Managing technical risks in PV investments

Risk mitigation | The EU-funded Solar Bankability Project has developed a framework for managing the potential legal, technical and economic risks associated with PV projects. Here, members of the team behind the project set out some of the key tools and guidelines that have been devised to ensure ongoing quality management over the entire lifecycle of a PV power plant

In the Solar Bankability project the term 'solar bankability' was defined as 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 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.

The guidelines and tools developed in the project can be considered as steps towards standardisation and de-risking for the PV sector and are to assist stakeholders in developing their own individual risk management strategy along the lifecycle of a PV project through risk identification, assessment, management and control (Figure 2).

Risk identification

In PV financial modelling, inaccurate inputs (e.g. costs, yield) will inevitably result in incorrect calculations of revenue, cost, cash flow etc., thus giving an inaccurate assessment of the investment-worthiness of a PV project. Financial model inputs are strongly influenced by technical assumptions. In the project, we have compiled a list of 20 most common levelised cost of electricity (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. Focus was then placed on technical risks during the whole PV project value chain, and on those risks which are relevant to the calculation of the PV LCOE. The failures are tabulated in a so-called technical risk matrix (available at www.solarbankability.org).

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, the 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.

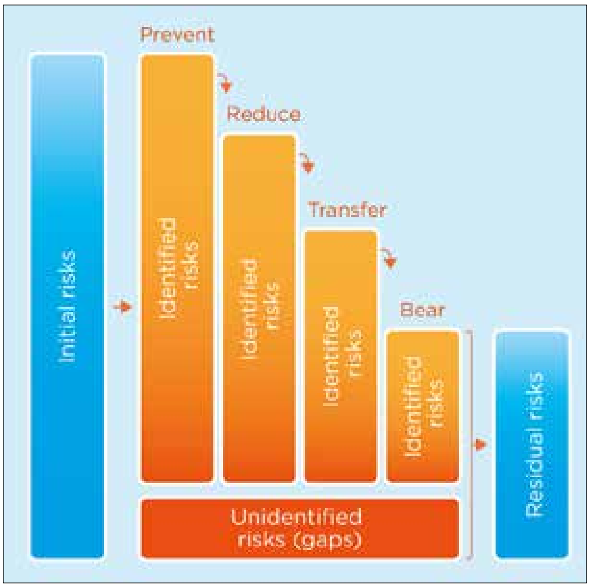


Figure 2. Potential plan for the management of technical PV project risks

Gap analyses were performed systematically according to the phases in the PV project life cycle and whether the root causes are likely to occur before 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. The root causes 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 were presented in [1].

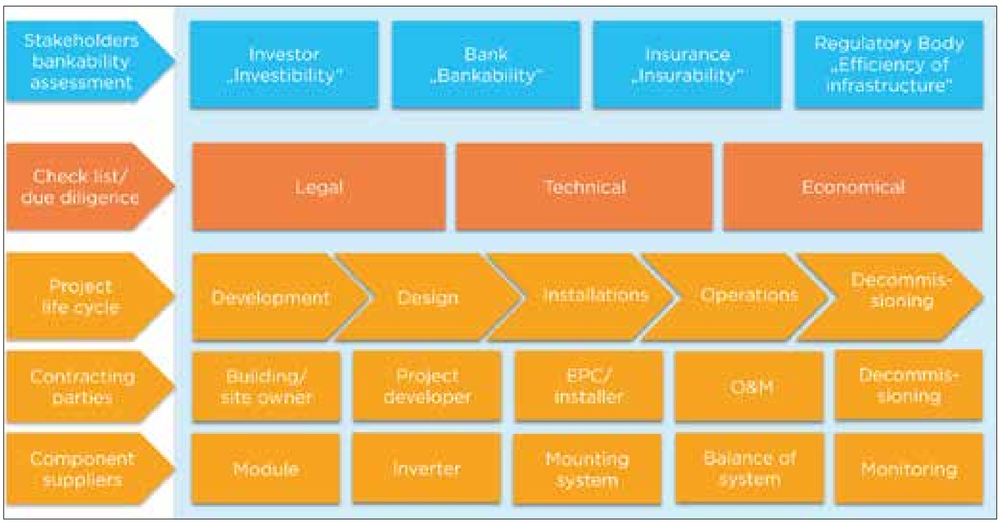


Figure 1. Solar Bankability assessment from different stakeholders' perspectives

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

Table 1. Example of risk matrix for PV modules and inverters

For more details on this topic, see the full Solar Bankability report [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 that can affect solar plants, either during development or 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 (including ~2 million modules and ~12,000 inverters); this portfolio corresponds to 442MWp of PV plants nominal power, i.e. roughly 0.5% of the installed capacity in Europe. Each failure collected was categorised based on which PV plant component the failure occurs. 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 risk matrix. Table 1 gives some examples of technical risks for PV modules and inverters, while all 140 technical risks are described in detail in [3].

Risk assessment

Once risks were identified, 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:

- A cost-based FMEA (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.

Risks in yield estimation during planning

Some of the technical risks listed in the risk matrix 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 literature in order to quantify the impact of uncertainties in yield estimation of PV plants. The review exercise of current practices shows that the various uncertainties could have an overall impact as high as ±10% on the estimated energy yield. These uncertainties are in turn used to calculate the exceedance probabilities for a PV plant estimated yield (e.g. P90/ P50). The uncertainties are typically calculated by fitting the dataset to a standard probability distribution (often assumed Gaussian/ normal). However, when possible (e.g. solar resource) for more accurate determination of uncertainties, a more precise analysis would benefit from the use of an empirically established probability distribution.

CPN methodology: new tool for technical risk economic impact assessment

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 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 O&M phase of a PV project, and how the risks affect the LCOE and business models of PV projects.

As explained in [1], 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, expressed in euros/kWp or euros/kWp/year. Thus, the overall CPN value for various components and failures would correspond to the true operational costs for various scenarios without differentiating in terms of cost ownership (insurance, O&M, module warranty, etc).

Impacts of technical risks on CPN

The CPN methodology was applied to

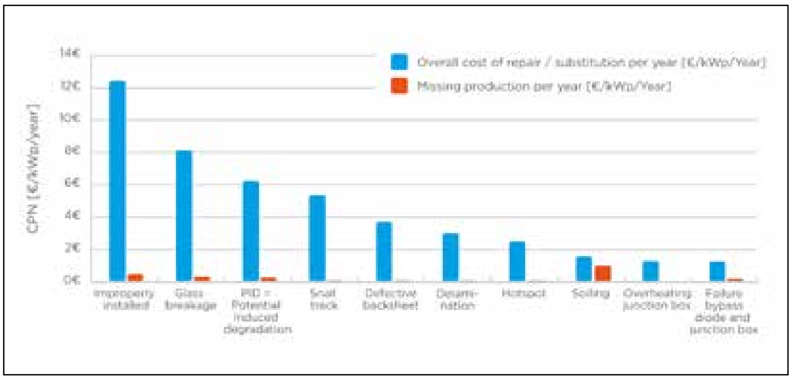


Figure 3. CPN, repair costs and performance losses for top 10 risks for PV modules of all system size

the risks included in the matrix. The risks are ranked by their CPNs to see which have the highest economic impact. To assess the impact of failures for various 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". In the second scenario, we assumed that the failure is fixed after detection using a lead time to repair/substitution of one month.

The analysis of CPN for PV modules for all market segments combined is shown in Figure 3. 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 only plant downtime. As 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 potential-induced degradation (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), (red bars in Figure 3) appears to be minimal for the module failures. The dominant factor in the failure fix scenario (blue bars in Figure 3) 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 diode 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 10 module risks for each market segment, the trend reflected in Figure 3 applies to larger-scale PV systems. This is because for such systems, different defect detection techniques from basic visual to advanced 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 advanced inspection tools tend to escape detection due to the absence of the use of such tools.

Impacts of technical risks on solar PV generation cost (LCOE)

In the project, we also assessed the relative impacts the identified technical risks would have on the PV LCOE via sensitivity analysis, thus pinpointing the areas where mitigation measures should be prioritised.

The LCOE sensitivity analysis was performed by varying six LCOE input parameters (CAPEX, OPEX, yield, discount rate, yearly degradation and system lifetime) by ±20%. Each input was treated as if one is independent from the others. The analysis includes three different market segments: <5 kWp residential PV systems, <1 MWp commercial rooftop PV systems and >1 MWp utility scale ground-mounted PV systems (see Table 2). Three scenarios have been selected for this analysis – one representing PV systems in mature markets such as Germany (low scenario) where high competition has driven the CAPEX and OPEX prices down

Table 2. LCOE results for the three selected scenarios

Input parameter	Low scenario	Medium scenario	High scenario
CAPEX [€/kWp]			
Ground-mounted utility (≥ 1 MWp)	€ 900	€ 1000	€ 1200
Commercial rooftop (< 1 MWp)	€ 1000	€ 1200	€ 1400
Residential (up to 5 kWp) (VAT excluded)	€ 1300	€ 1400	€ 1600
OPEX [€/kWp/year]			
Ground-mounted utility (≥ 1 MWp)	€ 13	€ 15	€ 20
Commercial rooftop (< 1 MWp)	€ 10	€ 10	€ 18
Residential (up to 5 kWp) (VAT excluded)	€ 5	€ 5	€ 9
Performance Ratio 'PR' [%]			
Ground-mounted utility (≥ 1 MWp)	86%	84%	86%
Commercial rooftop (< 1 MWp)	84%	82%	84%
Residential (up to 5 kWp)	82%	80%	82%
POA irradiation [kWh/m2]	1331	1821	1168
Discount rate [%]	4%	8%	6.5%
Degradation rate [%]		0.5% linear	
Lifetime [years]		25 years	

Market segment	Low scenario	Medium scenario	High scenario
LCOE without any mitigation	*[€cents/kWh]*	*[€cents/kWh]*	*[€cents/kWh]*
Ground-mounted utility (≥ 1 MWp)	5.4 – 8.1	6.2 – 9.3	10.3 – 15.5
Commercial rooftop (< 1 MWp)	5.8 – 8.7	7.0 – 10.7	11.8 – 17.8
Residential (up to 5 kWp)	6.9 – 10.6	7.9 – 12.2	12.5 – 19.2

	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 4. Four business models selected for technical risk impact modelling

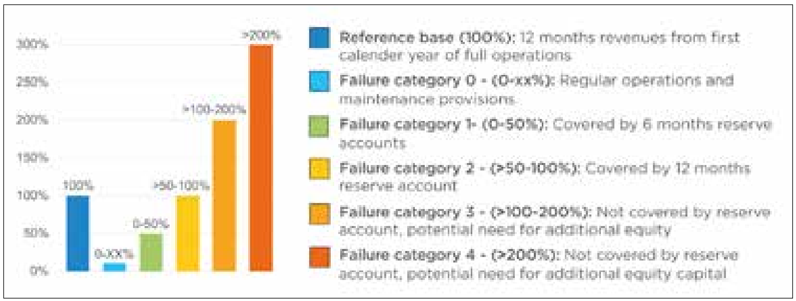


Figure 5. Categories to measure the impact of technical risks on PV project cash flow

and the market bears less regulatory risk; the second representing systems in markets such as Italy (medium scenario) 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 (high scenario) with high CAPEX and OPEX but with irradiation level rather low and a relatively moderate discount rate. 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].

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. Since there are no commercial risk modelling tools available in the market that 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.

Four representative business models as shown in Figure 4 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 or rooftop mounting, solar electricity feed-in tariff and self-consumption, geographic location and climatic conditions.

For each business model, 10 to 12 typical technical risks from the risk matrix were selected and their impacts assessed for both individual risks and risk scenarios with a combination of up to four risks.

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 5). For more details on this topic, see the full Solar Bankability report on Financial Modelling of Technical Risks in PV Projects [4].

Risk management

The framework for the assessment of the economic impact of technical risks allows for the analysis of how these risks can be managed, through mitigation or risk transfer. The effectiveness of the mitigation measures was assessed by evaluating how their implementation changes i) estimated yield, ii) the CPN 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.

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.

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 (see Figure 6), 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) validated 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 cases where 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 uncertainties related to shading and soiling effects, and to the use of the right transposition model, play a role in the uncertainty of the final yield. In general, the uncertainty of the final yield

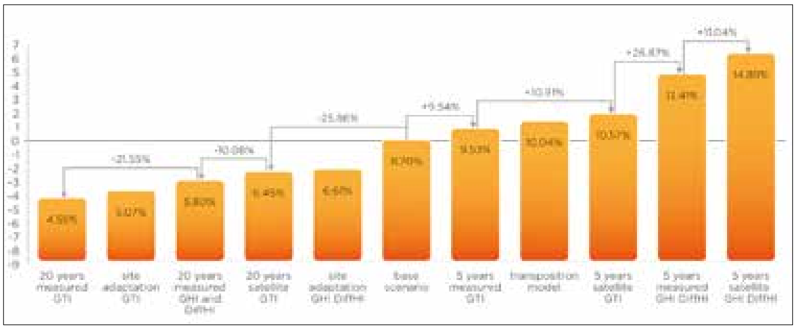


Figure 6. Impact of mitigation measures on yield assessments compared to the base scenario

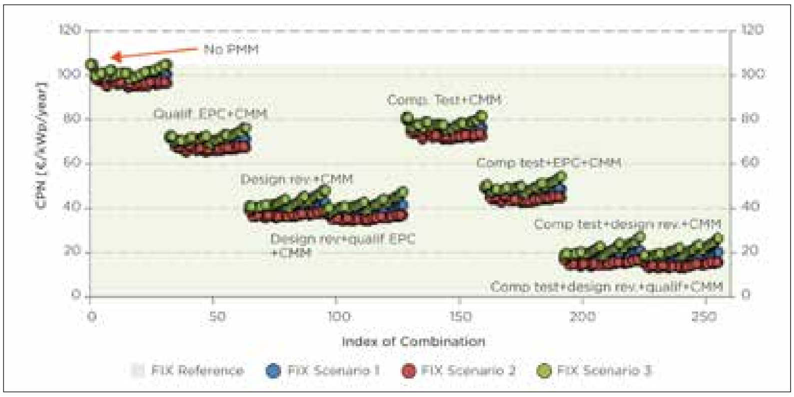


Figure 7. CPN with mitigation measure combinations for the overall CPN

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 can lead to a P90/P50 ratio reduction of up to 20%. The uncertainties could thus have a significant impact on the estimated energy yield.

For more details on this topic, see the full Solar Bankability report on the Minimising Technical Risks in Photovoltaic Projects – Recommendations for Minimising Technical Risks of PV Project Development and PV Plant Operation [6].

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 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 previously identified, 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. They are basic and advanced monitoring, visual and advanced inspection, and spare part management. The costs are mostly related to the OPEX due to the implementation during the operation and maintenance phase.

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 yield loss due to downtime and the costs of repair or substitution, thus changing the overall CPN value. The new CPN value arises from the cost-benefit analysis by adding the CPN after mitigation to the cost of the mitigation measures. Figure 7 shows the results of calculating the costs of the failure fix scenario for selected failures when applying combinations of the eight selected mitigation measures mentioned before.

The CPN analysis above shows that for 99% of all mitigation measure combinations, the scenarios will result in economic benefit by reducing the CPN 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. 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 basic and advanced monitoring and visual and advanced inspection appear to have less impact on the CPN. In reality CMMs can further reduce the CPN by around €3/kWp/year, which is of fundamental importance to apply effective O&M strategies which suffer at the moment of high cost pressure.

For more details on this topic, see the full Solar Bankability report on the Minimising Technical Risks in Photovoltaic Projects – Recommendations for Minimising Technical Risks of PV Project Development and PV Plant Operation [6].

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. There are 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 are summarised in Table 3 below.

For more details on this topic, see the

- 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 the 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 surpasses the extra cost incurred.
- The mitigation measures most effective in lowering PV LCOE are:
  1. Qualification of EPC;
  2. Component testing prior to installation;
  3. Advanced monitoring system for early fault detection.

Table 3. Relative impacts of implementing different combinations of risk mitigation measures on PV LCOE

full Solar Bankability reports on the Best Practice Guidelines for PV Cost Calculation: Accounting for Technical Risks and Assumptions in PV LCOE [5].

Best practice in EPC and O&M contracting for risk mitigation

From the risk identification, we have found that technical risks are linked to poor assumptions in PV financial models. These risks could be introduced either during project development (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 (available at www.solarbankability.org):

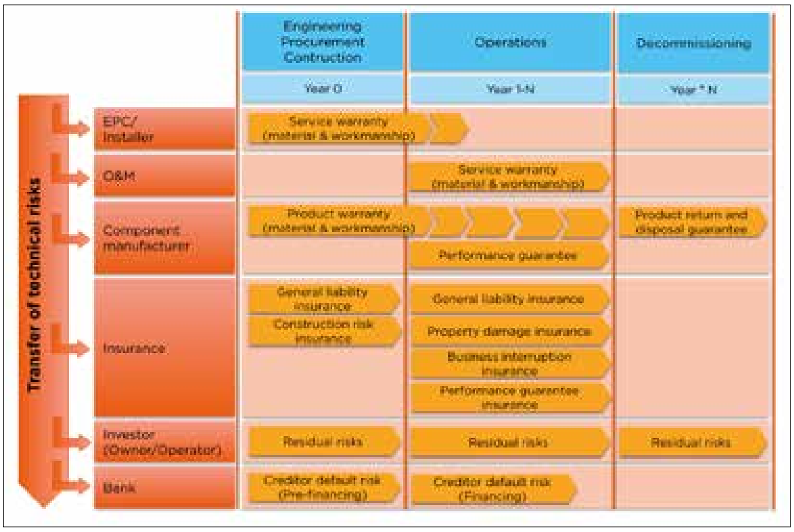
1. Best practice checklist for EPC technical aspects
2. Best practice checklist for O&M technical aspects
3. Best practice checklist for long-term yield assessment
4. Checklist for as-build documents – type and details
5. Checklist for record control
6. Checklist for reporting indicators

Transfer of technical risks to relevant parties

Besides risk mitigation, risk transfer is an integral part of any risk management strategy. Solar Bankability suggests transferring the ownership of technical risks to those parties which are best positioned to control them along the project life cycle (see Figure 8). 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 8. 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 [7].

Risk controlling

The regulations set by financial regulatory bodies require institutional investors to introduce a hierarchically independent risk management function. This function oversees the firm-wide risk management including ongoing risk control and 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 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 every few years depending also on the availability of an online monitoring system.

Recommendations for risk management strategies

Based on the findings of the project, we recommend different stakeholders 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 control. 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 systems.

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 lifecycle.

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. Corrective mitigation measures in plants where preventive mitigation measures were considered can have an important impact

11. The mitigation measures most effective in lowering PV LCOE are:

- Qualification of EPC;
- Component testing prior to installation;
- Advanced monitoring system for early fault detection.

12. Small residential PV systems tend to be more sensitive to the impact of technical risks than large utility scale PV power plants.

13. A professional risk management strategy should become integral part of each PV investment.

14. The risk management function should be hierarchically independent and can be provided by qualified in-house or external third party experts.

15. 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.

Acknowledgements

The Solar Bankability project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 649997. Reports, guidelines and useful Excel tools developed as part of the project are freely available on **www.solarbankability.org**

References

[1] "Technical failures in PV projects", www.pv-tech.org. Available: https://www.pv-tech.org/technical-papers/technical-failures-in-pv-projects. [Accessed: 11 July 2017].

[2] C. Tjengdrawira and M. Richter, "Review and Gap Analyses of Technical Assumptions in PV Electricity Cost - Report on Current Practices in How Technical Assumptions are Accounted in PV Investment Cost Calculation", Solar Bankability WP3 Deliverable D3.1, July 2016.

[3] David Moser et al., "Technical Risks in PV Projects - Report on Technical Risks in PV Project Development and PV Plant Operation", Solar Bankability WP1 Deliverable D1.1 and WP2 Deliverable D2.1, March 2016.

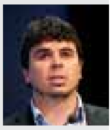
[4] M. von Armansperg, D. Oechslin, and M. Schweneke, "Financial Modelling of PV Risks." 2016.

[5] Caroline Tjengdrawira, Mauricio Richter, and Ioannis-Thomas Theologitis, "Best Practice Guidelines for PV Cost Calculation: Accounting for Technical Risks and Assumptions in PV LCOE", Public report Solar Bankability WP3 Deliverable D3.2, December 2016.

[6] U. Jahn *et al.*, "Minimising Technical Risks in Photovoltaic Projects." August 2016.

[7] M. von Armansperg, D. Oechslin, and M. Schweneke, "Technical Bankability Guidelines - Recommendations to Enhance Technical Quality of PV Investments", Public report, February 2017.

Authors

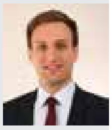


David Moser coordinates the activities of the Research Group Photovoltaic Systems of the Institute for Renewable Energy, EURAC, Bolzano, Italy. His work focuses on solar resource assessment, performance and reliability of PV modules and systems, building integration of PV systems and PV integration in the grid. He is also active in PV potential studies on a regional scale and a member of the board of directors of the Association of European Renewable Energy Research Centres, EUREC, and of the steering committee of the EU-PV ETIP.

Caroline Tjengdrawira is a senior project manager (solar PV) in the Energy Generation department at Tractebel Engineering (Brussels, Belgium). She has been working in the engineering consulting field in the solar PV sector for over 10 years, advising PV developers, owners and lenders in various phases of their projects. Caroline previously worked as senior project manager and technology expert at 3E NV (Belgium) and as a project manager at the Energy Research Center of the Netherlands.

Ulrike Jahn graduated in physics and leads various research and development projects in the business area of solar energy of the TÜV Rheinland Group in Cologne, Germany. Her work focuses on characterising PV module technologies and on PV system performance analysis. She is a project manager of an international expert group examining PV system performance and module reliability of the PVPS programme of the International Energy Agency (IEA).

Matthias v. Armansperg: Matthias graduated in mechanical engineering and business administration. After 12 years international sales and marketing experience in the chemical industry he joined the PV industry in 2004 as senior strategic advisor. In 2009 he founded ACCELIOS Solar, which offers technical, commercial and financial advisory services with an integrated perspective on solar bankability and risk management including feasibility studies, due diligences, expert opinions and management of insurance claims.



Máté Heisz is a business analyst at SolarPower Europe, working on topics linked to O&M, standardisation, sustainability and R&D. Before joining SolarPower Europe he worked as a renewable energy advisor at the Tunisian Ministry of Energy on behalf of the German Society for International Cooperation (GIZ).