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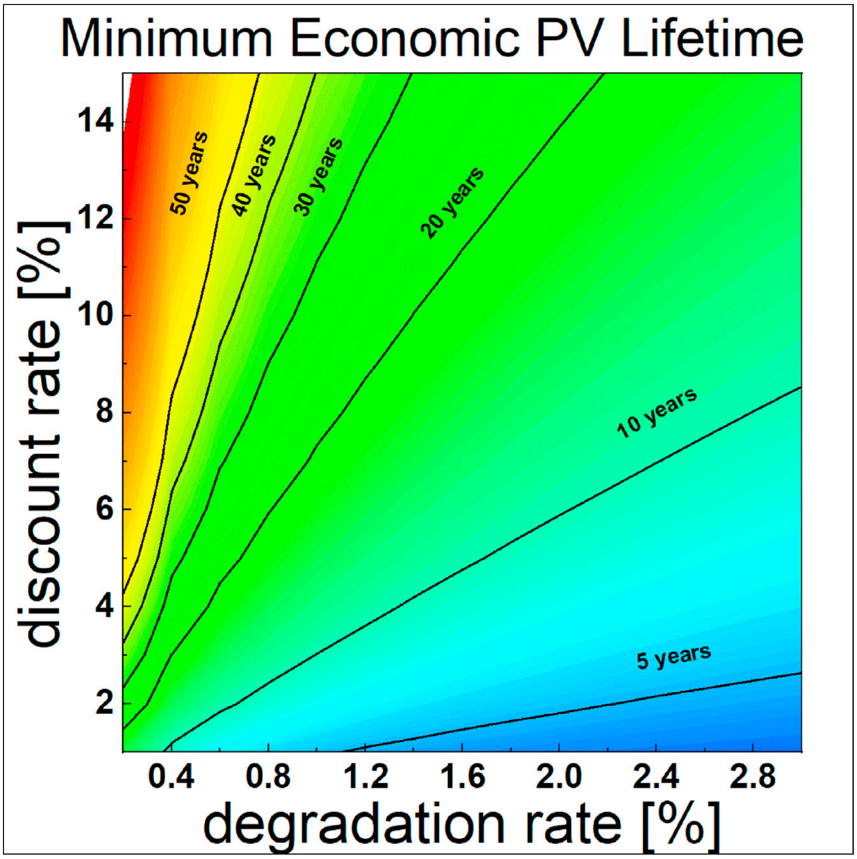
The value of stability in photovoltaics



Perspective matters for the valuation of photovoltaic installations. Economic projections and warranties often assign a lifetime of 25 years to PV modules. This lifetime is, to some extent, a choice, and this choice has consequences for the economic and sustainable performance of photovoltaics. In this work, we adopt a different mindset: photovoltaic installations are operated perpetually with maintenance at regular intervals. With this perspective, power maintenance gains in value, stability in importance, and module lifetimes of 50 years become desirable.

Ian Marius Peters, Jens Hauch, Christoph Brabec, Parikhit Sinha

im.peters@fz-juelich.de

Highlights

We introduce a model for long-term operation of PV installations

In long-term operation, maintenance becomes 33% more valuable

Reducing degradation from 0.5% to 0.2% implicates a cost entitlement of 12 ct/W

The same reduction in degradation will increase module life to 50 years

Peters et al., Joule 5, 3137–3153
December 15, 2021
https://doi.org/10.1016/j.joule.2021.10.019

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The value of stability in photovoltaics

Ian Marius Peters,[1,4,*] Jens Hauch,[1,2] Christoph Brabec,[1,2] and Parikhit Sinha[3]

SUMMARY

Warranties for photovoltaic modules last 25 years. The same duration is frequently used when predicting economic performance. Yet, many modules still produce more than 80% of their original power after 25 years, and there is no economic reason to retire them. Here, we adopt a different mindset: photovoltaic installations are operated indefinitely with maintenance at regular intervals. We reflect this view in a steady-state economic model. We find that in this view, maintenance gains in value—33% compared with a 30-year lifetime—and time constraints for maintenance are lifted. We also find that stability becomes even more important. Reducing annual degradation from 0.5% to 0.2% entails a 12 ct/Watt cost entitlement, increases the economically useful lifetime by a factor of 1.69, defers end of life by decades, and reduces resources and infrastructure needed for recycling by 40%. We foresee that modules installed today should ideally be operated for 50 years.

Context & scale

We explore the implications of adopting a long-term perspective about PV installations. At the end of the designated lifetime of a PV system, which is often assumed to be 25 or 30 years, many PV modules still operate at high fractions of their initial power. Economically, there is no reason to discontinue the operation of such modules, and even less so from a sustainability point of view. Here, we introduce an economic model for PV operation that assumes perpetual operation with maintenance at regular intervals. When adopting such a long-term view, we find that greater investments for keeping the installation in good shape pay-off compared with a mindset with limited lifetime. We also find that module stability becomes more important for economic evaluation. Inferior stability cannot be compensated by lower module prizes and can only be compensated by much higher efficiency. Finally, we predict that modules installed today should be operated for 50 years before they are replaced.

INTRODUCTION

When looking at projections of a photovoltaic (PV) system's lifetime, one will frequently encounter durations between 20 and 30 years. These durations are used, for example, when calculating the levelized cost of electricity (LCOE) or similar economic metrics. Probably the main motivation for assuming this lifetime is the performance warranty for PV modules given by manufacturers, which is usually 25 years today. In the early 2000s, the assumed system lifetimes of 20 years may also have been motivated by the Renewable Energy Source Act, which came into force in Germany on April 1st, 2000 and guaranteed a technology-specific feed-in tariff for 20 years for every kWh generated by a renewable electricity source.[1] A feed-in-tariff was already enacted in 1991 through the Electricity Feed-in Act, but only after the 2000 version, PV installations in Germany took off.[2] Performance warranties for PV modules were given since the late 1970s with Solarex providing a 1-year warranty on its products in 1977.[3] Within 20 years, warranties extended to 25 years, a value on which they have plateaued. Only recently, a few companies, such as Silfab and First Solar, have started to offer 30 years performance warranties.[4,5]

The duration of a performance warranty says little about performance reduction, and additional information about the guaranteed performance level of a solar panel at the end of life is needed. Guaranteed performance values for different manufacturers range from 80% to Sun Power's 94% of the original power after 25 years.[6] Furthermore, solar panels come with a product warranty in addition to the performance warranty. The product warranty specifies until when the manufacturer will ship a replacement in case of module failure. This warranty ranges between 5 and 25 years.[7] Figure 1 gives an overview of warranty durations and guaranteed performances. The measured performance of PV systems is in line with guaranteed PRs. Jordan et al.[8] compiled annual degradation rates for 384

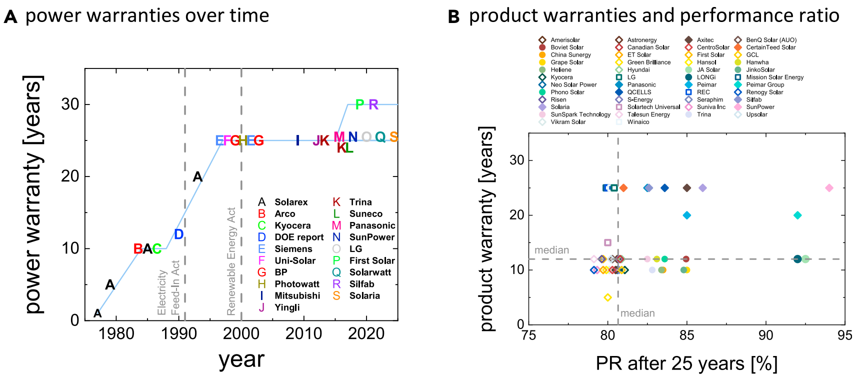

Figure 1. Warranties for PV modules over time

(A) The development of power warranty over time with examples of companies offering this warranty.

(B) Product warranty and guaranteed performance ratio after 25 years.[7]

crystalline-silicon PV systems and found a median value of 0.64%, corresponding to an 85% PR after 25 years.

Performance warranties and political measures have determined the typical project lifetimes used in PV system planning and economic modeling. However, there is no reason to retire a PV system when it reaches 80% PR,. This point was brought up, for example, by Sun Power, which, based on their very low degradation rates, introduced a useful life of their modules of 40 years, defined as the time after which 99% of their modules will produce more than 70% of their nameplate power.[9] Yet, even 40 years and 70% PR are arbitrary end dates. A PV-system owner has no reason to retire a PV system while it operates safely and generates a profit. From this perspective, there is no reason why a PV power plant should be retired at all.

In this study, we propose to change the mindset about PV systems operating for a fixed period to systems operating continuously. We introduce an economic steady-state model to support this way of thinking, and we explore how degradation rate, power maintenance, and environmental footprint of PV systems are affected by this change of mindset. We will show that changing our thinking about a PV system to a permanent asset will result in a different evaluation of new technologies. It will increase our valuation of power maintenance, and it will have positive implications for sustainability. We will also introduce a new lifetime metric, the minimum economically sensible lifetime that defines for what period a PV system should at least run and which is based on system efficiency, degradation, and value of produced electricity.

Economic models

Throughout this paper, we will use three economic models to compare and evaluate different aspects of PV systems.

Levelized cost of electricity (LCOE)

The LCOE balances yield and cost of a PV system over its lifetime.[10,11] It is calculated as the discounted quotient of the two via

$$LCOE = \frac{\sum_{t=0}^{N} c(t)(1+r)^{-t}}{\sum_{t=0}^{N} EY_0(1-deg)^{t}(1+r)^{-t}} \qquad \text{(Equation 1)}$$

[1]FZ Jülich, Helmholtz-Institut Erlangen-Nürnberg for Renewable Energies, Immerwahrstraße 2, 91058 Erlangen, Germany

[2]Institute of Materials for Electronics and Energy Technology (i-MEET), Department of Materials Science and Engineering, Friedrich-Alexander University Erlangen-Nürnberg, 91058 Erlangen, Germany

[3]First Solar, 350 W Washington St, Suite 600, Tempe, AZ 85281, USA

[4]Lead contact

*Correspondence: im.peters@fz-juelich.de
https://doi.org/10.1016/j.joule.2021.10.019

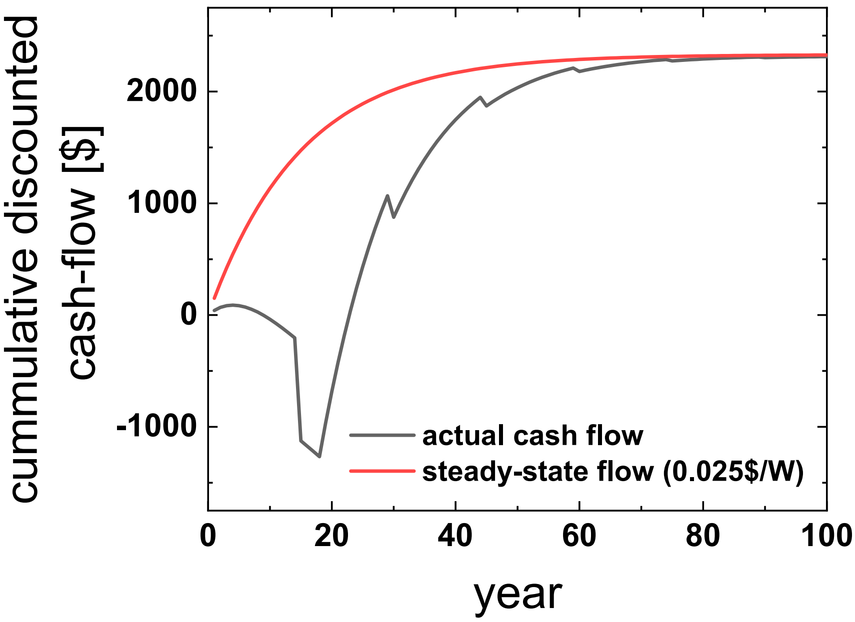

Figure 2. Cumulative cash flow in the steady-state model

The black line shows the actual cumulative cash flow year by year for a small, fictional PV system with regular inverter replacement every 15 years. The red line exemplifies the meaning of the steady-state value *SV*. Per definition (Equation 3) the red and the black curve converge toward the same value. The significance of *SV* is that it describes this convergence with a single number—an equivalent, constant (before discount) annual payment, which we use as a figure of merit for the steady-state model. In the shown example, *SV* is 0.025$/W.

With N being the lifetime of the system (30 years), $c(t)$ the time-series of cost due to installation and power maintenance, which include loan interest payment, r the discount rate (the default value we use is 6.9%, corresponding to the equity discount rate (real) taken from[12]), $EY_0$the energy yield of the system in year zero, and *deg* the degradation rate. Note that year one power losses are not included if a constant degradation rate is used. EY_0 is calculated from module harvesting efficiency and specific yield. Values in brackets are used by default; deviations from this value will be mentioned. In the model used for calculations here, we assume that the system is financed by a loan with 4.8% interest rate, which is paid back with a constant rate over 18 years.[13] LCOE is typically given in cent per kWh, and it marks the cost of electricity for a system that reaches a net present value (*NPV*) of 0 at the end of its life. As a cost metric, LCOE assigns a minimum monetary value to electricity in the sense that the returns generated by the system equal those defined by the discount rate. System operators will attempt to sell electricity at a price above LCOE.

Discounted cash flow model

In the discounted cash flow analysis, income and expenses for a PV system are balanced, here on a once-per-year basis. Consistent with LCOE, we use a net present value approach, i.e., values in future years are discounted with constant discount rate r. Income is generated by electricity sold at a constant price p_{el}. A constant price was chosen for simplicity; in power purchase agreements (PPAs), price escalators are common. Electricity production reduces each year due to degradation with constant rate *deg*. Costs are generated by paying back a loan to finance system installation as specified earlier, in addition to yearly operation costs and inverter replacement in year 15. Balance for subsequent years are added, and a final balance, the $NPV(N)$ is obtained at the end of the system lifetime (30 years).

$$NPV(N) = \sum_{t=0}^{N} \left[EY_0 (1 - deg)^t \cdot p_{el} - c(t) \right] \cdot (1+r)^{-t} \qquad \text{(Equation 2)}$$

The cash-flow model is equivalent to the LCOE model if $NPV(N) = 0$. In practice, cash flow models are used to calculate the economic performance of a PV system in an environment with given electricity sales prices. This price can change over time; in the examples discussed here, we will use a constant price for simplicity's sake. The net present value specifies whether the system provides sufficient returns to investors. A positive *NPV* means that the returns are above those defined by the discount rate.

Steady-state model

Common to the LCOE and the discounted cash flow model is the requirement of a finite and arbitrary system lifetime. Moreover, the system lifetime is a factor with significant impact on LCOE, or end-of-life balance. In the steady-state model, the system is run indefinitely. Steady-state operation can be characterized by a constant steady-state value *SV* that comprises all income and expenses. One way to calculate the steady-state balance is by solving the following equation:

$$\lim_{N \to \infty} \left[\sum_{t=0}^{N} SV \cdot (1+r)^{-t} \stackrel{!}{=} \sum_{t=0}^{N} EY_0 (1 - deg)^t (1+r)^{-t} \cdot p_{el} - c(t)(1+r)^{-t} \right] \qquad \text{(Equation 3)}$$

For a system generating sufficient returns, *SV* has a constant, positive value for all relevant degradation rates and discount rates. *SV* can be interpreted as the value of a constant annuity that delivers the same NPV as the detailed discounted cash flow analysis (see Figure 2). Although, on a first glance, Equation 3 might look similar to being just a limit of Equation 2, there are some more important differences behind it. The main motivation for this model is to allow exploring a mode of operation in which a PV system is run continuously. The change in mindset that continuous operation requires is a transition from focusing on recovering an initial investment, to maximizing profit by managing degrading components.

We introduce the steady-state model as a way to explore commercial PV systems that have the potential for a long lifetime. Under the right circumstances, ground-based-, roof-based-, floating- or agro-PV installations could be operated for many decades. Installations in which lifetime is limited by other considerations, such as, for example, vehicle integrated PV, some façade-integrated PV elements, PV integrated in consumer electronics, in the internet of things (IoT), or in clothes, have different life cycles and value propositions. Specific economic models for each business case are needed for an appropriate evaluation of different technologies.

RESULTS

Stability/performance tradeoffs

In a first exercise, we explore the tradeoffs between degradation rate and two module properties, efficiency and module cost, in the three economic models for a utility PV installation. For this purpose, we co-vary the two parameters such that the cost metrics (LCOE, net present value *NPV*, and steady-state balance *SV*) remain constant. For the cash flow and steady-state models, an electricity price of 10 cents per kWh is used. Results are shown in Figure 3. Table 1 summarizes the results for an improvement in degradation rates according to SunShot 2030 goals.

In Figures 3A and 3C we show the tradeoff between degradation rate and efficiency. The scenario modeled here is as follows: Given is a utility PV installation with a given

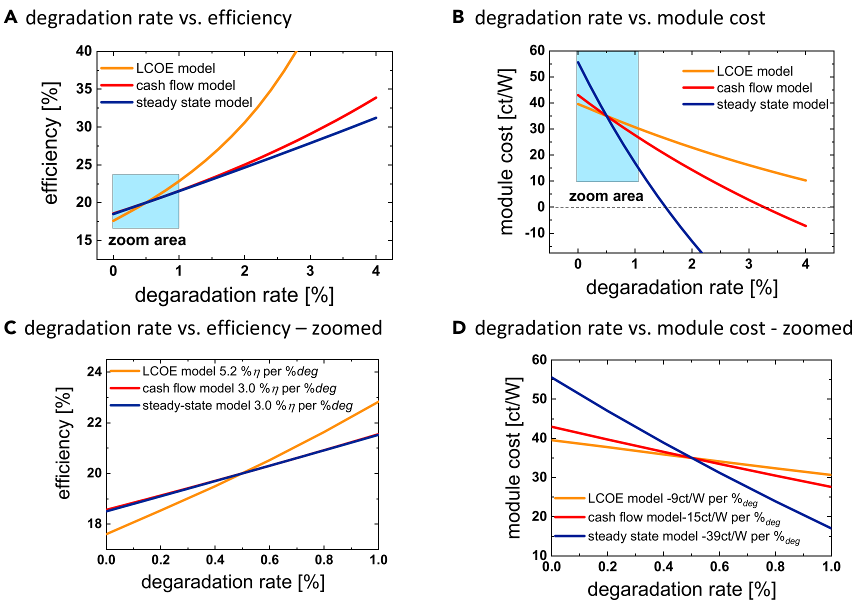

Figure 3. Comparison of constant values for the figures of merit in each model

(A) Tradeoffs between efficiency and degradation rate for the three cost models. The reference case is a system with module efficiency of 20% and a degradation rate of 0.5% annually. The LCOE of this exemplary system would be 3.3 ct/kWh when operated in Kansas City.

(B) Tradeoffs between degradation rate and module cost. The reference module cost in this case is 35 ct/W.

(C and D) Same as (A and B) in the range of 0 to 1% annual degradation. Also given are the linearly approximated slopes in this region

number of modules. In this installation, all modules are replaced by modules of a different degradation rate. Consequently, the installation will produce a different yield and hence will have a different economic performance. To balance the change in economic performance, the efficiency of the modules are also changed. The change in efficiency again affects yield, but it has implications on the installation costs, too. Because the installation now has a different power rating, the number of inverters and the capacity of the used cables need to be adjusted. Considering these effects, we numerically adjust efficiency until the economic performance is the same as that of the initial installation. Results depend on the choice of system cost parameters (see Table 2 for details) but are independent of specific yield.

Of the three used cost models, LCOE is most sensitive to tradeoffs between degradation rate and efficiency. As a change in module efficiency affects LCOE in both numerator and denominator, there is a non-linear contribution to the resulting iso-LCOE curve. This means that high degradation rates make it very difficult to lower the cost of electricity, or conversely, that improving solar cell and PV module stability are essential for lowering it further. In the cash flow- and steady-state models, non-linear contributions are weaker. Of the two, the steady-state model is slightly less sensitive to the

Table 1. Efficiency and module cost entitlement for the example mentioned earlier if the SunShot 2030 utility target of reducing annual degradation rates from 0.5% to 0.2% are achieved

	Efficiency entitlement	Module cost entitlement
LCOE	−1.6%	0.03$/W
Cash flow	−0.9%	0.05$/W
Steady state	−0.9%	0.12$/W

Table 2. Parameters used to model a rooftop PV installation in Germany and a utility installation in Phoenix, AZ

Parameter	Values Erlangen[14]	Values Phoenix[15,16]
Module cost	700€/kWp	350 $/kWp[16]
Inverter cost	230€/kWp	40 $ / kWp
Module installation	200€/kWp	150 /kWp
Other bos cost	570€/kWp	510$/kWp
Electricity value	0.3€/kWh	0.1 $/kWh
Specific yield	1,113 kWh/kWp	1,900 kWh/kWp
Inverter replacement	15 years	15 years

Module replacement cost is calculated as module cost + module installation cost.

efficiency/degradation rate tradeoff. Differences become visible only for large degradation rates (Figure 3A). The slope of either curve depends, among other factors, on the discount rate and the value of electricity. The slope is greater when discount rates are smaller and the electricity value is smaller. A sensitivity analysis for the given example gives an increase in slope of just below 0.4% relative if either factor is scaled down 1% relative. In practice, this means that a system owner can use PV modules that are a little less stable, provided they compensate this detriment with higher efficiency, especially if the system has a limited lifetime, discount rates are high, and/or the value of electricity is high. These boundary conditions define opportunities for new solar cell technologies for which it may be easier to match and exceed state-of-the-art efficiencies than to match degradation rates.[17]

The tradeoff between degradation rate and efficiency to achieve a certain cost metric can also be portrayed as an efficiency entitlement for a certain improvement in module stability. We show this entitlement in table I for stability improvements suggested by the SunShot 2030 targets for utility installations.[18] The shown values represent the allowable efficiency deficit if the annual degradation rate changes from 0.5% to 0.2%.

In a similar way as described earlier, tradeoffs between degradation rate and module costs were calculated (Figures 3B and 3D). When considering module costs, improving degradation rates result in a cost entitlement for PV modules. This entitlement is greatest for the steady-state scenario, smaller for the cash flow scenario and has the smallest impact on LCOE. In the steady-state model, degradation reduces revenue for an infinite time, whereas lower module costs only reduce the initial investment, which is a comparably small fraction of the entire capital involved. This argument also holds for the discounted cash flow model, although the limited lifetime also limits the lifetime revenue of the system; hence, the impact of degradation is smaller. As an example, we give the cost entitlement for all three models for a utility PV installation operated in Kansas city and p_{el} = 10ct/kWh in Table 1.

A similar argument holds for the cash-flow model, but as system lifetime is limited to 30 years, the overall reduction in total earnings due to degradation is smaller. For system owners, the message here is clear: buying less-stable modules, even if they are cheaper, is almost certainly not a good idea, especially if you plan to run your system for a long time. In the LCOE model, the effect is softened as a lower value is assigned to electricity, and a reduced production due to higher degradation results in smaller economic losses. To achieve a principally lower cost of PV electricity, it is within limits possible to compensate higher degradation rates with lower module costs.

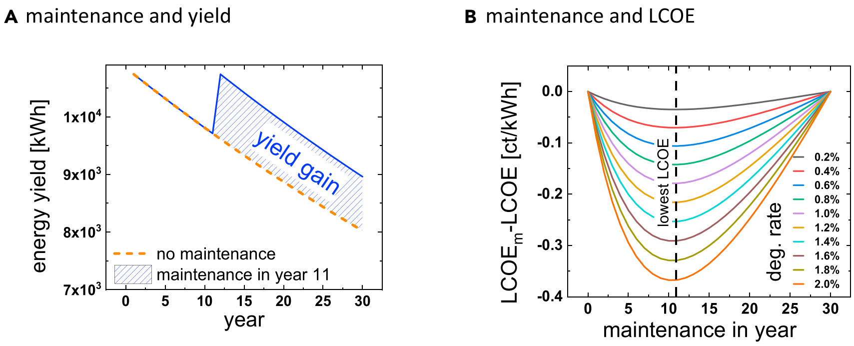

Figure 4. Introducing maintenance
Energy yield with and without power maintenance in year eleven (left). LCOE difference for a system with and without power maintenance as a function of the time of maintenance and the degradation rate of the system.

The results shown here require us to revisit some statements made in.[19] In this study, we already explored the relation between LCOE, efficiency and degradation rate and concluded that compensating inferior degradation rate with superior efficiency was very challenging. This statement remains valid if the goal is to reduce electricity production costs, i.e., LCOE. To reduce LCOE, e.g., to approach the values defined in the SunShot 2030 scenario,[18] achieving low degradation rates is key. Yet, when it comes to matching the net present value of an existing PV technology, the impact of degradation is smaller, particularly in situations in which discount rates are high and system lifetime is limited.

Power maintenance

In all considered economic models, system performance degrades over time with a constant rate *deg* that reduces energy yield. The term power maintenance refers to any action that restores power to the PV installation and includes module replacement, and module or system repairs. To explore the techno-economic characteristics of power maintenance, we devised a two-step scenario. In the first step, we restore energy yield of the considered PV system in year n to the original yield EY_0 and monitor the changes in the corresponding cost metric in comparison with a system that operates without restoring yield. In this first step, no cost is assigned to restoring yield. In the second step, we calculate the maximum allowable cost of restoration, also called restoration value v_R, by finding the cost value, which results in the cost metric of the system with restoration being equal to that without.

Levelized cost of electricity (LCOE)

LCOE of a system with power maintenance is calculated via

$$LCOE_M = \frac{\sum_{t=0}^{N} c(t)(1+r)^{-t} + c_m(n)(1+r)^{-n}}{\sum_{t=0}^{n-1} EY_0(1-deg)^t(1+r)^{-t} + \sum_{t=0}^{N-n} EY_0(1-deg)^t(1+r)^{-(t+n)}}$$
(Equation 4)

with maintenance cost c_m added in year n. Figure 4 shows the yield/time function with and without restoration (left) and the impact of power maintenance on LCOE as a function of n and for different degradation rates for $c_m = 0$.

The most opportune time for power maintenance for the explored system in the LCOE picture is in year 11. At this point, the balance between power lost and power restored is greatest. This conclusion is independent of the degradation rate. It

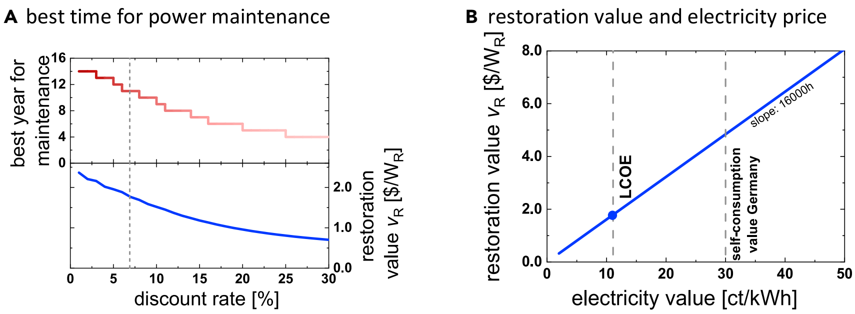

Figure 5. Impact of discount rate and electricity value

(A) How discount rate influences the ideal time for power maintenance (upper half) and the restoration value v_R (lower half) in a discounted cash flow model for a rooftop PV system in Germany. The discount rate used *in* this study is 6.9%.

(B) Restoration value v_R as a function of the electricity price p_{el}. Vertical lines indicate the calculated LCOE for the exemplary system and the self-consumption value for electricity in a German household.

depends on the discount rate and changes if degradation rates are not constant. For a non-constant degradation rate, the most opportune moment shifts toward occurrences of high degradation.

The value of power maintenance is calculated by finding the value of c_m that results in the same LCOE as the system without power maintenance-

$$LCOE_M(c_m) \stackrel{!}{=} LCOE \quad \text{(Equation 5)}$$

This relation is solved numerically. From the result, the restoration value v_R in $/W is calculated via

$$v_R = \frac{c_m}{(1-(1-\deg)^n)\cdot cap} \quad \text{(Equation 6)}$$

with *cap* being the system nominal capacity.

Discounted cash flow model

Consistent with the LCOE model, we introduce power maintenance by intervening in year *n* to restore yield to its original value and add maintenance cost c_m in the same year.

$$NPV_M(N) = p_{el}\cdot\left(\sum_{t=0}^{n-1} EY_0(1-deg)^t(1+r)^{-t} + \sum_{t=0}^{N-n} EY_0(1-deg)^t(1+r)^{-(t+n)}\right)$$
$$-\sum_{t=0}^{N} c(t)(1+r)^{-t} + c_m(n)(1+r)^{-n} \quad \text{(Equation 7)}$$

The value of power maintenance is again obtained by the condition that the net present value with and without power maintenance is equal

$$NPV_M(N, c_m) \stackrel{!}{=} NPV(N) \quad \text{(Equation 8)}$$

The restoration value is calculated as discussed before (Equation 6). Note that the restoration value remains the same if only a part of the yield is restored. A first finding when comparing the cash flow and LCOE models is that the optimum time for power maintenance remains the same. Figure 5A shows the best time for power maintenance as a function of discount rate. For small discount rates, a single maintenance event is most profitable at half the system lifetime. As discount rate increases, the best time for power maintenance shifts to earlier years. In conjunction with ideal time, also v_R reduces with increasing discount rate.

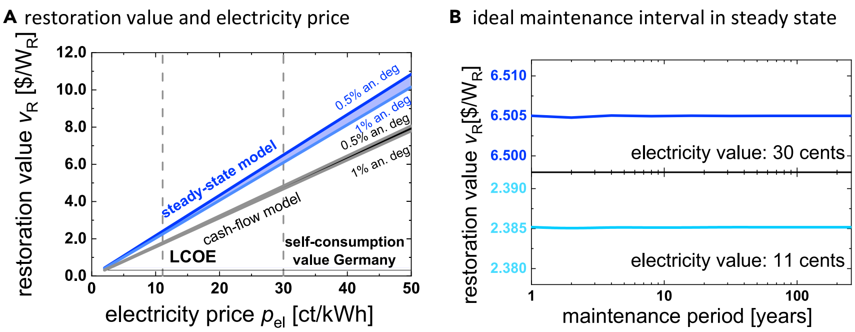

Figure 6. Value and ideal timing of maintenance in the steady-state model

Restoration value as a function of electricity price (left) for the steady-state model (blue) and the cash-flow model (gray). Also, in the steady-state model, there is a 1:1 correspondence between electricity price and restoration value; yet, this value is higher than the value obtained from the cash-flow model. Restoration value as a function of maintenance period (right).

Figure 5B shows the restoration value as a function of electricity price. We find a linear relation between v_R and p_{el} with a system specific scaling time, here 16,000 h or 1.8 years. We note that the amount of money that can be spent on power maintenance depends 1:1 on what value is attributed to the generated electricity. For a rooftop system in Germany used to generate for self-consumption, the value of electricity is comparably high—approx. 30 ct/kWh. The LCOE of the same system, i.e., the value at which the system breaks even at end of life, is approx. 11ct/kWh. Utility-scale solar projects in China and India today operate at between 2 and 4 ct/kWh,[20] illustrating that there is a good order of magnitude in range in how much different players can spend on power maintenance.

Overall, the magnitude of the restoration value shown in Figures 5B and 6A may appear high. There are various reasons for that. First, the exemplary system is a small rooftop installation with a relatively high installation cost to begin with—2.58$/W. Second, v_R may exceed the installation cost, if the value for electricity is significantly higher than LCOE; in the example in Figure 5A, v_R exceed the installation costs for $p_{el} > 16$ct/kWh. Third, the mental anchor for PV systems is linked to system costs. Because power maintenance acts primarily on lifetime revenue, not on costs, this anchor is misleading.

Steady-state model

In principle, power maintenance in the steady-state model is treated in the same way as in the cash-flow model. In the spirit of transitioning to a long-term perspective, power maintenance is now not considered as a single event any more but as a repeating event with a fixed maintenance period. Hence, instead of restoring yield to the original value in year n, year is now restored every n years, and the corresponding costc_m is applied to the system with the same interval.

$$EY(t) = EY_0(1-deg)^{t_n},\ t_n = t \bmod n \quad \text{(Equation 9)}$$

$$c_m(t) = \begin{cases} c_m, & t = k \cdot n \quad k \in \mathbb{N} \\ 0, & else \end{cases} \quad \text{(Equation 10)}$$

The value of power maintenance is given if c_m is chosen such that SV is the same as for a system without power maintenance (i.e., n = ∞) would.

$$SV(c_{m,n}) \stackrel{!}{=} SV(c_{m,\infty}) \quad \text{(Equation 11)}$$

The restoration value is calculated as previously given in Equation 6. Some noteworthy things happen with the transition to the long-term perspective. A first observation is that more money can be spent on power maintenance when using steady-state thinking than when applying the discounted cash flow or the LCOE model. We show this in Figure 6A. Compared with a system with a 30-year lifetime, the restoration value in the steady-state model is consistently about 1/3 higher than in the cash-flow model, regardless of the electricity price. We also observe that the degradation rate has a stronger influence on restoration value. We will discuss this aspect later. A second observation, which is illustrated in Figure 6B, is that the restoration value is (almost) independent of the maintenance period. In steady-state thinking, there is no particular optimum maintenance time as there is when the system lifetime is fixed. Power maintenance should be completed whenever damage occurs and sending a maintenance team is worthwhile.

The minimum economically useful lifetime

The definition of a restoration value and a steady-state model for module operation allow defining the commercially useful lifetime of a PV module. Module replacement pays off once module power has reduced by a relative value equal to one minus the ratio of replacement cost c_R to restoration value.

$$\frac{yd_N}{yd_0} = 1 - \frac{c_R}{v_R} \quad \text{(Equation 12)}$$

Using a constant annual degradation rate, the minimum economically useful lifetime (*MEL*) becomes

$$MEL = \frac{Log\left(1 - \frac{c_R}{v_R}\right)}{Log(1 - deg)} \quad \text{(Equation 13)}$$

MEL specifies the time at which replacing modules becomes economically superior to not replacing them. The two main factors influencing *MEL* are the degradation rate and the discount rate. Higher degradation rates reduce *MEL* values, and higher discount rates increase it. In Figure 7, we show the performance ratio at which module replacement starts to be economically sensible on the left and on the right the corresponding *MEL*, assuming a constant annual degradation for two different example scenarios. The upper half shows a rooftop system in Germany producing for self-consumption, the lower half a commercial utility system in Arizona. Cost parameters for these scenarios are given in the table further on. Following an analysis by Jordan, the median degradation rate for PV modules over a wide variety of measurements was 0.9% annually.[8] Using this value and a 6.9% discount rate,[14] the *MEL*, i.e., the time that the modules in these systems should at least be operated for, of the rooftop system in Germany is 25 years, that of the utility system in Arizona 24 years. Also, note that this calculation currently assumes no price learning, i.e., modules are replaced at the same $/W value that they originally had.

Price reductions of PV modules reduce the MEL. If modules get cheaper, replacing old modules becomes economically attractive earlier. The relation between MEL and the annual price-learning rate is plotted in Figure 8 again for the rooftop system in Erlangen and a utility installation in Arizona. Note that incentives effectively work similar to price reductions and also reduce MEL. Other than in Figure 7, here an annual degradation rate of 0.5% was used.

In addition to MEL, in this figure we also plot the economically ideal lifetime. This lifetime was calculated numerically and marks the year in which module replacement

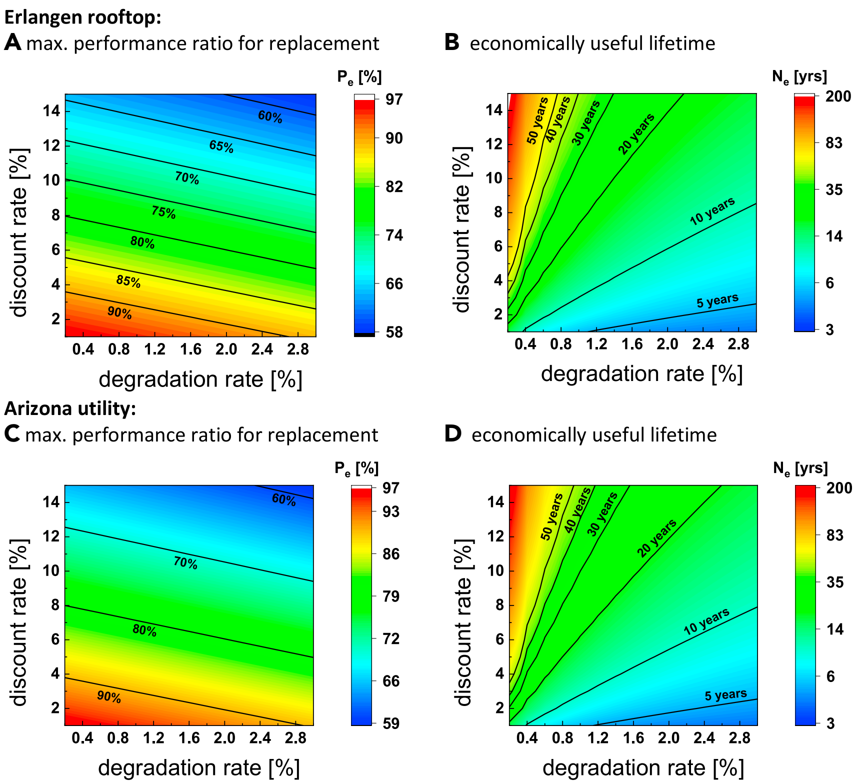

Figure 7. Threshold performance and MEL for a rooftop installation in Erlangen (top) and a utility installation in Arizona (bottom)

(A and C) Performance ratio at which module replacement is economically sensible.

(B and D) Corresponding MEL assuming a constant degradation rate. Two cases are portrayed, the upper half (A and B) show a rooftop system in Germany producing for self-consumption, the lower half a utility system in Arizona (C and D). Parameters are given in Table 2.

provides the greatest economic advantage over not replacing them. The ideal lifetime will strongly depend on which cost reductions will be realized in the future. Historical cost-reduction rates in the last 50 years have been around 10%[21] annually. Continuing this learning rate for the next 25 years would reduce MEL to 12 years and the ideal lifetime to just below 25 years. Although, a continued 10% learning rate would also mean that the price for PV installations in 2050 would fall to less than five percent of their current value. A more conservative projection foresees a PV-system price development with a 50% reduction in 2050 compared with 2020,[22] which corresponds to a learning rate of approx. 2.5%. In such a scenario, the economically ideal lifetime would increase to 35 years. Lower degradation rates additionally increase MEL. Realizing the SunShot target of 0.2% annual degradation further increases the ideal lifetime to 50 years.

The simple models we have used here do not distinguish between replacement of a single module or a great number of them. In practice, replacement costs per module depend on the number of modules replaced, and it will be cheaper to replace a greater number—c_R. is a function of the replaced capacity.

Implications for sustainability

Improving degradation rates

Degradation rates strongly affect MEL as they determine when the threshold performance is reached at which replacement becomes economically interesting. The

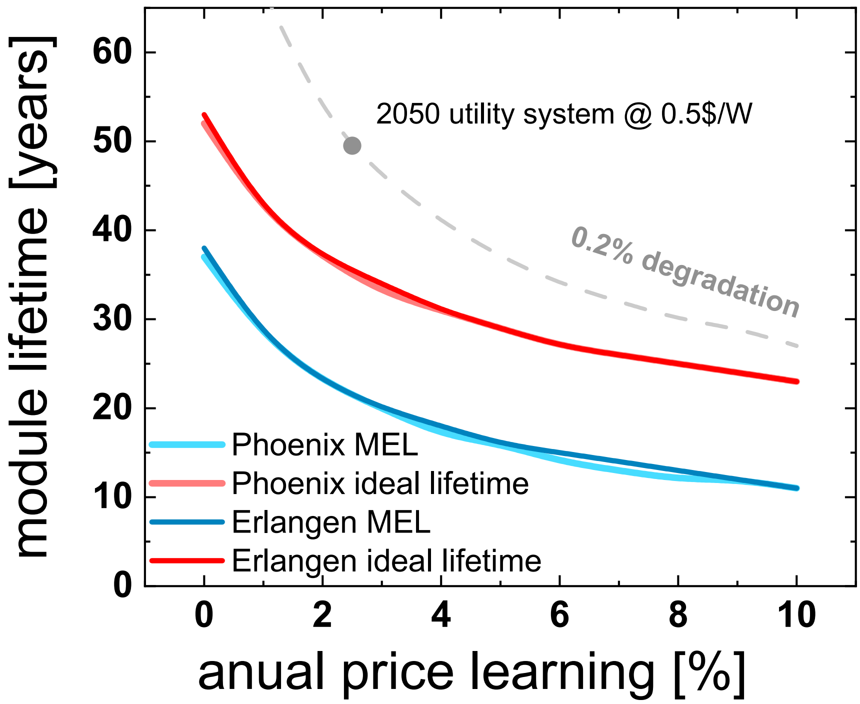

Figure 8. Cost reduction and lifetime

Minimum economically useful lifetime (MEL) plotted in blue and economically ideal lifetime plotted in red for a utility installation in Phoenix, AZ and a rooftop installation in Erlangen, Germany, as a function of cost-reduction rate. The used annual degradation rate here is 0.5%; results for a value of 0.2% are plotted in gray.

relation between degradation rate and yield generated by the time MEL is reached is shown in Figure 9A. An annual price-learning rate of 2.5% was used for this calculation. Yield was arbitrarily normalized to a system with 0.5% annual degradation. The normalization results in this curve being very similar across many different systems—we calculated it for both the rooftop system in Erlangen and the utility system in Arizona and found differences of around 1% relative. The normalization also largely removes the influence of discount rates.

Using this curve, we explored how changes in degradation rates influence MEL and yield at MEL (Figure 9B). For this purpose, we calculated multipliers for the case that the degradation rate changes from deg1 to deg2. The lower right triangle corresponds to stability improvements, the upper right triangle to deteriorations. Since lifetime is determined by a threshold performance reduction, the multipliers for lifetime and for yield are almost identical. As example cases, we show two scenarios, one in which degradation rates are improved from 1% to 0.5% annually (gray) and one with an improvement from 0.5% to 0.2% annually (black). The corresponding multipliers are 1.52 and 1.69; the latter factor corresponds to the SunShot 2030 goal for utility PV installations.[18,23] Provided lifetime is determined by a threshold performance, the multipliers depend very little on the specific choice of lifetime metric. Improved stability should imply extended field times and Figure 9B shows how to quantify this effect.

The combination of reduced degradation rates and increased lifetime results in higher lifetime electricity production, which is a common variable in sustainability metrics, such as carbon or water footprint, or energy return on investment (EROI). For example, EROI is defined as[24]:

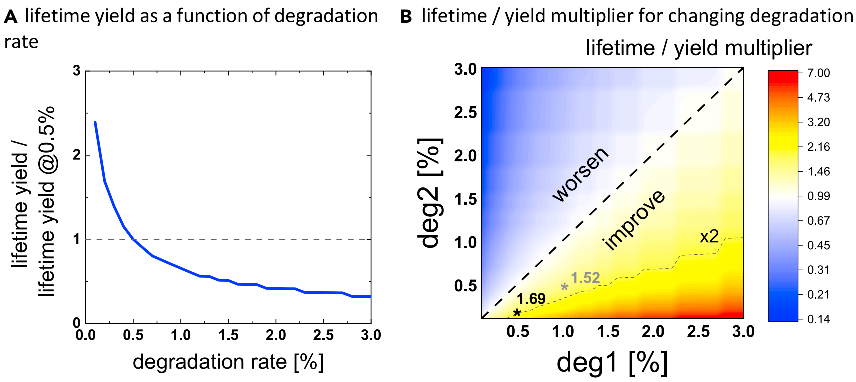

Figure 9. MEL as a function of degradation rate

(A) Yield of a module at MEL (MEL yield) as a function of degradation rate and normalized to the value at 0.5% annual degradation.

(B) Lifetime/yield multiplier when degradation rate is changed from deg1 to deg2. The two dots mark two improvement scenarios—reducing degradation from 1% annually to 0.5% (gray) and from 0.5% to 0.2% (black), the two lines mark conditions for a multiplier of two and four.

$$EROI_{PE_{eq}} = \frac{EY}{\eta_g \cdot Inv} \quad \text{(Equation 14)}$$

where PE_{eq} is primary energy equivalent, EY is lifetime electricity yield, η_g is the life-cycle grid efficiency where the system is deployed, and Inv is the life-cycle energy demand to build, operate, and dismantle the system.

By increasing lifetime electricity production by a factor of 1.69 in the examples mentioned earlier, the PV-system EROI would scale accordingly, resulting in greater net renewable energy delivered to the grid. $EROI_{PE_{eq}}$ values of ~10–60 were found ranging from mono-c-Si PV systems in low irradiation locations to thin film CdTe PV systems in high-irradiation locations.[25] Increasing lifetime electricity production by a factor of 1.69, $EROI_{PE_{eq}}$ values above 100 may be achievable for PV systems in high-irradiation locations.

Implications for material usage and recycling

Large-scale PV installations are a relatively young development. Global cumulative installations have gone up by about one order of magnitude in one decade.[26] Transitioning to carbon-free energy production will require comparable growth rates for the next two decades or more. Such a growth will keep the average age of the installed PV fleet low; a growth rate of 27.5%, as we had it in the last years,[21] results is an average fleet age of 13.2 years. During this growth phase, system lifetimes of 20 to 25 years are sufficient to push questions about recycling and material efficiency back. The initial goal is to reach the multiple ten-TW of capacity[27] required for the energy transition with all the resources this requires. Once sufficient capacity is installed and the growth slows down, the system lifetime will play a decisive role in determining the resources needed for maintaining the PV infrastructure.

Figure 10 shows an exemplary estimate of the rate of replacement (upper part) and cumulative probability of loss (lower part) for modules with a lifetime of 25 and 42 years. The latter lifetime corresponds to the multiplication factor of 1.69 taken from Figure 9. The end-of-life distributions were modeled according to results from IRENA/IEA PVPS,[24] using a Weibull distribution with a shape factor of 5.4, corresponding to the regular-loss scenario. Using these numbers, the onset of module replacement (1% probability of loss) is shifted back by nine years, and peak annual loss probabilities are reduced

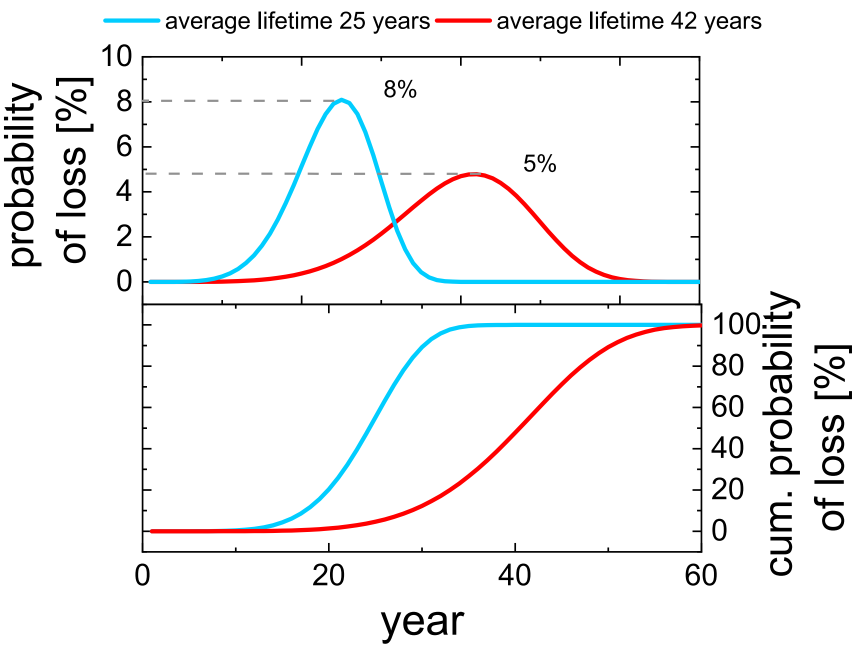

Figure 10. Probability of PV module loss

Based on 25- and 42-year average lifetime (top) and cumulative probabilities of loss obtained with Weibull distributions with shape factors of 5.4[23] (bottom).

by 40% relative from 8% to 5%, scaling again with the same 1.69 factor. Peak loss probabilities are an indicator for the resources required to maintain PV capacity at a given level. Reducing these numbers by 40% signifies, for example, that the required recycling capacity (facilities, material, energy, ...) is 40% smaller. Hence, improving module life will give us more time to develop the needed recycling infrastructure, and it will reduce the number of resources required for recycling. Given that modules installed today will likely live into the post-growth phase of PVs, extending system lifetime and reducing degradation rates are tasks to be solved now.

DISCUSSION

Adopting a long-term perspective for PV systems has implications on the priorities for technical performance of PV modules, system maintenance, and sustainability of the PV energy infrastructure. In this study, we used three types of techno-economic models to explore these changes.

The first is an LCOE model. LCOE is a metric to determine the cost of electricity, i.e., the minimum price at which electricity has to be sold for the system to generate sufficient returns over its assumed lifetime. LCOE models are useful to explore how innovation in PV enables lower electricity prices. The first model we contrast LCOE with is a discounted cash flow model. The discounted cash flow model illustrates a system owner's perspective for a PV system with finite lifetime. The discounted cash flow model balances all expenses and all income. A major difference between LCOE and the discounted cash flow model is that electricity is assigned a monetary value. In the LCOE model, this figure is a result; in the discounted cash flow model, it is an input. For a PV system with *NPV* above zero at the end of its designated life, the discounted cash flow model values electricity higher than the LCOE model. As the third model, we introduce a steady-state model. The steady-state model is similar to the discounted cash flow model with two alterations: the system lifetime is without end and power maintenance occurs at regular intervals.

Importance of degradation rate for system design

Different models rate priorities of module parameters differently. When looking at the tradeoffs between degradation rate and efficiency, we find that LCOE is more sensitive than the steady-state and discounted cash flow model, with the former having a higher sensitivity than the latter due to the long-term perspective. Improving degradation rates is therefore most important to reduce the cost of electricity principally but slightly less in order to achieve a certain net present value—provided a product with greater efficiency is available. In any of the three models, compensating lower stability with higher efficiency is only possible within limits and achieving high levels of or further improving stability should be a priority for any manufacturer.

Looking at the tradeoffs between degradation rate and module cost, we find that inferior stability can only be balanced by significantly lower module costs. This trend is least distinct for LCOE and most distinct in the steady-state model. In the shown example for the latter case, a module with greater than 1.5% annual degradation should not even be accepted free of charge. The reason for this strong sensitivity is that greater degradation in the steady-state model will reduce yield for a long time and the loss in value quickly reaches an amount similar to the value of the module. In other words, more stable modules are usually to be preferred even at a higher price. For example, improving degradation rates from 0.5% to 0.2% annually results in a price entitlement of between 0.03$/W (LCOE) and 0.12$/W (steady state) for a utility PV installation.

Valuation of power maintenance

In all three models, we define the value of power maintenance (called restoration value) as the amount of money that can be spent to restore power such that each cost metric remains unchanged. The restoration value scales with the value of electricity; hence, in a discounted cash flow model for a PV system with *NPV* above zero at the end of its designated life, power maintenance is valued higher than in an LCOE model. Moreover, how much money can be spent on power maintenance depends on how and where the system is operated. The owner of a rooftop system in Germany used for self-consumption can spend significantly more on power maintenance than the owner of a utility PV installation in China or the US. Power maintenance is also valued higher for longer system life; hence, the steady-state model values power maintenance the highest of all models. The amount that can be spent on restoring 1W of power is about 1/3 higher in the long-term view than for a system with a 30-year lifetime.

Maybe even more significant is what each model tells about the ideal time for power maintenance. For a constant degradation rate, the two models with finite system lifetime produce an ideal time for power maintenance at about half the system lifetime, shifted forward the greater the assumed discount rate is. For a discount rate of 6.9%, the best time for power maintenance in a system with a 30-year lifetime is after 11 years. On the other hand, in the steady-state model, there is no ideal time for power maintenance. The same amount of money can be spent on restoring 1W of power, no matter when. The exact amount depends on system cost, discount rate, and degradation rate and can be as high as 6$/$W_R$ for a rooftop installation in Germany. We take this result to mean that plans for PV-system operation should take a long-term perspective, because only then power maintenance is properly valued. Keeping a PV system in good shape to generate revenue for a very long time is the economically (and ecologically) better strategy.

Minimum economically useful lifetime

The steady-state model allows defining a system lifetime that is based on techno-economic performance. In the steady-state model, there is a time at which the value of maintaining the system equals the replacement costs. After this time, which we termed as MEL, replacing modules with new ones of equal properties will result in an increase in revenue. MEL depends on the discount rate, degradation rate, system cost, value of electricity, and the price-learning rate of the PV industry. Hence, MEL mixes external and internal factors of the module. External factors are the value of electricity (at least in an infrastructure not dominated by PV) and discount rates, and internal factors are module cost, efficiency, and degradation rate. The cost-reduction rate is a mixed factor that is determined by external, as well as internal factors. As is the case often in techno-economic calculations, MEL is per trend more sensitive to external factors than to internal ones. Exemplary calculations for a rooftop system in Erlangen and a utility system in Phoenix, AZ place MEL at around 25 years. Although this duration coincides with typical warranty lengths, note that it is a minimum lifetime, and longer operation is economically and ecologically preferable. When estimating the economically ideal lifetime, we find that a module with 0.5% annual degradation should be operated for 35 years and a module with 0.2% degradation for 50 years.

Degradation rate and sustainability

Lowering degradation rates will unfold their main impact on sustainability in the post-growth phase of PVs. Degradation affects the lifetime of a PV system, and the lifetime affects the rate of replacement. The extent to which reducing degradation increases lifetime depends on the cost reductions realized by the PV industry. Projecting the cost of a PV system in 2050 to be 0.5$/W, reducing degradation rates from 0.5% annually to 0.2% will scale lifetime by a factor of 1.69. Increasing module lifetime by this factor will reduce energy, resources, and facilities needed to recycle PV modules by the same factor and will defer the need for recycling facilities to be available by a decade. It will also mean that PV systems could reach EROI values above 100. As PV systems installed today will reach this phase, improving stability is a task to be pursued now and not when multiple TWs worth of panels are installed.

EXPERIMENTAL PROCEDURES

Resource availability

Lead contact

Further information and requests for resources and materials should be directed to and will be fulfilled by the lead contact Ian Marius Peters (im.peters@fz-juelich.de).

Materials availability

This study did not generate new unique materials.

Data and code availability

All data used in this paper is publicly available and links are provided in the references. Mathematical procedures are completely described. The authors are happy to share their implemented versions for the calculations shown in this paper. Please address requests to im.peters@fz-juelich.de.

ACKNOWLEDGMENTS

This work was supported by the Bavarian State Government (project "PV-Tera - Reliable and cost-efficient photovoltaic power generation on the Terawatt scale," no. 44-6521a/20/5).

AUTHOR CONTRIBUTIONS

Conceptualization, methodology, validation, investigation, and resources, I.M.P., J.H., C.B., and P.S.; writing – original draft, I.M.P.; writing – review and editing, I.M.P.; visualization, I.M.P. and P.S. All authors reviewed and approved the manuscript.

DECLARATION OF INTERESTS

P.S. works for First Solar, a US-based manufacturer of solar panels and a provider of utility-scale PV power plants and supporting services that include finance, construction, maintenance, and end-of-life panel recycling.

Received: July 22, 2021
Revised: September 3, 2021
Accepted: October 26, 2021
Published: November 19, 2021

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