POWER
PV TECH

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In association with Energy Storage News

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*vs. Standard TOPCon, data from a 100MW utility-scale power plant in Madrid, Spain using TNC 2.0 640W modules

PV TECH POWER

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Introduction

Recent political events in the US have plunged the country's solar industry into chaos. Until 4 July, American PV developers and manufacturers had, as much as is ever possible in this sector, been enjoying a period of comparative stability thanks to the various tax credits created through Joe Biden's Inflation Reduction Act.

But that tranquil scene was blown apart by the passing of the so-called 'One, Big, Beautiful Bill' into law. As the clean energy luminary Jigar Shah puts it in our cover article on p.16, the bill's passing, followed swiftly by a presidential executive order placing further restrictions on the industry, seems intentionally cruel.

Our report explores in detail the likely impacts of the recent federal volte-face on solar and other renewables. Unsurprisingly, it doesn't make for easy reading, and it seems the prospect of a protracted slowdown is strong. But, despite the gloom, the takeaway message is one of optimism: that solar is a resilient technology, is hugely popular and offers the advantages of quick deployment and ever-improving economics that will be hard to ignore as energy demand continues to grows. The industry may be down, for now, but it certainly isn't out.

Elsewhere in this edition, we take an in-depth look at the phenomenon of module glass fracture that has become a growing concern for the industry (p.58). David Devir of technical due diligence provider VDE Americas traces the emergence of the issue and its likely causes. Importantly, he also outlines a pathway to remedying the problem, including a collective industry-wide effort to identify the root causes and new test sequences to screen for problems found in the field.

On p.68, Brett Beattie of Castillo Engineering examines the issue of solar site grading, which, as he explains, is an area ripe for significant project cost savings. With the 'easy' PV sites having already been developed, it's the less straightforward ones with tricky topography and soil conditions that are now at the front of the queue. As we hear, there's a right way and a wrong way to do grading work, and the difference can mean millions of dollars saved or pointlessly spent.

On p.46, Jonathan Touriño Jacobo looks into the blackout that struck the Iberian peninsula in April and left Spain and Portugal with no power for half a day. In the immediate aftermath, speculation was rife that solar was to blame. Well, that was partly true, but not as was initially claimed; as we hear, it was in fact wider systemic failings that lay behind the outage. We discover how the Spanish authorities are moving to remedy the situation, with solar and storage at the heart of the solution rather than the problem.

Finally, our colleagues at Energy-storage.news have put together a bumper section, featuring a quadruple bill of articles. These look at developments in the leading US BESS markets, ERCOT and CAISO, fire safety in battery systems, performance optimisation of hybrid systems and why the time has come for long-duration storage.

As always, we'll be at RE+ in Las Vegas in September and hope to see you there. Quite what the mood will be like remains to be seen. But judging by the optimism expressed in our cover article in the face of gathering storm clouds, it would be reasonable to bet that the industry will be looking ahead for new opportunities rather than ruing the past.

Ben Willis
Editor
PV Tech Power

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ANKER SOLIX
New Product
Coming Soon

Tongwei's TNC 2.0 Series redefines performance standards with breakthrough bifaciality and proven reliability

As the global solar industry evolves toward higher energy yields and long-term performance stability, Tongwei Solar's latest product—the TNC 2.0 module series—is setting new benchmarks. With remarkable advancements in bifaciality, conversion efficiency, and system-level value, the TNC 2.0 shows Tongwei's strong technological leadership.

Building on over a decade of deep integration in the solar supply chain, Tongwei has rapidly ascended as a world-class manufacturer of polysilicon, solar cells and modules. In 2024, the company invested RMB 2.673 billion in R&D, reinforcing its long-term commitment to innovation across the PV value chain. Dr. Xing Guoqiang, CTO of Tongwei Co., Ltd., emphasised the company's focus on emerging mainstream technologies such as TOPCon, HJT, xBC and perovskite tandem, all of which are under active development at its Chengdu-based Global Innovation R&D Center. This facility also houses the world's largest single-site PV testing center by area, capable of performing comprehensive IEC-standard tests with a high degree of intelligent automation—ensuring the performance, safety and reliability of every new product platform.

Bifaciality records certified by TÜV Rheinland

The TNC 2.0 series drives from this innovation engine. Tailored for utility-scale, C&I, and residential applications, the company's G12R-66 TNC module, with a standard size of 2382*1134 mm, has been tested by TÜV with a front-side power output of 682.8 W and a conversion efficiency of 25.28%. Meanwhile, the G12-66 TNC module, with a standard size of 2384*1303 mm, achieved a certified power output of 778.5 W and a conversion efficiency of 25.06%.

Importantly, its rear-side performance is equally compelling. TNC 2.0 modules in R&D have already achieved a bifaciality of over 88%, as certified by TÜV Rheinland and CGC.

Meanwhile, according to a recently posted research paper in Solar Energy Materials and Solar Cells, Tongwei's TNC module, built with advanced TOPCon solar cells, has achieved a bifaciality factor of 91.7%, verified by TÜV Rheinland.

According to Xiajie Meng, Tongwei's Head of PV Cell Development, this was made possible by two key innovations: a selective sunken pyramid structure on the rear side and a zebra-crossing passivation contact design. As for the first one, it helped optimise the rear texture of the non-electrode area of the cell rear side, while the second one was able to optimise the passivation on the rear side and improve the conversion efficiency based on SiO_2/poly-Si/Al_2O_3/SiNx multi-layer composite passivation design. These features significantly increase the harvest of ambient low irradiance and the module's energy yield by per W while extending its effective operating hours.

These performance figures demonstrate not only technical sophistication but also consistent reproducibility in near-commercial conditions. Notably, mass production of modules with >85% bifaciality will start this year, and the company is piloting cells with >90% bifaciality.

Industry-leading reliability validated by KIWA PVEL

Reliability is another cornerstone of the TNC 2.0 offering. In the 2025 Kiwa PVEL PV Module Reliability Scorecard—widely recognised as the industry's most rigorous benchmarking program—Tongwei was again named a "Top Performer."

As one of only two companies in the global top 10 to earn maximum ratings across all categories, Tongwei's modules passed an extensive range of stress tests, including TC600, DH2000, PID192, LeTID486, MSS, HSS, PAN performance test and the newly introduced UV120 sequence. These results confirm that TNC 2.0 modules are built not only for peak performance but also for long-term durability under extreme environmental conditions.

Tangible gains in cost and system value

Beyond lab-validated performance, the TNC 2.0 modules offer clear system-level benefits. According to Allen Xue, VP of Sales & Marketing at Tongwei Solar, the G12R-66 format modules reduce Balance of System (BOS) costs by 1.42% and levelised cost of electricity (LCoE) by 1.65% when compared to market-standard products. They also improve land-use efficiency by approximately 4.6%—an increasingly critical factor in space-constrained installations.

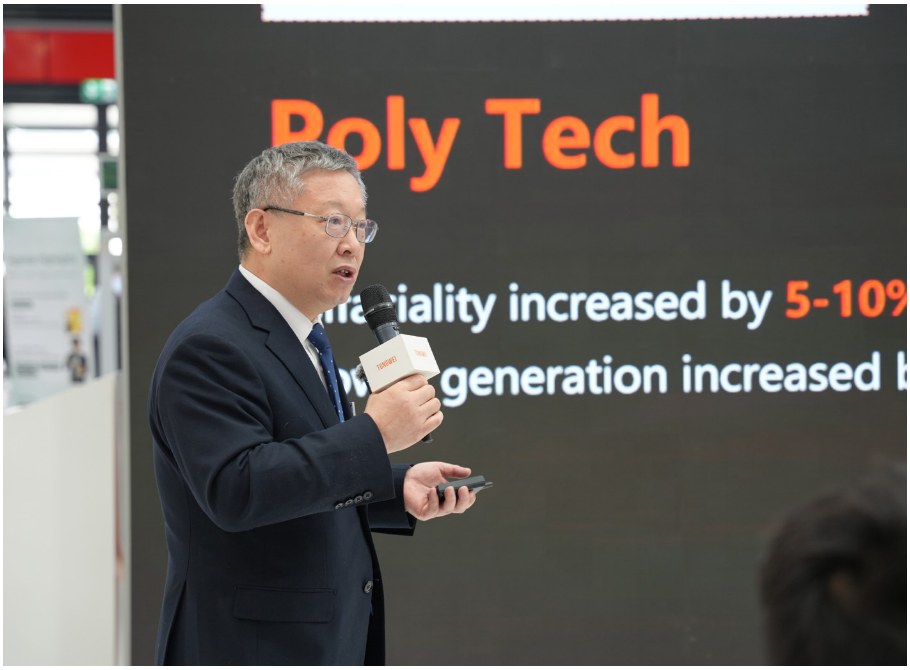
Based on performance simulations from a 100MW utility-scale solar project in Madrid, Spain, TNC 2.0 modules demonstrated an additional energy yield of 0.67% over standard TOPCon modules. Extrapolated over a 30-year system lifetime, this results in 48.01 million kWh of extra power generation—a significant revenue uplift that strengthens project bankability and investor confidence.

Global market strategy

This technical strength is further amplified by Tongwei's globally integrated market strategy. The company's modules are now deployed in over 70 countries and regions, and its business model emphasises co-creation with local partners. "Our approach goes beyond product delivery," said Xue. "We offer multi-dimensional value, from strategic insights on market trends and regulatory policy to joint marketing initiatives that support customer growth." Xue added that Tongwei's ability to flexibly adapt product portfolios and service systems ensures it can meet the specific needs of diverse regional markets.

"Our goal is to foster long-term, mutual value creation with our partners by building together," Xue said.

The TNC 2.0 is more than just a high-performance module—it is a technological platform designed to help global PV stakeholders achieve sustainable, long-term value. With continued investment in future cell architectures and robust field performance data, Tongwei is well-positioned to lead the next phase of PV evolution.



AMERICAS

Indian PV companies among targets of new AD/CVD petition launched in US

Indian PV companies are in the crosshairs of a fresh antidumping and countervailing (AD/CVD) petition lodged by a group of US-based solar manufacturers alleging illegal trade practices by overseas producers.

The Alliance for American Solar Manufacturing and Trade has filed antidumping and countervailing duty (AD/CVD) petitions with the US International Trade Commission (ITC) and US Department of Commerce against Chinese-owned manufacturers operating in Indonesia and Laos and Indian-headquartered companies.

The petitioners, which include First Solar, Mission Solar Energy, Qcells and Talon PV Solar Solutions, allege that Chinese companies that have relocated manufacturing capacity to Indonesia and Laos and companies based in India are harming the US manufacturing industry by violating trade laws on products bound for the US.

The group cited a number of alleged illegal subsidies that enable producers in the identified markets to undercut producers based in the US. Additionally, it identified dumping margins of 89.65% for products coming from Indonesia, 213.96% for Indian products and 245.79-249.09% for products from Laos.

Credit: Tim Evanson via Flickr

AD/CVD petitions against Indian and other foreign companies have been launched with the US Department of Commerce

Average distributed solar module price hits US$0.27/W in the US at the end of June

The average price of solar panels used in distributed generation projects in the US increased from US$0.25/W at the start of the year to a high of US$0.28/W in May, before settling at US$0.27/W at the end of the first half of the year.

These are figures from Anza's July report into module price trends in the US distributed solar sector. The report notes that while June figures are still 3.6% lower than the high reported in May, this is still 12% higher than the prices reported in February 2024, which Anza suggested could be related to ongoing imposition of antidumping and countervailing duty (AD/CVD) tariffs on solar products from a number of markets.

For instance, cells from the four countries now covered by AD/CVD tariffs – Cambodia, Malaysia, Thailand and Vietnam, upon which tariffs as high as 3,521.14% – cost close to US$0.3/W in May, before falling to US$0.26/W in June.

Georgia Power's Integrated Resource Plan to add 4GW of renewable energy capacity by 2035

The Georgia Public Service Commission (PSC) has approved US utility Georgia Power's 2025 Integrated Resource Plan (IRP), which will see the utility aim to install 4GW of new renewable power capacity by 2035.

Georgia Power expects 8.5GW of electrical load growth in the state by 2030, an increase of over 2.6GW compared to the forecasts made in 2023. The approved 2025 IRP sets out Georgia Power's activities to meet this demand.

While some of the new power projects are not renewable energy – including a planned expansion of the Vogtle nuclear plant and upgrades to a natural gas plant near Savannah – the utility announced that it would focus on "economic new renewable energy procurements" through a competitive request for proposal (RFP) process.

California AB 942 removes controversial residential PV policy

The California Senate Energy, Utilities and Communications Committee has amended Assembly Bill 942 (AB 942) and removed a net metering amendment that would have affected residential solar owners' rates when acquiring a home or property.

In its previous iteration, AB 942, introduced by assembly member Lisa Calderon – a former utility executive – sought to have customers buying a property with an existing solar system to switch their net energy metering (NEM) tariff to the most current one instead of inheriting the one from the previous owner.

Had this policy gone through, it would have exposed new owners to a significant decline in net metering payments, with export rates for selling electricity back to the grid slashed by nearly 75% between NEM3.0 and previous iterations.

"This decision is a tremendous victory for California families and businesses who invested in rooftop solar with the state guarantee that their net metering agreements would remain intact—even if they sell their homes," said California Solar & Storage Association (CALSSA) executive director, Brad Heavner.

Model outlines survival plan for US residential PV as IRA cuts bite

Solar adoption platform OpenSolar has launched a new model aimed at helping US solar installers reduce the cost of a system by 50% and in the process reverse the decline of the US rooftop PV market.

The OpenSolar model details how US installers can cut their costs and continue operating without subsidies, drawing on best practice from markets where costs are much lower. The US residential solar market has been struggling in recent years, with changes to California's net metering programme driving a sharp decline in 2024.

OpenSolar CEO and co-founder Andrew Birch said: "Everyone's asking what happens when the ITC goes away. The better question is: what if we can stop relying on it?"

Speaking to PV Tech, Birch said the "fundamental truth misunderstood by everyone in the market" is that solar costs twice as much in the US as it does everywhere else in the world.

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ASIA

LONGi and JA Solar reduce Q2 losses, Aiko achieves quarterly profit

Supply-demand imbalances across the industrial chain and inventory pressures have driven down product prices and negatively impacted the operational performance of several listed Chinese PV companies that released their 2025 interim performance forecasts.

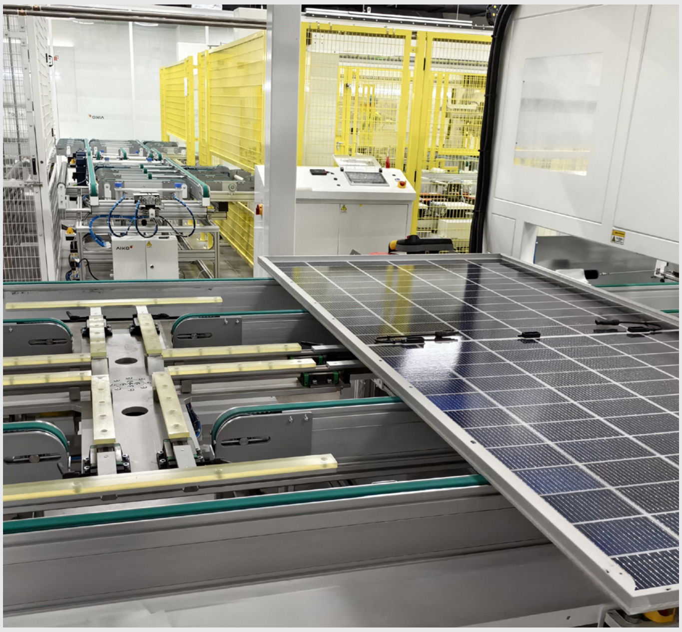
Taking TCL Zhonghuan, LONGi Green and JA Solar as examples, all three are expected to report losses exceeding RMB2 billion (US$278.6 million) in the first half of the year. These are among the largest revenue-generating companies in the PV industry.

TCL Zhonghuan's interim performance forecast stated that the company expects a net loss attributable to shareholders in the range of RMB4-4.5 billion in the first half of the year.

Although still in the red, leading module manufacturers LONGi Green and JA Solar have shown signs of improvement, with both reporting a quarter-on-quarter narrowing of losses in Q2.

In Q2, Aiko is expected to post a net profit of RMB20-130 million, making it currently the only PV material manufacturer to be profitable in a single quarter.

According to Aiko's earnings forecast, the company expects to report a net loss attributable to shareholders of RMB170-280 million for H1 2025.



Credit: Aiko Solar

Aiko Solar managed to turn a profit in Q2, the only producer to do so

SAEL to build 10GW solar cell and module plant in India

Indian renewable energy company SAEL Industries is developing a 5GW solar cell and 5GW module manufacturing facility in Greater Noida, Uttar Pradesh, located approximately 43km south of New Delhi.

SAEL, through its subsidiary SAEL Solar P6 Private Limited, is investing INR82 billion (US$954 million) in the project, which is set to begin construction later this year. Once operational, the facility will boost SAEL's total solar manufacturing capacity to 8.5GW.

The plant will manufacture Tunnel Oxide Passivated Contact (TOPCon) solar cells, known globally for their high efficiency. These cells will be integrated into solar panels on the facility's in-house module assembly line. The project complies with the Government of India's Approved List of Models and Manufacturers (ALMM) policy, ensuring adherence to domestic quality and sourcing standards.

Sukhbir Singh Awla, director of SAEL Industries Limited said: "Setting up this integrated facility in Uttar Pradesh allows us to bring technology and manufacturing close to home while contributing actively to India's clean energy transition."

APAC led 589GW global PV inverters shipments in 2024

The Asia Pacific (APAC) region was the destination for 69% of the 589GW solar PV inverters shipped in 2024, according to a report from research firm Wood Mackenzie.

Led by China, the APAC region accounted for nearly all of the 10% annual growth in inverter shipments last year, with demand in both Europe and the US declining.

China accounted for more than half of the global demand with 330GW, representing a 14% increase from 2023.

Wood Mackenzie's report also looked at the supply side. For a tenth consecutive year, Chinese PV inverter providers Huawei and Sungrow have ranked first and second. The two companies have combined for more than half (55%) of the global inverter market. It is a market that has been dominated by Chinese headquartered companies, who account for nine out of the ten top global solar PV inverter vendors.

India to add 28.3GW solar PV in FY26

India will install 28.3GW of utility-scale and rooftop solar PV during fiscal year 2026, forecasts JMK Research.

According to the latest Annual India Solar Report Card – FY2025, JMK, India is set to add 21.15GW of utility-scale solar and 7.15GW of rooftop solar PV between April 2025 and March 2026.

India installed 7.8GW of solar PV in the first three months of FY25 and by the end of March 2025, it had commissioned 85.5GW of utility-scale solar, with 68.2GW in the pipeline.

The western Indian state of Rajasthan remains the leading state for utility-scale solar, with 26.9GW installed followed by Gujarat with 12.8GW and Karnataka 10.6GW respectively.

SECI launches 1.2GW/3.6GWh solar-plus-storage tender in India

State-owned firm Solar Energy Corporation of India (SECI) has launched a solar-plus-storage tender seeking 1.2GW of solar PV.

SECI issued a request for selection (RfS) on the week of 19 June for the competitive solicitation process and aims to hybridise the solar PV generation with 600MW/3.6GWh of battery energy storage systems (BESS), ahead of connection to the Inter-State Transmission System (ISTS).

Successful bidders will enter into a 25-year power purchase agreement (PPA) with the agency for their build-own-operate (BOO) projects. Adding battery storage to the projects will enable power to be supplied during peak demand periods.

A pre-bid meeting for the tender takes place on 10 July 2025, and bidding will open on 21 August.

EMEA

Solar PV becomes EU's largest monthly power source for first time in June 2025

For the first time ever, solar PV was the biggest source of electricity in June 2025, according to data from energy think tank Ember.

Many European Union (EU) countries produced record amounts of solar power during that month, which led solar to overtake nuclear power with the highest share of electricity generation, with 22.1% versus 21.8%, respectively.

In total, solar PV generated 45.4TWh of electricity in June 2025, a 22% increase from the same period in 2024.

Credit: Sungrow via Unsplash

In June 2025, solar PV was Europe's biggest source of power for the first time

Europe signed 4.2GW solar PV PPAs in H1 2025

Companies signed 4.22GW of solar PV power purchase agreements (PPAs) in the first half of 2025, according to Swiss consultancy Pexapark.

This is a slight increase from the nearly 4GW of solar PV PPAs signed during the same period in 2024. However, it wasn't enough to offset the overall decline of renewable PPAs contracted in H1 2025, which dropped by 25% year-on-year.

Looking more closely at the landscape of European solar PV PPAs, the number of deals has significantly decreased from 95 signed in H1 2024 to 73 in H1 2025. After registering one of its lowest months since 2020 in May, renewable energy PPAs grew by more than 700% in June compared to the prior month, with nearly 1.4GW of capacity signed compared to the prior month.

Solar PV accounted for most of the volume signed in June, with 1.2GW across 12 deals.

Poland awards 1.6GW of solar PV in latest tender

Poland has awarded 1.6GW of solar PV in this year's renewable energy auction, according to the country's Energy Regulatory Office (URE).

A total of 129 bids were awarded for projects greater than 1MW, with all but three of them for solar PV. The remaining three bids were approved for wind projects.

Less than half of the volume (15.8TWh out of 32.25TWh) was awarded in the auction, which had nearly PLN8.9 billion (US$2.44 billion) allocated for the purchase of 32.25TWh of electricity.

The reference price for solar PV projects was set at PLN389/MWh (US$106.9/MWh), with the minimum price awarded at PLN216.9/MWh and the highest bidding price awarded at PLN329.68/MWh.

Among the solar companies awarded capacity are ib vogt, PAD RES and OX2, which recently started operations at a 100MW solar PV plant in southern Poland.

ACWA Power signs 12GW solar PV PPAs in Saudi Arabia

Saudi Arabian power developer ACWA Power has signed power purchase agreements (PPAs) with Saudi Power Procurement Company (SPPC) for five solar PV projects in the country.

As per the agreement, the five PV solar plants include Afif1, Afif2, Humaij, Bisha and Khulis, located across the central, western, and southern regions of Saudi Arabia. Afif1, Afif2 and Khulis will each have a capacity of 2GW. The remaining two projects, Humaij and Bisha, will have a capacity of 3GW each.

The portfolio of solar PV projects is expected to be operational in the second half of 2027 and the first half of 2028, while the company aims to reach financial close in Q3 2025.

UK government will not sign CfD for 11.5GW Xlinks Morocco-UK interconnector

The UK government has decided it will not sign a Contract for Difference (CfD) with Xlinks for the 11.5GW Morocco-UK interconnector project.

Officials from the Department for Energy Security and Net Zero (DESNZ) engaged with Xlinks to understand the details of the proposal and concluded that it was not aligning with the government's goal to build homegrown power in the UK.

This decision came only days after the government released its Industrial Strategy, including a Clean Energy Industries Sector Plan that it said will "ensure the clean energy revolution is built in Britain".

BayWa r.e. secures US$3.5 billion to build its renewables portfolio

German renewables company BayWa r.e. has secured a €3 billion (US$3.5 billion) loan for "operational initiatives and pipeline expansion".

Under the agreement, the funding package – including bank loans, shareholder loans and operational guarantees – remains valid until mid-2029. It includes €435 million (US$ 508 million) secured in March this year.

According to the Munich-based company, this financial package will strengthen its position as an independent power producer (IPP). The funds will be used to plan, develop and construct wind, solar and battery energy storage system (BESS) projects, as well as the operation and maintenance of such assets.

BayWa AG retains a 51% majority stake in BayWa r.e., while Energy Infrastructure Partners (EIP) holds the remaining 49%. The IPP has commissioned over 6GW of renewable energy capacity and manages more than 10.5GW of assets.

'Solar will continue to deliver'

Policy | Legislation withdrawing vital tax credits has plunged the US solar market into turmoil, putting project deployments and manufacturing at risk. But, as Will Norman reports, despite the prospects of a downturn, the industry remains defiant over its long-term future

Credit: Pexels/Ramaz Bluashvili

Many didn't think it would happen. Before the election, the US solar industry broadly thought the Inflation Reduction Act (IRA) would weather a second Trump administration. It wouldn't make economic sense to scrap it, they said. Red states had benefited too much to ditch tax incentives. And besides, the legal complexity of repealing the bill would be too great. Those predictions were wrong.

It's now clear the White House is attacking renewable energy and the federal apparatus which sustained its growth over recent years.

With MAGA tanks parked firmly on its lawn, the path forward for the solar industry is uncertain. Alongside tariffs, sweeping changes at the Department of Energy and orders to clamp down on solar and wind permits, tax credits are on the chopping block.

The rules of the game have changed, but many of the facts haven't. Energy demand will continue to grow, driven largely by data centres and the growth of AI. Fossil fuel emissions still cause climate change. Solar is the fastest-growing new source of US energy generation.

We spoke with leading US industry analysts, participants and lawyers to understand the state of play for the solar sector and look forward to what might come next.

Congress's approval of the 'One, Big, Beautiful Bill' has caused a political rupture for the US solar industry

The state of play – ITC, PTC

July's budget reconciliation bill – the 'One, Big, Beautiful Bill' – introduced an early end to the 30% 48E Investment Tax Credit (ITC) and 45Y Production Tax Credit (PTC) previously available under the IRA.

Solar and wind projects that begin construction before 4 July 2026 – one year from when the bill became law – are eligible for the credit under current "safe harbour" regulations. Those that start construction after that date must be placed in service by 31 December 2027. Projects which begin construction within that 12-month window are not required to be in service by the end of 2027. Projects which began construction before 2025 are generally safe from repeals.

The safe harbour also protects projects from Foreign Entity of Concern (FEOC) restrictions, which prohibit exposure to financial backing or "material support" from Chinese firms (as well as Russian, Iranian and North Korean).

The dates are key. The safe harbour for the 30% ITC or PTC is contingent on the definition of "start construction". Under the bill's wording, that may require developers to spend 5% of the project's total estimated cost by the deadline. They can also start "physical work of a significant nature" to access the safe harbour, "which can be something as simple as having a custom transformer made for you in a factory", according to Christian Roselund, senior policy analyst at Clean Energy Associates (CEA), who spoke to us for this piece.

Bob Moczeluwski, director at accountancy and tax advisory firm Baker Tilly, says similarly. "Ordering transformers has been a traditional one because they're [already] in some guidance on establishing the beginning of construction, and they're bespoke." We also heard that building maintenance roads for a project might count as "significant" physical work.

But the reconciliation bill's definition of starting construction might become irrelevant. The law was signed on a Friday; on the following Monday, president Trump issued an executive order which could rewrite the rules.

'Cruelty is part of the point'

The executive order gives the Treasury 45 days to assess stricter safe harbour rules than those in the bill. It wants to combat "artificial acceleration or manipulation" of safe harbour rules, and orders that "a substantial portion" of a project must be built for it to be eligible.

This targeted attack might dramatically reduce the number of solar projects that will secure safe harbour in the next year, with real impacts on deployments.

"The [order's] full impact is hard to predict," says Aaron Halimi, president and founder of US developer Renewable Properties. "One way or another, it's going to change the economics of building solar."

Roselund says: "That order will be a significant challenge for the industry. Our estimates were that there were 100GW of projects that planned to start construction by the end of the year, but now much of that is at risk."

It's not clear what a "substantial portion" of construction means. "The wording of the executive order suggests that you may have to do significant work on-site to claim start of construction," Roselund says. He also sees a "significant risk" that the order could be applied retroactively.

Despite some speculation, Robert Romeshko, partner at law firm Husch Blackwell, says the administration would "have trouble" applying new guidance retroactively; "There's relatively little precedent out there". However, he says that as the guidance is under review, the industry shouldn't assume it won't change. "Certainly [there is] a line of precedent which says that if you're on notice that they're re-examining something, you [risk] having the rug pulled from under your guidance."

The executive order represents the first move in a direct attack on clean energy, going beyond Congress's provisions. At Trump's behest, the Department of the Interior has also introduced tighter restrictions on permitting solar and wind on federal land, to combat what it calls "the Green New Scam".

As Jigar Shah, former director of the Department for Energy's Loan Programs Office (LPO), sums it up to us: "It feels intentional. It feels like the cruelty is part of the point of the whole thing. The problem is that once a bill passes, to then have an executive order that says we are going to deliberately put more uncertainty into the process on purpose – that feels personal. And that, I think, is the part that is the most upsetting. Because you're talking about hundreds of thousands of people in the United States, millions, even, who are working every day to make sure that we have the essential electricity generation added to the grid to be able to meet our economic development goals. And what signal exactly is it that you're sending to them about how important their role is in the energy system?"

You can read more of what Shah has to say in the box on the following page.

'Be prepared for an audit'

Whatever the language means, it seems certain there will be a rush to get projects moving before June 2026 and prove the start of construction.

"The plan was to lock in 100GW or more of projects in the next 12 months," Roselund says. "Based on conversations with developers, we estimate that 30GW of projects have already locked in start of construction from the beginning of this year.

Aaron Halimi says the industry must "move quickly" and have "robust documentation to prove project eligibility before potential rule changes".

Indeed, developers should "be prepared for an audit", according to Romashko. "People need to assume someone's going to want to look at that [documentation] at some point, and you don't want to have holes in it." He predicts that the IRS will increase enforcement on renewables, even as the Treasury itself is cut back. Given the "cruelty" on display against the industry already, it's hard to argue.

But there may be workarounds.

"As smart as the politicians like to think they are, the tax professionals and industry leaders ultimately become a lot smarter in the whole process," Moczeluwski says. "There are creative ways within the industry to set things up."

Last year, overturning the "Chevron defence", the US Supreme Court granted courts more freedom from federal agencies' interpretations of ambiguous laws. With a federal government hostile to renewables – and a lot of ambiguity – this could benefit the industry, though its impact will likely be case-by-case.

"You can [now] look at any regulation, IRS regulations included, and ask how much water they really hold," Moczeluwski says.

"Guidance is just guidance," Romashko says, "and you're always free to say we don't think this meets the statute and try to take another position. But you assume risk by doing so."

It's another turn of the solarcoaster

This year will be a big year for new projects as the industry rushes to start building. After that, things start changing.

"2026 will likely be a big year for putting projects in service," Roselund says. "And then in 2027, the changes made to eligibility for these tax credits will likely start to affect deployment levels. In 2028, all major market analysts expect to see a significant decline in deployment. And after that, the size of the market will depend on what deployment levels look like without the tax credits."

"It's another turn of the 'solarcoaster'", he continues. "There's still a solar market without the tax credits. CEA's analysis estimates that it is roughly half as big and it's a lot more geographically focused in states that have renewable energy mandates.

"Based upon binding renewable energy mandates, we expect that the Northeast will still install solar; Minnesota will still install solar, for the same reasons; Colorado, New Mexico, and Nevada will also still install solar.

"Texas doesn't have renewable energy mandates, so the market is more dependent on federal subsidies. FPL in Florida has plans to build a lot of solar, but we will see how changes in incentives affect that. There are large parts of the country, including the South, the plains states, and much of the Midwest, where the loss of incentives will likely affect the market more."

Energy mix could become another divide in polarised modern America.

'A flight to quality'

The industry will likely consolidate. Noam Yaffe, vice president at market intelligence firm Pexapark, expects big developers and investors to succeed and grow, while for smaller firms, "this is the most painful thing that you've experienced in the last decade plus. It's in many ways catastrophic for these businesses."

Aaron Halimi predicts a "flight to quality". "Investors will prioritise experienced developers with proven track records," he says. "In the short term, the uncertainty may put a lot of pressure on smaller developers, but I think any consolidation is going to make the solar industry stronger and prepared for an unsubsidised market."

But changes to the solar industry have implications beyond its own immediate concerns.

"What we're talking about today is powering the entire US economy. We're no longer talking about the solar industry," Jigar Shah tells us.

"AI, growth, manufacturing, all those priorities are at risk because of these dislocations in the market. It used to be that when we called things the 'solarcoaster', we were talking about the commercialisation of solar power. Today, we're fully commercialised and actually providing essential services to the US economy."

Some forecasts say that US electricity demand will grow by 50% by 2050, driven by transportation and data centres. The International Energy Agency (IEA) identified the US and China as the predominant development markets for data centres and AI. In Yaffe's words, "Solar is the best" solution for cheap, fast power.

The US might have shot itself in the foot if these policy changes collapse the solar market as much as Roselund and others predict. On the other hand, demand from big tech and other industries won't disappear overnight.

"I think [big tech companies] will continue to buy renewables," Yaffe says. "It's the right thing to do, and these companies genuinely want to reduce their carbon footprint." This optimism will be tested in the coming months and years, as will the eco-conscious claims made by firms like Meta.

But it's unlikely everyone will do the right thing. Markets don't have a conscience, nor do businesses.

"I was talking to someone who was going to buy between 3-4GW of renewables in ERCOT over several years," Yaffe says. "But now they're building data centres and trying to co-locate them with gas plants. Renewables are a nice plus, but it makes no difference to them."

We know that energy prices will go up as supply drops. The government will back more gas plants, which have a lead time of around seven years. We know some small developers will disappear. But demand for renewables won't; states will keep mandating new clean energy and the industry will find ways to realise

Plenty of capital, no projects to invest in

The veteran clean energy entrepreneur Jigar Shah speaks to Ben Willis about the impact of recent legislation on investment

The term 'solarcoaster' is well known in PV industry circles. It is popularly used to describe the highs and lows of a technology that, in most markets where it has appeared, has been supercharged by government backing of some kind before plunging to earth again as that support is withdrawn.

The solar industry has been around long enough now to see that the dips in the ride usually even out and eventually return to some kind of upward trajectory, as the economics of PV, especially coupled with increasingly cost-effective battery storage, win the day. Often, the second wave of growth is more sustainable than the first, as it is less cuopled to the whims and shifting priorities of politics.

According to US clean energy veteran, Jigar Shah, the highs may yet come again for the US solar business, but right now it's hard to look beyond the current crisis. The immediate challenge for solar industry stakeholders is weathering what Shah says looks like a personal, indeed cruel, attack on their business.

"We can talk about the longer term in rosy ways, in terms of the continuing cost reduction of solar and battery storage," he says. "But, right now, developers have a hard time keeping their promises to investors because they have a president in place who's not honouring deals made with the legislators that passed the bill. I thought we had a deal when the bill was signed. But then, right after, the President came out and said I'd like to create a whole bunch of additional confusion."

Shah is referring to the executive order issued only days after the passing of the "one big beautiful bill", the budget reconciliation package that has rolled back much of the support underpinning the US clean energy sector's rapid advances in recent years.

As explored in our main feature, the bill and subsequent executive order have created multiple layers of complexity and anxiety for US clean energy businesses as investors, developers and the wider supply chain scramble to understand what the new rules mean for them.

Of particular concern to Shah is the question of what energy investors will do with capital that is still looking for a home, regardless of recent political events. Even technology-agnostic energy investors will find life difficult because the alternatives for their money to clean energy—coal and natural gas—lack shovel-ready projects ready for investor dollars.

"Investors feel like they are not being given clear direction as to what to invest in," says Shah. "Even if you're talking to investors who have no climate agenda, they still need projects that have met the checklist. And what you find is that most of the natural gas projects in the United States have not met the checklist. They're still three years away from having all their paperwork in place. So if you're in the business of investing capital, and your bosses have given you US$50 billion to invest in clean energy or whatever it is, they're saying, 'Why have you not put the money out the door?' Everybody has to put money out the door."

its projects. But this is only one side of the story.

Even bigger impacts to manufacturing

"We at CEA expect this bill to result in a decline in US solar deployment, but we expect even bigger impacts to clean energy manufacturing," Christian Roselund says.

The roughly 50GW of US module manufacturing capacity represents millions in investment and thousands of jobs. But that expansion is under threat, too.

The 45X Advanced Manufacturing tax credit is preserved under the OBBB act, which accords with Trump's stated aim to bring back American jobs, particularly manufacturing jobs.

But one industry analyst who spoke to us called this aim "doublespeak", and the Solar Energy Industries Association (SEIA) previously warned the bill could risk over 300,000 jobs in the solar sector.

The problem is the FEOC restrictions. Projects directly owned by, under "effective control" of, or receiving "material assistance" from a designated foreign entity (read: Chinese entity) cannot receive the 45X credit. China and Chinese-controlled firms dominate over 80% of every stage of the solar supply chain, putting particular strain on the "material assistance" provision.

"If you're making modules, you have to get your cells from a non-FEOC company in order to access 45X," Roselund explains. US cell capacity is currently below 10GW, massively behind module capacity.

"And if you're making cells, you have to get your wafers from a non-FEOC company, and there is a limited supply of those that is both non-FEOC and not subject to AD/CVD duties," he continues. There is currently no US wafer manufacturing capacity.

Elissa Pierce, research analyst at Wood Mackenzie, said in July: "Despite billions in tariffs and years of diversification efforts, Chinese companies still control manufacturing through regional subsidiaries. When Malaysian glass suppliers and Vietnamese frame manufacturers are Chinese-owned operations, we're not achieving energy security. We're simply paying higher prices for the same supply chain risk.

"These new market distortions could ultimately harm [US] renewable energy deployment while potentially precluding domestic manufacturers from receiving the 45X tax credits due to the FEOC restrictions."

As with the developer market, big players will likely weather the storm and secure the credits.

First Solar will likely be able to secure the credit, as its cadmium telluride (CdTe) technology is largely isolated from Chinese supply and it's well established in the US market. Qcells' integrated factory in Cartersville, Georgia, will also likely receive the credit, as it can access non-Chinese supply deals through its Korean owner, Hanwha.

Indian firms, like Waaree – which owns a module production facility in Texas – will be able to import Indian cells and secure the 45X credit for that facility.

"CEA expects the FEOC-owned companies to divest a portion of their ownership rather than have to close down factories, which can't compete without the 45X", Roselund says.

More concerningly, he says, "To build and operate a solar factory in the US, you need to be able to sell the goods that you make in that factory into the US market. There is no business case to export overseas. That means that if or when the domestic solar market shrinks, domestic solar factories are at risk."

When the ITC and PTC phase out, they will take the domestic content bonus credit with them – Roselund says this removes the financial incentive to buy domestic modules. Coupled with inability to access the 45X credit, a number of US module factories may be stuck in limbo.

The potential fate of those factories is

Right now, all eyes are focused on the US Treasury's response to Trump's executive order and how that will be implemented. The 45-day deadline given to the Treasury was due to pass after this journal went to press. Once the new rules are known, there will be a period of time for them to be implemented and, most likely, court challenges, says Shah.

"In the meantime, there are many electric utility companies and others saying to the administration, hey, if you mess with these rules in a way that will make it difficult for us to deploy, then we may, in fact, have rolling blackouts," Shah warns. "So you need to be careful with how you do this, because if you do this incorrectly, then we will not be able to maintain service. We understand that you think that the solar industry is self-interested, but we, as the utility industry, are not self-interested. We're happy to install coal or natural gas or whatever it is, but we're just telling you that those are not options that are ready in the near term."

A further irony not lost on Shah is that if the net intention of federal policy is to push utility investors towards coal or gas projects, the result will be further reliance on China as the source of the necessary hardware.

"Many of those supply chains … are coming from China," Shah says. "I mean, the US doesn't manufacture coal components anymore, right? So we would have to import Chinese coal components."

Credit: First Solar

hardly rosy, with a shrinking market and no federal support. And there's a kicker.

"Foreign entity rules only come into play when you're trying to qualify for the ITC or the PTC," Roselund says. "But once those incentives phase out, companies will naturally look to source modules from wherever they can get the best price globally."

This could result in uncompetitive US products and all but a few leading producers closing down or selling up.

Once again, this is prediction, not prophecy. Halimi says: "In general, developers are going to prioritise US-owned manufacturers with documentation that they're free of FEOC concerns." He continues: "Of course, everyone's going to have that strategy, pushing up module prices. If the economics are better procuring equipment from outside the US, we'll have to do that to reduce our costs and, ultimately, electricity prices."

Supply chain, pricing and tariffs

Wood Mackenzie says the "complex web of tariffs and policy restrictions" is reshaping global solar supply chains.

Modules will get more expensive, adds Mike Hall, chief executive of solar supply chain platform, Anza. "It's possible that we'll see, over the coming weeks and months, a pricing spread between Chinese and non-Chinese companies. We haven't seen it yet, but that could emerge."

As developers rush to buy modules before the bill's deadlines, Hall says he's seen a divergence in strategy. Some "[who] want to purchase from the handful of suppliers they feel confident are not going to be subject to FEOC" have "focused on non-Chinese modules", says Hall. "But we also see a lot of companies purchasing from Chinese [manufacturers] now because they're concerned about their ability to do so in the future."

Trump's "reciprocal" tariff regime will also make solar products more expensive. That increase will likely be passed on in higher power prices.

The Middle East, North Africa and Turkey are expected to become alternative supply sources. However, Wood Mackenzie said most planned capacity there will not be online until 2026 at the earliest, and most is Chinese-owned, which may prevent developers using those products from accessing tax credits thanks to FEOC.

'We want to do the right thing'

"I think the industry can survive this. We've survived storms before, we're going to get through it," Yaffe says. "The difference with this industry and other industries is we're all here because we want to make a difference and do the right thing."

Beyond the specifics of market dynamics and uncertain policy, the industry believes it will continue to progress. "The US solar and storage industry can certainly stand on its own without subsidies. I wish the fossil fuel industry could say the same after over 100 years of subsidies," Halimi says. "AI data centre demand is too high, and with or without subsidies, solar is still going to be the fastest and cheapest way to meet that demand. Compared with gas, solar and wind are still the least expensive source of energy, even without subsidies, and there's a five-year wait for natural gas turbines."

Big utilities will also still set and meet green energy targets, states will mandate renewables and companies have international emissions targets they'll be unlikely to abandon. "A significant portion of the country lives in states that have binding aggressive renewable energy mandates," Roselund concludes.

First Solar is among a small group of US PV producers expected still to be able to access manufacturing tax credits. Others will find it harder

But rose-tinted glasses serve nobody. The situation has changed, and the government has made moves to directly hamstring renewables, particularly solar energy. In a few short months, the industry is facing the removal of mechanisms which have enabled its recent boom.

Yaffe is right. The difference between renewables and other energy industries is the urge to "do the right thing"—to transition away from fossil fuels and combat man-made climate change. Can you trust a market to do the right thing? What about one where sourcing and permitting for renewables are deliberately made difficult? The US is the second-highest carbon emissions producer and the largest economy in the world—what it does matters.

"This is my hot take: I think we need to get away from government intervention in renewables," Yaffe says at the end of our conversation. "I think this could be when the history books say, 'this was the beginning of when renewables broke free, became a thriving and scalable industry.' I don't think we can rely on the government anymore. I think the uninterrupted free market can absolutely create incredible things, like a renewables boom."

The same free market drove the climate change that necessitates renewables, and big fossil fuel firms like bp and Shell have rowed back on energy transition commitments under shareholder pressure, putting short-term profit over long-term priorities. They never drove the renewables market, but they show the priorities of some market forces. Then again, Yaffe is right that the industry can't rely on this particular government, so maybe it's better off on its own two feet.

Uncertainty is the operative word, for now. Abigail Ross Hopper told *PV Tech Power*: "Here's what I know to be true—the solar and storage industry is resilient. Our industry has a value proposition no other sector can match: clean, fast, local power that lowers costs and boosts resilience.

"Americans will still demand energy choices, and the solar and storage industry will continue to deliver them." ■

To learn more about the future prospects of rooftop PV in the US, turn to p.22

In search of silver linings

Rooftop solar | Although residential solar in the US has lost its main tax credit, there is still hope that its popularity and fundamental economics, helped by a concerted effort at city and state levels, could yet win the day. Ben Willis reports

Credit: Sunnova

Rooftop solar in the US has the chance to move to a more stable footing despite the withdrawal of the ITC

The loss of the 30% investment tax credit hitherto available for residential PV installations in the US is a further blow to a segment that was already struggling. Changes to net metering rules in America's rooftop solar powerhouse, California, created a chilling effect that had begun to spread and led to a 31% decline in the market in 2024, according to analysts Wood Mackenzie.

According to Sachu Constantine, executive director of lobby group Vote Solar, the loss of the ITC is therefore a "big deal" for the sector, on top of the other policy and financing challenges it was already facing. But for Constantine and other rooftop solar advocates, the end of the ITC does not spell the end of the rooftop solar market in the US. Far from it.

What the legislative disruption instigated by the passing of the so-called 'One, Big, Beautiful Bill' does not change is the fundamental value of solar, Constantine says: "What we know is that solar, especially rooftop solar, as a part of the portfolio, makes the overall grid more affordable. It increases resilience and reliability, and it adds affordability."

These attributes provide the bedrock of the case that Vote Solar and others are now making on a state-by-state basis, where many of the key decisions on energy issues are taken. "States have a lot of influence," Constantine says. "State regulators and the utilities themselves in their service territory have the ability to still streamline solar and solar choice. They can make it part of their portfolio. They can reduce the interconnection and permitting costs and delays, and they can provide fair compensation. And you know, from our point of view, they have every motivation to do that, regardless of the headwinds."

With that in mind, Vote Solar is therefore targeting these actors as it seeks to keep the pressure up in the wake of government policy reversals. The organisation has campaigns running in several states across the US seeking to influence policymakers, legislators, regulators and others to ensure solar remains top of the agenda during this time of federal pushback.

This will not be easy. For example, Vote Solar has been actively engaged in trying to change the balance between fossil fuel and renewables in the integrated resource plan for the state of Georgia, recently signed off by the regulator, the Georgia Public Services Commission. In the event, in mid-July, the decision went the way of the utility, Georgia Power, and its desire to increase fossil fuel capacity to meet growing demand from data centres. But it will be future battles like these that Vote Solar will be seeking to influence in favour of solar. As Constantine points out, there is some 150GW of PV that could be connected in short order; with load growth ballooning and gas or coal generation in no place to take up the slack in the requisite timeframe, the case for solar and storage will be hard to ignore.

"We're going to put pressure on governors, legislatures and regulators to understand that jobs are on the line, that affordability and resilience and reliability are on the line, and that solar is the practical common solution to all of these things," he says.

Driving down costs

A few days after the budget reconciliation package was passed by Congress and the solar industry was absorbing its implications, an interesting intervention came in the form of a new cost model for US residential solar released by Andrew Birch, the CEO of OpenSolar, a design, sales and project management software platform for solar installers. Based on international data, Birch's model detailed how US residential PV costs have typically been around twice as high as those in markets such as Australia, Germany and others with high levels of rooftop PV penetration.

For example, Birch points out that in Australia, where rooftop solar penetration runs at about 33%, costs are around US$2 per watt. By comparison, in the US, installing a residential solar and battery system costs around US$5/W. Birch describes this fact as a "fundamental truth" about US rooftop solar, and one that explains its ongoing reliance on subsidies such as the ITC and relatively lower penetration rate than markets such as Australia.

His model details where those addition-

Credit: OpenSolar

al costs reside and, importantly, how they could be squeezed out to bring the overall cost of US residential solar down to around US$2.50/watt. One big factor is the onerous permitting process in the US.

"If I decide to go solar with a UK installer today, I could get one installed on Friday, and the cost would be US$14-15,000 equivalent. If I do that in the US, I will go through somewhere between a two-to-six-month process of permitting, with multiple site visits, full documentation, paperwork… There are 16,000 jurisdictions in the US, each has its own planning process, so you have this incredibly laborious and expensive process to install the solar. The net result is US$5 a watt. It's US$2 a watt in Australia."

If these factors can be addressed, Birch argues that US residential PV can flourish without the need for subsidy. The technology already exists in the form of Solar APP+, an automated permitting platform developed by NREL and others and initially funded by the Department for Energy. "With automated permitting allowed in your area, and with efficient digital tools to design, sell, purchase, invoice and project manage, US$2.50 per watt is achievable," he says.

Like Constantine, in the absence of federal support, Birch believes more localised action holds the key to the future success of PV in the US. He says several states already have automated permitting processes in place, and several more are looking at it. Though he admits the prospect of getting all administrations on the same page with this will be "frankly, a challenge", his hope is that, perversely, the scale of the rupture in federal policy will drive action lower down the administrative chain.

Automation of sales, design and installation could enable US rooftop solar to survive without the ITC

"I think we will be forced in many ways to make changes now, because we don't have the reliance on the 30% ITC," he says. For example, a city mayor who has suddenly lost millions in receipts from solar permits and seen local jobs disappear, has a big motivation to act. "You're like, wait a minute. I have a climate agenda, I've just lost a lot of revenue and I seem to be losing thousands of jobs in my community. So if cities are losing those jobs and tax receipts, I think they will be forced to look at this as the only real solution to maintain the market."

Birch believes there is still a "massive appetite" for solar among the public and at city and state administrative levels, but says there is a right and wrong way to respond to the federal headwinds. He cites a couple of states that have introduced their own tax credit subsidy in the wake of its removal at the federal level, but points out that this is not necessarily the best course of action. "That's the wrong approach," he says. "Don't throw another 30% subsidy at this thing and try to outspend the federal government and put yourself up against fossil fuel lobbying. Actually solve the underlying problem."

Instead, with a concerted effort to instigate extensive permitting reform and digitalisation of processes, Birch believes rooftop solar in the US can not just survive but thrive. "Everyone's asking what happens when the ITC goes away. The better question is: what if we can stop relying on it?"

The "mega trend" Birch says it's important to keep in mind is the continuously falling cost of solar and storage. "So this will be a blip," he says of the current upheaval in the US. "We've seen this in Australia, we saw it in Spain, we saw it in the UK five years ago: you come through it, and you come out much more sustainable. The speed with which you come out of it will depend on how much people are willing to focus on true, fundamental change."

Birch foresees two possible courses the rooftop PV market in the US could take. One, without any action, would mean a spike in installations then a drop in sales, followed by a "bloodbath for job losses" as the market struggles to cope with the loss of the tax credit.

Path two is the more proactive approach that involves making some of the changes Birch describes – automated permitting and the other process-streamlining measures that will bring US rooftop solar costs more in line with the rest of the world.

"We really need people to open their eyes to this massive opportunity to completely change how solar is sold and installed in the States," he says. "If we focus on that and we get that executed state by state as fast as possible over the next 12 months, I think we will still have a downturn, but we have the opportunity to very quickly bounce back, without any subsidy, without any risk." ■

Turn to p.24 for details on the impacts of the OBBB Act on US energy storage

‘One Big Beautiful Bill’ Act brings changes, some clarity to US energy storage development

BESS | Energy storage escaped much of the pain inflicted on solar in the recent legislative changes, but foreign entity restrictions may create some supply-chain challenges. April Bonner reports

The energy storage industry faced a great deal of uncertainty during the refining of the 2025 budget reconciliation bill. At various points, the ‘One Big Beautiful Bill’ (OBBB) included an elimination of investment tax credits (ITCs), a 60-day construction commencement requirement and other provisions that would have proved problematic for energy storage developers.

In its final form, the OBBB Act largely maintains tax credits for battery and other energy storage technologies through the next decade. This decision underscores the Trump administration’s priorities on energy security, grid resilience, and domestic manufacturing. In contrast, the Biden administration’s Inflation Reduction Act (IRA) focused more on increasing a diverse range of renewable energy technologies.

Changes to investment tax credit incentives

US energy storage projects that begin construction by the end of 2033 will still be eligible for ITC incentives. These technologies can also qualify for technology-neutral tax credits at the full rate of 30% of capex, with additional domestic content bonuses increasing the total to around 45%.

The bill amends the regulations for technology-neutral tax credits outlined in sections 45Y and 48E of the US tax code. These credits are available for power projects with zero or negative lifecycle greenhouse gas emissions and battery and other energy storage projects, regardless of their emissions. They can cover between 30% and 70% of the project costs.

Projects claiming legacy tax credits under section 45 or 48 of the US tax code are unaffected by the bill. These credits can be claimed for projects that were under construction by the end of 2024. The 45Y tech-neutral PTC and 48E tech-neutral ITC will be phased out by 25% beginning in 2034, until they are eliminated after 2035.

The Section 45X tax credits for manufacturers of batteries and energy storage components remain mostly intact. The Act outlines a phased reduction of these credits over three years beginning after 2029, offering a more extended support period for domestic producers of battery and storage equipment relative to other clean energy technologies.

FEOC restrictions

Arguably, the most significant developments in energy storage are the new Foreign Entity of Concern (FEOC) restrictions. Technology-neutral tax credits for new power plants and energy storage projects will be denied if they rely heavily on Chinese equipment. Similarly, section 45X tax credits for US-made products will be withheld if they incorporate too many Chinese components.

As explained in an analysis from law firm Norton Rose Fullbright, tax credits will also be denied to companies that depend on Chinese investments or that make payments to Chinese-related counterparts through contracts and technology licences, especially when these counterparties have “effective control” over the companies, their projects, or products.

FEOC regulations will take effect for tax years after 4 July, 2025. As noted earlier, these regulations do not apply to renewable energy and storage projects claiming legacy tax credits under section 45 or 48. Starting in 2026, 55% of a project’s costs must originate from non-prohibited foreign entities, rising to 75% in and after 2030.

These calculations become more complicated when adding that a prohibited foreign entity is described as an entity with ties to China, Russia, North Korea or Iran. As explained by Norton Rose Fullbright:

“The ties can be such things as 25% or more ownership by a single Chinese shareholder or 40% by two or more such shareholders or at least 15% of total debt held by Chinese lenders, only counting debt holders at original issuance.”

Credit: esVolta

Despite possible future supply chain headaches, the US energy storage industry has broadly welcomed having clarity after months of uncertainty

Additionally, payments to over 50% of Chinese-owned companies or agreements granting such firms control, including long-term licensing rights, can classify a supplier as a prohibited foreign entity. It could be argued that these definitions encourage developers to prioritise domestic content sources, since the regulations create risks for US-based developers in sourcing content produced abroad; regardless of intent, they are stringent.

The IRS has six years to challenge a tax return over material assistance. A 20% penalty applies if the taxpayer pays more than 1% less tax due to miscalculation. For corporations, penalties apply if the tax shortfall from miscalculation is at least US$10 million or more than 1%. Equipment suppliers who provide false certificates face penalties of 10% of the customer’s claimed tax reduction. The reduction must be at least 5% of the owed tax or, if less, US$100,000.

For now, if projects obtain their cells from a foreign source not designated as an FEOC, the developer will not qualify for the domestic content bonus but will still receive the ITC. While the changes bring new issues to developers in the US, many market leaders agree that having more clarity on future projects is a welcome change from recent months. ■

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Dominance of PV and the shift to bifacial back contact c-Si technology in the next solar decade

Modules | The global energy transition has reached an inflection point, with solar PV technology emerging as the cornerstone of sustainable energy systems worldwide. Radovan Kopecek and Joris Libal examine the technological and economic factors driving PV's ascendancy, with particular emphasis on the transformative potential of bifacial back contact modules

The remarkable growth of solar PV installations in recent years has fundamentally altered the global energy landscape. According to the International Renewable Energy Agency (IRENA), solar accounted for over 60% of new power capacity additions worldwide in 2023, a trend that shows no signs of abating. This unprecedented expansion is being driven by three interrelated factors: continuous technological innovation, dramatic cost reductions and robust policy support across major economies.

The evolution of PV technology has progressed through several distinct phases, from early aluminium back surface field (Al-BSF) cells to the current generation of high-efficiency architectures. Among these, bifacial modules have emerged as particularly significant due to their ability to capture sunlight on both sides of the panel, typically yielding 5-20% more energy than conventional monofacial designs, depending on installation conditions and surface albedo. Within the bifacial category, back contact (BC) cell technology – as commercialised by industry leaders such as AIKO, Maxeon and LONGi – represents the current state-of-the-art, offering superior efficiency and reliability compared to mainstream TOPCon.

Figure 1 illustrates the exponential growth trajectory of global PV installations, highlighting the technology's increasing dominance in power capacity expansion. The consistent upward trend, even during periods of economic uncertainty, underscores PV's fundamental competitiveness in contemporary energy markets. The exponential growth will continue, reaching a 1TW market from 2027, which will be discussed further in the following. But first, we will look at the reason why this is and continues to be the case.

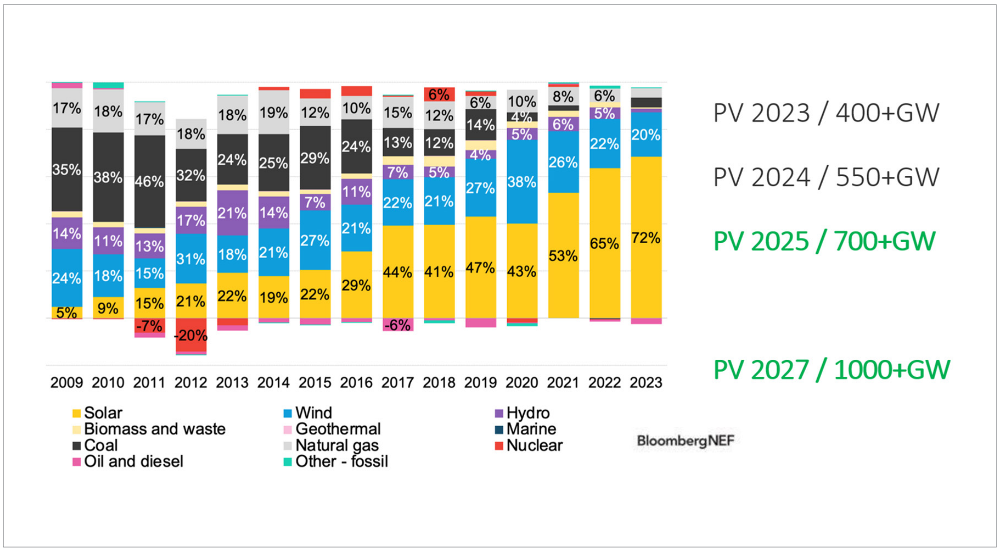

Figure 1. Graph from Bloomberg depicting the dominance of yearly additions of PV systems [1]

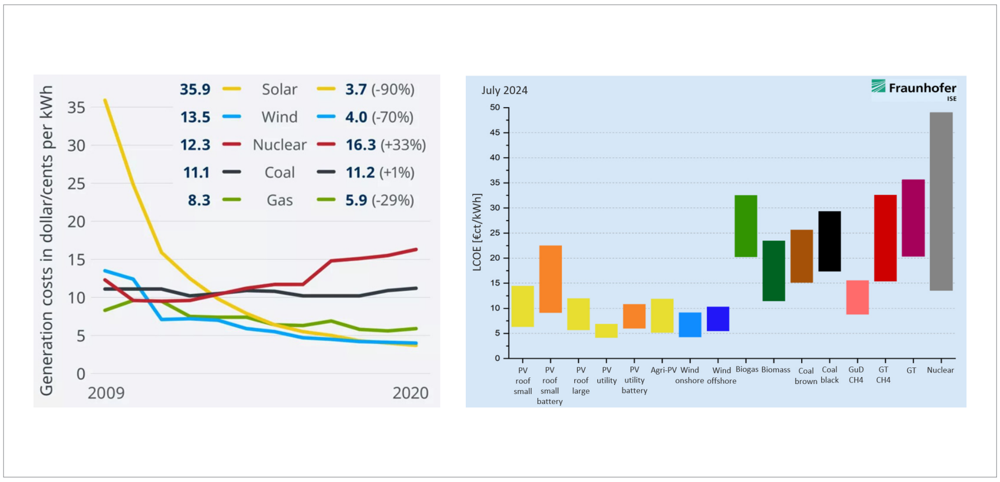

Figure 2. Development of LCOE from Lazard [2] (left) and current LCOE from ISE [3] (right)

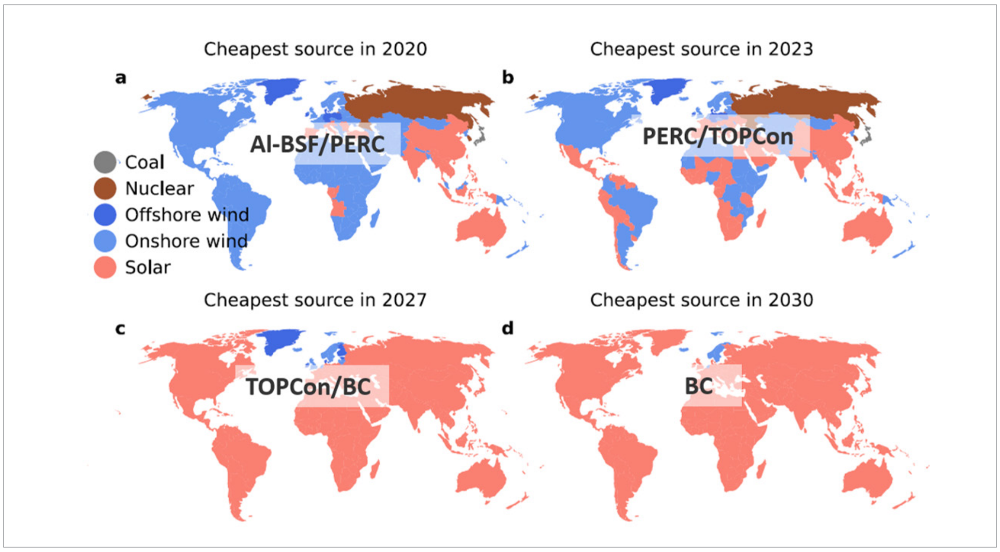

Figure 3. Global LCOEs for renewables including storage, modified from Nijsse [4]. The mainstream c-Si technologies for the various time periods (past, present and future) have been added

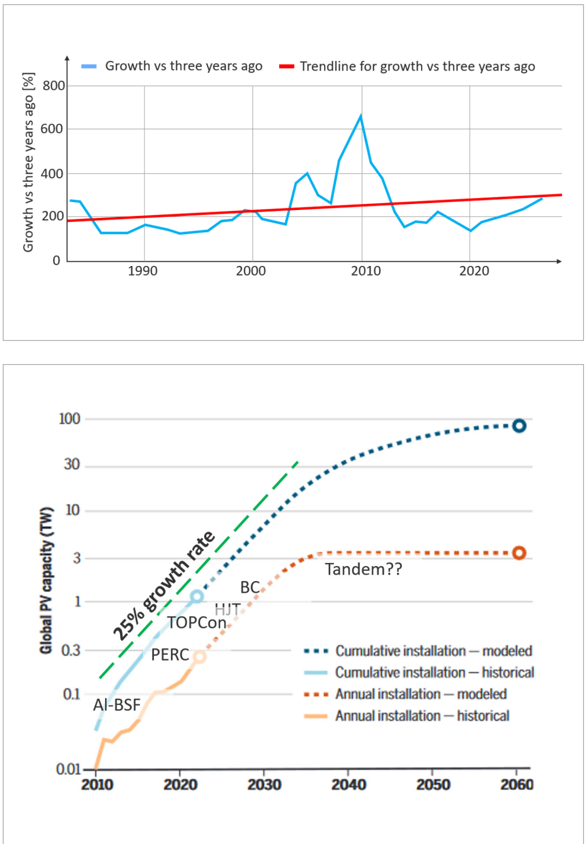

Figure 4. (Top) Past [1] and (bottom) past and future [6] exponential growth of PV installations depicted in a logarithmic graph. The mainstream c-Si technologies for the various time periods (past, present and future) have been added

Solar's economic competitiveness

The economic case for PV has strengthened dramatically over the past decade, with the levelised cost of energy (LCOE) for utility-scale PV projects falling by more than 90% since 2010 [2], as shown in Figure 2 on the left. Recent analyses by Fraunhofer ISE [3] indicate that solar PV now achieves an LCOE of €0.03-0.05/kWh (Fig.2 on the right) in optimal locations, significantly undercutting fossil fuel alternatives in most global markets. When paired with energy storage systems, PV remains competitive at €0.06-0.10/kWh, a price point that continues to decline as battery technologies advance.

Several interrelated factors contribute to PV's improving cost position. Manufacturing scale effects have driven down module prices, while simultaneous efficiency gains have increased energy yield per unit area as well as decreased area-related balance-of-system (BOS) costs. Further BOS cost reductions have also been achieved through standardisation and improved installation techniques. In this context, bifacial BC technology offers particular advantages, combining higher initial efficiency with better long-term performance due to reduced degradation rates (typically <0.3%/year compared to 0.5% for PERC). These characteristics translate into superior lifetime energy production and enhanced project economics.

The projected cost reductions from the publication of Nijsse [4] for PV and wind with storage in Figure 3 highlight the continued economic improvements expected as PV-plus-storage systems mature and scale. As PV is still on a fast learning curve with respect to efficiency increases (still 0.4% absolute efficiency increase in the next 5-7 years), PV is projected to dominate globally.

This implies that bifacial BC technology will be the winner, reaching close to 26% module efficiency with low temperature coefficient and low degradation values reaching LCOEs well below €0.01/kWh. The implementation of 30%+ efficient tandem modules is expected to happen on a different time scale.

Exponential growth of PV installations: mapping the trajectory toward PV dominance

The global PV market has exhibited consistent exponential growth, with annual installations increasing from approximately 7GW in 2009 to over 400GW in 2023. Current projections suggest this trend will continue, with cumulative capacity expected to surpass 5.5TW by 2030, according to the International Technology Roadmap for Photovoltaics (ITRPV) [5].

Figure 4 illustrates, at the top, the historical yearly PV installation data, redrawn from Bloomberg's dataset [1], displayed in a graph titled "Growth vs. three years ago". The bottom part of the figure shows the same historical data, complemented by forecasted data from the TW Workshop [6], including the total installation projections extending until 2060.

Based on the analysis of the above graph, it is evident that over the past 40 years, the trend in installation additions has followed a straightforward rule: "Every three years, the annual installations double." If this simple doubling rule is projected into the future, it illustrates how achieving the 80TW target for PV reaching our set CO2 reduction goals by 2050 – becomes feasible. The graph at the bottom, which was elaborated during the TW workshop [6], supports this projection with a linear growth of about 3TW from 2038. In addition, the most prominent technologies shaping and dominating the energy transition are included from us in this forecast. Currently, we are in the TOPCon technology era, which is expected to be succeeded by bifacial BC technology starting from 2028, coinciding with the anticipated yearly TW era milestone.

After 2050 (we believe this will happen even earlier) 100TW of PV will be installed globally covering about 75% of the total energy demand. Today, with installed 2TW about 1.5% of the primary energy demand with PV is covered. The rest will be delivered by wind and green hydrogen produced by low cost electricity from renewables. Battery storage will play an important role in this 100% renewable scenario as well.

Navigating the landscape of PV innovation and performance

The PV technology landscape has become increasingly diversified, with multiple cell architectures competing across different market segments. The TaiyangNews 2025 survey [6] of commercial modules depicted in Figure 5 reveals a clear efficiency hierarchy, with BC technology leading at 24+%, followed by heterojunction (HJT) at 23+% and TOPCon at 23%. Traditional PERC modules now primarily serve budget-conscious projects at 21.5-22% efficiency.

Several key factors differentiate these technologies. BC cells eliminate front-side metallisation, reducing shading losses and enabling the highest efficiencies and lowest degradations. TOPCon offers a balance between performance and manufacturing compatibility with existing PERC lines. HJT provides the lowest temperature coefficients but faces challenges in silver consumption and production throughput resulting in higher costs.

ITRPV's predictions: charting the course for future developments

The International Technology Roadmap for Photovoltaics (ITRPV) [5] serves as an authoritative guide to the industry's technological trajectory. According to the 2025 edition, several critical trends are emerging: HJT technology will lose its market share, whereas PERC will disappear completely from the production map and TOPCon will dominate the market share in the coming years. BC technology is expected to gain market share quickly, driven by its efficiency advantages and declining production costs. The roadmap anticipates commercial BC modules reaching 25% efficiency by 2026 and approaching 26% by 2028. Simultaneously, manufacturing innovations such as copper metallisation (screen printing and plating) and advanced patterning techniques are projected to reduce silver consumption by 80% compared to current levels. We actually strongly believe that the dominance of BC technology will happen much faster, as the technology switch in China, when it comes to evolutionary approaches, usually happens within about five years.

Looking much further ahead at "PV revolution", the ITRPV identifies tandem perovskite-silicon cells as the next major innovation wave, with initial commercialisation expected around 2030. These devices have demonstrated laboratory efficiencies exceeding 33%, suggesting potential for another step-change in PV performance.

Metrics: understanding the nuances and real-world implications

Efficiency remains a key metric for evaluating solar technologies, but interpreting efficiency claims requires careful consideration. Laboratory records (such as LONGi's 27.8% BC [8] and 27.3% HJT cell [9] as well as Jinko´s 27.02% TOPCon cell [10]) represent ideal conditions that differ meaningfully from field performance. Commercial module efficiencies typically run 2-3 percentage points below lab records due to manufacturing tolerances, interconnection losses and other practical factors. We have summarised this is already in a Photovoltaics International article in 2022 [11].

Figure 7 helps contextualise various efficiency metrics, distinguishing between laboratory records, champion modules and what is typically feasible in mass production. Evaluating the performance of solar cell technologies requires a nuanced understanding of the various efficiency metrics commonly cited. It is important to contextualise these figures, differentiating between results achieved in laboratory settings (here we differentiate also between laboratory in R&D centers or "GW

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Rank	Company	Series	Model	Wafer type	Cell Size	Cells No.	Cell Tech	Module Technology	Power (W)	Efficiency (%)
1	AIKO	Comet 2U	AIKO-G655-MCH72Mw	n-type	182	144	ABC	Half-cell, Back Contact	655	24.2
2	LONGi	Hi-MO 9	LR7-72HYD 625-650M	n-type	182	144	HPBC	Bifacial, Half-cell, Back Contact	650	24.1
2	Maxeon	Maxeon 7	SPR-MAX7-445-PT	n-type	125	112	IBC	Back Contact, Full-cell	445	24.1
4	HUASUN	Himalaya	HS-210-B132DS720W	n-type	210	132	HJT	Bifacial, Half-cell, MBB	720	23.18
5	TW SOLAR	-	TWMHF-66HD700-715W	n-type	210	132	HJT	Bifacial, Half-cell, MBB	715	23.0
5	ASTRONERGY	Astro N7	CHSM66RN(DG)/F-BH	n-type	182	132	TOPCon	Bifacial, Half-cell, MBB	620	23.0
5	DMEGC SOLAR	Infinity RT	DM620G12RT-B66HSW	n-type	210	132	TOPCon	Bifacial, Half-cell, MBB	620	23.0
5	JA SOLAR	DeepBlue 4.0 Pro	JAM72D40 595/MB	n-type	182	144	TOPCon	Bifacial, Half-cell, MBB	595	23.0
9	Grand Sunergy	-	GSM-MH3/132-BHDG710	n-type	210	132	HJT	Bifacial, Half-cell, MBB	710	22.86
10	TW SOLAR	-	TWMND-72HS585-590W	n-type	182	144	TOPCon	Half-cell, MBB	590	22.8
10	SPIC	ANDROMEDA 3.0	SPICN6(LDF)-60/BIH410W	n-type	166	120	TBC	Bifacial, Back Contact, Half-cell, MBB	410	22.8
12	JinKO Solar	Tiger Neo	JKM585N-72HL4-BDV	n-type	-	144	TOPCon	Bifacial, Half-cell, MBB	585	22.65
12	SolarSpace	Lumina II	SS8-72HD-585N	n-type	182	144	TOPCon	Bifacial, Half-cell, MBB	585	22.65
14	REC Group	AlphA®Pure-RX	REC470AA Pure-RX	n-type	210	88	HJT	Bifacial, half-cell, MBB	470	22.6
15	中来股份 JOLYWOOD	Niwa Pro	JW-HD108N415-440W	n-type	182	108	TOPCon	Bifacial, Half-cell, MBB	440	22.53
16	risen	Hyper-ion	RSM132-8-700BHDG	n-type	210	132	HJT	Bifacial,Half-cell, MBB	700	22.5
16	Trinasolar	Vertex N	TSM-NEG21C.20	n-type	210	132	TOPCon	Bifacial, Half-cell, MBB	700	22.5
16	DASOLAR	-	DAS-DH156NA-620-630W	n-type	182	156	TOPCon	Bifacial, Half-cell, MBB	630	22.5
16	Canadian Solar	TOPHiKu6	CS6W-570-580T	n-type	182	144	TOPCon	Half-cell, MBB	580	22.5
16	Eging PV	STAR Pro	EG-580NT72-HL/BF-DG	n-type	182	144	TOPCon	Bifacial, Half-cell, MBB	580	22.5
16	RUNERGY	-	HY-DH144N8	n-type	182	144	TOPCon	Bifacial, Half-cell, MBB	580	22.5
22	Qn-SOLAR	-	QNN182-HG-72	n-type	182	144	TOPCon	Bifacial, Half-cell, MBB	580	22.45
22	URECO	GLORY	FBF580B8D	n-type	182	144	TOPCon	Bifacial, Half-cell, MBB	580	22.45

Figure 5. Table of the highest efficient modules from Taiyang News [7]

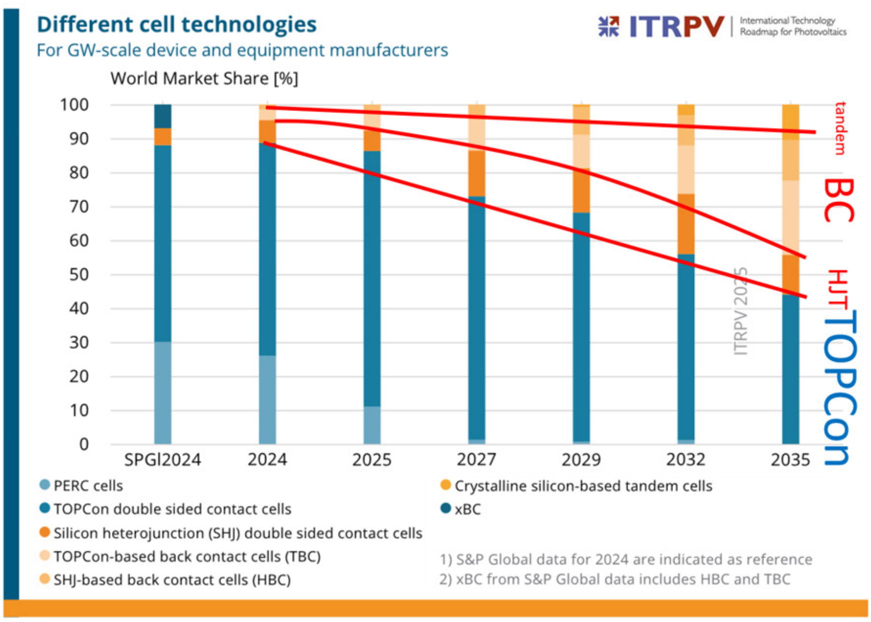


Figure 6. ITRPV showing the development of technology shares [7]

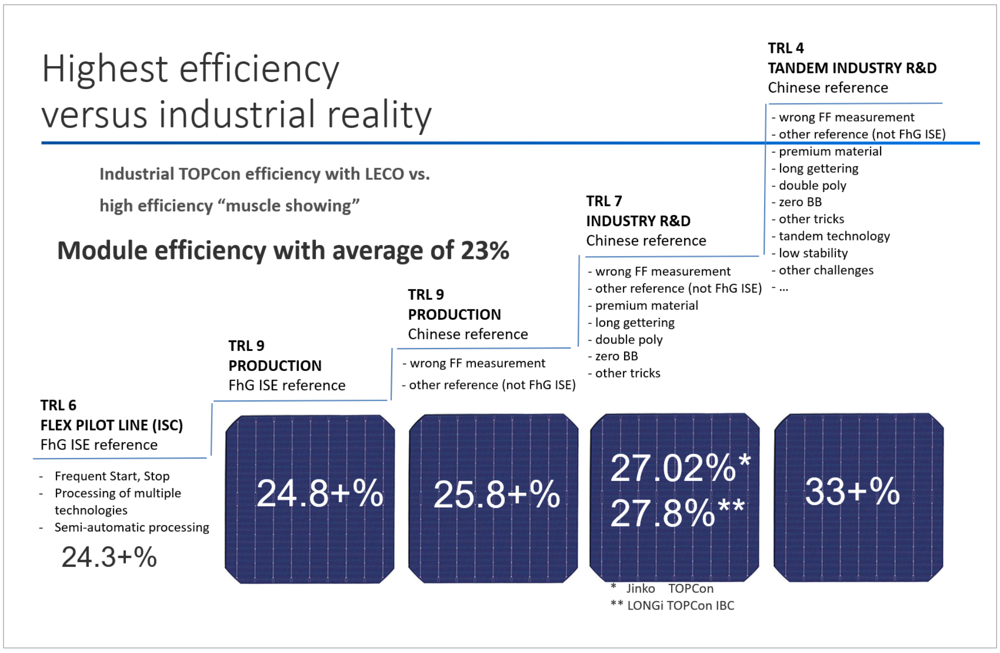


Figure 7. Discussion of different efficiencies in announcements from different Technology Readiness Levels (TRL). TRL 9 means production. The lower the TRL level, the less advanced the technology is. TRL4 means component or validation in laboratory environment as e.g enhancing the stability

pilot-line laboratory" of Tier1 manufacturers), champion modules and typical production environments [11].

In the PV industry, discussions surrounding module efficiency are widespread, with various claims being made about the capabilities of different technologies. For example, some state that TOPCon is already achieving 27% cell efficiency in production. However, it is crucial to recognise that such figures always represent record efficiencies achieved under controlled laboratory conditions, which are not representative of average efficiencies that can be actually achieved in industrial mass production.

From calibrating the measurements of organisations such as Fraunhofer CalLab, one can understand that TOPCon real efficiency in production is closer to 24.8% when using the Laser Enhanced Contact Optimisation (LECO) process. Furthermore, one must also be sure to take into consideration the source of the measurements and calculations. With Chinese references, in particular, there can be overrated fill factor (FF) and current, which might cause them to be off by around 1% absolute. Ultimately, "truth always shows in module", as shown in Figure 5. From what is currently on the market, TOPCon usually runs at a benchmark of around 23%. It is expected, however, that this benchmark will increase. For those who are looking into even more disruptive technologies, it is important to acknowledge that perovskites have managed to push levels above 30%. However, these technologies, in their current form, have not yet been stabilised, and come with multiple challenges in manufacturing and maintenance. For tandems to become bankable, it is expected to take more than seven years from now.

PV through the ages: a journey through past, present, and future eras

The evolution of solar PV technology can be conceptualised as a series of overlapping eras, each characterised by dominant cell architectures and manufacturing paradigms as shown in Fig. 8.

2000-2017: Al-BSF dominance

The aluminium back surface field (Al-BSF) cell represented the industry standard, with efficiencies ranging from 15% for mc-Si and 17% for Cz-Si. Manufacturing was relatively simple but limited by fundamental efficiency constraints mostly because of the high recombination on the rear side due to a lower passivation from the Al-Si alloy. In 2017 the time was ripe for passivated emitter and rear cell (PERC) technology.

2017-2023: PERC revolution

PERC technology emerged as the new benchmark, pushing efficiencies to 18-23% through improved rear-side passivation and light trapping. In addition, the technology became bifacial which revolutionidsed the utility-scale market [12, 13].

2024-2035: bifacial BC/HJT/TOPCon competition

The current decade features multiple high-efficiency architectures competing for market share, with BC, HJT and TOPCon all offering efficiencies above 24% in production. TOPCon currently has the largest market share, but that might change in 2028/2029 when BC technology will become mainstream.

Post-2035: tandem cells & advanced BC

The next technological frontier will likely involve perovskite-silicon tandem cells architectures, potentially breaking the 30% efficiency barrier for commercial modules.

Figure 9 highlights the key innovations that enabled each progression. Understanding these transitions is crucial for charting the future of solar cell technology and anticipating the next wave of advancements. The journey towards high-efficiency solar cells has been marked by several important developments. For instance, the transition to PERC technology was significantly enabled by the availability of low-cost Czochralski (Cz) silicon wafers from manufacturers such as LONGi.

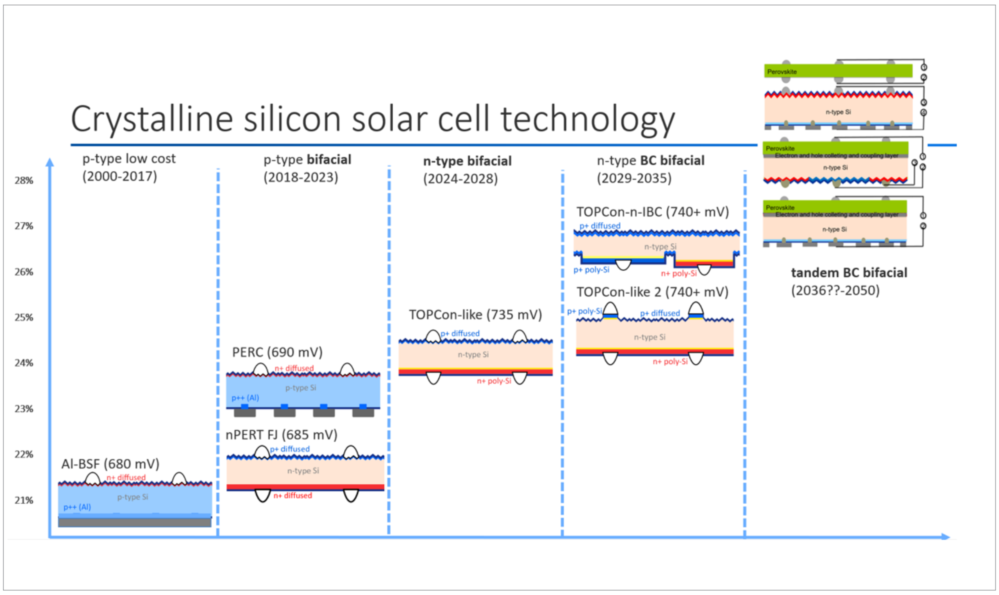


Figure 8. Past PV eras and forecast

Crucially, this shift was also facilitated by improved aluminum oxide (AlOx) passivation of the rear surface, enhancing carrier collection and reducing recombination losses. In addition, the increasing adoption of bifacial standards also played a very helpful role in this transition. These collective advancements underscored the industry's growing focus on cost-effectiveness without compromising performance.

Looking at the shift towards TOPCon technology, a different set of factors come into play. This shift is now largely based on the ongoing development of low-cost Plasma-Enhanced Chemical Vapor Deposition (PECVD) polycrystalline silicon (poly-Si) technology. As well as the implementation of the LECO process by companies such as Cell Engineering. The integration of LECO with TOPCon presents an opportunity to achieve even higher efficiencies and improved performance and stability characteristics. In some industry circles, this implementation of LECO has been credited with essentially rendering the older HJT technology obsolete.

As we look forward, the progression towards BC technology dominance hinges on a new set of innovations. The development of simplified stringing technology, pioneered by companies like SPIC/ISC Konstanz, and the use of fast lasers for processing selective structures are critical factors. In particular, the ability to streamline the stringing process for BC cells is essential for reducing manufacturing complexity and costs. Furthermore, the decreasing costs of laser technology is enabling wider adoption of laser-based techniques for precise contact formation and other critical steps in BC cell fabrication. Crucially, techniques such as laser-assisted etching, as well as methods like stencil printing, are contributing to the reduction of silver (Ag) consumption, directly impacting manufacturing costs and contributing to overall competitiveness. Due to the simplicity of process the future belongs to BC technology also because standardisation of the process flows is gaining momentum.

The exact timeline for when perovskite tandem technologies will achieve widespread deployment in the photovoltaic market at the GW scale remains uncertain. Several significant challenges still need to be addressed before this can become a reality. These include ensuring the uniformity and consistency of depositions over industry-relevant wafer areas, improving the long-term stability and durability of the materials, managing reverse current issues and overcoming various other technical and manufacturing hurdles. While promising advancements are being made, it may take some additional time to fully resolve these obstacles and enable large-scale commercial adoption.

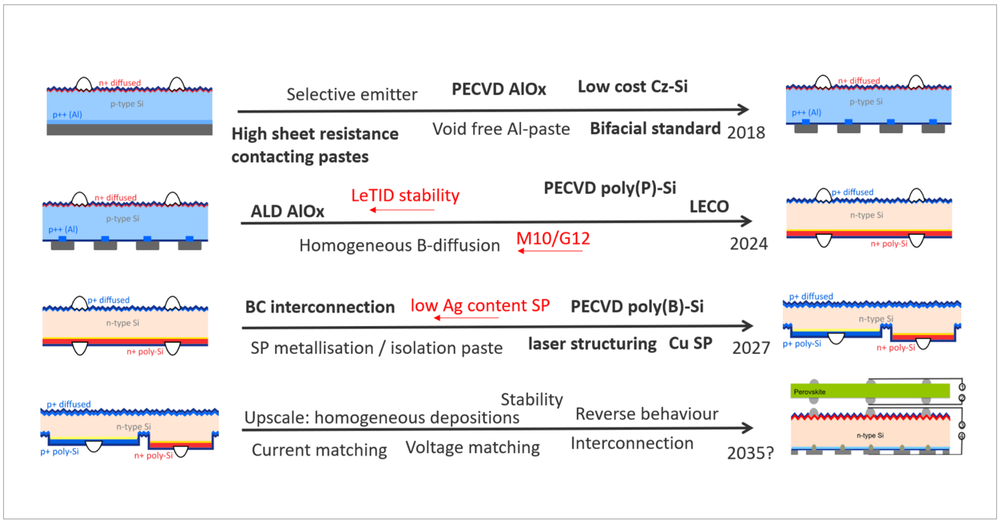


Figure 9. Necessary central developments for the switches in the past and in future

Bifacial BC technology as the next big thing

In this section we will now focus on the advantages of BC technology and why we believe it will become the next mainstream from 2028 on. In the past, we have summarised in several articles how BC technology is developing and why we believe that it is the future of PV [14].

Figure 10 highlights the diversity of

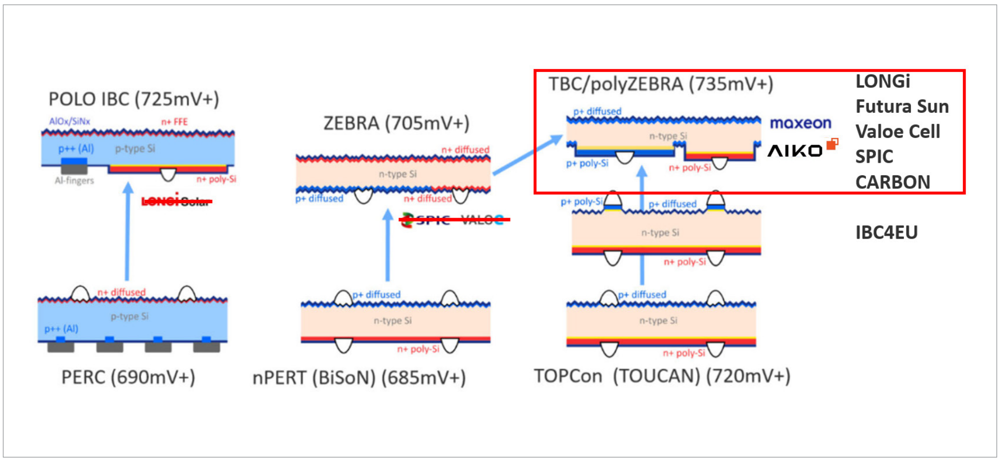
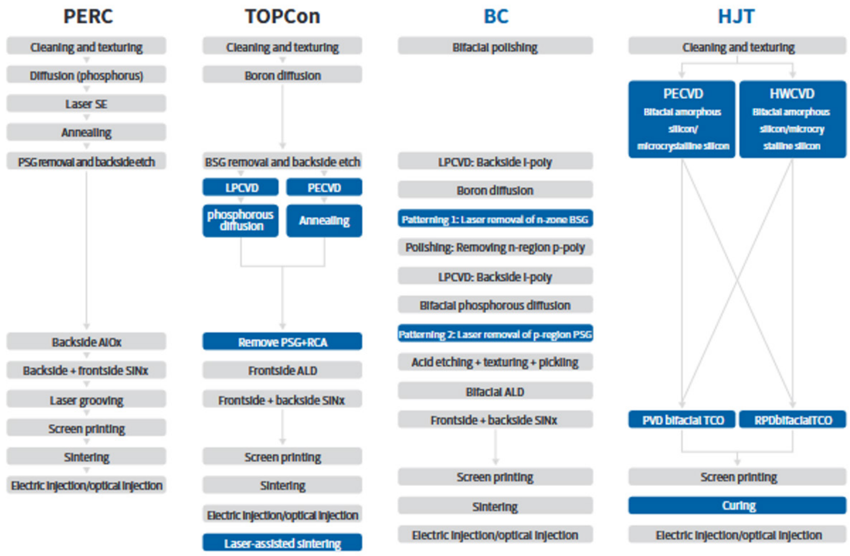


Figure 10. BC technologies in the past from PV Tech [14]. Now all producers are working on one standard BC tech

Figure 11. Panel from bifiPV2024 in Zhuhai where leading companies agreed to collaborate in BC tech for a faster implementation in the market



Cell process flow comparison diagram[7]

Six-dimensional capability assessment of four-generation technology

Evaluation dimensions	PERC	TOPCon	HJT	BC
Efficiency potential	★★	★★★☆	★★★★	★★★★★
Process compatibility	★★★★★	★★★★	★★	★★★★
Bifacial gain	★★★	★★★★	★★★★☆	★★★★
Temperature coefficient	-0.35%/°C	-0.29%/°C	-0.24%/°C	-0.26%/°C
BOS cost advantage*	-	-2.3%	-2.8%	-7.8%
Technology maturity	Withdrawal from the market	Mass production	Mass production	Mass production

Figure 12. Picture from white paper published by AIKO and LONGi at Intersolar Munich 2025. It shows the process sequences of all technologies on the top and comparison of cell parameters at the bottom.

approaches and innovations previously explored in BC technologies, noting the trend that key producers are now aligning toward a more standardised version of the technology – the TBC (TOPCon back contact) technology. Developments in the past suggest that standardisation can be very important for a technology to become mainstream. Ultimately, the development and implementation of high-quality n-type Cz silicon, particularly through the use of antimony (Sb) doping by manufacturers like LONGI (TaiRay), were crucial factors.

Figure 11 shows a panel discussion from bifiPV2024 in Zhuhai where leading companies agreed to collaborate in BC tech for a faster implementation in the market. It was emphasised that for these collaborative opportunities key drivers are:

1. Fast lasers for selective processing
2. Simple stringing also with 0-BB (zero busbar) technology is emerging
3. Bifaciality is important for BC tech as well to compete with TOPCon
4. 25% module efficiencies with bifacial factor of close to 0.8 will be reached this year
5. Reverse current behaviour is beneficial to avoid hotspots
6. It is easier to implement alternative metallisation (such as copper pastes) on the rear side
7. From this workshop it was agreed to work on a common white paper for BC tech

Through collaborations such as those that took place in the Zhuhai panel, it has become clear that the move will continue to be undertaken with the following key points in mind: Highlighting the important and ongoing innovations with bifacial technology. It was confirmed that the PV industry as a whole is moving more and more to rely on semiconductor level purity in production. With high material standards, the new aim should be needing 10N purity of poly-Si feedstock for wafers for BC technology. From this panel AIKO and LONGi have partnered up to formalise a white paper [15] on bifacial BC technology, summarising the advantages and the future role of this promising technology. The results of the white paper were presented at Intersolar 2025 in Munich. One central picture of the white paper is depicted in Figure 12.

Not only the cell front side efficiency has the highest potential but at the end the balance of system cost saving is the major argument. It is important to note that, in conjunction with the previous information provided, in the table often displayed in presentations from ISC Konstanz that is depicted in Figure 13, similar performance outcomes were recorded just a few months prior. Figure 12, originating from a white paper jointly presented by AIKO and LONGi at Intersolar Munich 2025, offers a side-by-side comparison of the process sequences for a range of solar cell technologies including PERC, TOPCon, HJT and BC. With this, emphasis is also placed on the importance of the overall BOS cost savings as a key argument for adoption of particular technologies.

With a comparative evaluation of the six-dimensional capabilities, it has come to show how each technology can provide excellent overall results in the key performance metrics that the technology targets ("Evaluation dimensions"), which are of course the following: efficiency potential, process compatibility, bifacial gain, temperature coefficient, BOS cost advantage and technology maturity.

A comprehensive comparison of TOPCon and bifacial BC solar cell technologies highlights their respective advantages and trade-offs at the cell, module and system levels. Understanding these differences is crucial for guiding future innovation in photovoltaic development.

Regarding cell efficiency, BC technology is projected to deliver an overall increase of approximately 0.5% absolute compared to TOPCon designs. This gain is primarily attributed to the distinctive architecture of BC cells, which reduces shading losses and enhances light absorption. At the module level, BC technology offers roughly a 1% absolute efficiency benefit, driven by the so-called "negative gap" technology—an approach that further optimises performance.

Beyond efficiency gains, BC technology simplifies the integration of copper metallisation on the rear side of the cell, enabling easier manufacturing. This advantage allows for the use of more cost-effective and abundant materials, leading to significant reductions in production costs and boosting profitability. The higher efficiency and lower costs are expected to reduce the LCOE and improve overall system economics, as increased energy output inversely impacts system costs and affordability. Additionally, BC modules exhibit a low breakdown voltage, which provides increased resistance against hotspots, potentially enhancing the modules' long-term durability and safety profile. Independent evaluations from organisations such as TÜV Rheinland and PVEL confirm the reliability and performance of high-quality BC modules. These assessments confirm that well-produced BC modules perform reliably under standard operating conditions, validating their commercial viability.

In addition, it is important to note that as module prices decline, the lowest LCOE can be achieved with high ground coverage ratios in PV systems, which in turn decrease the bifacial energy yield gain of such a system and thus reduce the relative importance of a high bifacial factor of the deployed PV modules. Accordingly, lower costs for modules and systems have led to a reduction in the additional benefit that bifacial technology provides. For example, recent presentation at the IEEE PVSC conference in Montreal by TOTAL [16] highlighted the effectiveness of horizontal single-axis trackers (HSAT) combined with high efficiency BC technology even though having lower bifacial factor.

Looking ahead, the trajectory of PV technology points towards the increasing dominance of bifacial BC modules, especially when integrated with advanced tracking systems like HSAT. This progression is expected to shape the future landscape of utility-scale solar, emphasising efficiency, cost-effectiveness and system reliability.

Projections indicate a clear trajectory for utility-scale solar: the ascendance of bifacial BC technology. Expect module efficiencies to surpass 25%, accompanied by improved temperature coefficients—below 0.3%/K, potentially nearing 0.25%/K—and high bifacial factors around 0.8. Combining these advancements with substantial area-related BOS savings is expected to drive the LCOE below €0.01/kWh. This cost-effectiveness will accelerate global solar adoption, a trend also unfolding within the European Union, solidifying BC technology's leading role.

Figure 15 illustrates a 58MW utility-scale solar power system located in Bosnia and Herzegovina, utilising bifacial AIKO modules [17]. This setup exemplifies the ongoing shift toward more advanced and efficient PV solutions, combining high-efficiency bifacial technology with tracker systems that maximise solar exposure throughout the day. The deployment of AIKO bifacial modules contributes significantly to increased energy yields by capturing sunlight from both sides, thereby enhancing overall system performance, especially in regions with reflective ground surfaces or specific environmental conditions.

The integration of HSAT systems with bifacial BC modules is a strategic move towards lowering LCOE, boosting energy generation and improving grid integration. These systems are particularly well-suited to large-scale utility projects due to their high power density, simplified installation process and proven reliability in a large number of installations worldwide.

	BC (ABC, polyZEBRA)	LECO TOPCon (TOUCAN)
Cell efficiency and (potential)	26% (26.5%+)	25% (26.0%+)
Module efficiency and (potential)	**24% (25%+)**	**23% (24%+)**
Bifaciality and (potential)	0.76 (0.80+)	0.8 (0.85+)
COO and (potential)	5.0ct/W (3.5ct/W)	4.0ct/W (3.0ct/W)
Lowest LCOE and (potential)	2ct/kWh (**below 1ct/kWh**)	2ct/kWh (**below 1.5ct/kWh**)

Figure 13. Comparison of TOPCon versus BC tech on cell, module and system level

Figure 14. Future of PV technology in utility-scale systems. Bifacial BC will dominate

Summary and outlook

This article discusses the shift in solar technology towards bifacial BC c-Si technology and its potential dominance in the next decade. It highlights solar PV technology as a cornerstone of sustainable energy systems, driven by technological innovation, cost reductions and policy support. Bifacial modules, capable of capturing sunlight on both sides, yield 5-20% more energy than monofacial designs. BC cell technology, commercialised by leaders like AIKO, Maxeon and LONGI, offers superior efficiency and reliability compared to mainstream TOPCon.

The LCOE for PV has significantly decreased, making it competitive with fossil fuels. Manufacturing scale effects and efficiency gains contribute to this cost reduction. The International Technology Roadmap for Photovoltaics (ITRPV) predicts BC technology will gain market share, reaching 25% efficiency by 2026 and nearly 26% by 2028. BC cells eliminate front-side metallisation, reducing shading

Figure 15. Large utility-scale system in Bosnia and Herzegovina using bifacial AIKO modules [17]

losses and degradation. While TOPCon offers a balance between performance and manufacturing compatibility, HJT faces challenges in silver consumption and production throughput.

The article also touches on the importance of material quality and laser technology in BC cell production, noting collaborations among leading companies to standardise BC technology. The move towards BC technology will continue, emphasising semiconductor level purity and high material standards.

Bifacial BC technology is poised to become the dominant PV solution, also for utility-scale applications, starting around 2028. This shift is driven by its superior efficiency, energy yield and long-term reliability. The industry is expected to increasingly favour BC technology, especially when combined with advanced tracking solutions. This will optimise land use, maximise energy production, and achieve lower costs per megawatt-hour, positioning BC technology as a promising solution for the evolving renewable energy landscape. Continued innovation and standardisation will further enhance its economic attractiveness and accelerate its global adoption. ■

More details will be discussed at the bifiPV2025 workshop in November in China: www.bifiPV-workshop.com

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Authors

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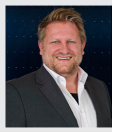

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A year in review: solar moves centre stage in UK's decarbonisation goals

Policy | The UK's new Labour government took power last summer, promising a renewable energy revolution, with solar playing a lead role. A year on from its landslide victory, Molly Green looks at what has been achieved

Last July, a Labour government was elected to power in the UK, heralding a positive shift for the renewable energy industry.

Voted into government off the back of a manifesto that centred renewables and pledged rapid solar expansion, Labour's election marked a break from a period during which those in power had, if not actively encouraged, then willingly overseen anti-solar rhetoric that allowed misinformation to circulate.

The new Labour government's Department for Energy Security and Net Zero (DESNZ) was quick to act. In his first week as energy secretary, Ed Miliband granted development consent orders (DCOs) for three solar plants with a combined capacity of over 1.3GW.

One year on, eight solar nationally significant infrastructure projects (NSIPs) have received a DCO from Miliband, most recently giving the nod to Baywa.r.e for the 140MW Oaklands Farm solar-plus-storage development.

According to Sulaiman Ilyas-Jarrett, former head of policy and strategy, renewable delivery for DESNZ, who now provides private consultancy and hosts the Energy Revolution podcast, "solar has been an unsung success story in the UK over the last year".

Labour's manifesto pledged to reach 72GW of installed solar capacity by 2035, after having tripled solar capacity by 2030 to roughly 42GW.

The 2035 target has been slightly lost behind the government's Clean Power 2030 Action Plan, which details the necessary steps to a majority (98%) renewable energy-powered energy system operating in the UK by 2030. Within this, the government is committed to between 42 and 47GW of solar installed by 2030.

Lead solar analyst for Solar Media Market Research Josh Cornes says that the uptick in solar NSIPs entering the planning system since the election could be the result of improved developer confidence following Miliband's quick DCO approvals and supportive signals from government, or the CP30 plan pushing them to act sooner than later.

Planning system changes

As promised, the government has changed the UK planning system to make it harder for local authorities to reject solar developments on spurious grounds.

Previously, wording in the National Planning Policy Framework (NPPF) referenced consideration of agricultural land for food production in considerations for renewable energy project applications. The common misconception that solar PV development will lead to food insecurity by taking agricultural land out of commission is one that has been disproven on several counts, including in a statement made by Miliband to the House of Commons in July 2024. Accordingly, in December, the government implemented a reworded NPPF to state that planning authorities should give "significant weight to the benefits associated with renewable and low carbon energy generation and the proposal's contribution to a net zero future" when determining applications.

The NPPF is aligned with other changes to wording the government made to National Policy Statements (NPSs), which cover NSIPs. Adjustments mean that NPS EN-3 calls NSIPs "critical national priority", and as such their "national security, economic, commercial and net zero benefits" should outweigh impacts from their development.

These changes were introduced alongside the CP30 Action Plan, but as Chris Hewett, chief executive of the UK solar trade body Solar Energy UK and co-chair of the government's Solar Taskforce, points out, they will not have a major effect on installed generation capacity until after 2030.

Credit: Lauren Hurley/DESNZ

Energy secretary Ed Miliband has put solar at the heart of his clean energy plans for the UK

The action plan, Hewett says, creates a welcome urgency to build towards a looming target: "More projects came through from our industry because of that."

Likewise, Ilyas-Jarrett says it's "important and useful" to have the 2030 target.

Grid connections: creating winners and losers

When Hewett spoke to *PV Tech Power* last year in the wake of the election, he was clear that grid connections were the biggest concern for the industry.

Since then, the UK energy regulator Ofgem approved plans put forward by the National Energy System Operator (NESO), the independent body that manages the UK energy system, including gas, for a new way of managing grid connection applications.

In an effort to cut 'zombie projects' that apply for a grid connection with little chance of ever being realised from the queue, the new system arranges applications into 'gates', prioritising projects that are likely to deliver and are aligned with UK-wide energy policy.

According to Hewett, "it's fair to say it's been an uncomfortable process". The new methodology had to be developed very quickly and has been met with some discontent in the solar industry. Hewett says that because government and NESO moved so fast, it has caused economic ripples in the industry, and throughout the process, which was "pretty opaque", it was not clear that generators' views were being properly taken into account.

"There are winners and losers out of it as a whole," he says.

This is another area in which the situation post-2030 has not been discussed. The flip side of the urgency created by CP30, and the speed at which connection reforms have been implemented, is that there are "probably greater question marks over what's going to happen between 2030 and 2035".

The rooftop revolution

The rooftop solar sector in the UK has "done well" out of connection reform, Hewett says.

A long-standing ask of the connections process was that the transmission threshold be raised from 1MW to 5MW in England and Wales. In Scotland, the threshold was raised from 50kW to 200kW in summer 2024.

By raising the capacity at which a rooftop installation needs a transmission impact assessment (TIA), which previously slowed or prevented rollout of larger rooftop PV installations, NESO said it hoped to "release around 400 distributed generation projects from having to demonstrate Gate 2 compliance or alignment with Clean Power 2030 targets".

At the time, Solar Energy UK issued a "warm welcome" to the news that "a burdensome element of red tape that has added many years to getting projects off the ground", contributing to the government's stated ambition to "unleash a rooftop revolution".

The government had pledged in its manifesto to implement a mandate for all newly built properties in the UK to have rooftop PV systems installed, a policy that had been floated by the previous government.

However, close to a year after its commitment to the rooftop revolution, the policy that had seemed a sure thing from the off was only made official in June 2025, with the Future Homes Standard to be published in Autumn this year and include the mandate.

Speculating on why the government took so long to make good on that pledge, Ilyas-Jarett says: "I'm sure there were inter-ministerial conversations about priorities and how to balance the desire to have increased rooftop solar with the desire amongst the Ministry of Housing and Treasury to build new homes quickly [another of the government's manifesto promises]."

"That's front and centre [for DESNZ] but it's not necessarily there for ministers in the housing industry—it's a more complex policy environment to jump into," he explains.

Something more in reach for DESNZ was reform to the Contracts for Difference scheme, something Ilyas-Jarett explains effectively uses existing tools.

Last year's auction round six (AR6) broke records for the highest budget, which Miliband increased to £1.56 billion (US$2 billion), and capacity secured, with 3.3GW solar projects receiving contracts (out of a total of 34.74GW awarded). Shortly after the success of last year's auction, the government announced its ambition to reform the process for an even bigger capacity in AR7.

To meet CP30 targets, at least 12GW capacity will need to be secured in AR7, AR8 and potentially (depending on speed of deployment) AR9 across all technologies. For its speed to deploy and comparably low cost (in comparison with other technology types included in the auction), solar could meet much of this new capacity.

Changes to the scheme approved on 15 July 2025 include increasing the length of contracts available for wind and solar projects from 15 to 20 years and allowing the energy secretary to view developer bids ahead of setting the final budget.

According to Ilyas-Jarett, this move gives more forward certainty to industry as to what application rounds will look like for the projects set to be delivered by 2030, something that has been well received.

"CfD privileges medium to large-scale projects in the way that it's set up," he points out. "But the area for future growth is smaller scale and domestic solar," because "from a political standpoint, that kind of domestic rooftop solar will be just as, if not more, important."

He says this is where the government's flagship Great British Energy company could play a role: "This small-scale, lower capacity but higher social impact solar [is what] GB Energy could do".

The state-owned energy company has begun to take shape, after being promised as a flagship entity by the government when it came to power, even if its precise role was initially vague.

Hewett notes that on the launch of GB Energy, the solar industry's advice was that the investment vehicle-stroke-renewable energy developer use some of the £8.3 billion it is allotted to invest in the public sector—"which is exactly what they've done".

A £200 million investment from the UK government and GB Energy will see the company work with schools and the NHS to install rooftop solar PV on a total of 400 sites, delivering between 70MW and 100MW of solar generation.

In England around £80 million in funding will support around 200 schools, alongside £100 million for nearly 200 NHS sites, with the first solar systems to be installed by the end of summer 2025.

A more recent development in the company's remit is an amendment to the Great British Energy Bill that sets an obligation to ban the use of solar products with forced labour in their supply chains in its projects. It will also find opportunities to develop "technology sovereignty" by driving the UK's domestic clean energy supply chain, in line with the UK government's recently released Industrial Strategy.

Supply chain and the Solar Roadmap

Perhaps the government's most keenly awaited promise, but arguably the slowest to deliver, has been the Solar Roadmap. Soon after the election, Miliband recalled the Solar Taskforce, co-chairing the group with Hewett as a signifier of the emphasis he placed on its mission.

Hewett says that "you can't fault the ambition" in the speed at which Miliband moved. The roadmap was first promised for autumn 2024, after a shift to reflect the new government's increased ambition and one month after its first meeting in September 2024.

Ensuring alignment with the CP30 Action Plan delayed this, and Hewett concedes that Miliband wasn't able to be "as hands on" with the Taskforce as he would have liked.

However, with the government's first Spending Review confirming its economic commitment to renewable energy development, the Solar Roadmap has at long last been published—with not an insignificant amount of focus on the supply chain issues.

The Solar Roadmap is explored in more detail on the following pages of this journal. ■

Turn to p.38 for further detail on the UK's Solar Roadmap

UK charts path to trebling solar by 2030

Strategy | The UK government and solar industry have jointly published a long-anticipated roadmap detailing how to maximise the country's solar potential. Chris Hewett, CEO of Solar Energy UK takes a closer look at the detail

Credit: Quinbrook Infrastructure Partners

Cleve Hill, the UK's largest PV power plant. The Solar Roadmap sets out how the UK plans to treble its solar capacity by 2030

A new era of clean energy independence dawned in early July, with the publication of the UK's highly anticipated Solar Roadmap [1].

The government-industry paper describes 62 practical measures to boost the supply of cheaper and more secure power, deliver new industries and create skilled jobs – all while providing significant reductions in greenhouse gas emissions and gains in biodiversity. By addressing issues such as the electricity grid, supply chain, skills and planning, it will play a major role in delivering the British Labour government's mission for the UK to become a clean energy superpower and meet – or potentially exceed – the capacity goals set out in December's Clean Power 2030 Action Plan.

By then, we could see around 9 million small-scale rooftop installations, up from 2 million now, with the sector supporting 35,000 jobs – almost twice the number of today. Meanwhile, solar farms would still take up a tiny amount of the country, put at significantly less than 1% of farmland.

The roadmap was produced over two years and two governments by the Solar Taskforce, led by secretary of state for energy security and net zero, Ed Miliband, and Solar Energy UK, and supported by leading figures from across the solar industry and related sectors. The taskforce will shortly transition into the Solar Council, set to drive future progress and guide the implementation of the plan.

Writing in a foreword to the roadmap, the secretary of state wrote: "This is an incredibly exciting time for solar in our country. More than 1.5 million homes across Britain now have solar installed, and since this government came to office my department has consented almost 3GW of nationally significant solar projects – nearly three times as much as the previous 14 years combined. But we know we need to go further to deliver our goals for clean power by 2030 and beyond

"Solar offers huge potential to boost our energy independence, bring down bills and tackle the climate crisis. It also presents significant economic opportunities; we estimate that around 35,000 jobs supported by solar will be needed by 2030, a doubling of today's number."

Added to those reflections, solar energy is among the lowest-cost and most popular forms of power generation in the UK. Unlocking its potential will increase Britain's energy security, drive down bills and be a major contributor to preventing dangerous climate change. The fact that it can be deployed rapidly in so many ways, from household rooftops to warehouses to reservoirs and large-scale solar farms, is the key ingredient to this potential.

Rooftop

Despite enormous cost reductions over recent years, one key barrier to more widespread adoption of rooftop photovoltaics remains their upfront cost. So, the government will work with the Green Finance Institute, the finance sector, consumer bodies and the solar sector itself to provide financial solutions for all customers.

The taskforce also identified an ongoing lack of awareness of the benefits of both domestic and commercial solar energy as a further obstacle, with potential buyers unaware of trusted sources of information. Accordingly, the government will update its Energy Efficient Home website to promote solar deployment. Meanwhile, the UK Warehousing Association has agreed to develop a toolkit for the commercial-scale market, including how to obtain a power purchase agreement.

How solar is reflected in energy performance certificates will be updated next year, and incentives to install solar energy will be considered for social landlords. Meanwhile, the Royal Institution of Chartered Surveyors will ensure that the value of solar homes is assessed properly, while incentives to install solar power on social housing will be considered.

As may be expected, the paper also

Credit: Sundog

mentions the recently confirmed Future Homes Standard. This should, alongside the forthcoming Future Buildings Standard, virtually mandate solar on new properties. In due course, retrofit customers will benefit from a review of consumer protections, so they can have confidence in the quality of work when upgrading their homes.

Warehousing has huge potential to expand solar generation but faces many barriers [2]. To resolve these, the UK Warehousing Association will collaborate with the real estate and solar sectors to overcome problems with building leases, develop standard contacts for landlords and tenants and develop a standard approach for building valuation. The connection processes of independent distribution network operators (DNOs), which often operate power systems in business parks, will be reviewed and the regulation of the sector reconsidered by the regulator, Ofgem.

According to government estimates, only around one in five schools have solar panels, leaving them paying for power rather than investing in the nation's youth. To help remedy this, the government will commit to supporting schools to deploy the technology, possibly through the DESNZ's 'one stop shop' Net Zero Accelerator Service, building on the newly founded, publicly funded clean energy company GB Energy's recent investment in 200 schools, in which it plans to spend £180 million on investing in 70-100MW of PV on schools and hospitals.

Supporting its anticipated Local Power Plan, GB Energy will provide "funding, capacity and capability support at all stages of project development", to drive the growth of community energy, building on the Local Net Zero Hubs Programme. In parallel, the National Wealth Fund also offers free advice and low-cost, long-term finance to local authority infrastructure projects that align with net-zero and economic growth mandates, which includes the development of solar projects.

Developing a skilled workforce is a key goal of the Solar Roadmap

Meanwhile, the National Wealth Fund will "explore potential structures to finance solar projects or portfolios". The Department of Business and Trade will coordinate a cross-government steering group to "consider potential government intervention" to promote corporate power purchase agreements – buying power directly from solar farms, at a significant discount from the grid.

A study into the safety of small-scale solar energy systems that can be plugged directly into the domestic mains supply will also commence. Current UK regulations forbid them, although they are increasingly popular on the Continent.

Grid access

Excessive waiting times for electricity grid connections have long been the bane of the solar industry, for both ground-mounted and large-scale rooftop systems.

The Solar Roadmap spells out a series of measures to address the issue, in parallel with reforms arising from the Winser Review and raising transmission impact assessment thresholds. These include adopting a common definition of commercially sensitive data, which should provide a better understanding of which projects are most likely to proceed. Ofgem will also consider introducing standards to improve levels of service after grid connections are accepted, with the UK's National Energy System Operator (NESO) conducting a series of technical measures to improve transmission impact assessments.

As things stand, solar projects above 3.68kW, corresponding to 16 amps per phase, must receive approval from DNOs. This red tape can encourage installers to limit system capacity below the threshold, though one operator has raised the threshold to 5kW, encouraging larger residential installations. Those under 14.72kW are now subject to a fast-track process, with responses due within ten working days.

The roadmap also indicates that high-voltage overhead power lines over 2km long mounted on wooden poles will no longer be considered nationally significant infrastructure projects due to their low visual impact.

One of the most welcome aspects of the package concerns the treatment of battery energy storage systems (BESS), commonly co-located with solar farms. BESS are currently considered a hindrance to the electricity system, rather than providing the benefits of absorbing excess power and supplying it during periods of peak demand. New and harmonised modelling procedures will be introduced in response.

Reforming who pays for new high-voltage supergrid transformers, which the roadmap describes as a "postcode lottery", is also expected.

Ground-mount solar

The roadmap endorses Solar Energy UK's Community Engagement Good Practice Guidance [3]. Aside from supporting developers, operators and the supply chain, it is equally "useful to local authorities and communities as a referencing material for engaging with solar industry developers and operators", says the paper.

The association has also committed to developing a template for developers to use for stakeholder mapping and a communications toolkit for conveying the benefits of solar power when engaging with local communities.

In parallel, the provision of community benefits has a vital role to play, and it is the subject of an ongoing DESNZ consultation [4]. While the Government's position is being considered, Solar Energy UK will publish a voluntary protocol and guidance for community benefits later this year, covering installations over 5MW (other than rooftop, 'behind the meter', community-owned or community-led solar farms).

Scotland is consulting on refreshing its principles for community benefits, while the Welsh Government has issued guidance already [5, 6].

Supply chain

The roadmap represents a "once-in-a-generation opportunity to grow the solar supply chain and manufacturing capacity in the UK". While economics exclude the manufacturing of conventional silicon-based panels, there is scope to grow the production of transformers, inverters, switchgear, supporting bracketry and cabling, it says, not to mention batteries and R&D, particularly for lightweight and cutting-edge perovskite PV technology.

Accordingly, the government will consider supporting companies looking to scale up production of innovative solar technologies, processes and associated equipment, alongside the development of standards and testing facilities for next-generation solar technologies.

The roadmap also details the government's support for the "world-leading" Solar Stewardship Initiative, intended to prevent the procurement of solar panels produced with raw materials coming from forced labour. This comes after confirming that the system will be used by Great British Energy.

"The UK Government is clear that there should be no procurement of solar panels where there is evidence of forced labour. Government will empower contracting authorities to exclude suppliers from government contracts who have committed labour market misconduct and/or environmental offences in the UK or overseas… The UK solar sector has been proactive in its response to this issue," says the roadmap, noting Solar Energy UK's Supply Chain Statement and Responsible Sourcing FAQ [7, 8].

Skills development

The rapid growth of the UK solar industry, expected to expand by up to 17% this year, "offers a generational opportunity to create a wealth of high-quality jobs. At this crucial juncture, we must put the structures in place to build the skilled workforce needed now and in the decades to come," the roadmap says.

Without action, there is a risk of skilled labour shortages, skills gaps, loss of key skills "and potentially costly, urgent intervention further into the future," it warns.

Solving the problem will require intervention from across government, including the National Wealth Fund, GB Energy, Skills England, the Office for Clean Energy Jobs and the devolved administrations. Solar Energy UK has also stepped up, with the formation of the Solar Careers UK initiative, which will provide information and guidance on what skills and competences are needed for jobs in the sector and how to attain them. It has already held its first careers fair and is continuing to expand engagement.

The roadmap itself offers no fewer than 11 actions on skills, including improving the provision and effectiveness of training, mapping the routes to competence for core occupations and connecting colleges and businesses. Solar Energy UK will work with other trade bodies on how to attract and retain newly trained installers and prepare teaching materials for schools.

Planning

In the case of development planning, much of the action needed to help the sector has already been undertaken or is underway. This includes raising the threshold for solar farms to be considered 'nationally significant infrastructure projects' from 50MW to 100MW, in force from the end of the year, and the recruitment and training of new planning officers.

The Planning and Infrastructure Bill currently proceeding through parliament will simplify the consenting process for major infrastructure projects and require national policy statements to be reviewed every five years. The environmental impact assessment system is also being streamlined, and the first Spatial Energy Plan and Land Use Framework are being developed.

The National Planning Policy Framework has been reformed to give greater weight to the benefits of renewable energy and proposals' contributions to meeting net zero, and a consultation on the National Policy Statement for Renewable Energy was held recently [9].

But there is still more to do. Solar Energy UK has committed to working with the planning profession to ensure that training is fit for purpose. It will also produce factsheets to advise planners and councillors, plugging the gap in the expertise needed to assess solar applications effectively. We also intend to engage with any regional mayor or combined authority interested in driving forward solar developments in their area.

There is also work to do in relation to floating solar, which has significant potential but currently faces higher costs than deployment on the ground. Reforms to support the nascent sector will be considered under the planning regime and potentially via the Contracts for Difference system.

Solar Energy UK would like to extend our sincere thanks for the work of the former co-chairs of the taskforce, Andrew Bowie MP and Graham Stuart MP, alongside the members of its five sub-groups on networks, skills, supply chain and innovation, rooftop solar and communications. We are also grateful to former MP Chris Skidmore, who suggested the taskforce's formation in his 2023 Review of Net Zero. ■

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Chris Hewett became the chief executive of industry body Solar Energy UK in 2018, bringing 25 years of experience in environmental and energy issues. He was previously head of climate change for the Environment Agency, an associate at Green Alliance and a senior research fellow at the Institute for Public Policy Research. He was co-chair of the government-industry Solar Taskforce that produced the roadmap.

The Latin American energy storage boom that could happen, if…

Solar-plus-storage | The growing penetration of solar and other renewables in Latin America makes the case for energy storage ever more compelling. John Price and Valentina Menesses of Americas Market Intelligence profile some of the key regulatory and market dynamics helping and hindering the rollout of BESS across the region

Latin America is entering a transformative decade in its energy landscape, driven by the urgent need to expand power output, decarbonise, lower energy costs, improve grid resilience and integrate massive volumes of renewable energy. Battery energy storage systems (BESS) have emerged as the linchpin technology to realise these objectives. With projected revenues of nearly US$5.9 billion by 2030—up from US$680 million in 2023—the region is poised for a rapid and uneven expansion in storage markets across utility-scale, commercial & industrial (C&I) and remote grid applications.

However, such a rosy forecast is predicated upon the sudden spread of common sense across well-informed bureaucrats and regulators who see common ground and are motivated by a sense of purpose to transform Latin America's energy sectors. Those are demanding caveats that will not become reality in all markets, even if the benefits of expanding investment in energy storage are both economically and politically clear to see.

Recently, Americas Market Intelligence joined forces with Informa, publisher of this journal, to conduct a webinar on the status and future of Latin America's BESS market. Joining us in the webinar was Sandra Barba Lizarralde, director of business development and policy in Latin America for Tesla Energy. The webinar was replete with insights and worth a listen/watch. One of the clearest takeaways from the webinar was that each of the top eight BESS markets in Latin America are all marching to the beat of their own realities and warrant separate study.

Credit: Engie Chile

Engie's Capricornio storage project in Chile. The company has a growing pipeline of battery energy storage systems under development in the region

Regional leaders: Chile, Brazil and Mexico

Chile: Latin America's BESS pioneer

Chile remains the regional leader in battery storage, thanks to a combination of ambitious renewable targets (60% renewable share of all energy use by 2030), advanced regulatory frameworks and successful project execution. Some of Chile's market highlights include:

- 5.9GW of BESS (24.7GWh) installed capacity is projected by 2030
- Government mandates at least 2GW of storage to support its 60% renewable electricity goal
- Engie's "Coya" project (638MWh) is currently the largest in Latin America
- Annual battery additions could exceed 800-1,000MW in the late 2020s if supportive policies fully take effect

The Chilean government has enabled standalone storage systems and created favourable rules for remuneration, energy arbitrage and grid services. Chile's storage market success stems from the alignment of regulation, market incentives and project bankability.

The utility-scale segment dominates Chile's energy storage landscape. Large power generation companies are the primary investors in BESS, usually pairing them with renewable plants. Key players include Engie, AES Andes (AES), Enel and Colbún, who are deploying batteries to provide firm capacity and ancillary services (see Figure 1). For instance, Engie has a portfolio of big projects: along with the 139MW Coya system, it commissioned a 48MW/264MWh "Capricornio" BESS in 2023 and is building nearly 1GWh of solar-plus-storage in Antofagasta. AES Andes is likewise investing (it announced a ~US$400 million plan at COP26 to boost Chile's BESS capacity) and even piloting non-battery storage (e.g. a thermal storage project).

The mining industry – a huge power consumer in Chile – is an indirect beneficiary: mines are increasingly sourcing renewable energy, so utility-scale batteries on the grid help ensure stable supply, even when solar or wind output fluctuates. Some mining operations are also evaluating on-site BESS for microgrids or backup, though most large mine projects so far have leaned on grid improvements. The commercial/industrial BTM segment in Chile is currently small (residential and C&I behind-the-meter accounted for only ~8% of projected capacity additions). Chile's excellent solar resource has not translated to big behind-meter storage uptake yet, due to limited retail incentives. Thus, the largest "customers" for storage in Chile will continue to be grid operators and utilities procuring batteries to smooth renewable generation and defer transmission upgrades, as well as renewable developers adding batteries to earn capacity payments and reduce curtailment of their projects.

Chile has developed one of the most advanced pro-storage regulatory frameworks in the region. Recent reforms explicitly recognise energy storage and create multiple revenue streams. In late 2022, Chile passed an energy storage and electromobility law enabling standalone BESS to earn income from energy arbitrage and capacity reserve services. Further, a new grid regulation in 2023 allows batteries (including those co-located with renewables) to receive fixed payments for grid support (sufficiency capacity) and participate in ancillary service markets.

Some regulatory challenges remain. Despite strong growth, virtual power plant (VPP) models and ancillary services are still not fully monetisable, limiting the financial return of some storage business models. But if the rest of Latin America had its regulatory ducks in order the way the Chileans do, this industry would be 20 times larger than it is today.

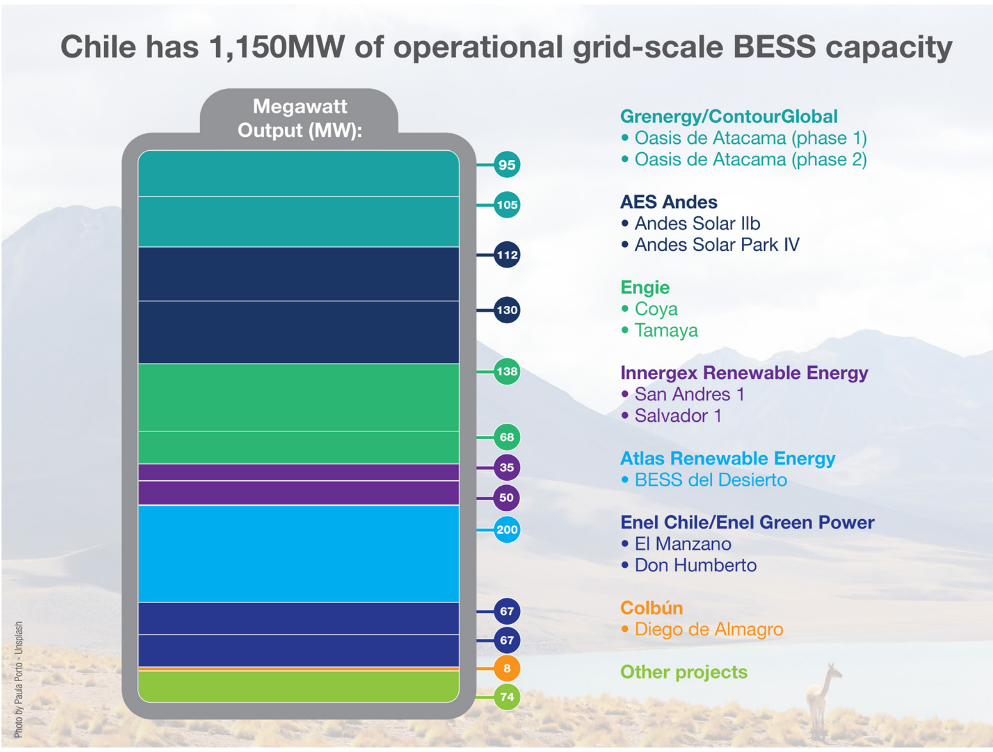

Figure 1. Ambitious targets and favourable regulation have helped Chile's BESS market become the regional leader

Credit: Paula Porto, Unsplash/Solar Media

Brazil: a sleeping giant awakens

Brazil, the largest power market in the region, is on the brink of a major BESS breakthrough. Though dominated historically by hydroelectricity, the country's increasing solar and wind penetration is introducing grid imbalance and curtailment risks, opening the door for batteries. Some market development highlights include:

- First national BESS auction in 2025 to contract 300 MW with 4-hour discharge
- Market projected to exceed R$22.5 billion (US$3.8 billion) by 2030
- Over 685MWh of installed capacity by 2024, 70% of it behind-the-meter

Thus far, industrial and commercial consumers have been the primary adopters of batteries in Brazil. An unreliable grid and expensive self-generation costs drive businesses to install BESS for energy security. For example, data centres and large manufacturers are deploying battery systems to ride through outages and perform peak shaving (reducing peak demand charges) – demand for storage components in Brazil's C&I segment jumped nearly 90% from 2023 to 2024. In the utility-scale space, power producers and grid operators are now entering several pilot projects (e.g. a 30MW battery system by ISA for transmission support) that have proven technical viability.

Traditional energy companies are also investing – for instance, Portugal's EDP and others have signalled interest in Brazil's upcoming battery auctions. We can expect major utilities and renewable developers (some of the largest being Neoenergia (Iberdrola), Engie, AES Brazil, etc.) to become key customers for large BESS projects that provide peak capacity and ancillary services to the grid.

Brazil's regulatory development is still evolving and should take shape this year (2025). The government is implementing a three-phase roadmap:

1. Technical definitions and service modelling
2. Regulatory sandboxes and pilot projects
3. Integration of advanced market mechanisms and aggregators

However, industry players emphasise that economic signals (e.g., time-of-use pricing) are currently too weak to support storage arbitrage, and tax burdens on imported BESS tech reach up to 70% of CAPEX, rendering many projects inviable. Until these issues are addressed, the focus will remain on regulated auctions and capacity remuneration. Needless to say, if a Brazil-US tariff battle ensues, project costs could rise even further.

Mexico: regulation-driven growth
Mexico is emerging as a regional BESS hotspot due to new government regulation under President Sheinbaum. Its new Grid Code mandates that all new solar and wind plants must include BESS equal to 30% of generation capacity, with at least three hours of storage. Some of the market development highlights include:

- Forecast: 574MW of storage by 2028
- To meet its ambitious renewable energy output goals, Mexico will need 4-6GW of energy storage by 2030
- CFE (Federal Electricity Commission) has concrete plans to add 2GW of storage by 2030, tied to 21.8GW of new generation, 80% of which will come from clean sources
- New DAC regulations require renewable projects to incorporate 30% BESS capacity
- Several utility-scale BESS project tenders were announced in 2025 alone

Energy sovereignty is a highly charged political issue in Mexico and an important driver of Mexico's about-face on energy reform. Two administrations ago, President Peña Neto opened up the monopolies of CFE and Pemex, the two state-owned companies that respectively dominate the power and energy sectors in Mexico. President AMLO blocked many of the private sector investments that followed the guidelines of the standing energy reforms. In a dramatic political legacy move, during the last 30 days of his presidency, AMLO, armed with a supermajority, re-legislated the predominance of CFE and Pemex, under the ideological banner of energy sovereignty. President Sheinbaum aims to sustain energy sovereignty while simultaneously embracing clean energy.

With historically high demand charges and an unreliable grid in some areas, large companies have turned to batteries for energy cost management and backup. For example, Grupo Bimbo (the world's largest baker) and Walmart have piloted BESS to cut peak electricity bills by 35% or more while improving supply stability. Local developers such as Quartux and ON Energy have installed dozens of MWh of behind-the-meter batteries at hotels, resorts and factories in tourist regions such as Cancún. A 25MWh C&I battery by Quartux in Cancún is cited as the largest C&I installation in Latin America.

Credit: Americas Market Intelligence

Moving forward, renewable energy developers and utilities will become the largest storage customers due to the 30% co-location rule. Many new solar and wind farms (including projects by state utility CFE and private independent power producers, such as Acciona, Iberdrola, AES, etc.) will incorporate on-site battery banks to meet the requirement. We can also expect independent power producers to deploy BESS for providing grid services: for instance, developers are exploring stand-alone storage projects for ancillary services in the northern grid, where wind/solar penetration is rising.

Overall, Mexico's biggest storage users in the late 2020s will likely be a mix of C&I firms seeking bill savings and large renewable project owners integrating batteries to smooth intermittent output.

The regulatory support for storage across Latin America is patchy despite huge demand

Secondary movers: Colombia, Argentina, Peru, Panama and the Dominican Republic

Colombia: an energy security play
Colombia's heavy hydro reliance exposes it to climate volatility, as seen in Ecuador's recent blackouts and Brazil's a few years ago. Storage is seen as a grid reliability tool and a solution for transmission congestion, especially in the north, where solar and wind potential are concentrated. Some market highlights include:

- First utility-scale BESS (45MW) launched in 2023
- National Energy Plan calls for 2GW of storage by 2030
- Regulatory Resolution 823 allows batteries to provide grid support services

The regulatory framework today remains incipient. BESS are currently permitted only as temporary congestion relief tools and are not yet eligible for energy market or ancillary service compensation. But regulators are working toward a more integrated role for batteries. Colombia's Ministry of Energy and Mines is considering launching tenders for storage co-located with solar and wind farms in La Guajira, a region with high renewable resource potential but weak grid infrastructure.

Argentina: a bold first step
Argentina entered the BESS race with the "Alma GBA" tender for 500MW of storage, launched in early 2025 and worth US$500 million. The project targets grid reliability in

Buenos Aires and is scheduled for deployment by 2026. After decades of under investment in grids, the ENRE (National Electricity Regulatory Entity) is studying use cases where BESS can mitigate peak load and defer network investments.

The Milei administration is keen to create investment incentives to quickly modernise Argentina, beginning with infrastructure. Though Argentina is blessed with burgeoning national gas and oil resources with the Vaca Muerta discoveries, the southern reaches of the country are also endowed with some of the best wind power potential in the world. Renewable developers in Patagonia and Jujuy are eyeing storage for improved dispatch priority.

As the world descends upon Argentina to mine its enviable lithium deposits, these remote sites, much like those found in Chile, will be prime locations for stand-alone solar power generation projects with integrated battery systems. As a dollar-generating export, developers can use dollarised PPAs to lower forex risk for investors. There are increasing calls for using renewable energy to support an export-driven battery manufacturing industry that leverages Argentina's lithium deposits.

Peru: gradual progress

With 16GW of generation capacity, Peru is focusing on deploying BESS for ancillary services. Natural gas is cheap and abundant in the south, making it hard for batteries to compete. However, northern regions have non-interconnected zones where batteries can provide reliable power. As a result, some industrial and auto-generation plants are starting to use batteries.

Peru's future in BESS may lie in combining storage with isolated grid and industrial use cases. Mining companies operating in the Andes and the Amazon have shown interest in hybrid solar-plus-BESS systems to reduce diesel dependency.

With regulatory support still under development, demand forecasts are modest, predicting an installed market size of a few hundred megawatts by 2030.

Panama: Central America's first mover

Panama made history with its 2024 tender for 500MW of renewables plus storage, aiming for 120-150MW of BESS deployment. This represents the first market-based approach to energy storage in Central America, potentially serving as a model for the region.

Dominican Republic: high stakes, high opportunity

The Dominican Republic is uniquely motivated to embrace BESS:

- Grid instability, frequent blackouts, and heavy fossil fuel use dominate the landscape
- The country is expected to need 250-400MW of BESS by 2028
- In 2025, a 15-assignment capacity tender was launched, including storage with solar PV plants >20MW

A history of misguided privatisation—subsidising distribution while guaranteeing high generator prices—contributes an estimated US$475 million to the national public fiscal deficit each year. Batteries are seen as a financial and technical solution to optimise generation and reduce subsidies. Not surprisingly, the government has signalled strong support for utility-scale storage deployment.

Market drivers and use cases

Grid stability & ancillary services. As renewables increase volatility, BESS can deliver frequency regulation, reserve power and reactive support. Chile leads the way with a regulatory framework that defines these services and enables monetisation.

Renewable integration & curtailment avoidance. Co-locating BESS with solar and wind farms helps mitigate curtailment and stabilise output. Mexico's storage mandate exemplifies this.

C&I and behind-the-meter applications. Especially strong in Brazil, where 70% of capacity is behind the meter. Industrial parks, data centres, shopping centres and mines are early adopters.

Remote and island microgrids. BESS is essential in non-interconnected zones, such as Peru's Amazon, mining throughout the Andes and pockets of the Dominican Republic, to replace diesel, stabilise power and enhance energy security.

Regulatory challenges

The demand case for BESS in Latin America is clear. Investors, integrators and equipment providers are all ready to pounce at the opportunities in the region. The biggest bottleneck holding back the BESS industry in Latin America is the lack of clear and well-designed (from an incentive perspective) regulations. Specifically:

- Ambiguity in market participation: many countries still lack clear rules for storage participation in wholesale and ancillary markets
- **Import duties and taxes:** Brazil's duties make imported batteries cost-prohibitive without local assembly
- **Weak price signals:** arbitrage opportunities are often limited by flat pricing structures or subsidised energy models
- **Virtual power plant models:** still under testing in Chile and unavailable in most other countries.
- **Limited pilot projects:** while regulatory sandboxes have helped in Brazil, they need to be expanded regionally

Conclusion: a decade to build upon

Battery storage is no longer a futuristic technology for Latin America—it is a critical pillar of the region's energy future. As utilities, regulators and private sector players embrace its versatility, BESS is becoming essential not just for renewable integration but also for grid resilience, peak load management and energy access.

The next five years will determine whether Latin America can overcome regulatory inertia, attract the necessary capital and execute on the many storage targets already announced.

Chile offers a blueprint. Mexico shows the power of mandates. Brazil must unleash its latent potential. And the rest of the region watches and learns. ■

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After the blackout

Power system | The huge power outage that hit Spain and Portugal in April was initially blamed on the countries' high penetration of solar and wind generation. Jonathan Touriño Jacobo explores the emerging evidence of wider systemic problems and some of the solutions already being implemented

Credit: BayWa r.e.

In late April 2025, Spain and Portugal witnessed a complete power blackout that lasted for more than 12 hours. From 12:33 for half a day, there was no electricity in the country, and those of us overseas were receiving messages from family members back home asking if the lights were still on for us.

It was an unfortunate event that temporarily cut Spain and Portugal off from the rest of the world and prompted a swath of speculations and accusations that lasted for nearly two months, until the Spanish government and Redeia, the parent company of Spanish transmission system operator (TSO) Red Eléctrica, released the reports of their investigations into the blackout in July.

The government report's conclusions emphasised a three-pronged issue that ultimately caused the Iberian blackout: insufficient control capacity on the grid, unusual voltage oscillations and improper disconnection of some power plants.

These conclusions came with actual measures and laws implemented that aim to fix the problems that happened in April and avoid a repeat, while improving the Spanish grid.

Starting from next year, solar PV plants of 5MW or more will be able to participate in voltage control in Spain

What happened on 28 April 2025

Less than a month after the blackout in the Iberian Peninsula, Sara Aagesen Muñoz, the Spanish minister for the ecological transition and the demographic challenge, first ruled out a cyberattack during a Congress of Deputies' session. During that same session, she gave details of what occurred minutes before the blackout, which happened at exactly 12:33.

The first unusual event happened at 12:03 with two oscillations that were detected both in the Iberian Peninsula and outside. The first oscillation lasted for less than five minutes, during which strong oscillations in both voltage and frequency occurred.

Another oscillation occurred minutes later at 12:16, with a variation of 0.6 Hz, leading to voltage fluctuations that resulted in voltage drops between 405kV and 380kV at the most affected substations.

Finally, a third oscillation occurred at 12:19 and lasted for three minutes. The Spanish minister said at the time that this second oscillation was more frequent within the European system.

In its report, Redeia – the parent company of Spanish TSO Red Eléctrica – identified the origin of the oscillations to a solar PV plant in Extremadura, without naming it, but making it very simple to identify that it was Iberdrola's Nuñez de Balboa. At the time of the first oscillation the solar PV plant was generating nearly 250MW of power and then increased

Credit: BayWa r.e.

technologies that we know we need for the future power system can actually provide some of these services that have traditionally been provided by fossil fuel or conventional power stations. And we need a mindset shift in the way that grids operate to keep track with the transition," adds Rosslowe.

This will open a new electricity market for solar PV and wind projects with an installed capacity of 5MW or above, as they'll be able to compete with thermal plants in the voltage control market starting from next year. This marks an important step for renewable energy and the Spanish grid overall, as having these plants providing voltage control will most likely reduce costs.

Not every installed power plant of more than 5MW will be able to participate in it, as they might not meet the requirements needed but most of the ones installed after 2020 will, says Baywa's Visquert.

"Most renewable generators connected after 2020—which represent the vast majority—already have voltage-control capabilities as mandated by the Spanish grid code (NTS 2.1)," adds Visquert. According to data from Red Eléctrica, Spain added more than 23.5GW of solar PV since 2020 and had a total of 32.4GW installed at the end of 2024.

Héctor de Lama explains that in 2024, Spain spent around €2 billion (US$2.3 billion) to have thermal plants on standby in case of any incident happening, which the blackout showed clearly did not work.

"In the blackout we've seen multiple instances of system actors, let's say, not behaving as the system operator expected them to do, or they should have done based on existing kinds of regulations, so that that applies across many generation types," adds Rosslowe.

But the participation of solar PV plants will bring even other benefits for the solar industry. As de Lama says, with solar being able to do voltage control at a lower cost, it will most likely force thermal plants to be decommissioned. This will allow for more solar PV to be added to the Spanish grid in general, and not just for voltage control.

"That implies less curtailment, whether market or physical curtailment knots. And that means much more integration of renewables, fewer emissions, cheaper prices … in other words, it's a very good thing," says de Lama, adding: "Voltage control is a nodal

to 350MW during the 12:19 oscillation incident.

Despite the fact that Redeia identified a solar PV plant to be at the cause of these oscillations, this incident alone was not enough to be the cause of the blackout, as Héctor de Lama, technical director at Spanish trade association Spanish Photovoltaic Union (UNEF), highlights.

"An electrical system is prepared for that to happen. For instance, in Spain, there are times when one or two entire nuclear plants are shut down very quickly and nothing happens," explains de Lama adding that each of these nuclear plants represents 1GW of capacity, whereas the Nuñez de Balboa plant does not even reach 500MW of grid connection capacity.

"Contrary to some early speculations, both the Spanish government and the Spanish TSO Red Eléctrica de España concluded in their respective reports that renewable generators not only cannot be blamed for the blackout on 28 April, but should also be seen as potential solutions to help prevent such incidents in the future," adds the global head of grid at BayWa r.e., José Andres Visquert.

Solar PV participating in voltage control

It did not take the Spanish government much time to take action after the blackout, and only days after releasing its report with recommended measures, it approved some of those through a royal decree law.

Technology moved faster than regulation, meaning PV was unable to contribute to preventing the blackout

A key one for the solar industry is an update of 'Operating Procedure 7.4', which will allow solar PV to participate in voltage control, which was one of the issues highlighted during the blackout, as only conventional generators were able to participate in this. During the blackout, the regulation that was in operation was from 2000, despite a draft from the Spanish TSO that included renewables having existed since 2020.

"One of the major conclusions of the blackout, I would say, is that the technology moved much faster than regulation. Although solar PV could have provided that stability, regulation moved more slowly, and so there was too much dependence on thermal power plants that did not behave adequately [that day]," explains de Lama.

Chris Rosslowe, senior energy analyst at think tank Ember, says this is a lesson that should be applied well beyond the Iberian Peninsula.

"The broad lesson here for countries beyond Spain is to make sure that you're technology neutral as far as possible when it comes to providing these key system services and acknowledge that now we're at a point where renewables, battery storage and these new issue. It is a matter of each node in the network, so having renewables do it instead of thermal power plants is much more appropriate because we are much more granular, much more distributed in the territory [than thermal plants]."

Co-locating with storage

Among the other regulatory improvements that will be implemented in Spain is a faster permitting process to co-locate battery energy storage systems (BESS) with renewables. Permitting energy storage projects, either as a standalone or hybridised with solar or wind, was an "extremely difficult" task in Spain, says de Lama. The Spanish government aims to install 22.5GW of storage by 2030, but is currently far behind compared with other European countries. This change will reduce the permitting times to add energy storage.

"Standalone and co-located BESS can offer fast frequency response (FFR) with activation times below one second, helping stabilise the grid during perturbations. Additionally, grid-forming inverters and Flexible AC Transmission Systems (FACTS) can contribute by adding synthetic inertia and oscillation-damping capabilities to enhance the stability, security and robustness of the electricity infrastructure," explains Visquert.

On the subject of frequency response, Rosslowe adds: "[BESS] can also provide essential grid services. Even though the primary cause of the blackout wasn't a frequency issue this time, batteries can provide very fast frequency support. It would strengthen the resilience of the grid against other potential [blackouts]."

Similar to BESS, adding more pumped hydro storage plants – so long as they fulfil the necessary environmental requirements – could also be beneficial for the grid, says Jonathan Bruegel, power sector analyst at the Institute for Energy Economics and Financial Analysis' European team. However, these projects can be very costly and would most likely require government incentives.

"This technology is expensive, takes time to build, but if you have it in the system, it will not last for 10-20 years. It will last for 100 years. The oldest plants we have in Europe are from the end of the 19th century, and some are still running. To me, it's a perfect complement to a fully renewable system, where you have lots of wind and solar."

System inertia

Aside from energy storage, a solution that could be quickly implemented would be a demand-side response directed towards industrial consumers, says Bruegel. Plant factories participating in this would receive incentives for stopping or dropping their production load immediately for a certain amount of time.

"You can even do that for residential customers," says Bruegel. "There is a device you can install, which is connected to the grid, and will respond automatically, adjusting the consumption in your home to the grid load. If the grid is overloaded, your device in your home will reduce automatically."

Implementing this would not require any major technological improvement, being a purely regulatory matter that would be fast to implement, adds Bruegel. "Demand response is really underdeveloped, both at the residential, commercial and even industrial side," he explains.

System inertia has also been highlighted as one of the technologies to implement in the days and weeks after the blackout. However, de Lama emphasises the fact that the blackout was not caused by a lack of inertia, as shown in both reports.

"There was no lack of inertia, there was plenty of inertia," says de Lama, adding that the synchronous compensators that are being added now are not used for inertia but voltage control. Although not needed now, the fact that these synchronous compensators are being added for voltage control will have a positive effect in the future, in terms of inertia. When Spain closes all its remaining nuclear power plants, these synchronous compensators will be able to cover the loss of inertia from the shutdown of nuclear plants

"These synchronous compensators are versatile machines that are currently needed for voltage control, but in the future they may provide other benefits," adds de Lama. Such as when Spain decommissions its remaining nuclear power plants, and with it, the need for inertia arises.

Rosslowe adds that synchronous compensators are a key technology to consider, one that was highlighted in the reports. "It's an existing technology that is already being rolled out that just needs more of a push behind it."

More interconnection?

Finally, it is no surprise that Spain and Portugal currently operate as an island in terms of the grid, with very limited cross-border interconnection with the rest of Europe through France. And the people *PV Tech Power* spoke to agreed that, had Spain been better interconnected with France and the rest of Europe, the blackout would have not been as bad as it was, and it wouldn't have taken more than 12 hours to reconnect the entire grid.

"If the interconnection between France and Spain was a stronger capacity, yes, it would have helped. But overall, Spain is not a very much an importer-reliant country," says Bruegel.

Rosslowe adds: "The report clearly stated that if Spain had been better interconnected with its neighbouring countries, principally France, some of the oscillations that occurred and destabilised the system would have been less likely to occur.

"It's well documented that the connection between France and Spain is a weak connection, and it's a real bottleneck on allowing the rest of Europe to benefit from the renewable resources that are in Spain."

Almost at the same time as the reports were released, news of an interconnection financing from the European Investment Bank (EIB) was released. The investment from the EIB will support the construction of the Bay of Biscay interconnector, which will increase the electrical exchange capacity between France and Spain by 2.2GW, bringing the total to 5GW once the project is operational.

One thing is clear, though, is that the Spanish government and the involved parties have acted quickly to implement solutions that aim to avoid a repeat of what happened on 28 April. The blackout has highlighted that renewables are moving at a faster pace than the grid and even regulation in the case of voltage control. Making sure that the transformation of the grid and the regulations go hand in hand with the pace at which renewables are added will be very important to ensure everything works accordingly and that Spain and Portugal don't get disconnected from the world for half a day again.

"As Spain's energy mix continues to evolve toward higher shares of renewables, modernising grid operations and regulation will be key to ensuring a secure and stable electricity supply," concludes Visquert. ■

The 2,000V transition: why utility solar is ready for its next leap

System architecture | Utility-scale solar is preparing for its next voltage evolution, with 2,000V systems emerging as the successor to the 1,500V standard that has come to dominate the sector. But with familiar challenges around certification and supply chain development, when will this next evolutionary leap take place? David Pratt reports

Credit: Shoals Technologies

The history of utility-scale solar has been defined by a constant race to lower costs while boosting efficiency. This drive to compete with conventional generation has led to an 84% reduction in costs since 2009, with solar now the cheapest form of generation at US$58/MWh.

Increasing the voltage of PV systems has been a key element of this progress as higher voltages unlock a range of system benefits that translate into lower costs. Liam Coman, solar market analyst at S&P Global Commodity Insights, explains to *PV Tech Power:* "By increasing voltage while holding current constant, systems can transmit more power while improving efficiency. Increasing voltage also means less components on site, reducing costs and complexity."

These factors have historically driven upgrades to standard voltage specifications, with higher voltages decreasing the number of components needed to generate the same power. This lowers capital expenditure (capex) across various elements and reduces operational costs over time, as fewer inverters and balance-of-system (BOS) components require

The solar supply chain is gearing up for a shift to 2kV in its ongoing effort to drie down costs

Credit: GE Vernova.

The 2kV FlexInverter solar power station was released in September 2024, over a decade since GE's 1,500V inverter

maintenance. Additionally, a decrease in DC-side resistance losses allows more power to reach the inverters, leading to higher energy yields and a marginally better return on investment.

The industry initially moved from 600V to 1,000V to pursue these benefits before 1,500V was adopted as a de facto standard. The most recent shift arguably began in 2012 when GE's newly developed 1,500V DC open circuit central inverter was installed by Belectic in Germany. GE then continued to work with First Solar's 1,500V-rated modules on US pilots in 2014.

Standards and technology converging

Now, over a decade after its 1,500V system was released, GE Vernova has announced the next iteration of its inverter technology: the 2,000V (2kV) FlexInverter system. According to Owen Schelenz, solar and battery energy storage product leader at GE Vernova, the apparent pause before progressing to higher voltages was not necessarily a result of slow-moving technology development.

"In 2012 we had the first 1,500V inverter really maxing out the low-voltage directive and then we stayed there for a decade. There was really nothing that stopped us other than limitations of standards," he explains.

"The challenges are primarily around certification, which engineers need to provide for bankability and project sign-off. The whole industry gets caught up in this wait and see [loop]…because there are no references [or] bankability assessments. That's why we were stuck for a long time at 1,500V."

The wait for new safety standards to be developed by UL Solutions (UL) in the US or the International Electrotechnical Commission (IEC) has been a key determining factor in when transitions to higher voltages occur. European regulation has generally reflected UL standards, with 1,500V considered to be the low-voltage DC limit since 2014, before IEC and UL module standards were harmonised further in late 2017.

UL has continued to lead in development to higher levels, with an October 2023 update to the UL 1741 safety standard covering inverters "paving the path for testing at higher voltages" with a GE Vernova customer willing to take the plunge with new system architecture.

Schelenz explains: "You have to find somebody that's crazy enough to want to be first because nobody wants to be first in an industry like this. We finally found that catalyst [with] a customer that is innovation friendly, can bank or finance projects, and is their own AHJ [authority having jurisdiction] able to assess the risk behind the projects themselves," he says.

The unnamed North American customer brought together GE Vernova, Shoals Technologies and Jinko Solar to test 2kV-rated solar systems at a pilot that went live in January 2025. Together the project partners converted a 1,500V block of an existing project, taking the section's capacity from around 4MW to 6MW without changing the footprint.

Each company brought leading technology to the 2kV upgrade, although Jinko is the only project partner to have achieved UL certification for its 2kV solar modules. At the time of writing, GE Vernova was still awaiting UL 1741 SA certification for its FlexInverter 2kV system, while Shoals is one of the first to undergo UL testing for its electrical BOS (EBOS) solutions. According to Troy Renken, vice president of product and engineering at Shoals, the availability of varied 2kV components made the pilot project a success.

"You really have to think about it as a whole system [and] make sure that your modules, your EBOS and your inverter all meet that 2kV DC rating," he tells *PV Tech Power*.

Overcoming technical challenges

This step up in voltage required Shoals and GE Vernova to tackle specific issues related to the move to 2kV. For example, BOS solutions become more sensitive to leakage current, a key indicator of insulation integrity, while creepage distances need to be increased between conductors throughout the system to prevent arcing.

Schelenz adds: "I don't think anyone thought this was going to necessarily be challenging. Perhaps a better word to use is that it's a bit tedious because of the lack of component availability. You have to work through component-by-component [with] certification agencies."

By boosting voltage without impacting current, the FlexInverter 2kVdc system can increase power output by 30% within the same footprint. Fewer of the power-dense inverter units are needed on site, creating knock-on reductions in capex across the project.

Renken says: "A lot of the similarities between now and when there was interest in moving from 1,000V to 1,500V boils down to the key words 'fewer or less'. When you increase that voltage it means, for the same exact size of site with the same exact number of solar modules, you're going to end up with fewer strings and fewer inverters."

GE Vernova has suggested a 2-3% project-level saving can be made from the reduction in necessary DC cable alongside fewer power stations, strings, combiner boxes and connectors.

Schelenz says: "The savings are not earth-shattering [but] you get one or two cents a watt for a project and that's not nothing. If you then look at the sustainability aspect, we will ship 30% more power conversion capability for the same steel in a container. All of a sudden, steel usage goes down, logistics go down because for one shipment we pack more power. Then efficiency tends to go up because you can use less cable than you

The Mengjiawan PV project – 2kV at scale

The project, claimed to be the world's first grid-connected demonstration of a 2kV system, brings together 2kV n-type bifacial double glass modules developed jointly by CHNG and DAS Solar's research and development (R&D) department with new inverter technology from Sungrow, which developed the equipment under a RMB2.45 billion (US$341.47m) investment programme.

The DC side of the project is said to occupy the smallest area for a project of its size among centralised PV sites in northern China, covering 11.3 hectares per 10MW. According to DAS Solar, the 30% increase in installation capacity of individual modules resulted in significant savings in DC cable and combiner box usage.

The company says it carried out thorough insulation tests and 13,500V high-voltage withstand tests on the supplied 2kV modules. Sungrow, meanwhile, developed intelligent graded shutdown technology and adaptive voltage and power control algorithms for its 2kV inverters.

In addition to reduced BOS costs, the project partners have claimed faster build-out times, lowered costs for infrastructure construction, equipment transportation and maintenance and higher energy yields.

did before. So in terms of everything that's impacting the supply chain, it's very beneficial."

Project savings have also been reported in China, where 2kV projects have already moved past small-scale pilots. The 182MW Mengjiawan PV project, jointly built by China Huaneng Group (CHNG) and Sungrow, was grid connected and commissioned in Yulin, Shaanxi Province, in summer 2023. The use of 2kV modules, developed with DAS Solar and deployed across 34 subarrays, and inverters from Sungrow reduced EBOS costs by a reported RMB0.04 (US$0.55) per watt compared to 1,500V systems.

Forming the supply chain

While these initial projects show encouraging signs of the benefits inherent to increasing voltage, a lot needs to happen before the transition to 2kV as a new industry standard is achieved. The supply chain has yet to fully form around the technology, with only a handful of module suppliers in addition to Jinko, such as Astroenergy and TrinaSolar, achieving certification of some kind for their 2kV solutions. The challenge also lies in getting 2kV subcomponents certified and available on the market as part of completed solutions.

ABB has been at the forefront of increasing voltage capabilities in the past, releasing a line of 1,500VDC disconnect switches and other components in late 2014. Less than ten years later, the company had developed a 2kV-rated switch disconnector but faced delays in getting the equipment certified to UL standard 98B.

Brian Nelson, renewables segment leader for ABB, says: "The reality is that ABB had a switch capable of being UL listed a year and a half ago but the standard didn't exist or wasn't extended to 2kV.

"It's okay to have a science project that is not UL to [show] it is possible, but it's not okay to have a product that isn't meeting a UL standard for broad adoption. We now have a UL-listed switch, so in a way we've hit the finish line of our development and now it's the starting line for [our customers]. They have to take our switch and put it in their combiner and get that UL listed. It's a domino effect of getting that UL listing, which then leads to everything else."

While UL does not have to provide the testing that would result in a certification, it is viewed as the preferred testing body due to the fact that it develops the standards that new products must reach. This means that technology providers, such as Shoals, are seeking it out as the first option.

Credit: ABB

ABB has been waiting for testing standards to catch up with its development of a 2kV switch disconnector

"We're strategically choosing to work with UL because they are the authors of the standard. We feel that gives us the fastest path to getting a listed product because the interpretation of the standard is a bit easier [and] it instills the most confidence in the industry," said Renken.

"From a regulatory perspective, we have all the parts in place in terms of the standards that we need for EBOS so we have been working with the major component manufacturers to make sure they have products that are going to work for our systems. In almost every category we have more than one manufacturer who has a product that meets the new 2kV standard. Then what we have to do is bring all of those components together and test it as a system to achieve the UL regulatory certification that we need."

This process is not simple, as Nelson explains: "Going from 1,500V to 2kV is not an easy thing to do. We're starting to talk about a pretty substantial DC voltage, and so, technologically, as a component supplier, that's a technical challenge that took us a little while to figure out. Then you have to wait for the standard to be ready so that we can test to make sure that it's safe.

"That really is the missing link to this. When that happens, I think we'll start to see some developers really start to consider this with their EPC partners. It's the lack of a totally UL-compliant solution that is holding us back."

Tracker producers such as GameChange Solar have begun producing 2kV-compatible equipment

Credit: GameChange Solar

Ready and waiting

There are, however, components ready and waiting to accommodate higher voltage systems. Solar tracking solutions have come to dominate the utility-scale sector, utilising sensors and motors to orient solar panels for optimal generation. Unlike many other components, they require little change to take 2kV systems depending on their existing design.

GameChange Solar has successfully installed and commissioned tracking systems for 5MW worth of 2kV modules at a new build site in the south-east of the US. As chief engineer Scott Van Pelt tells us, the design of the company's Genius Tracker racking system was already well-suited to 2kV systems.

"The GameChange system does not have parasitic losses, so we don't pull energy from the string wires. We have a stand-alone charging module battery that's powering the motor, and obviously that makes things significantly simpler in that our system does not have to be rated for 2kV directly while still being able to support a 2kV system," he says.

"Our system is flexible enough that the change in string length does not cause a big design lift or strain on our engineering resources."

The limited interaction with the site's other components meant the system could be verified compatible with approved components for operation at 2kV. The review was conducted by Intertek, which evaluated the Genius Tracker under UL 2703 standards and confirmed that no additional testing or modifications were required. This expeditious process through Intertek demonstrates that standardisation can be achieved without joining the queue forming around UL.

2kV as an industry standard

The question, therefore, remains: when will the transition to 2kV take hold? Previous increases in voltage across the sector have generally occurred years after the first products appeared on the market. Standards need to catch up to the pace of change driven by the market before they can be understood by the developers and EPCs deploying projects.

Cormac Gilligan, director of research and analysis for clean energy technology at S&P Global Commodity Insights, says: "UL and the IEC are working on updating standards, but widespread adoption requires developers and engineers to understand these protocols before mass adoption. Until pilot projects demonstrate reliability and cost savings, developers and EPC companies are cautious about adopting 2kV, given the higher perceived risk and limited supplier base."

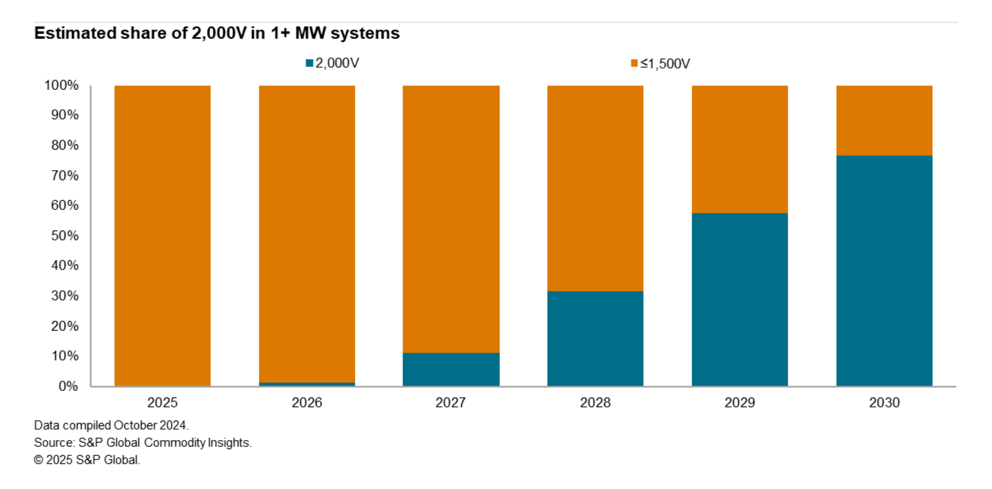


Figure 1. 2kV could become the industry standard by the end of this decade. Data compiled October 2024 by S&P Global Commodity Insights

This timeline, according to S&P Global Commodity Insights, will see 2kV move from pilot stage into the mainstream in 2026/27, ramping up in installations to become the industry preferred voltage in 2028/29 (see Figure 1).

Estimated share of 2kV in systems over 1MW

Nelson agrees with this assessment, having rowed back from his previous claim that 2kV could become the standard by the end of 2025.

"The industry is going to be talking about it a lot more, but are projects going to be built at 2kV at the end of this year? No, I don't think so. I think this is probably more of an end of 2027, even into 2028, deal if I want to be more realistic," he says.

Consensus on the 2027/28 timeline of industry adoption of 2kV is also shared by Schelenz, who believes the maturing of engineering prowess across the solar value chain, including among customers, will result in a faster transition.

"I think 2027 will be the first year we do a number of projects that will be 2kV, and then hopefully 2028 is off to the races," he says.

These races will take place in the US and China first, according to Coman, reflecting the steps that have already been taken towards 2kV systems. While some European standards have already been harmonised with the US, Coman believes the European market, along with the rest of the world, will "likely be 12-18 months behind the US and China adopting the technology".

Moving beyond 2kV?

Where Europe is potentially ahead of competing markets is in looking beyond 2kV to the next stage of development. The evolution from 600V has been a predictable one and, according to Schelenz, 2kV "is by no means the final boss of voltages and string configurations".

He explains: "2kV won't be the end. If you look at Germany, the Fraunhofer team has a working group that we're a part of for 3kV. Beyond that, there are other topologies we're working on that will further disrupt the way we think about solar plants and battery plants. It's always a continuum [and] we're always pushing for new heights."

Nelson agreed that 3kV is likely to be the next step for utility-solar in the coming years, despite the standards for this "big jump" being far from development. Coman believes the timeline will depend on the adoption of 2kV, as the industry continues its slow march to ever higher voltages.

"This jump will not occur until 2kV supply chains are fully matured and all cost benefits have been fully utilised. [We] expect this jump to the next voltage to happen sometime in the early 2030s," he adds.

The transition to 2kV is, therefore, just the latest step along a familiar path to greater efficiency and lower costs. As with previous voltage increases, widespread adoption remains contingent on the fast development of standards, availability of components across the supply chain and bold customers willing to try out the latest innovations. But with projects already underway and interest growing around the world, the move to 2kV seems as inevitable as previous voltage increases. The question is not if voltage will increase to 2kV, but how long before the industry moves even higher? ■

Now is the time for interconnection reform

Grids | Despite the prospects of a near-term drop in business following federal renewable energy cuts, US solar companies will already be looking ahead to the next upturn. IREC's Vaughan Woodruff considers the critical need for state-level reforms in readiness for the next shift in federal policy

Credit: Nexamp

The signing of the 2025 Budget Reconciliation Bill on 4 July 2025 will have a significant impact on the development and construction of solar facilities across the US. The Solar Energy Industries Association (SEIA) estimates that the federal government's pivot away from strategic investments in solar energy could result in a reduction of over 300,000 jobs by 2028 and approximately US$250 billion of lost investments by 2030 [1]. For those who have experienced the infamous 'solar-coaster, the near-term future likely feels like a steep drop with a familiar sinking feeling in the stomach. Instead of the thrill that comes with careening through twists and turns, industry professionals on this ride are likely going to be contemplating significant shifts in their business plan and navigating the world of layoffs, downsizing and potential business closures.

Those seeking to climb to the crest of the next hill are looking at several years of business innovation and uncertainty while anticipating another shift in federal policy that will help the US regain its standing in renewable energy deployment. If the impacts of this bill on jobs, investment and energy costs align with the forecasts from SEIA and others, a future change in leadership is likely to open the door to correcting course.

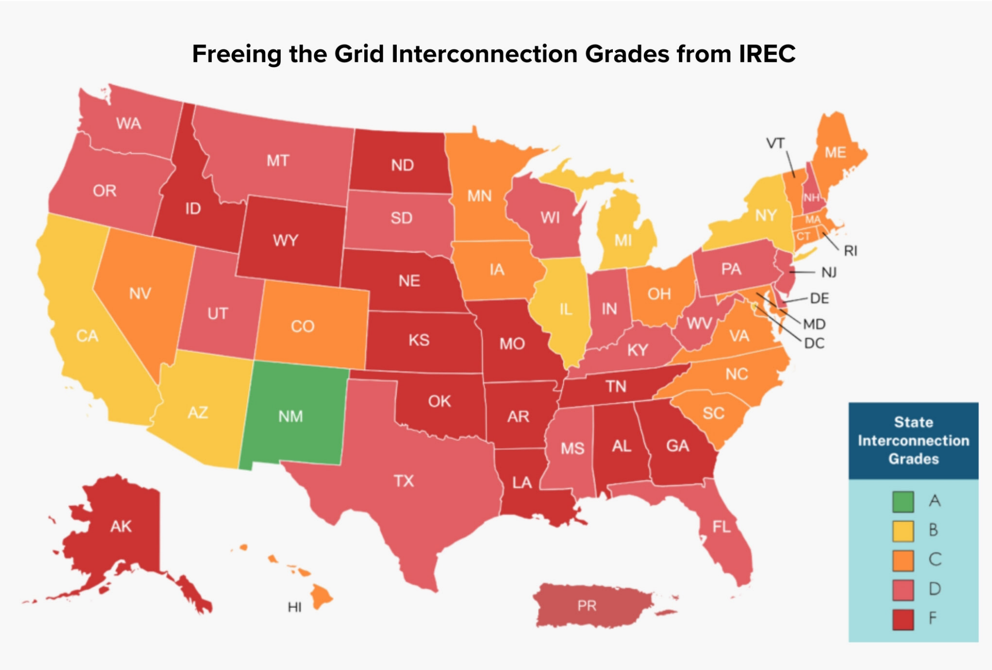
In the interim, the US will need to focus its efforts on advancing a clean energy future, state by state. While federal tax policy has had a significant role in advancing renewable energy investment, state-level energy policy and regulation are also substantial drivers. There are ample local opportunities to advance clean energy priorities that address short-term needs while creating a regulatory environment that is better prepared for expansive growth than the one we have today. In this article, we explore the opportunity and imperative for reforming interconnection policy for distributed energy resources (DERs), such as solar, energy storage and electric vehicle charging infrastructure, and how such efforts can address near-term challenges while readying the US for a streamlined transition to clean energy.

States will have to play a lead role in advancing US renewable energy deployment following recent legislative changes

The need for DER interconnection reform

In January 2025, the Interconnection Innovation e-Xchange (i2X)—a programme of the Department of Energy—released its 'Distributed Energy Resource Interconnection Roadmap' [2], which highlights key actions that can be taken in the next five to ten years to address DER interconnection challenges. Priorities include increasing grid transparency, streamlining utility approval, including interconnection in grid planning processes, and supporting grid reliability, resiliency and security. The authors argue that effectively addressing these priorities will provide significant benefits, including reducing interconnection approval timelines, increasing approval rates, improving interconnection queue data, ensuring DERs do not impact transmission-level reliability and reducing customer grid interruptions.

As highlighted in the roadmap, "[if] the potential for DER deployment is to be realised… interconnection processes must evolve to handle large and growing volumes of DER interconnection requests".



Credit: IREC

Figure 1. Nearly 60% of states in the US need to improve interconnection procedures for distributed energy resources

While the pace of interconnection requests is expected to slow down in 2026, this reduction in volume will not alleviate the challenges that individual projects face. Distribution grids have a finite amount of capacity for hosting DERs. With each subsequent project, the risk of interconnection challenges increases. Effective interconnection rules adopted by state utility regulatory commissions are essential to ensure that future projects are able to fully utilise existing hosting capacity and that processes are in place to pay for investments to modernise the grid equitably.

In 2023, the Interstate Renewable Energy Council (IREC) highlighted the scale of regulatory reform needed in the US through its 'Freeing the Grid' evaluation [3], which grades the strength of each state's interconnection rules (see Figure 1). Thirteen states scored an "F" because they do not regulate DER interconnection, and another 16 states scored a "D", indicating a need to significantly update their interconnection procedures to streamline review processes, reduce costs and improve transparency. In summary, nearly 60% of states in the US need drastic improvements to their interconnection procedures to address existing barriers to DER deployment, let alone to achieve the goals highlighted in the i2X roadmap.

Change takes time

One of the challenges of regulatory reform is that its timelines are typically measured in years. Take New Hampshire, for example. Interconnection customers knew well before the most recent update to 'Freeing the Grid' that improvements were needed. In January 2022, the state legislature passed Senate Bill 262 to address interconnection delays by directing its Department of Energy to investigate the state's interconnection procedures. That bill resulted in a year-long proceeding and a December 2023 report to the legislature that concluded working groups would be needed to identify regulatory changes. Recognising that a formal rulemaking would be required to address ongoing concerns, the legislature ordered the Department of Energy in January 2024 to instead initiate a formal rulemaking proceeding to align the state's interconnection rules with national best practices and cited IREC's 'Model Interconnection Procedures' [4] as a resource. A final revised rule is expected to be approved by April 2026.

New Hampshire's four-year process is not unique. Massachusetts began considering changes to include energy storage in its utilities' interconnection tariffs in May 2019. Over six years later, these improvements are currently being considered by the state's Department of Public Utilities. New Mexico, the only state to score an "A" in the 2023 edition of 'Freeing the Grid', overhauled its interconnection rules in November 2022 following passage of a grid modernisation bill that was signed into law in March 2020. Similarly, it took Maine over two and a half years to significantly amend its rules following the passage of interconnection legislation in March 2021.

How change happens

Reforming interconnection regulation requires prioritisation of the issue—typically either by the legislature or the utility regulatory commission—and formal public regulatory processes that evaluate whether any proposed changes will impact the utility's ability to maintain grid safety and reliability. The time requirements of these processes are better aligned with solving forward-looking challenges, but the reality is that a large majority of regulatory proceedings are reactive. As a result, a discrete interconnection issue can impact a market for years. And while that particular issue is being solved, numerous others can arise.

Whether a deficiency in a state's interconnection procedures is addressed depends heavily upon legislative or regulatory advocacy. Efforts may be initiated by a legislator who is contacted by a constituent or contractor who is experiencing considerable delays or is required to pay for significant upgrades to the grid to accommodate their projects. Or a regulatory commission may notice a pattern of complaints or receive a filing from a utility seeking guidance on how to comply with the state's interconnection rules for a particular set of circumstances. In very few instances do regulatory changes proactively seek to address issues experienced in other jurisdictions that are expected to arise locally in the future.

Often, interconnection issues experienced by utility customers never reach the key decision makers who can initiate needed change. Some solar contractors, when faced with an interconnection challenge and strong demand for projects from other customers, may avoid investing the considerable time needed to try to resolve the issue and instead abandon the project. Or they may try to resolve the issue with the utility and fail to find a reasonable pathway to resolution. If the contractor is successful in identifying an opportunity to resolve the issue, their customer may decide to cancel the project due to delays or uncertainty. Other customers may shoulder excessive costs or an excessive delay on a single project without raising the broader issue that, if addressed, would prevent similar issues for other customers. In extremely rare cases, negotiation between local industry and utilities can lead to resolution outside of formal regulatory proceedings.

Given the market disruption likely to occur in 2026, DER interconnection challenges need to be more visible and addressed promptly. Project cancellations due to interconnection challenges are likely to be more impactful to solar contracting firms and project developers. The importance of high interconnection approval rates increases with market contraction, and the ability to shoulder the costs to resolve interconnection disputes decreases with a smaller revenue base. Additionally, once the pendulum of federal policy swings again and the solar-coaster takes another exhilarating ride, it is critical that states don't spend years resolving interconnection bottlenecks that are very foreseeable today.

Prioritising regulatory reform during challenging times

With the burden of responding to very real and impactful market pressures, it may be difficult for individual solar companies to ramp up their activity in legislative and regulatory arenas where they may not see direct and immediate economic benefit. Even in good times, most of the companies engaging in interconnection reform do so with a specific project in mind. Durable interconnection reform requires a broader approach, one that may seem a significant luxury during lean times. Yet, interconnection strategy and regulatory engagement are fundamental to the success of companies that weather the impacts of the Budget Reconciliation Bill. For those committed to the long-term success of their business or their state, here are some tips for advancing interconnection reform:

1. **Identify the core interconnection issues facing your state.** If you work in the solar industry and are experiencing specific interconnection challenges, evaluate your state's interconnection procedures and determine whether the challenge is due to utility non-compliance with the rules or a deficiency in the rules themselves. If you are not experiencing interconnection issues and instead seek to be proactive, review your state's scorecard from 'Freeing the Grid' to identify where there are opportunities for improvement.
2. **Learn from other states.** Unless you are in California or Hawai'i, there's a strong likelihood the challenges you're seeing have been experienced elsewhere. IREC's 'Model Interconnection Procedures' represent a baseline model of effective DER interconnection provisions that have been adopted in states around the country. If your state scored a "D" or "F" in 'Freeing the Grid', a strong goal could be to adopt or revise your state's rules in alignment with the IREC Model. If customers are experiencing issues that aren't addressed in the IREC model, reach out to colleagues in other states to see whether they've experienced similar challenges or contact IREC directly.
3. **Identify areas of strength.** Regulatory reform requires broad expertise and benefits from collaboration. Once you've identified the challenges to address, identify what you can bring to the table. Are you a technical expert who can evaluate interconnection solutions from other states and how they apply in yours? Do you have expertise in the interconnection process, and what specifically needs to be improved? These insights are highly complementary to parties who want to advance local clean energy solutions and may be more familiar with the regulatory or legislative processes.
4. **Build alliances.** Interconnection reform requires people with influential networks, people who can motivate decision makers to act, lawyers or other regulatory policy specialists who can write compelling comments in formal proceedings and practitioners who can make and dispel technical arguments. Common advocates include individual DER companies, trade associations, nonprofit groups focused on climate or clean energy issues, energy agencies in states with climate goals and IREC. You may find collaborators in places you might not expect, such as with utilities. There are often renewable energy champions working on the front lines at utilities who also want to see processes improve. Building strong relationships with utility staff can help strengthen regulatory outcomes by more specifically identifying the barriers to change and the shared benefits of streamlined interconnection procedures.
5. **Take the long view.** In the states where interconnection reform has taken years to advance, the pathway was rarely a straight line. And even once those changes have been implemented, interconnection rules need to be updated regularly to address emerging challenges and opportunities. Engaging in these issues, either directly or through collaboration with other parties, is increasingly becoming part of doing business for those in the solar industry.

The second-best day to advance interconnection policy is today

There is an adage that the best day to plant a tree was 20 years ago, and the second-best time is today. The same holds true for developing strong DER interconnection regulation. While a majority of the states across the US would be better positioned to weather the interconnection challenges of today and tomorrow by initiating reform of their interconnection procedures two, four or even ten years ago, starting today is the next best time to remove barriers to solar and storage projects. Such efforts will reduce the burden on customers and companies seeking to connect DERs to the grid during what is expected to be a particularly challenging time for the advancement of solar technologies. Interconnection reform is also necessary to streamline processes ahead of the wave of projects that will come when a federal commitment to clean energy returns. The consequences of waiting are predictable and will further hamper US deployment of solar power. ■

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Author

Vaughan Woodruff is the vice president of regulatory reform at the Interstate Renewable Energy Council (IREC), an independent nonprofit building the foundation for rapid adoption of clean energy and energy efficiency. His team of engineers, regulatory attorneys and policy professionals helps states regulate their electric utilities to ensure DERs can rapidly and equitably decarbonise the grid. Prior to joining IREC, Vaughan was the founder and CEO of Insource Renewables, a Maine-based solar contracting company, the chair of Maine's solar industry trade group and later served as VP of workforce development and interconnection strategy at ReVision Energy.

Breaking point: understanding and preventing PV module glass fracture

Technology | Dual-glass PV modules are experiencing low-energy glass fracture under expected conditions of use at an alarming rate. David Devir of VDE Americas looks at the origins of today's supersized PV module glass problem and considers how the industry can engineer a return to reliability

The solar industry's sustained ability to reduce fielded PV plant costs is a collective success story with global implications. In 2024, solar markets around the world added approximately 600GW of new PV power generation, resulting in a cumulative global capacity of over 2.2TW. For the third year running, solar was the world's largest source of new power generation capacity.

Unfortunately, market growth and component cost curves do not tell the whole story. On one hand, exponential growth in solar development and deployment is foundational to electrification and decarbonisation strategies intended to ensure a worthwhile future. On the other, the technical due diligence community continues to find evidence of cracks in the industry's foundation.

PV module glass breakage has long been an observed failure mode in fielded solar projects. In recent years, however, the nature and causes of solar glass fracture have changed in alarming and unsustainable ways. Given the scale of the global market, increasing solar glass failure rates have the potential to become a major reliability issue for manufacturers, developers, owners, insurers and investors.

To help stakeholders mitigate the threat of premature field failures, this article looks at the market, technology, and testing trends that appear to contribute to a rise in reports of solar glass breakage. It also explores ways in which a holistic industry response might contain this multi-faceted issue and prevent a crisis of confidence. But first, I will briefly review recent symptoms and evidence of a failure mode that is largely specific to dual-glass bifacial PV modules.

Credit: Agata Bogucka/NREL

Scientists and researchers at NREL, including Timothy Silverman and Elizabeth Palmiotti, are investigating early failure in dual-glass PV modules

Rise of low-energy glass fracture

Glass fracture in real-world solar installations is not a new phenomenon—and, in and of itself, it is not necessarily cause for undue concern. Unlike a highly ductile material like aluminum, glass cannot withstand significant plastic deformation prior to mechanical failure. When glass deforms beyond its ability to return to its original shape, it fractures, either at the location of an applied external stress or a strength-limiting internal defect.

As operations and maintenance technicians and forensic investigators know all too well, PV modules have always been susceptible to brittle fracture. For several decades, the root causes of solar glass breakage in the field were generally readily apparent based on an analysis of fracture patterns and failure distributions.

A pattern of breakage originating at module clamps might reveal construction-related errors during installation, whereas back-side module damage might point to debris-contact damage during mowing. Failure distribution maps might identify terrain-related issues such as sinking piles, whereas temporal correlations mapped to severe weather events might point to wind, snow, or hail as a root cause.

A notable change in solar glass breakage in recent years is the emergence of low-energy fracture patterns, as shown in Figure 1. Prior to the early 2020s, PV module glass failure was typically catastrophic in nature, resulting in a highly branched crack pattern. A classic high-energy glass breakage pattern is characterised by radial and concentric fractures that provide clear evidence of

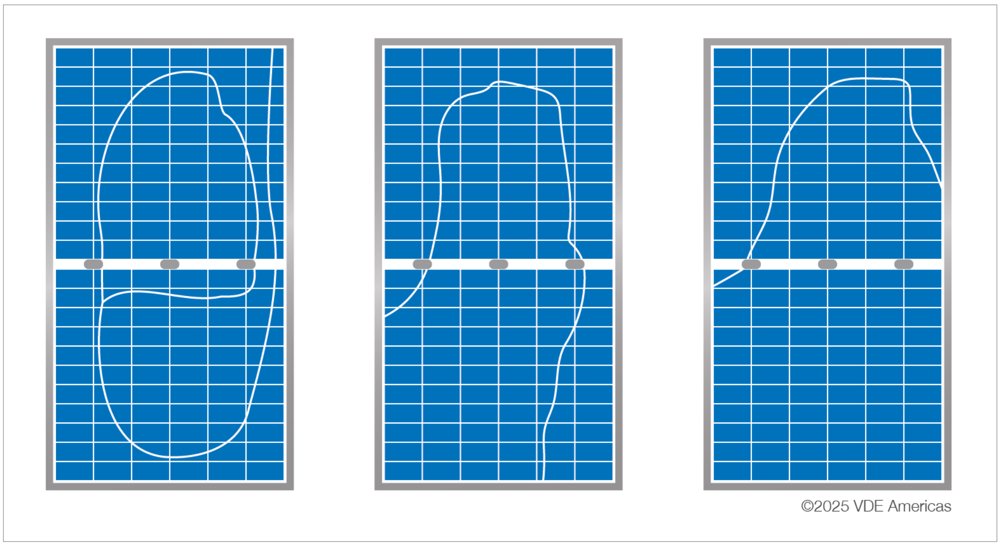

Figure 1. Examples of field-observed low-energy glass fracture patterns

the fracture origin. Unlike shattered glass resulting from a high-energy impact, low-energy glass fracture patterns often have few or no secondary branches. As a result, visual inspection in the field may not identify the specific external force that has triggered a low-energy fracture.

While the root cause of a low-energy fracture may not be readily apparent to an untrained eye, these are not truly spontaneous events. My first experience with glass failure was with Osram-Sylvania, an automative lamp manufacturer, analysing the root cause of low-energy fractures in glass with some assistance and guidance from Corning. In every case, our investigations would identify some sort of glass defect related to manufacturing—typically, a void, inclusion or edge flaw—at the fracture origin.

Fracture rates in fielded systems

Anecdotal reports from all corners of the globe and a growing body of published scientific data provide evidence of a potentially systemic problem characterised by seemingly unexplainable glass breakage.

"In the past few years, our team has found power plants around the world where PV module glass has broken with no obvious cause," write the authors of a November 2024 technical report published by the National Renewable Energy Laboratory (NREL). [1] "Instead of hundreds of cracks dividing the glass into tiny fragments, a few large cracks can form. The cracks often don't show a clear origin, and there is often no link to severe weather or an impact event."

At least one research institution has been able to document low-energy glass fracture in in the field over a period of time [2]. Specifically, the Strategic Research Group on Solar Energy at the Federal University of Santa Clara (Fotovoltaica UFSC) maintains a highly instrumented bifacial PV module testbed in the south of Brazil. At the ~100kW-rated pilot project, 158 large-area (~3m²) double-glass PV modules are deployed across five single-axis tracker systems and one fixed-tilt system.

Since commissioning the project in July 2022, Fotovoltaica UFSC researchers have documented glass fracture frequency, distribution and patterns across the site in parallel with meteorological data. According to a poster presented in March 2023, low-energy glass fracture occurred at an average rate of roughly 14 modules per month. Over an eight-month period, researchers observed glass cracks on 83 out of 158 modules (52.5%), as detailed in Figure 2.

While the glass fracture rate at Fotovoltaica UFSC is likely an outlier within the total population of large-area bifacial PV modules fielded since 2022, a DNV white paper published in 2024 documented a rear glass breakage rate of over 15% at a tracker-mounted bifacial project in the Asia-Pacific region. In this case, forensic investigators found a correlation between mid-level wind speed and glass fracture in moderately sized bifacial modules (~2 m²) [3].

Though project- or product-specific details are often obscured by owners and manufacturers, it is not uncommon to hear about real-world sites with 2%, 5% and even 10% glass fracture rates at PV reliability workshops or operations and maintenance conferences.

As a thought experiment, imagine a 100MW-rated utility-scale solar farm deployed using 600W bifacial PV modules. A 2% glass fracture rate on a project of this scale would eventually require the removal of 3,333 modules and the procurement of five 40-foot container loads of replacement modules. This would likely be considered a devastating hit to a project's operating expenditures and pro forma cash flow.

Winning the race on price

Reviewing the due diligence community's technical reports related to spontaneous glass breakage in modern double-glass module, one is reminded of the admonition, "Be careful what you wish for." In 2011, the US Department of Energy launched a SunShot Initiative with an end-of-decade goal of reducing the total cost of solar energy by 75%. The US utility solar sector achieved this goal in 2017, well ahead of the 2020 target [4].

Global markets followed a similar trend. According to an annual report published by the International Renewable Energy Agency (IRENA), the levelised cost of electricity (LCOE) for utility-scale solar

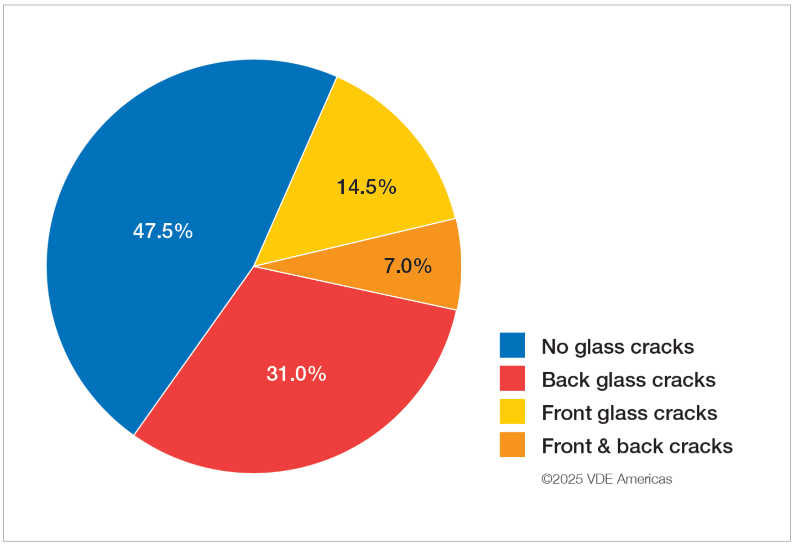

Figure 2. Glass fracture rates at Fotovoltaica USFC's bifacial testbed

UTILITY-SCALE CRYSTALLINE SILICON PV MODULE (TYPICAL)	2015	2020	2025	Change
Average power (W)	280	375	≥600	114%
Module area (m^2)	1.7	2.1	2.8	65%
Module weight (kg)	19.0	21.1	37.8	99%
Frame height (mm)	35	35	30	(-14.3%)
Frame width (mm)	40	35	35	(-12.5%)
Front glass thickness (mm)	3.2	3.2	2	(-37.5%)
Mechanical load (Pa)	3,600	2,400	1,600	(-55.6%)

Utility-scale c-Si PV module design trends over the past decade

power plants dropped by 82% over a 10-year period running from 2010 to 2019 [5]. While electricity prices writ large have generally increased due to inflationary pressures over the past five years, utility-scale solar currently offers the lowest LCOE of any power generation source [6].

To win the race to the bottom on energy pricing, the solar industry has had to leverage economies of scale and cost-cutting opportunities wherever and whenever possible—all the while raising the bar on power, efficiency and specific yield (kWh/kW). The good news is that the industry has largely met or exceeded expectations on all counts. The bad news is that achieving these cost savings has resulted in some PV power plants racked with panes stressed to the breaking point.

Supersized glass, lighter structures

Since 2015, the power output, gross area and weight for typical crystalline silicon (c-Si) PV modules intended for utility-scale applications have increased by roughly 114%, 65%, and 99%, respectively. In parallel, aluminium frame height, front glass thickness, and mechanical load profile have decreased by more than 14%, 37% and 55%, respectively. In other words, as utility-scale PV modules have increased in size and weight, they have grown weaker. These electrical, physical, and structural trends are evident in Table 1.

The net result of the trend toward supersized PV modules (~3m²) is generally positive, as larger high-efficiency PV modules increase energy yield while reducing levelised cost. The reduction in total module count provides material and labour savings by driving down the number of support structures and mechanical and electrical connections, and reducing the amount of cabling, all of which allow for reductions in assembly time. Though these technology trends allow for meaningful downstream cost savings, they are not necessarily conducive to system durability and resiliency.

Engineering, procurement and construction (EPC) firms are integrating larger and weaker modules on single-axis tracker tables that are often longer or larger in area than ever before. To minimise upfront capital expenditures, engineers have gone to great lengths to remove any unnecessary structural material from these support structures. In parallel, leading tracker manufacturers have developed hail defence strategies that stow modules at the highest possible tilt angle—in some cases as high as 75° or 77°—and increase wind loading.

As compared to earlier PV power plant designs, supersized PV modules and tracker tables expose structural systems to higher loads and more stress. At the same time, changes to perimeter frame profiles and dimensions mean that a shorter and narrower beam now supports a larger sail area. Moreover, project stakeholders intentionally use the shortest and thinnest rails possible to make the mechanical connection between the torque tube and the module. The difference is visible to the naked eye.

"The interaction between these components is where the term 'big floppy modules' comes from," explains Theresa Barnes, who manages the Photovoltaic Reliability and System Performance Group at NREL. "A module is really a whole system, often consisting of glass, a perimeter frame, and a mounting rail. While glass has always been a structural element in the module system, it may be bearing more weight now, which may be bad because we have made the glass weaker."

Glass packaging and strengthening

As recently as 2020, monofacial PV product designs accounted for more than 80% of module shipments globally. Today, bifacial technologies are ubiquitous, especially in utility-scale applications. According to a recent International Energy Agency report, bifacial PV module market share exceeds 90% in utility-scale PV power plants currently under development globally, while single-axis trackers enjoy a 60% market share [7].

As the name suggests, bifacial solar technologies capture energy from both the front and back sides of a PV cell or module. While rear-side irradiance is largely diffuse and reflected, this additional energy capture provides bifacial gains in utility applications in the order of 2-10%, depending on ground albedo and other factors. Stacking these bifacial gains atop typical tracker gains of 15-20%, relative to fixed-tilt designs, enables modern utility-scale PV power plants designs to lead all power generation technologies in terms of average LCOE.

To facilitate the trend toward larger and more powerful bifacial PV products, module companies have largely moved away from glass-plus-backsheet packaging in favour of a dual-glass designs that control weight and costs while optimising back-side light capture. Prior to 2020, manufacturers typically would have packaged monofacial cells within a sandwich consisting of a 3.2mm front glass superstrate and an opaque polymeric backsheet. Today, bifacial module manufacturers typically use 2.0mm glass for both front- and back-side packaging material.

Based on typical breakage patterns, researchers at NREL have noted that standard 3.2mm solar glass appears to functionally meet the threshold for fully tempered safety glass, meaning it tends to break into relatively small and harmless fragments [1]. Meanwhile, the low-energy fracture patterns observed in 2.0mm dual-glass products are indicative of decline in surface compression.

"What is interesting about glass as a structural material is that its strength is largely an extrinsic property, meaning it is not inherent to the glass itself," explains James Webb, senior research manager for reliability sciences at Corning, a nearly 175-year-old glass manufacturer. "What dictates strength is largely what manufacturers do to the surface of the glass. Heat tempering adds compressive strength, which provides protection against surface flaws resulting from manufacturing processes, handling processes, or environment exposure that would otherwise limit the inherent strength of the glass."

As part of a conventional high-volume manufacturing process, it is relatively straightforward for solar glass manufacturers to drive a thermal differential into

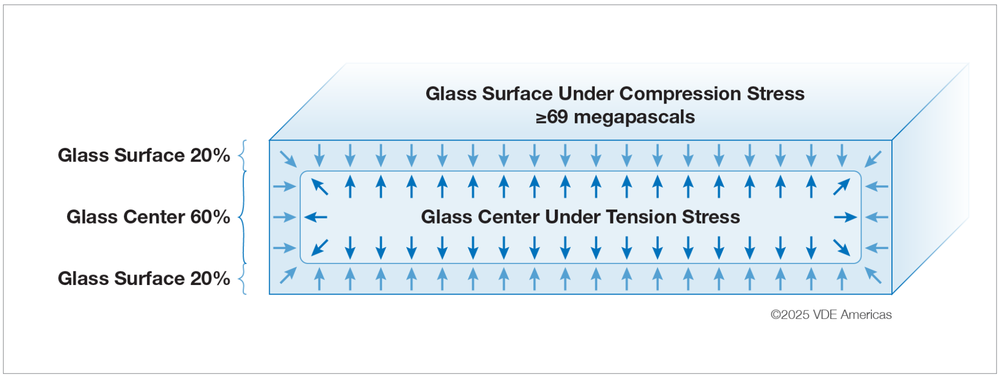

Figure 3. Surface compression in tempered glass per ASTM C1048

3.2-mm glass that results in a minimum surface tension of 69 megapascal (MPa) and meets the ASTM C1048-18 standard for fully tempered glass, as shown in Figure 3. Achieving the same level of strengthening in thinner glass is more challenging.

While it is technically possible to fully temper thinner 2.0mm glass, the manufacturing process control window is narrower, meaning procurement options are more limited. As glass gets thinner, more surface compression is required to achieve a given strength threshold. Moreover, the probability that a sheet of glass will contain a strength-limiting flaw or defect increases with sheet size. [8]

"Compressive strength in glass is not binary—it is a continuum," notes Mike Pilliod, president and chief technical officer at Central Tension. "The ability to get a good temper crosses a threshold around 2.6mm, and you begin to reach the thermal tempering limits for fully tempered glass as you approach 2.0mm. With aluminium, normal manufacturing variances have little effect on fundamental material properties. With glass, you need a consistently good manufacturing system, as any processing flaws will limit compressive stress."

Testing the structural limits

The same PV module can withstand different design loads depending on how it is mounted. In an optimally supported fixed-tilt configuration with perpendicular steel rails as load-bearing members, a PV module might be able to withstand a uniformly distributed design load as high as 5,400Pa. In a tracker-mounted application with long unsupported cantilevers and short center rails, load bearing capacity for the same module could drop below 1,600Pa.

To account for these different integration scenarios, the International Electrotechnical Commission (IEC) standard for terrestrial PV modules, IEC 61215-1:2021, allows module manufacturers to declare a design load specific to a particular installation method. This allowance lets product and system designers engineer substructures and foundations on a site-specific basis, adding or eliminating load-carrying capacity as needed to withstand expected wind or snow loads.

"In the laboratory, we apply a safety margin to the manufacturer's self-declared design load and use this as the basis for our mechanical load tests," says Cherif Kedir, president and CEO of RETC (Renewable Energy Test Center), part of the VDE Group. "For qualification purposes, we test one or two modules using a specific combination of field hardware. If something fails, the tracker manufacturer can test again, perhaps with longer or thicker rails. Eventually, this iterative process will identify a system of components that meets the design load."

Unfortunately, testing a limited number of samples to IEC qualification standards sheds little to no light on the ways in which commercial products tend to fail or wear out prematurely under real-world conditions of use, as shown here in Figure 4. IEC 61215 is a safety standard. It is the minimum bar to market entry. It is not intended as a long-term reliability indicator.

"The industry should not solely be using IEC 61215 as a baseline mechanical standard for bankability," says Frank Oudheusen, manager of Azimuth Advisory Services, a consultancy that specialises in structural technical due diligence and failure root cause assessment. "If you drive costs all the way down to the IEC 61215 standard, product evaluation does not guarantee a system will survive the 10,000-plus wind loading cycles associated with a single hurricane, let alone exposure to a second named storm or 20 years of field exposure. Frankly, it may not be able to withstand the expected wind gust pressure at tracker row ends in many parts of the United States."

Credit: RETC

Figure 4. Catastrophic failure resulting from mechanical load testing

The case for breaking glass

One of the best ways to understand and prevent solar glass fracture in the field is to break more glass in the lab. This is especially true today, given that mechanical load tests based on IEC 61215 do not trigger field-observed low-energy glass fracture patterns in large-area dual-glass PV modules [9]. Until testing laboratories have a way to reliably recreate this failure mode, it will be difficult, if not impossible, to prevent spontaneous glass breakage in the field.

Testing to failure is one of the main tools Pilliod uses to make sense of complex fracture mechanics. "What really interests me as a glass reliability engineer is measurement systems that provide a statistically representative probability of failure. The use case doesn't really matter. Automotive glass, cell phone displays, architectural glass, you name it. If you're not breaking glass—and not testing a representative number of samples to failure—you are not doing your job as a reliability engineer."

The problem with pass/fail testing paradigms, Pilliod explains, is that they stop too soon. "Okay, one module passed. But why did you stop? Keep going. Figure out where the sample fails. If you gradually increase the applied load and test a meaningful number of samples to failure, you can generate Weibull distribution curves that plot the probability of glass failure on a product, or bill of materials-specific basis with low uncertainty. Now you can stack these Weibull curves and compare them. Do the curves overlap? If not, you can be reasonably certain that there is a statistical difference in resiliency."

Since glass fracture is probabilistic with a random distribution pattern, RETC and its sister company, VDE Americas, recently introduced a Weibull-based test-to-failure programme for hail. This so-called Hail Resiliency Curve (HRC) Test uses a calibrated air cannon to shoot progressively larger freezer ice balls, a laboratory proxy for naturally occurring hail, at increasingly higher speeds and impact energies until glass breakage occurs. By testing an entire pallet of modules (~20 samples) rather than only one or two, the HRC test provides a robust statistical representation of resilience or vulnerability in a population of modules [10].

This type of test-to-failure approach—perhaps conducted using dynamic mechanical load testing, shown in Figure 5—may also be useful as a way to understand the probability of low-energy glass fracture in today's tracker-mounted bifacial PV systems.

"If a manufacturer sends half a million modules to a particular utility-scale solar project, that population will include a variety of stress profiles due to manufacturing process variability and other factors," notes Kedir. "Each sheet of glass has a different stress profile based on the tempering process and includes different strength-limiting flaws. Drilling holes in the back-side glass changes that stress profile, as does glass patterning between cells to improve back-side light capture. Lamination and material handling processes effect the stress profile. The only way to understand these differences is to test more samples to failure."

Credit: RETC

Figure 5. Dynamic mechanical load testing at RETC, part of the VDE Group

Credit: Agata Bogucka/NREL

Figure 6. Elizabeth Palmiotti, a researcher at NREL, is helping to define the scale of the glass failure problem

Standards to the rescue?

Though product qualification standards undoubtedly provide a possible pathway to engineering a return to reliability for dual-glass PV modules, it is not clear whether a critical mass of technical committee and working group members are in favour of more rigorous mechanical load testing.

Tracker systems are exposed to dynamic forces and cyclical wind loading in real-world applications, but the product qualification standards do not hold manufacturers to a standard of fatigue life. Similarly, real-world wind and snow loads are typically unbalanced in nature rather than uniform, but proposals to add unbalanced load testing guidelines to IEC standards have not made it out of committee.

These persistent gaps between the standards and reality are frustrating for Lauren Busby Asher, vice president of engineering at steel solar frame specialist, Origami Solar. "If module manufacturers made the switch to our high-strength steel frames in place of traditional aluminium perimeter frames, utility-scale solar projects would be considerably stronger and more reliable than they are today. We know this because we have conducted side-by-side tests to failure that validate our product's ability to achieve higher load ratings and safety margins. But the current qualification standards let companies lower their design load ratings, test one module and call it a day."

According to Kedir, standards simply cannot address everything. "Generally speaking, the working groups that write product qualification tests allow manufacturers to push certain design limits with the understanding that the industry will police itself. If the standards groups could force the module manufacturers to test the edge of their processes and test-to-failure, that could be good for the industry. But I don't think you can rely on the standards to govern every possible installation method, simply because technical committees take years to release or update a standard."

At the end of the day, accelerated time frames between innovation and mass production are precisely what have allowed the solar industry to cross the grid parity threshold to become the leading source of new power generation capacity. This is an agile industry, one in which technical advancements appear move at the speed of light as compared to the slow and steady march toward consensus on codes and standards.

Raising the bar for bankability

Solar glass fracture is a probabilistic event that occurs based on a combination of internal and external factors, many of which are hiding in plain sight.

As an example, module manufacturers have largely continued to treat solar glass as a commodity—meaning it is rarely subject to batch traceability or lot tracking—even though tempering process control becomes more important as modules get bigger, as shown in Figure 6. Meanwhile, forensic analysis has revealed evidence that glass supply chain plays at least some role in the proliferation of low-energy glass fracture.

"A developer came to RETC recently with two side-by-side projects," recounts Kedir. "While both sites used modules from the same manufacturer, the number of cracks exhibited on one site was an order of magnitude higher than the other. Testing modules from the site experiencing glass failure, we found that 75% of samples tested under the design load rating. It turned out that the modules at these side-by-side sites came from two different production lines, each supplied by a different glass manufacturer."

If a change in glass vendor at the point of production can account for an order of magnitude difference in early mortality in the field, why isn't this variable part of a standard bill of materials (BOM) verification process?

From my perspective as a technical advisor who helps de-risk large utility-scale solar projects, identifying and procuring resilient BOMs requires traceability, transparency and data. After all, that is one of the main ways independent engineers, owner's engineers and consulting engineers ensure fielded projects can withstand site-specific conditions of use while optimising investor returns.

Given that collective action is required to prevent today's infant mortality issues from stymying tomorrow's growth, the role of the industry's technical due diligence community is more important than ever. Reliability engineers have a responsibility to help module and tracker companies make fielded systems as inexpensive as possible, but not so cheap that upfront cost savings drive up operational expenses.

Scientific researchers and testing laboratories have a responsibility to help industry stakeholders identify the root causes of low-energy glass fracture and develop new test sequences that screen for field-observed failure modes. Technical advisors have a responsibility to demand better data than vague module datasheet glass descriptors such as "semi-tempered", "half-tempered" or "heat treated".

Further downstream, system developers, owners and operators, and EPC firms have a responsibility to make science- and engineering-based decisions regarding product procurement and deployment. Last but not least, project financiers and insurers have a responsibility to raise the minimum bar for bankability and provide differentiated terms and conditions for projects that meet or exceed these best practices. ■

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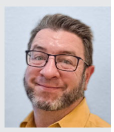

David Devir has over two decades of global product, project and programme management experience in the renewable energy industry. As a principal engineer for VDE Americas—a wholly owned subsidiary of one of the largest technology organisations in Europe—David helps advance the deployment of large-scale solar and energy storage projects that are financeable and insurable. Previously, he spent much of his career optimising critical solar energy components, including power conversion devices, energy storage systems and single-axis trackers. David holds a bachelor of science degree in mechanical engineering from Alfred University.

Strategies for managing ageing solar assets

O&M | The global fleet of ageing PV installations grows bigger every year, raising questions about the optimal strategies for managing maturing assets. Marco Zaniboni and Juanma Fernandez of Sonnedix examine the key considerations in deciding whether to revamp, repower or retrofit

Credit: Sonnedix

Plant operators have numerous options for getting the most out of an ageing PV asset

The 'golden age' of photovoltaic production in Europe began in the early 2000s, supported by feed-in tariff (FiT) schemes that encouraged the rapid installation of new plants. This has led to a vast global fleet of ageing photovoltaic (PV) installations. As these systems approach and pass mid-life, operators face an increasingly prominent issue: how to manage assets approaching the end of their lifespan.

At the same time, technology and innovation have evolved rapidly alongside solar, and new solutions have emerged since the initial boom. This presents opportunities to upgrade maturing systems and replace older technologies to drive efficiencies, reduce costs, extend asset lifespan and optimise renewable energy generation, considering also the rapid evolution of the energy market.

With solar expected to play an ever-greater role in global energy markets, optimising these older assets is essential for maintaining output, improving efficiency and ensuring continued financial viability. As a long-term partner and provider of renewable energy, our dedicated operations team is focused on the optimisation of our +3GW operating portfolio, to increase efficiencies and performance, minimise supply disruption and enable competitive pricing.

This has been achieved through initiatives such as our panel and inverter replacement strategies, driving higher energy yields and lower operations costs for in excess of 200MW so far; large wind corrective reporting, ensuring accurate quantification and assessment of available renewable energy resources; and importantly, our digitalisation strategy – with artificial intelligence being a key aspect of this.

But what exactly is an aged asset? As a general definition, it refers to equipment that has outlived its usefulness and requires an update. And what does it mean from a practical point of view? And how do operators manage assets which are coming towards the end of their lifespan?

Let's look at a few key strategies.

The three Rs: revamping, retrofitting or repowering

Revamping, repowering and retrofitting are the primary options available to mitigate any reductions in a plant's performance.

Revamping is a process through which key components, typically inverters and modules are replaced to restore the plant to its original intended total installed capacity. Retrofitting is a specific type of revamp, usually driven by regulatory changes, to bring a plant up to date with new regulatory requirements or to fix specific issues. Repowering goes one step further, replacing components with advanced new technologies, to boost the capacity beyond the project's original total installed capacity.

The market for repowering and revamping solar assets is growing rapidly, especially in Europe, where many plants are reaching the end of their initial operational lifespans. According to recent reports, the global market for repowering activities could reach up to 30GW of capacity by 2030.

A step-by-step guide to assessing an asset's performance

How do asset owners and managers know exactly when to implement a revamp, retrofit or repower? And how do they get ahead of the curve to identify potential problems before they arise?

Accurately assessing whether an asset's performance has declined is key to determining whether a system requires an upgrade or replacement.

Step one. An assessment of the history and current status of the asset is the first priority. Conducting a thorough review of performance data, operation reports and maintenance records can help to identify patterns of degradation. This includes monitoring how systems have operated over time and identifying potential issues related to material degradation, efficiency loss, or increased failure rates.

It is also important to check for symptoms of ageing, such as corrosion, efficiency loss and increased fault rates. These symptoms often indicate that components have reached or are approaching the end of their functional life. As part of the assessment, a life extension evaluation and GAP analysis should be carried out, to analyse the current state of the system versus its original design to identify gaps in lifespan and performance.

Step two. Once all of the issues have been identified, the next step is to determine the modifications required to extend the system's life, such as replacing inverters, adding storage systems to improve and stabilise revenues, or implementing new technologies. You will also need to prepare for future obsolescence by considering how emerging technologies will impact the system's performance and life expectancy.

Step three. The third step is to conduct a comprehensive analysis to predict the long-term costs, taking into account replacement and operational costs, as well as potential revenue generation. The decision-making process should include a thorough cost-benefit analysis, considering factors such as improved efficiency, extended lifespan and potential regulatory incentives. Ensuring a risk-based approach is followed, prioritising critical systems and equipment based on risk analysis, will help identify and address high-risk components to help avoid catastrophic system failures.

What next? The conclusions from this assessment will help to inform the best course of action, weighing up the cost of continuing to operate with current systems against the expected outcomes of a revamp, retrofit or repower.

Repairs beyond warranty

As well as a comprehensive assessment, regular routine checks should be conducted throughout an asset's lifespan to identify and replace faulty or degraded components such as inverters, modules and wiring to ensure optimal performance.

However, solar assets typically come with a warranty of between ten and 20 years, which means that managers must plan ahead to ensure that they can implement repairs when an asset first shows signs of reduced performance, even after the warranty has expired. Budgeting for these expenses ensures that operators can support the extension of the asset lifespan for as long as is reasonably possible.

As an asset approaches the end of its warranty, operators should look to renegotiate contractual arrangements, ideally securing extensions or new service agreements. If this is not possible, a thorough inspection of the asset should be carried out prior to the end of the warranty to assess the condition of components and identify any issues that must be addressed. This allows the operator to plan for necessary repairs and to file any claims prior to the end of the warranty. At this stage, it is also important to conduct detailed risk assessments, including evaluating the condition of components and the likelihood of failure to identify potential risks associated with ageing assets, and develop mitigation strategies.

> "The renewable energy sector has rightly focused on deploying new capacity, but optimising existing assets offers one of the most immediate and cost-effective ways to accelerate the transition to a low-carbon future"

Influence of original design on feasibility of upgrades

The original design of a solar plant has a significant influence on the feasibility and cost of potential upgrades. While technological advancements are constantly evolving and offering new solutions to enhance the performance of ageing solar assets, it is important to fully assess the potential limitations created by the original design, to ensure it is feasible to implement the intended upgrades.

Issues to watch out for include:

- **Available space and existing infrastructure.** In some cases, upgrades such as adding new tracking systems or bifacial modules may not be possible without significant and costly changes to the plant's layout.
- **Structural design.** A common issue for older plants, where the original design may not accommodate the latest types of PV modules or may not allow for easy maintenance access, which is vital for long-term operation.
- **System design.** Mismatched components or improper electrical configurations can cause energy losses and hinder performance over time. The integration of new technologies or components may be restricted if the original design was not optimised for flexibility.

Enhancing performance with new technologies

While there are certainly limitations to take into account, technological advancements offer numerous opportunities for enhancing the performance of ageing solar assets. Given the importance of monitoring to optimise asset performance, operators should consider installing advanced monitoring systems which offer real-time monitoring and analytics. By integrating advanced sensors, digital tools and AI-based analytics, plant operators can detect issues early, optimise energy generation, enhance productivity through automation and ensure better uptime.

Additionally, upgrading to more efficient inverters, bifacial modules, or adding tracking systems can also significantly enhance performance. These upgrades can increase energy generation and improve system efficiency, leading to higher returns on investment.

Finally, hybridising your portfolio through the addition of energy storage

Before and after. Replacing key equipment such as inverters offer numerous opportunities for improving asset performance

Credit: Sonnedix

solutions such as batteries can offer highly beneficial returns by helping to balance supply and demand, enhancing reliability and increasing grid stability. Battery storage also helps optimise the use of renewable energy by storing excess power for later use, smoothing intermittency and stabilising grids.

Investment in hybridisation is a core pillar within Sonnedix's customer-oriented business strategy, as it increases the reliability and efficiency of energy produced while also driving down customer costs. Hybridisation can also be supported by AI and digitalisation, automatically optimising processes for predicting when certain failures might occur to allow preventative maintenance to take place.

Credit: Sonnedix

Keeping abreast of technological changes

To effectively manage ageing solar assets, it is crucial to stay informed about technological advancements, including innovations in PV modules, inverters, energy storage and grid integration.

Operators must remain flexible and agile, with a willingness to develop strategies that allow for easy adaptation to new technologies and mitigate the risk of obsolescence. Collaboration is also key, through engagement with industry experts, attending conferences and participating in professional networks to remain informed and share insights about best practices.

Potential pitfalls

While upgrading ageing solar assets offers many benefits, there are also potential risks to evaluate before taking action. The first consideration is technical risks, as integrating new components may lead to compatibility issues. New technologies may also introduce unforeseen technical challenges, such as increased downtime during installation or the need for more extensive training for staff. Linked to this, economic risks, including high upfront costs, are a major concern for many plant operators. Ensuring a positive return on investment requires careful planning and cost-benefit analysis.

Finally, it is also vital to ensure that new upgrades or system configurations are compliant with current regulatory standards and to try to anticipate future regulatory requirements to reduce the risk of requiring further changes later down the line, which can bring significant costs and complications.

Care and maintenance

Today, with technology and processes advancing at pace, plants can last for upwards of 30 or 40 years, and while the above methods for assessing and upgrading plants are critical to ensure efficient and maximum production, operators must ensure that assets can operate for as long as possible before requiring these strategies.

Proper care and maintenance of plants throughout their lifespan is paramount, and implementing a preventive maintenance schedule is essential to address potential issues before they become major problems. This includes regular cleaning, tightening connections and checking for signs of wear and tear or reduced performance. Particular attention must be given to the PV module, which has been found to be most common cause of operational failures. However, all plants should undergo regular and thorough inspections and services to identify and swiftly deal with any potential issues.

Operators must ensure plants function for as long as possible without needing significant upgrades

Setting up for success

The renewable energy sector has rightly focused on deploying new capacity, but optimising existing assets offers one of the most immediate and cost-effective ways to accelerate the transition to a low-carbon future.

It is important to draw upon expertise and data available to make informed decisions, and to collaborate across the industry to pool knowledge of ageing assets and identify the best strategies for repair and maintenance. As technology continues to advance and evolve, energy producers should also utilise the intelligence offered by real-time data and analytics to monitor system performance and make informed decisions about maintenance and repairs.

By adopting the right strategies, including business models for revamping, assessing the influence of original design, leveraging new technologies and staying updated on industry trends, operators can enhance the longevity and efficiency of their solar assets while maximising returns and maintaining sustainable energy production.

Authors

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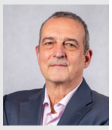

Juan Fernandez (Juanma) is the chief operating officer at Sonnedix, where he oversees the overall performance of the company's operating portfolio from an operational, asset management and commercial perspective. Juanma has over 20 years of experience in the renewable energy sector, spanning PV component technology, through renewable asset operational optimisation to effective technical and commercial asset management. He is also on the SolarPower Europe board of directors.

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11.6 M+ Media Explosure

USD 10 million Business Opportunity

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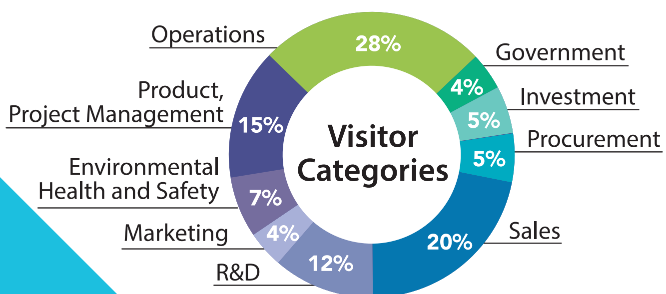
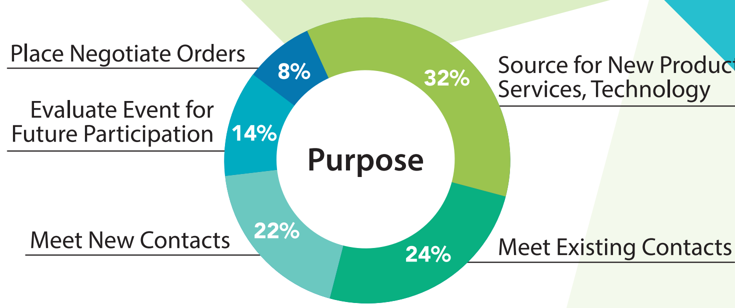
1,700+ Booths

25,000+ Visitors





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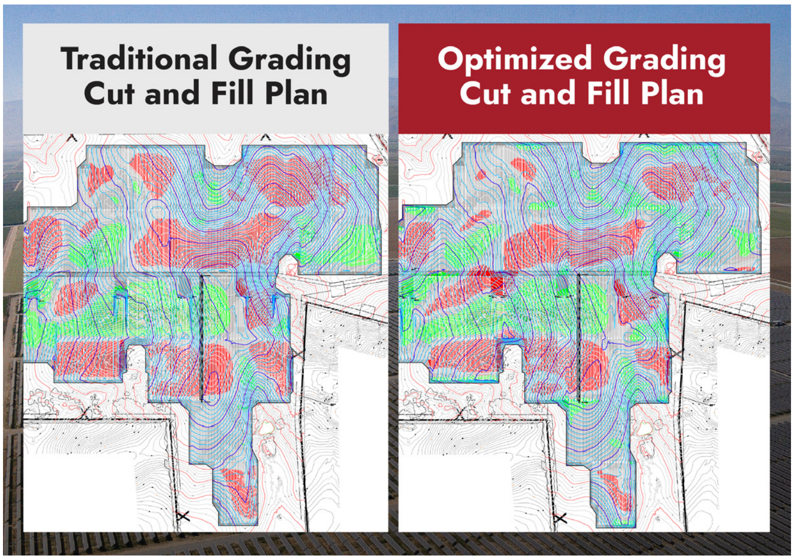
Slashing utility-scale grading costs: a hidden lever for optimising ROI

Civil design | As solar sites become more challenging, optimal land grading is becoming a critical focus for project economics. Brett Beattie of Castillo Engineering looks at some of the key areas that can make multimillion-dollar differences to project engineering costs



Credit: Castillo Engineering

Comparison of a traditional versus optimised grading plan for a sample project. The difference can mean millions of dollars saved

Optimized Earthwork for Sample Area: 15% Reduction

Grading Type	Cut (CY)	Fill	Net	Total Earthwork
Traditional	102,000	62,000	40,000	164,000
Optimized	69,900	69,000	900	138,900

While traditional grading methods for this sample require significant manual work to balance, optimised methods reduce labour by providing balanced earthwork initially

Optimized Earthwork for Entire Project: 20% Reduction

Grading Type	Cut (CY)	Fill	Net	Total Earthwork
Traditional	520,000	410,000	110,000	930,000
Optimized	386,000	356,000	30,000	742,000

Optimised earthwork design decreases costs, time and project risk

Civil design rarely makes headlines in the solar industry. But for utility-scale developers and EPCs, it can make the difference between a viable project and one that stalls out on budget or timeline. Grading, in particular, can vary wildly between sites; it's one of the largest variable costs in utility-scale construction, and one of the least standardised. A 200MW AC project's earthwork can vary from 10,000 cubic yards (CY) to over 500,000 CY, with earthwork costs ranging from US$50,000 to US$2.5 million.

Unlike modules or trackers, there's no catalogue for "how much dirt should be moved and where", so faulty assumptions can send ripple effects across permitting, scheduling, equipment rentals and erosion risk. This challenge is compounded by shifting project conditions:

- Interconnection pressures are forcing developers to consider sloped or irregular sites
- Shortage of skilled labour, especially experienced utility-scale solar engineers
- Permitting requirements and timelines for erosion control and vegetation establishment

As a result, two engineering firms can provide dramatically different grading plans even for the same site, with earthwork estimates diverging by hundreds of thousands of cubic yards. This variance can result in multimillion-dollar cost differences and months of added labour – or, conversely, an underestimated opportunity for optimising costs and timelines.

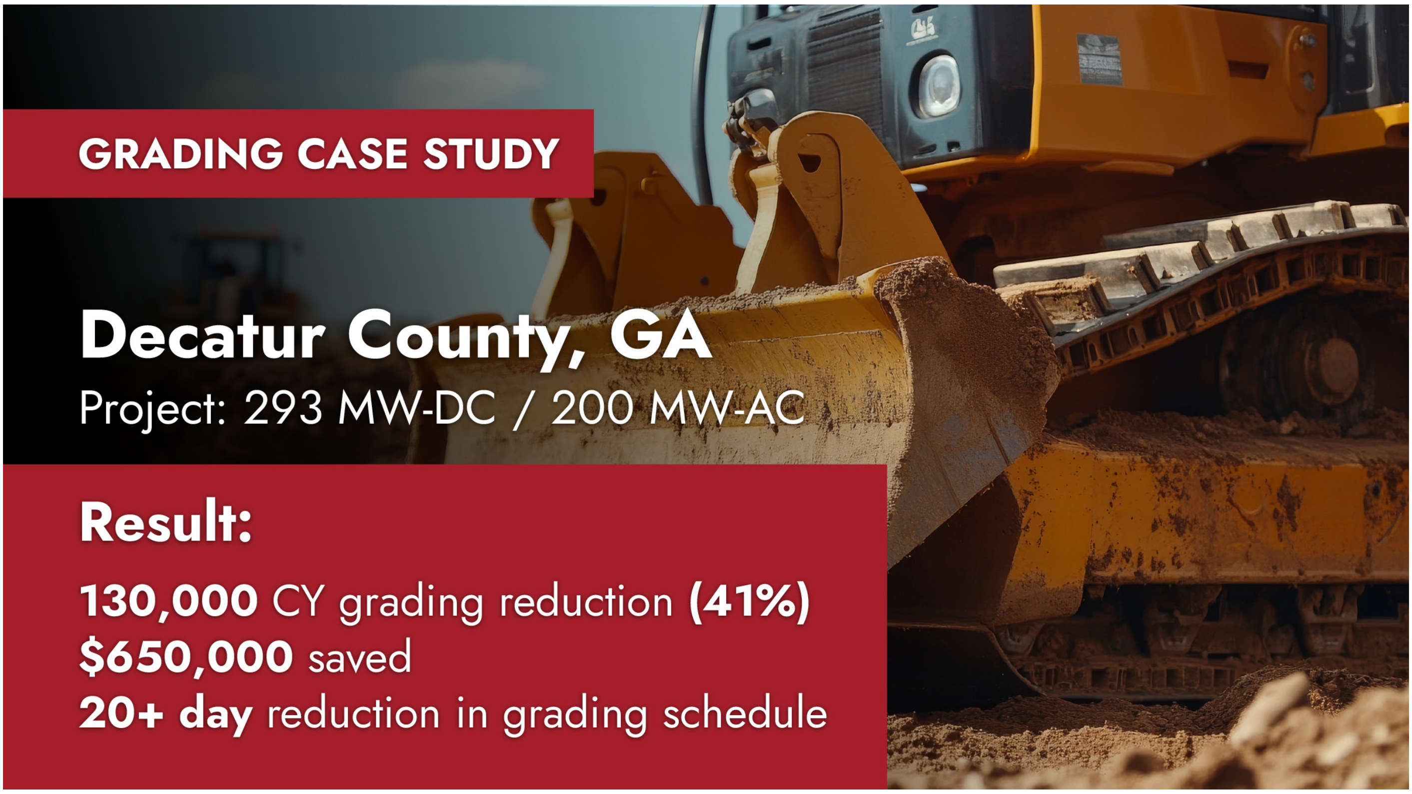
Grading plays an outsized role in utility-scale solar project economics, but it's often overlooked until costs or schedules start slipping. Traditional approaches can miss opportunities to reduce earthwork, simplify construction, and manage erosion risk. Fortunately, two recent utility-scale projects show that with the right tools and engineering practices, teams can save millions of dollars, accelerate delivery and improve long-term site performance.

What drives grading costs: volume and method

Grading decisions are often locked in early, during preliminary site layout or when the 60% civil plan set is issued for permitting. If those designs aren't aligned with actual field conditions or constructability constraints, project teams can end up with unnecessary rework, cost overruns, or extended construction timelines. Even modest inefficiencies in earthwork design can have outsized impacts on both budget and risk in a sector that depends on tight coordination between engineering, procurement and construction.

Grading volume: US$650,000 and 20 days saved in Decatur County, GA

Volume and method are the two most



Credit: Castillo Engineering

significant contributors to grading costs and timelines. Volume is dictated by how much cut and fill is required to bring the site within tracker and piling tolerances. This isn't a fixed value; for the same site, different engineering teams can produce vastly different estimates depending on design assumptions, tooling, and priorities. Even small changes in topography handling can drastically alter the volume of material moved. That's especially true on uneven terrain, where natural slopes intersect with tracker tolerances and substation elevations.

For instance, one recent project in Decatur County, Georgia had an initial 60% civil plan set projecting a combined 320,000 cubic yards of cut for the first two phases. A redesign, balancing sub-areas to avoid unnecessary haul distances, reduced the total to 190,000 cubic yards. This reduction of nearly 50% led to $650,000 in savings and shortened the grading schedule by over 20 days.

Redesigning to balance sub-areas reduced grading labour by nearly 50%

Grading method: US$950,000 and 57 days saved in Waco, TX

Grading methods matter as much as volume. Earthwork can either be internal (cut material is redistributed onsite) or external (off-site import or export of soil). The cost difference is substantial: internal movement typically costs US$4-5 per cubic yard, while external hauling can exceed US$15-30 per cubic yard, including transportation, staging and permitting costs.

Heavy equipment costs amplify these effects, since a single bulldozer costs U$4,000-5,000 per day including fuel, labour and maintenance. Haul distance, road quality and traffic restrictions, such as local daily limits, further compound cost and scheduling. As a result, a design that balances cut and fill can be exponentially more efficient than relying heavily on soil import or export.

Conventional grading methods often rely on a rudimentary process of drawing straight lines between table ends in CAD or similar software, making it tedious to adjust designs for earthwork balancing. In contrast, a more advanced and systematic layout approach begins by assigning each tracker and pile a unique identifier within a logically grouped pattern.

This organised structure enables the collection of terrain data across the entire torque tube and allows each tracker to reference data from adjacent trackers. With these large, structured datasets, engineers can efficiently apply statistical analysis and optimisation algorithms to minimise earthwork. This approach achieves more refined per-tracker grading adjustments than traditional methods, while ensuring that all tracker design and client-specific requirements are met.

For one recent 545MW DC project near Waco, Texas, early civil plans estimated 650,000 cubic yards of array grading – the volume of 1.5 Walmart Supercenters. Based on internal earthwork rates of US$4-5 per cubic yard, that figure carried an earthwork cost of over US$3 million. With typical equipment allowing only about 3,000 CY of earthwork per day, this would have created a critical bottleneck of over 200 earthwork-focused workdays.

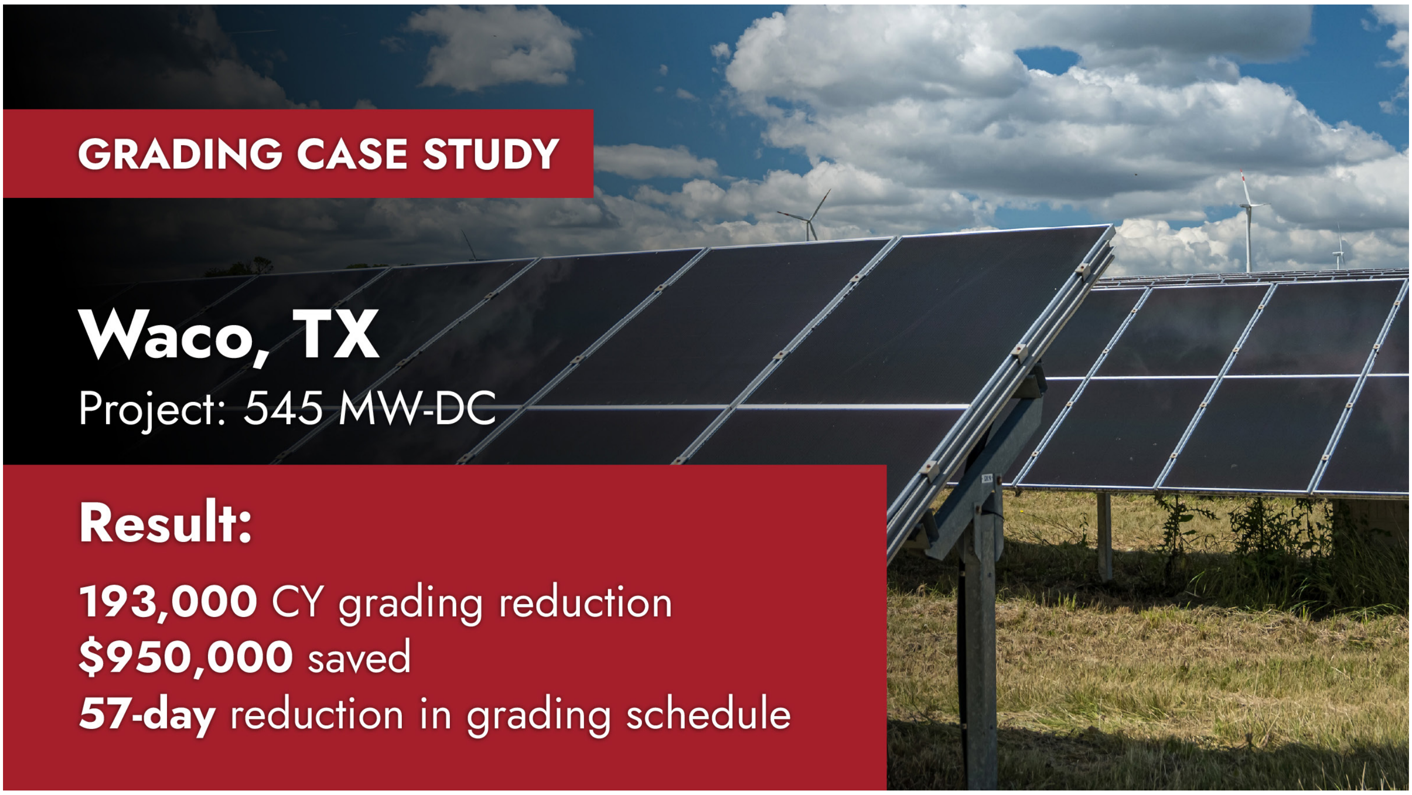
Realising this, the engineering team redesigned using the more strategic method outlined above. They applied a hierarchical identification system that categorised each tracker and pile in a clear, organised sequence. This allowed them to time-effectively smooth surface transitions, balance sub-areas to eliminate off-site haul charges and optimise the final grade for rapid pile installation. The new plan, remaining compliant with all specifications:

- Reduced the total volume by over 50%, to 193,000 CY
- Eliminated off-site haul charges by balancing sub-areas
- Cut over US$950,000 from the budget
- Shortened the grading timeline by 57 days

The variability of grading costs is significant, and so is the opportunity. Creating an organised grouping scheme, labelling each tracker and foundation element with a distinct ID, and applying statistical analysis and algorithms to optimise earthwork can result in significant time and cost savings.

Plan earthwork with field execution in mind

A civil plan may satisfy tracker tolerances and structural codes but still lead



Credit: Castillo Engineering

More strategic grading resulted in significant cost and time savings for this project in Waco, Texas

to costly inefficiencies and long-term erosion if it doesn't account for how construction crews work. This disconnect between theoretical design and practical constructability is one of the most consistent sources of budget overruns and delays in civil scope. That's why modern civil engineering must prioritise constructability in addition to cost and compliance.

How grading design impacts vegetation establishment

The faster vegetation can be reestablished post-grading, the sooner developers can move forward with mechanical installation and permitting signoff. Accelerated earthwork enables earlier seeding, which improves erosion control compliance and site stability. Overgrading adds not only costs but also delays in seeding and vegetation establishment.

On certain sites, faster grading improves the likelihood of meeting stormwater permitting deadlines or seasonal vegetation establishment requirements. For one Georgia site, quick-turn plan adjustments to improve surface smoothness allowed crews to seed earlier and reduce exposed soil time during a critical rainy period, mitigating both risk and regulatory attention. This saved US$650,000 in costs and allowed the contractor to eliminate haul charges between sub-areas and reduce equipment downtime. With a 24-hour turnaround for design revisions (compared to the five-day industry standard), the grading team helped keep vegetation schedules and erosion mitigation measures on track.

How grading decisions reduce (or increase) stormwater costs and risk

Designs that overlook stormwater management often increase volume and pressure on drainage infrastructure. This increases the risk of long-term erosion, non-compliance with stormwater permits and delayed stabilisation efforts, particularly in regions with strict permitting timelines. In contrast, optimised grading features surface flow paths that manage stormwater runoff naturally. Taking advantage of natural site topography instead of working against it reduces earthwork, exposed soil and long-term project risk.

Even projects that avoid the above risks might still lose money due to their stormwater designs. In one recent 5.5-acre Central Texas substation project, the original design met all height, slope and drainage requirements but required over 15,000 CY of import material to meet the final design elevations. Redesigning the pad with external drainage features reduced earthwork and eliminated the need for import fill, lowering costs by US$200,000 while meeting all original parameters.

Effective designs can often avoid over-grading, even in challenging terrain, by using tracking systems to optimise power production without needing perfectly flat ground. By adapting designs to the terrain instead of flattening it, trackers help projects conserve resources and minimise disruption [1]. Many major manufacturers (and some newer entrants) now offer products that support slope adaptability. These solutions vary in their degree of flexibility, so it's key to understand each system's design tolerances and real-world constructability. Selecting the right option will balance both engineering and installation considerations, achieving the lowest combined design and construction costs.

Designing a buildable plan

Modern earthmoving equipment is typically GPS-enabled and can adjust in real time to the engineer's proposed surface. However, this technology has also revealed significant limitations in many current surface design standards. The cumulative effects of such adjustments can impact the final surface quality needed to install piles, so contractors prefer "buildable" plans that don't need constant field corrections.

For instance, the Central Texas substation's Engineer of Record analysed the final topography to match the proposed conditions with existing conditions. Designs aligned with construction best practices and workflows reduce delays caused by micro-adjustments and rework and support efficient pile installation with fewer manual corrections. Execution-focused grading supports both downstream and long-term project phases.

A field-first approach prioritises the operator and tailors designs to accommodate the large-scale machinery used in utility-scale projects. This focus significantly reduces file sizes and complexity, enables smoother operations and allows field teams to make real-time adjustments without compromising the final surface quality required for pile installation.

Tools for smarter, faster grading designs

Traditional grading design workflows often rely on static CAD files and slow iteration cycles, with calculations taking several days to complete and changes propagating manually across multiple views and datasets. This rigid process leaves little room for refinement and even less for field feedback. Combined with a chronic shortage of experienced utility-scale solar engineers, these delays can translate into extended schedules, stalled equipment and increased labour costs. To overcome this, some engineering teams invest in purpose-built tools to reflect real-world site conditions rather than theoretical topographic models.

Grading and pile optimisation software

Traditional layout methods use straight-line connections between table ends in CAD, which makes earthwork balancing difficult and time-consuming. Engineering teams can create proprietary grading and pile optimisation software for constructible, cost-effective solar earthwork plans, such as the one used to create the optimised design at the beginning of this article.

This more time-effective, structured approach assigns unique identifiers to each tracker and pile based on spatial logic, enabling full-length terrain mapping along the torque tube and data referencing between adjacent trackers. The streamlined dataset supports efficient grading optimisation through statistical models, reducing earthwork at the tracker level while meeting all technical and client requirements. Used for the Texas and Georgia utility-scale solar projects mentioned in this article, this software has resulted in grading plans that more closely reflect real-world buildability.

Engineering design optimisation software

Underlying this grading and pile optimisation capability is an internal design optimisation software that supports standardised engineering workflows across a growing portfolio. The engineering team uses this system to automate repetitive calculations, maintain consistency across phases and track performance against cost and constructability benchmarks. The software also acts as a portal that aggregates historical design inputs, ensuring that the engineering team has access to the same knowledge base and that lessons learned from one project scale effectively to the next.

Such a collective body of knowledge helps lean engineering teams, particularly those with experienced and junior utility-scale engineers, to scale both design quality and production rates. Given the limited supply of qualified civil engineers with utility-scale solar experience, this scalability is critical. By building smarter software systems around known construction pain points, engineering teams can scale their capacity to deliver timely, cost-efficient designs that work in the field.

Accurate drone surveys

Finally, drone-based site scans equipped with RTK/PPK GPS and high-resolution sensors now routinely produce vertical accuracy of 1-3 cm, meeting survey-grade standards suitable for detailed grading analysis. Paired with the above grading tools, these scans allow real-time elevation anomaly detection and adjustment, significantly reducing rework by enabling more accurate and constructible designs.

The future of grading in utility-scale solar

Site constraints, skilled labour shortages and tight timelines are shaping how we must approach solar civil engineering. The most impactful civil engineering decisions go beyond numbers, taking into account what happens when boots hit the ground. As utility-scale projects grow in both ambition and complexity, grading design will play an even more central role in cost control and execution certainty.

Site selection trends are one major driver. Developers are running out of "A" land: flat, easily accessible parcels with minimal permitting friction. What's left often includes uneven terrain, agricultural conversions, or second-use land such as former industrial sites or landfills. These parcels demand more from civil design, including tighter tolerances, better hydrological analysis, tracking systems and grading plans that flex with topographical realities rather than fight them.

Meanwhile, developers are vying for limited interconnection queue space. When construction must begin within narrow windows, engineering teams need to deliver right-first-time quality to avoid last-minute redesigns or change orders. Fortunately, advances in drone-based topographic surveys, real-time modelling and AI-informed design logic are making it possible to analyse more site variables in less time. Internally developed tools, like those used in some firms' grading workflows, now run complex terrain calculations in hours rather than days. This allows teams to iterate quickly, test multiple approaches and hone in on constructible solutions before fieldwork begins.

As solar expands into new geographies and more demanding sites, grading is one of the last "black boxes" in project budgets where meaningful savings and certainty can still be unlocked. What was once a back-end concern is quickly becoming a front-end differentiator. The future belongs to those who treat grading not as an afterthought, but as a core part of how utility-scale solar is built.

As one civil superintendent told me, "The best grading plan is the one the crews don't have to think about." This alignment between paper and practice will define value-driven utility-scale solar engineering.

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Mind the gap

Hail | New data suggests the traditional assumptions behind hail stow modelling may be significantly underestimating the likelihood of damage to a PV system. Nicole Thompson and Reilly Fagan of kWh Analytics dive into the latest hail research and discuss its implications for insurance

Credit: Nextracker

The renewable energy industry has reached a pivotal moment. With nearly 50GW of solar capacity installed in 2024 alone [1] and renewable energy becoming more essential to the US electrical grid, the stakes for the industry have never been higher. Yet beneath this remarkable growth lies a sobering reality: hail damage represents the single most disproportionate threat facing solar installations today.

The industry's response has centred on two primary defences: thicker, heat-tempered glass modules and hail-stow protocols that tilt tracking systems to steep angles during storms. These strategies show promise, but a critical question remains: how effective are they really in preventing damage?

While real-world data are ideal, factors like hailstone density, measurement uncertainty and varying conditions complicate the answer, making physics-based models essential. However, the latest research shows that the widely used kinetic energy models may be significantly underpredicting the potential for damage by up to 48% for 3in hail, even when panels are in a high-degree hail-stow position. kWh Analytics has developed an empirically corrected hail model to begin to account for these modeling inaccuracies. While stow has been shown to effectively mitigate hail damage in many instances, overestimating its effectiveness can lead to costly miscalculations. Projects that rely heavily on operational protocols while using thinner glass modules may face substantially higher loss rates than anticipated, creating financial strain across the entire value chain from project owners to insurance carriers. To protect solar installations, stow is most effective when combined with thicker, heat-tempered modules, and in some severe hailstorms, the combination of the two is non-negotiable.

Typical modelling approaches can significantly underestimate the likelihood of hail damage to PV systems

Understanding the hail problem

By understanding the frequency and financial impact of hail events, we can better prepare for and mitigate their effects. While hail events account for only 6% of solar loss incidents, they drive a staggering 73% of total financial losses [2]. This knowledge empowers us to take proactive measures to address this imbalance and reduce its impact.

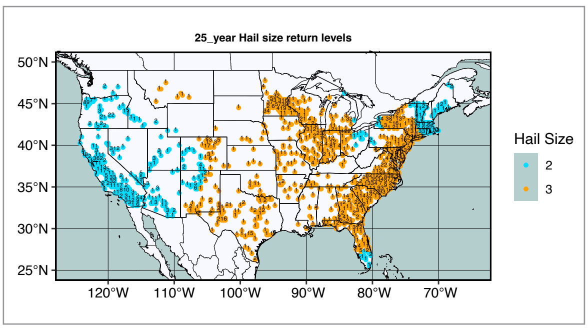


Figure 1. 25-year return intervals for hail greater than 2 inches (blue) and 3 inches (yellow). Dots represent current solar projects across the US

The traditional risk maps are changing, too. New research from Dr. John Allen and Central Michigan University in the 2025 Solar Risk Assessment challenges long-held beliefs about hail exposure across the United States. Using Bayesian modelling, researchers found that 91.18% of utility-scale solar locations in the US have a 10% annual chance (10-year return period) of seeing hail greater than 2 inches (50mm) within approximately 17 miles of their location. Perhaps more concerning, 64% of these locations showed hail over 3 inches for a 25-year return period. This includes sites in traditionally low-risk areas such as California, proving that hail risk is pervasive throughout the United States.

Hail differs fundamentally from other natural catastrophe perils in both its impact pattern and financial consequences. Major hail events like those that devastated Fighting Jays demonstrate hail's ability to cause millions in losses across sites within minutes. These events create insurance nightmares, as concentrated losses can exceed hundreds of millions of dollars from single weather events, far surpassing typical fire or wind damage claims.

Hail creates distinctive damage patterns that pose particular challenges for both operators and insurers. While wind damage typically affects racking and mounting systems (often limited to the perimeter rows), and fire creates localised thermal damage, hail strikes directly at a solar plant's most vulnerable component: the glass surface of the modules. This creates cascading effects, including glass cracks, hot spot formation, and microcracks, as well as safety and production issues.

Analysis of loss patterns reveals that 29% of damaged sites have experienced multiple events. However, the data shows an important distinction: sites that implement comprehensive protection measures after initial losses significantly reduce damage in subsequent storms. This suggests that proper risk mitigation can break the cycle of repeated losses that plague some installations.

Accurately predicting the probability of damage from a natural catastrophe event is imperative to industries like insurance, which base premium pricing on these calculations. The industry leaders use physics-based models to assess the likelihood of damage in different scenarios by comparing the estimated kinetic energy that modules can withstand to the estimated impact energy at different module tilt angles.

These current modeling approaches assume that hail impacts behave as perfectly elastic collisions, where all kinetic energy (energy associated with movement) is conserved as kinetic energy, as opposed to being converted to other forms of energy (heat, sound, deformation, etc.). However, emerging research from laboratory testing suggests that the inelastic components of real-world hail impacts shouldn't be ignored, and some of these more nuanced details of hailstone impacts should perhaps alter our view of stow effectiveness.

This modelling gap has profound implications. Because inelastic components are at play, current models that assume all energy remains as kinetic energy (and thus decreases predictably with increasing stow angle) may overestimate the effectiveness of protective strategies by as much as 48%, creating blind spots in risk assessment that affect everything from insurance pricing to technology investment decisions.

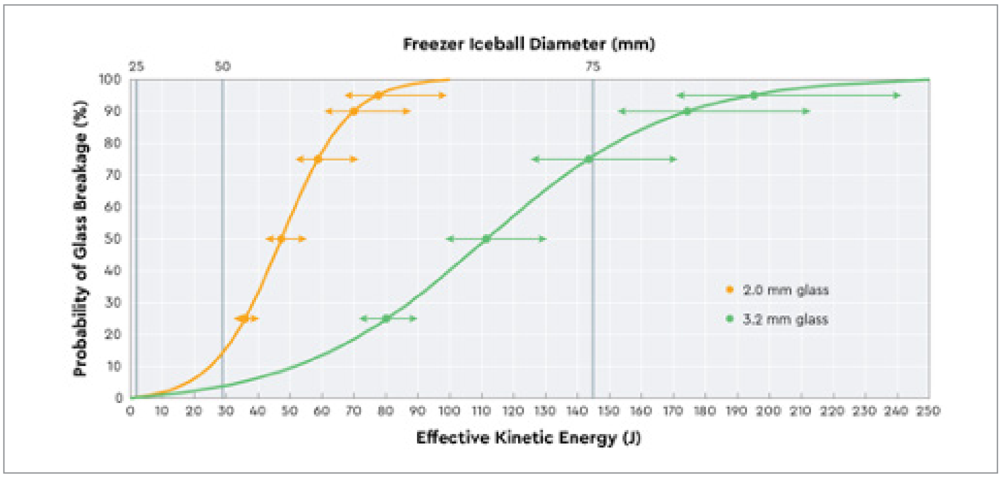


Figure 2. Increasing effective kinetic energy also increases the probability of glass breakage, though 3.2mm glass panels can withstand a higher impact energy overall. RETC 2023

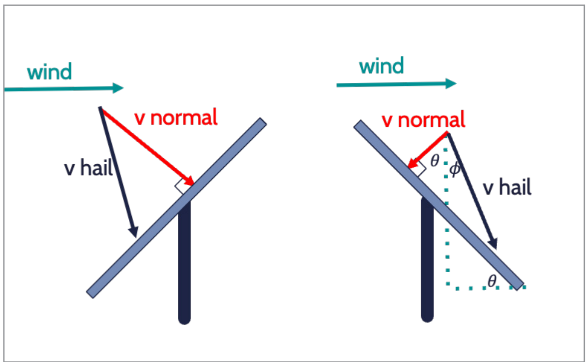


Figure 3. The impact energy of hail is decreased significantly when panels are faced away from the wind during a hailstorm. Hail is more likely to 'glance' off of panels in this position, instead of directly impacting the glass

The goal of all hail resilience strategies remains straightforward: reduce the probability of glass damage. When glass breaks, modules cannot effectively produce electricity and hot spots form, causing cascading failures. But achieving this goal requires confronting uncomfortable truths about modelling limitations, reassessing protection strategies and embracing new technologies that can withstand increasingly severe weather.

How hail actually damages solar panels

To understand adequate hail protection, we must first examine the physics governing these destructive impacts and how models can be used to assess the probability of glass breakage when hail events occur. Further, we can scrutinise these models' assumptions to understand how simplifications are introduced in modeling, which may lead to inaccuracies in loss estimates.

Explaining kinetic energy

Hail damage begins with kinetic energy—the energy of motion carried by falling hailstones. This energy can be represented by the classic physics equation $KE = ½mv^2$, where mass (m) and velocity (v) determine the total kinetic energy of a falling hailstone. This kinetic energy can then be compared to the kinetic energy required to break a module, often obtained via lab tests, to ultimately determine the probability of a module breaking given a hailstone of a certain mass and velocity.

Panel glass thickness plays a crucial role in determining the likelihood of breakage. RETC's research in the 2023 Solar Risk Assessment shows that 3.2mm glass/polymer backsheet modules substantially outperform 2mm glass/glass alternatives across all impact energies, with the protection benefit increasing at higher energy levels, as seen in Figure 2.

This lab testing data provides a guide for how probability of damage scales with hailstone kinetic energy. We can take this a step further and assume this relationship holds, regardless of the stow angle, so long as we can calculate the effective kinetic energy imparted onto the module. This can be accomplished by assuming the collision is perfectly elastic, so that only the portion of kinetic energy that is perpendicular (normal) to the module contributes to breakage (i.e. angled impacts result in predictably less kinetic energy being transfered to the module and thus lower breakage risk). So, for angled impacts (e.g. when modules are placed in a high-degree hail stow), the kinetic energy which contributes to damage can be represented follows, where KE is total kinetic energy of the hailstone and KE_normal is the effective kinetic energy the module "sees":

$$KE_{normal} = KE \times cos^2(\theta)$$

Therefore, a panel tilted at 60 degrees would be expected to receive only one-quarter of the impact energy of a flat installation, assuming no wind and that hail is falling straight down. When wind is present, the calculation remains the same; however, the velocity and fall angle of the hail may be affected by the wind (Φ below, Figure 3), ultimately affecting the impact angle with the module. While this model provides a valuable baseline, it is built on simplifications that don't fully capture real-world hail behaviour.

Elastic vs. inelastic conditions

While the simple kinetic energy model provides a useful starting point, it overlooks key complexities in how impacts cause breakage. The kinetic energy of a falling hailstone represents the total

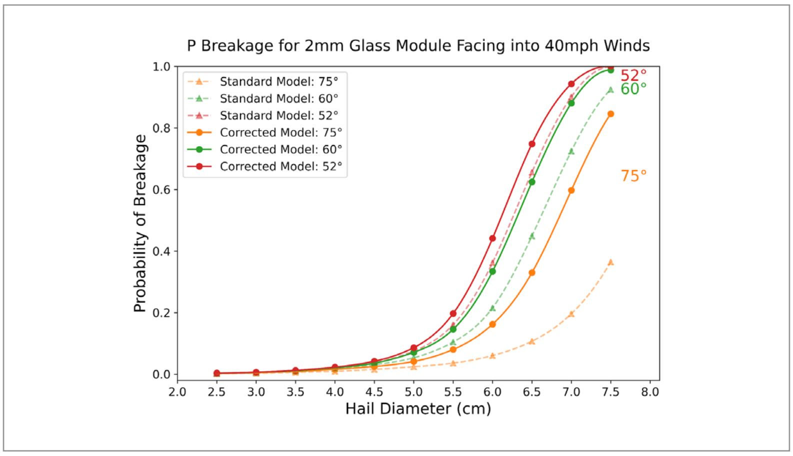


Figure 4. Probability of glass breakage shows large variability between the simple KE model and the corrected model

energy available to be transferred, absorbed, or dissipated during the collision. But fully understanding how, why and when modules break requires knowing how that total energy is distributed during a collision. Factors such as how concentrated and abrupt the energy transfer is (i.e., the force applied to the module), how kinetic energy converts into deformation or vibrational energy and how the tangential component of kinetic energy generates additional shear forces all play a role in breakage—factors that a simple kinetic energy model fails to capture.

In short, using kinetic energy as the sole predictor for breakage probability—and assuming it scales with $\cos^2(\theta)$ as in a perfectly elastic collision — may be fundamentally flawed.

Lab testing from Groundwork Renewables (2025 Solar Risk Assessment) reveals that the inelastic complexities of hailstone collisions may be significant when accounting for angled impacts. The simple elastic kinetic energy model $KE\cos^2(\theta)$ underestimates the energy delivered to a sensor under angled impacts by up to 69% at 75°. This observation may be explained by the simple model assuming that all transferred energy follows the $\cos^2(\theta)$ relationship, a relationship that only applies to perfectly elastic collisions. It overlooks energy converted to deformation or vibration and ignores tangential kinetic energy that can generate shear forces—mechanisms at play in an inelastic collision. Furthermore, previous studies on rockfalls [3] have noted that the inelasticity of the collision increases with increasing impact angle, meaning that this divergence from the perfectly elastic model would be expected to increase with higher stow angles. In plain terms, the benefits of higher stow angles would be especially overstated if the simplified model were used when compared to the lower tilt angles.

Taking these corrections for inelasticity into account, kWh Analytics and Ground-Work Renewables derived an increase in the probability of module breakage of up to 48% for 7.5cm (~3") hail when compared to the simple elastic model (2025 Solar Risk Assessment).

The real-world implications are striking. Using a traditional physics-based model that does not account for inelasticity, a 2mm glass module has approximately a 36% chance of breakage at ~3in (7.5cm) hail under 40mph winds when stowing at 75°. When we include inelasticity into modelling assumptions, the probability of breakage jumps to approximately 84%.

While impact dynamics with a sensor differ from those with a PV module, this analysis provides a directionally accurate approach to adjusting for stow angle. We urge PV testers to conduct hail test-to-failure experiments at various stow angles to better capture real-world impact behaviour, including inelastic effects. This direct approach would reveal the true influence of stow angle, providing far more reliable insights than simply assuming breakage probability scales with the normal (perpendicular) component of kinetic energy.

An aside about wind

Studies show that the probability of module breakage from hail decreases significantly when panels are faced away from the wind, but this scenario is not always possible. Large utility-scale solar installations can span many acres, and the wind direction at one corner of the plant may differ from that at the opposite end. In these non-ideal scenarios where modules are tilted into to the wind, high-degree tilt angles are more likely to prevent breakage than low angles, especially for thinner glass modules.

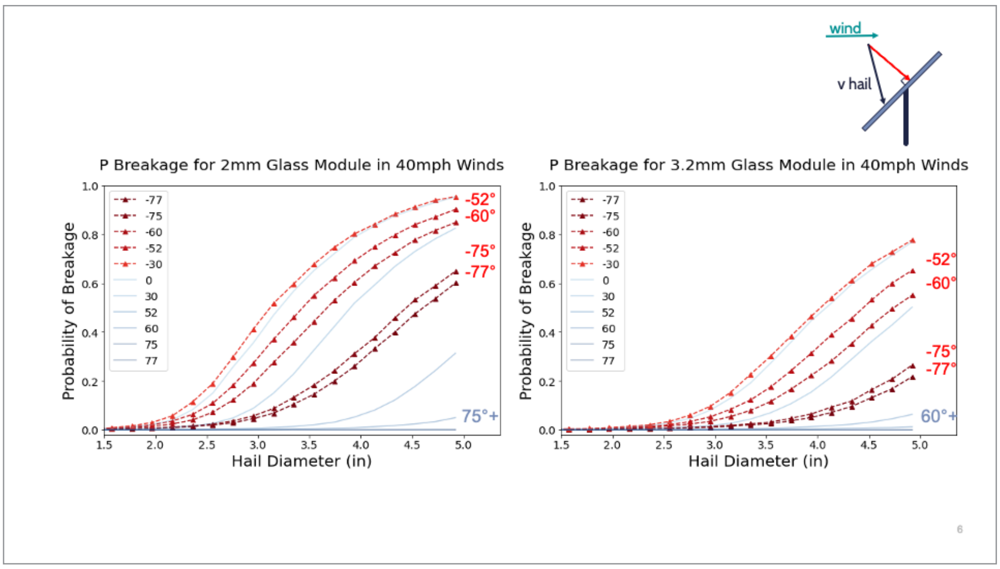
Insurance loss modelling

Because insurers rely on physics-based models to price hail risk, flaws in those models can lead to inaccurate assessments of project vulnerability and mispriced premiums. For the few insurers offering premium differentiation for stow, utilising the simple kinetic energy model may overestimate the effectiveness of stow by nearly 50%. When these models predict lower damage probabilities for installations with stow capabilities, insurance companies may price policies based on protection levels that differ from field reality.

Understanding the true physics of hail impacts is helping the industry develop more realistic expectations about the effectiveness of protection. While stow strategies remain valuable components of comprehensive protection, recognising their actual performance levels allows for better planning, risk management and cost-benefit analyses. This understanding encourages continued innovation in material improvements and multi-layered protection approaches that can deliver the reliability both project owners and insurers require.

Insurance companies are actively addressing this challenge. Progressive

Figure 5. The benefit of tilt angles past 52 degrees becomes evident when considering the scenario where modules are stowed into the wind



renewable energy insurers now request detailed documentation of protection measures and are developing more sophisticated models that better account for the actual performance of stow strategies. Some carriers are beginning to offer premium differentiation for projects that combine multiple protection approaches rather than relying solely on positioning systems.

The path forward

The research reveals a fundamental challenge facing the solar industry: current hail modelling may be underestimating damage risk by up to 48% for large hailstones, even when panels are positioned at high-degree stow angles. This modelling gap could potentially create cascading effects across technology investment, insurance pricing, and operational strategies that the industry must address through comprehensive protection approaches as well as further quantification of the effects of stow.

While our corrected modelling shows that stow provides less protection than traditional calculations suggest, effective hail protection still works when implemented as part of a multi-layered strategy.

This shift has created new requirements for project development. Asset hardening measures now influence project economics from initial design through ongoing operations. VDE Americas, in collaboration with Wells Fargo, has developed a best practice guide for solar resilience [4], identifying several critical protection strategies:

Module selection. This represents the most fundamental choice in hail protection. The popular 2mm glass/glass construction performs poorly when subjected to hail impacts, due to the thinner, untempered front glass. Upgrading to a 3.2mm glass/polymer backsheet module provides measurably better resilience, especially if the front glass is tempered. Even better, using a thicker front glass, such as 4mm glass, is thought to increase resiliency, and the latest 3.2mm/2mm glass/glass modules also offer increased protection compared to 3.2mm glass/polymer backsheet.

These configurations use 3.2mm tempered glass for the front surface where hail impacts occur, with 2mm glass on the rear for structural integrity. Initial studies are showing a marked improvement over standard 3.2mm/polymer backsheet construction, with panels sustaining up to 1.7x higher impact energies to the front glass without glass breakage ((Groundworks and kWh Analytics, 2025 Solar Risk Assessment). While the front glass thickness is the same as the 3.2mm/polymer backsheet, industry speculation suggests this increased resilience is due to the increased rigidity of the module as a whole from using the 2mm glass backsheet, but research is still ongoing.

Hail stow. The act of tilting panels into steep angles to reduce the probability of glass breakage during wind or hail events demands reliability across multiple interconnected components: weather monitoring alerts must be live and in real-time, the trackers must have reliable power to enter into stow, operators must know and employ the appropriate procedures and communication networks must be fully functional to deploy a stow command uniformly across the entire solar array. Regular testing can reveal potential failures ahead of a storm, and the most effective installations ensure redundancies across critical components (weather alerts, communication nodes, etc.).

Operational protocols. These extend protection beyond equipment specifications. Night stow procedures ensure protection during overnight storms when manual intervention is more difficult. Documentation protocols that satisfy insurance requirements are becoming essential for favourable coverage terms.

For operational sites that do not have 3.2mm or thicker glass installed, all is not lost. VDE Americas shared a case study in the 2025 Solar Risk Assessment that demonstrates how proper operational protocols can deliver exceptional results, even without thicker modules. Three projects in Fort Bend County, Texas, using standard 2mm dual glass panels successfully weathered ~4in (100mm) hailstones that devastated the nearby Fighting Jays site. Their success came from flawless execution: reliable 52° stow positioning, robust communication systems and comprehensive operational protocols that ensured every tracker responded properly. Two sites sustained zero damage, while the third saw minimal impact only due to a pre-existing tracker motor issue and flying debris. This validation demonstrates that while thicker glass provides superior protection, operational excellence with proven materials can still deliver remarkable resilience.

Getting the hail modelling right matters for everyone in the solar value chain. Accurate risk assessment enables appropriate insurance pricing, proper economic incentives for effective protection strategies, and continued innovation in technologies that deliver real-world resilience. The combination of improved materials, reliable stow systems and comprehensive operational procedures works when implemented together. To close the gap between perceived and actual risk, the industry must adopt empirically validated models, optimised around the physics of what actually happens when hailstones hit solar panels to ensure that our renewable energy infrastructure can withstand the increasingly severe weather it will face.

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Reilly Fagan is a senior data analyst at kWh Analytics. Prior to joining kWh Analytics, Reilly worked at a as a lead research analyst in the research department of a venture capital firm. There, she created research reports for corporate clients on solar technology, battery recycling, sustainable aviation fuels, and more. Reilly received a B.S. in chemical engineering from the University of Colorado at Boulder.

From energy yield to real-time performance: a new metric for PV project success

Modelling | The size of PV projects and increasingly complex market conditions in which they operate demand greater sophistication in plant performance modelling. Marcel Suri explores the datasets that will help improve the accuracy of PV output estimation and reduce the gap between projected and actual performance

Credit: American Public Power Association/Unsplash

For two decades, solar energy project design and evaluation has centred around annual energy yield as the most important metric. Defined as the theoretical energy production of a PV plant under typical weather and system assumptions, energy yield is a concept that is largely focused on maximising the quantity of energy produced by a solar power plant per year.

However, as the solar sector evolves in response to real-time market demands, volatile pricing and increasingly complex grid requirements, this once-reliable metric is no longer sufficient on its own. A new paradigm is emerging – one that prioritises quality over theoretical maximum output, and focuses on the optimal performance of the PV power plant, the timely delivery of energy and long-term operational resilience.

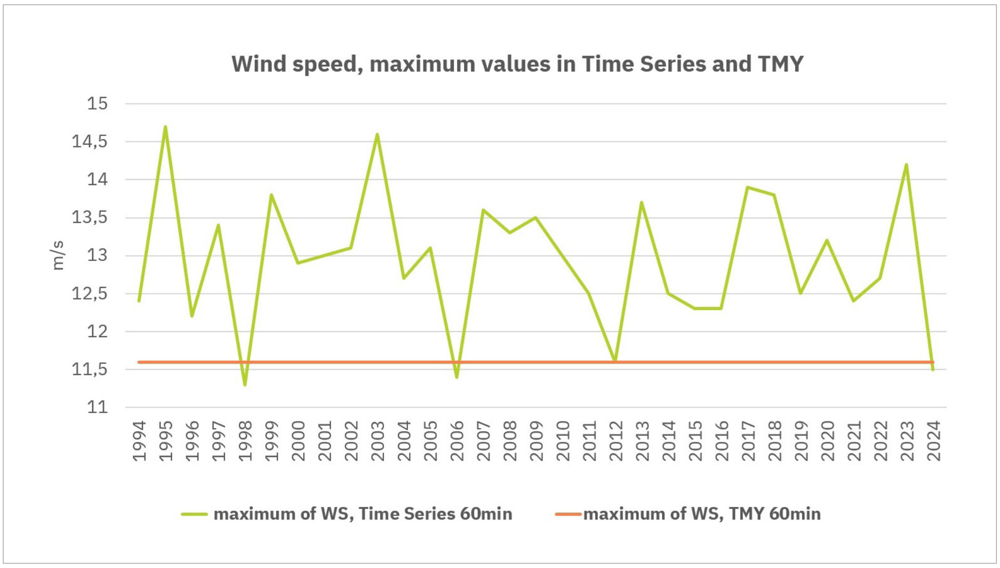
PV performance becomes the new standard – encompassing not just how much energy a plant can produce, but when, how reliably and how profitably it can do so.

The limitations of energy yield as a standalone metric

While annual energy yield remains a technically meaningful parameter, its relevance in business modelling and real-world operations is limited. Historically, developers could assume that all energy generated would be sold at a predictable price, regardless of when it was delivered. Under those conditions, maximising total annual production was a logical goal. This is no longer the case.

Energy yield as a metric for PV performance is no longer sufficient on its own

In today's competitive energy market, the value of electricity is highly volatile. Energy generated during periods of low demand or high offer may reach negligible prices – or may not be accepted at all. Worse, energy delivered outside of contractual delivery windows in power purchase agreements (PPAs) can lead to financial penalties. In short, a high



Source: Solargis Evaluate.

Figure 1. A graph showing differences in wind speed data as represented by hourly TMY (Typical Meteorological Year) versus hourly Time Series (TS)

theoretical yield does not guarantee commercial success.

Modern PPAs and grid codes increasingly require alignment between forecasted and actual production, often down to hourly or sub-hourly intervals. PV asset owners and operators are now directly responsible for forecasting accuracy and delivery performance, particularly during peak demand windows or critical grid events. Deviations from forecast can lead to financial penalties, dispatch curtailment or additional balancing charges.

As a result, performance – defined as the ability of a PV power plant to consistently deliver energy at the right time, under real-world conditions and in line with market or contractual expectations – has emerged as a more actionable and financially relevant metric. This shift has significant implications for PV system design, monitoring and forecasting.

Accurate forecasting is central to succeeding in performance-based markets. In many regions, deviations from intraday and day-ahead forecasts can lead to financial penalties or curtailment. For that reason, developers and investors face greater pressure to design projects that are predictable, resilient and where performance simulations and financial models match the new reality.

Designing for optimal PV performance

To optimise for real-time performance, PV systems must be designed not just for maximum annual output, but for temporal alignment, weather resilience and long-term system health.

Temporal alignment

Optimal PV performance begins with aligning the system's output with real-time demand. Rather than peaking at noon, when wholesale electricity prices are typically the lowest, a well-designed plant maximises production during periods when demand and prices spike. This shift is increasingly important in markets with time-of-use tariffs, dynamic pricing or capacity-based incentives.

One of the most effective ways to meet the temporal demand is by integrating battery energy storage systems (BESS). While PV generation is inherently tied to solar availability during the day, BESS enables time-shifting of energy delivery to match it with higher-value periods, such as early evening hours. This flexibility not only enhances profitability in markets with variable pricing but also supports grid stability and improves the overall dispatchability of solar energy.

When properly sized and integrated into the system design, BESS can transform a PV power plant from a passive generator into a responsive energy asset.

BESS integration also requires adjustments in the system design and modelling, including dispatch strategies and energy forecasts. Accurate simulation of charge/discharge cycles is essential for optimal sizing of inverters and system availability. Degradation modeling becomes more complex as cycling patterns impact both battery life and long-term system output.

Additionally, revenue stacking – combining energy arbitrage with services, such as frequency regulation, capacity payments or grid balancing – further underscores the need for high-resolution data. Without it, the economic modelling of hybrid PV+BESS systems remains incomplete and potentially misleading.

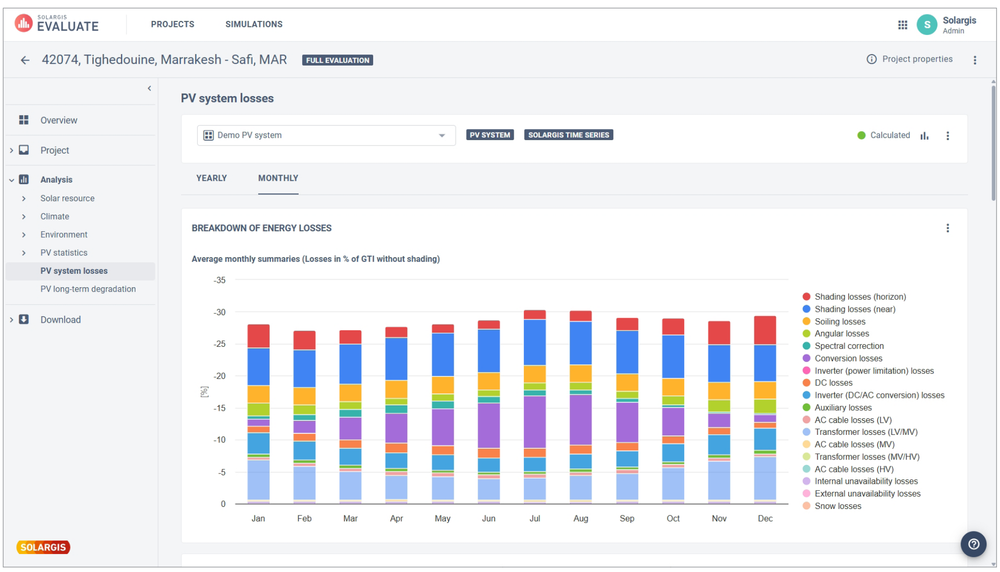
Resilience to critical events

Many PV system designs still rely on the use of TMY (Typical Meteorological Year) datasets, which only provide 'typical' or 'average' weather conditions, obscuring the risk of extreme weather events, such as sudden temperature changes or strong winds. Figure 1 shows the difference in actual wind speed versus wind speed as recorded as TMY.

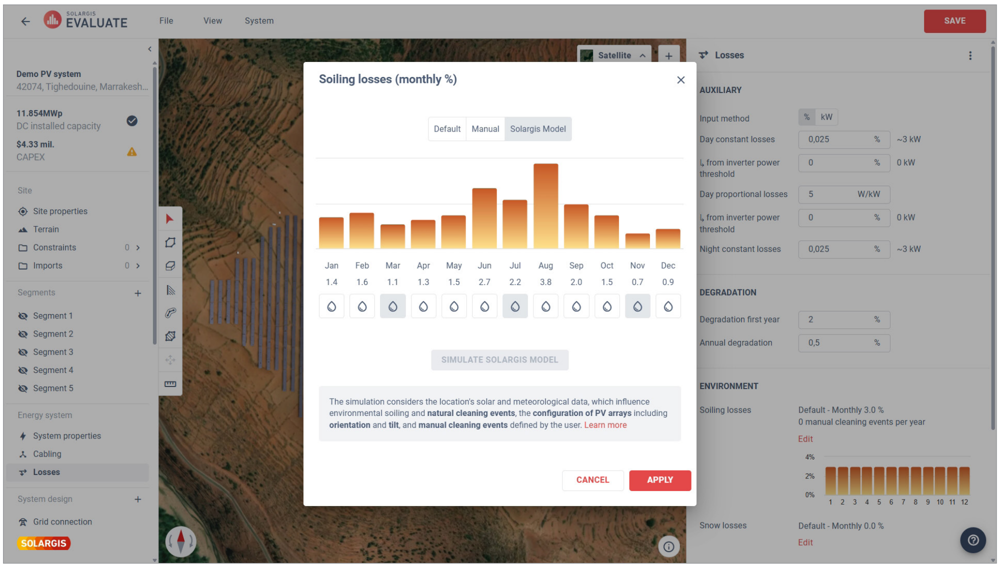
This may lead to inverter overloads, overvoltage, shutdowns or even damage. For example, if events of very low air temperature are not accounted for in the design, overvoltage can occur – causing system faults or hardware damage. Such technical failures can undermine a project's performance and jeopardise the PV power plant's financial viability.

Designing for resilience also means anticipating non-meteorological stress factors that are amplified during critical events, such as grid-induced voltage spikes, mechanical strain from thermal

Figure 2. A graph showing yearly and monthly electrical losses



Source: Solargis Evaluate



Source: Solargis Evaluate.

Figure 3. Electrical losses due to PV module soiling, based on time series data

cycling or increased soiling after sandstorms or wildfires. These risks can be mitigated through better inverter protection settings, thermally tolerant cable routing, reinforced mounting systems and adaptive cleaning schedules.

Just as engineers design bridges for 100-year floods, PV systems must be specified for rare but plausible operational extremes – not just average conditions. In the context of long-term performance guarantees and insurance coverage, the return on resilience-focused design is substantial.

System health and longevity

Integral to PV performance is long-term asset health. There are a large number of solar power plants that underdeliver against expectations. Poor design choices can cause thermal or electrical stress, accelerating the degradation of modules and inverters. When solar power plants underperform due to preventable wear and tear, it signals a misalignment between design assumptions and real-world conditions.

Investors are increasingly focused on this alignment. A project with a strong theoretical yield is no longer enough – financial stakeholders now demand more robust modelling of PV performance. That means more than just P50 and P90 yearly energy production estimates. Figure 2 demonstrates some of the factors affecting energy loss that can be reported on at PV projects.

In today's high-stakes environment, where electricity markets are volatile, and operational risks are more visible, the emphasis has shifted from theoretical output to real-world resilience. Lenders and insurers want to see simulations that take into account variability, extremes and uncertainty. Investors expect to see credible simulations based on realistic meteorological data and risk mitigation strategies.

This trend also reflects the growing importance of performance stability over time. Investors understand that a solar project with a high theoretical yield may still underperform financially if its output is misaligned with market pricing, or if it is vulnerable to curtailments, voltage issues or environmental stressors.

What can PV developers do to ensure optimal PV design?

PV developers must move beyond outdated, empirical models and low-resolution datasets. This includes using advanced PV simulation software that works with high-resolution time series data instead of the hourly TMY datasets.

High-resolution 15-minute time series data capture temporal variability and enable more accurate modeling of real-world operating conditions. It can better capture site-specific conditions and model the system behaviour more accurately, resulting in PV designs that reflect actual operating conditions and support modern business models. Figure 3 includes a graph showing soiling losses at a project site.

Another critical layer is software built on advanced physical modelling. Technologies, such as ray tracing and the Perez all-weather model, enable more accurate calculation of shading in complex terrain or densely packed layouts. Unlike the simplified view factor model, ray tracing simulates the exact path of sunlight through a 3D environment, making it possible to accurately model PV output for bifacial PV systems and uneven surfaces.

Factors such as soiling and snow losses also have a significant impact on PV performance, particularly in dry, dusty, or high-latitude environments.

Software solutions must be capable of simulating soiling losses dynamically, based on site-specific, high-resolution time series data, PV model configuration and local weather conditions such as wind and precipitation. Realistic modelling of soiling losses helps developers schedule cleaning and maintenance more effectively.

Ultimately, these improvements result in a more accurate PV output estimation, reducing the gap between projected and actual performance. For bankability assessments, that accuracy is essential.

Performance as a strategic advantage

The goal is to build PV systems that are healthy, reliable and profitable. In today's market, a high-performing solar asset is one that delivers energy when it's most valuable, withstands operational stress and is long-term efficient. Designing for that reality is no longer optional; it's the new standard.

As energy markets grow more dynamic and expectations rise, stakeholders across the value chain, from developers to financiers to grid operators, will increasingly demand performance-oriented metrics. Those who embrace this shift early will be best positioned to thrive in the next generation of solar energy projects.

Being able to predict and consistently deliver energy, not just in quantity, but at the right time and under the right conditions, is becoming a core differentiator for PV projects. Advanced forecasting and PV evaluation lead to better decisions and healthy PV assets that are ready for active collaboration with electricity markets. ■

Author

Marcel Suri is an entrepreneur and cofounder of the solar data and software company Solargis. He is an expert in solar resource, photovoltaics and geoscience. Holding a PhD in geography and geoinformatics, Marcel has made significant contributions to solar energy through science and peer-reviewed research. Driven by a passion for innovation, Marcel is dedicated to improving the efficiency of digital tools and data resources and analytics that mitigate weather-related risks and elevate industry standards.

Historically 'benign' solar markets for climate risk must adapt to intensifying extreme weather conditions

Insurance | Damage to solar from so-called Natural Catastrophe events is increasing as the technology expands its reach and weather conditions worsen. James Totton looks at some of the regions where risk exposure is growing and how the industry should respond

An unwelcome irony follows solar PV's journey to commercial adoption in the global energy mix: one of the greatest threats to its success is the extreme weather that solar projects are supposed to counteract. As the solar sector has expanded into new territories at a larger scale, the more acute this irony has become for developers and insurers. The exposure of panels to sunlight comes hand in hand with their exposure to other climatic conditions, and, in the case of intensifying climate risks, that means severe convective storms (SCS) and increasingly large hailstones.

Although solar PV's vulnerability to Natural Catastrophe (Nat Cat) damage is well known across the industry, the North American market has often been singled out as the focal point for these challenges. This reputation has grown out of significant recurring losses in the 'hurricane alley' of the US, encompassing the Gulf Coast and the southeastern Atlantic coast.

Such is the pressure climate risks have applied on project economics that we now see instances of lenders refusing to finance projects in high-risk areas due to gaps in available coverage. Moreover, to rebalance risk, project owners are finding that many insurers are changing their approach to deductibles, moving to a percentage-based model that relates to asset values instead. This means deductibles are rising, and, with sublimits falling, project owners in North America are carrying a heavier financial burden than before.

Credit: Nextracker

However, it is no longer true to say that Nat Cat is an exclusively North American concern. In recent years, extreme weather events have become increasingly global phenomena, and the level of risk is exacerbated by:

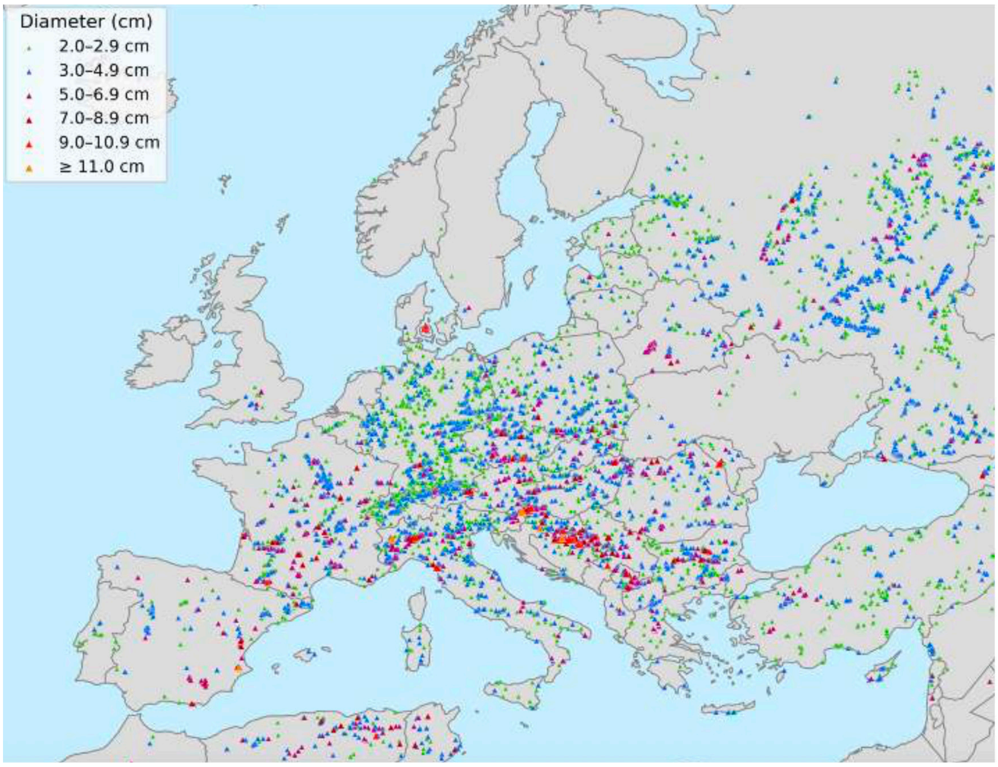
- The global intensification of extreme weather patterns
- The construction boom pushing solar deployment into new unmodelled and unmonitored locations
- The underestimation of exposure and risk severity

Solar is increasingly vulnerable to 'Nat Cat' risks such as storms and hail

For markets historically considered to be 'benign' for climate risk, Europe and MENA experienced record-breaking rainfall events last year and suffered significant losses to their installed solar capacity. Elsewhere, after atypically calm weather in 2024, Australian insurers have already seen claims for insured losses exceed AU$1 billion (US$650 million) this year, following the previous five-year trend of escalating Nat Cat damages in the region [1].

We know from the industry's experience in parts of the US that if these risks go unchecked then the insurability of projects will be precarious in future. Markets freshly experiencing severe damages from intensifying weather conditions must adapt now to protect their assets and ensure that the boom in solar deployment is sustainable.

This article explores the rising Nat Cat exposure in three key solar markets, how risk is being managed and shared and highlights what more can be done to improve adaptability.



Source: European Severe Weather Database, www.eswd.eu

Figure 1. Hail reports in Europe, 2024

Europe

In the first half of the 2020s there has been a notable shift in Europe's experience of extreme weather. Larger hailstones are being recorded than before, along with faster windspeeds and heavier rainfall – and all three elements are occurring with greater frequency.

The uptick in extreme weather in the region is attested to by the €24 billion (US$27.8 billion) of insured losses accumulated in the headline weather events over the last five years: 2021's European flood caused by low-pressure weather system, 'Bernd'; 2022's hailstorms in France; 2023's SCSs in Italy; and 2024's flooding in Spain.

Of Europe's renewable assets, solar is the most vulnerable to intensifying weather conditions. Our data shows that external perils account for 90-95% of solar losses (loss quantum). The map in Figure 1 demonstrates that there is a corridor emerging across northern Italy, southern Germany and into southeastern Europe where hailstones up to 10cm in diameter are now prevalent, forming a hotspot for potential solar losses.

Due to Europe's relatively climate-friendly reputation, the insurance protection gap has grown in step with recent weather changes. Typical coverage limits for solar now look low compared to risk exposure, leaving project owners vulnerable to severe losses in the event of a hailstorm, losses compounded by business downtime and an inflated supply chain.

The expansion of solar projects across Europe has illuminated blind spots in the region's weather data and monitoring strategy. Recent events underline the need to invest in higher-quality data collection for more reliable models of Nat Cat scenarios in Europe.

However, improved weather tracking is ineffective without implementing resilient mitigation strategies onsite. Developers and OEMs must collaborate on panel designs that better withstand Europe's climate challenges, and site managers must hone extreme weather protocols to protect assets and proactively store replacement parts in case of a loss event.

Key to Europe's adaptation to climate risks will be the revision of insurance packages and risk-sharing. The current approach to project financing and insurance is based on an outdated understanding of Nat Cat risk, and it will take open discussions between developers, brokers, insurers and lenders to correct this and avoid the market hardening that we've seen elsewhere.

Middle East

The rise of solar megaprojects in the Middle East is a major part of the region's energy transition strategy. The appetite for large-scale projects is driven by high levels of irradiance, abundant land to develop on, state support and keen investable capital. Indeed, the UAE boasts both the world's largest single-site solar farm, the Mohammed bin Rashid Al Maktoum solar park (2.62GW), and the world's largest concentrated solar power project, Noor 1 (950MW).

Since the region is less prone to heavy precipitation, the usual precautions taken in other parts of the world to protect enormous assets have been undervalued and underprioritised, leaving a big gap in weather data modelling and risk management strategy.

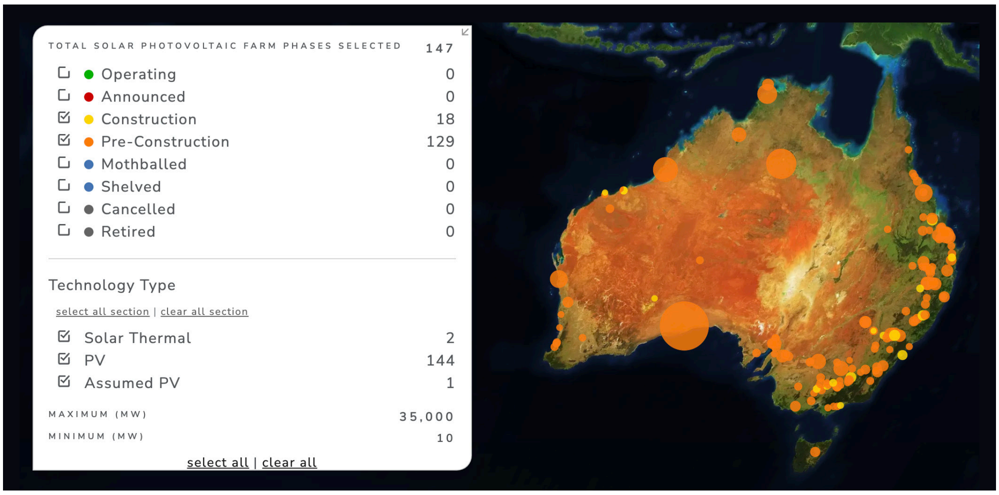
Both projects were massively exposed in last year's Persian Gulf floods, during which 254 litres of water fell in one day, causing almost US$3 billion in insured losses and inflicting heavy damage to these two projects. While this moment drew global attention as a unique event, observant market spectators know that the MENA solar market is no stranger to substantial Nat Cat losses.

Previous solar losses from Jeddah to Jordan predate this high-profile flood event. The combination of high wind speeds and wet sand foundations has been a persistent source of losses in the Middle East, with asset substructures and tracking systems sustaining damage in these conditions. Such is the shortage of available weather data that efforts to determine whether these risks are new or part of a long-term pattern in the region are inconclusive.

Until now, belief in the market's benign climate risk profile has dictated the low demand for better weather modelling, physical weather defences and enhanced insurance coverage.

Even before the flood last year, the General Arab Insurance Federation (GAIF) launched the Arab Initiative for Natural Disaster Risk Reduction in 2022 to address the high insurance protection gap and to improve local underwriting services. Since then, mandatory construction standards have been upgraded to 'Grade Three' from 'Grade One' in order to build more resilient projects. More generally, the power of the MENA market in the global supply chain affords it greater manoeuvrability when it comes to sourcing repairs and replacement components.

Nonetheless, with lots of capital and reinsurance capacity in the market it is easy to underestimate the value of long-term measures over short-term fixes. Beyond investing in enhanced weather data and modelling, developers can de-risk their projects further by



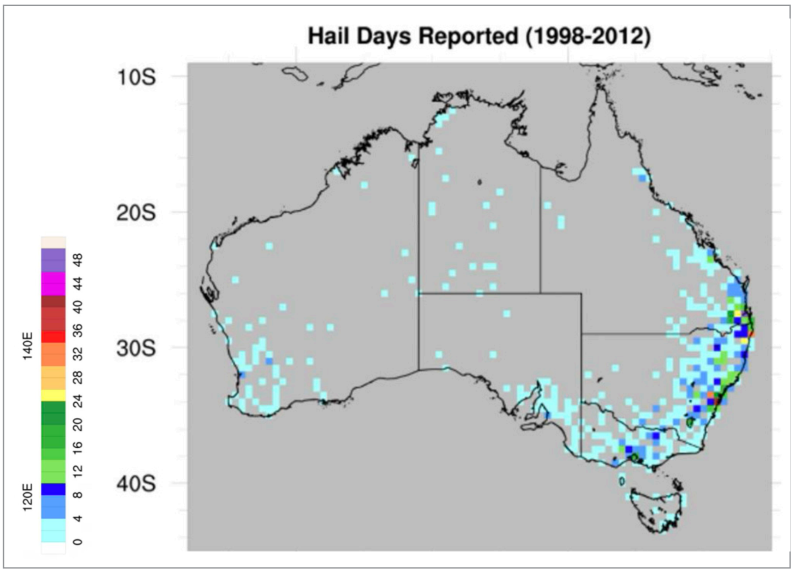


Figure 2 (top). Global Energy Monitor, 19.06.25, Australia's pre-construction/construction pipeline; Figure 3 (left). Hail days reported (1998-2012).

working closely with specialist insurers to better understand their exposure and how they can share risk for improved financial protection.

Players in the Middle East have shown they can develop at size and pace, but the success of megaprojects depends just as much on their resilience in the testing conditions they will inevitably face at some point in their life cycles.

Australia

Unlike the Middle East and Europe, Australia's climate sensitivity is not such a looming surprise. Australia's modest insured losses for 2024 – a 20-year low that the Insurance Council of Australia reported was the first Nat Cat-free year since 1982 – were significant for their exceptionality.

By contrast, both Australia's east and west coasts have been struck this year by storms, flooding and bushfires. Hailstones exceeding 10cm in diameter were recorded in January storms in Queensland and New South Wales; simultaneously, bushfires, such as that at Windy Harbour, took months to extinguish. At the start of June, the federal Treasury analysed that Nat Cat events had cost Australia's economy AU$2.2 billion (US$1.4billion) in the first half of 2025.

The unknown factor that the market must adapt to is less the probability of extreme weather and more the expansion of solar into uncharted territory. The re-elected Australian government reiterated its plan for the country to generate 82% of its electricity from solar, wind and hydropower by 2030, an ambition that hinges on the rapid deployment of new assets. However, the accumulation of new solar projects on the east coast coincides with the most exposed hail hotspots, according to the two maps in Figures 2 and 3.

While local underwriters have experience of Australian climate risks and have successfully collaborated with project owners to mitigate bushfire and flood damage, the influx of capacity to support Australia's growth ambitions puts increased pressure on terms designed to mitigate those risks. To realise Australia's solar potential, investment in resilient equipment and adoption of hail safety systems will be crucial, as will knowledge-sharing across key stakeholders in the industry to educate players on Australia's unique climate risk profile.

Given the amount of investment and policy support pumped into solar, the sector must prioritise designing projects to be operational for the entirety of their 25-year life cycles, which must factor in a more extreme climate.

Solar growth unsustainable without proactive response to climate risks

The solar sectors in Australia, Europe and the Middle East can all learn from the serial Nat Cat losses in parts of the US that have made project insurability and bankability major barriers to industry growth. These markets operate with either considerable installed solar capacity or a considerable pipeline of solar capacity, and the experiences of intensifying extreme weather in this decade should be a wake-up call to protect assets.

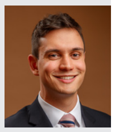
Not only does the global industry need to move beyond the dismissive idea that Nat Cat is a North American issue, but it must also reassess the allocation of risk across projects. This is an issue for everyone, not just insurers, and the earlier insurers join project discussions, the more proactively owners can de-risk them and secure protective coverage.

As insurers, our primary aim is to ensure the sector's sustainability by encouraging healthy risk management practices and supplying capacity demand for insurance cover. When it comes to the 'known unknown' of extreme weather, we firmly believe that sustainability is achieved by acknowledging that climate risks are intensifying and sharing knowledge within the industry to fully understand how best to protect its growth. ■

Reference

[1] Insurance Council of Australia, https://insurancecouncil.com.au/resource/2025-extreme-weather-claims-reach-1-2-billion/

Author



James Totton is an underwriter at GCube Insurance. With a background in environmental consulting, he joined GCube in 2019 and specialised in renewable energy as an underwriting assistant after completing a master's degree in economics and policy of sustainable resources at the University College London. He became an underwriter in early 2024.

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Energy Storage NEWS

Introduction

Welcome to another edition of 'Storage & Smart Power' from the team at Energy-Storage.news.

Every year, this Q3 edition of the journal goes out to RE+, the US's biggest solar PV and energy storage trade show, giving attendees a flavour of the great content our subscribers enjoy all year round.

This time out, we're just as excited as ever to be at RE+ with our industry friends and colleagues, but it's evident that a few things have changed since last year. They've even changed dramatically since last quarter.

Three short months ago, tariffs were the talk of the industry in the US and the countries that do business with it.

That topic hasn't gone away, but, as our colleagues have covered in this journal's cover feature, what followed with the 'One, Big, Beautiful Bill Act' was even more of an unexpected turn of events.

Likely due to the administration's focus on energy security and grid resilience, energy storage was treated very differently from solar PV, wind or electric vehicles, but the foreign entity of concern (FEOC) restrictions on ITC eligibility present a new supply chain paradigm.

It's still difficult to tell whether the new developments put energy storage back onto a pre-Inflation Reduction Act growth trajectory, or something else entirely, but it has certainly presented the industry with new questions to ask and find answers to.

That said, while developers and investors in the US have been cautious and can likely expect more of that, activity in many other parts of the world has been encouraging.

Gearing up for the 2025 edition of the Energy Storage Summit Asia, which this year is being held in the Philippines' capital, Manila, market design and project development in key markets including the Philippines, Indonesia and Japan have been relatively robust, albeit with some challenges and early-stage market teething issues.

Likewise, our coverage has featured projects and investments from Europe that bring the continent's markets to a new level of scale and (hopefully) opportunities, with a few caveats around market design and regulation issues.

If one thing stands out more than all else, it's the industry's can-do attitude, which has always weathered the storms. We're confident the energy storage industry shares this perspective and has more than a few tricks up its own sleeve to stay strong and ultimately prosper.

In 'Storage & Smart Power' this time, you will find:

- A deep dive into the US energy storage market landscape from Rabobank Americas energy transition research specialist Amit Mathrani, viewed through the prism of its two leading markets: CAISO in California and ERCOT in Texas.
- A look at the ever-important topic of enhancing fire safety for grid-scale lithium-ion battery storage, from risks to technologies and standards, by Drew Bandhauer, BESS engineer at US developer Leeward Renewable Energy.
- An exploration by 3E of optimising the performance of mixed assets combining PV, storage and other generators.
- And an update on the global evolution of long-duration energy storage (LDES) market drivers and solutions from Julia Souder, executive director of the LDES Council.

Andy Colthorpe
Editor
Energy-Storage.news @ Solar Media

Credit: Pexels/Tom Fisk

The budget reconciliation bill passed by Washington legislators in July kept tax credits for energy storage intact for the time being

US energy storage to 'retain momentum' post-reconciliation bill, near-term rush to complete projects

US energy storage projects that begin construction by the end of 2033 will remain eligible for investment tax credit (ITC) incentives.

During the Independence Day national holiday (4 July), US President Donald Trump signed the budget reconciliation bill into law. The 'One, Big, Beautiful Bill Act' brought an abrupt end to 48E ITC and 45Y production tax credits (PTCs) for solar PV and wind.

However, certain other clean energy technologies, including energy storage, geothermal, biomass and hydroelectricity, can qualify for technology-neutral tax credits at the full rate, which is 30% of Capex cost, plus domestic content bonuses to a value of about 45% in total.

FlexGen steps into Powin bankruptcy proceedings as stalking horse bidder

FlexGen Power Systems (FlexGen) has bid to take over rival US system integrator Powin during the latter's Chapter 11 bankruptcy proceedings.

Oregon-headquartered BESS manufacturer and system integrator Powin is facing well-documented financial struggles. Its Chapter 11 case is currently with the bankruptcy court in New Jersey.

FlexGen has been named as the stalking horse bidder behind a debtor-in-possession (DIP) Lender offer, detailed as part of an interim order at the New Jersey US Bankruptcy Court on 26 June.

CATL launches 9MWh 'two in one' stacked BESS product in response to transportation weight limits

CATL has launched a 9MWh grid-scale BESS product which comprises two smaller units stacked on top of each other, which it said gets around weight challenges for transportation.

The lithium-ion OEM launched the Tener Stack product at the ees Europe 2025 clean energy trade show and conference in Munich, in May, following which it gave a Q&A to media including Energy-Storage.news.

The 'two in one' design comprises two half-height units, which are under 36 tonnes each, ensuring compliance with transport regulations across 99% of global markets, the company said. It can reduce waiting times and specialised transport costs by up to 35%, the company claimed.

CATL's CTO ESS Europe Hank Zhou said the company saw a clear need for easy transportation while still having a higher energy density per square meter, which were the main reasons for developing the product.

PowerChina begins construction of 'world's largest generation-side' battery storage project

PowerChina has begun construction on what is claimed to be the world's largest generation-side electrochemical energy storage project.

On June 30, PowerChina announced that an official groundbreaking had taken place for the 1,000MW/6,000MWh facility in Chayouzhong Banner, Ulanqab, Inner Mongolia, undertaken by PowerChina.

The project adopts an engineering, procurement and construction (EPC) turnkey contract model including operation & maintenance (O&M) services.

The project covers an area of approximately 700 mu (about 46.7 hectares). The main infrastructure includes 1,200 units of 5.016MWh lithium iron phosphate (LFP) energy storage battery cabins, four 250MVA dual-split 220kV main transformers, and a new 220kV transmission line linked to the Chayouzhong 500kV substation.

AEMO sets grid-forming BESS as a priority action for 2026, set to form the 'heartbeat' of New South Wales

The Australian Energy Market Operator (AEMO) has made grid-forming BESS a priority for the National Electricity Market (NEM) and South West Interconnected System (SWIS) for 2026.

According to the organisation's Engineering Roadmap – FY2026 priority actions report, many of the priorities for 2026 are centred around harnessing the potential of grid-forming batteries and tapping into consumer energy resources (CERs) such as rooftop solar PV, distributed home battery storage, and electric vehicles (EVs).

AEMO has committed to 29 priority actions across the NEM and the SWIS for the upcoming financial year. One of the group's primary areas of focus will be understanding future technology capabilities within both markets. This includes a full analysis of fault current contributions from grid-forming BESS.

EU needs 500GWh-780GWh of BESS to meet 2030 renewables targets, SolarPower Europe says

The European Union (EU) will not meet its 2030 clean energy targets unless cumulative battery storage deployments rapidly accelerate, SolarPower Europe has said.

The solar PV trade association launched the Battery Storage Europe Platform on 1 July, which it describes as a "major new initiative to drive forward the business case and regulatory framework for battery storage across the European Union."

The platform is a dedicated advocacy organisation for battery storage technology, led by EU and international trade law expert Juhi Dion Sud.

According to SolarPower Europe, integrating the greatly increased share of renewables in the energy sector, responsible for more than 75% of the EU's greenhouse gas (GHG) emissions, would require between 500GWh and 780GWh of storage.

Megawatts are not enough anymore for leading US BESS markets

Markets | After an initial rush to deploy megawatts that gave CAISO and ERCOT the lead in US BESS adoption, both markets have become focused on capacity and availability, writes Amit Mathrani of Rabobank Americas

Battery energy storage has sprinted from niche experiment to indispensable grid asset in barely half a decade. Nowhere is that transformation clearer than in California and Texas.

By the end of 2024, the California ISO (CAISO) operated 12.5GW of utility-scale battery capacity, up from just 1GW in 2020, while the Electric Reliability Council of Texas (ERCOT) surged from essentially 0.5GW to 10GW over the same period. Together, these two markets now host a little more than 65% of all US grid-connected battery storage capacity (see figure 1).

The similarities end with scale. CAISO's build-out has been propelled by policy mandates and long-term Resource Adequacy (RA) contracts that favour 4-hour duration, close to urban load centres. ERCOT's boom, by contrast, has unfolded in a pure merchant setting, with no capacity market, minimal regulatory guardrails, and revenues earned (or lost) in real-time energy and ancillary-service markets. The result is a dual stress test on the same technology.

California now grapples with revenue compression and interconnection logjams, Texas with price cannibalisation, transmission bottlenecks, and a push towards multi-hour discharge.

These contrasts preview the grid's next chapter. Duration is edging out volume, siting advantage now beats speed, and investors increasingly prize fluency with evolving policy rules and flawless operations. Other ISOs – PJM, MISO, NYISO – are already importing elements of both playbooks. To see where battery economics and grid planning are headed next, let's start with California and Texas.

Two different routes to battery supremacy

California and Texas share the same headline: double-digit-gigawatt battery

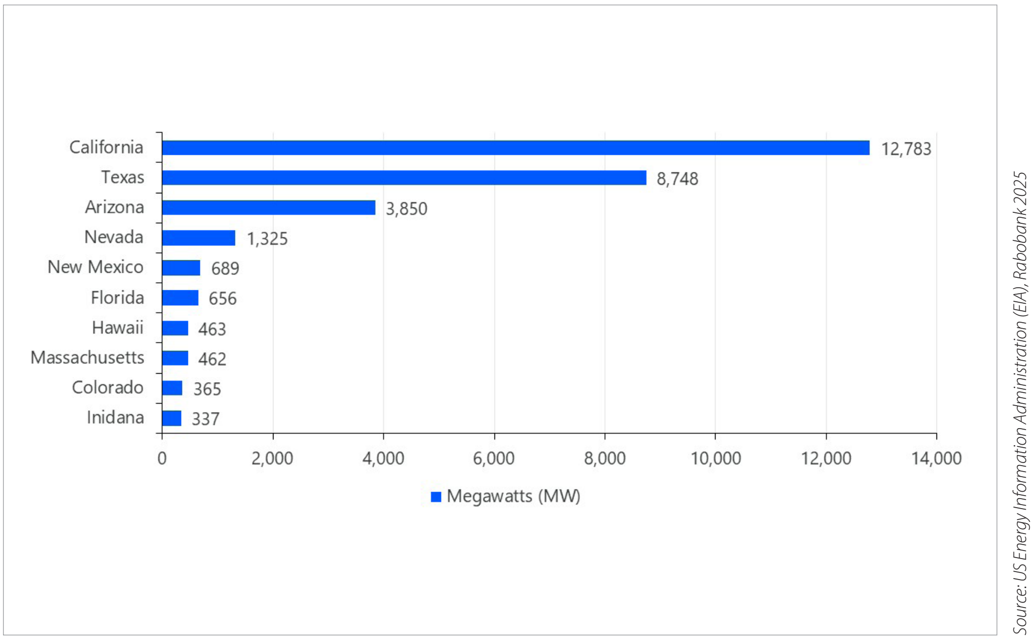


Figure 1. Top ten US states ranked by operating grid-scale battery capacity, May 2025 ;

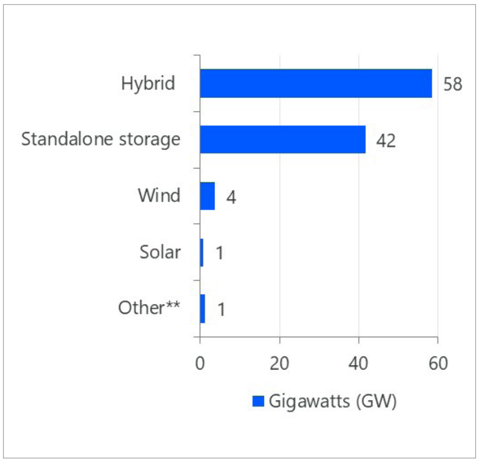


Figure 2. CAISO Interconnection queue by technology type, April 2025. Note: Includes projects that are active in the interconnection queue; hybrid consists of solar + BESS, wind + BESS, gas + BESS, pumped hydro + BESS, geothermal + BESS, other + BESS. **Other includes wind plus solar hybrid, pumped hydro, geothermal, gravity with rail, and water. Source: CAISO OASIS interconnection queue report, Rabobank 2025.

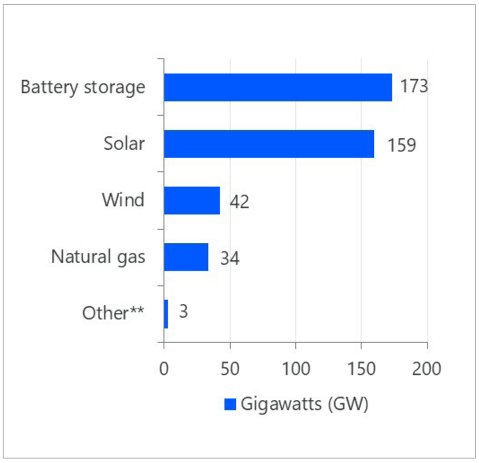
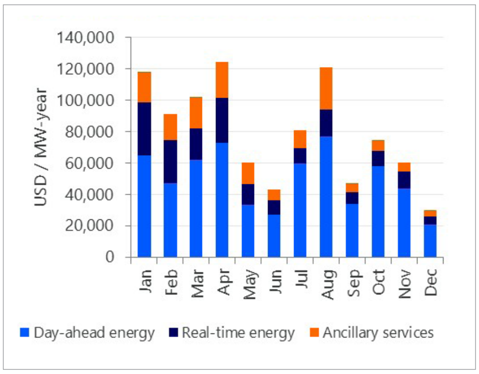


Figure 3. ERCOT interconnection queue by technology type, April 2025. Note: Includes only large generator projects for which a screening study has been requested, small generators for which an interconnection request has been made, and projects that are not inactive. **Other includes petroleum coke (pet coke), hydroelectric, fuel oil, geothermal energy, nuclear, other miscellaneous fuels reported by developers, and fuel cells that use fuels other than natural gas. Source: ERCOT GIS report, Rabobank 2025



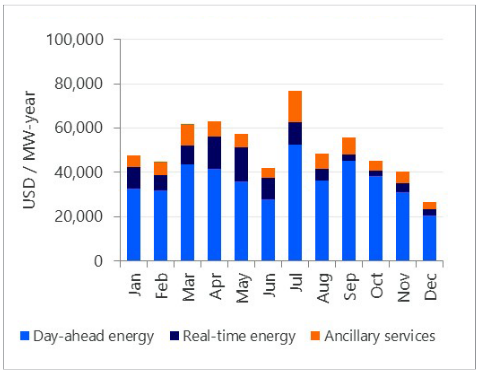


Figure 4 (left). CAISO BESS revenue stack, 2023. Source: Modo Energy, Rabobank 2025; Figure 5 (right). CAISO BESS revenue stack, 2024. Source: Modo Energy, Rabobank 2025

fleets built in record time. However, the mechanics behind that growth could not be further apart.

CAISO's 12.5GW of operating BESS is the product of a policy-catalysed glide path: mid-term reliability mandates such as the California Public Utilities Commission's (CPUC) 15.5GW of clean capacity by 2027, a 4-hour resource adequacy standard that underpins long-term offtake contracts, and interconnection reforms that now screen projects for site control and deliverability before they enter detailed study. The policy signal shows up in the pipeline: >90 % of CAISO's active interconnection queue are battery projects, and more than 51GW of that sits in the SP-15 zone in Los Angeles, San Diego and the southern desert counties, where RA scarcity commands premiums (see Figure 2).

Even so, history reminds developers that ambition outruns reality: Lawrence Berkeley National Laboratory (LBNL) puts CAISO's battery completion rate below 12%, a function of permitting drag and upgrade costs [1]. By Contrast, ERCOT's 10GW of operating capacity has been built almost entirely without mandates, capacity payments, or federal oversight. Developers plug into a "first-ready-first-served" queue that can move a large project from filing to energisation in 18-30 months, racing to monetise nodal price spikes. The merchant payoff triggered a gold-rush pipeline: ERCOT's April 2025 interconnection list shows batteries made up 42% of queued capacity, while solar held 38% and wind 10% (see Figure 3). Early projects were mostly 1-hour systems chasing ancillary-service revenue. Currently, the fleet averages 1.5-2 hours, and the queue mix is expected to shift toward 4-hour duration ahead of the Dispatchable Reliability Reserve Service (DRRS) launch in ERCOT in 2026 to compensate resources that can provide at least four hours of continuous energy during emergency conditions, supporting system stability without requiring formal capacity obligations. For investors, the divergence frames a strategic spectrum: from California's contract-anchored, lower-beta returns to Texas's volatility-driven, higher-beta upside. Understanding where a new market will sit on that spectrum is now the opening question in any storage diligence process.

Scale bites back and reshapes prices, risk and revenues

Battery growth has delivered its own headwind: as battery fleets swell, price spikes shrink.

In CAISO, data from Modo Energy shows that average merchant revenue for 4-hour batteries sliding from US$78,000/MW-year in 2023 to US$51,000/MW-year in 2024 (see Figures 4 and 5). Two structural shifts explain the fall. First, deeper midday solar oversupply now dampens the evening price ramp that batteries once captured. Second, CAISO's July 2024 Minimum State-of-Charge (SoC) extension requires resources to maintain an energy buffer through the evening net peak, limiting midday discharge-and-reload cycles.

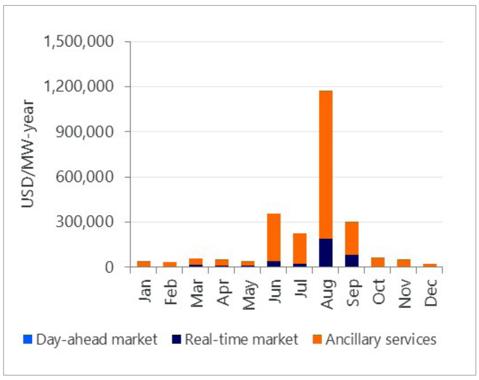
To add to the pain, the cost of failure rose just as spreads tightened. A thermal runaway fire at Vistra's 300MW Moss Landing facility in January 2025 sidelined the plant for ten weeks. Subsequent risk briefs show insurance premiums increased for large urban battery projects.

Faced with thinner spreads, California sponsors anchored earnings in 4-hour RA contracts, which still cleared between US$90,000/MW-year and US$120,000/MW-year in the latest CPUC solicitation. With merchant income supplying barely one-third of cash flow, sponsors focus on telemetry accuracy, fire-suppression upgrades, and strict state-of-charge (SoC) compliance; a single missed RA dispatch can forfeit an entire month of contracted revenue.

Texas experienced a faster shock. Battery supply chasing Regulation and Responsive Reserve Service tripled in a single year, while product volume held flat. Average ancillary revenue collapsed from US$168,504/MW-year in 2023 to just US$36,317/MW-year in 2024 (see Figures 6 and 7). Operators pivoted to evening arbitrage, only to find a flatter curve: during August's record heatwave, the Houston load-zone premium over off-peak settled at US$128/MWh even as demand set new highs. Meanwhile, transmission congestion added insult to injury. Batteries behind the Tonkawa–Morgan Creek bottleneck in West Texas forfeited an estimated US$5,000/MW-year and US$7,000/MW-year to nodal price haircuts.

ERCOT is restoring margin through new market tools. Real-Time Co-optimization (RTC), a dispatch mechanism used in other markets (e.g., PJM, CAISO) to allocate energy and ancillary service commitments based on real-time system needs and marginal value, slated for late 2025, will allow 5-minute re-bidding between energy and reserves and is projected to raise gross margins 10-15% for 2-hour assets. In 2026, the 4-hour DRRS begins, and ERCOT is expected to add a reliability payment on top of today's energy-plus-ancillary stack. The service's design explicitly favours 4-hour resources.

In CAISO the most reliable dollar now comes from delivering contracted RA capacity without a single penalty. In ERCOT it will come from meeting RTC and DRRS performance thresholds with the right duration. Price volatility launched the storage boom, but rule-defined execution, and the cost of missing it, now determines who keeps earning when the spikes are gone.



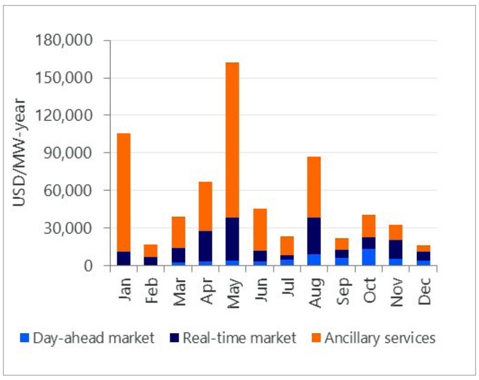


Figure 6 (left). ERCOT BESS revenue stack for 2023. Source: Modo Energy, Rabobank 2025; Figure 7 (right). ERCOT BESS revenue stack for 2024. Source: Modo Energy, Rabobank 2025

Duration is starting to define storage value

When price spreads stopped doing the heavy lifting, planners and investors pivoted from how many batteries a market could absorb to how long each unit could deliver.

During a late-season heatwave on 7 October 2024, CAISO batteries peaked at 8,354MW, serving around 21% of system demand. Grid data shows the fleet's aggregate state-of-charge dipped rapidly after 8pm, highlighting how little margin a 4-hour system retains if the peak lingers. That close call now shapes state planning. The California Energy Commission's draft 'Pathways to 2045 – 2025 Update' assumes ≥11GW of 6-hour storage by 2030 to shore up deeper solar penetration. CPUC procurement dockets already ask bidders to flag "extended-duration" options, signalling that the next RA tranche may carve out separate pricing for assets beyond four hours.

If California is nudging duration upward by modelling, Texas is doing so by arithmetic. ERCOT's February 2025 Effective Load Carrying Capability (ELCC) study mapped how much dependable capacity a battery storage system actually contributes under stress. The result was stark: 1-hour systems received only 13.7% credit during summer evenings, while 5-hour systems earned 68.2%. In winter the gap widened further, with 4- and 5-hour assets surpassing 90% credit as morning peaks stretched longer in cold snaps (see Figure 8).

Figure 8: Summer and Winter ELCC values by duration (2026 planning year)

Planners beyond California and Texas are arriving at the same destination, and the road map is easy to read. A November 2024 NREL study shows that stepping from 4- to 6-hour storage roughly doubles marginal capacity credit in every US region, while 1-hour batteries offer little dependable value [2]. That analysis is already edging into policy as NYISO's latest roadmap proposes lifting its Special Case Resource minimum from four to six hours to cover longer peak events [3]. With PJM, MISO, and other grids working off the same reliability pressures, it would be no surprise to see their stakeholder groups roll out similar duration-weighted rules in the next filing cycle.

Duration is no longer a nice-to-have. It is increasingly a precondition for capacity credit, contract awards, and even basic bankability. Moving from one to four hours still adds about 35-45% to capital cost, but a single tariff product or accreditation bump can earn that back in the first contract term. Deal teams now treat augmentability, pad space, DC oversizing and modular chemistry as core diligence items, right alongside offtake strength and warranty terms.

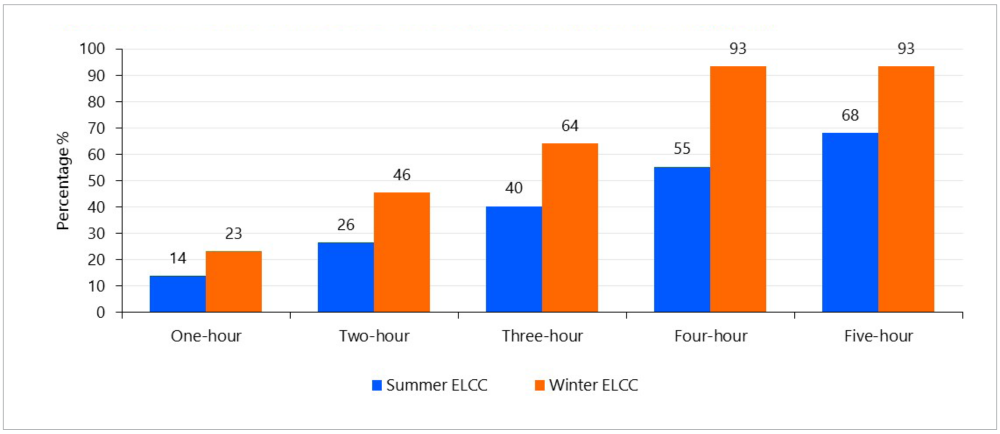


Figure 8. Summer and winter ELCC values by duration (2026 planning year). Source: ERCOT Effective Load Carrying Capability Study (February 2025), Rabobank 2025

Location, congestion and the new gatekeepers

Batteries that earn today sit where the grid needs relief – nodes defined by congestion, scarcity and price spikes. Interconnection headroom and transmission topology decide which projects reach commercial operation and which languish in restudy, with no developer enthusiasm.

California: one zone attracts the lion's share – and the bottlenecks

Southern California still remains attractive to battery storage developers. As of April 2025, SP-15 hosts more than 51GW of storage requests, over three times the capacity queued in either ZP-26 or NP-15. The sheer weight of applications has forced CAISO to rewrite its interconnection rulebook. In response to FERC's Order 2023, CAISO's May 2025 tariff amendment now requires every new requester to prove 90% site control on Day One and 100% before signing a Large Generator Interconnection Agreement [4, 5]. Projects that miss the market drop to the back of the line. A parallel reform introduces a screening stage that ranks projects on viability and alignment with state resource plans before they enter full study.

History justifies the clampdown. As LBNL's Queued Up 2024 survey showed, only 12% of CAISO requests submitted between 2000 and 2018 reached commercial operation, the lowest build rate among US ISOs. Each late-stage withdrawal triggers restudies that delay the rest of the cluster, raising carrying costs and eroding tax-credit timing.

Investors now treat queue position and deliverability status as hard diligence gates, equal to offtake strength.

Transmission headroom is equally selective. CAISO's 2024-2025 Transmission Plan identifies US$4.8 billion in upgrades, but most come online after 2029, leaving near-term projects exposed to local congestion, especially around solar-heavy Kern and Fresno counties.

Texas: fast queues, slower electrons

ERCOT still moves projects from application to energisation in 18-30 months. Lightning speed by ISO standards. However, geography is beginning to narrow the fast lane. The 2024 ERCOT Constraints & Needs report lists the Tonkawa Switch – Morgan Creek 345kV path as the single most expensive constraint on the system, absorbing US$156 million in congestion rent between October 2023 and November 2024. The broader West Texas Export Interface booked US$148 million over the same period, and ERCOT's economic forecast shows rents rising to US$178 million in 2026 without new wires. Batteries sited behind those bottlenecks often clear into the real-time market but collect a discounted nodal price.

Houston, once considered congestion-proof, is not immune. Projected constraints in the North-Houston Interface reach US$46 million in annual congestion rent by 2026. ERCOT has endorsed a US$2.2 billion pipeline of upgrades, yet most will enter service after 2027, meaning today's queue will energise into tomorrow's pinch-points. Sponsors installing batteries on the load-side of a popular constraint are starting to price nodal basis risk the way wind developers priced curtailment a decade ago.

For developers and lenders, congestion risk now shapes deal terms as much as project size. Lenders are paying closer attention to site control, deliverability studies, and nodal-price hedging,

knowing that a project stuck behind a constraint can miss the very spreads its model assumed.

Policy exposure and political weather are driving storage risk

Regulation first pulled batteries onto the US grid; it now separates bankable projects from speculative ones. California and Texas illustrate two flavours of exposure: one market is tightening already-detailed mandates, the other is debating whether to impose them at all, while federal politics adds a moving ceiling over both.

California: selective gatekeeping, not new megawatt mandates

The CPUC's Mid-Term Reliability Procurement still requires utilities to procure 15.5GW of clean capacity between 2023 and 2028, with 4-hour lithium systems expected to deliver the bulk. What is changing is how selectively those megawatts pass through the gate. CAISO's latest interconnection reforms, filed to comply with FERC Order 2023, make land control and deliverability proof the first hurdle. Developers that clear the screen then face California's higher-level target – Senate Bill (SB) 100's mandate for 100% zero-carbon electricity by 2045 – which continues to steer long-range planning toward ever-deeper storage penetration.

The net effect: fewer speculative queue spots, stricter deliverability proof, and growing interest in eight-hour resources now highlighted in the CPUC's integrated-resource-plan (IRP) modelling. None of these shifts expands headline megawatts, but each makes missing a performance metric - SoC during a stress hour, or deliverability under a new transmission scenario - a capital event.

Texas: rules still in flux, politics on the horizon

Texas has so far rejected a capacity market, but politics in Austin keep throwing sparks. During the 2025 session, three Senate bills - SB 388, SB 715, and SB 819- recast "dispatchable" as the gold standard. SB 388 grabbed headlines as it would have required at least half of all future capacity additions to deliver through an emergency, a definition that favoured gas and 4-hour batteries while pushing wind, solar, and 1-hour storage to the sidelines. SB 715 and SB 819 reached for the same outcome by different levers, slapping firm-backup or permitting fees on anything that couldn't sustain four hours. Although the bills died in Congress, developers took the close Senate votes as warning shots, highlighting the pivoting sentiment in Texas politics.

Meanwhile, ERCOT is nudging the same behaviour with carrots: RTC in late-2025 and the 4-hour DRRS in 2026, reward duration and penalise 1-hour opportunism.

Credit stays, strings tighten

At the federal level, this year's Independence Day celebrations brought clarity. The One Big Beautiful Bill Act left the 30% standalone storage ITC, created by the Inflation Reduction Act (IRA), intact through 2032 – no phase downs, no haircut. The catch is provenance. Starting in 2028, battery cells or packs with more than 30% "foreign-entity-of-concern" (FEOC) content lose the credit, and the 15% Section 301 tariff reinstated in May for Chinese lithium-ion cells remains in force. Tax equity is safe, but only for projects that can document an increasingly domestic supply chain.

Policy still leaves plenty of runway for storage, but the path isn't straight anymore. Anyone building or financing battery storage projects under these policy crosswinds now spends as much time following committee hearings and tariff dockets as they do watching price curves.

Discipline can make or break battery economics

The question for storage assets has shifted from, "Can the BESS project make money?" to, "Can it keep that revenue once SoC rules, outage penalties, insurance costs and degradation kick in?" Operational discipline now drives the gap between a deal that meets pro-forma and one that backpedals on covenants.

CAISO has required 4-hour batteries to hold a minimum reserve going into the evening ramp. The rule was supposed to sunset in 2024; instead, the ISO extended it through 2026 while it evaluates longer-term reliability options. The extension means storage resources must hold energy through the late afternoon peak with a preset charge margin or face potential bidding restrictions and availability penalties.

At the same time, availability risk is widening. CAISO's Q4 2024 Market Issues & Performance Report shows battery outages, planned and forced, rose 26% Y-o-Y, reflecting both rapid fleet expansion and longer downtimes for fire-safety retrofits. The most public reminder came on January 2025, when a thermal runaway event at Vistra's 300MW Moss Landing unit forced a three-month outage and community air-quality monitoring. While no injuries occurred, the incident hardened lender and insurer attitudes overnight. Verisk – Munich Re highlight tighter underwriting criteria for lithium projects lacking dedicated setbacks or advanced suppression.

Performance penalties compound those cost pressures. In a typical CAISO 4-hour Resource Adequacy contract, a single missed dispatch during a system-stress hour can forfeit an entire month of capacity payments. An outcome that now carries more weight than day-ahead spread assumptions in many debt models. Sponsors respond by investing in redundant battery-management telemetry, automated SoC forecasting, and additional fire-suppression layers that push EPC budgets up by 2-3% but protect far larger revenue streams.

Texas presents a different operational gauntlet. ERCOT's merchant batteries cycle more frequently, often three to four times per day during shoulder seasons, to capture brief price spikes that still emerge between solar oversupply and evening peaks. High-cycle operation accelerates degradation. Lithium iron phosphate (LFP) packs rated at 10,000 cycles see usable energy fall below 80% of nameplate in seven years under ERCOT's dispatch pattern, compared with ten years in CAISO's less frenetic market, according to performance warranties filed with two recent interconnection agreements. That degradation matters because ERCOT's forthcoming DRRS imposes a 4-hour continuous-discharge requirement. Sponsors that fall short risk losing DRRS eligibility unless they augment mid-life with new modules.

In a market where spreads compress faster than projects retire, operational proof is becoming the last lever left to protect asset value.

Strategic outlook: five signals investors should track next

Battery storage's first phase was a land-grab for megawatts. The second is proving to be a contest of selective discipline. Together, California and Texas host roughly 60% of all US grid-connected capacity, offering a preview of what the rest of the country will soon confront. From their experience, five strategic signals stand out.

Duration premiums harden quickly once price spikes fade. ERCOT's ELCC tables already value 5-hour systems at nearly five times the dependable capacity of 1-hour units; CPUC modelling now assumes 8-hour resources enter by 2030. Markets that still reward 1-hour batteries are living on borrowed time.

Deliverability trumps queue position. CAISO's viability screen and Texas' looming congestion bottlenecks mean a smaller, well-sited project can secure cheaper capital than a larger asset stuck behind a restudy or constraint.

Rule-defined revenues outlast merchant spreads. 4-hour Resource Adequacy in California and the forthcoming 4-hour DRRS product in Texas have replaced opportunistic arbitrage as the anchor cash flow. Future markets—PJM's capacity reforms, MISO's seasonal accreditation—are heading the same way.

Operational discipline is no longer optional. A single missed stress-hour dispatch can wipe out a month of RA payments; a thermal event can raise insurance costs across an entire portfolio. Lenders now treat SoC telemetry, fire-suppression audits, and augmentation reserves as gating items, not nice-to-haves.

Policy risk is a two-sided coin. The 'One, Big, Beautiful Bill Act' kept the ITC for storage but tightened the FEOC rules; state legislatures can pivot from laissez-faire to duration mandates in one session.

Hedging that volatility through flexible design, staged capex, and locational optionality will separate resilient balance sheets from speculative bets.

Put bluntly, the next phase belongs to those that match hours to need, electrons to the right node, and operations to ever-stricter rulebooks, before the rules tighten further. ■

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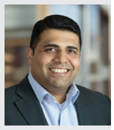

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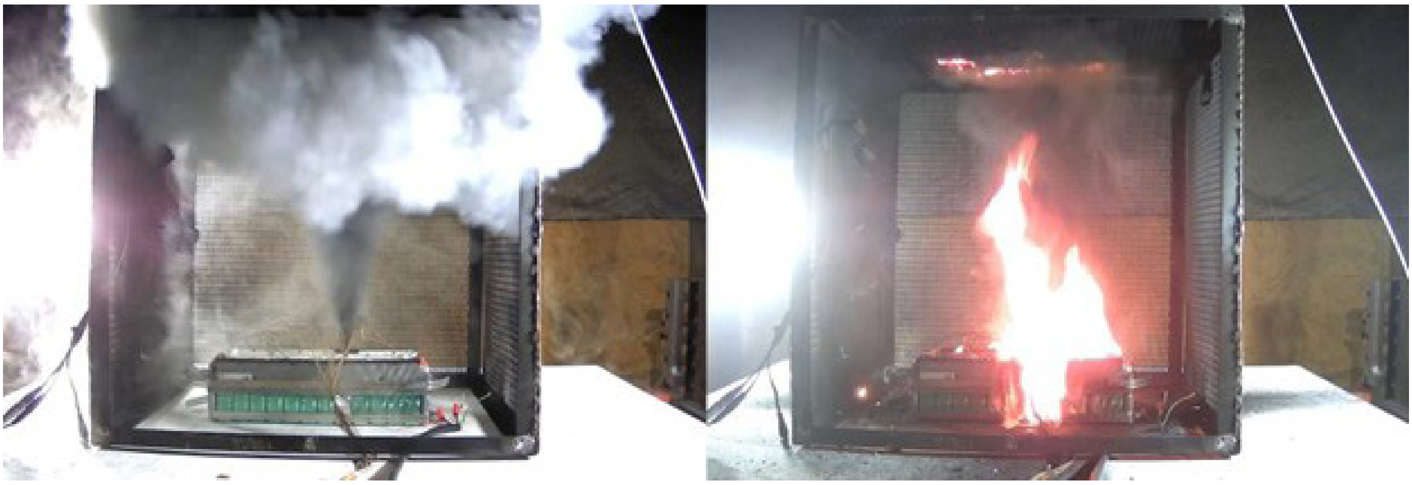
Enhancing fire safety in lithium-ion energy storage: understanding risks, chemistry and standards

Battery safety | Fire safety has become a key concern for the battery energy storage sector. Drew Bandhauer examines how changes in lithium-ion battery chemistries help manage fire risk and how industry standards are evolving in step with technological advances



Credit: UL Research Institutes

Li-ion module undergoing abuse/ignition testing, smoking on the left and flaming on the right

Exploring the critical topic of fire safety in battery energy storage systems (BESS) highlights the advancements in lithium-ion technology safety. As these systems become increasingly prevalent, understanding how they operate is key to harnessing their full potential safely and efficiently. By examining their chemistry and historical development, we can proactively advance fire safety measures, ensuring these technologies remain both effective and secure.

Key insights include:

- **Understanding BESS safety:** Identifying factors that could impact safety, allowing for proactive management and prevention
- **Comparison of battery chemistries:** Evaluating different battery chemistries to identify those that offer the safest and most effective solutions for various applications
- **Exploring current standards and emerging technologies:** Investigating existing standards and cutting-edge technologies that enhance safety and efficiency

Understanding BESS safety: managing thermal runaway

Thermal runaway occurs when a battery cell or module experiences mechanical or electrochemical stress, leading to short-circuiting, high current flow and elevated temperatures. This heat can spread rapidly, causing a "runaway" effect.

The key signs of thermal runaway include venting, which is the ejection of hot gases from the cell (see Figure 1). Smoking is often the first visible sign of a problem, as shown in the main image. Flaming, which typically follows smoking, indicates a more severe issue (also see main image).

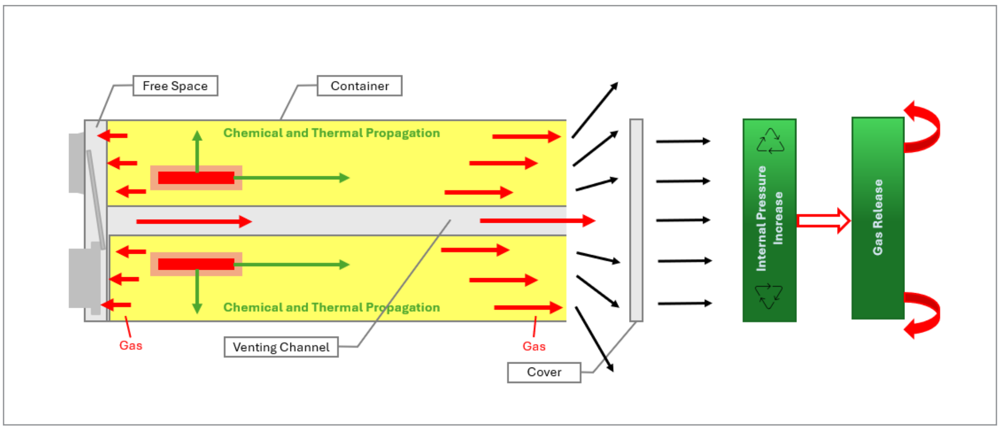


Figure 1. Lithium cylindrical cell venting using a terminal plate

Ensuring safe operation is essential, and proactive measures are key to managing potential failures safely. Today's original equipment manufacturer (OEM) battery systems are equipped with advanced safety features that prevent conditions such as overcurrent and overvoltage, critical factors that can lead to system failure.

Robust quality control processes and advancements in battery technology have significantly reduced concerns about thermal runaway. The solid electro-

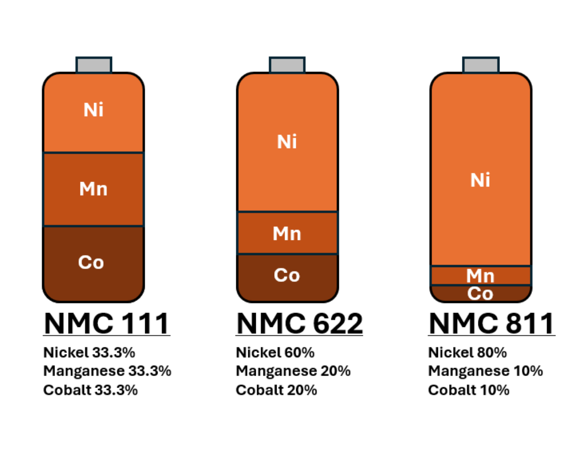


Figure 2. Composition differences in NMC battery chemistry

lyte interphase (SEI) layer plays a vital role in battery performance by preventing electrolyte decomposition. A well-formed SEI layer, along with regular maintenance and monitoring, can extend the battery's lifespan by up to 25%.

Additionally, technological innovations and rigorous safety standards continue to enhance the reliability of BESS. These advancements include state-of-the-art monitoring systems that detect early signs of potential issues, proactive and reactive ventilation to relieve pressure buildup and improved insulation between components to limit the spread of heat and fire. Improved cooling methods, such as liquid cooling, also help manage heat in a system to prevent thermal runaway.

With these layered protections and ongoing innovation, today's BESS solutions are safer, more resilient and well-equipped to meet growing energy demands with confidence.

Comparison of battery chemistries

Li-ion battery chemistry has evolved over the past 50 years, beginning with specialised applications in space and defence. Non-rechargeable lithium batteries (primary lithium) were soon adopted in both industrial and consumer markets, while rechargeable lithium batteries (secondary lithium) steadily gained prominence.

In the 2010s, with the growth of utility-scale energy storage in the US, nickel manganese cobalt (NMC) chemistry became predominant. Nickel cobalt aluminum (NCA) chemistry held a smaller market share. Within NMC, different compositions were used: higher cobalt content enhanced performance and thermal stability, while higher nickel content reduced costs but affected performance and stability.

Within NMC, various formulations emerged: higher cobalt content improved performance and thermal stability, while higher nickel content reduced costs but introduced greater performance and stability trade-offs.

Thermal event behaviour per chemistry

NMC batteries were commonly deployed before the development of modern safety standards, such as NFPA 855 and UL 9540A. As these standards were adopted, the industry transitioned swiftly to LFP chemistry, attracted by its lower cost and superior thermal performance.

LFP batteries exhibit a lower flash point and heating rate compared to NMC or NCA chemistries, leading to more favourable results in large-scale fire tests. In contrast, NMC and NCA systems often require additional safety measures—such as enhanced fire barriers or suppression systems—to mitigate thermal event risks.

As safety standards have advanced, so too has LFP technology. Its improved performance and enhanced safety profile have made it the leading choice for energy storage applications, supporting a safer and more reliable energy infrastructure.

Current standards and emerging technologies

Between 2018 and 2023, significant advancements in BESS safety practices have been achieved, driven by the adoption of more stringent fire safety standards for energy storage systems.

Key among these is:

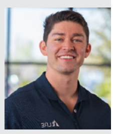
- **UL 9540:** This certification dictates the overall design for the entire system, ensuring compliance in all facets of the BESS, electrical, mechanical, environmental, and system safety.
- **UL 9540A:** This certification involves tests at the cell, module, rack/unit, and large-scale levels by inducing thermal runaway to ensure no propagation to adjacent units.
- **NFPA 855:** The primary fire standard guiding BESS site design and installation, supported by critical sub-chapters, including:
  - **NFPA 68:** This standard provides guidelines for designing and installing deflagration venting systems to protect buildings and equipment by safely relieving pressure from rapid combustion events. These vents are reactive to a thermal runaway system
  - **NFPA 69:** This standard outlines the design and implementation of systems and methods to prevent explosions in equipment and buildings, focusing on reducing the likelihood of hazardous combustion events through active ventilation and pressure relief
  - **NFPA 72:** Code outlining safety regulations for smoke detectors, alarm signalling devices, pull stations, heat detectors, fire alarm control panels, and related requirements

These standards establish essential requirements for BESS design, ensuring that thermal runaway events are confined within enclosures, preventing their spread and effectively mitigating the risk of uncontrolled fires, thereby significantly enhancing site safety.

Emerging technologies such as solid-state and non-lithium batteries are paving the way for safer and more sustainable alternatives, including non-flammable and non-toxic solutions. Non-lithium technologies such as sodium-ion might be poised to replace Li-ion in the same way NMC was replaced in the late 2010s, offering a safer and cheaper alternative and marking a transformative shift in the industry.

The commitment to developing and adopting these technologies reflects an industry-wide dedication to safety, sustainability and long-term resilience. Integrating next-generation solutions strengthens BESS's reliability while advancing a cleaner and more secure energy future. As demand for storage grows, BESS is well-positioned to play a foundational role in modern energy infrastructure—minimising risks, maximising performance and enabling a future that is both safe and sustainable.

Author



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From stability to volatility: rethinking performance management in today's changing electricity markets

Digital twins | As hybridisation and changing grid and market conditions redefine the scope of asset performance management, Anouk Hut looks at the growing importance of physics-based modelling and integrated digital infrastructure

Credit: Eneco

Congested grids, frequent curtailment, hybridisation and rapidly shifting market dynamics have made asset performance management far more complex than it used to be. Where increased energy production once guaranteed higher revenue, today it can actually be more profitable to shut down production entirely to avoid exposure to negative pricing. If curtailment isn't a challenge for you yet, it soon will be. And if you're still relying on classic performance metrics, like the performance ratio (PR) or ASTM E2848-based evaluations, you're likely getting an incomplete, even misleading, view of your plant's true performance. It's time to rethink how we assess and optimise PV plant performance in this new, market-driven reality.

The hybrid reality: why asset performance management must evolve

Not long ago, you were either managing photovoltaics (PV) or wind power. Today, chances are you're dealing with both, plus battery energy storage systems (BESS), often integrated within the same project. Hybridisation is no longer an exception; it's become the industry standard, especially in regions battling grid congestion.

Grid connection points are being reengineered with added storage capacity to help mitigate curtailment risks and navigate exposure to fluctuating market prices. This trend extends beyond PV: more and more wind farms are being hybridised with PV and BESS to maximise asset utilisation and revenue flexibility.

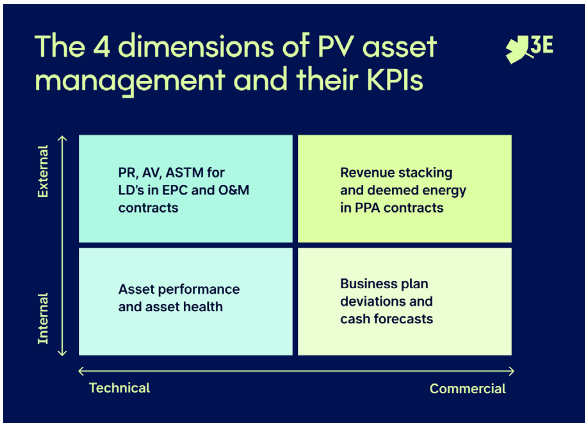
Hybridisation of technologies is just one factor creating greater complexity in renewables asset performance management

In fact, hybridisation is the fastest way to get new power projects connected to the grid [1]: over 20GW of PV projects in the US include BESS [2], and over 30GW of hybrid projects are planned or in development in Europe, according to SolarPower Europe.

However, with this flexibility comes a new level of complexity:

- More intricate system design and integration challenges
- Expanded IT/OT infrastructure requirements
- Greater coordination across multiple internal and external stakeholders
- New operational workflows impacting both technical and financial teams

In this article, we propose an alternative methodology for structuring interactions with both internal and external stake-



holders involved in managing a curtailed portfolio: leveraging a physics-based digital twin as the reference model. This approach offers more accurate, transparent and actionable insights for technical performance assessment, financial forecasting and ensuring contractual compliance.

You can't optimise what you can't trust: the new scope of asset performance

As plants become exposed to dynamic market and grid conditions, increasingly complex control mechanisms and a mix of technologies, the scope of an asset manager broadens.

This broadening is not just technical; it includes managing a web of internal and external stakeholder interfaces, spanning financial performance, technical KPIs, contract negotiation and grid coordination.

In the following sections, we'll break down how this changing context affects PV asset management across four key dimensions: technical and commercial, both at the internal company level and externally, regarding, for example, grid, O&M and EPC contractual arrangements.

Technical KPIs (internal): hybridisation and curtailment blur visibility on underperformance

Traditional PV performance KPIs typically centre around irradiation, capacity and system output. Intentional power control events, triggered by grid or market signals, are often not included in the equation. When ignored, these events can misleadingly appear as plant underperformance. In Europe, the PR has long been the dominant KPI, comparing actual energy output to expected output based on solar irradiation. Curtailment reduces actual output and therefore negatively impacts PR. In the United States, standards by NREL and ASTM too, are often ill-equipped to address external variability and operational diversity, leading to inaccurate performance assessments.

But the issue goes deeper: under frequent curtailment, operators may lose visibility into the true health of their assets. DC-side issues, such as degradation or string-level faults, can go unnoticed, leading to long-term performance losses.

While the industry has introduced exclusion periods in contracts to account for curtailment, this approach obscures a clear view of performance. In high-curtailment countries like the Netherlands, where grid congestion is common, these exclusions become frequent, resulting in unreliable PRs, increased manual work to differentiate between curtailment and actual underperformance, and burdensome reporting.

Furthermore, standard availability KPIs may unintentionally discourage optimal maintenance scheduling. For instance, they fail to incentivise performing O&M during negative price periods, precisely when such interventions would be least disruptive and most cost-effective. This disconnect between operational and market incentives underscores the need to redefine availability metrics.

Commercial KPIs (internal): business plan parameters no longer meet expectations

How long did it take to build your 2025 energy budget? Across the industry, crafting a realistic business plan has become more difficult. Shifting subsidy schemes, rising market exposure and evolving grid conditions have added volatility and reduced predictability. Layer in hybridisation, and it's safe to say financial forecasting today involves more headaches than it did five years ago.

In addition, revenue is no longer derived from a single, predictable stream. With the decline of fixed PPAs, asset owners now rely on revenue stacking, combining spot market sales, imbalance markets and grid services. Each stream responds differently to market or curtailment signals, making forecasting increasingly complex.

These dynamics complicate the estimation of long-term revenues and financial KPIs like the investment performance ratio (IPR) and operating performance ratio (OPR). If these parameters don't accurately reflect market realities, the result is unrealistic objectives, missed KPIs, ROI disappointments and a distorted view of performance.

Business plans must, therefore, evolve into living models that are flexible and regularly updated to reflect the ever-changing energy landscape. Static annual budgets are no longer sufficient for sound asset management or transparent investor communication.

Technical KPIs (external): lengthy liquidated damages discussions

Let's extend these internal challenges to external stakeholders: the performance landscape is shifting, and this has direct implications for contractual agreements. Take traditional EPC and O&M contracts, for example. These often specify guaranteed PR and availability, energy yield targets and, more recently, response and resolution times.

Traditional EPC contracts will include performance guarantees (PR or ASTM-based) that are derived from a yield model of the actual design of the asset. In this yield model, the presence of curtailment conditions is mostly not taken into account, resulting in performance guarantees that are not really representative of the actual operating conditions of the plant. Common practice in EPC contracts is to exclude curtailment periods from performance guarantee calculations. This can, however, result in the evaluation of the performance guarantees during limited periods that again can be less representative of the long-term operating meteorological conditions for which the performance guarantee was defined in the design and contracting phase: e.g. low irradiation conditions or start-up periods. The result is that the investor and EPC contractor start discussing liquidated damages and the end of the contract based on KPIs that merely represent the purpose of contractual guarantees and often end up in lengthy discussions on exclusions and actual performance. This drains energy and impacts on the relationship between buyer and supplier.

Similar situations can occur in O&M contracts with performance guarantees or availability formulas that don't take curtailment into account properly.

Commercial KPIs (external): merchant PPAs under curtailment

Plants must navigate the hybrid revenue landscape—partly regulated (e.g., grid balancing services) and partly unregulated (e.g., merchant PPAs). This brings new challenges for owners and investors alike:

- The predictability of revenue has sharply declined, leading to significantly more risk
- Grid and market dynamics now directly impact plant profitability
- Revenue models are fragmented between regulated and unregulated sources

On the commercial side, the asset manager holds a PPA contract to monetise the energy production of the asset. In comparison to fixed-price PPAs and feed-in tariffs, a lot has changed. The business model of the asset might be a complex revenue stack of grid services and power market services. Parameters that define the revenue model can range from spot market prices or other unregulated price sources to forecast accuracy or asset availability. Moreover, complex formulas are either part of the PPA agreement or of the grid access contract to define energy loss due to curtailment.

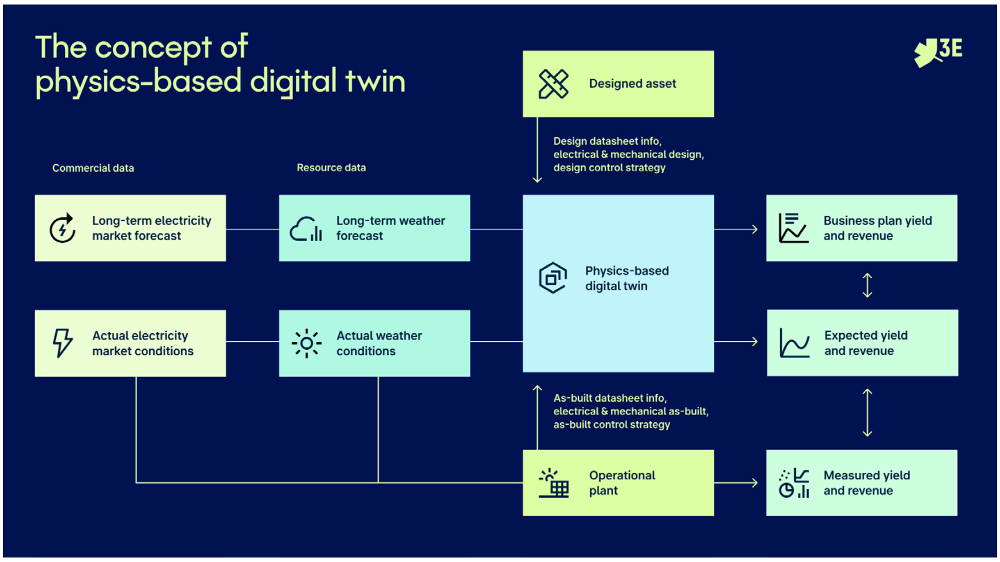
Summary & guide to the reader: classical KPIs don't work

Traditional KPIs, based on irradiation, yield and system availability, have long been used in technical monitoring and contractual frameworks. But they rely too heavily on idealised conditions, ignoring today's market dynamics and operational complexity.

This shift is redefining the scope of PV asset management. Previously, maximising yield was directly translated into financial gain. Today, that link is broken. Asset performance management must now shift from yield optimisation to revenue optimisation, while incorporating grid and market conditions.

In addition, KPIs must reflect the complex web of stakeholders, PPA counterparties, EPCs, grid operators, investors and internal teams, all of whom need performance metrics that are both technically accurate and easily interpretable. This demands a new generation of KPIs: aligned, transparent and tailored to real-world operations.

In the next section, we explore a four-step approach to implementing a physics-based performance model, designed to establish new, practical PV performance standards equipped for the current dynamics in the industry.



The concept of a physics-based digital twin

A new methodology for stakeholder interfaces using physics-based digital twin technology

A digital twin is a virtual representation of a physical asset that mirrors its expected behaviour across all stages of its lifecycle, from design and engineering to real-world operations.

In the design and engineering phase, a digital twin of a solar plant is used to simulate lifetime performance under typical conditions. This helps optimise system design and support business case modelling, much like what's done with PVSyst simulations.

What makes a digital twin powerful is its continuity: the same model can be carried forward into the operational phase. But instead of relying on historical weather data to predict long-term output, it now uses measured data, such as actual irradiance, temperature or wind, for recent periods. This enables a much more accurate calculation of expected performance under real conditions.

The model can also be enriched with additional layers of context. For example, data on extreme wind events can help assess tracker response, while curtailment records can refine energy output estimates. In this way, the digital twin evolves from a design tool into a dynamic performance benchmark, grounded in physics but tailored to real-world variability.

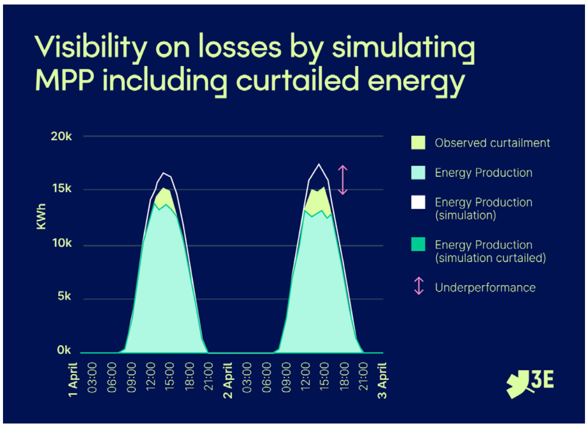
Step 1: selection of input parameters of the digital twin

A solid physics-based technical model of your plant remains the key element for detailed loss analytics. Especially in changing market conditions, a physics-based model is an enabler to keep visibility on performance and losses. Your digital twin model is defined by the technical configuration information of your asset, such as datasheet info of modules and inverters, system design information of arrays, trackers, cable sizes etc. It consists of a detailed overview of both the DC and AC sides of your plant, all devices and sensors, orientations, connections and relevant geographical data.

Besides the technical model, which is the basis for plant expected energy simulations, commercial elements are becoming more important to include from the design phase onwards. For the detailed technical model of the plant, this implies that the plant control expected operational modes and setpoints need to be included in the plant configuration. However, if you truly want to move from optimising technical performance to optimising revenue, it is key to also add business parameters in your model. Carefully consider all elements that can affect your expected revenue: market(s) data, forecasts and relevant regional regulations that affect your revenue stacking strategy.

Step 2: model continuity from design to operations

Bridging the gap between design modelling and operational performance management is not optional; it is essential. While traditionally treated as separate domains, aligning feasibility-phase modelling with operational-phase analytics is the only way to ensure continuous performance optimisation and revenue realisation across the asset's lifecycle. The digital twin model used during design – often built on long-term forecasts such as TMY weather data or historical market



Visibility on losses by simulating MPP, including curtailed energy

assumptions – should not be retired at commissioning. Instead, it should evolve. In the operational phase, this model must be fed with real-time inputs: actual weather conditions, live power market pricing and prevailing grid constraints. This shift enables the twin to simulate expected asset behaviour under actual operating conditions and flag deviations from it. By using the same modelling framework across both phases, asset owners gain a feedback loop between strategy and reality, refining business case assumptions, surfacing real-time losses, and informing tactical decisions in O&M, dispatch and commercial strategy. This is the foundation of true, data-driven asset performance management.

Let's take the curtailment context as an example again. Frequent curtailment can hide underperformances if there is no reference model that provides a simulated curtailed MPP, to which you can compare your operational data. If you want to optimise revenue throughout the asset, it is important to have a quantified view on the impact of curtailment on your business plan, cash flow planning, maintenance planning, commercial agreements, market-specific regulations and fines. This can only be done if you have the right parameters in your design and operational models, allowing you to simulate detailed curtailment losses and other performance losses, and using these insights to reflect back on your business plan and operations.

The impact of including commercial parameters in your model from the start reaches further than just covering frequent curtailment use cases. It can unlock prioritisation based on lost revenue instead of lost yield, offer calculations of revenue-based availability and provide assessments of your plant's profitability in a certain market context, for example by including capture rates or specific subsidy schemes related to negative price hours compensation. It's the next step that asset performance management platforms need to take, enabling the transition from performance optimisation to revenue optimisation in today's market context.

Step 3: stakeholder-based reporting to satisfy SLAs

Once you have your model in place in your day-to-day operation, it can now be the foundation for creating stakeholder reports. Often, there is no one-size-fits-all: different stakeholders have different needs. Whether you report based on Excel, PowerBI, Salesforce or any other tool, a detailed model is key for interoperability of these systems to maintain data quality and transparency.

Let's go back to the four categories mentioned at the start of this article: technical and commercial impact, both internally and externally. Below you'll find recommendations on what to include in each of these reports.

Technical KPIs (internal)

Energy performance index. In complex environments, it is clear that traditional formulas – for example a PR in all its flavours – can fall short and hide performance losses. A digital twin enables simulation of the expected behaviour of your plant, which can then be used as a reference to compare with the measured production data.

The result of this comparison is an indicator that is gaining popularity: the energy performance index (EPI) [3]. EPI-based analytics are more sensitive to detect underperformance and account for external factors such as seasonality of weather and curtailment events. As this sensitivity is only valid in the case of a strong simulation model, it is important that the EPI is built according to industry's best practices, such as the IEC TS 61724-3 Photovoltaic system performance - Part 3: Energy evaluation method.

A strong digital twin can be the backbone to model expected behaviour and provide an EPI for wind and BESS as well, either separate or combined in a hybrid EPI.

Curtailment loss and other losses. If not managed correctly, curtailment affects visibility on performance. When output is lower than expected, it is key to distinguish curtailment events from equipment faults, soiling, or tracker issues. Simulating the expected MPP and estimated MPP (including curtailment quantification) allows for the separation of curtailment from other losses.

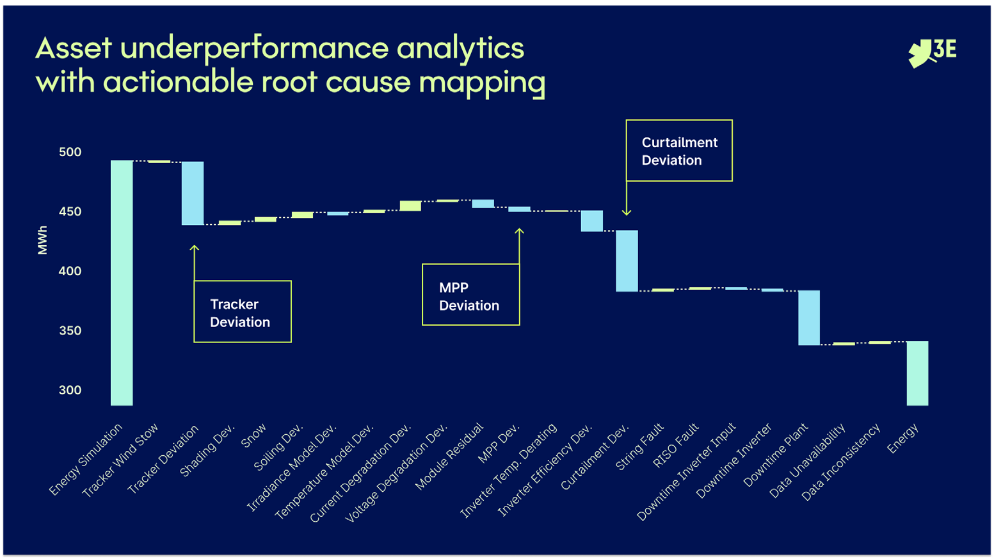
This can be achieved by modelling inverter-level status codes, inverter- and plant level control setpoints and additional techniques to detect curtailment in case these are not available.

In practice, this leads to two different simulations that can then be used to calculate:

- Energy Performance Index
- Energy Performance Index (Simulation Curtailed)

In the context of frequent curtailment, it is advised to take the Energy Performance Index (Simulation Curtailed) as a reference. If it's below 100, there are other underperformances that can be studied using an automated loss identification tool that generates a loss waterfall. These losses can then be linked back to the business plan and financial parameters of the site, giving insight into the potential

Asset underperformance analytics with root-cause mapping



revenue loss and "sweet spot" on when to take recoverable action.

Hybrid KPIs. Hybrid plants demand more than isolated performance metrics; they require a unified digital twin model capable of accurately simulating each technology individually and, critically, the energy flows and control logic between them. Without this, operators are left with fragmented insights that obscure key interdependencies. The lack of an integrated view leads to missed opportunities in planning maintenance, resolving electrical mismatches, and optimising hybrid dispatch. More importantly, it jeopardises high-impact KPIs such as EPC performance guarantees, deemed energy compliance and forecast accuracy. As hybridisation increases, the cost of misalignment grows, both technically and commercially.

Commercial KPIs (internal): short- and long-term business plan

The times of a simple P50 and P90 based on historical weather data to assess the next 20 years of potential revenue are over. While there are differences per country, there is a general trend towards more market exposure, new revenue streams, and penalties. Even if you currently work with a fixed feed-in tariff, limited curtailment and no market imbalance, chances are that this will change within the asset's lifetime and thus needs to be reflected in the long-term business plan.

Business plan requirements change instead of hiding them in an Excel file, ensure that you have live access to clean and standardised KPIs that reflect whether you are on track or not. For the year-to-year follow-up and stakeholder communication, in addition to market specific regulations and revenue streams it is important to track capture prices, capture rates, market prices and negative price hours. For the technical performance assessment in a business plan, the Energy Performance Index (Curtailed) can also be included as an alternative for simpler traditional formulas. In the case of hybrid plants, it is important to include a reflection on the financial optimisation strategy of the plant, since there is always a trade-off between degradation costs and short-term financial opportunities.

Technical KPIs (external)

It seems like every utility-scale plant has its own PR formula and exclusion rules nowadays: performance KPIs and SLAs in contracts are becoming more complex, variable and linked to revenue loss instead of uptime. For any discussions around service violations or liquidated damages, a physics-based model offers insights that are detailed, explainable and still work in complex conditions.

We see more and more investors, independent engineers and EPC companies aligning on a project basis to use a physics-based digital twin model to assess performance during PAC and FAC, as it is in their mutual interest to align on meaningful KPIs and avoid lengthy discussions about liquidated damages that do not relate to real business value.

Of course, the inclusion of a yield model is not apparent in every contract, and traditional formulas will continue to play their part. When deviations occur, it is important to understand and explain them and provide a detailed loss categorisation that can separate curtailment events from other performance issues.

Commercial KPIs (external)

Standardised energy calculations. In terms of commercial agreements, it's all about expected yield. A physics-based model can provide you with the right insights on curtailment quantification and availabilities affected by internal and external causes, which can be used in communication and contracts with power and grid stakeholders.

On the one hand, it will provide you with an automated and standardised way of calculating expected energy. This standardisation is becoming increasingly urgent with the rise of curtailment. Instead of drowning in a variety of custom formulas and agreements, the industry has to work together to agree upon a solution that automates energy calculations that can be used in contractual agreements. A first step towards that agreement is the IEC standard IEC 61724-3, as mentioned in the Energy Performance Index section above, clarifying how to accurately quantify curtailment, including its source and other causes. This states:

"In the case of curtailment because of external requirement limiting the update of grid that was accounted for by the original model, then the model should correct for this accurately. The expected energy should be calculated in the same way." […] If the external requirement for limiting the uptake of the grid differs from the original model (either requiring no connection to the grid or an input to the grid that is less than what was originally modelled), the difference between the two external requirements shall be documented as a time of unavailability if the new external requirement is reduced".

Availability and outage reporting. Commercial KPIs should enable accurate insights related to energy availability. As discussed in the problem statement, purely basing your reporting on exclusion periods does not give sufficient context to the PPA party in case there is frequent curtailment, and is often not accepted anymore. As power control sources and setpoint variations become more extensive, it is key to automate these insights to avoid spending days in Excel to verify and categorise every reduced power event. Asset performance management systems can play a critical role here since they have the input from:

- all relevant (expected) energy and weather data,
- any alarm or event on site,
- market, grid and business plan data
- power control sources (grid, trader, EMS, PPC, BMS, inverter portals, …),
- manual input on plant specifics, such as planned maintenance, renovations, …

loss analytics breakdown including the root cause of the event (component breakdown, grid curtailment, soiling, degradation, RISO faults, …)

Step 4: driving change: the need for a new way of looking at performance management

For an accurate view of performance, you should always simulate actual weather and grid conditions to have the most accurate expected line in the background, which is still missing in most contracts or analysis today.

Investing in a physics-based simulation model will save you time because it automates your performance insights and contractual reporting. It even allows you to simulate repowering, refinancing, and restructuring of PPAs. It requires upfront investment, though the barrier to change is lowering with new technology for automated onboarding at scale. However, technology is only one part of the story.

A significant effort lies in realising and evangelising the need for a new way of looking at performance management, both internally and externally. Change will happen more rapidly when all parties are putting their feet into the mud: from initial concept to end-of-life, from commercial to technical, from EPC to PPA.

Referral to IEC standards and other industry best practices, versioning and agreeing contractually on a yield model as the basis for discussion, significant steps can be made towards real performance management and revenue optimisation.

Use Case: Performance Management in a Hybrid Portfolio Portfolio with Grid Constraints

In the Dutch energy landscape, where grid congestion, negative price periods, and rapid hybridisation are increasingly common, new operational and performance management challenges are emerging. This case study examines a utility-scale hybrid project in the Netherlands where an independent power producer (IPP) integrated a PV system into an existing wind plant, all under a constrained grid connection.

Context: high-capacity hybridisation under a limited grid connection

The hybrid site combines an existing 70MW wind installation with a newly added 50MWp PV system. Despite a total installed capacity of 120MW, the plant is restricted to a 60MW grid connection point. This constraint is compounded by frequent grid congestion, near-daily curtailment, and exposure to negative electricity prices. Nevertheless, for asset owners, hybridisation offered a compelling business case: diversify revenue streams, mitigate market risks, and maximise infrastructure utilisation.

Challenge: traditional KPIs become obsolete under continuous curtailment

Under typical operational conditions, metrics such as PR and availability serve as standard indicators of plant health and performance. However, in this hybrid setup, curtailment is not an exception; it is the norm. Grid-imposed power setpoints are rarely at 100%, leading to the exclusion of large portions of data from PR calculations. As a result, conventional KPIs either provide misleading signals or fail to populate entirely.

Further complicating the issue, curtailment periods mask other performance degradations, such as string-level faults, excessive soiling, or inverter errors, which go undetected due to lack of effective benchmarking.

Solution: a physics-based digital twin for realistic performance assessment

To address these limitations, the operator deployed a physics-based digital twin model of the hybrid plant. Originally developed during the design and engineering phase, this model was adapted for operational use to simulate expected plant behavior under real-world conditions, factoring actual measured weather data, curtailment setpoints, and market events.

Using this model, the team introduced the EPI, a next-generation performance metric that compares simulated (expected) production with actual output, even during curtailed periods. This allowed for:

- Accurate isolation and quantification of curtailment losses
- Identification of hidden, recoverable losses during curtailed operations
- Root-cause classification of underperformance, enabling targeted interventions

In this specific case, the simulation exposed an unexpectedly high degree of soiling—previously hidden by curtailed setpoints—prompting a revised, ROI-optimised cleaning schedule.

Operational transformation: adapting to a hybrid, market-driven reality

The deployment of a performance model was only one piece of the puzzle. The hybrid nature of the plant demanded broader changes to operational workflows and stakeholder alignment:

- **Alarm management:** Conventional "no production" alarms were reconfigured to account for curtailment logic, ensuring real asset issues remained visible without over-alerting
- **Enhanced digital twin configuration:** The model was enriched with grid and market data, allowing real-time monitoring of power control signals, market incentives, and dynamic tariff schemes
- **Integrated reporting frameworks:** Financial, technical, and contractual reports were redesigned to incorporate simulated energy baselines, curtailment-adjusted KPIs, and stakeholder-specific loss categorisations. This included grid and market setpoints, reactive power deviations, and regulatory compliance metrics

Results: improved transparency and performance recovery

Within the first quarter of implementation, the digital twin-enabled approach identified recoverable energy losses equating to approximately 2.3% of annual yield, primarily from undetected soiling and inverter inefficiencies. More critically, the plant operator was able to deliver clear, defensible performance reports to internal teams, regulators and investors, despite operating in a highly curtailed and volatile market environment.

This case underscores the limitations of classical PV KPIs in hybrid, market-exposed contexts and the growing importance of physics-based modelling and integrated digital infrastructure to manage asset performance in real time.

Conclusion

With changing grid and market conditions, traditional performance management methods have fallen short. Curtailment can hide visibility underperformance. A physics-based model is your reference for performance management under external conditions by simulating MPP and analysing deviations. It ensures visibility during curtailment. Moving away from formulas to a physics-based simulation model impacts internal and external technical and commercial agreements. ■

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Authors

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Don’t miss the moment: why we must scale long-duration energy storage now

Technology | Challenging times demand resilient energy solutions, and, as Julia Souder argues, now is the moment for long-duration energy storage to take its place as a key plank in the energy transition


Credit: Energy Dome

Rendering of LDES Council member Energy Dome’s 20MW/200MWh Ottana project in Sardinia, Italy, currently under construction

Flexibility and resilience aren’t optional—they’re essential. We’re in an era of energy complexity: record-high renewable deployment targets, surging demand from artificial intelligence and data centre growth, electrifying industries and increasing threats from climate extremes and geopolitical instability.

In times like these, certain truths become increasingly clear in resilient and reliable energy systems: flexibility is power.

Long-duration energy storage (LDES) is uniquely positioned to deliver both, yet today’s markets, policies, and investment mechanisms still fall short of enabling the scale we need, leaving energy systems at risk of losing critical societal and system-wide benefits.

We must move swiftly to:

1. Ramp up the LDES marketplace
2. Strengthen public-private financing frameworks, and
3. Accelerate supportive policy and regulatory action

Why should we care?

Because reaching net zero targets will happen, and the variability of renewables needs the energy-shifting power of LDES.

Because storms and weather patterns will only get more intense, and security of supply can be provided by LDES.

Because energy affordability is critical, and the deferment of curtailed energy and excess infrastructure, as well as congestion relief, saves money.

Because the new ways of generating and storing power and heat need new markets and revenue systems to capture benefits.

New energy demands require new storage thinking within all levels

Even though in the United States, policies are turning away support for renewables, a majority of governments around the world are racing to meet ambitious renewable energy targets – such as the 11TW of renewables by 2030 (IEA and IRENA). Now, post-COP29 and looking ahead to COP30, long-duration storage is receiving more attention alongside generation—most notably through global storage and grid infrastructure pledges.

Other than pumped hydro storage, most of the new storage currently deployed is short duration, designed for only minutes to a few hours of flexibility. That’s no longer enough.

We can’t solve today’s challenges with short duration alone

Short-duration energy storage is essential, but insufficient. For both thermal and electric grids, it falls short in these critical areas:

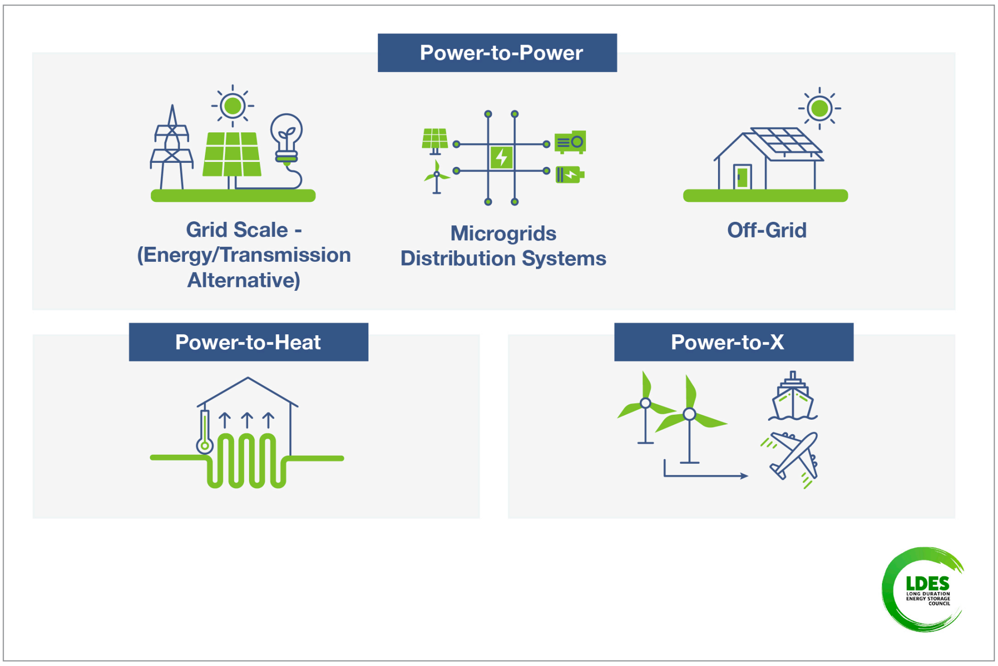
- **Limited duration**: Can’t support multi-day or seasonal imbalances
- **Reduced system resilience:** Fails to sustain energy access during extended outages or disruptions
- **Narrow applications:** Optimised for daily balancing, but not for industrial decarbonisation, grid congestion relief or long-term backup

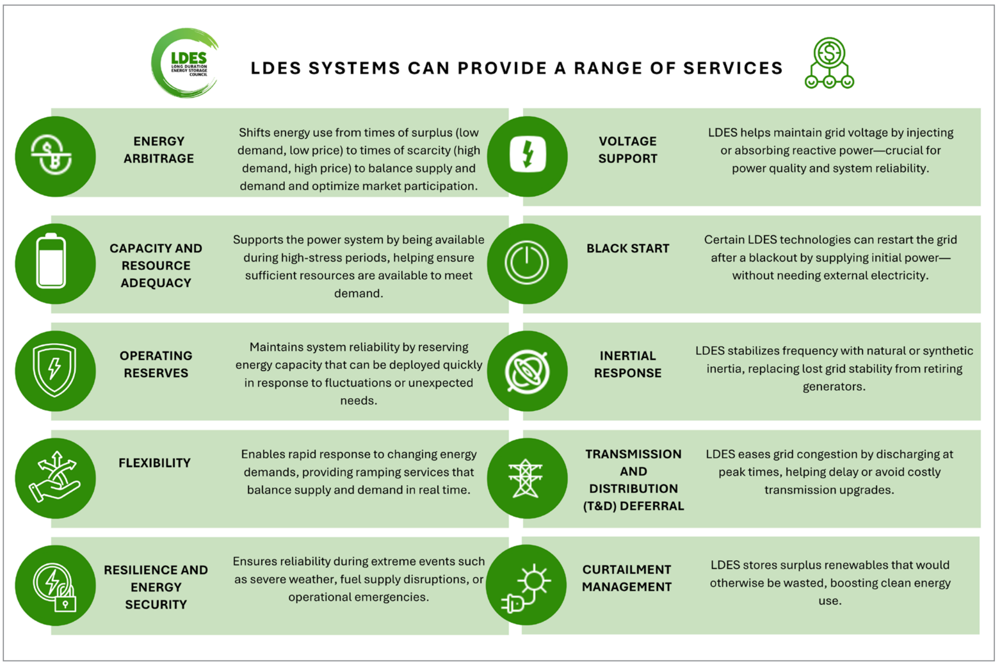
We need complementary solutions that can store and dispatch energy over days, weeks, and seasons. This is where LDES steps in.

LDES unlocks multiple revenue streams, decreases grid congestion, has a cross-sector impact and is a more efficient use of renewable energy. It’s more than a tool for utilities—it’s a system-wide enabler across industry,

What is LDES

Long-duration energy storage, defined as storing energy from eight hours to multiple days or even weeks, provides the missing link: firm, flexible and clean power that can be dispatched when it’s needed most, not just when the sun shines or the wind blows.





transport, buildings and fuels. The more we deploy and integrate these applications, the faster and cheaper our path to net zero becomes.

LDES is not a single technology—it's a family of solutions, including thermal, mechanical, electrochemical and chemical systems. What they share is a singular mission: to bridge the gap between variable supply and variable demand, over periods that short-duration batteries alone can't economically or technically address.

While many think of storage as simply saving electricity for later, LDES goes far beyond. What makes LDES a powerful solution is in how the stored power or heat is ultimately used, with applications often referred to as power-to-power, power-to-heat and power-to-X. Each application type is outlined here/below:

Figure 1. The many applications of long-duration energy storage; Figure 2. Some of the benefits of LDES. Source: Systemiq analysis for LDES Council

Long-duration energy storage can take several forms depending on how stored energy is ultimately used. Power-to-power refers to storing electricity and discharging it as electricity later. This approach supports grid balancing, peak shaving, renewable energy firming, seasonal backup and ensures grid stability during extreme weather.

Power-to-heat involves converting electricity into stored thermal energy. It's particularly useful for decarbonising industrial heat processes, enabling district heating systems and reducing reliance on natural gas.

Power-to-X stores energy as green molecules such as hydrogen, ammonia, or synthetic fuels. These can serve as industrial feedstocks, exportable clean fuels, or support more efficient operation of electrolysers. Each pathway expands the role of LDES beyond the grid, unlocking flexibility across sectors.

LDES as a strategic reserve for every nation

As geopolitical and climate shocks grow more frequent, every country needs a strategic energy reserve, and LDES is uniquely suited to play that role. LDES can provide clean, dispatchable energy over long durations and help countries weather blackouts, extreme heat or cold and supply chain disruptions. These are advantages that fossil-based reserves cannot offer as LDES is not a volatile fuel, but rather allows for energy to be stored, used and reused again and again.

LDES should be treated as critical national infrastructure, like emergency fuel stockpiles, water reservoirs or strategic grain stores. With the right policies, countries can build domestic clean energy reserves that enhance sovereignty, reduce import reliance and stabilise markets in times of crisis.

The real benefits: beyond renewables

The impact of LDES expands beyond decarbonisation; it enables an affordable, secure and resilient energy system. LDES acts as the shock absorber and stabiliser for energy systems, such as firming renewables, shifting surplus energy, replacing fossil fuel peakers and enhancing grid resilience.

And it's not just theoretical, look at the map of projects in Figures 4 & 5.

Globally, the LDES Council has tracked 360 projects, 43 of which are under construction, with the latest year of completion in 2032. There are hydro projects in LATAM, but not new pumped hydro storage.

Focusing on the United States, not only are diverse applications of LDES in construction or being deployed, but also new gigawatt factories.

LDES projects are already proving their worth, delivering value to grids, customers and communities, as many communities need LDES to strengthen their energy infrastructure as well as providing resilience. But this is just a handful of what is needed to scale. More needs to be done.

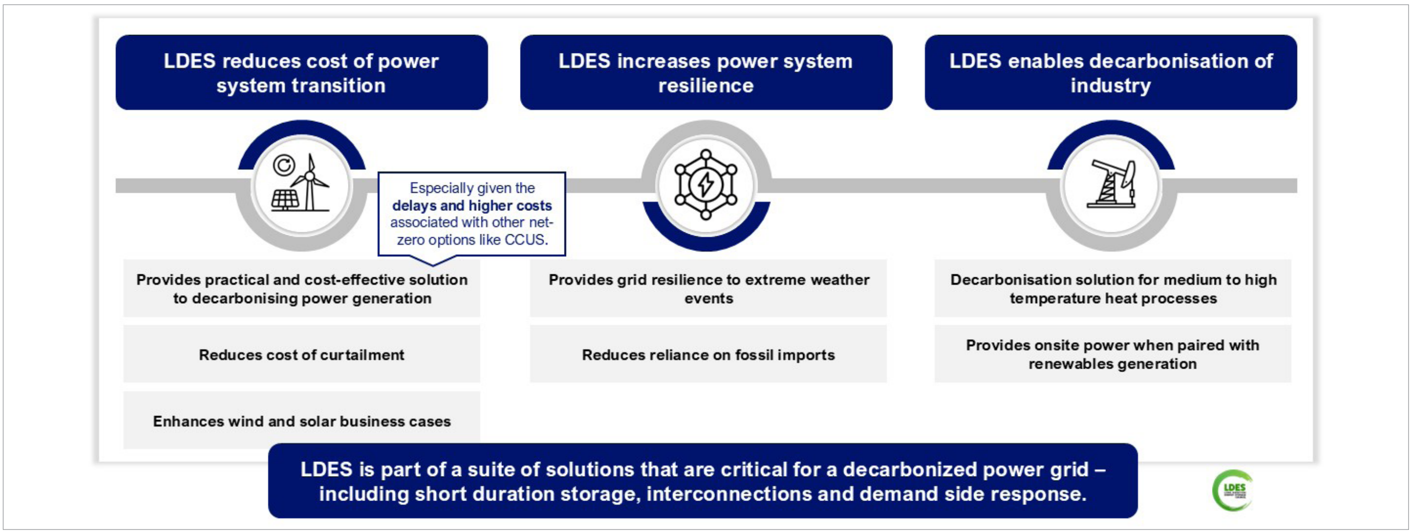


Figure 3. LDES can provide a wider range of services

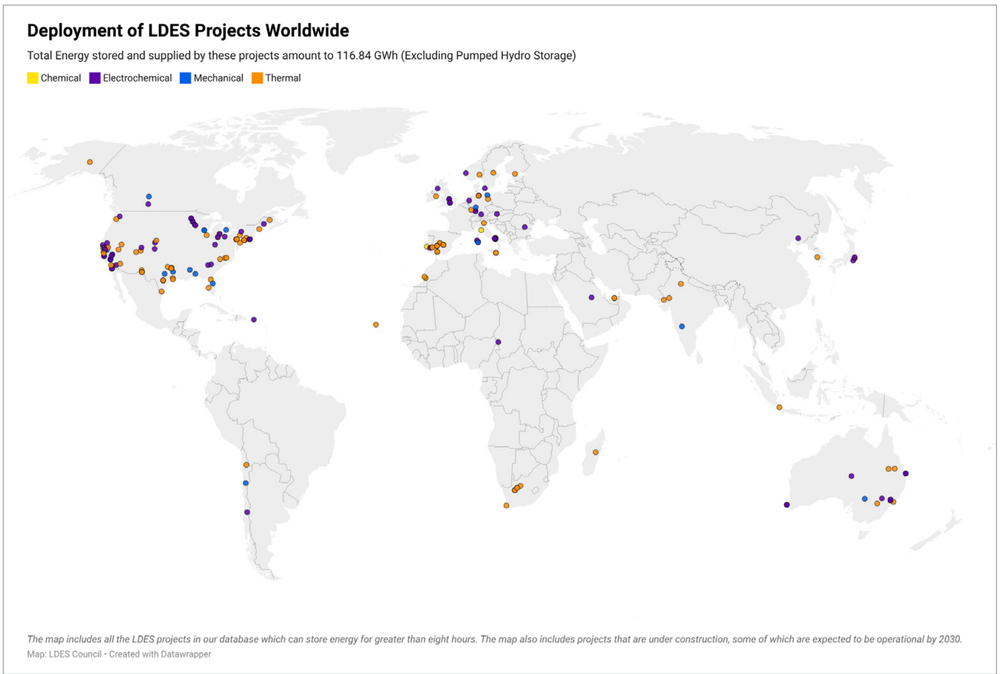


Figure 4. LDES projects around the word

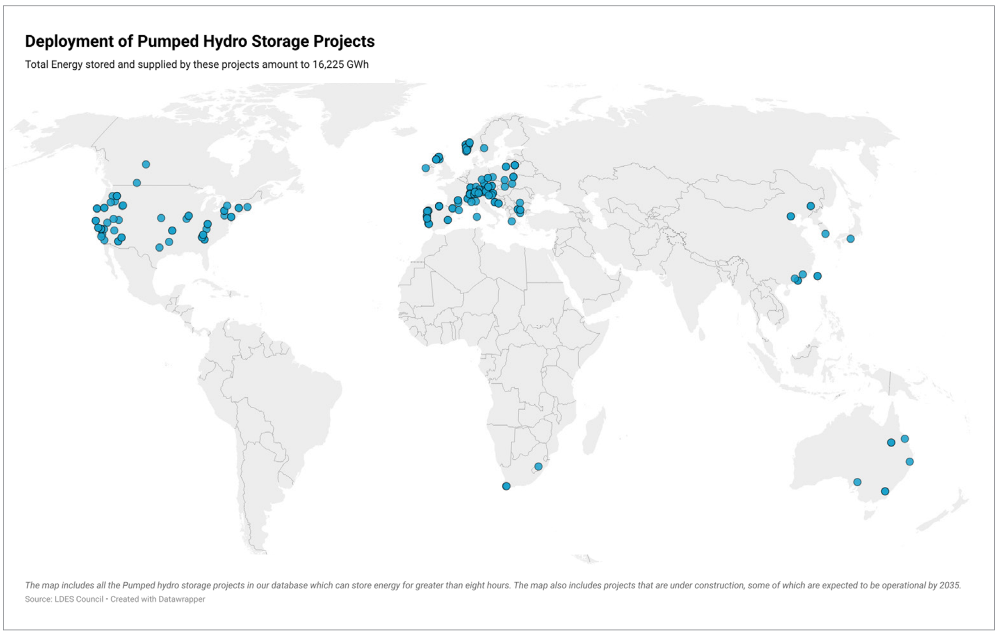


Fig 5. Pumped hydro projects worldwide collectively account for over 16GWh of storage capacity

Momentum is building—but gaps remain

- LDES Council members have deployed dozens of commercial projects globally.
- Global market potential: up to 140TWh and US$4 trillion in value by 2040.
- Estimated US$540 billion in system cost savings.
- Since 2019, over US$58 billion has been committed to LDES, but hundreds of billions of dollars more is needed.
- New funds like Europe's Decarbonisation Bank, the European Investment Bank and the UK's cap-and-floor model show that targeted financial mechanisms are emerging and supporting market growth.

An enabling environment for deployment

LDES success requires coordinated action across three key pillars:

- **Need:** Clearly define the role of LDES in system planning and long-term decarbonisation.
- **Finance:** Develop investable business cases with de-risked project pipelines.
- **Deployment:** Streamline permitting and remove regulatory bottlenecks.

These three conditions are foundational. As detailed in the LDES Council's Implementation Best Practices report [1], aligning all three creates the fertile ground for LDES projects to grow at scale.

What's next

To fully realise the LDES opportunity, governments, regulators and financial institutions must act on these priorities:

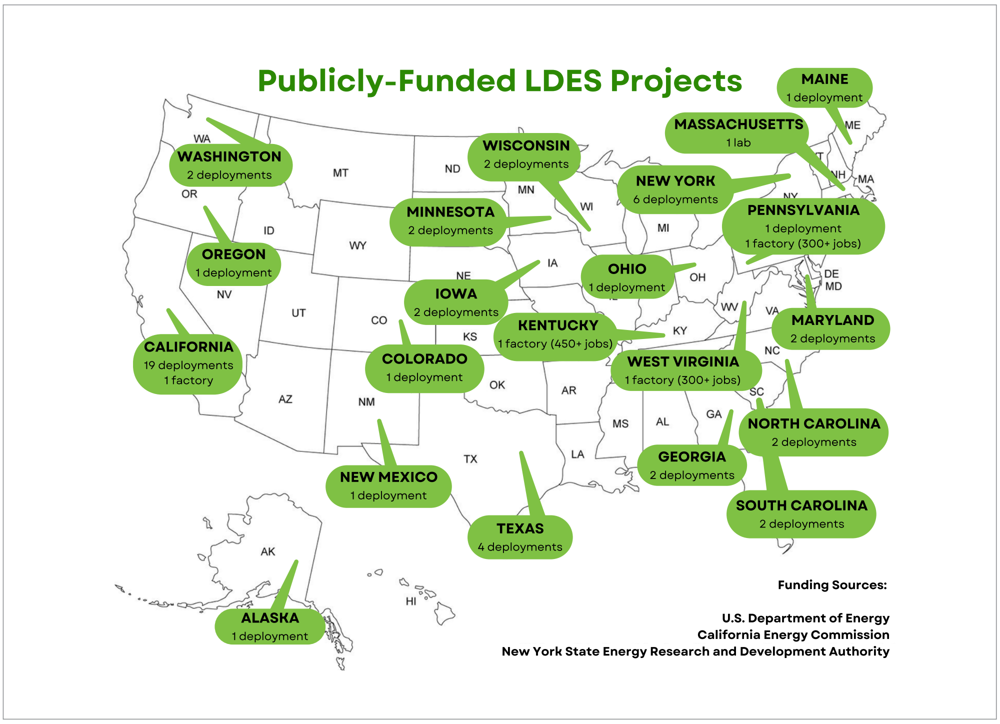


Figure 6. Publicly funded LDES projects in the US

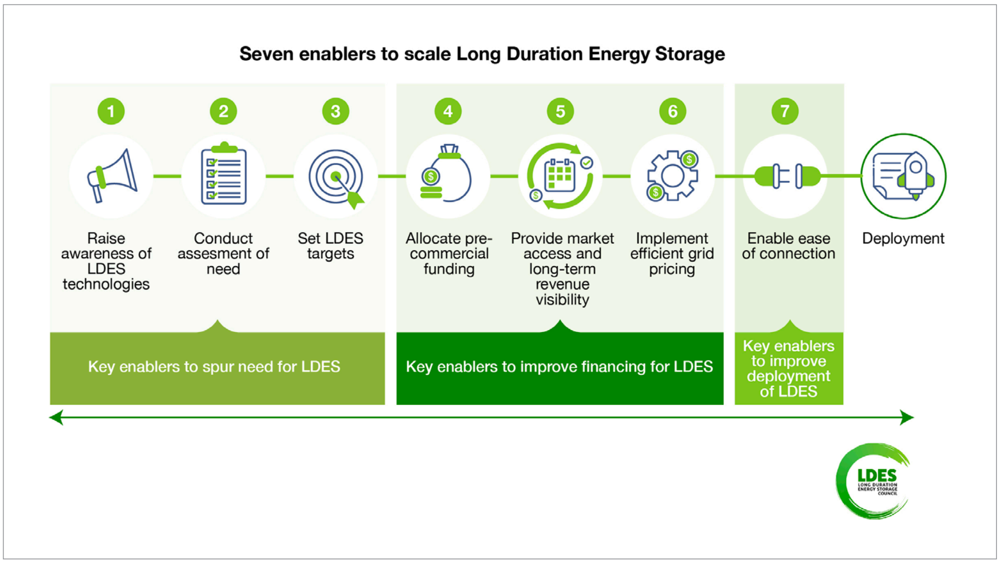


Fig 7. The key enablers for scaling LDES

1. Establish Clear market signals:
- Set long-duration storage targets at national and regional levels
- Ensure procurement mechanisms support duration diversity
- Set a resource adequacy value for LDES 8+ hours

2. Modernise planning frameworks:
- Include LDES in transmission, distribution, and reliability planning
- Recognise LDES contributions to system resilience, inertia, and heat decarbonisation

3. Expand financing mechanisms:
- Blend public and private capital, support new revenue stacks
- Support early-stage deployment via loan guarantees, offtake models, and grants

4. Celebrate and scale success stories
- Share case studies and best practices (e.g., Spain, Massachusetts, India)
- Build trust with communities, utilities and investors

5. Streamline permitting and build public trust
- Simplify permitting for low-impact LDES projects
- Remove excess grid fees
- Engage local communities early
- Embed LDES in just transition and workforce development plans

What success looks like with LDES

- Stable energy prices – even during climate extremes
- Reliable industrial decarbonisation
- Renewables backed by distributed energy storage systems
- Transmission savings via deferment and congestion relief
- Energy resilience in every region

Let's not miss this moment

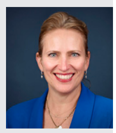
LDES is an infrastructure necessity. The next five years are decisive. Regulatory inertia must give way to bold action because the crisis warrants action. Most importantly, the tools and talent exist. With the right policies, financing and deployment urgency, we can scale LDES technologies in time to deliver resilience, affordability and climate security. Without it, the clean energy transition risks faltering under its own ambition.

The energy transition we are in is a once-in-a-century transformation. Missing this opportunity to scale long-duration energy storage, we risk higher costs, greater emissions and a less resilient grid and energy system, unable to meet the demands of a decarbonised world. But if we succeed, LDES becomes the quiet force that makes the transition work, delivering resilience, affordability and true climate security.

Reaching the necessary amount of LDES by 2030 is a critical step to the much-needed energy system inflexion – and we have reached the horizon where fossil fuels are no longer needed for energy system security.

We cannot afford to wait. The time to build the LDES marketplace isn't someday—it's now. Let's move with the speed this moment demands, before the window closes and, with it, the future we still have the power to shape.

Author



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