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SERENDI PV

Key Performance Indicators (KPIs) on state of the art of PV reliability, performance, profitability and grid integration

Assessment of KPIs on state of the art for PV reliability, performance, profitability and grid integration

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Summary

The purpose of this report is to define the main parameters affecting the performance, reliability, profitability, environmental impact and grid integration of PV systems and components, while also providing a reference of the state-of-the-art for each one of these parameters. Special attention is given to those parameters considered as **K**ey **P**erformance **I**ndicators (**KPIs**) within the context of the SERENDI-PV project.

The present report is divided in two sub-sections. The first presents a detailed list of the Key Performance Indicators which are relevant to the assessment of PV projects and will be particularly implemented to assess the SERENDI-PV project. In this section each KPI is clearly defined providing a benchmark value from publicly available data, and (when possible) an evaluation on assets relevant to the project before its execution.

The second section deals with PV and grid interactions. First, by describing the different types of PV systems and their connection to the grids. Then, by analysing the interactions between these systems and the network, defining grid-specific performance parameters and services which could be provided by PV systems to the grid (both at DSO level and at TSO level).

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1 EXECUTIVE SUMMARY

1.1 Description of the deliverable content and purpose

The purpose of this report is to define the main parameters affecting the performance, reliability, profitability, environmental impact and grid integration of PV systems and components, while also providing a reference of the state-of-the-art for each one of these parameters. Special attention is given to those parameters considered as **K**ey **P**erformance **I**ndicators (**KPIs**) within the context of the SERENDI-PV project.

This document is the output of task 1.1 of the SERENDI-PV project. After an introduction to the project and a short description of the objectives of this report, the main contents are divided in two chapters.

The first section (chapter 3) provides a definition for the main parameters considered when assessing PV systems. These have been classified in the following groups according to their importance and to their links to the work packages of the SERENDI-PV project: performance, reliability, power modelling and forecasting, monitoring, profitability, environmental impact and finally accuracy and uncertainty of PV production estimates. The state of the art is provided for each one of these parameters. The parameters which are considered relevant in the frame of the SERENDI-PV project have been clearly identified as KPIs (section 3.8). These KPIs will be studied at different stages of the project to measure its impact.

More specifically, parameters related to performance and reliability are found in sections 3.1 and 3.2, respectively. Those related to modelling and forecasting, are in section 3.3. Monitoring-related parameters are in section 3.4. Sections 3.5 and 3.6 introduce parameters relevant to profitability and environmental aspects of the PV systems. More details to clarify the impact on the accuracy and uncertainty of using experimental and/or modelled data are presented in section 3.7.

The second section (Chapter 4) provides an introduction to the main interactions of PV power production with the grid and the challenges to overcome in order to achieve the required levels of penetration and achieve the Paris Agreement targets, while maintaining a high-quality functioning electrical network.

The aspects linked to the impact of PV integration in the grid presented on this report consist on the following: voltage deviation (4.1); system management (4.2); power quality (4.3), congestion management (4.4); data integration to TSOs & DSOs (4.5)

Grid specific indicators are introduced in section 4.7, including aspects like the Possibility to control power output (4.7.1), the Obligation to participate in system services (4.7.2), the Possibility to participate in market-based system services(4.7.3) or the availability of life data 4.7.4. Section 4.8 presents an Inventory of services provided by PV systems to the grid comprising for example inertial response; ramp rate control, among others. Finally, the services which are provided by PV solar today are presented at the end of this document.

1.2 Reference material

The second part of this document is strongly linked to another report published simultaneously in the scope of this project where more details about the integration of PV to the grids can be found: **"D1.2 - Assessment and characterization of the current PV fleet capabilities and regulatory environment for grid integration".**

1.3 Relation with other activities in the project

Table 1.1 depicts the main links of this deliverable to other activities (work packages, tasks, deliverables, etc.) within SERENDI-PV project. The table should be considered along with the current document for further understanding of the deliverable contents and purpose.

Table 1.1: Relation between current deliverable and other activities in the project

Project activity	Relation with current deliverable
All	The current deliverable feeds from and to all project activities and work packages. This report serves as a reference for all the technical activities in the SERENDI-PV project. It provides a clear definition of the main parameters affecting PV production and enabling the assessment of aspects linked to its performance, reliability, profitability, environmental impact and grid integration. The KPIs defined in this report will serve as a reference to assess the long-term impact of the different activities in the project.

1.4 Abbreviation list

Table 1.2: Abbreviation list

Abbreviation	Meaning
AgroPV	Agro Photovoltaics
BAPV	Building Applied Photovoltaics or Building Attached Photovoltaics
BESS	Battery Energy Storage System
BG	Bifacial Gain
BIPV	Building Integrated Photovoltaics
BoS	Balance of System
BPR	Bifacial Performance Ratio
CAPEX	Capital Expenditures
CdTe	Cadmium Telluride
CF	Capacity Utilisation Factor
CIGS	Copper, Indium, Gallium and Selenium
CPR	Temperature Corrected Performance Ratio
DEM	Digital Elevation Model
DER	Distributed Energy Resources
DG	Distribution Grid / Distributed Generators
DIF	Diffuse Horizontal Irradiation
DNI	Direct Normal Irradiance

DSM	Demand Side Management
DSO	Distribution System Operator
e.g.	*exempli gratia* – For example
EPI	Energy Performance Index
ESCO	Energy Service Company
GHI	Global Horizontal Irradiation
GM	Ground Mounted
GTI	Global Tilted Irradiation
HV	High Voltage
ICT	Information and Communication Technology
i.e.	*id est* – that is to say
IEA PVPS	International Energy Agency Photovoltaic Power Systems Programme
IPP	Independent Power Producer
IRR	Internal Return Rate
KPI	Key Performance Indicator
kWh	kilowatt-hour
LCoE	Levelized Cost of Electricity
LID	Light Induced Degradation
LV	Low Voltage
MAE	Mean Absolute Error
MBE	Mean Bias Error
MIT	Minimum Irradiance Threshold
MV	Medium Voltage
NPV	Net Present Value
NWP	Numerical Weather Prediction
O	Observation
O&M	Operation and Maintenance
OLTC	On-Load Tap Changer
OPEX	Operational Expenditures
P0	Rated PV Power
P	PV power
PLR	Performance Loss Rate
PCC	Point of Common Coupling
PET	Polyethylene Terephthalate
PPA	Power Purchase Agreement

PR	Performance Ratio
PtG	Power to Gas technology
PU	Public
PV	Photovoltaics
PVF	Polyvinyl Fluoride
RES	Renewable Energy Systems
RfG(NC)	Requirements for Generators (Network Code)
RMSE	Root Mean Square Error
RT	Rooftop
SCR	Short Circuit Ratio
SR	Soiling Ratio
SS	Skill Score
STC	Standard Test Conditions
SuR	Surface Ratio
T	Task
TG	Tracker Gain
TRL	Technology Readiness Level
TSO	Transmission System Operator
VRE	Variable Renewable energy
WACC	Weighted Average Cost of Capital
WP	Work Package
Y_a	PV Array Energy Yield
Y_E	Expected Energy Yield
Y_f	PV Final Energy Yield
Y_r	Reference Yield

2 INTRODUCTION

PV is today one of the cheapest options to decarbonize the electricity sector and thus decrease GHG emissions in Europe. The latest "*Net zero by 2050*" report by the IEA calls for a rapid scaling up of solar PV, estimating global annual additions of 630 GW per year by 2030 [1]. While the latest Snapshot report from the JRC projects 1 TW annual PV production required by the same year to maintain the targets of the Paris Agreement [2]. Regardless of the exact value, PV appears more and more as a viable electricity production option for Europe. Its competitiveness has improved significantly in the last few years and is expected to continue improving [3].

With 151 GW cumulative installed capacity in the EU [1] at the end of 2020 [4] and a projected cumulative capacity of at least 300 GW to reach the EU's 55% GHG emissions reduction target by 2030, and between 455 to 605 GW for the net-zero target by 2050; one thing is for certain: the penetration of PV in the electricity mix is growing. The annual EU PV market is expected to grow from 19.4 GW in 2020 (~150 GW cumulative) to 50-80 GW annually by 2030.

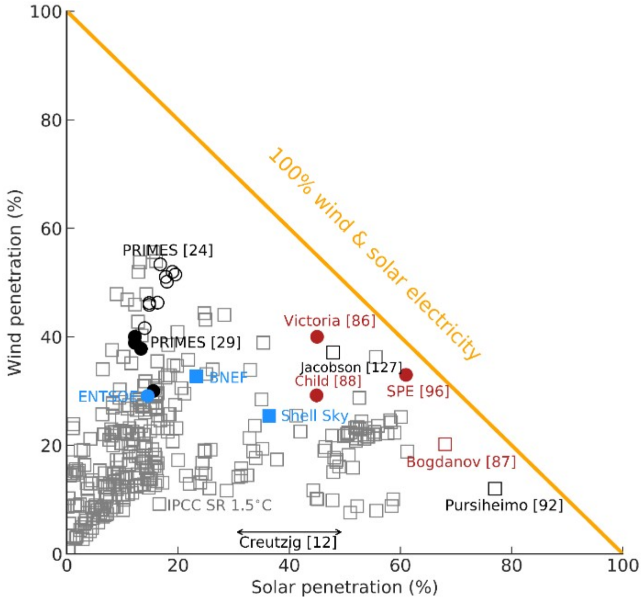


Figure 2.1: Solar and wind contribution to electricity supply in IPCC 1.5C global warming report [5]
The circles indicate models for EU, while the squares represent global models. Grey squares represent the IAM scenarios included in the IPCC 1.5°C Special report. Red dots correspond to cost-optimal scenarios obtained with energy models which include sector coupling, uninterrupted hourly resolution, and network modelling.

In 2020 the penetration of PV power generation in Europe was 6% of the demand. Estimated values for the PV penetration by 2050 range from 20 up to 69% depending on the model implemented for the estimation (see Figure 2.1) [5]. In real time, the penetration of PV in some countries can already reach very high levels based on current installed capacity. For example, a highlight occurred in Germany on the 1st of July of 2020 when PV represented 56% of the total instantaneous electricity production. Sometimes this occurs at the same level as high wind power as well: this creates new challenges for grid operators and specially to TSOs to maintain system stability, frequency and avoid congestion. With higher shares of PV electricity expected in the coming years, the management of the grids will imply to better know the current and future contribution of PV to energy supply but also to the provision of ancillary services.

The SERENDI-PV project intends to increase utility-friendly integration of PV generation at high penetration levels and the performance and profitability of PV systems. This implies to deal with the constraints limiting PV penetration in the electricity grids actors (operators, ESCOS, electricity companies, traders), to improve the performances of PV components and systems, to increase the knowledge of the PV fleet by grid operators, its energy production, its performances and the availability and reliability to offer network services, when necessary, with a clear perspective on the evolution of performances over time.

[1] Including the UK

The SERENDI-PV project has 5 main objectives:

1. Increased reliability and performance of PV systems and components
2. Decreased LCoE from PV generation
3. Higher profitability from PV generation into the grids
4. Grid stability at high PV penetration levels
5. Lower barriers to enhance the development of the PV sector in Europe

With the ambition to advance beyond the state of the art, the SERENDI-PV project has been organized according to the following work packages:

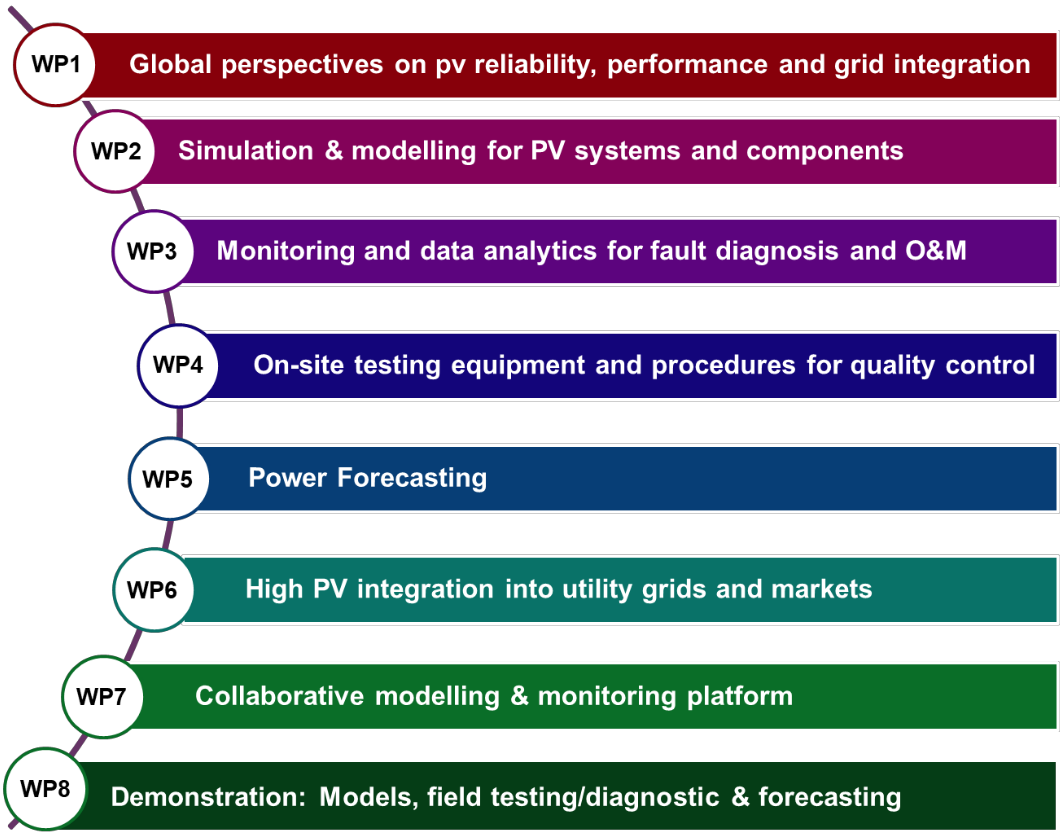


Figure 2.2: Technical Work Packages in the SERENDI-PV project

3 ASSESSMENT OF KPIS ON STATE OF THE ART OF PV RELIABILITY, PERFORMANCE, PROFITABILITY, AND ENVIRONMENTAL IMPACT

This chapter presents a set of parameters, typically implemented for the evaluation of diverse aspects affecting the production of PV systems, linking the most relevant areas of a PV installation to the work packages defined in the SERENDI-PV project. Parameters related to performance and reliability are found in sections 3.1 and 3.2, respectively. Those related to modelling and forecasting, whether calculated with measured or simulated data are in section 3.3. Monitoring-related parameters are in section 3.4. Sections 3.5 and 3.6 introduce parameters relevant to profitability and environmental aspects of the PV systems. More details to clarify the impact on the accuracy and uncertainty of using experimental and/or modelled data are presented in section 3.7. Section 3.8 clearly defines which of these parameters are selected as KPIs for the SERENDI-PV project.

The electrical energy produced by a photovoltaic system depends on several factors (Table 3.1). The most important is the solar radiation impinging on the surface of the PV modules. The performance of a PV system also depends on local climate and environmental conditions. Ultimately, a technical design of a PV system (especially of the PV module field) determines how the power production is aligned with local conditions.

Table 3.1 Factors affecting PV power production

	Group of factors	Parameters/components	What do they influence	Sources of uncertainty
Location-specific	Solar radiation	Global tilted (plane of array) irradiation, GTI (calculated from global horizontal, direct normal and diffuse irradiation: GHI, DNI, DIF)	Power generation System performance System availability	Accuracy of estimate Year-by-year variability Long-term trends
	Weather	Air temperature, wind speed, humidity		
	Environment	Albedo, snow, dust, pollution		
Technology-specific	PV technology	PV modules, inverters, other components System architecture	System performance System availability System reliability	Failures System availability Grid availability (curtailment, blackouts)

Methodology

A definition is provided for each parameter and, when possible, a reference value for the state of the art is presented. The parameters, which are considered relevant in the frame of the SERENDI-PV project are singled out as Key Performance Indicators (**KPIs**) in section 3.8.

Different types of KPIs require data at different granularity levels (time step) as shown in Table 3.2. While different applications also require specifications on data granularity, which are shown in Table 3.3.

Table 3.2: Choice of data Type of data used for regular performance evaluation

	Data from solar and meteorological models	Site-adapted data from solar and meteorological models	Quality-controlled measurements, gap filled by model data
Small residential systems	Yes	-	-
Medium size systems (rooftop and ground-mounted)	Yes	(Yes)	(Yes)
Utility scale systems	-	Yes	Yes

Table 3.3: Selection of data for evaluation of PV systems: Data granularity as a function of the application

	Long-term energy yield estimate + contracting	Technical design and system optimisation	Performance evaluation of PV assets	Monitoring and failure detection	Data quality control	Forecasting, trading grid integration
Long term averages (yearly and monthly)	Yes	-	Yes (as a reference)	-	-	-
Monthly/yearly time series	Yes	-	Yes	-	-	-
Daily time series	-	(Yes)	(Yes)	Yes	-	Yes
Hourly	-	(Yes)	-	Yes	(Yes)	Yes
Sub-hourly (1 to 15 minutes)		Yes	-	Yes	Yes	Yes

3.1 PV Performance-Related parameters

The performance of a PV system is strongly affected by diverse factors: the solar resource available at the installation site, the choice of technology and how is this technology impacted by environmental constraints (like changes in temperature and the temperature coefficient of the devices) and the specifics about the installation (is there a tracker? What is the tilt of the installation? etc.). When assessing the production of a PV plant, the parameters defined in this section help to differentiate the causes resulting in differences in the total energy produced.

3.1.1 Yields

The yield indicators are related to the incident energy in the PV collector plane. They have been defined to facilitate a comparison between different PV installations. They are independent of the array size. Figure 3.1 depicts the main yield concepts as a function of the energy flow from the solar radiation to the grid. The reference yield provides information about the available solar resource, while the array yield includes the array collection losses. The final energy yield also includes the system losses. Finally, the expected energy yield, describes the expected energy yield for a given array in alternate current (AC) calculated based on measurements and simulations. Specifications on how to calculate them are provided in this sub-section.

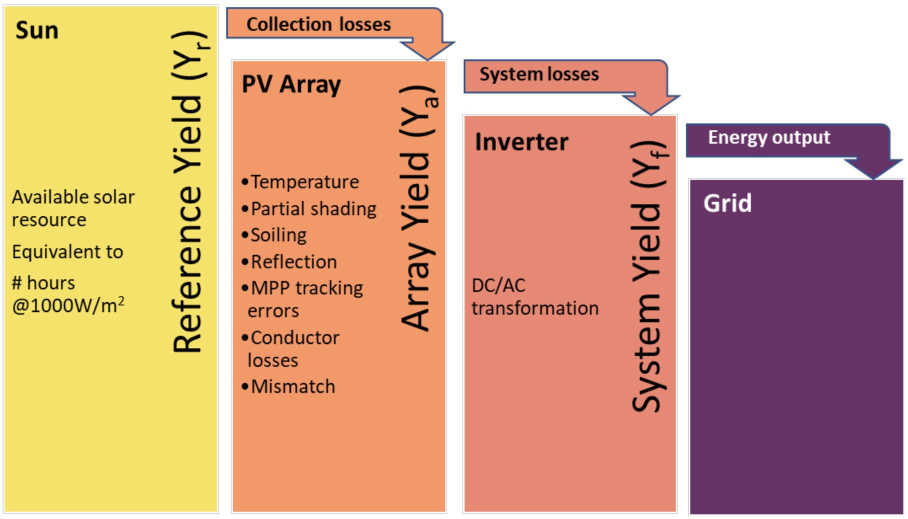


Figure 3.1: Energy yield flow evaluation scheme for grid-connected PV systems

3.1.1.1 Reference Yield (Yr)

The refence yield (Y_r), as defined in the IEC 61724-1 standard, is the total irradiation in the plane of array (H) divided by the reference irradiance (G_{ef}) used in standard testing conditions (STC) [Eq. 1].

$$Y_r = \frac{H}{G_{ref}} \qquad \textbf{(Eq. 1)}$$

In STC: G_{ref} equals 1000 W/m², the air mass is 1.5AM and the temperature is 25°C.

The unit for the irradiation H is kWh/m², while G_{ref} is kW/m². The Y_r unit is kWh/kW, which is equivalent to the solar radiation resource for a PV system [1]. It can also be considered as the number of hours in a defined time period (day/month/year), during which the system would be exposed to the STC reference irradiance level.

The irradiance can be measured with pyranometers or with reference cells. Reference cells can be chosen to feature a technology close to the one of the plant's PV modules, thus having a similar behaviour. Yet, there are some relevant disadvantages: the response from a reference cell depends on local environmental parameters (temperature, solar spectrum), the output signal may be less stable, and less accurate. The values recorded by reference cells can be compared between the sites only considering the higher uncertainty of the instruments. There are also temperature-corrected reference cells, which can then be as accurate as pyranometers, but these are very expensive.

Well-maintained pyranometers, are more accurate, and are considered as a stable reference source of a site, which makes them comparable across different sites and technologies. Therefore, the pyranometers are typically used for bankability studies.

State of the art:

Solar radiation maps, showing the regional irradiation differences, can be found e.g. at https://solargis.com/maps-and-gis-data/overview (source Solargis)

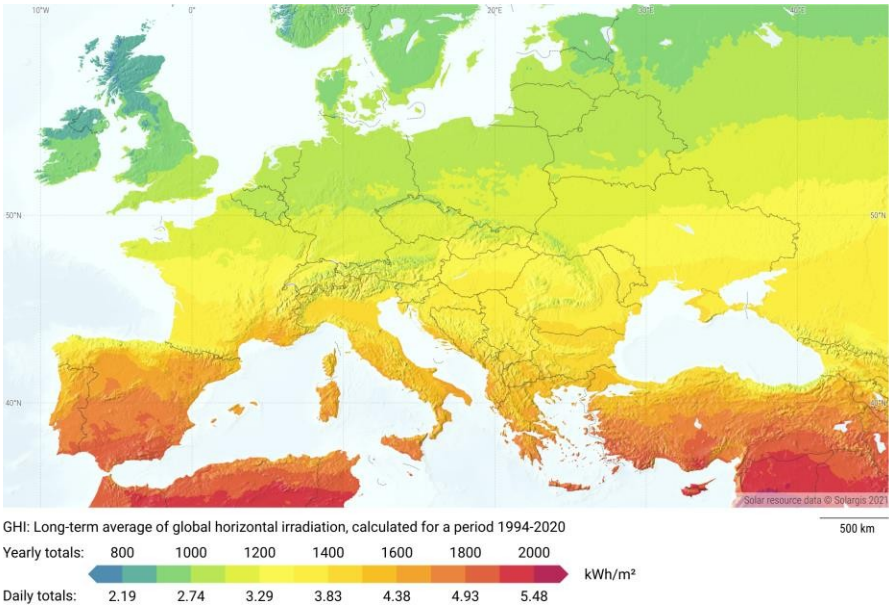


Figure 3.2: Global horizontal irradiation, long term yearly average (LTA), period 1994-2020 [source Solargis]

Solar radiation varies from year to year, as it is illustrated in the following maps showing the percentage difference between the global horizontal irradiation for a given year, compared with the long-term average (LTA) calculated over 27 years (Figure 3.3).

More maps can be seen here: https://solargis.com/products/monitor/solar-performance-maps.

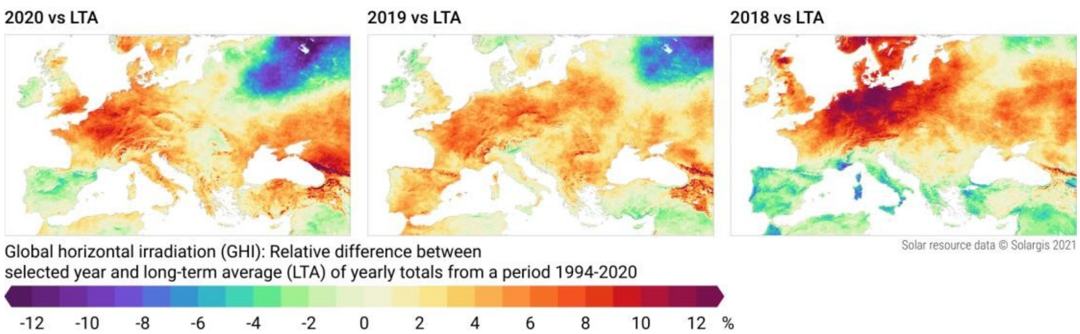


Figure 3.3: Relative difference of global horizontal irradiation for years 2018, 2019 and 2020 compared to long term average (LTA) calculated for a period 1994-2020 (Source: Solargis)

3.1.1.2 Energy Yield (Ya and Yf)

The PV Array energy Yield (Y_a), as defined in the IEC 61724-1 standard, is the ratio between the DC energy output for a given PV array (EA), in kWh, to its rated peak power (P_0) in kW_p. See Eq. 2.

$$Y_A = \frac{E_A}{P_0} \qquad \textbf{(Eq. 2)}$$

The array yield only includes capture losses, which can be caused by temperature effects, soiling, partial shading; poor MPP tracking, among others. It can also be interpreted as the number of hours in a defined time period during which a PV system would have to operate at its peak power to provide its total energy output (DC).

The final system energy yield (Y_F) is the ratio between the system net AC energy output (E_{out}) in kWh divided by the rated DC peak power of the PV array installed in the system (P_0) in kW_p, sometimes also called nameplate power, See Eq. 3.

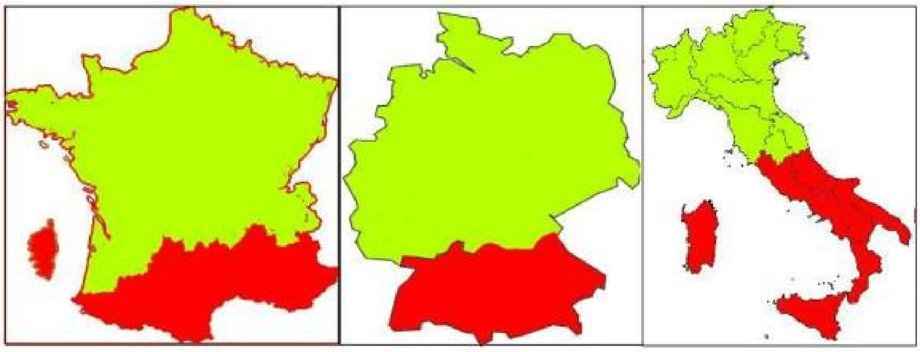
$$Y_F = \frac{E_{out}}{P_0} \qquad \textbf{(Eq. 3)}$$

- Y_F also includes the conversion losses from DC to AC.
- P_0 is equal to the sum of power of individual modules in an array, under STC and usually during the initial operation phase.

State of the art:

Energy yields are often used to estimate the potential production of PV installations.

For instance, participants in the IEA PVPS Task 13 collected appropriate data for a large amount of PV rooftop systems.



	Country	2011 kWh/kW_p	2012 kWh/kW_p	2013 kWh/kW_p
North	Germany	979 ± 153	937 ± 126	882 ± 109
South		1081 ± 154	1044 ± 121	922 ± 125
North	France	1030 ± 362	993 ± 201	959 ± 154
South		1099 ± 96	1092 ± 224	1103 ± 166
North	Italy	1219 ± 170	1177 ± 157	1094 ± 148
South		1352 ± 113	1337 ± 199	1288 ± 203

Figure 3.4: Yearly yields in European countries [6]

Potential production maps are also available (Figure 3.5), see more maps here: https://globalsolaratlas.info/download.

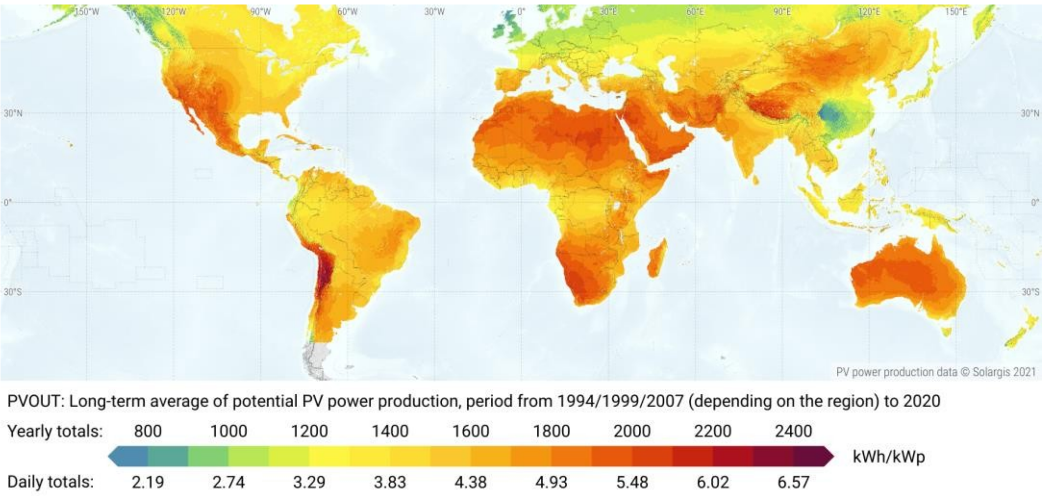


Figure 3.5: Photovoltaic power potential (Source: Global Solar Atlas and Solargis)

Energy yield strongly depends on the solar irradiation and thus vary from one location to another, and from one year to another.

3.1.1.3 Expected Energy Yield (Y_E)

The Expected Energy Yield (Y_E) expresses the energy, which should have been produced over a certain period. It is based on measurements (irradiances and temperatures) and simulations. It is calculated with the following formula:

$$Y_E = \frac{PR_{exp}}{Y_r} \qquad \text{(Eq. 4)}$$

- PR_{exp} is the expected Performance Ratio, which is calculated using the plant characteristics, the irradiance and/or temperatures as inputs (see definition hereafter).
- Y_E is expressed in kWh/kW$_p$ and it refers to the expected specific AC energy. Its value depends on the simulation accuracy. It should be therefore used only for the identification of performance flaws and comparison of plants.

State of the art:

See section 3.4.1 about EPI, which is based on the expected energy yield.

3.1.2 Performance ratios

3.1.2.1 Performance ratio (PR)

The most widely used metric for reliability remains the performance ratio, which provides an indication of the performance in real conditions of the PV plants. In the IEC 61724-1 standard, the Performance Ratio (PR) is defined as the ratio between the Final Energy Yield (Y_f) and the Reference Yield (Y_r) according to the following formula:

$$PR = \frac{Y_f}{Y_r} = \frac{E_{out}}{P_0} / \frac{H}{G_{ref}} \qquad \text{(Eq. 5)}$$

Remembering that: the final energy yield equals the output energy from the system to the network in AC (E_{out}) weighted by the peak power of the installation in DC (P_0); and that the reference yield is the total irradiation in the plane of array (*H*) divided by the reference irradiance (G_{ef}). It is the equivalent of the ratio between the effective energy produced (AC), which could be injected to the grid, and the energy available from the sun. It accounts for all the losses in the PV system, such as: efficiency loss of modules and converters, resistive losses in cables, temperature, and irradiance effects, far and near shadowing, soiling, components outages, etc. It has no unit. It can be calculated at the inverter level and/or the delivery point level, and on a daily, monthly, or yearly basis.

The PR value also depends on the choice of the solar radiation data, which can be acquired from three sources:

- Pyranometers,
- Satellite-based solar models
- Silicon reference cells

There are different views on the most accurate source for radiation measurements. Some of the consortium partners consider that the best accuracy is obtained by pyranometers, on conditions that high accuracy sensors are used, and they are well cleaned, maintained and calibrated. Pyranometers offer stable signal for a variety of geographical conditions, but they require steady attention by skilled and trained personnel. Solar radiation from satellite-based models offers cost effective and accurate solutions suitable for majority of multiple cases. Other consortium partners consider that temperature-controlled, calibrated reference cells are as accurate, as pyranometers; with the disadvantage that a technology matching is required. This makes them more relevant for specific applications. In the frame of the SERENDI-PV project, where an assessment of multiple PV plants is performed, and different types of module technology are compared we will not implement radiation measurements from reference cells.

The Performance Ratio (PR) has been defined as a **Key Performance Indicator** to assess the performance of PV systems in the frame of the SERENDI-PV project. A selection of SERENDI-PV partners' PV power plants will be assessed according to this KPI on a yearly basis and at the delivery point level (See 3.8). Quality-controlled solar radiation data from solar models and high-accuracy ground-measured instruments will be used. Table 3.4 presents an example of a PR loss breakdown in a PV system.

Table 3.4: Contribution of each loss factor in the yield assessment [Fraunhofer ISE]. The starting point of PR = 100 is considered after applying the horizon shading as this become the annual insolation seen by the PV modules [7]

Annual values	**uncertainty**	**value**	**gains/loss**	**PR**
	%	kWh/m²	%	%
global irradiation on horizontal plane	4.0	1248		
irradiation on module plane	2.5	1448	16.0	
shading				
horizon shading	0.5	1445	-0.2	100.0
row shading	2.0	1422	-1.7	98.3
object shading	3.0	1422	0.0	98.3
soiling	0.5	1414	-0.5	97.9
deviations from STC				
reflection losses	0.5	1376	-2.7	95.2
	%	kWh/kWp	%	%
spectral losses	0.5	1363	-1.0	94.3
irradiation-dependent losses	0.8	1342	-1.5	92.9
temperature-dependent losses	1.0	1309	-2.5	90.5
mismatch losses	0.5	1298	-0.8	89.8
DC cable losses	0.5	1287	-0.8	89.1
inverter losses	1.5	1272	-1.2	88.0
inverter power limitation	0.5	1272	-0.1	88.0
additional consumption	0.5	1270	-0.1	87.9
AC cable losses low voltage	0.5	1265	-0.4	87.5
Transformer medium voltage	0.5	1253	-0.9	86.7
AC cable losses medium voltage	0.5	1252	-0.1	86.6
Transformer high voltage	0.0	1252	0.0	86.6
total	**6.5**	**1252**		**86.6**

State of the art:

A tendency of increasing annual PR values during the past years is observed due to improved maintenance, higher component reliability, better design and to an increased number of large PV plants, which are easier to manage. In 2014, a review of the typical Performance Ratio values in Europe was published and its conclusions are summarized in Table 3.5

Table 3.5: Average values and ranges of performance ratio for installations from different decades [8]

Installed	Location	Range of *PR*	Average *PR*
1980s	Worldwide	0.50 - 0.75	Individual estimates
1990s	Worldwide	0.25 - 0.90	0.66
1990s	Worldwide	0.50 - 0.85	0.65 - 0.70
1990s	Germany	0.38 - 0.88	0.67
2000s	France	0.52 - 0.96	0.76
2000s	Belgium	0.52 - 0.93	0.78
2000s	Taiwan	<0.3 - >0.9	0.74
2000s	Germany	0.70 - 0.90	0.84

In 2015, another study presented the state of the art of the PV systems in Europe corresponding to a range of yearly integrated PR values between 0.6 and 0.9, with average values typically between 0.75 and 0.8. This represents a difference of some 30% between the best and the worst performers. Ideally, the PV sector should aim at reaching PR values around 0.9 for most of the PV systems to be installed in the future.

The Performance Ratio is here the main indicator, for each segment. We will consider the SET Plan for PV's latest document as the key reference for PR levels to be reached. Since the SET-Plan targets an increase from 78% (2017) to 85% (2025) for residential and small-scale installations and an increase from 81% (2017) to 90% (2025) for commercial, industrial and ground-mounted PV plants, we consider here at the end of the project respectively 84% and 89%. Floating PV plants have been assessed between 78% and 90% by SERIS. We will target the same level as for large-scale ground-mounted PV: 89%.

The base-case PR losses scenario that were established by the SET-PLAN in 2017, i.e. PR = 78% for residential and small-scale PV systems and 81% for large-scale PV plants, were in part grounded on the assessment of the performance of dozens of thousands of PV systems in Europe [9], [10], [11], [12], [13], [14], [15], [16]. The data came from all over Europe, but the residential PV installations were mainly located in France, UK and Belgium, while the large-scale PV plants were mainly located in Spain and Italy. The data provided a representative picture of the PV reality in Europe because PV plants are typically encountered in the southern part of Europe, while smaller scale and residential PV systems are typically encountered in mid-latitude Western Europe. Therefore, these are the two PV development contexts that the SET-PLAN also associated with the PR values that were taken as the starting point for 2017 and for the goals to be reached in 2025.

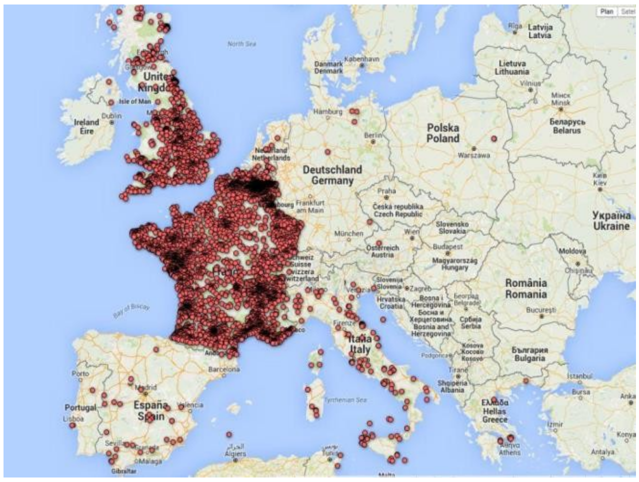


Figure 3.6: Location of the 31,000+ PV systems analysed in Leloux et al., 2015. Most of them are in the UK, Belgium, France, Spain and Italy

The PR data analysed in Europe show that that the Weibull explains very well the PR distribution from PR values ranging from 0.6 to 0.9. This range values represents most of the P' systems. On the contrary, the Weib distribution does not explain the da for PR values lower than 0.6 and highe than 0.9. The former PV systems ar subject to severe performanc problems and faults. On the other har the Weibull law does not explain the F values that are higher than 0.9, wh also suggests that these PV system belong to a different population. It very likely that these PR values ar simply not real, and that they ar caused by uncertainties on sola irradiation data, as well as on th azimuth and tilt angles and the peak power of the PV systems. This probability plot allows us to suggest that the yearly integrated PR values ranging from 0.6 to 0.9 are representative of the state-of-the-art for PV systems in Europe

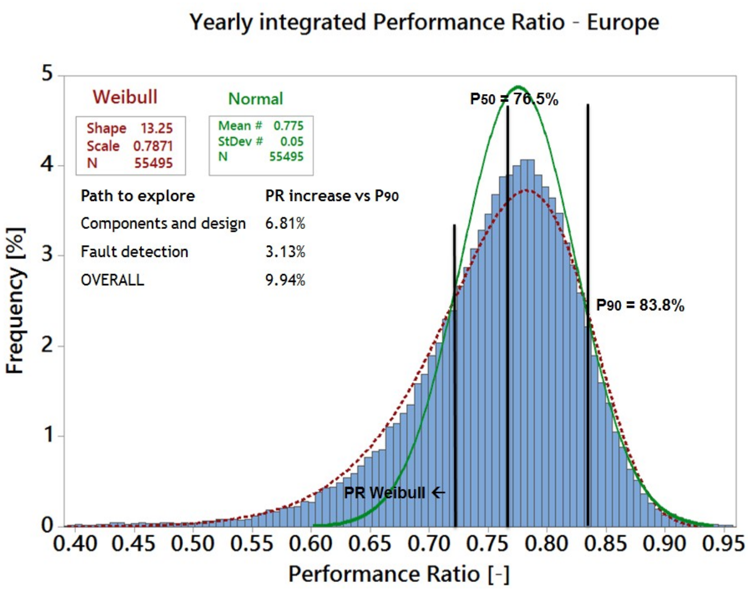


Figure 3.7: The distribution does not follow a normal (or gaussian) distribution because it is skewed towards the low PR values. The distribution is better fit by a Weibull distribution

More recent studies have assessed the performance of several thousands of PV systems in Europe [17], [18], [19] and they have confirmed the PV values and trends already observed in the previous studies.

From these analyses, it can be concluded, as it was done in the SET-PLAN 2017, that the state of the art of the PV systems in Europe corresponds to a range of yearly integrated PR values between 0.6 and 0.9, with average values typically between 0.75 and 0.8. This represents a difference of some 30% between the best and the worst performers. Ideally, the PV sector should aim at reaching PR values around 0.9 for most of the PV systems to be installed in the future. In practice, the highest PR values might not lead to the lowest Levelized Cost of Energy (LCoE) for the PV systems, because the best performers could be more expensive than the other systems. If the ultimate goal is to minimize the LCoE of the PV systems in Europe, the optimum could therefore correspond to PR values that are somewhat lower than 0.9. Nevertheless, we have not observed a clear and systematic correlation between the performance of the PV system components and their overall performance, which leads to think that the optimum could correspond to PR values that are in any case higher than 0.84, and that many of the low PR values are not justified by a lower cost of installation. More quality controls and further improvement in the state of the art are therefore a very promising option towards a leap in overall performance. Among these possible improvements in the state of the art, some 7% can be gained from a better PV system design and better (i.e. more efficient, more reliable) components, and some further 3% can be reached through an effective operation and maintenance scheme, which includes a good fault detection procedure.

As an example of the influence of the PV modules on PV system performance, it is instructive to analyse whether there was a significant difference in performance between PV systems equipped with PV modules produced by different manufacturers (except for the thin-film technologies, that are dealt with later on). Previous studies observe that there is a difference in the median value of PR of some 6% between the best performer and the worst performer. This seems to be partly in line with the datasheets of the PV module manufacturers, most of which have a nominal power tolerance of +- 3%.

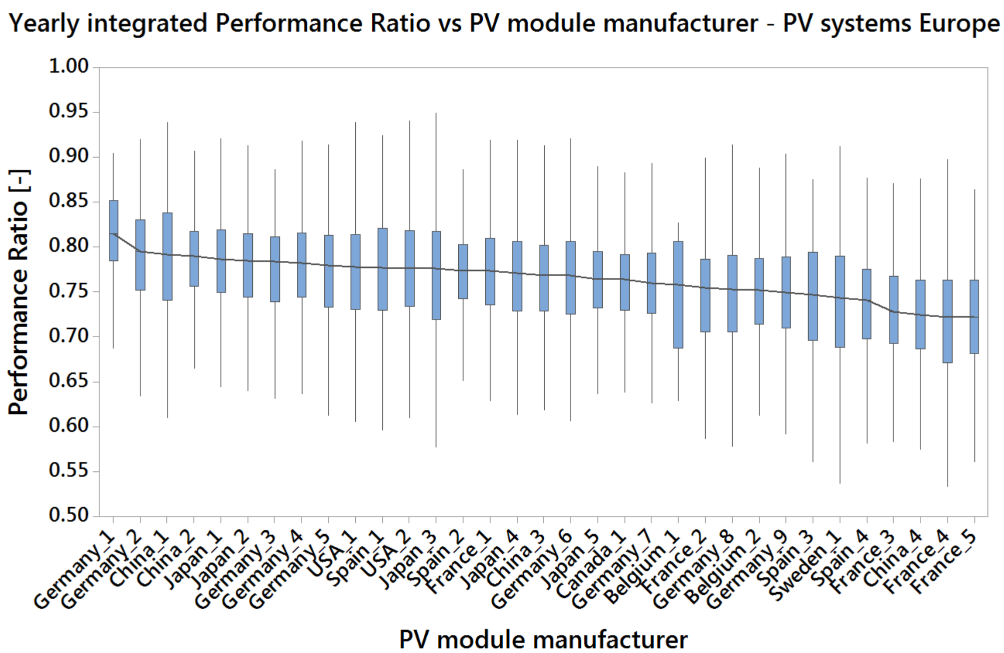


Figure 3.8: Boxplot representing the yearly PR for the PV modules that equip at least 100 PV systems (excluding thin-film technologies). We observe that there is a difference in the median value of PR of some 6% between the best performer and the worst performer

The work done at SERENDI-PV will make it possible to directly address these issues that were identified in previous studies and that are limiting the performance ratio of most installations, explaining this wide disparity observed between the worst and best performers. The following figures summarize the impact of the achievement of the tasks carried out at SERENDI-PV on the performance of the PV systems in Europe, where the two same typical topologies have been retained: large-scale PV plants in southern Europe, and residential PV in mid-latitude Western Europe. The global PV system losses, and their complementary, the PR, have been presented along with the most relevant categories of partial losses that take place at the PV systems.

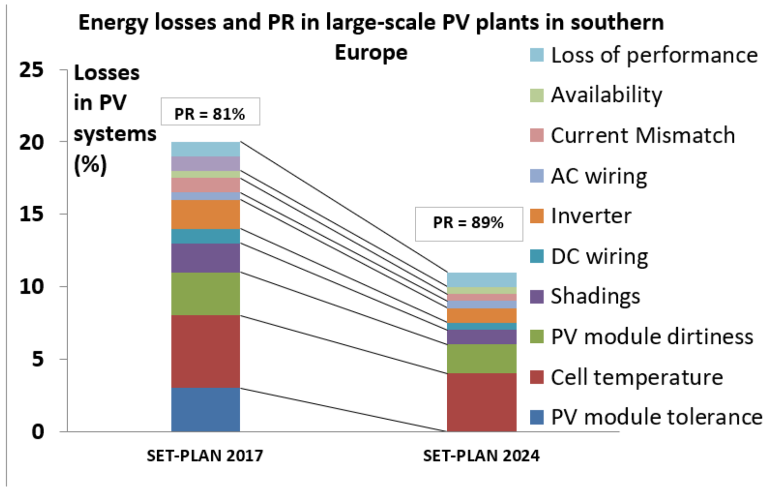


Figure 3.9: Energy losses and performance ratio before and after SERENDI-PV for large-scale PV plants in southern Europe

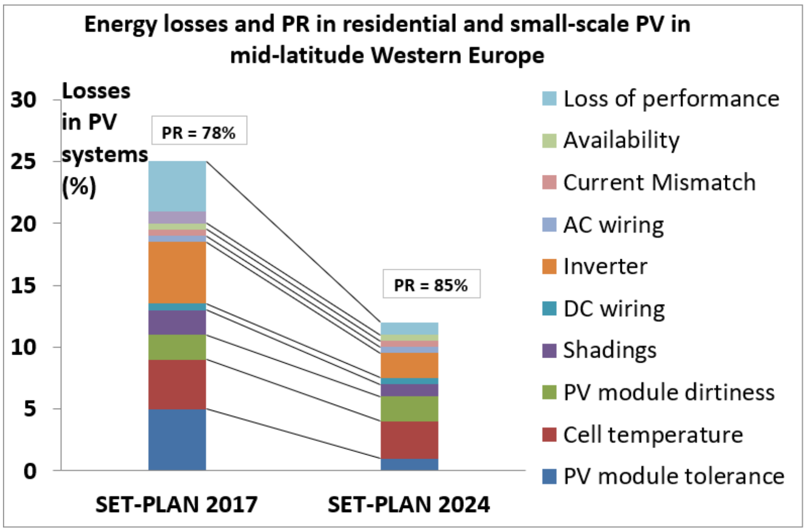


Figure 3.10:Energy losses and performance ratio before and after SERENDI-PV for Small-scale and residential PV installations in mid-latitude western Europe

For the mainstream PV technologies, part of the PR improvement will already take place during the next years as part of the natural and ever ongoing process of improvement of the quality of PV components and PV engineering practices. However, SERENDI-PV has identified three new PV technologies for which the modelling, quality control and monitoring are more complex: Bifacial PV, floating PV and BIPV. For these technologies, SERENDI-PV has proposed several specific tasks that aim to make sure that all the necessary developments at all levels will take place so that these technologies can also benefit from these expected PR improvements. These tasks for the core of the WP2, 3, and 4 from the work plan (see INTRODUCTION).

For example, for bifacial PV, it is important to minimize the risk of a power mis-rating for the PV projects. Several key factors for the bankability of a bifacial PV plant can be accurately determined, such as:

- Rated power and I-V curve for each side (front and back) measured independently
- Bifaciality ratio
- Temperature coefficient
- Equivalent weighted rated power under any combination of front-back irradiance conditions.

SERENDI-PV will adapt all the measurement equipment and procedures so that these key measurements can effectively take place in the industry (particularly in WP4).

On the other hand, although accurate modelling tools and measurements procedures are still pending, and no good method can provide satisfactory legal warranties, there are good reasons to believe that once the main electrical characteristics of a bifacial PV module are known, together with the installation conditions, it is possible to estimate a rough range of energy production and gain, within a relatively high degree of certainty. The studies that were carried out and that led to the proposal of an IEC standard have drawn some very important conclusions that constitute good news for the bankability of bifacial PV plants. In particular, they have shown that the rear irradiance can typically reach 50 – 250 W/m2 when the front irradiance is 1000 W/m2 at noon, for tilted systems. This means that the power gain can be anywhere between 5 and 25% (if bifaciality factor is equal to 1), and that the annual integrated energy gain lies somewhere between these two extremes too. It is typically in the 10–20% range, which is substantial. These studies also concluded that if all the key parameters are kept as close as possible to the IEC standard (in particular albedo = 0.2 and ground clearance = 1 m), then the rear irradiance is very often encountered in the relatively narrow range of 130–140 W/m2. SERENDI-PV will develop modelling tools that make it possible to establish a clear relationship between indoor and outdoor measurements (see in particular WP2 and WP3, and also WP7 for the bridge between SERENDI-PV and other important stakeholders that will need to be involved in this process).

For floating PV, the recent field experience shows that the measurements and quality controls have to be especially adapted as regards with the installation setup on the water including the floating elements (see WP4), and on the other hand the modelling has to take particular care to the effect of water evaporation on PV cells temperature (see WP2 and 3). Recent publications tend to show that floating PV might even benefit from a PR boost because of the cooling effect of temperature, of up to 10% of the relative annual performance [20]. However, other unexpected parameters might hinder this new technology, so SERENDI-PV has chosen to stay conservative and set the same end targets for floating PV than for onshore PV plants in general.

For BIPV, the most pressing challenges concern standardization and quality control (see WP4), the adaptation of the modelling tools to make it possible to model entire neighbourhoods with high-spatial resolution while maintaining a relative simplicity of use (see WP2), and advanced monitoring and fault detection procedures (see WP3). Recent work [21] from some of the partners of SERENDI-PV have shown the impact of these modelling and monitoring aspects on the global performance of BIPV systems and the tasks of WP2 and WP3 have been designed so that the pathways towards higher PR in BIPV that were identified in that study will be applied.

3.1.2.2 Temperature corrected performance ratio (CPR)

In order to limit the variations of the performance ratio due to temperature variations, a temperature corrected performance ratio is also defined in the IEC 61724-1 standard. The STC performance ratio (CPR), also called DC corrected PR, is calculated by adjusting the power rating at each recording interval to compensate for differences between the actual PV module temperature and the STC reference temperature of 25 °C:

$$CPR = \frac{Y_f}{Y_r} = \frac{\frac{E_{out,comp}}{P_0}}{\frac{H}{G_{ref}}} = \frac{\frac{E_{out}}{P_0}}{\frac{H * C}{G_{ref}}} \quad \textbf{(Eq. 6)}$$

Where:

- C is the temperature adjustment factor and is calculated according to:

$$C = 1 + \gamma * (T_{mod} - T_{ref}) \quad \textbf{(Eq. 7)}$$

Where:

- T_{mod} is the module temperature
- T_{ref} is the reference temperature (25 °C) at STC and
- γ is the relative maximum-power temperature coefficient (in units of $°C^{1}$)

Note: the bifacial performance ratio may also be temperature compensated, as shown in Figure 3.12.

State of the art:

Using the CPR metric enables to have a smoothed curve:

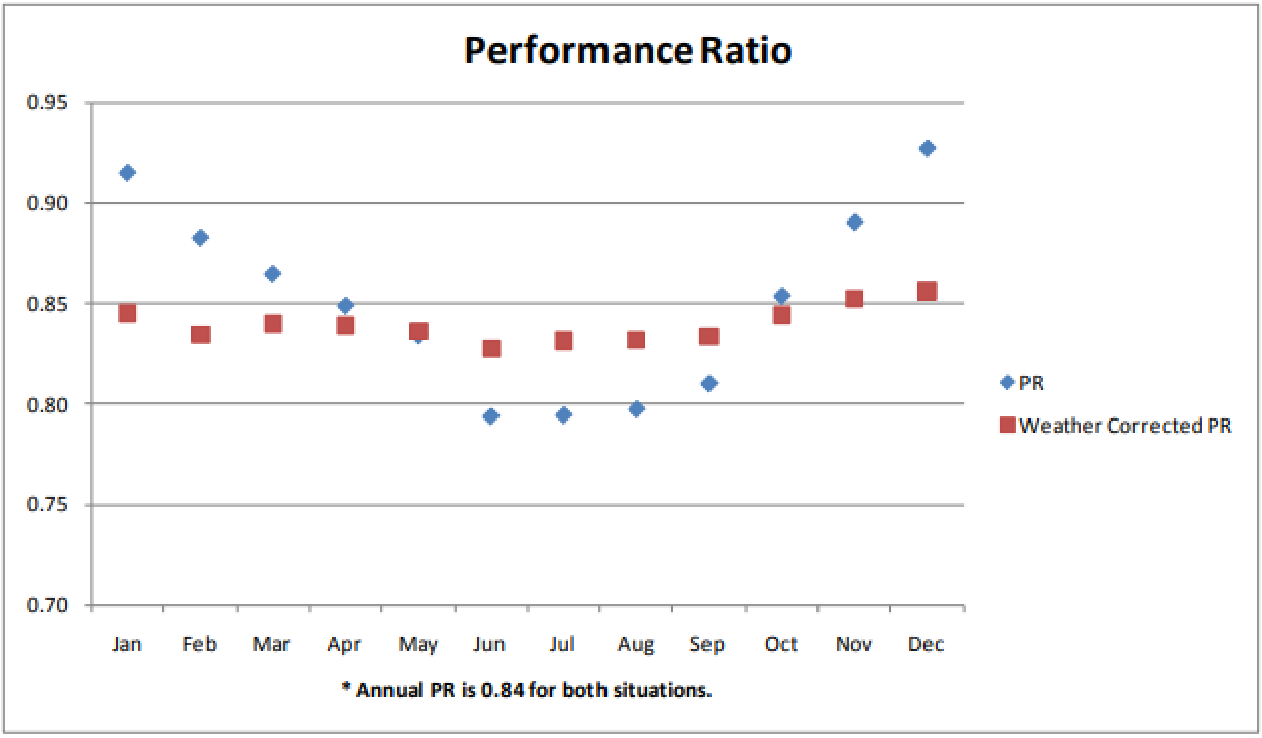


Figure 3.11: Results of modelling of uncorrected PR and weather corrected PR [22]

3.1.2.3 Bifacial performance ratio (BPR)

For bifacial modules, which can produce electricity from both the front-side and the rear-side, the total energy output is increased thanks to the rear-side generation. This generation depends on the rear irradiance and the capacity of the module to use this energy. Therefore, a more accurate measurement of the PR of a bifacial module includes the consideration of a higher total irradiance and the characteristic difference for each module in power generation when measured from its front or from its rear side. The ratio of rear power production by the front power production for a bifacial PV module, under STC conditions (illumination of 1000 W/m^2 at 25 °C), is known as power bifaciality. If the efficiencies are considered, then we typically speak about the bifacial factor. Therefore, in order to calculate a realistic PR for a bifacial PV module, the irradiance reaching the rear side of the module has to be weighted by the module power bifaciality and then, added to the front one, calculating the effective in-plane irradiance for a bifacial PV module ($H_{bifacial}$) as:

$$H_{bifacial} = H_{front} + \mathrm{BF} * H_{rear} \qquad \text{(Eq. 8)}$$

where BF is the power bifaciality of the modules. Then, the PR is calculated as usual considering this effective in-plane irradiance.

The precise determination of the rear irradiance gain is not simple, especially considering that there will be at least partial shading of the diffuse irradiance by another module array installed close-by [23]. A detailed chapter about the non-uniform rear-side irradiance and different techniques to quantify it can be found in reference [23].

State of the art:

The bifacial performance ratio should be used to assess the performance of a bifacial PV plant and account for the operation losses. It should not be used obviously to compare monofacial and bifacial systems.

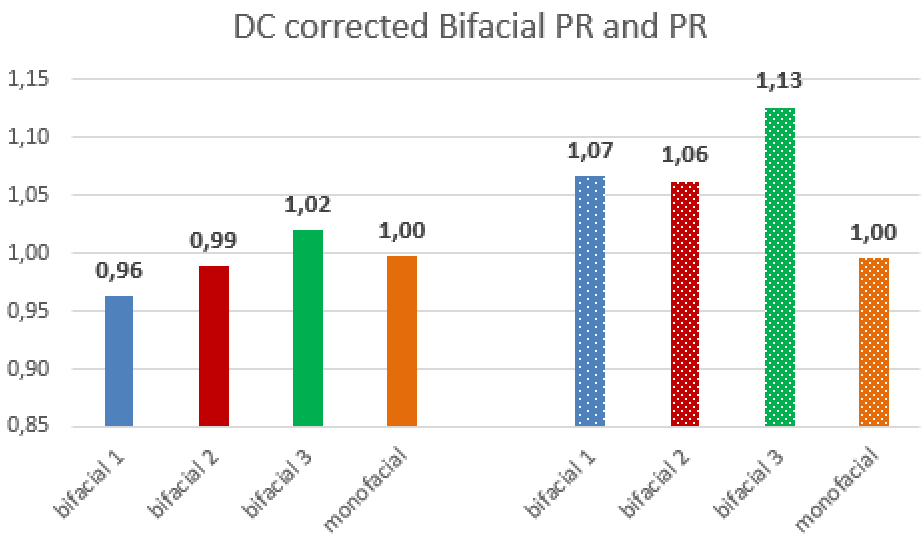


Figure 3.12: Examples of DC temperature corrected bifacial PR (left) and DC temperature corrected PR (right) for 4 string PV systems [Source CEA internal measurements]

3.1.3 Capacity (Utilization) factor (CF)

The capacity factor is not a standardized metric. It is defined by the ratio between the yearly produced energy and the energy that would be produced by the plant operating constantly (i.e., 24 hours a day) at its maximum output and is expressed in % (sometimes also in hours/year):

$$CF = \frac{Eout}{P0 * 365 * 24} * \qquad \text{(Eq. 9)}$$

Note: it can be also calculated for shorter durations.

The capacity factor is defined for any electricity producing installation and it’s a metric used for comparison among different electricity sources.

State of the art:

Traditional use of CF is for the comparison of renewable energy sources with conventional thermal energy sources:

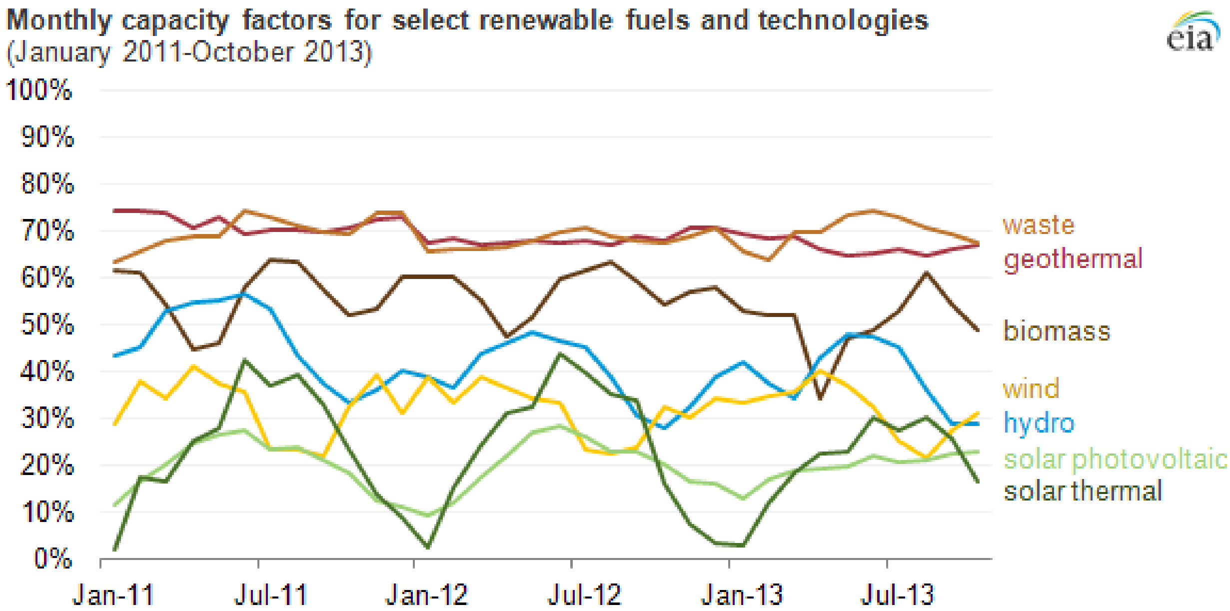


Figure 3.13: Monthly capacity factors for renewables, 2011-2013, in USA [24] [25]

For PV plants, CF usually ranges from 10 to 35%, depending on site location.

Some people think it is an inappropriate indicator as it does not consider the differences of irradiation conditions when comparing the CF of two PV plants.

3.1.4 Soiling ratio (SR)

It is defined in the IEC 61724-1 standard as the "ratio of the actual power output of the PV array under given soiling conditions to the power that would be expected if the PV array were clean and free of soiling". It is measured by using a "soiled" device (PV reference cell or PV module, preferably representative of those used in the PV plant) and a "clean" device of same type, which is kept clean (by regular (i.e., daily or at least twice a week) manual or automatic cleaning, or by other protective means). A measurement system of the maximum power or short-circuit current, as well as the device temperature, monitors in parallel both devices. Initial calibration is required to calculate the needed correction to ensure that both devices give the same initial values of power or current. The soiling ratio is then calculated by dividing the "soiled" measurement by the "clean" measurement" (with temperature correction if needed). As the ratio may depend on the good alignment of the devices, integrated values (i.e., energies) may be preferred to instantaneous values.

State of the art:

Module soiling is site-dependent, it varies greatly from region to region, and within regions, and it is impacted by meteorological parameters.

The rate of soiling deposit depends on geographical and technical factors such as:

- The type of the landscape,
- The proximity to deserts, agriculture, industry, and roads (generating suspended atmospheric particles) and type of human activity nearby,
- The type of ground particles (size and chemical nature),

- The meteorological parameters such as rain (frequency and intensity), temperature, wind, humidity, and cloud cover,
- The configuration of the PV modules (inclination),
- The texture of the module front glass (adhesion of particles).

[26] states that SR is typically between 0 %/day and 1 %/day, but higher rates can be observed (ex: 2.5 %/day in China). [27] is reporting daily losses higher than 4%, but monthly losses around 2%, in the South of Spain. [28] made a map of dust intensity, mainly showing the weight of desert areas:

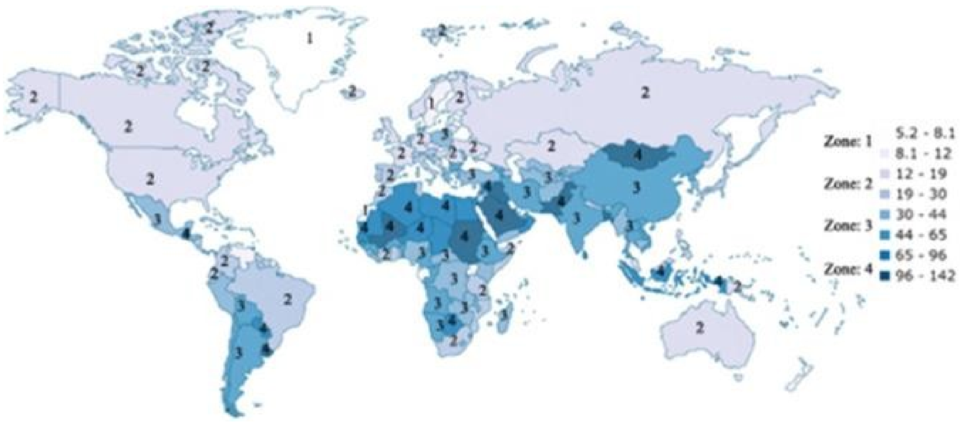


Figure 3.14: Dust intensity map [28]

But local considerations should be made. For instance, [29] made some measurements in an urban environment (Santiago de Chile): monofacial and bifacial modules show a similar soiling rate of about only 0.2-0.3 %/day and estimates of 0.04%/day on the rear face of bifacial ones.

3.1.5 Surface ratio (SuR)

The surface ratio is not a standardized metric. It is derived from the PR definition, replacing the STC power P0 by the PV module area (S). It is defined as the product obtained by multiplying the PR with the STC module efficiency (EFF_{STC}):

$$SuR = PR * EFF_{STC} \quad \textbf{(Eq. 10)}$$

With:

$$EFF_{STC} = \frac{P0}{S} \quad \textbf{(Eq. 11)}$$

The surface ratio can be written like following and is expressed in W/m²:

$$SuR = \frac{\frac{Eout}{S}}{\frac{H}{Gref}} \quad \textbf{(Eq. 12)}$$

This metric may be relevant when comparing the productions of different PV plants regarding the ground coverage.

Note: the surface ratio may also be temperature compensated.

State of the art:

It seems to be rarely used.

Depending on the module efficiency, the ranking of module technologies may not be the same when comparing performance and surface ratios:

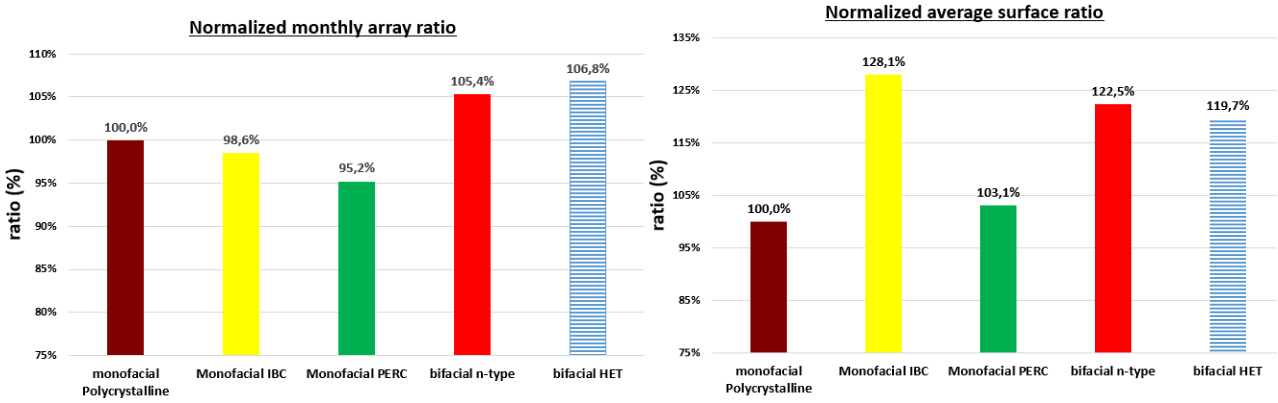


Figure 3.15: Examples of normalized DC PR (left) and DC SuR (right) for 5 string PV systems [source CEA]

3.1.6 Bifacial gain (BG)

The bifacial gain is not yet a standardized metric. It accounts for the gain of energy provided by the rear side of a bifacial module or system. On a system level it is defined as the ratio between the rear and the front energies. When considering the total bifacial gain for a system (BG_{syst}), it's possible to split the different aspects affecting the total gain:

- **Optical gain** (BG_{opt}): calculated in a simplified manner as the average irradiance gain from the rear surface of the module as compared to the front surface

$$BG_{opt} = G_{rear} / G_{front} \quad \textbf{(Eq. 13)}$$

with G_{rear} and G_{front} representing the average rear and front irradiances, respectively.

- **Module gain** (BG_{mod}) also called direct current (DC) bifacial gain. Calculated as the product of the bifaciality factor and the optical gain. The bifaciality factor (φ) equals the rear-side maximum power (P_{rear}) divided by the front-side maximum power (P_{front}) for the PV module.

$$\varphi = \frac{P_{rear}}{P_{front}} \quad \textbf{(Eq. 14)} \qquad BG_{mod} = \varphi * BG_{opt} \quad \textbf{(Eq. 15)}$$

- **System bifacial gain:** it is usually different than the module bifacial gain. The final bifacial gain value maybe be calculated by comparing a bifacial vs a monofacial module with identical properties, operating in the same conditions of operation (azimuth, tilt, ventilation for instance), on the same place and over the same given period of time.

$$BG_{syst} = \frac{E_{rear}}{E_{front}} = \frac{(E_{bifacial} - E_{monofacial})}{E_{monofacial}} * \% \quad \textbf{(Eq. 16)}$$

The bifacial gain strongly depends on the module technology, geometry, clearance/inclination of modules, irradiation, and ground albedo. The overall system performance can also be affected by an improved low-light efficiency and a better temperature coefficient [30]. More information about factors affecting bifacial gain can be found in the latest IEA PVPS T13 about bifacial photovoltaic modules and systems [23].

State of the art:

Empirical models are simplified analytical approximations based on measurements or simulation, to calculate an approximate bifacial gain per year. [31] developed a simple empirical expression for bifacial gain:

$$\boldsymbol{BG = 0.317 * \beta + 12.145 * h + 0.1414 * R} \qquad \textbf{(Eq. 17)}$$

Where:

- β is the module tilt angle in degrees;
- h is the module ground clearance in metres, and
- R is the ground albedo in %.

A second empirical model is presented here based on ray-tracing modelling, the Kutzer model [32]:

$$BG = Albedo * bifaciality\ factor * 0.95 * \quad \{1.037 * (1 - \quad ^{\frac{1}{2}}) * [1 - e^{-8.691 * \frac{h}{r}}] + (0.125 * (1 - \quad ^{-4}))\}$$

(Eq. 18)

Where:

- h is the normalized module ground clearance and
- r is the normalized row-to-row spacing (normalization to the table length).

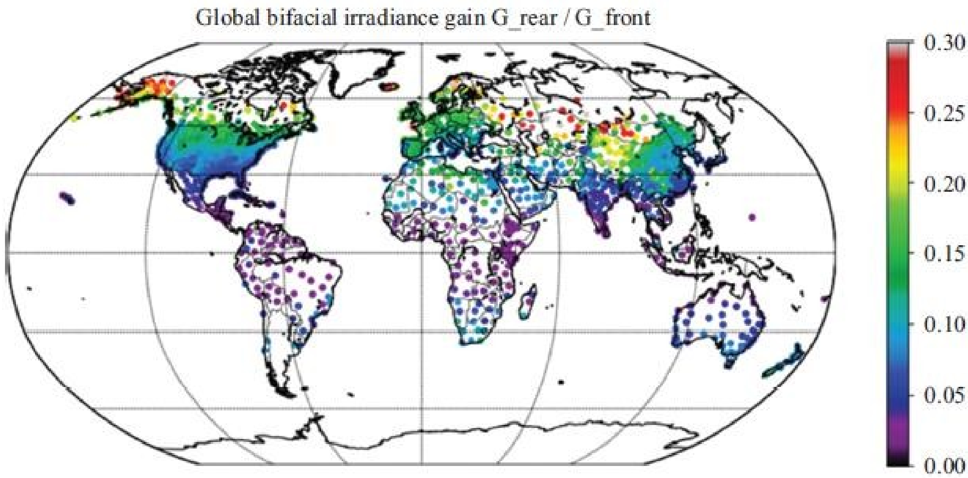


Figure 3.16: Results of modelling for the bifacial rear-irradiance gain for a fixed latitude tilted system (h=1 m, r is based on latitude and tilt) [33]

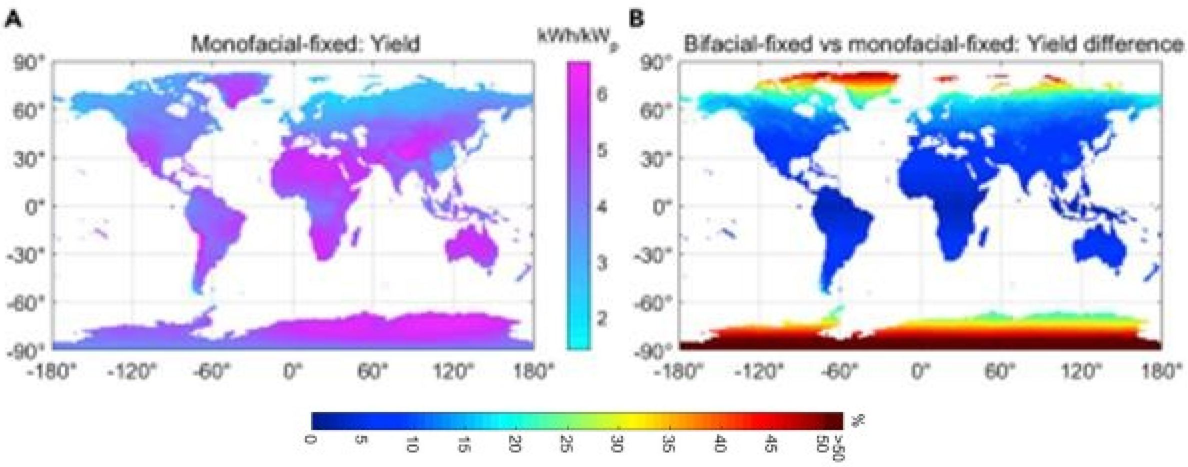


Figure 3.17: Average daily yields of fixed monofacial and bifacial systems [34]

3.1.7 Tracker gain (TG)

The tracking gain is not yet a standardized metric. It accounts for the gain of energy provided by a PV module or system on a tracker. It is defined as the ratio between the specific energy of a tracking PV system ($Eout_{tracking}$ /P1) and the specific energy of a fixed system ($Eout_{fixed}$ /P2), operating with the same PV modules, on the same place and over the same given period of time.

$$TG = \left[\frac{\frac{Eout_{tracking}}{P1}}{\frac{Eout_{fixed}}{P2}} - 1\right] * \qquad \textbf{(Eq. 19)}$$

Where:

- TG is expressed in %
- P1 is the rated kW of installed PV modules (tracking) and
- P2 is the rated kW of installed PV modules (fixed)
- E_{out} should be a DC energy in order to avoid the impact of inverters.

The tracking gain strongly depends on the characteristics of both systems (azimuth and inclination for the fixed one, axis orientation and tracking range for the mobile one).

Note: Calculating the tracking gain with bifacial modules is possible but the estimation may be impacted by the bifacial effects.

State of the art:

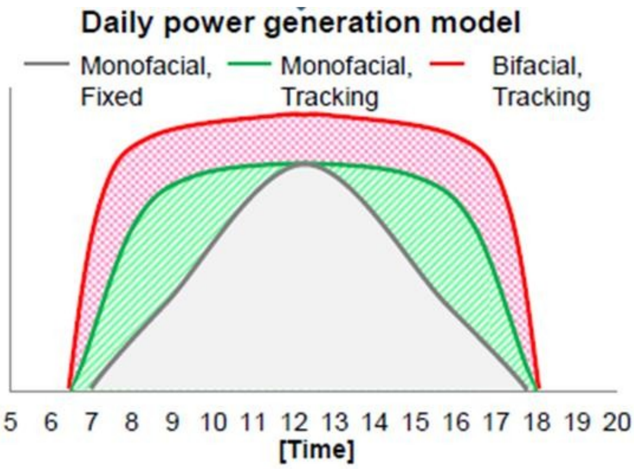


Figure 3.18: Schematic of tracking gains with monofacial and bifacial modules

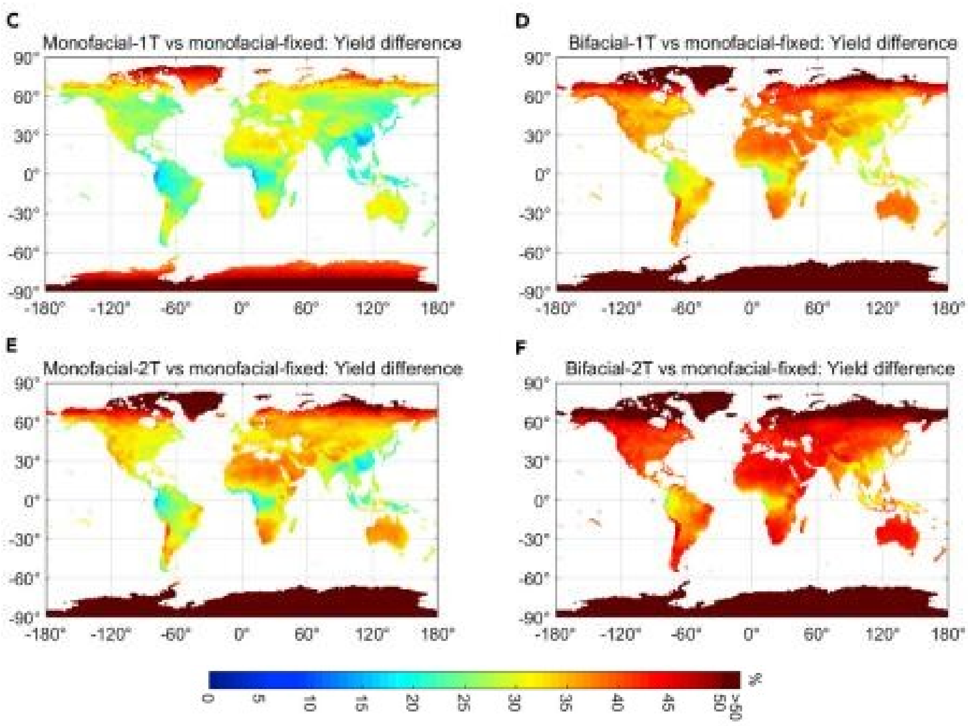


Figure 3.19: Average daily yield gain of monofacial and bifacial 1-axis and 2-axis tracking systems versus monofacial fixed systems [34]

3.2 PV Reliability-related Parameters

3.2.1 Performance Loss Rate

The **performance loss rate** (PLR) of PV system can be defined as the rate of performance reduction over time. The term "performance loss rate" refers to the reduction of the performance on the system level and therefore includes not only irreversible physical degradation of PV modules (which can be quantified by calculating a "degradation rate"). Beside degradation of the PV modules, it also measures performance-reducing events, which may be reversible or even preventable [35]. Its value depends on a high number of factors such as cell and module technology, materials and Balance of System (BoS) and even the O&M practices used. Over the PV system's lifetime, different types of performance loss can occur. All the different mechanisms (light induced degradation (LID), delamination, encapsulant decolouration, hot spots, cracked cells, …) are initiated through one or more environmental factors including solar irradiance, temperature (high and low levels and fluctuations), humidity, rain, dust, mechanical loads from wind, hail or snow.

The performance loss rate can be calculated as the ratio between the daily/weekly/monthly/yearly (weather-corrected) performance ratio of two subsequent years [16], [17]. However due to different filtering methods, performance metric selection and application of statistical modelling method there is no general method which is accepted as state-of-the-art at the moment [35].

State of the art:

Beside other factors performance loss rates depend on the degradation rate of the PV technology used. Most important degradation rates are observed for thin-film based modules such as amorphous silicon-based modules or CIGS-based modules (median value: 1,5%/year) and to a lesser extent CdTe (median value: 0,7%). On the contrary, monocrystalline silicon-based PV is associated with lower degradation rates (median value: 0,5%). The climatic area is also an important influencing factor. Lower degradation rates are seen in snowy climates (median value: 0,4%) while higher degradation rates are observed in desertic climate (median value: 0,8%) or hot and humid climate (median value: 0,7%). In moderate climate zones, median degradation rates values lie around 0,6%. For all these values it should however be taken into account that a sound separation of performance loss and degradation rate based on filed measurement data is not possible. Additional indoor measurements of the PV modules can help to improve the separate quantification. In particular, the average performance loss rates measured for a portfolio of 40 rooftop systems in Germany and over a ten-years period (2008-2018) showed an average performance loss rate of 0,7%/year, while the degradation rate of the PV modules was around 0.2%/year [36], [37].

3.2.2 Availability

Availability can be measured based on energy production or times of production as well as at the scale of the whole PV system or focusing on a specific part of the PV system such as the trackers.

The **energy-based availability** (KPI) is the ratio between the electricity that was actually produced by the system compared to the electricity that would have been produced based on the reference yield (see reference yield definition). Different events can lead to an energy-based availability different than 100% such as planned maintenance, failures and replacements, curtailment and other events which will be gathered under the notion of disconnection time.

The **time-based availability** (KPI) is the ratio between the time when the PV system produces electricity and the expected operational time. Events leading to a time-based availability different than 100% are same as for the energy-based availability.

Usually, in contracts for the exploitation / operation /provisional acceptance of PV systems, events excluded from the analysis on energy-based or time-based availabilities are defined.

The **technical availability** is the ratio between the time when the PV system produces electricity and the time of plane-of-array irradiance above a minimum irradiance threshold (MIT).

The **tracker availability** is the ratio between the time when the tracker operates within a certain deviation angle (to be defined) range around the set point and the time when the tracker is functional [38] [39].

State of the art:

Figure 3.20: Reported energy-based availability, all sources of unavailability combined (Elaboration by Becquerel Institute based on [40], [41], [42] and [7])

(Note: "GM" refers to ground-mounted PV systems, "RT" refers to rooftop PV systems, "MIX" refers to values reported for a mix of ground-mounted and rooftop systems. "AVG" refers to a reported average value for multiple PV systems, "MED" refers to a reported median value for multiple PV systems, "IND" refers to values reported for one individual PV system)

3.3 PV Power Modelling and Forecasting-related Parameters

This chapter describes KPIs used (i) for evaluation of PV energy simulation models and (ii) for evaluation of PV power forecasting models. **PV power modelling** is an essential basis to evaluate PV reliability, performance, and profitability. Grid integration of large shares of PV power essentially relies on **forecasting of PV power**. Therefore, the quality of these models is important for the objectives of SERENDI-PV.

The parameters and KPIs introduced here evaluate the agreement of time-series of modelled or predicted PV power with PV power measurements:

1. *Modelled PV power* refers to PV power values that are calculated from solar irradiance and air temperature from ground measured observations or estimates of satellite-based solar models or meteorological models. They are used e.g. as a reference in PV performance monitoring.
2. *Predicted PV power* refers to PV power forecasts for the next minutes, hours or days. A forecast typically starts with an initial value (for forecast horizon of zero) which is either a measured value or a modelled value.

Here, it must be kept in mind that not only modelled and predicted values are provided with uncertainties. Also, measurements of PV power, which are used as a reference for validation, have some uncertainty. To account for this, in the context of solar resource assessment, differences between modelled and measured values are frequently referred as "**deviations**" rather than "errors". In context of forecasting, mostly the term "**error**" is used. To keep definitions simple, here we use the term "error" for both PV power modelling and forecasting.

3.3.1 Root Mean Square Error (RMSE)

The RMSE is defined as a KPI for both PV power modelling and forecasting. It is a frequently used metric for comparing time-series of modelled or predicted values to observed values, also in the context of irradiance and PV power modelling and forecasting (e.g. [43], [44]).

In PV power modelling and forecasting, the Root Mean Square Error $RSME_P$ of PV power P for is defined as

$$RMSE_P = \sqrt{\sum_{i=1}^{i=N} \frac{(PP_i - PO_i)^2}{N}} \quad \textbf{(Eq. 20)}$$

With:

- PP_i [kWh]: modelled or predicted PV power for the time step i
- PO_i [kWh]: observed PV power for the time step i
- i [-]: index for the time step considered
- N [-]: the value sample size ie. the number of time steps considered

For the evaluations in SERENDI-PV only day-time values (cosine of the solar zenith angle larger than zero) are included to the evaluations, night values with zero PV power production are excluded.

The RSME measures the scatter of modelled or predicted versus observed values (see Figure 3.21). RMSE of zero corresponds to a perfect match of the model with observations or a perfect forecast. High RMSE values indicate a high uncertainty and accordingly a low accuracy of the predictions or estimates. The RMSE gives more weight to large model (forecast) errors than to small errors. Hence, it is a suitable metric when small errors are more tolerable and larger errors cause disproportionately high costs, which is the case for many forecasting applications, e.g. energy market or grid management. A disadvantage is that it is also sensitive to the measurement outliers.

In addition to absolute values $RMSE_P$, which strongly depend on the rated power P0 of a PV plant or a portfolio, also normalized versions are used.

One way to derive normalized values of $RMSE_P$ is diving by the rated PV power P0

$$RMSE = \frac{RMSE_P}{P0} \quad \textbf{(Eq. 21)}$$

This allows for a better inter-comparison for PV power plants with different size. It is typically used for evaluations of PV power forecasts in the context of grid integration of PV power. Here, it will be applied for both PV power modelling and forecasting.

A second option is the relative $RMSE_{rel}$ in relation to the average value of the observations $\overline{PO}$

$$RMSE_{rel} = \frac{RMSE_P}{\overline{PO}} \quad \textbf{(Eq. 22)}$$

With:

$$\overline{PO} = \frac{1}{N}\sum_{i=1}^{i=N} PO_i \quad \textbf{(Eq. 23)}$$

$RMSE_{rel}$ is frequently applied in solar resource modelling and will be used here for PV power modelling and forecasting. Also, the $RMSE_{GHI}$ of modelled irradiance values is frequently normalized to average irradiance values.

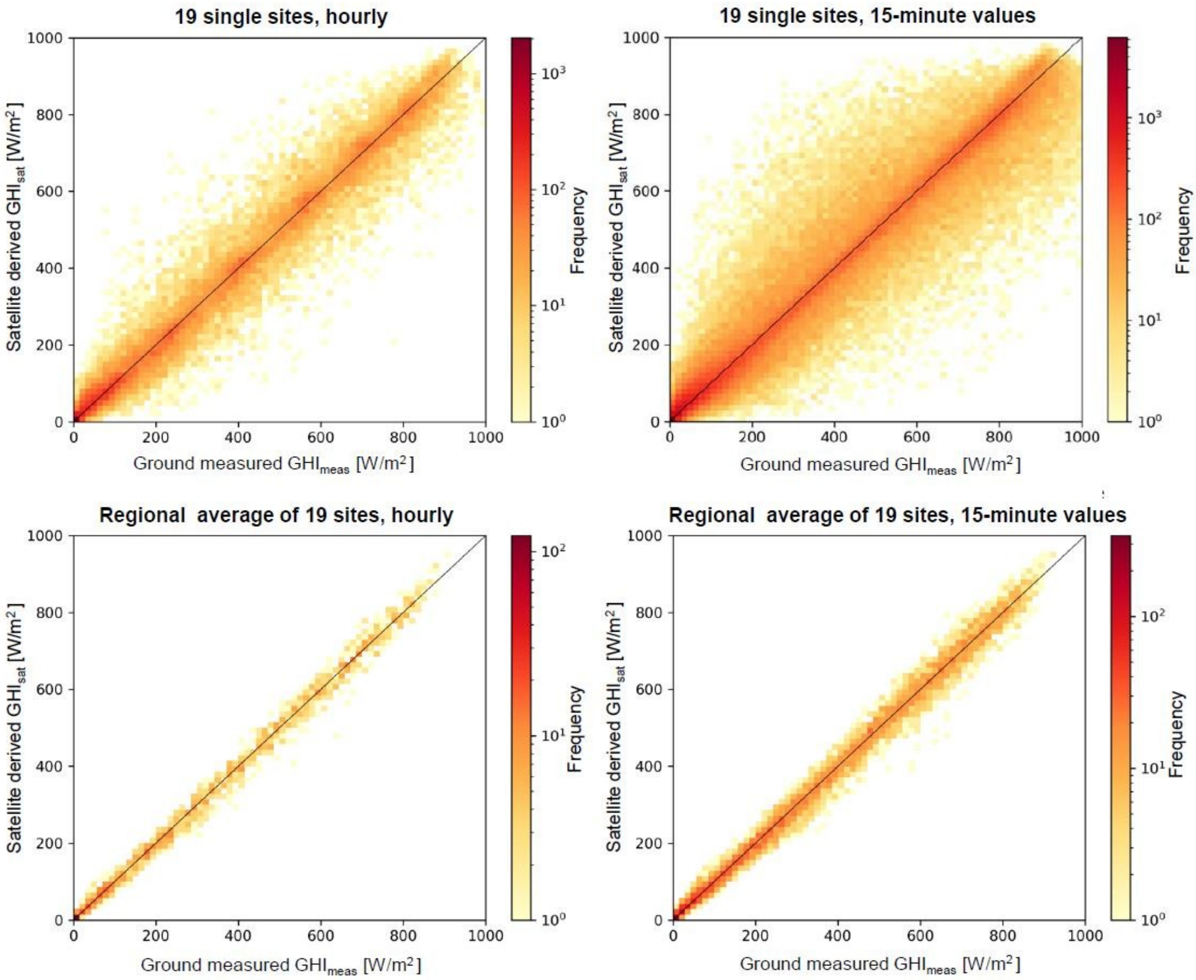


Figure 3.21: 2d Histogram of satellite derived versus ground measured irradiance with corresponding RMSE values top, left: hourly values for single sites, $RMSE_{GHI}$ = 55 W/m^2, $RMSE_{rel}$ = 17.3 %; top, right: 15-minute values for single sites, $RMSE_{GHI}$ = 77 W/m^2, $RMSE_{rel}$= 24.3 %; bottom, left: hourly values for the average of 19 sites, $RMSE_{GHI}$ = 24 W/m^2, $RMSE_{rel}$ = 7.6 %; bottom, right: 15-minute values for the average of 19 sites, $RMSE_{GHI}$ = 27 W/m^2, $RMSE_{rel}$ = 8.6 %. Data set: 19 sites distributed in the German state of Baden-Württemberg, February to September 2018. (Apdated from [45])

State of the art

The magnitude of RMSE values depend on a variety of factors:

- Temporal resolution of the time-series: RMSE values are increasing with decreasing temporal resolution, e.g. the RMSE values for a time-series with 15-minute resolution (Figure 3.21, right) are larger than for hourly time-series (Figure 3.21, left)
- Modelled or predicted PV power
- Forecast horizon: RMSE values are increasing with increasing forecast horizon (Figure 3.22)
- Spatial aggregation: When considering the aggregated output of spatially averaged PV system, RMSE values are decreasing with increasing region size and number of systems (Figure 3.21, Figure 3.22, Figure 3.23)

- Climate: like many other KPIs in PV performance evaluation, RMSE values depend on the climatic conditions.

High values of RMSE in PV power modelling can be attributed to different uncertainty sources [46], [47]. High values of RMSE in PV power forecasting are mostly due to high irradiance forecast errors.

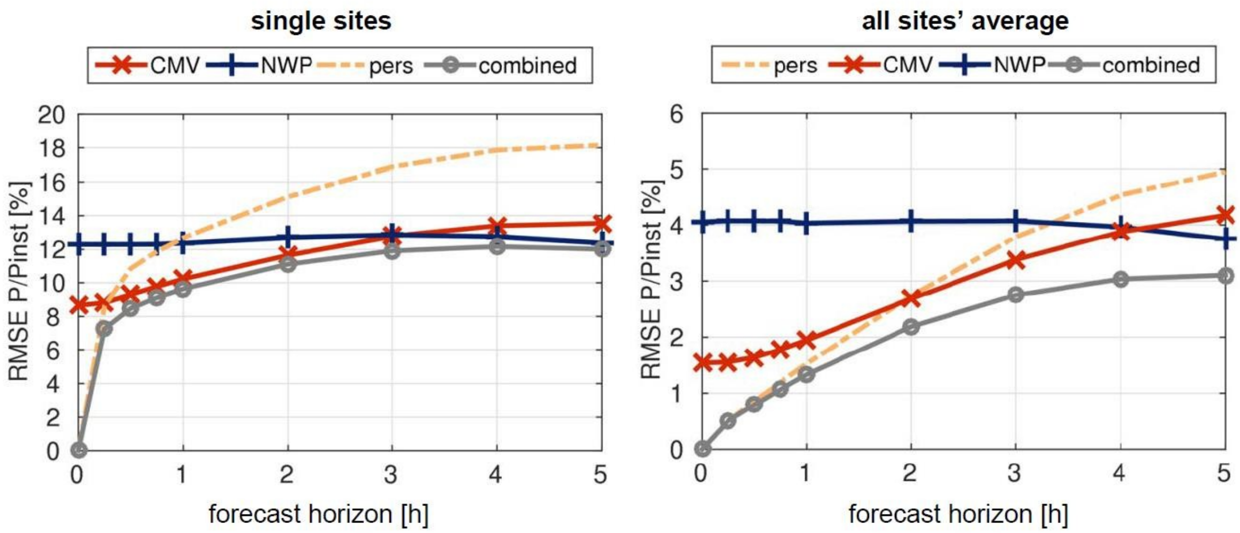


Figure 3.22: RMSE of quarter-hourly PV power predictions versus forecast horizon for different models for single site predictions (left) and regionally aggregated forecasts of all sites (right). RMSE values are normalized to the rated power, here denoted as installed PV power 'Pinst'. The predictions are based on the assumption of persistence ('pers'), on cloud motion vectors from satellite data ('CMV'), on numerical weather predictions ('NWP'), and on a combination of these approaches ('combined'). Dataset: 921 PV sites in Germany, May 1st – November 30th 2013. Source: [48]

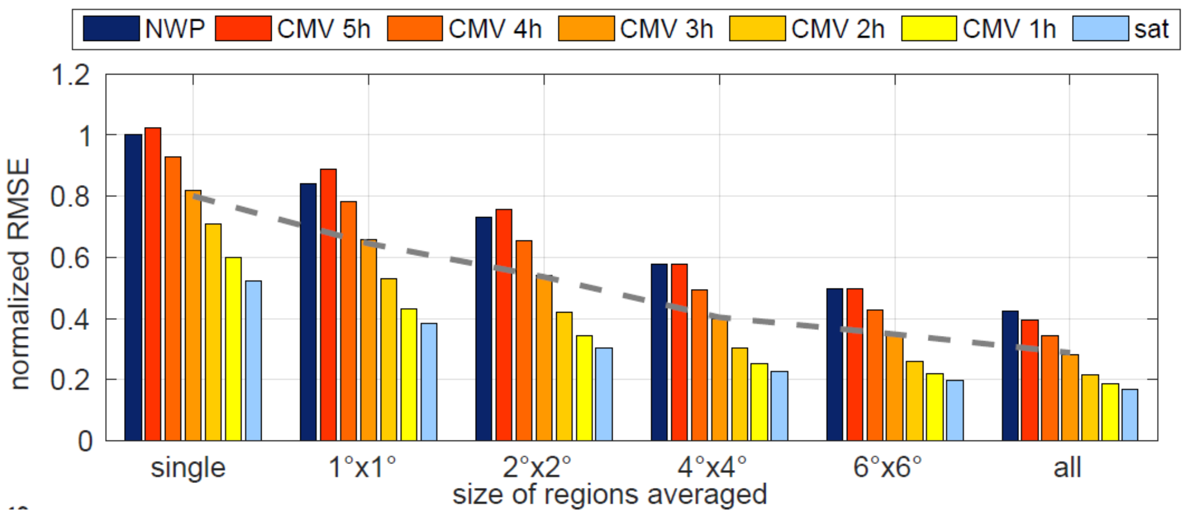


Figure 3.23: RMSE of hourly irradiance predictions for averages for different regions size, normalized to NWP single site forecast errors. The predictions are based on cloud motion vectors from satellite data ('CMV') for different forecast horizons, on numerical weather predictions ('NWP') for day-ahead forecasts. They are compared to satellite derive irradiance values ('sat'). Dataset: 217 irradiance measurement stations in Germany, Jan 2012-December 2013. Source: [48]

3.3.2 Mean Absolute Error (MAE)

The Mean Absolute Error MAE is also considered as a KPI for PV power modelling and forecasting.

The MAE_P for PV power is defined as

$$MAE_P = \frac{1}{N}\sum_{i=1}^{i=N}(PP_i - PO_i) \quad \text{(Eq. 24)}$$

Like RMSE, MEA evaluates the scatter of modelled or predicted versus observed values, Therefore, it is similar in many aspects. As for RMSE, a MAE of zero corresponds to perfect forecasts and increasing values correspond to decreasing accuracy. It differs from RMSE by equal weighting of small and large forecasts errors and is less sensitive to outliers than the RMSE. The MAE is a suitable metric for applications with linear cost functions (i.e., in forecasting, when the costs caused by inaccurate forecasts are proportional to the forecast error).

Like for RMSE, normalized values of MAE are defined as:

$$MAE = \frac{MAE_p}{P0} \quad \text{(Eq. 25)}$$

And

$$MAE_{rel} = \frac{MAE_p}{\bar{P}} \quad \text{(Eq. 26)}$$

State of the art

The magnitude of MAE values depends on the same factors as given for RMSE values above (Section 3.3.1). Typically, MAE values are smaller than RMSE values.

3.3.3 Mean Bias Error (MBE)

The MBE is a KPI for PV power modelling. It is especially important to assess the quality of long-term or yearly estimates of PV power.

The Mean Bias Error MBE_P for PV power P is defined as

$$MBE_P = \frac{1}{N}\sum_{i=1}^{i=N} |PP_i - PO_i| = \overline{PP} - \overline{PO} \quad \text{(Eq. 27)}$$

With

$$\overline{PP} = \frac{1}{N}\sum_{i=1}^{i=N} PP_i \quad \text{(Eq. 28)}$$

The MBE measures systematic deviations between the modelled or predicted values and observations. A positive MBE indicates an overestimation by the estimates/predictions, i.e. in average they are higher than the observations. Correspondingly, a negative MBE indicates an underestimation by the estimates/predictions. The MBE can be calculated for single PV systems and then corresponds to the deviation of the long-term mean values of modelled and observed data. When evaluating the MBE for several sites, it gives information on systematic deviations of a model for these sites.

Like for RMSE and MAE, normalized values of MBE are defined as

$$MBE = \frac{MBE_p}{P0} \quad \textbf{(Eq. 29)}$$

And

$$MBE_{rel} = \frac{MBE_p}{\bar{P}} \quad \textbf{(Eq. 30)}$$

<u>**State of the art**</u>

MBE values of PV power forecasts are typically small for state-of-the-art forecasting systems (less than 1% of rated PV power). Also, for larger PV systems forecasts are often adapted to PV power measurements with statistical methods ranging from linear scaling to advanced machine learning, which further reduces forecast MBE. Forecast RMSE is largely determined by the scatter of forecasts rather than by systematic deviations for single-site forecasts. For these reasons, MBE is not considered a KPI for forecasting in SERENDI-PV. Still, when considering forecasts of the aggregated output of spatially averaged PV systems with their much smaller scatter (see Figure 3.21), systematic deviations may significantly contribute to forecast RMSE.

3.3.4 Kolmogorov-Smirnov test integral (KSI)

The Kolmogorov-Smirnov test integral (KSI) is used as an addition parameter to evaluate the quality of modelled PV power (e.g. [49]). It gives information on the agreement of the frequency distributions of modelled and measured values. It does not evaluate the match of individual data points but rather gives information whether a time series contains “realistic values”.

The KSI is defined as:

$$KSI = \int_{0}^{PV_{max}} |CDF(PP) - CDF(PO)|\,dPO \quad \textbf{(Eq. 31)}$$

With

- CDF(PP): Cumulative distribution function of estimated/predicted PV power.
- CDF(PO): Cumulative distribution function observed PV power.

Typically, KSI values are normalized by a critical value that depends on the sample size, i.e. the number of events included to the evaluation.

<u>**State of the art**</u>

Like RMSE and MAE, KSI values vary with different factors.

3.3.5 Forecast skill score

Forecast skill evaluates an error metric in comparison to a simple reference model, a concept widely applied in meteorology. The skill score is defined as a KPI for evaluating forecast models. It is not applied in PV power modelling.

Here, the skill score SS is defined using the error metric RMSE, which is the first SERENDI-PV KPI for forecast evaluation:

$$SS = \frac{RMSE_{ref} - RMSE}{RMSE_{ref}} \quad \textbf{(Eq. 32)}$$

With:

- $RMSE_{ref}$: RMSE of a simple reference model for PV power prediction.

A skill score value of 1 indicates a perfect forecast, and a skill score of 0 means that the evaluated forecasts have the same RMSE as the reference forecasts. A negative value indicates performance that is worse than the reference.

A common reference model for short-term forecasting is persistence, i.e. assuming that the current situation does not change and using the current or recent measurements as forecast values. For forecasting of irradiance and PV power the deterministic daily solar irradiance profile should be considered as an additional constraint. Therefore, persistence is typically defined for the clear sky index rather than for irradiance or PV power values (e.g. [43], [44], [50, 48]).

The clear sky index for global horizonal irradiance k_c is defined as

$$k_c = \frac{GHI}{GHI_{clear}} \quad \textbf{(Eq. 33)}$$

With:

- GHI_{clear}: GHI for clear sky conditions, derived with a clear sky model.

The clear sky index for PV power P $k_{c,P}$ is defined accordingly

$$k_{c,P} = \frac{P}{P_{clear}} \quad \textbf{(Eq. 34)}$$

With:

- P_{clear}: PV power for clear sky conditions, derived with at clear sky model and a PV simulation model.

On this basis, persistence $P_{per,\Delta t}(t)$ for forecast valid time t and a forecast horizon of Δt is defined as

$$P_{per,\Delta t}(t) = k_{c,P}(t - \Delta t) P_{clear}(t) \quad \textbf{(Eq. 35)}$$

More advanced concepts of reference models include “smart persistence” which has been proposed in the context of the IEA PVPS Task 16 [43] or a combination of climatology and persistence as suggested in [44].

<u>State of the art</u>

State-of-art-forecasting models have positive skill.

The use of the RMSE skill score as an additional KPI in the verification of deterministic solar forecasts is strongly recommended by [44]. RMSE values strongly vary for different climatic conditions, they are increasing with increasing irradiance variability at the site of the PV power plant. The RMSE skill score allows for a better comparison of forecasts for PV plants in different climatic conditions, because -like forecast RMSE - the RMSE of the reference model is increasing with the variability at the forecast site, i.e. the difficulty of the forecast scenario is taken into account.

3.4 PV Monitoring-related parameters

Ideally, the uncertainty of the monitoring system could be calculated as the convolution of all the sensor uncertainties, correspondingly weighted. However, the actual uncertainty of a monitoring system will not only depend on the quality or type of sensors installed in the PV plant but on several variables which can hardly be controlled. For instance, the actual installation of a device (orientation, inclination, location in the PV plant, etc.) or its maintenance by the O&M contractor (cleaning routines, revisions, recalibrations, etc.) will certainly impact the uncertainty in the monitoring system. Furthermore, even if the only uncertainty to be considered were that of the devices themselves, determining a unique value for the uncertainty of the overall monitoring system would be a cumbersome task. Nevertheless, the current bottleneck of a monitoring system impeding to obtain more accurate and reliable results is not its overall uncertainty. For monitoring systems, the two KPIs that better define them at the moment are data availability and data quality. Meanwhile, the Energy Performance Index (EPI) is a useful tool to detect potential issues with a PV installation.

3.4.1 Energy Performance Index (EPI)

The Energy Performance Index (EPI) is defined as the ratio between the Energy final Yield (Y_f) and the Expected Yield (Y_E) determined by a PV model:

$$EPI = \frac{Y_f}{Y_E} \quad \textbf{(Eq. 36)}$$

It is recommended to regularly calculate it, using the actual weather data as input to the model, on a daily, monthly or yearly basis. With a perfect model, its initial value is 100%. It can be also used for the identification of performance flaws and comparison of plants. Its value is dependent on the model accuracy.

State of the art:

Calculating the EPI is in fact a method to detect underperformance or faults of PV systems as an EPI, much lower than 1, may exhibit a problem of operation. First, a training period of data is required (where it is assumed that the system operates properly) to calculate the equation coefficients of the model. Then, the model is applied to the testing period.

[51] gives an example of a regression equation using hourly data and based on four coefficients:

$$E_{ACout} = A + Temp * Irrad * B + Irrad * C + Irrad^{2} * \quad \textbf{(Eq. 37)}$$

[52] uses an extended formula, with seven coefficients, also using temperature (T_m) and irradiance inputs to calculate the power (P):

$$P(S, Tm) = P0 * S * [1 + a * (S - 1) + b * (S - 1)^2 + c * ln(S) + d * ln^2(S) + (e + f * (S - 1)) * (-)]$$

(Eq. 38)

With:

- S=G/G_{ref}

Other models can be used, like the open-source SAM tool:

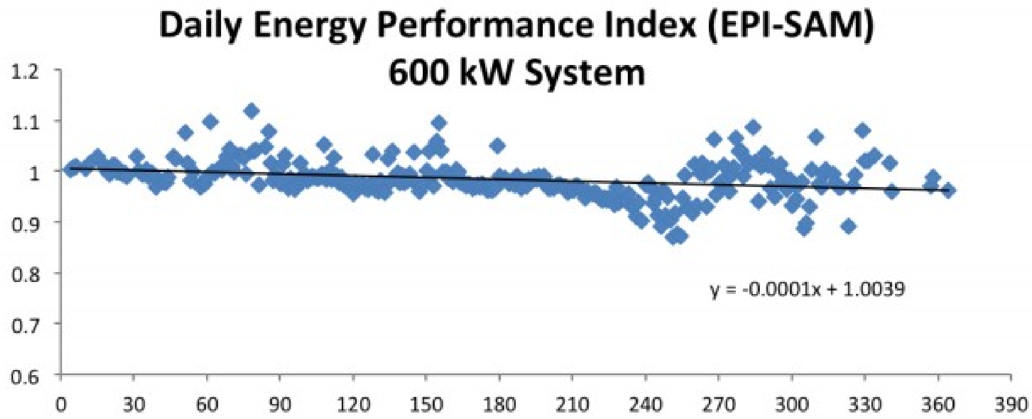


Figure 3.24: Daily EPI-SAM for One Year Using Actual Weather and SAM [51]

3.4.2 Data availability

The evaluation of this KPI for a monitoring system is quite straightforward, it is the fraction of time that the system delivers data divided by the time of the reference period for which this KPI is calculated. The lower the amount of empty values registered by the monitoring system the better. For an individual measurement time series (e.g. data of an in-plane irradiance sensor) data availability should be logged separately and the overall data availability for this measurement can be calculated by multiplying the availability of the monitoring system and the availability of the sensor data.

Fraunhofer ISE PV system monitoring reaches a long-term data availability (>10 years of data) of about 99%. However, for commercially operated PV system monitoring typical data availability is generally lower.

3.4.3 Data quality

Data quality refers to the accuracy of the data for further analysis to ensure that there are no false values. Filters are generally used to evaluate and guarantee this quality. Thus, the data quality is related to the amount of values filtered by the monitoring system. This means that the value has been indeed recorded or measured, but it is clearly incorrect (such as an irradiance of 2000 W/m² for instance). In this regard, the KPI is not as simple as defining that the fewer data filtered the better, because that could be consequence of a poorly defined filter. Nevertheless, a first estimation of this KPI could be obtained when comparing different PV plants applying the same filter strategy.

For both data availability and data quality: it is challenging to pin down a minimum target value, as they will be dependent on the PV plant location, weather conditions, etc. As absolute minimum requirements for these KPIs, it could be considered that the data availability should be at least 90 %, and the data filtered less than 10 % while guaranteeing that any non filtered data differs no more than 0.5 % from its actual value. These thresholds are a first proposal based on typical values in power plants, during the project they will be adapted to different technologies, being this itself part of the state of the art.

3.5 PV Profitability-related Parameters

The profitability of PV systems is strongly affected by diverse factors: the PV performance, the PV costs and the business models. Parameters such as Capital Expenditure and Operational Expenses, typically referred to as CAPEX and OPEX, provide a direct indication on the cost-competitiveness of PV installations. However, they are not sufficient to give a holistic overview on the profitability of the system. Parameters such as the Levelized Cost of Electricity (LCoE) or the Net Present Value (NPV) and the Internal Rate of Return (IRR), allow to give a more encompassing vision on the profitability by considering the CAPEX and the OPEX, but also the system lifetime and its yield among others.

3.5.1 Levelized Cost of Electricity (LCoE)

The **Levelized Cost of Electricity (LCoE)** is expressed in $€_{\text{base year}}$/kWh and can be defined as the cost that, when assigned to every unit of electricity produced by the system over its (theoretical) useful lifetime, will equal the total life cycle costs of the system when discounted back to the initial year of the investment. The discounting to the initial year of investment is applied to obtain a single value in currency of the base year.

Formulas of different complexity levels (ie., taking into account a different number of technical-economic inputs) exist to calculate the LCoE for a given PV system. In the frame of the KPIs defined for SERENDI-PV's Task T1.1, a rather simplified formula has been chosen to be applicable for all types of PV systems (residential, utility-scale, …) studied in this project.

$$LCoE_N = \frac{CAPEX_0 + \sum_{i=1}^{N} \frac{OPEX_i + T_i}{(1+d)^i}}{\sum_{i=1}^{N} \frac{E_i}{(1+d)^i}} \qquad \textbf{(Eq. 39)}$$

With:

- $LCoE_N$ [€/kWh]: the LCoE calculated for a theoretical system lifetime of N years
- $CAPEX_0$ [€]: the capital expenditures for year 0
- $OPEX_i$ [€]: the operational and maintenance expenditures for year i
- T_i [€]: the taxes and similar payments for year i
- E_i [kWh]: the energy produced in year i
- d [%]: the discount rate
- N [years]: theoretical system lifetime

State of the art:

The economic inputs for the LCOE formula presented above are not often disclosed in the literature. Therefore, the state of the art presented here for the LCoE KPI is based on tender results in various European countries. These tender results are not completely representative of current achievable LCOE since, multiple factors included in the LCoE formula, such as access to grid connection points, subsidized local employment or direct funding from public sector may have a significant impact on the tender results thus leading to values that are not representative of the actual cost of producing electricity with a PV system in a given country. However, when removing tender results which are strongly distorted by some local specific regulatory or political context such as in Portugal, the observed median value provides a fair indication of current LCoE levels in Europe.

Indeed, most observed average LCoE values for utility-scale PV lie around 50 €/MWh, which is in line with feedbacks provided by several actors of the PV sector.

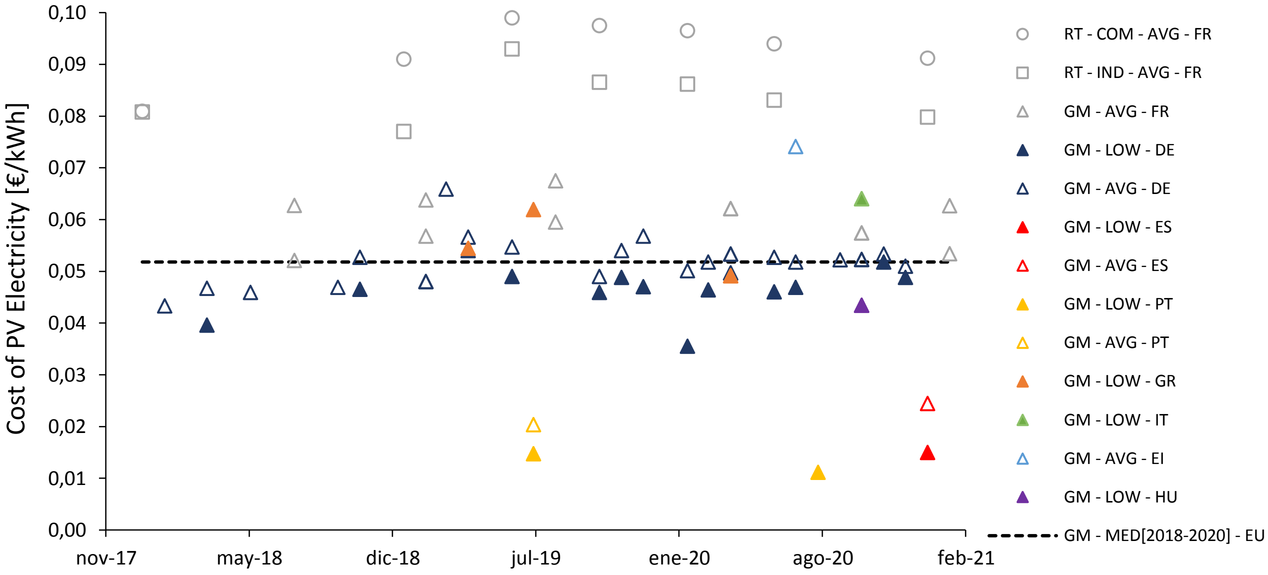


Figure 3.25: Recent tender results in a selection of European countries (Elaboration by Becquerel Institute based on [53], [54] and [55])

(Note: "AVG" and "LOW" refer respectively to the average and the lowest bid observed for a given tender. "GM" refers to ground-mounted PV systems and "RT-COM" and "RT-IND" refer respectively to commercial and industrial rooftops)

3.5.2 Weighted Average Cost of Capital

The discount rate, often used to take into account the time value of money in calculations of economic indicators of PV projects, is the after-tax weighted average cost of capital. It can be interpreted as a way to express the opportunity cost of investing capital in the considered project rather than allocating it to another purpose, with a similar estimated level of risk. Hence, it also intends to reflect the expected return of the investment made using that capital, composed of debt and/or equity, which is directly correlated with the risk of such investment. This risk is influenced by many factors. Indeed, a PV project is exposed to the power market risk, as it relies on retail and/or wholesale electricity prices, but also to regulatory risks or resources and technological risks, among others. It is also influenced by the economic environment the investing company is operating in. The WACC can thus be used to reflect the level of risk associated with investment. Maturity and track record of technologies used, for instance at cell/module level, tracker or inverter will impact the WACC as well, and novel technologies are perceived as risky in financial terms, increasing the WACC.

The nominal WACC is defined as follows:

$$WACC_{nom,t} = \frac{D_t}{D_t + E_t}(1 - T_c) \ast {}_{D,t} + \frac{E_t}{D_t + E_t} r_{E,t} \qquad \textbf{(Eq. 40)}$$

And the real WACC can be computed with:

$$WACC_{real} = \frac{(1 + WACC_{nom})}{(1 + Inflation)} - 1 \qquad \textbf{(Eq. 41)}$$

Where:

- D_t is the amount of debt used

- $r_{D,t}$ is the cost of debt
- T_c is the average corporate tax rate
- E_t is the amount of equity used
- $r_{E,t}$ is the levered cost of equity
- $Inflation$ is the estimated average yearly inflation

Note that in most cases, a simplifying assumption is taken, and it is assumed that the WACC remains constant on the duration of the project. Thus, the subscript t can be dropped, and the calculated WACC at the time of investment is applied for all subsequent periods of system's operational lifetime.

State of the art:

Here, the different components of the WACC can be discussed. The ratio of debt to equity is often 70/30 in commercial, industrial or ground-mounted systems. This can go up to 90/10 or higher in extreme cases. For small scale PV like residential systems, the ratio of debt on equity is usually lower, and in some cases the investment can be fully made on own funds, i.e. equity. This is less of an issue than in the case of larger systems, as the equity cost of an individual homeowner is relatively limited.

Then, to define the cost of debt, the interest rate of the contracted debt can be used. If various sources of debts are used, this cost can itself be a weighted average of these different debts. While the interest rate varies in function of the estimation of the risk of the project, it is constantly lower than the cost of equity, and is thus often favoured by project developers. Nowadays, in the European context, it typically varies between 1% and 3%.

Regarding the cost of equity, it depends on the kind of investor. As evoked, for an individual homeowner investing in a small rooftop PV system, it is very low, and can be approximated by looking at alternative investments with such time horizon and comparable level of risk. It results in very low cost of equity, ranging between 1% and 3%. For bigger rooftop PV systems, typically invested in by companies for self-consumption purposes, the same logic can be applied to approximate the cost of equity, but the result varies, and a value ranging from 3% to 5% at most can be considered. A state-of-the-art cost of equity for ground-mounted PV systems is much harder to define, considering the high variety of possible equity investors in PV systems and their different objectives. Although, a constant decrease has been witnessed in the recent years, as the technology matured and has been more and more recognized as a safe investment, in spite of regulatory instability in some countries. It permitted to attract investors with new profiles, i.e. lower risk appetite, thereby pushing the required return of equity down. In the European context, a typical 5% to 6% cost of equity can be considered. Although, it could go as high as 8% in extreme cases.

Eventually, in the European context, for residential PV systems, the nominal WACC is assumed to equal 2% on average. For larger rooftop PV systems, it is a bit higher, and it can be as high as 4%. For ground-mounted system, the range of state-of-the-art possibilities is much wider, and could be as low as a few percent up to more than 6%.

3.5.3 Net Present Value (NPV)

All positive and negative cash flows are simulated, on a yearly basis, they are then summarized in a profit and loss statement, which allows to subsequently quantify the yearly "free cash flows" via the cash flow statement. Based on the free cash flows, the **net present value** of the project, expressed in €$_{\text{base year}}$ is calculated, by discounting all these free cash flows back to the initial year of investment.

$$NPV = \sum_{i=0}^{N} \frac{Free\ Cash\ Flow_i}{(1+d)^i} = -I + \sum_{i=1}^{N} \frac{Free\ Cash\ Flow_i}{(1+d)^i} \qquad \textbf{(Eq. 42)}$$

With:

- NPV [€]: the Net Present Value calculated for a theoretical system lifetime of N years
- Free Cash Flow$_i$ [€]: the free cash flow in year i
- I: the initial investment
- d [%]: the discount rate
- N [years]: theoretical system lifetime

State of the art:

The net present value is extremely dependent of the project it concerns, such as its size and the source of financing or the level of risk associated with it, which can influence the discount rate. Thus, it is extremely challenging to come up with state-of-the-art values. In addition, it would be challenging to define a meaningful scale to rank PV projects, as for example a project with a NPV value of 10.000€ compared to a project with a NPV value of 100.000€ does not necessarily mean that the first one is less attractive than the second one. Indeed, the NPV indicator fails to fully inform on the ratio of revenues generated to the capital invested. In our example, the 10.000€ positive NPV might have been generated with very low initial investment, e.g. 5000€, while the 100.000€ positive NPV might be the result of an enormous investment of 500.000€. This is why it must be completed with other indicators, in particular the modified Internal Return rate (M)IRR of the project.

Note that to allow an easier comparison of PV projects between them, the NPV values can be normalized, e.g. by dividing it by the nominal DC capacity installed, resulting in an indicator in €/kWp. This can also help solve the previously mentioned issue of establishing a meaningful ranking using the NPV.

In the end, the NPV will also diverge in function of the objectives of the investor, which can vary highly in function of the type of PV installation we are considering. On the one hand, an individual installing a small PV array on its roof might just aim at contributing to the energy transition, with low requirements in terms of return on investment. This can also be the case for a company investing in a BIPV system for the façade of its headquarters' building. On the other hand, an industrial company might have clear financial objectives when installing a large rooftop array on one of its energy-intensive factories. An IPP might also be in the same situation with its ground-mounted systems, having a strict target return to satisfy the requirements of its shareholders. Hence, no state-of-the-art value can be provided, but it is clear that in all cases, this NPV's state-of-the-art value is equal or superior to 0€.

3.5.4 (Modified) Internal return rate (IRR)

The **internal rate of return** is a discount rate that makes the net present value (NPV) of all cash flows equal to zero in a discounted cash flow analysis. The modified internal rate of return is a slight variation of the internal rate of return, in which the financing rate and the reinvestment rate are differentiated, which better reflects reality. Note also that the MIRR can be computed in various ways. Firstly, it can be calculated for the PV asset as such, not considering the financing conditions, leading to the project MIRR. For that reason, this indicator can also be referred as the unlevered IRR. Secondly, the so-called equity MIRR, or levered MIRR, can be computed, i.e. the MIRR for equity investors of the project, taking into account the financing conditions of the project. Both are often computed as they provide valuable information and can have an interest for different stakeholders.

State of the art:

The state-of-the-art estimation of the (M)IRR is strongly tied to the NPV, as anticipated considering its definition. In all cases, the (M)IRR should at least be equal to the discount rate used in the calculations, i.e. the WACC in most cases.

When considering residential PV systems, an average project (M)IRR of 2% to 4% can be considered as state-of-the-art, except in areas with very favourable conditions, i.e. high retail electricity prices and/or generous irradiation. For larger rooftop PV systems, invested in by companies for instance, a comparable return can be considered as state-of-the-art. For ground-mounted PV systems, a state-of-the-art project (M)IRR of 3% to 6% can be considered.

3.5.5 Payback Period

The **payback period** is the amount of time, typically expressed in years, necessary to recover the cost of an investment, i.e. break-even point is reached. More concretely, it is thus the number of years, that when used as the total lifetime in the NPV formula makes the net present value (NPV) of all cash flows equal to zero in a (discounted) cash flow analysis. When discounted cash flows are used, it can be referred to as the discounted payback period.

<u>State of the art:</u>

It is difficult to define precise state-of-the-art values per type of PV installation, as the payback period is extremely dependent of project's conditions (cost, performances, type of financing, valuation of the generated electricity, discount rate when using discounted cash flows, …). While payback period might have been in the past, in some extreme cases, very low because of very advantageous support schemes, one can say that low payback periods of 5 to 7 years are today much less common, although they still exist. Overall, payback periods of 10 to 15 years can be defined as today's state-of-the-art.

3.5.6 Profile factor

The definition of profile factor varies depending on the country where it is considered. The profile factor describes how the solar hour-to-hour production profile compares to the wholesale electricity price profile. Wholesale electricity price is considered here as in a 'merchant' Power Purchase Agreement (PPA) price. Usually the day-ahead wholesale market is used as a reference. The profile factor is calculated as the ratio between the weighted average wholesale price (weighted by the volume of produced PV electricity for each considered time step) and the average wholesale price. The profile factor can be calculated over different time periods, but usually one year is chosen to account for seasonal fluctuations in both the solar irradiance profile and the wholesale market price profile. Only actual power production data is used to calculate it, instead of forecasted data. Even in a situation where an electricity buyer would have a Power Purchase Agreement (PPA) under a fixed price, it is good to know the profile factor, since the PPA buyer needs to buy the demand not covered by solar on the market.

The profile factor is calculated using the following formula [56]:

$$PF = \frac{\Sigma_n Q_n * \quad _n}{\Sigma_n Q_n} / \frac{\Sigma_n P_n}{N} \qquad \textbf{(Eq. 43)}$$

With:

- PF is the profile factor
- N is the total number of hours in a year (i.e. 8760 hours)
- n an hour on the year, comprised between 1 and N
- Q_n is the volume of PV electricity produced on hour n, in kWh
- P_n is the wholesale electricity price on hour n, in €/kWh

The numerator of the equation is called the market value of PV.

State of the art:

The profile factor varies per market, even if the degree of interconnection in Europe is high. As shown on Figure 3.26, it as has evolved in time, following a downward trend as the penetration of PV and other renewables increase. This data has been computed over the years by ECN (TNO) in the Netherlands in the frame of the SDE(+) program, in order to define the level of financial support to be allocated to solar PV systems. It is important to note that this ratio is based on the profile factor but also considers imbalance costs (or revenues) to which solar PV systems are exposed (see the following section for more details), which explains why it is called the “profile and imbalance factor”.

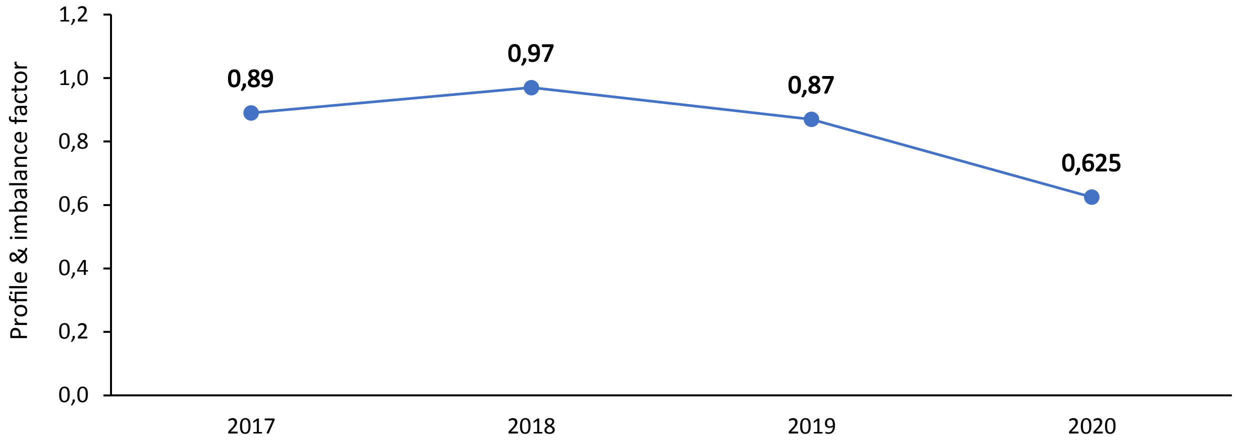


Figure 3.26: Evolution of the solar PV "profile and imbalance factor" as calculated by the ECN (TNO) to define the level of support to be allocated in the frame of the SDE(+) program in the Netherlands (Elaboration by Becquerel Institute based on [57])

Between 2017 and 2019, the “profile and imbalance factor” remained relatively stable. Then, between 2019 and 2020, a sharp decrease can be seen. This is mainly caused by the significant increase of installed PV capacity in the Netherlands in 2019, as explained by researchers from TNO in their report [56]. Also, the detailed split between the profile factor and the imbalance factor shows that the decrease between 2019 and 2020 is, in absolute terms, largely caused by an increase of the imbalance costs, which almost doubled. Although, it is worth noting that on the same period the economic losses due to the profile factor have increased by a higher degree in relative terms, i.e. a factor of 2.5, even if their absolute impact is almost twice as low as imbalance costs [57].

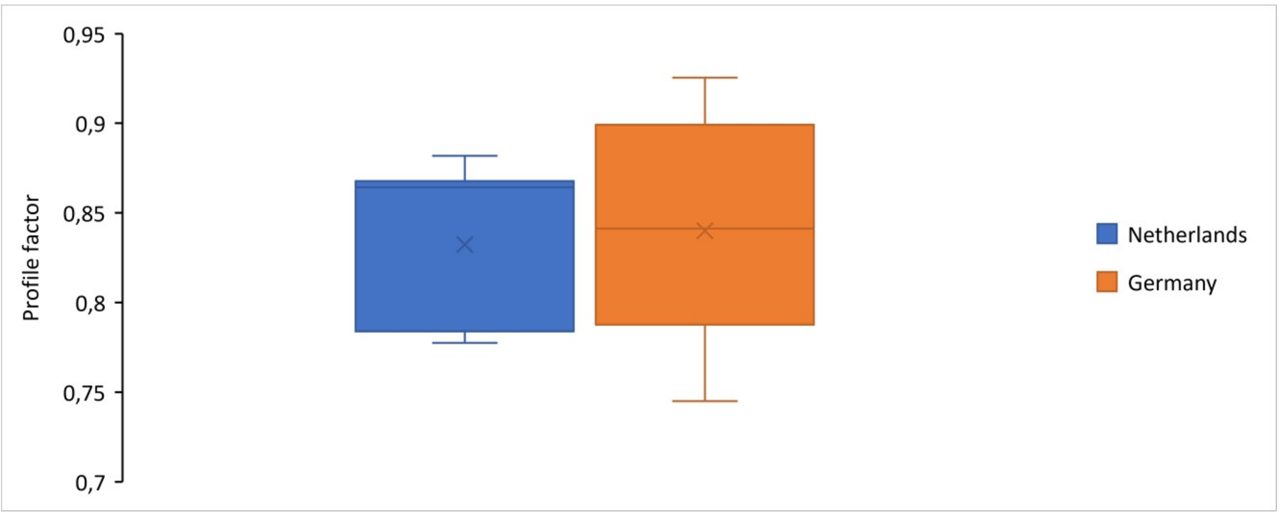


Figure 3.27: Distribution of profile factors value for our sample of solar PV systems, calculated on the years 2019 and 2020

Focusing on the profile factor exclusively, a sample of 7 PV systems in the Netherlands and of 15 PV systems in Germany has been analysed, with installed capacities ranging from 0.5 MWp to 15 MWp, permitting to give an up-to-date overview of the profile factor. The results of the analysis are displayed on Figure 3.27 above.

On this graph, it can be seen that the average profile factor value is similar in both country samples. The range of values is also much larger in Germany than in the Netherlands (which is also caused by the larger sample size), with extreme values lower than 0.75 and higher than 0.90. This is consistent with values computed by TNO and shown on the previous figure, as it demonstrates the importance of considering the imbalance costs as well. Indeed, the profile factor only gives a partial picture of the economic situation of solar PV plant. This is highlighted by TNO researchers in a recent report, where it is shown that the imbalance factor has a larger negative effect than the profile factor on the profitability of solar PV plants, both on 2019 and 2020 [57].

3.5.7 Imbalance cost

The **imbalance cost** is the sum of all imbalance fees incurred due to differences between the volumes sold in the wholesale electricity market, based on forecasts, and the actual injection. European countries use different imbalance settlement schemes. In general, a short position (i.e. more power was sold than what has been injected) is penalised at a price higher than the day-ahead market. At moments of shortage in the grid, these imbalances fees will be many times higher than the day-ahead market prices. A long position (i.e. when less power was sold than what has been injected), the extra volume receives a payment which is usually lower than the day-ahead market prices. At moments of large excesses in the grid, these prices might become zero or negative.

The cost, or revenues, incurred by a solar PV plant owner on a certain period of time due to imbalances between forecasted production and actual injection can be summarized by a factor called the imbalance factor. This imbalance factor is calculated using the following formula [56]:

$$IF = \frac{\sum_n \Delta Q_n * (p_n - P_n)}{\sum_n Q_n} / \ PF * \frac{\sum_n P_n}{N} \qquad \textbf{(Eq. 44)}$$

With:

- IF is the imbalance factor
- PF is the profile factor
- N is the total number of hours in a year (i.e. 8760 hours)
- n an hour on the year, comprised between 1 and N
- Q_n is the volume of PV electricity produced on hour n, in kWh
- ΔQ_n is the difference of volume between forecasted production and the actual injection, in kWh
- p_n is the imbalance electricity price on hour n, in €/kWh
- P_n is the wholesale electricity price on hour n, in €/kWh

State of the art:

It is challenging to provide a vision on the imbalance between forecasted and actual production of PV plants, as well as the associated cost or revenues, as these are very sensitive data. Although, aggregated estimations can be given. In the Netherlands, researchers have calculated that the imbalance factor for PV plants with a capacity equal to or higher than 1 MWp was equal to -9% in 2019, and equal to -23.5% in 2020 [57].

In addition, as an illustration of the potential risk PV plant owners are exposed to in case of forecasting error, the figure here below presents the prices on the Belgian imbalance market, between April 2020 and March 2021.

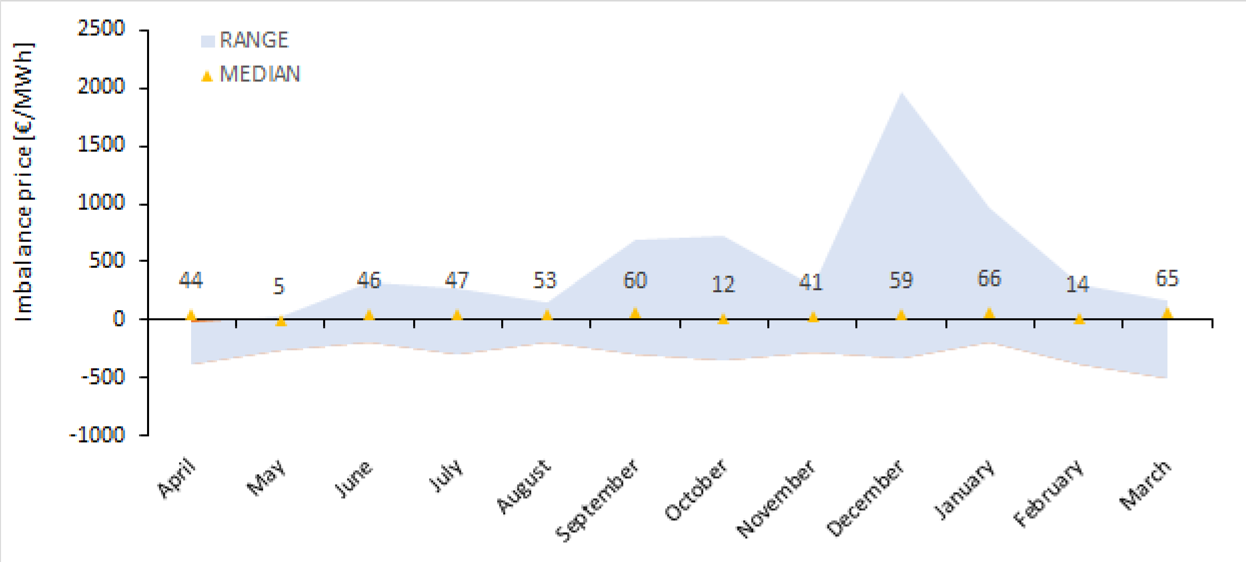


Figure 3.28: Imbalance price range and median value in Belgium over one year, between April 2020 and March 2021(Elaboration by Becquerel Institute based on [58])

3.6 PV Environmental impact-related parameters

3.6.1 Simplified environmental footprint of modules

The simplified environmental footprint of modules is expressed in $kgCO_{2,eq}/kWp$ and calculates the emitted $CO_{2,eq}$ emissions related to the PV module production. In particular, in the case of crystalline silicon-based PV modules, the environmental footprint includes the manufacturing of polysilicon, ingots, wafers, cells, modules, glass, encapsulants, PVF (Polyvinyl fluoride), PET (Polyethylene terephthalate). Greenhouse gas emission related to the other life cycle steps of the module such as the transport to the installation site, the installation, the operation and the end of life/recycling and not taken into account. This calculation method is in particular used in the frame of ground-mounted PV tenders' evaluation in France [59].

State of the art:

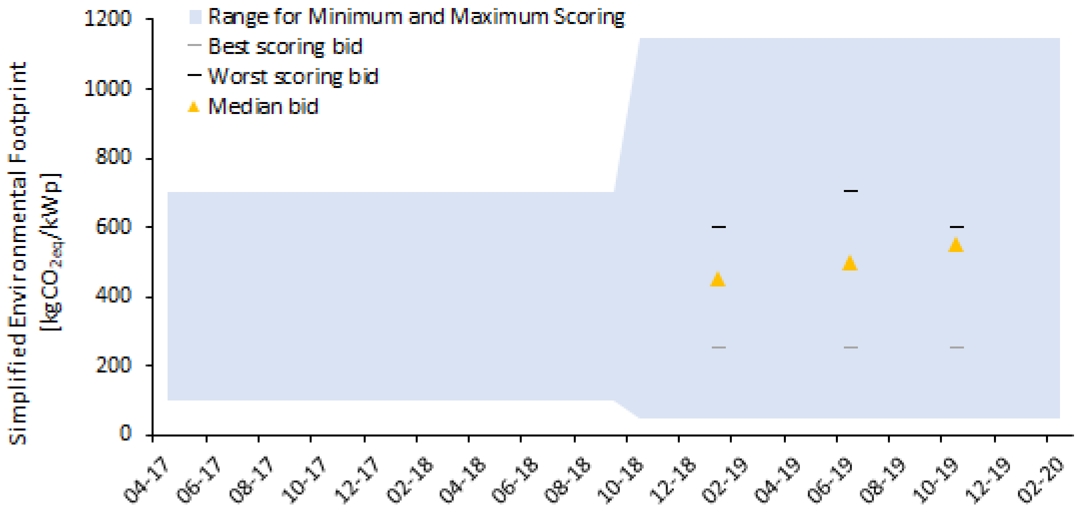


Figure 3.29: Upper and lower range for lowest and highest possible grade concerning the Simplified Environmental Footprint criteria and bid results in recent French tenders for ground-mounted PV (Elaboration by Becquerel Institute based on [59] [60] [61] [62]

3.7 Factors affecting the accuracy and uncertainty of PV power production estimates

Evaluation of a PV system via different KPIs is based on the use of location-specific factors (solar radiation weather and geographical parameters). Understanding the accuracy and uncertainty of estimates of these factors is critical for the correct interpretation of KPIs.

Data describing location-specific factors are acquired by the following options:

1. Local measurements: a suite of sensors and support equipment installed at a meteorological station, typically as a project site or nearby.
2. Data from models: modern solar and meteorological models, namely satellite based solar models or numerical weather prediction (NWP) models offer high accuracy data available for a long history, for real-time monitoring as well as forecasting.
3. Often, a mixture of the locally measured and model data is used as an input to KPIs.

Use of data from measurements and models have specific benefits, and the most accurate and robust system is to use both data acquisition systems, and to merge them via data correlation techniques.

Table 3.6 compares the data acquisition techniques.

Table 3.6: Measuring and modelling techniques: features and benefits

	Measurements	Models	Combination of both techniques
Accuracy	Data accuracy strongly depends on the accuracy class of instruments, on the operation and maintenance practices, and data quality control. High-accuracy and well-maintained instruments can provide time series data at high accuracy, subject to a strict data quality control	Data accuracy depends on the time and spatial resolution of the models and their ability to physically represent meteorological and geographical phenomena. Models offer comparable or better accuracy for aggregated data (yearly and monthly). At daily, hourly, and sub-hourly level, the accuracy of models, compared to high-quality and high-accuracy measurements, is typically lower	Models are adapted (using local measurements) for the specific conditions of a site so that they can generate time series with higher accuracy (given by the measurements), representing long history given by the model data
Spatial representation	Measurements represent a point specific information of a given location	Models represent area-specific information: a model grid cell may represent an area of 1 to tens (hundreds) of square kilometres	
Time representation	Data represent a limited period of time, given by the operation of a meteorological station	Models represent a long history, and many of them allow for calculations to the near or medium future	
Time resolution	Best practice for data acquisition time step is 1 to 10 minutes	Typical time resolution of modern satellite-based solar models is 5, 10, 15 minutes. Meteorological models operate often at hourly or coarser resolution	Statistical synthetic generator allows creating 1-minute time series data from lower resolution model values
Data stability in time	Measurements are prone to various disturbances given by measuring equipment and local conditions, resulting in incorrect or missing values. Signal in time series drifts for instruments with insufficient maintenance and calibration	Due to continuous developments, the characteristics of the models and input data improve in time, temporal stability is maintained by specific time-harmonization algorithms. Data from modern models rarely suffer from gaps or physical errors. Data quality control and post-processing should be inherent part of any calculation scheme.	Combined use of measured and model data is very powerful in data quality control procedures and postprocessing, including data gap-filling.
Reliability	Reliability is strongly determined by the technical quality and accuracy of the sensors and equipment (mostly the data logger) and most of all by the regular and rigorous cleaning, maintenance, and calibration of instruments. Rigorous data quality control is important to	Accuracy and reliability of the model outputs depends on the choice of input data, pre-processing and postprocessing techniques, backup, and redundancy of data acquisition and processing infrastructure	Combination of data from meteorological stations and models offers an added value, but it requires a sophisticated and resilient infrastructure that can cope with failures, and data quality and availability issues

	Measurements	Models	Combination of both techniques
	assure reliability and quality of measurements. Merging data from multiple sensors requires specific knowledge and tools.		
Costs for the end-user	High CAPEX and high OPEX. This service requires trained personnel, specific organization, and infrastructure, or hiring a dedicated service provider	Low costs, low requirements for operation and logistics. Reliability of the data, the service, and level of technical support depends on the choice of the model data provider	Service based on the operation of a customized measuring infrastructure combined with the use of the model data offered by a professional service provider yields the best ratio between the value and costs

Costs of data acquisition and requirements for uncertainty differ, depending on the size of a project or needs:

- For **estimates of long-term power generation** for projects in development, only the model data can be used, characterizing long history in a harmonized and continuous way.
- For regular **performance evaluation** the choice of input data for KPI calculation is either the model data or also measurements (

- Table 3.6).
    - For *small and medium size PV systems*, often data from models are sufficient
    - For *medium-size and large-scale PV systems* a combination of measured and modelled data provides a best value for the effort
    - The evaluation of *utility scale PV systems* relies on the measurements, quality controlled and gap-filled by data from the models.
- In **PV power forecasting,** the forecast accuracy is enhanced by assimilation of the PV power production data with the models. A first step to data assimilation is a quality control of the power production data acquired from the PV power plants.

3.7.1 Uncertainties of modelled and measured solar radiation

Measurements and models related to solar radiation are affected to different uncertainty factors (Table 3.7).

The choice of data acquisition depends on the size of a power plant, available budget, needs for data accuracy, and possibility to assure to follow high standard of measuring procedures and data quality control (Tables 4-3 and 4-4):

1. **Ground measuring instrument**s: for majority of cases, it is standard to use the high accuracy instruments (e.g. class A pyranometers with a ventilation unit), as they offer the most stable signal and the best control of the uncertainty factors (cosine effect, temperature effect, dew/frost, etc.). Yet, the quality of data from ground sensors strongly depends on routine sensor cleaning, maintenance, regular calibration and rigorous data quality control.
2. In most cases, data from **satellite-based solar models** are used (in a combination with the ground measurements or without), as they offer a good ratio between costs and a value, both for long-term energy yield assessment, and regular performance evaluation. At some occasions, e.g. in PV variability studies, solar radiation from **meteorological reanalysis models** may be used. The accuracy of solar parameters from meteorological models is typically lower, compared to the outputs of the satellite-based models. In forecasting, solar radiation is derived by two different approaches: from (i) numerical weather prediction models and (ii) from satellite-based cloud motion vector models.

Uncertainty related to measurements can be minimised by:

- Choice of high accuracy sensors
- Following strict operation, cleaning and maintenance procedures related to the instruments and to the equipment of meteorological stations
- Regular calibration, following the standards
- Application of data quality control and gap-filling, for the case of missing or rejected data records.

Uncertainty related to solar models can be reduced by:

- Design of the underlying models, so that they represent accurately different geographical environments. The advancements in atmospheric science, better geographical data and geospatial analysis make it possible to improve accuracy and develop more sophisticated and more physically-based models
- Quality control, pre-processing and harmonisation of data inputs used in the models. Data used as inputs to the models come from different sources, observation missions and meteorological models. In order to achieve best possible accuracy and harmonisation, sophisticated radiometric, geometric and physical models have to be used.

- Adaptation of models to local conditions of a site (based on local measurements). For the analysis of a specific site, it is beneficial to combine good quality measurements with the model outputs to reduce uncertainty and to achieve time series matching the local climate.

Table 3.7: Satellite-based solar models vs. solar measurements: uncertainty factors

	High-accuracy sensors	Satellite-based solar resource data
Sensor active area	ca. 3-5 cm^2	10 km^2 and more
Air temperature	Little	-
Calibration	Yes	-
Local pollution	Yes	-
Time shifts	Yes	-
Local shading	Yes	-
Missing values	Yes	Almost none
Position of sensor	Yes	-
Dew, droplets, frost	Yes	-
Snow, ice	Yes	Partially
Low sun angle	Yes	Yes
State of the atmosphere – aerosols/pollution	-	Yes
Clouds, fog	-	Yes
Satellite image quality	N/A	Partially (managed by pre-processing)
Indicative uncertainty of yearly/monthly values	Higher than 2% *	Higher than 3.5% *

Factors that can be reduced by model site adaptation

Factors that can be reduced by rigorous operation and management

* Minimum achievable uncertainty for GHI

Uncertainty of modelled or predicted values is decreasing with increasing temporal resolution: Uncertainty of daily, hourly, quarter-hourly or minute values are higher compared to the uncertainty of yearly and monthly values. The uncertainty of high-quality solar irradiance measurements is comparatively stable for different temporal resolutions. The factors influencing the measurement uncertainty (such as local shading, time shifts, missing values, misaligned sensor, soiling, pollution, snow, dew of frost) spread across the data in all time resolutions.

3.7.2 Uncertainties related to weather parameters

Weather parameters are also used in energy yield modelling and performance evaluation. The most important are:

- Air temperature at 2 metres above ground
- Wind speed and wind direction at 10 metres above ground
- Relative humidity at 2 metres above ground.

All parameters can be acquired by instruments (i) mounted on a meteorological station or (ii) they can be derived from meteorological models.

Table 3.6 and Table 3.7, describe the main considerations determining choice of the data acquisition and processing approach.

Similarly, to the discussion on solar radiation, for all weather data the same argument applies: in case of larger projects with sufficient budget, the measurements based on high accuracy and well maintained equipment with strict data quality control offer reliable and high quality meteorological data. For most cases, the data from models or combined with local measurements offer good value for low costs.

3.7.3 Uncertainties related to environmental parameters

Albedo is the most important parameter for modelling of bifacial PV modules. Typically, the data is acquired from satellite -based archival units. Ground measurements can help in adaptation of model data to the local conditions.

Soiling and snow on PV modules are still considered as a high-level expert guess. The innovations within this project will bring new solutions based on processing of numerical weather models and satellite data.

- **Soiling ratio**, measured by the method based on the comparison of clean and soiled devices, is an instantaneous value. It is therefore impacted by residual angular misalignment of the two reference devices as well as angle-dependent light scattering from soiling particles. It should be integrated to compute a daily average value (irradiance-weighted average).

  Effects of soiling, in PV energy simulation, will be quantified by algorithms, making use of data from meteorological models. Uncertainties related to soiling estimation can arise from various reasons: a first source of uncertainty comes from the measurements (current, power) on the devices; then the spatial non-uniformity of soiling over PV modules within the same system. Typical measurement related uncertainties can be of the order of 1 % [7].

- **Snow losses**, in PV power generation, will be evaluated by algorithms making use of the data from numerical meteorological models.

3.7.4 Uncertainties related to PV-related technical parameters

PV performance indicators are estimated from weather measurements (ex: irradiance, air temperature, wind speed), environmental parameters (ex: soiling, module temperature), electrical measurements (ex: DC/AC current, voltage) and technical parameters (ex: STC power, bifacial factor, temperature coefficient for power).

Concerning electrical measurements, IEC61724-1 standard requires a class A (high accuracy, i.e. ±2.0% measurement uncertainty) equipment at the inverter level, DC measurements prior to power conversion and AC measurements following power conversion.

For multi-phase inverters, class 0,2 S (high accuracy) or class 0,5 S (medium accuracy) are required.

As for technical parameters:

- **STC power**: in large PV plants with numerous modules, it is not easy to calculate the exact total power. This total power is usually determined from manufacturer datasheets, module labels, or specific measurements (for example manufacturer’s flash test results attached in PV modules packaging). Three hypotheses are thus made: (1) the deviation of the effective module efficiency and the manufacturer specifications is neglected (uncertainty about 1%), (2) the mismatch between modules/strings/arrays is neglected (uncertainty about 2%), (3) the performance loss of the modules is also neglected (0.5 to 1%/year of power loss).

- **Bifacial factor**: it is usually stated as a constant value (ratio between front side and back side STC powers) but it is also affected by degradation (i.e. 0.5 to 1%/year of power loss for both sides). The value is indicated in the module datasheets.
- **Temperature coefficient for power**: it is usually stated also as a constant value, but uncertainty is here very low. The value is indicated in the module datasheets.

Photovoltaic power production is calculated using numerical models (optimally) based on the use of sub-hourly time series of solar radiation, weather and environmental data representing a long history. Generally, in PV simulation, the energy losses can be classified in two groups:

- Static (quasi static): factors which change in a longer time span - module surface pollution, losses in cables, and mismatch between PV modules,
- Dynamic: these losses depend on solar irradiance and air temperature, which change over time of day and over seasons.

There are several energy conversion steps incorporated in irradiation-to-electricity simulation chain:

Step 1 **Global tilted irradiation**	**Global irradiation on the tilted surface of PV modules** Global tilted (plane of array) irradiation impinging on a tilted plane of PV modules, calculated from global horizontal irradiance, direct normal irradiance, terrain albedo, and instantaneous sun position within (sub) hourly time interval.
Step 2 **Terrain shading**	**Losses due to terrain shading** Shading by far terrain features (horizon) or shading of local features such as from nearby buildings, structures or vegetation can be also considered.
Step 3 **Angular reflectivity**	**Losses due to angular reflectivity** Angle of incidence effects on the surface of PV modules, where the magnitude of effects depends on relative position of the sun and plane of the module. The accuracy of calculations of angular reflectivity losses depends on cleanness and specific properties of the module surface (antireflection coating, texture, etc.).
Step 4 **Frost and snow**	**Losses due to frost and snow** Considering the climate conditions, losses due to frost or snow may need to be considered in wintertime. The long-term effects are not satisfactorily known, and often only indicative expert-guess parameters are used.
Step 5 **Dirt and soiling**	**Losses due to dirt and soiling** Losses of solar radiation at the level of surface of PV modules depend mainly on the environmental factors and cleaning of the PV modules surface during the power plant lifetime. The long-term effects are not satisfactorily known, and often only indicative expert-guess parameters are used.
Step 6 **Conversion in PV modules**	**Losses due to performance of PV modules outside of STC conditions** Global plane of array irradiation reaching modules of the given type is here converted to electricity. The conversion efficiency is non-linear and depends on solar and weather (solar irradiation, air temperature) and technical (module technology and mounting type) factors.

Step 7 **Inter-row shading**	**Losses by inter-row shading** Near-distance losses, depending mostly on distance between rows of PV modules. The topology of module interconnections, strings layout and PV module technology and orientation can suppress or increase impact of shading to PV production.
Step 8 **Power tolerance of modules**	**Power tolerance of modules** The power tolerance of modules, in the true sense, is not an energy conversion step, but has impact on mismatch losses of the modules connected in series. Therefore, it increases uncertainty of power output estimation; the more the higher power tolerance PV modules are connected in string. It is assumed that after initial degradation of the modules their performance will drop to the name plate nominal power values.
Step 9 **Mismatch and DC cabling**	**Mismatch and DC cabling losses** Mismatch due to different MPP operating point of modules connected into an inverter and heat losses in the interconnections and cables depend on the design and components of the PV power plant. DC cabling losses include ohmic losses of cables and all devices that are in a path of DC current produced by the PV modules (connections of modules, strings, DC string boxes, connectors, fuses, switches, etc.) into inverter.
Step 10 **DC/AC conversion in inverter**	**Inverter losses from conversion of DC to AC** DC to AC conversion is performed by inverters, where small part of generated DC energy is transformed into heat, consumed by internal circuits, etc. All these losses are described by inverter efficiency in form of one number (European or CEC weighted average efficiency, less accurate) or efficiency curve (dependence of the inverter efficiency on the inverter load and inverter input voltage), used with sub-hourly pairs of DC data (more accurate).
Step 11 **AC losses**	**AC cabling losses, transformer losses and self-consumption** The additional AC side losses reduce the final system output by a combination of cabling (both on low and high voltage side up to grid connection point), transformer losses (core, windings) and self-consumption losses of PV power plant supporting devices (protection, monitoring, heating or cooling, modules tracking, etc).
Step 12 **Technical availability**	**Losses due to production unavailability** This empirical parameter quantifies electricity losses incurred by the shutdown of a PV power plant due to maintenance or failure (due to internal reasons, may be named internal availability) or due to failures or shutdown of the local substation, grid lines, etc. (due to reasons outside of power plant, external availability).
Step 13 **Long-term performance loss**	**Long-term performance loss** Long-term operation of power plants put all components under stress during the weather cycles. Currently produced modules and system components represent a mature technology, and low performance loss can be assumed. Although it has been observed in different studies that performance loss rate of PV modules is higher at the beginning of the exposure (initial degradation), and then stabilizes at a lower level, an assumption of linear annual performance loss rate is a good approximation for the payback time of the investment costs.

The total uncertainty for the annual electricity yield value is calculated by the quadratic sum of all the uncertainties related to every step in the simulation. Uncertainty values are often expressed at P90 confidence level (90% probability of exceedance), which is also close to characterisation of 80% probability of occurrence.

The values in Table 3.8 consider the long-term annual average value, and do not represent one single year, as this would need the interannual variability analysis from the full time series of data.

Table 3.8: Uncertainties of estimate for long-term annual values

Description		Uncertainty at P90 [%] Low	Uncertainty at P90 [%] High	Comments
Global irradiation on in-plane surface	Global horizontal irradiation	±4.0	±8.0	Depends on the climate
	Splitting and transposition models	±0.0	±2.0	No angle limitation is considered for tracking systems
PV conversion model	Losses due to terrain shading	±0.0	±4.0	Depends on the location
	Losses due to angular reflectivity	±0.2	±0.5	Depends on soiling
	Losses due to performance of PV module outside of STC conditions	±2.0	±3.0	Generic values for each PV technology are used
Other DC losses	External shading	±0.0	±5.0	
	Inter-row shading	±0.0	±1.0	
	Pollution, soiling	±1.0	±2.5	
	Snow, frost	±0.0	±2.0	
	Cable losses	±0.2	±0.5	
	Mismatch	±0.2	±0.8	
Inverter losses from conversion of DC to AC	Inverter power efficiency	±0.5	±1.0	
AC and transformer losses	Cable losses	±0.2	±0.7	
	Transformer	±0.2	±0.5	
Availability and distribution network level power regulation	Power plant	±0.1	±0.7	
	Distribution grid	±0.0	±0.0	Depends on PPA
	TOTAL	±4.6	±11.5	

Small roof or façade systems are usually directly connected to distribution grid, what means that inverter must provide all protections required by regulations (voltage, frequency, isolation check, etc.). It is also required that inverters have anti-islanding protection, which means that they work only if grid voltage is present (due to safety reasons). Since these are low-power systems, inverters have lower efficiencies, especially those with internal isolation transformer. Typical losses and uncertainties for this type of PV installations are summarized in Table 3.9. It has to be noted, that extreme cases may exceed the mentioned limits.

Table 3.9: Breakdown of losses and uncertainties for long-term energy yield estimate of a small PV system

Description	Loss range [%] Low	Loss range [%] High	Uncertainty at P90 [%] Low	Uncertainty at P90 [%] High	Comments
Global horizontal irradiation	-	-	±4.0	±8.0	Depends on the climate
Transposition model	-	-	±0.0	±2.0	No angle limitation is considered for tracking systems

Losses due to terrain shading	0.0	3.0	±0.0	±4.0	Depends on the location, in extreme cases may be over 3.0%
Losses due to angular reflectivity	1.0	5.0	±0.2	±0.5	
Losses due to performance of PV module outside of STC conditions	2.0	15.0	±2.0	±3.0	Generic values for each PV technology are used, in extreme cases may be outside of range 2.0-15.0%
External shading	0.0	5.0	±0.0	±5.0	For extreme cases shading losses may be higher than 5.0%
Inter-row shading	0.0	2.0	±0.0	±1.0	Applies only if modules are installed in tilted rows.
Pollution, soiling	3.0	5.0	±1.0	±2.5	
Snow, frost	0.0	4.0	±0.0	±2.0	
DC Cable losses	0.2	0.5	±0.2	±0.4	
DC Mismatch	0.5	2.0	±0.2	±0.8	
Inverter power efficiency	2.0	6.0	±0.5	±1.0	
AC Cable losses	0.2	0.5	±0.2	±0.4	
Transformer losses	0.0	0.0	±0.0	±0.0	Usually connected without transformer
Power plant	1.0	3.0	±0.1	±0.7	
Distribution grid	0.0	0.0	±0.0	±0.0	Depends on a contract
TOTAL	9.5	42.1	±4.6	±11.5	

Large utility scale PV power plants are designed to provide maximum performance with minimum possible losses. Horizon and near shading losses are often reduced by selecting a project sites with minimum occurrence of disturbances. PV power plants are usually built with inverters, optimized to high performance and efficiency.

Fixed tilt installations provide robust and low maintenance solution, but inter-row shading losses are present, depending on designed tilt and row spacing. Projects are very often built on remote sites with harsh conditions like dust or sand, where regular maintenance is difficult, thus soiling losses must be considered accordingly. Large power plants may have significant impact on the medium voltage distribution grid in the point of connection and distribution company may reserve the right to occasionally disconnect PV power plant during peak hours (according to Power Purchase Agreement) to ensure grid stability, what will decrease availability of production. Typical losses and uncertainties for this type of PV installations are summarized in Table 3.10. It has to be noted, that extreme cases may exceed the mentioned limits.

Table 3.10: Breakdown of losses and uncertainties for long-term energy yield estimate of a ground based fixed-mounted PV system

Description	Loss range [%]		Uncertainty at P90 [%]		Comments
	Low	High	Low	High	
Global horizontal irradiation	-	-	±4.0	±8.0	Depends on the climate
Transposition model	-	-	±0.0	±2.0	No angle limitation is considered for tracking systems

Losses due to terrain shading	0.0	1.5	±0.0	±1.0	Depends on the location
Losses due to angular reflectivity	1.0	3.0	±0.2	±0.5	
Losses due to performance of PV module outside of STC conditions	2.0	13.0	±2.0	±3.0	Generic values for each PV technology are used, in extreme cases may be outside of range 2.0-13.0%
External shading	0.0	0.5	±0.0	±0.2	
Inter-row shading	0.0	2.0	±0.0	±0.8	
Pollution, soiling	1.5	3.0	±1.0	±2.0	
Snow, frost	0.0	2.0	±0.0	±1.0	
DC Cable losses	0.3	2.5	±0.4	±0.8	
DC Mismatch	0.4	1.0	±0.2	±0.8	
Inverter power efficiency	1.5	3.0	±0.5	±1.0	
AC Cable losses	0.5	1.5	±0.2	±0.8	
Transformer losses	0.5	2.0	±0.0	±1.0	
Power plant	1.0	1.5	±0.1	±0.7	
Distribution grid	0.0	0.0	±0.0	±0.0	Depends on PPA
TOTAL	8.4	31.8	±4.6	±9.4	

Notes on PV system parameters and solar forecasts:

- Uncertainties in PV forecasting are considerably higher than the uncertainties of long-term mean values. PV power forecast uncertainties are largely determined by the uncertainty of solar radiation forecasts.
- Impact of PV technical parameters has a similar magnitude compared to long-term estimates and is therefore small compared to forecast uncertainties of solar irradiance.
- Factors with considerable impact are snow and ice on PV modules, soiling, and shading.
- For small PV systems, often an information on a system lay-out is missing or not correct: the most important is information on the tilt and orientation of PV modules. Also, high resolution data are typically not available for these PV systems that could be used for training of forecast models. This leads to higher forecast uncertainties for small PV systems. It also impacts uncertainty of regionally aggregated forecasts for grid areas, which include many small PV systems.

3.7.5 Uncertainties related to PV-related financial parameters

The uncertainties mentioned above eventually directly impact various financial parameters used as inputs in the feasibility studies of PV projects. Moreover, other uncertainty factors, aside of technical- or weather-related ones, can also be impactful. Overall, the impacted key financial aspects can be divided into two main categories: (1) the estimation of risk and (2) the cash flows. Note that these two aspects are closely linked and can influence each other.

Concerning the estimation of risk, which translates in concrete terms into returns required by both debtholders and equity investors, it is directly correlated with uncertainties. As the total level of uncertainty increases, the level of risk of the investment rises as well, and so does the return required by investors. This uncertainty can be linked to weather or technical parameters impacting the amount of kWh projected to be produced. Today, most of investors use P90 yield estimations to minimize risks linked to the PV production.

The uncertainty can also be linked to the potential monetization of these kWh. For instance, in case of direct sales on the market, the PV project would be exposed to power market risk, i.e. the uncertainty of the level of prices on the wholesale electricity market at which the PV production can be sold, and the overall level of risk of the investment would be pushed upwards. One can also mention regulatory and political risks, which might be non-negligible, as recent history as shown for different types of PV investors, even on mature European markets, like Spain[2], France[3] or Belgium[4]. These risks can impact the possibilities to value the produced kWh, and in general the rentability of the investment, as it can also increase the associated costs or taxes.

In the end, the estimation of risk is mainly reflected in the discount rate, should it be the weighted average cost of capital or the cost of equity. Hence, it influences how future cash flows are taken into account, i.e. their weight in the present estimation of rentability.

Then, cash flows of the PV asset constitute the second key financial aspect influenced by uncertainties. Firstly, via the estimation of risk and the associated discount rate, as evoked above, but also via the debt service, which varies in function of the interest rate. Secondly, as there is uncertainty on the produced energy, there is also uncertainty on the revenues it will generate. From one period to another, they could vary significantly as well as deviate from the predicted values.

To limit the negative consequences of uncertainties on financial estimations because of cash flows variations, stochastic variations corresponding to uncertainty levels are associated to relevant technical or performance parameters of the simulations. The simulations are then run multiple times, e.g. between 100 to 1000, and the distribution of results is studied. It allows to estimate the probability of reaching the necessary rentability values, using indicators like the IRR and the NPV.

[2] See https://www.pv-tech.org/spain-leaves-sun-tax-days-behind-with-self-consumption-decree/
[3] See https://www.pv-tech.org/french-solar-industry-braces-for-impact-of-retroactive-feed-in-tariff-cuts
[4] See https://www.pv-magazine.com/2020/09/29/wallonias-prosumer-grid-fee-comes-into-force/

3.8 KPIs for SERENDI-PV

For this assessment, the PV systems are categorized according to the schema shown in Figure 3.30. Indeed, most parameters vary significantly depending on the type of PV system considered (differentiated along columns) and on the installed PV capacity (differentiated along lines). Therefore, KPIs need to be assessed for different segments (combination of PV system type and installed PV capacity) separately to have representative, meaningful and exploitable results. The segmentation shown in Figure 3.30 is made according with the main objectives of this project (see section 3).

Some system types are merged since their differentiation does not show a significant impact regarding the focus of the SERENDI-PV project. For example, the differentiation between ground-mounted PV and agrivoltaic-PV was not included in favour of a differentiation between ground-mounted PV systems with a fixed tilt and ground-mounted PV systems based on a tracker. In case, a further differentiation would result an impact on the KPIs assessment, this is would be clearly detailed with the evaluation of the KPI.

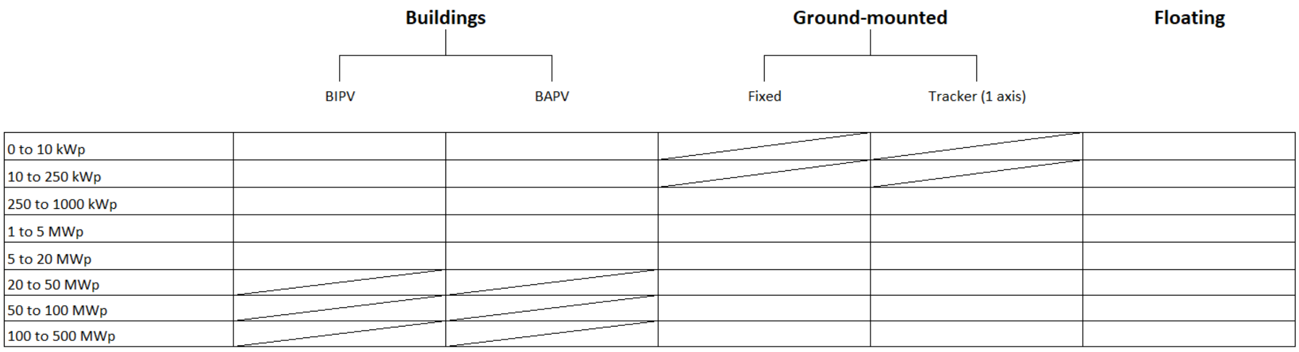


Figure 3.30: Used segmentation for PV systems

In sections 3.1, 3.2, 3.3, 3.4, 3.5 and 3.5.6 most important parameters with regards to PV performance, PV reliability, PV power modelling, PV monitoring, PV profitability and PV environmental impact have been presented. A definition was provided for each parameter and, when possible, a reference value for the state of the art was provided.
In the frame of the SERENDI-PV project, some of these parameters have been singled-out as Key Performance Indicators.

Table 3.11 lists the most relevant KPIs in the frame of the project, i.e. parameters, which will enable to measure the impact of the project on the aspects of PV (performance, reliability, modelling, monitoring, profitability and environmental impact).

Table 3.11: SERENDI-PV project's KPIs

SERENDI-PV KPIs Category	SERENDI-PV KPIs
Performance	Performance Ratio
	Temperature corrected performance ratio (PR at STC)
	Soiling ratio
Reliability	Performance Loss Rate
Power modelling and forecasting	Root Mean Square Error
	Mean Absolute Error
	Mean Bias Error
	Forecast skill score
Monitoring	Energy Performance Index (EPI)
	Data availability
	Data quality
Profitability	LCoE
	Profile factor
	WACC
	NPV
	(M)IRR

4 ASSESSMENT OF CURRENT IMPACT OF PV INTEGRATION IN THE GRIDS vs THE KPIs

In this section the focus is on the integration of PV plants to the grid, and the services that they can provide for both TSO and DSO levels. We introduce the impact of PV on the system management, on power quality, congestion, as well as the need for additional reinforcements and investments on DSO level. In addition, system stability, generation adequacy and frequency control questions at DSO/TSO level are studied.

4.1 Voltage deviation

The electrical grids, which were mainly built some decades ago, are under the transition from a centralized power supply through some hundreds of large power plants to a decentralized power supply through millions of distributed energy resources (DER). In general, voltage problems occur locally at certain grid nodes, which are usually far from the transformer substations. This voltage local phenomenon is explained in a simplified low voltage (LV) grid, containing one simple line as depicted in Figure 4.1.

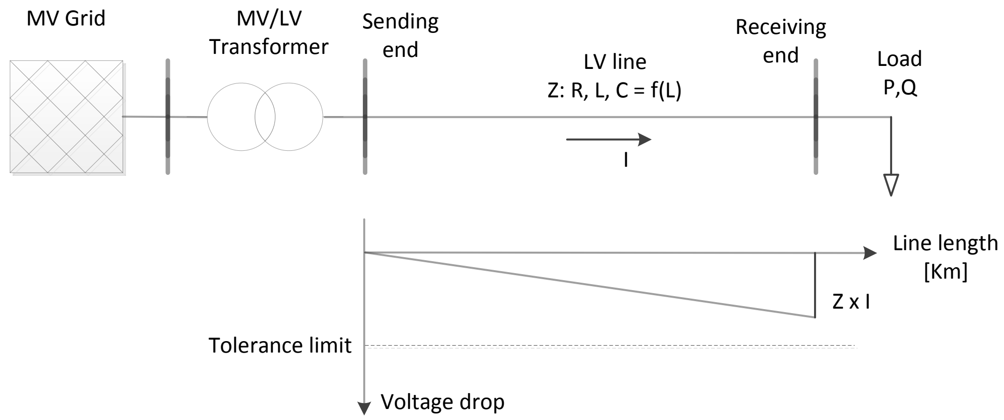


Figure 4.1: Schematic illustration of the voltage at receiving end considering a simple line

The local voltage value at the receiving node in Figure 4.1 is basically the voltage at the sending node plus a voltage drop based on the current and the impedance of the line. Theoretically the voltage drop is proportional to the current in the line and its impedance. The factors that affect the voltage drop at the receiving node can be summarized as follows:

- The reactive power injection in the receiving end affects the current value and the voltage drop. The capacitive reactive power injection leads to voltage increase, while inductive reactive power leads to voltage drop at the receiving end.
- The active power consumption at the receiving end leads to higher current and thus higher voltage drop. If there is active power injection at the receiving end, for example through DER, the voltage drop will decrease and can be possibly converted to a voltage rise if the injection at the receiving end is high enough.
- The length of the line affects the impedance, so that the longer the line is, the higher the impedance is, and thus the voltage deviation increases.

In the case of high DER penetration, especially PV, the power from PV generators can be higher than the consumption in high feed-in hours (i.e. in the noon). In this time, the voltage at some nodes can increase and exceed the voltage tolerance band. This case is one of the most important concerns of the network operators, as different nodes would need different mitigation measures. The example in Figure 4.2 explains the concept of voltage violation at a node with high PV feed-in. In case a large PV capacity is installed at the receiving end, the power injection can be very high, so that it can be higher than the consumption by the load. Therefore, the current in the line changes the direction and the voltage drop in Figure 4.1 becomes a voltage rise, which can exceed the voltage tolerance band and leads to an operation problem.

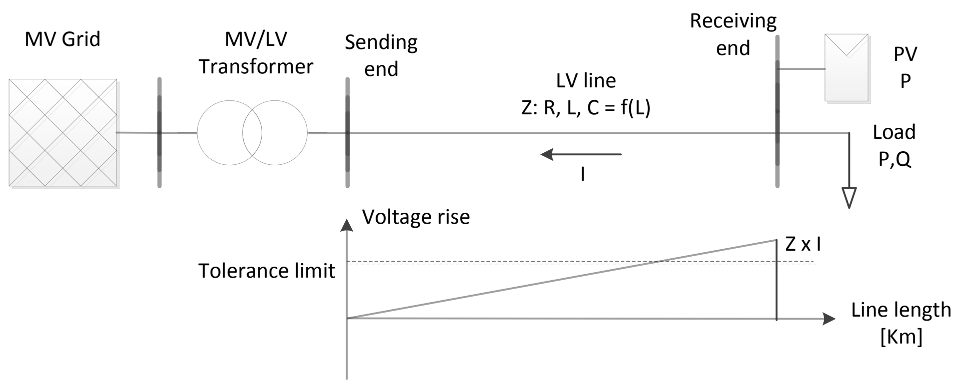


Figure 4.2: Schematic illustration of the voltage rise at receiving-end considering high PV feed-in

Some general information in relation to voltage violation are given hereinafter:

- Voltage problems in distribution grids can be more complicated compared to frequency problems, since the voltage values can vary diversely in the same grid, whereas the frequency has the same value in the whole network. In one LV grid, the voltage can be too high in some nodes and too low in other nodes, based on the local consumption and feed-in.
- It is usually difficult for the DSO to detect voltage violations in the network, since voltage measurement devices are not installed at all nodes in the distribution grid, which contains high number of DER. Usually, they are installed at the transformer stations; instead of at the end of the lines where most problems occur. In fact, installing so many measurement devices for the aim of voltage control requires a lot of money and efforts from DSOs, and thus not implemented in the present in most LV and MV grids. In SERENDI-PV, digital twin of the grid based on measurements from PV system will be investigated.
- In SERENDI-PV, we will focus on the steady state voltage problems that result from the long-term voltage deviations. Most DSOs set-up their voltage control strategies according to the averaged voltage value of 10 minutes, which should not exceed ±10% to comply with the European norm (EN 50160).
- Further examples and references related to voltage deviation caused by DER can be found in Appendix A section 5.1.

4.2 System management: grid loading, hosting capacity, reinforcements.

The hosting capacity can be defined as the maximum penetration rate of DER allowed in a grid, with which the grid can still be operated in the normal operation conditions.

4.2.1 Limitation of Hosting Capacity

The main limitation criteria for the DER penetration are the frequency stability criterion, voltage stability criterion and the overloading of grid components.

4.2.1.1 Frequency Stability Limitation

The frequency stability is an important criterion for a quality operation of the grid, given the control levels and their timeframe of allowed frequency deviation. The frequency stability is usually the task of TSOs and will not be under the focus in this chapter, since the focus will be mainly on the distribution grid, which hosts the high penetration of PV.

4.2.1.2 Voltage Stability Limitation

As a main limitation factor for the DER penetration level, especially for distribution grids, the voltage rise should be taken into consideration. The installation of VRE should not lead to voltage violation at any part of the network, even in the peak feed-in hours when the reverse power is at the highest value (e.g. the noon for PV generation). The voltage violation is defined as the excessive voltage rise at one node that leads to a voltage value outside the voltage tolerance band (see 4.1). The estimation of this limitation is usually based on grid calculation for a worst-case analysis of high VRE generation in relation to the highest reverse power. The worst-case analysis is characterized in most grid studies as the grid status when all DERs inject their peak power and simultaneously all loads have the lowest possible consumption.

For a strategic grid planning considering high penetration of DER an accurate estimation of the hosting capacity should be performed by the network operators. For this estimation, a detailed modelling of the grid is required, and also statistical information about the loads in the grid is necessary to model the lowest load consumption for a worst-case analysis.

4.2.1.3 Component Overloading

The installation of DERs in the grid should not lead to overloading of grid components such as lines and transformers to maintain normal operation. The grid is considered to reach its hosting capacity if at least one component exceeds its nominal capacity defined by the manufacturer. A simplified algorithm to estimate the hosting capacity of the grid of PV penetration is depicted as a flowchart in Figure 4.3.

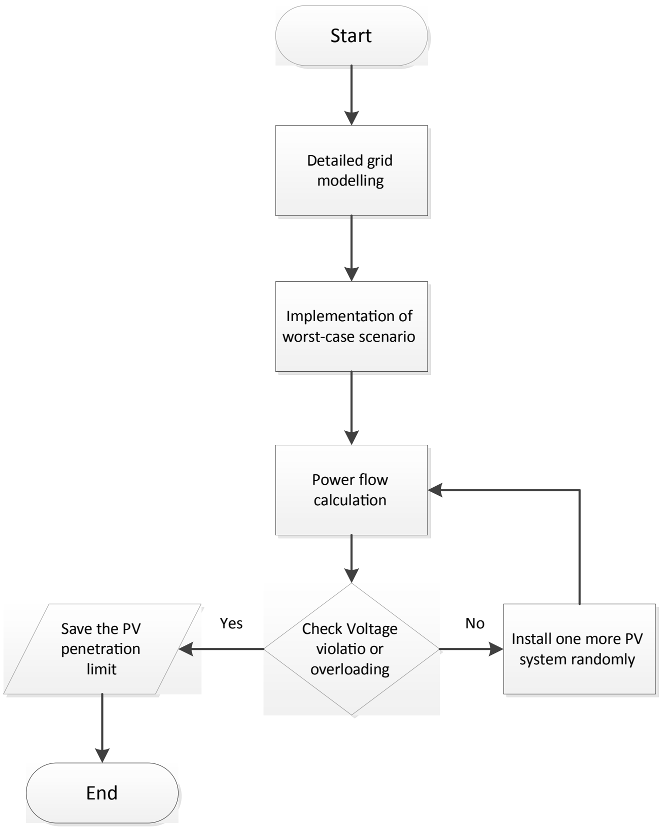


Figure 4.3: Simplified algorithm to estimate the grid hosting capacity considering voltage and overloading constraints

4.2.2 Techniques to Increase Grid Hosting Capacity

The challenges in terms of grid stability arising from the integration of a high penetration of DERs can be solved through several possible mitigation measures. Some main measures are presented hereinafter.

4.2.2.1 Grid Reinforcement

As a basic and classical measure for solving problems, which is caused by a DERs like PV installation, the grid should be strengthened to be more stable. The grid reinforcement can be defined as increasing the loading capacity in some parts in the grid, such as replacing an old line or transformer by ones with higher capacity and thus lower impedance. With less impedance, the voltage violation can be solved, where the overloading problem will be solved by the increased capacity.

Another option, especially for distribution grid, is the placing of a parallel line to an old line in the same route as can be seen in Figure 4.4.

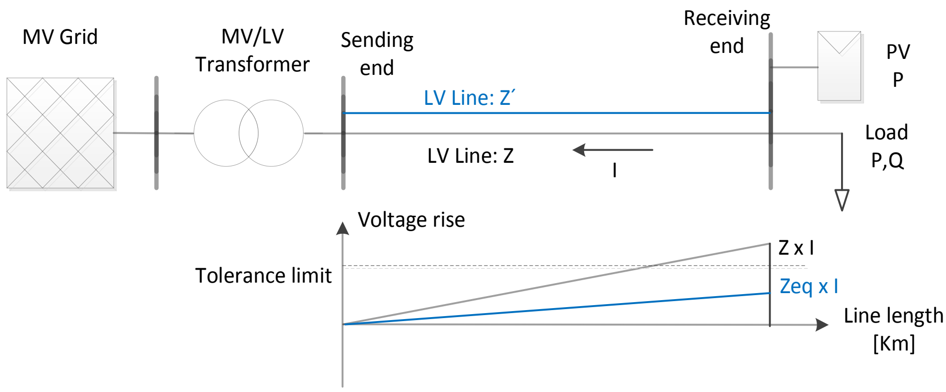


Figure 4.4: Schematic illustration of the voltage rise considering adding a parallel line

The line overloading can be solved as the original reverse current in the peak feed-in hours will be divided between two lines in parallel. In addition, the voltage problem can be solved in the case of parallel line, since the equivalent impedance (Zeq) is lower than the original impedance (Z) of the old line, as explained in the equation:

$$Zeq = \frac{Z \times Z'}{Z + Z'} \qquad \textbf{(Eq. 45)}$$

Where:

- Z´ is the impedance of the new parallel line.

The cost of the adding or replacing line is mainly dependent on the length and type of the line (e.g. overhead line or underground cable) as well as the grid level and rated voltage (e.g., transmission, distribution, LV, MV or HV line). However, the grid reinforcement measures are in general very expensive. For example, the exchange of an underground cable can cost more than 100,000€/km. Considering these high prices, DSOs have to look first at all the smart alternatives to reduce the need for reinforcements. If nevertheless, a reinforcement is required, for example due to a new installation; the costs are split between the owner of the installation and the DSO/TSO. DSOs. It is important to note that in some countries (like Belgium) the legislation in this matter is still being adapted today.

4.2.2.2 Local PV control strategies

The control strategies based on local control of the PV inverters is one of the most attractive measures. In general, the implementation is simple and can be setup in most modern inverters. In many grid studies, the implementation of the inverter local control is not associated with high additional costs for the DSOs. Two simple and recommended control strategies will be summarized hereinafter.

1) Constant Power Factor

As indicated previously in section 4.1, the injection of inductive reactive power at a certain grid node leads to reduction of the voltage deviation. This strategy suggests injecting reactive power by the PV inverter according to the power factor of the PV (e.g. cosϕ=0.95 inductive). With this power factor a voltage rise can be reduced to avoid voltage violations as in Figure 4.5. However, this strategy does not mitigate the problem of overloading in the grid, since it does not lead to a reduction in the currents flowing in the grid.

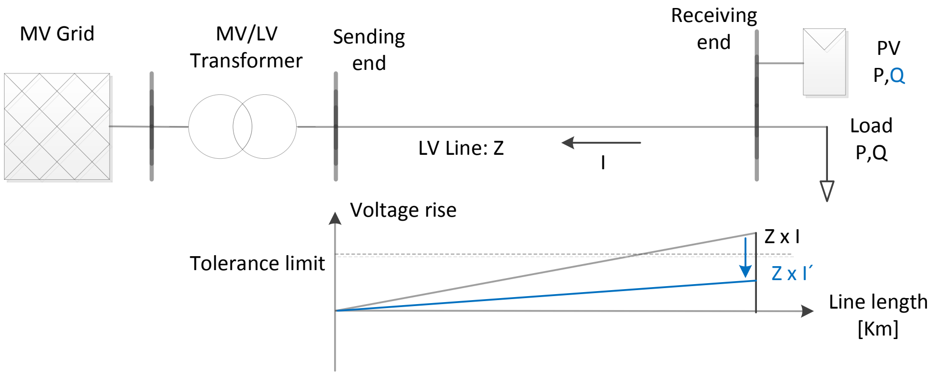


Figure 4.5: Schematic illustration of the voltage rise considering reactive power provision of PV

2) Q(U) Control

As with the constant power factor, this control strategy suggests the provision of reactive power by the PV inverter. The reactive power injection in this strategy is a dependent on the voltage at the point of common coupling (PCC). In other words, the reactive power provision increases if the voltage at the PCC increases (maximum value corresponds to cosϕ=0.95 inductive) as described in Figure 4.6.

This strategy is discussed in several studies as an alternative to the constant power factor strategy. However, the overloading problem cannot be solved with this mitigation strategy neither, as the case with the constant power factor strategy.

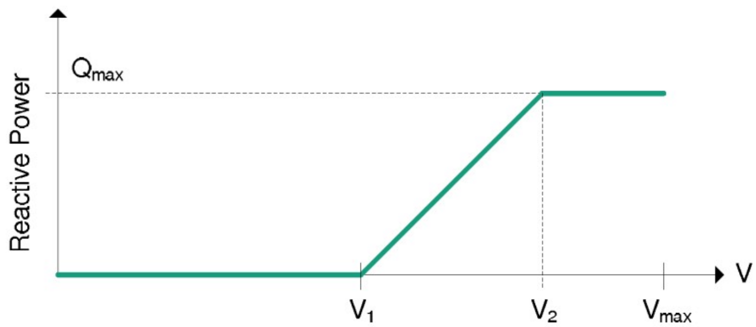


Figure 4.6: Reactive power characteristics for the Q(U) strategy

4.2.2.3 Power Curtailment

In case of high penetration in some grid sections and during the high feed-in hours, the limitation of the power injected by the DER can reduce the reverse power, and thus mitigate the grid stability problem. This strategy can mitigate the voltage violations as well as overloading problems. On the other hand, this strategy can lead to waste of green energy during the curtailment hours. Therefore, the strategy for the power curtailment should be optimized and integrated in a holistic smart grid solution. In other words, it should be based on the measurements and a good estimation of the grid state in order to avoid any unnecessary power curtailment.

4.2.2.4 On-Load Tap Changer (OLTC)

The tape changer control is a classic approach to control voltage at the secondary side of the transformer by changing the number of windings in the transformer and thus change the transformer ratio. The implementation of the OLTCs is suggested in many studies as a mitigation measure for voltage violations in the grid. However, overloading problems cannot be solved by means of OLTC control. A simple example to explain the concept of the OLTC to support the voltage stability is depicted in:

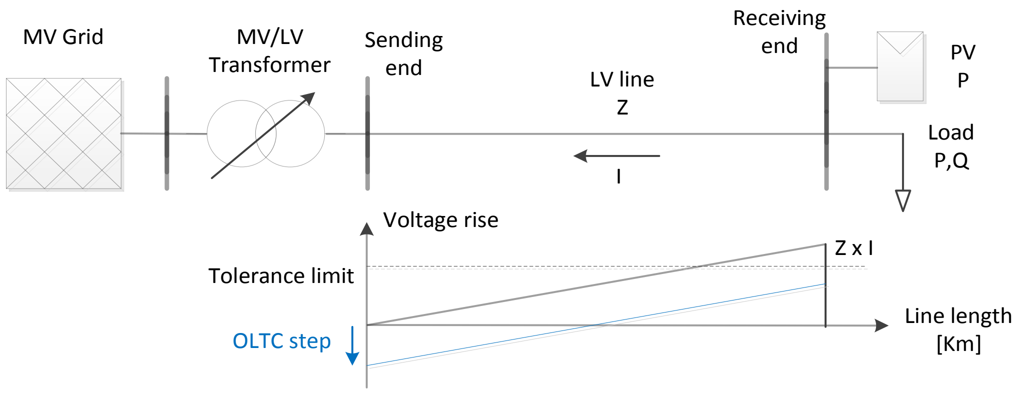


Figure 4.7: Schematic illustration of the voltage rise considering OLTC control

In general, the majority of HV/MV transformers are equipped with OLTC control, but MV/LV transformers are seldom equipped with OLTC. Replacing an old transformer with one with OLTC for the voltage control can be expensive for DSOs. However, it is sometimes possible to install OLTC to an old transformer. In this case the implementation of OLTC control can be more economically feasible for DSOs.

4.2.2.5 Demand Side Management (DSM)

DSM is the modification of consumers' load profile for the energy consumption through various methods, such as financial incentives or public awareness. Usually, the goal of DSM is to reduce the system energy consumption at **peak load hours** by shifting it for example to late night hours or weekends. In the case of high DER penetration, it is important to encourage the customers to consume energy during the peak feed-in hours (around noon for high PV scenarios) or incentivize consumers to store the excessive energy in a battery or use it for a heating/cooling device making use of thermal inertia. DSM does not necessarily decrease total energy consumption but is expected to reduce the need for investments in networks and/or power plants for meeting peak demands. DSM can be performed in an automated way thanks to the use of smart systems (see Figure 4.8).

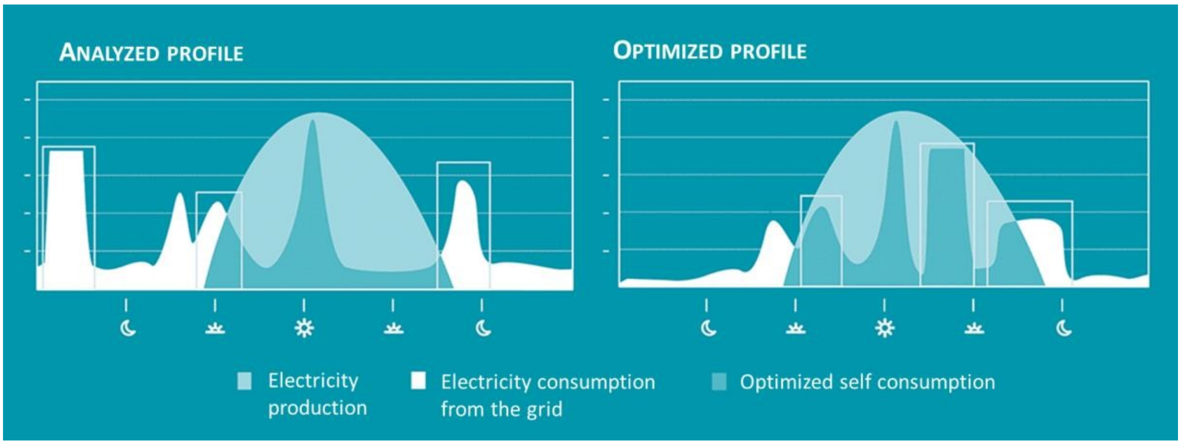


Figure 4.8: Example of demand side management by MyLight systems [63]

4.2.2.6 Smart Grid Technology

The smart grid solutions can be considered as a modern electric power grid infrastructure for enhanced efficiency and reliability. This is achieved through automated control, high-power converters, modern communications infrastructure, sensing and metering technologies, and modern energy management techniques, among others. The energy management techniques are based on the optimization of demand, energy and network availability. While current power systems are based on a solid information and communication infrastructure, the new smart grid needs a different and much more complex infrastructure, as its dimension is much larger. The basic need of smart-grid applications is Information and Communication Technology (ICT). Most control systems are based on the collection of information from the measurement devices and sending optimized set-points to several grid components.

Further literature and references related to grid hosting capacity, reinforcements and grid loading can be found Appendix A, section 5.2

4.3 Power quality

An often-highlighted concern related to the integration of PV power in the grid, is linked with the dependence of its power production profile on the weather. It makes it difficult to predict and control the PV systems output. Such non-scheduled power production can lead to power fluctuations in the system, which might become larger with the increase of PV penetration. Power fluctuations can result in the appearance of *voltage flicker* at user end. In order to mitigate this impact, actual grid codes already impose limits to the PV generation flicker which can be achieved with the current penetration levels.

In addition, PV generators are connected to the grid through power electronics converters. This presents significant differences from conventional generators and can lead to challenges related to the system power quality as PV penetration increases. Due to the switching nature of the power electronics converters, the connection of PV generators leads to the appearance of mid-high frequency harmonics in the system, which can increase system losses and cause interferences with communication systems. In addition, such harmonic components can interact with other elements in the grid leading to resonances in the system. However, in the recent years several limits to the harmonics' emission have been imposed in the different grid codes, to guarantee that such harmonics remain at low values and avoid undesirable interactions. In addition, due to the characteristics of the high frequency components, their propagation capability in the system is very low.

Not only switching related high frequencies but also the low frequency range is becoming more relevant as the PV penetration and the presence of nonlinear loads in the system increase. Traditionally, PV inverters have been controlled as current sources, which are controlled to inject balanced fundamental frequency current at the point of connection. The main reason for such approach is that the injection of unbalanced current components or harmonic currents might lead to voltage distortion due to the voltage drop across the system impedances. However, as the presence of nonlinear loads in the system increases (power electronics devices such as computers, monitors, telecom systems…), the demand of low frequency harmonic currents to feed such loads is also increased. Such nonlinear currents are naturally fed by the traditional generators, which are controlled as voltage sources. For low PV penetration levels there is no need to provide such nonlinear currents but, as the PV penetration increases and old traditional generators are removed, such increasing demand of nonlinear currents will be fed by a smaller number of generators and therefore the nonlinear current flow will concentrate in specific parts of the system, leading to higher voltage unbalance and distortion because of the nonlinear voltage drop. In strong meshed grids, voltage drop will be small and voltage distortion levels will be kept low. However, due to the PV price reduction and previsions, its global penetration is expected to increase a lot, and PV plants are being installed in locations with weak grids with higher impedances. As a result, if the provision of nonlinear currents is not shared between all the generating agents, voltage distortion and unbalance might become a challenge in some locations. Therefore, a development in terms of PV control algorithms to allow optimal nonlinear currents sharing in the system might be needed in the close future. In addition, several grid codes impose limits to the harmonic and unbalanced currents emission, which should be reviewed in order to allow such nonlinear currents sharing.

Grid impedance is not only relevant in terms of voltage distortion but also for control stability and quality of the power injected to the grid. PV plants are becoming larger in terms of power and connected in remote locations which show low short circuit power levels at the point of connection. As a result, the ratio between the short circuit power and the plant rated power, which is defined as the Short Circuit Ratio (SCR), becomes smaller. Smaller SCR values result in higher influence of the PV plant injection in the system voltage levels, which can lead control stability issues. These issues are related to the fact that the inverters are traditionally controlled as “grid following” generators, which means that they try to track the grid voltage angle and remain aligned with it. As the influence of the PV plant on the voltage increases, it becomes difficult to track such voltage angle because it heavily depends on the PV plant injection. In order to overcome this issue, in the recent years the new “grid forming” concept has emerged. This concept means that the PV generator will no longer track the grid voltage but generate its own voltage in order to stabilize the system. Although this is a promising concept, up to date its inclusion in the grid connected PV systems is under development.

4.4 Congestion management

Congestion takes place mainly when grid components become overloaded and are not sufficient to transfer the power in the normal operation conditions. Thus, congestion management is a tool for efficiently transport the power available without violating the system constraints. Congestion management refers to avoiding or relieving congestion. Typical congestions in distribution grid levels are grid components overloading and voltage violations. In a much broader sense, congestion management can be classified under two broad paradigms. One is the cost-free method and other is the non-cost-free method. The cost-free measures include those which are at the disposal of the grid operators. These employs for example the modification of the topology of the grid through closing or opening some switches, changing the position of a transformer tap changer, reactive power provision through some devices e.g. PV inverters, etc. These are coined as cost free measures because of nominal economical consideration, meaning that the grid operator so not have to pay for implementing the measures. The non-cost-free measures include usually a change in the power generation or consumption, such as power curtailment of some DERs or the increase or reduction of some loads.

An example of possible congestion management strategies exists in the distribution grids in Germany: PV systems with an installed capacity of more than 30 kWp and no more than 100 kWp must be equipped with devices that allow the grid operator to remotely reduce the feed-in power at any time in case of congestion (as per renewable energy law “EEG 2017”). This is often realized by installing a radio ripple control receiver, with the help of which the grid operator can regulate many plants simultaneously, for example in the steps 0%, 30%, 60% and 100%.

Further references related to congestion management strategies can be found Appendix A, section 5.3

4.5 Data integration of PV for TSOs and DSOs

The availability of energy system data models and data interfaces in the DSOs and TSOs data system, such as SCADA (Supervisory Control and Data Acquisition), is an important prerequisite for stable system operation and efficient congestion management. For the operation of conventional electric grids, the data collection is conducted till the LV/MV substation level. In the past, it was unnecessary for a DSO to integrate DER data models with detailed technical data, operational state, and measured values in its data system since there was less demand for data collection directly from individual DER devices according to their minor role in the grid operation. Most of the data integration and modelling procedures could be completed manually by a DSO/TSO staff, which might take months though.

However, the digitalization of energy system transition will bring a dramatic transformation to this integration process, as decarbonization requires an increasing share of decentralized and controllable energy systems in smart grids. To reduce the system and labour costs, ensure the efficiency and reliability of DER data integration in DSOs and TSOs data system, and even avoid manual errors, automation approaches based on the application of standard communication protocols and data models should be utilized.

Two widely used standards for data exchange and model integration are IEC 61850 and CIM (Common Information Model, i.e. IEC 61970 and IEC 61968), whose data nodes and data attributes are hierarchical and self-described, this special feature makes them more usable for automation purposes. Although the DER data integration topic should be on DSOs roadmap, most of them are not yet ready for this new challenge. This is due to several reasons, such as:

- IEC 61850/ CIM compliant modules are not available in SCADA database and communication front end
- Feasible implementation of automation approach with high TRL (Technology Readiness Level) is lacking on the market
- There is no massive implementation of decentralized communication units
- DER data integration is not yet one of their priorities

However, decentralization is an inevitable trend in smart grids, and also several standardization committees are working on the usability enhancement of the data integration standards. More and more DSOs and TSOs will tend to deploy distributed intelligent devices, controllable systems, and merging units to improve the state estimation and flexibility provision in smart grids, which correspondingly requires automated data integration algorithms.

Beside all of its benefits for grid operators, the implementation of standardized data models and interfaces can also help stimulate the standardization and implementation of ancillary services for other facilities, such as DER registration; DER marketing business cases; interoperable inter-station communication between DSOs and TSOs, and cyber-security relevant implementations.

Further information about data integration for PV for TSOs and DSOs can be found in the Appendix A, section 5.4.

4.6 Adequacy of PV and other renewables to cover energy demand in local area grids and the electrification of transport and heating sectors

Distributed generators (DG) of renewable energy, e.g. PV, are being installed increasingly in the last years, mainly in rural and suburban areas. In some of these areas, the PV penetration level exceeded already the consumption level, so that the accumulated feed-in energy in a year is higher than the yearly energy demand in some areas, such as the demo site of Hittistetten. With further installation of DGs, more areas can cover their local demand from local generation. Because of its clean and low generation prizes as well as anywhere-available conditions of wind and solar power, electricity will become the most common energy type in the future [64].

The impact of this high distributed feed-in spreads from low-voltage (LV) grid level to medium voltage (MV) in the nearby urban areas. In addition, most industrial areas are also located on the outskirts of a city. The MV grid connect the suburban areas with the industrial areas, where high industrial loads dominate. Due to such conditions, the lines linking these areas can often be overloaded. A smart grid approach to tackle this problem is the active balancing of feed-in and load locally, using e.g. power to gas technology (PtG). With an advanced substitution of fossil energy by renewable sources, storage solution will be more and more important to balance demand and generation in the electrical sector. Hybrid energy grids and multi energy systems couple energy systems, such as gas networks and heat networks, which were separated in the past. This allows first to use the heat and gas sectors as a power sink for electrical surplus and, with increasing feed-in of DGs, as storage in their physical conditions [64].

PtG is an essential technology for long time storage in scenarios with high penetration of DGs of renewable energy. Therefore, it can be a solution to avoid bottlenecks in the electrical distribution grids when transporting local power surplus from low voltage to the high voltage levels. Furthermore, the industry needs hydrogen for processes of producing goods e.g. in the sectors of steel, oil refinery and chemistry [65], [66], [67]. These sectors have no alternative to hydrogen and emitting numerous millions of tons of CO2 yearly. Thus, there is a large reduction potential of CO2 that can be targeted today. Heavy-duty transportation on road and in ships, trains without electrification lines, long-range vehicles and working machines are sectors, where it is difficult to substitute fossil energy carrier by renewables. The energy density of electro-chemical storage is not suitable for the requirements of these sectors. Hydrogen produced from PtG technology could be, in combination with fuel-cell technology, a promising solution [68], [64].

4.7 Grid-specific indicators: Introduction of new grid service indicators

The increasing proliferation of PV systems in the European electricity grids will challenge the grid operators to maintain and ensure a stable and safe operation of the electricity grid. The impact and consequences for the grid, such as congestion problems, frequency and power quality issues, as previously described at the beginning of this chapter, will force grid operators to search for innovative methods to avoid these situations. Whereas PV systems can put more pressure to maintain the safety of the grid, it is interesting to study the possibilities for solar systems to contribute to the safe operation of the electricity grids by delivering ancillary services and participating in balancing markets. In the past, ancillary services were offered by conventional power plants, such as gas-fired power plants. However, with the liberalization of the electricity market and the current standardization of ancillary service products in the member states where TSOs are encouraged to make the provision of grid services more technology neutral, more opportunities are created for renewable energy sources to participate.

In this section, several basic indicators are presented which describe the ability of a solar PV system to perform or deliver grid services. The grid service indicators are quantitatively described and expressed as levels in Table 4.1, the higher the level the greater the ability to provide or to perform (advanced) grid services by a PV system. In addition, the formulation of the KPIs is based on the technological capability of a PV system to provide grid services, such as inverter controllability and forecast accuracy, as well as the applicable legislation and regulatory framework. A second report (D1.2) from the SERENDI-PV project (T1.2), called "***Assessment and characterization of the current PV fleet capabilities and regulatory environment for grid integration***", elaborates further on the different kinds of ancillary services, and the regulatory framework of the grid services in the European member states applied to PV systems. Also, more detailed grid service indicators will be presented there. These indicators could also be called grid-KPIs; but for the sake of avoiding confusion with the KPIs defined in Chapter 3, the notation of grid indicators is used in this chapter.

Table 4.1: Grid service indicators quantitatively described and expressed as levels

Grid indicators	Level 1	Level 2	Level 3
Possibility to control power output	No	Yes, local control or remote control with reaction time between 3' - 1'	Yes, remote control with reaction time < = 1'
Obligation to participate in system services with PV	No	Yes, with restriction of market-based system services	Yes
Possibility to participate in market-based system services with PV	No	Yes, PV is not treated non-discriminatory (negatively)	Yes, PV is treated non-discriminatory or treated beneficial compared to other technologies
Availability live data	No	Yes, with temporal resolution between 15', with delay between 15'-1'	Yes, with temporal resolution < = 1', with delay < =1'

4.7.1 Possibility to control power output

A basic requirement to provide grid services with solar PV is to have a controllable system. This could be a local control mechanism based on an on-site optimization or a local grid optimization - e.g., based on the voltage of the PCC (Point of Common Coupling) - or being able to be controlled remotely. In order to be able to provide advanced system services, remote controllability is often a must, since most of them are centrally controlled.

4.7.2 Obligation to participate in system services

Delivery of system services is obligatory for certain production units connected to the grid. These connection requirements are described in the European Network Code on Requirements for Generators (RfG). In addition, national legislation is often different in the European Member states. Examples of obligatory system services are voltage control and the obligation to disconnect from the grid at 50,2 Hz.

4.7.3 Possibility to participate in market-based system services

Other grid services are voluntary and organized as a market or auction in which parties can voluntarily participate. Grid operators are often responsible to facilitate these grid services and organize these markets/auctions themselves and/or work together with (European) market platforms. Grid operators oblige participants in these markets to meet certain requirements and follow a prequalification process including simulations or pragmatic testing. The requirements can have a discriminatory character by excluding certain types of technologies, e.g. market entrance is only allowed for large (thermal) power plants or by excluding consumption installations. Technological requirements can also indirectly exclude PV power plants, e.g.: a required availability of 24h that excludes PV because of the inability to produce at night and forecast uncertainties. Examples of market-based grid services are reserve power provision (e.g. FCR, aFRR, mFRR), black start and congestion management.

4.7.4 Availability of live data

Live data of PV power plants is essential to have a high forecast accuracy, which is often needed to provide (advanced) grid services such as provision of reserve power. It is used to evaluate if and how much system services a solar plant can provide in the next hours or days. The higher the resolution and the lower the delay of the transmission of the live data to the grid service provider, the better the forecast and the better the estimation of the available power to provide grid services.

4.8 Inventory of services provided by PV systems to the grid

Converter-interfaced solar PV parks are technically capable of providing grid supporting services. Such services help grid operators at both the distribution and transmission grid to maintain safe system operation. Some of these services are prescribed as part of the connection requirements, which need to be fulfilled by a solar PV plant before it can get connected to the grid. The services outlined in the connection requirements become more demanding for higher voltage levels and nominal power of the solar asset. Besides connection requirements, grid operators make use of balancing power for their daily operation of the grid. The participation in the balancing mechanism is therefore discussed as well.

Since both connection requirements and the organization of balancing power are heavily dependent on the regulatory framework, these topics are covered in much more detail in deliverable D1.2, chapter 3 ('Assessment of regulatory environment related with high-level PV penetration into the grids'). We invite the reader to consult D1.2 for an analysis of the regulation in different Member States. In this section, we limit ourselves to EU-wide observations.

4.8.1 Technical potential of solar PV for grid services

Converter-interfaced solar PV parks can respond quickly and accurately to set-points or triggers, consequently adapting their active and/or reactive power. Scientific literature and pilot projects confirm that solar PV can participate effectively in several services that would support grid operation ([69]). They can be divided in two groups, based on the fact that they are either triggered by a certain system state (frequency or voltage level, rate of change of frequency…) or through an external setpoint sent by a grid operator or market party.

Support based on the system state:

- **Inertial response,** either as synthetic inertia or as physical inertia in case the solar asset is connected to a fast energy storage system, such as a supercapacitor.
- **Ramp rate control**, which refers to the active regulation of the power output increase or decrease of the solar PV plant.
- **Controlled fault behavior,** when frequencies or voltage levels largely deviate from normal levels, solar PV convertors can respond in a prescribed way to avoid escalation of the issue and contribute to a return to normal values.

- **Voltage support through reactive power provision:** modern solar PV convertors are able to absorb and inject reactive power and as such support stable voltage levels in the grid.
- **Frequency containment reserves,** which is the automatic response to frequency fluctuations in the grid.

Support based on external triggers from e.g. the grid operator:

- **Curtailment of the power output**, in case of voltage issues or congestion in the grid area to which the solar PV system is connected.
- **Frequency restoration reserves,** which are activated by TSOs to restore the balance between supply and demand in their control area. Since activation of restoration reserves can last over several quarter hours to multiple hours, the reliability of its provision by solar PV can be increased by coupling it to a battery energy storage system (BESS).

4.8.2 Services provided by Solar PV today

In Europe, a number of grid support services are already required from (newly built) solar PV assets in the so-called grid connection requirements. Such services are expected to be always delivered by the solar PV asset and are usually not remunerated. Services related to frequency support are organized in a separate manner in the so-called balancing power products.

4.8.2.1 Grid connection requirements

Grid connection requirements prescribe the technical requirements new assets should comply with before they are granted a grid connection. Usually, these requirements differentiate between type of asset (generation or demand), the voltage level they want to connect to, and their nominal power. To ensure a well-functioning market for (renewable) generation technology and a level-playing field in the context of the European Energy Union, the European Commission saw the need to harmonize the national connection requirements in a European framework. In 2016, the Network Code on Requirement for Generators (RfG NC)(Commission Regulation (EU) 2016/631) was put in place, which provides a harmonized framework for connection requirements for generators in Europe.

In the RfG NC, generators are classified in 4 groups according to their size and voltage level they connect to: Type A, Type B, Type C, Type D. The RfG NC sets default thresholds for each type, but Member States can deviate from them. Types A and B are smaller assets which are considered to have limited significance for grid security. Types C and D are large assets that have an immediate impact on system security and therefore must fulfill more stringent requirements than Type A and B assets.

A detailed comparison between a selection of Member States on the choice of Thresholds, and the detailed implementation of the RfG NC, is provided in D1.2. Below, the most important observations are summarized:

Obligatory in all member states:

- All solar PV installations need to fulfil several requirements to withstand large frequency deviations.
- Solar parks of Type C and D need to be able to respond to grid operators’ requests to adapt the active power in case of voltage issues.
- Solar parks of Type B and higher need to be able to reconnect after an automatic disconnection in case of a black-out.

Requirements that can be made obligatory if the relevant grid operator chooses to:

- Grid operators have the option to make remote controllability for switching off solar plants of Type A obligatory.
- Grid operators have the option to make remote controllability for active power control of solar plants obligatory for Type B plants.

- Solar parks of Type C and D can be obliged to provide synthetic inertia.
- Reactive power provision can be made obligatory by grid operators for Type B plants and higher.
- Grid operators can demand black start provision by solar parks of Type C and D.

4.8.2.2 Balancing power

One subset of ancillary services is especially important in the day-to-day operations of a grid: balancing power. This refers to the practice of ramping generation assets and demand assets up and down to re-establish a balance between demand and supply in the grid, to restore the frequency to its desired level of 50 Hz.

The approach to balancing power still differs greatly between European Member States. This also holds for the possible participation of solar PV in the mechanisms set up by grid operators to procure and activate this balancing power.

In D1.2, a detailed overview is given of the differences between Member States. The most important take-aways are as follows:

- Many Member States have ambiguous rules when it comes to allowing solar PV to participate in balancing. It is therefore not always clear if solar PV can participate and under which conditions.
- In countries with central dispatch, renewables are already integrated in the grid operations, and considered in balancing and congestion management. This is the case in, for example, Spain and Greece.
- Countries with a self-dispatch approach usually work with a market-based procurement of balancing services. Participation of solar PV then mostly depends on whether the market rules that define the balancing products and auction design are 'solar PV friendly'.
- We did not find any Member State with a self-dispatch model that explicitly excludes solar PV from participation in balancing power markets. Yet, there are several inherent barriers in the market design that cause solar PV to not yet participate on a commercial basis:
- The balancing power is procured by the grid operator too far in advance to reliably forecast the available solar power that can be dispatched for system balancing.
- The balancing power product needs to be provided during both daytime and night-time, the latter is impossible for solar PV because there is no power production.
- The lack of appropriate measurement and quantification standards, which are needed to evaluate the amount of balancing power a solar PV plant activated and needs to be remunerated for.
- Several Member States are running pilot projects to identify and resolve the barriers in both the central and self-dispatch model.

5 APPENDIX A: RELEVANT REFERENCES RELATED TO DIFFERENT ASPECTS RELEVANT FOR THE GRID INTEGRATION OF PV SYSTEMS

5.1 References related to voltage deviation

Table 5.1: List of several references related to voltage deviation caused by DER

Ref.	Investigations related to the topic	Main findings
[70]	Two algorithms for centralized voltage control (CVC) in LV distribution grids with high penetration of PV units are presented: 1- Based on regulation of on-load tap changer transformers (OLTCs) 2- Based on feeder interfaces via back-to-back (B2B) converters	Both the devices effectively regulate the voltage of the LV grid. The B2B converter has an advantage over OLTC: • It decouples the feeders from each over giving the CVC more freedom in its operation. • Operational flexibility is reachable by considerably less active power curtailment requirement.
[71]	Distributed and centralized solutions for voltage control in LV grids with high PV penetration.	From the specific cases analysed, the use of static var compensator (SVC) has emerged as a better solution than OLTC for the centralized control coexisting with the local control at the PV inverters level, mainly because the timings of the tap changes do not fit well with the voltage variations for PV production.
[72]	Investigates voltage violation problems caused by the integration of large-scale PV into a MV grid in Noordwolde, the Netherlands.	The proposed sequential control scheme that coordinates reactive power absorption and active power curtailment is successfully verified through simulations using Vision Network Analysis along with data measurements in the field.
[73]	Overvoltage caused by single and three-phase connected PV to a LV grid in Sweden.	It is shown that the voltage rise due to single-phase connected PV is six times the rise for three-phase connected PV. Coordinated connection helps in reducing the overvoltages caused by single-phase PV.
[74]	This paper analyses the influence of a 1 MWp PV on a 10 kV MV grid in Bosnia-Herzegowina, considering voltage quality parameters.	There was no correlation between PV plant production and total harmonic distortion values of voltages found. The PV plant contributes to voltage increase during power generation though. In this case, all obtained results are in accordance with EN 50160:2011.
[75]	Reduce energy losses and mitigate voltage deviation in high PV penetrate distribution networks, based on three-stage robust inverter-based voltage/Var control (TRI-VVC)	A TRI-VVC strategy is proposed, simulations showed that it can reduce system losses and mitigate voltage deviations. The strategy consists of hourly scheduling of capacitor banks and OLTC in a rolling horizon, 15 min

		inverter output dispatch and real time inverter droop voltage control.
[76]	Overview of research results and field experiences on the subject of local voltage support by PV. The focus of this report is the German power supply system.	Reactive Power provision by PV • Can help to maintain the voltage within operating limits • Is capable of increasing the PV hosting capacity • May be able to delay or avoid cost intensive grid reinforcement measures. In the future, the PV systems will provide additional ancillary services to the network operator like for example frequency control, congestion management, reserve capacity, volt/Var coordination or black start capability.
[77]	Analysis on the impacts of PV on the French Grid and several solutions (such as, intelligent control, protection, energy storage) are presented.	Several Impacts of PV on the grid: • Changing the voltage profile • Varying the power production • Increasing the voltage unbalance between phases • Increasing harmonics on the network • Introducing stability and protection problems

5.2 References related to hosting capacity, reinforcements and grid loading

Table 5.2: **List of several references related to hosting capacity, reinforcements and grid loading**

Ref.	Investigations related to the topic	Main findings
[78]	How to deal with high PV penetrations in local distribution grids.	Major Technical Barriers for PV: • High voltage (HV) level: Typically transmission capacities at the HV level and substations. • MV level: Over-voltages and over-loadings of conductors and transformers, especially in rural areas. • LV level: Over-voltages, especially in rural areas.
[79]	A voltage droop control method for autonomous control of active MV/LV transformers to increase the PV hosting capacity and prevent over-voltages in LV grids is proposed.	Using efficient control of active transformers, the limitation of installing new PV systems is no longer the overvoltage in the grid but the ratings of the grid components. In addition, the field test results confirmed that, the proposed voltage droop control method increased the PV hosting capacity, without reducing the lifespan of the transformer.
[80]	Estimating the grid's hosting capacity of residential solar photovoltaic at both the national and local scale is presented. The model is applied to Sweden, Germany and the UK.	Large grid capacity for residential solar PV is not utilized efficiently at present. Avoiding grid reinforcements by allocating and sizing solar PV systems appropriately is possible.
[81]	Active management of PV systems in order to reduce technical issues such as voltage deviation and asset congestion.	An adaptive centralized congestion management was proposed. By estimating total PV production and demand the maximum possible PV production can be fed in without leading to asset congestion.
[82]	Overcoming the barriers that prevent the further rollout of PV in Europe.	Technical solutions are divided in three categories: prosumer solutions, DSO solutions, interactive solutions. Several solutions were proposed for these different categories.
[83]	Utilizing existing technologies for increasing hosting capacity factor.	The papers investigations indicated three main factors for increasing the hosting capacity: restricting PV locations closer to the substation, adjusting power factor of the PV inverter and applying volt/Var control.
[84]	Increasing renewable energy integration through smart demand management and active and reactive power generation.	Increasing the hosting capacity is the most important factor. Centralized solutions are more effective than decentralized. Often the reinforcement of one node solves a grids bottleneck.

[85]	Experiences of German DSOs with integrating PV into their grids.	Ensuring compliance with the permissible limits for voltage and current is the main reason for grid expansion measures. • Capacity issues in southern Germany • Voltage issues in northern Germany Expansion measure steps in descending order: • Grid optimization • Classic grid expansion • Intelligent operating equipment
[86]	Methods to increase the PV hosting capacity for an MV grid in Germany are presented.	• An even installation of PV systems along the feeder results in higher hosting capacity of PV for the analyzed grids. • For most analyzed feeders in this study, an overloading of MV/LV transformers was the main limitation for potential PV power.
[87]	Comparative case study, three representative distribution grids in Germany, varying degree of PV penetration to quantify the effect of grid stress and grid reinforcement overestimation.	The magnitude of voltage rise and thermal overloads • Depend largely on individual grid characteristics. • Is stronger at higher PV penetration levels. Adjusting the rated power of PV systems in the empirical approach affects the choice of suitable technologies for grid reinforcement: • Potential applicability of smart technologies increases • Necessity of conventional reinforcements decreases.
[88]	Impact of local PV production on the maximal power transmitted and its equivalent yearly duration in a LV grid in France. Steps, depending on the penetration rate of PV are identified.	At low and medium PV penetration rates, the peak consumption is the sizing criteria for grid expansion planning, at high PV penetration rate the peak production becomes the sizing criteria.
[89]	Two grid-tied PV facilities are presented. Energetic and economic performance of both installations has been compared in a Spanish Study.	The central inverter system is compared to the string inverter system. The string inverter outperforms the central inverter.
[90]	An analysis of the self-consumption possibilities of the local electricity generated in a grid-connected to low voltage PV system in a Spanish study.	Demand side management and storage systems improve the rate of electricity self-consumption. Electricity imported from the grid can be reduced by using a storage system combined with an active demand-side management (ADSM) system.

5.3 References related to congestion management

Table 5.3: List of several references related to congestion management

Ref.	Investigations related to the topic	Main findings
[91]	A review work is carried out to unite all the publications in congestion management.	It is established that optimization tools play a very important role in relieving congestion. The techniques adopted in countries like Germany, the European countries and the US has been portrayed in the review.
[92]	This paper proposes a flexibility market led by the DSO and aimed at solving distribution grid congestions.	Up-regulation and down-regulation can both be valuable tools for DSO. An optimization has been developed which takes into account the modelling of the grid power flow constraints and the complex rebound effect.
[93]	Active management of PV systems in order to reduce technical issues such as voltage deviation and asset congestion.	An adaptive centralized congestion management was proposed. By estimating total PV production and demand, the maximum possible PV production can be fed in without leading to asset congestion.
[94]	Central energy management system for avoiding PV-caused grid violations	Mixed integer linear programming model was applied. The proposed method provides a feasible solution to optimal and secure scheduling of appliances and batteries for all the houses without violating the grid operation limits.
[95]	Application of energy storages for reducing renewable-caused system peaks and congestions.	System congestion was mitigated by reducing the variance of the daily branch power flow. The robust optimization reduced the system peak and the congestion in severe cases. The approach enables an existing system to deal with increased renewable energy production with lower investment cost.
[96]	Adaptive voltage and congestion management strategy for both MV and LV networks based on smart meter data is presented.	Results demonstrate • That the control strategy can effectively mitigate all voltage and thermal issues in both MV and LV networks • The importance of multi voltage level analysis • The true interdependencies between voltage levels • That the control strategy can help to increase the hosting capacity

[97]	Enabling local flexibility to address a day-ahead congestion problem in parts of the LV grid. Interactions between the local aggregators, commercial aggregators and the DSO.	With respect to the results of a field test, the battery and the PV could provide high availability in terms of offering and high reliability in delivering the required flexibility.
[98]	Practical power management of an integrated system with PV and energy storage system (ESS) to solve line congestion and voltage problems in an LV grid.	Both simulation and experimental results verified that the proposed PV-ESS integrated system (PEIS) with new power management system (PMS) can successfully solve the line congestion problem, mitigate the variations of voltage, and increase the economic profit of the producer at the same time.
[99]	Cost-effective way to deploy inverters for the mitigation of both over - and under-voltage is presented	Results show that an optimal use of existing non-smart as well as smart inverters will facilitate larger PV penetration as well as help reduce maintenance of voltage regulation equipment, reduce congestion, and contribute towards robust voltage profile in future.
[100]	Analyses of different scenarios based on real data from the distribution grid of Milan, Italy, that evaluates benefits and costs of demand response (DR) implementation to solve problems related to feeders congestion, power losses, and voltage drops.	The high potential of DR management in an urban environment has been demonstrated. The DR implementation would allow to better distribute the load, improving the existing plant usage, and to increase the hosting capacity.

5.4 References related to DER data integration for DSOs and TSOs

Table 5.4: List of several references related to DER data integration for DSOs and TSOs

Ref.	Investigations related to the topic	Main findings
[101]	Model driven methodology to implement an interoperable communication architecture supporting TSO-DSO data exchange	This paper describes a model-driven methodology in order to introduce an interoperable communication architecture supporting TSO-DSO information exchange. The methodology is based on a set of international standards
[102]	TSO – DSO data management report	This report provides input to the European Commission in their work on identifying an appropriate TSO – DSO framework, being part of the forthcoming "Market design and Renewables package
[103]	EU-project "TDX-ASSIST": Coordination of Transmission and Distribution data eXchanges for renewables integration in the European marketplace through Advanced, Scalable and Secure ICT Systems and Tools	This project focus on the data exchange for the DSO TSO collaboration, it also addresses possible data models and communication standards for the integration of renewable energy resources.
[104]	Distribution System Operator Observatory 2020	The third edition of the European DSO observatory aims at capturing all the various directions towards which DSOs are evolving, including technical features and smart grid dimensions.

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