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PV Investment Technical Risk Management

Best Practice Guidelines for Risk Identification, Assessment and Mitigation

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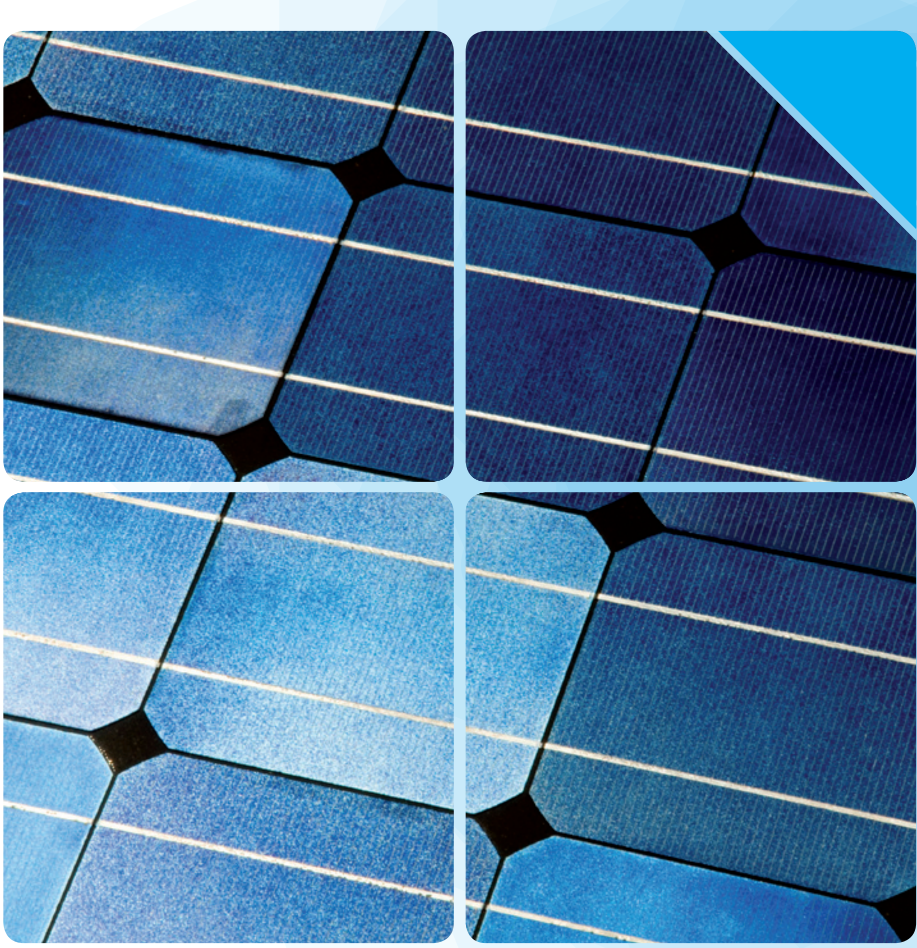

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Foreword

Europe has recently passed the historic milestone of 100GW of installed solar PV capacity across Europe. In the last decade grid-connected photovoltaic power has advanced from a niche to a central building block of future electricity generation and energy transition. Costs of PV systems have fallen more than 70% since 2008 and Levelised Cost of Electricity (LCOE) will continue to decline supported by economies of scale and ongoing innovation. Along with the increasing importance in Europe's future energy mix, the technical reliability and financial stability of PV investments have to match established standards in the (wider) utility industry. This is even more important as solar in Europe is more exposed to the market for its financing than ever before. It is therefore crucial to minimise risks for those looking to invest in solar.

When assessing the investment-worthiness of a solar PV project, different financial stakeholders such as investors, lenders and insurance companies evaluate the impact and probability of investment risks differently depending on their respective investment goals. Similarly, risk mitigation measures implemented are also assessed in differing ways by the stakeholders. In the financing process, stakeholders seek business models that accurately reflect technical aspects of their PV projects.

The Solar Bankability project has supported the establishment of such best practices for professional risk assessment to reduce technical risks associated with investments in PV projects and increase trust from investors, financers and insurance companies. It is a project funded by the European Commission under the Horizon 2020 Programme, running from March 2015 to February 2017. The project consortium includes the EURAC Institute for Renewable Energy (Italy), 3E N.V. (Belgium), ACCELIOS Solar GmbH, TÜV Rheinland Energy GmbH (Germany), and SolarPower Europe (Belgium). Over the last two years (2015-2017), the consortium worked on several high-quality deliverables on technical risk assessment, risk mitigation measures, cost assessment, and business model assessment. Many leading financial institutes, developers and component providers supported with advisory roles in the development of the project.

The Solar Bankability consortium is pleased to therefore publish this final report of the project. Here we present the overview of the results of the Solar Bankability project, and our Best Practice recommendations on how to manage and account for PV technical risks in PV investment costs and business models.

Other Publications from the Solar Bankability Consortium

Description	Publishing date
Snapshot of Existing and New Photovoltaic Business Models	August 2015
Technical Risks in PV Project Development and PV Plant Operation	March 2016
Review and Gap Analyses of Technical Assumptions in PV Electricity Cost	July 2016
Minimizing Technical Risks in Photovoltaic Projects	August 2016
Financial Modelling of Technical Risks in PV Projects	September 2016
Best Practice Guidelines for PV Cost Calculation	December 2016
Technical Bankability Guidelines	February 2017

Proceedings from the Project Advisory Board and from the Public Workshops

Description	Publishing date
1st Project Advisory Board closed meeting	June 2015
2nd Project Advisory Board closed meeting	December 2015
First Public Solar Bankability Workshop - Enhancement of PV Investment Attractiveness	July 2016
3rd Project Advisory Board closed meeting	February 2017
Solar Bankability Final Workshop - Improving the attractiveness of solar PV investment	February 2017

1. Introduction

Solar Bankability is an active quality management process where all stakeholders in the approval process of a PV project attempt to identify potential legal, technical and economic risks through the entire project lifecycle. These risks need to be quantitatively and qualitatively assessed, managed and controlled. Despite a wide overlap in this quality management process, the focus and the assessment criteria will vary depending on whether the stakeholder represents an investor, a bank, an insurance company or a regulatory body, as illustrated in Figure 1 below.

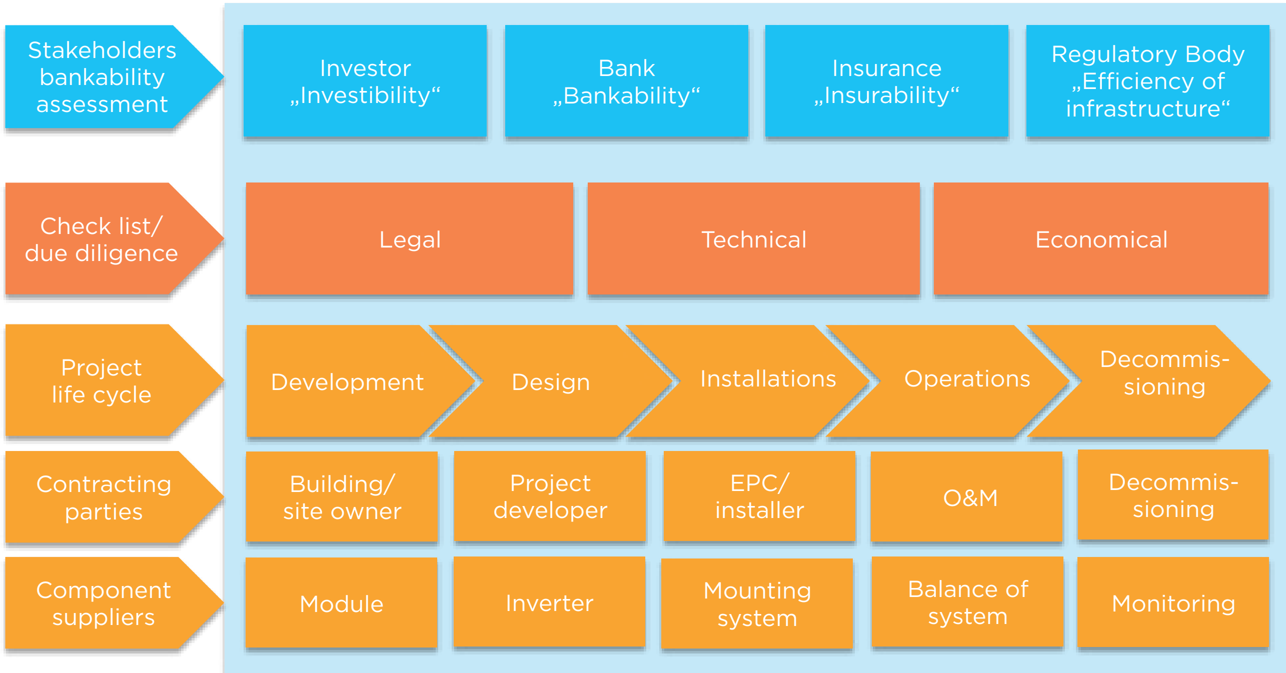


Figure 1: Solar Bankability assessment from different stakeholders' perspectives

In the Solar Bankability project, we have developed a set of best-practice guidelines and useful tools which could serve two functions: first, as de-risking tools to reduce the risks associated with investments in PV projects, and second, as standardisation tools which serve as guidelines for common standards for professional risk assessment in the PV investment sector. These guidelines and tools are to assist stakeholders to develop their own individual risk management strategy along the lifecycle of a PV project through the following steps (Figure 2):

- Risk identification;
- Risk assessment;
- Risk management;
- Risk controlling.

These tools and guidelines were developed based on market data from historical due diligence, operation and maintenance records, as well as damage and claims reports. We have also engaged different relevant stakeholders in the PV industry for their inputs during this process. These stakeholders include financial market actors, valuation and standardisation entities, building and PV plant owners, component manufacturers, energy prosumers and policy makers.

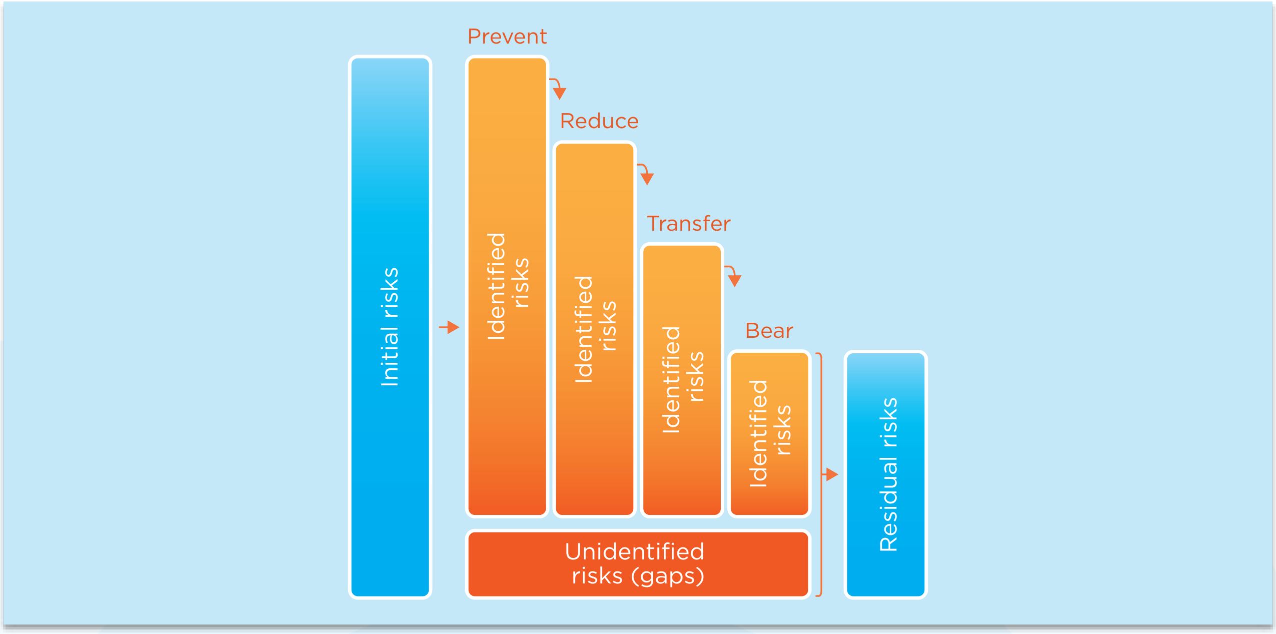


Figure 2: Potential plan for the management of technical PV project risks

In **risk identification**, we have compiled technical risks caused by incorrect technical assumptions in the calculation of the PV levelised cost of electricity (LCOE), and technical risks associated with PV plant failures. The LCOE technical assumption risks were obtained from gap analyses on the technical assumptions used in samples of present-day PV financial models and plant yield estimation reports. The plant technical risks were collected by going through databases of technical failures in samples of hundreds of MWp of PV plants and tabulating the different failures into a Risk Matrix organised by the project phases and plant components. Focus was placed on technical risks during planning and during operation and maintenance, and those risks which are relevant to the calculation of the PV LCOE. The results of the risk identification work are **two tools** – *a list of top 20 LCOE technical risks* and a technical *Risk Matrix*, which could be used by stakeholders such as PV plant component suppliers, EPC contractors, and O&M operators.

For **risk assessment**, we evaluated the risks in terms of how they impact i) the initial yield estimate (for risks from uncertainty during planning), ii) costs during operation and maintenance phase, and iii) PV LCOE. Three tools were developed for risk assessment: a new methodology *(CPN methodology)* which assigns a cost priority number (CPN) to each risk based on the associated economic impact on plant operation, *an LCOE sensitivity analysis excel calculation tool, and cash flow risk categorisation*. These tools will serve stakeholders in assessing the different technical risks and their impacts on the operation costs of their PV plants and what electricity cost should be set for profitable investment.

For **risk management**, a list of eight mitigation measures were put forward. Furthermore, the effectiveness of the mitigation measures was assessed by evaluating how their implementation changes the cost priority number and PV LCOE. Scenarios consisting of different mitigation measure combinations and market segments were studied and the mitigation measures were ranked based on their effectiveness in reducing the CPN and LCOE. For mitigation measures to reduce the uncertainty in the yield estimation, several scenarios on the P50 and P90 values were simulated. Since the suggested mitigation measures consist of solutions at different phases of PV project lifecycle, the analyses of their effectiveness also allow for assessing the best PV project phase for implementation, thus the risk management is achieved by transferring risk from one actor to another. The transfer of risks can help to allocate these risks to those parties, which have the best control of each risk. Finally, we have developed six best-practice checklists relevant for EPC and O&M contracting, and yield estimation. *The list of mitigation measures and the six best-practice checklists* will assist market actors from PV system designers to plant owner to lenders and investors in minimising risks due to improper yield estimation and improper settings of EPC and O&M contracts.

For **risk controlling**, new financial market regulations have been introduced after the 2008 financial crisis to improve the transparency and stability for institutional investors from the banking, insurance and investment fund sectors. These enhanced controlling and reporting requirements apply also to large-scale PV investments. The overview of these regulations is summarised and presented for informative purpose in the Solar Bankability project.

1.1. Recommendations for Risk Management Strategies

Based on the findings of the project, we recommend the different stakeholders to develop their own individual risk management strategy along the lifecycle of a PV project using the four-step process of risk identification, risk assessment, risk management and risk controlling. Solar Bankability provides best-practice guidelines and concrete tools to better manage technical risks throughout the PV project lifetime. The ultimate responsibility of project risks remains with the owner and operator of the PV plant. With the help of a professional risk management plan they can significantly reduce and transfer the initial risks associated with a PV project.

We would like to note that although the risk management strategies above are recommended for commercial and utility PV systems, residential PV system owners are advised to follow a simplified version of the risk management strategy used for larger size systems.

2. Risk Identification

In PV financial modelling, improper inputs (costs, yield, e.g.) will inevitably result in incorrect calculations of revenue, cost, cash flow etc, thus give inaccurate assessment of the investment-worthiness of a PV project. Financial model inputs are strongly influenced by technical assumptions related to the PV levelised cost of electricity (LCOE).

In the Solar Bankability project, we have compiled a *list of 20 most common LCOE technical assumption risks* by carrying out gap analyses on the technical assumptions used in samples of present-day PV financial models and plant yield estimation reports. We then extended our analysis and compiled technical failures from databases of hundreds of MWp of PV plants in operation. Focus was placed on technical risks during planning and during operation and maintenance, and those risks which are relevant to the calculation of the PV LCOE. The failures are tabulated in a *technical Risk Matrix*. The risk of each failure was assessed based on which PV project phase and on which PV plant component the failure could originate from.

The conclusion from this exercise is that there is a strong correlation between incorrect LCOE technical assumptions and PV plant technical failures. In fact, the technical failures listed in the Risk Matrix are likely caused by the mistakes related to technical assumptions used in the PV LCOE calculation faulty planning, installation and operation and maintenance practice.

2.1. Technical Risks Due to Poor Assumptions in PV Financial Models

To compile technical risks which could impact PV financial models, we surveyed samples of present-day PV financial models, EPC and O&M contracts, and plant yield estimation reports. These samples are from large-scale and commercial PV plants in France, UK, Germany, Italy and the Netherlands developed between 2011 and 2016. The survey highlights that in general there is neither a unified method nor a commonly accepted practice for translating the technical risks into PV financial models. The CAPEX appears to contribute a significantly large portion (roughly75-90%) to the PV lifecycle costs compared to the OPEX (Figure 3). Moreover, EPC and O&M costs are dominant in the CAPEX and OPEX (70-90% and 30-70%, respectively).

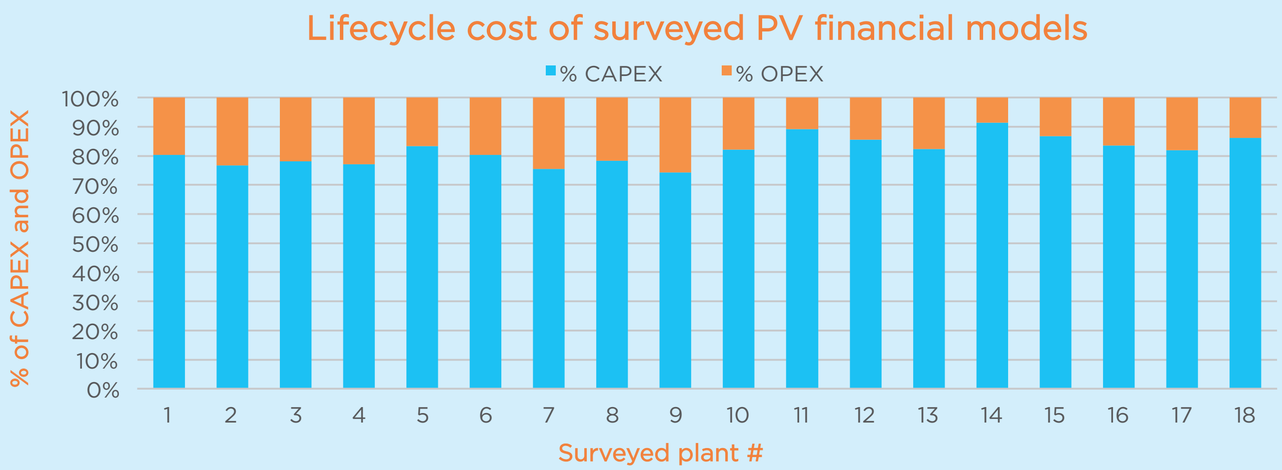


Figure 3: Lifecycle costs (CAPEX and OPEX) of surveyed PV financial models showing a significant portion of CAPEX in PV lifecycle costs

Gap analyses were performed systematically according to the phases in PV project life cycle and whether the root causes are likely to occur before, that is at year-0, or during the PV operation. The results show that technical gaps generally exist across all PV project phases. They occur in all elements of the PV LCOE, namely CAPEX, OPEX and energy yield estimation. There are two types of technical risks: those with economic impact on the energy yield of the PV plant, and those with economic impact due to plant downtime and cost of fixing during operation. The root causes of both types of risks could be introduced either during project development (procurement, planning and construction, i.e. EPC) or during PV operation (O&M). The list of important gaps identified in the analyses are presented in Table 1 below.

For more details on this topic, see the full Solar Bankability report on the ***Review and Gap Analyses of Technical Assumptions in PV Electricity Cost*** [1].

Table 1: Most common mistakes in the present day technical inputs for PV financial models

Risk	Phase/field	Identified critical technical gaps
Year-0	Procurement/ product selection and testing	1. Insufficient EPC technical specifications to ensure that selected components are suitable for use in the specific PV plant environment of application. 2. Inadequate component testing to check for product manufacturing deviations. 3. Absence of adequate independent product delivery acceptance test and criteria.
	Planning/ lifetime energy yield estimation	4. The effect of long-term trends in the solar resource is not fully accounted for. 5. Exceedance probabilities (e.g. P90) are often calculated for risk assessment assuming a normal distribution for all elements contributing to the overall uncertainty. 6. Incorrect degradation rate and behaviour over time assumed in the yield estimation. 7. Incorrect availability assumption to calculate the initial yield for project investment financial model (vs O&M plant availability guarantee).
	Transportation	8. Absence of standardised transportation and handling protocol.
	Installation/ construction	9. Inadequate quality procedures in component un-packaging and handling during construction by workers. 10. Missing intermediate construction monitoring.
	Installation/ provisional and final acceptance	11. Inadequate protocol or equipment for plant acceptance visual inspection. 12. Missing short-term performance (e.g. PR) check at provisional acceptance test, including proper correction for temperature and other losses. 13. Missing final performance check and guaranteed performance. 14. Incorrect or missing specification for collecting data for PR or availability evaluations: incorrect measurement sensor specification, incorrect irradiance threshold to define time window of PV operation for PR/availability calculation.
Risks during operation	Operation	15. Selected monitoring system is not capable of advanced fault detection and identification. 16. Inadequate or absence of devices for visual inspection to catch invisible defects/faults. 17. Missing guaranteed key performance indicators (PR, availability or energy yield). 18. Incorrect or missing specification for collecting data for PR or availability evaluations: incorrect measurement sensor specification, incorrect irradiance threshold to define time window of PV operation for PR/availability calculation.
	Maintenance	19. Missing or inadequate maintenance of the monitoring system. 20. Module cleaning missing or frequency too low.

2.2. Technical Risks Causing Plant Failures over PV Project Lifetime

Based on a statistically significant number of existing PV installations, we documented the technical risks which can affect solar plants, either during the development phase or during operation. More than 1 million PV plant failure cases were collected from multiple databases comprising more than 750 PV plants and roughly 2.4 million components (~2 000 000 modules and ~12 000 inverters); this portfolio corresponds to 442 MWp of PV plants nominal power, i.e. roughly 0.5% installed capacity in Europe (Table 3). Each failure collected was categorised based on which PV plant component the failure occurs. We then assessed in which PV project phase(s) the failure could originate. A Risk Matrix was developed; it consists of five phases of PV lifecycle and 11 plant components (Table 2). All collected failure cases were compiled and allocated to each project phase and each component. In total, more than 140 types of technical risks have been identified and documented in the Risks Matrix. Table 4 gives some examples of technical risks for PV modules and inverters, while all 140 technical risks are described in detail in [2].

For more details on this topic, see the full Solar Bankability report on the ***Technical Risks in PV Projects – Report on Technical Risks in PV Project Development and PV Plant Operation*** [2].

Table 2: Risk Matrix to identify the technical risks during all project phases (I to V) and for 11 components of a PV plant

		I	II	III	IV	V
Component / Project Phase		Product testing/ development	PV plant planning/ development	Installation/ Transportation	Operation/ Maintenance	Decommissioning
A	Modules					
B	Inverter					
C	Mounting structure					
D	Connection & Distribution boxes					
E	Cabling					
F	Potential equalization & Grounding, LPS					
G	Weather station & Communication & Monitoring					
H	Transformer station & MV/HV					
I	Infrastructure & Environmental influence					
J	Storage system					
K	Miscellaneous					

Table 3: Summary of main figures of the failure data collection to develop the Risk Matrix

	Total number of plants	Total Power [kWp]	Average number of years
Total	772	441676	2.7
Components	**No. tickets**	**No. Cases**	**No. Components**
Modules	473	678801	2058721
Inverters	501	2583	11967
Mounting structures	420	16147	43916
Connection & Distribution boxes	256	12387	25305
Cabling	682	384600	246084
Transformer station & MV/HV	57	224	759
Total	2379	1094742	2386742

Table 4: Example of Risk Matrix for PV modules and inverters

A. MODULES	B. INVERTERS
Product testing / development	
• Failed insulation test • Incorrect cell soldering • Undersized bypass diode • Junction box adhesion • Etc.	• Inverter derating issue • Maximum power point tracker issue
PV plant planning / development	
• Soiling losses • Shadow diagram issue • Modules' mismatch • Uncertified modules • Etc.	• Inverter wrongly sized • Incorrect IP rating • Inverter cabinet inadequately ventilated • Inverter exposed to sunlight • Etc.
Transportation / installation	
• Module mishandling (Glass breakage) • Module mishandling (Cell breakage) • Module mishandling (Defective backsheet) • Etc.	• Inverter configuration incorrect • Missing contact protection • Inverter has no surge protection • Etc.
Operation / maintenance	
• Improperly installed • Hotspot • Delamination • Glass breakage • Snail trails • Etc.	• Fan failure and overheating • Theft or vandalism • Grounding fault • Firmware issue • Etc.
Decommissioning	
• No product recycling procedure defined or implemented	• Inverter size and weight issue

3. Risk Assessment

The PV technical risks identified in the previous chapter will have economic impact on the energy yield of the PV plant, or economic impact due to plant downtime and cost of fixing during operation. In this chapter, we assess the technical risks in terms of how they impact: yield estimate (especially for risks from uncertainty during planning/design phase), costs during operation and maintenance phase (CPN), and PV LCOE and project investment.

We have built upon existing studies and collected available statistical data of failures with the aim to i) suggest a guideline for the categorisation of failure, ii) introduce a framework for the calculation of uncertainties in PV project planning and how this is linked to financial figures, and iii) develop a methodology for the assessment of the economic impact of failures originating from different phases in PV project life cycle. Subsequently, three tools have been developed which can be used in the PV technical risk impact assessment:

- CPN *methodology* which provides an assessment of the related economic impact caused by a certain risk.
- *LCOE sensitivity analysis excel calculation tool* which allows for the simulation of different risk scenarios (individual or combined several risks) and the resulting LCOE values.
- *Cash flow risk categorisation* which was determined by cash flow modelling on different risk scenarios on a customised tool.

3.1. Risks in Yield Estimation During the Planning Phase

Some of the technical risks listed in the Risk Matrix [2] have an economic impact on the overall uncertainty of the energy yield. These uncertainties can impact either the expected yield during the planning phase, or the actual yield during operation.

In the Solar Bankability project we have reviewed available public yield reports and scientific literatures in order to quantify the impact of uncertainties in yield estimation of PV plants [2]. Table 5 summarises the typical ranges of uncertainties found from the review exercise of current practices. This shows that the various uncertainties could have an overall impact as high as ±10% on the estimated energy yield. These uncertainties are used to calculate the exceedance probabilities which are used to calculate PV plant estimated yield (e.g. P50/P90). The uncertainties are typically calculated by fitting the dataset to a standard probability distribution (often assumed Gaussian/normal). The exceedance probabilities are then obtained from the distribution's cumulative distribution function (CDF). However, for more accurate determination of uncertainties, a more precise analysis would benefit from the use of an empirically established probability distribution. Unfortunately, there is not always a sufficiently large dataset available to establish the CDF from which to interpolate exceedance probabilities. Nevertheless, for some elements involved in the calculation of the long-term expected yield (e.g. the solar resource) this method can be applied.

For more details on this topic, see the full Solar Bankability reports on the ***Technical Risks in PV Projects – Report on Technical Risks in PV Project Development and PV Plant Operation*** [2], and the ***Review and Gap Analyses of Technical Assumptions in PV Electricity Cost*** [1].

Table 5: Overview of uncertainties in the different conversion steps

	Uncertainty	Range
Solar resource	Climate variability Irradiation quantification Conversion to POA	±4% - ±7% ±2% - ±5% ±2% - ±5%
PV modelling	Temperature model PV array model PV inverter model	1°C - 2°C ±1% - ±3% ±0.2% - ±0.5%
Other	Soiling Mismatch Degradation Cabling Availability...	±5% - ±6%
Overall uncertainty on estimated yield		±5% - ±10%

3.2. CPN Methodology: New Tool to Technical Risk Economic Impact Assessment

Historical performance data for PV systems on which to base technical risks assessments and investment decisions are difficult to access by all market players such as investors, PV plant owners, EPC contractors, etc. This issue is because most PV systems have been operational for only a few years (GWp cumulative installations in many countries was only reached after 2010) and a tendency among system operators and component manufacturers to keep PV plant performance data confidential. In addition, performance data is in most cases not available for small PV systems (e.g. residential-commercial market < 250 kWp) as the cost of monitoring is still perceived as an unnecessary added cost. Finally there is often an insufficient level of detail and a lack of standard definitions of PV plant failures and corrective measures to allow for meaningful statistical analysis of PV plant performance and technical risk assessments.

For the PV industry to reach a mature market level, a better understanding of technical risks, risk management practices, and the related economic impact are thus essential to ensure investors' confidence. With this in mind, we have developed the *CPN methodology* to assess the economic impact of technical risks occurring during the operation and maintenance phase (O&M) of a PV project, and how the risks affect PV LCOE and business models of PV projects.

The CPN methodology assigns a *cost priority number* (CPN) to each technical risk based on how it impacts the costs of running a PV plant or a portfolio of PV plants. The impacts are related to the economic losses due to downtime (utilisation factor) and component repair or substitution (OPEX), expressed in Euros/kWp or Euros/kWp/year.

For the calculation of costs due to downtime (C_{down}), parameters such as time-to-detection, time-to-repair, and repair time are considered. For the calculation of the costs of repair or substitution (C_{fix}), cost-for-detection, labour cost, cost-of-repair/substitution, cost-of-transportation are included. Thus, the overall CPN value for various components and failures would correspond to the cost of O&M for various scenarios. The CPN methodology has the following advantages:

- The CPN methodology is based on statistical analysis and *can be applied to a single PV plant or to a large portfolio of PV plants in the same market segment.* The quality of the analysis depends on the amount of failure data available and on the assumptions taken for the calculation of a parameter defined as the Cost Priority Number (CPN).

- The CPN methodology considers the year of installation, the year of failure, and the nominal power, thus *allowing for analysis for different market segments and evaluation of the failure probability distribution* (the latter if the available data reaches statistical relevance).
- The CPN methodology considers other statistical parameters such as the number of affected plants, and the number of components in affected plants. It is therefore possible *to understand if a specific failure is PV plant dependent or if it is equally present over the whole PV plant portfolio*.

Finally, by analysing the costs due to downtime versus costs of repair or substation, one is also able to assess the effectiveness of where to place mitigation measures as well.

For more details on this topic, see the full Solar Bankability report on the ***Technical Risks in PV Projects – Report on Technical Risks in PV Project Development and PV Plant Operation*** [2].

3.3. Impacts of Technical Risks on CPN

The CPN methodology was applied to the risks in the Risk Matrix. The risks are ranked by their CPNs to see which have the highest economic impact. The results are grouped in four market segments: residential (<10 kWp), commercial (10 – 250 kWp), industrial (>250 kWp), and utility (>1 MWp).

To assess the impact of failures for various operation and maintenance (O&M) strategies, we defined two extreme types of scenarios. In the first scenario, we assumed that failures are never detected; this scenario is called "never detected" resulting to a $CPN_{never\_detected}$. In the second scenario, we assumed that the failure is fixed after detection using a lead time to repair/substitution of one month resulting to a $CPN_{failure\_fix}$.

The analysis of CPN for PV modules for all market segments combined is shown in Figure 4. The blue bars represent the scenario where the issues are detected and fixed (either by repair or substitution), and the red bars represent the "never detected" scenario causing plant downtime. As it can be seen in this figure, the 10-dominant module risks for all PV systems range from installation issues to material/processing defects to maintenance practice. The dominant risks with high economic impact (high CPN) such as bad quality installation, glass breakage and PID can be distinguished from low-order risks with small impact (low CPN) such as soiling and shading. The improperly installed module failures comprise of various failure modes such as module mishandling during the installation, damaged frame, clamping system etc. Overall the common failures such as glass breakage, improper installation or PID bear a higher level of economic risk.

The economic impact in the never detected scenario (entirely due to downtime), $CPN_{never\_detected}$ (red bars in Figure 4) appears to be minimal for the module failures. The dominant factor in the failure fix scenario (blue bars in Figure 4) here is the cost of substitution. This is because for PV modules, repairing modules is not a preferred solution as the action could void the module manufacturer's warranty restriction resulting in warranty claim exclusion. Thus, substitution of the defective module is the preferred procedure. Few possible module repair actions generally involve minimally intrusive procedure such as module surface cleaning or bypass diodes replacement.

It is important to highlight that a lower CPN value for the "never detected" scenario does not mean that this strategy is more cost-effective than fixing the problem. Power losses will increase over the years and the existing or impending failure could also pose safety risks.

When looking at the top ten module risks for each market segment, the trend reflected in Figure 4 applies to larger-scale PV systems. This is because for larger-scale systems, different defect detection techniques from basic visual to advance inspection tools are available. For small-scale residential, it appears that failures which could be detected by basic visual inspection are the ones which are dominant; defects requiring advance inspection tools tend to escape detection due to the absence in the use of such tools. We would like to point out these results are obtained based on our failure database; as such the top module failures are likely to vary depending on the nature of the data used for the analysis (e.g. database size, plant locations, year of installation etc.)

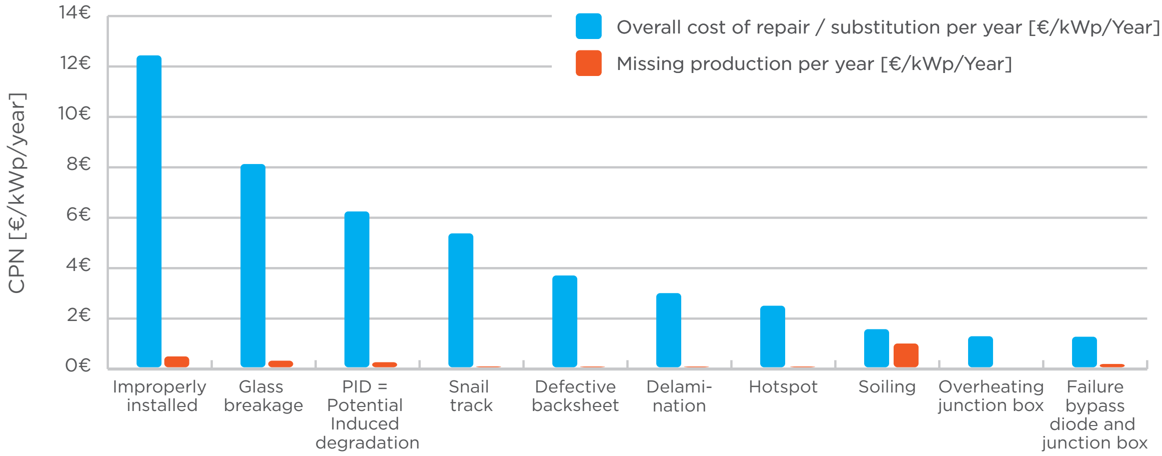


Figure 4: CPN, repair costs ($CPN_{failure\_fix}$) and performance losses ($CPN_{never\_detected}$) for top 10 risks for PV modules of all system sizes

The most important risks of inverters sorted by the CPN parameter for all market segments combined are shown Figure 5. The significant number of tickets and cases of bad installation errors evidently shows the lack of expertise in parts of the PV sector when it comes to PV inverters. The most important specific failure is related to fan failure and overheating.

Unlike the PV module risks, the inverter-related risks appear to have a significant impact on the production, $CPN_{never\_detected}$ (red bars in Figure 5). The production losses caused by plant downtime are higher than the overall CPN when failures are fixed, $CPN_{failure\_fix}$ (blue bars in Figure 5). Therefore, repair or substitution of the PV inverter component should be addressed as early as possible once detected. The same conclusions apply for almost all the market segments.

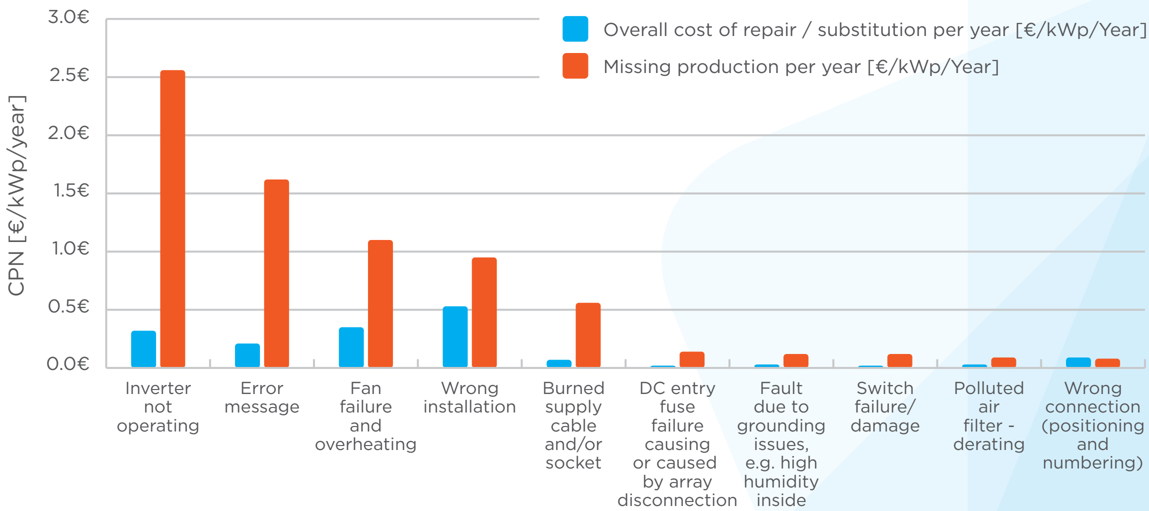


Figure 5: CPN, repair costs ($CPN_{failure\_fix}$) and performance losses ($CPN_{never\_detected}$) for top 10 risks for PV inverters of all system sizes

For more details on this topic, see the full Solar Bankability reports on the ***Technical Risks in PV Projects – Report on Technical Risks in PV Project Development and PV Plant Operation*** [2] and ***Financial Modelling of Technical Risks in PV Projects*** [3].

SIDE NOTES

The CPN methodology can only be applied to the failures with a direct economic impact to the business plan either in terms of the reduced income due to downtime or the costs for repair or substitution. The technical risks included in the Risk Matrix which cannot be described by an exceedance probability (yield uncertainties) or by a CPN, are very important and should be considered as they could impact the CPN value of other component failures. For example, the technical risks related to, inter alia, monitoring system, spare parts, normative and documentation, insurance reaction time, O&M contract, video surveillance, advance field inspection (IR, EL, etc.), can reduce or increase the time-to-detection or the time-to-repair/substitution and thus will have an impact on the detection costs. In Solar Bankability project, "year 0 risks" related to yield uncertainties are addressed in [2] and "Risks during operation" with a CPN integrated in risk scenarios are discussed in [3].

3.4. Impacts of Technical Risks on Solar PV Generation Cost (LCOE)

In the Solar Bankability project, we assessed the relative impacts the identified technical risks would have on PV Levelised Cost of Electricity (LCOE) via sensitivity analysis thus pinpointing the areas where mitigation measures should be placed in priority. A simple excel worksheet has been developed in the Solar Bankability project for the calculation of LCOE based on the following formula:

$$LCOE = \frac{CAPEX + \sum_{n=1}^{N} \frac{OPEX - RV}{(1+r)^n}}{\sum_{n=1}^{N} \frac{Y_o.(1-D)^n}{(1+r)^n}} \qquad (1)$$

where

N = PV system life [years]
CAPEX = total initial investment (CAPEX) [€/kWp]
OPEX = annual operation and maintenance expenditures (OPEX) [€/kWp]
RV = residual value [€/kWp]
r = discount rate [%]
Y_0 = initial yield [kWh]
D = system degradation rate [%]

The LCOE sensitivity analysis was performed by varying six LCOE input parameters (CAPEX, OPEX, yield, discount rate, yearly degradation, and system lifetime) by ±20%. In the calculation, a linear system degradation rate is assumed, discount rate values for different scenarios (countries) are extracted from [4], and no residual value is accounted for in the calculations. Each input was treated as if one is independent from the others. The analysis includes three different market segments: residential PV systems <5 kWp, commercial rooftop PV systems <1 MWp, and utility scale ground-mounted PV systems ≥1 MWp. Three scenarios have been selected for this analysis – one representing PV systems in mature markets such as Germany where high competition has driven the CAPEX and OPEX prices down and the market bears less regulatory risk; the second representing systems in market such as Italy with a relatively high discount rate and where the irradiation level is high and the CAPEX and OPEX are in the mid-range among the values in EU region; and the last scenario representing PV systems in countries such as UK or Netherlands with high CAPEX and OPEX but with irradiation level rather low and a relatively moderate discount rate.

The LCOE sensitivity analysis results rank the following from having the most to least impact on LCOE. As it can be seen, yield is the most influential factor in the final LCOE value, followed by CAPEX, lifetime and discount rate, OPEX and finally degradation.

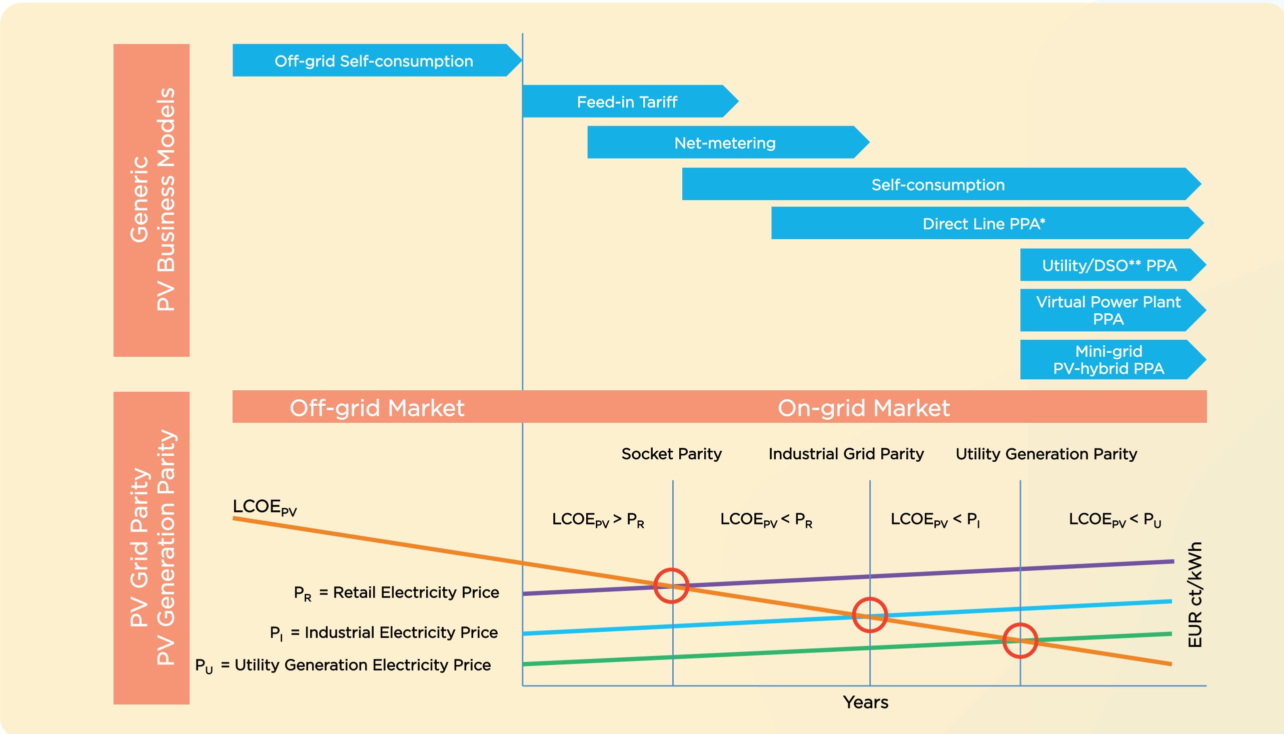
Table 6: Ranking of LCOE technical risks' impacts on PV LCOE

Sensitivity of LCOE in 2015-2016 on CAPEX, OPEX, yield, discount rate, yearly degradation and system lifetime (ranking from most to least impact)				
1 Yield	2 CAPEX	3 Lifetime or discount rate	4 OPEX	5 Degradation

For more details on this topic, see the full Solar Bankability reports on the ***Best Practice Guidelines for PV Cost Calculation: Accounting for Technical Risks and Assumptions in PV LCOE*** [5].

3.5. Impacts of Technical Risks on Business Models

Modelling the economic impact of technical risks on the cash flow of PV projects requires the selection of the underlying business models, selection of associated technical risks, likely risk scenarios and the underlying cost assumptions. As part of this work, the Solar Bankability project first introduced eight generic PV business models shown in Figure 6. A snapshot of seven national PV markets (Germany, Italy, France, Spain, United Kingdom, Romania and the Netherlands) and their current business model roll-out situation were then reviewed.



* PPA = Power purchase agreement
** DSO = Distribution system operator

Figure 6: PV LCOE vs. grid parity trigger points and generic business models

Since there are no commercial risk modelling tools available in the market which allow analysing technical failures and their economic impact over the lifecycle of PV systems, a customised financial modelling tool has been developed based on the PV project cash flow to measure the impact of technical risks on PV investments (Figure 7). The system architecture of the risk modelling software uses a proven spreadsheet-based cash flow model as backbone. Auxiliary spreadsheets are dedicated to the yield and debt financing calculation. The cash flow model is linked with a risk modelling module programmed in Visual Basic. The entire modelling software is controlled from a dashboard embedded in the spreadsheet-based tool.

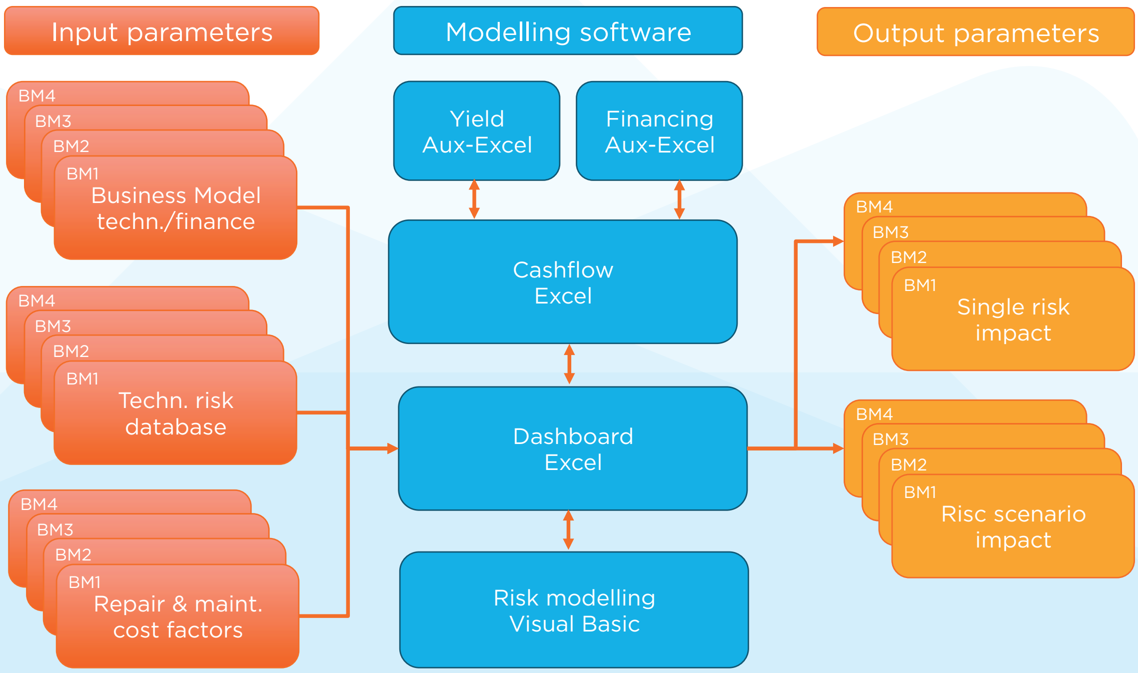


Figure 7: System architecture of Solar Bankability financial modelling tool

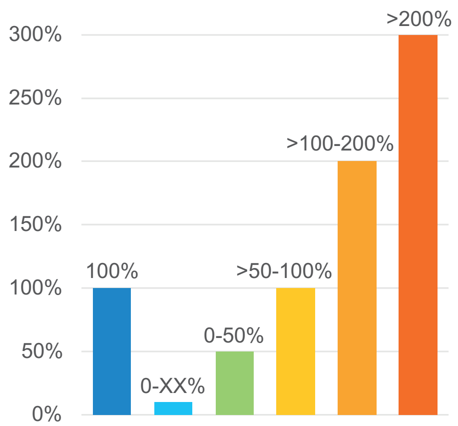
Four representative business models as shown in Figure 8 were then selected for the financial modelling of technical risks. In the selection process, various criteria were considered such as PV system size, module and inverter technology, ground and roof-top mounting, solar electricity feed-in and self-consumption, geographic location and climatic conditions.

	Description
Business model 1	Residential rooftop PV system with crystalline modules located in central Europe (5.6 kWp, c-Si, Germany)
Business model 2	Residential rooftop PV system with crystalline modules and battery storage located in central Europe (5.2 kWp c-Si + storage, Germany)
Business model 3	Utility scale ground mounted PV system with crystalline modules, central inverters, located in northern Europe (7.6 MWp, c-Si, UK)
Business model 4	Utility scale ground mounted PV system with CdTe modules, string inverters, located in southern Europe (0.6 MWp, CdTe, Italy)

Figure 8: Four selected business model selected for technical risk impact modelling

For each business model, 10 to 12 typical technical risks from the Risk Matrix have been selected and their impacts were assessed for both individual risks and risk scenarios with a combination of up to four risks. The output section shows the impact on internal rate of return (IRR) and cumulative cash flow and gives a detailed breakdown of the failure cost composition.

Four different impact categories have been introduced to classify the influence of technical failures on the cash flow model. In an analogy to the debt reserve account used by banks during debt financing, the categories measure the financial impact in relation to the revenues during the 12 months from the first calendar year of full PV project operations (Figure 9).



Reference base (100%): 12 months revenues from first calender year of full operations

Failure category 0 - (0-xx%): Regular operations and maintenance provisions

Failure category 1- (0-50%): Covered by 6 months reserve accounts

Failure category 2 - (>50-100%): Covered by 12 months reserve account

Failure category 3 - (>100-200%): Not covered by reserve account, potential need for additional equity

Failure category 4 - (>200%): Not covered by reserve account, potential need for additional equity capital

Figure 9: Categories to measure the impact of technical risks on PV project cash flow

For more details on this topic, see the full Solar Bankability reports on the ***PV Business Model Snapshots – Country Snapshot of Existing and New PV Business Models*** [6] and ***Financial Modelling of Technical Risks in PV Projects*** [3].

4. Risk Management

In this chapter, we present *eight mitigation measures* established in the Solar Bankability project to manage PV technical risks identified and assessed in the earlier works. Scenarios consisting of different mitigation combinations and market segments were studied. The effectiveness of the mitigation measures was assessed by evaluating how their implementation changes i) estimated yield, ii) the cost priority number and iii) PV LCOE and business models. Analysis was also carried out on who is best placed to take on the risks and at what point in the process this should happen.

As EPC and O&M costs are dominant in the PV lifecycle costs, the technical aspects in the EPC and O&M contracts are decisive for managing the technical risks in PV project investment. Therefore, we have developed seven *best-practice checklists* relevant for EPC and O&M contracting, targeting different market segments.

4.1. Mitigation of Risks Due to Yield Uncertainties During Planning

Analysis was carried out in the Solar Bankability project to identify mitigation measures to minimise the different uncertainty components in Table 5.

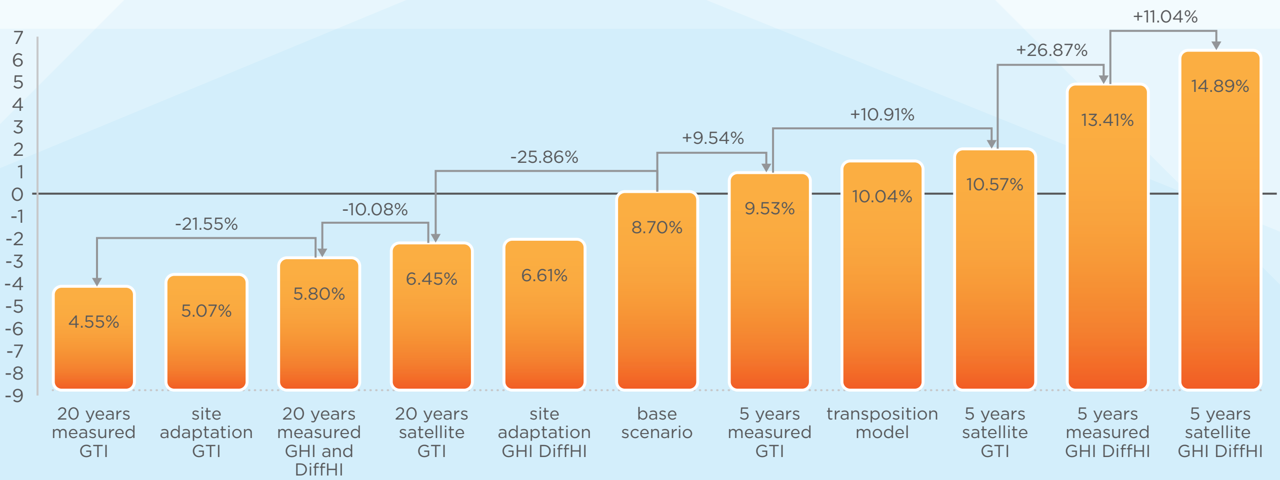


Figure 10: Impact of mitigation measures compared to the base scenario

The analysis highlights the *range of the available insolation data* as the most important factor affecting the uncertainty of the yield estimation. The results show that there is a group of cases assuring a low level of uncertainty (4.55% to 8.70%). They all refer to the use of long series of either ground- or satellite measurements of insolation.

Among the analysed scenarios, the best case corresponds to the use of 20 years of measured values of Global Tilted Irradiance (GTI), showing also that a lower uncertainty is ensured when a) ground measurements are used instead of satellite measurements and b) time series of plane-of-array irradiance are available without the need to apply transposition models. Results show also that *using a combination of long-time series of satellite data with a short series of measured data* is preferable over just using satellite data. In the case a PV plant is to be installed in a location with high insolation variability, the uncertainty of the yield estimation is also negatively affected.

Among the parameters that are not related to either insolation variability or solar resource, the *uncertainty related to shading and soiling effects*, and *to the use of the right transposition model*, plays a role in the uncertainty of the final yield. In general, the uncertainty of the final yield of the PV plant used in the analysis can range between 4.6% and 14.9%. The latter becomes 16.6% in the eventuality that the planner has the worst information quality available.

The exceedance probabilities calculated using these uncertainties are presented in Figure 11. The different curves represent the cumulative distribution functions for the low-end scenario (σ=4.6%), a high-end scenario (σ=9.3%) and the worst-case scenario (σ=16.6%). As it can be seen, the uncertainties could have a significant impact on the estimated energy yield.

For more details on this topic, see the full Solar Bankability report on the ***Minimizing Technical Risks in Photovoltaic Projects – Recommendations for Minimizing Technical Risks of PV Project Development and PV Plant Operation*** [7].

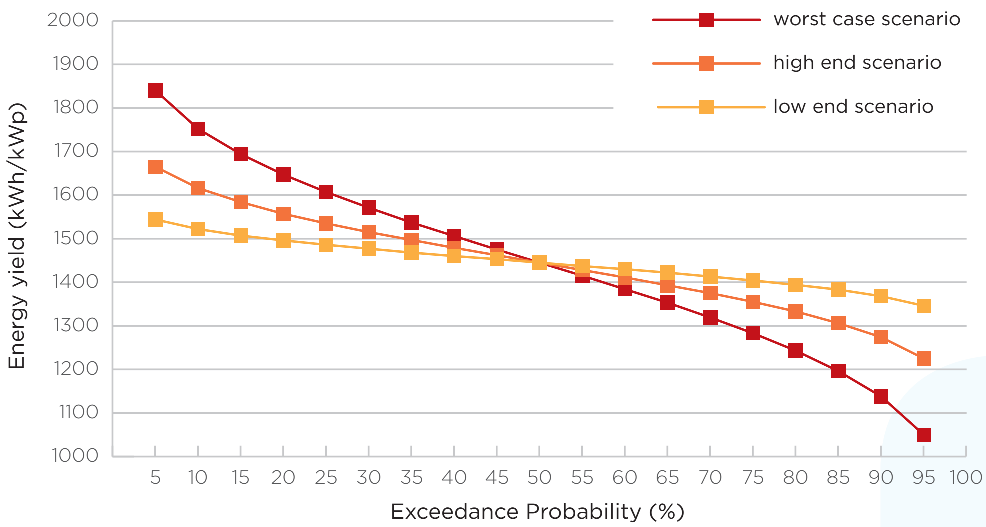


Figure 11: Exceedance probabilities based on uncertainties following mitigation measures in Figure 10

4.2. Mitigations of Risks During Operation and the Impacts on CPN

Mitigation measures must be identified along the value chain and assigned to various technical risks. Some failures can be prevented or mitigated through specific actions at different project phases. For example, for potential induced degradation (PID), the mitigation measure could be using different encapsulant or glass during the product manufacturing phase, or installing PID boxes during the operation/maintenance phase (for reversible PID). Others can be prevented or mitigated through a more generic action. For example, the monitoring of performance or visual inspection can be considered as generic mitigation measures that can have a positive impact on the reduction of the CPN of many failures. In summary it is important to understand how mitigation measures can be considered as a whole to be able to calculate their impact and thus assess their effectiveness.

By analysing the technical risks identified in Chapter 2, we put forward eight mitigation measures for PV technical risk management. They are categorised into two main categories. Preventive measures are applied before the risk occurs to prevent it from happening. They are component testing, design review and construction monitoring, and EPC qualification. These measures can be implemented during the early phases of PV project lifecycle and are likely to increase the CAPEX. Corrective measures are mitigation measures that aim to reduce higher losses and costs, if the risk has already occurred. The costs are mostly related to the OPEX due to the implementation during the operation and maintenance phase.

- **Component testing** of important plant components such as PV modules or inverters. The testing could be performed by the manufacturer in the factory, or independent testing at certified laboratory, or on-site at the PV plant;
- **Design review and construction monitoring** serve to catch issues caused by bad PV plant conception and poor PV construction workmanship;
- **EPC qualification** focuses on ensuring the competencies of the field workers, e.g. by requiring certain technical qualification prerequisites or regular training of the field workers;
- Implementing **advanced monitoring** system for early detection and diagnosis of faults;
- Use of **basic monitoring** system to monitor plant level alarms and notifications;
- **Advanced inspection** (e.g. using infrared or electroluminescence camera) to detect defects not usually visible with the naked eye;
- **Visual inspection** to establish any visible changes in PV plant components;
- **Spare part management** to minimise the costs of downtime and repair/substitutions of components.

For more details on this topic, see the full Solar Bankability reports on the ***Minimizing Technical Risks in Photovoltaic Projects – Recommendations for Minimizing Technical Risks of PV Project Development and PV Plant Operation*** [7].

4.3. Mitigations and Impact on CPN

The Solar Bankability project aims to create a framework of well-defined mitigation measures which have an impact on the global CPN (given as sum of CPNs of all technical risks). The cost-benefit analysis can then include the combination of various mitigation measures and derive the best strategy depending on market segment and plant typology. In addition to this, it is important to assess in the CPN analysis who bears the cost and the risk to derive considerations not only on the overall economic impact of the technical risks, but also on cost and risk ownership.

Mitigation measures will have different impacts on the costs of lost yields due to downtime (C_{down}) and the costs of repair or substitution (C_{fix}), thus changing the overall CPN value. In the Solar Bankability project, the analysis of the impact of various mitigation measures on CPN was carried out based on two different scenarios: i) a failure FIX scenario and ii) a never detected scenario as previously defined. The overall sum of the CPNs for all components prior to mitigations was around 105 Euros/kWp/year (green line in Figure 12).

The new CPN (CPN_{new}) value arise from the cost-benefit analysis by adding the CPN after mitigation to the cost of the mitigation measures. Figure 12 shows the results of calculating the costs of the failure fix scenario for selected failures when applying combinations of the eight selected mitigation measures (MM) mentioned before. The costs related to fixing the failures result from the sum of the costs of repair/substitution, the costs of detection, the costs of transport, and the cost of labour.

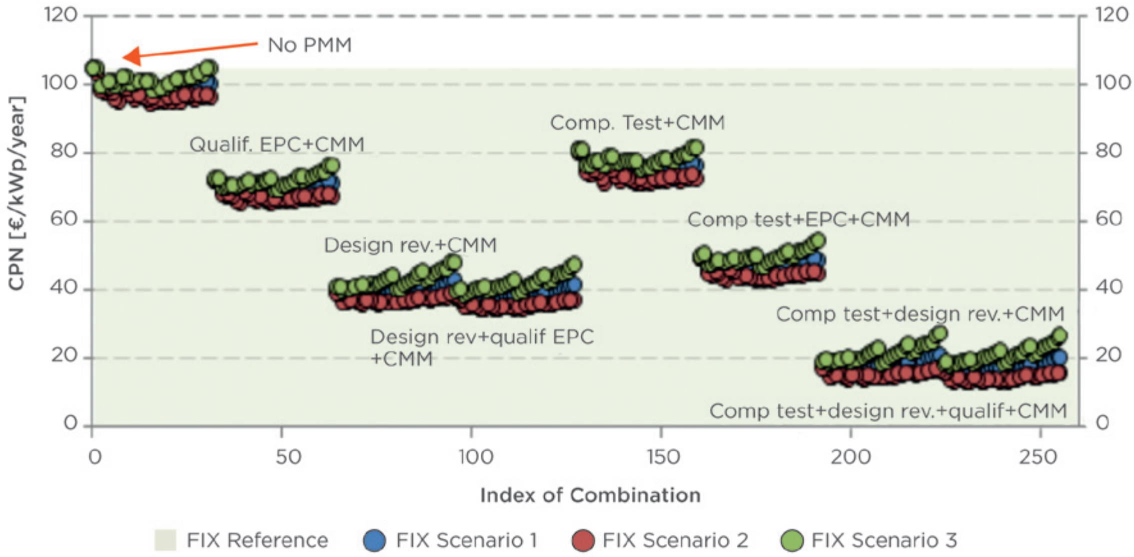


Figure 12: New CPN with mitigation measure combinations for different FIX cost scenarios

The CPN_{new} analysis above shows that for 99% of all mitigation measure combinations, the scenarios will result in economic benefit by reducing the CPN_{new} to values lower than the reference (104.75 €/kWp/year). Savings up to 90 €/kWp/year appear possible for the best combinations of selected mitigation measures. Furthermore, we can conclude that in general, mitigation measures which reduce the failure occurrence have the highest impact due to the related reduction in substitution costs. Preventive mitigation measures (PMM) have the highest impact on CPN_{new}, for instance, qualification of EPC will bring down CPN_{new} to 75 €/kWp/year, and design review will further reduce the CPN_{new} to 40 €/kWp/year. In fact, the highest savings can be achieved by applying all three preventive measures (component testing + design review + qualification of EPC). On the other hand, corrective mitigation measures (CMM) such as e.g. basic and advanced monitoring and visual and advanced inspection appear to have less impact on CPN_{new}.

For more details on this topic, see the full Solar Bankability report on the ***Minimizing Technical Risks in Photovoltaic Projects – Recommendations for Minimizing Technical Risks of PV Project Development and PV Plant Operation*** [7].

SIDE NOTES

In the coming years, as the availability of measured data will exponentially increase, it will be important to build large databases with a potentially uniform method to increase the confidence level of the statistical analysis and thus reduce the perceived risks for PV investors. With the availability of these large databases, the necessary information (minimum requirement) can be filtered out to perform tailored analysis in a uniform way i.e. same granularity, same data, same formulas. Our CPN methodology and approach attempt to provide such a benchmark.

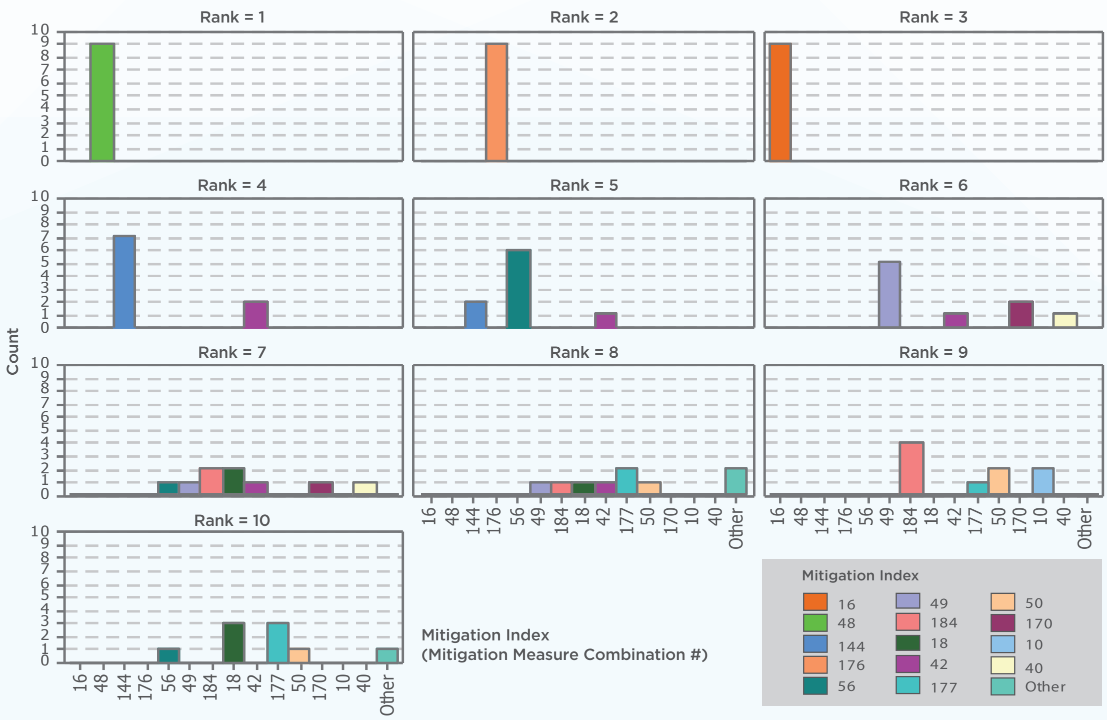
4.4. How Risk Mitigations Will Change PV LCOE

The analysis of the impact of implementing various scenarios of the above eight mitigation measures was extended to how it could affect the final PV LCOE value. The analysis covered the three market segments and three scenarios described in §3.4. In addition, case studies consisting of three PV systems with specific issues are considered: one case where poor PV yield estimation method has been used in the design phase; the second case involves low PV module power output in the procurement phase; and the last case where PV module cleaning is not included in the operational phase. The LCOEs before and after the application of mitigation measures for these three cases were calculated.

The top 10 most effective mitigation combinations from LCOE perspective for all nine cases are extracted and summarised in Figure 13 below. Each individual plot represents one LCOE reduction ranking. On the x-axis of each plot is the number (index) representing each mitigation combination. On the y-axis on each plot is the number of cases (the *count*) a certain mitigation combination works. For example, for the most effective mitigation combination plot ("Rank = 1"), mitigation combination #48 (combination of qualification of EPC and advanced monitoring) has a count of 9 which means it is the most effective combination to lower the LCOE across three market segments under all three scenarios. From this figure, it is apparent that there is only a dozen or so mitigation combinations which are most effective in reducing PV LCOE across all three market segments for all three scenarios. The conclusions drawn from the analysis of mitigation measures' impacts on PV LCOE is summarised in Table 7 below.

For more details on this topic, see the full Solar Bankability reports on the ***Best Practice Guidelines for PV Cost Calculation: Accounting for Technical Risks and Assumptions in PV LCOE*** [5].

10 Most Effective Mitigation Measure Combinations to Reduce LCOE



Mitigation Index	Component testing	Design review construction monitoring +	Qualification of EPC	Advanced monitoring system	Basic Monitoring system	Advanced Inspection	Visual Inspection	Spare part management
10	✘	✘	✘	✘	✔	✘	✔	✘
16	✘	✘	✘	✔	✘	✘	✘	✘
18	✘	✘	✘	✔	✘	✘	✔	✘
34	✘	✘	✔	✘	✘	✘	✔	✘
40	✘	✘	✔	✘	✔	✘	✘	✘
42	✘	✘	✔	✘	✔	✘	✔	✘
48	✘	✘	✔	✔	✘	✘	✘	✘
49	✘	✘	✔	✔	✘	✘	✘	✔
50	✘	✘	✔	✔	✘	✘	✔	✘
56	✘	✘	✔	✔	✔	✘	✘	✘
144	✔	✘	✘	✔	✘	✘	✘	✘
168	✔	✘	✔	✘	✔	✘	✘	✘
170	✔	✘	✔	✘	✔	✘	✔	✘
176	✔	✘	✔	✔	✘	✘	✘	✘
177	✔	✘	✔	✔	✘	✘	✘	✔
184	✔	✘	✔	✔	✔	✘	✘	✘

Figure 13: Top 10 most effective mitigation measure combinations for LCOE reduction

Table 7: Relative impacts of implementing different combinations of risk mitigation measures on PV LCOE

- PV LCOE reduction in the order of 4% to 5% is observed for all cases.
- The different combinations of mitigation measures have a larger impact in lowering the LCOE for scenarios where the higher CAPEX, OPEX, and/or discount rate results in a higher LCOE.
- Mitigation measures which are most effective in lowering PV LCOE are similar across all three market segments and for all scenarios.
- The most effective mitigation measures are those implemented at the early stage of project lifecycle. Those implemented in the operation phase still show some positive impact on LCOE but less gain is found.
- Although the implementation of mitigation measures increases either CAPEX, OPEX or both, the overall LCOE decreases as the gain in yield is higher than the extra cost incurred.
- The mitigation measures most effective in lowering PV LCOE are:
  1. Qualification of EPC;
  2. Component testing prior to installation; and
  3. Advanced monitoring system for early fault detection.

4.5. Best Practice in EPC and O&M Contracting for Risk Mitigation

From the risk identification in Chapter 1, we have found that technical risks linked to poor assumptions in PV financial models. These risks could be introduced either during project development (procurement, planning and construction, i.e. EPC) or during PV operation (O&M). Since EPC and O&M contracts provide the technical framework of the whole PV project lifecycle, it is important to ensure that all technical aspects of EPC and O&M contracts are based on best-practice quality. To this end, a set of six checklists for utility-scale (ground-mounted) and commercial rooftop PV installations have been developed to serve as guidelines for best practices in EPC and O&M technical aspects.

- Best Practice Checklist for EPC Technical Aspects.
- Best Practice Checklist for O&M Technical Aspects.
- Best Practice Checklist for Long-Term Yield Assessment.
- Checklist for As-Build Documents – Type and Details.
- Checklist for Record Control.
- Checklist for Reporting Indicators.

For more details on this topic, see the full Solar Bankability report on the ***Best Practice Guidelines for PV Cost Calculation: Accounting for Technical Risks and Assumptions in PV LCOE*** [5].

4.6. Transfer of Technical Risks to Relevant Parties

Besides risk mitigation, risk transfer is an integral part of any risk management strategy. Solar Bankability suggests to transfer the ownership of technical risks to those parties which are best positioned to control them along the project life cycle (see Figure 14 below). An effective transfer of ownership will depend on a professional understanding of the underlying legal documents such as contracts, guarantees, warranties, insurance policies and credit agreements and their corresponding durations.

The installer or EPC is liable for the material and workmanship during the construction phase. The O&M operator is liable for the material and workmanship of his services. The component manufacturer must meet the warranty and performance guarantees and disposal guarantee for their products. Mandatory and optional insurances can cover financial risks caused by external or internal factors. For all risks which are not covered by the above measures, the owner/operator of the PV project will be held responsible with their equity capital. Banks are last in the risk transfer chain and only get involved in cases of a creditor default.

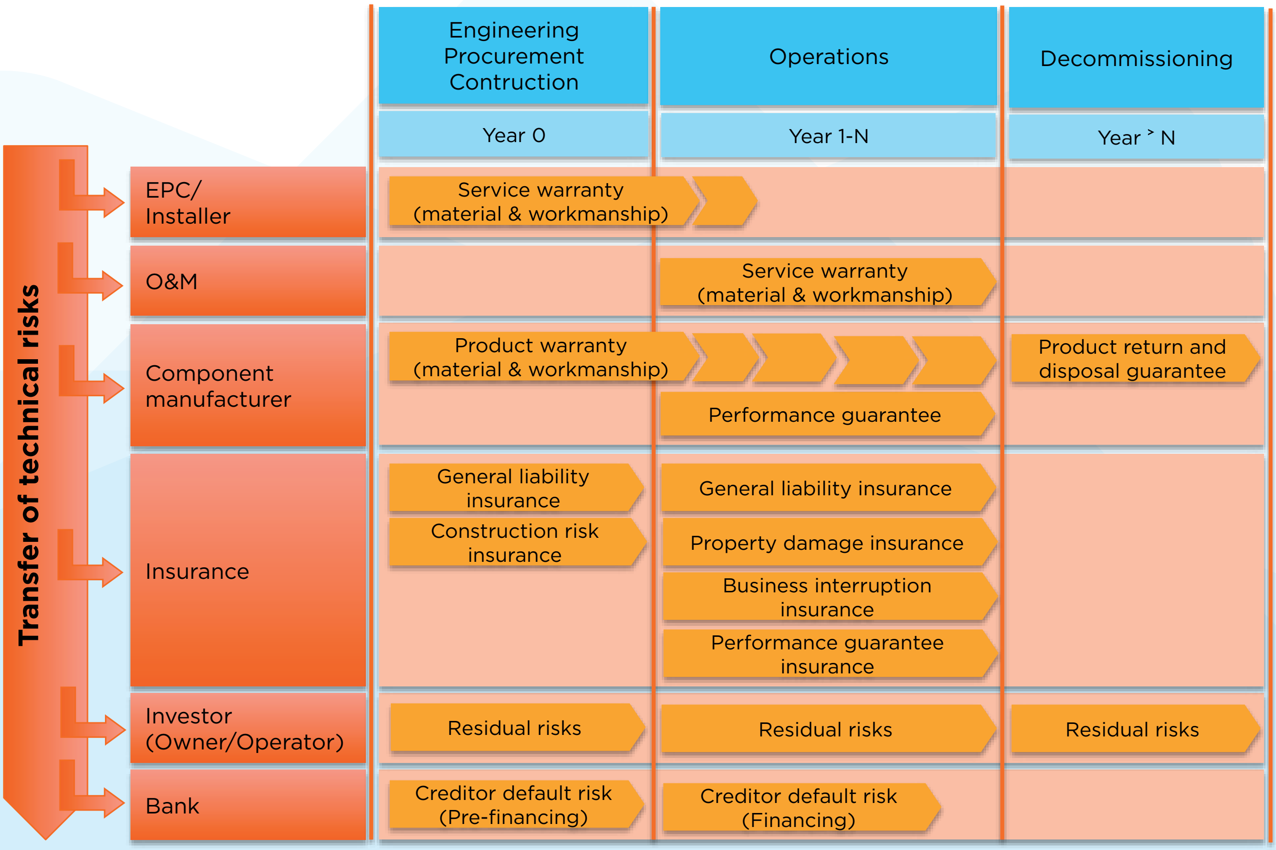


Figure 14: Potential plan to transfer technical PV project risks

For more details on this topic, see the full Solar Bankability report on the ***Technical Bankability Guidelines: Recommendations to Enhance Technical Quality of Existing and New PV Investments*** [8].

5. Risk Controlling

In the aftermath of the financial crisis in the year 2008 new capital market requirements have been created for institutional investors from the banking, insurance and investments fund sector to enhance the transparency and stability in global capital markets [3]. The new capital market framework is based on three pillars (Figure 15) [9]. This means PV investments are expected to also comply with these regulations.

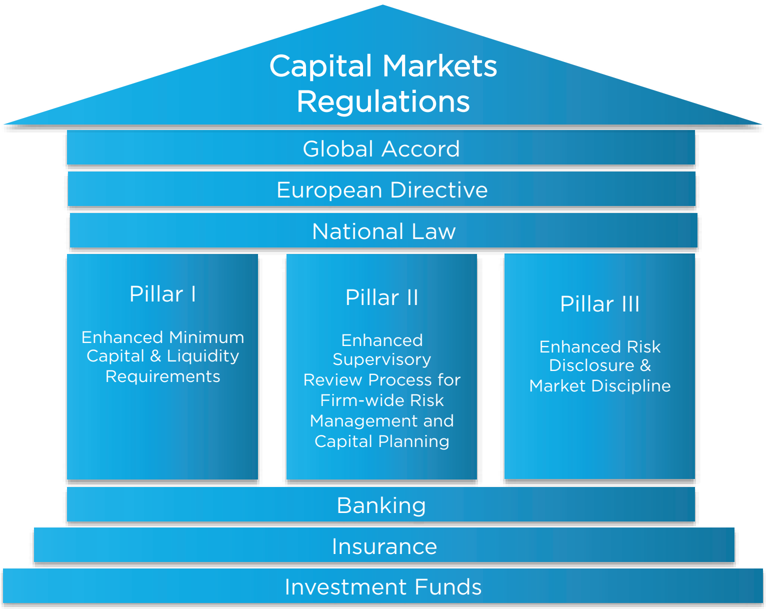


Figure 15: Three pillar model for new capital market regulations

Financial regulatory bodies on a global, European and national level have developed a set of harmonised regulations for each capital market sector:

- Banking (Basel III),
- Insurance (Solvency II),
- Investment Funds (UCITS V / AIFM).

The regulations require institutional investors to introduce a hierarchically independent risk management function. This function oversees the firm-wide risk management including an ongoing risk controlling and a transparent risk reporting at least once a year. Institutional investors can either enhance their own risk management organisation and build up an in-house team specialised in PV risk assessment or they can access external rating services, which are being offered by specialised consulting firms or international rating agencies.

The checking of technical risks for large commercial and utility-scale PV projects is often transferred to specialised owner's engineers. They ensure the professional supervision of the engineering, construction and commissioning of the PV plant and provide an ongoing risk monitoring during the operational phase with regular risk reporting at least once a year.

For residential PV systems, the owner is responsible for the risk management. Most of these systems are not covered by a regular service and maintenance contract. Therefore, a regular check-up of the PV system is recommended at least every four years for PV systems equipped with an online monitoring system. For systems without an online monitoring system, the check-up intervals should not exceed two years [10].

For more details on this topic, see the full Solar Bankability report on the ***Technical Bankability Guidelines: Recommendations to Enhance Technical Quality of Existing and New PV Investments*** [8].

6. Final Takeaways

Based on the findings of Solar Bankability project, the following conclusions and recommendations can be derived:

1. Technical risks can have a major impact on the total project risk rating scheme.
2. The occurrence and impact of technical risks for different business models vary and depend on the system size, system technology, geographic location and climatic conditions.
3. The occurrence of technical risks follows a bathtub-shaped curve with high occurrence at the beginning and end of the PV project life cycle.
4. Technical risks can be systematically organised in a Risk Matrix.
5. Technical risks need to be defined using a standardised nomenclature.
6. Technical risks can have an economic impact in terms of uncertainty on the energy yield or in terms of CPN (directly or indirectly) or can be a precursor for failures occurring in a later stage of the PV project.
7. Different options are available for the economic assessment of technical risks:
    - CPN methodology;
    - LCOE sensitivity analysis;
    - Cash flow categories.
8. The cash flow model is most sensitive to risks in the early PV project life cycle.
9. Mitigation measures which prevent risks or allow early detection are most effective.
10. The mitigation measures most effective in lowering PV LCOE are:
    - Qualification of EPC;
    - Component testing prior to installation; and
    - Advanced monitoring system for early fault detection.
11. Small residential PV systems tend to be more sensitive to the impact of technical risks than large utility scale PV power plants.
12. A professional risk management strategy should become integral part of each PV investment.
13. The risk management function should be hierarchically independent and can be provided by qualified in-house or external third party experts.
14. PV systems with a professional risk management will fall into the category of qualified infrastructure investments. Their risk/return profile is favourable over other asset classes.

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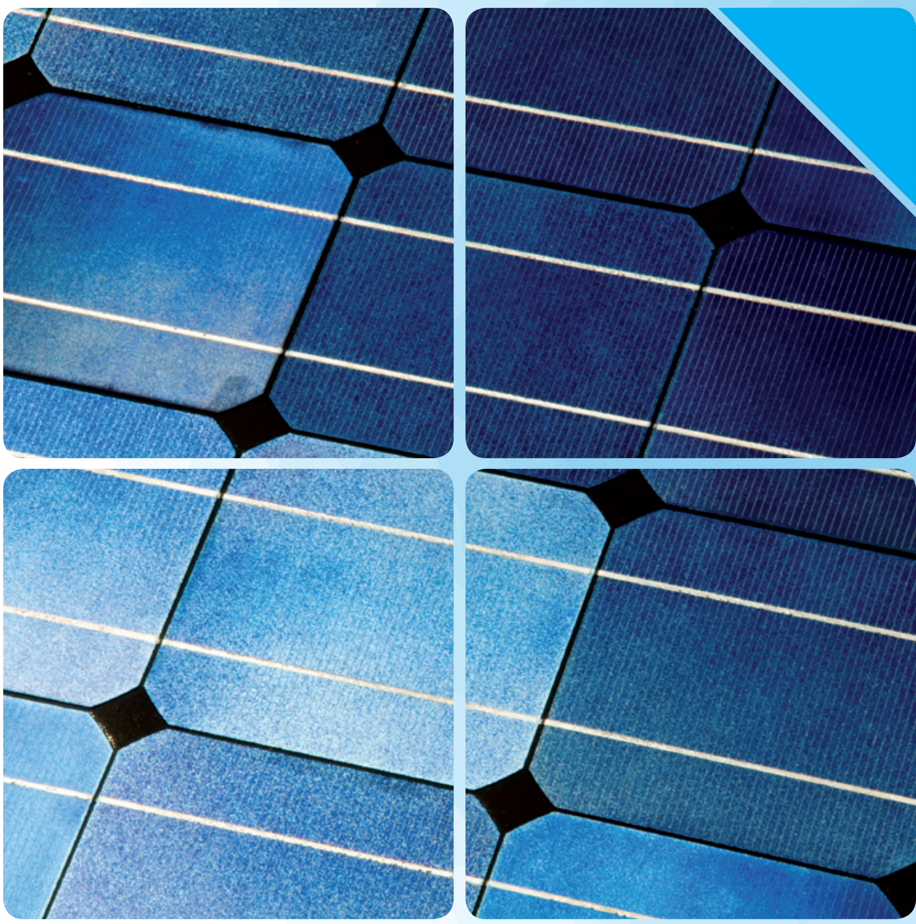

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