PV POWER TECH

Volume 37 | PV POWER PLANT TECHNOLOGY AND BUSINESS | November 2023 (Q4)

STANDING STRONG

Building PV resilience in the age of extreme weather, p.16

SYSTEM INTEGRATION

Degradation in bifacial modules, p.59

PLANT PERFORMANCE

Understanding the shift to predictive O&M, p.70

FINANCIAL, LEGAL, PROFESSIONAL

The growth of hybrid PPAs, p.82

STORAGE & SMART POWER

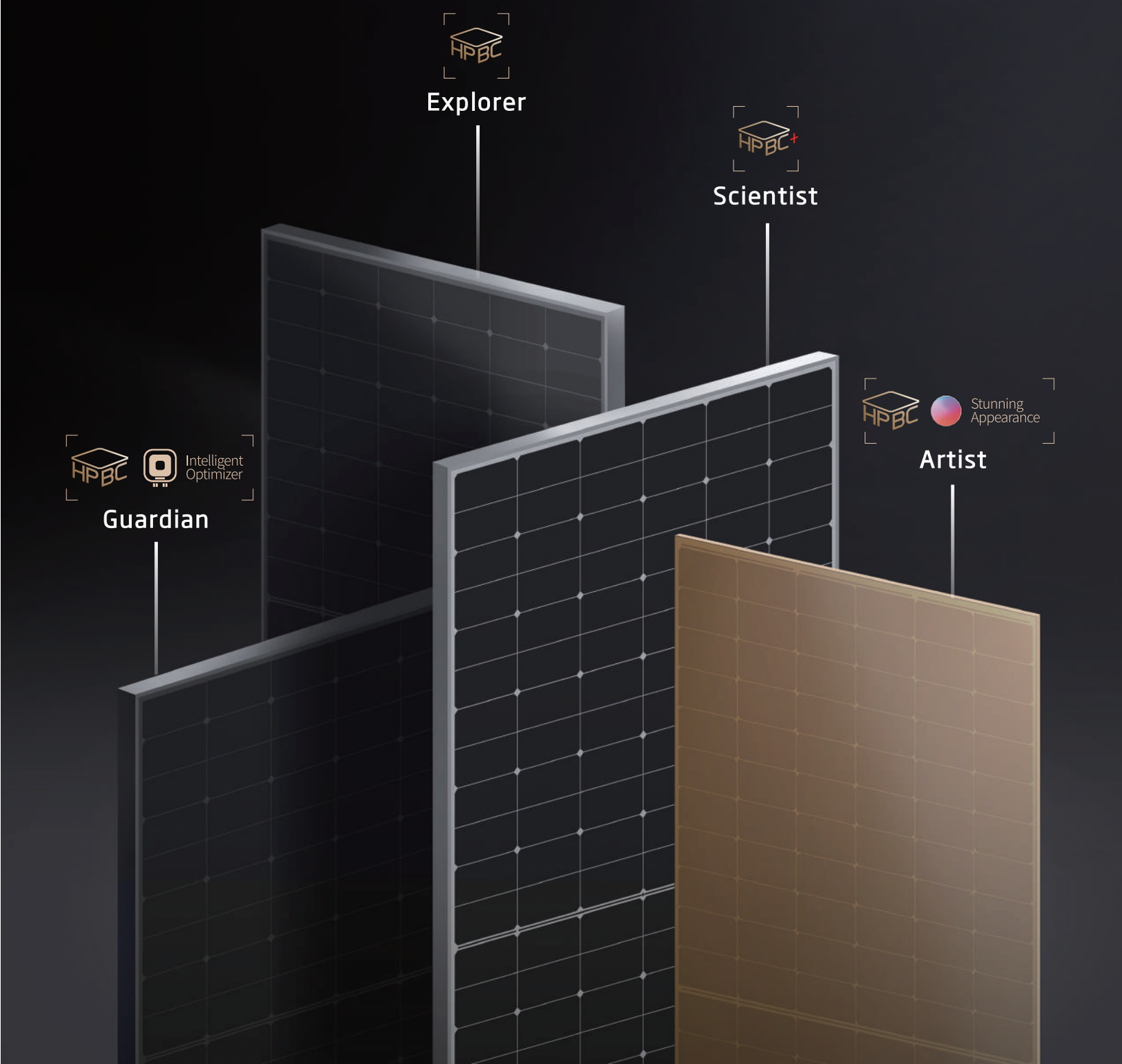
Strategies for battery augmentation, p.95

In association with Energy Storage NEWS

LONGi

Hi-MO X6

Illuminating Possibilities



PV TECH POWER

Published by
Solar Media Ltd.
123 Buckingham Palace Road
London, SW1W 9SH, UK
Tel: +44 (0) 207 871 0122
www.pv-tech.org

Publisher
David Owen

Editorial
Acting editor in chief:
Ben Willis
Senior news editor:
Mark Osborne
Editorial manager (China):
Carrie Xiao
Editors:
Andy Colthorpe, Simon Yuen, JP Casey
Reporters:
Cameron Murray, Lena Dias Martins, George Heynes, Jonathan Tourino Jacobo, Will Norman, Tom Kenning

Design & production
Design and production manager:
Sarah-Jane Lee
Production:
Daniel Brown

Advertising
Sales director:
David Evans
Account managers:
Graham Davie, Lili Zhu, Adam Morrison
Marketing manager:
Caroline Marques

Printed by
Buxton Press Ltd., Derbyshire

PV Tech Power Volume 37, 2023
ISSN: 2057-438X

While every effort has been made to ensure the accuracy of the contents of this supplement, the publisher will accept no responsibility for any errors, or opinion expressed, or omissions, or for any loss or damage, consequential or otherwise, suffered as a result of any material here published.

The entire contents of this publication are protected by copyright, full details of which are available from the publisher. All rights reserved. No part of this publication may be reproduced, stored in a retrieval system or transmitted in any form or by any means – electronic, mechanical, photocopying, recording or otherwise – without the prior permission of the copyright owner.

Brands of Solar Media:

Photovoltaics International
PV TECH
PV TECH PRO
CURRENT±
SOLAR POWER PORTAL
SOLAR ENERGY EVENTS
Energy Storage NEWS

Cover illustration by Luca D'Urbino

Introduction

As the COP28 circus packs up and leaves Dubai, the debate over the future of fossil fuels continues to rage. A deal to "transition away" from fossil fuels is certainly a step in the right direction, but for island nations in imminent danger of submersion, the vagueness of what this means in practice is likely more than a little frustrating.

A more tangible outcome of COP28 is the commitment by well over 100 countries to triple the global deployment of renewables by 2030. Low carbon technologies such as solar, wind and storage have already outperformed expectations and, with deployments set to gather further pace, the ever-improving economics of renewables will make the continued hegemony of fossil fuels increasingly difficult to justify.

But an interesting subtext to the solar story is emerging: at the same time as being a solution to the climate problem, solar is also a potential victim. As the hottest year on record, 2023 has demonstrated all too vividly that, with temperatures soaring around the world, intensifying storms, flooding, extreme hail and wildfires, the age of climate disruption is upon us. As a product of the very problem solar is helping humanity address, such phenomena also pose a very real threat to the longevity of PV power plants.

With this in mind, a collection of articles in this issue examines how the solar industry is addressing the question of resilience, beginning with Dirk Jordan and his colleagues at the US National Renewable Energy Laboratory (NREL), who explore how extreme weather events can have a potentially ominous long-term impact on the energy production of PV systems (p.16).

Meanwhile, James Elsworth, also of NREL, paints a detailed picture of how, with the right design and construction, PV power plants can stand up to the full range of extreme conditions nature is throwing at them (p.22). Alongside these technical deep-dives, our team at *PV Tech Power* zoom in on some of the emerging technologies and strategies that are helping build PV resilience, both in terms of hardware (p.32 and 34) and AI-enabled O&M and monitoring systems (p.38).

Elsewhere in this edition, a double bill of articles explores developments in Australia, where the Albanese government's recently announced 32GW renewables programme looks set to bring an end to an investment drought seen in 2023 (p.46). Meanwhile, Nexa Advisory's Stephanie Bashir looks at the role utility-scale storage will play in delivering the country's decarbonisation goals (p.102).

Also on the storage side, leading storage integration expert Wärtsilä investigates the all-important subject of battery augmentation as a solution to long-term system degradation.

As always, we hope you find this edition of *PV Tech Power* informative and enjoyable. Thank you for reading, and we wish you a prosperous 2024.

Ben Willis
Acting editor in chief
Solar Media

Contents

Fusionsolar

FusionSolar Residential Smart PV Solution

A Home that Always Shines

Shine on Active Safety | Shine on Full Journey Convenience | Shine on Energy-using Prospect

@Huawei FusionSolar

HUAWEI

REGULARS

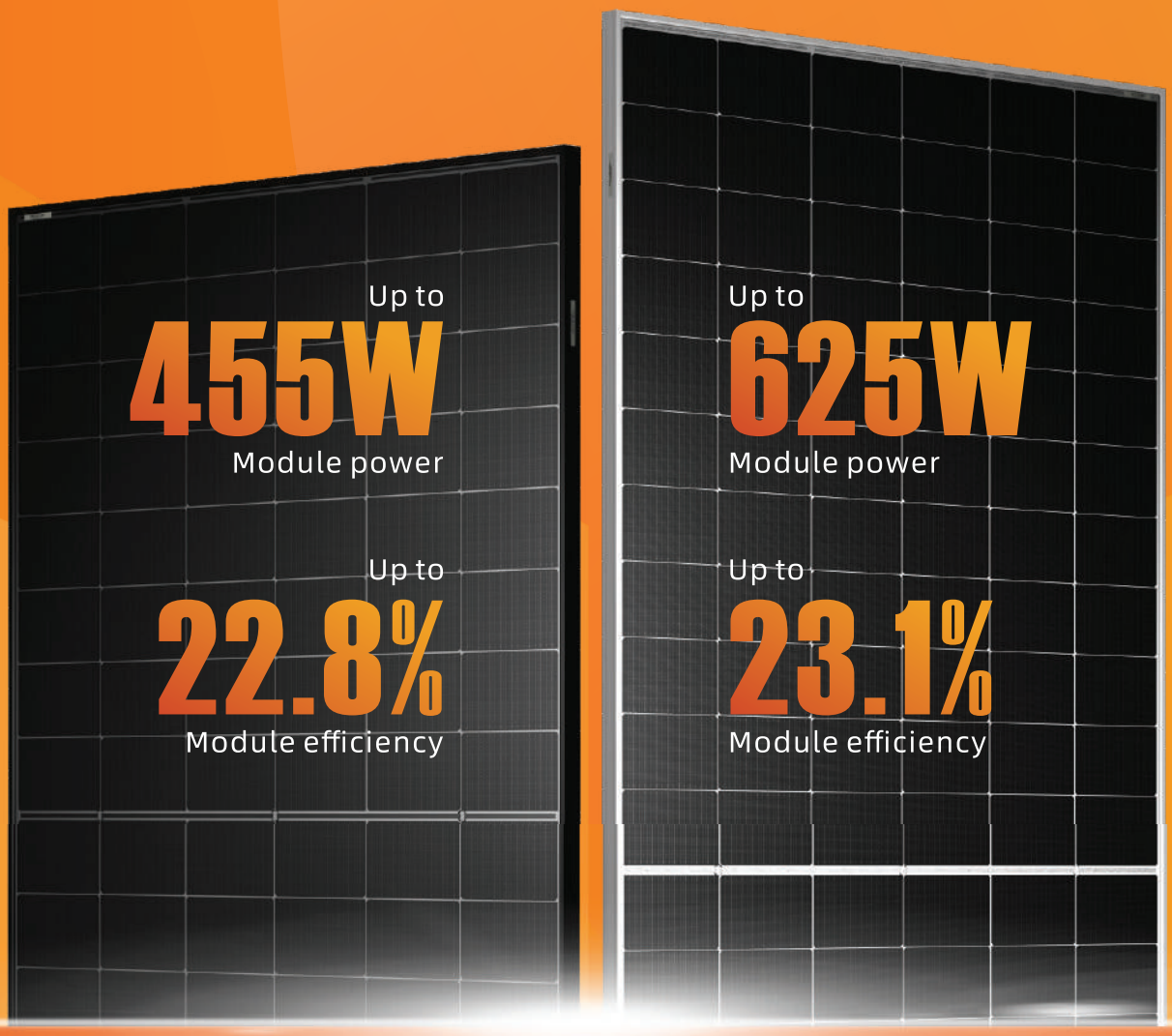
TW SOLAR

FORTUNE GLOBAL 500 | TIER 1 Bloomberg

TONGWEI

NEW G12R SERIES

New Generation Large Rectangle Products



sales@tongwei.com

http:en.tw-solar.com

Tongwei Solar on its tenth anniversary, expanding globally and its new TOPCon product line

A decade can seem like a long time, especially in a fast-moving sector like the solar industry. Tongwei Solar celebrates that landmark this year, a period that has seen it evolve into a vertically integrated solar manufacturer when it started manufacturing modules in 2022. PV Tech spoke with the Chinese manufacturer's vice general manager of PV business, Yan Li, about its ten-year mark, the launch of a new TOPCon module line and the rollout of its Global Partner Program.

PV Tech: This year marks the ten-year anniversary of Tongwei Solar. Could you give us an overview of the challenges during these ten years and the advantages you bring?

Yan Li: The most prominent challenge is market competition; the competition in the PV industry is becoming increasingly fierce, and we need to continuously innovate and improve efficiency to maintain competitiveness.

However, Tongwei Solar has several unique advantages that make us stand out in the industry. Relying on Tongwei's extensive presence in the upstream, midstream and downstream of the industrial chain, our vertical integration enables us to control product quality and cost, and provide integrated services.

We are committed to providing high-quality PV products. Through continuous technological innovation and quality control, our products have competitive advantages in reliability and performance.

Adhering to the concept of green and sustainable development, Tongwei Solar is committed to promoting the application and popularisation of clean energy. Our PV products help customers reduce their dependence on traditional energy sources, lower carbon emissions and contribute to environmental protection.

Looking ahead, what do you expect the solar industry to achieve in 2024 and beyond?

The entire PV industry has experienced a relatively strong price adjustment in 2023. Spot prices of PV modules are at a noticeably low level, which is very beneficial to the rate of return of power stations and end users. Looking forward to 2024, the nominal production capacity of the four segments across the supply chain is expected to exceed 1TW, respectively. The forecasts of solar demand by various analysts for next year roughly fall at 500-600GW, which seems to suggest an oversupply situation. However, we need to consider that N-type advanced production capacity (mainly TOPCon) will increase its market share next year, while outdated P-type capacity will be gradually reduced. Therefore, there will not be a significant surplus in terms of market demand. Considering that module prices have reached a relatively low position this year, the price fluctuations across the industry chain are expected to be smaller next year, which will greatly stimulate solar demand.

You entered the module market in 2022. What challenges did you face when entering that segment? What motivated you to become a fully integrated manufacturer?

We needed to establish a competitive advantage in the market and attract customers to choose our products. In order to address this challenge, Tongwei Solar drew on many years of industry experience and technical strength to provide high-quality and efficient module products. Our vertical integration advantages have allowed us to achieve supply chain stability and cost control and given us a competitive advantage in the market.

Furthermore, to enter the module market, we need to continuously promote technological innovation and improve product quality and performance to meet customer needs. Tongwei Solar has been committed to R&D and innovation and has established cooperative relationships with scientific research institutions and partners at home and abroad. We continuously promote technological advancements in efficiency, reliability and sustainability, and provide customers with excellent module products.

Being a vertically integrated company clearly gives you an advantage. What other aspects do you believe helps you stand out from the competition?

We have a strong R&D team constantly exploring new PV technologies and solutions. Through continuous R&D investment, we can provide industry-leading products to meet the evolving market demand. Relying on the national enterprise technology centre, Tongwei has comprehensively carried out R&D on new solar cell technologies and made a series of important achievements. At present, we have a presence in mainstream technologies such as TOPCon, HJT, IBC and perovskite/silicon stacking, and each technology direction is matched with perfect test lines, laboratories and other R&D facilities. We have developed in various technology R&D fields. For example, in terms of TNC technology, we have developed the industry's first 210 PECVD Poly cell pilot line and taken the lead in implementing PECVD technology in the industry. At present, more than 50% of the industry's production capacity uses this technology, making Tongwei a pioneer and explorer in the industry's technological development.

Tongwei Solar has established a wide range of business networks and partnerships around the world. With global market insight and flexibility, we are able to respond quickly to the needs of different regions. By expanding our business globally, we are better positioned to capture market opportunities and provide customers with a wider range of options.

Our products are also rigorously tested and certified to meet the highest international standards and industry requirements. By providing reliable products, we have won the trust and reputation of our customers.

You develop both TOPCon and heterojunction modules. Why did you decide to work with both when most of the module manufacturers only produce one?

As a world-leading PV enterprise, Tongwei Solar recognises the importance of technological diversity and the need to explore various module develop-

ment approaches. Through simultaneous R&D of TOPCon and heterojunction technologies, Tongwei Solar aims to maximise its R&D capabilities and diversify its product portfolio. This approach enables us to offer a wider range of products to meet the diverse needs of our customers and serve different markets.

TOPCon and heterojunction technologies represent two different approaches to module design and construction, each with unique advantages. TOPCon modules perform well in reducing resistive losses and increasing power output, while heterojunction modules provide higher efficiency and better temperature coefficient performance. By developing both technologies simultaneously, Tongwei Solar can optimise the performance characteristics of modules and offer options based on customer-specific project needs. This enables us to reach a wider customer base and effectively meet diversified project needs, ensure customer satisfaction, and maintain a competitive edge in the market.

You recently launched your Global Partner Program. What is the aim with this new venture?

Through the Global Partner Program, Tongwei aims to establish long-term and stable partnerships with excellent enterprises everywhere. We hope to cooperate with enterprises with professional experience and strength in the PV field, complement each other's advantages in technology, market, channel and other aspects, and jointly explore the global PV market. We will provide professional training and support to help partners better understand and sell our products. Through close cooperation, we will jointly promote the development of the PV industry and achieve mutual benefits.

The Global Partner Program will provide partners with a broader space for technological innovation. We will share technology R&D achievements and resources, explore and promote innovative applications of PV technologies with partners, and provide more advanced and efficient solutions. We welcome more enterprises to join our partner network and jointly create a bright future in the PV field.

You also recently launched the 'G12R' TOPCon module line. What improvements do they offer compared to your previous modules? And what markets are they targeted at?

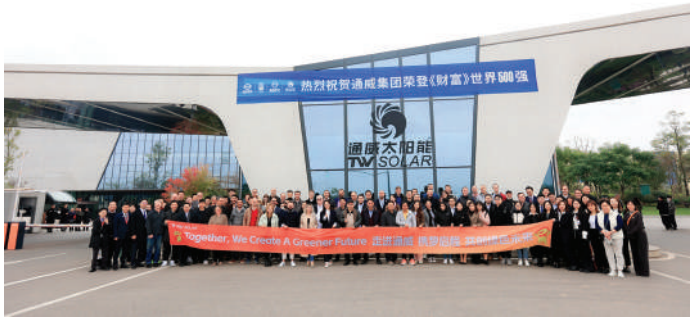
On the one hand, Tongwei G12R is designed and optimised on the basis of traditional 182mm products. Based on mainstream transportation modes, it maximises the container utilisation rate and reduces transportation costs. Marine transportation is an important part of China's PV "going global", and the utilisation rate of containers has a significant impact on cost-competitiveness. The length of the new G12R module is increased from 2,278mm to 2,382mm ± 2mm while maintaining a width of 1,134mm, further improving the utilisation rate (up to 98.5%) of containers.

On the other hand, G12R series products have a maximum power of 625W and an efficiency exceeding 23.1%, which can fully meet the needs of downstream diversified PV scenarios with advantages such as lower attenuation, higher output, higher return and high reliability. Compared with TOPCon-182mm modules, G12R has a power increase of more than 25W, an efficiency increase of more than 0.68%, a BOS cost reduction of 1.54% and a LCOE reduction of 0.96%. The greatly improved product power reduces integration costs and improves system benefits to bring higher product value and customer value.

The new generation of flagship products is aimed at the residential, commercial and industrial (C&I) and utility-scale power plants markets. For the residential market, we have launched two modules: one is a full-black bifacial 450W with an efficiency of 22.5%, and the other is bifacial 455W with an efficiency of 22.8%. For industrial and commercial and utility-scale power plants projects, we have launched two 620W+ monofacial and bifacial modules with an output power of up to 620W/625W and an efficiency of 23%/23.1% respectively.

As you expand your global reach, which countries or markets do you find the most interesting to grow your presence? And why?

The most promising markets include Europe, Australia, Brazil and Middle East and Africa. Europe is the main market for overseas demand. Since the outbreak of the Russia-Ukraine war in 2022, Europe is accelerating the deployment of green energy sources to cope with the increasingly serious energy crisis. Although it is currently facing labour shortages and high inventories, the installed capacity is still expected to reach 65-70GW in 2023 and 70-80GW in 2024 (according to IHS). As a traditional and established PV market, Australia has very stable demand, which we will also pay attention to. As for Brazil: In previous years, the local market was mainly stimulated by incentives for projects below 5MW – mainly targeted at the distributed generation market. With the termination of this incentive, the industry will face a decline starting next year. At the same time, utility-scale projects will dominate market growth next year. Large-scale PV projects in Saudi Arabia and the United Arab Emirates will support the majority of new installed capacity in 2024, and the Middle East market is dominated by these countries. In Africa, South Africa's growth rate is outstanding. Therefore, we will further explore the above markets, improve channel layout, and serve global customers with competitive products.



EUROPE

Market

Europe installed 56GW of solar PV in 2023

The EU has installed 55.9GW of new solar PV capacity in 2023, up significantly from the 40GW installed in 2022. Germany topped the list of total solar installs with 14.1GW over the year, followed by Spain (8.2GW), Italy (4.8GW), Poland (4.6GW) and Netherlands (4.1GW) to round out the top five. 2023 also saw three new markets from central and eastern Europe – Czechia, Bulgaria and Romania – reach the 1GW threshold for installed capacity. However, SolarPower Europe, which published the data, has predicted that 2024 will see the market slow down as the factors that drove the exceptional growth over the last three years – namely the energy price spikes and fears of outages, along with a backlog of projects that were unable to be met in previous years – will return to normal. As such, it called for actions to "enable the solar sector to realise its growth potential".

Credit: R.Power

European PV installations have hit almost 60GW in 2023

EU

Europe's solar industry reacts to EU's Net Zero Industry Act vote

The European Parliament voted to accept the Net Zero Industry Act (NZIA) on 21st November, which will seek to onshore manufacturing for renewable energy technologies such as solar PV, battery energy storage and wind to the EU. The legislation was adopted with 376 votes to 139, with 116 abstentions. Parliament's decision has been met with both approval and some trepidation by representatives in the European solar industry. The NZIA proposes non-price and pre-qualification criteria to be applied in public auctions and tenders for renewable energy capacity. These include legislation that will introduce a local content requirement for projects and technologies to be included in public procurements.

EU to improve energy performance of buildings, rooftop solar required to be installed from 2027

The European Parliament and the European Council have reached a provisional agreement on the strengthened Energy Performance of Buildings Directive (EPBD), aiming to boost the energy performance of buildings and requiring new buildings to be solar-ready. According to the revised EPBD, each EU member state needs to reduce the average primary energy use of residential buildings by 16% by 2030, and 20-22% by 2035. All countries can choose which buildings to target and which measures to take. Additionally, the EPBD requires that EU member states have to ensure new buildings are fit to host rooftop solar PV or solar thermal installations. Existing public and non-residential building solar will need to be installed starting from 2027.

European Commission approves €1.7 billion for Italian agrivoltaics

The European Commission has approved a €1.7 billion (US$1.8 billion) scheme to support the deployment of 1.04GW of agrivoltaics projects in Italy. Set to run until the 31st December 2024, the funding comes in part through the Recovery and Resilience Facility, which was introduced by the EU to aid in economic recovery from the COVID-19 pandemic. The Commission said that it is part of the efforts to support Italy's portion of the bloc's decarbonisation targets under the EU Green Deal. All of the projects will be awarded via a bidding process, and in order to be eligible must be operational before 30th June 2026. Agrivoltaics ('agriculture' + 'photovoltaics') is the practice of using land for both solar PV and agricultural production in a way that optimises both uses.

Spain

Velto Renewables to develop 1GW of solar projects in Spain through new partnership

Spanish independent power producer Velto Renewables has partnered with renewables company Kenergy to develop 1GW of solar projects in Spain. Under the agreement, both companies will co-develop early-stage solar power projects, which Velto Renewables said would benefit from the two companies' "significant development, financial, technical, and operational expertise". With this partnership, Velto Renewables can expand its footprint to more European countries, as prior to the deal, its portfolio only covered solar projects in Spain and offshore wind in the UK.

Manufacturing

REC Group abandons Norwegian polysilicon facility

Solar module manufacturer REC Group ceased operations at its polysilicon production facility in Norway on the 22nd November due to high electricity prices and a fierce polysilicon market. Representative bodies for the European solar industry have expressed concern over the implications of the closure for domestic manufacturing. According to a press release from REC, the price of electricity in Norway, alongside worldwide overproduction of polysilicon, made its operations untenable in comparison with its Chinese competitors. Polysilicon prices have plummeted in 2023; leading Chinese polysilicon giant Daqo New Energy saw slashed revenues in Q3 2023, down more than 50% year-on-year despite shipping almost twice the volume as in Q3 2022. In its press release, REC cited these inhospitable market conditions, which it expected to continue, as another reason for its closure.

AMERICAS

USA

New York state reaches milestone of 2GW of community solar capacity

New York state in the US has deployed 2GW of community solar capacity, according to the New York State Energy and Research Development Authority (NYSERDA). NYSERDA also announced that the state has installed 5GW of distributed solar capacity,

risen

HJT

Choose RISEN ENERGY

Contact us

Linkedln

www.risenenergy.com

with a further 3.3GW under development, as small-scale solar looks to become a significant part of the state's energy mix. The state plans to expand its installed distributed solar capacity to 6GW by 2025 and 10GW by the end of the decade, and the 2GW community solar milestone is an important step in this process. Community solar alone now accounts for 61% of new solar projects installed this year.

Michigan signs 100% renewables by 2040 target into law

Michigan governor Gretchen Whitmer has signed a number of bills into law to increase the contribution of renewable energy to the Michigan energy mix. The state legislature agreed the bills, collectively known as the Clean Energy Future Plan, earlier this month, and Whitmer has now signed them into law in their original form. The new legislation is headlined by a commitment to meet 100% of the Michigan energy demand with renewable energy sources by 2040, and a requirement for Michigan utilities to acquire 15% of their electricity from renewable sources.

SB Energy raises US$2.4 billion for 1.3GW US solar portfolio

US renewables investor SB Energy has raised US$2.4 billion to support the construction of 1.3GW of new solar capacity in the US. The funding consists of US$800 million in tax equity, raised through four US lenders: Bank of America, J.P. Morgan, Morgan Stanley Renewables and Truist Bank. The remainder of the funds consists of US$1.2 billion in construction debt and US$450 million in term debt, raised through an international group of backers: US bank Fifth Third Bank, the Canadian Imperial Bank of Commerce, Dutch bank ING, French investor Société Générale and Asian firms MUFG, the Sumitomo Mitsui Banking Corporation and the Americas division of Mizuho. SB Energy said it had signed a power purchase agreement with technology giant Google, which will acquire 75% of the power produced by the entire portfolio to power one of its data centres in Texas.

PPA

Meta, SRP and Ørsted to collaborate on 300MW solar-plus-storage project in Arizona

Social media and data giant Meta has signed a power purchase agreement (PPA) with US utility Salt River Project (SRP) and Danish energy company Ørsted to acquire electricity from the latter's Eleven Mile Solar Center in the US state of Arizona. The project is currently under construction, and once completed, Ørsted expects the facility to have a power capacity of 300MW, and a four-hour battery energy storage system (BESS) with an output of 300MW (1,200MWh). The company plans to commission the project next year, and Meta announced that it would acquire "the majority" of the electricity generated for use at a data centre in the city of Mesa, with the remainder being made available to SRP customers in the region.

Credit: Ørsted

Meta reached net zero emissions across its operations in 2020.

Latin America

Trina Solar to supply bifacial modules and trackers to Brazilian solar project

Credit: Trina Solar

Trina Solar's 1P Vanguard trackers will be installed at the project in Brazil

Chinese manufacturer Trina Solar has signed a supply agreement with Brazilian EPC contractor Fiber X for the supply of PV modules and trackers to a project under development by Brazilian firm Cemig Sim. Cemig Sim, the renewable development arm of Brazilian power company Cemig, plans to commission the 90MW project in the second quarter of 2024. Trina Solar will provide bifacial PERC DEG21-660W modules from its Vertex series to the project, along with its Vanguard 1P trackers to optimise electricity generation at the facility.

AES raises US$368 million for Dominican Republic renewable projects

28 November. AES Dominicana has raised US$368 million in a loan facility that will be used to finance renewable energy projects in the Dominican Republic. The company, the local arm of energy giant AES, will build three new projects, Mirasol, Peravia I and Peravia II, which will have a combined capacity of 240MWac, which AES expects to commission by the end of next year. Multinational bank Banco Latinoamericano de Comercio Exterior (Bladex) served as the joint lead arranger and bookrunner for the loan facility, and worked with the Inter-American Development Bank, JP Morgan and Scotiabank to raise the funds.

MIDDLE EAST & AFRICA

Masdar

Masdar to develop 10GW of renewables across Africa

Masdar has signed a number of agreements to develop new renewables projects in Africa, including 300MW of solar capacity in Angola and Uganda. The company announced the deals during the COP28 conference, held in Dubai, which are part of Masdar's plans to develop 10GW of new renewable capacity in Africa. The

Masdar

Masdar inaugurates 'world's-largest' 2GW solar project in Abu Dhabi

UAE state-owned renewable energy developer Masdar has inaugurated the 2GW Al Dhafra Solar solar PV project in Abu Dhabi. Encompassing about four million bifacial solar modules, the project will supply power to the Emirates Water and Electricity Company (EWEC), as both companies signed a power purchase agreement (PPA) in 2020. Masdar claimed that this project is the world's largest single-site solar PV plant. After adding this project to the UAE's solar portfolio, the country's solar power production capacity will increase to 3.2GW. Located 35 kilometres from Abu Dhabi city, the project was co-developed with Abu Dhabi National Energy Company, French power company EDF Renewables and Chinese solar developer JinkoPower. Masdar added that the solar modules were installed at an average rate of 10MW a day during construction.

Credit: Masdar

2GW Al Dhafra PV Solar Plant

projects are headlined by a 150MWac solar project in Angola, for which the company has signed a concession agreement with the Angolan energy ministry; and a 150MW project in Uganda, for which Masdar has signed a roadmap agreement with the Ugandan government. These two projects are part of Masdar's plans to develop 2GW of renewable capacity in Angola and 1GW of capacity in Uganda. Masdar and financier Africa50 are also "exploring a collaboration" to build floating PV projects in Mozambique.

Africa

Clean energy investment target in Africa needs to double to US$25 billion per year by 2030

Clean energy investment across Africa has to double the current US$90 billion target by 2030 and reach nearly US$25 billion per year, according to a report by the International Energy Agency and the African Development Bank Group. The increased investment would be needed for the continent to achieve its energy development and climate goals, with two-thirds of spending towards clean energy. The report, Financing Clean Energy in Africa, outlines the cost of capital for utility-scale renewable projects is twice to treble higher in Africa than in advanced economies, which prevents developers from pursuing commercially viable projects.

Scatec powers 540MW solar-plus-storage project in South Africa

Norwegian independent power producer (IPP) Scatec has started producing energy from a 540MW solar-plus-storage project in the Northern Cape province, South Africa. The 'Kenhardt' project consists of three solar plants and a battery energy storage capacity of 225MW/1,140MWh. The Norwegian IPP had previously secured a 20-year power purchase agreement with state-owned utility Eskom to provide 150MW of dispatchable energy between the hours of 5am and 9:30pm to the national grid. The project had an investment of nearly US$1 billion, marking Scatec's largest project commitment.

Ghana targets 150GW of solar PV and US$550 billion investment by 2060

Ghana has updated its Energy Transition and Investment Plan (ETIA), which was developed with Sustainable Energy For All (SEforALL), with a target to deploy nearly 150GW of solar PV capacity in order to achieve its net zero emissions target by 2060. The plan will represent US$550 billion in investment opportunities for companies and other nations. Under the new plan, solar PV would account for 86% of Ghana's generation electricity, while the country expects to reach 26GW of deployed solar capacity by 2040. From 2040 onwards, the country aims to add 5GW of solar capacity per year.

Off-grid solar

Husk Power secures US$100 million to grow community solar mini-grids in sub-Saharan Africa

Colorado-based mini-grid specialist Husk Power has secured more than US$100 million in equity and debt funding aimed to grow its community solar mini-grids in rural sub-Saharan Africa and South Asia. Out of the more than US$100 million raised, US$43 million are from a Series D funding, the largest equity raise in the mini-grid industry, according to the company. The equity funding includes new investors STOA Infra & Energy, the US International Development Finance Corporation and Proparco, as well as existing investors Shell Ventures, Swedfund and FMO. The other part was secured through a US$60 million debt from several financial institutions, among them the European Investment Bank and the International Finance Corporation.

ASIA-PACIFIC

China

China forecast to install record 230GW of new renewable capacity in 2023

China is on track to install a record 230GW of new solar and wind capacity in 2023, around treble the capacity installed in the rest of the world, according to a report from Wood Mackenzie. The report, 'How China became the global renewables leader', expects China's additions to dramatically outpace the 75GW of solar and wind Europe is expected to install in 2023, and the 40GW of new capacity forecast to be added in the US. "China announced its 2060 carbon neutral target in 2020 and since then has been quietly reorganising the entire power sector to support rapid electrification and expansion of renewables," says Alex Whitworth, vice president and head of Asia Pacific power and renewables research at Wood Mackenzie.

India

India renewables capacity to reach 170GW by Q1 2025

India's renewables capacity will increase to 170GW by March 2025 for a number of reasons, including the decline in solar PV

cell and module prices, according to a study conducted by Indian rating agency ICRA. As of October 2023, the installed renewables capacity in India was 132GW, meaning there will be an increase of 38GW in only 17 months. ICRA added that renewable additions will likely continue after March 2025 thanks to the significant improvement in tendering activity in the current fiscal year, with over 16GW projects bid out so far. Another 17GW bids will be from the tenders launched by the central nodal agencies. This is in line with the 50GW annual bidding trajectory announced by the government of India in March 2023.

Adani Green Energy closes financing for 2.1GW renewables construction

Indian renewables developer Adani Green Energy has closed a US$1.36 billion debt facility to support the development and construction of its large-scale projects.

The funding forms an expansion of the company's Construction Financing Framework, which now totals US$3 billion. Several banks backed the financing, including BNP Paribas, Coöperatieve Rabobank U.A., DBS Bank Ltd and others. Adani Green Energy said the financing will support the construction of its planned renewables capacity additions at the Khavda renewable park in the state of Gujarat. Its initial plan is for 2,167MW of capacity additions at Khavda, with further expansion expected in the future. The company has plans for 45GW of installed renewables generation capacity by 2030.

ReNew Energy signs deal with Asian Development Bank for US$5.3 billion of renewable project funding

Indian renewable power developer ReNew Energy Global has signed a memorandum of understanding with the Asian Development Bank (ADB) to raise US$5.3 billion in funding for new clean energy projects until 2028. The deal was signed at the COP28 conference in Dubai, in the UAE. At the event, 118 countries signed pledges to treble global installed renewable capacity to 11TW by 2030, and the raising of additional funding for new solar projects will help meet this target. While ReNew Energy did not announce which projects or developments would receive the funding over the next five years, it already boasts a sizeable solar portfolio in India, with 4.1GW of commissioned and committed capacity in place since it entered the sector in 2013.

Australia

Australia announces backing for 32GW of renewables investment

Credit: CEFC

Australia's federal government is to underwrite 32GW of renewables investment

The Australian government will underwrite 32GW of renewable energy generation and energy storage capacity in an attempt to stimulate investment into the country's energy transition. Minister for climate change and energy Chris Bowen announces plans for an expansion of the existing Capacity Investment Scheme (CIS) and National Energy Transformation Partnership (NETP) programmes to facilitate 9GW of dispatchable capacity and 23GW of variable capacity nationally. The government says that this capacity is equivalent to roughly half of the demand on Australia's national energy market (NEM). The Australian solar sector has grown considerably in recent years, with the Australian PV Institute reporting that cumulative capacity installations reached 32.7GW in August 2023, up from 28.2GW in August 2022 and 16.2GW at the start of the decade.

Indonesia

Masdar and PLN inaugurate 192MWp 'largest' floating PV site in Southeast Asia

The Indonesian state utility PLN and UAE state-run renewables developer Masdar have inaugurated the 145MWac (192MWp) Cirata floating solar PV (FPV) plant in the West Java province of Indonesia. Opened by the president of Indonesia, Joko Widodo, Masdar and PLN said that the plant is the 'largest' FPV site in Southeast Asia, a region which leads the world in FPV deployments. Cirata is a first for Masdar – an arm of the Abu Dhabi National Oil Company – on two counts: its first FPV project and its first entry into Southeast Asia. Masdar has already signed a memorandum of understanding (MoU) with PLN to develop Cirata phase II which would add up to 500MW capacity.

MANUFACTURING

Trade & markets

European solar sector opposes trade defence measures

More than 400 European solar companies have published an open letter via industry body SolarPower Europe, opposing trade defence measures for the solar sector in the EU. The 429 signatories, including 18 manufacturers and 28 associations and research institutes from 26 member states, said imposing trade defence measures on solar PV products would slow down solar deployment. The signatories suggested measures to provide long-term and sustainable support to the European solar industry, such as adjusting the EU state aid framework to allow member states to support the running costs of factories.

'Cut-throat' polysilicon market could see sector consolidate in 2024

"Cut-throat" competition in the polysilicon production industry in 2024 could push many Chinese producers out of business, according to analysis from industry research firm Bernreuter Research. A consolidation phase could be triggered by massive capacity expansion by the largest producers next year, most notably Chinese producer Tongwei. Polysilicon prices have plummeted this year, which Bernteuter predicts will continue into next year as supply outstrips demand significantly and Chinese players who entered the market when prices were high in 2020-21 will be unable to compete.

Capacity expansions

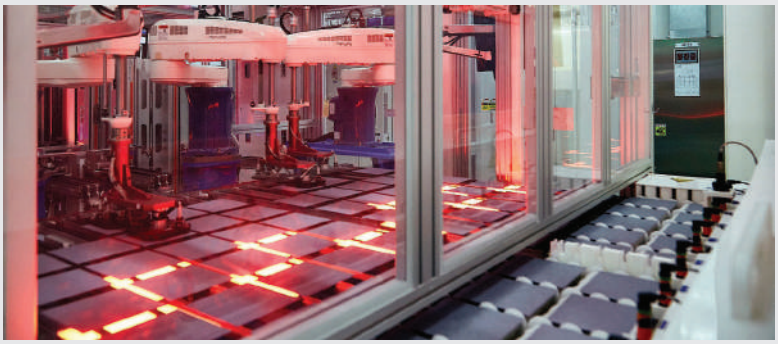
Heliene expands Minnesota TOPCon module line to 300MW

Canadian solar PV module manufacturer Heliene has doubled the capacity of its Mountain Iron, Minnesota module production line

IRA

US faces imbalance of domestic module capacity versus cells, says CEA

Domestic supply of solar cells in the US will be insufficient to keep pace with module manufacturing expansion plans announced since the 2022 Inflation Reduction Act was passed, according to advisory body, Clean Energy Associates (CEA). With a large majority of global cell processing capacity located in Asia, procurement of cells will have similar constraints seen up until now with modules, limiting the available supply due to the Uyghur Forced Labor Prevention Act (UFLPA), which came into force in June 2022 or the anti-dumping/countervailing duty (AD/CVD) with tariffs suspended until July 2024, under US president Joe Biden's two-year waiver. In upstream manufacturing, the problem will also arise for ingots and wafers as domestic cell capacity additions far exceed US ingots/wafers capacity additions.



Credit: Qcells

Domestic cell supply in the US is unlikely to keep pace with module production, says CEA

to 300MW following an extra US$10 million investment into the facility. With this expansion to one of its original manufacturing lines Heliene will now be able to produce n-type tunnel oxide passivated contact (TOPCon) solar modules. It will also improve the efficiency of production, the company said. The line is located contiguous with another, 500MW production line, which brings the total capacity of the Mountain Iron facility to 800MW.

AmpIn Energy to build cell and module manufacturing plant, 600MW renewables projects in India

Indian power company AmpIn Energy Transition has invested INR31 billion (US$371.7 million) to build renewables projects of more than 600MW and a solar cell and module manufacturing plant in India. The company did not unveil the capacity of the manufacturing plant, adding that the investments were planned in the states of West Bengal, Bihar, Odisha, Jharkhand, and Chhattisgarh, as well as the Northeastern states. Currently, AmpIn Energy Transition has a solar portfolio of about 200MWp in the region. In October, AmpIn Energy Transition entered into a "strategic partnership" with fellow Indian power company Jupiter to build a 1.3GW cell and module manufacturing facility in India. The companies have not yet announced the details of their joint venture, or the location of their new manufacturing facility. The project will benefit from a production-linked incentive scheme announced earlier this year by the Indian government, for which AmpIn applied for an annual manufacturing capacity of 4GW.

PVCELLTECH
CONFERENCE EUROPE

12-13 March 2024 | Frankfurt, Germany

Global PV Manufacturing at the Terawatt Level

Join us for answers to the important questions in PV cell technology:

- Who are the leading TOPCon and heterojunction cell producers and what are their roadmaps to increased efficiencies?
- What disruptive PV manufacturing solutions are maturing?
- What is on the horizon for tandem cell manufacturing?
- What back contact variants could become mainstream offerings after TOPCon?
- Who is manufacturing what in Europe and what is the long term viability of European manufacturing?

www.pvtechconferences.com/pv-celltech-europe | email: pvcelltech@pv-tech.org

Extreme weather impact on PV—resilience lessons for long-term performance

Degradation | Aside from the immediate, visible damage, extreme weather events have a longer lasting impact on PV systems. NREL's Dirk C. Jordan, Kirsten Perry, Robert White, Josh Parker, Byron McDanold and Chris Deline report on research revealing the long-term consequences of hail, wind and other weather phenomena on PV production

Terrestrial photovoltaics has its origins in the late 1970s and early 1980s. Cost, efficiency and reliability were the focus then—as they are today—to increase PV adaptation. Systematic investigations and improvements in reliability started in the USA in the Jet Propulsion Laboratory (JPL) so-called Block Buy programme. Many of the standard tests are still being used today to ensure quality can be traced to that time, with additional tests coming from a European effort. These quality measures played no insignificant part in the remarkable success PV has enjoyed in the last 40+ years, leading to the astonishing installed capacity curve of Figure 1. Testing for extreme weather conditions such as temperature extremes, but also hail impact and wind loading, were a concern even in these pioneering days. Additionally shown in Fig.1 is the frequency of extreme weather events—weather events that caused more than US$1 billion damage (inflation-adjusted)—from the National Oceanic and Atmospheric Administration (NOAA) database [1]. Coincidentally, the database also goes back to approximately the same period. As global installations have increased, so has the number of these extreme weather events. This begs the question: how have these events impacted PV installations today? And what, if anything, can the PV community do to increase resilience? PV quality standards are continuously adapted to new field observations and an investigation like this could ultimately lead to higher quality products.

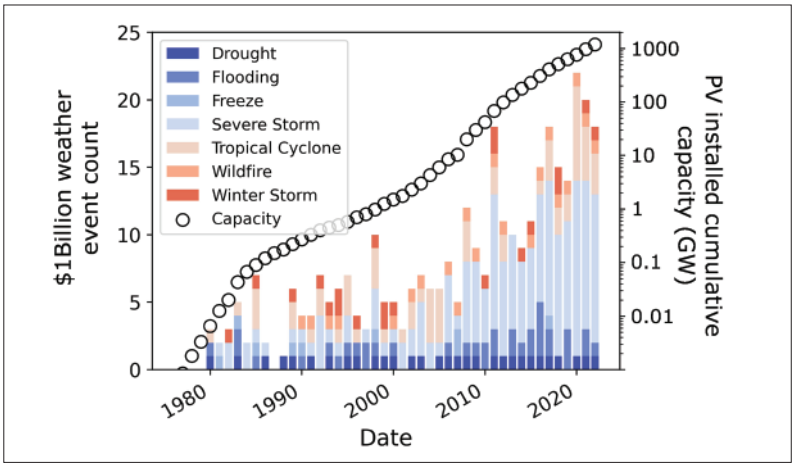


Figure 1: Count of US$1 billion (inflation-adjusted) weather events in the USA over time (left axis). Cumulative worldwide installed PV capacity in GW (right axis)

Method

In this analysis we compared NOAA's database on extreme weather events with our own PV Fleet Data Initiative timeseries database. The NOAA Storm Events Database specifically documents storms or other significant weather phenomena such as hurricanes, floods, hail and windstorms etc. with high enough intensity to cause loss of life, property damage, injuries, or disruption of commerce. Data in the storm events database includes the start and end date of the event, event type, starting and ending latitude-longitude coordinates, as well as event severity, when applicable. It is important to note that multiple storm event types can occur simultaneously in the same geographic area; for example, a location may experience lightning and a windstorm simultaneously.

The other database, the National Renewable Energy Laboratory (NREL) PV Fleets database, contains time series performance data from more than 24,000 inverters' data and over 3700 PV sites, with most sites commercial or utility scale. The total installed capacity is more than 8GW with a mean site age of more than five years [2].

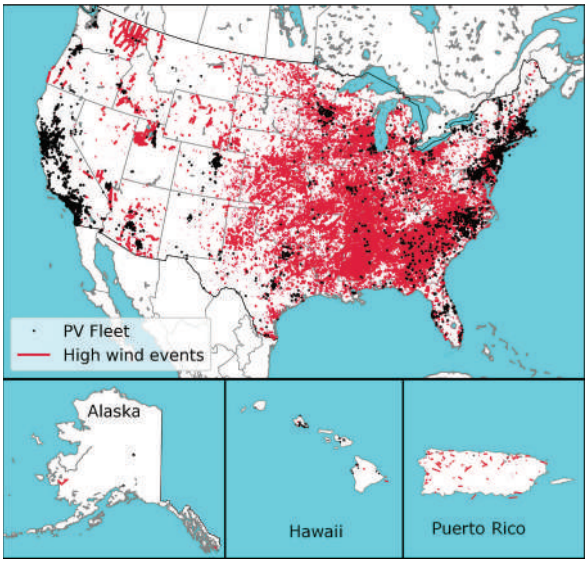


Figure 2: Extreme wind events in the USA including the territory of Puerto Rico from 2008-2022 (red). PV Fleet data systems are indicated in black

As an example, Fig. 2 shows a map of high wind events (red) for the USA and Puerto Rico overlaid by the PV Fleet systems (black). To build relationships between storm data and PV system data, the latitude-longitude coordinates associated with each storm event were compared to PV system latitude-longitude coordinates. Specifically, storm events within 10 kilometers of a PV system, occurring during a period where measured time series data for that system was available, were marked for further analysis.

To calculate the long-term impact, we determined performance loss rates (PLR) using the open-source software package RdTools [2]. Because the methodology is based on a year-to-year comparison, at least two years before and after the associated weather event were required. Consequently, some systems were eliminated for not meeting this requirement. Irradiance sensors can substantially bias PLR measurements if not calibrated every other year. Therefore, we used satellite data from the National Solar Radiation Database (NSRDB) [3]. The current NSRDB provides data within 4km horizontal resolution and the irradiance may differ within that resolution window, especially on partly cloudy days. Hence, we filtered for clearsky and therefore relatively stable outdoor conditions, allowing us to detect smaller changes in PLR [4].

Long-term results

The impact of different hail sizes on long-term performance losses is summarised in Figure 3 (a). The blue and orange boxplots show the PLRs before and after the hailstorm, respectively. Individual data points are overlaid with a representative uncertainty bar from the analysis given for each category. For the smallest hail category, approximately the size of peanuts, no higher PLR after storms was detected. However, each hail category of 25mm or greater displays statistically significant higher PLRs after the storms. Of particular interest is the 25mm hail size because that is the hail size used in the International Electrotechnical Commission (IEC) module qualification test standard 61215. Although the modules used in these systems were qualified to that hail size, when exposed to that same size hail in natural settings, higher PLRs resulted. Several possibilities exist that may explain the discrepancy: first, in hailstorms, more strikes below the maximum size may occur and deliver more kinetic energy

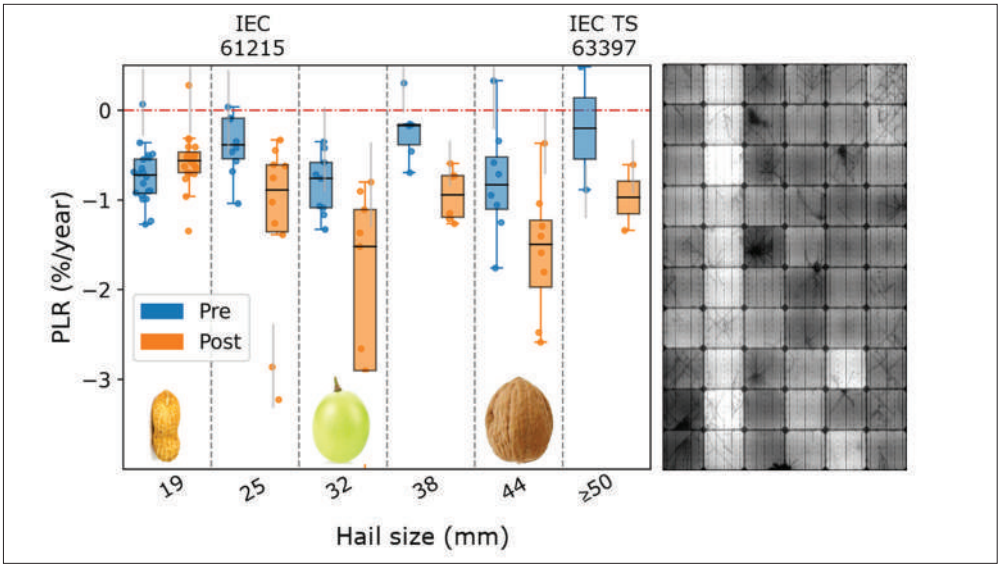


Figure 3: PLR before hailstorms (blue) and after storms for systems impacted by different hail sizes (a). Electroluminescence (EL) image of a crystalline silicon module after being exposed to a 32mm maximum size hailstorm

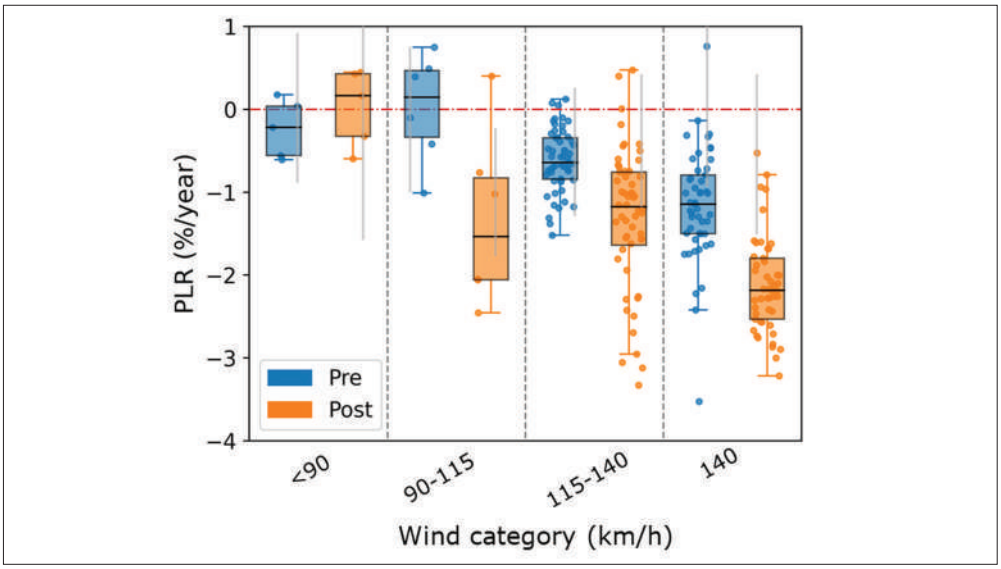


Figure 4: PV performance loss rates (PLR) before (blue) and after (orange) windstorms, binned by recorded wind speed

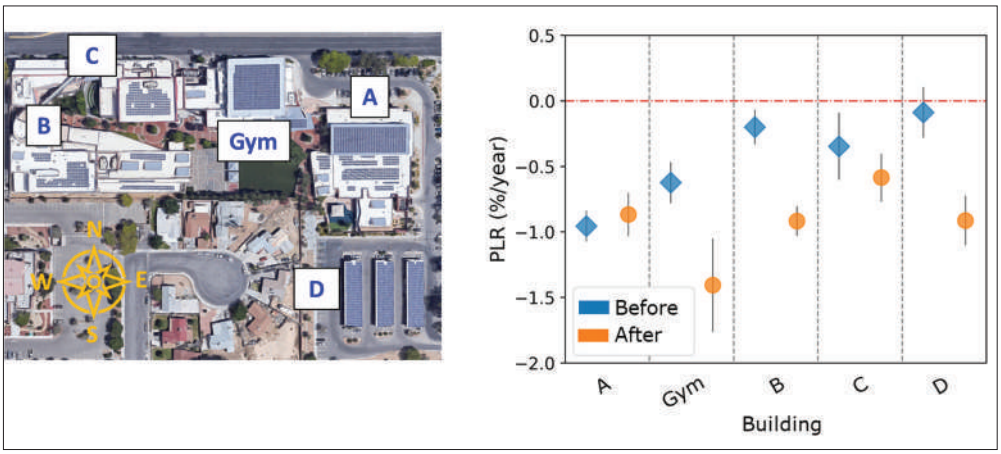


Figure 5: PV site in Las Vegas, USA, exposed to high wind event in the 90-115 km/h range. Modules on all buildings are the same model installed approximately at the same time but in different mounting configurations (a). PLRs before (blue) and after (orange) the windstorm event for the different buildings (b)

to the module [5]. In addition, naturally occurring hail may not be round, as used in indoor tests. Furthermore, differences in mounting configuration between indoor and outdoor settings may be present. Finally, after exposure to hail outdoors, thermal cycling from diurnal and seasonal changes always follows the hail exposure. Thermal cycling is used following larger hail exposure in the more stringent hail testing standard IEC technical specification 63397, which was published at the end of 2022 [6]. More widespread adaption of this new standard is required to validate or fine-tune the test procedure and improve product quality.

As with hail, systems exposed to differing high wind speeds reveal an analogous threshold behaviour shown in Figure 4. For the wind analysis, we found the threshold to be about 90 km/hour or about 55 miles/hour, below which no higher PLRs can be detected. However, most systems exposed to higher wind speeds exhibit higher PLRs after windstorm exposure. In this case, most but not all systems display this behaviour because some sub-systems are wind sheltered by other systems or adjacent structures at the same site. An informative example of this performance is presented in the next figure, Figure 5. This is a site in the desert Southwest of the United States of America (USA) where the same modules were installed on different buildings in different mounting configurations. PLRs before a severe windstorm are given again in blue. The initial different degradation behaviour is because of the mounting. Building A and the gymnasium have large sections close-mounted to metal roofs and therefore experience higher degradation prior to the storm. After the windstorm, which was situated to the Northwest of the site, the gymnasium, as the highest building, exhibits a substantially higher PLR. In contrast, building A shows unchanged behaviour because it was wind sheltered by the gymnasium. Buildings D (carport) and B were precariously exposed to wind gusts in the 90-115 km/hour range and exhibit greater PLRs after the storm. However, building C shows almost unchanged behaviour despite the exposure.

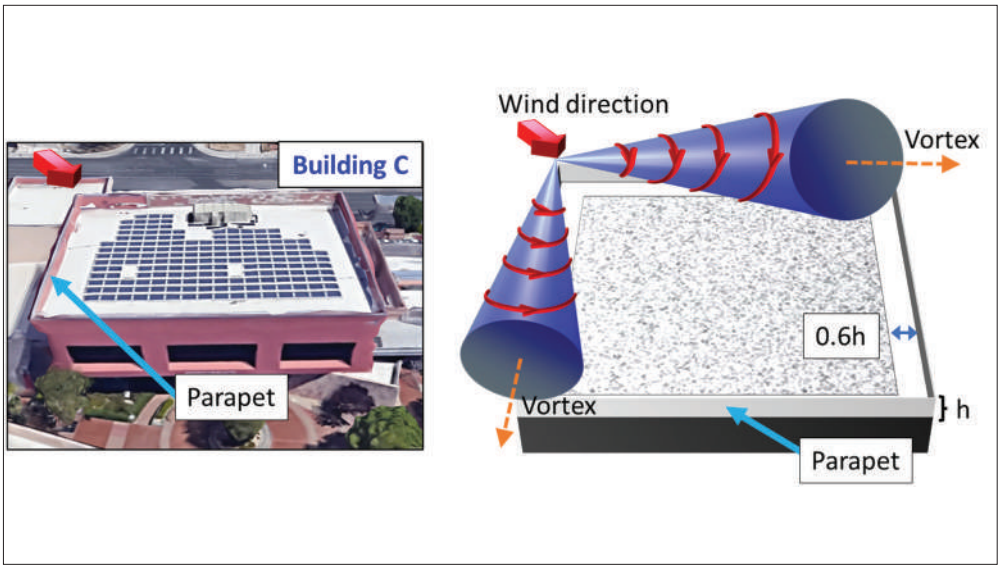


Figure 6: Three-dimensional view of the PV system on building C (a). Illustration of vortex formation atop a building circumscribed by a parapet, adapted from the Structural Engineers Association of California (b)

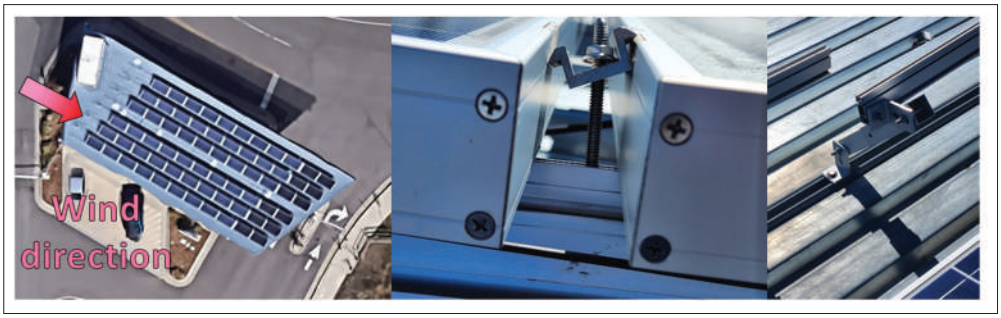


Figure 7: Satellite view of a PV site in Colorado, USA impacted by a windstorm in the same 90-115 km/h category (a). Double clamp failure (b) and bent mounting rack (c) after the storm

"A long tail extending to 60% annual losses is an ominous sign of the risk extreme weather may pose to PV production. Yet the PV community can be proactive by focusing on quality systems, components, designs and installations"

An explanation may be provided in Figure 6 with an adaptation from the Structural Engineers Association of California. The top of building C is surrounded by a parapet that can have an important impact on the resilience of the PV system. As the wind flows across the building, vortices form at the edge of the building where modules, if mounted in that zone, can experience pronounced uplifting forces. The width of this zone depends on a variety of factors such as wind speed, the parapet height, etc. [7]. Building C has no modules mounted in the zone that experiences strong forces, which may provide an explanation for the almost unchanged long-term performance of the system.

In contrast, the system in Figure 7 was exposed to similar wind gusts, but it is immediately noticeable that the modules are very closely mounted to the edge of the roof without a parapet. In this case, modules were damaged and about half a dozen modules were uplifted from the roof to the ground. Yet, improvements in the design of the system and in the quality of the installation could have possibly prevented the damage the system incurred. The usage of double clamps, Fig. 7 (b), is not recommended for high wind-prone areas. Instead, through-bolting is the preferred method [8,9]. In addition, adequate mounting strength brackets are needed for such exposed locations, Fig. 7 (c).

A third weather type we examined for long-term performance losses was extraor-

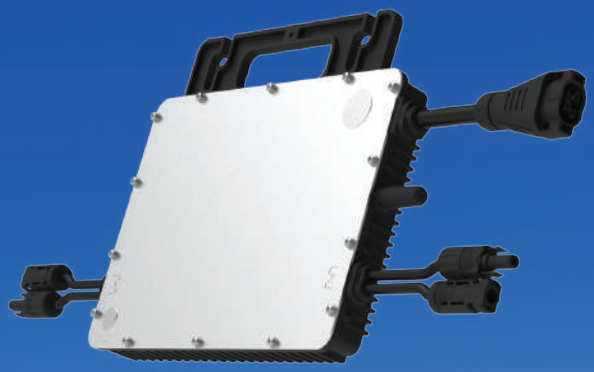
hoymiles

POWER UP YOUR BALCONY

Lower energy bills

Built-in Wi-Fi

No-brainer setup



HMS-W SERIES MICROINVERTER

Industrial+ grade Wi-Fi module

1/2 inputs and MPPTs

300-1000 W output power

hoymiles.com

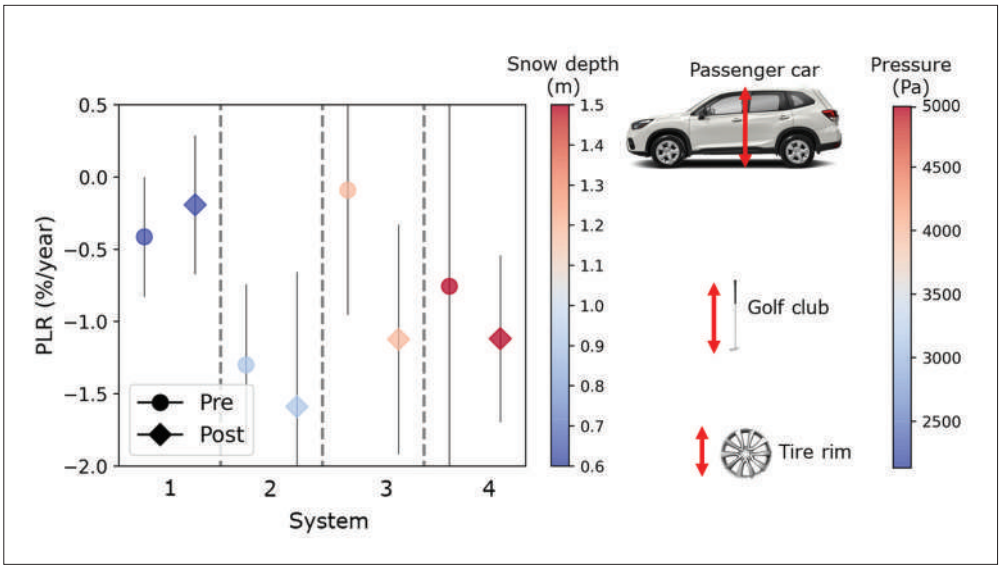


Figure 8: PLR before and after severe snowstorms colour coded by the snow depth ranging from about 0.5 to 1.5 meters. Pressure estimate from the snow depth estimates is shown on the secondary colourbar

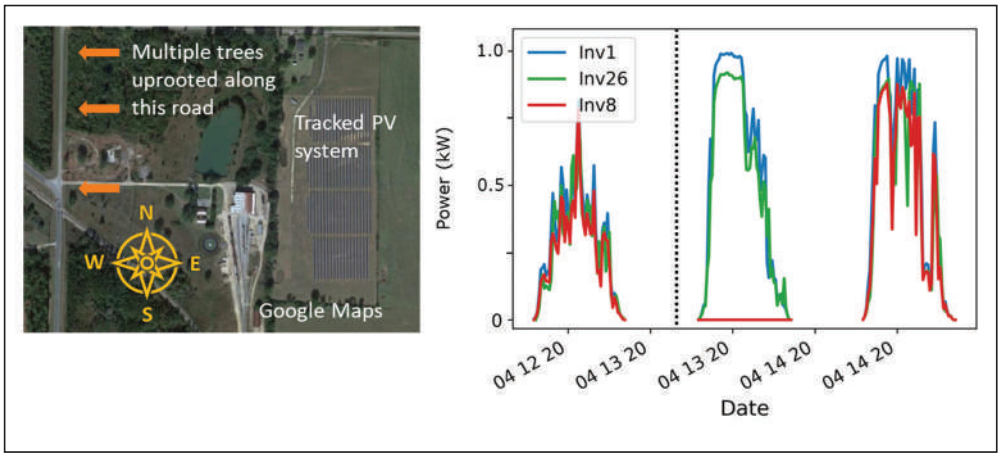


Figure 9: PV system impacted by a high wind event (a). Power production for three representative inverters of the system within one day of the event (b). The vertical dotted line indicates the timing of the event

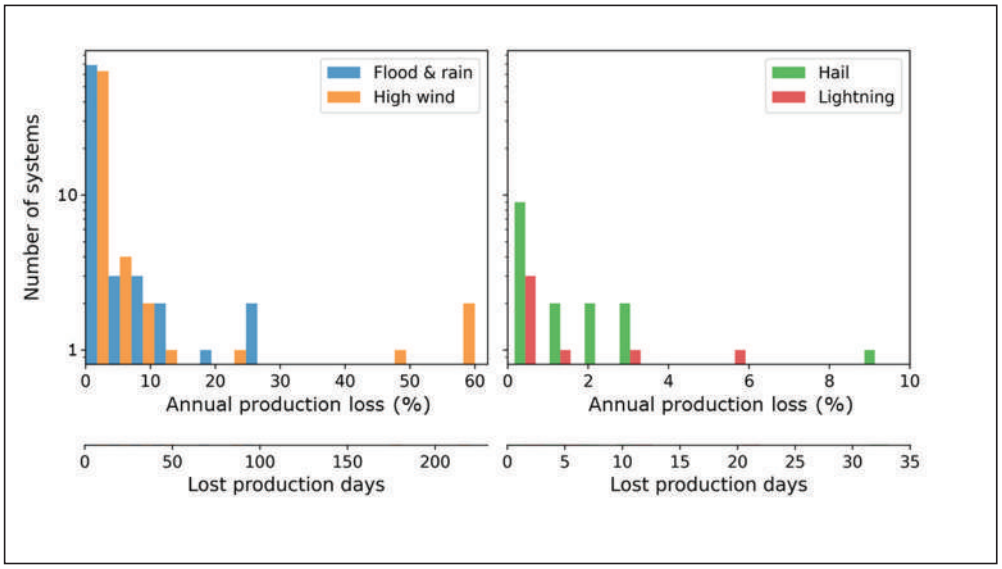


Figure 10: Histograms of the production impact caused by extreme flooding and high wind events (a) and hail and lightning (b). The secondary horizontal axis displays the lost production days

dinary snowstorms, as shown in Figure 8. The data is coloured by snow depth and pressure in Pascals, with size comparisons shown. The weight of snow can vary considerably from 0.2kg per centimeter (cm) of depth per square meter (m^2) of area of dry snow to ca. 9kg/(cm m^2) of ice [10]. In this case we used a medium value of typical wet snow of 3.8kg/(cm per m^2). All these systems were located in northern latitudes making it unlikely that the snow melted quickly after the storms. Furthermore, the storms impacting these systems were all associated with considerable wind exposure in late winter, increasing the likelihood of high-water (heavy) content. No direct measurements of the water content of the snow were available, therefore the conversion into pressure should be considered only as an approximate value. Similar to wind and hail, a threshold of ca. 1 meter depth seems to exist, above which higher PLRs may be expected. However, higher quality data is needed to confirm these preliminary findings.

Short-term results

Apart from long-term consequences, short-term outages can occur following extreme weather events, an example of which is shown in Figure 9. In that case, a small tornado uprooting several trees along the North-South running road was reported. The production of three inverters within a day of the event is given in Figure 9 (b). The dotted vertical line indicates the timing of the wind event. At this particular site 26 inverters were installed, but only one of them is offline the day following the tornado. Therefore, this particular plant lost only the production of one inverter on one day. Inspecting all the time series following storm events, we can integrate the lost production for all 170 identified crystalline silicon systems.

It is important to note that multiple storm effects can be associated with a single storm. For example, flooding and heavy rain could occur within hours over a single storm, and both events would be considered contributors to a PV system outage. We also estimated lost annual production from the downtime intervals using PVWatts simulation [11]. Figure 10 (a) displays the distributions for flooding and high wind events and hail and lightning in Fig. 10 (b). The primary horizontal axis displays the estimated production loss while the secondary horizontal axis shows the number of lost production days. Both overlaid histograms exhibit markedly skewed distributions although at different scales. At the median, all these weather events have an impact of around 1% annual lost production or

Event	Systems within 10 km of event	Systems with lost production	Systems impacted (%)	Median lost production (%)	Median lost days	Systems with more than 2 weeks lost production (%)
Flood & rain	2716	80	3.0	1.1	4.2	0.4
Hail	1010	16	1.6	0.8	3.1	0.1
High wind	2293	74	3.2	0.7	2.7	0.4
Lightning	437	6	1.4	1.0	3.6	0.2
Total	6456	176	2.7	0.9	3.5	0.4

Table 3. Outage summary table

between two and four days, which is relatively small. However, a few systems are much more severely impacted, as can be seen in the tail of Figure 10. More details including the percentage of systems losing more than two weeks of production are provided in Table 3. This tail is especially pronounced for floods and high wind events.

Therefore, from a fleet perspective the short-term impact of these extreme events is relatively minor, yet the risk is exemplified in the long tail of the distributions. Because we did not have full operations and maintenance (O&M) tickets for these specific systems, it is not clear if the loss was caused by damage to the system and possible associated safety aspects or merely a communications issue. Finally, the risk associated with the long tail of lost production demonstrates the need to continue to build systems engineered to withstand safely the extreme weather that may occur over the decades-long expected lifespan of the modules.

Conclusion

Severe weather has been increasing in frequency and impact. We investigated the impact of some of these severe events on the performance of PV systems from a fleet perspective. Median short-term outages led to production losses of only approximately 1% of annual production per event. Yet, a long tail extending to 60% annual losses is an ominous sign of the risk extreme weather may pose to PV production. Long-term consequences in the form of increased degradation beyond specific thresholds were found for hail, high-wind and snow events. Yet, the PV community can be proactive and minimise the impact of these serendipitous events by focusing on quality systems, components, designs and installations. More stringent hail testing and adoption of a higher hail testing standard is required. Different testing for dynamic (wind) and static (snow) mechanical loading may be required to improve system resilience. Quality design and installations are also an integral part of storm resilience and require the development of a well-trained workforce. However, recent industry trends such as larger module formats, thinner cells and thinner front glass may increase system vulnerability. Despite these long-term challenges, PV can provide extensive backup power and save lives when infrastructure is damaged by extreme weather events. Finally, although this study is limited to events and deployments in the USA, we hope to lessons can be applied internationally. ■

Turn to p.22 for insights into designing more resilient PV systems

Acknowledgement

The authors would like to thank James Elsworth, and Katherine Jordan. This work was authored in part by Alliance for Sustainable Energy, LLC, the manager and operator of the National Renewable Energy Laboratory for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under Solar Energy Technologies Office (SETO) Agreement Number 30295. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

References

1 NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023).
2 M. Deceglie, A. Nag, C. Deline, A. Shinn, G. Kimball, D. Ruth, D. Jordan, J. Yan, K. Anderson, K. Perry, M. Mikofski, M. Muller, W. Vining, RdTools v2.1.0 beta.1. Computer Software. https://github.com/NREL/rdtools. DOI: 10.5281/zenodo.4307010.
3 M. Sengupta, Y. Xie, A. Lopez, A. Habte, G. Maclaurin, J. Shelby, "The National Solar Radiation Data Base (NSRDB)", Renewable and Sustainable Energy Reviews 89, pp. 51-60, 2018.
4 D.C. Jordan, C. Hansen, Renewable Energy, 209, 393 (2023).
5 P. Bostock, "Hail Cat: Presenting a Method to Identify, Quantify, and Mitigate Hail Risk", PV Reliability Workshop, Golden, CO, USA, 2023.
6 IEC TS 63397:2022, "Photovoltaic (PV) modules – Qualifying guidelines for increased hail resistance", 2022.
7 Structural Engineers Association of California, Wind Design for Solar Arrays, Report SEAOC PV2-2017, July 2017
8 C. Burgess., S. Detweiler, C. Needham, F. Oudheusden, "Solar Under Storm Part II: Select Best Practices for Resilient Roof-Mount PV Systems with Hurricane Exposure", Clinton Foundation, FCX Solar & Rocky Mountain Institute, 2020.
9 National Renewable Energy Laboratory, Sandia National Laboratory, SunSpec Alliance, and the SunShot National Laboratory Multiyear Partnership, "Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems", National Renewable Energy Laboratory. NREL/TP-7A40-73822, 2018.
10 https://roofonline.com/weights-measures/weight-of-snow/?utm_content=expand_article
11 M. Sengupta, Y. Xie, A. Lopez, A. Habte, G. Maclaurin, J. Shelby, "The National Solar Radiation Data Base (NSRDB)", Renewable and Sustainable Energy Reviews 89, pp. 51-60, 2018.

Authors

Dr. Dirk Jordan is a Distinguished Member of Research Staff at the National Renewable Energy Laboratory in Colorado, USA. He received a Ph.D. in physics from Arizona State University and a B.S. in physics from the University of Heidelberg, Germany. He specialises in performance and degradation of PV modules and systems.

Kirsten Perry is a data scientist at NREL in the PV Reliability & System Performance Group. Her research is primarily focused on developing solar analytical solutions to assess photovoltaic field performance data, with a particular emphasis on applying deep learning and machine learning techniques.

Robert White is a senior data scientist with a background and degrees in astrophysics from New Mexico Tech and the University of Texas. He has been working at the National Renewable Energy Laboratory for 15 years in PV materials and performance, focusing on autonomous systems and big data analysis.

Josh Parker is a photovoltaic research technician at the National Renewable Energy Laboratory. His focus is on diagnostics, fabrication, instrumentation, and calibration of diverse outdoor testbeds on NREL's campus. Josh comes from an extensive background in BMW automotive repair and diagnostics.

Byron McDanold is a research technician at the National Renewable Energy Laboratory specialising in long term photovoltaic reliability and durability. He received his bachelor's degree in mechanical engineering from the University of Colorado, Denver. Byron specialises in the construction, maintenance, instrumentation, and calibration of numerous long-term outdoor tests.

Dr. Chris Deline is the group manager of the PV Field Performance Group at the National Renewable Energy Laboratory. He also manages the PV Fleet Performance Data Initiative, which aggregates and analyses third-party field performance data and manages the PV Proving Grounds programme for field assessment of novel PV technologies.

The nuts and bolts of PV resilience

Credit: NREL

System design | Research shows the ability of PV systems to withstand extreme weather conditions is down to rigorous design. James Elsworth of the National Renewable Energy Laboratory in the US looks at some of the engineering methods for bolstering PV infrastructure resilience in the face of ever increasing climatic and environmental threats

Extreme weather is the leading cause of power system outages [1]. Extreme weather events are increasing in frequency and severity and climactic conditions are worsening [2]. This will have increasing impacts across the power system, including on solar PV system assets.

PV systems, like other power system infrastructure, are vulnerable to damage and failure from a wide range of threats, including tropical storms, hail and winter weather. PV systems have many advantages over large, centralised power generation assets, but also have their unique vulnerabilities.

PV can and has served as a resilient power source by surviving extreme weather events and delivering power to communities afterwards. There are many examples of this, including [4] and [5]. On occasion, however, PV systems have suffered damage that has prevented them from fulfilling this potential. Much of this damage could have been avoided with better design and installation practices. Many of these practices are simple and inexpensive.

This article focuses on PV structural resilience to extreme weather events, and how best practices for PV system design can promote resilient PV infrastructure and reduce its vulnerability to damage from extreme weather events.

The Why (why have PV systems failed)

While PV can be and has served as a resilient power source, it has failed to do so on occasion. This results in damaged assets, power capacity that cannot be delivered to communities after extreme weather events, and potential reputational damage for the industry.

Sometimes the events causing failures are *force majeure* type events surpassing what structures were designed to withstand. PV systems sometimes fail during below design level events, though, highlighting areas for design improvements.

PV is a young industry, and design practices haven't yet matured to match that of many other industries. PV structures are unique, with significant differences from buildings, yet building codes are commonly used as the basis for PV design. The lightweight nature of PV systems, for example, makes them more susceptible to movement and being affected by dynamic loading. This system movement can lead to loading on system components that they aren't designed to withstand.

All structures have natural frequencies that, if excited, can lead to resonance in the structure. Wind forces can excite these frequencies in PV structures and lead to resonant effects, causing increased movement of the structure and possible structural failure. Tracker systems are especially prone to this [8].

The author surveying PV modules damaged by wind-blown debris. Increasingly extreme weather is a growing threat to PV systems worldwide

Recurring loads from wind or snow events can degrade PV structures. Design standards, however, typically only stipulate a onetime maximum magnitude event design threshold (i.e., design wind speed) [7]. The impacts are different (e.g., a one-time 115 mph wind gust compared to 90 mph wind gusts six times a year). So, structures aren't always designed for the loads they will experience.

PV systems are also being installed in new locations, exposing them to more and more varied conditions [6].

There is significant ongoing work aimed at updating PV standards [9] to reduce failure modes, but until PV codes and standards come to maturity and address these issues, it is important to realise that basic design standards aren't always adequate and that these standards can be misinterpreted by designers. PV project developers and owners can demand more robust, resilient systems by requiring additional specifications and standards beyond the few that are commonly used.

Other factors contributing to PV system damage range from poor installation practices to counterfeit components, though system design is the focus of this article.

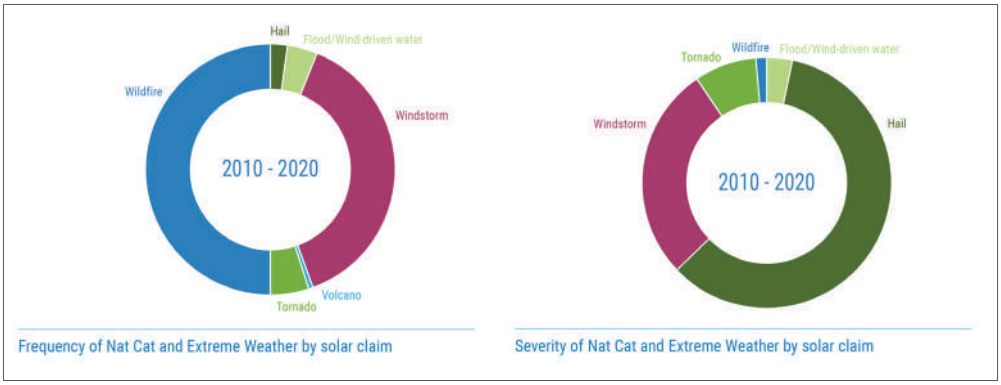


Figure 1: Insurance claimed losses to PV systems based on number of claims (left) and total dollar value of claims (right) shows that wildfires and windstorms have most frequently impacted PV systems, while hail and windstorms have caused the most damage [6]

The What (what has caused PV systems to fail)

PV systems have survived many types of extreme weather. Windstorms and wildfire are the perils that impact solar PV most frequently, though hail and wind events have caused the largest losses, based on insurance claim data (Figure 1).

Most locations are vulnerable to at least one of the hazards given in Figure 1, making PV design for extreme weather far-reaching.

The Where (where have PV systems failed)

Events that have caused PV system failures are not limited to locations prone to the most extreme weather. Poorly designed and installed PV systems have experienced failures from less severe events, as well. While PV damage is rarely reported or publicised, there are enough examples of failures to be confident that they occur everywhere.

The How (how have PV systems failed)

PV systems are composed of various components that must work together. The two main sub-systems—the structural system and the electrical system—can both suffer damage from extreme weather events.

Structural

The structural system comprises PV modules, racking systems, foundations and all the connections between and within these components. Hail is most likely to impact PV modules. Snow is most likely to cause module or racking failure. Wind can cause impacts to all components, especially the structural connections.

Structural connections in PV systems typically consist of nuts, bolts and clamps that connect modules to the racking structure, racking elements to each other, and the racking structure to the foundations or roof. Module attachments have been the most common failure mode in numerous events [11, 12, 13].

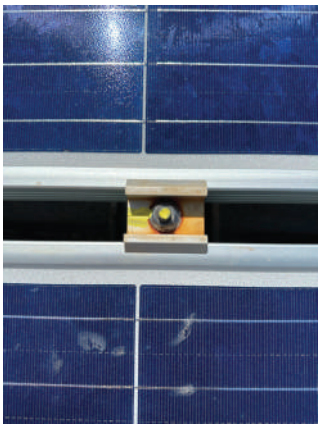
There are two main approaches to attaching modules to the racking: clamp systems and direct bolting. Clamp systems typically apply a clamping force from the top of the module frames at four or more points on the module. One clamp typically holds two adjacent modules (Figure 2).

Top clamp products vary significantly in several ways:

- The amount of contact area between the clamp and the top of the module frame. Small contact areas make it easier for modules to come free of the clamps.
- The amount of contact area between the clamp hardware (bolt head or nut) and the rail in the support structure. Small contact areas can lead to bolt heads or nuts tearing out of the rail slots.
- The amount of rotation that is needed to release the clamp hardware from the rail slot. Some clamps have small bolt heads that slot into wide rail gaps that can rotate out of the rail easily (after only 45-65° of rotation). System vibrations or poor initial torquing can allow this rotation.

Each of these three are places where top clamps have failed. Determining exact minimum specifications for these three clamp parameters is an area where future work is needed, but designers should consider them when selecting between different products.

Top clamps also typically hold adjacent modules simultaneously. This means that if one module comes loose or is damaged, then the adjacent module may no longer be held securely, and it

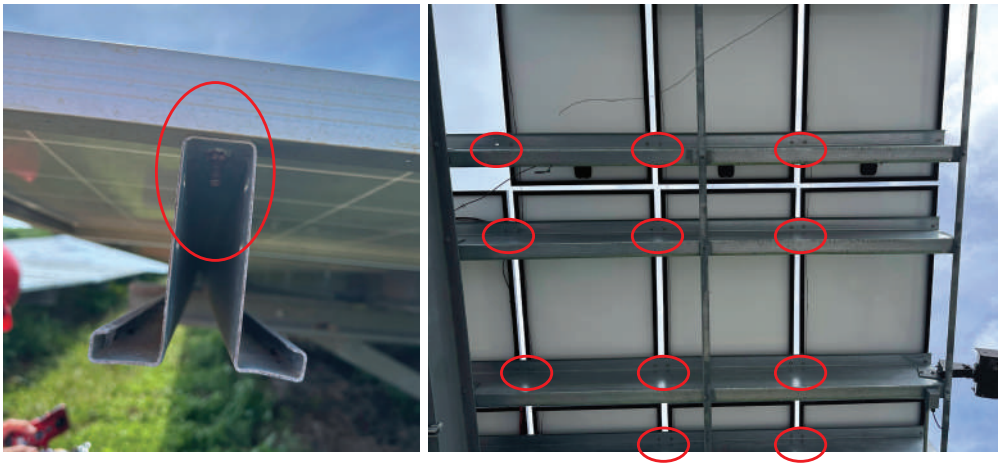


Credit: James Elsworth & Otto Van Geet, NREL

Figure 2: Various top clamps that are commonly used to attach PV modules to racking systems. Left: A "mid-clamp" that holds adjacent modules simultaneously. Right: The nut or bolt head of top clamps typically fits into a slot in the racking rail

Credit: James Elsworth, NREL

Figure 3: Cascading/progressive failure of two rows of modules. One (or a small number) of failures can lead to the loss of many neighbouring modules. This is because the top clamps used require the presence of two adjacent modules to maintain adequate clamping force. If one module comes loose, the whole row is vulnerable to failure



Credit: James Elsworth & Otto Van Geet, NREL

Figure 4. Various through-bolting approaches in which the bottom flange of the module's metal frame is bolted directly to the racking system underneath

can then come free. The same can then happen for the subsequent module. The result is that an entire row of modules can be lost because of one point of failure (Figure 3).

Through-bolting is where the module is directly bolted to a racking rail below (Figure 4). Compared to clamping, bolts aren't shared between modules, so there is no chance of progressive failure. The bolts also cannot simply rotate out of rail slots. Through-bolting can be difficult, however, for rooftop systems where installing bolts under modules may be impractical. There is also more labour time involved in through-bolting. The most common through-bolt failure is bolts tearing out of either the racking rail or module frame.

The location of the module attachments has a significant impact on the load ratings of the modules. Module installation manuals give load ratings for various mounting locations. Figure 5 shows that for one module, the uplift load rating can be as high as 4,300 Pa or as low as 1,600 Pa based on mounting location. Some sites assume top load ratings despite not mounting modules in the locations that will achieve these load ratings.

Certain features of PV racking systems can also contribute to PV system failures, especially from wind events. Racking with high tilt angels or systems that mount panels high above the ground or roof surface are particularly prone to wind damage. Many racking systems use thin gauge steel and are only designed to resist upward and downward loads. These are vulnerable to damage from loading along other axes.

Meanwhile, tracker systems have failed several ways. Moment forces on the torque tube have caused failures, especially at splices between sections of torque tube. Modules on tracker systems are also typically attached closer to the centre of the module. This overhang means the top and bottom of modules are susceptible to damage from wind and snow load forces at the edges of the modules they aren't rated to withstand. Load ratings are lower as a result (Figure 5, bottom).

Electrical

Much of PV design for extreme load conditions focuses on module load ratings. PV system failures, however, are usually not a result of module loading failure, suggesting that other system-level considerations should take design priority.

Electrical systems on PV structures are also vulnerable to damage from extreme weather. Water ingress into electrical enclosures and conduit has caused failures. Insufficient wire management systems can leave cables and PV connectors dangling where winds and water can cause damage.

How to design (more) resilient PV infrastructure

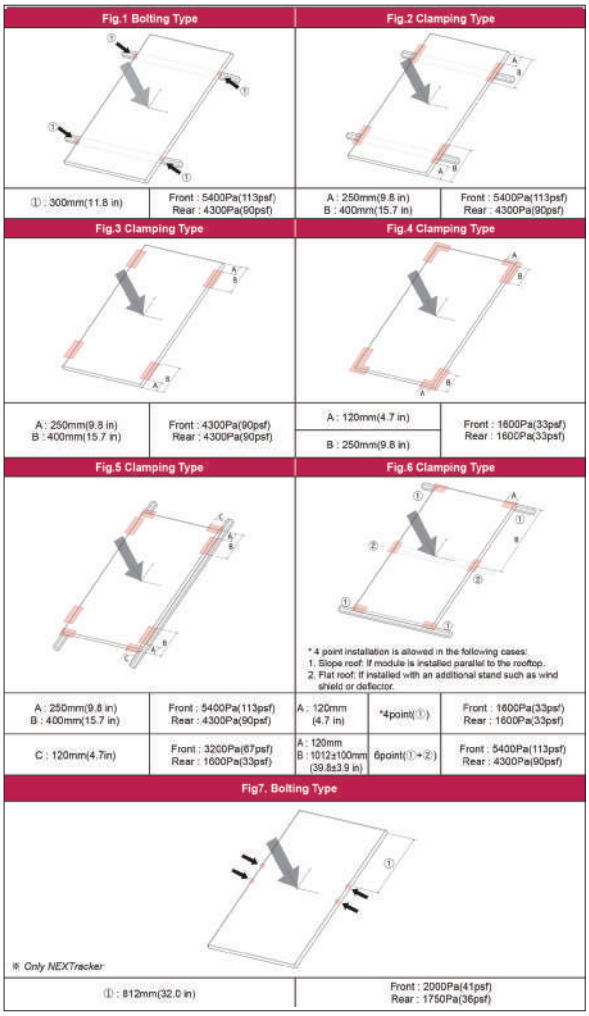
A resilient solar PV system is one that can withstand the conditions it will experience in the field. While resilient PV design is site-specific, there are some principles that apply for designing systems to be resilient to specific threats.

High wind resilient PV design recommendations

Layout Where possible, install large fixed-tilt ground-mounted systems at low tilt angles, low to the ground, with front and rear support posts and cross bracing [14]. Do not install PV modules in corner zones on roofs. See SEAOC PV 2-17 for guidance [15].

Module attachments Through-bolt modules to the racking if feasible, using washers large enough to prevent bolt tear-out. For more information on these types of fasteneres see [11]. If using top clamp module attachments, choose clamps that hold modules individually. Select clamps with greater surface clamp area (both on the module frame and on the racking) that cannot easily rotate out or tear out of the racking [14]. Additional module attachment points help and can give the modules higher load ratings. Six mounting points are sometimes used in areas with higher design wind loads but may require the installation of an additional racking rail. More attachment points don't necessarily increase resilience if the attachment is poor to begin with [11].

Bolted Joints Torque all system bolts as specified and perform a torque inspection annually [11]. Use locking hardware on bolted joints to prevent loosening. Lock bolts, wedge-lock washers, Belleville washers, thread lock, and nylon inserts can all help. Do not use split washers



Credit: https://www.lg.com/us/business/download/resources/BT00002151/BT00002151_2571.pdf

Figure 5: Module installation manuals show front and rear load ratings for various mounting configurations. This module can achieve up to 5,400 Pa front and 4,300 rear load ratings. With tracker mounting holes (bottom), the module is rated for less than half of that

[11]. All structural connections shall be designed to be slip-critical and redundant, avoiding single points of failure. [16]

Racking The overall goal of the racking structure should be to reduce movement and vibration in the system and transmit loads to the ground or roof. The structure should be designed for dynamic loading and resonant effects. See SEAOC PV 2-17 for guidance [15]. Racking systems should make modules part of the load path. Racking systems should be braced laterally and longitudinally to transmit forces from all directions to the ground or roof. Front and rear posts increase system stiffness and reduce system movement [13].

Modules Smaller modules – 60-cell or equivalent – should be used for rooftops or places with hurricane risk. 72-cell or equivalent are adequate for ground-mounted systems; avoid larger format modules in high wind regions. Modules with 3.2 mm front glass or thicker should resist fracture from flying debris better than those with 2.0 mm glass [17]. Ensure modules are mounted in accordance with the installation manual to give the desired load ratings [11]. Select modules with the highest uplift load ratings – 4,000 Pa or higher – in high wind risk locations [11].

Electrical Use NEMA 4 or 4X rated enclosures on all electrical boxes. Enclosures should also be gasketed, with locking hinges designed to prevent water intrusion from driven rain. Enclosures should have weep holes, be mounted on a vertical surface with conduit entering from the bottom, and designed to prevent water intrusion should water get into the conduit above the enclosure [16].

Mount electrical enclosures above 500-year flood and storm surge levels [11]. Use durable wire management devices, such as those made specifically for PV wire routing. Plastic or nylon wire ties are unreliable; even UV exposure-rated ties aren't adequate. Should wire management fail, wires and PV connectors can dangle or lay on the ground or roof, prone to damage from water, animals, or wear from wind gusts [11].

Ensure cables are not taut against sharp edges of conduit or module frames. Sharp edges can wear through cable insulation through thermal expansion cycles, wind gusts, or gradual system movement over time [11].

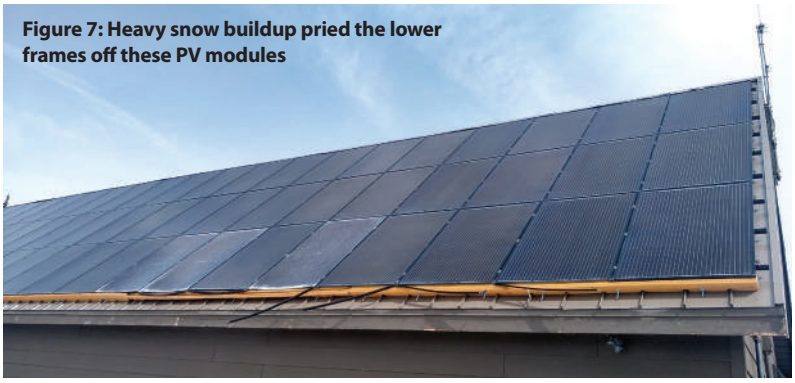


Figure 7: Heavy snow buildup pried the lower frames off these PV modules

Credit: Aaron Bougie, NPS

Hail

PV systems have fared well in hailstorms, though some very large events have damaged PV systems. Hail has been the greatest contributor to insured losses on PV systems worldwide [6]. To help increase resilience of PV systems in areas prone to severe hail:

Modules Select modules with 3.2mm or thicker front glass (Figure 6) [17]. Select modules with frames, the thicker the better [19]. Select smaller modules, such as 60-cell or equivalent [18].

Minimum hail certification and lab tests are not sufficient. Require that modules pass a more stringent test, such as the IEC TS 63397 tests for 50mm hail, FM Global Standard 4478, RETC's Hail Durability Test, or PVEL's Hail Stress Sequence [18].

System considerations For fixed-tilt systems, higher tilt angles reduce the likelihood of a direct impact [20]. For trackers, select a system with a "hail stow" mode that rotates modules to maximum tilt in hail events. Engaging stow typically takes minutes and communications and controls need to be fully functioning to engage [20].

Pre- and post-storm Some hail damage may not be obvious. Hail can cause microcracks that can hurt production over time. Conducting pre-storm baseline and post-storm imaging of panels allows a complete storm damage assessment.

Snow and winter weather

Winter weather events bring snow accumulation and ice. Best practices to avoid winter weather event damage include:

Modules Select modules with front test load ratings of at least 5,400 Pa, when mounted in accordance with the installation manual. Additional mounting points can increase the load rating [21]. Employ IEC 62938 standard for non-uniform snow loads [22]. Use smaller modules [21]. Orient modules in landscape to allow for greater production as snow melts off the top and middle thirds of modules.

Frameless modules allow snow to slide off the modules more easily. In some cases snow and ice loads have forced the bottom frames off of PV modules (Figure 7). Frameless modules often aren't rated to withstand loads as high as framed modules. Load rating should take precedence over the framing [23].

Racking and tilt angle Higher tilt angles allow snow to shed off modules more easily. Select tilt angle consider-

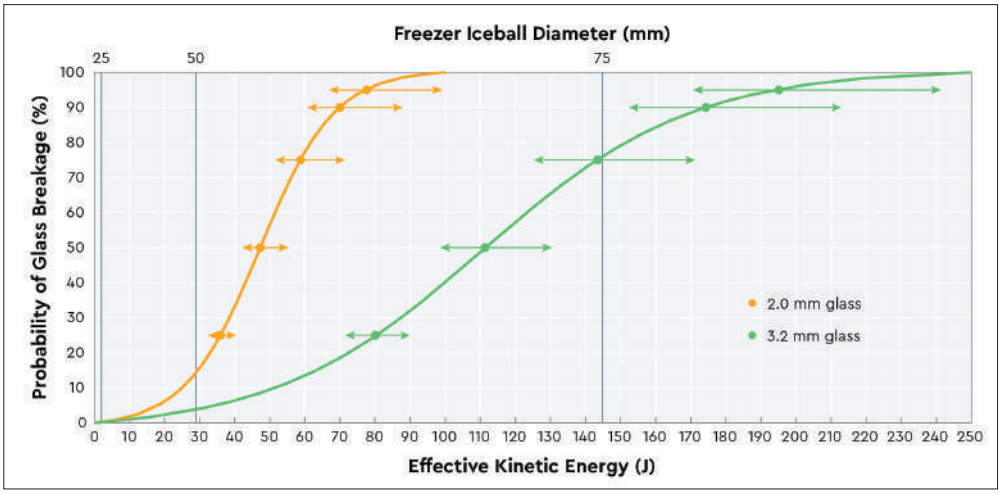


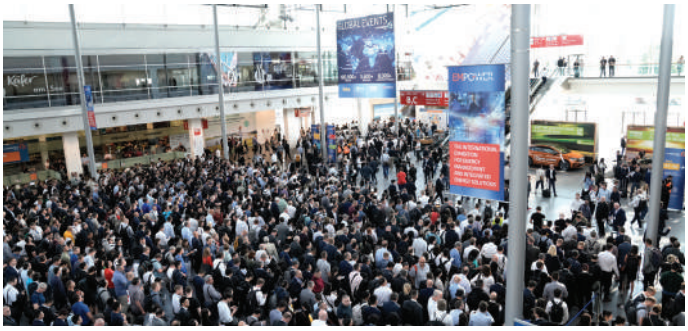
Figure 6: Lab testing shows that it takes higher impact energy to break glass on modules with 3.2 mm glass than on those with 2.0 mm front glass [17]

The World's Leading Exhibition and Conference Series for the New Energy World

Dear solar enthusiast,

The world has entered its solar terawatt age and will hit the 2 TW mark within the next three year. Citizens, businesses, and governments around the world are recognising the immense power of the sun to secure energy sovereignty, protect the climate and provide relief from high energy prices.

Started as the local exhibition, "Solar '91" in Germany, Intersolar has already become the most important meeting point for the solar industry in Europe for more than two decades. With the establishment of Intersolar in the United States, India, South America, Mexico and the MENA region, Intersolar took the leap to promote the expansion of solar energy in the most important global markets - paving the way for a sustainable energy system based on renewable energies. Providing a space for networking,



trading as well as experiencing solar technology innovations was the initial focus.

The increasing electrification of the mobility and heating sector as well as the use of hydrogen or synthetic gas in the context of Power-to-X require cross-industry and cross-sector solutions. We wish to promote these solutions together with the relevant players.

This is why we have created The smarter E, the leading innovation and communication platform, which focuses on the generation, storage, distribution and use of energy and its intelligent and interlinked interaction.

We open markets, promote knowledge exchange and at the same time offer a global stage for innovation. Our vision: a renewable, decentralised, digital energy supply available around the clock.

Watch out for the next opportunities to connect your solar and renewable energy business! www.TheSmarterE.com

inter solar
connecting solar business

www.intersolar-events.com

2024 INTERSOLAR EVENTS

The World's Leading Exhibition Series for the Solar Industry

- **JANUARY 17–19, 2024, SAN DIEGO, USA**
  www.intersolar.in
- **FEBRUARY 21–23, 2024, GANDHINAGAR, INDIA**
  www.intersolar.in
- **APRIL 16–18, 2024, DUBAI, UAE**
  www.intersolar.ae
- **JUNE 19–21, 2024, MUNICH, GERMANY**
  www.intersolar.de
- **AUGUST 27–29, 2024, SÃO PAULO, BRAZIL**
  www.intersolar.net.br
- **SEPTEMBER 3–5, 2024, MEXICO CITY, MEXICO**
  www.intersolar.mx
- **INTERSOLAR SUMMITS WORLDWIDE**
  www.intersolar-summit.com

Follow us

ing increased wind loads that come at higher tilt angles [24]. Elevate system so that modules are high enough to give room for accumulation of shedded snow underneath. Allow at least two feet above maximum normal snow depth [21]. Trackers with a "snow stow" mode can reduce snow buildup on modules and allow faster shedding [21]. Ice formations on structures can cause additional loading on racking, cables, and other components. Categorise solar racking and components as "ice-sensitive structures" and follow according ASCE 7 guidance [7].

Foundations Freezing and thawing grounds in cold climates can lead to forces on foundations that push them up out of the ground. Design for this "frost heave," even though it isn't required in most building codes. Consider frost depth in determining the depth of the foundation. [25] provides guidance for frost heave calculations for solar PV systems.

Site considerations Install perimeter markings around arrays where snow may accumulate and bury an array. This will help prevent damage from snow removal crews or vehicles [21].

Construction Even the most robust, resilient PV system design can be totally negated with poor installation. A challenge lies in creating design specifications that limit room for installer error or procurement of unspecified components.

O&M While design and installation of PV systems will have the most impact in extreme weather resilience, operations and maintenance activities can keep systems in good shape and identify vulnerabilities that may be exposed in extreme weather. Regular activities include:

- Visual inspections for loose cables, taut cables, modules with broken glass, and deformed modules or racking.
- Structural bolt torque audits on the module attachments and racking structure to ensure bolts haven't loosened. Workers should be trained on how to properly torque check bolts and tighten them to torque specifications (not too tight or too loose) using a calibrated torque wrench [11].
- Testing of tracker stow systems and controls.
- Thermal or EL imaging of system to identify invisible damage and vulnerabilities. These can serve as a baseline to reference after any damage from future events.

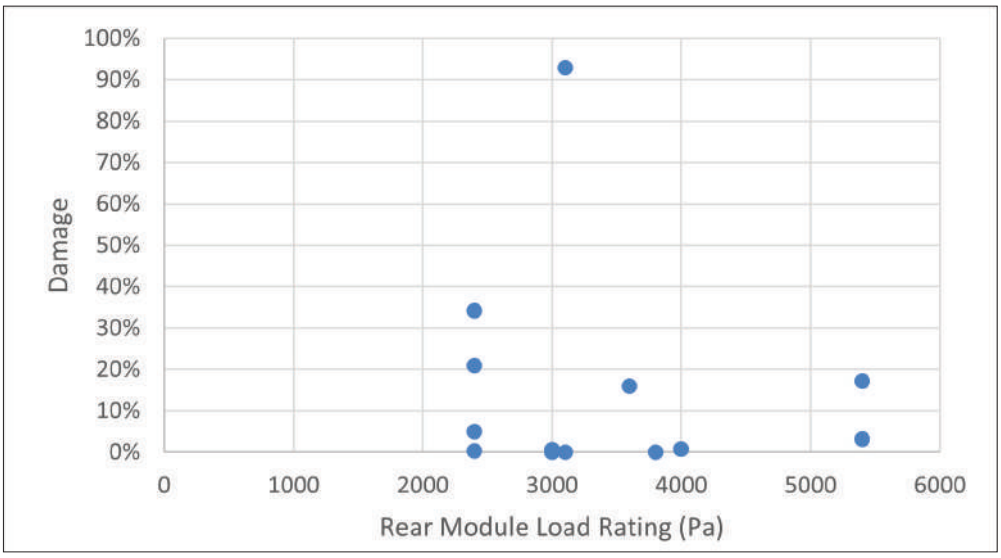


Figure 8: There was no correlation between module wind load (rear pressure) test ratings and damage suffered across the systems visited after Typhoon Mawar in Guam. Percent damage on these systems was assessed by taking the percentage of modules that were missing or broken

Post-event After a storm or other extreme weather event, clean up the site to remove any modules or other debris which could cause damage in a subsequent storm. Do a visual inspection and record damage to all system components. Perform electrical string level testing of open circuit voltage and short circuit current before repowering the system. Perform thermal or EL imaging.

Case Studies

Guam – Typhoon Mawar

Typhoon Mawar struck Guam in May 2023, reaching sustained wind speeds of up to 140 mph and causing damage to PV systems and other infrastructure. Findings from post-storm PV damage assessment of 29 PV systems can inform resilient PV design globally. There were systems with no apparent damage, as well as systems that were completely lost, with those two cases sometimes occurring on neighbouring arrays [14]. Failures were most commonly the result of:

- Inadequate module clamping;
- Module clamps rotating out of underlying support rail. This often led to cascading failure;
- Debris impact on modules resulting in a fracture;
- Excessive tilt angle (greater than 5 degrees increased risk).

There was no clear evidence of modules failing due to direct high wind loading, despite how much focus in PV wind design is given to module load ratings. Other structural system failures were far more prominent, suggesting modules load ratings should be a secondary wind load design consideration. To further support this, module load ratings show no correlation to system damage (Figure 8).

Percentage of missing or broken modules was used to estimate the failure rate on each system, summarised in Table 1. Rooftop damage is inflated by a handful of systems that experienced total loss. Of the 25 rooftop systems observed, 17 had less than 5% damage. Two of the ground-mounted systems were in locations that experienced lower wind speeds. On the canopy system, the structure was undamaged, but module attachments tore out of the frames.

Interestingly, wind speed did not appear to be a determining factor in how much damage systems suffered (Figure 9). Several systems experiencing gusts above 180 mph survived completely, while some systems that had gusts of

System Type	Missing or broken modules	Total modules	Total average failure Rate	Median failure rate	Number of systems
Rooftop	1160	6484	18%	2%,	24
Ground-mount	544	305,291	0.18%	0%	4
Canopy	15	92	16%	6%	1

Table 1: Average damage across 24 rooftop systems, 4 ground-mounted systems, and 1 canopy structure

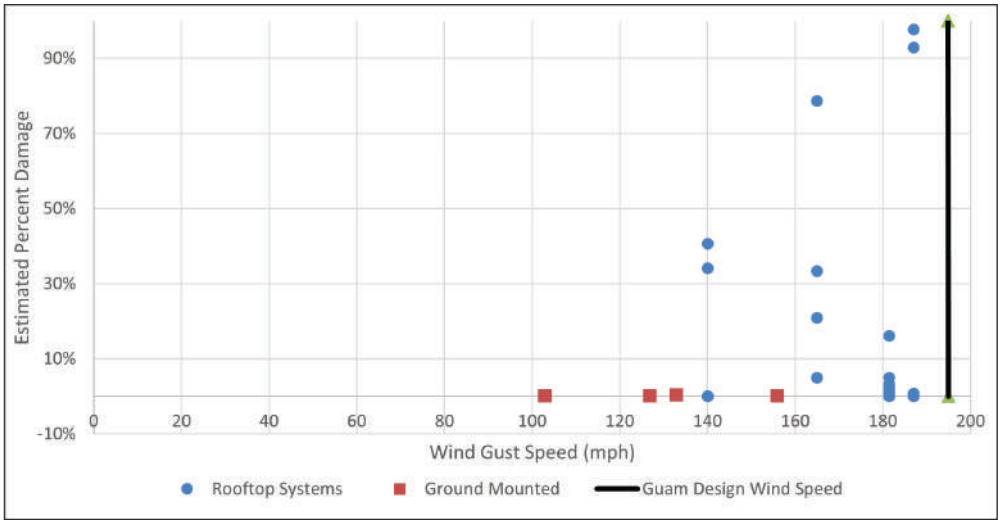


Figure 9: Wind gust speed does not appear to be a determining factor in predicting damage. Attempted curve fits showed no correlation. Wind gust speed was estimated by a National Weather Service post-typhoon analysis

140 mph were substantially damaged. This implies that system design and installation, rather than wind speed, determined the extent of damage. This is encouraging; if PV is designed well, it can survive extreme wind events. Systems that performed best on Guam:

- Were ground-mounted or mounted very close to the roof. On flat roofs, surviving systems typically had tilt angles of 4-5°.
- Used through-bolting or clamping systems with a larger bearing surface (0.4-1.2 in^2 per clamp) or used continuous clamping systems along the entire long edge of modules.
- Used clamping systems that use a "T"-bolt that must rotate 90 degrees to come free from racking, rather than bolts that could rotate free with less rotation (~60°).
- Did not feature modules near the corners of roofs.
- Had racking systems made of thicker gauge components with significant cross-bracing.

As a remote island with 100% clean energy targets, it is paramount that PV installed in Guam learn from these lessons and heed these recommendations to be resilient to future tropical storms.

St Croix, US Virgin Islands – Hurricane Maria

Hurricanes Irma and Maria struck St. Croix in the US Virgin Islands within weeks of each other in September 2017 as Category 5 and 4 storms.

One PV system, a 469kW fixed-tilt ground-mounted system was destroyed. While the conditions in the storm were extreme, a post-storm damage assessment revealed that there were design features and installation practices that led to more damage than was necessary [26], including "lack of beam stiffness, inadequate clamp and fastener use, reliance on outdated codes, and improperly selected electrical enclosures". Wind speeds on the site were lower than the design wind speed of the system.

Before reconstructing the array, an engineering firm was contracted to analyse wind loading at the site and develop specifications for the rebuild. This analysis led to the installation of a PV array that will be much more resilient in the face of future events (Figure 10).

The engineering analysis began with an analysis of PV design codes and where gaps existed that led to these failures. A major gap was that the current codes only required design for static loading—mechanical loads of a fixed magnitude and direction. Wind loading, however, can be dynamic—the load can vary in magnitude and direction, cause turbulence within the array, and can cause system components to sway. Dynamic loading can impart loads on PV systems that they were not designed to withstand, leading to component failure. Dynamic loading can also cause failures by exciting natural frequencies inducing resonance.

The engineering team applied dynamic loading calculations and guidance from SEAOC PV2-2017 [15], analysed the resonant frequencies of various PV system designs and built computational fluid dynamics (CFD) models to find maximum pressure on PV modules under various system designs.

The resonant frequency analysis showed that the proposed tilt angle of 5° was prone to resonance from wind loads. Steeper pitches mitigated the likelihood of wind-induced resonance. Too high a tilt angle, however, led to greater direct wind loading and higher pressures on

Figure 10: A St. Croix PV array was destroyed in a hurricane (top). After extensive engineering analysis and adherence to high quality installation, a much more resilient PV system was installed (bottom).

the panels. A compromise of 12° yielded the lowest overall loads for this specific array and avoided resonance that could occur at lower tilt angles while keeping wind pressure on the panels under their rated loads.

Other design features that helped increase the robustness and resilience of this array included front and rear support posts, locking fasteners, modules with high published load ratings, and lowering the array by one foot compared to standard design.

More detailed information on the array and rebuild can be found at "Toward Solar Photovoltaic Storm Resilience: Learning from Hurricane Loss and Rebuilding Better, https://www.energy.gov/femp/articles/toward-solar-photovoltaic-storm-resilience-learning-hurricane-loss-and-rebuilding

Conclusion

As seen through various examples of systems surviving and failing, often in the same events, it is the characteristics of the system that ultimately have determined survivability, not the magnitude of the event. This should be encouraging, because it is possible to design PV systems that can survive extreme events. Given the current state of codes and standards and relative inexperience of designers in this young industry, however, this may require additional project requirements above the typically required standards. These additional requirements aren't necessarily overburdensome or costly. Little things can make big differences. Following good design fundamentals, down to the literal nuts and bolts, is essential for designing and building resilient PV that can power communities after extreme weather events. ■

Turn to p.32 for insights into the role of trackers in PV resilience

Author

James Elsworth is a mechanical engineer and researcher at the United States Department of Energy's National Renewable Energy Laboratory. His work focuses on assessing and promoting resilience at all scales, from country-wide power system resilience down to the (literal) nuts and bolts of PV system infrastructure. He specialises in hardening solar PV systems for locations experiencing extreme environmental conditions such as hurricanes and high wind events.

References

[1] U.S. Dept. of Energy. 2016, "Electric disturbance events," U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, 2016. http://www.oe.netl.doe.gov/oe417.aspx

[2] NASA. "Extreme Weather and Climate Change," NASA Global Climate Change. https://climate.nasa.gov/extreme-weather/

[3] Hotchkiss, Eliza, Alex Dane, and Connie Komomua. 2018, "Resilience Roadmap," National Renewable Energy Laboratory (NREL), 2018. https://www.nrel.gov/ resilience-planning-roadmap/

[4] De la Garza, Alejandro. 2023. "In Puerto Rico, a Small Town Takes Climate Action Into Its Own Hands." Time. March 20, 2023. https://time.com/6264631/puerto-rico-adjuntas-solar-microgrid/

[5] Sherriff, Lucy. 2023. Babcock Ranch: Florida's first hurricane-proof town. BBC.com. 4th September, 2023. https://www.bbc.com/future/article/20230904-babcock-ranch-floridas-first-hurricane-proof-town

[6] GCube Insurance. 2021. "Hail or High Water: The rising scale of Extreme Weather and Natural Catastrophe losses in Renewable Energy." Q1 2021 Report.

[7] American Society of Civil Engineers, 2022. "ASCE/SEI 7-22: Minimum Design Loads and Associated Criteria for Buildings and Other Structures (ASCE/SEI 7-22)."

[8] Roedel, Alex and Stuart Upfill-Brown. 2018, "Designing for the Wind: USING DYNAMIC WIND ANALYSIS AND PROTECTIVE STOW STRATEGIES TO LOWER SOLAR TRACKER LIFETIME COSTS." NexTracker, A Flex Company, 2018. https://info.nextracker.com/nextracker-designing-for-the-wind

[9] Manning, Jon PE and Steve Gartner, PE. 2021, "New ASCE committee will focus on advancing the reliability of solar PV structures," PV Magazine, June 25, 2021. https://pv-magazine-usa.com/2021/06/25/new-asce-committee-will-focus-on-advancing-the-reliability-of-solar-pv-structures/

[10] World Risk Index. 2022, "Worldmap of Risk 2023," https://weltrisikobericht.de/en/#:~:text=The%20WorldRiskIndex%20indicates%20the%20disaster,mean%20of%20exposure%20and%20vulnerability

[11] Elsworth, James and Otto Van Geet. 2020. Solar Photovoltaics in Severe Weather: Cost Considerations for Storm Hardening PV Systems for Resilience. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-75804. https://www.nrel.gov/docs/fy20osti/75804.pdf.

[12] Burgess, Christopher, Sanya Detweiler, Chris Needham, and Frank Oudheusden. 2020, "Solar Under Storm Part II: Select Best Practices for Resilient Roof-Mount PV Systems with Hurricane Exposure," Rocky Mountain Institute and Clinton Foundation. https://rmi.org/insight/solarunder-storm/ and www.clintonfoundation.org/Solar-Under-Storm.

[13] Burgess, Christopher, and Joseph Goodman. 2020, "Solar Under Storm: Select Best Practices for Resilient Ground-Mount PV Systems with Hurricane Exposure," Rocky Mountain https://rmi.org/insight/solarunder-storm/

[14] Elsworth, James, Otto Van Geet, Chuck Kurnik, and James Salasovich. 2023, "Solar Photovoltaic Damage Assessment after Typhoon Mawar: Findings and Recommendations for Resilient PV on Guam" U.S. Department of Energy's National Renewable Energy Laboratory. Confidential: Not available for public release. Public release version forthcoming.

[15] Structural Engineers Association of California. 2017. "Wind Design for Solar Arrays." https://www.seaoc.org/content.aspx?page_id=586&club_id=32108&item_id=18912

[16] U.S. Department of Energy's Federal Energy Management Program. "Technical Specifications for On-site Solar Photovoltaic Systems." https://www.energy.gov/femp/technical-specifications-site-solar-photovoltaic-systems

[17] RETC. 2022, "2022 PVMI Report," https://retc-ca.com/download-2022-pvmi

[18] U.S. Department of Energy's Federal Energy Management Program. 2023, "Hail Damage Mitigation for Solar Photovoltaic Systems." https://www.energy.gov/femp/hail-damage-mitigation-solar-photovoltaic-systems

[19] Wormser, Paul. 2020, "Investment Confidence," Clean Energy Associates. https://www.pv-magazine.com/wp-content/uploads/2020/12/02_Paul-Wormser_CEA.pdf

[20] Roedel, Alex and Kent Whitfield. 2020, "Mitigating Extreme Weather Risk PART 1: Understanding How Differentiated Design and Control Strategies Unlock New Opportunities for Solar Development," NexTracker, Inc. https://info.nextracker.com/mitigating-extreme-weather-risk

[21] U.S. Department of Energy's Federal Energy Management Program. 2023, "Solar Photovoltaic Hardening for Resilience – Winter Weather." https://www.energy.gov/femp/solar-photovoltaic-hardening-resilience-winter-weather

[22] International Electrotechnical Commission. 2020, "IEC 62938:2020 Photovoltaic (PV) modules - Non-uniform snow load testing, " IEC TC 82 2020. https://webstore.iec.ch/publication/33027

[23] Per-Olof A. Borrebaek, Bjorn Petter Jelle, Zhiliang Zhang. 2019, "Avoiding snow and ice accretion on building integrated photovoltaics – challenges, strategies, and opportunities," Solar Energy Materials and Solar Cells, Volume 206, March 2020, 110306. https://doi.org/10.1016/j.solmat.2019.110306

[24] Powers, Loren, Jeff Newmiller, and Tim Townsend. 2010, "Measuring and modeling the effect of snow on photovoltaic system performance," IEEE, 2010 35th IEEE Photovoltaic Specialists Conference. https://ieeexplore.ieee.org/document/5614572

[25] Newson, T. and Hammad, M. 2022, "Solar Foundation Design in Cold Climates, " GeoCalgary 2022, October 2-5, 2022. https://geocalgary2022.ca/wp-content/uploads/papers/235.pdf

[26] Elsworth, James, Otto Van Geet, Gerald Robinson, Ghazi Bari, Jonathan Calton, John Hickey, Erin Morrison, Kelly Payne, and Kurt Lyell. 2023. Toward Solar Photovoltaic Storm Resilience: Learning from Hurricane Loss and Rebuilding Better." U.S. Department of Energy's Federal Energy Management Program. Feb 6, 2023. https://www.energy.gov/femp/articles/toward-solar-photovoltaic-storm-resilience-learning-hurricane-loss-and-rebuilding

[27] U.S. Department of Energy's Federal Energy Management Program. 2023, "Successful Deployment of a Solar Power System at Mount Rainier National Park." https://www.energy.gov/femp/successful-deployment-solar-power-system-mount-rainier-national-park

SNEC PV+
PHOTOVOLTAIC POWER
CONFERENCE & EXHIBITION

WWW.SNEC.ORG.CN

17th (2024) International Photovoltaic Power Generation and Smart Energy Conference & Exhibition

2024.6.11-15

National Exhibition and Convention Center
(333 Songze Avenue, Shanghai)

Exhibition: June 13-15, 2024
National Exhibition and Convention Center
(333 Songze Avenue, Shanghai)

Conference: June 11-13, 2024
InterContinental Shanghai Hongqiao NECC
(No. 1700 Zhuguang Road, Shanghai)

SNEC ES+
ENERGY STORAGE
CONFERENCE & EXHIBITION

SNEC H_2+
HYDROGEN & FUEL CELL
CONFERENCE & EXHIBITION

WWW.SNEC.ORG.CN

9th (2024) International Energy Storage Technology, Equipment and Application Conference & Exhibition
7th (2024) International Hydrogen and Fuel Cell Technology, Equipment and Application Conference & Exhibition

2024.9.25-27

Shanghai New Int'l Expo Center
(2345 Longyang Road, Pudong District, Shanghai)

◎ **Hosted by: Shanghai New Energy Industry Association**

◎ **Show Management: Follow Me Int'l Exhibition (Shanghai), Inc.**

Add: Room 905-907, No. 425 Yishan Road, Xuhui District, Shanghai, China
For Exhibition: Tel: +86-21-64276991
E-mail: info@snec.org.cn

For Conference: Tel: +86-21-33683167-809 / 810
E-mail: office@snec.org.cn

◎ **International Agent: Follow Me Int'l Exhibition (USA), Inc.**

Add: 2055 Junction Ave., Suite 225, San Jose, CA 95131
Tel: +1.408.386.3373

Fast track out of trouble

Balance of system | Tracker systems are emerging as a key tool in efforts to bolster PV system resilience in the face of extreme conditions. Jonathan Tourino Jacobo looks at some of the latest developments underpinning trackers' growing status as an indispensable ingredient in solar's continued growth

Credit: Nextracker

Tracker hardware and software are central to PV system resilience in extreme conditions

Extreme climate events are becoming more frequent across the globe, causing millions, if not billions, of dollars of damage when they occur. The solar industry is no stranger to these, with projects being damaged or affected by windstorms, hail, extreme heat, fires or flooding. In the industry's response, trackers have emerged as a key technology, with manufacturers developing some innovative solutions – both with hardware and software – to help PV projects be better prepared and more resilient to these increasingly extreme climatic conditions.

With solar projects being developed in all the corners of the globe, weather conditions will vary from region to region or even within a region depending on the latitudes. For instance, colder areas will be more prone to hail and flooding, while drier areas such as the Atacama desert will require a greater focus on extreme heat and winds.

Trackers and the smart software that sits behind them are an increasingly key part of a PV system's ability to withstand the extreme weather and climatic conditions that are becoming a common feature in the era of global heating.

"Trackers play a pivotal role in PV system resilience, especially during extreme weather. Beyond the current capabilities, continuous innovation and research remain critical. Factors like maintenance protocols, material durability, and adaptive design for varying climate conditions also contribute significantly to the overall resilience of PV systems," say PV Hardware's (PVH) global commercial director Álvaro Casado and Ivan Arkipoff, CTO.

Similar to the fact of each region being affected by different climatic conditions, not every part of a PV system is affected the same by the different climate events, with modules more impacted by hailstorms and extreme heat, while trackers by wind, says Colleen Mahoney, vice president of product management at Array Technologies: "As module sizes continue to increase, the wind load increases on the overall tracker or fixed tilt system. Instances of destructive wind events have been seen in the industry as a result."

Among the tracker suppliers contacted for this feature, two weather events were mostly outlined as the most problematic for the durability of a PV system: wind and hail. With another feature in this edition of *PV Tech Power* looking at hail on the module side, here we will look at what solutions tracker companies have come up against strong winds and hailstorms.

Three factors for a resilient power plant

Building and maintaining a resilient solar power plant could be defined by three key elements, says Nextracker's VP of design and engineering, Alex Roedel. The first one is to select the right module technology for a given region and is "the first and most crucial step". For instance, thicker glass can provide important protection.

The second important aspect is the capacity to stow rapidly, as stowing to the right angle and in some cases in the direction of the wind could offer more protection to the solar modules. This is where the trackers system comes into its own. "The speed of stow is critically important because every second counts and damages can rack up quickly," says Roedel. "If it takes longer to stow, that means you need to also be able to forecast much more accurately to pre-empt extreme weather events. While wind events such as hurricanes can be forecasted days in advance, hail forecasts may come only minutes prior to a risk event."

The final step is to implement solid emergency processes and ensure they are activated in time to help prevent damage. "If an extreme weather event causes a power outage, operators might not be able to put that technology to use," explains Roedel. "Likewise, if controls are activated manually,

someone needs to be ready to respond at the right time. Automated systems with backup power ensure that protective measures can be taken even in the event of a blackout."

Gone with the wind

Along with hail, wind events are the most problematic for the resilience of a PV system, according to all the tracker companies contacted; unsurprisingly, trackers offering wind-resilience features are also the most sought-after products from customers. Mahoney says that wind events are one of the most discussed challenges among its customers, due to the fact that wind events reduce the energy production when modules are stowed to maintain stability of the array.

To give project owners an alternative to active wind stowing, Array provides a passive wind stow solution that minimises potential energy loss during wind events, says Mahoney. "Rather than putting the whole site in a stow position, Array's system maintains an optimum tracking angle for the majority of the site, while only the most exposed rows rotate up to a 52° stow angle with a mechanical support at every post," she explains.

"This unique passive wind system operates on a row-by-row basis, as needed, which optimises energy production during wind events and recalibrates when the wind eases. This mechanical system does not require power or batteries, an added bonus in cold weather environments."

Not having to necessarily rely on manual labour is an important consideration to take into account as automation might have a better capacity to react to sudden high winds. "In instances where extreme wind events occurred, projects with non-operational trackers faced risks due to their inability to react. However, operational trackers were able to promptly respond and overcome these challenges," says PVH.

This could also be applied to events of extreme cold, when blizzards hit a region and it would be nearly impossible for an operator to get to the solar plant. Implementing a backup power to the trackers would ensure that resiliency systems can operate even if a power outage occurs, explains Roedel.

The use of automation and more recently AI is also an important tool in the software side to find solutions to enhance system resilience too. "ProInsights Neurona's AI-driven weather predictions and the lidar solution for wind forecasting demonstrate our commitment to preemptive resilience strategies," say Casado and Arkipoff.

Credit: Nextracker

The need for trackers to be able to withstand very low temperatures is becoming increasingly critical

Whereas Nextracker uses smart controls that consider real-time data from weather forecasts to mitigate risks and when it sends an alert to a project, the system will automatically go into a 75° position, explains Roedel.

Stow, stow, stow

Unsurprisingly, this year the solar industry has seen several products being released to help mitigate hailstorms, with Spanish tracker producer Soltec publishing recently (in November 2023) a whitepaper about it or Nextracker's NZ Horizon Hail Pro unveiled ahead of RE+ Las Vegas in September 2023.

With the central strip of the US quite prone to hailstorms, and with hailstones' diameter bigger than PV module certification value – according to Soltec's whitepaper 'Harnessing Smart Solar Tracking: Advanced Algorithms for Hail Protection' – it is not surprising that American tracker suppliers have come up with products in the past few years to remediate to that issue.

"Taking hailstone velocity as a vector, it is easy to deduce that any action aimed at increasing inclination between this vector and the normal module surface vector, favours a reduction in module damage because impact related kinetic energy is also reduced. Thus, the most favourable panel position is that in which the normal direction is perpendicular to hail direction," said Soltec in its paper.

Due to the fact that hail is usually accompanied by strong wind currents, it is important for solar trackers to be able to quickly respond to these, as unlike a hurricane, they can happen in a question of minutes. "The speed of Nextracker's hail stow reduces downtime, allowing frequent stowing at minimal cost. Nextracker has had projects in Texas go into hail stow mode over fifty times per year," says Roedel.

Similar to wind events, the ability for a solar tracker to quickly respond is crucial in order to reduce the exposure of modules to hail impacts. "Given the rapid evolution of hailstorms, it is necessary to have quick activation mechanisms, as that is an advantage when it comes to damage prevention. In the case of Soltec, our fast motor, with a final rotation speed of 20°/min, allows us to quickly position solar trackers in their hail defence position," stated Soltec's recent white paper.

Trackers are key in a PV system's resilience

Even though wind and hail are the two most prominent climatic conditions that solar tracker suppliers have worked on to help improve the resilience of a PV system, these are not the only ones with hardware or software specifically designed to prevent them. Nextracker developed trackers with flood sensors that can read water depth and lift solar panels above floodwaters. "Nextracker's solar farms received no damage after extensive flooding caused by Hurricane Matthew in 2016," explains Roedel.

Moreover, with the democratisation of solar technology and the costs of developing a project continuing to decrease, it will be less unusual to find solar plants in colder and harsher regions. Thus, the need for solar trackers to be able to withstand very low temperatures and still be able to operate is becoming more and more critical. "Project development in extremely cold weather climates is a growing trend. One of the main challenges in such conditions is battery survivability when temperatures drop to/below -40°C. Array's cold weather tracker package enables system operation in temperatures as low as -48°C," concludes Mahoney.

With the prospect of climate conditions worsening in many areas and solar energy pushing into new regions where extreme conditions are the norm, expect trackers to become an increasingly indispensable enabling technology. ■

For more on the solar industry's battle against hail, turn to p.34

Hail risk mitigation in PV power plants: how to better protect modules?

Module durability | Hail represents a significant threat to PV modules, more so as climate change increases the potential for severe storms. Simon Yuen looks at some of the methods being used to protect solar projects against hail damage

Credit: PVEL

Among the many extreme weather events impacting on PV plants, hail is one that has the potential to cause significant damage. A single hailstorm can be devastating, but climate change is likely to bring bigger hailstorms with more hail in the future.

According to PV Evolution Labs (PVEL), the most significant contributor to insured losses from thunderstorms worldwide is severe hail — defined as hail larger than 25mm in diameter. Globally, hail severity is expected to increase, as meteorologists are forecasting more frequent hailstorms worldwide. Not only that, but with more moisture in the air and more powerful updraughts, there is a strong chance that hailstones will become larger.

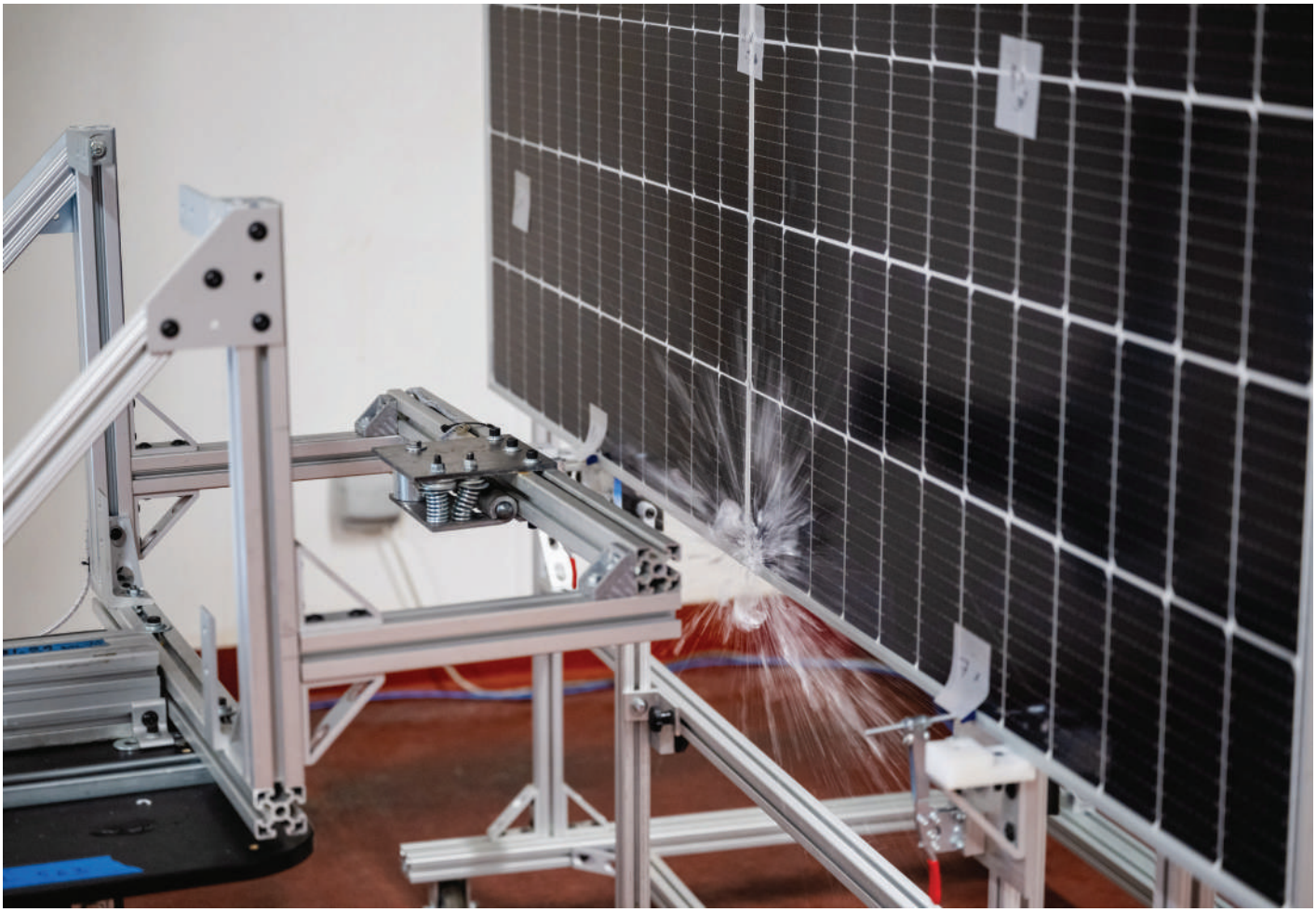
Hail basics

Hail occurs during thunderstorms which are usually triggered by an updraught – a storm's early development, during which warm air rises to a level where condensation begins and precipitation develops. As the inside of a hailstorm cloud is constantly moving and changing, it is impossible to forecast the moment when hail becomes too heavy to stay in the cloud. Where hail will land is unpredictable, as is the size of hail. Although climatological models are available for the probability of certain hail sizes in a given region, hail strikes are still completely random.

Beyond-qualification testing is one way to enhance PV resilience in hail-prone regions

Against this backdrop, solar power plants are not uniformly affected by hailstorms, meaning that the severity of impacts on different solar PV plants from the same hailstorm could be different.

Moreover, PVEL says the important driver for hail damage is impact energy or kinetic energy, which is the amount of force that the hail inflicts on an object and how that object can react. Variables affecting impact energy include hail size and



Credit: PVEL

shape, mass and density, speed and the angle of incidence.

Among these factors, mass and density are worth mentioning. Hail smaller in diameter can be denser and more destructive than larger slushy hail that may weigh less. The density of naturally occurring hail can range from about 0.32g per cm^3 to 1g per cm^3.

The angle of a hail strike affects the direction and distribution of the strike's force across the surface area of a module. A module mounted horizontally will be subject to higher impact energy and incur more damage than the same module stowed at a tilt.

Industry tests

Although hail strikes could cause serious damage to solar PV plants, a meticulous plan could help mitigate losses.

PVEL's Hail Stress Sequence replicates the impact energy of natural hail and simulates field conditions to assess PV module durability. The Hail Stress Sequence is also a required test in the latest version of PVEL's PV Module Product Qualification Program (PQP).

In November, PVEL updated its PQP with four major changes, including refocusing the Hail Stress Sequence on identifying the threshold of glass breakage, among others.

PVEL's Hail Stress Sequence tests a modules's durability.

During the Hail Stress Sequence, sample modules are struck by a 50mm lab-manufactured ice ball at terminal velocity (32 meters per second) in 11 different locations at a zero-degree angle. PVEL adds that the simulated hail strikes deliver an impact energy of 31.4 joules, comparable to the approximate impact energy of a 77mm strike with the same density at terminal velocity at 30 degrees.

Generally speaking, laboratory-made hail is extremely dense and more uniform than natural hail, so its impact energy is usually far greater; the impact energy of a lab-made 50mm ice ball is comparable to a natural hailstone as large as 100mm in diameter, depending on their density and impact angle.

PVEL has assessed more than 1GW of hail-damaged projects, identifying three consistent patterns of hail damage.

First, in strings with two or more broken glass modules, the cells of the remaining modules with intact glass are likely to experience severe cracking. Second, in sites with a capacity of more than 100MW that suffer glass breakage from hail, it is likely that some areas of the array will not have any cell damage. Third, glass breakage and cell cracking will be variable in the areas of the site between the two above extremes.

Speaking of the test results, Tristan Erion-Lorico, vice president of sales and marketing at PVEL, says the glass breakage rate of glass-glass modules could reach 89% if they are impacted by hail of 50mm diameter. "That should be quite alarming considering how prevalent glass-glass modules are these days," he comments.

However, the glass breakage rate drops to only 34% for glass-backsheet modules that use fully tempered glass.

PVEL is not the only company offering testing services. US independent test lab Renewable Energy Test Center's (RETC) Hail Durability Test Program assesses the characteristics of the PV modules and their bills of materials, attaining test results by using repeatable speeds and consistency in ice ball quality.

During the testing programme, PV modules undergo a simulation of conservative wind speeds and are checked for their performance near the threshold of damage, just over the threshold, which is

repairable damage, and at material failure.

RETC CEO and president Cherif Kedir says understanding hail resilience requires kinetic energies an order of magnitude larger than those found in module certification standards, such as IEC/UL 61215 and IEC/UL 61730.

"RETC's Hail Durability Test Program expands and improves upon minimum IEC/UL impact test requirements in three ways. First, it subjects modules to higher kinetic impact energies to better reflect the hail risk over a 25- or 30-year operating life," says Kedir.

"Second, it thoroughly investigates a range of possible outcomes — from cell cracking to glass breakage — which provides valuable data for probabilistic analyses. Third, it includes thermal cycle and hot-spot tests to reveal potential long-term module degradation modes."

Asked what types of modules fare better in general, Erion-Lorico says modules with fully tempered glass are less likely to break due to hail. However, Cheir offers a different answer.

"Our data indicate that PV module hail resilience or vulnerability is largely a function of glass thickness and strengthening, but what might surprise people is that this relationship between glass thickness and impact resistance is not necessarily linear," he says.

"As true heat-tempered glass is generally twice as strong as glass that is 'heat-strengthened' only, our test data shows that PV modules made with 3.2mm fully tempered front glass are approximately twice as resilient to impact as modules packaged with 2.0 mm heat-strengthened front glass."

Cheir says qualification tests represent the legal minimum requirements for product performance and safety. However, as these tests are not intended to predict long-term reliability or performance in real-world applications, beyond-qualification hail testing should be the norm for project stakeholders developing and deploying large solar farms in hail-prone regions.

Erion-Lorico agrees that beyond-qualification testing should be the form for modules deployed in hail-prone regions but adds that the solar manufacturing industry should start designing modules for certain climates. "There's no need to have every module on the market be 'hail-hardened', but companies should offer such modules for sites where that is important," he says.

Early warning systems

In addition to module resilience, solar developers can also rely on hail risk assessments to better protect solar PV plants.

Engineering advisory and test services provider VDE Americas offers solar project hail risk assessments based on site-specific meteorological data from a small grid area spanning about 16 square kilometres, as well as product-specific technical details. The reports produced by VDE Americas provide solar project stakeholders with financial loss and risk exposure estimates based on project-specific lat-long coordinates and fielded PV module and tracker technologies.

With the insights from the reports, solar developers can guide equipment specification, insurance terms and risk exposure beyond insurance coverage.

"Some examples of work we're supporting include providing maps to developers to make better siting and equipment procurement decisions, helping module manufacturers design hardened modules, and working with tracker companies and operators to launch automated hail monitoring and stow procedures," says Jon Previtali, senior principal engineer of VDE Americas.

As we discussed at the beginning of this article, hail strikes are completely random. Therefore, there may be no advance warning if hail forms directly over a site.

"So, project stakeholders may want to monitor weather conditions hours before a possible hailstorm and put the project into hail stow well before any hail alert. Since stormy days tend to be cloudy, it may be worth sacrificing a small amount of energy production to optimise hail risk mitigation," Previtali says.

Stowing modules

The possibility of mitigating losses stemming from hail strikes can be further enhanced by using the appropriate stowing strategy.

According to Nicole Thompson, data scientist at climate insurance provider kWh Analytics, moving panels into hail stow, where trackers are placed in a high degree tilt to reduce the impact energy of hailstones, is an effective and well-documented mitigation technique. However, this practice could move the modules out of an optimal production angle, and solar developers may delay this move until hail falls, limiting this mitigation strategy's effectiveness.

To test whether it's worth stowing the modules before a hailstorm, kWh Analytics simulated one-year production for a 200MW single-axis tracker site. The site was modelled under two scenarios. First, it assumed no hail stow. Second, the simulation took a 60-degree stow during all US National Weather Service (NWS) severe thunderstorm watches, warnings and advisories (WWA).

Under a US$22 per MWh power purchase agreement (PPA), moving into the hail-stow mode during WWA events throughout the year for this particular simulated site resulted in a total production loss of US$12,000, or 0.1% of the US$9.75 million estimated annual revenue.

Thompson says: "If you consider this with the fragility of modules in the face of hail and the quick onset of hailstorms, the picture becomes clear: stow early, and stow often."

Thompson also examines how to stow modules to minimise losses incurred by hail.

"The best strategy is to proactively stow panels at the first sign of potential severe weather. In an ideal world, modules would be stowed away from the direction of the wind, but the shifting gusts make it difficult, if not impossible, to predict.

"Implementing hail stow at the earliest indication of severe weather, in addition to the best guess of wind direction, provides the maximum protection," she says.

Insurance

In 2019, a solar farm in Texas was damaged by a hailstorm, causing insurance losses totalling US$70 million. Given the rise in extreme weather events, coverage for damage from these events, including hail, should be included, as advised by Thompson.

As insurers may have varying levels of data and expertise in the solar industry, only a few of them are capable of accounting for solar-specific resilient factors in their underwriting.

"The most sophisticated, data-driven managing general agents are best positioned to model catastrophe risks and provide consideration for operational, regional, technical, and proactive resiliency measures," Thompson says. "Asset owners would be wise to seek all available market quotes for property insurance, as some insurers may provide more beneficial terms for risk mitigation efforts than others." ■

Turn to p.38 to learn more about how AI is helping maintain PV power plant performance in the face of extreme conditions

PV TECH PREMIUM

Your indispensable guide to achieving business growth in 2024

SAVE 35%
ON YOUR FIRST YEAR AS A PV TECH PREMIUM SUBSCRIBER.
USE CODE: PVTPOWER

PV TECH PREMIUM

US$ 315
per year

PREMIUM ARTICLES

- Regular insight and analysis of the industry's biggest developments
- In-depth interviews with the industry's leading figures
- Exclusive access to PV Tech's PV Price Watch series of content

PV TECH POWER

- Unlimited digital access to the PV Tech Power Journal Catalogue - past editions from 2014 to today

PHOTOVOLTAICS INTERNATIONAL

- Unlimited digital access to the Photovoltaics International Journal Catalogue - past editions from 2008 to today

TECHNICAL PAPERS

- More than 1,000 technical papers written by recognised industry experts

EVENTS

- Exclusive webinars and interactive 'Ask the Editor' sessions
- Discounts on Solar Media's portfolio of events, in-person and virtual

Subscribe at:
pv-tech.org/pv-tech-premium

In the AI of the storm

Artificial intelligence | AI-based monitoring systems can help PV plant operators understand and manage the impacts of extreme conditions in a multitude of ways. George Heynes looks at some of the ways AI is being harnessed to bolster system output and longevity

Across 2023, the globe has been subject to increasingly erratic weather conditions with extreme heat, cold, rain and wind having made their mark. Many of these erratic weather patterns have been attributed to global warming and, with the world forecast to continue its alarming trajectory, this could mean a further increase in extreme weather conditions.

As we have learned in the preceding pages, erratic weather can prove troublesome for solar farms. For example, the efficiency of silicon solar panels drops when an air temperature of 23°C is exceeded. Other extreme weather conditions such as hail and wind can also damage systems thus impacting production yields. With this in mind, it is important to recognise the impact this can have on modelling and how companies are using technology to mitigate the effects of extreme weather conditions – particularly via the use of data and artificial intelligence (AI).

Credit: Above Surveying

Data gathered by unmanned drones can help with the rapid detection and rectification of weather damage to PV systems

The impact of erratic weather on modelling PV output

According to Neeraj Dasila, chief technology officer and co-founder of SmartHelio, a Switzerland-based software company that has developed algorithms to make solar assets more climate resilient, the impact of erratic weather patterns on PV systems modelling is "profound and multifaceted" with rising temperatures not only reducing the efficiency of the solar module, but also accelerating degradation of critical system components.

Dasila says: "Rising temperatures, for instance, not only diminish the efficiency of solar modules but also accelerate the degradation and damage of critical system components like power electronics of inverters/switches, relays, sensors, etc.

"Additionally, extreme weather events — such as severe storms, hail, and fluctuating precipitation levels — can cause direct physical damage to PV systems, leading to substantial deviations from projected performance metrics.

"This scenario underscores the critical importance of incorporating localised, long-term weather trends into PV system modelling, which is essential for realistic cost-benefit analyses."

Hail in particular can have a severe physical impact on a solar PV system. Perhaps the most recognisable damage is known as "microcracks", something that occurs primarily via external impact upon the module. These can have a damaging effect on PV output modelling and thus identifying where the microcrack is located could be paramount.

Will Hitchcock, CEO of smart solar software company Above Surveying, explains that non-visible microcracks can cause issues for a system in the future.

"If the weather is erratic, it can be very difficult to model. If you have a severe weather event, and for solar the main problems are hail and wind, then our services are very well placed to deal with post-event issues and returning the asset to a higher quality state as quick as possible. It all relies on mapping the damage using drones or other ground-based measurements to chart the change in the modules in different areas. This lets you validate the damage," Hitchcock says.

This showcases how the use of drones, which incorporate AI technologies, can roam around a solar farm and identify any damaged modules. Conducted on the ground, this can be very time consuming and so it allows damaged sites to return to operation at a much faster rate.

Turning our attention back to the use of data and output modelling, Dasila believes there is a significant lack of "detailed information which hinders the ability of system modelling experts to adequately account for the nonlinear effects of weather and climate change and to tailor their assessments to individual PV installations".

"The current scarcity of comprehensive studies on the evolving weather patterns and their specific impacts on PV systems exacerbates these challenges," Dasila explains.

"Consequently, there is an increasing need for advanced analytical tools and methodologies that can effectively manage these complexities and provide reliable, localised insights into PV system performance under changing climatic conditions."

An abundance of data is a 'double-edged sword' for PV

It is common knowledge in the industry that the use of data and AI is core in optimising a solar farm or module. However, Dasila believes this surge in available data can offer a "double-edged sword" for PV yield modelling.

"The surge in available data offers a double-edged sword for PV yield modelling. On one side, it provides a richer pool of information to draw from, enhancing the potential accuracy of models. However, the reliability and relevance of this data are crucial," Dasila says.

"Inaccurate or irrelevant data can lead to erroneous forecasts, making it imperative for the industry to employ robust data validation and selection processes. We have seen huge deviations, in the range of 10% to 20%, between the projections and the actual performance of the PV installations. Most of these deviations are attributed to poor weather modelling and accurate weather data."

Despite this it is worth noting that data can be incredibly useful for creating forecasts for solar PV. For Hitchcock, the use of data forms part of a wider aim to achieve "digitalisation of the asset down to the component". This can have multiple benefits such as supporting optimisation but, in the context of erratic weather and the damage this can cause, it can help identify issues within a module.

Hitchcock says: "If lots of modules are damaged, then you've got a lost yield immediately. But if it's more subtle, and performance is being impacted by humidity and temperature extremes, we are able to store all forms of testing and inspection data within a digital twin.

This enables patterns in component underperformance arising from weather-related impacts that would otherwise be difficult to spot to be swiftly identified and rectified: "We are able to identify a correlation of, perhaps, a poor performing inverter with low RISO tests on a string of modules. Those RISO tests might be a result of some weather-related impact," Hitchcock says.

Casting an eye to the future for the use of data for yield modelling, Dasila adds: "Future advancements are likely to involve more sophisticated machine learning models that can dynamically adjust to new data, providing more accurate and adaptive forecasting capabilities.

"These developments will also include better integration of disparate data sources, such as satellite imagery and local weather stations, to create a more holistic view of the factors affecting PV performance."

The role of AI and predictive analytics in PV system operation

As explained earlier in the article, predictive analytics and AI play a huge role in the optimisation of solar assets. By predicting weather patterns and PV output, asset owners are able to detect patterns and predict potential system issues before they occur. In doing so, this maintains the operability of the solar asset and thus increases its output.

This is something Dasila touches on, stating that it is "revolutionising PV system operation, particularly in the face of unpredictable climate conditions".

"AI and predictive analytics are revolutionising PV system operation, particularly in the face of unpredictable climate conditions. By harnessing large datasets, AI algorithms can detect patterns and predict potential system issues before they manifest," Dasila says.

"This proactive approach allows for anticipatory adjustments, reducing the reliance on reactive measures. AI-driven predictive maintenance can also pre-emptively identify components at risk of failure, enabling timely interventions. We bring speed by anticipating a 50% direct reduction in O&M efforts and costs with the use of data-driven advanced analytics and predictive maintenance solutions."

It is also important to note the impact it could have with unpredictable weather patterns. According to Dasila, the integration of real-time weather monitoring further enhances the solar PV system.

"The integration of AI with real-time weather monitoring systems further enhances this capability, allowing PV systems to dynamically adjust to immediate environmental changes, thereby optimising performance, mitigating risks associated with unpredictable weather patterns and resulting in an increase significant increase in revenues," Dasila adds. ■

AI in operational decision-making

SmartHelio was brought in by a "major European solar developer" to apply its predictive analytics capabilities to optimise the client's O&M efforts and minimise overall degradation.

"We used real-time climate and PV system production data along with their historical performance telemetry to develop and train the framework of our predictive models," Dasila explains.

"For instance, by analysing incoming weather patterns, the AI system pre-emptively predicted the environmental/situational stress on various components of the PV system and predicted their performance and potential failure with an urgent call for immediate action."

With this regarded as one of the company's successes in recent years, Dasila was keen to express the useful nature of AI and data, and the potential it could have on the global solar industry as unpredictable climate conditions continue to ramp up.

Dasila says: "[Our] AI model's capability to forecast potential issues based on environmental factors is a significant advancement in PV system management. The model intelligently predicts the increased likelihood of IGBT (Insulated Gate Bipolar Transistor) failure due to higher operational temperatures, a direct consequence of the heat wave and increased dust deposition. This kind of failure is particularly concerning as IGBTs are crucial for the inverter's function, converting the DC output of the PV panels into AC for grid integration or use.

"The system's predictive maintenance capabilities also identify potential component failures, enabling pre-emptive repairs and reducing downtime. This approach has resulted in a marked improvement in both efficiency and reliability, showcasing the transformative potential of AI in managing PV systems under variable climatic conditions."

AI-driven predictive O&M can pre-emptively identify components at risk of failure in extreme conditions

Credit: Above Surveying

Utility-scale PV in the US is poised for liftoff

Large-scale | With the United States on the cusp of an IRA-driven surge in utility-scale PV deployment, Mark Bolinger and Joachim Seel of the Lawrence Berkeley National Laboratory cover key technology and market trends in this synopsis of their annual "Utility-Scale Solar" report series

Credit: Lightsource bp

Much has changed in the four years since our last market update in *PV Tech Power*, which covered utility-scale PV market trends in the United States through the end of 2018 ("Utility-Scale PV surges onward in the United States" in *PV Tech Power*, Volume 2022, February 2020). Cumulative deployment has increased by 150%, from 24.6GWac at the end of 2018 to 61.7GWac at the end of 2022. Adding battery storage to both new and existing PV plants to boost their market value has become common in parts of the country with relatively high solar market shares, like California and the Southwest. And the amount of solar capacity in interconnection queues across the US has increased by more than 660GWac (+235%).

This impressive expansion of the utility-scale market over the past four years has occurred despite significant headwinds. The US solar market has weathered the same 'perfect storm' of a global pandemic, a war in Ukraine, supply chain disruptions and related project delays, high inflation, and rising interest rates that all other industries have faced. In addition, US solar developers have had to deal with tariffs on imported solar cells and modules, as well as US Customs and Border Protection seizures of substantial shipments of imported modules under the Uyghur Forced Labor Prevention Act.

Finally, though its impact is only starting to be felt, there has been a dramatic shift in federal policy over this period. Four years ago, the solar industry was in the midst of a multi-year phaseout of its primary federal incentive, the Investment Tax Credit or ITC (indeed, another article in that same Volume 22 of *PV Tech Power* was titled "Life after the ITC"). Today, however, the industry is looking forward to a decade or more of policy certainty, with renewed and expanded incentives, under both the Bipartisan Infrastructure Law (BIL) passed in November 2021 and, more notably, the Inflation Reduction Act (IRA) passed in August 2022.

Against this backdrop of remarkable change, the rest of this article highlights select key trends from the latest edition of Berkeley Lab's annual 'Utility-Scale Solar' report (available at utilityscalesolar.lbl.gov), which presents trends in deployment, technology, capital expenditures (CapEx), operating expenses (OpEx), capacity factors, the levelised cost of solar energy (LCOE), power purchase agreement (PPA) prices, and wholesale market value among the fleet of utility-scale photovoltaic (PV) and hybrid PV+battery plants built in the United States through the end of 2022. We define "utility-scale" to include any ground-mounted PV or PV+battery plant where the PV capacity is larger than 5MWac.

The impacts of the IRA in the US are starting to be seen in utility-scale deployment figures

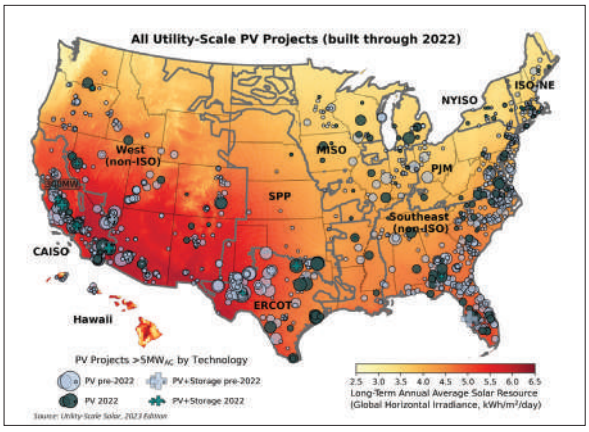


Figure 1: Map of operational utility-scale PV and PV-plus-storage plants at the end of 2022

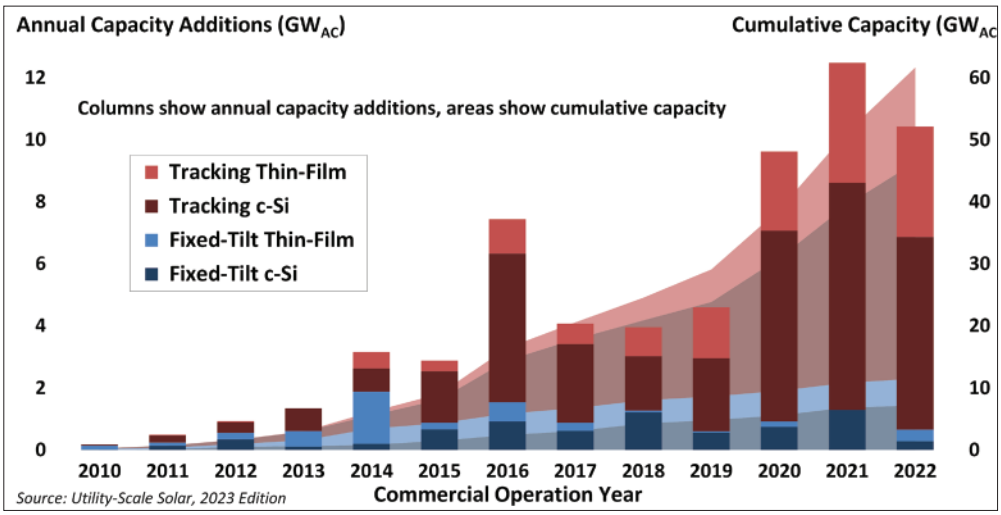


Figure 2: Annual and cumulative capacity deployment by mount and module type

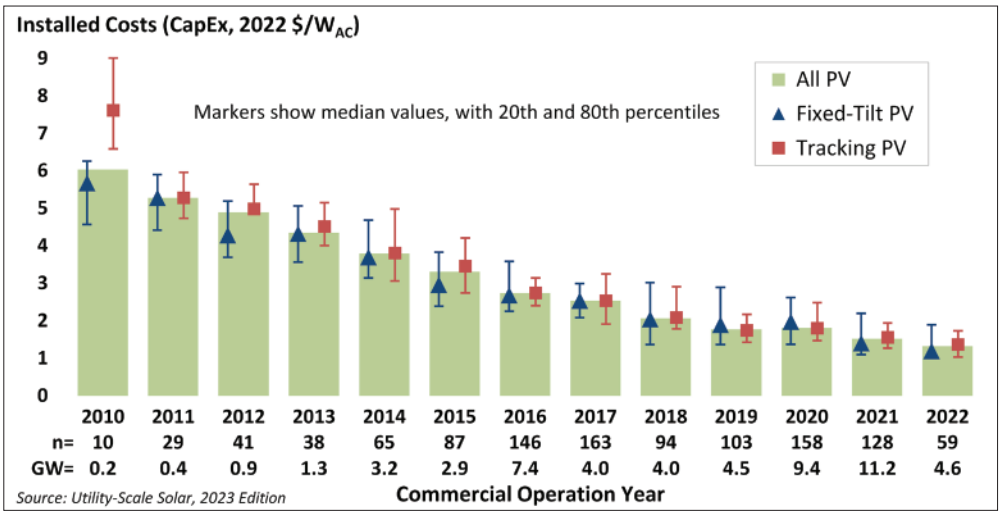


Figure 3: Installed costs over time by mount type

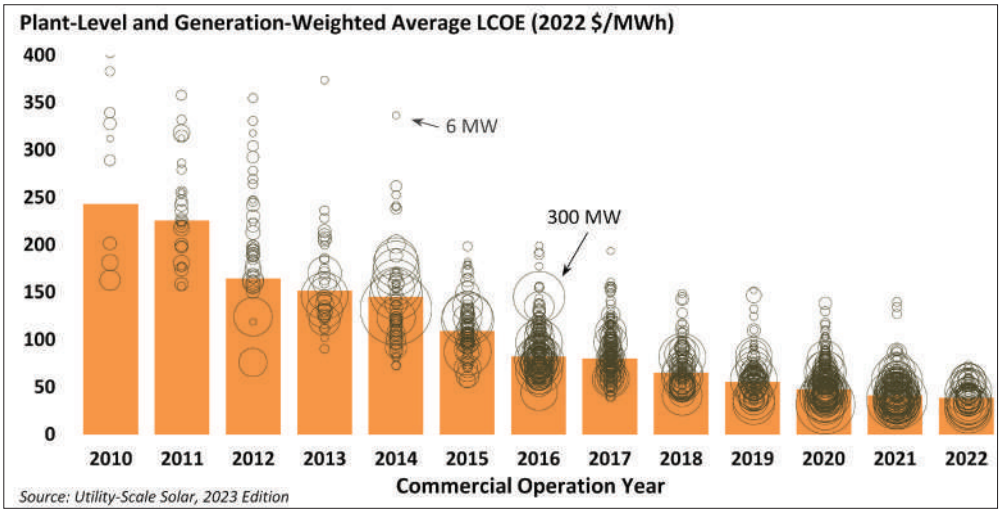


Figure 4: Plant-Level and average LCOE by commercial operation year

Last year (2022) was another strong year for utility-scale PV deployment in the United States. Though below 2021's record buildout of 12.5GWac, 2022's addition of 10.4GWac brought cumulative installed capacity to 61.7GWac across 46 states (Figures 1 and 2). Texas (2.5GWac) added the most new utility-scale PV capacity in 2022, followed by California (2.1GWac), Virginia (0.6GWac), and Georgia (0.5GWac).

Post-2014, as its CapEx premium diminished (Figure 3), single-axis tracking became the dominant mount type, and has been deployed with 94% of all new utility-scale PV capacity added in 2022 and 81% of cumulative capacity (Figure 2). Although c-Si modules still account for the majority of utility-scale PV capacity in the US (62% of 2022 and 68% of cumulative capacity), their market share has declined over the past few years (Figure 2). Conversely, the only currently viable alternative to c-Si—i.e., thin-film CdTe module technology from First Solar—has become more attractive over this period, in part because of its domestic manufacturing presence, which has enabled it to avoid tariffs and module impoundments at the border (and which will qualify First Solar modules for domestic content "bonus credits" under the IRA going forward). First Solar's CdTe modules account for 38% of capacity additions in 2022, bringing its cumulative US market share to 32%.

Despite general inflationary pressures over the last two years, installed costs (CapEx) among the sample of plants for which we have data—including 59 plants built in 2022, totalling 4.6GWac—continued to fall, though the year-over-year decline has been modest for the past four years. Median installed costs for the 2022 sample were U$1.3/Wac (or US$1.1/Wdc), and installed costs in general have fallen by 78% (averaging 10% annually) since 2010 (Figure 3). Post 2015, the incremental cost of tracking (over fixed-tilt) mounts has been barely discernible at the sample level.

The decline in CapEx (Figure 3), in combination with generally improving capacity factors, lower operating expenses, and (until recently) record-low financing costs caused utility-scale PV's LCOE to fall slightly to US$39/MWh on average in 2022 (Figure 4). The average LCOE has fallen by about 84% (averaging 14% annually) since 2010, though LCOE reductions over the past few years have been quite modest.

Of course, LCOE is somewhat of an analytical construct, and does not directly impact investment decisions on its own. For insight on what buyers are actually paying for solar generation, we can instead look to power purchase agreement (PPA) prices, which have largely followed the decline in solar's LCOE over time, but since 2019 have stagnated and even increased slightly (Figure 5). Unlike LCOE, PPA prices generally reflect the receipt of federal tax credits—i.e., the investment tax credit (ITC) through 2022,

but either the ITC or the production tax credit (PTC) starting in 2023, thanks to the IRA—and so are typically lower than corresponding LCOEs. PPA prices from a small sample of contracts signed in 2022 average US$25/MWh (levelised, in 2022 dollars), which represented relatively good value at the time, given elevated wholesale power prices resulting in part from the war in Ukraine.

Looking ahead, solar's newfound access to the PTC in 2023 and beyond should help to relieve some of the upward pressure on PPA prices. A decade ago, when utility-scale PV's CapEx was much higher (e.g., ~US$5/Wac per Figure 3) and capacity factors were lower, the ITC was a more lucrative tax credit for the industry. But particularly with CapEx at current levels (i.e., a median of US$1.3/Wac, per Figure 3), many utility-scale PV plants would be better off choosing the PTC instead of the ITC—and, starting in 2023, that choice is now readily available under the IRA.

Figure 6 models the preference for either the ITC (shown in green) or PTC (in red) based solely on various combinations of CapEx and capacity factor. Higher-cost, less-energetic plants may still favour the ITC, particularly if able to capture one or both tax credit adders by satisfying domestic content thresholds and/or locating the plant in a designated "energy community" (e.g., a community that has lost jobs in the fossil fuel industry). This is because the ITC's "10 percentage point" adders for domestic content and energy communities are worth more than the PTC's "10 percent" adders (e.g., moving from a 30% to a 40% ITC represents a 33% increase—rather than a 10% increase—in the value of the ITC). But given the typical CapEx and capacity factor of most utility-scale PV plants in the United States, we expect to see many plants opt for the PTC instead. Of course, other factors besides CapEx and capacity factor also affect this choice, such as financing considerations related to the potential preferences of tax equity investors or tax credit buyers (under the IRA's new transferability provisions) for one type of credit or the other.

Hybrid PV+battery plants were still mostly just a concept in development pipelines back in 2018, but after two breakout years of deployment in 2021 and 2022, there were 7.1GWac of PV paired with 3.9GW/12.1 GWh of battery storage operating in the US at the end of 2022 (Figure 7). These PV+battery hybrid plants have become increasingly common in markets with a higher share of solar generation, as a way to increase solar's market value by shifting a portion of excess (and low-value) mid-day solar generation into higher-value evening hours. Despite the IRA's extension of the ITC to standalone storage (meaning one no longer must pair storage with PV in order to qualify it for the ITC), this trend of pairing PV with batteries seems likely to continue. For example, year-to-date PV+battery hybrid plant deployment through October 2023 has already surpassed the capacity added in 2021 or 2022, and nearly half of all solar capacity in interconnection queues at the end of 2022 was paired with a battery (Figure 9). Notably, in November 2023, the US Internal Revenue Service clarified that hybrid PV+battery plants will be able to

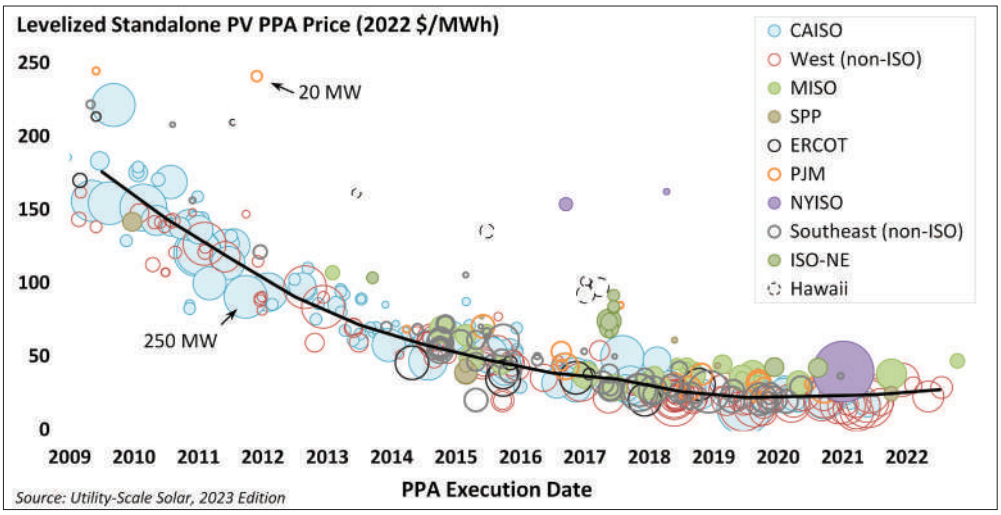


Figure 5: Levelised PPA prices by region, contract capacity and PPA execution date

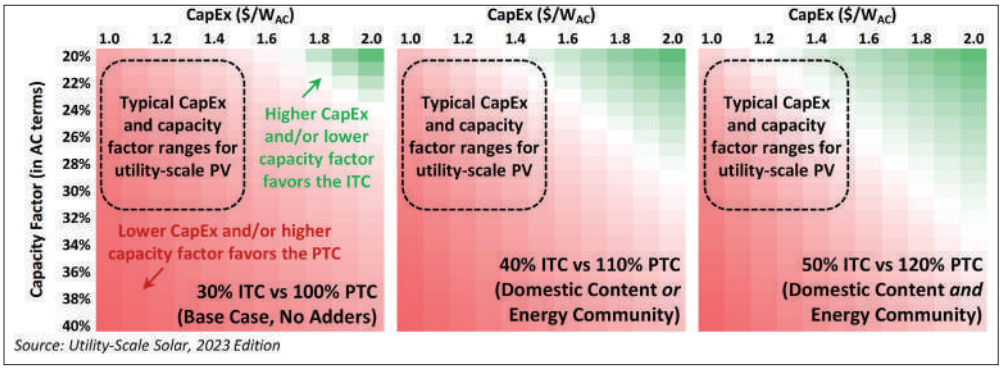


Figure 6: Preference for PTC versus ITC based solely on CapEx and capacity factor

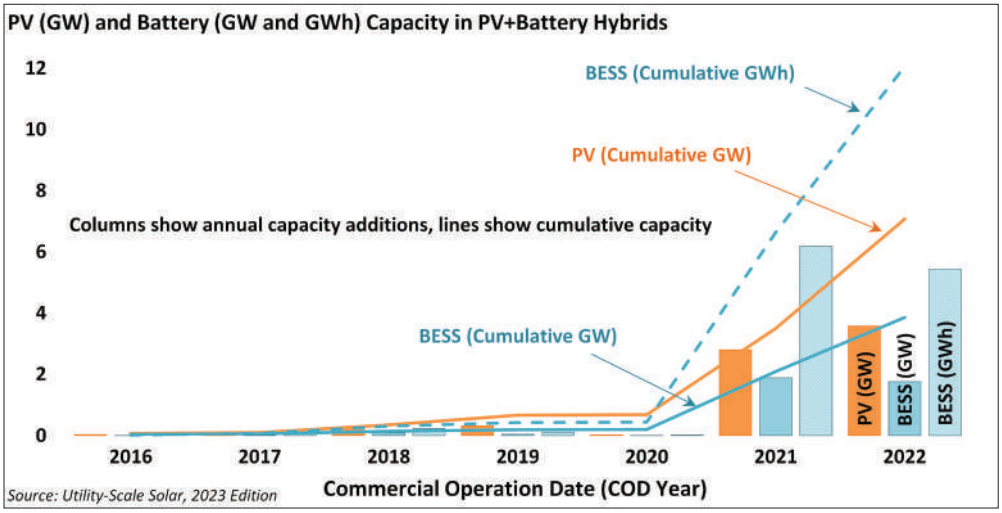
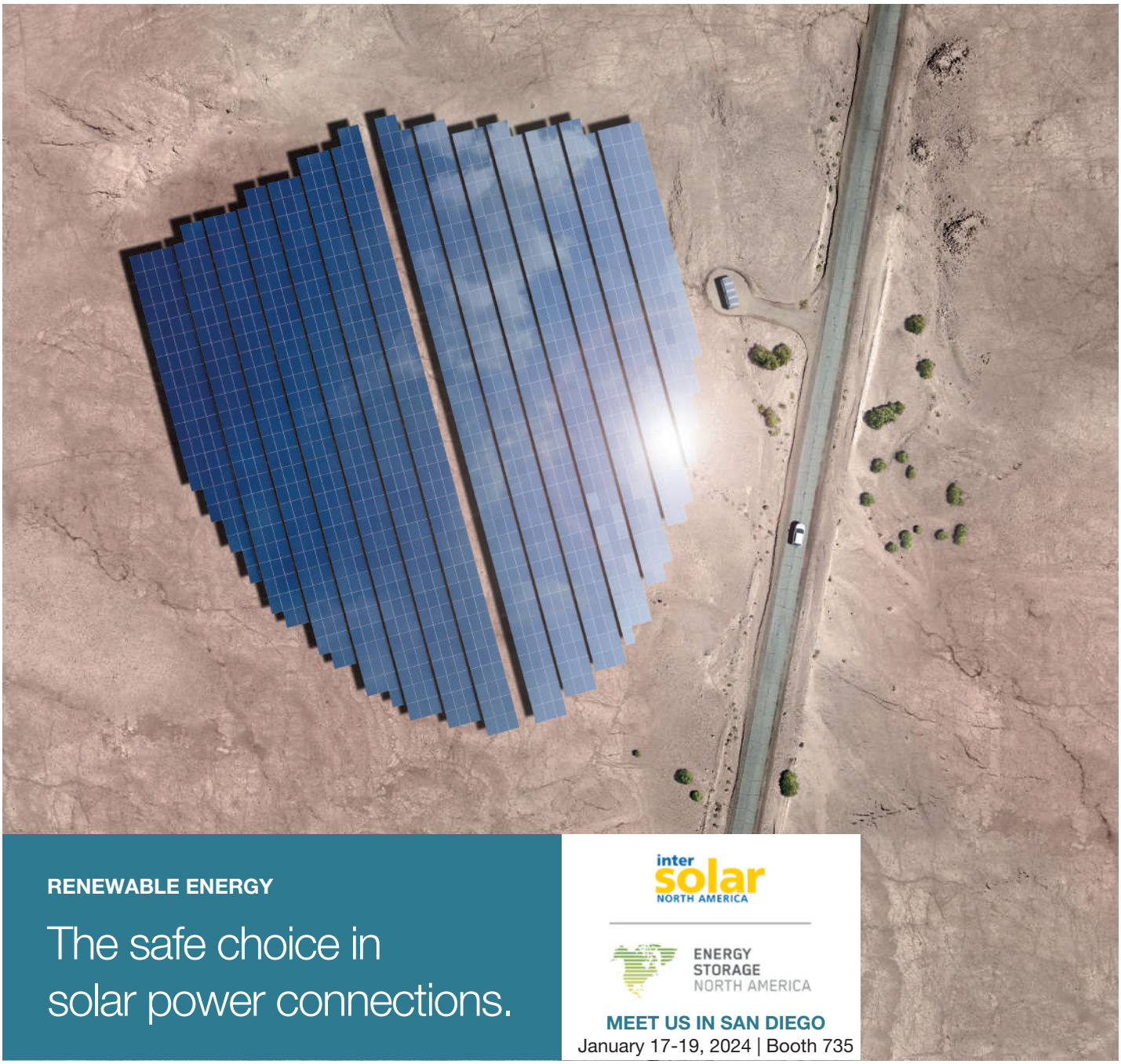


Figure 7. PV and battery capacity in operational PV+battery hybrid plants

FAST MOVING TECHNOLOGY

STÄUBLI



RENEWABLE ENERGY

The safe choice in solar power connections.

inter solar NORTH AMERICA

ENERGY STORAGE NORTH AMERICA

MEET US IN SAN DIEGO
January 17-19, 2024 | Booth 735

**The Original MC4 by Stäubli –
the world-leading connectors for PV systems.**

When it comes to photovoltaic power stations, measurable success depends on even the smallest details. Designed with Swiss precision craftsmanship, our connectors help you prevent unnecessary and costly downtime. To ensure longstanding performance, rely on the partner with a superior safety track record.

THE ORIGINAL MC4 SINCE 1996

Stäubli – Powered by nature. Connections for sustainable change.

www.staubli-renewable-energy.com

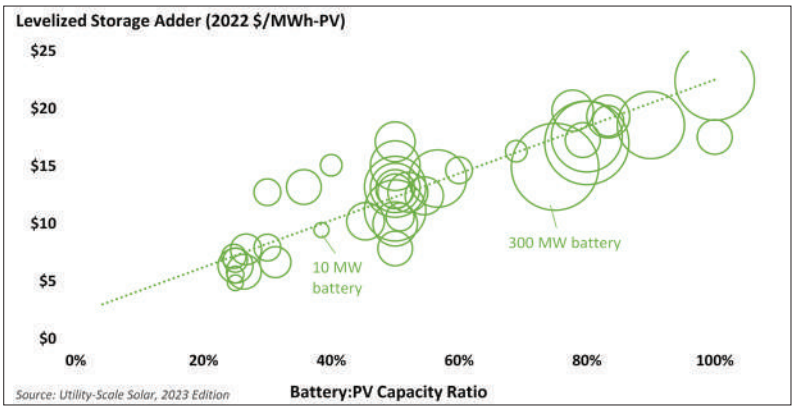


Figure 8. Levelised storage adder to standalone PV PPA price by battery:PV capacity ratio

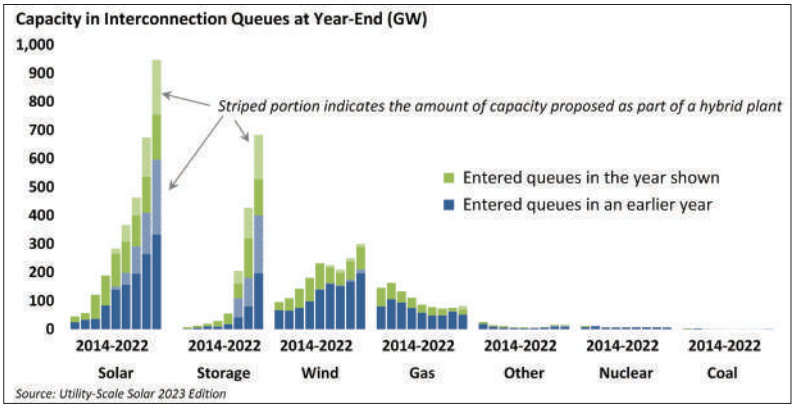


Figure 9: Capacity in interconnection queues across the United States from 2014-2022

claim the ITC on the cost of the battery system while also claiming the PTC on the solar generation—a winning combination for PV plants sited in good solar resource areas.

Of course, adding a battery to a standalone PV plant adds cost and, therefore, requires higher compensation. PPA price data from a sample of 40 PV+battery hybrid plants (totalling more than 5.6GWac of PV and nearly 3.2GW of four-hour batteries) that break out the pricing of the PV and battery components suggests that adding batteries has increased standalone PV PPA prices by anywhere from US$5/MWh-PV to US$25/MWh-PV (levelised in 2022 dollars), depending on the amount of battery capacity relative to PV capacity (Figure 8).

Looking ahead, a massive pipeline of utility-scale PV and PV+battery plants dominates the interconnection queues across the country. At the end of 2022, at least 947GW of solar capacity was in the queues, and nearly 457GW (or 48%) of that total was paired with a battery (Figure 9). This, too, stands in stark contrast to back in 2018, when there were "only" 283GW of solar in the queues, and only 10% of it was paired with a battery. Though not all the capacity in the interconnection queues will ultimately be built (e.g., historically, only about 10% of solar capacity in the queues has achieved commercial operations), the queues are nevertheless a clear indication of strong interest in utility-scale solar (and storage). And with a decade of policy stability to look forward to under the IRA, sustained growth in the coming years seems likely.

While the IRA's policy developments—perhaps most importantly for utility-scale PV, providing the option of a PTC for solar along with various bonus credits or tax credit adders (e.g., for locating projects in energy communities and/or for using domestically produced equipment) for either the ITC or PTC—have generated much excitement within the industry, we did not see the full impact of these incentives in the 2023 edition of our 'Utility-Scale Solar' report, for several reasons. First, the IRA was passed relatively late in 2022, with Treasury guidance on implementation coming even later, and the market naturally takes time to react. In addition, several incentives only came into effect starting in 2023, while the latest edition of our 'Utility-Scale Solar' report focuses primarily on projects built in 2022 (or earlier). Meanwhile, interconnection queues from some of the bigger regions had either already closed their open application season by the time the IRA passed, or else discouraged or did not accept new interconnection requests in 2022.

Nonetheless, 2023 is shaping up to be the strongest year on record for utility-scale solar in the United States, driven in large part by early activity under the IRA. For example, the first ten months of 2023 have already yielded 10.6GWac of PV capacity additions, with at least several more gigawatts likely to come online by the end of the year. Moreover, as mentioned above, year-to-date PV+battery hybrid plant deployment in 2023 has already surpassed prior-year records. Particularly as some of the headwinds mentioned at the outset start to diminish, and the industry moves beyond the initial "waiting on IRA implementation guidance" period and upshifts into a higher gear, it seems likely that the utility-scale PV market in the US could very well soon start to "sound like a broken record" in terms of repeatedly breaking its own prior-year deployment records. ■

Acknowledgement

This material is based upon work supported by the US Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under Solar Energy Technologies Office (SETO) Agreement Number 38444 and Contract No. DE-AC02-05CH11231. The US Government retains, and the publisher, by accepting the article for publication, acknowledges, that the US Government retains a non-exclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this manuscript, or allow others to do so, for US Government purposes.

Authors

Mark Bolinger is a research scientist at Lawrence Berkeley National Laboratory, where his work focuses on understanding the cost, performance, and value of renewable generation and storage within electricity markets. Mark holds a masters degree in energy and resources from the University of California at Berkeley and a bachelors degree from Dartmouth College.

Joachim Seel is a policy researcher at the Lawrence Berkeley National Laboratory. His research focuses on solar and wind market developments, the integration of high shares of renewable generation into the electricity grid, and associated effects on electricity markets. Joachim holds a PhD and MS of energy and resources and a masters degree in public policy from the University of California at Berkeley.

inter solar NORTH AMERICA | ENERGY STORAGE NORTH AMERICA

JOIN US IN SAN DIEGO

JANUARY 17-19, 2024

Intersolar North America and Energy Storage North America is the premier US-based trade show and conference focused on solar, energy storage, and EV charging infrastructure.

Connect and do business with exhibitors showcasing and demonstrating their solutions. Select from 24 educational sessions focused on technology, policy, safety, financing, and more! Build your professional network and strengthen existing relationships during the numerous networking events.

1	120+	500+	9,000+
SOLAR GAMES COMPETITON	EXPERT SPEAKERS	EXHIBITING COMPANIES	CLEAN ENERGY PROFESSIONALS

SECURE YOUR DISCOUNTED CONFERENCE PASS

Register using the **PV Tech** discount code to save 20% on your conference pass *(free expo hall access included)*.

Are the exhibits your priority? Explore the expo hall for free.

Scan here to register and save!

Use promo code: **PVTECH** at checkout.

intersolar.us #isnaesna

Produced by: diversified

Private investment in Australian solar fell off a cliff in 2023. What went wrong?

Policy & finance | Despite having the ideal attributes to become a clean energy superpower, Australia has never quite lived up to its potential. Will Norman assesses the barriers and asks whether recent investment announcements could turn the tide

Australia seems as if it was designed for solar PV. World-beating solar irradiance levels and swathes of available land has led it to become one of the largest markets in the world for both utility-scale and rooftop solar. The latter in particular is a huge market in Australia, but the utility-scale segment has had a more turbulent time.

Historically, Australia has been mostly coal-powered, but that coal power fleet is ageing and becoming less financially rewarding, to say nothing of its effects on climate. The Australian Energy Market Operator (AEMO) is engaged in the long-term retirement of the country's coal capacity and has said that by 2033 the shift away from coal needs to be over 60% completed. This in itself starts the clock ticking for Australia's energy transition, but AEMO has gone further and said that "urgent" investment into grids and renewables is needed if the country is to avoid energy security and availability issues.

No surprises, then, when the Clean Energy Council (CEC) – Australia's preeminent renewable energy association – said it was officially "concerned" with the lack of financial commitments to new renewables projects in the first nine months of 2023. Just six new renewables generation projects reached financial close in the three quarters of the year, adding up to around AU$375 million (US$248 million) and 509MW planned capacity.

Projects are still being built and connected to the grid, but the pipeline of projects to come, which generally take around 24-28 months from financial close to operations, is running dry.

This article will look into what has been done recently to get investment flowing again, the short-term outlook for Australia and the factors that led to the investment drought in the first place.

Credit: ARENA

A clean energy investment drought in the first three quarters of 2023 have prompted concern

Too successful?

Since 2001, Australia has had some form of the Renewable Energy Target (RET) legislation in place, which required that 20% of the country's energy was sourced from renewables by 2020. In 2015 the scheme was split into two strands, the large- and small-scale Renewable Energy Targets, which created financial incentives for deploying and using renewable energy.

By 2017 over half of the 2020 target had been met and by mid-2019 it was exceeded. This was a significant achievement and spoke to the confidence that investors had in Australia and its potential for renewables. But the then-government put nothing in place to follow up or expand on the RET beyond its initial 33,000GWh target, which left a vacuum of national framework or support for investment.

State projects continued, as did government support through the Clean Energy Finance Corporation, but the big draw for large-scale private investment had gone.

This made Australia less competitive and less attractive. As the RET aged out, the COVID-19 pandemic began and caused a raft of problems worldwide. Global supply chains and labour shortages since have played their part too, as has international competition.

The CIS Expansion

Eventually, on 23rd November 2023, Australia's Minister for Climate Change and Energy Chris Bowen announced expansions to the country's Capacity Investment Scheme (CIS) initiative. The CIS will see the

government look to underwrite investments into 32GW of renewable energy generation and storage capacity, enough to cover half of current national electricity market (NEM) customer demand.

Of the 32GW, 23GW will be allocated to renewables generation and 9GW to energy storage. The government will underwrite the capacity investments through a 'Contract for Difference' scheme where a price is agreed on for the power produced and money exchanged either way depending on how the spot prices on the market fluctuate. Though the impact of the CIS expansion is currently unproven, the response has been positive and the government said that it was intended to provide certainty for investors.

Chief executive of the CEC Kane Thornton said: "We have today welcomed news that the Albanese Government has taken decisive action to provide massive support to bring forward new investment in large-scale generation.

"While renewable energy remains the lowest cost form of new generation, there is a clear role for government to facilitate the enormous levels of investment needed to transition our energy system.

"We look forward to working closely with the federal government on the detailed design of the contracting mechanism to ensure it is effective and delivers the new investment and lower power prices that are expected.

"It's crucial that any new policy provides increased certainty to investors and the enormous private sector capital and capability that will be essential to Australia becoming a clean energy superpower."

The expansion to the CIS, along with a modified National Energy Transformation Partnership (NETP) scheme and binding agreements with state governments to allow for public procurement of renewables capacity, is the closest thing that Australia has seen to the coordinated framework introduced by the Biden administration in the US last year, the Inflation Reduction Act (IRA). At time of writing, the financial extent of the Commonwealth government's underwriting commitments has not been revealed, but the support will take the form of competitive auctions at regular intervals.

Whilst it's a promising move from the government and ultimately has the potential to stimulate the investment that Australia needs to get back on track with its renewable energy and decarbonisation targets, it's useful to ask how we got here.

The CIS will help Australia regain its competitiveness in the global race to decarbonise

Credit: Sterling & Wilson

International competition

In response to questions from *PV Tech Power*, the CEC cites international competition as a reason for the pressure on the pipeline of Australian renewables. The CIS expansion plan is first and foremost a bid to remain competitive against other international schemes.

"A large pipeline of renewable projects across Australia is in the midst of heightened global competition for capital investment, a skilled workforce, and equipment, driven primarily by the Biden Administration's Inflation Reduction Act in the United States," a spokesperson says.

For some incidental context, in its Power Playbook document the CEC says that the IRA has been "more consequential" in the increased push for renewables investment and deployment the world over than the Russian invasion and subsequent war in Ukraine, which triggered an energy price crisis for much of the developed world that saw them turn to renewable energy.

This isn't the first time that the IRA has caused alarm overseas. Markets in much of the developed world have had to play catch-up to the US' legislation and the investment it has drawn; a report from the Solar Energy Industries Association (SEIA) found that solar and storage investments had added US$100 billion to the US economy as of August 2023 due directly to the IRA.

Echoing what the CEC says, Niall Brady, head of solar and storage at the Clean Energy Finance Corporation (CEFC) – the Australian government's green investment bank – tells *PV Tech Power* that "the US Inflation Reduction Act has increased global competition for finance as many countries react with their own initiatives to attract capital".

In its Power Playbook report from October the CEC said that the government needed firm, decisive and well-planned actions to carve out Australia's role in the international renewable energy marketplace. The document said that "we [Australia] are currently lacking a framework to bring the domestic transition and the international opportunities together, understand the resource and infrastructure requirements in capturing these opportunities, and provide a cohesive roadmap for coordinated public and private investment."

However, this is not to say that the government has sat idle. In its Federal Budget for 2023-24 it made AU$4 billion (US$2.6 billion) available for renewable energy technologies, tenders and energy storage. Niall Brady also points out to this publication that, as a government-owned investment bank, the CEFC has backed specific large renewables projects from international companies: "Recognising that private sector capital is critical to the clean energy transition, CEFC finance works to attract this asset class to large-scale renewable energy projects around Australia.

"The AU$75 million (US$49 million) CEFC finance to ACEN Australia to support its 8GW portfolio including [the 400MW Stubbo solar farm] was part of a debt raise targeting AU$600m (US393 million) of capital, while its AU$100 million (US$65 million) investment in the 300MW Walla Walla Solar Farm – its largest single commitment to a solar farm since inception – was alongside finance from ING and Export Development Canada."

Yet it would be fair to say these don't represent a framework with the scale of the IRA or the EU's Green Deal, and the CEC's financial reports mentioned above show that the piecemeal approach hasn't drawn investment in the same way either.

Does bigger equal better?

Another factor contributing to a challenging investment environment is the increasing size of renewable energy projects,

which is leading to "lumpier" trends in commitments, CEFC's Niall Brady says. And one need only look to recent announcements from the Australian solar market for confirmation of this.

In July, a newly established aboriginal development group – the Aboriginal Clean Energy Partnership – entered into an agreement to develop a 900MW solar PV plant to support a green hydrogen export facility. (Financial investments are scheduled for mid-2024 to 2025 as of the time of writing.)

ACEN Australia, subsidiary of the Philippines-based energy company, also developed the 400WM Stubbo solar farm which is currently under construction and expected to begin operations in 2025. Brady says that Stubbo "is nearly the cumulative size of the ten separate solar projects financed by the CEFC under its Large-Scale Solar Programme launched in 2015."

He continues: "This means that while at times there may be fewer transactions closed, those that will often have significant renewable energy generation capacity."

One that didn't close was the planned 5.4GW Uaroo solar and wind hub in the Pilbara region of Western Australia. Mining giant Fortescue, through its subsidiary Pilbara Energy (Generation), abandoned the project in October during the approvals process, according to the Western Australia government's Environmental Protection Authority. It would have contained 3.3GW of solar PV and the plan was to use the renewable energy from the hub to power Fortescue's mining operations in the mineral-rich Pilbara region. Fortescue did not respond to a request for comment from *PV Tech Power*.

Perhaps the epitome of a large, unwieldy and ambitious project is the so far ill-fated Australia-ASEAN Powerlink (AA Powerlink). It still has a planned capacity of between 17-20GW of solar PV, 36.42GWh of energy storage and 4,200km of subsea cable to reach from the Northern Territory to Singapore, but its owner, Sun Cable, recently entered administration and went up for sale.

It is true that bigger projects are more cumbersome to plan, slower to develop and harder to attract investment for. Indeed, the CEC outlines "the complexity of planning and approvals processes for projects" as one of the hurdles that Australia needs to overcome to generate renewables investment.

It continues: "The success of a timely clean energy transformation for Australia relies on strong partnership between industry, investors and federal, state and territory governments, to direct our collective resources and work together in expediting assessment and deployment processes for different renewable energy projects and infrastructure."

Storage succeeds

"There is also a trend towards hybridisation with co-located solar and battery energy storage systems (BESS)" the CEFC says.

The same CEC investment report that found a concerning downturn in renewables generation funding showed that energy storage was the one sector of the Australian energy transition that was succeeding. In Q2 2023, for example, 1497MW, or 3802MWh, of energy storage projects reached financial close, which massively exceeded the rolling quarterly average for the preceding year. Notably, the report found that all of the projects that reached financial close during Q2 had funding or concessional financing from a government body.

However, investment in storage dropped off in Q3 too, with just 12MW/13MWh of new projects reaching financial close.

More recently, November 2023 saw 2,800MWh of BESS awarded contracts under the New South Wales (NSW) government tender for firming infrastructure, and all the similar storage auctions in NSW have been oversubscribed.

A shift towards co-located solar and storage plants is well-suited to a grid like Australia's, where the operator the National Electricity Market (NEM) has committed to phasing out coal generation in the next decade. Dispatchable power from storage coupled with low-cost solar generation – whilst the capital cost of both is trending downwards – represents a reliable replacement for coal plants. The recently announced expansion of the CIS will operate auctions in a "contracts for difference" model, with a view to stabilising prices and making investments more certain, which can guarantee prices for stored energy.

The CEFC says: "Australia needs to install about 29GW of large-scale renewable generation in the national electricity market (NEM) alone – 3.7GW a year or 310MW per month – to achieve 82% renewables by 2030–31.

"On top of this we need significant investment in transmission, rooftop solar and large- and small-scale storage – the CEFC estimates that some AU$120 billion (US$79 million) of capital expenditure is needed to finance new solar, wind, transmission, storage and ancillary services to 2030/31 in the NEM in order to meet renewable energy and emissions goals."

Looking forward

Looking to the future, despite the setbacks, the CEFC is positive. In response to questions posed prior to the announcement of the CIS expansion, Niall Brady said that: "Despite sector challenges, we expect a number of projects will reach financial close in the short term, many of which have been successful in state offtake schemes."

Indeed, state schemes have seen some success – if inconsistently across the country – despite the lack of central guidance. Queensland has set an ambitious target of 22GW of renewables capacity by 2035 which included the development of 12 renewable energy zones (REZ) which are specially designated for solar and wind deployments.

It also reiterated its confidence in the trend for co-located solar and storage, which it said would "develop new revenue opportunities and should drive the next wave of solar investment."

Prior to the November CIS expansion, the CEC was more cautiously optimistic. It cited challenges to grid capacity, labour shortages, uncertainty regarding the retirement of coal plants and supply chain issues, but says that "If we overcome these barriers, we are confident in delivering a more reliable and low-cost energy system, achieving 82% renewable energy by 2030, delivering our long-term emission reduction targets, and setting Australia up to become a clean energy superpower."

A comparison with its statement following the CIS announcement perhaps sums up the shift in attitude for Australia's renewables future: "[The legislation] is a significant commitment that is intended to put Australia back on track to achieve the government's policy of 82% renewables by 2030, replacing ageing coal-fired generation with cheaper renewable energy and driving down power prices.

"There is now wide acceptance of the need to accelerate our shift to renewable energy." ■

For more on the role of battery storage in Australia's energy transition, turn to p.102

EU PVSEC

EU PVSEC 2024

41st European Photovoltaic Solar Energy Conference and Exhibition

23 — 27 September

ACV
Austria Center Vienna

Vienna
— Austria

Call for Papers Open!

Abstract Submission deadline:
02 February 2023

BE A PART OF EU PVSEC 2024 AND SHOWCASE YOUR EXPERTISE!

Join the 41st European Photovoltaic Solar Energy Conference and Exhibition - Europe‘s largest gathering for PV research, technologies and applications. Immerse yourself in a cutting-edge PV industry exhibition where leading experts will showcase their latest products and innovations.

Why attend?

- Present your groundbreaking research and get the recognition you deserve.
- Network with the global PV community, including scientists, industry representatives, experts and policy makers.
- Be part of a trendsetting event in Vienna that is shaping the upstream PV sector.

Call for Papers Open!
Submit your abstract by 2 February 2024 and play an important role in shaping the event‘s programme.
Don‘t miss the chance to be at the forefront of solar energy innovation!

We look forward to welcoming you in Vienna!

EUPVSEC.ORG

Fifth Contracts for Difference round pushes UK solar forward

Credit: Solar Energy UK

Large-scale solar | The latest round of the UK's renewable energy support scheme saw solar scoop almost 2GW of new capacity. Gareth Simkins examines the winning projects and looks ahead to assess how solar is likely to fare in future rounds

A total of 56 ground-mounted solar projects won backing in the latest round of the UK's Contracts for Difference (CfDs) renewable energy support scheme in November.

According to government figures released on 8 September, the total capacity of allocation round 5 (AR5) comes to 1,928MW. Considering that Solar Media estimates that national capacity, on the ground and on the roof, will hit 17.6GW by the end of the year, the figure represents a significant inroad into reaching the government target of 70GW by 2035 [1].

Doing so implies deploying around 4GW of capacity each year, both on roofs and on the ground, so deployment will have to accelerate further. But this is precisely what the Department for Energy Security and Net Zero (DESNZ) is seeking: AR5 was the first round to be run annually, rather than every two years. It also comes ahead of the roadmap due to be published in February by the government-industry Solar Taskforce, which will set out how the sector expects to meet the goal and overcome barriers such as grid access and the availability of skilled workers.

Of 56 winners, 13 (with a capacity of 394MW) are contracted to come online in 2025/26, 4 (151MW) in 2026/27 and 39 (1,383MW) the following financial year. The total is lower than AR4, which had 66 winning projects, coming to just over 2.2GW.

The agreed strike price was £47/MWh,

Almost 2GW of new ground-mounted solar projects were awarded contracts under the latest round of the UK's CfD scheme

the same as the maximum bid price set by the government.

As strike prices are expressed in 2012 prices, adjusted according to the Consumer Price Index, the actual value of the price is 37.4% higher, coming to about £64.60/MWh in today's money. Although the increment is substantial, the cost is still far less than it was when the CfD regime kicked off in 2015, when £79.23/MWh was agreed for three projects to be commissioned in 2015/16 (equivalent to about £108.88/MWh now).

It is also worth stressing that £64.60/MWh is considerably less than what these projects would receive if they were run on a merchant basis, assuming current wholesale electricity prices persist. The upshot

is that the 56 sites are expected to return significant sums of money to the Treasury, in return for financial security and thereby the confidence to invest.

The published capacities of the winning solar projects range from only 7MW to 57MW. But on inspection, there appears to be some ambiguity about what these figures represent.

On the face of it, the largest project – an unnamed one from Enso Green Holdings – looks like the only nationally significant infrastructure project (NSIP) on the list, being above the 50MW threshold for consideration by the government, rather than local authorities. Its nearest competitors in size are all 50MW, or just below.

But the NSIPs in the pipeline are well known – and nothing matches this project. Furthermore, the extra costs of building such installations mean that building one so close to the capacity threshold would make little sense.

So 57MW clearly refers to the project's planned DC generation capacity, which would push capacity below the 50MW threshold, after accounting for inverter losses. This is despite guidance from the Energy System Operator and the Low Carbon Contracts Company (which runs the CfD system) saying that installed capacity should be expressed as AC. The National Policy Statement for Renewable Energy Infrastructure (otherwise known as EN-3) also makes it clear that capacity should be measured on an AC basis.

So, this leaves the question of how big the other projects are supposed to be and therefore how much capacity will be delivered by the round. Are the figures AC, DC, or a mix thereof? A DESNZ spokesperson simply said that some checks are needed.

So why are there no NSIPs among the winners of AR5? Although many are being developed, the answer is that plans for them have not yet reached the stage where CfDs may be sought. Only one has been approved recently, namely EDF Renewables' Longfield project in Essex, while larger ones, such as the Sunnica, Botley West, One Earth and Great North Road projects, all around 800MW, remain in the pipeline.

It is also possible that these will not be supported with CfDs at all, or only partially, as the regime is far from the only route to market for utility-scale ground-mounted solar. Some developers, backed with finance seeking higher returns, at accordingly higher risk, may prefer to sell on a merchant basis. Power purchase agreements are also an option.

At first glance, it looks like JBM Solar, bought by RWE in the spring, secured the greatest number of CfDs, with six projects with titles such as 'JBM SOLAR PROJECTS 6 LTD' in the spreadsheet provided by DESNZ. However, the information is again somewhat deceptive.

It turns out that Low Carbon has ten, totalling 340MW, the first of which are due to commence construction in 2024.

The largest of its AR5 projects is Jafa Solar Farm in Norfolk, which is listed as 49MW in the CfD list, or 49.9MW according to its website. The plans include a battery energy storage facility, a £100,000 community benefit fund, providing £100,000 in business rates each year, and providing an educational programme for local schools, while saving an estimated 11,000 tonnes of CO2 annually and delivering a biodiversity net gain of 87%. This would be through creating a wildflower meadow, enhancing hedgerows, planting new native trees and erecting nest boxes.

Inflation, offshore wind and AR6

The relative success of solar in AR5 cannot be discussed without mentioning the elephant in the room: offshore wind power. Unlike every round before it, no CfDs were awarded for the sector this time, even though up to 5GW was made available. Last year, 7GW was secured, scheduled to come online in 2026/27.

The reason boils down to the mismanagement of the auction process. The maximum bid price for the sector was set at £44 per megawatt-hour (again in 2012 prices), too low to attract a single bid – and £2 lower than AR4. While this may have appeared reasonable based on the historically falling costs of renewables, it failed to accommodate current reality: inflation in the cost of steel and other commodities, the greater cost of financing projects due to raised interest rates, wage inflation and the broader impacts of Russia's invasion of Ukraine.

While the same issues have impacted solar, they have had less of an impact – explaining why the strike price was not pushed down through the auction process, as would normally happen.

In the absence of more offshore wind, consumers will be paying an extra £2bn a year on their household electricity bills, according to wind industry association RenewableUK. More broadly, the attainment of net zero has been harmed, not least by slowing investment in vital grid upgrades, which the wind industry needs as desperately as solar.

The fact that so many solar projects have been successful in AR5, particularly as the sector has only recently been able to participate, shows how resilient solar has become to economic shocks. It remains the cheapest way to generate power in the UK. That said, the pace of solar installations needs to roughly double to meet the government's capacity target of 70GW by 2035.

Industry lobbying following the debacle has evidently paid off, with the government tacitly recognising that a mistake had been made. On 16 November, the government announced that the maximum bid price for AR6 would go up 30% for solar, to £61/MWh (worth £83.83 now). Those for the wind industry went up considerably more, up 52% to £73/MWh for offshore and up 66% floating offshore, bringing it to £176/MWh.

Budgets for AR6 are scheduled to be revealed on 13 March. Offshore wind will be given its own funding pot, separate to solar, in recognition of the high number of projects ready to participate.

In conclusion, the Contracts for Difference system has been a major factor in the growth of the UK's solar power sector, by providing investors with secure and reliable incomes. Solar remains the cheapest source of power in the UK, according to the government's own figures, although lately installation costs have been affected by factors outside the control of the industry, notably the war in Ukraine. So, from Solar Energy UK's perspective, it is gratifying that that the maximum bid price for AR6 has been raised by a significant amount, which should bolster growth further towards reaching the capacity target of 70GW by 2035. ■

Turn to p.52 for more on the UK's large-scale solar market

References

Colville, F., "UK on track to add 1.7 GWp-dc of solar PV, 31 October 2023, Solar Power Portal https://www.solarpowerportal.co.uk/uk-on-track-to-add-1-7-gwp-dc-of-solar-pv-in-2023/

Author

Gareth Simkins is senior communications adviser at Solar Energy UK, after having been an environmental journalist at ENDS for over 16 years. He played a crucial part in efforts to stop Liz Truss' solar farm ban in late 2022. He is also a trustee of the toxic chemicals campaign group CHEM Trust and an active member of Croydon Community Energy and other local organisations.

Renewable subsidies: between a ROC and a hard place

UK | Proposals to shift the UK's legacy programme for incentivising large-scale solar to a fixed-price mechanism are under consultation. Marianne Anton looks at the potential impact on project revenues of the proposals on the table

The Renewables Obligation (RO) has incentivised UK renewable electricity generation since 2002 through a system of tradeable green certificates called Renewables Obligation Certificates (ROCs). Following a series of finetuning reforms, the RO support scheme was closed to new participants in 2017 and replaced with Contracts for Difference (CfDs) as the main government scheme supporting large-scale renewable generation. CfDs are a mechanism for "hedging" price volatility. RO-accredited facilities will continue receiving ROCs until 2037.

The journey from ROCs to CfDs

The RO scheme incentivised electricity suppliers to purchase green energy by requiring them to present a number of ROCs allocated by their market share to energy market regulator Ofgem annually. Accredited renewable generators accrue ROCs and sell them to suppliers along with the power they generate, usually under short or long-term power purchase agreements (PPAs). ROCs have a separate price in addition to the power produced and therefore sale of ROCs resulted in a subsidy for renewable generators. Historic "banding" meant that less developed technology received more ROCs per MWh generated, resulting in a higher subsidy to encourage development of new technology. The price generators can obtain for their ROCs is based on the "buy-out price", which is set by Ofgem for each obligation period; where suppliers do not have sufficient ROCs to cover their obligation, they must make a corresponding payment into the buy-out fund [1]. ROCs were designed to create a market and are traded at market prices that differ from the official buy-out price.

In contrast, CfDs are arguably a simpler mechanism and generators contract directly with the government-owned Low Carbon Contracts Company. The available budget is split into pots for more and less established low carbon technology, with the latter achieving higher strike prices (and therefore a larger subsidy).

Fixed-price ROCs

Earlier this year, (31 July to 9 October 2023), the government issued a call for evidence on introducing Fixed Price Certificates (FPCs) into the UK-wide RO schemes, presuming it would be "of particular interest to those currently in receipt of ROCs, electricity traders and suppliers, businesses operating in the energy sector, and consumers and environmental groups with an interest in the electricity sector" [2]. No responses or follow up consultations have been published yet.

The move to FPCs is not new; in 2011, the Cameron-Clegg government announced its intention to transition the RO from a live-traded to an FPC-based scheme from 2027. This was intended to address the anticipated volatility in ROC price as early generating stations retired from the scheme and projects moved to the CfD model. Due to a glut of stations joining the scheme prior to closure, this volatility has not yet materialised and is expected in the mid-2030s. However, there has been renewed interest in FPCs for the benefits they might offer regarding supplier payment default and the potential rebalancing/reduction of costs.

The call for evidence sets out the potential benefits of moving to an FPC system. These include price stability, reducing the risk of supplier payment default and mutualisation and reducing the cost of the RO scheme. It also outlines the potential downsides, including risk of short-term disruption, design redundancies, reduction in suppliers' working capital and reduction in scheme value. The call for evidence also sketches out two possible models for an FPC-based RO Scheme.

Under Model 1, a central counterparty is appointed and – unlike the current system – no trading in certificates is allowed. The rationale is that this could enable increased revenue certainty for generators, create long-term administrative savings for suppliers and reduce consumers' costs (as third-party traders' fees would be eliminated).

Under Model 2, a central counterparty is still appointed but trading in certificates is allowed. This maintains the current portability of ROCs and allows market participants more leeway in managing their cashflow. Trading should also foster stronger relationships between generators and suppliers.

Whatever its final shape (if it does, indeed, materialise), an FPC system will have enormous ramifications for players dealing in ROCs. Previously, the government had said that, under an FPC system, it would buy ROCs directly from generators to protect existing PPAs. But as ever, policy remains subject to change.

We recommend clients check their PPAs well in advance of the impending change, particularly where large portfolios may be affected. Any such transition could have a substantive impact on revenues payable under a PPA. If a PPA expires before 2027, revisions to the RO scheme are unlikely to present issues. However, for those lasting beyond 2027, we recommend a review focussed on determining what (if any) provisions are made for a transition to FPCs. ■

References

[1] The proceeds of the buy-out fund are paid back to suppliers in proportion to how many ROCs they have presented. Therefore, if there is a shortfall in compliance against the obligation, ROCs become worth more than the face value of the buy-out price.

[2] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1175231/renewables-obligation-fixed-price-certificates-cfe.pdf

Author

Marianne Anton is Counsel in Watson Farley & Williams LLP's London Regulatory, Public Law & Competition team. Her practice includes advising on a broad range of energy matters, notably in the renewables sector, from corporate and commercial transactions to regulatory compliance requirements and power market restructures.

Save 20% on all tickets use code: PVTP20

12th Edition

LARGE SCALE SOLAR EU

26 - 27 March 2024
Altis Grand Hotel, Lisbon, Portugal

HOST SPONSOR

SMARTENERGY

Shaping Europe's Solar & Energy Storage Landscape

Our Expert Speakers

Alexandre Kisslinger
CEO Portugal
Acciona

Karen Boesen
Chief Financial Officer
Sonnedix

Joao Maria de Macedo Santos
CEO
Akuo Portugal

Ezio Ravaccia
CFO & CIO
Solar Ventures & Solar Ventures Capital

Ewelina Szulc
Managing Director, Polish Portfolio
DIF Capital Partners

2024 Sponsors

Host Sponsor: SMARTENERGY

Diamond Sponsor: JinkoSolar — Building Your Trust in Solar

Silver Sponsors: LUXEN SOLAR; SMA

Bronze Sponsor: prediktor

Supporting Sponsors: KYOS ENERGY ANALYTICS; POWERFACTORS; risen; SUNOVA SOLAR Pv Tech Expert

Editorial Partners: PVTECH; SOLAR POWER PORTAL

Partners: Borderless Renewables; Joint Forces for Solar Global

Visit us to Learn More lss.solarenergyevents.com

#LSSEU

The opportunities and challenges within Ireland's solar market

Market update | Despite having a healthy solar target, Ireland's most recent renewable energy capacity auction saw a disappointing result for PV. Lena Dias Martins looks at the obstacles causing delays and barriers to the rollout of solar on the Emerald Isle

Credit: Power Capital

A number of hurdles led to a disappointing outcome for PV in Ireland's recent RESS auction round

In a nation boasting a 5,585MW installed wind energy capacity, according to Wind Energy Ireland, solar may appear as an overshadowed technology; however, Ireland's solar market is on a steady growth trajectory.

In order to support its renewable market, especially solar, Ireland launched its first Renewable Electricity Support Scheme (RESS) auction in 2020, a government subsidy scheme, similar to the UK's Contracts for Difference (CfD), which allows renewable projects to bid in auctions for contracts to provide electricity at a guaranteed price.

The first auction round (RESS-1) guaranteed solar up to 10% of the available capacity. Instead, solar superseded expectations winning 796MW – 34% of the overall auction energy volume – at an average strike price of €72.92/MWh (US$79.65/MWh), overtaking onshore wind which secured 479MW.

Unfortunately, after an extremely successful RESS-2 – which awarded a total solar capacity of 1,534MW – the third auction saw a significant decline in awarded solar capacity. The decrease was alluded to when the Irish government – announcing RESS-3's provisional results – voiced its concern that only 1GW of the 3GW of eligible projects decided to compete in the auction.

These fears were confirmed when, in October 2023, Irish grid operator EirGrid confirmed that only 20 solar projects with a total capacity of 497.49MW were successful in the third auction. The largest of these being the 101.1MW Tracystown Solar Park, submitted by ESB Solar (Ireland).

The Irish Solar Energy Association (ISEA) attributed these results to an "overly rigid" auction design plagued by "unavoidable systematic failures". One of these alleged failures was that the auction price cap was published only after developers would have faced a penalty for not bidding, leaving the industry to gamble on the viability of their investment.

Another hurdle for developers wishing to bid in the RESS is a penalty sanctioned if project development delays occur, despite many of the causes of these delays being outside of their control.

Last December the Irish government increased its renewable capacity target from 15GW in Climate Action Plan 2021 (CAP21) to 22GW in CAP23, so as to reach an 80% renewable electricity share by 2030. This catapulted the solar capacity target from 1.5-2.5GW in CAP21 to 8GW.

It is imperative to Ireland's solar industry and its renewable targets that these issues are addressed.

As of October 2023 Ireland has 349MW of utility-scale solar connected to the grid, according to the ISEA's 'Scale of Solar' report. However, according to market researcher Cornwall Insight's July 2023 'All-Island forward curve' report, each RESS action must now secure a total of 1,700MW of solar capacity to achieve its renewable capacity goal – a target missed in RESS-3.

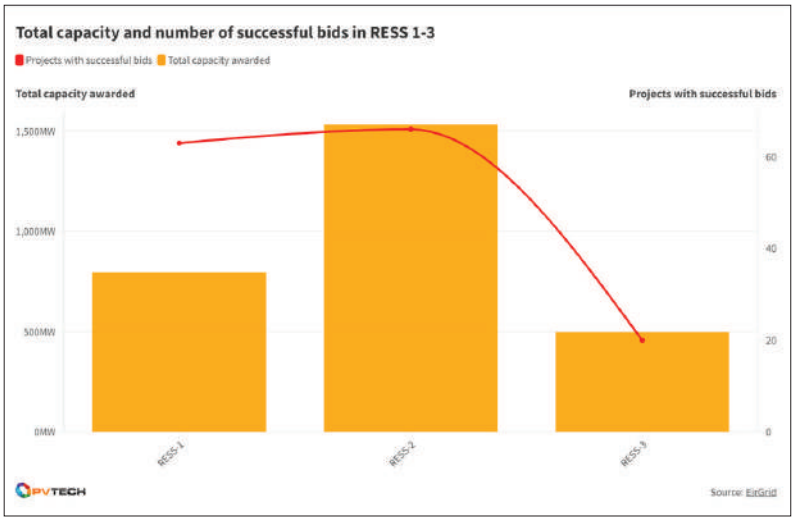
To reach its 8GW solar target, Ireland must capitalise on the opportunity presented by the early success of the RESS and tackle any challenges disincentivising investment in solar and slowing potential projects down.

In this article, *PV Tech Power* explores what challenges developers face when building solar in Ireland and what role the technology will have in securing net zero for the country.

Planning and pricing delays

Throughout the industry delays have been identified as one of the most pressing hurdles to overcome within the Irish solar market.

This encompasses a number of separate issues, the first of which is delays in the planning permission process. Planning processes can be trying for developers in any country, but it's particularly tricky for



Bidding for solar was down in Ireland's latest auction round. Source: EirGrid

those looking to build solar in Ireland as only shovel-ready projects with planning permission and a grid offer from EirGrid are eligible to compete in the RESS auction. This was a new rule implemented for RESS-3.

Unfortunately, in the current climate where planning delays are becoming increasingly common, this restriction is having a negative effect on projects wishing to bid in RESS.

"The planning delays are very serious. There seems to be a black box in terms of timelines from when an application is submitted to receiving a result, and then the appeals and judicial review processes commence," says Lisa Foley, principal consultant at Cornwall Insight Ireland.

Ørsted was among the successful bidders in RESS-3, securing contracts for two of its projects, the 81MW Garreenleen solar project in Carlow and the 43.2 MW Farranrory onshore wind farm.

Despite this success, the renewable energy developer notes that the Irish government is not enabling its own renewable ambition in setting planning permission requirements for the RESS and attributed these tough rules to the decrease in successful renewable projects.

"The level of ambition set in Irish policy does require an efficient planning system to ensure that timely decisions are made on renewable projects of strategic value to the Irish State," says TJ Hunter, senior director for development and operations UK & Ireland at Ørsted.

This sentiment was echoed by Foley who tells *PV Tech Power* that the shovel-ready requirement for projects has "limited the possible pool of participants" within RESS.

Fellow developer Power Capital was also successful in its RESS bid for two solar projects; however the developer reveals that it had "multiple" projects in the wings awaiting grid offers that weren't able to bid in RESS-3.

"If the Terms & Conditions were similar to RESS-2, the auction would likely have been double in size, closer to the 3GW of eligible projects," says Bill Senior, director of operations at Power Capital.

A strong feeling within the industry is that the strict planning restrictions for RESS-3 bids penalises developers for factors outside of their control.

"The continuing delays we experience in reaching planning decisions and grid offers, both of which are outside the control of developers, are reflected in the drop in volume of renewable power offered in RESS-3," continues Hunter.

Citing the same hurdles as Ørsted, Senior says that RESS-3 ought to have permitted projects pending grid connections to bid, as well as "more flexibility on non-contestability timings for connecting to the grid".

Following a review of the planning process in 2022, the Irish government published a new Planning and Development Bill in November 2023, which introduced statutory timelines for decision making and a reform of the judicial review process to increase certainty across the planning system.

Another delay affecting RESS-3 bids was the Auction Price Cap – the maximum bid permitted to a developer – which was only published after developers would have faced a penalty either for failing to bid or withdrawing an existing bid.

Conall Bolger, CEO of the ISEA recognises that this left the industry little choice but to "gamble significant sums of money with no knowledge if their investment will be viable or not".

"The developer of any renewable project wants to ensure it is up and running as soon as possible. But the reality is that delays, at the hands of state institutions, make that challenging for many. Delays in planning and receiving the required connections to the national electricity grid are entirely out of developers' hands and entirely within the state's," Bolger continues.

"Yet it is the developer who will be sanctioned by the state for the state's own failings if a delay occurs. A failure to account for these state-inflicted problems will have limited the number of projects bidding in this RESS auction."

The role of solar in securing energy security for Ireland

The carbon intensity of Ireland's electricity is amongst the highest in Europe sitting at 331g CO2/kWh in 2022, according to the Environmental Protection Agency.

Hunter notes that this is a particular concern during amber alerts – which occurred several times in Ireland during summer – where wind speeds are low and the cost of electricity remains high due to an "over-reliance on fossil fuels". Increasing the country's solar capacity will help mitigate this, providing energy during calm, sunny days.

"One of the big advantages of solar power to meeting our renewable energy targets is that it is often fast and comparatively less complex to deliver," says Hunter, adding that company is expecting to begin construction of the 81MW Garrenleen solar farm – approved in RESS-3 this September – in Spring 2024, pending a final investment decision.

The site is hoped to be fully operational within two years, illustrating the speed at which solar can begin supplying clean, cheap power to Ireland.

Foley adds the consideration of Ireland's geography: "As an island nation on the edge of Europe, Ireland is exposed from a security of supply perspective, and we see solar energy as the fastest way to address these joint challenges."

Holding an ambitious solar target of 8GW, Ireland maintains an attractive solar market, as the country looks to diversify its electricity supply and hedge electricity costs.

The RESS remains one of the most appealing routes to market for developers, as Foley points out, although corporate power purchase agreements (CPPAs) are also viewed as a viable route to market, despite being less lucrative or assured than the RESS and investors lean towards certainty.

"Corporate power purchase agreements do however tend to be indexed linked," adds Foley. "It may be that choosing between the either-or option of RESS or CPPA might not be the answer, there may be synergies that could be established between the RESS and the CPPA processes that might encourage participation."

Both Ørsted and Power Capital reveal to *PV Tech Power* that they will continue to build solar in Ireland, with the latter featuring a 2GW pipeline of solar and battery hybrid projects in the country.

Ørsted has secured planning permissions for a 160MW solar farm in Carlow and a 55MW farm in Cork. Additionally, in September 2023 the developer announced a new partnership with Terra Solar to develop a portfolio of solar projects in Ireland with a combined capacity of up to 400MW.

"When assessing different markets and their potential, a key consideration is whether solar energy is supported in policy," adds Hunter.

To that effect, Hunt concludes, the Irish government's increased solar target of 8WG by 2030 – alongside the government support offered by the RESS scheme, despite its drawbacks – send "a clear signal to the market". ■

Product reviews

Modules | Maysun launches range of IBC modules with conversion efficiency as high as 25.8%

Chinese module producer Maysun has launched a new range of panels, which take advantage of interdigitated back contact (IBC) cells to remove busbars from the front of the modules and improve the overall conversion efficiency of the panels.

Market & applications: Ensuring operational efficiency is a fundamental part of all electricity generation operations, and Maysun's latest range of panels looks to optimise power generation. The presence of the junction on the back of the cell removes the need for busbars to be placed along the front side, allowing more of the panel to be used to convert the sun's rays to electricity and improving the overall efficiency of the system.

The range of panels is also aimed towards use on rooftops, with the modules boasting a wattage of between 425-600W. The relatively small size of these panels means that high conversion efficiency is of particular importance, as customers will likely be looking to generate electricity from solar projects that cover a relatively small surface area.

Industry challenges: Optimising cell conversion efficiency is an ongoing aim for the solar industry, and back contact-type technologies help boost cell efficiencies. Maysun estimates its IBC modules to have a conversion efficiency of between 22.9% and 25.8%.

Technical solution: The IBC modules offer a number of benefits, beginning with the placement of junctions on the backs of the cells, removing busbars and obstacles from the front of the cell. However, Maysun notes that its cells are still more efficient than other back contact-type cells, with its reports noting that passivated emitted rear contact (PERC) cells typically have a conversion efficiency of up to 23.2%, lower than the maximum conversion efficiency of the Maysun cells.

The company's cells also have a temperature coefficient of -0.29% per degree Celsius, a stronger performance than the -0.34% per degree Celsius offered by many PERC modules. As a result, the Maysun modules have a power output of 94.2% and 88.4% at 45 and 65 degrees Celsius, respectively, higher than the 93.2% and 86.4% offered by PERC modules.

Unique features & benefits: The Maysun modules have a first-year power degradation figure of just 1.3%, and a 0.4% annual power degradation figure beyond the first year, suggesting that they will be able to efficiently produce electricity over a sustained period of time.

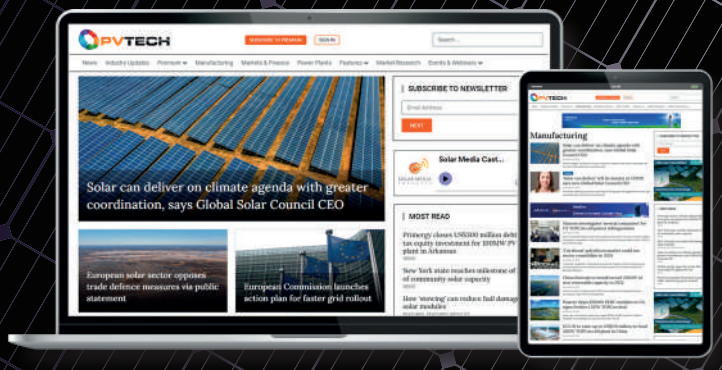
The IBC range also comes in a number of sizes for different applications. The IBC silver frame module is the largest in the series, with a capacity of 555-600W, ahead of the IBC full black module, with a capacity of 430W, and the IBC black frame module, with a capacity of 425-450W.

Availability: The IBC range of modules is available now.

PV TECH .ORG

The No.1 source for in-depth & up-to-the-minute news, blogs, technical papers, and reviews on the international solar PV supply chain covering:

- Manufacturing
- Technical innovations
- Markets & Finance
- Events



Subscribe to the daily PV Tech newsletters for the biggest stories in PV from around the world.
Scan QR Code to sign up for free:

SCAN ME

Or visit
pv-tech.org/newsletter

Trackers | Protect solar projects from hail with Nextracker's NX Horizon Hail Pro

Nextracker's NX Horizon Hail Pro offers an industry-first solar tracker solution to the threat of hailstorms for utility-scale solar installations. It leverages Nextracker's industry-leading NX Horizon solar tracker platform and adds new hardware features, software tools and optional services to provide maximum protection against hail.

Market & applications: This hail risk mitigation product is designed for utility-scale solar PV installations, which dominate today's electricity generation pipeline. It builds on the proven NX Horizon platform, which has been deployed on over 75GW of solar installations globally including 17GW in hail-prone regions. The base features of NX Horizon provide significant advantages against hail, including uninterruptible power supply for each tracker row to ensure performance during grid outages, as well as the rapid stowing capabilities of its mechanically-balanced design.

Industry challenges: Sudden hailstorms are a massive threat to utility-scale solar

projects, raining baseball-sized globes of ice up to 3" (75mm) in diameter at velocities of over 85 miles per hour (135km per hour) – enough to shatter PV glass and cause millions of dollars in damage. This insurability risk is a threat to the solar industry in some of its fastest-growing regions. For example, one of the most at-risk states in America's "hail corridor" is Texas, a national leader in solar growth.

Technical solution: Hail Pro addresses this risk with multiple layers of protection, including additional resilient design features and rapid response capabilities. On the hardware side, Hail Pro provides operators with the added flexibility and speed required to mitigate hail risks. Hail Pro features 360° wind structural engineering, allowing operators to backwind the system to the direction of the storm to minimise hail damage without fear of wind damage.

Unique features & benefits: Projects facing severe hail risks can opt for Hail Pro 75, which boosts NX Horizon's maximum hail stow angle from 60° to 75° – shown to increase panel glass survival to >90% against 3" ice balls in lab tests. These projects may also wish to take advantage of optional hail stowing during project construction, delivered via self-powered NCUs with cellular communications prior to site power and ethernet.

Finally, Hail Pro offers seasonal and annual hail-stow functional testing support, ongoing system readiness monitoring, and other service add-ons to ensure solar installations are prepared for hail risks year-round. Nextracker's experts can also provide underwriter and third-party validation support for risk category reduction, helping insurers understand the value of Hail Pro's comprehensive protection capabilities.

Availability: Hail Pro is available today, following a special project launch at RE+ 2023.

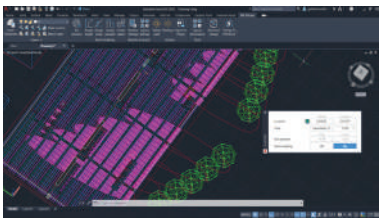
Software | PVcase launches PVcase Roof Mount for commercial and industrial solar rooftop installations

PVcase has launched PVcase Roof Mount, a tool for commercial and industrial rooftop solar installations. Land shortage, climate change, and relatively easy implementation make rooftop solar one of the most promising clean energy options.

Market & application: PVcase Roof Mount is an AutoCAD add-on for rooftop commercial and industrial PV projects.

It is intended to help users make rooftop solar engineering faster, more efficient and more accurate. The tool has rapid 3D building preparations, layout generation, shading calculation, innovative electrical design and the capacity to export a bill of material (BOM) and to PVsyst.

It allows users to easily build a model of a roof by inputting its dimensions or simply using an orthographic photo. Moreover, PVcase RM's shading analysis tool has two functions: the first predicts roof shadows before placing PV modules, creating a shadow projection; the second analyses shade's energy impact on each module, providing the affected percentage over the course of a day.



Industry challenges: Rooftop solar is set to transform how the world generates and consumes energy in the near future. Its remarkable growth can be attributed to increasingly affordable solar panel technology and supportive government policies. According to SolarPower Europe, 49% of solar PV capacity added in 2022 was on rooftops.

As individuals and communities recognise its environmental and economic benefits, rooftop solar has become a symbol of energy independence. Integrating energy storage solutions makes solar power a reliable energy source, reducing dependence on centralised grids and decreasing carbon emissions.

However, this growth brings significant challenges as well. Namely, the need to quickly scale up the rooftop solar industry while ensuring the correct design and engineering of a growing number of systems, taking into account factors such as geographical location, tilt and orientation of the panels and local climatic conditions.

Technical solution: PVcase does not offer a pre-defined set of modules based on manufacturer specifications. Therefore, users are required to define these parameters themselves. This includes specifying the module's length, width, thickness and power rating.

For the electrical design, users can customise strings or use a pre-made template for a quick and detailed design, and modify string labels as needed. Users can also pair modules with the main device in the cabling window, choose a basic or complex design, set the number of strings and maximum power point trackers (MPPTs), and reposition if necessary.

PVcase Roof Mount also has a cabling generating function, which automatically routes through the cable tray, optimising path and dimensions.

Availability: PVcase Roof Mount is currently available for Auto-CAD users.

Product reviews

Design | Planning a utility-scale PV plant digitally with RatedPower's pvDesign software

RatedPower's pvDesign is a cloud-based software available for all types of users as well as systems. As it works on the cloud, there is no need to download any program or have a computer with technical characteristics.

Market & application: The product is ideal for developers, engineering, procurement and construction (EPC) companies and investors. It helps developers to reduce time when manually optimising PV plant designs and calculating energy yields. For EPC firms, it is useful to add or modify any inputs or items in the project itself, as pvDesign enables users to iterate designs. Banks and funds can use the software to have a clear and accurate yield estimate of their projects, with well documented plant performance analysis.

Industry challenges: Some companies also lack the skills or staff to do basic engineering and design

in-house and therefore may need to outsource these tasks. Banks and funds who lack technical expertise but want to know the long-term yields of solar sites may also need to get external help to calculate these values. Deploying pvDesign enables teams do all this work in-house.

Technical solution: pvDesign aims to not only accelerate the whole process through automation, but also solve these challenges by making it easier to be ahead of other companies when submitting projects, allowing users to modify and add any parameters to fit the regulations any time and compare designs with different inputs in order to achieve the most optimal configuration. The software has already been used by companies including BayWa r.e.

Unique features & benefits: RatedPower's pvDesign software automates and optimises the study, analysis, design and engineering of all stages of a PV plant. It helps companies optimise the design and engineering of utility-scale projects and maximise their profitability. The software has reportedly reduced the LCOE of solar plants designed with it by 5%, which translates to a 20% higher solar plant profitability. RatedPower estimates that using the platform can reduce the time spent designing a PV plant by 85%.

Availability: pvDEsign is available now.

PV MODULETECH CONFERENCE USA

21-22 May 2024
Napa, California, U.S.A.

Identifying reliable PV module technology suppliers to the U.S. market

"PV ModuleTech USA conference allowed me to see into the future while making new contacts in the present that I could never do anywhere else.
Randy Eager, SilisiumTech Inc.

"What separates PV ModuleTech USA from most conferences is the targeted list of attendees and the feedback loop of content (from field to procurement to manufacturer).
Jesse Nickerman, PI Berlin

"PV ModuleTech USA was a fantastic event. Well attended by the leading developers, IPPs, and manufacturers of North America. I am looking forward to the 2024 event!
Jenya Meydbray, Nevados

moduletechusa.solarenergyevents.com | email: **pvmoduletech@pv-tech.org**

Mismatch voltage & thermal patterns in half-cell bifacial technology

Module quality | The rapid emergence of new PV technologies such as bifacial has in some cases outpaced the evolution of suitable technical and regulatory specifications. The occurrence hotspots in non-shaded areas of half-cell bifacial solar modules highlights the need for a rethink of international standards, write Sergio Suárez, Jose María Álvarez, Daniel Villoslada, Ignacio Fernández, Sofía Rodríguez and Gustavo Navas

The swift uptake of photovoltaic technology at a global level has led to a rapid pace of technological improvements, impacting both the tech innovation sector and the wider utility-scale market. As a result, over the past decade, the power output of solar modules has soared, while the cost per watt has been significantly reduced, two factors that led to a dramatic increase in the competitiveness of this technology. Recent advancements in the PV industry include enhancements throughout the solar module's value chain, from the Bill of Materials (BOM) to the technology within the solar module itself.

This burgeoning demand and development have spurred scientific efforts to conduct studies and tests to ensure that international standards keep pace, yielding results that provide technical solutions for stakeholders operating in the solar industry.

In recent years, substantial technological shifts have occurred in the PV market, therefore companies face considerable uncertainty in the definition of the technical specifications of their PV projects. A prime example is the emergence of bifacial technology, which notably improved solar panel energy production, but also introduced widespread technical and regulatory uncertainty.

Proper technical advice at different stages of photovoltaic projects

Some standards that ensure in-factory quality control during the module manufacturing phase, such as the IEC 61215, have been updated with a broader focus and are supported by solid scientific literature. However, other standards, such as the IEC 62446-3, which are more oriented towards O&M services, have not yet been approached with such an expanded perspective. In this context, relying on specialised support from an independent third party, such as Enertis Applus+, is always underscored for proper technical advice at different stages of photovoltaic projects.

Figure 1: Enertis Applus+ technical consulting services for solar photovoltaic projects

The study on "Thermal issues on half-cell bifacial modules. A way through albedo and mismatch voltage", presented by Enertis Applus+ at this year's EU PVSEC conference, offers an intriguing technical perspective on the thermal behaviour exhibited by half-cell bifacial solar modules under certain undesirable partial shading conditions during operational phases. These phenomena are not addressed by current standards, yet they provide valuable insights for industry companies.

Recent advancements pose fascinating technological challenges, such as characterising the "light source" from the ground in bifacial technology or the presence of parallel electrical circuits in half-cell technology, that carry certain physical implications when external variations are induced. In this study, we address the occurrence of hotspots in non-shaded areas of solar modules.

In Figure 2, captured using a standard thermographic camera in the field, an unusual element at the top of the module can be seen casting a shadow over one of the solar cells, leading to a typical hotspot in this type of semiconductor. However, a pattern of hotspots

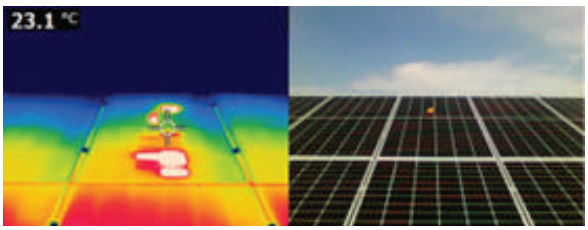


Figure 2: Hotspot caused by an external element in an on-field thermography camera

Figure 3: Case study example: differentiated thermal parts

on the non-shaded part occurs in a way that is analogous to a reflection in a mirror. This is why we refer to this type of hotspot as a "hotspot mirroring" (H_{mirror}) during the study.

This type of defect ought to be scrutinised during ground or aerial inspections applying the IEC 62446-3 standard criteria. However, this is one of the instances where technological evolution has outpaced the standards: there is no classification for this kind of thermal anomaly, nor recommendations for its management, therefore it can potentially be mistaken for a thermal short circuit.

Surprisingly, there is a limited scientific discourse addressing these challenges, with international standards lagging in accommodating these findings.

While half-cell bifacial technology is widely integrated in utility-scale solar projects, anomalies are often observed with few misinterpretations. Recent trials we carried out on half-cell bifacial technology uncovered unique defects, prompting a re-evaluation of international standards. By merging on-field discoveries with internal experimentation, intriguing insights into the thermal behaviour of these modules emerge.

Enhancing quality control procedures

At Enertis Applus+, we conducted a series of forced-shadowing tests to categorise the new thermal anomalies found in these types of modules and we are excited to share some of these findings with the scientific community.

The overarching goal of our exercise is straightforward: enhance quality control procedures within the solar PV industry and chart a clearer, more definitive path in the unfolding renewable landscape that awaits all stakeholders in this transformative shift.

Our study seeks to bridge existing research gaps by delving into the impact of ground albedo and voltage mismatch on the formation of hotspots in half-cell bifacial PV modules. Using an empirical methodology grounded in on-field data collection, our findings provide a more intricate view that deviates from previous simulation-driven research [1]. Within this context, we introduce the concept of hotspot mirroring (Hmirror) to highlight a distinctive feature of half-cell modules and we explore its ramifications for thermal management.

The primary ambition of our research is to furnish insights that could shape forthcoming technical guidelines and standards pertinent to the design and installation of half-cell bifacial photovoltaic modules.

The study focuses on inducing hotspots using a type of textile to observe the thermal behaviour across different parts of the photovoltaic module under varying levels of irradiance.

Throughout the thermographic testing, five distinctly differentiated parts become clearly visible. These are:

- The induced hotspot, referred to in this study as hotspot shadowing (H_{shad});
- The substring affected by the shading, the mirrored hotspots (H_{mirror});
- The upper substring impacted by these unusual hotspots;
- The lower substring impacted by these usual hotspots;
- The module's normal operating temperature.

The hotspot mirroring (H_{mirror}) phenomenon stands out prominently in our investigation. It arises due to a voltage mismatch between the upper and lower substrings in half-cell modules. This mismatch is different from current mismatch between cells, and it manifests when a cell under forced shading starts to produce a negative voltage.

Figure 4: Irradiance and thermal sensors on monofacial (left) and bifacial (right) devices

Figure 5: Thermal representation of the module tested during the experiment

Since there are now three electrical circuits in parallel (one being the protection diode, another one the upper substring, and the third one, the shaded lower substring), the voltage across them must always be similar, due to basic electrical laws.

The presence of a negative voltage in the lower substring, which does not correspond with the positive voltage of the upper substring, results in a voltage mismatch that forces the non-shaded substrings to align their voltage with the rest of the circuit.

The ripple effect of this is a disturbance in the regular operation of cells situated on the opposite side of the shaded cell. A distinct checkerboard-like thermal pattern emerges as a result, primarily impacting the more vulnerable cells in the adjacent substring.

Our experimental observations of (H_{mirror}) align with conclusions drawn from previous simulation-based studies [1]. To elucidate this phenomenon further, we have incorporated an on-field infrared (IR) image (Figure 3), which vividly displays the checkerboard thermal patterns spanning the affected cells.

The experimental validation of the hotspot mirroring phenomenon underscores its significance in thermal considerations for bifacial half-cell PV modules, where the ground albedo effect can lead to increased current in cells and create potential partial shading under various specific conditions.

To conduct a thorough analysis of the thermal behaviour in both half-cell bifacial and monofacial photovoltaic modules, we developed an elaborate experimental framework. Both module types were integrated with a monitoring system, capturing data on irradiance and temperature at various locations across the tested devices.

Each module featured five thermocouples specifically for temperature monitoring (Figure 4). To ensure an accurate reading of irradiance, two sensors – termed G_{front} and G_{rear} – were placed on each module to measure frontal and rear irradiance, respectively. A visual aid showing the schematic representation of the sensor arrangement can be seen in Figure 4.

Such instrumentation ensured precise measurement of the irradiance conditions influencing the current production of the PV modules and the temperature gradients across various module sections.

To further our investigation, we introduced intentional shadowing to both monofacial and bifacial half-cell modules. The goal was to simulate and understand the phenomenon we term hotspot mirroring (H_{mirror}). Preliminary verification of the presence and spread of these hotspots on the module was done using thermographic (IR) camera imaging.

Irradiance and temperature data were collected over a 30-day period, establishing the relationship between irradiance and the temperature reached at each of the measured points. A clear distinction between bifacial and monofacial devices was observed, with behaviour varying depending on the type of day and cloud levels.

For a holistic grasp of the modules' thermal behaviour, the five thermocouples were strategically positioned at:

A) Shadow-induced hotspot (H_{shad});
B) Hotspot mirroring (H_{mirror});
C) Upper substring region without thermal anomalies;
D) Lower substring region without thermal anomalies;
E) Central position free from thermal anomalies.

Designated locations of the area

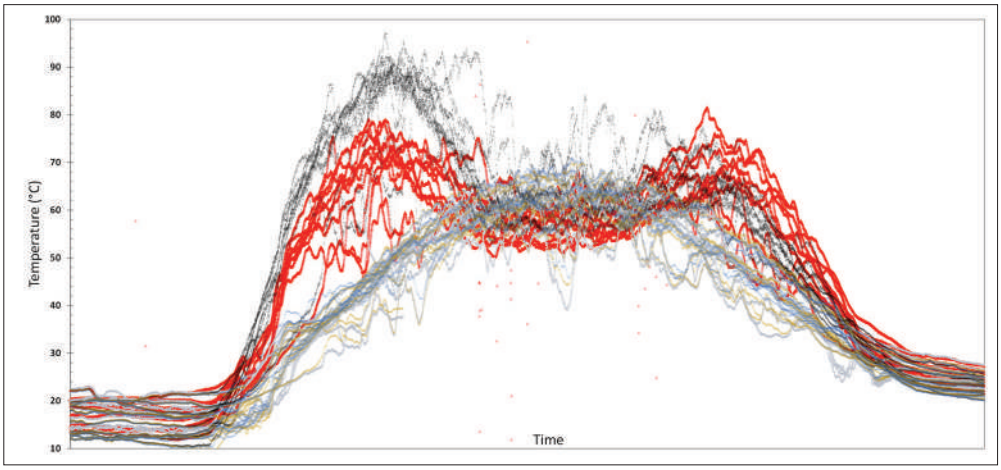
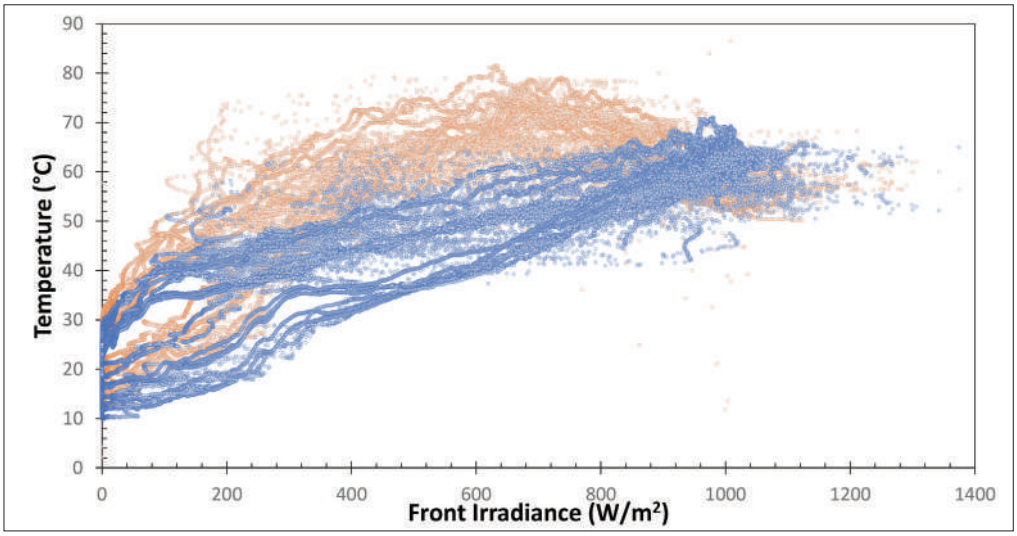


Figure 6: Clear and cloudy days with thermal values of each position (A&B, black and red lines respectively)



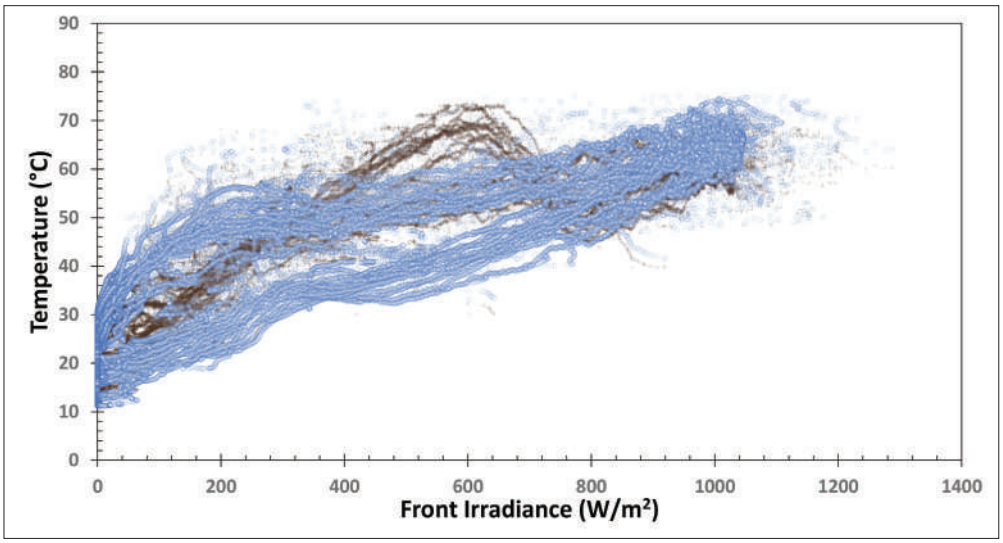


Figure 7: Temperature reached vs irradiance in monofacial (upper) and bifacial (lower) modules vs baseline (blue lines)

shadowed (left) and the area subjected to thermal defects (right) can be visualised in Figure 5.

To comprehensively gauge and juxtapose voltage mismatches in both configurations, we calculated temperature gradients using thermocouples judiciously distributed across the modules. Over a span of 30 days, a pronounced correlation emerged between temperature gradients and the irradiance levels each module received. This correlation was particularly evident on cloudless days with peak irradiance. By utilising the central thermocouple (point E) as a benchmark, we calculated temperature differentials, contrasting shadow-induced hotspots and hotspot mirroring effects.

To graphically evaluate the behaviour of each measured point, a chart is presented in Figure 6, which displays two types of days distinguished by the shape of their thermal curve. A clear day is characterised by a smooth curve reaching operational temperatures above 60° C, and a cloudy day is marked by a serrated, sawtooth curve with abrupt changes in the module's temperature.

Figure 6 illustrates the temperature increase of the hotspots A&B (H_{shad} and H_{mirror}, black and red lines, respectively), showing an aggressive rise as the module's irradiance increases. Beyond a certain thermal stress and irradiance level, the negative voltage reached in the shaded cell is sufficient to trigger the protection diode, leading to the deactivation of the substring. This results in a cooling effect with a degree of thermal inertia, eventually reaching thermal equilibrium with the rest of the module.

The relative thermal difference between these two hotspots depends on the time of day when it has been inspected, achieving higher thermal values at mirrored hotspots in the afternoon for this shading. However, the results between both types of hotspots are highly dependent on the type of shading performed and the percentage of covered area, such as the number of shaded cells in the module.

A quantitative comparison of the thermal gradients produced between the various inspected points for each technology is presented in the results, providing average and maximum values for the 30-day test period and for the same degree of partial shading. Upon computing maximum values, a peak deviation of 27.0°C for monofacial modules and an even more significant 41.9°C for bifacial modules.

The observed increase in temperature in the bifacial module, compared to the monofacial module, is primarily due to albedo, and therefore, the irradiance reflected by the ground.

The influence of albedo on bifacial and monofacial modules showed distinct characteristics. While its impact on temperature in monofacial modules was marginal, bifacial modules demonstrated heightened sensitivity to changes in ground reflection. This was particularly evident in the traits of hotspots under varying shading conditions.

One of the key aspects that was investigated is the peak irradiance levels that trigger the protection diodes in both monofacial and bifacial modules. The diode's activation is marked by a noticeable dip in hotspot temperature. It is worth noting that, in contrast to monofacial modules, bifacial ones are also exposed to rear irradiance (G_{rear}) which influences the circulating current and, as a result, accentuates the thermal gradients.

A comparative analysis between monofacial and bifacial modules in Figure 7 reveals distinct irradiance thresholds for diode activation. The monofacial module triggers its protection diode at an irradiance of 770 W/m^2, while the bifacial module's threshold stands at 630 W/m^2.

Comparative temperature profiles between H_{mirror} and the central position for both monofacial and bifacial devices. The thermal profile assessment indicates the point at which hotspot temperature achieves thermal equilibrium with the module. A shift in the profile slope denotes diode activation due to heightened heat generation by affected cells and subsequent negative voltage in shaded areas.

Given the pronounced influence of G_{rear} on the thermal performance of bifacial modules, it becomes imperative to reconsider the standard guidelines for accurate characterisation and defect

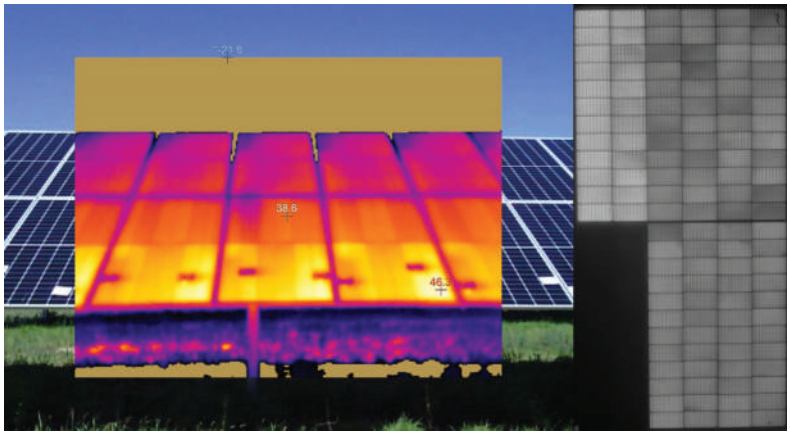


Figure 9: Diode activated in half of the substring in thermography (left) and electroluminescence (right)

diagnosis. Our study showcases the limitations of the existing IEC 62446-3 standard, particularly with the omission of the hotspot mirroring phenomenon and the lack of provisions accounting for the rear irradiance's impact.

Evolution of the governing standards alongside technological advances

For the solar industry to continue its trajectory towards improved efficiency and reliability, it is essential for governing standards to evolve alongside technological advancements. Outdated or incomplete standards could lead to overlooked defects, premature module degradation, and suboptimal PV plant performance, thereby undermining the investments and efforts in promoting sustainable energy sources.

Since the same thermal level for two similar defects is recorded at two distinct irradiance levels, the standard requires normalisation to Standard Test Conditions (STC) of 1,000W/m^2. At this juncture, a thermal gradient at a given temperature can be extrapolated to the thermal gradient that would be expected at STC irradiance.

$$\Delta T_2 = \left(\frac{G_2}{G_1}\right)^x \Delta T_1$$

Figure 8: Equation for extrapolation of thermal gradients. Source: IEC 62446-3

This is a clear example of the current regulatory framework not being up to date, where, pending a future revision, the levels of reflected irradiance or ground albedo are not taken into account when normalising thermal gradients in bifacial technologies.

In this study, we have presented some of the most striking examples, showcasing the results of albedo behaviour and voltage mismatch in the formation of hotspots. However, it is worth noting that the existence of parallel circuits in half-cell technology or rear shading in bifacial technology leads to a series of peculiar consequences under certain conditions.

In Figure 9, we present a similar case observed during an on-field inspection, where it can be seen that the diode is activated only in part of the circuit (left side of the image). The electroluminescence of the modules indicates a partial soldering problem that only affects one of the two parts of the lower substring.

This is why we recommend thorough thermal investigation of modules to enhance international standards, always advocating for the inclusion of a technical advisor in your PV projects.

It is our hope that this research serves as a catalyst for the necessary amendments to the IEC 62446-3 standard, ensuring that it remains robust and relevant for the diverse range of photovoltaic technologies available today. The integration of half-cell and bifacial technologies into the mainstream solar market demands a comprehensive understanding of their unique behaviours and potential challenges.

In conclusion, as the global reliance on solar energy grows, there exists an urgent need for up-to-date guidelines and standards that fully encapsulate the complexities and nuances of emerging PV technologies. Only with an accurate and comprehensive foundation can we ensure the longevity, efficiency and success of renewable energy solutions in the years to come. ■

"For the solar industry to continue its trajectory towards improved efficiency and reliability, it is essential for governing standards to evolve alongside technological advancements"

References

[1] J. Qian, A. Thomson, A. Blakers, and M. Ernst, "Comparison of Half-Cell and Full-Cell Module Hotspot-Induced Temperature by Simulation," *IEEE J Photovolt*, vol. 8, no. 3, pp. 834–839, 2018, doi: 10.1109/JPHOTOV.2018.2817692.

Authors

Ignacio J. Fernández is the head of testing and optimisation at Enertis Applus+. With more than 11 years of experience in the PV industry, Ignacio has managed TDD processes, contract negotiations, expert works and QA/QC campaigns related to PV plants worldwide.

Sergio Suárez Sánchez is the global technical manager of testing and optimisation at Enertis Applus+. With more than five years of experience in the PV industry, Sergio is currently taking a PhD in Electronics at UPV/EHU (Spain), an institution involved in the manufacturing of bifacial PV cells, participating in R&D projects as principal researcher, and developing new testing methodologies.

Sofía Rodríguez is the R&D manager at Enertis Applus+. She has worked on the development of innovative defect detection systems in solar photovoltaic modules, coupled with categorisation and classification techniques. She is currently dedicated to the coordination of different lines of research in the company.

José M. Álvarez Fernández is a project manager of testing and optimization at Enertis Applus+. With five years of experience in the photovoltaic industry, José María has managed the execution of QA/QC PV projects, as well as the development of new procedures and services on his department area.

Daniel Villoslada Fontán is a senior technical of testing and optimisation at Enertis Applus+. With more than three years of experience, he has participated in multiple QA/QC and R&D projects. Daniel is currently developing and coordinating QA/QC PV projects in Brazil.

Gustavo Navas is a technology expert whose career began in the oil and gas sector before shifting focus to solar photovoltaic energy. He holds an academic background in chemical engineering and a master's degree in solar photovoltaic energy. Presently, he leverages his expertise as project manager at Enertis Applus+.

World Future Energy Summit will shine light on current ME solar strength

Taking stock of the world's solar growth patterns is a topic of keen interest not only to those benchmarking global progress on climate change, but also to investors and project developers in the solar power space. While 2023 has been a highly successful year for boosting solar adoption across key regions, time will tell if the pace is fast enough to keep our collective climate goals on track.

As a region, the Middle East has consistently remained a bright spot in solar developments, even despite the disruption of the pandemic and then the impact of the ongoing energy crises that have driven up oil and gas prices on global markets. The region added 7.14GW of new solar PV capacity in 2022, up massively from just 2.64GW the year before. This led to the MEA solar PV market gaining a $5 billion valuation in 2022, though it's due to catapult itself towards $27.71 billion by the end of this decade.

Cumulatively, installed solar PV capacity is set to leap upwards in leading GCC economies. Saudi Arabia looks set to outperform all its ME peers, with a predicted CAGR of 63.4% between 2019-2030, when it will have 40.88GW installed. The UAE is predicted to achieve an impressive 10.22GW during this period, representing a CAGR of 17.4%. This commitment to solar can be attributed to its key position within ME nations' respective economic diversification and decarbonisation plans, as they strive to achieve a sustainable, Net Zero future.

Exploring exactly how the ME solar landscape is changing, and where it is headed next, is best done via leading energy industry platforms such as the World Future Energy Summit which will take place from 16 – 18 April 2024 at ADNEC, Abu Dhabi. Here, attendees can get to grips with the most crucial factors shaping the development of solar energy in the region through the well regarded conference track. Additionally, an extensive showcase of products relevant to this sector surge will be on hand as well as the ability to source from leading global business innovators through the highly popular exhibition. The three-day event will also bring together academics, government policymakers and influential figures from the clean energy industry.

Crucial to the Middle East's ongoing success in solar adoption is the ability of leading ME economies to attract growing investment volumes,

not just from sovereign wealth funds and national infrastructure budgets, but also from diverse international sources. The region is successfully courting global investors and innovators because it not only has the right geographical conditions for solar to thrive, but it also continues to demonstrate the political will to radically overhaul its respective economies. Alongside major solar PV installations, EV charging infrastructure, energy storage solutions, green hydrogen production, solar rooftops and off-grid deployment are all contributing to the creation of a Middle Eastern solar ecosystem that is rapidly growing in size, scale and sophistication.


WORLD FUTURE ENERGY SUMMIT
Hosted by
MASDAR
Is it possible to change tomorrow today?
We think so.
Register now
16 - 18 APRIL 2024 | ADNEC, ABU DHABI
worldfutureenergysummit.com
Built by
RX
In the business of building businesses

"A spirit of cooperation": tackling challenges in the solar EPC sector

EPCs | Booming solar deployment in solar markets worldwide has led to fears that a bottleneck in the availability of qualified contractors could squeeze project completion rates. As JP Casey discovers, the reality is more complicated than that

In many jurisdictions, the future is bright for solar power. Analyst McKinsey and Company expects solar PV to be the driving force behind the expansion of US renewable plus storage capacity to 1.2TW over the next decade, a rate of growth that is 2.7 times faster than what was seen prior to last year's passing of the Inflation Reduction Act (IRA).

There is a similar story in Europe, with trade body SolarPower Europe expecting European solar capacity to exceed 50GW this year, and reach 85GW by 2026, while China is on track to install a record-shattering 230GW of new renewable capacity this year alone.

While the sudden expansion of new renewable capacity, and new solar projects in particular, is encouraging for those involved in the sector, the rapid change in the global solar industry is putting unique strains on the supply chain. This has been most keenly felt in the area of grid connection, with the Lawrence Berkeley National Laboratory noting in April 2022 that almost 1TW of renewables were waiting for connection to the US grid alone, but the supply chain is facing other challenges.

One such issue is that of capacity among engineering, procurement and construction (EPC) contractors, with the very real prospect of the construction industry simply not having the requisite number of interested and capable companies to install the vast quantities of solar capacity that the renewables sector is planning to build. McKinsey and Company reports that, in the US alone, EPC capacity will have to almost triple to meet the demand for new renewable projects just to 2027, to say nothing of the demand on the EPC sector in other jurisdictions, and farther into the future.

With projects growing larger than ever before, and more money being committed to the global solar sector than at any other time in history, there is considerable pressure on EPC contractors, developers, investors and permitting organisations to work effectively together to ensure that the world can install the solar capacity necessary to meet its climate targets.

Credit: Brookhaven National Laboratory via Flickr

Pressures on EPC capacity from booming demand has prompted concerns over a looming bottleneck

Growth leading to uncertainty

"I think there is a bottleneck at the moment, but I think it is also because the portfolios of larger projects are getting more and more," says Stefan Müller, chief operating officer of Enerparc, a German contractor that has completed extensive EPC work in the solar sector. The growth of both total installed capacity and size of individual projects is evident in Germany, with the German solar association BSW reporting that the sector added 7.2GW of new capacity in 2022, a 28% increase on the previous year.

Critically, the number of large-scale ground-mounted installations built in 2022, funded by the Erneuerbare-Energien-Gesetz, the German renewables energy act that came into force in 2021, increased by 70% over 2021 figures, suggesting that large-scale projects are increasingly popular in the German solar industry in particular.

"You see new developers coming into the markets, for example, big utilities, and I think they have a bit of their own process," continues Müller, suggesting that a wider range of investors and players in the solar industry could disrupt the established operating procedures for EPC companies.

"Probably they are, I would say, a bit behind how the market really works and really ticks and very often they make a tender, for example, and a lot of EPCs are not participating in tenders anymore."

The more varied nature of the German solar industry, with an increasing number of EPC players conducting business in a greater variety of ways, is part of a wider trend in the European solar sector, where the complexities of governance in individual countries, and the sophistication of each solar project, is slowing down the processes of permitting and construction.

"There is availability for the right

projects," says Isabel Rodriguez, investment director at clean energy fund manager Glennmont Partners, suggesting that EPC companies are willing to engage in the sector, but that processes such as permitting are creating delays in project commissioning.

"It's not that there is less [capacity], they are there, and they'll continue to be available, but there seems to be a greater number of megawatts to be built, because for reasons that probably were not the right ones, [EPC contractors] were obtaining permits that are going to be difficult to build given certain conditions surrounding the permits or the location," she says.

These delays in the processes necessary to develop a project from planning to permitting to commissioning is evident around the world. The US Energy Information Administration reported that, in 2022, 1.9GW of solar capacity came online later than expected in the US, and another 1.7GW of capacity additions were pushed back to 2023, as the country's appetite for new solar capacity was not matched by the capacity of the EPC sector to deliver these projects.

There is also considerable regional variation, in both EPC capacity and interest in building new solar projects.

"If you look at what's going on in Europe, Spain is going gangbusters and sucking in a lot of EPC capacity, particularly from the French companies," says Philip Wolfe, former director-general of the Renewable Energy Association and the man behind utility-scale solar deployment and EPC tracker site Wiki-Solar.

"The main topic is the grid connection"

However, a lack of EPC availability, and regional variation in the number of companies involved in the sector, is perhaps not the most pressing concern for the European solar sector. When asked about the greatest challenges for the industry, Wolfe suggests that EPC capacity is one of several questions the sector still has to answer.

"I don't think it's a primary constraint at the moment," says Wolfe. "Obviously, the market continues to expand very rapidly and that places demands on all sorts of things to increase, [such as] volume and capacity. But I think typically what we've seen when there have been these growth spurts, it's been things like supply of solar panels [and] supply of inverters, that has tended to be the real constraint.

"I can't say I've noticed in the global utility-scale industry that the availability of EPCs has been a primary bottleneck, let's put it that way."

Indeed, many of the challenges faced by the global solar sector pertain to the international supply chain, rather than EPC capacity. SolarPower Europe has called for European governments to do more to protect European solar manufacturing, following layoffs at Norwegian solar ingot manufacturer NorSun due to cheap Chinese-made products undercutting those made in Europe, and uncertainties regarding the financial viability of manufacturing, and how these materials are traded internationally, poses an existential question to the sector.

Similarly, the passing of the IRA dramatically incentivised US-made solar components but raised concerns that it would simultaneously dissuade imports of foreign-made modules. Considering that such products, notably those made in China, are often the most cost-effective materials for contractors to use, this push to emphasise domestic-made equipment could make the entire solar industry less financially viable.

Müller, meanwhile, notes that grid connectivity, a longstanding issue in a number of energy issues, continues to be a challenge for the solar sector, particularly as a lack of available grid capacity could dissuade developers from applying for solar permits in the first place, and EPC companies from making themselves available to commission those projects.

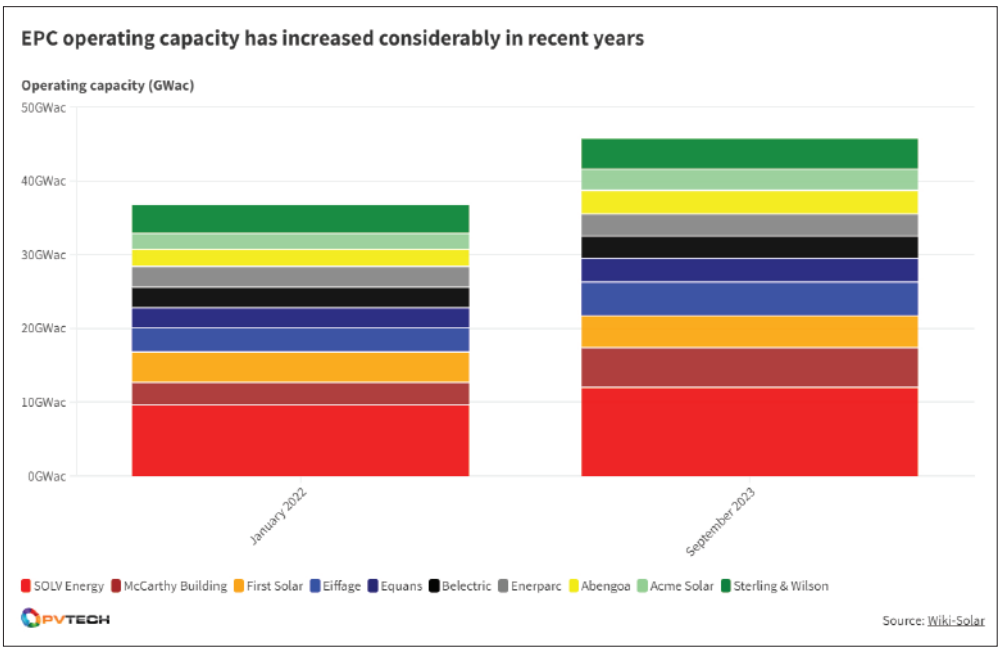
"The main topic is the grid connection – transformers and whatever handover stations – and they have a delivery time, easily, of up to two years," says Müller. "This is the biggest issue. If you do not get a guaranteed slot or semi-guaranteed slot, then you cannot develop anything that you want."

New players, new relationships

The presence of a greater range of companies in the investment and commissioning of new solar project is not an inherent problem, however. The graph in Figure 1 shows the ten EPC companies with the largest operating capacity as of September 2023, according to Wiki-Solar, sorted geographically, with US companies in red, French firms in blue, German companies in black, the sole Spanish company Abengoa in yellow and Indian firms in green.

The graph demonstrates that, over the last two years, the distribution of EPC capacity around the world has remained mostly stable, with US companies dominating global EPC capacity. However, the work of Eiffages, which added 1.3GWac of new capacity, the most of any company in the top ten not based in the US, suggests that the EPC sector exists in a state of flux, with new players expanding their influence in the sector.

"I think what is already happening, as the market accelerates in certain parts of the world, is that rather than relying on the expansion of existing participants, if you like, it draws in specialist participants from other sectors," says Wolfe, suggesting that this breadth of expertise could be a benefit for both individual EPC contractors, and the quality of EPC work done in the solar sector in general.



Credit: PV Tech

Figure 1 The operating capacity of EPC firms has increased. Source: Wiki-Solar

"What we've seen in Europe in the EPC sector, for example, [are] substantial engineering companies like Eiffages in France and Bouygues in France coming into the market as EPC contractors because they have the EPC skillset, albeit not historically from solar, and they're bringing that skillset in into the industry," adds Wolfe.

"On the EPC contractor side, I do see the benefit of a framework agreement, where there is an alignment of interest and there is skin in the game for both of them, so I do see that as a possibility," adds Rodriguez, suggesting that the inherently collaborative elements of EPC work, in which contractors must work alongside permitting authorities and solar developers, could benefit from a greater range of companies, from multiple sectors and offering multiple skillsets, working together.

However, this state of affairs could make EPC work more challenging, at least for the EPC companies themselves. Müller suggests that there is so much interest in developing new solar capacity, and so much money going towards these projects, that developers and investors feel empowered to set the terms of their relationships with EPC contractors, potentially presenting challenging working conditions for EPC companies, or encouraging competition between EPC players to win lucrative large-scale contracts.

"The reality now is very clear," says Müller: "Big investment funds, and let's call it Blackrock KKR, Vattenfall, IKEA [or] big utilities, who have 500MW to 1-2GW portfolios around the globe, they generally are keen working with one or two companies only.

"For example, somebody like Blackrock says, 'We only work with companies who can provide 10% bank guarantees and have a strong balance sheet', and then automatically 15 of the 20 EPC companies in the market are out of this range," adds Müller. "So financial expectations, technical expectations and HSE topics [are] on a very high level on these companies, and I think a lot of I would say medium-sized companies probably cannot manage this."

Delivering EPC work

Ultimately, while suggesting a lack of EPC availability could stymie the world's solar plans is perhaps strong, the fact remains that many of the processes that go into EPC work and solar deployment could be improved. Rodriguez is confident that improving the efficiency and effectiveness of permitting will go a long way to accelerating EPC work across the sector.

Credit: Asian Development Bank via Flickr

"The only way to accelerate [permitting] is to be quite efficient in preparing all the documentation that needs to be prepared for starting construction, and also for reaching the operational phase," says Rodriguez. "It's quite important that the different sets of paperwork and the tests are progressed in the set time that they need to be progressed and they have the engagement at the local level with the different technicians."

Ensuring good relations between the various players in the installation of solar projects is also essential. With a number of groups working on a number of objectives within the process, from permitting and planning to construction and maintenance, a situation where companies are looking to protect their own interests, and deflect responsibility for perceived errors and delays, is harmful for the entire sector.

"The level of risk is transferred from the construction company to the sponsor from that point in time, once all the permits have been achieved, and then it goes to the penalties and the delays that you put onto the contractors and then they will try to say that it's not their fault, but the fault of the authorities," says Rodriguez.

"There's always a little bit of a game, but that's all normal," Rodriguez concludes. "But if it becomes too cumbersome, and there are some points where actually [contractors] really tried and they did everything that they had to do by the book, and yet still the permits are not there, it can create an area of tension between the two counterparts, and that's not a good time and it's not good for the industry."

There are a number of joint venture projects in the solar sector that have failed to reach commissioning. In March, Singapore's Sembcorp, utility company PT PN Batam and renewable developer PT Trisurya Mitra Bersama abandoned plans to commission a 1GW solar-plus-storage project in Indonesia after completing construction work.

New players are coming into the solar EPC business, potentially bringing new skills and expertise

Another example is the high-profile plight of Sun Cable, the vast project that aimed to build a subsea power cable connecting solar farms in Australia to Singapore. The project's backers, billionaires Mike Cannon-Brookes and Andrew Forest are reported to have fallen out over the future of the plan, culminating in the latter's departure from the project, and questions as to what will come of the ambitious international solar project.

Clearly, this is an extreme example, but the presence of more decision-makers, and critically more decision-makers with a great interest in solar power but little experience in the practicalities of commissioning projects, in the solar industry could lead to uncertainty as to how projects are built and commissioned.

As a result, what Rodriguez calls "a spirit of cooperation" between investors and EPC companies from a range of backgrounds could be necessary, if the world is to realise its ambitious solar capacity goals. ■

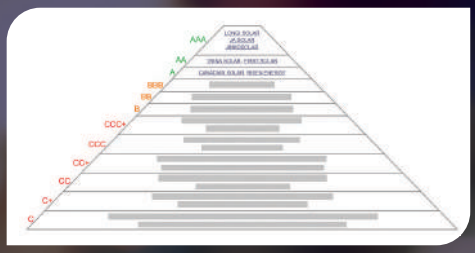
PV Tech Power publisher Solar Media is hosting a panel on EPC availability at the 11th annual Solar Finance & Investment Europe held in London on 31 January-1 February, which will be moderated by Isabel Rodriguez. Further details are available at https://financeeurope.solarenergyevents.com/

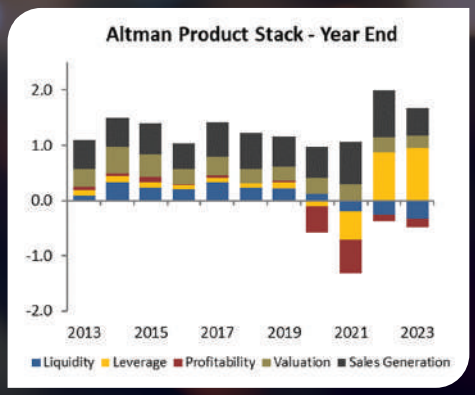
PV MODULETECH
BANKABILITY RATINGS

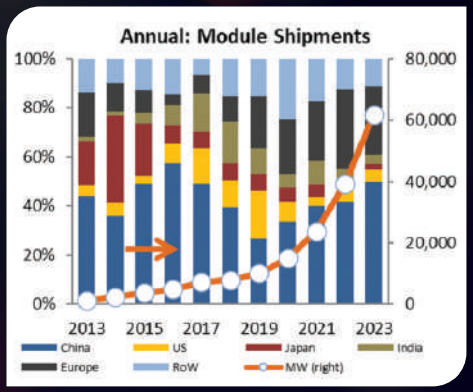
The PV ModuleTech Bankability Ratings Quarterly is the official sister-report to the conference. Our independent, quarterly-updated risk analysis of global module suppliers is used by investors, developers and EPCs to help de-risk module purchasing decisions.

Using the PV industry's most rigorous bankability methodology, we produce an analysis and rating for each company that can be used to benchmark your suppliers against each other in terms of risk. The analysis is performed independently by the PV Tech Research team, led by Dr Finlay Colville, a must-have for anyone buying modules or performing due diligence on module suppliers at the utility scale level.

- All suppliers ranked from AAA – C, with each company presented as a detailed profile clearly explaining the narrative behind their rating.
- Gain an intimate understanding of each supplier's financial health metrics (both public-listed and privately-held), technology roadmaps, module shipment trends and manufacturing operations.
- Avoid suppliers at risk of defaulting on warranties, near bankruptcy, or with low global shipment volumes to protect your project's long term returns.







We are offering free introduction webinars to companies interested in accessing the full range of services available – email **marketresearch@solarmedia.co.uk** to find out more **marketresearch.solarmedia.co.uk**

SOLAR MEDIA MARKET RESEARCH

Understanding the consequences of switching to a predictive O&M strategy

Operations and maintenance | Digitalisation offers PV plant operators the opportunity to shift from preventive to predictive maintenance practices. Eduardo Sarquis reports on research aimed at shedding further light on the system performance benefits of moving to a predictive O&M strategy

Credit: SMA Solar

In 2012, the total capacity for electricity generation through solar photovoltaic (PV) technology was 100GW. One decade later, in April 2022, the world reached a landmark of 1TW. Half of this installed capacity was installed in the last three years from 2018 [1]. The global market for solar power is growing exponentially. SolarPower Europe, an association that represents over 270 organisations across the entire solar sector, predicts in its "Global Market Outlook For Solar Power 2022-2026" that global solar capacity will more than double to 2.3TW by 2025. [2]

The Covid-19 pandemic has caused significant delays in many installations of renewable energy projects due to disruption of global value chains caused by lockdowns and geopolitical frictions. Nevertheless, these problems have not undermined the "green infrastructure boom". Solar energy capacity additions continue to break records with 145GW in new installations becoming operational globally in 2021 and 190GW in 2022 [3].

The initial challenge of making solar technology affordable and accessible seems to have been overcome. Due to advances in the industry in making systems more effective, durable and affordable, the investment needed to install a system is only a fraction of what it once was. An analysis conducted by the National Renewable Energy Laboratory (NREL) shows that between 2010 and 2022 there was a reduction of around 66% of the total costs associated with the installation of PV systems for residential or commercial rooftops. For utility-scale ground-mount systems the reduction was even larger, around 81% [4].

Ever larger PV systems and fleets create challenges from an O&M perspective

As a consequence of this, the levelised electricity cost (LCOE) generated by PV technology is now the third cheapest among renewables, only behind hydro and

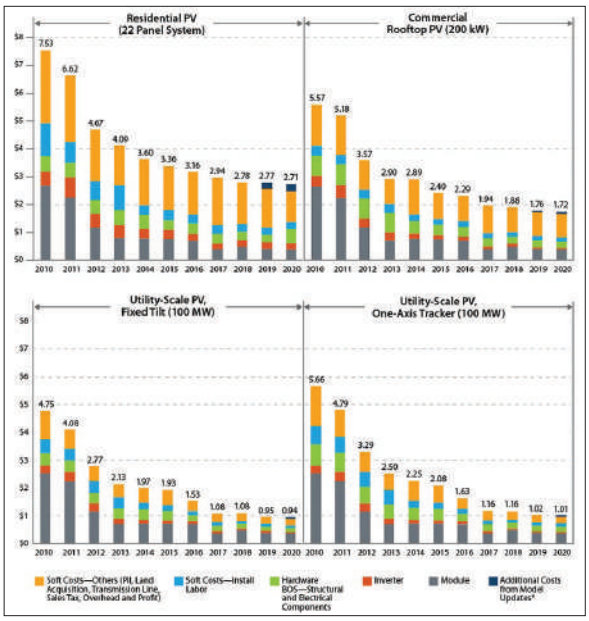


Figure 1: The ongoing reduction of the full costs of PV systems—including installation- over time [4]

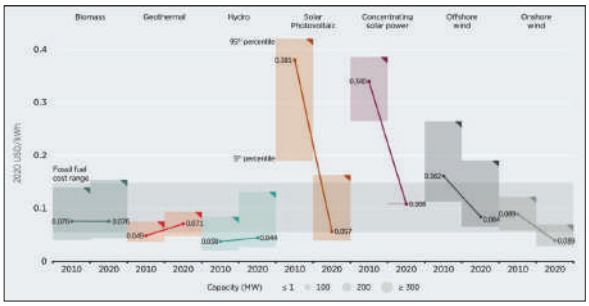


Figure 2: Global LCOEs from newly commissioned, utility-scale renewable power generation technologies, 2010-2020 [5]

onshore wind [5]. Most renewable power generation technologies have had a lower global LCOE than fossil fuel technologies since 2020 (Figure 2).

The continuous and successful increase in the installation of solar systems creates new challenges, one of which is the operation and maintenance (O&M) of larger and larger fleets of systems. Contrary to what was once a popular belief, PV power plants are not maintenance free; they require a regimen of continuous monitoring, periodic inspection, scheduled preventive maintenance, and service calls [6]. Lack of attention to O&M results in costs higher than those presented in initial investment plans, increasing project risks; a situation that can undermine market confidence [7]. This is especially critical if we observe that most PV plants have only been operational for a short period of time. Around 90% of PV plants worldwide have become commercially operable in the last seven years, a relatively short period compared to their expected lifetime of 20+ years [8].

These systems are still experiencing the moment of youth in their life. With the ageing and flourishing of new technologies, an increasing need has been observed for removal and replacement of parts or the entire system [9]. This means that the demand for professional and experienced O&M services in the PV industry tends to increase dramatically. Given evolving technologies, climate and maintenance resources, and all other influencing factors, optimising the O&M of photovoltaic systems is critical to protecting investments in solar energy infrastructure.

O&M of PV systems

The O&M of PV systems includes carrying out various activities. Among them, monitoring and maintenance are activities of special importance. In the photovoltaic industry, maintenance practices have been built around the recommendations of component manufacturers – such as modules and inverters – and national and international technical standards [10]. Best-practice guidelines in the industry recommend the use of preventive maintenance through annual inspection plans. It focuses on preventing major future problems from occurring through a regular routine of visual and physical inspections, as well as verification activities. Preventive maintenance improves system performance, prevents the occurrence of more severe failures, and maximises the life of the system.

Preventive maintenance inspections are performed by trained personnel following checklists to ensure that inspections are thorough and complete [11]. According to industry best practices, all inspection activities and checklists, as well as the inspection time schedule, should be established in a detailed annual maintenance plan [12]. It should also contain the guidance on how to test and maintain key components given by their manufacturers [10]. Activities must be consistent with warranty terms and national standards for periodic inspection of certain electrical components.

A close look into an example of annual maintenance plans for utility and distributed solar plants, suggested by recent best practice guidelines for PV O&M [12], reveals an extensive list of inspection activities, some of which are indicated as mandatory (minimum requirement) while others are only recommendation. The frequency at which these tasks must be carried out varies, but the vast majority are annual. Whenever possible, the verification should be extended to the entire system. In the case of very numerous components, such as the clamps that secure the modules to the mounting structure, the check can be performed on only a random subset of components.

In addition to basic visual inspection, specialised inspections, such as infrared (IR) thermography, electroluminescence (EL) imaging, and I-V curve tracing, can be used to assess the quality and performance of equipment on site [12]. These verifications include specialised tools such as an I-V curve tracer and an infrared thermographic camera. These inspections might incur larger costs, and their adoption must consider the potential benefits according to the system size, design, complexity, and environment. As pointed out by [10], preventive maintenance must maximise the output of the system, prevent more expensive failures from occurring, and maximise the lifetime of a PV system. Thus, the cost of scheduled maintenance must be balanced with the yield and cash flow throughout the life of the system.

Associated with the preventive strategy, best-practice guidelines in the industry also recommend the adoption of corrective maintenance. Corrective maintenance paradigms represent a strategy based primarily on reacting to equipment failures and system breakdowns. This paradigm, which was once the standard in some industries, allows low upfront costs, but also brings with it a higher risk of component failure and higher costs in the long run [13]. In the PV industry, the core strategy is based on preventive maintenance, and corrective maintenance is reduced to unplanned interventions to restore the systems' normal operation after a failure has been identified [12].

Faults or conditions that introduce a safety problem or revenue losses due to reduced system output are the main motivations for an unplanned intervention. Safety problems should be addressed as soon as possible. Lost revenue should take into account the response cost according to the size of the system, geographic location, spare parts inventory, other scheduled maintenance and fleet performance requirements [10]. For example, for small residential systems, a fleet operator may make repairs only when losses are high enough to justify a truck roll to the area or at the next regularly scheduled inspection of a site. Generally, the maximum response time for alerts or corrective action is specified as part of the

O&M service contract but typically will be 10 days or less for non-safety-related corrective maintenance services [10, 12]. The combination of the preventive and corrective maintenance paradigms has been used successfully in the PV industry for the past decades.

Digitalisation and new trends

In the continuing technological evolution of PV systems, there is a trend towards expanding the collection and digitalisation of production data, which allows for more complex and comprehensive monitoring. This sets the stage for a more data-driven approach, so that in recent years best practice guidelines have included predictive maintenance among the paradigms adopted in the O&M of photovoltaic systems [12].

Predictive maintenance, also known as condition-based maintenance, is a data-driven strategy that analyses the PV system's monitoring signals to identify signs of degradation and detect anomalies, identify faults (diagnostics) and estimate the equipment's remaining useful life (prognostics). The extracted information is used to prioritise maintenance activities and resources.

The information collected should allow assessing the need for intervention, instead of adopting a pre-established calendar of interventions. In the conventional preventive strategy, systems without problems are inspected only as a routine, and systems can remain with unnoticed failures for a long time until the next inspection occurs. Alternatively, adopting a predictive strategy should allow reducing the frequency of interventions when possible or anticipate them if necessary.

Information that allows identifying problems at an early stage, before a critical failure occurs, can also extend the time available to plan interventions and reduce the need for urgent corrective actions, which often translates into more expensive and logistically difficult interventions.

The success of the predictive approach depends on the quality of the data interpretation. To decide to postpone or anticipate an inspection or maintenance intervention, high diagnostic reliability is required. Achieving such a high level of confidence normally involves some manual data analysis before the decision-making, which may impose limitations on the scalability of monitoring capability.

Companies specialised in O&M have monitoring centres with a specialised team that evaluates the performance of systems to identify problems with the help of monitoring software equipped with automatic alert features [14]. It is key that the automatic monitoring system triggers as few false alerts as possible and ensures no critical problem passes unnoticed. Reliable solutions capable of helping the monitoring process are highly needed for the scalability of the O&M monitoring services.

In the scientific literature, there are several studies and procedures for automatic fault detection in PV systems, however there is a general lack of validation of such methods under real operating conditions. Recently, in a study with field data from a portfolio of 80 photovoltaic systems for multiple years [15], we have verified that a combination of multiple fault detection algorithms can achieved a sensitivity of 99% and a specificity of 93%, and less than 12% false alerts. This means that an alert will be raised for 99% of the days with a fault and 7% of the days without any fault.

Knowing the level of reliability that can be expected from data interpretation, in this case from the automatic fault detection system, is fundamental to understanding how much we can trust its results and whether additional measures are needed to balance its limitations, such as, for example, manual verifications before scheduling an intervention.

Comparing O&M strategies

The adoption of predictive maintenance fundamentally changes the O&M strategy. It holds clear potential for improvement and comes with strong expectations. For the technological advancement of O&M practices, it is important to balance the expectations and objectively quantify the potential gains from investing in improved monitoring and maintenance practices.

To evaluate the potential benefits of adopting a maintenance strategy based mainly on predictive actions, we first need to establish a methodology to quantify the effects that a maintenance strategy can have on a portfolio of systems.

An O&M strategy is the collection of resources, procedures and rules used to identify defects and repair or replace components so that the system can perform its designated function during its expected useful life [16]. Understanding the consequences of adopting different maintenance strategies is not a simple task. Various aspects should be considered, such as the frequency with which faults occur, their impact on system performance, the procedures adopted to detect failures, the sensitivity of the tools used for monitoring and inspection, and the reaction time for maintenance.

The designated function of a PV system is to generate electrical power, and the occurrence of faults will cause a reduction in system performance until the fault is detected and removed. The total energy yield loss will be a consequence of the severity of the fault and the time elapsed between its occurrence and repair. Different O&M strategies may lead to a shorter or longer time to detect and repair, resulting in a lower or higher total energy yield loss. Quantifying this yield loss is fundamentally important for comparing strategies. To do this, we adopted a methodology with four main steps:

1) Define the fault-free expected yield for the PV system typical profile;
2) Generate a random sequence of fault events;
3) Define the sequence of O&M events in response the faults;
4) Quantify the impacts of the events on the energy yield.

In addition to evaluating the performance of the systems, it is important to measure the maintenance efforts made over the years, here characterised by the number of interventions and the number of repaired components.

PV systems are designed to match local conditions, but despite their individual

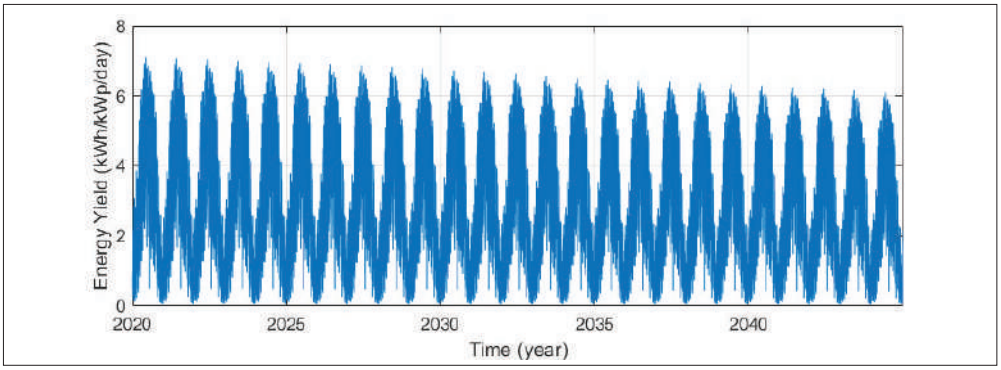


Figure 3: Expected energy yield in kWh/kWp per day simulated for 25 years

RE+

HAWAI‘I

JANUARY 22-23, 2024
HONOLULU, HAWAI’I

POWERED BY SEIA Solar Energy Industries Association® | Smart Electric Power Alliance

Join conversations with industry buyers, suppliers, distributors, consultants, and more to explore solutions, exchange ideas, and discover new technologies within the industry.

RE+ EVENTS

REGISTER TODAY | RE-PLUS.EVENTS/HAWAII

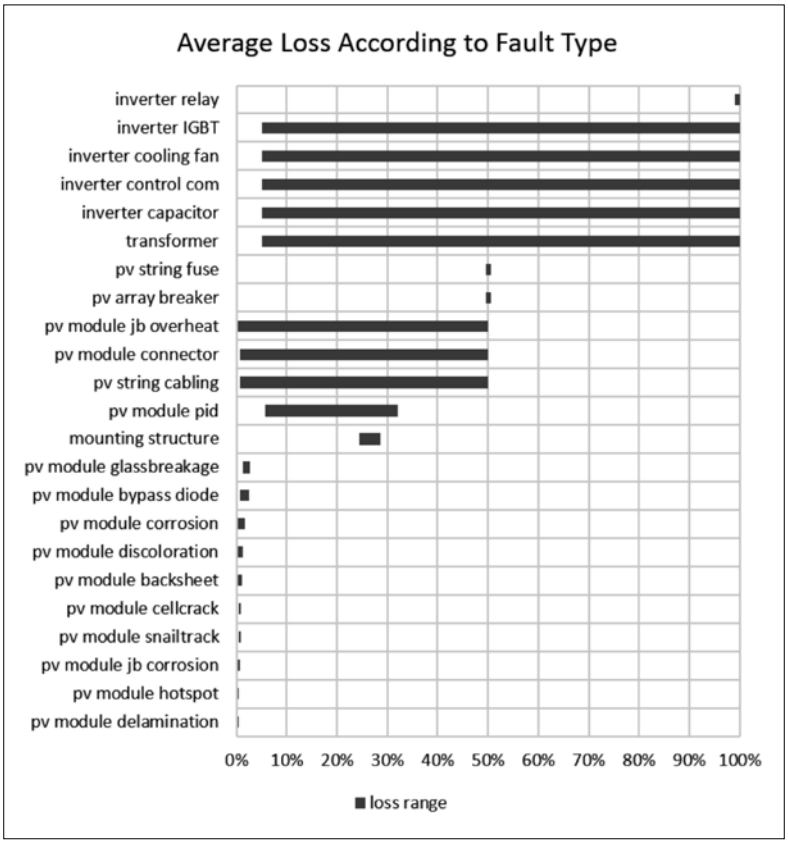


Figure 4: Inverter and PV array performance loss range according to the fault type

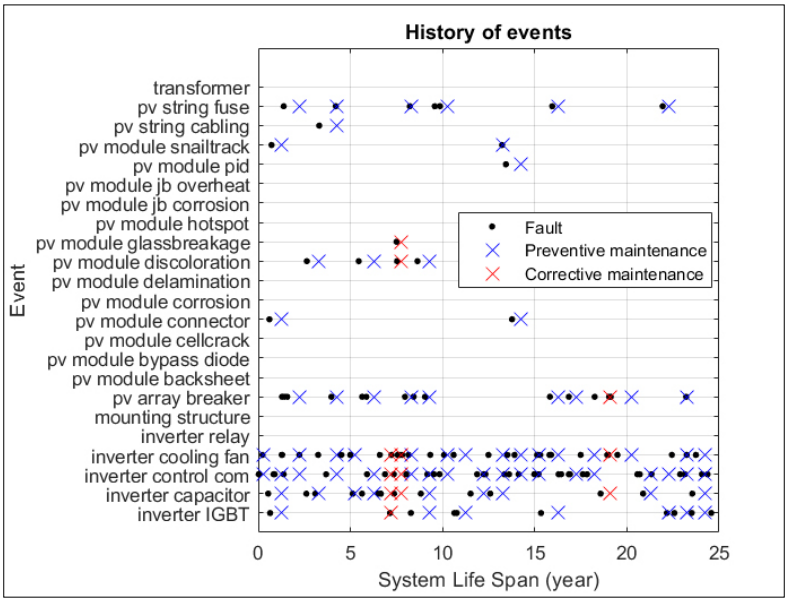


Figure 5: An example of a 25-year story of fault and maintenance events following a preventive maintenance strategy

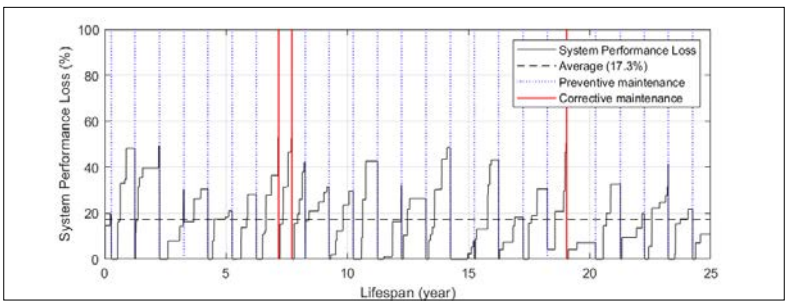


Figure 6: An example of performance loss of a system following a preventive maintenance strategy

characteristics, they are built with very similar architecture and components due to constraints imposed by other factors such as standards, regulations, procurement optimisation, etc. It is reasonable to assume that a group of systems with such similar characteristics can be fairly represented by a typical system whose specifications are an average design. In this study, we considered a 150kWp rooftop PV system with 576 PV modules connected to six string inverters.

The expected energy yield for the typical system can be obtained using a project design tool for PV systems, e.g., PVSyst. The fault events will be added later; thus the simulation of expected energy yield must consider no losses due to soiling or shading and 100% availability. The performance loss rate was assumed to be 0.4%/year. The simulation provided a time series of energy yield in kWh/kWp per day for 25 years, and the weather conditions reflect the typical meteorological year (TMY) of Freiburg, Germany, as shown in Figure 3.

A component fault is an unexpected event that results in loss of performance. To generate examples of failure events, we rely on reliability engineering theory for modelling failure occurrence using the failure rate (λ). The failure rate is the probability of failure per unit of time, given that the component has not yet failed. For most of their operating life, electrical components have a constant failure rate. A constant failure rate leads the time-to-failure to be an exponential distribution [17] with λ as the rate parameter.

To generate examples of fault events, for each component and fault type, we define continuous random variables that follow an exponential distribution with λ equal to its failure rate. These random variables generate random samples, representing the specific time each component will be affected by each failure type. With a careful selection of quantitative data available in the literature [18], we have a list of the typical failure types for each type of component and their respective failure rates derived from field data of hundreds of PV systems.

Each failure event causes the total or partial loss of performance of the affected component, which in turn results in reduced performance of the system as a whole. Figure 4 shows the range of power loss associated with each failure type for the typical system previously defined. The severity of each fault event is randomly defined to be somewhere between the worst and the best case. The system

performance loss over the years is then a consequence of the accumulated losses due to the fault events.

The inspection and maintenance events are defined according to the maintenance strategy. In the case of traditional maintenance practices based on preventive and corrective maintenance combined, the intervention events follow a pre-established calendar of inspections (one per year). If the system experiences a severe performance loss (e.g., > 50%), an exceptional urgent intervention is scheduled shortly after (e.g. 10 days).

In case of a predictive maintenance strategy, the need for maintenance intervention is defined based on the identification of system performance loss above a tolerance (e.g., 20%), and the maintenance date is scheduled after a predefined time window (e.g., 90 days).

To simulate the limitations of data interpretation, a daily assessment of the system's performance loss was considered with a sensitivity of 99% and specificity of 93%. This means that alerts are issued for 99% of days with a loss above tolerance, but also for 7% of days with acceptable losses. This limitation in accuracy needs to be counterbalanced by waiting for at least five alerts in 10 consecutive days before scheduling an intervention.

In an intervention, defective components are usually maintained by replacing them with new components of the same type. Here we assume the maintenance action is perfect, i.e., the performance loss associated with the defective component is fully recovered. A full recovery of the system performance loss will be observed after the day of maintenance.

The resulting energy yield considering failure and maintenance events is a direct product of the initial expected and the performance loss at each day throughout the 25 years lifespan. The average energy yield provides a measure of the effectiveness of a maintenance strategy for that particular story of failure events. By performing this calculation across a significant number of random stories (e.g., 1,000), we derive a representative measure of the effectiveness of the evaluated maintenance strategy for the scenario.

We applied the proposed methodology to test two maintenance strategies. The first adhered to best practices, involving preventive maintenance with a regular calendar of inspections. The second strategy focused on predictive maintenance, incorporating a dynamic inspection schedule with varying response times, ranging from one to 12 months.

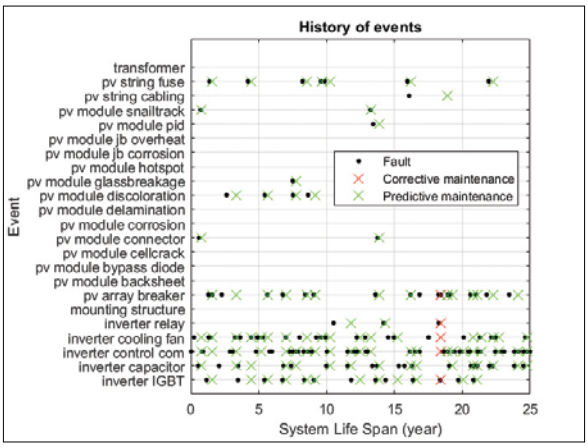


Figure 7: An example of a 25-year story of fault and maintenance events following a predictive maintenance strategy

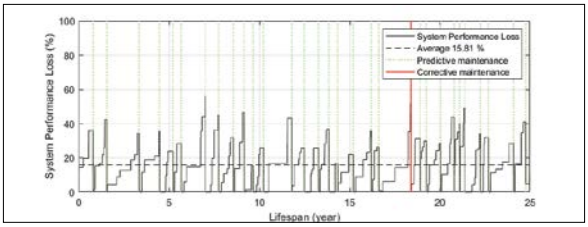


Figure 8: An example of system performance loss of a system following a predictive maintenance strategy

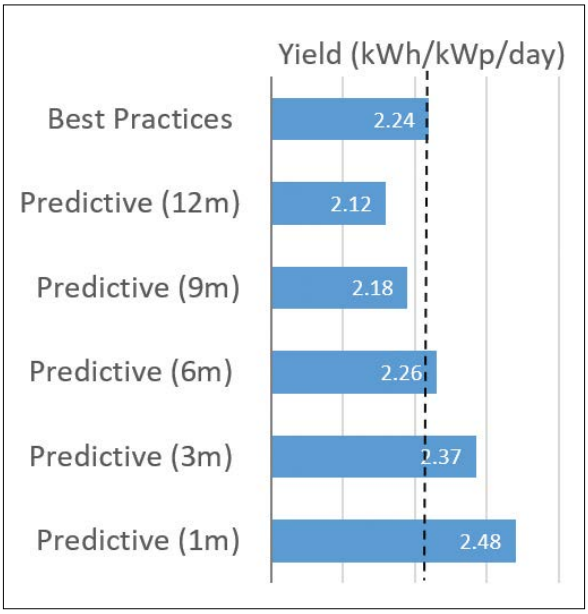


Figure 9: Average energy yield according to the maintenance strategy.

For both strategies, we considered corrective actions in case of severe performance loss. In each scenario, we generated 1,000 stories of faults and maintenance events, and their metrics were averaged for comparison.

The resulting average energy yields summarised in Figure 9 reveal that, in comparison with best practices, the adoption of predictive strategy with large response time (nine and 12 months) reduce yield, while short response times (one and three months) improve yield up to 10%. There is a response time (in this case six months) in which energy yield is equivalent in both strategies.

Upon examining the average number of interventions conducted, we see that, to sustain the same average energy yield level, the number of interventions with a predictive strategy was 10% lower compared to a preventive strategy. Shorter response times, especially within the three-month range, led to an overall increase in the total number of interventions. Notably, extremely short response times resulted in a significant increase in intervention frequency. Shifting our focus to unplanned urgent interventions, it is noteworthy that adopting a predictive strategy with a response time limited at six months reduced the need for urgent interventions

Putting together the deviations of yield, interventions and components replaced, we can see a sweet spot of between three- and six-months response time. In that range, the adoption of a predictive strategy provided additional yield with a small variation of the maintenance efforts, which is an improvement in comparison with best practices based on preventive actions (Figure 12).

Summary

Results show the benefits of moving towards a maintenance strategy mainly based on predictive actions. Namely, the need for urgent interventions is reduced, and the total number of interventions and replaced components can be reduced without compromising the average performance of the systems.

These benefits are very dependent on the response time, which is the time between the detection of a failure and the execution of an intervention for maintenance. Short response times can enhance the average performance of the systems, leading to higher energy yield, with an increase in the average number of interventions.

What exactly can we expect from a more data-driven strategy? A data-driven strategy gives you the power to decide between low effort and higher performance by tuning your loss tolerance and response times.

Is it really an improvement in comparison to the current industry best practices? It reduces the need for urgent, unplanned interventions. With the proper tuning, it is possible to increase the average energy yield or decrease maintenance efforts. ■

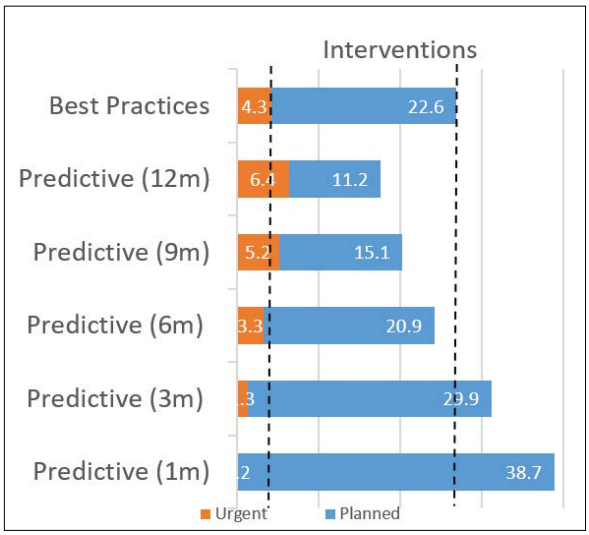


Figure 10: Average number of interventions according to the maintenance strategy

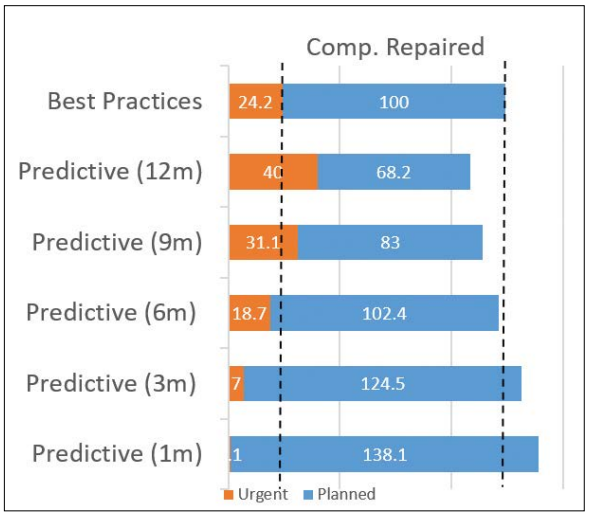


Figure 11: Average number of replaced components according to the maintenance strategy

O&M Strategy	Deviation (%)		
	Yield	Interventions	Comp. Repair
Best Practices	0	0	0
Predictive (12m)	-5.2	-34.3	-12.9
Predictive (9m)	-2.7	-24.7	-8.2
Predictive (6m)	0.8	-10	-2.5
Predictive (3m)	5.8	16.2	5.9
Predictive (1m)	10.5	45	12.1

Figure 12: Percentage deviation relative to the best preventive practices strategy

"A data-driven strategy gives you the power to decide between low effort and higher performance by tuning your loss tolerance and response times"

References

[1] Renewables IEA. Analysis and Forecast to 2026. International Energy Agency: Paris, France. 2021.

[2] Europe S. Global market outlook for solar power 2022–2026. Solar Power Europe: Brussels, Belgium. 2022 May.

[3] https://www.irena.org/Data/View-data-by-topic/Costs/Global-Trends

[4] https://www.nrel.gov/solar/market-research-analysis/solar-installed-system-cost.html

[5] La Camera F. Renewable Power Generation Costs in 2020–IRENA. International Renewable Energy Agency: Masdar City, Abu Dhabi. 2020 Jun.

[6] Enbar N, Key T. Addressing Solar Photovoltaic Operations and Maintenance Challenges, a survey of current knowledge and practices. Electric Power Research Institute EPRI White Paper. 2010.

[7] Hill RR, Klise GT, Balfour JR. Precursor Report of Data Needs and Recommended Practices for PV Plant Availability Operations and Maintenance Reporting. Sandia National Lab.(SNL-NM), Albuquerque, NM (United States); 2015 Jan 1.

[8] Walker H, Lockhart E, Desai J, Ardani K, Klise G, Lavrova O, Tansy T, Deot J, Fox B, Pochiraju A. Model of operation-and-maintenance costs for photovoltaic systems. National Renewable Energy Lab.(NREL), Golden, CO (United States); 2020 Jun 1.

[9] https://pv-magazine-usa.com/2022/05/17/solar-om-why-a-long-term-maintenance-plan-is-essential/

[10] Walker HA. Best practices for operation and maintenance of photovoltaic and energy storage systems. National Renewable Energy Lab.(NREL), Golden, CO (United States); 2018 Dec 21.

[11] Haney J, Burstein A. PV system operations and maintenance fundamentals. Solar America Board for Codes and Standards Report. 2013 Aug.

[12] B. Clarke, A. Ara and W. Hemetsberger. O&M Best Practice Guidelines. Version 5.0. SolarPower Europe. 2021.

[13] Enbar N, Weng D, Klise GT. Budgeting for Solar PV Plant Operations & Maintenance: Practices and Pricing. Sandia National Lab.(SNL-NM), Albuquerque, NM (United States); 2016 Jan 1.

[14] Rapaport S, Green M. IEA PVPS Task 13: The Use of Advanced Algorithms in PV Failure Monitoring. Tech. rep., International Energy Agency, IEA PVPS Task 13; 2021.

[15] Sarquis Filho EA, Kollosch B, Müller B, Holland N, Kiefer K, Costa Branco PJ, Reise C. Development and Evaluation of an Automatic Failure Detection System for O&M of PV Portfolios.

[16] Kelly A. Plant maintenance management set. Elsevier; 2006 Jun 7.

[17] Breneman JE, Sahay C, Lewis EE. Introduction to reliability engineering. John Wiley & Sons; 2022 Apr 26.

[18] Sarquis Filho EA, Zúñiga AA, Fernandes JF, Branco PJ. Failure Rates in Photovoltaic Systems: A Careful Selection of Quantitative Data Available in the Literature.

Author

Eduardo A. Sarquis Filho, Ph.D. in electrical and computer engineering, is head of data analytics and modeling at Enmova GmbH. His areas of expertise include data analytics applied for photovoltaic systems. In 2020-2021, he contributed to R&D projects with Fraunhofer ISE, focusing on cost-optimisation for O&M of PV power plants. Since 2021, Eduardo has been at Enmova, dedicated to devising advanced solutions for the efficient management of PV power plant portfolios.

- World Meets Energy -

Held inside SMART ENERGY WEEK 2024 March

PV EXPO

19th Int'l Photovoltaic Power Generation Expo

Visit Japan's Largest PV Industry Show!

1,600+

70,000+

expected, including concurrent shows

Phone

+81-3-6739-4119

Dates

Feb. 28 - Mar. 1, 2024

Location

Tokyo Big Sight, Japan

Email

visitor-eng.wsew.jp@rxglobal.com

Built by RX In the business of building businesses

ABOUT

Japan's largest PV industry show, PV EXPO, is organised by RX Japan and will be held from February 28 (Wed) - March 1 (Fri), 2024 at Tokyo Big Sight, under SMART ENERGY WEEK, the world's leading exhibition for renewable energy technology.

Photovoltaic power is expected to play an increasingly important role in achieving carbon neutrality by 2050 as the main power source. PV EXPO brings together a full range of products and technologies, from next-generation solar cells to solar power plant construction, maintenance and operation, and is well established in the industry as a business platform which attracts experts from all over the world.

CONCURRENT SHOWS

- H2 & FC EXPO
- BATTERY JAPAN
- SMART GRID EXPO
- WIND EXPO
- BIOMASS EXPO
- ZERO-E THERMAL EXPO
- DECARBONISATION EXPO
- CIRCULAR ECONOMY EXPO

Filling the workforce gap: How AI can enable huge global PV targets

Construction | The streamlining of all phases of a PV project will be essential to ensuring anticipated deployment goals are met. Tom Kenning looks at the AI-enabled technologies helping speed up project construction and easing a shortage of skilled labour

Credit: Built Robotics

In the solar 'terawatt era', huge volumes of PV coming online mean the construction of projects must be as streamlined as possible to meet capacity targets despite logistical delays and labour shortages. Artificial intelligence is now being used across a variety of applications from robots installing trenches and foundations, to systems that can model a whole construction site and offer numerous optimal response options to any potential problem. With global solar capacity expected to hit 2TW in early 2025 and 3.5TW by the end of 2027, the use of AI promises to help solar EPC companies build more projects in faster times while saving money. AI has mainly been used in the construction phase to date, so this feature examines the smart technologies being deployed to overcome construction challenges encountered in large-scale solar.

While the availability of suitable land dwindles but projects increase in size, the huge procedures of installing millions of modules, trackers, piles and cables with precision are under increasing scrutiny with developers looking to AI. Similarly, while solar supply chain obstacles from COVID-19 and trade restrictions are abating to some extent, responding to logistical delays in optimal ways remains a huge challenge and AI can offer solutions.

Built Robotics

The workforce gap in US construction, for example, is particularly problematic, with EPCs struggling to find workers to build projects, costs being high and many using old and outdated techniques. Companies are, therefore, analysing each step of the solar construction process and considering whether there are better tools or automations that could apply.

Built Robotics' RPD 35 pile driving machine collapses four labour-intensive steps into one robot

Focusing on traditional piling infrastructure for solar PV farms, San Francisco-based company Built Robotics takes heavy equipment, skid steers, continuous track loaders (CTL), dozers and excavators and turns them into robots by installing its hardware and software package known as the Exosytem. Once connected internally this turns the machinery into fully autonomous robots that can also be controlled via company software.

One of the first processes automated by Built Robotics was moving PV panels into place for material handling using a CTL. It then performed trenching on solar farms for the underlying electrical frameworks and the company is now trialling driving traditional metal pile foundations into the ground for solar. Erol Ahmed, director of communications at Built Robotics, claims the tools typically used for this were never meant for pile driving at scale and are loud, repetitive and dangerous, so it should be an automated process.

The company claims that contractors using the robots to automate trenching tasks can bring about savings of 10–30% on the existing costs of those specific tasks, depending on the labour market cost in that project locale. The savings come from installing faster with more precision and less reworking. The firm has completed around 24 projects across the US and Australia ranging between 100-250MW in capacity using its trenching robots since 2018, with its piling offering to be launched next year with similar savings expected.

"What's interesting about solar is it's built like a large outdoor factory," says Ahmed. "The difficulty of robotics in construction historically has been that construction sites are super dynamic and hard to automate. They're not assembly lines or warehouses which are designed to be automatable."

Solar farms on the other hand are well suited to automation because of the highly repetitive processes involved combined with the technology becoming cheap enough.

Ojjo

AI-based offerings can also go beyond traditional structures. California-based Ojjo, for example, offers a truss foundation optimised for solar that can bear the same loads as a single member placed directly into the ground, but using around half the amount of material. Taking advantage of the forces of tension and compression, the truss bears weight in "a much more elegant way than straight lines do," says Mike Miskovsky, founder, chairman and CEO of Ojjo.

On top of this, the company uses AI in its unique Truss Driver machines to significantly reduce foundation installation time. Here, the AI can sense changes in conditions in real time and then make intelligent choices to optimise the installation in terms of accuracy, time and wear on equipment (see case study in box).

EPCs can deploy a fleet of these Truss Driver machines to deliver precision foundations on huge sites. They use automation software to drill to soil-specific conditions sensed by the machine and perform simultaneous drill and drive operations.

The technology has been deployed on 2GW of installed projects already since 2019 with another 2.7GW under commitment, including some of the country's largest projects such as the 284MW Eagle Shadow Mountain facility in Nevada, which was considered to have some of the toughest caliche soil in the country. Ojjo's system was able to eliminate the need for predrilling at this difficult site.

"We're beginning to develop those projects in ever more difficult soil conditions, where underfoot you'll run into any number of unknowns," adds Miskovsky. "Conditions underground are dramatically different from foundation to foundation and left to their own devices, the machinery operators installing these piles are faced with any number of opportunities for inaccuracy and for time and project money lost."

Spoiled for choice and simulating future solutions

San Francisco-based Alice Technologies offers a platform that uses AI to generate many possible construction schedules for a solar project. Each of these schedules represents a fully resourced planning option, instead of relying on one plan put together arduously over a long period of time.

The AI technology known as ALICE can then be used for what the company calls "optioneering" where an EPC can go through a range of possible scenarios to see how the project build could be optimised.

Phil Carpenter, CMO at ALICE Technologies, describes how after ALICE has suggested a set of promising drilling schedules, a team can then experiment via AI-driven simulations, such as adding an extra crane on site to see if the build would go faster, adding an extra concrete crew for two days, or testing the overall impacts of an extreme weather event preventing construction for a month. Many multi-faceted options can then be tested quickly for that EPC to finalise a construction schedule that fits best.

PV projects spread over a number of different sections or fields are very suited to using ALICE, says Kevin Fuller, industrial solutions leader at ALICE Technologies. Using the least fertile farmland, for example, may require building a project on eight different fields, in which case it becomes important to decipher the best order of operations, with trucks travelling long distances between sites. ALICE can also model in long linear cabling activities and electrical work between the sites. It can then dynamically model how to pivot if conditions change such as the weather or working with new contractors.

EPCs also often have to be flexible around late deliveries, while procuring electrical grid connection equipment and transformers is a major bottleneck in the industry at present. However, if there is a delayed transformer, for example, the ALICE AI can help companies to model how to meet commission deadlines in spite of the setback. Moreover, if a project falls behind during construction, ALICE can generate corrective schedules automatically to bring a project back on track.

The construction aspect of solar is "not wildly complex", says Fuller, but putting in rails, adding solar panels and running trenches thousands of times over becomes more difficult with scale. This is where AI can deliver sequencing plans that consider an abundance of different possible scenarios.

"The easiest thing to do in construction is put things together," he adds. "The hardest thing to do is put them together in the right area at the right order at the right time."

The savings offered by the ALICE technology for solar projects have been reported to average at 17% reduction in project duration, 14% reduction on labour costs, and 12% reduction on equipment costs. So far, the company has worked with large general contractors in Europe and North America.

Does AI take away jobs?

The creation of jobs by solar development has been a major PR win for the PV industry, but in many industries, there are fears of human labour being replaced by AI. Nonetheless, many of the AI solution providers in this article claim instead that there is a shortage of workers in the solar industry on projects for which strong financing and public willingness exist. Furthermore, these AI tools will often be put in the hands of skilled labourers rather than taking away manual jobs. Miskovsky claims these new tools allow EPCs to make more judicious use of labour to build more

How building large-scale solar with AI can jettison three machines, crews and processes

Ojjo's machine installed foundations on one of the largest solar-plus-storage projects in America

The Gemini, North America's largest standalone solar-plus-storage system, comprising 967MW of solar and a 380MW battery, required vast quantities of foundations to be installed on tricky terrain in the north-western Mojave Desert. Soil conditions were too challenging and variable to use brute force alone. The project owner Primergy chose foundation technology provider Ojjo to use its software-driven Earth Truss system to install 257,000 trusses.

Mike Miskovsky, founder, chairman and CEO of Ojjo says the introduction of this level of machine intelligence and accuracy helps EPCs to drop the use of three classes of machines, three crews, and three parts of a typical project schedule.

Without this software-driven approach, EPCs are compelled to use a very expensive drill to predrill the holes for every single H pile. They also have to over-engineer by clearing the way for obstructions and unknowns. They then need to bring a second class of machines with a pile driver to pound each of those H piles into the ground. Then a third class of machine is required to bring bent, twisted or torqued piles back into alignment and put refused piles – those that have not been driven to their full depth – all the way down to their intended depths.

Miskovsky claims that the Ojjo machine eliminates the need for a separate drilling and driving operations by doing both in one pass, whilst also avoiding the remediation stage as "each of the foundations is dead accurate each time, every time".

At the Gemini project, the AI system dynamically sensed when the conditions were changing underground, finding vast portions of the site where the soil conditions changed at every foundation. It was able to penetrate very difficult hard soils and rocky sections underground, but also dynamically sense where the soil became soft. Such sudden variations require dramatic changes in drilling behaviour such as slowing down to disturb less soil. The machine can make this change in a timeframe that, Miskovsky claims, would be unavailable to a human operator using a diesel-powered machine.

"The very soil you are you're drilling through is the only thing that's going to provide you with the friction and pull-out force for the foundation that you're installing. Two foundations later it could be hard caliche soil, almost like a parking lot cement from the topsoil on down and the machine needs to be able to make these real time decisions in order to get a job of that scale accomplished on time and on budget."

He also says it's very important that, as the industry expands into larger projects, it judiciously uses factory automation, machine automation and artificial intelligence, to make its decisions and processes "faster, more compact, more intelligent and more accurate".

The Gemini project has been installed, but it is currently in the process of being energised sequentially.

Credit: Ojjo

Ojjo's Truss Driver uses automation software for soil-specific drill and drive operations.

projects and deliver higher project capacities out of a finite and difficult to locate labour pool.

"We're actually paving the way for tonnes of new jobs and making it possible for a larger number of workers to quickly train and to learn how to use these machines," he adds.

His company Ojjo, for example, provides training to employees with no direct background in in solar construction to quickly receive certifications to operate its machines out in the field.

"You still require a lot of humans, they're just doing different tasks, and we would argue tasks that serve them very well throughout their careers," adds Miskovsky.

Ahmed agrees that if anything, AI will help create more jobs, because it will enable the building of more solar than without it.

AI to enable grid integration of PV

One company is ensuring that AI uses for solar go beyond construction by focusing on grid resiliency in a world increasingly threatened by storms, floods and other extreme weather events. US-based company Rhizome uses AI and historical data to model the social and economic costs of future extreme weather events on the grid and offers a tool to utilities for long-term planning of the grid.

Both distributed and large-scale solar are used as mitigating power generating technologies in many geographies, but Rhizome CEO and co-founder Mish Thadani claims that there are no comprehensive mechanisms for utilities to assess the future reliability and resilience requirements for PV additions as extreme weather events get worse over coming decades.

Rhizome's tool helps utilities to decide what hard investments will be needed such as undergrounding, replacing ageing assets on transmission and distribution infrastructure, and – notably for PV developers – introducing the right mix of distributed technologies to ensure long-term resilience on these grids.

"When utilities are doing Distributed Resource Planning or third parties are implementing these solutions for resilience purposes, it's really hard to quantify that value of resilience to get the buy-in from regulators as well as the customers," says Thadani. "By measuring risk over the long term and how much investments reduce that risk, our platform comes up with cost-benefit analyses for any type of solar project on the distribution system today."

Thadani admits this does not fully solve the grid interconnection issue facing many solar developers, but the tool will enable more distributed energy resources to be deployed by making a business case to both customers and regulators for those resources by calculating their value of resilience.

Bearing in mind all the AI solutions covered in this article, it seems clear that AI looks forward to a bright future in solar project construction and planning, with a plethora of as yet undiscovered uses still to come.

"We are very much at the dawn of the use of this technology," says Miskovsky. "We're all assessing where it makes sense to increase the level of automation and intelligence in the tools and processes that we're using. We're all working for the same goal, which is more solar and a faster, cleaner energy infrastructure, because we just don't have time to wait."

"It definitely has the feeling of a gold rush period," adds Ahmed. ■

3rd Edition

LARGE SCALE SOLAR USA

1-2 May 2024

Marriott Dallas Las Colinas, Dallas, Texas

The Meeting Place for USA Solar Dealmakers

2024 Key Themes

- Maximizing IRA Incentives
- The Return of US Manufacturing
- EPC, Labor & Workforce
- Interconnection Costs & Timelines
- Supply Chain Dynamics
- Land & Permit Scarcity
- Storage & Revenue Optionality
- Asset Management Optimization

Visit us at: **lssusa.solarenergyevents.com**

#LSSUSA

Our 2024 Sponsors

Silver Sponsor: Soltec

Bronze Sponsor: TGS, prediktor

Supporting Sponsors: AURORA ENERGY RESEARCH, CEA Clean Energy Associates, CPS America, ENVERUS

Exhibitor: Solar Ranch Development Company

Editorial Partners: Energy Storage News, PVTECH

Partners: BloombergNEF, Texas Solar Power Association

Hybrid power purchase agreements for renewable generation co-located with storage

PPAs | The co-location of renewable generation and energy storage demands new contractual arrangements to make such projects commercially viable. Jack Rankin, Miguel Valderrama and Brian Knowles of Pexapark explore how hybrid PPAs are becoming a favoured solution for structuring deals that capture the full value of both assets

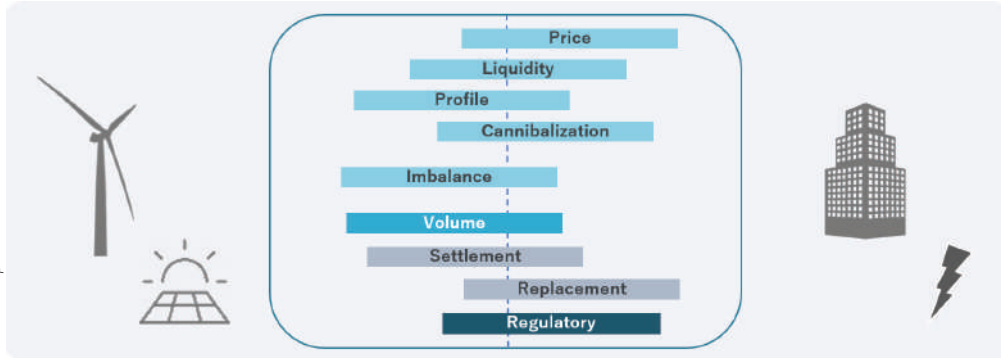
Credit: Business Wire

In the world of power infrastructure, we may broadly define "co-located" assets as those that share a single connection to the grid. Although various co-location schemes could be devised in this context, there is one which has gained great relevance in recent times: the co-location of renewable energy generation (RES) – especially solar PV – and battery energy storage systems (BESS). Indeed, the combination of two asset classes traditionally viewed as stand-alone may offer a plethora of advantages, for example optimising output and minimising losses through complementary dispatch profiles, slashing project costs thanks to equipment sharing, or simplifying administrative procedures by amalgamating permit applications.

However, for all the potential benefits that co-location can bring, trying to combine two complex assets in a way that is both technically and commercially viable poses a wide array of challenges: What is the optimal use-case of the hybrid set-up? What's the optimal revenue-streams strategy when there are competing interests between the two assets? How does the industry model a cost-benefit analysis to evaluate an investment decision?

Hybrid PPAs are an emerging solution to the challenge of maximising the commercial value of co-located solar and storage

Such questions demand sophisticated



Source: Pexapark.

Figure 1: Exposure to uncertainties when producing and selling renewable energy. Note that the distribution of risks shown in the figure is merely referential (i.e. not a general rule of how risks are distributed in any given renewable PPA)

support and Pexapark, as a specialised advisory and enterprise software provider for the energy transition, has been at the forefront of raising awareness, generating knowledge [1], and facilitating watershed deals in this space. Notoriously, in June of 2023 the UK's first unsubsidised and bankable solar-plus-storage off-take agreement was signed. In this transaction, Pexapark advised DIF Capital Partners (asset owner and seller) in analysing, structuring, and executing a deal with Engie (acting as buyer and storage optimiser) combining a power purchase agreement (PPA) and a battery optimisation agreement for a co-located 55MW solar farm and 40 MW/80 MWh BESS in Leighton Buzzard, Bedfordshire, providing clean energy and secured revenue across the solar and BESS over a 10-year term [2].

Following such landmark, we continue helping our clients in a number of ongoing transactions that explore diverse contracting models and continue pushing the boundaries of renewable-plus-storage co-location. Drawing on all this experience, this article will attempt to give readers a high-level explanation of what hybrid PPAs are and how they can be arranged and priced in practice. We also include some important notes on risks associated with PPAs, technical aspects of co-location, and markets of interest.

Notes on risks and renewable energy PPAs

As the subsidy mechanisms that were initially put in place by governments to spur the growth of RES generation become less ubiquitous, and RES technologies have themselves matured, experienced significant cost reductions and ultimately become more competitive, PPAs have turned into a commonplace market mechanism to address different actors' needs: developers' and lenders' wish for higher long-term revenue certainty allowing projects to become bankable, consumers' desire to procure clean energy and certificates that satisfy their sustainability goals, and so on. How these needs are effectively addressed by a PPA will come down to the way in which the parties agree to distribute risks. Without going in detail about each specific concept, Figure 1 lays out the main risks that parties in a PPA would typically want to consider and assign.

As it is well known, non-conventional RES generation such as solar and wind is intermittent and thus its output cannot be managed to respond to market signals. For a merchant RES asset, there is a risk that when the sun is shining or the wind is blowing and the asset is injecting power into the grid, market prices may be low due to an abundance of generation (broadly speaking, this is known as the profile cost). This risk could be hedged through a PPA under a classic pay-as-produced (PaP) volume structure, in which the buyer takes over the risk of the intermittent generation profile and commits to purchasing all or part of the seller's output (regardless of when it is produced) for a fixed long-term price. But what if the buyer demands higher certainty around the profile and associated volumes of energy they will commit to purchase or applies a significant risk discount to take this profile cost and cannibalisation risks associated with it? Then the seller might consider offering a baseload structure where the profile is fixed for a given period. Although a baseload PPA may command a price premium over a PaP structure, it exposes the seller to uncertain market prices in times when its generation output is higher or lower than the baseload hedge.

All in all, contractual hedges are a tried-and-tested mechanism to manage risk in the post-subsidy RES world. Nevertheless, contracts can only go so far. When RES generation owners consider further ways to optimise the performance of their assets, BESS is now more present than ever not only as a stand-alone asset with an independent business model, but as the complementary physical hedge that can fill in some of the missing pieces left by traditional PPA structures.

Configuration	Assets	Inverters	Grid connections	How assets are managed
AC coupled	2	2	1	Independent
Hybrid AC coupled	2	2	1	Joint (hybrid)
Hybrid DC Coupled	2	1	1	Joint (hybrid)

Source: Pexapark

Table 1: Co-location technical configurations

Technical renewable-plus-storage setups

Putting two assets in the same site does not necessarily mean that there's a single way of operating them. In the case of renewable generation co-located with a battery, Pexapark's research suggests there are generally three setups found in the market today, as set out in Table 1.

The key point to keep in mind here is that the chosen configuration is likely to impact the contractual structures that the co-located project may adopt. Therefore, selecting one of these setups should be a process that analyses them from multiple angles, not just a technical perspective. It is fair to say that Pexapark's early-stage quantitative and contractual support has proven critical for the design and future commercial viability of our clients' projects.

What are hybrid PPAs?

The value of flexibility, not only for individual assets, but for the entire electricity system is widely recognised. On one hand, the ability to bid into the market and deliver grid services contributes to tangible 'value creation' for storage assets. On the other hand, 'value capture' is the tough job of how to tap such value and convert it into realised revenue. This is where tools like optimisation agreements and hybrid PPAs fall into place.

From a traditional stand-alone perspective, BESS assets tend to focus on accessing

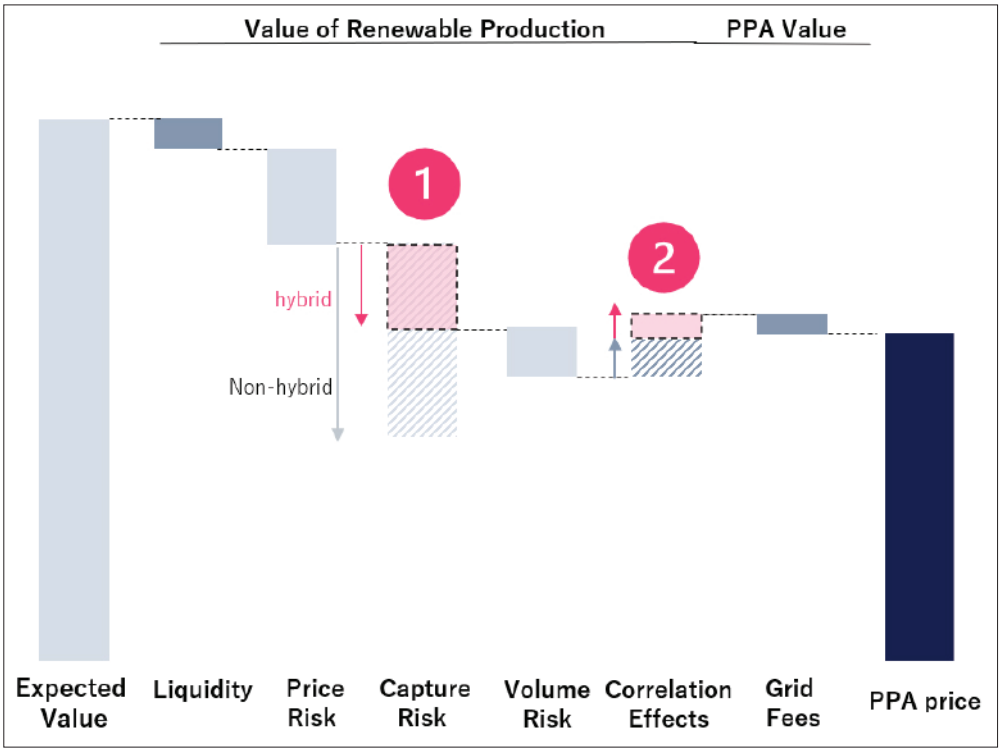
Arrangement	No. of contracts	Asset operation	Synergies	Pros	Cons
Renewable PPA & Storage capacity or optimisation agreement	2	Generation and storage assets are operated independently	Technical and financial benefits (e.g. sharing connection costs)	Value coming from each asset is more easily identifiable	The contracts could have negative impacts over one another
Hybrid shaped pay-as-produced (PaP) renewable PPA	1	Generation and storage assets are operated in combination to achieve the desired result	Storage allows the seller to adjust the PaP profile to deliver a partially shaped profile covering specific need in the buyer's load	Premium price for energy blocks while mitigating profile and volume risk; seller could react to market signals and choose to deliver energy via storage or spot market	Due to volatility, some price risk remains for positions that must be settle in the spot market; harder to identify value coming from each asset
Blended renewable and storage premium PPA	1	Generation and storage assets are operated in combination to achieve the desired result	Storage allows the seller to deliver a highly flexible profile covering diverse or variable needs in the buyer's load	Premium price for all delivered energy while mitigating price, volume and profile risk. Buyer can shape the delivery profile, and/or on how the battery operates	Loss of potential upside for the seller due to flexibility given to buyer. Valuing additional revenues from ancillary services can be challenging

Source: Pexapark

Table 2: Contractual arrangements for hybrid PPAs

grid-level revenue streams that a given market's operator may offer, such as providing capacity, balancing energy, or ancillary services, as well as wholesale energy trading. As the stand-alone energy storage concept matured, market players started looking at such assets from a complementary angle, that of co-location. Asset-level opportunities are centred around the idea that storage is primarily improving the performance, and therefore investment returns, of renewables through mitigating the risks deriving from their inherent intermittent nature. Profile shaping comprises a prime example, tackling the effects of cannibalisation in spot markets.

The latest mega trend in the renewables-plus-storage sphere is on hybrid PPAs, where several different contractual arrangements may be found. So, what is a hybrid PPA? For Pexapark, it is a contractual arrangement leveraging benefits both for the grid- and asset-level, only available to co-located assets. With a hybrid PPA, the idea is to get the best of the two worlds: potentially generate revenues through grid services, while improving the investment returns of the renewable asset. The first financial-benefits touchpoint of considering co-locating a renewable asset with storage is the cost savings from the shared grid connection. Such cost savings, as well as saturation in the ancillary service markets, increased cannibalisation risk for renewables, and volatility in the wholesale markets incentivising profile shaping of intermittent renewables, comprise factors driving market players to explore the co-location model overall.



Source: Pexapark

Figure 2: Pricing impact of storage on a hybrid shaped PPA

The maturity of tangible contractual arrangements and the emergence of hybrid PPAs make the co-location consideration even more attractive. How the two assets will communicate will be dependent on the contractual details. With a hybrid PPA, it's possible to have a physical asset to manage the different types of PPA structures, practically turning storage into a physical hedge to complement the financial hedge of the renewable asset. At the same time, another option would be for the two assets to operate virtually independently, with a renewable PPA for the generation, and an optimisation agreement for storage. Or, adding a price premium to the energy produced from the renewable asset by valuing-in the flexibility which allows better risk management of the energy.

Bearing in mind the above, Pexapark's view is that the arrangements set out in Table 2 are currently available.

At this point we should also mention certain potential costs of co-location: co-location could lead to the constraints of one part of the system, and, depending on the type of physical coupling, may reduce ancillary service revenues available to the BESS. Hence, understanding these interplays is key for making sound investment decisions in co-located assets and structuring the right contractual arrangement to satisfy the project's goals.

Hybrid PPA pricing

Pricing a hybrid PPA is usually less straight forward than pricing a conventional PPA. In this section, we illustrate this considering

11th Edition

SOLAR FINANCE & INVESTMENT EUROPE

HOST SPONSOR

SMARTENERGY

See what to expect, watch the promo video.

SCAN ME

31 Jan - 1 Feb 2024 | Victoria Park Plaza, London

Connecting Solar & Storage Project Developers with Capital

Headline Speakers

Roberta Boscolo
Climate and Energy Leader
& Top 10 Global Sustainability Influencer
World Meteorological Organization

Nicolas Firzli
Director-General
World Pensions Council

Bianca Ziccarelli
Managing Director -
Sustainable Energies Europe
CPP Investments

Aristotelis Chantavas
Head of Europe & President
Enel Green Power &
SolarPower Europe

Key Themes for 2024

- Cost and Availability of Capital
- Scaling with 2030 Targets in View
- Commercial Perspectives on ESG
- EPC Bottlenecks
- Long-Term Asset Management
- Power Price Problems
- The PPA Market Potential
- Grid Investment and Modernisation

2024 Sponsors

Host Sponsor
SMARTENERGY

Platinum Sponsor
JinkoSolar

Gold Sponsor
EDF renewables

Silver Sponsors
JLL
NovoGrid

Supporting Sponsors
axpo
KYOS ENERGY ANALYTICS
RAWICOM
res power for good
Skyfri
SQUEAKY

Exhibitor
QuintasAdvisory

Editorial Partners
Energy Storage News
PVTECH
Solar Power Portal

Partners
Renewables
Climate17
Energy Tech Review
ISEA
SeeNews
Solar Energy UK

#SFIEurope

financeeurope.solarenergyevents.com

SOLAR MEDIA

a hybrid shaped PPA (see the third type of arrangement in Table 2), for which we need appropriate granularity to understand how both assets' complementarity will play out and subsequently estimate the value of profile shaping. Pexapark's hybrid PPA pricing uses hourly forward curves, where we model the behaviour of how renewable generation and storage operate together and determine what is the value of that profile resulting in a premium PPA price. It's a valuation tool to bring transparency into the hybrid project's pricing after profile shaping.

Certainly, energy storage is among the prime physical tools to mitigate capture risk, because through profile shaping the storage element can shift the power delivery to slots when the energy is needed the most. Likewise, through the addition of a physical hedge, the timely reaction to daily pricing patterns not only results in reduced profile costs, but such costs could also become profile benefits. Figure 2 illustrates the series of elements that go into the hybrid shaped PPA pricing process for a given renewable generation asset, highlighting how the addition of storage could reduce the negative price impact of capture risk and contribute a positive correlation effect between volume and price, ultimately leading to a higher PPA price than that which would be obtained from the stand-alone renewable asset.

In addition to the above, we should also keep in mind that the pricing impact on the hybrid PPA is not only limited to the energy generation level. After the impact of improved capture risk and reduced profile costs, additional revenue from ancillary services can become part of the PPA price or perform a separate valuation process.

Hybrid PPA markets

The British energy storage market is currently the largest and most sophisticated in Europe, largely owing to a welcoming environment for stand-alone BESS that can access a plethora of innovative regulated grid services, balancing services and the capacity market, as well as wholesale trading. Capital providers have gradually become more comfortable with financing batteries and many players are flocking towards these assets. Hence, it is natural that the British market is leading innovation in the storage space, including co-location and hybrid PPAs. One signal is that the volume of hybrid solar projects seeking approval substantially outgrew that of stand-alone projects (according to Pexapark research, these figures stood at 3.4GW and 921MW respectively, as of Q1 2023). Another signal is that the first hybrid PPA transactions in Europe have been closed here, with the latest publicly announced example being the DIF-Engie deal referenced in this article's introduction, where Pexapark was DIF's adviser.

Outside of Britain, markets for co-location and hybrid PPAs are less advanced at the moment but we can find promising signals in several countries. One of these signals is increasing cannibalisation in markets with high renewable penetration of renewable generation. This is something we are already seeing in countries such as Spain, Germany, and the Nordics [3].

Spain currently hosts more than 19GW of installed solar capacity, with several thousands more in the pipeline (especially after a recent government push to disentangle recurring permitting bottlenecks) and this has led to an already visible price cannibalisation effect. For instance, in April of 2023 Spanish solar capture factors reached all-time record lows at nearly 0.6. Likewise, in Germany the solar capture factor fell to 0.6 in May of 2023. In the Nordics the same issue is present, although rather than solar it is linked to the widely deployed onshore wind generation, whose captor factors have reached record-low levels (even to a point of 0.36 in Finland during September). To add salt to the wound, many offshore wind projects in the Nordics sit on baseload PPAs, so their need to cover their contractual shortfalls with expensive energy in the market has led to numerous cases of serious financial distress. In all these markets, hybridisation is becoming a growing trend, with developers seeking to add co-location to both new and existing projects (retrofitting), as the physical hedge of storage can greatly help mitigate the impact of cannibalisation. It is only natural that with a larger co-located BESS deployment, more opportunities for hybrid PPAs will start to appear.

Finally, in addition to the cannibalisation factor we may find other drivers for co-location growth that could signal an uptick in hybrid PPA activity. One of these drivers is Germany's innovation auctions. The country was the first to hold government-backed auctions for hybrid projects, with solar-plus-storage having swept more than 1GW of the awarded capacity. Due to the merchant element included in the partial subsidy scheme, such hybrid assets could be on the lookout for further contractual arrangements.

In conclusion, we expect that gradually more and more markets will continue to devise mechanisms to stimulate flexibility additions, as this is indispensable in grids with a growing share of intermittent renewables; this in turn will favour the deployment of storage co-location, leading also to a growth in hybrid PPA contracting. ■

References

[1] Visit www.pexapark.com to find our full report "Renewables-plus-Storage Co-location Trends: Hybrid PPAs and More" (on which the present article is largely based), as well as our upcoming academy sessions on energy storage, power purchase agreements, energy risk management, among others.

[2] For further information on this deal, see https://www.solarpowerportal.co.uk/dif_announces_uks_first_bankable_and_unsubsidised_hybrid_ppa_for_solar/

[3] Our market data and PPA pricing can be found in our platform PexaQuote. To open a freemium account, see https://pexapark.com/pexaquote-freemium/

Authors

Jack Rankin is the regional lead for Pexapark's PPA Transaction Advisory business in the UK and Ireland, responsible for the origination, structuring and negotiation of a range of Pexapark's co-located clients projects in GB. Previously, Jack worked as a utility and corporate PPA originator for SmartestEnergy and Centrica. Jack also has experience in M&A and in the energy markets team at a boutique investment bank, advising clients on their off-take arrangements alongside the raising of senior financing for client's portfolios.

Miguel Valderrama is currently a senior PPA transactions associate at Pexapark. Previously, he was head of business development at CVC Energia, a utility, and associate at LQG Energy & Mining, a consulting firm. He is also a member of the World Energy Council's Future Energy Leaders (FEL-100) group. Miguel holds an MBA from the University of Cambridge and a Law degree from Universidad del Pacifico (Peru).

Brian Knowles is director of energy storage and flexibility at Pexapark. He has over ten years of development and power markets experience.

RE+ NORTHEAST

FEBRUARY 13-14, 2024
BOSTON, MA

POWERED BY SEIA Solar Energy Industries Association® | Smart Electric Power Alliance

Join conversations with industry buyers, suppliers, distributors, consultants, and more to explore solutions, exchange ideas, and discover new technologies within the industry.

RE+ EVENTS

REGISTER TODAY | RE-PLUS.EVENTS/NORTHEAST

National, nodal or zonal: potential of different pricing structures in the world's energy markets

Markets | The rapid deployment of solar and other renewables is creating new pressures on the efficient operation of electricity markets. Stephen Woodhouse looks at whether a shift from national to locational pricing offers a solution to optimal market design as decarbonisation efforts gather

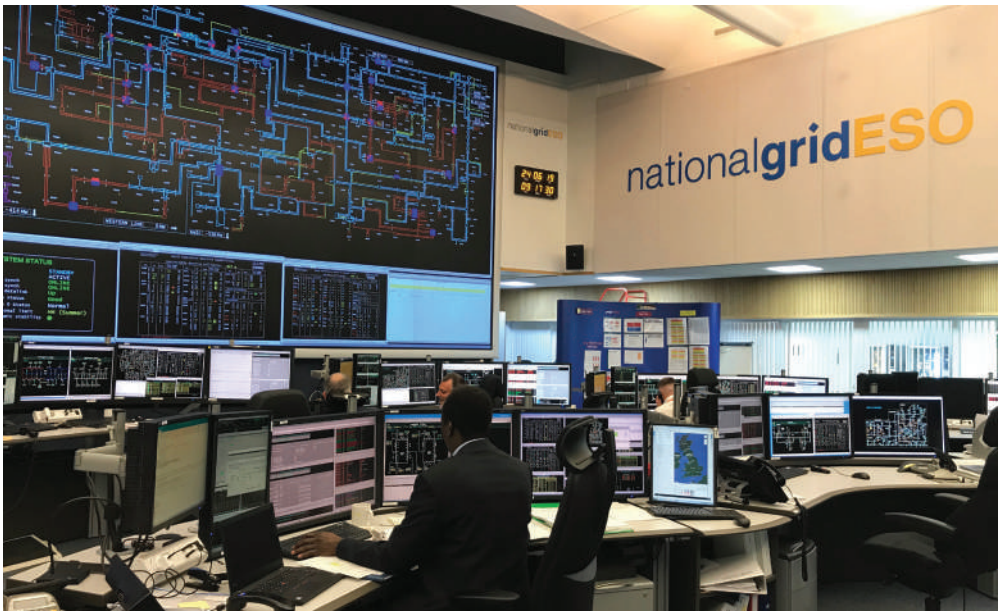
The value of everything is affected by its location, but in most countries electricity prices are still determined nationally. Renewables are modular and are being added rapidly, outpacing the development of network infrastructure, which in turn is creating expensive congestion issues.

ESO, the electricity system operator in Great Britain, forecasts constraint costs for the next 12 months at an eye-watering £1.5 billion (US$1.9 billion). Could moving to more granular locational electricity prices help? While the answer is complicated, AFRY's analysis shows that risks of shifting to locational pricing may outweigh benefits.

Almost every aspect of the electricity market design in Great Britain is being reconsidered under the UK government's Review of Electricity Market Arrangements (REMA). There is widespread agreement that today's market arrangements are not suitable for a net-zero system, but little consensus on the nature or extent of change which is necessary.

One of the most contentious issues in the REMA process is whether to move from the current market with a national price, across Great Britain, to one in which wholesale prices differ by location. The debate about locational pricing is also raging in key markets in Europe – including France, Germany and the Netherlands – which are also facing proposals for separation into new price zones.

To frame this debate, AFRY has conducted an independent study of the REMA options under consideration – including a detailed modelling evaluation of both zonal and nodal locational pricing options. The study was funded by 12 industry members with diverse opinions on the subject, with observers from key stakeholders, and this article draws on our key findings.



Credit: National Grid ESO Electricity National Control Centre (ENCC)

The UK's Electricity National Control Centre. Like most markets where renewable energy deployment is booming, the UK is grappling with the question of electricity pricing

What are the options for locational energy pricing?

All electricity markets are locational to some degree. There are broadly three options within a country: national, zonal (different areas) or nodal pricing (each point on the transmission network). In most countries the price area matches national borders, with a single national wholesale price at any time.

Some national markets are split into a small number of zonal price areas: Norway (five zones), Italy (seven, for generation), Australia's NEM (five). The EU's wholesale energy market uses 'price coupling' for over 60 zones across the continent in a sequence of linked spot markets, until recently, including Britain.

In contrast is the nodal market design typical of the restructured US markets such as PJM, California (with around 10,000 nodes) and Texas (with around 4,000 nodes). US nodal markets tend to be regional, with relatively poor optimisation of flows between neighbouring markets. Customers generally face prices at a more aggregate level than generators.

National market management

For national markets, prices are formed by national supply and demand, and import and export trade through interconnectors.

Transmission constraints within the country are managed by the transmission system operator (TSO) through 'redispatch'. For example, the TSO may curtail solar output sited behind an export transmission constraint, then replace it with more expensive natural gas generation outside the constraint which had not been previously traded.

Compensation arrangements for generators whose output is constrained vary between markets. In Britain, 'firm' transmission access rights generally mean

that generators are not commercially disadvantaged by transmission constraints, even for lost RES support payments. In other markets, for instance Australia, there is no compensation for a generator being constrained off because of network congestion.

Timing is key: the wholesale national market operates before consideration of within-zone network constraints, and then redispatch happens relatively close to real time. Therefore, less flexible assets, including interconnectors, may not be redispatched efficiently in a national market. This is a potential source of inefficiency, for which a locational market may bring improvements.

Simultaneous delivery in zonal markets

In zonal markets, the market simultaneously delivers prices and matched trades for each zone and defines total traded flows between zones. Trades and flows may be refined in the intraday markets. Bids and offers for each zone are combined with input parameters, calculated by the TSOs, which define the usable transmission capacity between zones.

The pattern of price differences between zones is linked to flows on the network. With no congestion, prices may be the same across multiple zones. When transmission limits are reached, prices diverge between zones. Zonal prices normally apply to both sellers and buyers.

Mechanics are important: generation behind a zonal boundary constraint is not curtailed by the TSO, as in national markets. Instead, prices in export constrained areas will tend to be lower than under a national price and prices in import-constrained areas will tend to be higher than under a national price. Market revenue for generators in zones with export constraints will be reduced.

Forward trading is needed within and between zones. The arrangements vary for obtaining transmission rights to trade between zones, but the effect is similar: a generator and a customer in different locations may trade with each other and may buy rights to hedge against price differences between their respective zones. Transmission rights are generally short term, between one and two years, and baseload in profile.

The zonal markets broadly respect the network capacity between zones but not within the zones. Any intra-zonal constraints must be dealt with by the TSO through 'redispatch' as described above for the national markets.

This design of zonal markets – in which the network is represented in a simplified way – has enabled day-ahead market coupling to be extended to the whole of Europe, where there are 61 zones for 27 countries. The markets are decentralised and voluntary in nature, and participants may choose the timeframe and market venue in which they trade.

Nodal markets and central optimisation

The intent behind nodal pricing is similar to zonal: prices at each location reflect supply and demand allowing for transfers from elsewhere. Nodal markets use a (near) complete view of the network, so market outcomes should respect all transmission constraints without further need for redispatch.

Nodal markets are centrally optimised: this is a complex topic but in essence they are organised around a mandatory market optimisation which runs at discrete times: day-ahead and 'real-time', with no traded intraday market. Some nodal markets co-optimise energy with reserve and response.

> "Ultimately, nothing substitutes for the construction of network capacity. Investment in grids – at transmission and distribution level – is behind the curve of renewable investment and accelerated investment is essential to achieving our energy transition"

Market power still exists in a nodal market but has different impacts and is exercised in different ways. It is the physical circumstances which confer market power, not the market arrangements. The ability of participants to exploit market power depends on where they are on the grid, their access rights and the regulatory oversight.

A well-designed electricity market should effectively coordinate supply and demand over operational and investment timeframes, while appropriately allocating costs, rewards and risks. The theory of nodal pricing sounds attractive: based on the offers by participants, the market calculates optimal dispatch and prices energy at every location based on the available network capacity. The reality is more complex.

Implications for short-term trading and dispatch

Nodal pricing gives a more integrated dispatch process and is likely to give more efficient dispatch than zonal or national markets. Nodal markets accommodate network constraints, simplifying the process of scheduling and dispatching. Compared with a national or zonal system with residual intra-zonal constraints, dispatch decisions are taken more effectively for those less-flexible units which might not be available when redispatch is conducted.

However, nodal markets use algorithms, which were designed for large thermal generation units. It is questionable whether a centralised market is truly compatible with a decentralising power system. Optimisation of resources such as storage and electric vehicle (EV) chargers has not been fully implemented in any nodal market, and it is unclear whether the systems could deal with a large number of small resources. Aggregation is limited as each trade is linked to a point on the transmission network.

Centralised nodal markets operate at intervals, generally day-ahead and real time, with no intraday or continuous trading. Conversely, decentralised zonal and national markets allow continuous trading, allowing flexible resources to find a niche in the market to support varying demand and renewable generation.

If network congestion is typically caused by high levels of renewable generation, those renewable operators will face self-curtailment and reduced capture prices under a locational market. This may be partly mitigated by any support arrangements in place.

We could argue that centralised nodal spot markets focus on optimising location, whereas national or zonal markets focus on flexibility. In the future electricity system, it is not clear that a change away from favouring flexibility towards favouring location would be a step forward.

Impacts on investment and the role of politics

Advocates of zonal or nodal pricing suggest that it improves incentives to place resources in areas where the network is strong. Again, this sounds attractive.

However, there are potentially negative implications of locational pricing structures for forward trading and investment. A national market will generally have many buyers and sellers, fostering liquidity. Any internal transmission constraints are dealt with by the TSO and do not generally impinge on the market outcomes.

In markets with smaller zones or a nodal market, volatility is higher and liquidity is likely to be lower. Participants are commercially exposed to transmission constraints between price areas, especially to future policy decisions such as the siting of hydrogen and carbon capture and storage (CCUS) infrastructure. In a zonal system, zone boundaries themselves may be revised, undermining existing forward contracts.

As a consequence, market risk increases as the market is subdivided into smaller areas. Exposure to locational risk may be expected to increase the cost of capital for new investment. This could easily outweigh any benefits arising from more efficient dispatch of less flexible resources in a locational market.

Zone size is politically and economically important. There are obvious consequences of separating wholesale prices by location for both consumers and producers. A change from a national to a locational market will create winners and losers as pricing and risk profiles change.

The EU zone boundaries are reviewed every three years. The European Union Agency for the Cooperation of Energy Regulators (ACER) has proposed alternative bidding zone configurations for Germany, the Netherlands, France, Italy and Sweden. Despite the economic case for change, there is widespread opposition: in theory the Commission could enforce price zones on countries but this would be highly contentious. If zoning changes are made, any existing contracts in these countries would need to be adapted to deal with the revised price areas.

Alternatives to locational markets

There are alternatives to locational energy prices which may provide incentives for siting decisions and congestion management. The market toolkit includes a combination of connection policy, transmission access rights and network charges.

In Britain, zonal transmission network charges are paid by generators and customers. These charges are significant in deciding location: the range of network charges for 2023/24 between locations could equate to 20% of captured price for an onshore wind plant. The variation for solar would be less, as PV is less prevalent in Britain. Loss factors can also vary by up to 10% of gross revenue between favourable and unfavourable locations. These are powerful incentives. If locational energy markets were introduced to Britain, we believe that the existing locational network fees would be flattened.


Credit: Wikimedia Commons

Debate about optimal market design for the energy transition creates uncertainty for developers

In that case, it is not clear whether remote generators would be, on average, better or worse off from locational pricing, especially if grid reinforcement reduces the extent of congestion. The arrangements for grandfathered rights and renegotiation of existing contracts would be key to any implementation of locational pricing, in Britain as well as in Europe.

Other investment support mechanisms interact with wholesale market pricing. Renewable support mechanisms, such as feed-in tariffs or Contracts for Difference, are linked to the national price but would switch to a local reference price in any change to a locational market. This would partly, but not completely, wipe out the impact of locational pricing for those generators. For future renewable support mechanisms changes would be needed, and generators may face increased risk, which we believe would increase the cost of capital.

Potential for Great Britain

AFRY analysis of a potential move to zonal or nodal pricing did find a small improvement in operational efficiency, with economic benefits amounting to around 1% of total consumer bills in the period 2028-2050.

However, we believe that the additional risk on market participants would increase the cost of capital for investors. Under credible assumptions, we found that these increased costs could easily be double the efficiency gains.

AFRY found the benefits of a move to locational pricing in Britain are small and could be outweighed if additional risks to investors cannot be mitigated.

We recommend that nodal pricing should not be progressed further due to the scale and risk of change, the time needed for implementation and the doubt over whether a centralised market is compatible with the future range of decentralised resources. Any further exploration of a zonal market design should be accompanied by a programme of work to explore ways in which the risks – and wealth transfers – could be mitigated.

Further work should also be undertaken to improve incentives and information flows under the existing national market design: specifically more targeted investment and operational dispatch incentives, particularly for interconnectors and for resources behind transmission constraints.

Our recommendations reflect the difficulty of changing market arrangements during a period of high investment needs. While there is a case for change, existing arrangements have had significant success in delivering decarbonisation, whereas radical change is likely to deter the investment.

The present discussion in Britain relates to transmission, but distribution networks are now being designed for some level of congestion management. Distribution System Operators (DSOs) in Britain are using a range of tools to manage congestion including buying flexibility services and offering 'flexible' connections, and local flexibility markets are being developed across Europe.

For renewable developers, the policy debate creates uncertainty. Optimising electricity market design for the transition is a complex topic, with no easy answers. Any shift in market design will create winners and losers.

Ultimately, nothing substitutes for the construction of network capacity. Investment in grids – at transmission and distribution level – is behind the curve of renewable investment and accelerated investment is essential to achieving our energy transition. ■

Author

Stephen Woodhouse is a director with AFRY Management Consulting. Stephen has 25 years' experience in design and evaluation of energy markets and the role of innovation, contributes to the global debate on market design for the energy transition and is a well-known conference speaker.

Presented to you by: Energy Storage NEWS

STORAGE & SMART POWER

98

#StorageSummit

Save 20% on all tickets. Use code: PVTP20

6th Edition

Energy Storage USA

HOST SPONSOR SunGrid

19-20 March 2024 | Double Tree Hilton, Austin TX

Accelerating the Market for Energy Storage in the USA

Key Themes for 2024

- Supply Risk & Resource Planning
- Technical Sessions and Networking
- Technology Evolution & Long-Duration
- Fire Risk & Safety
- Transmission & Interconnection
- Storage in a Post-IRA World
- Financing & Revenue Strategies
- Market Forecasts

Book now: storageusa.solarenergyevents.com

2024 Sponsors & Partners

Host Sponsor: SunGrid

Diamond Sponsor: MODOENERGY

Platinum Sponsor: FLUENCE

Gold Sponsor: stem

Silver Sponsors: ESS INC, TrinaStorage

Bronze Sponsors: Customized Energy Solutions, ENERGYDOME, EVLO, FRACTAL, FRACTAL EMS, IEP TECHNOLOGIES, POWIN, TWAICE

Supporting Sponsors: ACCURE, Akin, ampt, AURORA, CEA, CPower, Gridmatic, IHI terrasun, POWERFACTORS, PowerUp

Exhibitors: INVINITY, jama software, TORCSILL, transect, US Helicals, YES ENERGY

Editorial Partners: CURRENT±, Energy Storage News

Partners: American Solar Investment, Renewables, Climate17, ENERGY Tech Review, IBESA

Introduction

Welcome to another edition of 'Storage & Smart Power', brought to you by Energy-Storage.news.

It's already been a year since I was last commenting on how quickly a year goes by. Once again, there are two main takeaways from another 12 months in clean energy: 1. Renewable energy and energy storage are scaling up faster than ever before, and this rate is accelerating; and 2. It still is not enough.

As we speak, the COP28 talks are coming to their end. The conference began with 118 countries committing to tripling their renewable generation, but didn't end with any specific pathways to net zero emissions being agreed upon. That sort of exemplifies the global situation.

At Energy-Storage.news, we will continue to do our best to shed light on industry talking points and analysis, delivering information and insights to aid you and your colleagues on the journey of a lifetime into the energy transition.

In this edition alone, we span some really interesting areas:

Australia: the country voted for a government that ran on a climate-friendly platform, for the first time taking on the net zero challenge. Stephanie Bashir of Nexa Advisory looks at what needs to happen for Australia to quit coal.

Augmentation: strategies for managing and mitigating degradation of batteries come under the spotlight in a piece from Giriraj Rathore, business strategy manager at Wärtsilä Energy.

Energy density: Ben Echeverria and Josh Tucker from Burns & McDonnell on how the industry should be thinking about energy density and its impact on everything from footprint to cost.

Finally, before you turn the page to peruse those fine articles, there's no better way to end the year with a run-through of the winners of the inaugural Energy Storage Awards, which were celebrated at the end of September. The 2023 winners and runners-up below exemplify the best of the industry, as chosen by a panel of independent expert judges.

Andy Colthorpe
Editor
Energy-Storage.news @ Solar Media

Category	Developer of the Year	System Integrator of the Year	Outstanding Contribution to Energy Storage	Trading & Optimisation Team of the Year	Product of the Year
Winner	Zenobē Energy	Fluence	Alex O'Cinneide (Gore Street)	Habitat Energy	UltraStack by Fluence
Highly Commended	Kyon Energy	Trina Storage	Lars Stephan (Fluence)	EDF UK	Li-ion Tamer GEN3

Category	Grid-scale Standalone Energy Storage Project of the Year	Breakthrough R&D/ Innovation of the Year	Newcomer/ Startup of the Year	Challenge of the Year	Grid-scale Co-located Project of the Year	Distributed Energy Storage Project of the Year	Grid Operator-led Project of the Year
Winner	Pillswood (Harmony Energy)	EnZinc	Atlantic Green	Atlantic Green	EasyPower's Hybrid EV Charging Station	Elisa Distributed Energy Storage	ELES Sincro. Grid Project
Highly Commended	Capenhurst (Zenobē)	Zenobē	Cellect Energy	N/A	Larks Green Project	Sara Kulthurhus	Transnet GridBooster

www.energy-storage.news

Visit the site and **subscribe free** to the **Energy-Storage.News newsletter** today.
Technology with the capacity to change the world.

LFP cell average falls below US$100/kWh as battery pack prices drop to record low in 2023

After a difficult couple of years which saw the trend of falling lithium battery prices temporarily reverse, a 14% drop in lithium-ion battery pack cost from 2022-2023 has been recorded by BloombergNEF.

On average, pack prices fell 14% from 2022 levels to a record low of US$139/kWh this year, driven by the dynamics of falling raw material and component prices, and increases in production capacity.

Despite the good news, BloombergNEF no longer expects to find average pack prices fall below US$100/kWh by 2024 (as it predicted in 2020), nor by 2026 (as it predicted last year).

It will however be likely to happen before the end of this decade, with BNEF forecasting that the average pack will cost about US$113/kWh in 2025, and decline in cost sharply to around US$80/kWh by 2030.

20MW/80MWh containerised BESS in Virginia, US. This year saw battery prices fall once again after a difficult 2022 for the industry.

Credit: Dominion Energy Virginia.

US-made DC containers to be cost-competitive with China in 2025

US-made BESS DC container solutions will become cost-competitive with those from China in 2025 thanks to incentives under the Inflation Reduction Act (IRA), Clean Energy Associates (CEA) has said.

A DC BESS container fully manufactured in the US sits at an average price of US$256/kWh in 2023 for a 2024/25 delivery, while one manufactured in China for US delivery in 2025 sits at US$218/kWh, CEA said.

CEA said that if certain subsidies for US clean energy technology production brought in under the Inflation Reduction Act (IRA) are passed directly onto the customer, the US-made BESS price could fall by 13%.

Huawei and BYD in global top five system integrators of 2022 amidst China 'price war'

Huawei and BYD were among the five largest BESS integrators globally last year, with the Chinese market going through a 'price war' of competition, according to research from Wood Mackenzie.

Sungrow topped the list of 2022 deployments with a market share of 16% last year, Wood Mackenzie said, followed by Fluence and Tesla, each with 14% of the market, and Huawei and BYD, each with a 9% share. The top five collectively held a 62% market share.

The US market meanwhile was more concentrated than the global one last year, with Tesla (25%), Fluence (22%) and Sungrow (13%) making up the top three holding a collective 60% market share, and the top five holding 81%.

Northvolt and Altris develop 'breakthrough' 160 Wh/kg sodium-ion battery for energy storage

Gigafactory company Northvolt and sodium-ion battery technology firm Altris have together revealed a battery with an energy density of 160 Wh/kg, designed for energy storage systems.

Sodium-ion battery technology is widely seen to be the most commercially mature electrochemical-based alternative to lithium-ion.

The firms said the battery they have developed together will provide the foundation for Northvolt's next-generation energy storage solutions.

Its low cost and safety at high temperatures make it especially attractive for deployment in "upcoming markets" including India, the Middle East and Africa, it added.

Microgrids, battery storage projects get funding through US' 'biggest-ever investment in the grid'

A US$10.5 billion programme to "strengthen grid resilience and reliability" across the US includes funding for microgrids and other projects that will integrate battery storage technologies.

The Grid Resilience and Innovation Partnerships (GRIP) programme is being directed with a focus on underserved communities and working with unionised labour – three-quarters of the selected projects have involvement from the International Brotherhood of Electrical Workers (IBEW).

The list of projects includes a wide variety of initiatives, technologies and mitigation measures alongside the hundreds of (mostly) solar-plus-storage microgrids, including enhancements to the grid from software to high voltage DC hardware level, better integration of distributed energy resources (DER), direct wildfire mitigation efforts and others including community battery storage.

California introduces fire safety rules around booming battery storage sector

New legislation in California requires battery storage facilities to put in place safety and communication protocols.

Senate Bill 38 (SB 38) makes it a requirement for battery storage facilities in the state to put in place emergency response and emergency plans, in addition to existing requirements for their maintenance and operation to meet standards set by the regulatory California Public Utilities Commission (CPUC).

The bill comes into force with California's rapid deployment of BESS assets continues. BESS resources help balance the grid, integrate growing shares of renewable energy, maintain electricity supply reliability in the face of load growth, wildfires and other causes of outages and enable thermal generation retirements.

Augmentation strategies to manage long-term battery degradation

Battery oversizing | With storage playing an increasingly central role in the energy transition, the importance of managing battery degradation is coming to the fore. Giriraj Rathore of Wärtsilä Energy Storage & Optimisation explores some of the main strategies for successful battery augmentation as a means of offsetting the impacts of system degradation

Credit: Wärtsilä

Augmentation will become increasingly important as battery systems age

Energy storage is the backbone of the renewable energy transition, able to offset periods when the wind isn't blowing and the sun isn't shining. With broad market recognition that energy storage is key to catalysing a future powered by zero-carbon energy sources, the sector is experiencing robust growth. Energy storage deployments in 2023 are on track to double those of the year prior. By the end of the decade, total capacity is set to expand tenfold, surpassing 400GWh.

All battery-based energy storage systems degrade over time, leading to a loss of capacity. As the energy storage industry grows, it's critical that project developers proactively plan for this inevitable 'degradation curve'. Failing to do so will not only limit potential revenues but could even jeopardise the role of energy storage as a key enabler of grid stability and, by extension, the energy transition.

As the initial wave of grid-scale energy storage deployments begins to mature, managing the effects of battery degradation will emerge as a key strategy for developers looking to future-proof assets and accelerate renewable energy adoption. Many industry experts suggest that augmentation is poised to be the solution of choice, allowing developers to take advantage of declining battery costs and technological advancements.

Understanding battery degradation

Battery degradation in energy storage systems is a natural phenomenon. Just like portable electronics wear out to become less efficient over time — think of how long your old phone can hold a charge — the amount of energy that can be stored and dispatched from energy storage systems gradually declines. Whereas the average rate of battery degradation in electronics or electric vehicles is generally predictable, it's harder to calculate the decline of energy storage systems with similar accuracy. The rate of degradation and capacity loss is influenced by a variety of factors, including frequency of use, operational pattern, battery chemistry, and ambient operating environments.

Energy storage systems that engage in heavy arbitrage are particularly prone to rapid degradation. Arbitrage strategies involve purchasing and storing energy when prices are low and selling and discharging it when the demand for energy increases. Optimal charging and discharging intervals often run contrary to preferred arbitrage opportunities, meaning developers have limited visibility into the pace at which energy storage systems lose capacity. This is significant considering nearly 60% of installed energy storage systems were used for price arbitrage in 2021 — a number that is expected to continue to grow.

Degradation rates also differ by battery type. There are several kinds of lithium-ion battery chemistries being used in the energy storage market today, and each comes with its respective benefits and drawbacks. Nickel manganese cobalt (NMC) had historically been the dominant chemistry for energy storage, but this is quickly changing. By 2030, lithium iron phosphate (LFP) is expected to be the dominant chemistry — growing from a market share of 10% in 2015 to more than 30% in 2030. The primary benefit of LFP battery technology is that it enables a

longer lifespan compared to other lithium-ion chemistries.

Temperatures, both hot and cold, can have a significant effect on battery degradation. Higher temperatures may increase energy storage system performance in the short term, but eventually lead to higher degradation rates and a diminished lifespan. Once temperatures surpass 100 degrees Fahrenheit (approximately 38 degrees C), degradation in lithium-ion cells quickly accelerates. Prolonged exposure to extreme cold can also impact battery performance. When temperatures drop, internal battery resistance increases, which requires more effort to charge. This, in turn, lowers the system's overall capacity.

Managing degradation through oversizing or augmentation

Battery degradation in energy storage systems is inevitable. But it can be managed with careful planning and consideration. It can even present opportunities for developers to improve the profitability and efficiency of energy storage facilities.

Traditionally, developers have accommodated battery degradation by oversizing their installations at the initial outset of the project. This approach involves installing more battery capacity upfront than needed and typically consists of site preparation, wiring, and system integration. The excess capacity enables developers to offset the expected degradation losses over the years, allowing them to maintain the contracted capacity over the project's lifetime.

A key advantage of oversizing is that it doesn't require site mobilisation, permits, additional labour, or the commissioning of new hardware down the line. By fronting the installation process, developers can keep their energy storage systems operational even as they contend with degradation. There's no need for assets to be shut down — either partially or entirely — for weeks or longer to perform retrofits. Oversizing also enables developers to lock in capital expenditures at the project outset, mitigating future cost uncertainty and helping to improve forecasting. As the cost of lithium-ion batteries continues to fall to new lows, however, developers may lose out on significant savings by taking this approach.

Alternatively, developers may choose to offset degradation by augmenting the capacity periodically throughout the project's lifetime. In this case, there must be extra physical space with adequate electrical configuration in the initial project layout to add new hardware. Proper planning is critical to minimise downtime and risks associated with augmentation.

In 2013, one kilowatt-hour (kWh) of lithium-ion battery technology cost more than US$730. Flash forward to 2021 and that price had come down to US$141/kWh — a marked reduction of more than 80%. Had a developer opted to oversize their system back in 2013 as opposed to augmenting it years later, they would have paid almost twice as much while missing out on important technological advances that offer greater efficiency. Of course, battery prices do occasionally tick up — like in 2022 as a result of inflationary pressures and supply bottlenecks — but these can be seen as an exception to a much wider trend.

"A key advantage of oversizing is that it doesn't require site mobilisation, permits, additional labour, or the commissioning of new hardware down the line"

Suppliers have since rebounded from 2022's difficulties and battery prices are once again trending downward. Costs are further expected to fall as battery manufacturers ramp up production. By 2030, lithium-ion battery capacity is set to more than double, which will go a long way towards alleviating supply shortages. Furthermore, the US National Renewable Energy Laboratory suggests that the costs of lithium-ion energy storage systems could decline by up to 47% by 2030.

As prices continue to fall, augmentation is becoming an increasingly attractive way for developers to mitigate battery degradation and capacity loss. It may not be right for every situation, though, as each energy storage project is unique and different augmentation strategies depend on the appetite for potential risk and reward. Still, the likelihood of further cost reductions — especially considering the already low price of lithium-ion battery technology — makes augmentation particularly alluring.

Choosing between augmentation strategies

There are two primary methods of augmentation — alternating current augmentation (AC) and direct current (DC) shuffling — that developers can choose between based on their system type, grid connection, and needed services.

AC augmentation focuses on improving the interplay between the energy storage system and electrical grids, enhancing system stability, and enabling grid support functions. With AC augmentation, new physical infrastructure is added to the project, including inverters and Power Conversion Systems (PCS), which are responsible for making AC electricity usable in downstream devices like energy storage.

Alongside the PCS, new protective enclosures are installed to house essential components, including the batteries themselves and associated safety, control and monitoring equipment. The added capacity of AC augmentation can be installed without requiring significant modifications to existing equipment, minimising disruption. It also offers significant system flexibility, allows for incremental sizing, and presents an extremely low risk of technical complications.

However, there are a few drawbacks associated with AC augmentation that developers should keep in mind, particularly for grid-connected energy storage systems.

Adding new PCS equipment — while relatively straight forward from a technical standpoint — requires permitting and regulatory approval when connected to the grid. This process is cumbersome, time-consuming and extremely complicated, slowing down the ability of developers to augment their systems. These limitations don't impact energy storage systems that are independent from the grid, however. Islanded microgrids can forgo lengthy bureaucratic approvals, making them well-suited for AC augmentation. For grid-connected energy storage systems, DC shuffling is the more suitable augmentation strategy.

DC shuffling prioritises the internal distribution of energy within battery stacks to ensure balanced charging and discharging of individual cells and modules, which is vital for prolonging battery lifespan and maximising overall system efficiency.

Whereas AC augmentation primarily focuses on external interactions between energy storage systems and the grid, DC shuffling optimises energy distribution within battery stacks, delivering greater internal efficiency and resiliency.

By reconfiguring battery enclosures

Credit: Wärtsilä

The choice of augmentation method depends on the type of system, its grid connection and the services it provides

from one string of batteries and transferring them equitably throughout the system, DC shuffling leads to a more balanced distribution of energy across the battery stack.

A new string of enclosures is then introduced behind the PCS from which the existing batteries were shuffled. This addition guarantees that the overall system retains its power capacity and that the number of PCS units and the nominal power of the plant remain unchanged. This allows DC shuffling augmentation to bypass permitting and regulatory approval, as there are technically no new connections being made to the grid.

DC shuffling also benefits from lower equipment costs relative to AC augmentation, as there's greater repurposing of infrastructure. DC shuffling is well suited for grid-connected ESS, though it may not always be possible due to technical limitations, from auxiliary load breaker and busbar limitations to short circuit ratings. Consequently, developers must diligently evaluate the specific technical and operational aspects of their systems before deciding whether to invest in AC or DC augmentation.

Bringing it all together

There may not be a standardised rate of battery degradation in energy storage systems, but software can provide invaluable insights, helping inform augmentation decisions. Sophisticated energy management programs, such as ES&O's GEMS Digital Energy Platform, can gather operational data over a period to inform recommendations on capacity enhancements that can result in significant monetary gains.

Energy management software is not only useful for making data-driven decisions, but it's also key to seamlessly and cost-effectively implementing augmentation strategies. Software optimises the dispatch of augmented energy storage systems and harmoniously integrates the new and existing equipment. Energy management software must be flexible and powerful enough to incorporate disparate battery technologies and capacity levels. In cases where new equipment differs significantly, a software system's ability to coordinate and control these diverse technologies is indispensable.

Developers must also consider the importance of complementary augmentation technology. Augmenting with batteries of different capacities can introduce significant complexities that need to be handled with the utmost care. LFP batteries, for instance, require different thermal management strategies compared to NMC batteries. Improperly integrating these technologies can lead to potential repercussions, including voltage imbalances that could trigger thermal runaway. Moreover, developers that incorporate battery modules from different manufacturers run the risk of software incompatibilities, which could impact monitoring and controlling processes and risk overall system performance and safety.

To mitigate these issues during augmentation — whether AC or DC shuffling — developers should look to leverage complementary technologies wherever possible. The careful selection of augmentation equipment and the utilisation of advanced software solutions can help ensure the successful and safe augmentation of energy storage systems.

Battery degradation management will remain important into the future

The energy storage landscape may be dominated by lithium-ion battery technology today, but that could very well change in the future. There is a range of emerging technologies including sodium-ion (Na-ion), hydrogen, and long-duration energy storage (LDES) that have significant potential.

Na-ion batteries, for instance, offer a reduced environmental impact and safety benefits relative to lithium. Hydrogen, lauded for its high energy density and versatility, also holds great promise as a clean and flexible storage solution. Meanwhile, LDES technologies offer extended discharge periods, addressing the need for sustained power during prolonged lulls in renewable energy production.

These technologies, while promising, have not yet been deployed at scale. They will have to prove themselves individually at the grid level before developers have enough faith in being able to use them for augmentation. But as these up-and-coming storage technologies mature, they have the potential to reshape the augmentation landscape, providing developers with an array of options that can enhance the resiliency, efficiency, and sustainability of their energy storage systems.

With hundreds of gigawatts worth of battery-based energy storage systems operating at a global scale, mitigating capacity losses will become a central part of managing projects for developers and integrators in the years to come. Careful battery degradation management practices including augmentation will enable developers to drive greater performance, lower lifetime costs and keep the renewable energy transition moving forward. ■

Author

Giriraj Rathore, in his role as the business strategy manager at Wärtsilä Energy, harnesses a blend of technical expertise and strategic acumen to drive innovation in energy storage solutions. His grasp of market trends and emerging technologies helps foster sustainable energy initiatives and paves the way for a greener, more efficient energy landscape. His educational background includes a bachelor's degree in mechanical engineering, complemented by an MBA specialising in international business.

Energy storage and energy density: an EPC's view

System integration | Energy density is becoming a key tool in optimising the economics of battery energy storage projects as suitable sites become harder to find. Ben Echeverria and Josh Tucker from engineering, procurement and construction firm Burns & McDonnell explore some of the considerations of designing projects on constrained land

Credit: Burns & McDonnell

When transmission authorities in the USA first began to realise that utility-scale storage facilities would be necessary to help manage the intermittency of renewables being connected to the grid, land availability was not a concern. With Arizona, California and Texas leading the way, land was readily available for large project footprints.

Given both space and favourable market conditions, buildout was not an issue and, as a result, those three states currently contain more than 75% of today's battery storage capacity nationwide.

Those early market conditions are no longer the reality. Sites with large amounts of available land near transmission interconnections are becoming increasingly less available, and that can make today's project sites more challenging, especially as demand for these facilities continues to grow. A range of federal tax incentives and state mandates is creating more momentum for decarbonisation efforts than ever, further increasing the demand for large-scale battery energy storage systems (BESS).

Sites may still be available near interconnection locations, but they typically have much smaller footprints, and as a result of constrained supply and high demand, land prices in these situations are increasing. As a consequence, developers are seeking to significantly increase the amount of energy storage per acre. This drive to optimise project economics is being pursued by seeking more energy-dense batteries while also optimising the available site footprint.

Taller battery racks are one option for increasing energy density as battery sites become more constrained

What is energy density?

The volume of energy contained in each battery cell can play a pivotal role in project economics. The standard definition of volumetric energy density is the amount of energy a battery can store in proportion to its volume (specific energy density is stored energy in proportion to its weight). To be clear, we will be referring to energy density in this article as volumetric energy density. The industry has progressively improved upon battery energy density, with lithium-ion batteries increasing the energy available in the same footprint by about 10-12% over the last year.

Of the most common lithium-ion battery chemistries used today, nickel manganese cobalt oxide (NMC) and nickel cobalt aluminium oxide (NCA) battery technologies are the energy density leaders. Lithium iron phosphate (LFP) battery technology is another common battery chemistry, but it is much less energy dense. More recently, however, LFP has made gains in this area with some believing there is significant opportunity for this chemistry to attain densities close to NMC and NCA.

These lithium-ion technology advances, including energy density, are being largely driven by demands from the electric vehicle (EV) industry for improved ranges and performance characteristics for batteries installed in vehicles. Because the power industry holds such a relatively small share of the lithium-ion battery market, the reality is that advances in utility-scale BESS installations will likely move in lockstep with the auto industry. Supply chains, manufacturing advances and general use cases for battery technology all are heavily weighted toward meeting auto industry demands.

On the horizon, it seems that very large, energy-dense battery cells will be developed to produce more energy from increasingly smaller volumes. With new and improved electrolytes, anode advancements and cathode evolution, ranges for EVs and output for storage facilities can be greatly improved.

Building up, not out

In densely populated metropolitan areas like Los Angeles, New York City and Boston, decarbonisation efforts are creating unique challenges for battery energy storage projects.

New York is an interesting case example. Though actual numbers will vary by the time of season, it is generally assumed that approximately 70% of the power load within the state of New York is centred around demand from New York City. As New York utilities move toward meeting regulatory mandates for reduced or zero-carbon emissions, thermal generation systems are being ramped down or retired. Renewable energy backed by storage-based power systems will be needed to fill the gap.

It is logical to locate these renewables and storage systems within the city. In New York City, smaller facilities in the 5-20MW range are being planned and developed. As deadlines for decarbonisation grow closer, it seems likely that these smaller projects will fall short of demand and larger projects will be needed.

However, the reality is that within large, dense urban areas, only small plots of land are available. The only realistic and economically viable option is to design these projects vertically, either with batteries installed in enclosed building structures or with vertically stacked battery enclosures. If the building is the preferred solution, this may involve stacking multiple racks to increase total rack heights up to 15 feet, versus the conventional seven-foot racks. This could involve the building having multiple stories of these taller racks.

With this configuration combined with higher energy density within battery modules themselves, the overall energy capacity will come close to meeting higher energy demands of these metro areas.

Going vertical is more complex

Though numerous projects are now on the drawing board, it must be noted that no high-rise BESS facilities are currently operational.

That's because going vertical requires careful evaluation of operations and maintenance impacts, including installation of robust safety systems. These analyses shift the focus from performance and design of modules toward a holistic look at the entire site. Considerations will be given, for example, to the broad operational effects of utilising heavy mechanical equipment in compact spaces that must operate safely.

Operating conditions for vertical BESS projects — as well as conventional projects — must be evaluated for each site. Storm and flood risks, relative humidity, seismic considerations and prevalence of salt within coastal air are among the environmental factors that can affect how the site will be designed and operated. The development of an operations and maintenance programme should include evaluating tolerances of all critical battery chemical processes in parallel with design, safety and equipment decisions.

There is a range of battery storage enclosure design options available, but all must account for the challenges of airflow, thermal management and accessibility for routine maintenance.

Enclosing a BESS facility in a multi-level steel structure may have advantages in accommodating equipment and incorporating critical safety systems. Alternatively, an open-air design, similar to a mezzanine, can create an accessible internal layout with systems on different levels. Many innovative variations of enclosed and open-air systems go beyond rack storage or purpose-built solutions. Most can accommodate modular design options and must be evaluated to select the right approach to meet unique project challenges and goals.

Other options for density

Battery suppliers are modifying cell and module designs and footprints, along with enclosure designs, to maximise battery density and to decrease spacing between enclosures. Numerous creative designs are currently being developed to make maximum use of space, thus increasing energy density for the project site.

One realistic constraint is the tonnage that can be feasibly transported to the job site and then lifted into place either by crane or forklift. This becomes a logistics challenge that starts as a total turnkey operation from the original manufacturer (primarily in Asia), transport to a container ship, offloading to a truck, transporting to the project site and final offloading to be set in place.

Planning for these highly energy-dense facilities also must factor in degradation of battery performance over time. The operations and maintenance strategy should incorporate a workable installation process to augment battery capacity over time as the overall system degrades, and/or to overbuild the system from the start to extend the time frame when augmentation is to occur and thus reduce the amount of battery augmentation required. Augmentation is explored in more detail on p.95.

What about safety?

Thermal runaways start as a short circuit within or external to the battery cell that triggers an exothermic reaction. The electrolyte is quickly vaporised in an off-gassing process that then proceeds to chemical reactions between the metals and minerals within the battery. These reactions produce enormous heat and explosive gases that can lead to fires and/or explosions if the event occurs within a contained space that is not ventilated.

The amount of heat and gas emitted during a thermal runaway event is dependent on several factors including the battery's state of charge — in other words, the amount of energy within a battery cell compared to its full capacity. That means that as battery cells are designed to store more energy, thermal runaways can become more intense. Thermal runaway events within NMC and NCA batteries generate more heat, which in turn causes a greater chance of thermal runaway propagating to other cells and modules. NMC and NCA battery chemistries also tend to have a flame associated with a thermal runaway event that can burn off the explosive gases that are emitted from the battery.

LFP technology does not emit as much heat during a thermal runaway event due to the chemistry and metals utilised, and thermal runaway events for LFP can have a lower risk of thermal runaway propagation. However, this chemistry can pose another set of risks.

Due to heat values being lower and lack of flame during a thermal runaway event, LFP chemistry can create more explosive gases that can raise the risk of explosions for these batteries located in contained spaces.

Fire suppression systems for all lithium-based technologies currently aim primarily to protect the building and related enclosures. There is no silver bullet for stopping thermal runaway within the lithium-ion technology group, simply because it is a chemical reaction that is hard to stop once it begins.

Effective thermal management programmes may utilise HVAC (Heating, Ventilation, and Air Conditioning) or chiller systems that aid in maintaining operational stability while lowering the risk profile for batteries to go into thermal runaway

Credit: Burns & McDonnell

The tonnage that can be feasibly transported to land-constrained sites is one consideration to make

due to thermal abuse. For example, direct expansion air handling units using refrigerant liquid are an option. Though these are reasonably cost effective to install, it must be noted that efficiency decreases over time. Central utility plant designs incorporating large centrifugal chillers are another option that can be used to distribute cooled water across large interior spaces. This proven technology offers the potential for redundancy and greater operational flexibility. Placement of racks in vertical configurations can add another element of thermal management by creating different heat zones and hot and cool aisles.

Other battery chemistry options

Though there are a number of non-lithium technologies in development, none to date can compare to the energy densities, better efficiencies and lower capital cost of lithium-ion batteries.

Several non-lithium battery technologies are proven but are unlikely to unseat the dominance of lithium-ion anytime soon because of its overall scale and the maturity of supply chains for commodities and materials needed for mass manufacturing. Unless a technology emerges with the scale and economic viability to support a robust supply chain, we are unlikely to see another dominant technology emerge in the utility-scale energy storage market in the near term.

If it weren't for the demand for batteries generated by the automotive industry, it's difficult to predict what type of storage technology would be emerging to meet the changing demands of the power industry. The known alternatives currently provide only a fraction of the energy density currently available from the primary lithium-ion battery technologies. The round-trip efficiencies — defined as the percentage of electricity put into storage that is later retrieved (i.e., the higher the round-trip efficiency, the less energy is lost in the storage process) — are not as high with alternative battery and other storage technologies at present.

Flow battery technologies, for example, offer certain advantages such as longer output duration and longer cycle life, but are hampered by lower round-trip efficiencies.

The market dynamics will change as more thermal power plants are retired. As dispatchable power units with capacity to provide many gigawatts of round-the-clock baseload power leave the market, use cases for long-duration storage will increasingly come to the forefront. Though market dynamics currently favour lithium-ion BESS facilities, that could change if these facilities were needed to provide round-the-clock power output. In order to offset the loss of a 600MW coal plant that had provided baseload grid power, it would require 14,400MWh over a single day.

No project is identical

It is difficult to forecast precisely how the battery energy storage market will evolve because it is changing so quickly. With battery technologies changing rapidly, project execution from year to year can look very different.

Energy density has become a priority for both operational and financial reasons, but to date most of the advances have come primarily from the batteries and secondarily from space optimisation within enclosures, along with creative enclosure configurations.

Energy density has become a priority for battery OEMs to help reduce total project cost and fit more capacity within small footprints. However, as the grid continues to change and the market shifts to deeper decarbonisation, it is unclear whether energy storage technologies will advance enough to meet the demand for baseload power. Ultimately, money is the driver within any market, and with the reduction of capital it may be that planners and policy makers begin to conclude that it is imperative to adjust policy or regulatory drivers to keep pace with continued increases in capital cost, or to provide further incentives to advance the development of lithium-ion technologies and other technologies.

One possible sign to indicate the technology advancement for the energy storage market is shifting is the development of battery cell types geared specifically to meet the needs of the power industry. The energy storage market previously used battery cells generally designed for the EV market and not necessarily designed with a use case for the storage market. By optimising the cell design for storage applications, it is likely that improvements in degradation and cycle life (i.e., life of the battery) can be achieved. In fact, some manufacturers are starting to offer a 25-year performance guarantee (based on one cycle per day) for certain battery types.

As more fossil-based thermal generation will be exiting the market, that capacity must be replaced by other sources along with energy storage playing a key role. As these energy storage systems are moving into more urban areas, energy density and land availability will be topics of great interest for the foreseeable future. ■

Authors

Josh Tucker is engineering manager for the Energy Storage Department at Burns & McDonnell. He has over 17 years of professional experience in electrical engineering, construction execution, and engineering and project management. He is responsible for all engineering for the energy storage business. His experience includes engineering and project management on EPC projects, engineering on power distribution systems, control interfaces, and protection for auxiliary electrical systems for coal fired power plants, simple and combined cycle power plants, and energy storage systems.

Ben Echeverria, energy storage regulations and compliance at Burns & McDonnell, is responsible for assisting the EPC project teams on energy storage projects globally, focusing on the safety, regulations and overall compliance of the interconnected systems. He helps to coordinate all the project stakeholders including project end-users or owners, insurance carriers, and direct communications with the project's Authorities Having Jurisdiction. He is a voting member on UL9540(A), UL1973, UL1741, and currently working on task groups within NFPA 855.

2024 Asia #1
Smart Energy Connected Expo

June 25(Tue.)-27(Thu.) 2024

KINTEX, SEOUL, KOREA

Visitors	Exhibitors	Value of Buyers Consulting(Est.)	Exhibition Space
25,000	500	US$0.575B	20,000Sqm

Booking Now!!

E. interexpo@infothe.com

www.exposolar.org www.essexpo.co.kr www.batteryexpo.co.kr www.derexpo.com

Early Bird Booking
15% OFF

Reserve Your Booth!

Australia needs renewables, transmission and lots of storage to quit fossil fuels

Decarbonisation | Australia runs a great risk of failing to meet its ambitious but achievable renewable energy goals, writes Stephanie Bashir, CEO of Nexa Advisory, who explains why utility-scale energy storage is among the crucial tools in the country's energy transition toolkit

The clean energy transition is critical to meeting Australia's climate targets, securing our energy future and 'keeping the lights on', as well as controlling cost of living pressures experienced by Australian households and businesses.

Australia has set goals to be net zero by 2050 (requiring a 43% reduction in carbon emissions), and 82% renewable electricity generation by 2030. However, right now, Australia is behind in this task to deliver a low-emission power system.

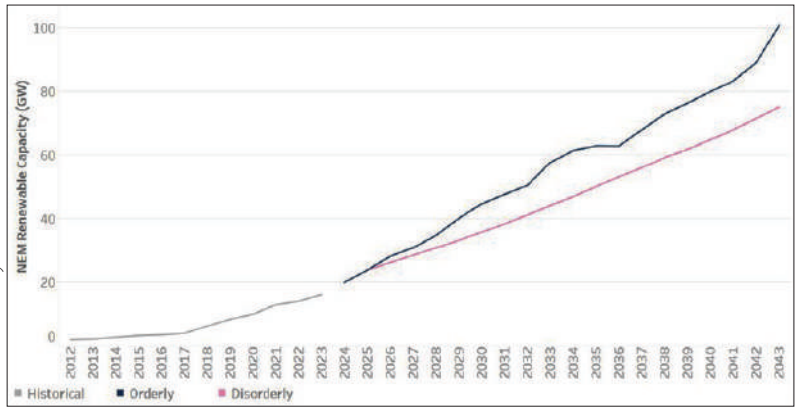
The scale of renewable power generation (of all types and size) that will need to be built is unprecedented. The Australian Energy Market Operator (AEMO)'s Integrated System Plan (ISP) 2022 "Step Change" scenario implies that we will require an additional 138.5TWh of wind and solar generation by 2035, and 197TWh by 2042, to replace retiring coal power stations.

The transmission that will be required to fully connect the new large-scale decentralised generation, rather than centralised fossil fuel power stations, is the equivalent of 25% of today's entire grid. It will now need to be built in less than seven years.

Although key transmission projects have been identified, across the country we are a long way behind on their development. No new interconnectors have been built in Australia for over 20 years and the five regulated Primary Transmission Network Service Providers (PTNSPs) have yet to demonstrate they have sufficient capabilities or scale to mobilise the resources necessary for Australia's transmission build out.

Lack of engagement with communities in the early-stage processes of major projects has evoked severe resistance, which has become a bottleneck to new renewable generation capacity.

The issues facing our energy transition are exacerbated by the global race to decarbonisation. New programmes in the United States of America, European Union and Asia are accelerating the clean energy transition by providing clear financial incentives (e.g. the Inflation Reduction Act, USA; the Green Deal Industrial Plan, EU). Australia will need to move quickly to ensure it can attract funding, materials and skilled people.



Credit: Nexa Advisory

Figure 1: Required renewable generation (dark blue) in the NEM as recommended in the 2022 ISP Step Change scenario versus projected future delivery of renewable generation (pink) based on past delivery rates (grey) showing the significant and escalating shortfall in delivering renewable generation required

Credit: Queensland government

Rendering of Stanwell Clean Energy Hub, a mixed technology development underway at the site of a retired fossil fuel plant

Political context

The 2022 "climate election" saw a change in Federal Government and the election of several climate-focused independent candidates. The notable increase in pace and ambition of the political leaders in this sphere over the past 18 months means that Australians are beginning to understand that the shift to a clean energy economy is in our national interest.

Since taking office in May 2022, the Australian government has established new and improved 2030 emissions reduction targets (43%, up from 26-28%), renewable energy targets (82%) and stronger industrial decarbonisation policies.

32GW Capacity Investment Scheme

In November 2023, Minister for Climate Change and Energy, Chris Bowen MP, announced a historic new plan to drive investment in renewable energy generation and storage.

A significantly expanded Capacity Investment Scheme (CIS) will now act as the central enabler of Australia's 2030 renewable energy target. Its key feature is that the federal government commits to underwrite up to 32GW of renewables and storage this decade to drive record levels

of private investment in solar, wind and batteries. For context, Australia's National Electricity Market (NEM) currently has an installed capacity of 64GW, of which approximately 24GW is renewables.

It is expected that the CIS will go a long way towards Australia meeting our 2030 climate targets but, just as importantly, the scheme keeps energy prices down because renewables are Australia's cheapest source of energy and it will help ensure replacement generation is available as the national fleet of unreliable coal-fired power stations shuts down.

At the energy consumer level, Australians remain prolific adopters of rooftop solar, and, reflecting the more ambitious approach taken by political leaders, we are increasingly aware that harnessing the nation's unique access to mineral resources and renewables-friendly weather conditions can benefit our families, towns and the nation as a whole.

However, despite these encouraging indicators of progress, we have a long way to go to meet climate targets and make the most of our natural advantages. AEMO forecasts the energy system will need a total of 44GW of variable renewable energy (+28GW), 15GW of storage (+13GW) and 10,000km of new transmission lines before 2030 just to keep the lights on. This is largely to replace coal-fired power stations as they are retired over the next seven to ten years.

Meeting this challenge will be critical to maintaining the confidence in and the buy-in for the transition, both at a political level and, more importantly, for businesses and families.

Challenges

Where Australia's energy market is concerned, understanding what needs to be done and getting on with the job of doing it are two very different propositions. While the 2022 Integrated System Plan provides Australia's energy system with a decarbonisation roadmap, it is becoming extremely unlikely that we will meet our 2030 and 2050 targets. There are two main reasons for this devastating conclusion.

First, we simply don't generate enough power from renewables to meet our energy needs. Second, even if we could generate enough renewable energy, we do not have the transmission infrastructure required to convey it to consumers. Major transmission projects take around seven years to go from start ("Phase One") to finish (connection).

Coal remains our primary source of energy and keeping these power stations open not only produces harmful emissions, it also increases energy costs to Australian consumers.

We can't afford to keep debating the same issues. We need to get really good at building renewable energy and transmission infrastructure, fast.

We need to rethink how our transmission market operates and how we gain the social acceptance that is required get wind and solar projects approved and connected. We will also need better investment, competition and collaboration.

Key transmission projects have been identified but they are a long way behind on development. The hold up is caused by a complex mix of regulation, social license and consumer trust challenges.

Transmission line infrastructure in Australia typically operates as a regulated monopoly market, with the five PTNSPs lacking the capability, capital or scale to mobilise the resources required for the transmission build-out.

Making matters worse, a lack of engagement with communities by the PTNSPs and governments in the early-stage process of development has prompted well-organised resistance to new transmission that is a practical and political dead weight to progress. While support for renewable energy projects has improved in Australia, support for overground transmission lines lags well behind, and is eroding further.

Transmission is now the missing link in Australia's energy transition. Winning the support of farmers and regional communities looms as one of the most consequential challenges for the energy sector and political leaders committed to transforming Australia into a "renewable energy superpower".

What needs to happen

The transmission infrastructure we need to build in regional areas, where the wind and solar farms are, are major constructions, and they can be an eyesore and impact land use. Getting community buy-in is absolutely essential.

One of the things we can do differently is to engage with local communities in a more genuine and meaningful way, listening to and taking account of the unique issues and challenges of each region. Communicating the unique role the regions have in hosting the clean energy transition, and ensuring communities obtain tangible and relevant benefits, can go a long way towards unlocking support.

Prioritising environmental impact and planning processes

Environmental impact assessments and planning reports are vital to the preservation of our native flora and fauna. But each of these reports takes at least three years to complete and this is time we do not have.

We are not advocating for cutting corners on protecting our nation's biodiversity. We do need to, and can, streamline environmental impact reports without shirking our duty of care, whether by cutting red tape and bureaucracy, or automating these very time- and resource-intensive processes where possible.

It certainly needs to be made clear as soon as possible where new generation and transmission infrastructure can and can't go. Land use mapping and engagement with key communities to set those boundaries is key.

Transmission supply chains are constricting the bottleneck

Expanding and strengthening our transmission infrastructure is Australia's biggest bottleneck in the energy transition.

Thanks to global 2030 and 2050 emissions targets and high fossil-fuel prices, the worldwide renewable energy sector is set to boom over the next three decades. Such rapid and massive growth will significantly increase demand for labour, expertise, materials and specialised electrical equipment.

We are in a global race for supply chains and procurement—and as a result, delivering transmission cost-effectively, efficiently and on time will be difficult.

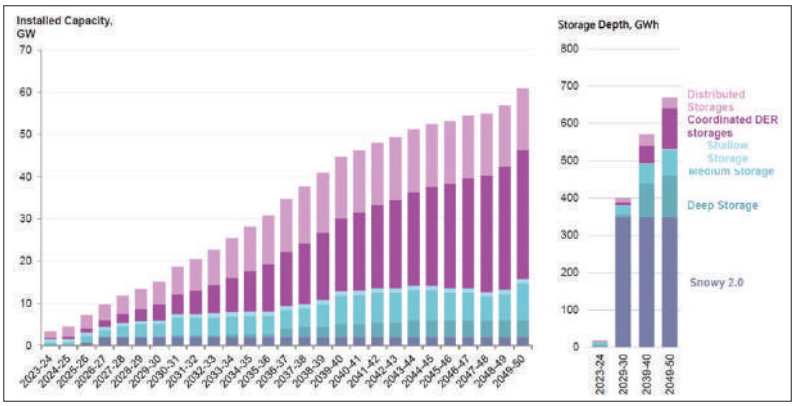
This means attracting investors, and stimulating competition through open tenders which will provide access to global procurement and supply chains to help us speed things up.

Distributed energy resources (DER) can be a key contributor

To meet our 2030 renewable generation target, the 2022 ISP suggested that we need a total capacity of 79GW, 35GW of rooftop solar PV and 44GW of large-scale wind and solar generation.

So far, we have 21GW of rooftop solar PV already installed, and 25GW of large-scale renewable generation built. So, to meet our 2030 target we need a further 33GW of renewable generation: 14GW of rooftop solar PV and 19GW of large-scale renewables.

Breaking this down further, we need to add approximately 6GW of new renewable generation each year. Excitingly, the combination of rooftop and large-scale renewable and storage development is



Credit: AEMO's 2022 ISP

AEMO Integrated System Plan - Expected Energy Transition to 2050 (Storage)

almost meeting that annual requirement.

In 2022, Australia added 2.8GW of new large-scale renewable generation and storage, and 2.7GW of residential-scale rooftop solar PV (3.3GW in 2021). However, the balance between large- and small-scale solar PV is different to that envisaged in AEMO's 2022 ISP.

As noted above, accelerating the build and connection rate of large-scale wind and solar generation is proving difficult.

The current rate of annual rooftop solar PV installations (2.5GW per year) means that, in the next seven years, DER could "take up the slack" and contribute a minimum of 18GW of additional renewable generation capacity, which is over 55% of the 33GW required to hit the Federal Government's 82% renewable energy target.

Energy storage: Opportunities at every scale

Storage capacity at all scales will be required to ensure a reliable energy system. This includes the storage available on the distribution network as well as in homes, such as community batteries and virtual power plants (VPPs), and demand-side management.

The 2022 Integrated System Plan sets out the scale of the storage challenge: today, Australia has a little less than 2GW of storage connected to the energy system. By 2030, we need a total of 15GW of storage, and by 2050 we need 61GW. Even with a supercharged Capacity Investment Scheme (which aims to secure 9GW of dispatchable capacity this decade) and the rapid rate that batteries can be deployed, that's a big ask.

Small-scale storage in households can play a critical role in stabilising the enormous amount of energy being created on Australian rooftops.

Increasingly, rooftop solar and batteries are being paired together in new installations (nearly 50% of new rooftop solar PV installs are accompanied by a battery, according to the Australian Energy Council). This is encouraging. However, while this uplift has made storage more affordable, residential batteries remain out of reach for most households due to cost — likely to remain the case for the foreseeable future without government intervention.

Utility-scale storage is critical to a successful transition

Utility-scale storage will be needed to "firm" Australia's clean energy grid to stabilise a bigger and more complex energy network and ensure the lights stay on.

South Australia is the home of the world's first "big battery," the Hornsdale Big Battery. Since that was connected, large-scale batteries in Australia have been deployed faster than was expected.

Batteries provide a number of benefits to the system and overall transition, which are sometimes underestimated or not understood.

Utility-scale storage:

- Provides "frequency" support which helps to stabilise the grid in real time
- Supports the power system's integrity and the network in case of exceptional events.
- Allows "arbitrage" when intraday prices are volatile — with the increase in variable renewable generation in the system and the exit of coal, this will be a significant commercial incentive in Australia.
- Provides inertia services as coal power plants phase out, to solve a network issue in the system.
- Smooths the intermittency of renewables—firming is critical to a 100% renewable energy system.

What is needed

Australia's economy remains dominated by fossil fuels, and our national emissions continue to rise. Clearly, there is plenty of work to be done to add more speed and ambition to Australia's energy transition.

Nexa Advisory and our partners across industry and the community are focused on driving this ambition. We have identified the solutions to roadblocks holding Australia back from accelerating its energy transition and meeting our generation and emissions reduction targets:

To roll out transmission infrastructure at speed, we need to open up regulated monopoly markets to competition and investment (as the Victorian government has done) and we need to design the planning approvals process in line with energy generation capacity requirements identified by energy market operators.

The pilot phase of the Capacity Investment Scheme, announced by state and federal governments in December 2022, has seen Australia build more utility-scale storage ("big batteries") than ever before. But to meet the "gap" in dispatchable energy caused by forecast coal-fired power station closures, governments will need to ensure the next stage of the CIS delivers on its promise of 32GW of new variable renewable energy and storage by 2030. That could drive the need to legislate the scheme to ensure political endurance and investor certainty.

To drive decarbonisation at the household level, governments should look to expand the Small-scale Renewable Energy Scheme to include household batteries and legislate a national mechanism to provide investment. It also means prioritising tariff reform to ensure people are incentivised to build trust and allow for innovation in service delivery.

Australia already has smart solutions to meet new and improved energy targets. The science and economic cases have been made and political will is beginning to align with 2030 climate targets. What's left is finding the money, the ambition and the leadership to realise our potential and become a world-leading renewables-powered clean economy. ■

Author

Stephanie Bashir has over two decades of experience in the Australian energy sector with extensive experience in commercial, regulation, energy policy, government and stakeholder engagement. She is the founder and CEO of Nexa Advisory advising a broad range public and private clients including renewable energy developers, investors and climate impact philanthropists to help accelerate efforts towards a clean energy transition.

Energy Storage NEWS PREMIUM

Get the inside track on the energy storage sector

Enjoy 12 months of exclusive analysis

Premium subscription benefits include

ESSENTIAL & FRESH ANALYSIS

- Regular insight and analysis of the energy storage industry's biggest developments
- In-depth interviews with the industry's leading figures

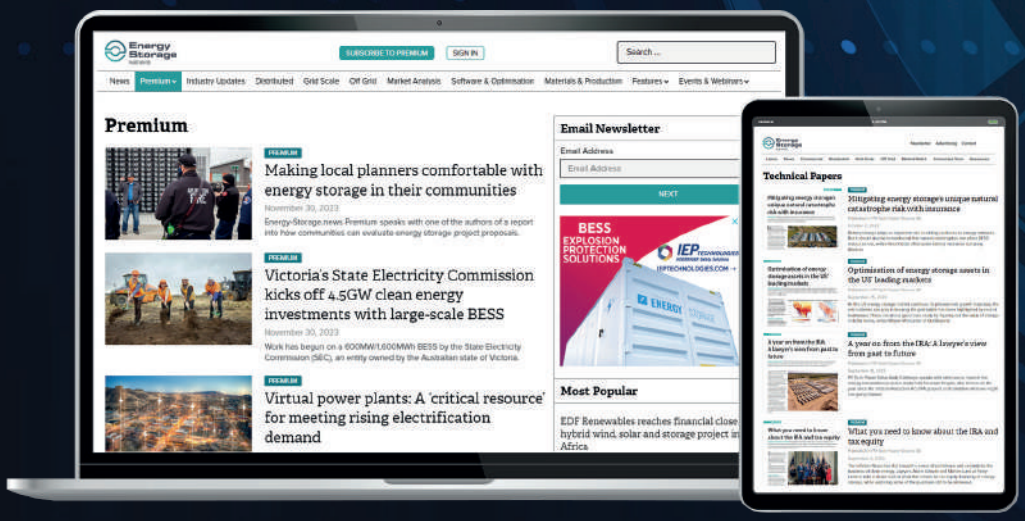
PV TECH POWER JOURNAL

- Unlimited digital access to the PV Tech Power catalogue, previously published by PV Tech, dating back to 2014. Including more than 30 editions

EVENTS

- Discounts on Solar Media's portfolio of events, in-person and virtual

Just $249 USD/year



Subscribe at: energy-storage.news/premium

SCAN ME

advertisers & web index

Advertiser	Web address	PAGE No.
Energy-Storage.news Premium	www.energy-storage.news/paywall-tags/premium	105
Energy Storage USA	storageusa.solarenergyevents.com	92
EU PVSEC	www.eupvsec.org	49
Expo Solar Korea	www.exposolar.org	101
Hoymiles	www.hoymiles.com	19
Huawei	solar.huawei.com/en	5
Intersolar	www.intersolar-events.com	26-27
Intersolar America	www.intersolar.us	45
JA Solar	www.jasolar.com/html/en	IBC
Large Scale Solar Europe	lss.solarenergyevents.com	53
Large Scale Solar USA	lssusa.solarenergyevents.com	81
LONGi	www.longi.com/en/	IFC
PV CellTech Europe	www.pvtechconferences.com/pv-celltech-europe	15
PV Expo Japan	www.wsew.jp	77
PV ModuleTech Bankability Ratings	marketresearch.solarmedia.co.uk	69
PV ModuleTech USA	moduletechusa.solarenergyevents.com	58
PV Tech	pv-tech.org	57
PV Tech Premium	www.pv-tech.org/paywall-tags/premium	37
RE+ Hawaii	re-plus.events/hawaii	73
RE+ Northeast	re-plus.events/northeast	87
Risen	www.risenenergy.com	11
SNEC	pv.snec.org.cn	31
Solar Finance & Investment Europe	financeeurope.solarenergyevents.com	85
Stäubli	www.staubli.com/gb/en/corp.html	43
Tongwei	en.tw-solar.com	7, 8-9
Trina Solar	www.trinasolar.com/en-glb	OBC
World Future Energy Summit	worldfutureenergysummit.com	64-65

next issue

Module quality

The US interconnection challenge

De-risking floating solar

SUBSCRIBE TODAY! www.pv-tech.org/power

JA SOLAR

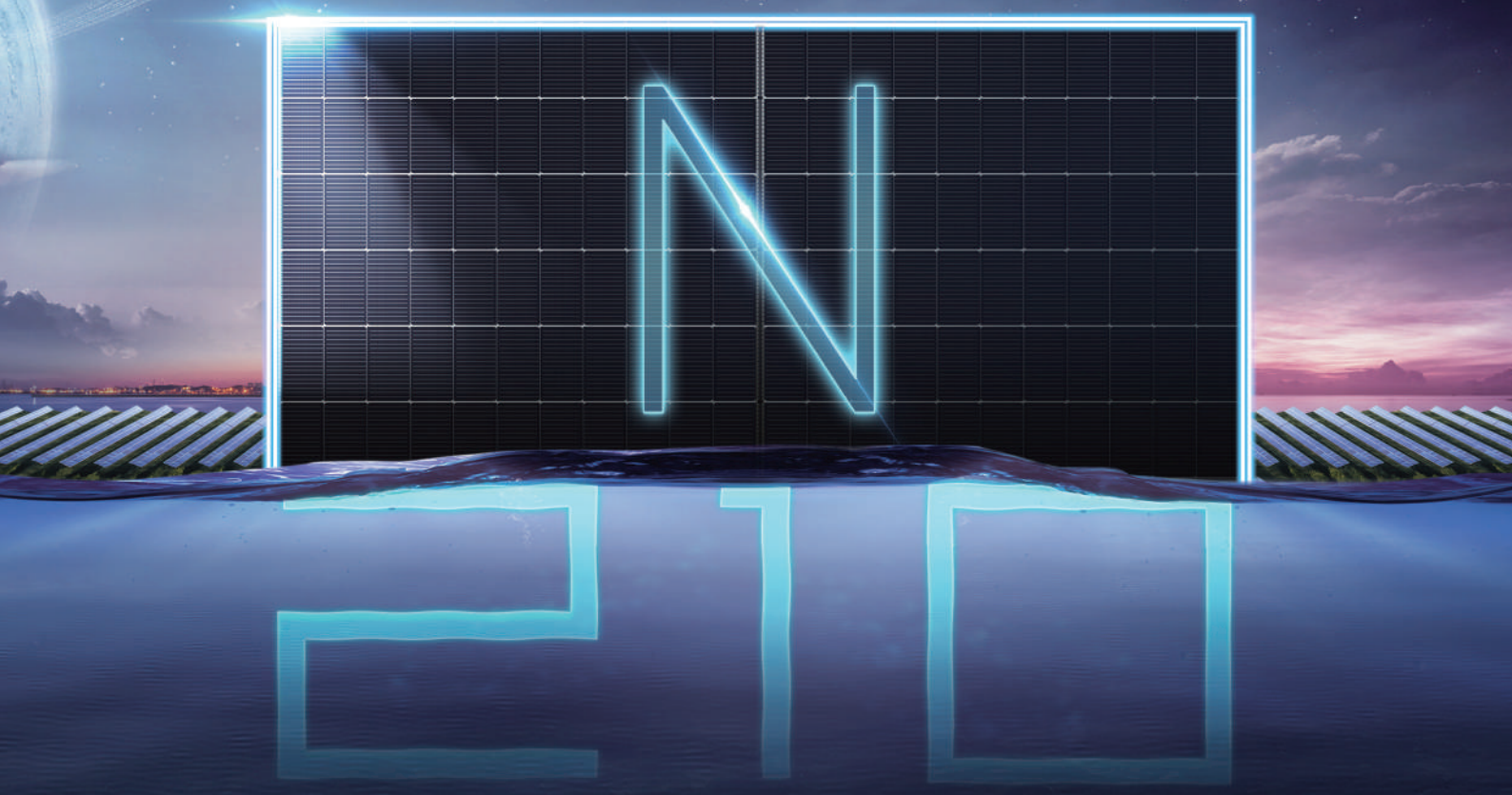
DEEP BLUE 4.0 Pro

BYCIUM+	22.5%	Higher	630W
Cell technology	Module efficiency	Reliability	Power

www.jasolar.com

Trinasolar

Leading in the N era of solar energy



Vertex N