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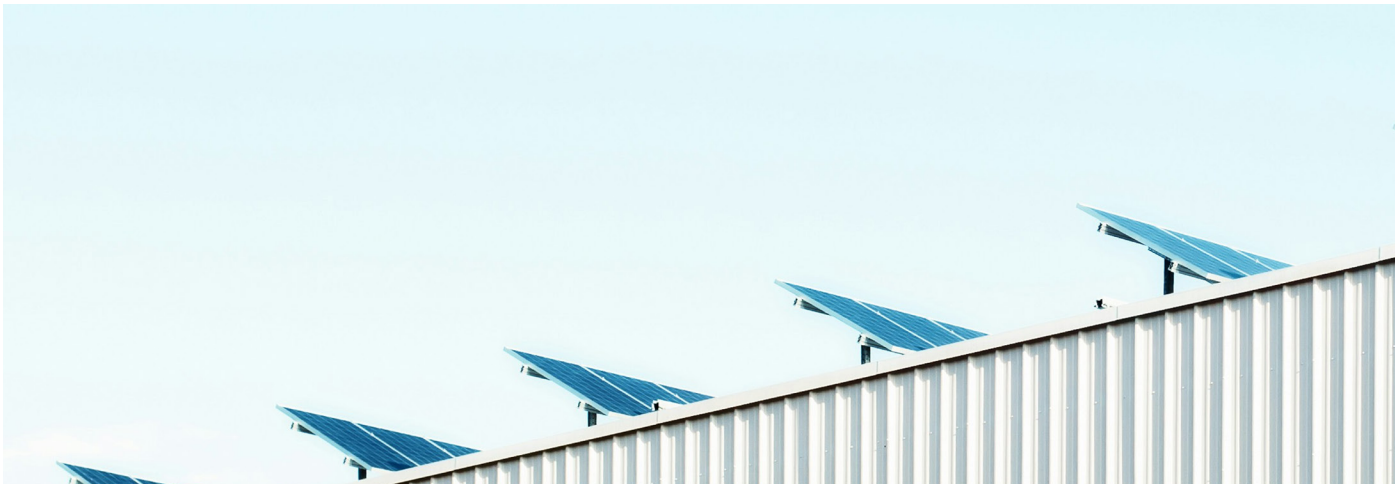
Recharged: Repowering America's Solar Fleet with Storage for a New Era of Demand



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Section 1

Executive summary

The United States' solar fleet is entering its first major replacement cycle. The initial wave of American solar plants was built between 2010 and 2016; those plants are now reaching the end of their technical and contractual lives. When inverters fail, modules have lost meaningful output, and initial offtake contracts expire. This point arrives as electricity demand is growing at a significantly higher rate than in previous decades and as new electricity supply remains constrained by interconnection queues, permitting timelines, and supply chain bottlenecks.

In short: America's first generation of solar plants is aging out at the exact moment the grid can least afford to lose the capacity. What owners do with aging solar plants — retire them or reinvest to rebuild them — is an increasingly significant question for the solar market and the nation's electricity system.

Against this market backdrop, "repowering" solar assets — replacing aging equipment while retaining a solar site's interconnection, permitting, and land — is a market with significant growth potential. Technology advancements enable a rebuilt plant to produce substantially more energy and store the surplus; today's modules deliver 50% more power from the same footprint, and battery costs have fallen 90% over the last decade. Capex is lower than at greenfield sites because existing plants can reuse existing equipment such as transformers and racking.

Repowering can also bypass the slowest parts of new development: permitting and interconnection. In many markets, repowered solar plants that hold output at the existing interconnection limit can avoid the multi-year interconnection queues that constrain new development.

Repowering is one of the few levers that can add meaningful capacity on a timeline of months rather than years.

This paper attempts to define this emerging market opportunity. We size the technical potential of US solar repowering — the capacity it could unlock and the investment it would represent — using a bottom-up model of the installed fleet by installation year and segment (all capacity figures are in GWac). We also set out the considerations — interconnection and permitting, capital sources, and tax credits and equipment rules — that owners and market participants will need to work through as they approach the opportunity.



Our findings

1

Repowering could meet one-third of the growth in peak demand driven by data centers by 2035.[1]

Repowering could unlock the equivalent of 9.6 gigawatts (GW) of new solar and 13.1 GW of dispatchable battery capacity by 2030, rising to 29.0 GW and 41.4 GW by 2035 and 67.0 GW and 91.7 GW by 2040, all on existing land and grid connections. That capacity translates into a $10.8 billion annual market in 2030, growing to $51.8 billion by 2040 — a 17% compound annual growth rate (CAGR) — and roughly $346 billion in cumulative spend over 2026–2040. These figures refer to equivalent new-build capacity and represent technical potential rather than a forecast of adoption.

2

Repowering is a storage opportunity, as well as a solar one.

Because a modern array produces more than a fixed interconnection can export, the case for repowering rests heavily on adding a battery to store and shift that surplus. Battery additions and replacements account for nearly half of potential spend, and the dispatchable capacity unlocked exceeds the solar capacity added.

3

The near-term market opportunity is largest in distributed generation.

Commercial and industrial (C&I) distributed generation (DG) represents 52% of capacity in 2030. Three states — California, North Carolina, and Arizona — account for roughly two-thirds of 2030 potential. The market broadens through the 2030s as the large post-2017 utility-scale cohorts reach repowering age; utility-scale represents nearly two-thirds of potential by 2040, and Texas and Florida join California as the largest markets.

[1] The North American Electric Reliability Corporation (NERC) projects that summer peak demand across the North American bulk power system will grow by 224 GW between 2025 and 2035, with data centers accounting for "over half" of that increase. Applying the Grid Strategies share of data center peak demand (Grid Strategies found that data centers account for roughly 54% of forecast peak growth through 2030), this would imply that data centers will add 121 GW to peak demand. The 41.4 GW of dispatchable battery capacity that we estimate repowering could unlock equals 34% of this addition.

Repowering overview

Solar repowering refers to replacing and upgrading the major equipment at an existing solar plant to restore or increase output, or to extend the plant's operating life, while retaining the assets that are hardest to replicate: interconnect, permits, and site control.

In practice, repowering spans a spectrum of interventions. This can involve maintenance-driven component replacements (swapping degraded or defective solar modules, replacing aging inverters, and remediating other issues) to array power uprates (installing higher-wattage modern modules on existing racking and land) to installing a battery to store excess energy production and discharge it at times of peak demand.

These forms are frequently combined. Because a repower already involves site disturbance and engineering review, and because a modern array produces more than the plant's existing interconnection can export at midday, it's often cost-effective to add a battery at the time of module and inverter replacement. The market analysis in Section 2 of this paper assumes a full repower with a co-located battery: it finds that a repowered solar plant with added storage can deliver significantly more energy per year than the aged plant it replaces — in some cases more than 50% more. At the same time, the cost of repowering is meaningfully lower per watt than equivalent new construction because it avoids land acquisition, interconnection application, and substation costs while incurring teardown and disposal costs.

Repowering's economic potential differs from greenfield solar's in two respects: First, a repower begins with the interconnection agreement, permits, and site control that new development spends years securing. A plant rebuilt within its existing interconnection limit faces, in most markets, no new queue and little new permitting, before any battery is considered. Where a battery, which is the source of most of the incremental energy in this analysis, is added, the treatment of surplus interconnection and of storage under existing permits varies by market and locality. Second, the economic case rests primarily on avoided capital cost and on energy and capacity value rather than on tax credits.

Regulatory decisions will affect where and how fast the repowering market develops. The current direction is broadly favorable: regional transmission organizations (RTOs) are implementing and reforming surplus interconnection service, several states have adopted policies to support utilization of existing generators, and utilities and new market participants alike are beginning to offer contract terms that reward storage additions. The markets that make it easiest for existing plants to use their interconnection and permits fully will see repowering first. Section 3 sets out what market participants will need to work through.

Several factors are driving early uptake of repowering:

Fleet replacement requirements

The first large wave of US solar is now approaching 15 years of age; roughly 10% of the installed base will reach this point over the next 5 years. At this age, significant reinvestment becomes unavoidable. Inverters carry design lives of only 10–15 years, so these first-wave assets are already reaching or beyond nominal replacement age. Modules degrade gradually — at the National Laboratory of the Rockies' (NREL) median system-level loss rate of 0.75% per year, a 15-year-old array produces about 11% less electricity than a new array.

However, inverter failure is the costliest issue on a solar plant because it is total rather than gradual. When an inverter fails, every panel behind it stops earning, typically forcing a near-term replacement. For many first-wave plants, the inverter manufacturer is no longer in business, making like-for-like replacement impractical and necessitating a broader decision on how to rebuild the plant.

Technology and cost improvements

The decision on how to rebuild a plant has shifted because of technology improvements since earlier generations of plants were installed. Today's solar modules produce more than 50% more power from the same array area than 2011-era modules, so replacing modules on existing racking can raise plant output rather than merely restoring it.[2] Installed battery costs have declined around 90% over the past decade. That, in turn, has changed how new solar gets built: about 22% of capacity planned to come online in the second half of 2026 is paired with a battery. That proportion rises to 48% for projects planned to reach operation in 2029.[3] The same economics apply to older plants, which were almost universally built without storage and now sit on interconnections that a modern array can over-produce against for several hours a day. Because repowers already involve site disruptions to energy production and site outages, and in some markets, the battery can use the plant's existing interconnection, a repower may be the most cost-effective time for older plants to add a battery.

Interconnection scarcity

Interconnection is the most binding constraint on new supply in the majority of US electricity markets. The assets an aging solar plant holds — an executed interconnection agreement, secured permits, and site control — can take new projects many years to assemble. Repowering monetizes those assets on a substantially compressed timeline, making it among the fastest and lowest-cost paths to deploying additional capacity. As queue backlogs have lengthened, the value of an existing interconnection has risen, and with it the economic case for rebuilding on an existing site.

Contract expiry

Many first-wave plants were built on 10- to 15-year power purchase contracts. This includes both behind-the-meter assets and the more than 3,300 PURPA-qualifying facilities totaling more than 22 GW, of which a significant share will reach contract expiry over the next five years. An owner facing an expiring contract on a 15-year-old plant must decide whether to continue on successor terms, retire, or repower. Successor contract pricing and design is an important factor for market participants to evaluate, as discussed in Section 3.

[2] Authors' analysis: ratio of current to 2011-vintage module efficiency, from NREL's US solar PV system cost benchmark parameter series (Q1 2025), https://www.osti.gov/biblio/3009689.
[3] Authors' analysis of EIA-860M (June 2026 edition): share of utility-scale solar capacity, by vintage, located at plants with co-located battery storage, https://www.eia.gov/electricity/data/eia860m/.

Section 2

Sizing the repowering market

We size the repowering opportunity along two dimensions: the capacity it could add — new solar capacity and dispatchable battery power brought online behind existing grid connections — and the investment it would represent. These estimates assess technical potential, rather than a forecast of adoption.

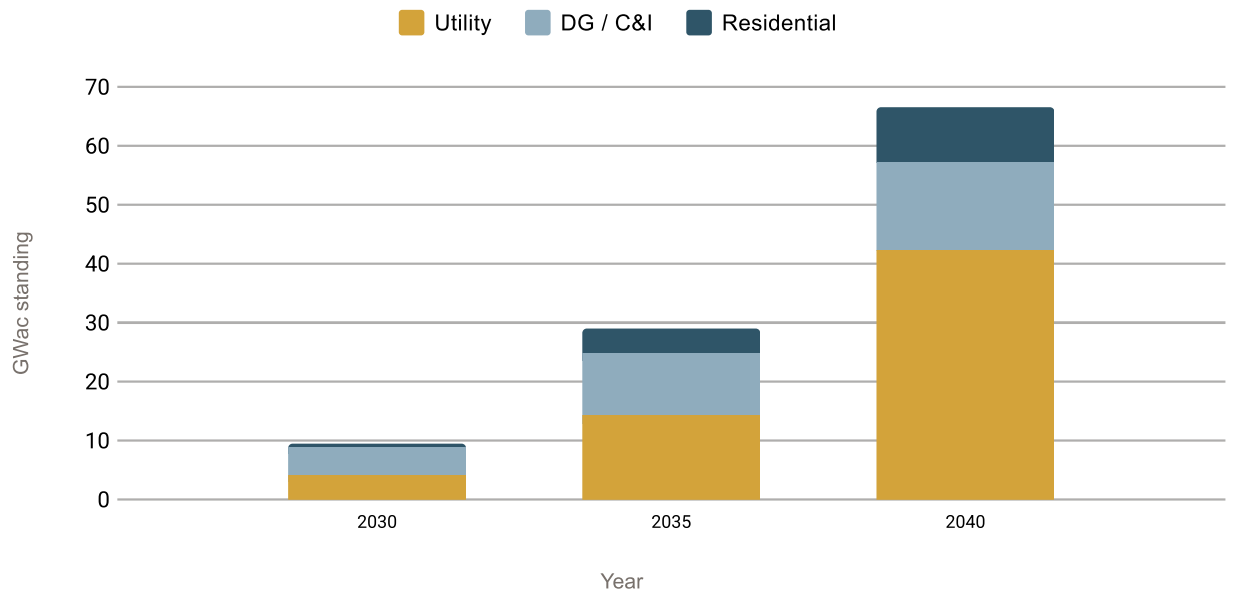
We model repowering bottom-up from the installed fleet: using US Energy Information Administration (EIA) data, we measure US solar capacity by vintage across four segments (utility-scale, DG ground-mount, DG rooftop, and residential). We assume each plant replaces both inverters and modules at age 15 (age 20 for residential, on the roof-replacement cycle), while land, racking, and the grid connection stay unchanged. Repowering adds energy in two ways: it erases accumulated degradation and replaces each vintage's modules with modern, efficient modules.

Because the upgraded array produces more than the fixed interconnection can export, each site also adds a DC-coupled battery sized to store the surplus. Costs are built component-by-component from NREL's PV system cost benchmarks, in 2025 dollars (see the appendix for full methodology).

We find that repowering could unlock the equivalent of 67.0 GW of new solar by 2040 (9.6 GW by 2030 and 29.0 GW by 2035) from existing land and grid connections, a 21% CAGR over 2030–2040.

Figure 1

GW brought online: New solar, equivalent new-build GWac



Throughout, power is in GWac — both the interconnection limit, which a repower leaves unchanged, and the battery discharge capability that operates within it — modules are in GWdc behind that limit, battery energy is in GWh, and duration is their ratio in hours; solar potential is reported as equivalent new-build GWac, the nameplate that would have to be built and interconnected elsewhere to deliver the same energy. All dollar figures are 2025 real dollars.

The battery potential is larger, amounting to 91.7 GW of dispatchable capacity by 2040 (13.1 GW by 2030, 41.4 GW by 2035), or 596.0 GWh by 2040 (76.0 GWh by 2030, 252.0 GWh by 2035). The batteries store the additional midday output of the more efficient modules and discharge it when demand peaks, letting each plant deliver more energy without changing its maximum output and thus its interconnection.

The early repowering potential is concentrated in distributed generation. In 2030, DG and residential together account for more than half of the equivalent capacity added (5.3 of 9.6 GW) because the small-plant fleet was built out earlier and reaches repowering age sooner. By 2040, the mix inverts: utility-scale supplies nearly two-thirds of the 67 GW as the larger post-2017 utility cohorts reach repowering age. The residential opportunity emerges later because it is contingent on the 20-year roof-replacement cycle; it grows from 0.3 GW in 2030 to 9.5 GW by 2040 as solar plants built out during the mid-2010s residential solar boom reach the need for reroofing.

In 2030, the solar repowering opportunity is greatest in California (4.4 GW, driven by utility-scale solar), North Carolina (1.0 GW, driven by DG), and Arizona (0.9 GW, driven by utility-scale). By 2035, California and North Carolina remain the leaders in repowering potential, with repowering unlocking 9.4 GW and 2.6 GW, respectively, along with Texas (2.1 GW). By 2040, repowering potential extends across most states, led by California (15.4 GW, a mix of utility-scale, DG, and residential), Texas (9.4 GW, almost entirely utility-scale), and Florida (5.4 GW, primarily utility-scale). The opportunity is highly concentrated in early years — the top three states account for roughly two-thirds of 2030 potential — and broadens through 2040.

Figure 2

Dispatchable power brought online: New battery discharge capability

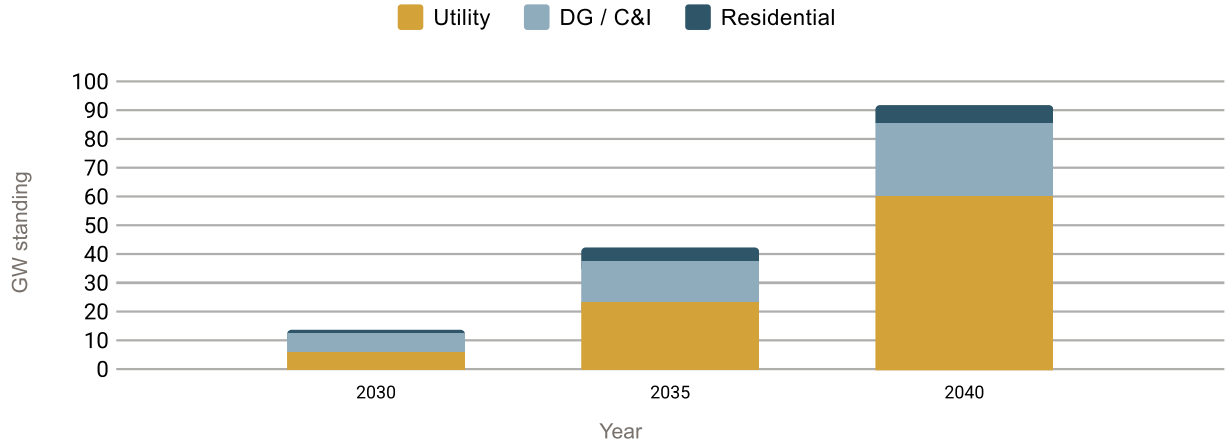
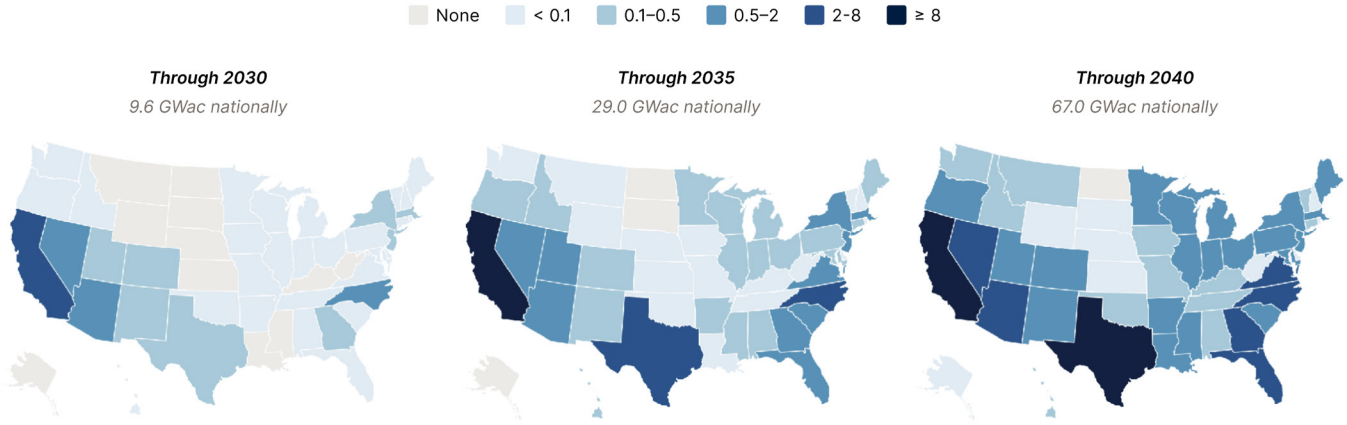


Figure 3

New solar unlocked by repowering — equivalent new-build GWac

Cumulative GWac of new plant that would have to be built and interconnected to deliver the same energy, by state — utility, DG and residential combined



Plants measured from EIA-860; rooftop segments allocated to states by 2024 distributed capacity (EIA-861). AC stated as equivalent new-build nameplate - the repower itself adds no export capacity. States sum to the national model exactly.

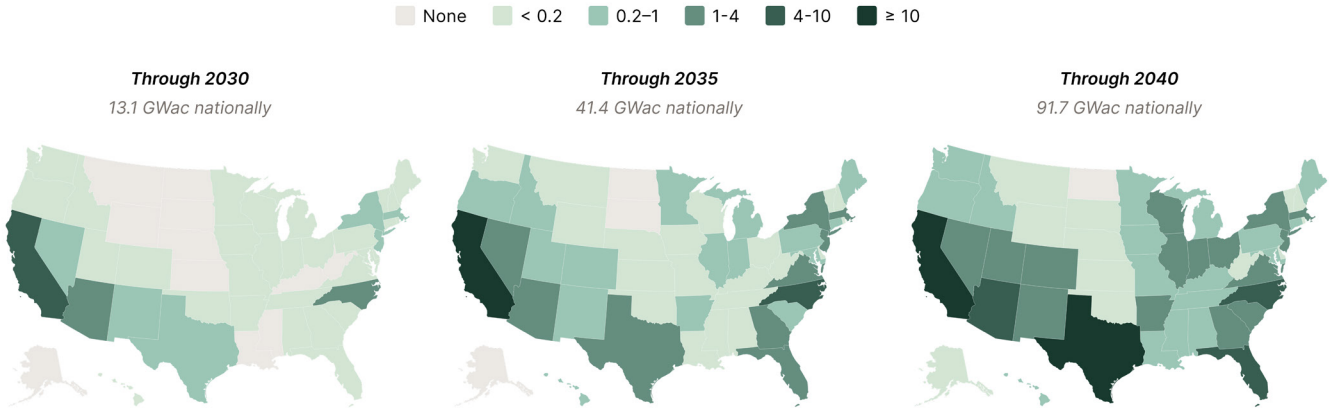
For battery storage, the greatest opportunity from solar repowering is in California, North Carolina, and Arizona in 2030. By 2035, California, North Carolina, and Texas are the leaders. By 2040, storage potential is geographically broad, led by California, Texas, and Florida.

We estimate total repowering spend at $10.8 billion in 2030, rising to $27.9 billion by 2035 and $51.8 billion by 2040 — a 17% CAGR over 2030–2040 (21% over 2030–2035, 13% over 2035–2040) and approximately $346 billion in cumulative investment over 2026–2040. Batteries are the largest single component; battery additions or replacements represent nearly half of spend. The sectoral pattern matches the capacity analysis: distributed generation and residential together account for a majority of spend through 2030 (53%), with utility-scale taking roughly 60% by 2035 and 80% by 2040 as its mid-2010s cohorts reach repowering age. On a per-watt basis, we estimate a full repower costs roughly 20% less than equivalent new construction. A repower incurs additional costs associated with disassembling and removing existing modules, but avoids other major cost drivers including land acquisition, interconnection application, and substation construction.

Figure 4

Battery power unlocked by repowering — GWac of dispatchable discharge

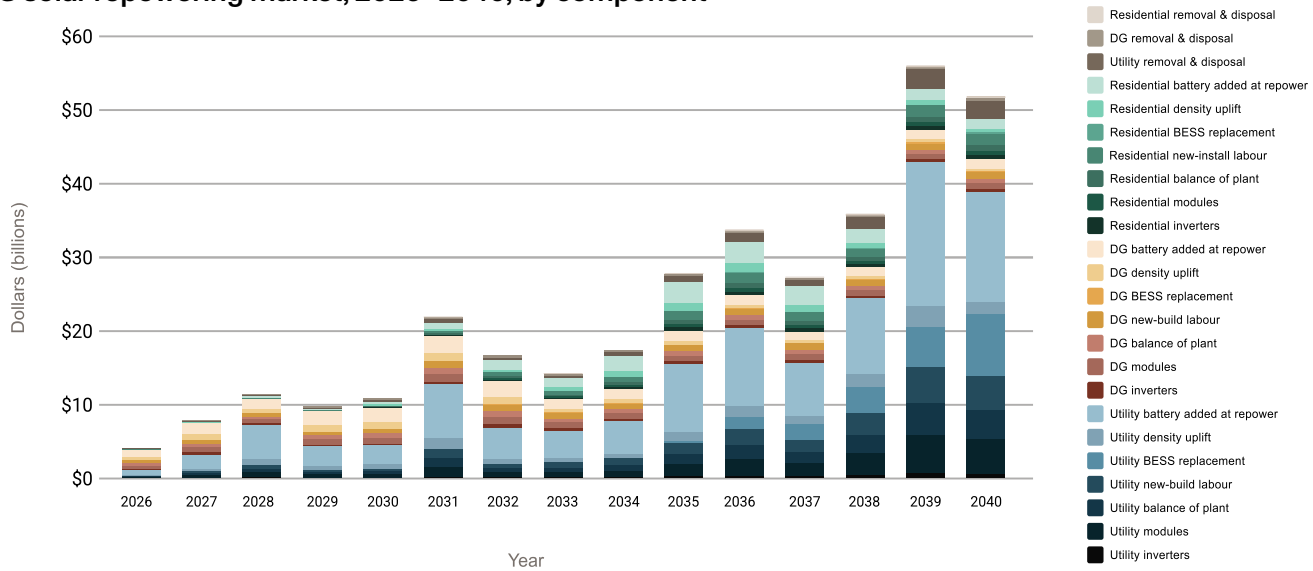
Cumulative GWac of battery discharge power added at repowered sites, by state — utility, DG and residential combined



Plants measured from EIA-860; rooftop segments allocated to states by 2024 distributed capacity (EIA-861). Discharge power is the clear-day peak surplus, capped at the existing connection - it is dispatchable within capacity the grid already accommodates. Sites already paired with storage excluded. States sum to the national model exactly.

Figure 5

US solar repowering market, 2026–2040, by component



These estimates assume that battery duration is capped at four hours for DG and residential and eight hours for utility-scale. Removing that cap leaves the power ratings in GWac unchanged and raises energy capacity in GWh by roughly 10%.

Sources: fleet volumes EIA-860M, EIA-861, EIA AEO2026; unit costs NLR PV System Cost Model Q1-2025; cost decline NLR ATB (2026=1.000).

Section 3

Considerations for market participants

Section 2 of this paper estimates the additional capacity that the installed fleet of solar could technically support. This section is written for the owners, investors, lenders, and developers who will decide whether and how individual plants are repowered, and it sets out the questions they will need to answer across a range of relevant factors: interconnection and permitting, access to capital and project finance, tax credit availability, and supply chain constraints.

Repowering operates under the same tax code, trade rules, and interconnection and siting authorities as greenfield solar, but from a different starting position. A repowering project already holds an interconnection agreement, permits, site control, an operating record, and, in most cases, a lender, an offtake contract, and a land lease. Those existing positions are the source of repowering's advantages over new development. They are also the constraints that a participant has to work within. The considerations below follow the order in which an owner typically encounters them:

- **What the site allows.** How much can be rebuilt within the existing interconnection and permits without triggering new review, and how the market and locality treat a storage addition. This is the question that most determines a project's timeline, and the answer varies more by geography than any other factor in this section.

- **How to finance against an existing capital structure.** Where the capital comes from, what the incumbent lender or investor requires, and where an operating asset earns better terms than a new one by replacing an existing offtake contract and adding revenue from batteries.

- **What credits and equipment rules apply.** The solar tax credit is phasing out for repowers on the same schedule as greenfield; the storage tax credit remains through 2033. Equipment eligibility and tariff rules weigh on repowers as they do on greenfield assets.

Throughout, there is a general pattern: like-for-like replacement is close to policy-independent in every market, and the storage addition, which carries most of the asset's incremental value, is where market-by-market treatment matters and where participants should focus their diligence.



Interconnection & permitting

The first question for an owner considering a repower is how far the plant can be rebuilt in its existing interconnection agreement and permits. Interconnection and permitting are a significant advantage for repowers. The size of that advantage, however, varies based both on the scope of a repower and on the market in which the repower finds itself and determines the project's timeline more than any other factor.

Like-for-like replacements, meaning new modules and inverters that leave nameplate capacity and electrical characteristics at their point of interconnection unchanged, can retain interconnection agreement and existing permits in nearly all US markets. These projects will require at most a notification or a limited material-modification review. Changes that increase capacity or add a resource type, most importantly a battery, are treated differently. Depending on the market, they may trigger a modification study, a surplus interconnection request, a new permit, or, in some markets, all three. Because storage carries most of the incremental value in a repower, diligence on interconnection and permitting is largely diligence on how the relevant market and locality treat a storage addition at an existing site.

In practice, three questions determine the path:

- Does the rebuild change the plant's export capability or electrical characteristics at the point of interconnection?
- If storage is added, can it charge from the grid or only from the solar panel?
- Do the existing permits cover the new equipment and its use?

The interconnection agreement, the permit conditions, and any land-use approvals should be read against these questions before design work begins.

Three layers of authority apply:

1. RTOs and independent system operators (ISOs) govern interconnection for transmission-connected generators. Federal Energy Regulatory Commission (FERC) Order 845 (2019) is the federal baseline that requires transmission providers to offer surplus interconnection service, which lets a new resource use an existing plant's unused interconnection capacity without joining the queue.
2. States and utilities govern interconnection of distribution-connected DG under state tariffs.
3. Local authorities hold siting and permitting authority over all sites, with significant variation by region.

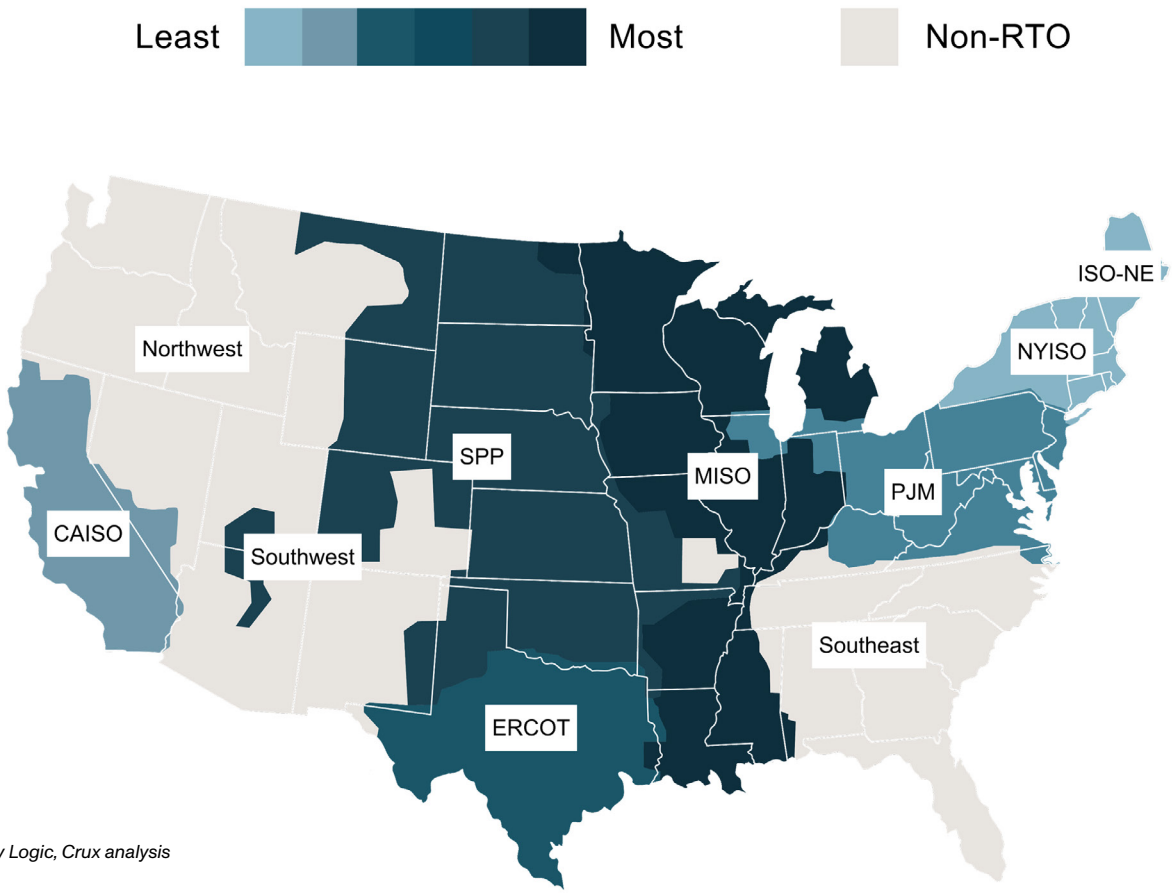
For early-market participants this distribution is meaningful: two of the three largest 2030 markets, Arizona and North Carolina, are outside any RTO, and distributed generation accounts for 52% of 2030 repowering potential, so most early repowering decisions will be made under state, utility, and local rules rather than RTO surplus processes.

Transmission-connected plants

RTOs have implemented FERC Order 845 unevenly, and the same storage addition can take a year in one market and be unavailable in another. Figure 6 summarizes the treatment of repowers and storage additions by RTO/ISO.

Figure 6

Ranking of RTO/ISOs by favorability of interconnection policies for repowering



Source: Foundry Logic, Crux analysis

- The Midcontinent Independent System Operator's (MISO) Generator Replacement process lets new generation connect at the same point of interconnection (POI) as a retiring resource, and its surplus interconnection service lets a generator add storage or hybridize up to its existing rights for a $60,000 study deposit (possibly rising to $150,000) rather than per-MW costs. This approach has resulted in 14.8 GW under study as of mid-2026.

- The Southwest Power Pool's (SPP) similarly FERC-accepted expansion allows surplus use even where minor upgrades are needed and 14.3 GW under study as of mid-2026.

- The Electric Reliability Council of Texas (ERCOT) sits outside FERC's jurisdiction entirely and has no formal surplus interconnection service (SIS) program, instead relying on its "connect and manage" framework, which studies only local upgrades and has historically meant faster, cheaper interconnection generally — but with no dedicated surplus mechanism.

- PJM's SIS lets new resources use excess injection rights at an existing POI. Despite recent reforms, uptake remains limited because combined-output modeling still takes nearly as long as a standard study and host asset owners are often reluctant to share capacity rights — prompting a proposed second round of reforms letting hybrid resources participate in markets as separate, independent resources.

- The California Independent System Operator (CAISO) runs generator-replacement and surplus through the same queue cluster as greenfield projects but with a separate repower-study track that preserves queue position and skips re-study for true like-for-like replacement.

- In the Northeast, ISO New England (ISO-NE) keeps repowering (a material modification studying only incremental impact) and surplus service legally separate — the latter barred from repowering use, with a formal bridging pathway now under review — while the New York Independent System Operator (NYISO) requires a retired facility to file an entirely new interconnection request, carving out only capacity increases under 10 MW or 5% on non-retired facilities.



The direction of policy on surplus interconnection is favorable to repowering. In February 2026, Virginia and Indiana lawmakers passed bills aimed at spurring SIS use. Virginia's FAST Act requires Appalachian Power and Dominion Energy Virginia to assess available interconnection capacity at existing and planned intermittent generating facilities — both utility-scale and DG — and stand up pilot programs.

Indiana's SB 240 requires utilities to analyze SIS potential in integrated resource plans and, starting in 2030, requires anyone seeking state approval to build, buy, or lease a power plant to show how the project uses or enables SIS. Similar legislation is pending in Maryland, which would direct the Maryland Energy Administration to study the state's SIS potential and share results with data center developers. Together with the RTO reforms above, these measures indicate where existing plants will find it easiest to make full use of their interconnection, and those are the markets where repowering with storage will move first.

Distribution-connected plants

For the DG fleet that makes up most of the early market, the governing question is whether the utility treats a storage addition or capacity increase at an existing system as a material modification requiring a new application and queue position, or as an expedited or non-export review. State rules on this point are generally less developed than RTO surplus processes for storage addition and vary based on the state.

A range of states and utilities have taken proactive measures to support repowering. For example, California's Rule 21 codifies distinct non-export and limited-export screens, with fast track eligibility for qualifying storage additions. Maryland permits reverse power relays to qualify systems as large as 10 MW for expedited review, a notably high threshold relative to peer states. In Massachusetts, regulators have proposed expanding expedited review eligibility for energy storage system additions. New York, on the other hand, defines the addition of an energy storage system to an existing facility — or a capacity increase above 2% — as a material modification, which generally triggers a new application and a new queue position rather than an expedited path.

Permitting and siting

Existing permits cover the solar equipment as built and typically do not contemplate a battery. Whether a battery inside an existing solar footprint is exempt from newer permitting siting rules or treated as a new discretionary permit is decided by locality and is not standardized. The environment for new storage siting is tightening. California's SB 283 requires a formal fire-authority "meet and confer" within 30 days of filing, and Los Angeles and San Diego counties are separately tightening zoning and setback standards. Counties in Indiana have enacted temporary moratoriums covering "any and all permits" for battery storage. Michigan townships (Oshtemo, Comstock, Gun Plain) and New York's Huntington have paused battery permitting over fire-safety concerns, with Comstock requiring setbacks nearly seven times the state minimum.

One tracker counts more than 125 active battery storage moratoriums across 13 states as of mid-2026. These restrictions target new siting decisions, which cut both ways for retrofits: a battery added within an existing solar site's footprint may sidestep the siting fights new-build batteries now face, but only if the jurisdiction treats the addition as exempt from its newest rules, not as a fresh discretionary permit. The battery permit is a critical item of early diligence, and project timelines for storage additions should be tested against the specific authority having jurisdiction.

Capital and financial structuring

Repowering finance is a newer discipline than greenfield project finance. Its distinguishing feature is that the project sits on top of contracts and capital that already exist. Whereas a greenfield sponsor assembles a capital stack and an offtake contract, a repowering sponsor inherits both. The work is to determine what the existing agreements allow, establish what the rebuild plan will earn, and secure any incremental capital.



Leveraging the existing capital stack

For a plant still within its original financing term, a repower is a major capital event under the credit agreement. The incumbent lender's consent is required, and the loan's coverage tests will be re-run against the repowered plant's projected production. Debt for the repower itself generally takes one of three forms:

- Drawing on expansion capacity built into the original loan.
- Refinancing the existing debt entirely.
- Adding a junior tranche behind the existing lender.

Which is available depends on the original documents and the lender's appetite. Residential and small commercial systems that have been securitized require bondholder consent under whatever process the bond documents specify, which can be slow because they were often not designed for this purpose.

A repower needs less capital and sits on top of an existing capital stack, so it is typically financed from sponsor capital, the incumbent lender, and monetization of tax credits, with the mix depending on segment. Utility-scale repowers sit closest to greenfield project finance, combining debt and tax equity at a smaller scale and often bringing in a tax credit buyer alongside the debt. Distributed-generation repowers are more likely to be financed at the portfolio level: sponsors bundle many small projects and finance, or sell the credits of, the bundle as a whole, because larger and more diversified tickets price better and reach a deeper pool of lenders and tax credit buyers. Crux's transaction data bear this out: 98% of total commercial and residential tax credit transfer volume since 2023 has transacted as portfolios rather than single projects. For these smaller projects, transferability has largely displaced tax equity, with tax credit value based on hard costs.



Two features of an operating asset work in the sponsor's favor at this stage. Lenders can underwrite against a decade or more of actual production rather than an engineering estimate, which narrows the uncertainty band and can improve terms. Insurance, which lenders require for the life of the loan, typically costs less for a repowered plant: it replaces equipment that is out of warranty and in its failure-prone years with new equipment at the start of its life curve, moves failure risk back to the manufacturer under a new product warranty, and allows the sponsor to select a currently well-regarded Tier 1 supplier rather than be underwritten against whatever manufacturer built the original equipment 15 to 20 years ago. This can be particularly valuable in a period of industry-wide premium increases.

Revenue considerations

The offtake contract and the site agreement need the same review. A repower extends the asset's life by 15 years or more, well beyond the terms of the power purchase agreement (PPA) and land lease it was built under, so both will need to be extended or replaced, and the current terms will determine how much room there is to do so.

What the rebuild plan will earn depends on where it sits. For behind-the-meter residential and commercial systems, the counterparty is the host customer, and securing consent to amend a PPA can be the slowest step in a repower, particularly where the system has changed hands several times and the current owner has no working relationship with the host. The offsetting factor is that retail electricity prices rose 9.0% year over year in early 2026 (10.7% for commercial customers), giving hosts a clear incentive to recontract for a repowered system, especially one that adds storage — and with it, demand-charge management and resilience. For front-of-the-meter assets, many first-wave plants are PURPA-qualifying facilities that were built on 10- to 15-year fixed-price contracts that are now expiring.

Successor terms have often been shorter and lower-priced as avoided-cost rates fell through the 2010s. However, market direction has reversed: solar PPA prices have risen roughly 40% since 2020, according to the Lawrence Berkeley National Laboratory, and are expected to rise further as the pool of tax credit–eligible projects phases out. A battery adds revenue the original contract never contemplated, including capacity payments, ancillary services, and energy shifted into peak hours. Utilities are beginning to price that in, as with Duke Energy's proposal to offer 10-year rather than 5-year renewals to North Carolina owners who add four-hour storage.

A new class of buyer is also emerging: PJM's "bring your own new capacity" proposal, filed with FERC in August 2026, explicitly counts repowered assets, storage, and distributed energy aggregations as qualifying capacity for large loads, and hyperscalers have begun contracting ahead of it — Google announced a 100-MW distributed-resource virtual power plant in PJM with Voltus in June 2026. Owners of repowered assets may increasingly blend a utility successor contract, a capacity sale to a large load, and merchant battery revenue rather than depend on a single offtaker.



Tax incentives and equipment rules

For solar equipment, the federal credit question is largely settled. The One Big Beautiful Bill Act (OBBBA, 2025) applied the same deadline to repowers as to new solar: projects must have begun construction by July 4, 2026 or be placed in service by December 31, 2027 to claim the §48E investment tax credit or §45Y production tax credit. Repowers that met the construction-start test have four years to reach commercial operation and can still qualify under the established pathways: either the "80/20 rule," under which a retrofitted facility is treated as newly placed in service if retained equipment is no more than 20% of the rebuilt facility's value, or the US Department of the Treasury's incremental production rule, which credits the new investment in a capacity addition without an 80/20 test.

For everything else, the module and inverter component of a repower is unsubsidized from 2028, apart from the permanent 100% bonus depreciation the OBBBA restored for property placed in service after January 19, 2025. Market participants are already underwriting solar repowers on this basis. The economic case for module and inverter replacement rests on avoided capital cost and on energy and capacity value rather than on credits, and participants should treat any residual solar tax credit as an exception rather than a planning assumption.

The tax credit that matters for repowering is the storage tax credit. The OBBBA left storage tax credits largely intact; storage installations can receive the full §48E credit through 2033, phasing to 75% in 2034 and 50% in 2035. Three features matter:

- A battery added to an existing solar site qualifies as a stand-alone, credit-eligible project regardless of whether the solar equipment qualifies for anything.
- The credit itself is worth 6% of eligible basis, or 30% if prevailing wage and apprenticeship requirements are met, with adders of 10 to 20 percentage points each for domestic content, energy community siting, and low-income community siting.
- Section 6418 transferability allows the owner to sell credits for cash rather than from a tax equity partnership; Crux estimates more than $10 billion in solar and storage credits transacted in the transfer market in the first half of 2026 alone. For the smaller deals typical of repowers, transferability is more often used in place of tax equity than alongside it.

One limit applies to sites that already have storage: an existing battery requalifies for a credit only if the modification increases nameplate capacity by at least 5 kWh (energy capacity), and only the new basis counts.

Equipment eligibility is the diligence item that most determines whether the storage credit is actually captured. The OBBBA tied the credits to prohibited foreign entity (PFE) rules built on three tests: ownership, effective control, and material assistance, the last a cost-ratio test that increases in stringency over time to trace how much equipment value originates with a prohibited entity. While Treasury guidance in February 2026 provided safe harbors for developers to comply with the material assistance cost ratios, the guidance was silent on the ownership and effective control provisions, creating uncertainty for market participants.

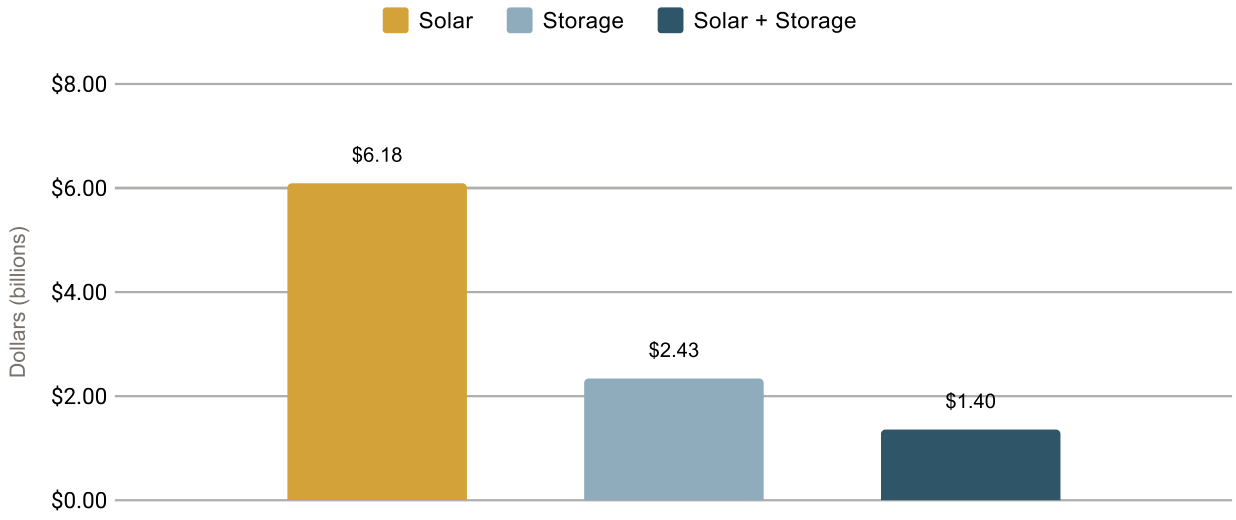
The market is pricing this uncertainty: Crux found that PFE-exempt tax credits traded at premiums of roughly $0.015 (ITC) and $0.020 (PTC) per dollar of credit over exposed credits in the first half of 2026.

Layered on the PFE rules are Section 301 tariffs (50.0% on Chinese solar cells and wafers, 25.0% on batteries; roughly 62.5% and 37.5% all-in with other duties), the Federal Communications Commission's July 2026 freeze on new authorizations for foreign-made inverters, and Executive Order 14420 of August 2026, which designates foreign-linked batteries and transformers a national security concern and directs the US Department of Energy to define covered equipment by late December 2026.

These rules apply to repowers as they do to new construction. The combination of foreign ownership restrictions and domestic manufacturing will influence uptake. Domestic manufacturing is expanding — roughly 75 GWh per year of US lithium iron phosphate cell capacity and every tier of the solar supply chain now have some domestic production — but midstream materials and wafer capacity remain years from meeting demand.

Figure 7

Estimated total tax credit transactions for solar, storage, and solar + storage technologies, H1 2026



Source: Crux analysis

Conclusion

The technical potential for solar repowering is substantial: by 2040, upgrading existing sites could unlock the equivalent of 67 GW of new solar and 92 GW of dispatchable battery capacity, representing roughly $346 billion in cumulative investment. That potential grows as the fleet ages, at a 21% CAGR between 2030 and 2040, as the large, post-2017 utility-scale cohort joins the first-wave assets already reaching replacement age. The advantages of repowering are meaningful: a repower avoids the land, interconnection, and substation costs that new construction incurs, and in markets with functioning surplus interconnection it can bring capacity online in a year or less, rather than the multi-year queues new projects face.

While repowering is less exposed to policy than greenfield solar, where and what shape repowering takes place will be determined by which markets are most favorable to surplus interconnection and how localities treat batteries under existing permits. The current direction is favorable: RTOs are implementing and reforming surplus interconnection service, states have begun directing utilities to use surplus capacity at existing generators, and utilities and large loads are offering contract structures that reward storage at existing sites.

The repowering market that this first asset-replacement cycle creates has not previously been measured. This paper is a first attempt at that measurement. We expect to revisit this assessment as the fleet ages and market practice develops.

Appendix: Methodology

We model repowering using a bottom-up, sector-specific approach that approximates the total addressable market rather than forecasting adoption. We assume each plant is fully repowered, with new modules and new inverters at age 15 (age 20 for residential, triggered by roof replacement) but hold land, racking foundations, and interconnection unchanged.

We measure the fleet's installed capacity by vintage (2006–2025) using EIA data (EIA-860M plant filings and EIA-861 distributed-generation data[4]), split into four archetypes:

- Utility-scale (plants over 20 MWac)
- DG ground-mount (front-of-meter plants at or below 20 MWac, predominantly community solar)
- DG rooftop (commercial and industrial)
- Residential

The energy added comes through two channels. First, new modules eliminate accumulated degradation: output declines 0.75% per year (NREL median system-level loss rate[5]), so a 15-year-old array produces 11.00% less than it did when new. Second, modern modules are more efficient than as-built modules from each vintage (efficiencies from NREL's benchmark-parameter series[6]). We assume module efficiency continues to improve following the International Technology Roadmap for Photovoltaics' 2025 estimates,[7] which projects mainstream crystalline-silicon module efficiency will improve by 2.8 points by 2035. We hold efficiency flat after 2035. Because the added output exceeds the fixed interconnection point, each repower includes a battery.

Each site adds a DC-coupled battery sized to the energy its array curtails on a clear day, computed from the plant's DC/AC ratio (measured per vintage from EIA-860M, or Lawrence Berkeley National Laboratory's Tracking the Sun[8] for residential) and its sun profile. For battery sizing, we assume all ground-mount plants are tracking and rooftop plants are fixed, and we cap storage at eight hours for utility-scale plants and four hours for DG and residential (at the battery's discharge power). Uncapped, the technical potential for storage would be ~10% larger.

System costs come from NREL's PV system cost model at the component level, supplemented with Electric Power Research Institute estimates for removing and disposing outdated equipment. We omit NREL cost components a repower does not incur, such as land purchase and interconnection application. Future costs are assumed to decline following NREL Annual Technology Baseline trajectories.[9] All figures are in 2025 dollars.

[4] EIA-860M, https://www.eia.gov/electricity/data/eia860m/; EIA-861, https://www.eia.gov/electricity/data/eia861/.
[5] NREL, PV Fleet Performance Data Initiative performance-loss-rate analysis, NREL/TP-5K00-92444, https://www.osti.gov/biblio/2522744.
[6] NREL, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, Q1 2025, https://www.osti.gov/biblio/3009689.
[7] VDMA, International Technology Roadmap for Photovoltaics (ITRPV), 2025 edition, https://www.vdma.org/international-technology-roadmap-photovoltaic.
[8] Lawrence Berkeley National Laboratory, Tracking the Sun, https://emp.lbl.gov/tracking-the-sun.
[9] NREL, Annual Technology Baseline, https://atb.nrel.gov/.

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