2 PV plant (a), both moments correspond to months with high ambient temperatures. A general ΔT_{HS}^* increase over time is noticeable (slope coefficient > 1). On the other hand, at the Cuenca PV plant (b), the final measurement corresponds to a cold winter month while the initial measurement corresponds to a hot summer month. In this case, an average ΔT_{HS}^* decrease can be observed (slope coefficient < 1). This difference between tendencies suggests a fluctuation of hot-spots during the year due to seasonal effects.

3.2.4.3 Electroluminescence

Figure 43 shows an example of an EL image obtained in the field and Figure 44 shows the relationship between the fraction of cell isolated by the micro-crack and the hot-spot temperature.

Figure 43. Electroluminescence relation with hot-spots (a) Example of an electroluminescence image of a PV module affected by a hot-spot. The image was obtained in the field (obviously, during night). Two cells with appreciable isolated areas can be observed (nearly a 40% for the left-hand side cell – 20% B-type and 20% C-type crack – and almost 20% for the cell in the upper row – B type crack). (b) *IR* image of the same PV module. The average temperature of the module is 20.1 °C, the left-hand side cell shows a normalized hot-spot temperature of 14 °C while the normalized hot-spot temperature of the upper row cell is only 5 °C. The PV module only seems to present a hot-spot in the former case.

Figure 44. Relation between normalized hot-spot temperature ΔT_{HS}^* and the area of a cell isolated by a crack. Squares and circles represent B-type and C-type cracks, respectively, in accordance with the Köntges et al. classification.

We observed that all the modules showing a hot-spot in the summer IR inspections had some micro-crack in the affected cell but none of the cells with B-type cracks generated a hot-spot in winter. Besides, a proportional but very weak trend between the isolated area and ΔT_{HS}^* ($R^2=0.03$) was found, even in modules with C-type cracks. The relationship between the isolated fraction area and the power loss of the module, which remained also very weak ($R^2=0.05$), was also analysed. A possible explanation to these weak correlation is that the contact resistance between the two sides of the micro-crack varies with module temperature and can thus be much larger during the day (when hot-spots are observed) than during the night (when EL images are obtained). Therefore, some areas can be miss-classified if attending to the EL results, leading to an incorrect estimation of the hot-spot problem. Whichever the case, EL images, despite being a very useful tool for quality control during the PV manufacturing processes, are not appealing for dealing with hot-spots in the field. Along similar lines, other authors have observed that the correlation between the number of cell cracks in a PV module and the power loss is very noisy (IEA, 2014).

3.2.4.4 Electrical inspections: power rating and operating voltage

Around 53% of the modules presented some anomalies in the I-V curve, as steps or an abnormally low fill factor. Figure 45(a) shows the relationship between ΔT_{HS}^* and the power loss with respect to the manufacturer's flash value, for 50 PV modules of the Cuenca PV plant. A high spread can be observed as well as the fact that most of the modules satisfied the usual power warranty condition (typically, 90% of the nominal rated power output after 10 years). However, this is scarcely representative of their in-field behaviour, which is better appreciated through the operating voltage of the module, when working within the PV array. Figure 45(b) shows the relationship between the power loss and the operating voltage loss for the same 50 modules. As can be observed, the effective losses are 55% higher than the power losses when considering the module alone.

Figure 45. Relation between electrical parameters and hot-spot incidence. (a) Normalized hot-spot temperature versus power loss for 50 PV modules. Eight of them are out of warranty conditions. (b) Power loss versus operating voltage loss (effective power loss). In this case, 19 modules do not comply with warranty requirements. As it can be observed, the effective power loss is much higher than the individual power loss, what makes the former a better parameter to measure the real effect of hot-spots in the module's performance.

Two key observations can be outlined. First, the standard peak power is not a good indicator of the energy production capacity of defective modules, so that it must be disregarded for dealing with hot-spots. Second, the correlation between ΔT_{HS}^* and ΔV_{HS}^* and thus, power losses during operation, is positive, but the large dispersion does not allow the correlation at individual levels to be applied. In other words, the power loss of a defective module must be deduced from direct voltage measurements not from thermal observations. Apart from that, Figure 46 shows the relationship between the normalized hot-spot temperature and the operating voltage loss for a more complete ensemble of the 113 PV modules of the three different manufacturers (78 from the Badajoz-2 PV plant and 35 from the Cuenca PV plant).

Figure 46. Relation between normalized hot-spot temperature and the corresponding operating voltage loss for 113 modules from 3 different manufacturers.

It can be observed that the behaviour is not the same for every manufacturer (neither in the correlation slope nor in the spread around it). The correlation between operating voltage loss and normalized hot-spot temperature is stronger in the case of module p-Si1 ($R^2=0.63$) and weaker for the cases of modules m-Si and p-Si2. These divergences likely reflect differences in the original material as well as non-uniform degradation affection due to different operation times (3 years in the case of module p-Si1 and 5 years for modules m-Si and p-Si2). Whichever the case, this behaviour spread is not relevant here.

3.2.5 Discussion

Hot-spots threaten the PV module lifetime, as degradation processes are generally accelerated by temperature. In particular, encapsulate discoloration and browning, and delamination (Jordan et al., 2012; Pern et al., 2000; Schlothauer et al., 2012). However, previous experiences do not allow a clear relation between module temperature and lifetime to be established (Osterwald et al., 2009). Therefore, in order to set a maximum acceptable value, $\Delta T_{HS,MAX}^*$, we must rely on intuitive but reasonable approaches. We propose to consider 85°C, which is the maximum temperature of the thermal cycling tests described in the IEC-61215, as the maximum absolute PV module temperature for acceptance/rejection purposes (Osterwald et al., 2009). Then, $\Delta T_{HS,MAX}^*$ should be thus so as to guarantee that the absolute temperature of the hot-spot remains below that limit. Obviously, the particular value of $\Delta T_{HS,MAX}^*$ depends on the local climate conditions. As an example, Figure 47 shows the annual frequency distribution of the day-time operating temperature of non-defective PV modules in the Cuenca PV plant, which can be considered as representative of a temperate climate (characteristic of Southern Europe and some parts of USA, Australia or South America). The maximum cell temperature is 70 °C and the 99-percentile temperature is 65 °C. As these high temperatures are also associated to high irradiances, setting $\Delta T_{HS,MAX}^* = 20\text{ °C}$ would limit the time above 85 °C to around 40 hours a year (1% of the daytime) for these climate conditions, which seems a reasonable commitment. Moreover, it avoids reaching 100 °C, which has been sometimes suggested as

an absolute maximum for preventing early degradation (Lathrop et al., 1982). Therefore, $\Delta T_{HS,MAX}^* = 20\text{ }^{\circ}\text{C}$ could be reasonably considered as an upper limit for the normalized hot-spot temperature, at least in temperate climates.

Figure 47. Annual frequency distribution of the operating temperature at the Cuenca PV plant. Only during a 1% of the daytime, temperatures are higher than 65 °C.

On the other hand, it should be mentioned that slight temperature differences also appear in non-defective modules, mainly due to differences in heat dissipation. It is to be expected that the module will be hotter around the junction box than in the rest of it, as heat conduction to the surrounding environment is more difficult. It is also normal for the PV modules to see a temperature gradient at the edges and supports. Consequent temperature differences of about 5 °C have been noted as typical (Buerhop et al., 2011a). Moreover, certain operating temperature dispersion within the cells of a same module is attainable, as the cell operation voltage is not fully homogenous, even among non-defective cells. Based on the IES-UPM in-field experience, we propose $\Delta T_{HS}^* = 10\text{ }^{\circ}\text{C}$ (roughly, 4 °C due to possible voltage variations and 6 °C due to dissipation differences) as a minimum threshold to consider the PV module as possibly defective.

As regards energy losses, it seems logical to just extend the application of usual warranties to defective modules. Hence, it is proposed to reject any module exhibiting hot-spots whose corresponding voltage losses (in relation to a non-defective module being part of the same string), within the PV system in normal operation, exceeds the allowable peak power losses fixed at standard warranties. This is also applicable to PV modules with defective by-pass diodes, regardless the derived hot-spot temperature.

3.2.6 Proposal

The following procedure is proposed as a practical in-field approach to accomplish IR imaging inspection:

- 1) Assure $G > 700\text{ W/m}^2$ and an angle of view not less than 60 ° to the module glass plane.
- 2) Perform the analyses in summer, preferably on the hottest days.

- 3) Normalize the hot-spot temperature, ΔT_{HS} , considering a lineal relation with the irradiance.

Then, for every PV module with a hot-spot, the following is proposed:

- 1) If $\Delta T_{HS}^* < 10^\circ\text{C}$, to consider the module non-defective, except in the case that one or more by-pass diodes are defective.
- 2) If $\Delta T_{HS}^* > 20^\circ\text{C}$, to consider the module defective.
- 3) If $10^\circ\text{C} < \Delta T_{HS}^* < 20^\circ\text{C}$, to consider defective all the modules with an effective power loss (measured as a decrease in the operating voltage in relation to a non-defective module of the same string) that exceeds the allowable peak power losses fixed at standard warranties.

Figure 48 shows the application of this proposal to the sample of modules tested in this work. In this case, manufacturer warranty 90% of the nominal rated power output after 10 years, so 10% is the maximum allowable power loss. The figure is divided in 4 regions: A, B, C and D. Modules in region A are considered non-defective, because their hot-spot temperature is not relevant. The modules in regions C and D are considered defective due to low power and lifetime threatening temperatures, respectively. The case of the modules in region B is less straightforward, because these modules are possible candidates for a hot-spot problem, but this problem is not evolved enough to imply a significant power loss. Therefore, these modules are not rejected, but they should be inspected again after one year.

Figure 48. Application of the proposed hot-spot classification criteria to the sample of modules analysed in previous sections. Modules in region “A” are considered non-defective, because their hot-spot temperature is not relevant. Modules in region “B” are considered non-defective, as the hot-spot is not evolved enough to imply a significant power loss, but they should be inspected again after one year. Modules in regions “C” and “D” are considered defective due to low power and lifetime threatening temperatures, respectively.

The here proposed restrictions for IR imaging inspection assure that the modules are analysed under the most unfavourable circumstances, trying to ease the classifying

process. However, as observed in figure 18, almost a 20% of the modules (those in region B) will be considered non-defective for the moment, as they are in a high uncertainty area. Even in the case in which all of them will be finally defective (type II error when establishing a null hypothesis that considers the module as defective), the method will have correctly classified the suspicious elements in more than the 80% of the cases. Furthermore, as the common practice in PV plants is to do an annual IR revision, those modules in the uncertainty region will be then reexamined and possibly classified as defective, as a result of the hot-spot worsening tendency over time, thus increasing the final effectiveness of the method. Other authors have also reached similar conclusions (Buerhop et al., 2011b).

Finally, it is worth mentioning that this procedure and these acceptance/rejection criteria have already been applied by the IES-UPM when mediating in conflicts between module manufacturers and EPC over hot-spots problems during the last years.

3.3 Dust as a hot-spot source

Considering the effect of dust on the performance of PV modules is typically restricted to analysing how it reduces the effective in-plane irradiance. This is equivalent to assuming that dust is uniformly distributed over the PV modules and PV array surfaces, thus reducing the short circuit current but without affecting either the open circuit voltage or the fill factor. Thus, the power delivered is reduced in the same proportion as the distribution of the dust. However, observed dust distributions are often far from being uniform; and this non-uniformity implies some kind of mismatch between cells in the same PV module, as well as between modules within the same string. In the former case, it translates into anomalies in the I - V curve when the affected PV module is considered separately. In the latter, it translates into voltage losses when the affected PV module operates in a string. Then, the corresponding power losses can be significantly larger than those derived from the simple dust coverage. Moreover, non-uniform dust patterns can also give rise to the formation of hot-spots, threatening the PV modules' lifetime.

This section presents some experimental observations made in the Murcia-3 PV plant. Figure 49-a shows dust deposits on several PV modules. Strongly non-uniform patterns can be clearly observed in some of them. These patterns arise spontaneously, probably as the result of complex combinations of dominant breeze winds with the PV module frames and the arrangements of the arrays. Figure 49-b shows dust affecting not only the free space between solar cells and frame, but also some of the solar cells' surface. In order to show that this case is not a very particular one, Figure 49-c and Figure 49-d show non-uniform dust patterns observed in other Spanish PV arrays. In fact, that can be often the case in non-cleaned PV arrays operating in arid regions.

Subsequent I - V curves and operating voltage measurements show that the derived power loss is significantly larger than the short-circuit reduction. Moreover, hot-spots up to 23 degrees on the surroundings have also been observed. That is, dust deposits are acting as partial shades, but with the additional annoyance of becoming permanent.

Figure 49. Non-uniform dust patterns spontaneously formed on PV modules and array surfaces. (a) At the Murcia-3 PV plant, the dust shows a tendency to accumulate in the lower and on the left-hand part of several PV modules. (b) A detail of the previous figure shows that dust deposits do not only affect the free space between solar cells and frame, but also the solar cells' surface (c) Dust on a close horizontal PV array on an industrial roof (d) Dust on the roof of a PV building prototype.

3.3.1 In-field measurements

The Murcia-3 PV plant is made up of 192 kW PV arrays, each including 42 strings associated in parallel. Each string consists of 20 PV modules associated in series, and each PV module is made up of 60 square solar cells and 3 bypass-diodes arranged as Figure 50 shows. From now on, a group of solar cells protected by a bypass diode will be referred to as a block. Measurements have been taken on the two dusty PV modules marked as M1 and M2 in Figure 49-a. The day was clear, with incident irradiances of more than 800 W/m^2 and module operating temperatures of around 50°C . Measurements were carried out in accordance with the subsequent steps:

Figure 50. PV module layout, presenting the three groups of cells, each of them protected by a by-pass diode.

- a) With the inverter working and both PV modules dusty, infrared images were taken, showing some cells up to 23° hotter than others (see Figure 51). These hot-spots are clearly due to dust, because they disappear when the modules are cleaned. In these cells, thermal degradation must probably take place at a higher rate. As presented in the previous section, 20° is considered the limit for acceptance/rejection of PV modules. According to this threshold, the presented situation is not admissible and, therefore, some means of avoiding it must be adopted.

Figure 51. IR images of the lower corner of the PV module called M2 in figure 1, showing a solar cell up to 23 degrees hotter than its surroundings.

- b) Again, with the inverter working and both PV modules dusty, the operating voltages of the concerned PV modules and blocks have been measured, together with those corresponding to a rather clean PV module, used as reference. This is done just by opening the PV module connection boxes, accessing the intermediate contacts. The outstanding result, as Table 17 shows, is that, in each dusty module, the voltage of a block is significantly lower than that of the others. It is not difficult to understand that this block is just the one with the aforementioned hot cells in it, taking into account that, as a result of the dust coverage, the short-circuit current together with the maximum power current of the dustier solar cells are lower than those corresponding to the other cells.

Let us assume that, as the here concerned PV modules are relatively few and as dust affection is relatively low, the maximum power voltage, which is the voltage imposed by the inverter to all the strings, remains unchanged. As a first approach, it is also assumed that the operating current of the affected string is roughly the same as its maximum power current.

Hence, in order to allow the maximum power current of the full string to pass, imposed by the inverter, the operating voltage of this cell must be lower than that corresponding to the others, even to the extent of reaching reverse polarization, thus dissipating and not generating power, as presented in Figure 32 and Figure 33. Moreover, as current is necessarily the same throughout all the cells of the string, and as all the PV modules are roughly identical, assuming they are perfectly

cleaned, power losses in the dusty PV modules almost coincide with voltage losses. In our case, voltage losses are 16.5% for module M1 and 11.4% for module M2, significantly larger than power losses when the dusty PV modules are considered separately, as is shown later on. The difference between both modules can be explained by the higher dust affection in module M1.

PV module	V_{D1} (V)	V_{D2} (V)	V_{D3} (V)	Total (V)
M1	9.1	9.0	4.6	22.7
M2	9.0	8.9	6.1	24.1
MR	9.0	9.1	9.1	27.2

Table 17. Block operating voltage in three PV modules. M1 and M2 are the dusty ones described in Figure 49. MR is a PV module of the same string, not specifically cleaned but still cleaner than M1 and M2, used as reference. Low voltage at M2-D3 and M1-D3 indicate power losses.

- c) With the inverter switched-off and both PV modules dusty, the corresponding I-V curves were traced and then translated into Standard Test Conditions following the IEC-60891. Figure 52 shows the results for M1, once the y and x values have been normalized to the short-circuit current and the open circuit voltage, respectively. This figure also includes the I - V curves of the same module, but once it has been cleaned (obtained in a further step). This way, irregularities caused by non-uniform dust patterns become evident. Figure 53 shows a close-up view of the maximum power point region. It is worth noting that the corresponding fill factor remains practically constant. This means that power reduction losses resulting from dust, when the PV modules are considered separately, are roughly the same as short-circuit losses. However, when the dusty PV modules become part of a string together with other cleaner PV modules, these irregularities combine with the short circuit reduction to significantly decrease the operating voltage. This fact has been exposed in the previous section and is shown again in Figure 54, where the y values (from both the dusty and from the cleaned PV module) have been normalized to the short-circuit current of the cleaned PV module, which helps to explain the previous step results. Again, Figure 55 shows a close-up view of the maximum power point region.

It is now opportune to note that in the case in which the operating current of the concerned string coincides with the maximum power current of the cleaner PV modules (as initially assumed in section 2.b), voltage losses at the dirty one (M1) would be 35.8%. However, just to compensate these voltage losses, voltage operation of the cleaner PV modules must be somewhat higher than its maximum power voltage. Hence, real string operating current must be slightly lower than the maximum power current, and voltage losses must also be lower than such value. In fact, experimental voltage losses are 16.5 %.

Figure 52. I - V curves of both the M1 PV module, dusty and cleaned. The y and x values have been normalized to the short-circuit current and the open-circuit voltage of each case, respectively. Non-uniform dust patterns produce curve irregularities but do not affect the fill factor.

Figure 53. Close-up view of the maximum power point region of the I - V curves presented in Figure 52.

Figure 54. I - V curves of the M1 PV module, dusty and cleaned. The y values have been normalized to the short-circuit current of the cleaned PV module. Dust causes short-circuit current losses and non-uniform patterns also cause voltage losses when both modules are forced to operate at the maximum power point current of the cleaned PV module.

Figure 55. Close-up view of the maximum power point region of the I - V curves presented in Figure 54. Note that voltage losses at M1 depend on the operating current.

- d) With the inverter switched-off and the PV modules having been cleaned alternatively, the short-circuit current of the two PV modules has been measured at each cleaning step. Table 18 presents the corresponding ratio between these currents. As each cleaning step only affects one PV module while the other remains unaffected, the variation in this ratio provides a precise indication of the short-circuit PV module losses, which is almost the same as the transmittance losses resulting from dust. Here the resulting values are 5.5% for module M1 and 4.3% for module M2.
- e) With the inverter switched-off and both modules cleaned, the I - V curves are again traced to complete step c) and Figure 52 to Figure 55.

M1 dusty/M2 dusty	M1 cleaned/M2 dusty	M1 cleaned/M2 cleaned
0.985	1.042	0.997
Dirtiness in M1 (%)		Dirtiness in M2 (%)
5.5		4.3

Table 18. Short circuit current ratios throughout the cleaning sequence, and losses resulting from dust.

3.3.2 Discussion

As a conclusion, strongly non-homogeneous deposits of dust can lead to more significant consequences than the mere short-circuit current reduction resulting from transmittance losses. In particular, operating voltage losses arise when the affected PV modules are part of a string together with other cleaned (or less dusty) ones. These voltage losses can be several times larger than the short-circuit ones. This way, power losses of dusty PV modules, when working in a PV array, can be larger than what measurements suggest when the PV modules are considered separately. Moreover, significant hot-spot phenomena can arise leading to cells exhibiting temperatures of more than 20 degrees over those of the other cells in the same PV module, leading to a threat to the PV modules' lifetime.

We do not know how often such heavy dust deposits come about in the field, but we think that it can be often the case in PV parks operating in arid and desert areas, where cleaning is sometimes difficult because of the lack of water. Hence, we suggest paying specific attention to this problem during routine maintenance procedures. For example, by performing an IR analysis of suspicious PV array areas.

3.4 Long-term durability

Another relevant question about the operation of PV plants is the evolution or PV module power over time. Publications on Si-x PV modules performance after long-term outdoor exposures are becoming increasingly available in the literature. They mainly come from dedicated test beds[1-4] and as well as from PV systems in the hands of research groups[5]. Together with specialized studies[6-10], they provide useful information, helping to understand outdoor degradation mechanisms and, therefore, to improve the long-term reliability of PV modules. In summary, they show that qualification in accordance with the IEC 61215[11], despite not being specifically designed for measuring degradation rates but just to assure a certain robustness[12], generally encompasses peak power degradation equivalent to 0.6 – 1% per year for spans of around 10 to 20 years. The main observed defects are: ethylen-vinyl-acetate (EVA) browning, metal grid oxidation, delamination, soiling, etc. In more detail, a summary[13] of reported degradation rates shows an average of 0.7% per year and a median of 0.5% per year. Maximum power degradation appears to depend mainly on UV light[14], which helps to explain the differences in reported degradation rates in terms of time (per year).

In this section, the degradation observed in the Madrid PV installation after 17 years of exposure is presented. Typical yearly meteorological data[15] of the site are: broadband horizontal irradiation, $G_y(0) = 1,640 \text{ kWh/m}^2$; effective in-plane irradiation, $G_y^{ef}(20) = 1,830 \text{ kWh/m}^2$; average ambient temperature, $t_{A,y} = 15 \text{ }^\circ\text{C}$; Relative humidity, $H_R = 57\%$. The PV array consists of 90 modules manufactured by Isofotón S.A. in 1992.

Each module is made up of 60 p-type, mono-crystalline silicon solar cells, textured, with a TiO_x antireflection coating and interconnected with tinned copper ribbons. The cells are encapsulated with EVA between a high transmittance flat tempered glass and a composite back-sheet of Tedlar® (PVF) and polyester (PET), with a PVF/PET/PVF configuration. The laminate is surrounded by an anodized aluminium frame, with a silicone joint. The PV system was connected to the grid on the 13th of December 1993 by means of an inverter with galvanic insulation between the DC and AC circuits; and has been kept in routine operation for around 75% of the time, while for the other 25%, it has been used for different research purposes, mainly PV pumping testing. It can be assumed then that the PV array has been mostly held at maximum power operating conditions. No particular maintenance or cleaning procedures have been made during this time. Figure 56 shows a general view of the installation and a close view of a PV module. It is worth noting the 2 cm gap between the metallic frame and the solar cells, because it has effectively avoided the impact of soiling on the energy performance and has also probably been effective in preserving electric safety.

(a)

(b)

Figure 56. Madrid PV installation (a) General view. (b) Close-up view of a PV module. The 2 cm gap between the frame and the solar cells in the bottom part has effectively prevented soiling affecting the energy performance, as well as preserving the electrical insulation.

3.4.1 Visual defects

During the first 13 years of exposure to the elements, the only visual symptom of degradation appeared in the terminal boxes. In fact, although these boxes are IP65, they are not specifically designed for PV modules but for general electric installation purposes and they include several lateral holes with their corresponding cable grips. The degradation appeared in form of cracks at these cable grips (Figure 57). However, it should be mentioned, on the one hand, that these pieces can be easily substituted by new ones and, on the other hand, that this kind of terminal box is not used any more in the PV industry; so that further in-depth comments are not required here.

Figure 57. Cracks in terminal boxes appeared during the first 13 years of operation.

During the following three years, serious back-sheet delamination developed at the outer PET/PVF interface (Figure 58) affecting large areas of 62 modules, 69% of the total. This indicates a stability problem in the corresponding adhesive used by the back-sheet supplier (Sánchez-Friera P, 2011). It is worth remembering that the adhesion between the polymer film (PVF) and the inorganic coating (PET) has been highlighted as a critical aspect of this technology^[2,10]. Moreover, degradation symptoms also appeared in the joint between the laminate and the frame (Figure 59). Finally, many solar cells exhibit some colour darkening. Visual appearance suggests that this degradation is due to antireflective coating oxidation, as has been already mentioned by other authors^[5]. Table 19 summarizes all the visual defects found and their incidence in the sample. Despite sometimes being mentioned by other authors, we have not observed other visual defects, like front delamination (milky pattern) or grid oxidation. The latter suggests that, despite back-sheet delamination, the remaining PVF/PET sheet is still being able to prevent significant moisture penetration. The relatively dry climate of Madrid can also help to explain this result.

Defect	Modules affected	Percentage (%)
Cracks in the terminal boxes	6	7
Low grade back-sheet delamination	42	47
High grade back-sheet delamination	20	22
Cracks in the frame joint	33	37
Moss in the frame joint	22	24
Solar cells darkening	75	83

Table 19. Main visual defects found and incidence in the sample.

Figure 58. Visual defects appeared after the first 17 years of operation: back-sheet delamination at the outer PET/PVF interface.

Figure 59. Visual defects appeared after the first 17 years of operation: (a) cracks and (b) moss in the joint between the laminate and the metallic frame. Solar cells darkening are also clearly visible in this picture.

3.4.2 Electrical performance

Just three days after installation, all the 90 PV modules were tested outdoors by means of an own-made capacitor I-V tracer and two reference PV modules of the same type, previously calibrated at the CIEMAT, for measuring incident irradiance and operating cell temperature. The same was also done in July 2009. Although a new capacitor I-V tracer was used in this case, it was made using the same design as the one used in the initial measurements. It is worth mentioning that both of them assured capacitor charging times above 30 ms along the same lines of what presented in section I-V curve of large PV generators. The reference modules were the same in both cases. They were kept indoors but not completely in the dark. For this reason, they were recalibrated in 2009, again at the CIEMAT. Differences between calibration values have been -11.2% in power, -6.8% in short-circuit current, -0.4% in open circuit voltage and -4.4% in fill factor. The I-V curves obtained were translated to *STC* following the IEC-60891, procedure 1^[17]. Because of the three days of initial exposure, we consider that possible light degradation, typical in

boron-doped P-type crystalline Si solar cells with oxygen contamination, had already occurred when the modules were measured. Hence, we consider our initial values correspond to the stabilised power. Table 20 shows the corresponding results in terms of mean and standard deviation values of the main characteristics at Standard Test Conditions. It is worth noting that outdoor exposure reduced the mean peak power but not enlarged the standard deviation values. This suggests homogeneous manufacturing procedures and can be understood as good news, because it implies that mismatch losses in large PV arrays do not significantly increase over time. References [3] and [5] mention a similar result. The mean peak power degradation has been 9.0% over 17 years, which is often considered as equivalent to 0.53% per year. The main source of degradation is the short circuit current, with a decrease of 8.0% (or an equivalent to 0.47% per year) while the open circuit voltage has diminished only a 1.2% (0.07% per year) and the fill factor has remained basically constant. A word of caution is necessary here: because we fully lack of intermediate measurements, we cannot say that degradation has been homogeneous over time, as it is suggested by a constant per year ratio. However, other authors have suggested that degradation of output power in PV modules tends to be linear, especially for periods of several years and more^[18].

Characteristics at STC	1992		2009		Degradation	
	Mean	Standard deviation	Mean	Standard deviation	Mean (%)	Per year (%)
Maximum power (W)	81.1	1.06	73.8	1.50	-9.0	-0.53
Short circuit current (A)	16.14	0.30	14.85	0.14	-8.0	-0.47
Open circuit voltage (V)	7.23	0.06	7.14	0.07	-1.2	-0.07
Fill factor	0.696	0.01	0.696	0.01	0.1	0.00

Table 20. STC characteristics of the PV modules, before and after 17 years of exposure.

Figure 60 to Figure 64 show the frequency distribution of the main electrical parameters at the beginning and at the end of the period. All of them followed a normal distribution before the exposition. The short circuit current and the open circuit voltage keep their shape after the 17 years of outdoor exposition while the fill factor and the maximum power follow now a Weibull distribution due to the presence of some outliers. It is worth noting that the skewness of the latter curves can translate to increasing mismatching losses^[19].

Figure 60. Short circuit current distribution before (ranging from 15.3 to 17.1 A) and after (ranging from 14.5 to 15.2 A) the 17 years of outdoor exposition.

Figure 61. Open circuit voltage distribution before (right) and after (left) the 17 years of outdoor exposition.

Figure 62. Fill factor distribution before (right) and after (left) the 17 years of outdoor exposition.

Figure 63. Maximum power distribution before (ranging from 78.4 to 84.0) and after (ranging from 65.5 to 76.8) the 17 years of outdoor exposition.

Figure 64. Degradation rate distribution, referred to the power loss.

3.4.3 Electrical insulation

In order to know the extent at which the aforementioned defects could affect the electrical safety of the installation, six modules showing low and high grade back-sheet delamination were submitted to the dielectric withstanding test and to the wet leakage test described in the IEC-61215. Applied voltages were 1216 V and 500 V, respectively. For both tests, acceptance criteria^[11] is that the product of the resulting insulation resistance, R_{ISO} , and the PV module surface, S , must be equal to or larger than $40 \text{ M}\Omega\text{m}^2$. As $S = 0.7965 \text{ m}^2$, it means that R_{ISO} must be larger than $50.2 \text{ M}\Omega$. Figure 65 shows details of the leakage wet test and Table 21 presents the obtained results. All the modules widely succeeded in passing the tests.

Figure 65. Wet leakage test. (a) Positive and negative poles are short-circuited. The PV module is then submersed up to the terminal boxes in a water solution with $656 \Omega\text{cm}$ resistivity and voltage is applied between the poles and the frame. (b) Detail of the partial submersion: the line indicates the liquid level. The non-submersed part of the module is sprayed with the same water solution.

IEC 61215 test result, $R_{\text{ISO}}(\text{M}\Omega)$			
Serial number	Delamination grade	Dielectric withstanding	Wet leakage
030	High	2590	327
066	High	3120	379
058	Low	2530	303
077	Low	2830	439
088	Low	2480	427
039	High	2210	316

Table 21. Results of the dielectric withstanding and the wet leakage tests for 6 randomly selected modules.

3.4.4 Discussion

Despite significant back-sheet delamination and silicon joint degradation, the PV modules successfully passed the two electrical insulation tests (dielectric withstanding test and wet leakage test) established by the IEC-61215 [11]. As far as we know, the wet leakage insulation test results for aged PV modules have not been published before. This is particularly interesting because thermal cycles and damp heat following the IEC-61215 do not normally give rise to delamination[16], so that the associated electrical safety hazard cannot be analysed on accelerated aged modules, but only on naturally aged ones after many years of exposure to the elements.

In addition, electric performance degradation has been equivalent to 0.53% per year, which is along the lines of that found by other authors. Despite not being a new result, we consider that it is still valuable, because obtaining reasonably accurate degradation rates requires an interval of several years between initial and final measurements[12], and the associated difficulty makes such measurements relatively scarce.

4 Operation surveillance

Once the PV plant is in operation, the objective of the quality assurance process is to evaluate up to what point the installation is fulfilling the initial expectative. In other words, it consists of assuring the compliance of the following equation:

$$E_{REAL,i} \geq E_{EST,i} \times F_{TOL}$$

Equation 18. Relation between the real energy and the estimated one, given a certain tolerance factor.

where i stands for the evaluated period. E_{REAL} is the energy produced by the PV plant, given by the energy meters. This value entails no uncertainty and is easily provable. E_{EST} is the energy estimated from the meteorological conditions, which calculation carries the uncertainty related to the measuring and estimating processes. Finally, F_{TOL} is a tolerance or coverage factor that relates the result with the contractual guarantees.

PV plants are usually monitored by means of SCADA systems that register all the operational data and alarms. Starting from them, when following the full quality control process (measuring irradiance and temperature by means of reference modules, PR_{STC} determination and in-depth characterization during commissioning tests...), it is possible to accomplish detailed energy balances and performance analyses. In particular, the comparison of the real production and the one estimated from the operating conditions allows detecting and diagnosing hidden failures. Then, anomalies can be classified into avoidable and unavoidable, once the source of the problem has been identified, thus maintaining the responsibility chain orientation described in previous sections.

4.1 Looking for simplicity

Originally, the compliance of production guarantees was based on the linearity of the energy produced with the broadband horizontal irradiation, what allows linking the produced energy to the design estimations by means of:

$$E_{EST,i} = \frac{E_{EST,0}}{G_0(0)} \times G_i(0)$$

Equation 19. Estimated energy, considering a lineal relation with the horizontal irradiation.

where subscript $_0$ refers to design values, and I stands for the considered year. As we have already seen, these data usually come from a Typical Meteorological Year (TMY) and a simulation from it. $G_i(0)$ is recorded by the pyranometer installed in the plant. This procedure is simple and, depending on the location, can be easily corroborated by independent data¹¹. Nevertheless, it suffers from high uncertainty derived from considering, on the one hand, that pyranometers have the same angular and spectral behaviour and response to dust and dirtiness than PV modules and, on the other hand, a lineal relation between horizontal radiation and energy, which is far from being an accurate assumption: effective in-plane irradiance responses not lineally to variations in the horizontal irradiance, especially in tracking systems, and the PV module efficiency

¹¹ There are progressively more regions with official agencies that provide updated solar radiation data, either from satellite observations (SoDa and Meteonorm in Europe) or on-ground meteorological stations (SIAR network in Spain).

dependency with the operating temperature behaves in a non-linear way with the horizontal irradiance. In fact, this process is of no practical application unless for yearly periods and, even then, the entailed uncertainty can reach 10%.

Finally, even if assuming a perfect behaviour of the model, some questions remain unanswered: which is the unavoidable losses distribution? What has been the PV plant availability? Is the measuring system working correctly? What has been the impact of the anomalies? What has been their occurrence frequency?

Therefore, turning to this procedure seems appropriate when the PV plant is small and the installation of measuring devices is not appealing, but not for large-scale PV plants, where more accurate methods are required.

4.2 Looking for accuracy

Lower uncertainty in the evaluation process is achieved when attending to the operating conditions, measured by reference PV modules, as presented in section 2.5. Then, the losses distribution chain can be detailed and calculated as:

$$E_{EST,i} = E^* \times (1 - \Delta E_{UNAVOID}) = E^* \times \prod_j (1 - \Delta E_{UNAVOID,j,i})$$

Equation 20. Estimated energy, calculated from the combination of a set of unavoidable losses

where i refers to the considered period and $\Delta E_{UNAVOID}$ to the combination of the j different types of unavoidable losses. E^* represents the reference energy, defined as the one produced by a hypothetic system with the same power and exposed to the same operating conditions as the analysed one, but whose components operate always at STC efficiency, and free from any anomaly:

$$E^* = \frac{P^*}{G^*} \times \int_i G(t) dt$$

Equation 21. Reference energy, given a system operating at STC .

Furthermore, unavoidable losses can correspond to operating cell temperature, low irradiance efficiency, shadowing, mismatching, wiring, inverter saturation, DC/AC conversion, LV/HV transformation... Figure 66 presents a scheme of the energy production process. All the elements of the losses chain have been defined in previous works, and some of them presented in section 2.2.

Figure 66. Power production process in a PV system. Each box represents a losses step

The following equations operate as a reminder of the definition of each losses step for a particular moment:

- Temperature losses: derived from an operating cell temperature higher than 25°C.

$$\Delta P_{T_C} = \gamma \times (T_C - T_C^*)$$

Equation 22. Power losses due to operating cell temperature

- Low irradiance losses: derived from the efficiency decrease associated to the variation of V_{OC} with irradiance.

$$\Delta P_{G < G^*} = a + b \times \frac{G}{G^*} + c \times \ln \frac{G}{G^*}$$

Equation 23. Power losses due to low irradiance

- Shadowing losses:

$$\rho_{SHAD} = 1 - \frac{(B + D^C) \times (1 - F_{ES}) + D^I + AL}{G}$$

Equation 24. Power losses due to shadowing

where B , D^C , D^I and AL are the direct, diffuse circumsolar, diffuse isotropic and albedo components of the irradiance, respectively; and F_{ES} is the effective shadowing factor, a geometric coefficient that depends on the physic disposal of the PV generator elements.

- Mismatching losses: derived from the difference between the real characteristics of PV modules connected in series and parallel. This parameter is difficult to measure (it would represent measuring all the PV modules in the field, as seen in section 2.6.3), so a reasonable solution is to make an estimation of its average value. In this work, we have used a 1% for this concept.
- Wiring losses: due to the Joule effect.

$$\Delta P_{WIR} = \Delta P_{WIR,MAX} \left(\frac{P_{WIR}}{P_{WIR,MAX}} \right)^2$$

Equation 25. Power losses due to wiring

where $\Delta P_{WIR,MAX}$ is the maximum power loss declared by the wiring manufacturer for a $P_{WIR,MAX}$ maximum operating power, and P_{WIR} is the effective power going through the wire.

- Inverter saturation: derived from the maximum output power limitation of the inverter. When the generator delivered power exceeds that maximum, the inverter stops following the maximum power point and protects itself by imposing a voltage coherent with the limitation.

$$\Delta P_{SAT} = P_{DC} - P_{DC,SAT}$$

Equation 26. Power losses due to inverter saturation

where $P_{DC,SAT}$ is defined by:

$$P_{DC} \times \eta_{INV} > P_{INV,MAX} \Rightarrow P_{DC,SAT} = \frac{P_{INV,MAX}}{\eta_{INV}}$$

$$P_{DC} \times \eta_{INV} \leq P_{INV,MAX} \Rightarrow P_{DC,SAT} = P_{DC}$$

Equation 27. DC power delivered by the PV generator, as a function of the saturation power.

- DC/AC conversion: derived from the DC to AC inversion process efficiency defined by Equation 3:

$$\Delta P_{INV} = 1 - \eta_{INV}$$

Equation 28. Power losses due to DC/AC conversion.

- LV/HV conversion: derived from the low voltage to high voltage transformation process efficiency, as stated in Equation 4:

$$\Delta P_{TRA} = 1 - \eta_{TRA}$$

Equation 29. Power losses due to LV/MV transformation.

The total losses during a certain period are calculated by making a weighted integration of the instantaneous values. As weighting factor, it is considered the input of each step of the losses chain. For example, in the case of the temperature losses the input is the effective in-plane irradiance:

$$\Delta E_{T_C,i} = \frac{\int_i \gamma [T_C(t) - T_C^*] G(t) dt}{\int_i G(t) dt}$$

Equation 30. Energy losses due to operating cell temperature.

while in the case of the transforming losses, the input is the AC power:

$$\Delta E_{TRA,i} = \frac{\int_i (1 - \eta_{TRA}) P_{AC}(t) dt}{\int_i P_{AC}(t) dt}$$

Equation 31. Energy losses due to transformation.

Table 22 presents an example of hourly losses analysis carried out at a 118 kW PV generator of the Cuenca PV plant. This generator is free from shadows and cannot saturate the inverter. In order to simplify the presentation, only the temperature, low irradiance and conversion losses are presented. Differences between estimated values and real ones are within a $\pm 1.5\%$ range, with a daily average value of 0.5%. These results are similar enough to open the door for accurate failure detection, as we will see in section 4.5.

Hour	G_h^{ef} (Wh/m ²)	T_c (°C)	ΔE_{TC} (%)	$\Delta E_{G<G^*}$ (%)	$\Delta E_{DC/AC}$ (%)	E_{EST} (kWh)	E_{REAL} (kWh)	Diff (%)
9:00	260	17.8	3.2	-4.2	-6.6	28	28	1.2
10:00	519	32	-3.2	-2.0	-5.1	55	56	-1.5
11:00	769	42.8	-8.0	-0.8	-5	79	79	-0.4
12:00	933	54.2	-13.1	-0.2	-5.1	91	91	-0.5
13:00	1.012	58.4	-15.0	0.0	-5.2	96	97	-0.8
14:00	1.016	58.4	-15.0	0.0	-5.2	97	97	-0.4
15:00	938	52.6	-12.4	-0.2	-5.2	92	92	-0.3
16:00	759	44.7	-8.9	-0.9	-5	77	77	-0.2
17:00	533	36.9	-5.4	-2.0	-5.1	55	56	-1.1
18:00	253	30.9	-2.7	-4.3	-7	26	26	-0.5
Total	6.992	50.3	-11.4	-0.8	-5.3	695	699	-0.5

Table 22. Hourly energy balance at a 118 kW PV generator of the Cuenca PV plant.

Now, and moving towards the idea of completely distinguishing between avoidable and unavoidable losses, a more adjusted indicator can be defined. The so-called performance index (PI) uses as reference the energy produced by a generator under the same operating conditions, once included all the unavoidable losses:

$$PI = \frac{E_{produced}}{E^*(1 - \Delta E_{UNAVOID})} = \frac{E_{produced}}{E^*(1 - \Delta E_{TC})(1 - \Delta E_{G<G^*})(1 - \Delta E_{Sat})(1 - \Delta E_{DC/AC}) \dots}$$

Equation 32. Performance index

This index results has a maximum value of one if the PV plant is not affected by any kind of anomaly and, therefore, constitutes a good indicator for discerning between avoidable and unavoidable losses.

4.3 Data consistency

The uncertainty reduction derived from measuring the operating conditions by means of PV reference modules has the return of the larger difficulty of performing an independent checking of the collected data¹². As a general case, we can consider a dataset composed of the 15-minute average records of the meteorological ($G(0)$, T_A , and S_w provided by the meteorological station) and operating (G^{ef} and T_c given by the reference modules) conditions. It is worth noting that it is not advisable to use data in shorter periods. As the correlation between irradiance and cell temperature is affected by the thermal inertia of the PV modules, which is characterized by a time constant of about 7 minutes, any analysis below that range lacks of physical sense¹³.

¹² The availability of effective in-plane irradiance or operating temperature data coming from independent stations is rather low.

¹³ A 15-minute period represents two times the time constant of the PV module, what assures 95% stability.

Data consistency is then checked by comparing certain combinations of these data with previously known values. In particular, two of them are considered in this thesis: the Nominal Operating Cell Temperature (*NOCT*) and the relationship between the irradiation gain at the generator tilt angle with respect to the broadband horizontal irradiation.

A) *NOCT*

For moderate winds, there is a linear relationship between $T_C - T_A$ and G^{ef} :

$$T_C - T_A = m \times G^{ef}$$

Equation 33. Experimental relation between ambient and operating cell temperatures, and effective in-plane irradiance.

where the value of m , which is a characteristic of the type of PV module, is derived from the concept of the Nominal Operation Cell Temperature (*NOCT*) by means of:

$$m \left[^\circ\text{C} \times \text{m}^2/\text{W} \right] \approx \frac{\text{NOCT} [^\circ\text{C}] - 20 \text{ } ^\circ\text{C}}{800 \text{ W}/\text{m}^2}$$

Equation 34. Experimental fit for the thermal coefficient m

NOCT is defined as the temperature reached by the open circuited cells in a module mounted on a structure with a 45° tilt angle and the rear side open and under the following conditions: 800 W/m² of effective in-plane irradiance on the cell surface, G^{ef} , 20 °C of air temperature, T_A , and 1 m/s of wind speed, S_w . The IEC-61215 standard describes both the procedure and the requirements for measuring the *NOCT*, such as installing the anemometer at 0.7 m above and 1.2 m to the west or to the east of the upper part of the modules; or considering only the moments with $G(I) > 400 \text{ W}/\text{m}^2$, $5 \text{ } ^\circ\text{C} < T_A < 35 \text{ } ^\circ\text{C}$ and $0.25 \text{ m/s} < S_w < 1.75 \text{ m/s}$. In accordance with these conditions, the manufacturer provides a reference NOCT_{MNF} value with typically a $\pm 2 \text{ } ^\circ\text{C}$ uncertainty. Using the in-field data, and once filtered by the aforementioned conditions, an experimental *NOCT* value (NOCT_{EXP}) can be calculated, following:

$$\text{NOCT}_{\text{EXP}} [^\circ\text{C}] \approx 20 \text{ } ^\circ\text{C} + m_{\text{EXP}} \left[^\circ\text{C} \times \text{m}^2/\text{W} \right] \times 800 \text{ W}/\text{m}^2$$

Equation 35. Experimental *NOCT*

where m_{EXP} is the slope of the best linear regression adjust of Equation 35 when using experimental values. Then, NOTC_{EXP} can be compared with NOTC_{MNF} . Any deviation of the experimental value from the theoretical one represents a measuring failure in one of the involved variables.

This procedure allows the NOCT_{EXP} to be estimated but, as some of the conditions established in the norm are not fulfilled when measuring in the field (neither the position of the anemometer nor the tilt angle of the modules usually coincide with the requirements), it could entail a wider range of uncertainty (estimated as $\pm 5 \text{ } ^\circ\text{C}$), even for periods with no anomalies. Hence, the key idea is that errors in the data acquisition

process generate deviations in the $NOCT_{EXP}$ value greater than that margin. As an example, this procedure has been applied at the Cádiz-2 PV plant, a double-axis tracking installation placed in the southern Spain. Figure 67 presents the weather and operating condition frequency distributions at the site along 2012. Figure 68 shows the $NOCT_{EXP}$ calculated every hour for the first six months of 2012. The spread around the trend is caused mainly by the effect of wind and shadows caused by clouds: again, the instantaneous reaction of a PV module to a variation in the irradiance contrasts with the several minutes needed to become thermally stabilized, what generates dispersion in the plot. Red triangles mark inconsistencies in the data that were effectively confirmed when analysing the data series. Without considering the anomalous points, the $NOCT_{EXP}$ value is 42.6 °C while the $NOCT_{MNF}$ is 46 °C, so the rest of data are validated.

Figure 67. Yearly frequency distributions of weather and operating conditions at the Cádiz-2 PV plant in 2012: (a) horizontal and in-plane irradiance, and (b) ambient and cell temperature.

Figure 68. $T_c - T_a$ versus G^{ef} , as recorded every hour at the Cádiz-2 PV plant throughout 2012, once filtered by the $NOCT$ measuring conditions. The two dashed lines represent the ± 5 °C margin around the trend (solid line). The outliers clearly mark errors in the data that were effectively confirmed when analysing the data series. Without considering them, the $NOCT_{EXP}$ value is 42.6 °C while the $NOCT_{MNF}$ is 46 °C, within an assumable margin, so the rest of data are validated.

B) Effective in-plane irradiation gain

In the second case, we plot the daily irradiation gain, $G_d(I)/G_d(0)$, versus the daily horizontal irradiation, $G_d(0)$, and compare the result with that obtained from a simulation exercise for the same location, accomplished with SISIFO¹⁴. Figure 69 shows an example of application at the Cádiz-1 PV plant, again a double-axis tracking PV plant located in the southern Spain. Black squares represent the values of the simulated daily irradiation gains, calculated for the months of October 2010 and 2011, on the basis of well-established models: in particular, we have considered the Erbs model for the K_D/K_T relationship and the Hay model for the distribution of the anisotropic diffuse radiation. As the irradiation gain during the day is not homogenous, different temporal and frequency distributions of horizontal irradiance could start from a common daily value but lead to different effective in-plane results. The dashed lines in the figure delimit a $\pm 20\%$ range around the simulated value in order to include the associated uncertainty and to prevent from type I errors. White diamonds represent experimental values and red triangles mark days with suspiciously low irradiation gains, which therefore do not fulfil the coherence condition. In fact, when looking into the details of these faulty days, in all the cases a tracking problem had occurred in the tracker bearing the reference modules.

¹⁴ Available at www.pvcrops.eu

Figure 69. Daily irradiation gain, $G_d(I)/G_d(0)$ in function of the daily horizontal irradiation, $G_d(0)$, recorded in the Cádiz-2 PV plant during October of 2010 and 2011. Black squares represent simulated values while white diamonds and red triangles respectively refer to coherent or incoherent experimental values.

4.4 Anomalies and availability

The availability of a PV plant is defined as the fraction of time that the installation performs without any anomaly or failure. Nevertheless, this definition gives all the failures the same weight, independently of when they occur. As a generation interruption does not entail the same energetic impact if it occurs in the noon or in the early morning, a simple time availability index is disregarded. In its place, it is especially advisable to work with an energy availability index, understood as the ratio between the real production and the production in the absence of performance failures, in order to address PV plant reliability:

$$Avail_E(\%) = \frac{E_{produced} - E_{loss}}{E_{produced}} \times 100$$

Equation 36. Energy availability

where E_{loss} represents the effective impact of all the contemporaneous anomalies. Looking at this definition inside out, the absence of anomalies can be identified with performance stability between two different periods. The idea lying in the back is that two PV generation units at the same location (being those strings, inverters, transformers...), if free from failures, deliver energy at a similar rate. In fact, the absence of anomalies can be identified with the stability in the relative performance during two different periods, as stated in Equation 37 for the energy produced:

$$\left. \frac{E_1}{E_2} \right|_{t_i} = \left. \frac{E_1}{E_2} \right|_{t_{Ref}}$$

Equation 37. Stability relationship between periods and generation units.

where E is the energy produced, t_i and t_{Ref} are two different periods and 1 and 2 refer to two different systems. A couple of precautions must be taken when applying Equation 37:

- 1) Period t_{Ref} should be free from anomalies for both generation units, to set the reference relationship between productions.
- 2) Array 1 in period t_i must also be free from incidences.

This way, possible failures in array 2 during period t_i can be detected. This equation can be applied to the production of any generation unit (arrays, inverter, transformer...) considering different periods of analysis (hour, day, month...). It takes advantage of the PV plant configuration, composed of several independent units that share location, tilt angle, orientation, PV components, electric configuration..., what assures a theoretical homogeneity among productions. In practice, even in periods with no anomalies, there is always a small spread in the energy performance due to varying degrees of dirtiness, shadowing or wind speed effects that derive in operating temperature differences. Therefore, it is not worth considering the absence of anomalies to the exact correspondence of their relative productions but to a small interval around it.

Based on Equation 37, a failure detection procedure can be built up following the next steps (as an example, the daily case is considered):

- 1) Definition of a reference period, t_{Ref} . When applying this protocol to a PV plant under operation, the best reference period is unknown. Therefore, a selection algorithm must be implemented to determine the best option for the reference period. Two requirements must be fulfilled:
 - a. In order to assure representativeness, the reference period has to be of good weather. A reasonable threshold at daily level is to exceed an effective in-plane irradiation of 7.000 Wh/m².
 - b. In order to assure that the PV installation has not experienced a general failure during the reference period, the difference between the real generated energy and the estimated energy of the whole plant, as calculated using Equation 37, has to be lower than 3%.
 - c. In order to assure that the PV installation has not suffered from individual failures, the standard deviation between the final yields (defined as the quotient between the energy produced in the period and the peak power of the concerned generation unit) of the different generation units has to be lower than 5%.

Then, the reference period will be that with a lower standard deviation between the final yields of the generation units.

2) Calculation of the production relations, as:

$$E_{Rel} = \begin{bmatrix} E_{1,t_i} / E_{1,t_{Ref}} \\ E_{2,t_i} / E_{2,t_{Ref}} \\ \dots \\ E_{n,t_i} / E_{n,t_{Ref}} \end{bmatrix}$$

Equation 38. Energy relation matrix for stability calculation

where E_{Rel,t_i} is the whole matrix of relative energy ratios for the period t_i , whose elements are the relations corresponding to each of the n generation units .

- 3) Establishment of a relation reference value. In order to compare the different production relations it is worth referring to a common statistic parameter that sets the good performance expected value. The mean is a first option but, it is less robust against outliers than the median. Even the latter can be not much representative of a good performance if, for example, two thirds of the PV plant are affected by failures. In this sense, we propose to work with the P_{95} relation coefficient, E_{P95} .
- 4) Establishment of a minimum production relation threshold, in order to consider the normal spread among productions. The IES-UPM experience shows that a deviation of more than 2% in daily energy productions implies some kind of performance anomaly. So, a reasonable threshold could be:

$$E_{min} = 0.98 \times E_{P95}$$

Equation 39. Energy relation threshold for stability calculation.

- 5) Finally, all the production relations below E_{min} will be considered defective, and the failure impact quantified as the difference between the particular production relation and the relation reference value, E_{P95} .

It is worth noting that a failure affecting one string of a 100 kW generator (usually made up of around 30 strings) entails a 3% reduction in the production. When considering, for example, a 2 MW plant, the application of this procedure entails the capability of detecting failures that imply a 0.1% reduction in the total production.

Figure 70 shows an application example at the Moquegua PV plant. This installation is composed of 3964 PV strings, being each of them made up of 18 PV modules connected in series. They are monitored in pairs, thus forming 1982 pairs. Figure 70(a) presents the daily yield of each of the pairs for the 30th of July 2015, once normalized to the daily maximum value. As it can be observed, there is some performance dispersion between pairs. This is mainly caused by peak power and operating conditions differences, what results in a 1.62% standard deviation. Some suspicious performances are also observed,

but the spread hinders coming to a decision of whether a particular string is defective or not.

Differences in peak power between pairs are eliminated when working in relative terms, as already explained. Figure 70(b) shows the normalized relative yield for the same day. As it can be observed, the result is more stable and leads to a 0.65% standard deviation, what paves the way for failure detection. Figure 71 shows another representation of the same case, once ordering the yields from higher to lower. In this case, the larger stability of the relative index, represented by the quasi-inexistent slope of the red line, is even clearer.

(a)

(b)

Figure 70. (a) Normalized daily yield and (b) normalized relative daily yield for the 1982 string pairs of the Moquegua PV plant, the 30th of July, 2015.

Figure 71. Normalized daily yield (in blue) and normalized relative daily yield (in red) for the 1982 string pairs of the Moquegua PV plant, the 30th of July, 2015, once ordered from higher to lower.

4.5 PV plants under operation

4.5.1 From provisional to final acceptance

In contractual terms, two milestones have been usually considered for checking PV plant production capacity, as mentioned in chapter 0. On the one hand, the commissioning tests are used to accomplish the on-site characterization, which concludes with the emission of a Provisional Acceptance Certificate, giving the PV plant surpasses the corresponding quality thresholds. On the other hand, the first or the first two years of operation are used to check if the PV plant performance fulfils those expectations, and concludes with the emission of a Final Acceptance Certificate.

This latter step can be used to evaluate the own quality control process, if considering an ensemble of PV plants. Table 23 presents the yield forecasting evolution during the quality control process, and its comparison to the real final yield in 14 PV plants. It is worth noting that, in order to assure a correct evaluation, the comparison can only be made in those installations in which all the steps of the quality control have been performed and assuring that they do not have suffered from big anomalies during the period. Then, the initial forecasted yield, Y_{FOR} , can be modified after the measuring campaigns, leading to $Y_{FOR,CHAR}$. In turn, both of them can be corrected by the real operating conditions, Y_{EST} and $Y_{EST,CHAR}$, and then compared to the real measured productivity, Y_F . The difference, weighted by power, between the initial yield prediction and the experimental yield is 2.2%, with a maximum individual deviation of 8.2%. When correcting the initial yield predictions with the results of the quality control process, this differences decrease to 0.8% and 3.9%, respectively.

Plant	Y_{FOR} (kWh/kWp)	$Y_{FOR,CHAR}$ (kWh/kWp)	Year	Y_{EST} (kWh/kWp)	$Y_{EST,CHAR}$ (kWh/kWp)	Y_F (kWh/kWp)	Diff _{FOR} (%)	Diff _{CHAR} (%)
Albacete-1	2,089	2,128	2009	1,731	1,763	1,757	1.5	-0.3
Cádiz-1	2,090	2,149	2009	2,194	2,256	2,219	1.1	-1.6
Cádiz-2	2,138	2,191	2009	2,302	2,359	2,320	0.8	-1.7
Caltanisseta-1	1,546	1,549	2009	1,579	1,582	1,614	2.2	2.0
Caltanisseta-2	1,557	1,538	2009	1,626	1,606	1,613	-0.8	0.4
Ciudad Real-1	1,979	2,140	2009	1,980	2,141	2,142	8.2	0.1
			2010	1,220	1,319	1,296	6.2	-1.8
Ciudad Real-2	1,976	2,152	2009	2,096	2,282	2,194	4.7	-3.9
			2010	1,952	2,126	2,054	5.2	-3.4
Córdoba	2,067	2,067	2009	2,166	2,166	2,140	-1.2	-1.2
Granada-2	1,462	1,558	2009	1,499	1,597	1,561	4.2	-2.3
			2010	1,488	1,586	1,556	4.6	-1.9
Murcia-1	1,997	2,109	2010	1,983	2,094	2,038	2.8	-2.7
Murcia-2	2,154	2,312	2009	1,994	2,140	2,074	4.0	-3.1
			2010	2,083	2,236	2,174	4.3	-2.8
Palermo-2	1,503	1,502	2009	1,470	1,469	1,457	-0.9	-0.8
Palermo-3	1,496	1,540	2009	1,458	1,501	1,491	2.2	-0.7
Valladolid-1	1,937	2,023	2009	2,022	2,112	2,108	4.2	-0.2
Total							2.2	-0.8

Table 23. Yield forecasting evolution along the quality control process in 14 PV plants. For each installation, the initial yield prediction, Y_{FOR} , and the estimation after the measuring campaigns, $Y_{FOR,CHAR}$, are presented, together with their corrections considering the real operating conditions, Y_{EST} and $Y_{EST,CHAR}$. The final experimental yield is also included, as well as the differences of the latter with the estimated values.

Figure 72 shows a graphic comparison of $Y_{EST,CHAR}$ and Y_F . The slope of the regression line is slightly different to the average value, due to the absence of weighting coefficients in this case. Nevertheless, it can be observed a really low spread around the trend, what indicates a high reliability of the proposed procedure.

Figure 72. Comparison between the estimated yield, once corrected by the characterization results and the operating conditions, and the final experimental yield.

Nevertheless, a complete quality control process should include the performance surveillance along the whole life-cycle of the PV plant. We will go further in-depth in this issue in the following section.

4.5.2 Operational results

Up to now, numerous reports have been published assessing the performance of PV installations. They have mainly analysed small installations, both for demonstration [1-3] or commercial purposes [4-12]. The analyses of large-scale commercial PV plants have basically focussed on single installations [13-15]. However, detailed information on their performance is still scarce [16]. In this section, the performance of 20 multi-megawatt plants is analysed during a period of up to 4 years. These installations sum up 90 MW and totalize 240 MW·year of performance. Their main characteristics were summarized in Table 1 and their main performance results are presented in Table 24.

Plant	Year	Y_F (kWh/kW)	Y_R (kWh/kW)	PR	Availability (%)
Albacete-1	2008	1,757	2,132	0.82	96.40
	2009	2,080	2,322	0.90	99.60
Albacete-2	2009	2,056	2,452	0.84	99.60
	2010	1,965	2,364	0.83	99.80
Badajoz	2009	2,005	2,724	0.74	99.40
	2010	1,893	2,458	0.77	99.19
	2011	2,021	2,556	0.79	99.02
	2012	2,108	2,547	0.83	99.22
Cáceres-1	2009	2,204	2,839	0.78	99.70
	2010	2,038	2,425	0.84	99.88
	2011	2,129	2,555	0.83	99.89
	2012	2,185	2,612	0.84	99.90
Cádiz-1	2009	2,219	2,682	0.83	99.90
	2010	2,266	2,743	0.83	99.90
	2011	2,186	2,573	0.85	99.60
	2012	2,349	2,883	0.81	99.91
Cádiz-2	2009	2,320	2,822	0.82	99.96
	2010	2,161	2,629	0.82	99.89
	2011	2,407	2,921	0.82	99.89
	2012	2,358	2,870	0.82	99.96
C Real-1	2009	2,142	2,528	0.85	99.20
C Real-2	2009	2,194	2,675	0.82	99.30
	2010	2,054	2,487	0.83	99.60
Córdoba	2009	2,140	2,635	0.81	99.80
	2010	2,067	2,638	0.78	99.91
	2011	2,264	2,866	0.79	99.11
	2012	2,168	2,718	0.80	99.05
Cuenca	2009	1,594	1,997	0.80	99.78
Granada-1	2009	2,050	2,639	0.78	96.60
	2010	2,036	2,586	0.79	99.00
Granada-2	2009	1,561	1,966	0.79	96.30
	2010	1,556	1,891	0.82	99.40
Huelva	2009	2,312	3,005	0.77	99.99
	2010	2,120	2,558	0.83	99.85
	2011	2,237	2,733	0.82	99.82
	2012	2,299	2,742	0.84	99.81
Murcia-1	2008	1,795	2,377	0.76	97.00
	2009	2,038	2,562	0.80	98.50
Murcia-2	2008	2,074	2,541	0.82	97.70
	2009	2,174	2,626	0.83	99.00
Sevilla-1	2009	1,975	2,645	0.75	98.60
	2010	1,962	2,518	0.78	99.30
Sevilla-2	2009	2,238	3,124	0.72	99.10
	2010	2,119	2,547	0.83	99.72
	2011	2,271	2,690	0.84	99.76
	2012	2,323	2,773	0.84	99.97
Sevilla-3	2009	1,563	2,135	0.73	98.90
	2010	1,480	1,834	0.81	99.43
	2011	1,533	1,922	0.80	99.76
	2012	1,549	1,847	0.84	99.54
Toledo	2010	2,084	2,569	0.81	99.73
	2011	2,184	2,672	0.82	98.88
Valladolid	2009	2,108	2,548	0.83	99.69
	2010	1,970	2,471	0.80	99.96
	2011	2,064	2,605	0.79	99.63
	2012	2,035	2,517	0.81	99.86
Total	N.A.	1,933	2,517	0.80	99.43

Table 24. Annual production results for the 20 PV plants considered in the period 2008-2012. For every installation it is shown: analysed year; final and reference yields; PR and energy availability.

Table 25 presents the overall results, separated in function of the tracking configuration.

Tracking configuration	Y_F (kWh/kW)	Y_R (kWh/kW)	PR (%)	Availability (%)	Availability without first year (%)
Static	1,578	1,978	0.80	99.5	99.5
2xhv	1,972	2,443	0.81	98.3	99.3
2xvh	2,121	2,637	0.80	99.6	99.6

Table 25. Summary of the production results presented in Table 24 grouped for each tracking configuration.

The analysed PV plants have produced, in average and yearly terms, 1,578 kWh/kWp, 1,972 kWh/kWp and 2,121 kWh/kW, for static (st), horizontal double-axis (2xhv) and vertical double-axis (2xvh), respectively. The lower production of the 2xhv configuration in comparison with the 2xvh configuration is due to structural limitations of the former trackers [27]. These productivities derive in average PR values of 0.80, 0.81 and 0.80, which reveals no significant differences between static and tracking systems or, in other words, that the effect of the higher shading losses of the tracking systems are compensated by lower losses due to angle of incidence and low irradiance effects. Energy availability, calculated as defined in section 4.4, results 99.0%, 98.4% and 99.6%, respectively, for each tracking configuration considered. It is worth noting that due to the usual incidences in the start-up of the plants, availability tends to be lower (<98%) in the first year. Excluding the initial year, availability rises to 99.5%, 99.3% and 99.8%, respectively. Again, the inexistence of significant differences between static and tracking systems, at least in the first years of performance, means that up-to-date trackers have shown a high reliability. Figure 73 shows the frequency distributions of Y_F and PR for each structure configuration.

Figure 73. Final yield frequency distribution for those PV plants with (a) static configuration, (c) horizontal double-axis tracking configuration and (e) vertical double-axis tracking configuration. *PR* frequency distribution for those PV plants with (b) static configuration, (d) horizontal double-axis tracking configuration and (f) vertical double-axis tracking configuration. Gaussian fits are also plotted in all the cases.

Final yield and *PR* behave as Gaussian distributions for all the configurations. In the case of the final yield, the best fit is achieved through the combination of two Gaussians (observed as a double lobe in the figures). This double behaviour occurs because of irradiation differences between different climatic regions, which lead to different yields. In fact, they disappear when moving to *PR* analyses.

As a final comment, the operation and maintenance (O&M) cost in these plants is around €15.000/MW/year. If combining this information with the energy yield values, this is equivalent to a maximum of €0.01/kWh. Currently, the costs of large-scale PV plants have decreased to about €1.0/Wp for static installations and about €1.7/Wp for the double-axis tracking ones. If we consider the values of the energy yield and O&M costs presented here, a 25-year life-cycle for the PV plant, a 5% discount rate and a financing of 80% of the capital with a 4.5% interest rate for 15 years leads to energy costs of around €0.09/kWh for static plants, €0.12/kWh for 2xhv tracking and €0.11/kWh for 2xvh tracking. All of them are low enough to talk not only about grid parity but also fuel parity in many scenarios. Actually, one of the larger costs nowadays are financial ones, so the importance of reducing the uncertainty associated to energy estimations by applying quality control processes.

4.6 PV evaluation tool: a software contribution

As we have already introduced, a complete quality control process should include an operation surveillance protocol, in order to detect failures and analyse the day-to-day performance of the installations. In the case of PV plants, this results in the need to analyse large amount of data coming from the field. A common standard in actual PV plants is to monitor the voltage and current values of each of the strings in a 15-minute frequency. In a 10 MW PV plant, for example, this implies more than half a million data each day, which has to be added to those coming from inverters, transformers, trackers... Obviously, any manual attempt to face such an analysis is unapproachable. Within this frame, we have design, developed and implemented PhotoVoltaic Evaluation Tool, PVET, a software instrument that allows not only the automatic detection of basic failures but also accomplishing in-depth analysis in PV plants. A first version of this software was developed to be run locally and included some manual intervention. This was applied to seven PV plants located in Italy, in which monthly analyses were performed during a year¹⁵. A further evolution of the tool is prepared to work remotely and fully automatic, and is being applied to the daily and monthly analysis of the Moquegua PV plant. This software is currently being commercialized through an IES-UPM spin-off company, Web-PV. The in-depth description of this software is out of the scope of this work, but its general design and some application examples are presented in the following sections.

¹⁵ The PV plants involved were Latina, Palermo-1, Palermo-2, Palermo-3, Palermo-4, Caltanissetta-1 and Caltanissetta-2.

4.6.1 Software design

PVET is a software tool designed to improve the monitoring knowledge and to ease the control of a PV plant through the analysis of its performance data. Its main objectives are:

- To verify the ambient and operating conditions records.
- To detect missing data.
- To detect and diagnose performance failures.
- To calculate operational ratios.
- To calculate the losses chain of the PV plant.
- To systematize and arrange all the data coming from the field.

Figure 74 presents the flow chart of the program, which starts from two types of data:

- 1) PV characteristics: devices features, location and geographical data and design topology, together with the results of the previous quality control steps, as energy yield forecasting or real efficiency parameters.
- 2) Temporal data of the period under analysis: data from the ambient and operating condition sensors, as well as that coming from each generation unit of the plant, (strings, inverters, trackers, transformers...).

Then, the software accomplishes the following analyses:

- 1) Data consistency: first of all both the data coming from conditions sensors and generation units is pre-analysed in order to detect missing data, erroneous values, and consistency failures. Filtering is done using, on the one hand, basic thresholds (negative productions or irradiances over the extra-atmospheric value are discarded) and, on the other hand, the combined ratios defined in section 0, for assuring mutual coherence between the signals.
- 2) Production analysis: this step includes the calculation of the final yields, performance ratios, efficiencies and energetic availabilities (as defined in section 4.4) of all the generation units, as well as their comparison to the initial estimations and the historic registered data. This analysis is performed for different time periods (15-minutes, hourly, daily, monthly...)
- 3) Unavoidable losses analysis: the losses chain is modelled starting from the operating conditions, according to equations presented in section 4.2. Besides, this procedure allows obtaining an estimated energy that can be compared to the real one, deriving in an energy difference that it is used also as a surveillance index.
- 4) Failure detection: the detection methods detailed in section 4.4, together with other statistical approaches are applied to energy, voltage and current values, in order to detect possible anomalous behaviour.

Then, the corresponding performance reports are automatically generated and delivered as the output of the program.

Figure 74. Flow chart of the PVET software.

4.6.2 Application results

This software has been applied to 7 PV plants in Italy during 2013. The O&M contractual requirements of these plants included a monthly performance analysis. Figure 75 to Figure 77 show some examples of analyses outputs. In particular, Figure 75 presents the ambient and operating temperatures evolution, in a 15-minute frequency, for the month of June 2013 in the Palermo-3 PV plant. For the same PV plant and month, Figure 76 shows the evolution of the temperature and low irradiance losses. Figure 77, in turn, shows the Sankey diagram of the energy production process, for the month of November 2013 in the Caltanissetta-2 PV plant.

Figure 75. 15-minute evolution of the ambient and the operating temperature during the month of June 2013 in the Palermo-3 PV plant.

Figure 76. 15-minute evolution of temperature and low irradiance losses during the month of June 2013 in the Palermo-3 PV plant. Losses are expressed as negative values while gains are represented by positive values.

Figure 77. Sankey diagram of the energy generation process during the month of November 2013 in the Caltanissetta-2 PV plant.

Moreover, the software is currently been applied to the analysis of the Moquegua PV plant. As a first phase of its application, the whole period from the 1st of January to the 31st of July

2015 was daily analysed. As a result of this analysis, the energy losses related to two phenomena that arose during the first months of PV plant operation were quantified. They were PID affection and early degradation of the connection boxes of some of the PV modules. Moreover, the software application allowed detecting, diagnosing and quantifying a tracking failure which was not detected during the on-site measurements.

4.6.2.1 Polarization induced degradation

PID affection was initially detected in the installation. As a consequence, two interventions were accomplished. First, the 7th of February 2014 the negative pole of all the generators was grounded. Then, the 17th of April 2014, specific PID recovery equipment was installed in half of the PV generators. For each of the string pairs (presented in section 4.4), the 15-minutes mean of current and voltage are recorded. Then, PVET was used to calculate the daily peak power value, P_d^* , obtained as the average value of the peak power calculated for every 15-minute interval, considering the following assumptions:

- Those moments with $G_{ef}(I) < 600 \text{ W/m}^2$ were discarded.
- Only those days with at least four hours with irradiations over 600 Wh/m^2 were considered.
- All those periods with tracking or inverter failures were not included. Inverter failures were defined according to section 4.4, and tracking failures detected as explained in section 4.6.2.3.

Figure 78 shows the evolution of P_d^* for the string pair number 1 during the period. A clear improvement can be observed after the grounding of the negative pole of the generators. The overall results showed a 3.0% power increase due to grounding and no appreciable effect due to the installation of the PID recovery equipment. In fact, the half of generators to which these equipment was connected, presented a 0.6% recovery, while the rest of them showed a 0.9% increase. This result allowed disregarding the installation of the recovery system for the rest of generators.

Figure 78. P_d^* evolution for the string pair number 1 of the Moquegua PV plant, between the 1st of January and the 31st of July 2015. An improvement can be clearly observable after the grounding of the negative pole of the generators.

4.6.2.2 Diodes

During the characterization tests, a hot-spot problem affecting the connection boxes of one of the type of PV modules of the PV plant was detected. It consisted in a problem in the strip that connected the bus-bar coming from the cells with the output cables (Figure 79-a). The connection of the strips with the cells is assured by a spring. The malfunctioning of this spring (derived from the stress produced by the thermal cycles to which the module is exposed in the field) caused the strip to not make a good contact with the bus-bar, increasing the resistance to current flow and causing a hot-spot (Figure 79-b). When the contact was too bad, it derived in electric arcs. In any case, the area heated up, what, in turns, increased the resistance of the metallization, accelerating the cycle. When the resistance at the contact point was large enough, it provoked the reverse biasing of the ensemble of cells, thus making the diode conducting. The current going through the diode contributed heating the region, and the process derived in the melting of the diode welding to the plate, the formation of new electric arcs and finally the breaking or disconnection of the diode and the burn of the plates (Figure 79-c and Figure 79-d).

This anomaly strongly affects the long-term durability of the modules, but also their energy production capacity. During the first phase, the affected substring lost power until its complete cancellation, when the diode was short-circuited. In the worst case, the diode broke or got disconnected, leading to the loss of the power of the whole string.

Figure 79. Examples of hot-spots derived from a bad connection between the plate and the bus-bar coming from the cells. (a) Detail of a plate and a diode. The hot-spot (100 °C versus 45 °C) is originated in the plate, while the diode remains at a quite low temperature (52.2 °C). (b) Box with two plates affected (100 °C and

83.1 °C versus 43 °C). (c) The large hot-spot (47 °C versus 98 °C) has burned the diode. (d) Example of connection box with two burn diodes, one of them directly detached.

In this case, the daily yield of each string pair was used as study variable. Figure 80 shows different cases of severe failures (those deriving in a disconnection of one of the two PV strings of the pair, which shows up as a produced energy decrease of around 50%) and medium failures (those provoking punctual disconnections or a delivered power reduction due to an increase of the series resistance).

Figure 80. Normalized relative daily yield of the 1982 string pairs of the Moquegua PV plant, for the 4th of May, 2015.

Once a failure was detected, the performance evolution of each singular pair was analyzed, in order to verify the occurrence of the failure and its duration, what leads to its quantification. Figure 81 presents the evolution along the period of the normalized relative daily yield for three string pairs affected by severe failures, medium failures and both of them. Tracking failures are also indicated, and will be further explained in the next section. In total, this problem led to a 23.2 MWh lost, 0.08% of the total energy produced in the period.

Figure 81. Normalized relative daily yield evolution over the analyzed period for string pair number: (a) 1020, which presents a severe failure; (b) 166, with a medium failure and (c) 1723, which shows severe and medium failures.

4.6.2.3 Tracking

The data analyses allowed detecting tracking failures. This kind of anomalies shows a periodical pattern, as the electronic control of the trackers is common for every six string pairs. Figure 82 shows the evolution of the normalized relative daily yield the 19th of February 2015. Beyond the existence of a severe failure, abnormal behaviour can be observed in all the generation units, with differences between with a periodic basis within a transformer. These events appear to be associated with tracking failures. These failures were subsequently verified, turning to the tracker position records.

Figure 82. Normalized relative daily yield for the 1982 string pairs of the Moquegua PV plant, the 19th of February 2015. Differences between trackers can be observed.

5 Back to modelling: the irradiance case

Long-term energy estimations are a key step to determine the feasibility of a photovoltaic (PV) project. They depend to a large extent on the calculation of the operating conditions, mainly on the effective in-plane irradiation. When lacking on-site measurements a common practice is to turn to available solar radiation databases. These are sometimes given in terms of hourly broadband horizontal values, so that the energy yield prediction exercise requires deriving it into the corresponding effective in-plane values. This is typically addressed by a sequence of three different steps. First, decomposing the global horizontal irradiation into its direct and diffuse components; second, transposing them from horizontal to in-plane values; third, reaching the effective values after correcting by the angular and spectral responses of the PV module. More often, solar radiation databases are given in terms of the monthly mean of daily broadband horizontal values. Then, PV yield assessment requires deriving the hourly values as a previous step.

Available literature offers several models for each of these steps. This results in a wide variety of possible model combinations. The objective of this paper is to review these different possibilities considering the whole conversion process, in terms of its impact on the final energy output estimations and its corresponding uncertainty. A total of 33 models, giving rise to 672 combinations, have been considered, some of which are novel. They have been selected according to the IES-UPM experience and from previous comparison studies

Accuracy is assessed by comparing the modelling predictions with the experimental values recorded at 16 commercial PV plants at the Mediterranean belt, where pyranometers and reference modules are available for measuring broadband horizontal and effective in-plane irradiances, respectively. This work is restricted to silicon PV modules, which represents more than 90% of today commercial installations.

5.1 Modelling from hourly values

Figure 83 shows the modelling path when global hourly irradiation values are the input, which is for example the case when the Typical Meteorological Year for the concerned location is available. Each box represents a modelling step and includes the corresponding end values. Following a widely extended practice, hourly irradiances (Wh/m^2) are assimilated to irradiance values (W/m^2) at the centre of the corresponding hour. The symbols G , B , D and AL respectively represent global, direct, diffuse and albedo.

Figure 83. Modelling process when starting from hourly irradiation data

5.1.1 Decomposition models

Decomposition models allow separating the global radiation into its direct and diffuse components through the diffuse fraction index, $k_d = D(0)/G(0)$, by means of empirical correlations of the latter with the clearness index, k_t . Table 26 summarizes the equations describing each of the 7 here-selected models and introduces the corresponding nomenclature. It includes the lineal equation proposed by Orgill-Holland (Orgill, 1977) as well as two polynomial relations defined by Erbs (Erbs, 1982) and De Miguel (De Miguel, 2001), the latter being proposed specifically for the Mediterranean region. Reindl (Reindl, 1990) and Skarveit (Skartveit, 1987) incorporate the solar elevation angle, α , as independent variable. A further proposal by Skarveit (Skartveit, 1998) adds an hour-to-hour variability index, σ_3 . Finally, it has been considered the BRL logistic model, proposed by Ridley (Ridley, 2010), which also considers a persistence parameter, ϕ , the daily clearness index, K_t , and the apparent solar time, A_s , as predictors.

Model	Equation
O-H (Orgill, 1977)	$k_d = \begin{cases} 1 - 0.249k_t & k_t < 0.35 \\ 1.577 - 1.84k_t & 0.35 \leq k_t \leq 0.75 \\ 0.177 & k_t > 0.75 \end{cases}$
Erh (Erbs, 1982)	$k_d = \begin{cases} 1 - 0.09k_t & k_t \leq 0.22 \\ 0.9511 - 0.1604k_t + 4.388k_t^2 - 16.638k_t^3 & 0.22 < k_t \leq 0.88 \\ +12.336k_t^4 & k_t > 0.88 \\ 0.177 & \end{cases}$
dMh (De Miguel, 2001)	$k_d = \begin{cases} 0.995 - 0.081k_t & k_t \leq 0.21 \\ 0.724 + 2.738k_t - 8.32k_t^2 + 4.967k_t^3 & 0.21 < k_t \leq 0.76 \\ 0.177 & k_t > 0.76 \end{cases}$
Reh (Reindl, 1990)	$k_d = \begin{cases} 1.02 - 0.254k_t + 0.0123\sin \alpha & k_t \leq 0.3 \\ 1.4 - 1.749k_t + 0.177\sin \alpha & 0.3 < k_t < 0.78 \\ 0.486k_t - 0.182\sin \alpha & k_t \geq 0.78 \end{cases}$
S-O (Skartveit, 1987)	$k_d = \begin{cases} 1 & k_t \leq 0.2 \\ f(k_t) = 1 - (1 - d_1)[0.27\sqrt{K} + 0.73K^2] & 0.2 \leq k_t \leq 1.09k_1 \\ 1 - 1.09k_1(1 - f(1.09k_1))/k_t & k_t \geq 1.09k_1 \end{cases}$ <p>where</p> $K = 0.5(1 + \sin(\pi(\frac{k_t - 0.2}{k_1 - 0.2}) - 0.5))$ $d_1 = 0.15 + 0.43\exp(-0.06\alpha)$ $k_1 = 0.87 - 0.56\exp(-0.06\alpha)$
BRL (Ridley, 2010)	$k_d = \frac{1}{1 + \exp(-5.32 + 7.28k_t - 0.03A_s - 0.0047\alpha + 1.72K_t + 1.08\phi)}$ <p>where</p> $\phi = \begin{cases} k_{t_{i+1}} & i = \text{sunrise} \\ \frac{k_{t_{i-1}} + k_{t_{i+1}}}{2} & \text{sunrise} < i < \text{sunset} \\ k_{t_{i-1}} & i = \text{sunset} \end{cases}$

<p style="text-align: center;">Skh (Skartveit, 1998)</p>	$k_d = d + \Delta(k_t, \alpha, \sigma_3)$ <p>where</p> $d = \begin{cases} 1 & k_t \leq 0.22 \\ f(k_t, \alpha) = 1 - (1 - d_1)[0.11\sqrt{K} + 0.15K + 0.74K^2] & 0.2 \leq k_t \leq k_2 \\ d_2 k_2 \frac{(1 - k_t)}{k_t(1 - k_2)} & k_2 \leq k_t \leq k_{max} \\ 1 - k_{max}(1 - d_{max})/k_t & k_t \geq k_{max} \end{cases}$ $K = 0.5(1 + \sin(\pi(\frac{k_t - 0.22}{k_1 - 0.22}) - \pi/2))$ $k_1 = 0.83 - 0.56\exp(-0.06\alpha)$ $k_2 = 0.95k_1$ $d_1 = 0.07 + 0.046(90 - \alpha)/(\alpha + 3)$ $d_2 = f(k_2, \alpha)$ $k_{max} = \frac{0.81^{(1/\sin \alpha)^{0.6}} + d_2 k_2 / (1 - k_2)}{1 + d_2 k_2 / (1 - k_2)}$ $\Delta(k_t, \alpha, \sigma_3) = \begin{cases} 0 & k_L \leq 0.14 \\ -3k_L^2(1 - k_L)\sigma_3^{1.3} & 0.14 \leq k_L \leq k_X \\ 3k_R(1 - k_R)^2\sigma_3^{0.6} & k_X \leq k_L \leq k_X + 0.71 \\ 0 & k_L \geq k_X + 0.71 \end{cases}$ $k_X = 0.56 - 0.32\exp(-0.06\alpha)$ $k_L = (k_t - 0.14)/(k_X - 0.14)$ $k_R = (k_t - k_X)/0.71$ $\sigma_3 = \begin{cases} \rho_i - \rho_{i+1} & i = \text{sunrise} \\ \sqrt{\frac{(\rho_i - \rho_{i-1})^2 + (\rho_i - \rho_{i+1})^2}{2}} & \text{sunrise} < i < \text{sunset} \\ \rho_i - \rho_{i-1} & i = \text{sunset} \end{cases}$ $\rho = k_t/k_1$
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Table 26. Hourly irradiation decomposition models

5.1.2 Transposition models

The irradiance components on an arbitrarily oriented surface are given by:

$$B = B(0)r_B$$

Equation 40. In-plane beam irradiance from horizontal beam irradiance.

$$D = D(0)r_D$$

Equation 41. In-plane diffuse irradiance from horizontal diffuse irradiance.

$$AL = G(0)r_{AL}$$

Equation 42. In-plane albedo irradiance from horizontal global irradiance.

The beam transposition factor is calculated straightforward from simple geometric considerations:

$$r_B = \frac{\cos \theta_i}{\cos \theta_z}$$

Equation 43. Beam transposition factor

where θ_i is the angle of incidence of the sun rays and θ_z is the zenithal angle of the sun, complementary of the elevation angle. Assuming isotropic albedo radiation the corresponding transposition factor is also immediately deduced:

$$r_{AL} = \rho \frac{1 - \cos \beta}{2}$$

Equation 44. Albedo transposition factor

where β is the tilted surface angle and ρ the ground reflection. In fact, the albedo radiation is scarcely relevant and rarely measured. In all the calculations, a general reflection value of 0.2 has been used.

The diffuse transposition factor depends on the assumption made for the sky radiance distribution. Table 27 presents the 8 here-selected modelling possibilities. Liu and Jordan considered an isotropic sky (Liu, 1960). Hay (Hay, 1980), Bugler (Bugler, 1977) and Klucher (Klucher, 1979) combined an isotropic and a circumsolar components using different weighting coefficients. Pérez (Perez, 1986) and Reindl (Reindl, 1990) added a horizon brightening component and Skarveit, in addition, compensated for the radiation around the zenith in overcast skies (Skartveit, 1986). Finally, Gueymard (Gueymard, 1987) constructed a weighted sum of clear and overcast sky irradiances.

Model	Equation
L-J (Liu, 1960)	$r_D = \frac{1 + \cos \beta}{2}$
Bug (Bugler, 1977)	$r_D = \frac{1 + \cos \beta}{2} + 0.05 \frac{B(I)}{D(0)} \left(\cos \theta_i + \frac{1}{\cos \theta_z} \left(\frac{1 + \cos \beta}{2} \right) \right)$
Hay (Hay, 1980)	$r_D = k_{HAY} r_B + (1 - k_{HAY}) \frac{1 + \cos \beta}{2}$ <p>where</p> $k_{HAY} = B(0)/B_0$
Klu (Klucher, 1979)	$r_D = \frac{1 + \cos \beta}{2} (1 + f_K \cos^2 \theta_i \cos^3 \theta_z) \left(1 + f_K \sin^3 \left(\frac{\beta}{2} \right) \right)$ <p>where</p> $f_K = 1 - \left(\frac{D(0)}{G(0)} \right)^2$
Per (Perez, 1986)	$r_D = k_1 r_B + (1 - k_1) \frac{1 + \cos \beta}{2} + k_2 \sin \beta$ <p>where k_1 and k_2 are determined by the Perez coefficients</p>

Ret (Reindl, 1990)	$r_D = k_{HAY}r_B + (1 - k_{HAY})\frac{1 + \cos \beta}{2} \left(1 + \sqrt{\frac{B(0)}{G(0)}} \sin^3 \left(\frac{\beta}{2} \right) \right)$
Skt (Skartveit, 1986)	$r_D = k_{HAY}r_B + (1 - k_{HAY} - Z)\frac{1 + \cos \beta}{2} + Z \cos \beta$ <p>where</p> $Z = \max(0.3 - 2F_{HAY}, 0)$
Gue (Gueymard, 1987)	$r_D = (1 - N_g)R_{d0} + N_gR_{d1}$ <p>where</p> $N_g = \max(\min(Y, 1), 0)$ $R_{d0} = \exp(a_0 + a_1 \cos \theta_i + a_2 \cos^2 \theta_i + a_3 \cos^3 \theta_i) + F(\beta)G(\alpha)$ $R_{d1} = \frac{1 + \cos \beta}{2} - \frac{\frac{1}{\pi}(\beta \cos \beta - \sin \beta) + \frac{1 - \cos \beta}{2}}{1 + \frac{3}{2b}}$ $Y = \begin{cases} 6.6667 \frac{D(0)}{G(0)} - 1.4167 & \text{if } \frac{D(0)}{G(0)} \leq 0.227 \\ 1.2121 \frac{D(0)}{G(0)} - 0.1758 & \text{otherwise} \end{cases}$ $F(\beta) = \frac{1 - 0.2249 \sin^2 \beta + 0.1231 \sin 2\beta - 0.0342 \sin 4\beta}{0.7751}$ <p>and $G(\gamma)$, a_0, a_1, a_2, a_3 are coefficients function of γ</p>

Table 27. Transposition models.

5.1.3 Angular and spectral corrections

Due to different shape and tilt, some dust affection differences can arise between pyranometers and reference modules. Moreover, dust affection can vary along the year according with the location characteristics (climate, rainfall, surroundings, etc.). In the absence of particular measurements concerning soiling evolution, we have postulated for all the PV plants a constant soiling reducing the transmittance at normal incidence by 2%. Then, the angular transmittance of PV reference modules has been calculated by means of the Martin-Ruiz model. This model proposes an equation for the ratio between the transmittance at θ_i and the transmittance at normal incidence, $F_B(\theta_i)$, which is directly applied to the direct and circumsolar irradiance components, and derives corresponding equations for the diffuse and albedo components, F_D and F_{AL} , respectively, as a function of the tilt surface. An advantage of this model is that internal coefficients can be adjusted to the amount of dirt. Table 28 sets out the corresponding formulae.

On the other hand, we have analysed whether the inclusion of a spectral model, in particular that proposed by Ruiz (Martin, 1999), improved the simulation results or not. This model characterizes the Earth atmosphere by means of k_t and AM (Air Mass) and defines a spectral correction factor, r_s , for each irradiance component. The corresponding equation is also given at Table 28. The final effective irradiance, G^{ef} , is given by adding the three corrected components:

$$G^{ef} = BF_B r_{sB} + DF_D r_{sD} + ALF_{AL} r_{sAL}$$

Equation 45. Effective in-plane irradiance.

Model	Equation
M-R (Martín, 2005)	$F_B = \frac{\exp(-\cos \theta / a_r) - \exp(-1/a_r)}{1 - \exp(-1/a_r)}$ $F_D = \exp \left[-\frac{1}{a_r} \left(c_1 \left(\sin \beta + \frac{\pi - \beta - \sin \beta}{1 + \cos \beta} \right) + c_2 \left(\sin \beta + \frac{\pi - \beta - \sin \beta}{1 + \cos \beta} \right)^2 \right) \right]$ $F_{AL} = \exp \left[-\frac{1}{a_r} \left(c_1 \left(\sin \beta + \frac{\beta - \sin \beta}{1 - \cos \beta} \right) + c_2 \left(\sin \beta + \frac{\beta - \sin \beta}{1 - \cos \beta} \right)^2 \right) \right]$ <p>where $c_1 = 4/(3\pi)$, and a_r and c_2 are two empirical coefficients related to soiling degree (in our case $a_r = 0.20$ and $c_2 = -0.054$).</p>
Rui (Martin, 1999)	$r_s = a_0 \exp(a_1(k_t - 0.74)) + a_2(AM - 1.5)$ <p>where a_0, a_1, a_2 are empirical coefficients that depend on the material energy bandgap and are different for B, D and AL</p>

Table 28. Description of angular and spectral losses models.

5.2 Modelling from monthly average of daily irradiation

Most widely available solar radiation databases (NASA, SWERA, PVGIS) use to provide information in terms of long term monthly averages of daily horizontal irradiation, $G_{d,m}(0)$. Subscripts “d” and “m” stand for daily and monthly average of daily values, respectively. Figure 84, Figure 86 and Figure 87 show three different modelling paths for deriving corresponding irradiance values, $G(0)$, from this information. Then, the modelling continues as explained in the previous section.

Figure 84. Modelling scheme when starting from monthly irradiation values and using monthly average profiles.

Following publication chronological order, the first approach (Figure 84) consists on defining the irradiance profiles in terms of irradiance divided by daily irradiation and on assuming that the profile of the extraterrestrial horizontal solar radiation, which is derived from simple geometrical considerations, translates directly into the profile of the diffuse component, while a slight empirical correction is needed for the global radiation. This allows obtaining global and diffuse irradiance values along the average day of each month $G(0)$ and $D(0)$. Corresponding equations are given at Table 29. The diffuse component of the average daily irradiation, $D_{dm}(0)$, is first derived from a decomposition model consisting, again, on an empirical relation between the clearness index and the diffuse fraction, but this time specifically adapted to monthly average daily values. Table 30 presents the four here-selected alternatives for such decomposition model: the lineal relation proposed by Page (Page, 1976), as well as two polynomial relations defined by

Collares (Collares-Pereira, 1979) and Erbs (Erbs, 1982) and a local correlation proposed by Macagnan (Macagnan, 1994). It is worth mentioning that some solar radiation databases also provide $D_{dm}(0)$ data (NASA, PVGIS), obviously avoiding the need of this decomposition step. Whichever the case, this approach requires dealing with only 12 days and is rather simple to implement but, because of the monthly averaging, the weight of the medium values at the corresponding irradiance frequency distribution tends to be larger than that observed in reality. Figure 3 present a representative example and clearly shows that high irradiances are more frequent in reality than on the derived mean profile.

Model	Equation
MS (Collares-Pereira, 1979)	$G(0) = r_G G_{d,m}(0)$ $D(0) = r_D D_{d,m}(0)$ $B(0) = G(0) - D(0)$ <p>where</p> $D_{d,m}(0) = G_{d,m}(0) \kappa_d$ $r_D = \frac{\pi}{24} \times \frac{\cos \omega - \cos \omega_S}{\omega_S \cos \omega_S - \sin \omega_S}$ $r_G = r_D (a + b \cos \omega)$ $a = 0.409 - 0.5016 \sin \omega_S + \pi/3$ $b = 0.6609 + 0.4767 \sin \omega_S + \pi/3$ <p>ω_S is the solar sunrise angle and ω is the solar angle.</p>

Table 29. Description of the sky models considered. The clear and cloudy models, as well as the clear models, differ one from each other in function of the diffuse treatment.

Model	Equation
Pag (Page, 1976)	$\kappa_d = 1 - 1.13 \kappa_t$
Com (Collares-Pereira, 1979)	<p>where</p> $\kappa_d = \begin{cases} a - b \cos(-1.4) & \kappa_t \leq 0.2 \\ a - b \cos(2\kappa_t - 0.9) & 0.2 < \kappa_t < 0.8 \\ a - b \cos(-0.2) & \kappa_t > 0.8 \end{cases}$ $a = 0.775 + 0.347 \left(\omega_S - \frac{\pi}{2} \right)$ $b = 0.505 + 0.261 \left(\omega_S - \frac{\pi}{2} \right)$
Erm (Erbs, 1982)	$\kappa_d = \begin{cases} \begin{cases} 0.6423 & \kappa_t < 0.3 \\ 1.391 - 3.56\kappa_t + 4.189\kappa_t^2 - 2.137\kappa_t^3 & 0.3 \leq \kappa_t \leq 0.8 \\ 0.1298 & \kappa_t > 0.8 \end{cases} & w_S \leq 1.4208 \\ \begin{cases} 0.6637 & \kappa_t < 0.3 \\ 1.311 - 3.022\kappa_t + 3.427\kappa_t^2 - 1.821\kappa_t^3 & 0.3 \leq \kappa_t \leq 0.8 \\ 0.1543 & \kappa_t > 0.8 \end{cases} & w_S > 1.4208 \end{cases}$
Mam (Macagnan, 1994)	$\kappa_d = \max(0.1, 0.758 - 0.428\kappa_t - 0.503K\kappa_t^2)$

Table 30. Monthly decomposition models.

Figure 85. Frequency distribution of the experimental and simulated (using an monthly average profile) hourly irradiances in a two-axis tracking system.

This problem can be overcome by synthetic generating of series of daily irradiation values (Figure 86) by the method proposed by Aguiar-Collares (Aguiar, 1988)]. This way, a different irradiation value, $G_d(0)$, is available for each day of the month. Then, a decomposition model, this time adapted to individual daily values, allows deriving the diffuse component, $D_d(0)$. Table 31 presents the 4 here selected alternatives for such decomposition model: two general polynomial relations, proposed by Collares (Collares-Pereira, 1979) and Erbs (Erbs, 1982), the latter depending also on the sunrise angle, w_s , and two local correlations, proposed by Macagnan (Macagnan, 1994) and De Miguel (De Miguel, 2001). Then the above described procedure for deriving irradiance profiles can be applied, leading to $G(0)$ and $D(0)$ values for each day. A possible refinement consists on the further direct generation of synthetic irradiance values, also following an Aguiar-Collares proposition (Aguiar, 1992). This way, a series of $G(0)$ is made available. It is worth nothing that this modelling path requires dealing with 365 days.

Figure 86. Modelling scheme when starting from monthly irradiation values and using synthetic series generation profiles.

Model	Equation
Cod (Collares-Pereira, 1979)	$K_d = \begin{cases} 0.99 & K_t \leq 0.17 \\ 1.188 - 2.272K_t + 9.473K_t^2 - 21.856K_t^3 + 14.648K_t^4 & 0.17 < K_t \leq 0.8 \\ 0.2427 & K_t > 0.8 \end{cases}$
Erd (Erbs, 1982)	$K_d = \begin{cases} w_s < 1.4208 & \begin{cases} 1 - 0.2727K_t + 2.4495K_t^2 - 11.9514K_t^3 + 9.3879K_t^4 & K_t < 0.715 \\ 0.143 & K_t \geq 0.715 \end{cases} \\ w_s \geq 1.4208 & \begin{cases} 1 + 0.2832K_t + 2.5557K_t^2 + 0.8448K_t^3 & K_t < 0.722 \\ 0.175 & K_t \geq 0.722 \end{cases} \end{cases}$
Mad (Macagnan, 1994)	$K_d = \begin{cases} 0.942 & K_t \leq 0.18 \\ 0.974 + 0.326K_t - 3.896K_t^2 + 2.661K_t^3 & 0.18 < K_t \leq 0.79 \\ 0.115 & K_t > 0.79 \end{cases}$
dMd (De Miguel, 2001)	$K_d = \begin{cases} 0.952 & K_t \leq 0.13 \\ 0.868 + 1.335K_t - 5.782K_t^2 + 3.721K_t^3 & 0.13 < K_t \leq 0.8 \\ 0.141 & K_t > 0.8 \end{cases}$

Table 31. Daily decomposition models.

Finally, recognizing that real skies can be understood as a succession of clear and cloudy moments (Figure 87), irradiance values for a particular day can also be derived from combining the irradiance profiles of a completely clear sky and of a completely overcast sky, whose combined irradiation coincides with the corresponding data of the concerned day, $G_{dm}(0)$. We have followed the proposal of the European Solar Radiation Atlas (ESRA) for modelling the direct and diffuse components of the clear sky, $B_{cs}(0)$ and $D_{cs}(0)$, respectively, using the Linke coefficients for the atmosphere turbidity as input data. Subsequent integrals give the corresponding daily irradiation values, $B_d^{CS}(0)$ and $D_d^{CS}(0)$, respectively. Note that defining T_{CS} as the fraction of the day that the sky remains clear, what ensures to be in compliance with the global irradiance input data, leads to:

$$T_{CS}[B_d^{CS}(0) + D_d^{CS}(0)] + (1 - T_{CS})D_d^{OS}(0) = G_{dm}(0)$$

Equation 46. Monthly mean of daily global irradiation, as a combination of clear and overcast periods.

where $D_d^{OS}(0)$ is the daily horizontal irradiation, all diffuse, of the overcast sky. Table 32 presents different assumptions for setting these mutually dependent variables T_{CS} and $D_d^{OS}(0)$. The simplest one is setting $D_d^{OS}(0)$. More sensible seems to assume a combination of $D_d^{CS}(0)$ and $D_{dm}(0)$ using the κ_t as weighting factor. Another appealing possibility is setting $T_{CS} = B_{dm}(0)/B_d^{CS}(0)$, where $B_{dm}(0)$ is the direct component of the daily irradiation, that can be deduced from a decomposition model adapted to monthly average daily values, as already given at Table 5. Whichever the case, this modelling path requires dealing with 24 days, 2 for each month, whose results are combined to get the final value. For example, the final monthly mean daily effective irradiation, G_{dm}^{ef} , is obtained as

$$G_{dm}^{ef} = G_{dm}^{CS,ef} T_{CS} + G_{dm}^{OS,ef} (1 - T_{CS})$$

Equation 47. Monthly mean of daily in-plane effective irradiation, as a combination of clear and overcast periods.

Figure 87. Modelling scheme when starting from monthly irradiation values and using synthetic series generation profiles.

Model	Equation
CS	$D_{dos}(0) = 0$
Cls	$D_{dos}(0) = \begin{cases} D_{dm}(0) & \kappa_t < 0.3 \\ D_{dm}(0) - \frac{D_{dm}(0) - D_{dcs}(0)}{0.5} (\kappa_t - 0.3) & 0.3 < \kappa_t < 0.8 \\ D_{dcs}(0) & \kappa_t > 0.8 \end{cases}$
Clk	$D_{dos}(0) = \frac{D_{dm}(0) - T_{CS} D_{dcs}(0)}{1 - T_{CS}}$ $T_{CS} = \frac{B_{dm}(0)}{B_{dcs}(0)}$

Table 32. Daily overcast diffuse models.

5.3 Experimental database

The experimental bases of this work are the broadband horizontal and effective in-plane irradiances respectively recorded from B class pyranometers and reference PV modules at sixteen commercial PV plants located in the Mediterranean region (Spain, Portugal and Italy). These installations include static structures, one-axis and two-axis tracking systems. They have been object of quality control and commissioning processes performed by the IES-UPM during the last 4 years. Figure 88 shows their location and type. All of them are in a relatively narrow latitude range and in a template climate region. Therefore, the results of this study are somehow restricted to sites with these characteristics. Both, pyranometers and reference modules are submitted to routine maintenance procedures on large PV plants, which typically include a cleaning per year, and are recalibrated biannually. We estimate the uncertainty of the original data is about 3-4%. Before the model evaluation, a data filtering is accomplished following the recommendations of Polo et al. (Polo, 2006). Then, one year of data has been considered in twelve installations, two years in other 5 and three years in a last PV plant. Hence, 25 years-plant data are available.

Hourly irradiation data have been derived from original ten minutes records. It is worth remembering that high frequency fluctuations of irradiance have not a real impact at energy levels and that modelling results from hourly irradiation have been demonstrated coherent with that coming from one-minute records.

Figure 88. Geographic distribution of the analysed PV plants. Squares represent static structures and triangles and circles represent 1-axis and 2-axis tracking configuration, respectively.

5.4 Model evaluation

The basic underlying exercise consists of comparing experimental and simulated effective irradiation values. Simulations are performed for each PV plant, for each year and for each possible combination of models. That leads to 3,472 different simulations when using hourly values as input (31 years–plant x 112 model combinations) and 17360 when using monthly mean values (31x560). Results are compared in both, hourly and yearly terms.

Attending to the difference between experimental and simulated values, model combinations are graded on the basis of three different evaluation metrics:

- Fitting to the experimental measurements, calculated through the relative Mean Weighted Bias Error (*MBWE*), according to:

$$MBWE = \frac{1}{n} \sum_i \frac{(G_{S,i}^{ef} - G_{E,i}^{ef}) \times G_{E,i}^{ef}}{G_E^{ef}}$$

Equation 48. Mean bias weighted error

where subscripts “S” and “E” refer to simulated and experimental values, respectively, while i stands for each of the n considered data. Note that errors are weighted by the irradiation, in order to give each value a relative importance in energy production terms. This way, irradiation error closely translates into energy production error, which is the relevant parameter on Yield Prediction exercises.

- Dispersion around the fit, through the relative Root Mean Squared Weighted Error (*RMSWE*), according to:

$$RMSWE = \frac{1}{n} \sqrt{\sum_i \left(\frac{(G_{E,i} - G_{S,i}) \times G_{E,i}}{\bar{G}_E} \right)^2}$$

Equation 49. Root mean square weighted error

These two latter statistics can be summarized through the relative combined weighted error (*CWE*), defined as:

$$CWE = \sqrt{(MBWE)^2 + (RMSWE)^2}$$

Equation 50. Combined weighted error.

Obviously, the lower *CWE* is the best the model is.

- Frequency distribution similarity, obtained through the Kolmogorov-Smirnov Index (KSI), according to:

$$KSI = \frac{\sum_j |f_{G_{h,E,j}} - f_{G_{h,S,j}}|}{a_{critical}}$$

Equation 51. Kolmogorov-Smirnov index

where $f_{G_{h,E,j}}$ is the frequency occurrence of the $G_{h,E}$ within a certain irradiance interval j ; $j \in 1, \dots, m$, being m the number of bins of the frequency distribution; $a_{critical} = 1.63/\sqrt{N} \times m$; and N the population size. For model comparison purposes it suffices to consider that the lower the KSI is the more similar the experimental and the simulated values are.

After performing all the simulations and calculating corresponding metrics, an ANOVA test is applied for each combination of models. This allows separating several statistical distributions in function of their variance and is especially useful when trying to identify different combined sources of uncertainty.

Finally, the evaluation has been, first, made with 25 years-plan coming from 14 “testing” installations, and the robustness of the derived lessons have been checked with 4 years-plant corresponding to the other 3 “control” installations.

5.5 Results

5.5.1 Modelling from hourly irradiation data

Figure 89 presents G_S^{ef} versus G_E^{ef} (with the BRL-Per-Rui model combination) for two PV plants representative of static and double-axis tracking, respectively. Both regression coefficients are close to one, within a $\pm 1.5\%$ range. A higher dispersion is observed in the tracking case, in coherence with the larger deviation from the horizontal plane and with possible tracking misalignments. It can be also observed how, in the static case, hourly irradiances are more homogeneously distributed while, in the tracking case, there is a concentration of values at low and especially high irradiances.

Figure 89. Experimental versus simulated (with the BRL-Per-No model combination) hourly irradiances in a static (20° tilt) and a double-axis tracking installations.

Figure 90 shows the same comparison in terms of daily irradiances. As expected from integration, the regression coefficients are virtually maintained (because errors have been weighted by irradiation), while the coefficients of determination increase.

Figure 90. Experimental versus simulated (with the BRL-Per-No model combination) daily irradiances in a static (20° tilt) and a double-axis tracking installations.

Figure 91-a shows, for the double-axis tracking PV plant, the cumulative frequency distribution of the irradiation measurements and two of the model combinations (Rei-

Gue-No and BRL-Per-Rui). Figure 91-b shows the differences between the simulations and the experimental measurements. Figure 91-c and Figure 91-d show the same distributions once weighted by the irradiation level. Variations induced by the weighting factor are clearly visible in the low irradiance range. The resulting KSI values are 41.8 and 65.6, respectively.

Figure 91. (a) Cumulative frequency distribution of the irradiance measurements and of two model combinations, Rei-Gue-No and BRL-Per-Rui, for a representative double-axis tracking PV plant. (b) Frequency differences between the two model combinations and the experimental measurements. (c) Weighted cumulative frequency distributions. (d) Weighted frequency differences.

Figure 92 presents the results of the ANOVA exercise applied to the CWE of the hourly irradiation results. It is worth remembering that each box shows the distribution of the CWE values corresponding to all the possible model combinations that include the model that gives name to the box. For example, the first box in the upper left corner of the figure presents the distribution of the 400 CWE values corresponding to the 25 years of data available for the testing PV plants multiplied by the 16 model combinations (8 transposition x 2 spectral) that use the O-H model for the decomposition step. For more details, Table 37 to Table 48(Annex 1) present the numerical values of the median resulting from the ANOVA exercise applied to the CWE and also to the MBWE, RWSWE and KSI. Looking for determining the best possible model combinations, and taking into account the uncertainty of the original data, the ensemble of this information suggests the following general comments:

- As $|MBWE| < 10\%$ and $|RMSWE| < 30\%$, all the selected models can be considered as “good” models, according with the criteria proposed by Badescu et al (Badescu, 2013)
- Erh, BRL, dMh and O-H decomposition models perform very similar and slightly better than Reh, S-O and Skh. Interestingly, complex models do not perform better than simpler ones. These results agree with those obtained in a recent and extensive review of 140 decomposition models.

- Per, Hay and Gue transposition models perform similarly, and better than L-J, Skt, Ret.
- There is not a significant advantage including the spectral correction model.

Figure 92. ANOVA analysis applied to the CWE of the hourly irradiation results for each of the models considered and for static and tracking systems separately.

The repetition of the ANOVA exercise, this time for the 4 years of data available at the control PV plants, essentially confirms these comments. Figure 12 shows, as an example, the comparison of the simulated (Reh-Per-Rui) and the experimental yearly irradiances, resulting from the integration of hourly values, and for all the installations. In average, simulations are 1.2% higher than measurements and the spread around the fitting line is low ($R^2 = 0.973$).

Figure 93. Yearly comparison between the experimental and the simulated (Reh-Per-Rui combination) effective in-plane irradiances.

Main results are presented in Annex 1 and lead to some additional comments:

- The Reh decomposition model improves its performance when considering yearly irradiances instead of hourly ones.
- The Bug and Klu transposition models also show a much better behaviour for yearly irradiances than for hourly ones.

These results allow selecting some model combinations as particularly suitable. Table 33 presents the corresponding metrics, again for the ensemble of the testing PV plants.

Model combination	Testing PV plants							
	Static				Double-axis tracking			
	MBWE	RMSWE	CWE	KSI	MBWE	RMSWE	CWE	KSI
<i>Best performing combinations</i>								
Skh-Per-No	-0.7	11.2	11.2	47	0.2	8.5	8.5	59.5
Erh-Per-Rui	-1.0	11.5	11.5	41	-2.0	7.7	7.9	41.4
BRL-Gue-No	-1.2	13.1	13.2	64	-0.6	9.0	9.0	60.8
O-H-Per-Rui	-1.6	11.8	11.9	52	-2.3	7.9	8.2	45.3
<i>Worst performing combinations</i>								
Reh-L-J-Rui	-7.6	20.9	22.2	114	-7.5	18.1	19.6	129.6
S-O-Skt-Rui	-15.0	21.3	26.1	233	-8.2	13.2	15.5	127.0

Table 33. Evaluation results of some example of model combinations among those with best and worst performance at hourly level.

¡Error! No se encuentra el origen de la referencia. presents the results of the ANOVA exercise for the testing PV plants but this time applied to the CWE of the total yearly irradiation results. As expected, the integration over the full year essentially maintains the MBWE values but significantly reduces the RMSWE and, therefore, the CWE ones. Previous comments regarding models suitability are confirmed when attending to yearly irradiances, as presented in

Model combination	Testing PV plants					
	Static			Double-axis tracking		
	MBWE	RMSWE	CWE	MBWE	RMSWE	CWE
<i>Best performing combinations</i>						
Skh-Per-No	-0.1	2.2	2.2	-1.0	1.9	2.1
Erh-Per-Rui	0.1	2.2	2.2	-1.7	2.5	3.0
BRL-Gue-No	-1.9	3.0	3.6	-1.9	2.5	3.2
O-H-Per-Rui	0.0	2.3	2.3	-1.8	2.5	3.1
<i>Worst performing combinations</i>						
Reh-L-J-Rui	-5.1	5.5	7.5	-5.0	5.5	7.4
S-O-Skt-Rui	-12.0	12.3	17.2	-6.5	6.8	9.4

Table 34. Again, the results coming from the control PV plants also confirm these comments.

Figure 94. ANOVA analysis applied to the CWE of the yearly irradiation results for each of the models considered and for static and tracking systems separately.

Model combination	Testing PV plants	
	Static	Double-axis tracking

	MBWE	RMSWE	CWE	MBWE	RMSWE	CWE
<i>Best performing combinations</i>						
Skh-Per-No	-0.1	2.2	2.2	-1.0	1.9	2.1
Erh-Per-Rui	0.1	2.2	2.2	-1.7	2.5	3.0
BRL-Gue-No	-1.9	3.0	3.6	-1.9	2.5	3.2
O-H-Per-Rui	0.0	2.3	2.3	-1.8	2.5	3.1
<i>Worst performing combinations</i>						
Reh-L-J-Rui	-5.1	5.5	7.5	-5.0	5.5	7.4
S-O-Skt-Rui	-12.0	12.3	17.2	-6.5	6.8	9.4

Table 34. Evaluation results of some example of model combinations among those with best and worst performance at yearly level.

5.5.2 Modelling from monthly averages of daily irradiation

Figure 95 and Figure 96 show the result of an ANOVA exercise applied to the CWE of the yearly irradiation results. Table 49 to Table 60(Annex 1) present the numerical results of this exercise. The following comments are derived:

- Regarding the irradiances distribution models, a different behaviour is observed depending on the structure type. In tracking systems, Clk, Syd and Syh outperform the rest of the models. In static structures, differences are lower and are CC and Cls models those presenting a better behaviour.
- The monthly decomposition models are nearly equivalent one to another.
- The Cod model for daily decomposition is the best performer in tracking systems while Mad fits better for static structures, although differences are smaller in this case.
- Regarding hourly decomposition, conclusions from the previous section are maintained, but adding the Reh model as the best performer for static structures.
- For transposition models Per, Hay, Gue and Klu models maintain their output for static structures. For tracking systems, only the Klu model maintains a good behaviour while Per, Hay and Gue worsen their performance and Ret and Skt improve it.
- The spectral correction still does not change significantly the results.
- In the frequency domain, none of the models satisfied the K-S test. However, regarding the decomposition models, Erh, Reh and BRL models present a better behaviour at hourly levels, Erd and Mad do it at daily levels and not appreciable difference is found at monthly levels. Hay, Per and Gue are the best transposition performers and the spectrum correction slightly worsens the fit.
- The KSI values indicates that to synthetically generate daily and hourly values is definitively better than relying on average days even when combinations of clear and cloudy days are considered. As expected, the bigger frequency distribution differences come from this simulation step.

Figure 95. ANOVA analysis applied to the CWE of the yearly irradiation results for each of the decomposition models and for static and tracking systems separately.

Figure 96. ANOVA analysis applied to the CWE of the yearly irradiation results for each of the irradiance distribution, transposition and spectrum models, and for static and tracking systems separately.

Again, the results obtained allow selecting some model combinations as particularly suitable. Tables 10 and 11 present their corresponding metrics, for static and double-axis tracking PV plants.

Model combination	Double-axis tracking testing PV plants			
	MBWE	RMSWE	CWE	KSI
<i>Best performing combinations</i>				
Sy1-dMd-Klu-No	0.1	3.8	3.8	243.7
Clk-Mam-Hay-No	-0.5	4.0	4.1	691.4
Sy2-BRL-Klu-No	-1.1	4.0	4.1	200.6
Clk-Pam-Per-No	0.4	4.1	4.1	364.2
Sy2-dMm-Bug-No	-0.2	4.2	4.2	214.1
<i>Worst performing combinations</i>				
Clk-Pam-Bug-No	19.7	19.9	28.0	351.4
CC-Erm-Hay-Rui	14.3	15.1	20.8	538.5

Table 35. Evaluation results of some example of model combinations among those with best and worst performance for double-axis tracking PV plants.

Model combination	Static testing PV plants			
	MBWE	RMSWE	CWE	KSI
<i>Best performing combinations</i>				
Clk-Pam-Hay-No	0.0	1.7	1.7	216.4
Sy2-O-H-Bug-No	0.3	1.7	1.7	132.0
CC-Com-L-J-No	0.0	1.7	1.7	364.3
Clk-Erm-Hay-No	0.1	1.7	1.7	202.0
Sy2-dMh-Klu-No	0.0	1.7	1.7	114.5
<i>Worst performing combinations</i>				
CC-Pam-Bug-No	9.2	9.3	13.0	407.9
Sy2-S-O-L-J-Rui	-7.5	7.9	10.9	286.0

Table 36. Evaluation results of some example of model combinations among those with best and worst performance for static PV plants.

5.6 Discussion

In the previous section, 30 models (7 of hourly decomposition, 4 of daily decomposition, 4 of monthly decomposition, 8 of transposition, 1 of spectral response and 6 for the daily evolution of irradiance) have been joined in 576 combinations, evaluated in 13 different locations and the results validated in other 3. Some general comments can be outlined:

- Certain location and metrics dependence has been observed during the process, thus not recommending deriving an absolute model classification from this study. This variation has been previously identified in the available literature as depending on the characteristics of the solar radiation at the site (diffuse/global ratio, turbidity, etc.), the orientation of the PV array, the solar cell and cover glass technology, etc.
- Nevertheless, there are some models that tend to be more globally stable and to have consistently better performance than others, as outlined in previous sections.

- Fitting is better for static structures than for double-axis tracking, both in mean values and dispersion terms, driving to lower uncertainty in energy estimation.
- Complex models do not perform better than simpler ones, what eases the incorporation of the models to engineering and projecting calculations, where a trade-off between accuracy and simplicity is welcome.
- Global models can perform as good as specific site-defined equations (for example, there are no remarkable differences between the De Miguel and the BRL propositions).
- Results for different periods (yearly or hourly) are coherent, as are the results from one year to another at the same location (the higher variations in the fitting coefficient are in the range of 2%).
- Regarding the performance in the frequency domain, the main improvement comes, as expected, from the use of synthetic series generation models.
- The best combination of models drive to almost 2% uncertainty both for static and double-axis tracking configurations when starting from hourly irradiances. The worst derived in 17% and 9% uncertainties, respectively.
- The best combination of models drive to 1.7% and 4% uncertainty for, respectively, static and double-axis tracking configurations when starting from monthly mean of daily irradiances. The worst derived in 13% and 28% uncertainties.

Finally, the identified model combinations can be directly applied to engineering design practices through any dedicated software. In our case, as explained in previous chapters, it has been used SISIFO, which incorporates all the described model possibilities.

6 Conclusions

PV technology has gone quickly over the learning curve in the last years, passing from being an expensive marginal energy source to a mature widespread technology that accounts already for a 1% of the total electricity consumption (up to 7% in some countries), growing at a 50% average rate in the last 8 years. It has reached grid parity in lots of countries and fuel parity in many scenarios. PV plants are a paradigmatic representative of this evolution. Nowadays, they are able to produce energy at less than 70 €/MWh, what makes them fully competitive. In this situation, exploitation margins are limited and financial costs play an important role when deciding whether a project is undertaken or not.

Current quality control procedures do not cover all the requirements PV plants are subjected to or the necessities investor demand, so they need to be updated and completed in order to guarantee a high reliability and a predictable performance of installations. In particular, the most used standards do not established how to accurately estimate the energy produced by a PV system, how to keep it under control once in the operation phase or how to deal with some of the most common problems a PV system can be affected by or how to quantify them.

In this thesis, a comprehensive quality control procedure has been presented, allowing reducing the estimation uncertainty and increasing the performance reliability. The main contributions to the state of the art have been

6.1 Quality control procedure

- A complete quality control procedure has been presented. This protocol goes from the initial yield estimation to the performance evaluation once in operation, and includes an on-site solar radiation measuring campaign, laboratory testing of PV module samples, the measure of operating conditions with reference modules and the accomplishment of in-field characterization campaigns during the commissioning phase.
- On-site campaigns before the construction of the PV plant should include the measurement of broadband horizontal irradiance through pyranometers and also effective in-plane irradiance through reference PV modules, incorporating the same tracking strategy that the future installation. It should last one year, assuring a careful maintenance of the measuring devices over the period. The implementation of this procedure allows calibrating the solar radiation databases used in the yield estimation exercise; identifying the relation between horizontal and in-plane irradiation, generating a local k_D - k_T correlation; and measuring dust impact.
- Laboratory testing of PV module samples have to go beyond the tests requested in the standard regulations and include the study of LID and PID affection and the measure of the temperature coefficients of the PV module (α , β and γ).
- Reference modules are still the best option to measure operating conditions in the field, as demonstrated in previous studies. Moreover, it has been proven their

larger stability over time, what make of them the most reliable option also in the long-term.

- The application of this quality control procedure allows obtaining more accurate yield estimations during the projecting phase, the corresponding uncertainty by a 60% to reach a final value of 3.2%. This result increases the $E_{P_{90}}$ and $E_{P_{95}}$ values by a 7% and an 11%, respectively, what improves the financing of PV.

6.2 Measurement contributions

- *I-V* curves of large PV generators: it has been shown that *I-V* curve analysis can also be applied to big PV generators (800 kW examples have been shown) and that, when taking some precautions (especially regarding the T_c), it is still a useful tool for characterizing them and therefore can be incorporated into maintenance procedures.
- Hot-spots: although hot-spots are a relatively frequent phenomenon in current PV generators and will likely persist in the next years, there is still not a widely accepted reference on how to face this problem within commercial frameworks. This thesis has reviewed the hot-spot related phenomena, paying particular attention to the fact that hot-spot appearance entails also operating voltage losses at the concerned PV module. Then, supported by experimental observations on 200 PV modules exhibiting hot-spots, it proposes a practical in-field approach to accomplish *IR* imaging inspection and straightforward acceptance and rejection criteria that address both the lifetime and the operational efficiency of the modules. First, hot-spots are characterized by the temperature increase in relation with the surroundings of the affected solar cells and normalized to the STC irradiance (1000 W/m²). Then, normalized hot-spot temperatures fewer than 10 °C are considered as not problematic, as they are caused by convective heat transfer and slight solar cells mismatch. On the other hand, those over 20 °C should imply a module rejection, as they entail significant probability of hot-spot absolute temperature exceed 85 °C. Those PV modules with hot-spot temperatures between 10 °C and 20 °C will be considered defective only if they have an effective power loss (measured as a decrease in the operating voltage in relation to a non-defective module of the same string) that exceeds the allowable peak power losses fixed at standard warranties.
- Dust as a hot-spot source: a real case showing that strongly non-homogeneous deposits of dust can lead to more significant consequences than the mere short-circuit current reduction resulting from transmittance losses has been presented. In particular, operating voltage losses arise when the affected PV modules are part of a string together with other cleaned (or less dusty) ones. These voltage losses can be several times larger than short-circuit ones. Moreover, significant hot-spot phenomena can arise leading to a threat to the PV modules' lifetime.
- Degradation: the long term performance of a 7 kWp PV array after 17 years of exposure in Madrid has been presented. The main visual defects are back-sheet delamination at the PET/PVF outer interface, antireflective coating degradation and cracks in the terminal boxes and in the joint between the frame and the

laminate. However, their impact on performance is rather low: the average peak power degradation is 9%, still within the power warranty offered by the manufacturer; peak power standard deviation remains basically constant; and insulation resistance is several times larger than that required to pass the corresponding IEC 61215 tests successfully.

6.3 Operating results

- In order to complete the quality control after the start-up of the installation, it has been developed a procedure to estimate the energy produced by a PV installation, starting from the monitoring data and the results of previous quality control steps.
- In particular, it has been presented a method to verify the validity of the incoming data by means of coherence tests, and a protocol to detect and diagnose operating failures. This procedure has been incorporated to a software solution, which application allows an in-depth knowledge of the state of health of a PV installation.
- The application of this protocol to several PV installations has resulted in a 0.8% yearly difference between estimated and real production. In another vein, the 240 MW·year analysed PV installations have presented an energetic availability as high as 99.5%, with an associated *PR* of 0.8.

6.4 Back to modelling

- Passing from broadband horizontal to effective in-plane irradiance is a key step for the yield assessment of PV plants. Accomplishing this process entails different steps, including the pass from monthly mean values to irradiance time series. Supported by the experimental measurements in 16 PV installations in the Mediterranean region, a review of the modelling state of the art has been carried out for every step of the process. The best combination options are given in terms of combined weighted error and frequency distribution similarity, together with some general advices that allow reducing the radiation estimation uncertainty.

7 Future research

The procedures exposed in previous chapters allow improving the state of the art of quality control for large PV installations. However, as the PV technology situation is continuously evolving and has not reached a steady paradigm, the quality control methods are still an open process that will have to continue adapting the new installations needs and requirements. In this sense, the following aspects represent some of the appealing forthcoming questions to be analysed in detail:

- Regarding the laboratory testing of PV module samples, it is necessary to incorporate examinations to foresee the problems arising in PV modules in the field. Nowadays connection boxes are one of the main sources of incidences. Specific testing protocols, paying special attention to diodes and the connectors themselves are appealing. On the other hand, despite the inclusion of electroluminescence and PID generation and recovery tests start to be usual in commercial frameworks, there are still no specific standards regulating the results of the tests and establishing concrete acceptance/rejection criteria. Moreover, accelerated degradation test should be implemented, including dump heat test and other climatic chamber possibilities.
- Regarding in-field measurements, most of the detection and characterization methods are satisfactory proven. Nevertheless, along the same lines of the hot-spot proposal presented in this work, specific criteria should be developed in order to progressively face new arising problems.
- The failure detection protocols provide accurate results (for example, string failures implying less than 0.5% daily production losses). However, there is still room for more diagnosing procedures. A possible improving path is to develop analyses based on the combination of various indexes, what is usually known as “stamp collections”. Some advances have been already achieved in this field, but none of them allow automatic diagnosing, which is capital to be able to deal with the huge amount of data that PV plants generate. Therefore, the door is open for new contributions in this field.
- Regarding also operation surveillance, more contributions could be added related to operating conditions dispersion along large PV fields and their influence in PV plants performance and production estimation uncertainty.
- Back to the modelling step, irradiance has been proven to be the main contributor to estimation uncertainty. Nevertheless, operating temperature also contributes to it. Along the same lines of the irradiance model review, different operating temperature calculation possibilities could be tested, using the records coming from the already available dataset. In particular, wind effect could be addressed and differences depending on the climate or PV plant physiognomy pointed out.
- Finally, in order to benefit small PV installations with the results obtained in large PV plants, specific quality control protocols could be defined, considering the advances made.

Annex 1: Results of the ANOVA test for irradiation modelling

1. Hourly irradiation data

a. Testing population

i. Hourly results

Hourly decomposition	Static (%)				2x tracking (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
O-H	-2,9	9,4	10,1	62	-3,0	16,4	16,8	95
Erh	-2,5	9,3	9,9	62	-2,3	15,7	16,6	91
Reh	-4,0	14,9	15,2	75	-1,2	18,5	19,1	80
S-O	-4,3	10,3	11,6	75	-5,7	16,1	16,8	101
BRL	-2,1	9,9	10,5	65	-1,4	15,7	16,6	106
dMh	-2,9	9,4	10,1	61	-3,0	16,3	16,4	90
Skh	-4,2	10,2	11,5	74	-5,0	15,4	15,8	93

Table 37. Hourly correlation models

Translation	Static (%)				2x tracking (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
L-J	-4,8	10,3	11,4	72	-10,4	18,3	20,8	134
Hay	-2,1	8,9	9,2	58	-2,1	13,5	13,8	62
Per	-0,7	8,5	8,5	61	-0,3	12,0	12,1	52
Gue	-2,2	8,7	9,0	57	-2,8	13,4	13,7	59
Skt	-5,2	10,6	11,7	75	-11,4	19,3	22,1	145
Bug	3,3	13,4	14,2	103	1,3	15,4	15,5	89
Ret	-4,7	10,2	11,2	71	-9,7	17,6	19,8	123
Klu	2,9	15,6	15,9	123	-1,4	18,0	18,0	93

Table 38. Diffuse decomposition models

Spectrum	Static (%)				2x tracking (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
NoS	-0,7	9,6	10,2	61,9	-2,0	17,4	18,2	109
Rui	-4,0	10,3	11,5	78,5	-4,5	15,8	16,1	87

Table 39. Spectrum correction

ii. Yearly results

Hourly decomposition	Static (%)			2x tracking (%)		
	MBE	RMSE	CE	MBE	RMSE	CE
O-H	-2,5	3,4	4,5	-2,7	3,5	4,4
Erh	-2,4	3,4	4,4	-2,5	3,3	4,1
Reh	-2,8	3,8	4,9	-0,2	3,6	4,6
S-O	-3,8	4,3	5,7	-4,4	5,0	6,7
BRL	-2,3	3,1	4,1	-1,5	3,0	3,6
dMh	-2,5	3,4	4,5	-2,6	3,4	4,3
Skh	-3,7	4,1	5,5	-3,8	4,4	5,8

Table 40. Hourly correlation models

Translation	Static (%)			2x tracking (%)		
	MBE	RMSE	CE	MBE	RMSE	CE
L-J	-4,5	4,9	6,6	-8,6	9,0	12,5
Hay	-2,5	3,0	3,9	-2,0	3,0	3,6
Per	-1,2	2,1	2,4	0,3	2,3	2,4
Gue	-2,6	3,1	4,1	-3,0	3,7	4,7
Skt	-4,8	5,2	7,0	-9,7	10,1	14,0
Bug	1,5	2,2	2,7	0,4	2,8	3,1
Ret	-4,3	4,7	6,4	-8,1	8,4	11,7
Klu	0,5	2,0	2,3	-2,1	3,0	3,7

Table 41. Diffuse decomposition models

Spectrum	Static (%)			2x tracking (%)		
	MBE	RMSE	CE	MBE	RMSE	CE
NoS	-1,9	3,0	3,9	-2,7	3,6	4,6
Rui	-3,2	3,7	4,8	-3,4	4,0	5,3

Table 42. Spectrum correction

b. Control population
i. Hourly results

Hourly decomposition	Static (%)				2x tracking (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
O-H	0,3	13,6	13,8	110	-4,2	13,9	14,3	62
Erh	0,6	13,6	13,7	107	-3,6	13,7	14,0	49
Reh	-0,2	14,2	14,2	81	-0,3	16,0	16,7	63
S-O	-1,3	14,0	14,4	118	-6,3	13,4	14,9	103
BRL	0,9	14,3	14,6	118	-2,4	13,2	13,2	50
dMh	0,2	13,6	13,8	110	-4,2	13,6	13,9	64
Skh	-1,0	13,5	14,0	111	-5,3	12,5	13,6	92

Table 43. Hourly correlation models

Translation	Static (%)				2x tracking (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
L-J	-3,2	13,6	13,9	119	-11,8	17,6	21,2	145
Hay	0,6	13,3	13,3	101	-2,8	11,5	12,0	39
Per	2,6	13,0	13,4	91	-0,5	10,1	10,4	34
Gue	0,5	13,0	13,1	98	-3,5	11,3	11,9	40
Skt	-3,8	13,8	14,3	121	-12,9	18,7	22,6	159
Bug	6,2	17,4	18,8	115	0,9	12,3	12,5	64
Ret	-2,9	13,5	13,7	117	-11,1	16,9	20,2	133
Klu	4,7	17,6	18,3	121	-2,6	14,6	15,2	53

Table 44. Diffuse decomposition models

Spectrum	Static (%)				2x tracking (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
NoS	1,8	13,8	14,1	116	-2,9	14,8	15,3	66
Rui	-0,6	13,4	13,9	103	-4,8	13,6	14,6	80

Table 45. Spectrum correction

ii. Yearly results

Hourly decomposition	Static (%)			2x tracking (%)		
	MBE	RMSE	CE	MBE	RMSE	CE
O-H	0,2	5,7	5,9	-3,5	3,5	4,9
Erh	0,2	5,7	5,9	-3,4	3,5	4,9
Reh	0,5	4,5	4,7	0,4	3,7	5,2
S-O	-0,6	5,7	6,2	-4,2	4,3	6,0
BRL	0,3	5,9	6,1	-2,1	2,3	3,2
dMh	0,1	5,7	5,9	-3,4	3,4	4,8
Skh	-0,4	5,5	6,1	-3,5	3,5	4,9

Table 46. Hourly correlation models

Translation	Static (%)			2x tracking (%)		
	MBE	RMSE	CE	MBE	RMSE	CE
L-J	-2,0	5,8	6,2	-9,5	9,6	13,5
Hay	0,2	5,3	5,3	-2,6	2,6	3,6
Per	1,9	5,5	6,0	0,3	0,4	0,6
Gue	0,0	5,3	5,4	-3,5	3,5	5,0
Skt	-2,5	6,0	6,5	-10,6	10,7	15,1
Bug	4,1	7,3	8,4	0,3	0,8	1,0
Ret	-1,7	5,7	6,0	-8,9	9,0	12,6
Klu	2,4	5,7	6,2	-3,3	3,4	4,7

Table 47. Diffuse decomposition models

Spectrum	Static (%)			2x tracking (%)		
	MBE	RMSE	CE	MBE	RMSE	CE
NoS	0,4	5,9	6,3	-3,4	3,5	4,9
Rui	-0,1	5,3	5,5	-3,4	3,6	5,0

Table 48. Spectrum correction

2. Monthly irradiation data

a. Testing population

Hourly decomposition	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
O-H	-2,7	4,7	5,5	226	-4,3	4,7	6,4	185
Erh	-2,3	4,6	5,1	204	-4,2	4,6	6,2	175
Reh	2,4	6,0	7,4	149	-2,5	3,1	4,1	151
S-O	-3,6	5,4	6,4	268	-5,1	5,5	7,5	223
BRL	-0,8	5,0	5,5	190	-4,3	4,7	6,4	181
dMh	-2,4	4,7	5,2	225	-4,2	4,7	6,3	184
Skh	-3,4	5,1	6,0	239	-4,8	5,2	7,1	214

Table 49. Hourly correlation models

Daily decomposition	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
Cod	-1,4	4,7	5,1	243	-3,8	4,3	5,7	158
Erd	2,4	6,3	7,7	158	-2,5	3,1	4,0	113
Mad	3,0	6,4	8,0	176	-2,1	2,9	3,7	121
dMd	0,2	5,8	6,9	218	-3,1	3,7	4,8	144

Table 50. Daily correlation models

Monthly decomposition	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
Pag	7,5	8,4	11,2	408	0,0	2,2	2,5	300
Com	7,1	8,5	11,4	417	0,0	2,2	2,5	311
Erm	8,0	8,8	11,9	403	0,0	2,1	2,5	311
Mam	7,6	8,7	11,5	403	0,0	2,1	2,5	312

Table 51. Monthly correlation models

Translation	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
L-J	-0,3	6,9	9,1	353	-2,9	3,5	4,5	245
Hay	6,4	7,9	10,2	338	-1,3	2,2	2,6	242
Per	7,8	9,1	11,9	334	0,3	2,1	2,3	234
Gue	6,1	7,8	9,9	338	-1,0	2,2	2,6	236
Skt	-1,2	7,4	9,6	390	-3,1	3,7	4,9	247
Bug	9,4	10,7	14,2	379	3,6	3,9	5,2	300
Ret	0,3	7,1	9,3	423	-2,8	3,4	4,4	309
Klu	5,0	6,5	8,2	403	0,9	2,1	2,5	303

Table 52. Diffuse decomposition models

Spectrum	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
NoS	3,6	6,8	8,8	334	-1,0	2,5	3,0	211
Rui	6,3	8,4	11,2	394	-0,4	2,4	2,8	300

Table 53. Spectrum correction

Irradiance distribution	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
CM	3,3	6,4	7,8	405	-1,4	2,9	3,7	298
CC	12,1	12,8	17,7	413	1,1	2,0	2,3	314
Cls	9,2	9,9	13,5	401	0,4	1,9	2,1	298
Clk	-1,9	4,7	5,4	420	-2,7	3,4	4,5	315
Syd	0,3	5,8	6,9	193	-2,8	3,4	4,4	119
Syh	-2,5	4,9	5,7	201	-4,0	4,5	6,0	171

Table 54. Irradiance distribution models

b. Control population

Hourly decomposition	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
O - H	-4,4	5,4	6,9	288	-1,6	5,7	5,8	169
Erb	-4,3	5,5	7,0	264	-1,6	5,7	5,9	161
Rei	0,9	4,4	5,8	217	0,5	5,2	5,9	141
S - O	-5,3	5,9	7,9	327	-2,4	5,9	6,5	204
BRL	-3,1	4,7	5,6	259	-1,6	5,8	6,0	166
DeM	-4,0	5,1	6,5	285	-1,5	5,6	5,8	168
Ska	-5,3	5,9	7,9	304	-2,1	5,7	6,2	194

Table 55. Hourly correlation models

Daily decomposition	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
Cod	-3,0	4,1	5,1	293	-1,0	5,5	5,9	149
Erd	0,9	5,3	6,8	222	0,5	5,5	6,0	130
Mad	2,4	5,7	7,8	244	1,3	5,6	5,9	129
dMd	-1,0	4,5	5,7	271	-0,1	5,6	6,1	142

Table 56. Daily correlation models

Monthly decomposition	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
Pag	8,6	8,8	12,3	484	4,2	6,3	7,6	352
Com	8,3	9,2	12,9	498	4,5	6,4	7,8	364
Erm	9,7	10,0	13,9	489	4,5	6,4	7,8	359
Mam	9,2	9,3	13,1	490	4,3	6,4	7,7	363

Table 57. Monthly correlation models

Translation	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
L-J	-0,1	7,0	9,9	396	0,5	5,6	6,4	329
Hay	6,6	7,0	9,6	378	2,8	5,8	6,3	325
Per	9,2	9,5	13,2	328	4,5	6,6	8,1	331
Gue	7,1	7,6	10,6	339	3,2	5,8	6,6	297
Skt	-1,0	7,7	10,6	449	0,0	5,7	6,4	330
Bug	10,3	10,8	14,9	459	7,1	8,9	11,4	341
Ret	0,6	7,3	10,3	501	0,6	5,7	6,5	363
Klu	4,9	5,7	7,7	488	4,2	6,4	7,7	355

Table 58. Diffuse decomposition models

Spectrum	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
NoS	3,6	7,0	9,5	349	2,4	6,1	6,8	291
Rui	7,2	8,9	12,4	474	3,5	6,0	7,2	353

Table 59. Spectrum corrections

Irradiance distribution	2x tracking (%)				Static (%)			
	MBE	RMSE	CE	KSI	MBE	RMSE	CE	KSI
CM	4,0	5,4	7,3	490	2,7	5,5	6,0	352
CC	14,9	15,0	21,1	490	6,2	7,6	9,8	373
Cls	9,8	10,1	14,1	483	4,5	6,7	8,1	353
Clk	-2,3	3,6	4,7	493	0,4	5,1	5,2	377
Syd	-0,8	5,0	6,4	244	0,0	5,5	6,0	156
Syh	-4,4	5,4	7,2	265	-1,5	5,7	6,0	229

Table 60. Irradiance distribution models

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