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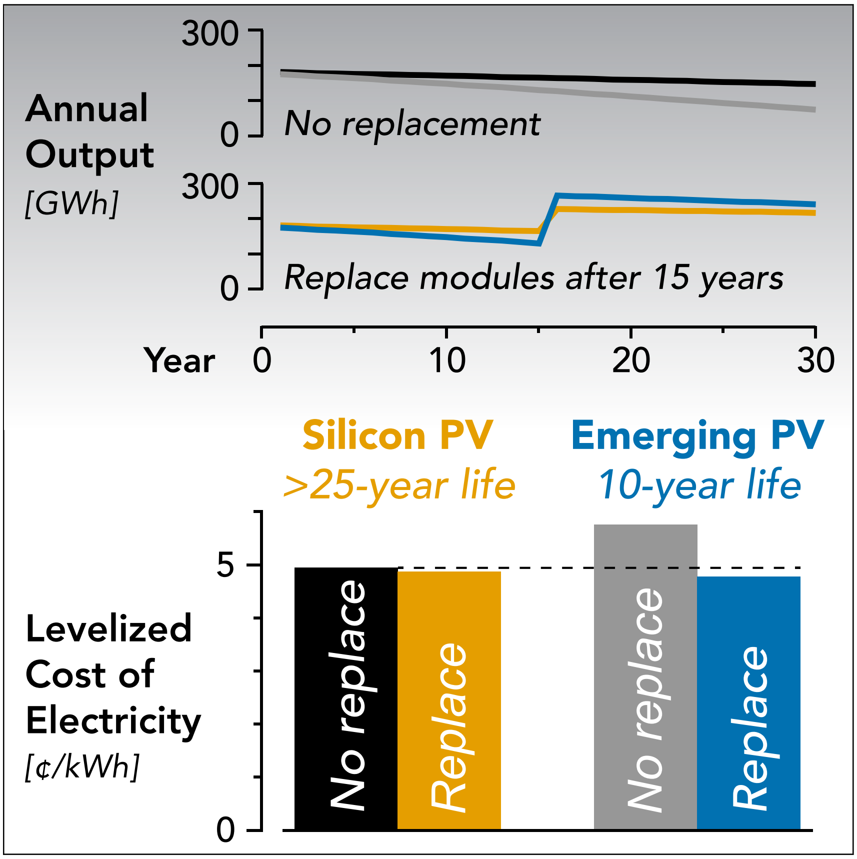
Accelerating Photovoltaic Market Entry with Module Replacement



This work highlights an opportunity for emerging high-potential solar photovoltaic (PV) technologies to enter the market sooner than expected. PV modules are conventionally required to operate with minimal degradation for 25 years or more. We evaluate a PV system operating strategy that anticipates periodic replacement of all modules. Shorter-lived modules are later replaced with higher-performing, longer-lived modules, leading in many cases to a competitive levelized cost of electricity (LCOE).

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HIGHLIGHTS

Periodic module replacement reduces initial lifetime requirements for PV modules

Emerging PV technologies with <15-year initial life can reach a competitive LCOE

Module replacement is most valuable when non-module costs dominate the system cost

Continued technology improvement is critical for realizing replacement benefits

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Accelerating Photovoltaic Market Entry with Module Replacement

Joel Jean,[1,2,4,5,*] Michael Woodhouse,[3] and Vladimir Bulović[1]

SUMMARY

Today's approach to deploying solar photovoltaics (PV) implicitly assumes that module technology is fixed. Solar panels are installed and expected to operate for the system life of 30 years or more. However, many PV technologies are improving rapidly along several dimensions, including cost, power conversion efficiency, and reliability. Periodic module replacement or planned repowering takes advantage of this technological improvement and counteracts predictable degradation. Here, we show that a module replacement strategy allows a competitive levelized cost of electricity to be achieved with an initial module lifetime of less than 15 years, assuming backward compatibility with the original system design. We also assess the life-cycle environmental impacts of module replacement and find that all commercial PV technologies offer benefits in the majority of impact categories, regardless of the replacement strategy, compared to today's electric generation mix. Module replacement can thus accelerate the market introduction and decarbonization impact of emerging PV technologies that have achieved a competitive module efficiency (≥20%), cost (≤\$0.30/W), and lifetime (≥10 years) and have the potential to improve further on all three metrics but lack decades-long field deployment experience.

INTRODUCTION

Mitigating climate change will require terawatt-scale deployment of solar photovoltaics (PV) and other low-carbon electric power technologies.[1–7] The International Energy Agency targets a 2030 global PV generation of 2,732 TWh/year,[8] corresponding to an annual investment of over \$135 B assuming an average cost of 5 ¢/kWh. Reducing the cost of mitigating climate change thus requires reducing the cost of solar electricity.

The levelized cost of electricity (LCOE) is the most widely used metric for comparing the cost of different power generation technologies.[9–12] Even though LCOE is an imperfect metric—it fails to account for dispatchability[13] and is insufficient on its own to guide real-world investment decisions—it remains a simple and leading metric for the cost-competitiveness of PV generation: all else equal, a technology with a lower LCOE is a more viable technology.

There are four major technological levers for reducing the LCOE of solar PV: reduce upfront system cost (consisting of module and balance of system [BOS]), reduce cost of capital, increase energy yield, or extend system life. PV cell and module technology can influence each of these levers (Table 1). For example, a new PV absorber material, cell design, or module format can reduce module and BOS costs, increase energy yield, or increase lifetime. In the case of new absorbers, however, the path to market is challenging: the expected future cost advantages are outweighed by

Context & Scale

Electricity costs from solar photovoltaics (PV) have dropped by a factor of 10 in the past decade, largely due to module cost reductions. Further gains will require continued innovation in financing, efficiency, and module cost. One promising route is through emerging technologies such as metal halide perovskites, especially in tandem structures; for any new technology, however, proving multi-decade lifetimes is a major challenge. We find that replacing modules periodically can allow technologies with short initial lifetimes to achieve competitive costs. Enabling replacement strategies will require further work on new designs, operating procedures, and financing options. Scaling up module recycling is critical for realizing carbon mitigation benefits without substituting other environmental harm. For policymakers and industry players, module replacement presents an opportunity to maintain low costs while supporting the near-term deployment of high-potential PV technologies.

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Table 1. Key Technological Levers for Reducing the LCOE of Solar PV

Economic Lever		PV Technology Goal
Reduce system cost ($/W)	reduce module production cost	reduce raw materials cost and usage
		increase process throughput
		reduce energy and labor requirements
		reduce factory capex
	reduce BOS cost	increase cell and module efficiency
		develop module formats for low-cost installation
Reduce cost of capital (%)		validate performance under real-world conditions
Increase energy yield (kWh/kW)		increase real-world cell and module power output
Increase system lifetime (year)		reduce cell and module degradation rate

relatively high initial degradation rates, which reduces the modeled 25-year energy yield and system lifetime, and by the lack of outdoor performance data, which increases the cost of capital. As a result, new technologies are often deemed unbankable, at least until decades of data have been accumulated. Thus, the 25-year lifetime requirement for PV modules—itself a product of historical circumstance rather than technoeconomic need—contributes to technology lock-in, hindering the market entry of promising new PV technologies.

The conventional design life of a PV system is dictated by the module degradation rate, and installed modules are removed only upon acute failure or at the end of the system life. This operating strategy makes sense in the historical context of PV: modules have traditionally comprised the majority of the system cost, and the dominant c-Si technology is engineered to operate reliably for decades.[14] It follows that reducing LCOE further means extending system and module lifetimes to 30 or more years.[12,15] For many PV systems today, however, module hardware and installation constitute only a small fraction of the total cost.[7,16] In this BOS-heavy cost structure—which, despite substantial commercial effort, is likely to persist for the foreseeable future—we hypothesize that a 25-year module lifetime is not strictly necessary. Shorter-lived modules can be replaced one or more times during the system life at a low cost, given that most of the BOS infrastructure is already in place.

Here, we propose a periodic module replacement strategy that counteracts degradation and allows new modules with <15-year initial lifetimes to compete effectively on LCOE with today's 25-year modules. The economics of this strategy benefit from the inexorable march of technological progress, which makes modules increasingly affordable, efficient, and reliable (Figure 1). Replacing old modules—even today's long-lived commercial panels—with more efficient and reliable new modules can upgrade a system's peak capacity significantly. For example, assuming a practical PCE limit of 25%, a system with 19.1% efficient modules today could be upgraded in 15 years with 23.9% modules—a 25% increase in installed direct-current (DC) capacity even without accounting for degradation.

This analysis explicitly does not compare the economics of replacing modules in an existing system versus building a new PV system in the future. The latter would

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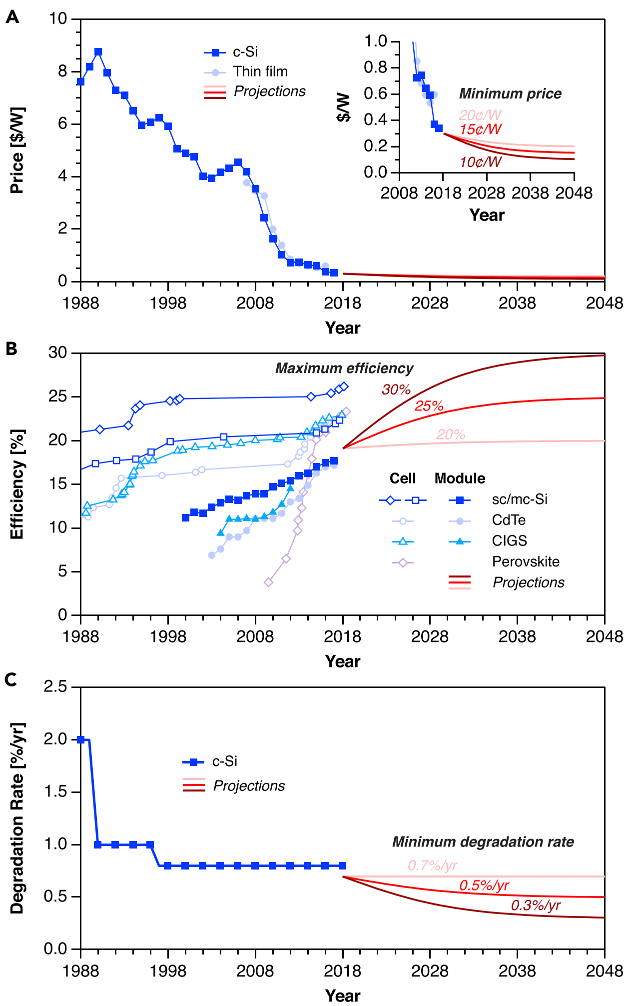

Figure 1. Evolution of Price, PCE, and Degradation Rate for Various PV Technologies

Historical data and three potential future sigmoidal trajectories for each parameter are shown.

(A) Module price trends for c-Si and thin-film modules.[50,51]

(B) Record cell and typical module efficiencies for single- and multi-crystalline silicon (sc/mc-Si), cadmium telluride (CdTe), copper indium gallium (di)selenide (CIGS), and perovskites.[51–56]

(C) Module degradation rates based on historical warranties for c-Si modules (converted to T80 lifetime or the time to reach 80% of the initial efficiency).[57]

require us to accurately predict the future evolution of BOS costs, a much more uncertain endeavor than predicting rough trends for future module cost and performance, which have improved consistently for decades. Furthermore, planning to build a new system in the future fails to accelerate and de-risk the market entry of emerging PV technologies—the primary goal of a module replacement strategy. Here, we focus on the economics of a single PV system to determine whether it may be favorable to plan ahead today for module replacement in the future.

RESULTS

Technoeconomic Modeling of Module Replacement Using US PV System Benchmarks

To analyze the LCOE impact of module replacement, we developed custom spreadsheet and Python-based cash-flow LCOE models (see Supplemental Experimental

Procedures). Input parameters are chosen based on 2018 NREL benchmarks for US PV systems and consultation with PV industry representatives (see Experimental Procedures and Table S1).[16] We model a 100 MW tracking utility-scale system, a 200 kW commercial system, and a 6 kW residential system in Kansas City, Missouri, representing the US-average annual insolation (1,430–1,870 kWh/kW/year energy yield). A discount rate of 6.3% for utility-scale and 6.9% for commercial and residential systems is assumed.[16] Example system cost and performance data over a 30-year analysis period are shown in Figure 2.

Our model inputs deviate from the NREL benchmarks in several regards. Instead of the benchmark US module price of $0.47/W, we use $0.30/W—more representative of the global multi-crystalline silicon module spot price.[16,17] Upfront system costs are then $0.96/W for utility, $1.66/W for commercial, and $2.53/W for residential. To account for different module efficiencies, we scale area-dependent BOS costs—including structural BOS; engineering, procurement, and construction (EPC) overhead; developer overhead; installation labor; and land acquisition, which add up to 25%–45% of the system cost—by the ratio of the benchmark efficiency (19.1%) and the assumed efficiency. Other BOS costs—including supply chain costs, electrical BOS, permitting, interconnection, taxes, contingencies, and profits—are not affected by module efficiency. The investment tax credit (ITC) and other incentives are omitted to improve generalizability, although we evaluate a representative utility-scale system in Phoenix, Arizona (1,750–2,350 kWh/kW/year) with a 30% ITC to reflect current deployment trends. The relative impact of module replacement on LCOE is independent of local insolation.

We model the future evolution of module price, efficiency, and degradation rate with default growth parameters representing typical multi-crystalline silicon (mc-Si) modules, as shown in Figure 1.[16] Module price—cost from the developer's perspective—is assumed to decline logistically from $0.30/W toward a cost floor of $0.15/W. Average efficiencies increase logistically from 19.1% toward a maximum practical value of 25%. Linear degradation rates decrease logistically from 0.70%/year (corresponding to a 29-year T80 lifetime) toward a minimum value of 0.30%/year (67-year lifetime). We vary these initial values and growth rate parameters to analyze the LCOE impact for different PV technologies. Limiting parameter values and modeling assumptions are discussed further in the Experimental Procedures.

Aside from the upfront module cost, two additional cost components are important determinants of the environmental impact and economic feasibility of a module replacement strategy—module recycling and module-specific installation labor costs.

Used modules can be reused, recycled, or landfilled. Module reuse can produce positive salvage values and is becoming increasingly common, with used modules selling at roughly 70% of the market price of new modules (e.g., $0.20/W in the EU spot market in 2019).[17,18] However, the majority of modules will likely be decommissioned at end-of-life rather than reused.

Landfill disposal is common for commercial PV modules today, with reported costs ranging from <$0.01/W for crystalline silicon (c-Si) and copper indium gallium (di) selenide (CIGS) to $0.08/W for cadmium telluride (CdTe)[19] and potentially higher for modules treated as hazardous waste.[20] The low cost advantage may be outweighed by the potential environmental impact of landfilling large volumes of end-of-life panels.

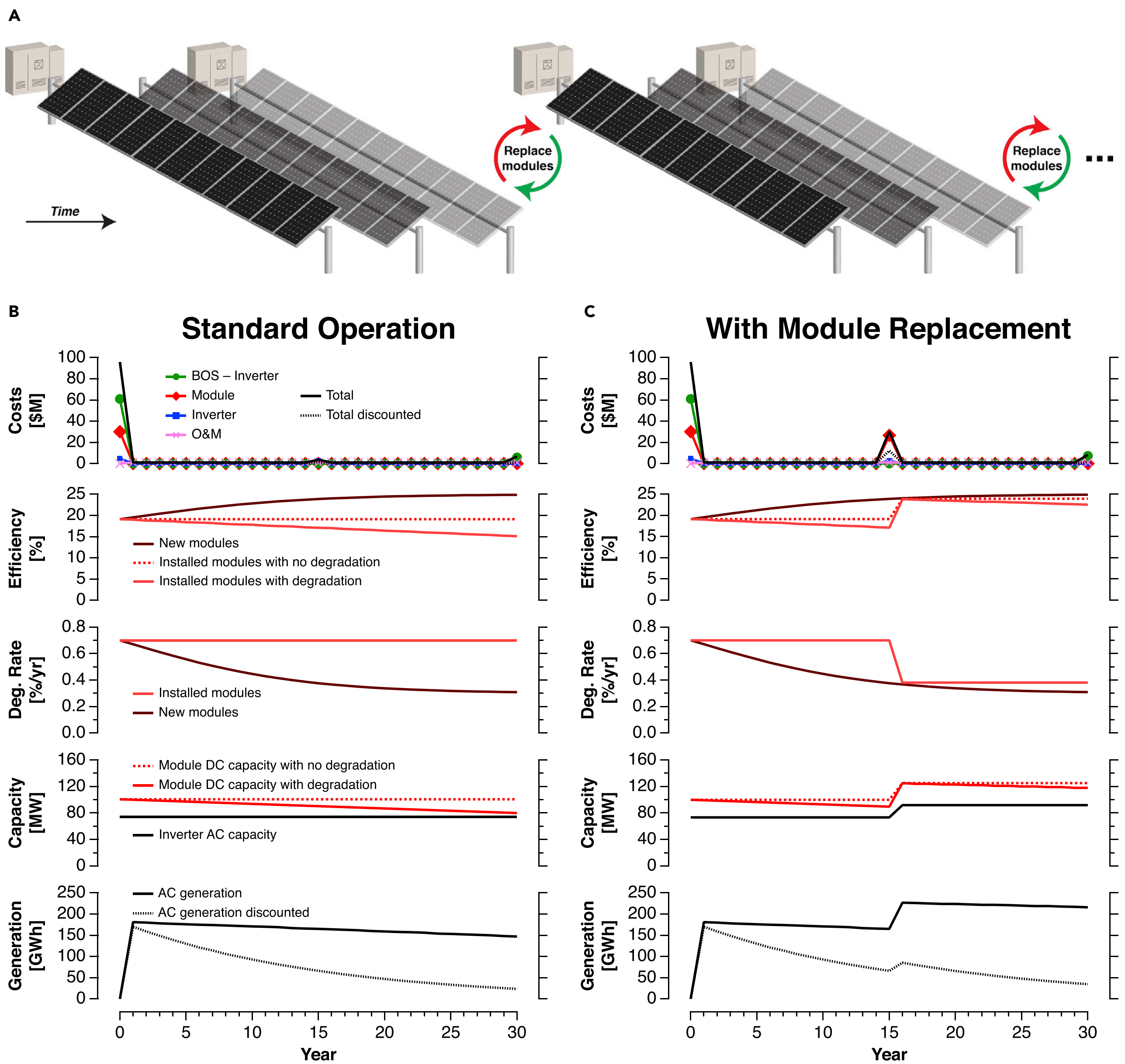

Figure 2. PV System Operation with Module Replacement

(A) Schematic of periodic module replacement.

(B) Time series data for a 100 MW utility-scale system employing a standard operating strategy with no module replacement. Year 0 is the time of initial installation. Module costs include module-related labor. Operation and maintenance (O&M) costs are incurred in every non-zero year. The PCE and degradation rate of newly manufactured modules improves toward limiting values of 25% and 0.3%/year, respectively. Degradation reduces the installed PCE and DC capacity, leading to a linear decline in alternating-current (AC) output. Discounting of the AC generation is required for calculations but has no physical significance.

(C) Time series data for the same system employing a module replacement strategy with a single replacement event at year 15. The installed DC capacity increases by 25% and degrades more slowly after module replacement, producing a higher AC output in years 16–30. The inverter is also upgraded to limit clipping losses.

See Table S1 for input parameters.

Recycling is the safest and most sustainable way to dispose of solar panels. Today's c-Si and thin-film modules are over 90% and 98%, respectively, composed of non-hazardous glass, polymers, and aluminum, with cumulative recovery yields exceeding 85% of the total module mass.[18] While volumes are low today, the PV recycling industry is expected to expand significantly in the next 10–15 years due to the projected growth in annual end-of-life module waste. Reported net recycling costs vary widely between PV technologies and between sources. Negative costs (profits) are possible because of recovery of glass, aluminum, and other materials—for example, in 2010, McDonald and Pearce estimated net recycling costs of $6.69, –$21.38, and $24.57 per module for glass-glass CdTe, CIGS, and c-Si modules, respectively—equal to $0.03/W, −$0.11/W, and $0.12/W, assuming a 20% module efficiency.[19,21] More recent anecdotal evidence suggests module-recycling costs of $0.03/W to $0.06/W. Here, we assume that all used modules are recycled at a conservatively high cost of $0.08/W, the average of the reported net recycling costs for CdTe and c-Si. Our analysis assumes a pay-as-you-go recycling model—the same financing model used by First Solar—whereby recycling is financed through later-year project cash flows rather than upfront funding.

Importantly, the labor cost for installing and replacing modules is only a miniscule fraction of the total system cost.[22] We use a typical breakdown of the total labor cost—50% structural and 50% electrical—where module installation accounts for one-seventh of structural labor and inverter installation accounts for one-tenth of electrical labor.

Our models were validated using four independent LCOE calculators[23–26] and NREL's System Advisor Model (SAM) software.[27] LCOE results without module replacement exactly match all of the online calculators and are 9%, 14%, and 12% higher than the US utility, commercial, and residential benchmarks calculated using SAM.[28] The discrepancy between our models and SAM arises largely from the latter's incorporation of debt financing, sales tax, and accelerated depreciation. These factors are not expected to substantially affect the LCOE difference with and without module replacement, so we omit them for the sake of generalizability.

Module Replacement Enables Competitive LCOE with Higher Initial Degradation Rates

For commercially available c-Si, CdTe, or CIGS modules—represented by the initial performance parameters and improvement rates described above—module replacement produces only modest LCOE savings. Figure 3 shows how LCOE depends on the module replacement period and initial degradation rate. Moving to the left from the no-replacement baseline corresponds to replacing modules more frequently. Moving from no replacement to 15-year replacement yields a 1.2% reduction in LCOE for utility-scale systems, 4.6% for commercial systems, and 8.9% for residential systems.

Despite the limited potential for LCOE savings, module replacement allows identical LCOEs to be achieved with higher initial degradation rates (e.g., over 1%/year for a limiting module efficiency of 25% and over 2%/year for a limiting efficiency of 30%). This increased design flexibility could enable lower-cost modules by relaxing initial reliability requirements for novel substrates, encapsulants, interconnects, and other components. We note that reliability still matters—all else equal, reducing the degradation rate always reduces LCOE, and modules must pass standard qualification tests to be accepted by project developers and banks. However, planned replacement may alleviate the need to engineer modules for 30 or more years of outdoor performance.

The exact timing and frequency of module replacement is not critical (Figure 3). For today's modules, the optimal replacement period is 15 years in all system types, with residential systems benefiting most due to the high BOS cost fraction, as we discuss

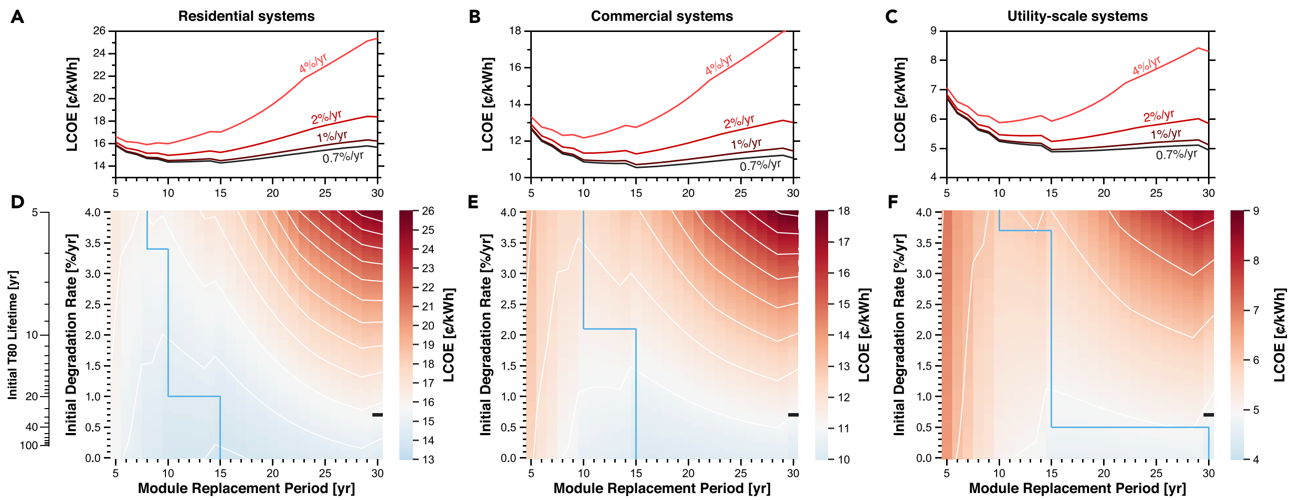

Figure 3. Impact of Module Replacement on LCOE for Different Initial Degradation Rates

LCOE optimization versus module replacement period for selected initial degradation rates for (A) residential, (B) commercial, and (C) utility-scale PV systems. LCOE heatmaps as a function of initial degradation rate and replacement period for (D) residential, (E) commercial, and (F) utility-scale systems. We assume improving module cost (decreasing from \$0.30/W toward \$0.15/W), efficiency (increasing from 19.1% to 25%), and degradation rate (decreasing from varying initial values to 0.3%/year). Initial degradation rates range from 0 (infinite lifetime) to 4%/year (5-year T80 lifetime). Module replacement periods range from 5 years (i.e., 5 replacement events during the system life) to 30 years (no replacement). Replacement periods yielding the lowest LCOE for each initial degradation rate are marked with blue lines. Baseline cases without replacement (\$0.30/W, 19.1%, and 0.7%/year) are marked with black rectangles.

further below. Less reliable modules benefit from more frequent replacement. For example, a hypothetical module with the same efficiency and cost as a modern c-Si module but an initial degradation rate of 2%/year (10-year T80 lifetime) has an optimal replacement period of 10 years in residential systems, yielding a 19% reduction in LCOE from the no-replacement case and a 5% reduction from the baseline c-Si (0.7%/year) no-replacement case. This strategy thus allows short-lived modules to achieve a competitive LCOE.

To evaluate the sensitivity of LCOE results to key input parameters, we vary each parameter around its default value while holding other parameters constant (Figure 4). LCOE is naturally most sensitive to upfront module and BOS costs, capacity factor, and discount rate—for example, increasing the annual energy output or decreasing the degree to which the value of future generation is discounted reduces the levelized cost. Other key parameters include initial and maximum module efficiencies, the analysis period, and the replacement period. We find that the LCOE is relatively insensitive to the module recycling cost.

Figures 3 and 4 indicate that periodic module replacement produces sharply diminishing returns to improvements in the module degradation rate, making LCOE insensitive to both the initial and minimum rates. For example, assuming a 15-year replacement period and an initial degradation rate of 0.7%/year, varying the minimum rate from 0.6%/year to 0%/year reduces LCOE by less than 2% for a utility-scale system. This effect makes shorter-lived modules relatively more competitive with long-lived commercial modules.

Shorter-Lived Emerging Technologies Become More Competitive with Module Replacement

For emerging PV technologies such as perovskites, module replacement may enable competitive LCOEs despite short initial lifetimes, assuming module cost and

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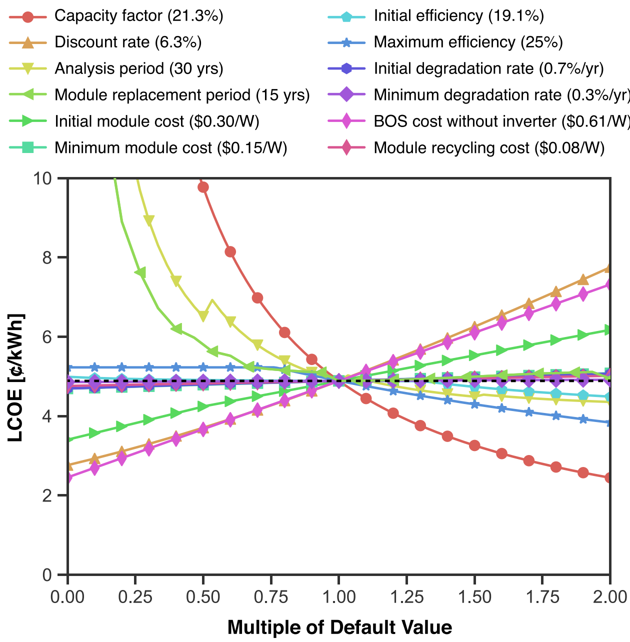

Figure 4. Sensitivity of LCOE to Key Input Parameters

Data are for a US utility-scale PV system in Kansas City, MO, with a default module replacement period of 15 years. Default parameter values are shown in parentheses. The default LCOE (4.885 cents/kWh) is marked with a dashed line.

performance continue to improve. Figure 5 compares the LCOE with and without module replacement for 3 technologies: a standard commercial module (e.g., c-Si, CdTe, or CIGS), a hypothetical low-cost commercial module, and a hypothetical high-efficiency emerging PV module. Each technology's future module price, efficiency, and degradation rate follows a distinct trajectory. For example, the emerging technology has a high efficiency potential of 32% but starts with a very high degradation rate of 2%/year (10-year T80 lifetime), representative of a new technology such as a perovskite-based tandem cell.[29–31] Here, we specifically choose to explore a scenario where a new PV technology has a fundamental cost-per-watt and efficiency advantage over today's commercial technologies, leading to a faster rate of decline in module price and increase in efficiency due to the sigmoidal form assumed for technology improvement.

We note that present degradation and failure rates for emerging PV technologies are highly uncertain. For example, cell-level stability tests have demonstrated T80 lifetimes exceeding 1,000 h for a variety of high-efficiency perovskite PV architectures, but the paucity of long-term outdoor test data on full-size encapsulated modules makes the module degradation rate trajectory shown in Figure 5 purely speculative. That said, many PV technologies have historically achieved degradation rates of well below 2%/year and approaching 0.5%/year,[14] which suggests that new technologies may achieve comparable degradation rates through sustained research and development (R&D) efforts.

Without module replacement, the emerging PV LCOE is 15%–16% higher than the standard PV LCOE for all system types. With module replacement every 15 years, however, the emerging PV LCOE becomes highly competitive with the standard PV LCOE (1%–2% lower). Importantly, the more efficient emerging technology reaches an ultimate steady-state LCOE without replacement that is 5% (residential

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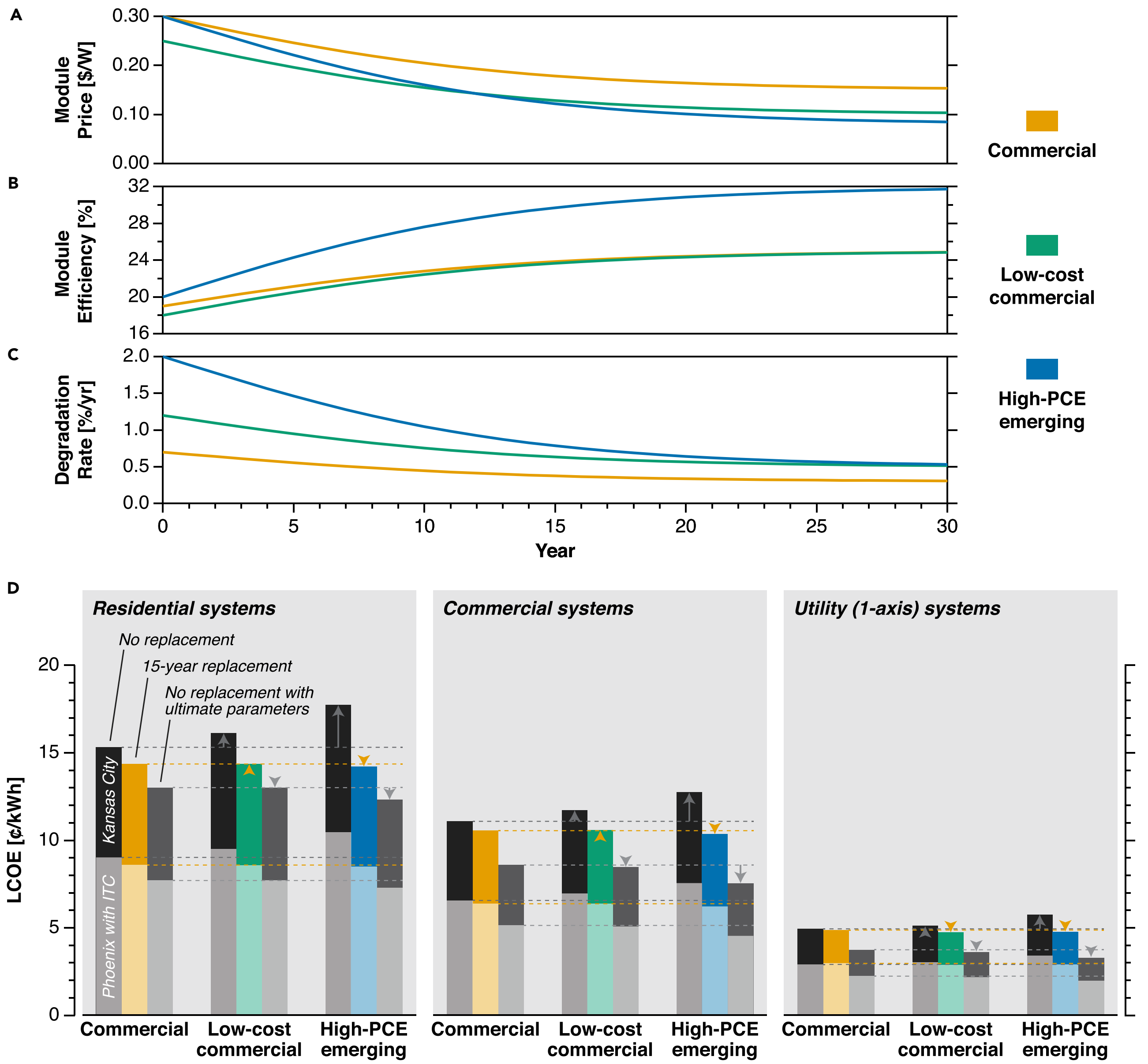

Figure 5. Module Replacement for Emerging PV Technologies

(A) Projected evolution of new module price per watt toward minimum sustainable values for a representative commercial module (silicon or thin film), a hypothetical low-cost version of a commercial module (e.g., c-Si with lower-cost encapsulation, framing, and glass), and a hypothetical high-efficiency emerging PV module (e.g., perovskite-perovskite, perovskite-silicon, or perovskite-CIGS tandem).

(B) Evolution of module efficiency.

(C) Evolution of module degradation rate. Emerging technologies are assumed to start at a high degradation rate of 2%/year, decreasing toward 0.5%/year with improvements in material engineering, stack design, and module packaging.

(D) Calculated LCOE for different system and module types without module replacement (black), with 15-year module replacement (colors), and without module replacement assuming initial module cost and performance equal to the ultimate values in (A)–(C) (gray). BOS costs vary with initial efficiency but are otherwise constant between module technologies. Results are shown for PV systems in Kansas City, MO, with no ITC and Phoenix, AZ, with a 30% ITC.

systems) to 12% (commercial and utility-scale systems) lower than that of the conventional technology. In this context, module replacement is a market entry strategy for new PV technologies with a high efficiency ceiling and low cost floor but lacking a proven 25-year lifetime.

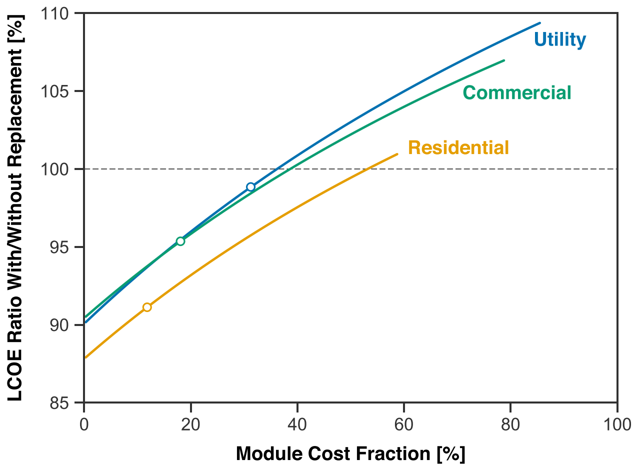

Figure 6. Sensitivity of LCOE with Module Replacement to the Module Cost Contribution
The ratio shown is the LCOE with module replacement every 15 years divided by the LCOE without replacement. The module fraction of the system cost is varied by sweeping non-inverter BOS costs while holding module and inverter costs constant at the 2018 US benchmark values for utility-scale, commercial, and residential PV systems. Open circles represent current benchmark BOS costs. See also Figure S2.

The LCOE impact of module replacement depends largely on the fraction of the system cost attributable to modules (Figure 6). The module cost fraction has decreased dramatically over the past decade due to faster reductions in module costs than in soft BOS costs. At $0.30/W, module costs comprise 31%, 18%, and 12% of the total system cost for US utility, commercial, and residential systems, respectively. Assuming the current cost breakdown and the representative technology improvement pathways for commercial modules discussed above, LCOE savings of up to 9% are possible with module replacement. Further reductions in the module hardware and installation costs relative to BOS costs would make replacement schemes more favorable.

We note that this analysis does not consider potential BOS cost savings enabled by high-efficiency emerging PV technologies with lightweight, flexible form factors—such module formats open the door to simplified installation methods (e.g., rapidly unrolling flexible modules) that could reduce the upfront labor and structural BOS as well as the labor required to replace modules. If realized, lower BOS costs would make module replacement less beneficial.

An alternative—and currently mainstream—LCOE-reduction strategy is to reduce degradation rates further from today's already-low values and increase the system lifetime.[3,12,32,33] For example, the US Department of Energy's SunShot 2030 program aims to reduce degradation rates to 0.2%/year and increase system lifetimes to 50 years.[32] To compare these strategies, we consider two 50-year system life scenarios for residential PV systems installed today: (1) no module replacement with 0.2%/year degradation rate (e.g., ultra-reliable c-Si modules) and (2) module replacement every 15 years with 0.7%/year degradation rate improving to 0.3%/year (e.g., typical c-Si modules). The corresponding 50-year LCOEs in Kansas City are 13.6 ¢/kWh and 12.8 ¢/kWh, respectively. In some cases, replacing modules periodically may thus be a more fruitful approach to reducing LCOE—with less R&D effort required—than pushing degradation rates ever lower.

Environmental Impacts of Module Replacement

The proposed strategy may at first glance appear to be an instance of planned obsolescence, whereby products—typically consumer goods—are intentionally designed to quickly fail or become obsolete in order to increase sales. The negative connotations of planned obsolescence indeed apply if manufacturers intentionally reduce the lifetime of today's highly reliable silicon and commercial thin-film modules simply to sell more modules. However, if reducing module lifetime requirements via replacement allows PV manufacturers to employ more abundant and scalable absorber materials, reduce reliability testing expense, or decrease module cost (e.g., by using thinner wafers or less-stringent encapsulation)—all while decreasing LCOE—such a practice can have a net positive environmental and economic impact.

Here, we evaluate the human and environmental health impacts of module replacement, building on previous life cycle assessments (LCAs) for solar PV. LCAs evaluate environmental impacts from cradle to grave—material extraction and processing, module manufacturing (including site preparation and facility construction), recycling of manufacturing waste, transportation, system construction (including BOS hardware), operation and maintenance (O&M), and decommissioning. A 2016 LCA study by the United Nations Environment Programme (UNEP) showed that the life cycle impacts of PV in most categories are substantially lower than those of the current power mix, yielding benefits that increase with time as PV technology improves.[34]

Following the UNEP study, we consider 7 environmental impact categories—metal depletion, freshwater ecotoxicity, land occupation, human toxicity, particulate matter, climate change, and freshwater eutrophication—each evaluated per unit energy and normalized to the impact of the current global average electric generation mix (see Experimental Procedures for category definitions). We calculate the additional life cycle impacts of module replacement for 3 commercial PV technologies—mc-Si, CdTe, and CIGS—by multiplying the portion of the total impact associated with modules, as determined by UNEP, by the number of module replacement events during the system life.[34]

We find that solar PV offers benefits in most environmental impact categories relative to today's electric generation mix, with or without module replacement (Figure 7). This general conclusion holds for all PV technologies and all reasonable replacement strategies. Comparing today's commercial technologies, we observe that module replacement increases the environmental impacts of mc-Si PV substantially more than CdTe or CIGS because of the larger fraction of life cycle impacts attributed to module production for mc-Si.[34] The metal depletion impact of all technologies is very high, largely due to the extensive use of aluminum framing, copper wiring, and steel structural supports as well as the shorter lifetime of PV systems compared to fossil fuel plants. We note that this analysis excludes recycling of modules and BOS components, which likely leads to an overestimation of both overall impacts and additional impacts attributed to module replacement.

A 2016 LCA study on perovskites suggested that a scalable perovskite PV cell architecture and manufacturing process would yield similar life cycle impacts to c-Si.[35] Other emerging thin-film PV technologies such as quantum dots and organics use similar device stacks, materials, and manufacturing processes to perovskites and thus may exhibit similar environmental impacts if they reach comparable efficiencies and lifetimes.

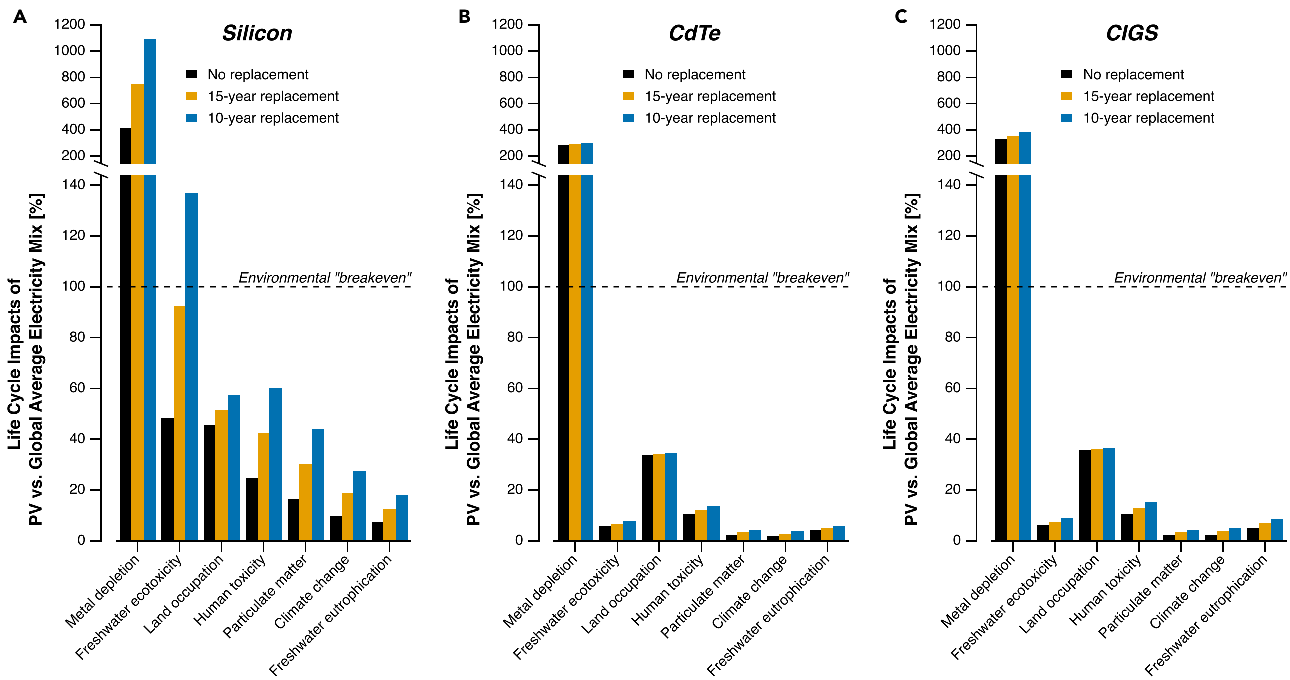

Figure 7. Life Cycle Environmental Impacts of Solar PV with and without Module Replacement

Environmental impacts are normalized to those of the global average electricity mix today. Three PV technologies are shown—(A) mc-Si, (B) CdTe, and (C) CIGS—assuming ground-mount utility-scale deployment. The smaller the bar, the larger is the environmental benefit or the smaller is the harm. The dashed line at 100% represents the environmental ''breakeven'' point, above which the environmental benefits of introducing PV to the generation mix become negative. Black bars represent standard PV system operation (no module replacement), while orange and blue bars represent 15-year replacement (1 event) and 10-year replacement (2 events), respectively.

One key metric for climate mitigation potential and overall sustainability is the energy payback time (EPBT)—the minimum operating period required to recover the total energy invested from manufacturing to disposal. For PV systems, the life cycle energy use is dominated by module manufacturing.[36] As long as the module's EPBT is shorter than the module replacement period, its net energy production is positive. In practice, it is desirable for the EPBT to be much shorter than the replacement period to ensure that the entire system is net positive.

Lower process energy requirements and higher lifetime energy output reduce EPBT, favoring thin films and high-efficiency PV technologies.[37] Current module EPBTs range from ~1 year for c-Si[36,38,39] to <0.5 years for CdTe[36] and perovskite tandems,[37] with substantial variation from the assumed insolation. The shortest optimal replacement period in our analysis is 8 years (for the highest initial degradation rates of over 3%/year)—far longer than the EPBT of all PV technologies. Thus, if a module replacement strategy can increase low-carbon energy generation by making PV more affordable, it is likely favorable from a CO_2 mitigation perspective.

DISCUSSION

Repowering versus Replacement

The concept of ''repowering'' PV systems has been proposed before, typically in reference to upgrading or retrofitting existing systems with improved modules, inverters, or power optimizers. In the more mature wind industry, a similar approach—replacing old wind turbines with taller, higher performance, and more reliable units—has been successfully used to extend the lifespan of proven high-resource sites, reduce ongoing O&M costs, and increase future revenues. However, because the solar resource is not as geographically variable as the wind resource, repowering is not as obvious a proposition. Conventional PV repowering is an operational decision for existing plants, primarily to fix underperforming systems or to extend operation beyond the design life. Consequently, most LCOE calculations account for module replacement only in the context of premature failure—i.e., as a minor O&M cost (<10% of total O&M)[16] incurred when modules fail unexpectedly, which anecdotally occurs at a rate of far less than 0.5% of installed modules per year (for example, First Solar reports a breakage rate of approximately 1% of modules over a 25-year operating life or 0.04%/year).[40]

Here, we propose instead to intentionally incorporate module replacement into the system design, operating plan, and project economics, focusing on enabling the rapid market entry of high-potential emerging PV technologies. Our analysis thus includes standard O&M costs to cover the replacement of individual modules in the event of acute failure as well as additional costs to cover periodic replacement of all modules. We differentiate here between unpredictable failure and predictable degradation: modules with higher median degradation rates may also suffer from higher failure rates, thus increasing annual O&M expenses. However, these rates are not necessarily linked—for example, if they arise from different and independent physical mechanisms, degradation need not precede failure.

Implications for PV System Operation and Financing

The results of this analysis are suggestive rather than definitive. While module replacement can be applied to any PV system regardless of size or location, we do not claim that replacement is always—or even often—economically favorable. When planning for a new PV system, detailed financial modeling should be carried out to evaluate system-specific characteristics—e.g., taxes, incentives, financing strategies, local permitting and grid integration requirements, electricity market structure, inverter type and replacement schedule, module technologies, backward compatibility, and recycling options.

Module replacement may affect the bankability of a PV system, especially before replacement strategies are widely adopted. The use of new technologies (e.g., less reliable or less proven modules) or operational strategies (e.g., module replacement) may increase financing (discount) rates. Because LCOE is highly sensitive to the discount rate, this effect could partially or fully negate the associated LCOE benefits. Furthermore, system owners or financiers would need to set up a reserve account to pay for future replacement, which may add to BOS costs. Such a reserve must be invested carefully to ensure stable returns. Backward compatibility with the existing structural and electrical BOS is a risk that can be partially mitigated with a commitment from manufacturers to make future module designs backward compatible with today's racking systems and with the use of versatile mounting structures to facilitate substitution. We note however that the average lifespan of today's top ten global PV module manufacturers is 17 years, with a range of 9–29 years. Increasing module standardization or mounting versatility may thus be a more promising strategy than counting on a manufacturer to still be in business at the time of replacement (e.g., 10 or 15 years in the future). Taxes, accelerated depreciation, and incentives may also affect the implementation of a replacement strategy, for better or for worse. For example, future investments in module replacement may re-trigger tax benefits, further reducing the LCOE. However, we largely omit such factors because they depend on the project location and may change abruptly with government policy.

The present analysis does not account for minor operational changes that may be needed to integrate and capture the value of increased generation after module replacement. For example, for a utility-scale system, substation and transmission line upgrades and new interconnection agreements may be needed to accommodate a higher peak generation capacity. New power-purchase agreement (PPA) models may also be needed to compensate generators fairly for increased production.

We recognize that most PV system developers are unlikely to choose a new technology over a proven technology without the promise of a clear and substantial economic gain. In the short term, it is likely that only specific market segments that benefit from realized attributes of emerging technologies—e.g., very high efficiency, light weight, or flexibility—will select new technologies over incumbents. In the longer term, emerging PV technologies could realize fundamental advantages over today's technologies—including higher efficiency, improved scalability, and lower module and BOS costs—leading to a lower LCOE floor. Thus, it may also be in the public interest to de-risk new PV technologies by supporting further research, development, demonstration, and deployment—including module replacement if it is needed to reach a competitive LCOE.

Realizing the benefits of a module replacement strategy will require a change in mindset—thinking of the PV module not as a one-time infrastructure investment but as an upgradable technology. We note that this strategy generalizes to other energy generation and storage technologies in which a core value-producing component degrades with time, can be replaced at a low cost, and shows rapid technological progress.

Conclusions

In modern PV systems that are dominated by non-module costs, we find that it is sometimes economically favorable to replace modules periodically with more affordable, efficient, and reliable modules. The key condition is that the efficiency gain over installed modules—accounting for degradation—must be large enough to justify the added cost of replacement. For example, assuming continuous efficiency improvements for a representative c-Si or commercial thin-film technology, periodic replacement with increasingly efficient modules enables a competitive LCOE even with a high initial degradation rate of over 1%/year for a limiting efficiency of 25% and over 2%/year for a limiting efficiency of 30%. Successful implementation of a module replacement strategy may also depend on manufacturers committing to maintain backward compatibility of future module designs with current BOS components.

Our analysis of the module replacement process shows that new PV technologies may not need 25-year lifetimes to enter the market and achieve a competitive LCOE—assuming they have achieved a competitive module efficiency (e.g., $\geq$20%), cost (e.g., $\leq$\$0.30/W), and lifetime (e.g., $\geq$10 years) and have the potential to improve further on all three metrics. This counterintuitive finding highlights a potential opportunity for the near-term market entry of emerging solar technologies that can reach extremely low costs but lack decades of field deployment experience.

EXPERIMENTAL PROCEDURES

LCOE Analysis

Input parameters for 100 MW utility-scale, 200 kW commercial, and 6 kW residential PV systems are summarized in Table S1. For each system type, the annual DC capacity factor (i.e., annual AC output divided by peak DC output) in Kansas City, MO, and Phoenix, AZ, is modeled using NREL's 2017 benchmark SAM model, including one-axis tracking for utility-scale systems. All costs are in 2018 US dollars. For utility-scale plants, we include an end-of-life decommissioning cost of \$0.058/W for removing modules, dismantling equipment, managing waste streams, and restoring the site.[41] Inverter prices are assumed to decrease at a conservative compound annual growth rate (CAGR) of −5% (historical CAGRs from 2010 to 2017 range from −12% to −15%).[16]

Most PV systems today have a larger module (DC) capacity than inverter (AC) capacity to increase inverter utilization and improve system economics.[42,43] This corresponds to an inverter loading (DC-to-AC) ratio (ILR) larger than 1. To calculate the inverter capacity at the time of installation (year 0) and replacement (year 15), we target a typical ILR of 1.3 for utility and 1.15 for commercial and residential systems, using the anticipated average module DC capacity (including degradation) over the upcoming 15-year inverter life.[16] In our model, the ILR can change over time: it decreases as modules degrade and increases when old modules are replaced with more efficient ones (assuming a fixed total area and inverter capacity). The drawback of high ILRs is high clipping losses, which occur at peak sunlight hours when the DC output exceeds the inverter's rated capacity. We consider inverter clipping as an additional variable loss factor, independent of the capacity factor, to correct for the large changes in ILR produced by module replacement. The assumed inverter capacity upgrade at year 15 helps limit clipping losses by anticipating simultaneous or future upgrades in module capacity. Annual clipping losses are calculated from each year's ILR, based on a second-order polynomial fit to literature data (see Figure S1).[42] Clipping losses are low (<5%) in nearly all modeled scenarios.

Future Module Cost and Performance

We assume a specific analytical form (sigmoidal) to model future improvements in module cost, efficiency, and degradation rate. These choices are informed by historical trends in technological progress[44] but are not based on rigorous historical analysis as others have done for module cost.[1,44–46] Our projections nonetheless provide a reasonable forecast of technology progress, and the analysis is not highly sensitive to specific trajectories.

To calculate the module efficiency (η_t) in year t, we assume a sigmoidal trajectory, starting from an initial PCE (η_0) and asymptotically approaching a practical limiting PCE (η_{max}): $\eta_t = \eta_0 + 2(\eta_{max} - \eta_0)\left(\frac{1}{1+exp(-kt)} - \frac{1}{2}\right)$. The absolute rate of improvement depends on the rate parameter k and the difference between the initial and maximum PCEs. Here, we empirically select $k = 0.15$ to reach the limiting performance over ~30 years. We model future module prices and degradation rates using the same formula, substituting a minimum price or rate for the maximum PCE. Following convention, we assume linear efficiency degradation for installed modules (e.g., a 1%/year degradation rate yields a 10% PCE drop over 10 years), although we note that the shape of the degradation curve can vary with technology and affect LCOE.[47]

Limiting values for module cost, efficiency, and degradation rate are informed by literature and fundamental limits. For module cost, the most recent bottom-up cost analysis from NREL suggests a \$0.24/W long-term minimum sustainable price for 23%–27% efficient bifacial c-Si modules.[48] However, we note that c-Si module prices have historically undercut predictions and are often below economically sustainable levels. We therefore estimate a floor of \$0.15/W for c-Si modules. For efficiency, the Shockley-Queisser limit dictates a single-junction cell efficiency limit of around 30%, so we assume a conventional module performance limit of 25% (accounting for geometric and electrical scaling losses). In contrast, two-junction tandems can achieve theoretical cell efficiencies of up to 46% and thus practical module efficiencies well above 30%.[29,49] For degradation rate, experimental data—and thus realistic limiting values—are difficult to obtain because of the long time scales required. Reported values range from below 0.2%/year to well above 1%/year for different technologies in different climate conditions.[14] We note that there are diminishing financial returns to reducing degradation rate—for example, even with a 50-year analysis period without module replacement, decreasing the initial rate from 0.7%/year to 0 decreases LCOE by <10% in a utility-scale system. These diminishing returns become far stronger with module replacement. Here, we assume a limiting degradation rate of 0.3%/year for commercial technologies.

Environmental Impact Analysis

The following environmental impact categories and definitions are adapted from the United Nations Environment Programme:[42]

- Metal depletion: global reduction of available metal resources, based on US Geological Survey reports on available reserves (measured by the cost damage—the marginal cost increase per kg extracted—in kg Fe equiv).
- Freshwater ecotoxicity: toxicity to living organisms other than humans (in kg of 1,4-dichlorobenzene equiv emitted to freshwater).
- Land occupation: sum of all agricultural and urban land directly and indirectly occupied by a system throughout its life cycle (measured in square meter-annum [m^2a], representing the area occupied over a specified time).
- Human toxicity: toxic potential of compounds in the human body (in kg of 1,4-dichlorobenzene equiv emitted to urban air).
- Particulate matter: all particulate emissions (in kg of particles of up to 10 μm diameter [PM10] emitted to air).
- Climate change: global warming potential due to greenhouse gas emissions (in kg CO_2 equiv).
- Freshwater eutrophication: response of freshwater environments to the addition of nutrients from human activities, leading to hypoxia in aquatic environments (in kg of phosphate ion [PO_4^{3-}] equiv)

DATA AND CODE AVAILABILITY

The LCOE spreadsheet model and datasets from this analysis are available from the corresponding author upon reasonable request.

SUPPLEMENTAL INFORMATION

Supplemental Information can be found online at https://doi.org/10.1016/j.joule.2019.08.012.

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AUTHOR CONTRIBUTIONS

Conceptualization, J.J.; Methodology, J.J.; Software, J.J.; Validation, J.J. and M.W.; Investigation, J.J.; Writing – Original Draft, J.J.; Writing – Review & Editing, J.J., M.W., and V.B.; Project Administration, J.J. and V.B.

DECLARATION OF INTERESTS

J.J. is the co-founder and CEO of Swift Solar, a US company developing perovskite photovoltaics. V.B. is an advisor to Swift Solar and the co-founder of Ubiquitous Energy, a US company developing visibly transparent photovoltaics.

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Supplemental Information

Accelerating Photovoltaic Market Entry with Module Replacement

Joel Jean, Michael Woodhouse, and Vladimir Bulović

Supplemental Data

Table S1. Default input parameters for LCOE model, Related to Figure 2

Category	Parameter	Unit	Utility	Commercial	Residential
System	Nameplate capacity	*MW*	100	0.2	0.006
	Total module area	*m²*	523560	1047	35
	Ground coverage factor	*%*	30%	30%	30%
	Total land area	*m²*	1745201	3490	116
	AM1.5G light intensity	*W/m²*	1000	1000	1000
	DC capacity factor (Kansas City)	*%*	21.3%	16.3%	17.1%
	DC capacity factor (Phoenix)	*%*	26.8%	20.0%	20.9%
Module	Initial efficiency	*%*	19.1%	19.1%	17.2%
	Initial degradation rate	*%/yr*	0.70%	0.70%	0.70%
	Maximum practical efficiency	*%*	25%	25%	25%
	Minimum practical degradation rate	*%/yr*	0.30%	0.30%	0.30%
	Logistic rate parameter (k)	.	0.15	0.15	0.15
Inverter	Maximum DC/AC ratio (ILR)	.	1.3	1.15	1.15
Costs	Upfront system cost	*$/W*	$0.96	$1.66	$2.54
	Area-dependent BOS cost (year 0)	*$/W*	$0.35	$0.82	$0.69
	Area-independent BOS cost (year 0)	*$/W*	$0.27	$0.46	$1.34
	Initial module price	*$/W*	$0.30	$0.30	$0.30
	Initial inverter price	*$/W*	$0.05	$0.08	$0.21
	Minimum practical module price	*$/W*	$0.15	$0.15	$0.15
	CAGR of inverter price	*%*	–5%	–5%	–5%
	Module replacement labor cost	*$/W*	$0.007	$0.011	$0.019
	Inverter replacement labor cost	*$/W*	$0.005	$0.008	$0.014
	Fixed O&M cost	*$/kW/yr*	$10.40	$12.00	$11.50
	Module recycling cost	*$/W*	$0.08	$0.08	$0.08
	Decommissioning cost	*$/W*	$0.058	$0.00	$0.00
Financial	Discount rate/cost of capital (real)	*%*	6.3%	6.9%	6.9%
	Financial analysis period	*years*	30	30	30
	Inverter replacement period	*years*	15	15	15

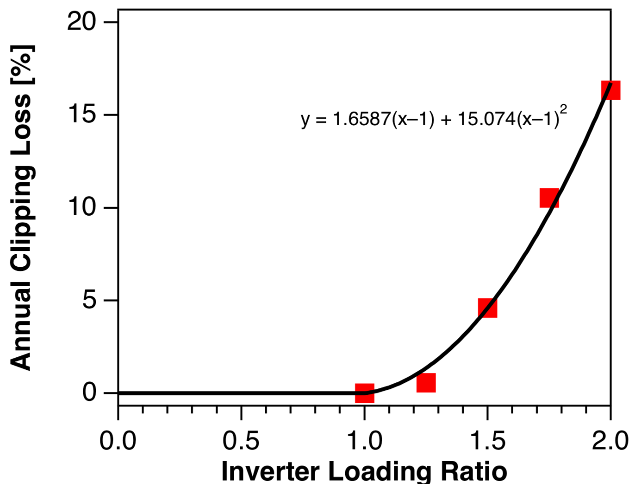

Figure S1. Annual energy loss due to inverter clipping as a function of inverter loading ratio (ILR), Related to Experimental Procedures

Clipping losses are shown as a fraction of the total annual generation. ILR is defined as the module DC capacity divided by inverter AC capacity. Literature data on clipping losses are fitted using a 2nd order polynomial with the coefficients shown. We assume no clipping loss occurs for ILRs below 1.

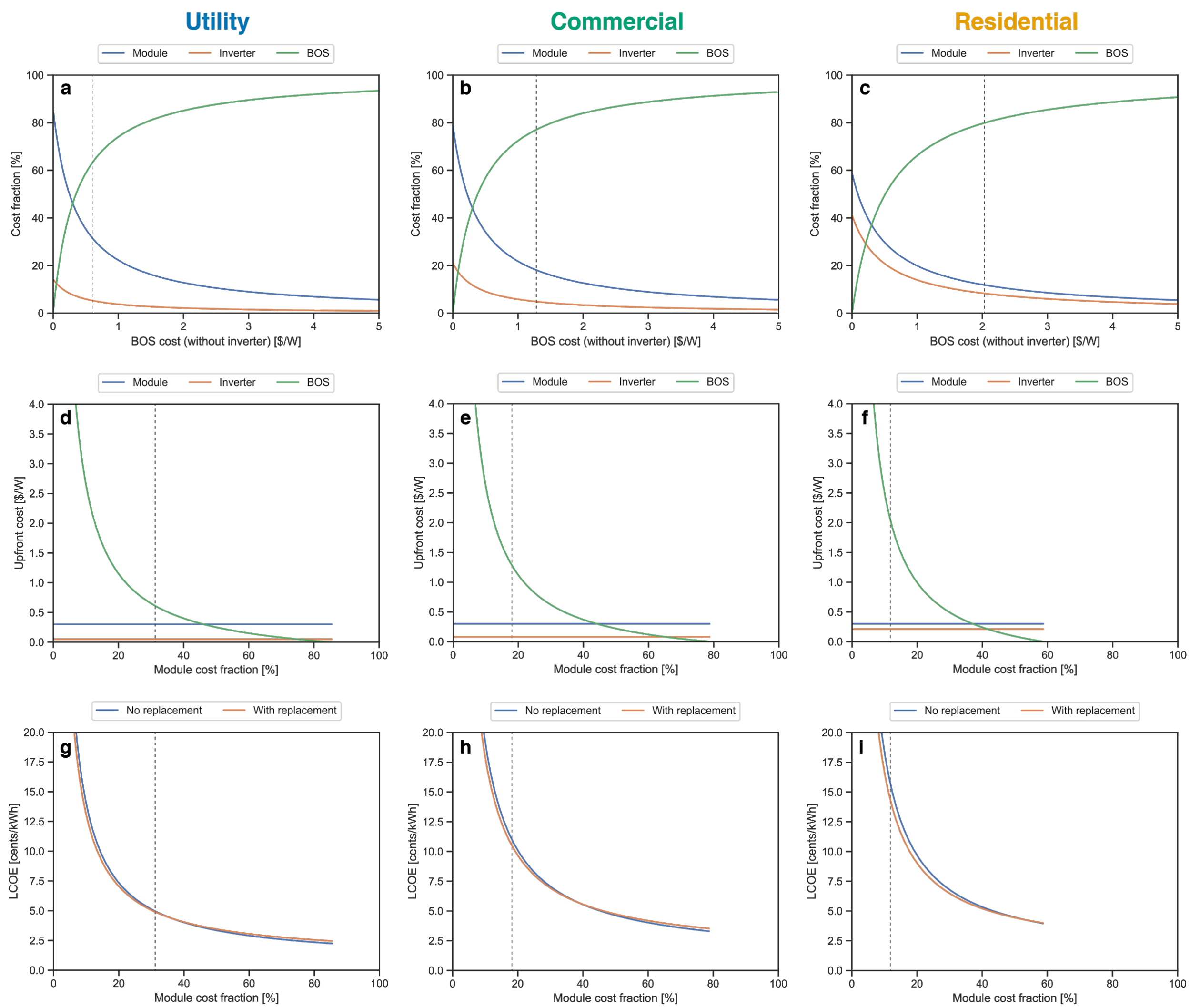

Figure S2. Impact of BOS costs and module cost fraction on LCOE, Related to Figure 6.
2018 U.S. benchmark system costs are assumed. **(a)–(c)** Fraction of upfront PV system cost contributed by module, inverter, and non-inverter BOS as a function of BOS cost, for 2018 U.S. utility-scale, commercial, and residential systems. **(d)–(f)** Assumed absolute $/W cost contributions of module, inverter, and non-inverter BOS. **(g)–(i)** LCOE with and without module replacement in Kansas City, MO.

Supplemental Experimental Procedures

Calculating the levelized cost of electricity (LCOE)

The LCOE of a PV system is the average revenue per unit of energy output required to break even financially over the system life. LCOE can be calculated using either a detailed financial model or a simple cash-flow model.

The financial model approach captures the complex financing arrangements, tax incentives, and electricity market details required for the operation of a utility-scale power plant. Such an approach is useful for optimizing the financial performance of a PV system in the design phase. However, the resulting LCOE values are highly specific to a particular project in a particular location. NREL's System Advisor Model (SAM) is a leading example of a detailed financial model.

A simplified cash-flow LCOE model that incorporates key system cost and performance parameters can be more easily generalized. This approach is well-suited for comparing new PV technologies, as it allows aggregation of parameters that are not yet fully characterized (e.g., temperature coefficients and shading losses are captured in the capacity factor). In this model, the LCOE is the present value of all upfront and operating costs divided by the present value of the energy output:

$$LCOE = \frac{\sum_0^L C_t/(1+i)^t}{\sum_1^L E_t/(1+i)^t}$$

where *L* is the financial analysis period (years), *i* is the real cost of capital or discount rate (%), C_t is the cost incurred in year *t*, and E_t is the energy output in year *t*. For PV systems, the upfront cost (C_0) typically dominates the total lifetime cost (numerator). The annual energy output depends on the nameplate capacity, panel orientation with or without tracking, module and system losses, shading losses, and local insolation, which in turn depends on the latitude and local climate (e.g., cloud cover, temperature, and humidity).