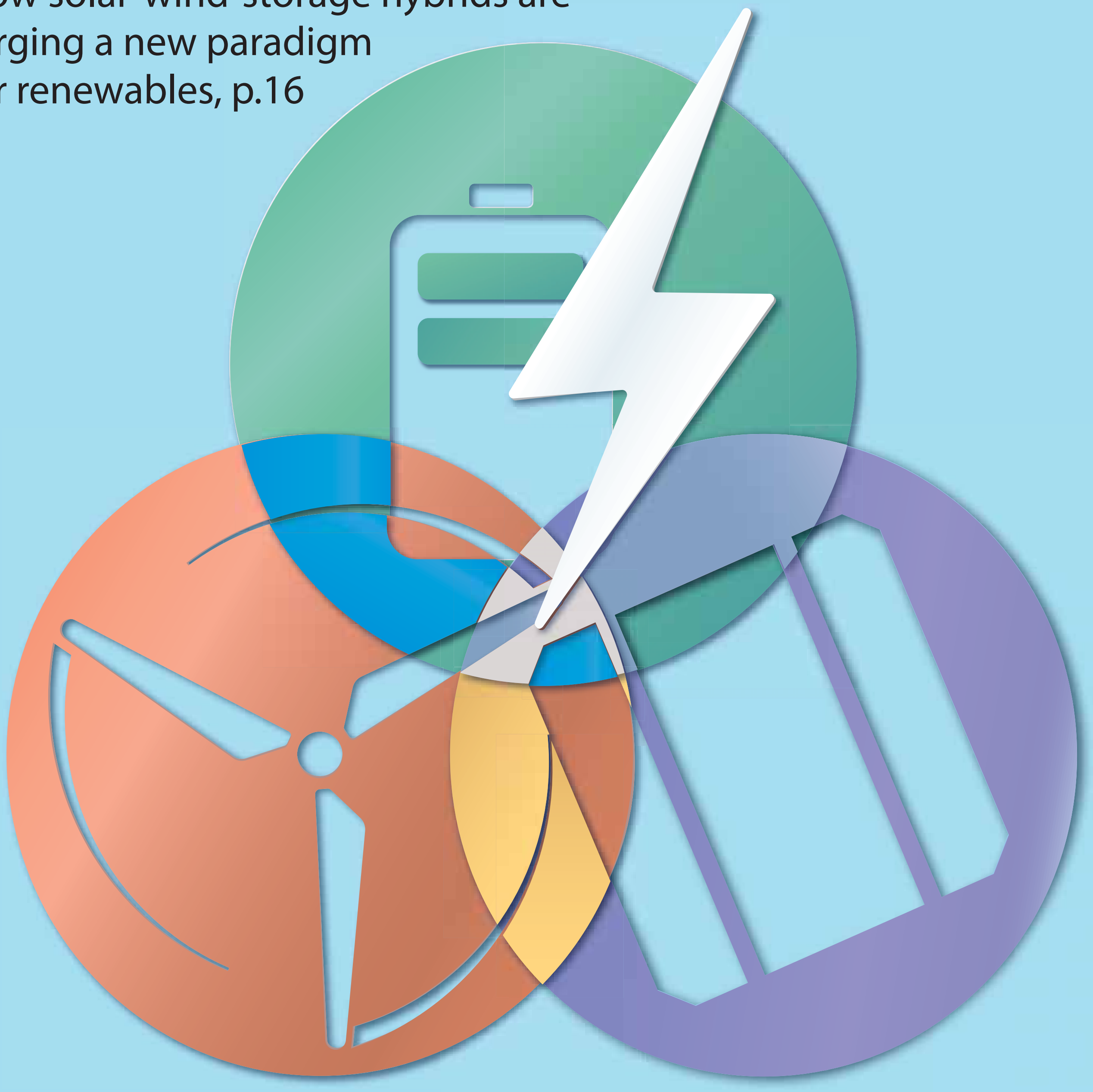
PV POWER TECH

Volume 22 | PV POWER PLANT TECHNOLOGY AND BUSINESS | February 2020

THE POWER OF MANY

How solar-wind-storage hybrids are forging a new paradigm for renewables, p.16



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

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Printed by
Buxton Press Ltd., Derbyshire

PV Tech Power Volume 22, 2020
ISSN: 2057-438X

Cover illustration by Adrian Cartwright, Planet illustration

Introduction

Welcome to volume 22 of *PV Tech Power*, the first volume of a new decade. Solar starts the 2020s riding the crest of a wave, having last year witnessed record low prices in tenders spanning multiple continents. The technology is being utilised in more applications than ever before and embracing merchant-based business models in markets years ahead of expectation.

The industry is maturing at a rate of knots and an example of this can be seen in this volume's cover story, which seeks to get under the skin of hybridisation. Combining wind and storage with solar looks primed to be one of the most interesting trends in large-scale renewables deployment in the early stages of this decade. Developers, funders and utilities alike are exploring the involvement of not just one clean energy technology, but combining the forces of three or more to strengthen the case for renewables all over the globe.

As you'll read (p.16), there are hurdles to overcome and technical challenges to navigate but given the sheer size of the potential market, those willing to tackle them are numerous. It's of little wonder that one chief executive of one major multi-national utility said he expects such developments to be the "new normal" within just 18 months.

We've further examples of solar's maturation littered throughout the pages of *PV Tech Power* 22. We've an in-depth examination of a new solar system design that developer BayWa r.e. promises will reduce costs and speed up the deployment of floating solar (p.42), while there is also a technical briefing from RES on the lessons it has taken away from designing and integrating bifacial-powered PV systems (p.37).

Elsewhere, leading developers give us the full story on how large-scale solar-plus-storage developments, and standalone storage for that matter, are coming of age in North America, and we've a detailed analysis of India's 100GW solar PV target, uncovering what the chances are of Narendra Modi's now famous ambition being realised by 2022. As you'll read (p.24), things aren't looking good.

Market nuances aside, it's become increasingly clear that as an asset class, solar continues to evolve and adapt to the application it finds itself in, driven predominantly by its financiers, developers and innovators. If the 2010s saw solar find its feet, the 2020s will be the decade it sets new standards for clean power generation.

So, here's to another decade of roaring solar. Thank you for reading, and I hope you enjoy the journal.

Liam Stoker
Editor in chief

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EUROPE

Mega-solar

Iberdrola completes 'Europe's largest', 500MW solar giant

Multinational utility Iberdrola has completed the giant 500MW Núñez de Balboa solar farm in Spain's Extremadura region, claiming it to be Europe's largest completed solar project. Iberdrola confirmed that the site had been completed in around one year and had subsequently received its commissioning permit from Spain's Ministry for Ecological Transition. Red Eléctrica de España, Spain's grid operator, has now started energisation tests and operations are slated to start in Q1 2020. Iberdrola is placing the project at the centre of a major strategy to help relaunch renewables development in Spain and deploy around 3GW of clean energy generation by 2022, the majority of which has been pegged for the Extremadura region. Around €290 million (US$325 million) of investment has supported the project, with the utility pocketing green financing from the European Investment Bank and Spanish state financial agency Instituto de Crédito Oficial. Around 1,430,000 solar panels have been installed and the project is expected to generate some 832GWh of power each year.

Credit: Iberdrola.

The Núñez de Balboa project during its construction

Portugal

Portugal confirms 2020 solar auction details

Portugal is to follow its record-breaking solar auction of 2019 with a fresh tender this year, with a tentative launch date now set towards the end of Q1 2020. The country's Environment and Climate Action Ministry said it expects this year's PV tender to get underway "by the end of March 2020". Asked about a potential separate storage tender – a move the government had discussed last year – a ministry spokesperson said these technologies will be incorporated to the PV auction. "A new bidding option shall be provided [under the solar tender] to promoters who wish to deploy a storage technology," the spokesperson explained. "These bidders will compete, in equal terms, with those choosing one of the previous bidding options (fixed tariff or payment to the system)."

Italy

Enel confirms multi-billion-euro renewables investment upgrade

Enel has announced a multi-billion-euro upgrade to its renewables investment programme as the utility plans to derive 60% of its power generation from renewables by 2022. More than €28 billion (US$30.85 billion) is now to be invested by the firm in renewables and clean technologies between 2020 and 2022, up 11% on its previous plan. The Italy-headquartered utility will now seek to invest some €14.4 billion (US$15.8 billion) in new renewable generation capacity, aimed at bringing forward more than 14GW of new renewables by 2022. That amounts to a 22% upgrade on its previous plan and will help reduce coal capacity significantly compared to 2018 levels. Renewables' share of Enel's generation capacity is expected to reach 60% within three years as a result.

Equinor

Equinor increases stake in Scatec Solar

Norwegian state-owned energy giant Equinor has increased its stake in international solar developer, Scatec Solar. The oil and gas major confirmed late last week that it had taken an additional 6.5 million shares in the Oslo-headquartered solar firm, taking its total shareholding to 15.2%. The transaction came at a total purchase price of NOK724 million (US$78.5 million), a transaction which values Scatec Solar at around US$1.5 billion. It comes just over a year after Equinor, formerly known as Statoil, first acquired an interest in the developer, picking up a 10% stake in November 2018. It was shortly followed by the completion of a 162MW solar project in Brazil that the duo worked on together. Pål Eitrheim, executive vice president at Equinor's New Energy Solutions division, said the deal would further strengthen the company's "exposure to the fast-growing solar energy sector".

France

France must double installed PV capacity by 2023 after roll-out flatlines

France has four years to double its installed PV fleet to keep up with government plans after years when annual additions have failed to keep up with other major European markets. The country's installed PV capacity grew by 890MW in 2019 to reach a cumulative 9.43GW at the end of the year, according to stats recently published by French renewable association SER, grid operator RTE and other government bodies. The current 9.43GW market size places France a long distance from the 18-21GW goal that, as SER and others noted in the statement, the country is aiming to hit by 2023. Under government plans, installed PV must grow further still after that point, reaching 35.6-44.5GW by 2028. The ambitions by Paris policymakers to quadruple capacity within less than a decade follow years of considerable, yet unchanging annual growth. From 2012, yearly PV installations have invariably remained in the 500MW-1.1GW range, according to historic IRENA figures.

Power pricing

Cannibalisation to threaten Europe's utility-scale solar drive

Wholesale price cannibalisation poses the most significant threat to Europe's utility-scale solar industry, a panel of investors has heard. Speaking at the Solar Finance & Investment Europe conference, organised by *PV Tech Power* publisher Solar Media, Michael Ebner, managing director for infrastructure at investment giant KGAL, said that the prospect of "unknown


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cannibalisation", caused by an influx of zero marginal cost renewables on European grids, was a "threat to the industry" as deployment looks set to accelerate. This has caused significant volatility with power price curves, Ebner said, with other investors on the panel remarking on how even the most pessimistic of price curves from years ago would appear optimistic if published today. Ebner did, however, conclude that of all renewable generating technologies, it was solar – hallmarked by its continuing declines in price – that could hurdle cannibalisation.

AMERICAS

Tesla warranties

Panasonic eases concerns over Tesla designated solar panel product warranties

Panasonic has warned US solar installers about Tesla selling a "large quantity" of its solar panels designated to the company to an unidentified third-party wholesaler that would not be covered by Panasonic product warranties. But Panasonic Corporation of North America later confirmed that there would not be any impact to consumers in relation to product warranties. The company clarified that Panasonic Life Solutions Company of America (PLSCA) would "no longer be the entity providing the services for certain solar modules." Panasonic said that product warranties would be managed "by a different Panasonic entity, so there is no impact to customers".

SunPower

SunPower to cut up to 160 jobs amidst restructuring

US solar firm SunPower is to cut up to 160 jobs as part of a restructuring plan following the spin off of its manufacturing operations. In a Securities and Exchange Commission filing made on 27 December 2019, SunPower said it was adopting a restructuring plan to "realign and optimise" its workforce in the wake of its decision to separate its solar panel manufacturing business into a separate listed entity, dubbed Maxeon Solar. SunPower revealed that it will shed up to non-manufacturing 160 jobs, with affected employees to leave over the course of the next 12-18 months. Between 65 and 70 jobs will be lost from its SunPower Technologies business units. Those affected have "largely" been informed, the company said, and are expected to leave the company after the spin off of Maxeon completes. A further 80 to 90 employees are to leave SunPower's Energy Services business between Q4 FY 2019 and the first half of 2020 as it "hones its focus on distributed generation, storage and energy services".

Credit: SunPower.

Up to 160 non-manufacturing jobs will be lost as a result of SunPower's restructuring

Company news

First Solar to pay US$350 million to settle 2012 class action case

First Solar has agreed to settle a 2012 class action lawsuit to the tune of US$350 million. The settlement is subject to approval by the United States District Court for the District of Arizona.The case, titled Smilovits v. First Solar, Inc., et al related to claims of false and misleading statements regarding the company's financial performance and prospects, after announcing a major restructuring plan, including two manufacturing plant closures in Frankfurt (Oder), Germany and idling four production lines in Kulim, Malaysia in April 2012. The class action lawsuit sought damages, including interest, and an award of reasonable costs and attorneys' fees, while the company had stated it believed it had "meritorious defences" and would vigorously defend the action. First Solar said it would incorporate the US$350 million settlement within its fiscal year ended 31 December 2019.

Tesla solar roof tile rival heads for Chapter 7 bankruptcy

RGS Energy (Real Goods Solar), a potential rival to Tesla's solar tile roof system, has succumbed to Chapter 7 bankruptcy, having failed to raise further capital on long-standing operating losses. RGS Energy had attempted to shift away from its loss making residential solar installation business in the US and supply subcontracted solar shingle roof systems to installers, house builders and conventional roofing companies after securing the rights and subsequent UL certification for the former Dow 'POWERHOUSE' 3.0 technology in November, 2018. Despite claiming significant interest in the product, notably from conventional roofing companies, revenue directly from the POWERHOUSE product had amounted to only US$367,000 for the first nine months of 2019, while third quarter 2019 POWERHOUSE sales totalled US$197,000.

Fraud

DC Solar execs plead guilty to 'biggest fraud' seen in California district

The executives behind a high-profile US solar scandal from recent years could spend decades in prison, after admitting to defrauding investors under a Ponzi-style scheme. The owners of now-bankrupt firm DC Solar have now pleaded guilty to various criminal charges after a still-ongoing government case accused them of "duping" investors of some US$1 billion, supposedly used later to bankroll a "lavish" style. In a statement issued in January, the US Attorney's Office said Jeff Carpoff has admitted to conspiracy to commit wire fraud and money laundering, while his spouse Paulette Carpoff admitted to a conspiracy to commit an offense against the US and money laundering. The duo, prosecutors said, "wove


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a web of lies and deceit" as they used their firm – a maker of mobile PV generators and light towers – to defraud investors on a "massive" scale. The government regards the case as the "biggest criminal fraud scheme" ever seen in California's Eastern District.

Finance

BlackRock keen on C&I PV, storage as new renewable fund hits record close

Rooftop solar, energy storage and other less-mainstream green energy technologies are among the targets of a new colossal renewable fund, the creation of the world's largest asset manager. BlackRock amassed over US$1 billion in its efforts to raise capital for its latest fund for global renewables, the third of a series it launched in 2011.The first US$1 billion, collected from 35 American, European and Asian institutional investors, takes the Global Renewable Power III (GRP III) fund closer to its US$2.5 billion final target. The "record" raise was achieved within six months from GRP III's launch in Q2 2019, BlackRock told sister publication PV Tech. According to the spokesperson, GRP III will focus on wind and solar plays in OECD markets, a group spanning Europe, the US, Turkey, Australia, Japan, Israel, Chile and others. In principle, the fund's US$2.5 billion pot will be equally split between the US, Europe and the Asia-Pacific region.

Trade tariffs

Trade tariffs have caused 'devastating harm' to US solar industry

Tariffs introduced to imported solar cells and modules have caused "devastating harm" to the US solar industry, new analysis compiled by the Solar Energy Industries Association has claimed. SEIA's analysis claims that trade tariffs have prevented billions of dollars in new private sector investment, cost more than 62,000 jobs and meant that 10.5GW of installations have collapsed. Furthermore, the trade body's analysis claims that each day the trade tariffs continue to be in place costs the US more than US$10.5 billion in lost economic activity, while each new job in manufacturing created by the tariffs costs an additional 31 jobs further down the supply chain. SEIA has also raised concerns that the Section 201 tariffs stand to unduly hit nascent markets in the US such as Alabama, Nebraska, Kansas and the Dakotas, claiming these markets "won't be able to get off the ground" as the trade barriers are making the technology uncompetitive.

Credit: Gag Skidmore.

Further analysis of Trump's tariffs revealed they had failed to stimulate growth of US-based solar cell manufacturers

Tesla

Tesla hits new storage record as PV installs tumble year-on-year

Tesla expects solid 2020 on the renewable deployment front after its figures for 2019 proved stellar for storage installs but far less so for PV additions. Tesla's full-year results for 2019 the firm reached 173MW solar installations throughout last year, a far cry from the volumes it had recorded in 2017 (522MW) and 2018 (326MW). Tesla's year-on-year slump of solar installations took place despite a slight recovery towards the second half of 2019. Quarter on quarter, the firm's PV roll-out dipped between Q1 2019 (47MW) and Q2 2019 (29MW) but then bounced back in Q3 2019 (43MW) and Q4 2019 (54MW).

MIDDLE EAST & AFRICA

Saudi Arabia

Saudi Arabia sets sights on 1.2GW PV pipeline

Saudi Arabia has pressed ahead with its renewable energy programme, launching proceedings for a PV-only new round even as the earlier phase has yet to allocate contracts. In January, the Middle Eastern kingdom said the third round of its green energy tender scheme will pick developers for four solar projects, representing a combined 1.2GW of PV capacity. The third tender's two-tiered design will see 200MW of the 1.2GW portfolio developed in the form of two 'Category A' plants, dubbed Layla (80MW) and Wadi Al Dawaser (120MW). The Renewable Energy Project Development Office (REPDO) – the state agency running the tenders – said the other 1GW will be split between 'Category B' Ar Rass (700MW) and Saad (300MW).

UAE

Solar gaining 'maximum traction' in UAE

Solar PV will play a critical role in the energy transition in Abu Dhabi and the wider United Arab Emirates, with deployment expected to ramp up as renewable energy targets near. Speaking at the World Future Energy Summit (WFES) in January 2020, H.E. Mohammed bin Jarsh Al Falasi, undersecretary at the Abu Dhabi Department of Energy, said solar was gaining "maximum traction" in the emirate following the completion of key utility-scale solar farms and some pilot projects examining the potential role for solar on Abu Dhabi's power grid. Al Falasi said the emirate was proud of the progress it had made in solar deployment, with Abu Dhabi emerging as an early adopter of both conventional and virtual power plants.

South Africa

South Africa plans three more 'fast-tracking' renewable energy zones

South Africa is set for three new special geographic zones for fast-tracking renewable energy projects, following the government's recent release of multi-gigawatt PV and wind plans up to 2030. The scheme to add three Renewable Energy Development Zones (REDZs) to the existing eight identified back in 2015 was announced this week by the Council for Scientific and Industrial Research (CSIR) in collaboration

Bifacial

Qatar utility hails ultra-low tariff in tender for 800MW bifacial PV park

A Qatar utility has secured what it claims is a world record-breaking tariff of QAR0.0571/kWh (US$0.01569/kWh) under a tender for the country's utility-scale debut, beating last year's low price milestones in Portugal and Dubai. The project was awarded in recent weeks to a Marubeni and Total consortium, which had originally submitted a price of QAR0.0636/kWh (US$0.01747/kWh) for the 800MW development planned 80 kilometres from Doha. The Qatar General Electricity & Water Corporation, also known as Kahramaa, pulled the tariff down by fractions of a cent – and in doing so, secured a self-styled world record for cheap solar electricity. "Kahramaa has signed the power purchase agreement (PPA) with the project company, with an aim to achieve financial close of the project in May 2020," the utility said in its updated statement.

Credit: Qatar General Electricity & Water Corporation

The signing ceremony of the 800MW facility

with the national Department of Environment, Forestry and Fisheries. The new additions would support the Integrated Resource Plan 2019 (IRP), which aims for 6GW of solar and 14.4GW of wind up to 2030, having been gazetted by the Minister of Mineral Resources and Energy last month. The new areas have been chosen based on clean energy resource conditions, where mining industries are located, and proximity to areas in need of "rehabilitation", with local coal power capacity to be decommissioned in the near future.

Ethiopia

ACWA Power progresses Ethiopia solar bid with 'first of a kind' 250MW solar PPA

ACWA Power has penned two long-term power purchase agreements (PPAs) with Ethiopia's state-owned Ethiopian Electric Power for 250MWac of solar in the nation. ACWA will sell the power at a price of US$0.02.526/kWh – what was billed as a record low for Africa back in September – over the course of 20 years, while implementation agreements were also signed with the Government of Ethiopia. The project developer heralded the agreements as a first of their kind for an Ethiopian utility. Letters of intent were exchanged between ACWA and Ethiopia's finance ministry in October this year, following ACWA landing contracts within the first round of auctions under Ethiopia's solar programme. ACWA fended off stiff competition from 12 pre-qualified bidders within the auction process.

ASIA-PACIFIC

Capacity expansions

Tongwei investing US$2.86 billion in new 30GW solar cell manufacturing hub in China

Major polysilicon and merchant solar cell manufacturer, Tongwei Group and subsidiary Tongwei Solar are to significantly increase high-purity polysilicon production and high-efficiency solar cell production over the next five years. Tongwei said that a new 30GW solar cell manufacturing hub in Jintang County, Chengdu, China would be built over a five-year period at an estimated cost of RMB 20 billion (US$2.86 billion) and be built on 600 acres of land. The project would be built in four phases in which the first and second phases would cost around RMB 4 billion (US$573 million) each to expand solar cell capacity by 7.5GW, up from 20GW currently. The first phase of the 7.5GW solar cell project would be started before March 2020 and is expected to be completed during 2021. Phase two will bring the new cell capacity to a total of 15GW.Tongwei expects to reach a cell capacity of 60GW in 2022 and could expand capacity to between 80GW to 100GW in 2023, subject to demand.

JA Solar unveils plans for new 5GW cell, 10GW module production facilities

JA Solar has unveiled plans to bolster its output with a new cell manufacturing facility and module production plant. In a filing with the Shenzhen Stock Exchange JA Solar said it would be investing some 6.6 billion Yuan (US$948 million) in the two facilities, which are to be developed in Zhejiang.

A framework agreement with the management committee of the Yiwu Information Optoelectronic High-tech Industrial Park – the location of the new facilities – has been signed. A 5GW cell production facility and a 10GW module production plant will be developed, costing 2.775 billion Yuan (US$399 million) and 3.825 billion Yuan (US$549 million) respectively. The filing states that the new facilities are being pursued to "seize market development opportunities", however the two facilities are expected to take some four years to come to fruition.

LONGi planning 40GW mono wafer expansion as 100GW capacity target looms

LONGi Green Energy Technology Co has signed a new agreement to build a new 20GW wafer plant in Chuxiong, Yunnan province with further plans to expand capacity to 40GW in the future. LONGi has signed an investment agreement with Chuxiong Yi Autonomous Prefecture for an initial 20GW mono wafer plant that LONGi is expected to invest around RMB 2.0 billion (US$286 million) in manufacturing equipment. The company had recently announced further mono ingot expansions for 2020 and beyond. The latest wafer expansion plans are in-line with those separate expansions to keep balanced capacity of bot ingots and wafers. However, the latest wafer expansion plans at Chuxiong include the expected further expansion of the new facility to 40GW. LONGi did not provide timelines for the latest wafer expansions in China.

Coronavirus

Coronavirus expected to impact solar industry supply chain

ROTH Capital Partners told investors that the recent outbreak of the Coronavirus in China is likely to impact the solar industry supply chain, due to extended work stoppage in eight provinces, many being key solar manufacturing hubs, through 9 February. ROTH said in an investor note that checks made, indicated many PV manufacturers continued some level of production during the Chinese New Year holiday period. "We've been told that the "not to return to work" order, i.e. work stoppage, may not be applicable to companies that never dismissed employees. We are still trying to confirm this. Our guess is that while most of the facilties have been up and running, they likely have not been running at 100% staffing," ROTH said in the investor note. Reports then suggested the CPIA (China Photovoltaic Industry Association) was to seek Chinese government support for the sector as the coronavirus continues to spread. The CPIA deputy secretary, Liu Yiyang told Bloomberg that the solar sector needed support, including perhaps interest-free loans for upstream manufacturers, while potentially seeking delays to downstream PV power plant FiT changes, due to the difficulty project developers would face meeting 2019 subsidy quota deadlines fast approaching for the end of March, 2020.

Credit: LONGi

LONGi said it had activated contingency plans to minimise disruption during the coronavirus outbreak

Bifacial

JinkoSolar sets mono-PERC bifacial solar module efficiency improvements

Leading 'Solar Module Super League' member, JinkoSolar has set new conversion efficiency improvements for its P-type PERC and N-type 'HOT' bifacial solar modules that have been verified during testing conducted by TÜV Rheinland. JinkoSolar reported that its N-type mono HOT bifacial solar module had achieved conversion efficiencies of 22.49% as verified by TÜV Rheinland. A P-type mono PERC module also set a new performance record with a conversion efficiency of 21.82%. Both modules were said to benefit from a number of new and refined technologies, which included newly developed ARC and advanced metallisation technologies for its N-type module, without providing further details.

Vietnam

Vietnamese PM demands solar auctions in place of subsidies

Vietnam's second-round solar feed-in tariff (FiT) could be cut short in favour of an auction model after the prime minister Nguyen Xuan Phuc issued an order highlighting shortcomings in the way the Ministry of Industry and Trade (MOIT) has handled the roll-out of solar power. The shock move, which still needs to be released in the form of regulations by the Ministry of Industry and Trade (MOIT) to come into fruition, would remove FiTs for future solar projects unless they have already signed a power purchase agreement (PPA) and can become operational in 2020, according to the document seen by sister publication PV Tech. As the original project completion deadline for the second FiT batch had been set at 31 December 2021, this move is likely to severely impact many projects under development.

M&A

Shell buys 49% stake in Australian developer ESCO Pacific

Shell has tightened its grip on Australia's energy market with the purchase of a 49% stake of utility-scale PV developer ESCO Pacific, just weeks after the oil major completed an AU$617 million (US$425 million) acquisition of one of the country's largest electricity retailers, ERM Power. The move will help Victoria-headquartered ESCO Pacific grow its project pipeline and work with a "wider range of corporate off-takers," according to a joint press release. Shell, the world's second-largest oil player, unveiled plans in March 2019 to become the biggest global power producer within 15 years and has committed to pour US$2 billion a year into clean energy investments.

Deployment forecasts

IHS Markit remains bullish on global solar demand hitting 142GW in 2020

Market research firm, IHS Markit expects global solar installations to continue double-digit growth rates in 2020, forecasting new installs to hit 142GW, a 14% increase over 2019. Despite concerns that China's market leadership is waning, IHS Markit expects more than 43 countries to install over 1GW each by the end of 2020, compared to only seven countries at that level a decade ago in 2010. The continued growth is expected come from outside of China, still the world's leading market. Market growth in 2019, excluding China was said to have increased by as much as 53%. In 2020, the market research firm expects continued growth in the double-digit range. As a result of wider global adoption, the top 10 solar markets are expected to experience market share declines to around 73 % of the total, down from 94% compared to 2010.

India

Indian renewables-plus-storage now 'attractive' against coal

A 1.2GW hybrid tender in India coupling pumped hydro, batteries, solar and wind power has achieved tariffs that are highly competitive against coal power, according to prominent industry figures. While the procurer, Solar Energy Corporation of India (SECI), cannot reveal the exact tariffs until they are approved by the board of directors, Sanjay Sharma, general manager at SECI, confirmed that the prices are "attractive" when compared to thermal power. Meanwhile, Pranav Mehta, chairman of the National Solar Energy Federation of India (NSEFI), said in a release that with the winning tariffs from this tender "thermal power in India has become priced out".

Joined at the hip: A hybrid future for onshore renewables

Hybrids | With industry heavyweights eyeing up developments of solar-wind-storage projects, Liam Stoker uncovers what's really driving hybrid power plants, and the regulatory and financing hurdles that must be surpassed to deliver them

Credit: Getty.

Such is the maturation of the renewables sector as we enter the 2020s that simply co-locating generation with storage is almost old hat.

Now renewables developers the world over are pushing the envelope even further, adopting their onshore wind cousins to bring forward hybrid projects that profess to unlock the full value of a grid connection and unleash the potential of onshore renewables as a whole.

As almost every nation eyes progress on climate targets, renewables proliferation looks set to soar in the coming decades. There will be no single technological solution either, with most countries calling upon a broad range of generation asset classes to play their role as renewables generation escalates. Indeed, the International Energy Agency – which itself has a track record of underselling renewables somewhat – forecasts there to be anywhere from 309 to 377GW of additional onshore wind generation across the world by 2024, second only to solar PV. The potential for the two most prolific onshore renewables to co-locate and share certain grid infrastructure is, therefore, perhaps obvious. Adding storage to the mix to play a crucial flexibility-driven role is all the more sensible.

It's enough for some of the industry's largest players to sit up and take notice. In recent months, renewables developers the world over have announced major plays for the co-located or hybrid power market, proving that this trend is not limited by regionality.

A new normal

Iberdrola's UK-based utility Scottish-Power unveiled in December 2019 a new strategy to retrofit solar *en masse* beneath its operating onshore wind assets in the country. French renewables developer Neoen, meanwhile, is to bring forward solar-wind-storage plants in Australia. NextEra Energy broke cover last summer to announce a 700MW hybrid plant in Oklahoma. Swedish state-backed energy giant Vattenfall has explored numerous such co-located generation assets, ranging from a pilot in Wales connected in 2017 to an upscaled project in the Netherlands set to come onstream this autumn.

Speaking at the time of ScottishPower's hybrid strategy unveiling, the firm's CEO Keith Anderson said the move was being driven by a need for innovation to squeeze "the absolute maximum potential out of every clean energy project" if climate targets are to be reached. He said that in the UK and Ireland in particular, the "perfect blend" of clean power "should include a mixture of clean energy technologies", invoking images of a future clean energy economy where technologies can dovetail in harmony.

ScottishPower evidently sees so much potential in this strategy that not only will it be retrofitting additional technologies to existing sites – ScottishPower owns and operates significant quantities of onshore wind in the UK – but also new projects will be delivered in a hybrid fashion as standard. "In the next 18 months I believe that hybrids will be the new normal for all renewable energy developers," he said.

Nick Boyle, chief executive at prolific solar developer Lightsource BP, says co-locating resources stands to bolster the value of a generator's most valuable item: its grid connection. "Grid is your limiting factor, [and] you have a 30% utilisation on that. It's sitting there doing nothing for 70% of your time and, even though it's not as simple as that, why wouldn't you co-locate?" he says.

> "In the next 18 months I believe that hybrids will be the new normal for all renewable energy developers"

Romain Desrousseaux, deputy general manager at international developer Neoen, says that his firm sees two kinds of hybrid power plants: those combining renewables with storage in an off-grid environment, something Neoen has been actively involved in since 2015, and newer forms of hybrid plants that co-locate multiple forms of generation in pursuit of a smoother or flatter generation curve. Alongside a storage component, these plants could deliver something more akin to baseload power and more 'useful' energy to customers.

In September 2019 Neoen unveiled plans for a major hybrid power plant in South Australia, combining 1.2GW of wind, 600MW of solar PV and a 900MW battery storage facility. To be developed in three phases, the project hinges on the construction of a 330kV high-voltage interconnector between South Australia and New South Wales, which transmission system operators ElectraNet and Transgrid aim to have completed by 2023 at the latest.

The prospect of sharing a grid connection between three generation technologies of such size could trim costs, but Desrousseaux says that while it is indeed a bonus – especially in an energy economy driven predominantly by economics – the bigger advantage of hybrid sites lies in the actual output. "The biggest benefit to us, we believe, is in offering several types of energy which complement each other and allow you to offer either baseload, or the type of energy that would be required by the customers," he says, indicating the firm's preference for power purchase agreements to underpin hybrid developments.

But often, as developers have encountered, the financing of hybrid sites – especially those retrofitting additional technologies or capacities – is far from straightforward.

Hybrid hurdles

"What we've seen is retrospectively putting solar on a wind farm is difficult – but not impossible – if the assets have all been financed," Kareen Boutonnat, chief operating officer at Lightsource BP, says, throwing a potential hurdle to any developer's dreams of approaching already-built assets with a retrofitting option.

That sentiment is echoed by a number of developers and financiers spoken to for this feature. Mark Henderson, chief investment officer at UK renewables developer Gridserve, says retrofitting new technologies or capacities onto already-financed and operational projects threw up "all sorts of problems" and one that was "a great idea, but practically quite difficult", perhaps offering an explanation as to why comparatively few battery storage retrofits have been conducted to date. Aldo Beolchini, managing partner and chief investment officer at European investor NextEnergy Capital, echoed Henderson's comments, stating that while his fund was always actively looking at retrofitting opportunities and remained open to alternatives, adding new capacity was "not an easy one to deploy" and an opportunity that is still somewhat constrained by grid.

Prototype power: A maiden co-location demonstrator for Vattenfall

In 2017 Swedish wind giant Vattenfall announced that it would be retrofitting its Parc Cynog wind farm in Carmarthenshire, Wales, adding a 4.99MW solar farm beneath the project's wind turbines, giving the project a 13.9MW generation capacity.

Both the wind and solar element were accredited under the country's Renewables Obligation scheme, propping up the project from a financial perspective. But far be it for financial reasons, the utility stressed at the time of energization that the prototype's development was so that it could learn from the experience and to "get some time generating under our belt" before the utility looked at exploring future developments.

The development itself was not exactly straightforward. Vattenfall had to switch sites, having previously identified an alternative wind farm in Leicestershire, owing to grid constraints, and committed to installing a power plant controller alongside network operator Western Power Distribution – and an element of curtailment from the solar element of the park – to gain approval.

This meant that as soon as combined output from the two technologies reached 4.1MW, the controller would kick in and curtail the solar array's output, with the wind generation deemed more valuable to the parties involved.

18 months later, Vattenfall provided an update to the UK market stating that the project's performance had been "very good", noting the complementary generation profiles of the two technologies.

Any fears over excessive curtailment were not borne out with the grid connection not maxed out "for the vast majority of the time", a company representative told sister publication Solar Power Portal at the time, while performance was suitable enough for Vattenfall to explore "all aspects" of maximising its asset base through co-location, both with additional solar and battery storage.

Such issues may go some way to explain why retrofitting existing assets may be restricted to multi-national utilities akin to ScottishPower/Iberdrola with the balance sheet and financial clout to do so, and why hybridisation has largely been constrained to new-build, freshly financed assets so far.

There are, too, obstacles holding back hybrid projects away from the finance community, not least of all within the regulatory landscape. As Alex Eller, senior research analyst at Navigant says, a lack of classification for hybrid projects that comprise multiple technologies from grid operators means they face more rigorous and time-consuming approval processes.

"In a lot of markets now there's not even a classification for energy storage, there's definitely not a classification for a solar-wind-storage plant. So because of that when developers go to their interconnection request [to] the utility, the grid operator has to study how the output of this project is going to impact the grid and because they don't have a lot of data on how they operate or the output profiles… they're either not allowed to build those projects or it's a very long and expensive process to do those studies versus just solar or just wind where it's more well-known and better understood what impact it might have," he says. Renewables technology would again appear to be outpacing regulation at a critical time for renewables policy.

Neoen's Desrousseaux concurs, saying that while he doesn't think grid operators are necessarily hesitant to approve hybrid projects, the problem is caused by a lack of operational data and the comprehensive modelling that's required for grid operators to hand over the keys to nationally


Vattenfall retrofitted solar on land surrounding its Parc Cynog onshore windfarm in 2016

Credit: Vattenfall.

Credit: Tesla.

The now famous Hornsdale Power Reserve battery, owned and operated by Neoen alongside its Hornsdale wind farm

significant infrastructure. "When you start to put more equipment and more complex [projects] than one pure, simple technology, it's getting a bit more difficult. I don't think there's any issue from the grid, but there's usually a challenge to be able to provide all the analyses with several technologies rather than a single one," he says.

Another such issue to overcome, right at the design phase, is in site identification. As Desrousseaux says, wind and solar plants are usually sited as such because of either their strong solar irradiation or wind speed portfolios. But it's a rare occurrence for these two to overlap, requiring more careful consideration than the standard renewables site.

And then there's the issue of the site's construction and how that is managed. Solar PV, famed for its speed of build, is likely to outpace even the most hastily assembled onshore wind farm, causing the construction of hybrid sites to require careful consideration. Desrousseaux says that while Neoen's maiden hybrid site still awaits construction, the developer has planned in advance to coordinate the issue of the three technologies moving forward. Lightsource BP's Boutonnat is of a similar opinion, commenting: "There's been very little [hybrid development] done so far. It's not as easy as that because effectively the timing of wind and solar are different. You're not developing a wind and solar plant at the same time, it takes a lot longer [for wind]."

Given the numerous hurdles that need to be surmounted, and that there is not exactly a dearth of standalone solar, storage or wind developments globally, what is it that is driving such interest in hybridisation, and what skillsets are necessary to be an early mover in this market?

Customer first

"I remember years ago making a statement that there would be more solar deployed in applications that we haven't even come up with yet in the next 20 or 30 years, than applications that we have now. And I absolutely still stand by that," Lightsource BP's Boyle says, commenting on the number of new applications solar finds itself in.

"We're seeing gas and solar, diesel and solar, wind and solar co-location, hydrogen, you name it. It depends on the need of a specific customer and what they want," Boutonnat adds. And it's this focus on the customer and their needs which can be a driving force behind hybrid sites. After all, a generator that produces power whether the sun shines or the wind blows stands to be a considerably powerful proposition for an off-taker.

Desrousseaux says that it is Neoen's belief that in bringing forward several sources of renewable power under one roof, or indeed under one grid connection point, there's a stronger opportunity to supply a wider array of end customers. This means identifying and selecting sites becomes paramount, however, placing importance on those teams within any would-be hybrid developer.

In turn, the financing and power purchase agreement (PPA) structures in place become more complex. Untangling PPA structures for a broader audience has been a particular bugbear for much of the utility-scale solar industry in recent years, so some reluctance to muddy the waters with new structures taking into account hybrid plants of multiple technologies is perhaps understandable. As Desrousseaux explains, if a PPA is based on a project's modelled output, adding more generation technologies than usual – coupled with the presence of energy storage – only increases the risk of a modelling error or energy shortfall, therefore increasing the risk associated with it. "It requires some expertise and knowhow in terms of energy management and some solar developers haven't thought in that direction yet," he says.

For that reason, it is to be expected that developers have not adopted hybridisation if their end goal is to sell the project on to an investment fund or other asset holder, rather than own and operate those assets in the long term. And if the opportunities in standalone renewables are bountiful, hybrid developments may take longer to emerge from the drawing board and onto the land. "If solar requires to be, because of the economics, co-located with wind then that's when we would look at wind… but we have enough to do without taking on the wind boys as well," Boyle says.

For that reason, the prediction from ScottishPower's Anderson that hybrid developments could become "the new normal" within 18 months may seem far-fetched. But if renewables have become known for anything in recent years it's their unrelenting pace of change. If the industry can approach hybridisation with a similar mix of innovation and know-how, Anderson's assumption could yet ring true.

As Navigant's Eller says, even the simple co-location of utility-scale solar with storage five years ago was more complicated and a marginal market, but that has changed quickly: "Everyone knew it made sense but it took a while to really happen and get sorted out, then all of a sudden in the last year or two it's like everywhere, half the big solar projects that are built now have storage with them. It's become much more standardised; once it got figured out, everybody was comfortable with it, it just became the new thing. And I would imagine that's what we'll see here [with hybrids] too." ■

Turn to p.20 for insights into some of the techincal challenges of hybridisation

Fine tuning the hybrid proposition

Technology | Realising the theoretical promise of solar-wind-storage hybrids is far from straightforward, with individual projects likely to vary considerably. Ben Willis examines some of the technical complexities of combining different technologies into a single, profitable entity

Large-scale solar-wind-storage projects present numerous technical challenges

Credit: Siemens Gamesa Renewable Energy

One site, one interconnection, multiple megawatts of clean energy from solar and wind systems, smoothed out and rendered grid-friendly with the addition of a co-located energy storage system. Such is the promise of hybrid renewable energy systems, which, as outlined on the previous pages, are seemingly poised to become an exciting new frontier in the decarbonisation of the global energy system.

The current interest in hybrids is perhaps unsurprising. Wind and solar have traditionally been thought of as having limitations related to their inherent intermittence. But side by side, those negatives are largely cancelled out, and coupled with storage offer the promise of reliable, dispatchable power traditionally thought of as the preserve of fossil fuel generation.

"Wind is typically strongest at night, solar production during the day, so if you put the two of them together you have a higher capacity factor," says Navigant senior analyst Alex Eller. "And if you add in storage, theoretically you could have round-the-clock output."

More surprising, perhaps, than the apparent interest in hybrids is the question of why it's taken this long for them to come to mainstream attention. Individually solar and wind have an enviable track record of rising deployment and falling costs, and the notion of putting them together to overcome their respective weaknesses is not a particularly new one. Storage is certainly a newer kid on the block, but as we hear elsewhere in this edition of PV Tech Power, in certain markets such as the US and Canada, the large-scale solar-plus-storage nut appears well on the way to being truly cracked (see p.87).

The reality, of course, is that what looks on paper like a seductively simple idea masks a number of interconnected complexities relating to cost, technology and market drivers that together make the hybridisation of the three technologies (and possibly others too) far from a simple prospect.

Cost and complexity

According to Eller, cost has been a significant barrier to date. "If you're working within a set budget to develop a project maybe it doesn't make sense to do both [wind and solar] in one place because your overall price tag is going to be higher even though maybe the costs per megawatt of solar and wind are going to be lower," he says. "That has maybe prohibited some of this in the past."

Linked to that is the capacity of developers to take on the altogether more complex prospect of projects combining several technologies on a single site. "Until pretty recently you had your wind developers and your solar developers, who were separate for the most part," Eller says. "So if they had a site where they wanted to build a windfarm, a wind developer would say we're just going to do that, we're going to be experts in wind, and maybe though there are some advantages of having solar as well, the complexity of it all, and having maybe to bring in a separate [solar] company that's going to own some of the project, that was something that would slow things down a lot."

But there are signs of things changing. As Eller points out, some of the larger developers in the US and elsewhere now have the necessary in-house expertise across different technologies to handle the greater complexities of hybrid projects. This in turn helps reduce the costs associated with bringing in partner companies with different expertise to work on different aspects of a hybrid project.

Another benefit of the growing professional capacity of the industry to handle the multi-faceted nature of hybrid projects is that it should ultimately lead to a virtuous circle of better project outcomes and thus greater confidence among key stakeholders such as utilities to embrace the new paradigm.

Eller makes the comparison with solar-plus-storage, which has reached a "tipping point" in markets such as Australia and the US, where it now outcompetes fossil fuel generation on price. This is partly a consequence of years of steady work within in the industry to improve and standardise the technology and familiarise utilities with what it can offer.

"Having the utilities be more comfortable with [solar-plus-storage] has been a big factor," he says. "A few years ago, it was really only certain utilities that wanted to pay a little bit more for solar-plus-storage and have some of that control [it offers]. And then once it became more standardised, there was more understanding of how it operated and what the advantages and costs were... then the utilities got on board and were like, ok, yes, that's better than getting all these things separately, so we'll pay a little more for all of this together than we would for say just solar or just wind."

A similar process will influence the acceptance or otherwise of hybrids by utilities and grid operators, Eller says: "It's [a case of] can the developers standardise this a little bit more – the complexities of hybrids in terms of the hardware, the interconnection and the design – so that it's cheaper to do that than it is to build a wind project here and a solar project there."

Technology

To be sure, work to develop the necessary technical backbone for hybrid systems is well underway, with some heavyweight technology companies already well embedded in this emerging space. Notable examples include GE, which has launched a dedicated 'renewable hybrids' unit, and Siemens Gamesa Renewable Energy, which has a dedicated test hybrid facility in Spain where it has been trialling solar, wind and various battery technologies in combination.

GE's technology formed a central element of one of the first solar-wind hybrid systems in the US, the 2MW Lake Region community hybrid built by Juhl Energy in Minnesota in 2018 (see box). Meanwhile, the new unit is working on new hybrids technologies, leveraging expertise drawn from several of the company's business areas, such as battery storage and solar power electronics.

According to Mike Bowman, the unit's chief technology officer, the primary technical challenge with hybrids is balancing a system's different generation and storage assets to give the grid what it wants, when it wants it.

"If you have a single-asset install like a wind farm, there are fairly sophisticated controls that make that wind farm operate," Bowman explains. "If you bring in solar to the same site, now you've got two generating assets behind a single interconnect, and so now you need to manage the generation of those to make sure you're delivering the power in the most efficient way. And then when you bring in a storage asset, you now have the ability for electrons to go in multiple directions: you can ship them out to the grid, you can push some of them into the battery...

"And then the grid is looking at a variety of services. It is looking for forward-looking delivery of power, maybe looking for frequency control; there's a variety of markets that you can play in. So how do you take all that information and control those operating assets in an optimal way that obviously maximises the capability of them, as well as participates in the markets of interest of the customer? It is quite a complicated system."

Essential to achieving this juggling act is a sufficiently sophisticated control system that can function as the digital brains of the hybrid, and this is where GE's hybrids team is focusing a lot of its R&D currently and most likely an ongoing basis, Bowman says. "Like any good software package, it is a continual development process," he says.

The development of a hybrid control system has also been a key focus for Siemens Gamesa's activity in the hybrid space thus far. Since 2015 the company has been trialling various hybrid technologies at its La Plana test site in Zaragoza, Spain (pictured below). Currently the site incorporates 850kW of wind, 245kW of PV, three diesel gensets and both lithium-ion and redox-flow batteries.

According to Antonio Segarra, the company's corporate development and strategy new business director, the controller is integral to any hybrid's ability

Credit: Siemens Gamesa Renewable Energy

Siemens Gamesa's La Plana test site in Spain is trialling various hybrid technologies

to operate profitably.

"What the controller is doing is basically integrating the forecast demand and the generation [to] manage and optimise the system," he says. "If I know in the next couple of hours I am going to have an excess of energy, I need to have a battery empty to be able to allocate this energy on the battery to later on put on the system. Also, it needs to understand the behaviour of the grid and when the grid requires more energy or some kind of service. So, the control is the brain that puts it all together in order to warranty that there is a return on the investment in the installation."

No two hybrids the same

An added challenge for hybrids is the likelihood that as more systems are built, very rarely are two going to be the same. Market by market, even site by site, exactly what a hybrid will look like will vary considerably depending on the drivers of individual markets. In India, for example, grid constraints are a big factor, and hybrids offer a good route to achieving high capacity factors on precious interconnections; in Australia, grid stability is the main driver; while in the UK and other penetrated markets, hybrids are most likely to be required to provide fast-response ancillary services.

This patchwork of possible use cases makes the nascent hybrids sector potentially fearsomely complex. "What works in one country sometimes doesn't work for another," Segarra says. "It depends a lot on the behaviour of the grid and the service being paid for. So what we cannot say is that all the hybrid models will apply everywhere."

This has implications at many levels. On the one hand, it means hybrid control systems must be sufficiently flexible to adapt to the drivers of particular markets. On the other, it means careful modelling to ensure hybrids systems are sized correctly and the right mix of technologies is deployed to maximise returns.

"What you end up doing is sizing the asset around those markets you want to play in," says Bowman. "We've got sophisticated models that will allow us to say, based on this level of generation, this level of interconnect, the market you want to play in, what is the optimal size of storage, whatever your optimal function is... we can run that model, whether you're doing an install in New York or California or the UK or Israel or wherever it might be. It's going to vary in the size of the asset you put in and then the type of battery you put in."

Future developments

Looking ahead, one of the aspects of hybrids that is likely to see most development is the type of batteries they incorporate. Battery technology generally is evolving rapidly, and although lithium-ion today is clearly the go-to technology, that is unlikely to remain the case forever.

Alongside a lithium-ion battery, Siemens Gamesa is also testing a 120kW/400kWh vanadium redox-flow battery systems at its La Plana site. Segarra says that although such flow batteries are not presently commercially mainstream, and would be unsuitable for providing the sort of short-term peaking capacity to which lithium-ion batteries are well suited, as demand for systems able to provide time-shifting capabilities grows, flow batteries are likely to come of age.

Eller concurs: "With these kinds of projects, there are two things the storage is going to need to do: it needs to smooth the output to make sure you have that consistent output and consist frequency. And then you want to store any excess energy or just a portion of the generation and shift that around so you try to get 24-7 output. And in those cases, something like a flow battery is well suited. I would not expect to see something like that any time soon, just because with some of the advances in lithium-ion batteries they're really cutting out everybody else. But definitely down the road I'm sure there will be opportunities for the longer duration things where you could do multiple days of output."

As for the trajectory of hybrids more generally, while there is agreement that deployment will be uneven across different markets depending on their individual circumstances, the reality is that the global community's aspirations to decarbonise the energy system means it is more case of 'when' than 'if' hybrids take off at scale.

"In countries like Spain, or Germany or Denmark, where renewable penetration in 2030 or 2040 is going to be higher than 70%, there's no other option than hybrids," says Juan Diego Díaz, onshore marketing director at Siemens Gamesa. "It seems impossible to reach these penetration level without any other technology than hybrid systems, including storage and obviously taking advantage of the best technology in each of the regions. Hyrbids are a quicker way to meet national climate change targets, because they're not going to be something that will be imposed top down; they're something that developers are going to do by themselves, because of the better investment returns. So it's clear." ■

Testing the tech

In 2018, Minnesota-based wind energy developer Juhl Energy and GE teamed up on what was billed as the first truly hybrid project in the US, a wind and solar installation combining a 2MW turbine and 500kW of solar on a single site.

The thinking behind the Lake Region project (pictured below) was to capitalise on the complementary generation curves of the two technologies – wind production being at its lowest during the summer months when solar is at its highest.

According to Clay Norrbom, managing director of Juhl Clean Energy Assets, the key enabler of the project was a newly developed piece of hardware from GE specifically designed to blend the electrical current from the combined wind and solar generators. The so-called WISE (Wind Integrated Solar Energy) technology removes the need for a dedicated solar inverter by routing the DC current from the PV element through the wind converter.

"From a hardware perspective, the biggest point there is the shared converter," says Norrbom. "The DC input from both the wind generator and the solar are both converted into AC in a common converter. The solar doesn't need a separate inverter."

Eliminating the need for an inverter clearly means capex savings in the project. The converter also has 'smart' capabilities that control the hybrid system's interaction with the grid, ensuring that should the generation from the wind and solar peak at the same time, their combined output never exceeds the project's 2MW grid reservation.

"We have a 2MW wind turbine plus 500kW of solar, but GE is able to represent to the utility that this is only 2MW, because the smart controller will limit it so that it never puts out more than 2MW," explains Norrbom. "When you model it, you know there is only a handful of hours in the year that it would or could ever do that. But the smart controller will guarantee to the grid that you're not going to over-produce in those few hours that the two things happen to be together. So you can give maximum certainty to the grid."

As yet, Lake Region does not incorporate storage, but Norrbom says the project is designed so that batteries can be retrofitted as and when they reach the right price point.

"That is the Holy Grail," he says. "And that is certainly where this technology is going and where it will need to go in order to really be interesting."

Credit: Juhl Energy

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Modi's mission

Market update | India's government insists that its target of 100GW solar by 2022 is still on track. But after 2019 proved another disappointing year, will the sector's barriers be overcome in time? Catherine Early reports

Credit: Tata Power

"When the energy sources and excesses of our industrial age have put our planet in peril, the world must turn to sun to power our future." So said India's prime minister Narendra Modi in December 2015, when announcing his International Solar Alliance alongside India's new target to install 100GW of solar generation by March 2022.

The goal was an ambitious upgrade by Modi from the previous government's aim to install 20GW by 2020, announced in 2010. The prime minister, at that point just 18 months in power, wanted to position India as a leader in solar power in front of the world audience at the UN climate talks in Paris.

By the end of December 2019, India had installed a total of around 35GW of solar power generation. Although final figures are not yet available, analysts at Mercom have estimated that some 7.5GW was installed in 2019, compared with 8.3GW in 2018. But the past two years have seen a slowdown in growth compared with 2017, when 9.8GW was commissioned.

"I'm disappointed with 2019, it could have been a boom year where solar installations went up 50- 100%," says Tim Buckley, director of energy finance studies at the Institute for Energy Economics and Financial Analysis (IEEFA). Buckley puts this down to "a myriad of regulatory headwinds and hiccups".

One major feature of early 2019 was the election, held in seven phases from April 11-May 2019. According to consultancy Mercom Capital Group, tender and auction activity slowed down in the run-up to the election, with central and state implementing agencies issuing just a few tenders. Land allocation was also delayed, and there was a shortage of labour as workers travelled to their home states to vote.

As the two-year countdown to India's 100GW solar target begins, deployment has faltered

Raj Prabhu, chief executive of Mercom says: "There is a quiet period for six months before an election, the government doesn't approve anything in order to avoid accusations of corruption. Lots of activity stopped, nothing was getting approved for a while."

Elections also spelt trouble for solar projects in Andhra Pradesh, when the state's newly elected chief minister Jaganmohan Reddy announced a review of power purchase agreements (PPAs) of solar and wind power projects awarded during the previous government, claiming that they were far higher than usual, and that corruption had taken place.

The issue ended up in the courts, while Modi's central government asked the state to stop creating uncertainty for investors, arguing that PPAs could not be revisited unless there was a clause to do so, or corruption was proven beyond doubt. At the time, there were around 3GW of large-scale solar projects operational in the state, with approximately 1.7GW of projects under development, and about 200MW tendered pending auctions, according to the Mercom India Solar Project Tracker.

"I'm pleased to see the central government has tried to hold firm and that the courts are involved, so the chief minister is now backing down to some extent," says Buckley. But he adds that the incident has damaged India's sovereign rating in the infrastructure space in the short term.

Meanwhile, in Gujurat, the state government refused to approve land acquisitions for contracts signed by the central government, which it said had failed to consult it on the projects. Buckley says that these policy disagreements between central and state governments highlighted the reality of a country, that though unified in name, is in reality 28 very different states. "Policy contradictions are probably not surprising, but it's annoying and disruptive to the long-term target," he says.

Developers have also faced problems in receiving payments from power distribution companies, known as DISCOMS. This has affected all types of electricity generators – DISCOMS have not raised their tariffs sufficiently to balance the rising value of power purchase agreements. They currently owe some US$1.36 billion to wind and solar developers, according to a report by the energy committee of the Indian parliament, published in December [1].

Trade barriers

At the same time, developers have been hit with increased costs for equipment, caused by the government introducing a tariff on their imports of solar cells from China and Malaysia for two years to protect domestic players from a steep rise in inbound shipments of the product.

The two-year safeguard duty on solar cells was introduced in July 2018. It was levied at 25% for the first 12 months, after which it was reduced to 20% for the next six months, and will fall again to 15% for the final six months.

The introduction of the duty was a "big policy screw up", according to Buckley. "It wasn't just that they did it, it was that they spent six months deciding on it, and six months without clarifying what they'd done. So, there were actually 12 months of disruption," he says.

The phased structure of the tariff in reality means that investors will just hold off for 12 months, he says. "On the one hand, the Ministry of New and Renewable Energy is hell-bent by getting 100GW of solar built by 2022, on the other, it's pushing a policy that encourages everyone to wait for a year," he says.

The policy has had the effect of disrupting the momentum in the US$20 billion a year solar installation market, while failing to make much progress on incentivising the US$1-2 billion domestic solar manufacturing sector, he says.

However, though module costs rose from a global low of US$0.26/watt two years ago to US$0.30/watt, they are now around 20c/watt, he notes. The fact that the industry has absorbed the cost of the 25% hike and still reduced costs overall reinforces the strong position solar holds in India, he adds.

However, the safeguard tariff has had a knock-on impact on solar auctions. The increased costs meant that developers could not bid at the same levels as previously, fearing projects would not be financially viable. In turn, the increased bids led the government to introduce a cap on the maximum value of a bid.

"A lot of tenders and auctions were cancelled because the developers thought the caps were too aggressive and they wouldn't make it financially at those levels. The government is trying to spend as little money as possible to procure solar, but the developers are going to fail at those levels, so they're not going to do it. Plus the lenders are not going to loan money for these low tariffs," Buckley says.

Another barrier to solar installations in 2019 was the slowdown in economic growth in India. This has suppressed power demand, which grew by only around one per cent last year, compared with predictions of six per cent growth, according to Vinay Rustagi, managing director of consultancy Bridge to India.

"The utilities are not keen to expand as quickly into renewable energy as the government wants them to; that has been one of the main hindrances to growth of the sector. We have excess capacity. Power demand is not growing fast enough and it's not viable for them to continue to contract more capacity from renewable sources," he says.

'Target on track'

Despite these challenges, the government has insisted that there is no shortfall on the 2022 target. It told the parliamentary energy committee that, as well as the total 31GW of solar installed by the end of September 2019, there were also 19GW under implementation, and a further 35GW tendered, taking total installed or pipeline projects to almost 86GW. The 15GW balance would be auctioned before the end of the 2019 financial year, so these would be built before the 2022 deadline, it stated.

Government policies to support and promote the solar industry include accelerated depreciation, which allows commercial and industrial customers to claim tax benefits on the value that solar assets depreciate; a waiver on charges and losses for the Inter State Transmission System (ISTS); viability gap funding for state-run power producers to cover the cost difference between the domestically produced and imported solar cells and modules; financing solar rooftop systems as part of home loans; and permitting Foreign Direct Investment up to 100% of the cost of projects.

But the Ministry of New and Renewable Energy (MNRE) also acknowledged the problems faced by the industry. "Major constraints being faced by the developers in commissioning of solar are land acquisition, evacuation infrastructure, non-conducive state policy for development of solar and business environment such as willingness of DISCOMS to purchase solar power. Ministry is making its concerted efforts to sort out the issues with the help of all stakeholders," it said, in comments quoted in December's report. The MNRE's secretary, Shri R.C.Tiwari, even went so far as to tell the committee that India would exceed its target.

But commentators do not share the MNRE's optimism. Some 65GW of solar will need to be installed in two and a quarter years, a tall order for a country where the most added in one year is 9.8GW. "Our sense is that we will probably add close to 25GW of capacity in this time. So, unfortunately we will fall very short of the target," says Rustagi.

Mercom is forecasting that around 70% of the 2022 target will be met, give or take 10%. "We have to install more

Rooftop solar

The levelised cost of energy (LCOE) for both residential and commercial customers in India is 39-50% lower than the global average cost, according to Bloomberg New Energy Finance. But despite promising signs, rooftop solar is yet to live up to its potential in India.

Forty gigawatts of the 100GW goal has been earmarked to come from decentralised solar on the rooftops of businesses, government buildings and homes. Yet at the end of September 2019, installations stood at just 5.3GW.

Electricity generated from rooftop solar costs around three or four rupees per kilowatt hour, so it is financially viable for commercial and industrial customers, who typically pay seven to nine rupees per kilowatt hour for power from the grid.

However, the price of electricity from the grid for residential and agricultural customers is around three rupees per kilowatt hour, as it is effectively cross-subsidised by commercial and industrial customers.

This makes rooftop solar an unattractive investment for farmers and homeowners, despite the availability of a 30% government subsidy for residential rooftop systems. It also means that DISCOMS are reluctant to connect business customers who want to install solar, as they will also lose the revenue used to cross-subsidise other customers.

The DISCOMS see net metering as a threat because good customers buy less power, Prabhu explains. "More than 25 states have net metering policies, but they're just on paper, when it comes to implementation there's always pushback. Almost every DISCOM is trying to make it harder," he says.

Opinions are split as to whether the market will ever live up to its potential. Though the market has grown swiftly in recent years, Rustagi says that the resistance of DISCOMS to net metering has slowed growth.

In addition, he reports that banks are generally reluctant to lend to the rooftop sector, due to the amount of time needed to conduct due diligence compared to the small size of the transaction.

Rustagi is not optimistic for the future of rooftop PV. "We expect growth to taper off in the next one or two years. The utilities hold the trump card to the growth of this market," he says.

IEEFA's Tim Buckley says that the "ridiculously ambitious" rooftop target was "never going to be achieved" considering the huge scale of new supply chains and trained technicians that needed to be established.

The uncertainty of the import tariffs and the slow economy has constrained business appetite in recent months, he says. "If your distribution company doesn't want you to install solar PV and capital is tight, you're probably not going to do it," he says.

However, a payback period of three to four years makes rooftop solar commercially viable for the commercial and industrial sector, even with the DISCOMS delaying connections, he believes. Carbon emission reduction is also an important driver for many business consumers, especially multinationals signed up for the global RE100 programme.

However, he remains bullish about the potential. "There's a big economic and regulatory barrier, but there is so much commercial benefit, they will do it anyway," he says.

Rooftop solar deployment in India has so far fallen well short of expectations

Credit: Tata Power Solar

than 20GW a year – that's a China level of installations. India has never even hit 10GW in one year, so to think that we could get to 20GW, that's not feasible at this point," Prabhu says.

"You might get some gimmicks whereby the government says that it has tendered so much, but tendered is not the same as actually commissioned. What counts is how many gigawatts are connected to the grid," he says.

Cause for optimism

Despite the target looking increasingly unlikely, and poor performance in 2019, commentators believe that the sector's fortunes will change for the better in the coming year.

Renewable installations in fact hit a record high in December 2019, with 1.5GW in total, 1.2GW of which was solar. This suggests a "slow but steady improvement", Buckley says. "They finished on a high and that's the trend I expect to see repeated in 2020," he says.

Prabhu expects around 9GW of solar to be commissioned in the year ahead, close to 20% growth on 2019's numbers. The forecast is based on the pipeline of projects that it expects to be commissioned in 2020, though the final number will depend on market conditions, he says.

And even though it seems unlikely that the 2022 target will be met, experts agree that India's transition to renewable energy is still heading in the right direction.

Buckley believes that the transition is now "totally unstoppable", despite the slippage on the target. "The 2022 target will almost invariably be one or two years late, and that's the cost of 2019's policy contradictions. But momentum is picking up in wind and solar, and at the same time, the headwinds against thermal power are building and building to the point where finance is almost unavailable."

"We've seen a multitude of renewable energy tenders in the past one to three years with prices all well below three rupees/kwh. It's taken as an absolute given in India that renewable energy is now the low-cost source of new supply."

The 100GW goal was always extremely ambitious, Prabhu notes. The fact that Modi's government raised the target from the original 20GW has already meant that far more will be installed than would have been otherwise, he says. "Even if they don't hit 100GW, for them to push it to 70GW is an achievement in itself. We have to give them some kudos for that," he says.

Buckley adds that the 100GW goal was always going to be "phenomenally ambitious". "They're looking at transforming India's energy market in the space of just over a decade," he says.

"That is almost unprecedented globally. Germany and Denmark have done it, but for a country of 1.3 billion people which is expected to see six to seven per cent growth per annum for the next decade, if they can deliver even 80% of this target, it will be a phenomenal world-changing event," he says. ■

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Credit: Michael Parulava / Unsplash

Turkish PV defies political ghosts in year of the rooftop

Solar politics | New stats show Turkish solar has swiftly boomed to 6GW despite the national chaos after the 2016 coup attempt. Can the country continue to dodge volatility as it vies to become a 1GW-a-year PV market via a mix of large-scale and net-metering policies? José Rojo investigates

The Brexit referendum and US president Donald Trump's rise to power aside, 2016 may come to be remembered by future history books as the year of another, highly symbolic political upset.

If Istanbul is the millennia-old link between Europe and Asia, the metaphor was put to the test in July four years ago, as soldiers marched along the city's very bridges in a bid to depose Turkish president Recep Tayyip Erdoğan. The military coup, spanning the 15 million-inhabitant metropolis and other major cities, failed and was followed by a crackdown by Erdoğan that saw thousands arrested within weeks. The chaos spilled into the macro-economic front, sending the Turkish lira into a short-term downwards spiral and fuelling a 1.3% nationwide GDP drop in Q3 2016.

Few markets of those examined by *PV Tech Power* have known such upheaval in recent years and yet Turkish solar appears to have come out unscathed. Historical IRENA stats chart (see Table 1) a surge in installed PV capacity even as Turkey reeled under the coup in 2016 (833MW) and staggered ahead to 2017 (3.4GW) and 2018 (5.06GW). Fast forward to late 2019, and cumulative capacity was said by state grid operator TEIAS to have been approaching 6GW, after 923MW were rolled out over the year. Approached for this story, operators claim annual additions of 1GW are possible going forward.

Turkey's failed coup attempt of July 2016 fuelled fresh currency crises, impacting US-denominated purchases of PV components

According to the Institute for Energy Economics & Financial Analysis (IEEFA), Turkey has every incentive to make sure PV growth comes as quickly as the industry wants. The country, the think tank wrote in a recent paper, faces the risk of a "ballooning" energy trade deficit as it continues to rely on its temperamental currency to fund fossil fuel purchases abroad. The state, IEEFA analysts noted, spent 12% more on coal imports in 2018 – reaching US$4.4 billion that year – but a depreciating lira means it may not be able to buy enough to sustain its pipeline of new coal.

Turkey, the IEEFA suggested, could curb the coal dependency by seizing on its PV resource of 1.6MWh/kWp, "some

Levent Yıldız, general manager of Ankara-based YP Enerji, believes Turkey offers PV investors consistency despite chaos on the currency front.

Credit: YP Enerji

of the best" worldwide. To illustrate the untapped nature of Turkish PV, the think tank drew comparisons with Germany; the Northern European state is half the size, features lower irradiation levels – 1.1MWh/kWp – but has installed 50GW where Turkey can only claim 6GW. Urging Ankara to play catch-up, IEEFA remarked: "The beauty of solar power for Turkey is that it exploits one of its most valuable energy assets, where it has a natural advantage."

The long game of large-scale YEKA growth

Post-coup attempt Turkey may have a sound reason to embrace a multi-gigawatt shift to solar, but does it have a sound plan?

Eren Engur, board member of Turkish solar body GÜNDER, is decidedly upbeat when *PV Tech Power* puts the question to him. "I see 2020 as the start of a sustainable solar market of 1GW per annum," says Engur, who heads up GÜNDER's Energy Storage Committee and is also the founder and CEO of consultancy Icarus Energy. "With the upcoming new YEKA schemes [of large-scale tenders], rooftop support, hybrid regulations along with energy storage and e-mobility support regulations, Turkey can even exceed the expectations."

Engur predicts the distributed PV segment will dominate in the shorter term, helped along by new net metering incentives. GÜNDER, he notes, believes most of the 800-1,000MW of Turkish solar additions it expects in 2020 will be self-consumption rooftops. Fast forward to 2021, though, and the spotlight may move to large-scale PV growth under the YEKA programme, Engur adds. He points at the upcoming 1GW YEKA solar tender due this spring, which he says will help bolster large-scale PV installations in 2021 and beyond.

Launched in 2016, the so-called YEKA scheme already awarded in 2017 15-year feed-in tariffs (FiT) to a Hanwha Q Cells-Kalyon Enerji consortium, who reaped a winner-takes-all 1GW solar contract. After a further 1GW round was cancelled in January 2019, Ankara's fresh attempt this year is reported to involve a shift from one to various winners, with contracts divvied up into 100 lots of 10MW capacity each. Noting Turkey's move away from FiT support, Engur comments: "For the upcoming solar era we'll be witnessing reverse auctions for GW tenders based on US dollar or euro."

With caveats, the bright outlook is echoed by Levent Yıldız, general manager of solar developer YP Enerji. The Ankara-based firm – with rooftop arrays and 1-10MW ground-mounted projects under its belt – has witnessed the solar growth fluctuations of the past years in Turkey, from the steady roll-out before 2017 to the boom and contraction sequence that followed. Yıldız notes, however, that the country more or less achieved its optimistic PV installation goals and offers today, despite the recent volatility, a "consistently" reliable economic and legislative framework for investors.

Investors come on board despite currency chaos

Industry confidence and world-class solar resources will be no good to Turkey's 1GW-a-year ambitions if it cannot attract financiers in their droves. As Turkish energy finance specialist Seyran Hatipoğlu writes, the current interaction between bankers and PV developers is not challenge-free even if it has gone from its beginnings of squabbles to today's far deeper mutual understanding.

In a piece she recently penned for PV association GÜNDER, Hatipoğlu notes it was FiT support that triggered the first wave of solar financing in Turkey; a conversation between keen but inexperienced actors that saw negotiations abandoned and transactions structured unsoundly. Happily for Turkish solar, Hatipoğlu adds, specialised training and the familiarity that comes with time brought together both sides of the developer-financier divide. "They started to understand each other, understand their task and started to meet on common ground," the finance expert remembers.

Like so much else in the Turkish economy, conversations on solar project financing were likely temporarily set aside by the foiled coup d'état of 2016, with tanks taking to the streets as an entire nation looked on. Whether the ensuing political tumult crippled solar investment remains a topic of debate for the industry. Writing for a SolarPower Europe report last year, GÜNDER secretary-general Esen Erkan linked Turkey's "dramatic" slowdown of PV roll-out in 2018 to the "severe financial crisis" and "missing political support" that followed the coup attempt.

Months after Erkan's grim assessment, the solar association's reading of the macro-economic backdrop appears to have brightened. Quizzed by *PV Tech Power* in 2020, GÜNDER board member Engur brushes aside the talk of links between Turkey's financial crisis and its more muted solar installation volumes in 2018. The slowdown, he says, was not driven by political and financial hurdles but rather the fact that deployments stayed within the 6GW the government had set aside. The interest from local and foreign investors in these PV projects has been "great" all along, Engur adds.

Whether caused by the 2016 events or otherwise, struggles around solar finance have not gone away in Turkey. Finance expert Hatipoğlu notes that the phrase "project financing is not available" is one she continues to hear, albeit less frequently than before, from market players. Ask the market players themselves and it quickly emerges the worry was never the military uprising itself but another, more insidious problem the coup exacerbated: the repeated lira crises that saw the currency fall 30% against the US dollar in 2018 alone, as a Turkey-US trade war raged on.

Asked about the key financing challenges for Turkish solar, YP Enerji's

2015 [1]	2016 [1]	2017 [1]	2018 [1]	2019 [2]	2020 [3]
249MW	833MW	3.4GW	5.06GW	6GW	6.8-7GW

Table 1. The past and future of Turkey's solar ambitions – cumulative installed capacity over the years. Sources: [1] historical figures until 2019, International Renewable Energy Agency (IRENA); [2] cumulative volumes by late 2019, TEIAS; [3] forecast for 2020, GÜNDER

Yıldız points out that upfront project costs – steel, copper, PV module semi-products, inverters and so forth – tend to rely on the US dollar. The dependence means, he says, a stable interaction between the US and Turkish currencies and reasonable levels of inflation are both paramount to developers. He accepts that the protection of national interests must guide the government's hand but urges Ankara to take into account the dynamics of the energy sector, adding: "Turkey has to act rationally in this context."

Net-metering bonanza as rooftop year beckons

Those searching for the spot where Turkish PV's next chapter will be written would do well to look up. The same rooftops that witnessed the rise and fall of the Roman, Byzantium and Ottoman empires are, it turns out, where local operators feel Turkish solar will grow next. YP Enerji's Yıldız echoes GÜNDER's prediction of a rooftop-dominated 2020 for the industry. "We observe an especially strong acceleration in the industrial rooftop market," he tells *PV Tech Power*. "The reason is that while the installation costs decrease, the retail sales prices in electricity increase."

It helps, of course, that financiers seem to be growing an appetite for the segment. As finance expert Hatipoğlu writes for GÜNDER, the market has evolved in recent years and developed a well-established framework specifically for rooftop PV funding. In previous years, Hatipoğlu notes, the feeling was that solar on buildings would take off as a segment in 2019. Perhaps aware of the prediction, the government chose last year to launch a net metering scheme aimed at domestic installations of rooftop PV.

The IEEFA expects this new avenue of state support to achieve much. Last December, the think tank authored a paper on the new incentives, which will offer electricity bill discounts to PV-equipped homes in return for the power they inject into the grid. A novelty versus earlier schemes – export and demand will be netted monthly, where before it was hourly – will majorly improve the economics of rooftop PV, the IEEFA said. Consumers will take 11 years to recoup investment costs (seven years in 2025, four-and-half years in 2030) where before they took 16, the think tank added.

Turkey, the IEEFA continued, could however aim even higher if it combines the new net metering scheme with other conducive policies. According to the think tank, Ankara could unlock seven-year payback periods for rooftop already today – plus two-year paybacks by 2030 – if it scraps VAT on solar systems, removes the fixed fee it charges for project approvals, subsidises solar loans and ramps up net metering support to the level seen in Western Europe. On this last front, the IEEFA noted the higher export tariffs Germany, Norway and the UK offer or will soon offer.

> "The Turkish people, the government, the associations and all other solar advocates – we believed with passion for the last 12 years and as a result Turkey installed 6GW of PV in three years. And we're just beginning"

Provided it gets the policy recipe right, how far can Turkey realistically take its distributed solar segment? The potential is vast, if industry forecasts are to be believed. In her contribution to the SolarPower Europe report last year, GÜNDER's Erkan claimed Turkey could roll out 46GW of rooftop PV capacity – split between homes (23GW), commercial and industrial locations (21GW) and public buildings (2GW) – if it installs arrays on around a third of its rooftop surface. According to state agency TEIAS, Erkan said, 6.5GW could be added now without the need for grid upgrades.

Turkey's just getting started

Not everyone has believed all along that Turkey will be able to translate theoretical solar strengths into sustained installation growth. In January 2019, analysts at Fitch Solutions struck a sombre tone as they assessed Turkey's renewables prospects for this year and next. "We forecast wind and solar capacity additions growth in Turkey to slow over 2019/2020, as a number of projects will face delays amid the country's challenging economic environment," said a note from the firm, amid predictions that raising project finance would be "challenging" after years of currency swings.

PV players reading the bleak forecasts may find solace in the fact that Turkey's macro-economic outlook appears to have brightened in the year since Fitch's note was published. The World Bank now expects GDP growth to bounce back to 3% in 2020, driven by reinvigorated private spending, further climbing to 4% in 2021. There seems to be little room for complacency, however. As analysts told trade outlet Global Capital last December, Turkey's reliance on so-called bad loans in foreign currency have seen corporate debt soar since the lira crisis flared anew in recent years.

The optimism of PV players, including GÜNDER's Engur, does not blind them to the inevitability of challenges. "Every report predicts the success story of Turkish solar will continue, but we need to build our strategies to do it in a sustainable and impeccable way," he says. For his part, YP Enerji's Yıldız does believe Turkey has, like others in Europe, a PPA future ahead – the firm is in talks to sign its own deals – but expects the shift will take longer, as the country risks are higher. The government, he says, could help persuade wary investors by enacting PPA-friendly legislation.

In addition, Turkey cannot escape from an energy transition question all countries with gigawatt-scale solar ambitions are currently confronting, that of how to bring about an energy storage boom. GÜNDER's Engur says the state is already busy working on workshops and pilot schemes, from 100MWh this year to 300-450MWh every year afterwards. According to him, the roll-out of batteries on commercial and residential self-consumption systems is now a reality. If power prices continue rising and the support schemes go ahead, Turkey will be a "big storage market" going forward, he argues.

Caveats aside, those approached for this feature believe Turkey has what it takes to outrun its political ghosts and cross the metaphorical bridge into an era of rapid, durable solar growth. GÜNDER's Engur cites a quote oft-attributed to Microsoft founder Bill Gates – "expectations are a form of first-class truth: if people believe it, it's true" – to underpin his faith in Turkey's potential. "The Turkish people, the government, the associations and all other solar advocates – we believed with passion for the last 12 years and as a result Turkey installed 6GW of PV in three years," he says. "And we're just beginning". ■

PV and ESS in Japan's changing energy market landscape

Japan | It has always been anticipated that by the early 2020s, the feed-in tariff would have tapered away in Japan's booming solar market. Andy Colthorpe speaks with analyst Izumi Kaizuka at RTS Corporation to learn more about what the future holds for post-subsidy solar in Japan

Credit: Sekisui House.

Japanese homebuilder Sekisui House has already established a profitable Zero Energy House (ZEH) business.

A land of high energy consumption, reliant on imported fossil fuels, Japan is also globally known as a country where everything from traditional crafts to high-tech industries are always striving to improve and innovate.

As the energy market moves towards deregulation and wider competition, the solar PV sector within that bigger picture moves away from the feed-in tariff (FiT) subsidy-driven phase.

Just announced as this edition of *PV Tech Power* went to press, were FiTs for the 2020 Japanese financial year, which begins in April.

While small-scale solar of under 10kW capacity continues to receive a fairly generous ¥22 (US$0.20) per kWh, anything between 10kW and 50kW gets ¥13 and 50kW to 250kW gets ¥12; anything larger than that has to compete in auctions.

"The big difference [to previous years] is that anything over 250kW has to enter into a competitive bidding process. It was the case that [only] 500kW capacity projects and over were eligible for auctions but it is now at the 250kW+ threshold," says Izumi Kaizuka, manager at Tokyo-headquartered analysis firm RTS Corporation.

Of a possible 416MW in a recent auction, only 39.8MW of contracts were handed out by the Ministry of Economy, Trade and Industry (METI) across 27 bids from an initial 72 project proposals, totalling 185.6MW. Successful bid prices ranged from ¥12.57 (US$0.115)/kWh to just ¥10.99 (US$0.1)/kWh.

"The price was low, but also having spoken to many in the industry, developers are really busy with contracts for projects that are not yet in operation but have been awarded the FiT in previous years; they are working very hard to get these built, rather than being able to focus on new projects," Kaizuka says.

"Anything awarded up to 2014 needs to be built this year or show evidence of construction by this March, so they are extremely busy and are finding it difficult to even think about new projects."

Indeed, the first few years of the FiT saw dozens of gigawatts of awarded projects apparently stall, for various and widely reported reasons. So, as our show preview for the upcoming PV Expo in Tokyo demonstrates (see p.100), activity in the ground-mounted sector focuses to a greater extent on these already-awarded but nowhere-near shovel-ready projects.

Taken from a different perspective however, the ¥22 per kWh for sub-10kW projects remains fairly generous. Kaizuka says it is also indicative of both a natural market shift and government policy shifting solar away from the fields – and hills and mountains – of Japan and towards domestic, commercial and industrial rooftops. These still-to-come rooftop sites will join Japan's existing high installed base of ground-mount capacity (installations have ranged from over 6GW to 9GW in years since 2013 with around 10.5GW deployed in 2015, the 'peak' year of the FiT).

RTS Corporation has modelled various scenarios and found that Japan could potentially find itself host to 150GW of PV generation by 2030. Indeed, the government's three-year Basic Energy Plan aims for renewables to reach 22-24% of the national energy mix by that year. That would peg solar's share at around 64GW.

But, as Kaizuka says, nuclear energy isn't generating anymore in Japan since the Fukushima Daiichi reactor was damaged by the 2011 earthquake and tsunami.

"A small nuclear power plant has restarted operation, but we can't expect more [restarts]. We thought solar can cover that gap, we studied the energy consump-

Credit: Wikimedia/Qurren

While the first few years of the FiT were marked by an abundance of 'megasolar' projects, the emphasis continues to shift to more distributed PV projects

Credit: RTS Corporation

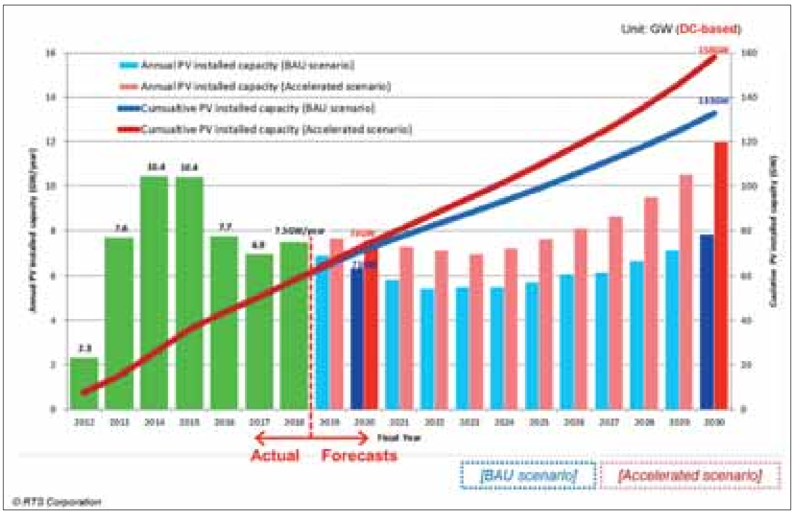

Figure 1. RTS forecast of annual and cumulative PV installed capacity in Japan toward FY 2030 (Business as usual scenario + Accelerated scenario)

tion of households and the commercial sector – and other sectors – and calculated how much electricity solar can replace and add; in total, our analysis that we can install 150GW by 2030 (see Figure 1). Of course, we have many restrictions including grid issues, but we believe that there will be major market shifts from the ground-mounted solar to buildings."

Kaizuka points out that as a mountainous country with densely packed urban areas dotted around it, Japan's three major regional power companies, Kansai Electric, Chubu Electric and Tokyo Electric make up approximately 65% to 70% of the country's electricity consumption alone.

"In those city areas it's impossible to have ground-mounted stations but we have many, many roofs! That's the reason that we are proposing that Japan can have 150GW by 2030 and appealing to the governmental sectors and industries how to achieve this. Even the fairly conservative International Energy Agency's World Energy Outlook report finds that Japan could achieve 108GW of solar capacity by 2030," Kaizuka says.

"We have to realise decarbonisation and unfortunately in Japan, for developing wind power, space is limited, while the north has very good locations but sometimes it's difficult because of the lack of transmission lines. In the case of solar, it can be everywhere."

There are some other big market dynamics worth considering in this context:

- Private households are investing in solar-plus-batteries for resilience in a country prone to earthquakes and typhoons. In the post-FiT age, there will either be self-consumption in a country ranked about sixth most expensive for domestic power prices, or the country's newly deregulated electricity market's many new retail players are offering modest domestic power purchase agreements (PPAs) to households. These can range from around ¥9 per kWh for solar sold straight to the power retailers, to ¥12 per kWh for homes with solar and batteries.
- Policy will encourage self-consumption. Japanese electricity bills have both a basic rate and a kilowatt-hour rate based on grid consumption. Installing batteries allows for a reduction on that basic rate. Previously, owners of systems under 50kW capacity had to sell all of their generated power to the grid. From the 2020 fiscal year, Kaizuka says, systems under 50kW have to be configured to self-consume a portion of their generated solar energy.
- In the C&I and residential space, third-party ownership models, so-called 'Zero Yen Installation' models, are being launched. The customer enters a power purchase agreement with the provider, sharing savings on electricity cost as well as potential revenues from selling energy to the grid where applicable.

Looking ahead, Kaizuka says that new products and business models are emerging in Japan, bit by bit. Some are offering battery storage and solar together, while the use of batteries for ancillary services and flexibility has not even really begun in Japan – yet.

There are also virtual power plant (VPP) demonstration projects underway, while the newly deregulated electricity retail market is finding tie-ins between different market stakeholders (Canadian Solar is partnered on sales with Nissan for its Leaf EV, for example) creating new business models to drive deployment of solar, batteries and other clean and futuristic energy technologies. Large-scale solar is still on its learning curve to hit lower soft costs too (see Figure 2).

"The market is changing right now, from all-FiT driven to the emergence, bit by bit, of self-consumption business models," Kaizuka says.

"The FiT itself will exist this year; but from 2021 onwards, the government is trying to create something called a feed-in premium. [This will be based around the] JPEX, an energy trading market, plus receiving a premium. Discussions around this are currently taking place. [This is likely to be] along the lines of what is happening in Germany but it's not clear yet which direction this will go in." ■

Turn to p.100 for more on how Japan is rising to the smart energy challenge

Credit: RTS Corporation.

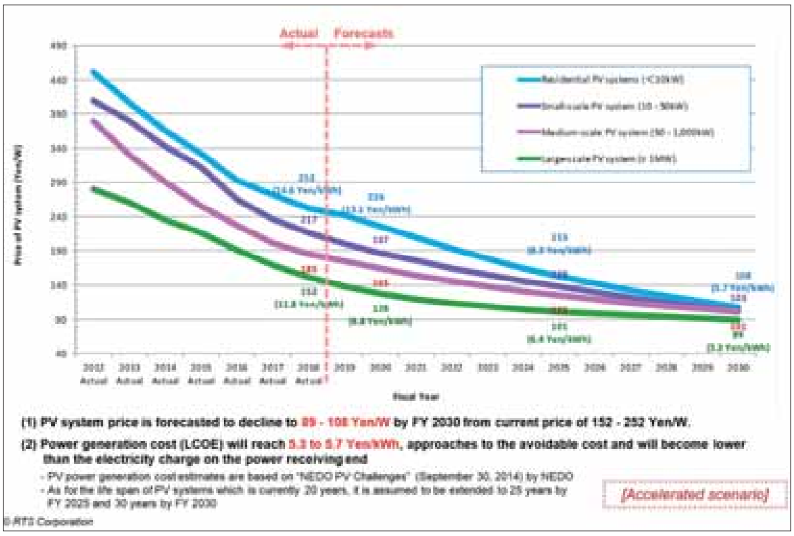

Figure 2. RTS PV system price forecast toward FY 2030 under accelerated scenario

Where next for China's energy transition?

China | A late rally boosted China's domestic solar installations in 2019 to a better-than-expected 30.22GW. But Frank Haugwitz asks whether a renewed interest in locally available coal and an economic slowdown could conspire to slow recent momentum in China's energy transition, in which solar has played a central role

Ever since when on 31 May 2018, China's National Energy Administration (NEA) abruptly and without warning decided to stop approving any new solar PV project until further notice, it was fair to assume that its domestic market would take a different course of development during the remaining period of the ongoing 13th Five-Year Plan (2016-2020). Back then, China was just halfway through with its 13th Five-Year Plan, but already exceeding its official solar PV target of 105GW by 2020 by approximately 47% (154.55GW); this decision was therefore a necessity, particularly in light of mounting financial obligations. The latter provided the reason to fix a budget in advance, earmarked for specific projects. Hence, during spring 2019 a total budget of RMB3 billion (US$436 million), including RMB750 million for residential PV, was set for the full year.

The year 2019 was characterised by a number of PV-related policy announcements, notably 30 April the new feed-in tariffs (FiTs) effective 1 July, 20 May the first batch of so-called grid-parity projects and 10 July the officially approved projects eligible for feed-in tariffs (FiTs). In summary, that amounts to approximately 41GW (including 3.5GW of residential PV) of solar PV power generation capacity to be deployed during 2019, thus somewhat roughly matching the 44.26GW installed in 2018.

On January 19, 2020, China's National Energy Administration (NEA) officially released its 2019 national power industry statistics. Accordingly, by the end of December 2019 China's cumulative installed solar PV power generation capacity amounted to 204.68GW, representing an increase of 17.4% YoY. Detailed information has yet to be released giving a breakdown of how many GW of utility-scale and distributed PV were installed, but the 204.68GW implies that China managed to install 30.22 GW last year, thus witnessing a 31.7% year-on-year decrease compared to 2018's 44.26GW. A total of 30.22GW for the full year 2019 could mean that in December alone up to 12GW were deployed, i.e. possibly exceeding the 11.4 GW installed during the entire first half of 2019.

Credit: GCL-SI

China's solar installations were better than expected in 2019 but prospects beyond 2020 remain unclear

Admittedly, AECEA did not estimate that up to 12GW would be installed in December 2019, in light of fairly low installations numbers in October (approximately 1GW) and November (approximately 0.5GW). A year-end rally is nothing unusual, however up to 12GW in one single month still beats all estimates. One factor which might have contributed is that projects that received approval up to two or even three years ago were finally executed, now taking advantage of fairly competitive module or overall system prices.

If compared to 2017-2018 deployment, when annual installations dropped by 16.4% YoY, the 30.22GW achieved in the 2018-2019 period represents almost double that drop at 31.7%. Nevertheless, 30.22GW is far better than anticipated and, given such a tailwind, AECEA is currently revising its 2020 estimate. Early indications suggest that during 2020 the Chinese PV market will experience a rebounding possibly in the order of 15-25% YoY.

2020 market drivers

In December 2019, a somewhat "first draft of the 2020 solar PV policy" was made publicly available. Accordingly, in principle 2020 shall be a continuation of 2019, i.e. first priority is grid-parity, second is utility-scale + distributed PV, with the distinction that distributed has to bid too, third residential PV and the fourth priority will be poverty alleviation, but subject to a different budget. The budget earmarked for 2020 could be with RMB1.75 billion (including RMB500 million for residential PV), approximately 42% less compared to 2019. To date, no information has been released indicating the potential 2020 FiTs.

According to AECEA's opinion, a reduction of the overall budget takes into account cost reductions for both technological advancements and general price erosions. As well, in an attempt to ensure that a 31 December 2020 deadline won't be missed (again), the quarterly reduction of FiTs till the end of 1H/2021, after which project development rights will be revoked, could be increased to RMB0.02

or even higher. Alternatively, possibly a hard deadline will be introduced, i.e. approved projects will be automatically cancelled, if not grid connected by 31 December 2020. Unclear is whether a second batch of grid-parity projects will be considered necessary, because the bulk of grid-parity projects (approximately 8.7GW in 2020) are still subject to execution and it appears fair to assume that the 5.2GW foreseen for 2019 were not entirely deployed either. In this context, the introduction of a base price + floating mechanism for the coal benchmark price scheduled to become effective on 1 Jan 2020 could become a challenge for such projects, because the coal benchmark can fluctuate by -15% and +10% annually; the latter only from 2021 onwards, in order to avoid a price increase for in particular the C&I sector in the first year of its introduction. Nevertheless, a drop of the local coal benchmark price by 15% could consequently challenge the competitiveness of such grid-parity projects and eventually may lead to postponements or even cancellation of such projects planned for next year.

Alternatively, room for optimism comes from an announcement released late November 2019 by China's National Development and Reform Commission (NDRC) seeking comments regarding the "Supervisory Measures for Grid Companies to Fully Guarantee Purchase of Renewable Energy". Overall, the measures shall clarify the responsibilities for the grid companies, power companies and power dispatch centres to ensure the full purchase of renewable energy. The new measures explicitly state that grid companies shall be responsible for any unjustified economic losses they cause for renewable energy power generation companies and are liable for providing compensation.

Equally impactful could be China's official renewable energy obligation policy jointly announced by NDRC and NEA on 10 May 2019. Accordingly, each province is subject to a mandatory renewable energy electricity consumption quota set by the national government. Such a legally binding obligation shall accelerate the overall renewable energy development. Furthermore, surplus quota can be traded, and the system can integrate into future spot power markets. It also considers the interaction with voluntary green certificates and energy consumption controls, in order to make implementation more flexible. The official monitoring and assessment process will start in 2020 and each province is asked to report to NEA in February 2021. Depending on the local situation, it may trigger additional demand for solar PV in 2020, in order to ensure compliance.

A potential new growth area in 2020 for solar PV could be that e.g. 11 provinces that account for more than 40% of China's coal consumption will have to stay within absolute limits according to their "Blue Sky Defence Plans" for 2018-2020. Given the increased coal consumption since 2017, the proportion of coal used for power generation increased by 8% year on year in 2018, meeting these caps is likely to require strong measures.

An additional new growth area in 2020 could be "solar-storage-charging", where power generated by, in particular, distributed solar PV is first being stored and later used to charge electric vehicles (EVs). During 2019 numerous projects were put into operation across almost a dozen of provinces. In the context of China's EV target, the estimated electricity consumption by EVs is approximately 5TWh in 2019 and shall increase to 32TWh per year by 2025.

2021-2025 transitional prospects

At the time of writing, it is too early to say how China will continue supporting the local deployment of renewable energy technologies in the future. A first indication in writing will be provide by the upcoming 14th Five-Year Pan (2021-2025), which will define the country's economic, development and energy policies.

In the context of the latter, China's premier Li Keqiang, who chaired a meeting of the National Energy Commission (NEC) early October 2019, re-emphasised coal as China's primary source of energy security. Furthermore, he stressed that an enhanced domestic oil/gas exploration and utilisation shall play an equally crucial role in the years to come, while downplaying the importance of a rapid energy transition towards a low-carbon economy. In the course of a similar meeting in 2016, Li Keqiang stressed the need to increase the share of renewables in its energy mix and accelerated energy transition. However, during last October's meeting the future role of renewable energy was not mentioned at all.

The renewed focus on domestic fossil fuel consumption possibly derives from China's increasing dependence on energy imports and its overall economic slowdown. In 2018, China's oil consumption was 3.4 times the domestic output and its import dependence reached an all-time high of 72%. In comparison, its import gas dependence reached 45.3% and total electricity consumption reached 6.846TWh, representing an 8.5% increase YoY and the highest annual growth since 2012. The debate about potential energy targets for the upcoming 14th Five-Year Plan has been initiated. Corresponding five-year plans for different industrial sectors will be published in 2021-22 and shall include detailed targets for different energy sources, power generating capacity, share of coal in total energy, etc., amongst them the potential adoption of a CO2 emission cap for 2025.

Against this background, China's Ministry of Ecology and Environment (MEE) has included five priority tasks explicitly addressing climate change to the 14th Five-Year National Economic and Social Development Programme Outline and the 14th Five-Year Ecological Environmental Protection Plans. The five priority tasks are covering the following aspects:

1. Encourage local government and major industries to formulate clear targets, roadmaps and implementation plans for carbon emission peaking
2. Achieve stable and effective operation of the national carbon market
3. Improve formulation of climate change laws and regulations and strengthen the capacity of local authorities and official
4. Promote global climate governance under the principle of fairness, joint but differentiated responsibilities and respective capabilities, while continuing to provide support to developing countries
5. Place equal importance on climate mitigation and adaptation and update China's national adaptation strategy

In summary, China's apparent re-focus on locally available fossil fuels, notably coal, combined with an anticipated prolonged economic slowdown, thus the need to maintain its overall macro-economic competitiveness, has the potential that China's initiated energy transition during the 13th Five-Year Plan (2016-2020) period may lose its momentum in the not too distant future. ■

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Getting the most from bifacial

System engineering | As the deployment of bifacial solar projects worldwide accelerates, so too is the industry's understanding of how to design and build systems that play to the technology's main strengths. Drawing on recent experiences in the field, Beth Copanas and James Willett from RES outline some of the technical lessons learned on realising bifacial's full potential

With global installed capacity increasing from 97MW in 2016 to an expected 5,420MW by the end of 2019, the promise of bifacial photovoltaic (PV) solar has begun to materialise [1]. As a leading independent renewable energy company, RES has seen a marked increase in owner/developer procurement of bifacial solar modules over the past two years. RES currently has over 550MW_{DC} of bifacial capacity in the design/engineering phase and recently completed construction of a larger than 200MW utility-scale bifacial project. Currently, this is one of the largest utility-scale bifacial projects in the USA. Standard industry practices for utility-scale PV design, construction and testing can be impacted by the integration of bifacial technology. This article addresses some of the valuable design and construction lessons learned RES has garnered thus far.


Bifacial solar systems present additional design and installation challenges

Credit: RES

Design and construction overview

Lessons learned on bifacial utility scale projects RES has designed or constructed thus far and that are addressed in this article include:

- DC collection system design;
- DC collection system construction;
- Commissioning and testing considerations;
- Meteorological station equipment and locations.

DC collection system design

PV array output current is directly proportional to the amount of irradiance incident on the PV arrays. The instantaneous current value can be impacted by albedo, reflections, cloud edge effect, and site elevation. Bifacial module cells are exposed on both sides and cell exposure to rear-side irradiance should result in increased PV output current as compared with monofacial modules. Therefore, design of the PV DC collection system must consider total incident irradiance when sizing the DC current carrying conductors and fuses. The US National Fire Protection Association (NFPA) National Electric Code (NEC) is the industry standard for sizing DC conductors and fuses. DC conductors and fuses for projects are sized by determining the maximum current of the PV Source Circuits using NEC 2017 Article 690.8(A) [2].

According to Article 690.8(A), the following equation is used to determine the worst case continuous current that a DC cable may carry under load.

$$Imax = Isc * IF$$

Where:

Imax: Maximum PV Source Circuit Current

Isc : Short Circuit Current per module or per string of modules in series. The Isc value is taken from the module manufacturer datasheet at Standard Test Conditions (STC).

IF (Irradiance Factor): To account for increased current due to increased incident irradiance, the default irradiance factor is 1.25, which assumes 25% more irradiance than at (STC) where incident irradiance is assumed to be 1,000W/m2. Therefore, if the module Isc at STC is 10 Amps an Irradiance Factor of 1.25 assumes incident irradiance of 1,250W/m^2 and an Isc increase of 25% to 12.5Amps. Even monofacial systems must consider an irradiance factor for situations where the modules experience greater than 1,000W/m^2.

The default assumption per Article 690.8(A)(1)(1) is an Irradiance Factor of 1.25 or 1,250 W/m^2. However, 690.8(A)(1)(2) allows a licensed electrical engineer to use an industry-approved method for deriving an Irradiance Factor that is different than the default value per NEC 690.8(A)(1). The NEC references the SANDIA 2004-3535 Photovoltaic Array Performance Model and the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) simulation programme as an industry-approved method for calculating the "highest three-hour current average resulting from the simulated local irradiance on the PV Array accounting for the elevation and orientation. The current value used by this method shall not be less than 70 percent of the value calculated using 690.8(A)(1)(1)". In RES' experience, a method acceptable to owners and independent engineers (IEs) is to model 20 or more years of solar resource data using SAM to determine the highest three-hour average irradiance factor over the 20 years.

Example calculations for a utility-scale bifacial project using 690.8(A)(1)(2) are outlined below. For bifacial systems, the highest three-hour average circuit current must account for the additional current a bifacial module will see due to the rear-side irradiance contribution. Using SAM and historical data, the electrical engineer of record (EOR) can determine the Irradiance Factor. While the SAM POA output values include a rear-side irradiance contribution, in RES' experience some EORs choose to add another factor of safety by using the module manufacturer published Isc datasheet values multiplied by an additional bifacial gain factor (BGF). RES has seen this BGF value vary from 10-15% across projects. Therefore, in this example the maximum photovoltaic source circuit current per 690.A(A)(1)(2) is calculated as follows:

$$Imax = Isc * BGF * IF$$

Where:
Imax = 13.225
Isc = 10
BGF = Assumed Bifacial Gain Factor, 1.15
IF = 1.15

When using the method outlined in NEC 690.8(A)(1)(2), a project can end up with a total safety factor greater than the 1.25 value as dictated by 690.8 (A)(1)(1).

To size the DC overcurrent protection devices, NEC 690.9(B) requires "not less than 125% percent of the PV maximum output current calculated in 690.8(A)" [2].

$$Ioc = Imax * 1.25$$

Where:
Ioc = Current value for Overcurrent Protection Rating as required by 690.9(B)
Imax = Max current calculated according to 690.8(A)
1.25 = NEC required safety factor per 690.9(B) that states an Overcurrent protection device can only be run at 80% of its continuous rating.

Using this example, the *Ioc* as calculated per 690.8(A)(1)(2) and 690.9(B) ended up at 16.53 Amps per module or per module string. The BGF value selected for projects can have material and installation cost implications for the DC wiring system. Due to the limitation imposed by the current industry 32A in-line fuse rating, the BGF factor assumption can result in the purchase and installation of up to two times the number of wire harnesses as compared with an equivalent monofacial project.

As Isc values on modules continue to increase with increased module efficiency, the assumptions around the bifacial gain factor are increasingly important. The DC collection system, including procurement and installation of the DC string wire harnesses and DC conductor homeruns (from field installed combiners to inverters), can comprise 7-8.5% of the total balance of system (BOS) cost stack – not including modules or project substation costs. A higher rated DC in-line fuse (~50A) coming to market could allow for more strings per wire harness. While this would have allowed the current design to use the industry standard method of two-string and one-string harnesses per three-string tracker row, the ability to put more strings in parallel per string, even with a higher fuse rating, will still depend on the EOR assumptions around the IF and the BGF.

If the bifacial current increase assumption is too aggressive owners run the risk of systems blowing fuses or compromising conductor insulation over the life of the project. However, conservative BGF and IF factors can add additional unnecessary capital costs to projects. Important consideration needs to be given to the seasonal and clear sky versus diffuse hourly rear-side irradiance gains when determining the total IF and therefore the assumed worst-case current value.

Figure 1. Wiring considerations for bifacial modules: to prevent shading of the rear-side of the module how the DC wire harnesses will travel down the racking structure without shading the rear side of the modules must be considered during the design and procurement stages of the project. Different modules paired with different racking structures require custom approaches

DC wire management

DC wire management is a critical aspect of the PV system installation that impacts project performance and the long-term reliability and health of the DC system. The size of these utility-scale PV projects means there are millions of feet of PV string wire to install. Per the NEC, system wiring must be installed such that exposed conductors are correctly rated for outdoor exposure, are protected by and secured to the racking structure, and maintain the correct bend radius to prevent conductor damage. For bifacial modules the typical method of securing DC string harness wiring to the backside

Figure 2. Installation crew familiarity with bifacial modules. To prevent shading of the rear side of the module ensure that crews are properly trained and understand that in addition to the usual wire management considerations the goal is to minimise rear-side shading

QTY per MET station	Measurement device	Instrument type	Typical ranges	Typical accuracy
1	Irradiance in the plane of array (E_{POA})	Pyranometer classified as secondary standard by ISO 0960:2018 and high quality by the World Meteorological Organization Guide 6th Edition	0-2,000 W/m2, 285 to 3,000nm	±2.0%
1	Irradiance in the plane of array (POA)-module rear side ($E_{\_Rear}$)	Pyranometer classified as secondary standard by ISO 0960:2018 and high quality by the World Meteorological Organization Guide 6th Edition	0-2,000 W/m2, 285 to 3,000nm	±2.0%
1	GHI irradiance	Pyranometer classified as secondary standard by ISO 0960:2018 and high quality by the World Meteorological Organization Guide 6th Edition	0-2,000 W/m2, 285 to 3,000nm	± 2.0%
1	Ambient air temp	Temperature probe	-40°C to +70°C	± 0.3°C @ 20°C
	Back of the module temperature sensor	Temperature probe	-40°C to +135°C	±(0.15°C + 0.002t)°C
1	Wind speed	Sonic wind sensor	0.1-60/ms-1	±3% (up to 40/ms-1)
1	Relative humidity	Humidity sensor	0-100%	±2%@20°C (10 to 90% RH)

Table 1. Example MET station equipment for a bifacial PV project

of the modules will contribute to shading of the modules and interfere with rear-side irradiance gain.

Before construction, the design and procurement phases must capture the conductor lengths required to prevent shading of the rear side of the modules. Figure 1 is an example of extra length required to keep the wire harnesses secure and maintain the correct bend radius without shading the module cells. Failure to evaluate wire management early in the project design phase may result in additional material and labour costs.

Additionally, as per Figure 2, installation crews largely familiar with monofacial systems need additional training to ensure that they are aware and working to minimise rear-side shading. Care must be taken to ensure crews' hours associated with array wiring is as efficient as monofacial module installations while still maintaining the required wire management practices.

Commissioning and testing considerations

The recent deployment of bifacial PV technologies that can convert rear-side irradiance into additional module power output has impacted the energy modelling and actual evaluation and measurement of utility-scale PV system performance. Testing and commissioning of large, utility-scale projects is a contractual obligation intended to demonstrate that a PV project is installed correctly and can achieve expected performance levels under actual environmental conditions.

As suggested by the PVSC 46 Manuscript, PVSC 46 2019-6-3, total Irradiance E_{Total} can be used to evaluate total incident irradiance on the modules for energy modelling and actual site performance evaluation purposes [3].

$$E_{\_Total} = E_{\_POA} + E_{\_Rear} * \varphi$$

Where:

$E_{\_POA}$ = frontside plane of array irradiance (POA)

$E_{\_Rear}$ = rear-side plane of array irradiance (POA)

φ = Bifaciality factor, ratio of rear-side to front-side efficiency determined by module manufacturer

Utilisation of this performance evaluation methodology requires modification of standard meteorological station equipment and placement as described below.

MET stations

While the increased equipment and installation cost for bifacial-compatible MET stations is not a significant adder to overall project costs, the design, location, and installation of the MET stations

Figure 3. Rear-side irradiance sensor location. Inverter cut-outs, roads, high traffic areas, and natural ground cover variations can result in rear-side POA measurements that are not representative of overall site albedo. Close-ups of the sensors can be found in Figure 4

Figure 4. Rear-side pyranometer mount. Options for rear-side pyranometer mounting systems are currently limited and non-standard. Most mounting systems will result in the pyranometer being some distance away from the back of the modules

can impact the system performance evaluation. In terms of equipment, the main addition to MET stations for bifacial projects is rear-side pyranometers or reference cells to measure rear-side irradiance for performance evaluations. Typically, utility-scale projects will consist of one or two front-side irradiance sensors and one rear-side sensor per 20-25MW_{AC}. To date, RES has used class A secondary standard rear-side pyranometers that match the model number and quantity of the front-side pyranometers. The remaining MET station measurement devices are the same as those used on standard utility-scale MET station configurations. A list of bifacial MET station equipment with ranges and accuracies is provided in Table 1.

In addition to selecting the appropriate types and quantities of rear-side irradiance sensors, the location and mounting of the sensors should be given due consideration. The placement of the rear-side irradiance sensors should be representative of the overall site albedo. This can be a challenge for 1,000 to 1,500-acre sites (400-600ha) where natural or unnatural variations in ground cover can make it difficult to get rear-side measurements that are characteristic of the overall site albedo. One difficulty is that due to power and communications requirements, MET stations are often located near inverter cut-outs and roads that see high traffic and construction activities. These areas will often have reduced ground cover that is not representative of the rest of the site. Natural variations in ground cover height/density can also cause rear-side irradiance measurements to not accurately reflect site albedo (Figure 3).

The rear-side sensor location and mounting method near the back of the bifacial modules should also be given consideration. Ideally, the rear-side mount should accurately reflect rear-side shading and irradiance uniformity, be as close as possible to the exposed cells, and be free from reflections and/or shading. Figure 4 depicts a rear-side pyranometer mount. Current mounting options for rear-side pyranometers are limited, non-standardised, and should be given forethought when designing MET stations for bifacial projects.

Although the equipment requirements and costs of bifacial MET stations are not substantially different from standard utility-scale MET stations, the design and siting of the stations and sensors can affect measurement accuracy. Proper consideration should be given to the MET station design to ensure successful performance testing.

Conclusions

As bifacial solar quickly moves to the mainstream, to fully realise the potential gains from bifacial projects, specific design and construction considerations should be incorporated into the project. Through RES' experience with recent projects, the most consequential considerations were related to DC collection system design (fuses and wire sizing), DC wire management, MET station design and location, and commissioning and testing procedures. ■

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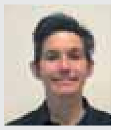

Beth Copanas is director of solar energy at RES (Renewable Energy Systems). She has over 15 years' experience in the renewable energy sector and began her solar career in 2005 as a rooftop installer for residential and commercial PV systems in California. Since then, her career has ranged from design and installation to energy modelling and performance testing of residential, commercial and utility-scale projects totalling almost 1GW of installed PV. Beth earned a M.S. from Stanford University's Atmosphere/Energy Program in 2009, became a NABCEP PV Installation Professional in 2010.

James Willett is an applications engineer at RES Americas, where he has worked on both distributed and utility-scale solar projects. He has master's degrees in photovoltaic engineering from The University of New South Wales and engineering management from The Polytechnic University of Madrid. He has a background in various solar applications, including off-grid electrification and residential/commercial design and installation.

Project briefing

NEW CONCEPTS IN FLOATING SOLAR TAKE TO THE WATER

Project name: Sekdoorn
Location: Zwolle, Netherlands
Capacity: 14.5MW

In August 2019, a team at BayWa r.e. began construction of its 14.5MWp Sekdoorn floating solar project near the town of Zwolle in the Netherlands. Just eight weeks later, it was complete, 40,000 solar panels afloat on the former sandpit.

The project was the company's third floating solar farm in the country, built with Dutch subsidiary GroenLeven, following on from the 2MWp Weperpolder project in Oosterwolde, and the 8.4MWp Tynaarlo plant in the province of Drenthe. With 25MWp already built in the Netherlands in less than one year, and its biggest project yet, the 27MWp Bomhofsplas partway through construction, BayWa r.e. now claims to be one of the biggest floating solar developers in Europe.

The secret to its rapid build-out is a bespoke floating platform for the modules, designed by German engineering company Zimmerman PV Stahlbau. The decision to design an entirely new floating plant concept came about following careful consideration of those already on the market, explains Franz Krug, project manager of Zimmerman: "We found that that other structures all look nearly the same, so they had the same advantages, but also the same disadvantages."

The Netherlands was chosen as the location for the company's first floating PV projects since BayWa r.e's partner company GroenLeven had already secured tariffs for installation on various lakes. The Dutch feed-in tariff (SDE+) is relatively high, meaning that there was still a working business model in the Netherlands for floating PV despite the higher cost of the floating installation compared to ground-mounted systems.

The partners developed and finessed the resulting 'Zim Float' system in around 18 months, with BayWa r.e. bringing its highly standardised electrical concept from ground-mounted projects to the water. It also prepared the layout of the plant, and the electrical concept from the panels to the injection point to the grid.

System anatomy

The so-called Zim Float platforms are square-shaped solar panel boats, with Huawei inverters floating alongside. The system also integrates maintenance walkways, cable ducts, wave barriers and a floating transformer station. The design makes it highly stable, improving its lifetime and easing maintenance.

The system's stability is the main difference between the Zim Float system and others on the market, explains Edgar Gimbel, head of power plant engineering at BayWa r.e. "We built a special boat, which is 12 modules packed in two floaters on a steel frame, which is very stable. Other systems on the market all have one floater on one module, which connect floater by floater, making them very flexible," he says.

The electrical components are fully integrated into the floating platform, and meet all regulations related to the installation of electrical systems. A grounding system protects from electrical failures, while all cables and components are certified for use in water. BayWa has VDE certification (VDE-PB-0016-2:2016-11) for electrical safety and energy yield, installation quality and planning compliance for solar farms. The VDE Institute has also certified BayWa installation of floating power plants and electrical systems on the water.

Credit: BayWa r.e.

By Catherine Early

"We are 100% safe on the electrical side. Nobody else in the market has this yet," says Gimbel.

Krug adds: "Floating solar is quite young technology and for our first project we wanted the verification of a third party, that what we developed fitted with VDE, the market standard."

The cabling design is kept completely out of the water, hidden under the subconstruction of the floating boats, so that cables are protected from the sun, and have only minimum contact with the water. This guarantees a longer life, as well as easy maintenance. The transformer station is also integrated into the floating system and is VDE certified.

Credit: BayWa r.e.

Speed of construction

The system is built onshore, including the floaters, steel frame, modules and cabling. Up to nine of these "boats" are then attached to together in a kind of "roller conveyor", after which the system is floated out onto the water row by row. A small motorboat is then used to take each row out to its final location on the water.

Prefabricating the system onshore is another key difference to other systems. Typically, these are partly constructed onshore, where modules are attached to floats, but installation of cabling then occurs on the water.

"Prefabrication makes it much easier to install, we are able to build up to 1MW per day, which is roughly 2,700 modules. It's like building a car in a factory, it's a lot of automised stuff," Gimbel says.

He is so confident in the system that he is predicting that the 27MWp Bomhofsplas project, also in Zwolle, will be complete in less than two months.

Built to last

The Zim Float system is not only very fast to construct, but also very safe for workers, Gimbel says. Between each row there is a maintenance street around 2.5 metres wide, which together with the stability of the system make it very easy and safe for workers to walk up and down. All the inverters are also located in this maintenance street, he says.

"It's very easy and safe if you need to change the inverter even in bad weather. Maintenance is actually easier on floating solar than for ground-mounted," he says.

Krug concurs that operations and maintenance (O&M) is very easy on the Zim Float system, which lowers the cost for customers. "Other systems move a lot when workers walk on them, which means it's not that easy to change cables and modules, especially when you have tools in your hands. O&M was really important for us to bring down the OPEX cost," he says.

The safety of the system was verified by Dutch organisation DNVGL, which conducted a risk assessment for O&M workers. This highlighted a few points for improvement, after which BayWa r.e. and Zimmerman tweaked the design. "They told us that we are way better than other systems," Krug says. So confident is BayWa r.e. in the stability of its system, that it tested it by two hundred workers standing on the Weperpolder project simultaneously (see photo above).

Gimbel says that the system will last for at least 30 years. Durability has been taken into account at each stage of the design, such as special covers with full UV resistance for the plastic floaters, and magnesium coating for the steel frame to prevent corrosion, he says.

BayWa r.e. and Zimmerman have also developed different anchoring systems. Other systems are mainly anchored just to the shore, whereas the Zim Float system can also be anchored to the bottom of the lake up to 50 metres.

This improves security, Gimbel says. "Nobody can see where the anchor points are so they can't cut the lines. The standard method of other manufacturers is just to the shore."

Krug explains that the anchoring systems are tailored to each project, after an assessment of conditions at the location. "We don't have a generic solution for anchoring, we do separate mooring anlaysis and options for each project. Because of this we have brought down the anchoring costs a lot," he says.

The partners developed specialised anchors for floating projects. These are driven into the ground at locations defined by mooring engineers, and then tested to ensure they are in compliance with the Eurocode harmonised technical rules for structural design.

Cabling was also specially designed, Krug says. "We had a deep look to the cables, so that we have clear cable routing, with clear cable ducts. Cables or inverters can


Credit: BayWa r.e.

have high costs for O&M if they are under too much stress. This is a disadvantage we found from other systems on the market that float."

BayWa r.e. chose GCL-SI's monocrystalline, monofacial M6 72GF modules for the Sekdoorn project. These are glass/glass modules with an aluminium frame, which Gimbel says is better at dealing with the humidity created by the water than glass/foil modules.

The company asked research institution the Fraunhofer ISE in Freiburg to conduct quality tests on the modules. These included standard test conditions (STC), which is a standard performance test to confirm power output; a test for potential-induced degradation (PID); and tests for light-induced degradation (LID) and light- and temperature-induced degradation (LeTID).

Costs for the Zim Float system are around 20-30% higher than ground-mounted projects. The increase is mainly due to the construction costs of the substructure, which are up to 200% more expensive than those on ground-mounted projects, says Krug. However, the fast installation and shorter cables minimise the price hike, he says.

"The Zim Float system is really compact, we can do 1.7MW/hectare compared with 1.2-1.3MW/hectare on land, so you save a lot of money on cabling," he says.

Despite the systems' higher costs, Gimbel says that attracting investors for its floating solar projects has not been a challenge. Existing investors in its ground-mounted systems have queued up to finance the floating projects, he reports. Floating PV is not a new technology, only a new application of an existing technology, so the return, risk and administration are no different than when investing in ground-mounted projects, BayWa r.e. says.

"We had a waiting line for investment, in fact; we had more interest from investors than we have projects. Interest has been roughly the same as for our projects on land, as they are the same investors," he says.

Greater efficiency

The higher upfront costs of floating systems are rewarded by better efficiency, due to the system being located on water. Zimmerman also designed a special cooling system for the modules, which are installed directly facing the open water surface without any obstacles in between. This means that heat does not accumulate there. The cool water body below the panels is therefore cooling the heated modules. Warm air is rising up through the so-called chimney between the east- and west facing module (see photo above).

The extra efficiency gained through this system depends a lot on the maximum temperatures. BayWa r.e. has calculated that in a relatively cool country such as the Netherlands, the average gained over a year is around 3%. But on hot days, the additional cooling effect can be much more, the company says.

This cooling effect of the water, together with the easy installation of floating solar and the high energy density per hectare, mean that floating PV systems larger than 50MWp will soon be viable in Southern Europe without the need for subsidies or government support, BayWa r.e. believes.

The Zim Float system has other benefits in terms of the environment of water bodies it is built on. BayWa r.e. is undertaking studies to fully assess the effects of its system on water quality, but it believes that it will not have any negative impacts. The water has maximum movement under the panels, and growth of algae is restricted by shadows cast under the panels.

Floating solar systems are also very efficient in terms of land use, and do not conflict with food production. They also have lower levelised cost of energy (LCOE), and construction and maintenance of floating PV plants bears lower risks for employees than working on rooftops. Compact installation and smart cabling result in a very low electricity consumption.

The module layout is designed to promote cooling and enhance performance

BayWa r.e. has a policy to install floating solar only on water bodies that have already been exploited for industry, such as reservoirs, fish farming waters or lakes on former open-cast lignite mines. All of its current projects have been built on former and active sandpits, which are suitable because they cannot be reused for many activities after the final digging depth is reached. Using them for solar therefore creates a double usage of the land.

Both activities can also work in parallel, BayWa r.e. says. Many sandpit operators are still active and creating even bigger water surface while the first finished part of the pit is already used for harvesting the sun's energy.

BayWa r.e. has a further 100MWp of floating PV projects at a late stage of development in the Netherlands, and says it intends to install "several hundred MWp" in Europe over the next few years. The potential for expansion of floating PV technology is huge: the Fraunhofer Institute for Solar Energy Research estimates that 15GW could be installed on decommissioned coal mining lakes in Germany alone, while a study by the World Bank Group identified the potential for 20GW in Europe using only 1% of the surface of man-made freshwater reservoirs.

"We think floating technology will spread quickly over Europe and make a significant contribution to the energy transformation. Grid parity for these systems is around the corner," says Gimbel. ■

Product reviews

Monitoring | Canopy Power's Hornbill v3.0 monitoring software optimises renewable energy micro-grids

Product Outline: Canopy Power has launched the latest update for Hornbill Technology, a technology platform for 24/7 monitoring and management of remote micro-grid systems. Hornbill Base has been enhanced by the addition of local touch-screen Human Machine Interface, surge protection, Uninterruptible Power Supply and additional local data storage. Hornbill Portal now features data download and graph comparison functions, as well as real-time error detection and condition monitoring.

Problem: While remote micro-grid systems are a huge enabler for significant economic development, poor management of them may result in system reliability and performance sustainability issues.

Solution: Hornbill has three essential components – real-time monitoring, remote management and advanced analytics. Linked to a remote micro-grid installation and with control services tailored to individual requirements, Hornbill minimises operation and maintenance costs, maximises uptime, and is claimed to increase project bankability.

Applications: Independent renewable energy microgrids.

Platform: The system is composed of the Hornbill Base – hardware installed at the site with the micro-grid. Hornbill Base comes with communication over Modbus TCP/IP, standard analogue input and digital outputs. It also has an illuminated front panel buzzer for local alarms. Surge protection is provided for main incoming power, ethernet and serial signal. The Hornbill Portal – a cloud-based visualisation and control interface. The micro-grid system performance can be checked on a smartphone or other device, allowing proactive measures to be taken to manage the system and optimise performance.

Availability: January 2020, onwards.

Resource assessment | DNV GL launches new online tool to minimise irradiance data variance for PV power plant projects

Product Outline: DNV GL has launched a new online tool, Solar Resource Compass (https://src.dnvgl.com/), that aggregates solar irradiance from many leading data providers to help users make more informed decisions about the data available and the variance between data sources to help users avoid selecting the wrong data for a solar project.

Problem: As the margins on solar projects are slim, developers, investors and owners require the most accurate tools to select sites and model energy calculations to ensure that their projects will provide the expected financial returns. Using irradiance data from multiple sources could reduce the risk of selecting solar irradiance data that may overvalue or undervalue a solar project.

Solution: Solar Resource Compass allows the user to compare irradiance data from multiple sources for any US project location. The results of the analysis include a statistical comparison of available resources presented in a user-friendly chart, table and map. Solar Resource Compass can be used to source irradiance data at any stage of the project development process.

Applications: PV power plants.

Platform: Solar Resource Compass incorporates DNV GL's analytics (which are based on both industry standard models and proprietary analysis) to calculate the monthly loss factors attributable to dust and snow accumulation. Irradiance uncertainty and soiling accumulation are the two most important site factors needed to properly model the energy potential of a solar energy project. By default, Solar Resource Compass will access data from NREL (including the PSM satellite model and the nearest TM2/TM3 locations), Meteonorm and DNV GL's SunSpot irradiance model.

Availability: February 2020, onwards.

Module coating | DSM's retrofit anti-reflecting coating boosts PV power plant yield

Product Outline: The 'Retrofit AR' coating, an offspring of DSM's anti-reflective coatings, gives older, uncoated solar modules an instant power boost of up to 3%, according to lab and field tests.

Problem: Anti-reflective coatings on the front side glass of PV panels have increasingly become a key way to increase PV panel yield, providing around a 3% boost to performance. However, many older operating PV power plants may not have panels with an AR coating and can suffer from transmission losses, due to high reflectance.

There is a need for AR coatings that can be applied competitively on older PV panels in existing solar parks – without having to replace them under expensive repowering programmes.

Solution: The Retrofit AR coating from DSM is typically applied by a tractor-mounted spray coating applicator at the rate of approximately one PV panel per second (around 10,000 panels per day) in the landscape configuration. Enerparc recently unveiled the results of a two-year pilot programme with the technology. The DSM Retrofit AR coating achieved a power gain of between 2-3% across some eight different power plants in Germany and Italy.

Applications: AR coatings can be applied competitively for older PV panels in existing solar parks.

Platform: The performance has been extensively lab-tested according to all IEC 61215 standards and other common PV glass and module tests. The silica-based coating is highly stable even after 259 hours of UV exposure in the IEC weatherometer (WOM) tests, both in wet/rainy and dry cycles. A small loss in transmittance occurs after 1,000 hours of rigorous damp heat testing after 10 cycles HF (< -0.5%).

Availability: Commercially available since late 2019.

Inverter | Growatt offering XH series of storage-ready inverters

Product Outline: Growatt's new XH series of storage-ready inverters work with a low voltage battery and have a battery interface which can be easily extended later to a storage system without retrofit cost, providing home owners who are looking to convert their rooftop PV systems into solar storage systems in the future.

Problem: As energy storage system costs continue to decline, multiple gigawatts of residential and commercial rooftop PV systems become economically viable to retrofit an energy storage system. However, extra costs are incurred with the need for a new hybrid inverter. Providing a future-proof PV inverter solution would reduce component and installation costs.

Solution: The Growatt MIN 2500-6000TL-XH storage-ready inverters are claimed to be the most up-to-date solution for residential PV systems in the industry. They have two MPP trackers and 1.4 DC:AC ratio. Its string current can reach 12.5A and is compatible with bifacial modules. For system monitoring and remote O&M, customers have multiple options such as WIFI-X, GPRS-X, 4G-X, RF or RS485. With the datalogger installed, customers can have access to Growatt Online Smart Service platform for reporting issues and troubleshooting.

Applications: Residential and commercial rooftops.

Platform: The TL-XH adopts integrated top cover case design and there are no screws on front cover. The design has fewer gaps and provides better protection against water and dust. Aerospace-grade materials are used for TL-XH, making the inverter light, durable and flame-retardant. It is around 10.8kg, 35% lighter when compared with other old generation inverters. Internally the inverter has invisible cable routing.

Availability: Available since September 2019w.

Inverter | Ingeteam hybrid inverter puts battery inverter and a PV inverter in a single platform

Product Outline: Ingeteam's latest hybrid inverter features a battery input and two more inputs for PV panels. Production of this new inverter is set to start in May 2020 and will be available with two power outputs: 3kW and 6kW.

Problem: These battery inverters integrate two PV inputs in order to offer greater functionalities as the PV inputs reduce the cost of the installation, allowing a battery inverter and a PV inverter in a single platform.

Solution: The INGECON SUN STORAGE 1Play TL M hybrid inverter features an

energy management system, making it possible to implement advanced operating modes, such as self-consumption, and facilitating system monitoring through the INGECON SUN Monitor smartphone application. For grid-connected systems, the inverter features a back-up functionality so that, in the event of a grid outage, the critical loads can be powered from the batteries and PV panels. Each PV input has its own maximum power point tracking system, making it ideal for harnessing the maximum amount of energy on roof-mounted, self-consumption PV installations, with the PV solar panels positioned in two different orientations.

Applications: Suitable for both grid-connected and stand-alone systems.

Platform: The system commissioning and the inverter's firmware update can be performed remotely with the application via PC, tablet or smartphone. The new hybrid inverter is said to be compatible with lead-acid and lithium-ion batteries and is also compatible with the storage systems made by the market's leading manufacturers.

Availability: May 2020, onwards.

Tracker | NEXTracker's 'NX Navigator' control system adds extreme weather safety

Product Outline: NEXTracker has released 'NX Navigator', its next-generation software and smart control system that enables power plant operators to efficiently monitor and securely control their solar assets for increased production and reliable operation across a wide range of weather conditions.

Problem: Many utility-scale PV power plants lack 'smart' advanced control systems that can react quickly to rapid commands to put the entire solar power array into a safe 60 degree stow angle when extreme weather conditions are expected such as hail storms that can cause major damage.

Solution: For monitoring, plant operators are provided timely information for key parameters at the site, subfield, and individual tracker levels, including precise array and angular values. For control, NX Navigator allows authorised PV plant operators to schedule maintenance operations such as cleaning and mowing, and instantly command the tracker in the event of extreme weather events such as hail, hurricanes and heavy snow. In the case of hail, a single operator command will rapidly put

the entire solar power array to a safe 60 degree stow angle. This action will have the benefit of up to tripling the hail resistance module toughness and dramatically reducing damage potential, according to independent tests carried out by RETC (Renewable Energy Test Center). In the case of snow shed, an authorised operator can pre-schedule two snow shed operations in a single day, which increases production by reducing snow cover on solar panels.

Applications: Utility-scale PV power plants.

Platform: With an intuitive graphical user interface (GUI), NX Navigator builds on the company's proven 'TrueCapture' system with new monitoring data, maintenance controls and instant risk avoidance tools using high rotation speed trackers.

Availability: February 2020, onwards

Product reviews

O&M | PVEL, Ariel Re and Beecher Carlson providing comprehensive PV plant insurance programme

Product Outline: PV Evolution Labs (PVEL), Lloyd's of London syndicate Ariel Re (a member of Argo Group), and Beecher Carlson Insurance Services have launched 'PV PlantProtect', a risk mitigation and insurance programme using technical due diligence best practices to improve solar project economics for developers.

Problem: Gaps in traditional insurance and manufacturer warranties have previously left developers and investors exposed to revenue risk. There has not been a comprehensive insurance solution on the market.

Solution: PV PlantProtect enhances solar power plant reliability while providing developers with revenue certainty as they

build financial models. It helps developers improve debt terms and project economics by guaranteeing revenue. Once developers sign on for PV PlantProtect, they gain insurance pricing visibility in the early stages of development. The Ariel Re team not only underwrites tailored risk solutions that deliver commercial value but also turns around reliable pricing and terms quickly so that developers can readily integrate insurance into their strategies. PVEL coordinates, oversees and executes the technical and diligence items such as resource measurement and site characterisation, testing for modules and string inverters as well as equipment pre-production factory audit and production oversight. Ongoing resource and performance monitoring of the operating PV power plant is also undertaken.

Applications: Offered for the duration of the revenue contract, PV PlantProtect is available for utility-scale solar power plants in any region, including systems with bifacial modules.

Platform: The insurance policy covers revenue losses due to weather, component performance and availability, system design, soiling and operations and maintenance (O&M), and other insured causes of loss.

Availability: December 2019, onwards.

Module | REC Group's 'Alpha' series panel comes in 120 half-cut heterojunction cell format and 380Wp output

Product Outline: REC Group's latest high-efficiency 'Alpha' Series PV panels use in-house 120 half-cut heterojunction (HJ) cells with an advanced connection technology from Meyer Burger to provide 380Wp output in the conventional 60-cell format. With HJ, REC combines the benefits of crystalline silicon solar cells with those of thin-film technologies for higher efficiency and energy yield, even at higher temperatures.

Problem: In the European Union, all new buildings are required to be Nearly Zero Energy by the end of 2020; in California, U.S., starting in 2020. Other countries are expected to adopt similar legislation in the

future, which requires the highest power density PV panels, while reducing the balance of system (Bos) costs.

Solution: The Alpha Series is claimed to deliver the world's best power density on a 60-cell module format to meet residential and commercial rooftop LCOE requirements. This equates to a claimed 20% or higher power output from the same area and the same number of panels. The Alpha's energy efficiency will make it easier for new-build owners to meet building energy performance directives such as those in the EU or California.

Applications: Residential and commercial rooftops.

Platform: The Alpha Series has two versions available: with white backsheet (up to 380Wp), and as a full-black panel for aesthetics (up to 375Wp). The Alpha features high efficiency n-type mono wafers between thin layers of amorphous silicon. The unique 30mm thin frame construction allows more panels per pallet, an easy installation and allows the Alpha to withstand snow loads of 7,000Pa.

Availability: Currently available.

Design | SolarEdge's 'Designer' tools provides extended feature set for commercial PV installations

Product Outline: SolarEdge is introducing an extended feature set on its 'Designer' tool that specifically supports commercial PV systems. To make commercial solar design faster and easier for large PV systems, SolarEdge is adding a variety of new features to its free, web-based PV design tool.

Problem: To help maximise self-consumption in commercial projects, better modelling tools are required that can incorporate not only flexible design rules but provide in-depth insight into expected energy production of the PV system being planned and designed.

Solution: To help maximise self-consump-

tion in commercial projects, users can now select the most suitable consumption profile from a list of different commercial load profiles that represent typical energy consumption patterns, such as in factories, retail stores, and office buildings. Modelling has also been made easier with a variety of new features, including multi-selection of objects, copy pasting and improved edge alignment. For the electrical design of commercial PV systems, Designer now provides an auto-string layout feature that, at a click of a button, quickly and automatically follows SolarEdge's flexible design rules. Users can also duplicate wired blocks of modules by stringing them together and using the duplication feature to easily and quickly expand system size.

Applications: Commercial PV systems

Platform: Designer offers accurate energy simulations and reports by providing insight into expected energy production of the PV system being planned and designed. Included in the simulations are shading analysis as part of the energy simulation calculation and additional system losses. Detailed irradiance analysis is also included in order to optimise PV design.

Availability: January 2020, onwards.

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Asset management: maximising the potential of solar power plants

Asset management | The services and skills offered by asset managers have a central role to play in boosting the value of solar PV investments. Adele Ara, Máté Heisz, Magda Martins, Diego Molina and Paul Norrish outline the key recommendations in the solar industry's first set of best practice guidelines for asset managers

Asset managers as key value contributors during the plant lifecycle

There is a myth about solar photovoltaic (PV) plants, that once the plant is built and the panels installed, as long as the sun is shining, the plant will require minimal management and operational effort. As more and more large-scale solar plants are being developed and built, it is important to recognise that this is, indeed, a myth.

Stakeholders in the industry, whether strategic or financial investors, have been crucial for the continuous growth of solar PV and have sustained high expectations as to the ultimate performance – both operational and financial – of solar plants. This has resulted in stakeholders indirectly imposing ambitious targets for service providers in the solar sector.

This article examines the wide variety of services an asset manager should provide to a solar PV owner, as a means of achieving the desired return. To achieve the expectations set by many owners and investors in the industry, it is not enough for the sun to shine – asset managers must deploy resources, skills and strategies well beyond what the industry expected in the early days of solar. These skills involve operating advanced digital asset management platforms, which enable the effective management of diverse solar portfolios. To help key stakeholders, asset managers, and asset owners in particular, deal with these new challenges, SolarPower Europe's O&M and Asset Management Task Force developed the industry-first Asset Management Best Practice Guidelines, based on the experience of leading asset management experts, covering the essential topics to facilitate high-quality service provisions.

When considering a solar PV plant as a business unit in its own right, it becomes apparent that, while fewer risks are involved compared to a traditional power plant, it is not risk free from a financial, operational and technical perspective. For the asset manager, this risk profile underpins the need for a multipronged approach to the risk mitigation and management of solar plants, and the importance of working efficiently to address the significant volume of work in an increasingly competitive environment.

The role of asset managers in solar PV is assuming growing importance

This challenge has also presented an opportunity to forward-looking asset managers. It is apparent that successful asset management organisations, whether independent service providers or business units within independent power producers, are not simply driven by the objective of fulfilling the services related to their scope of work, but are ultimately focused on realising the maximum return potential of the solar plant.

If the mandate of an asset manager involves working to ensure that each solar plant meets its expected value generation for the owner, then the entire suite of asset management services is designed to reduce volatility, through the stabilisation of operations, and to enhance performance, through the optimisation of the sites with the goal of increasing their longevity.

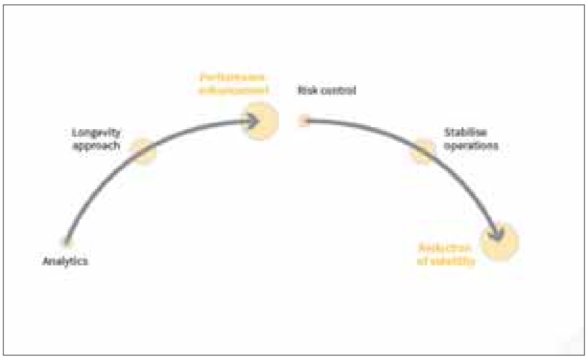

Figure 1. Steps to agree strategic approach to increased profitability

Technical asset management and critical monitoring services

Technical asset management (TAM) is focused on providing value to the asset owner through assistance relating to the regular operations of the plant. TAM involves a holistic approach, anticipating the asset owner's requirements in terms of the management support of its operations; not only from an asset perspective, but also keeping in mind other stakeholders, such as lenders, suppliers, or advisors.

The general guidelines when carrying out a TAM contract include the following activities:

- Communication with the asset owner and all relevant stakeholders, focusing on reporting the owner's needs and presenting suitable alternatives that can add value to the plant;
- Optimisation of value for the asset owner by maintaining a regular interest in opportunities applicable to the project – such as maximising energy production, minimising downtime, reducing costs;
- Mitigation of operational, financial and technical risks, and avoidance of general distress of the asset owner towards the plant – including compliance with national and local regulations and contracts, and repowering investments;
- Selection and implementation of asset management software and portfolio monitoring system for operational projects – such as, monitoring performance of operations assets, issue resolution and coordination of information flow;
- Insurance of risk management systems and processes, and contributing to policies, processes, and procedures.

The asset manager is expected to play an integral role in the design process from pre-construction to operation, and must ensure that the best output is presented to the asset owner. Such an important task may only be accomplished by working closely with local teams and partners.

The coordination of the design process is something that the asset manager must do when dealing with sub-contractors and on-site issues; the ability to manage the process and ensure it is cost- and time-effective are key drivers of success. In this regard, the asset manager must be a central point of contact for local team members working on operating assets, and the main person responsible for monitoring a pipeline of operational assets. The role includes not only the oversight of day-to-day administration, but also reporting on information flow, policies and corporate governance, along with monitoring project performance. To perform these tasks, the asset manager must be supported by critical monitoring systems and a dedicated team of experts.

The basis for the asset manager's data and monitoring requirements should be a specialised asset management platform, which will cover the storage and management of operational and non-operational data related to the asset or portfolio, as well as static and dynamic data. Such a platform makes it possible for the industry to transition to an asset-centric information management approach, which addresses five key challenges: (1) minimising production losses; (2) significantly improving efficiency; (3) reducing lack of data transparency; (4) improving the levelised cost of energy (LCOE); (5) positively impacting the return on investment for solar asset owners and operators.

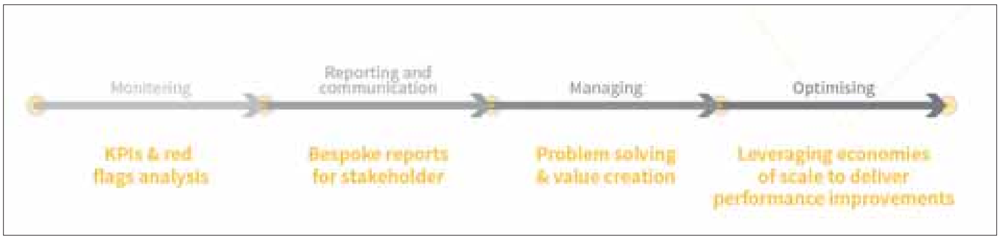

Figure 2. Drivers of operational asset management services

The asset management platform will include plant performance data management, which covers key performance indicators with a daily follow-up, incident remote detection, direct dispatching, and standard reporting elaboration. Further, the platform will include O&M site activity supervision, covering the full traceability of all maintenance completed for the plant or to particular equipment. Finally, the platform includes contract management and administrative optimisation.

The detailed data storage and treatment promotes the reduction of detection time and downtime, which will result in mitigating energy losses in the advent of an abnormal situation. Strategies for reducing and controlling operation & maintenance (O&M) costs, based on comprehensive plant data, can also be devised. The automation of monitoring, which is becoming increasingly popular, in combination with advanced data analysis, can lead to significant returns. This technology allows operation teams to make decisions based on the up-to-date data they receive from monitoring providers, SCADA systems, data loggers, inverters, satellite irradiation data, weather forecasting services and other sources.

Beyond the business sector trends, there is a growing tendency of opting for solutions that integrate the functionalities of monitoring systems, computerised maintenance management systems (CMMS) and enterprise resource planning systems (ERP) into one central platform. These integrated solutions should be regarded as a valuable contribution to asset management, highlighting that centralised data of a high quality is critical for reliable asset operations and effective decision-making. In fact, a recent study conducted by MIT showed that companies using data-driven decision-making are 5% more productive and profitable than their competitors. Indeed, asset managers are increasingly relying on advanced analytical tools to help asset owners reduce the LCOE and to facilitate the development of solar projects around the world.

Commercial and financial asset management

Commercial and financial asset management involves monitoring the business aspect of the solar PV plant, providing recommendations for improving the overall status and performance. This includes specialised management based on reporting individual and consolidated figures of the asset owner's portfolio and breaking down the contribution of each plant to compare it with financial model assumptions and historical years. Such analysis will comprise detailed financial interpretation and understanding of the results, and a periodic report can be fine-tuned in accordance with the asset owner's needs.

Strategy management refers to the need for the company to develop and implement a strategic framework for all of its asset management activities, implementing it with the required change management process and monitoring through regular audits and management reviews. Following from this, accounting is an essential area of expertise, responsible for meeting local and international legal, regulatory and tax requirements, as well as the reporting of financial transactions, including bookkeeping, administration and accounting procedures.

The most significant challenge of the asset manager is the control of revenues and expenses through rigorous invoicing monitoring. The asset manager is thus responsible for confirming the reading of the meters based on information collected on site by the O&M team, and for validating and comparing it with the billing issued by the electricity purchaser. Further, working capital reconciliation activities will see the asset manager overseeing accounts payable and accounts receivable through rigorous client and supplier contract negotiation, ensuring that the accumulated revenue generated is enough to meet the supplier's payment.

The asset manager is responsible for conducting financial analysis in order to achieve the company's financial goals. This refers to the set of processes, policies and procedures that enable the analysis of a company's actual activities from different perspectives at different times. Further, the asset manager is a key player in supplier relationship management – including O&M suppliers, landowners, insurance, technical consultancy, legal consultancy and electricity providers. With a comprehensive perspective of the operational business, financial performance and the supplier's contracts in place, the asset manager can add value by understanding the project's needs and pursuing individual contracts in order to ensure maximum business optimisation. It is not uncommon for EPC and O&M contracts to include penalty clauses linked to specific KPIs to protect the asset owner's interests. O&M contracts may also include bonus or penalty mechanisms linked to KPIs such as plant availability and reaction times, among others. In case of bonus payments, the asset manager must make suitable provisions in terms of financial planning; in case of penalties, they must calculate and invoice the correct amount to the O&M provider.

The asset manager must maintain a comprehensive understanding of the financing contract and the periodic reporting of financial statements, coverage ratio monitoring, escrow accounts monitoring and business plan updates, among other requirements. Additionally, the asset manager is responsible for monitoring the non-financing contracts that are indexed to and locked by the project finance – such as land lease, O&M and security – in order to avoid penalties raised by contract non-compliance.

Finally, the asset manager must have

a comprehensive understanding of the equity agreement and the bank loan requirements in order to work towards the solar plant's maximum optimisation and profitability, with an eye on shareholder remuneration and complying with debt services. This includes knowledge of local tax authorities' requests, which could result in distinctive tax legislation interpretations with the potential for tax exemption.

It becomes clear that the role of the asset manager includes the capability of contributing to the development of new indicators and of innovative reporting solutions. Therefore, the asset manager may contribute significantly to the improvement of the performance of the solar plant by managing all of the above activities. Overseeing the coordination of a set of corporate financial services that are essential to assessing the economic and financial performance of the plant is a crucial part of the asset manager's job.

Procurement strategy

Asset managers should leverage their experience and network of contacts to both identify the right trade-off between quality of service, price and key contractual terms, and constantly adapt all of them to market conditions. In line with the procurement best practices, it is suggested to use a Kraljic Matrix (see Figure 3). The supplier's class is based on two key criteria: (1) strategic relevance, in terms of value-added, impact on profitability and overall costs in the supply; (2) the complexity of the supplier market, in terms of the number of suppliers, features of the supply (scarcity).

Taking these criteria into account, the main suppliers involved in a solar power plant operation can be allocated in the following matrix:

Once a classification of the supplier class is analysed, then the supplier must be selected. The recommended methodology to select a supplier is the analytical hierarchy process (AHP), which is a recognised and standardised supplier selection methodology. The AHP methodology evaluates a set of potential suppliers, with each receiving a rating based on a set of evaluation criteria, assessed on the basis of specific indicators. It is important to note that since some of the criteria could conflict, the best option is not always the supplier that optimises every single criterion, but rather the one that achieves the most suitable trade-off among the different criteria. AHP allows for not only quantitative but also qualitative elements to be considered; it also enables a different weight to be attributed to the different indicators and selection criteria, and can thus attribute rational importance to the various aspects of the decision-making

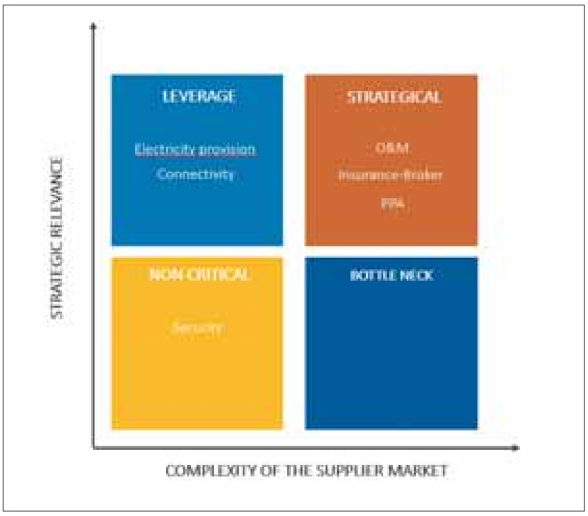

Figure 3. Kraljic Matrix of the main suppliers of solar power plant operation

process that could vary in a different environment.

The asset manager can add value in the procurement process, not only by leveraging its proprietary knowledge, based in particular on direct observations and historical evidence of the activity of various suppliers, and network of contacts, but also by allowing its clients to benefit from a scale effect to run a tender process. If the solar portfolio has sufficient scale, it is advisable to avoid single sourcing (i.e. allocating 100% of the activity to the same contractor). Instead, either a second sourcing (by identifying the main contractor which would manage the majority of the plants and a second contractor with more limited exposure) or parallel sourcing (with two or three contractors that manage similar percentages of the portfolios) is recommended.

In the case of portfolios with bank financing in place, the process of selecting the strategic contractors – mainly O&M, insurance companies and PPA counterparties – should take the prescriptions of the loan agreement into account. The selected supplier and the methodology of selection should be approved by the financing institution following a qualification process.

To monitor the supply account, the asset manager should identify certain indicators, periodically monitor them, and take appropriate and timely action in case of situations that are not aligned with expectations. Moreover, the asset manager should keep strict control not only on the supply side, but also on the demand side, by ensuring smooth interaction and regular communication with the suppliers.

Future challenges in a growing industry

As the solar industry is maturing, and owners are becoming increasingly industrialised, the role of asset managers will need to evolve beyond mere service provision. The industry is entering a new chapter of unsubsidised generation, a trend that is inevitably shifting the risk paradigm for owners and investors in solar plants. Not being able to rely on subsidies and government support introduces an incremental level of risk; solar plants are no longer relatively simple recipients of government-backed supporting schemes, rather they are becoming fully fledged electricity suppliers. This necessitates more sophisticated requirements for forecasting and remote operation of the sites.

This new risk allocation leads toward an expansion of the responsibilities and services of asset managers, as well as a further diversification of capabilities required to successfully manage solar plants. Further, this presents an opportunity for asset managers prepared to anticipate the new challenges that owners face, ultimately reshaping their services toward two different clients: the asset owners, as well as the energy consumers or electricity off-takers.

Asset managers must expand their scope and embrace investments in analytical tools as a necessary enabler to face the new challenges posed by the unsubsidised era. This will help to increase the understanding of solar plant behaviour and improve the ability to control and operate the plants more effectively.

This push toward new services to support the requirements of the unsubsidised market further emphasises the need for asset managers to contribute to optimisation throughout the lifecycle of solar PV plants. The longevity, longer-term sustainability and ability of the plant to deliver on owners' and off-takers' expectations is also dependent on new developments and projects having the opportunity to incorporate in their design, construction, contracting and financial strategy, the lessons learned during operation. Asset managers are uniquely placed to facilitate this feedback loop, thus creating additional value for asset owners.

In 2020, SolarPower Europe's O&M and Asset Management Task Force will address these future challenges in its upcoming Version 2.0 of the Asset Management Best Practice Guidelines. Experts and businesses that would like to be part of this initiative are invited to contribute. ■

Version 1 of the "Asset Management Best Practice Guidelines" is available via www.solarpowereurope.org

Authors

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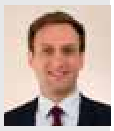

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Increase of PID susceptibility of PV modules under enhanced environmental stress

Module degradation | Potential-induced degradation (PID) is still one of the main reasons for unpredictable power losses in PV power plants. Volker Naumann, Otwin Breitenstein, Klemens Ilse, Matthias Pander, Kai Sporleder and Christian Hagendorf of Fraunhofer CSP examine how the PID susceptibility of PV modules is influenced by environmental stress. It is found that PID may develop in originally PID-resistant modules after a period of one to three years of unsuspicious operation, depending on climatic conditions

Credit: Fraunhofer CSP

State-of-the-art assessment of PID susceptibility and leakage currents of aged modules under accelerated test conditions, using the PIDcheck test device

Potential-induced degradation (PID) of PV modules containing silicon solar cells is an issue with high relevance to the long-term reliability of PV systems [1]. Despite knowledge of methods for mitigation of PID for standard module technologies, there are still new cases of PID arising related to new technologies such as bifacial solar cells or cheaper packaging materials. It was observed that even PV modules designed and specified to be "PID-free" can develop PID under particular outdoor conditions. Especially humid and hot climates in combination with soiling can lead to a change of the electric properties of the module encapsulation, which results in PID degradation of initially "PID-free" modules, in particular when they exhibit a conventional metal frame and a polymeric back sheet, which is to some extent water permeable. This is attributed to the change of the electric conductivity of the glass surface and of the encapsulating materials [2] causing increased leakage currents on the path from the frame across the glass surface and through the module encapsulation layers and thus change of the electric field in the anti-reflective coating (ARC) of the solar cells.

In a PV power plant, many modules (each delivering a voltage of about 35V) are switched in series, leading to voltages to ground up to several hundred volts. Both the module glass and the polymer back sheet are no absolute insulators, therefore tiny leakage currents may flow between the cells in the modules and ground. The leakage current that flows under high-voltage stress of 1,000 V amounts to typically some 10μA/m² for solar modules with soda-lime front glass and EVA encapsulation. This can be measured outdoors e.g. using the PIDcheck test device, as shown above.

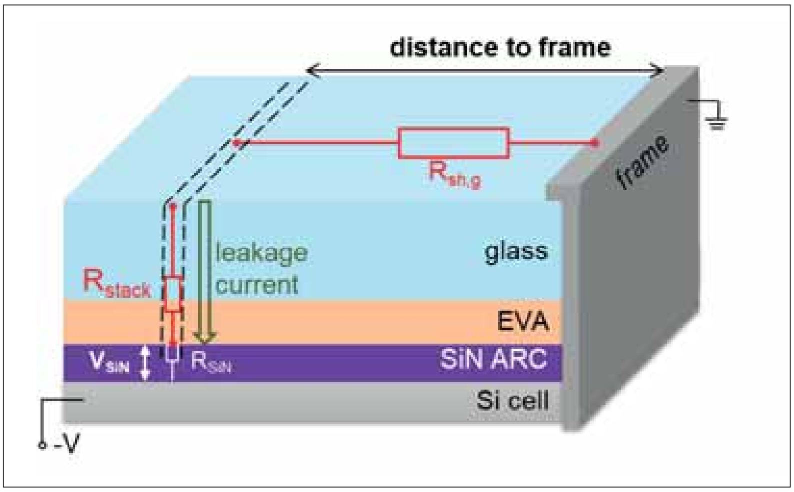

Figure 1. Equivalent circuit for the leakage current path at the front side of a framed PV module (voltage divider model). $R_{sh,g}$ and R_{stack} are subject to changes due to environmental influences like soiling and moisture. The voltage across the SiN ARC of the solar cells determines the strength and rate of PID and depends only on the local leakage current (density) through the encapsulating layer stack and the electric properties of the SiN layer (R_{SiN})

PID may occur if the voltage drop across the insulating SiN anti-reflective coating (ARC) layer at the top of the cells V_{SiN} exceeds a certain limit, driven by the leakage current. In this work, PID of the shunting type [1] (also called "PID-s") is addressed since currently it is the most detrimental type of PID.

Figure 1 illustrates the leakage current flow in a module. The Si cell is assumed to lie on a high negative voltage $-V_c$, since only negative cell voltages are known to lead to PID of the shunting type [1], and the metallic frame is assumed to lie on ground potential. Then, for enabling leakage current to flow to the cell at a certain lateral position of the module, first the current must flow horizontally to this position via the glass surface sheet resistance $R_{sh,g}$, and then it flows vertically through the stack of glass and the encapsulating polymer ethylene vinyl acetate (EVA) to the cell having a resistance of R_{stack}. Note that for this stack the EVA layer represents the limiting resistance, since the resistance of the glass is relatively low. On top of the cell there is an anti-reflective coating (ARC) made by amorphous silicon nitride (SiN), which is an excellent insulator. However, this layer is very thin (below 100 nm) and thus does not contribute significantly to the resistance across the layer stack R_{stack}. If the voltage across this layer V_{SiN} exceeds 5-10 V, which is well below the cell voltage to ground $-V_c$, leakage current J_{leak} flows through, which may lead to PID. It is known that V_{SiN} depends logarithmically on J_{leak} [3]. Thus, the circuit shown in Figure 1 represents a voltage divider [3], where the leakage current density J_{leak} and thus the voltage V_{SiN} (being critical for PID) becomes the larger, the lower the sum of $R_{sh,g}$ and R_{stack} is. In this work, the specific variations of the resistors $R_{sh,g}$ and R_{stack} are to be determined quantitatively in dependence of soiling and the humidity soaking process.

In the approximation of ohmic resistors the voltage across the SiN ARC V_{SiN} along a specific current path or location at the module, respectively, is given by

$$V_{SiN}=V_c \; R_{SiN} \,/\, (R_{sh,g}+R_{stack}+R_{SiN}) * J_{leak} \qquad (1)$$

Experimental approach

Thirty-six single-cell mini modules with three different commercial EVA encapsulation materials (A, B and C) were manufactured. The solar cells are special PID-susceptible multicrystalline silicon PERC cells with dimensions of 156.75 x 156.75 mm². The layer stack of the mini modules comprises (from front to rear): 3.2 mm low-iron float glass, EVA foil, solar cell, EVA foil and the back sheet. In addition to the mini modules, EVA-glass laminates with dimensions of 10 x 10 cm² were prepared using the same glass and EVA foil.

For acquisition of the electrical resistance of the clean and dusted glass surface as a function of the surface humidity, the surface humidity was increased from ~30% to ~100% by cooling of the mini module at constant air temperature and humidity. The temperature of the surface was measured with a precise thermocouple while the chuck was cooled from ~30°C to about 1 K below the dew point (~7°C), which represents 100% RH. The temperature profiles are recorded and used for calculation of surface humidity values.

The sheet resistance as a function of the relative surface humidity is calculated by measuring the current between two adhesive metal electrode strips on the glass surface before and after the soiling test by using a Keithley 2601A source measure unit. The applied voltage was 40 VDC.

"Soiling" means the unintended deposition of dust particles at the surface of solar modules during operation, which leads to additional light absorption and to a decrease of the glass surface sheet resistance, as mentioned above. One of the mini modules has been subject to soiling tests in a self-constructed soiling chamber, which is capable of controlled dust deposition at defined environmental parameters. For this, Arizona Test Dust A2 fine was used. The dust settled from the dust aerosol at about 40% relative humidity (RH) and 22°C ambient and 30°C surface temperature over 30 minutes, so that a surface coverage (area covered with dust) of about 20 % was reached.

For assessment of the influence of water ingress in the polymeric encapsulation foils, damp heat soaking of the mini modules is performed in a damp heat chamber at 85°C, 85% RH for 500, 1,000 and 2,000 hours. At each

> "Despite knowledge of methods for mitigation of PID for standard module technologies, there are still new cases of PID arising related to new technologies such as bifacial solar cells or cheaper packaging materials. Even PV modules designed and specified to be 'PID-free' can develop PID"

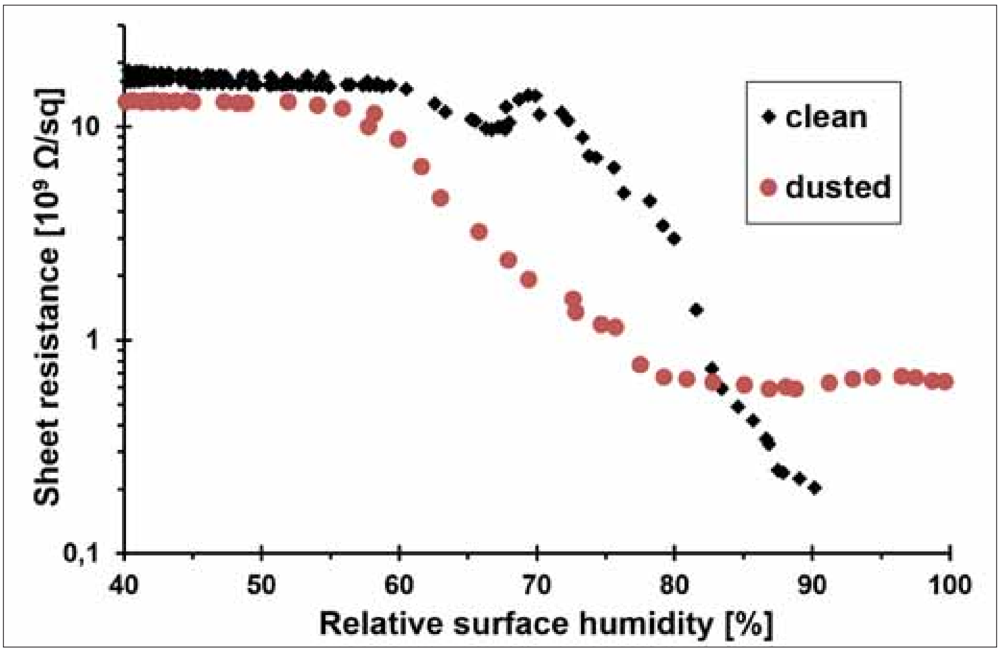

Figure 2. Glass surface sheet resistance $R_{sh,g}$ measured at the clean state (black) and after a well-defined soiling test (Arizona Test Dust) with a final dust surface coverage of ~20 % (red)

condition, including the dry (initial) state, PID tests and characterisation of the EVA have been performed at similar mini modules. For measurement of the water uptake of the EVA by so-called Karl Fischer titration, ~4 cm^2 sized pieces of the front side EVA are delaminated out of the mini modules at the centre and at the corner of the solar cells.

PID tests are performed using four PIDcon test devices by Freiberg Instruments, equipped with mini module test capabilities. The high electrical potential of +1,000 V is applied to the electrode that contacts the front glass of the mini modules on an area equal to the cell area. During the PID tests the shunt conductance of the cells is measured. In addition, the leakage current that is flowing through the glass and EVA layers is recorded.

The water content-dependent electric behaviour of two EVA samples is additionally measured at glass-EVA laminates, using a voltage source up to 1,000 V and a Keithley 2601A source measure unit for current measurements in the nA…μA range. The 10 x 10 cm^2 sized glass-EVA laminates are covered with a perforated Al foil on the EVA with small (sub-mm) holes in the Al foil at a pitch of 1 cm. They are tested at initial (dry) condition after lamination as well as after a one-week damp heat cycle, when the water uptake was presumably saturated.

Influence of soiling on surface sheet resistance

In Figure 2 the measured dependence of the glass surface sheet resistance is shown as a function of relative humidity level for two surface conditions: clean and dusted. We see that already for low humidity (below 50%) the dusted surface shows a slightly lower sheet resistance than the clean one. This difference becomes much stronger for humidity above 55%. Interestingly, the resistance of the dusted surface saturates for humidity above 80%, whereas that of the clean surface does not. This finding could be explained by the formation of a closed ultra-thin water film in the case of the clean sample above 80% humidity, but the proof requires more research. The basic result of Figure 2 is that the glass surface sheet resistance starts to reduce significantly at humidity levels well below the dew point of 100%. Note that the Arizona test dust used here does not contain any salts and only minor fractions of other hygroscopic contents. We attribute this behaviour to capillary condensation at the surface, which may happen both for the dusted and the clean surface already at lower humidity levels.

Moisture ingress to EVA

Figure 3 shows the water content (measured by weight) of the front side EVA in mini modules for the three investigated EVA foils, extracted from the centre and the corner in front of the solar cell after 0, 500, 1,000 and 2,000 hours of damp heat soaking. At the

centre: corner:

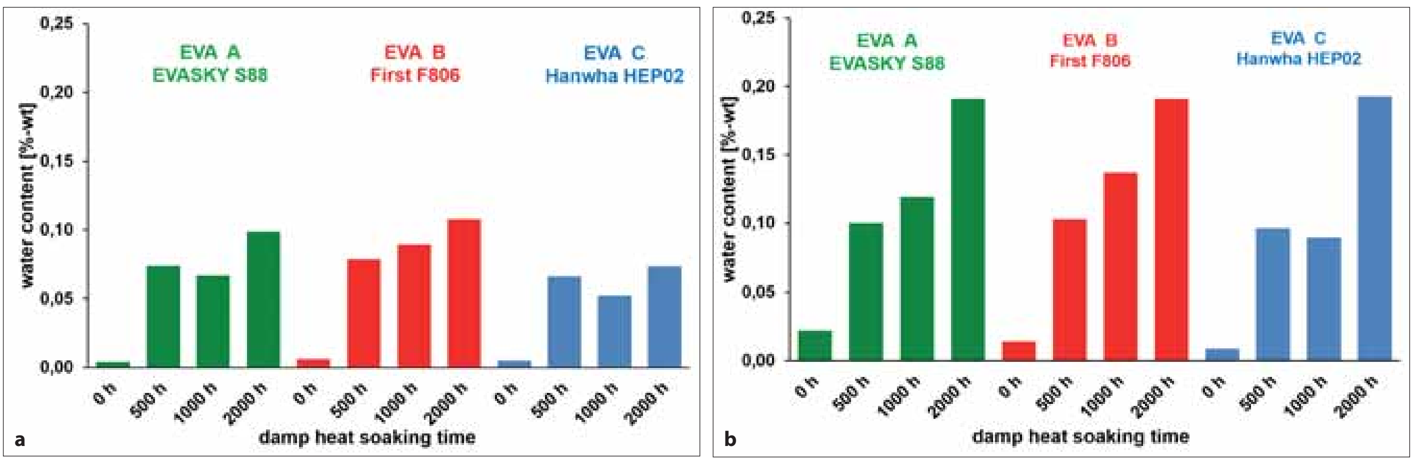

Figure 3. Water content of the front side EVA within mini modules as a function of damp heat soaking time (left) at the centre of the mini module; (right) at a corner of the cell

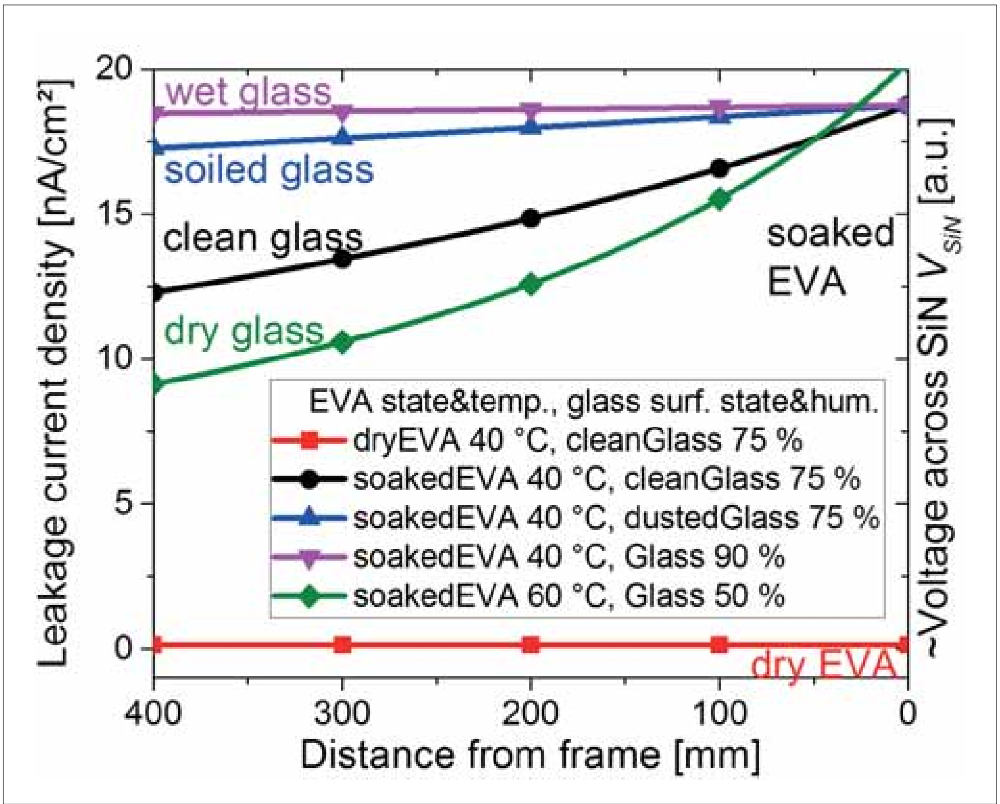

Figure 4. Calculated leakage current density as a function of the distance from the module frame based on measured electrical properties of the front glass surface (clean vs. soiled) and EVA (dry vs. damp heat soaked, here: EVA C)

centre position, the initial water content (in dry condition after lamination) is measured to be lower than 0.01% for all three EVA foils.

The damp heat conditions expedite the water ingress that will happen over time in the field [4]. As can be seen from Figure 3, the water content at the centre of the cell is lower compared to the corner just because of the different lengths of the diffusion paths. With increasing soaking time, the water content increases, but at different rates for the three EVAs. EVA A and B have quite similar soaking behaviour while the water uptake rate in EVA C is lower.

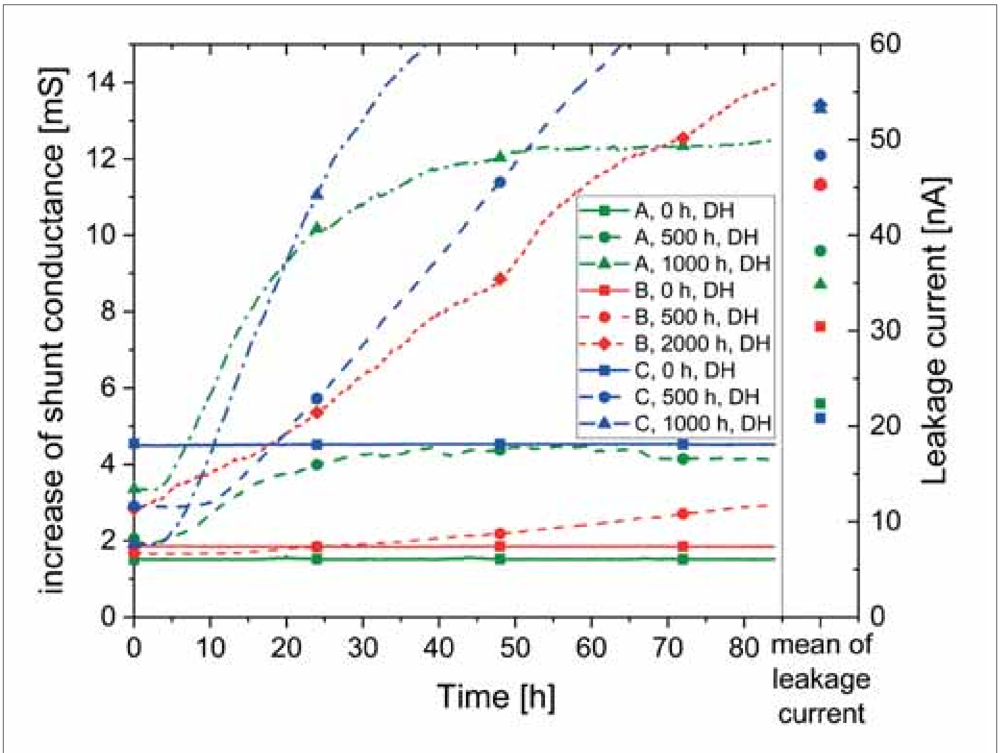

Figure 5. PIDcon PID tests at mini modules after different durations of damp heat soaking exhibit a significant increase of the PID (shunting) susceptibility of modules due to increasing water content of the front EVA

From the corner results (Figure 3b) after 2,000h, it seems that all materials will reach the same saturated value. Even if 2,000 hours are not representative for all climates, the significant increase of water content even after 500 hours of damp heat soaking, being equivalent to one to three years of outdoor weathering in tropical to arid climates [4], is remarkable. Consequently, brand-new modules, which are normally supplied for PID testing, generally have much lower moisture content than will later be the case in operation. Therefore, the PID testing on such modules may lead to false-negative results, since in operation the modules may absorb water and thus become PID-susceptible at some point.

Leakage current modelling

Based on the voltage divider model presented in Figure 3, the leakage currents can be calculated as a function of the distance from the frame. The leakage currents follow the electrical potential distribution from the metal frame across the glass surface and through the encapsulation polymers. The resulting voltage across the SiN ARC is the driving force for PID [3]. The leakage current density J_{leak} can be obtained for both full-scale and mini modules, respectively. As variable parameters in our model we used the measured resistivity values of the EVA material C after different pre-soaking durations, the glass surface sheet resistance values from the soiling tests at different humidity conditions and the distance to the frame. As a fixed parameter, the voltage V_c is set to 1,000 V.

Thus, different soiling and water soaking conditions as well as the resulting PID stress states of the solar module are deduced from the measured resistance values for the glass surface and the EVA-glass laminates. This is exemplarily shown in Figure 4 for the EVA material C in the dry condition (red graph) and in the soaked condition (other graphs). For the dry EVA a constant leakage current density of 0.14 nA/cm² is calculated for a temperature of 40°C, regardless of the glass surface condition (not shown here). This is attributed to the low contribution of the glass surface to the overall resistance along the leakage path. In the case of the soaked EVA (saturated water content of presumably 0.2 %) the regime of the strongly increased leakage current density level with a calculated maximum of 19 nA/cm² at 40°C depends on the condition of the glass surface. For the wet glass surface (90% RH), again, the resistance of the glass surface has a low contribution, leading to a flat behaviour of the leakage current. For the dry glass surface (50% RH) there is a pronounced drop of the leakage current density with increasing distance from the module frame. For moderate humidity levels (75% RH) the dependency of the leakage current on the surface state (clean vs. soiled) is clearly visible.

Even these comparably small differences in the leakage current density that are caused by soiling, can have a strong impact on the evolution of PID. Since the threshold of the voltage across the SiN ARC of the solar cell for beginning of significant PID (of the shunting type) is expected to be in the range of 10 V [5], the threshold for the leakage current density is in the range of 10…30nA/cm², according to [3]. Therefore, it is concluded that the soiling state of modules can have a strong impact on the evolution of PID by adding a small amount of leakage current stress to cells that are further away from the module frame.

PID tests at mini modules

The modelled leakage current densities and thereof implied voltage level across the solar cells' SiN ARC are compared with degradation rates measured through PID tests on the mini modules with the three different EVA materials after increasing damp heat soaking durations.

The increase of shunt conductance of the mini modules is shown in Figure 5 as a function of PID test time, together with corresponding average leakage current values also measured during the PID tests. The shunt conductance at the beginning of each PID test, which is governed by the parallel resistance of the non-degraded cells, has been set to 0 by subtraction of an offset. In the initial state (with 0 hours of damp heat soaking), all mini modules with the three tested EVA materials exhibit no increase of the cell shunt conductance (i.e. PID) during and after the PID tests performed with a high voltage of 1,000 V at 40°C for 84 hours each. After damp heat soaking of 500, 1,000 and 2,000 hours, respectively, there is a significant PID susceptibility measurable, which increases with the duration of damp heat soaking. It is interesting that even after comparably short damp heat duration of 500 hours there is a pronounced PID susceptibility, especially for the EVA material C. This might be a hint that not only the plain water content, but also the chemical formulation of the EVA has an influence on its resistivity at elevated water content levels.

Conclusion

A systematic investigation of the change of electric properties of the front glass surface and the polymeric encapsulation materials upon soiling and moisture ingress, respectively, is used for modelling basic dependencies. The impact on PID sensitivity is exemplarily measured for the case of water uptake of three commonly used EVA materials. Even though the modules exhibit PID resistance in the initial condition, all EVA products develop increasing PID susceptibility due to prolonged damp heat testing. Extrapolated to field conditions, this means that PID may develop after a period of one to three years of unsuspicious operation, depending on climatic conditions.

Furthermore, it was shown that soiling leads to boosted areal grounding of the glass surface at moderate humidity levels, thus promoting PID of the whole module area. This aspect will be part of future research, since soiling will become more and more relevant given the rising installation shares in the sunbelt regions of the world. ■

Acknowledgements

This work is funded through the German Ministry of Economics within project PID-Recovery (FKZ 0324184A). Thanks to Michael Wendt and Jing Yang for experimental support.

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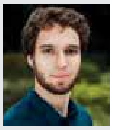

Klemens Ilse obtained his M.Sc. in physics from the M.Luther-University Halle (Saale), Germany in 2015. During his PhD thesis, Klemens Ilse has been working on the investigation of soiling issues for solar energy systems. In particular, his focus is on microstructural analysis of cementation processes, laboratory modelling of desert environments and the development of test setups for soiling and abrasion tests.

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Building in quality

EPCs | Solar engineering, procurement and construction contractors have a central role in ensuring the long-term performance and profitability of PV power plants. Ben Willis speaks to Adele Ara and Ralph Gottschalg of SolarPower Europe's O&M and Asset Management Task Force, which is drawing up the industry's first best practice guidelines for EPC companies

The work of EPC contractors has a key bearing on the operational performance of PV power plants

Credit: Lightsource BP

European trade body SolarPower Europe has just kicked off the process of drawing up what it is billing as a first for the industry – a set of best practice guidelines for solar engineering, procurement and construction (EPC) contractors.

As SPE is at pains to emphasise, the exercise is not about naming and shaming "black sheep" within the EPC community – rather an attempt to draw out and codify what works best in a part of the solar business that has such a vital role to play in ensuring PV power plants are built to last.

The guidelines, likely to be finalised sometime later this year, will follow a similar mould to SPE's best practice guidelines covering operations and maintenance (O&M), now in their fourth version, and more recently asset management, published at the end of 2019 and covered in more detail on p.50 of this publication. They will be the product of a detailed consultation with the European solar industry and seek to address how the long-term quality and O&M-friendliness of solar power plants are considered throughout the design and construction phases.

Here, Adele Ara, director of asset management at Lightsource BP, and Ralph Gottschalg, director of the Fraunhofer Centre for Silicon Photovoltaics, respectively the chair and deputy chair of the SPE task force leading this work, discuss why the guidelines are needed and how they are taking shape.

***PV Tech Power:* What is the thinking behind producing these guidelines at this point in time?**

Ralph Gottschalg: There is a lot of willingness among EPCs and a keenness to improve. I often get feedback [from EPCs]: if we had known that at the beginning, we would have done things differently. I think there is lacking a coherent set of information and sharing of best practices between EPCs to improve the overall lifetime of the asset.

Adele Ara: If you look at the UK, we [the solar industry] now have sites that are nine, 10, 11 years old, and we have enough operational data to look back and learn from what we did in the past. We are at a stage in the maturity journey of the industry to start looking back and asking ourselves what we can do better and what we have learned in the last nine or 10 years.

Your stated aim with this exercise is to safeguard the long-term quality of the PV power plant fleet. How important are EPCs in ensuring quality, or does this go beyond their specific role?

AA: Ultimately, I feel a bit bad giving all the responsibility for bad quality to EPC contractors, because there is a shared level of responsibility also sitting on the owner and investor. There is very little point in pretending to have a Ferrari if we only scope and pay for a Cinquecento; let's not forget that an EPC contractor is building what you're asking them to build. Components are critical too: owners, particularly if they have the ambition of being long-term owners or IPPs, really need to scale their games and increase the level of sophistication when it comes to component selection. So, if you look at us, we have a centralised component procurement team and we send out specialists to inspect manufacturing facilities in Asia, or wherever they are. Is this something everyone can do? Probably not, but the quality of components and how suitable they are for the environment where they're being installed is critical. And of course, if you're a prudent investor you're going to have a say on that and you're going to have to understand what you're asking your EPC contractor to do.

RG: The project developer determines what the EPC does. It's easy to say if something went wrong it's the EPC's fault. Yes, sometimes there are some black sheep, like in all industries, that's true. But the EPC just carries out the work according to the scope it was given by the developer.

There's been plenty of anecdotal discussion about quality problems in PV power plants and things going wrong in the field, but few examples actually coming to light because failures are very often hushed up under non-disclosure agreements (NDAs). What are some of the issues the industry faces in terms of poor-quality design and execution?

RG: That's entirely true [the use of NDAs], and maybe that's one of the shortcomings we have because people don't talk about it and people don't believe it happens. A couple of issues come to mind. In the UK [for example] you seem to have a relatively high occurrence of PID [potential-induced degradation] in the field because of the rain; unfortunately, PID is accelerated by precipitation and humidity. So, there are these problems which are lurking, they are hushed up, and I think knowledge sharing is one of the key things which we want to achieve in the guidelines here so that these things are ameliorated much faster than they are at the moment.

AA: Looking at this from a very different perspective, it's not just about the quality of the components, but also about what we are designing. For example, originally we were designing sites with an aim to maximise the capacity installed, but didn't realise that operationally it's much easier to do ground maintenance with tractors than a man with a strimmer, so we didn't put enough space between the panels [for tractors]. These are things that might not impact the production of the site and the performance, but for sure they do impact the bottom line and the overall profitability. So, it's always an effort between striking the right balance between what we are building and how we are optimising what we are building and making sure that it's designed in a way that is very cost efficient to manage operationally and maintenance wise. It's not wrong or right, it's just we need to get to fine tuning more and more how we are doing that.

RG: One of the points we are missing is the interfaces between different stakeholders in the process. What Adele is saying here is that the O&M provider needs to have an input into the system design, and I agree that this is absolutely critical. One key thing we want to do in this exercise is work on the interfaces between different stakeholders to get the most out of the entire build process and the system in the long term.

How will you gather the necessary information to inform the EPC guidelines?

AA: We are following the same type of approach the task force has used for the O&M and asset management guidelines. We have invited all the members of the task force and members of SolarPower Europe to contribute, either by providing information or expertise, specific or anecdotal experiences, or by offering to help draft some of the chapters of the publication. We are not pushing anyone to cooperate, we are very much looking for people willing to share the experiences. And we don't want only EPCs to contribute to this; we need EPC contractors to contribute, we need owners to contribute, we need O&M operators to contribute so that we can look at the problem from a 360-degree perspective, otherwise it becomes a very self-referential document.

What are some of the key areas the guidelines will look at?

RG: It will go through the entire process of a project – what is expected in a good design? What kind of component verification is useful? When starting system integration on site, what kind of verification is needed that the system has been built correctly? And then, looking at documentation, how do you pass information to O&M providers in a form that they can utilise without any information loss or additional costs from having to re-digitise things.

You talk about the need for better interfaces between all stakeholders in a project. How do you propose addressing that with these guidelines?

RG: It is a difficult and complicated area. I would say in version one we would look at certain handover sheets between different groups and stakeholders. Maybe a simple spreadsheet is sufficient, but maybe we will need something more. It would be ideal to bring the O&M provider into the system design; I just don't see that that's very practical, but these are the kind of things we need to discuss.

> "One key thing we want to do in this exercise is work on the interfaces between different stakeholders to get the most out of the entire build process and the system in the long term"

AA: For me, the ideal scenario would be a forum where we can very openly put on the table the list of challenges that are arising from scoping, specs and design that an O&M contractor faces. We might have a very long list of situations that are not optimal from an operational perspective, and it's very important that the EPC and owner understand those, but it's equally important that the O&M contractor gets a feel of why certain decisions were taken [during design and construction]. So maybe they were taken because at the time it was the best thing to do or the best components available, or perhaps they have been taken because they didn't have any other choice. If you look at the UK, for example, let's not forget that we all had to build in winter because we all had a very hard deadline to make sure we could get our subsidies. Therefore, the main driver of the design and construction was how do we compress the timeline as much as possible. So, for me this is a fantastic opportunity to show that the O&M contractor can contribute on how we can do things better and the EPC can say what their challenges are. And the owners need to listen, because they need to make sure they understand the costs of their expectations, because sometimes they have the wrong expectations for the price they're prepared to pay, and it's important for the long-term stability of the site that they appreciate that.

How open do you hope contributors to these guidelines will be, bearing in mind the commercial sensitivities around openly discussing quality-related topics?

AA: We have a number of limitations from the perspective of competition law. So the idea of this is not about naming and shaming; this is not supposed to be a process whereby we list bad practice and say what we shouldn't be doing; this is really mean to be a moment for people to share experiences. I am not expecting these guidelines to come out with: these are the good EPCs, these are not the good EPCs. And we have to be careful not to disclose the name of component manufacturers, because that would be unfair competition; therefore I'm expecting people to share their experience on a no-name basis. We will make sure it's anonymised, data is collected in a way that is as anonymous as possible

RG: It may also be a matter of generalising things; I don't foresee the need to identify black sheep. It is more about identifying what caused a particular issue and how it could have been avoided.

What form will the final guidelines take and who will they be aimed at?

RG: It will be relevant for everyone under the sun: owners, investors, project developers, EPCs, O&M, asset manager – all those have a stake here. And, also if you deliver something on site, this will set out what is a reasonable amount of verification to be expected from a developer's point of view. It would enable EPCs to obtain certain documentation from suppliers if they could state that according to European best practice guidelines this is what's expected and it gives them the support needed to argue their point. The guidelines will be critical in managing expectations throughout the entire value chain.

SolarPower Europe has in place various best practice marks for companies to use as a label demonstrating quality in disciplines such as O&M. Could you foresee something similar for EPC companies?

AA: Yes, I think the idea is to follow the same process we worked through for the O&M guidelines. So, if you look at the journey of the O&M best practice workstream, it started with the publication of the guidelines, we're now on version four, it's in a few languages, having great success. After publication of the guidelines we started working on the best practice mark. And I think the idea is to replicate the same thing for the asset management guidelines, which we published last year, so we will probably come up with the best practice mark later this year. And similarly, we would like to follow the same journey for the EPC guidelines. So, I would say we will be publishing the EPC guidelines in around Q4 of this year and then follow through with the best practice mark.

Bearing in mind what we have discussed about EPC companies having a key role in determining how well or otherwise a PV plant performs during operation, could you foresee a closer alignment between the two disciplines, with more companies offering both EPC and O&M services?

AA: I am not that sure how much we will see that happening. Certainly, we have EPC contractors that also provide O&M services, but that's very much linked to the warranty period immediately after the completion of the construction, because they have an interest to make sure the plant is performing as promised on paper. But I think the logic behind the EPC and O&M business models are rather different; they work on the basis of different business drivers, so it's difficult to see the type of integration you're talking about. And this is why these guidelines are very important – because we don't necessarily have forums where people working on design and installation and people working on operation have the opportunity of sharing their stories. And the reason why it's important for owners and investors to be there is that they need to be educated, they need to understand. So, the main readers of these guidelines, for me, need to be investors and owners because they really need to get a sense of how realistic their expectations are.

How significant do you hope these guidelines will be in helping the solar industry in its ongoing development?

RG: All the work of SolarPower Europe, be it the O&M or asset management guidelines, is a good sign of the maturing of the industry. We're not a fully mature industry yet, so all in all this is a pretty good step towards supporting the maturing of the industry as a whole and also to make sure that assets we are building today will work in the future and not only until the EPC has finished its contractual duties. ■

The outlook for mini-grids

Electrification | Mini-grids offer a quick route to electrification in parts of the world where grid extensions are unfeasible. Baptiste Possémé looks at the some of the technological and regulatory trends influencing the deployment of mini-grids in Africa and Asia

Strong developments have been seen in recent years in terms of global access to electricity as 800 million people gained access to electricity since 2010. However, 860 million people still lack access to electricity at the end of 2018 [1]. And 98% of them live in Africa and Asia.

Three main solutions exist to provide sustainable power to those populations: grid extension, solar home systems and mini-grids. The economical choice between those solutions is mainly a matter of distance to the grid, density of population and level of service.

Grid extension is the most classical answer but has several issues. It can be extremely expensive for remote communities and doesn't necessarily offer a good quality of service (case of "bad-grid").

Individual electricity generation systems such as solar lamps or solar home systems (SHS) are a very efficient way of providing a basic quality of service to regions with a low population density. SHS manufacturers and distributors such as BBOXX, Mobisol, Fenix International, Total or Schneider Electric have experienced a significant growth over the last years. However, those solutions usually power low power appliances and are usually used as transitional solutions.

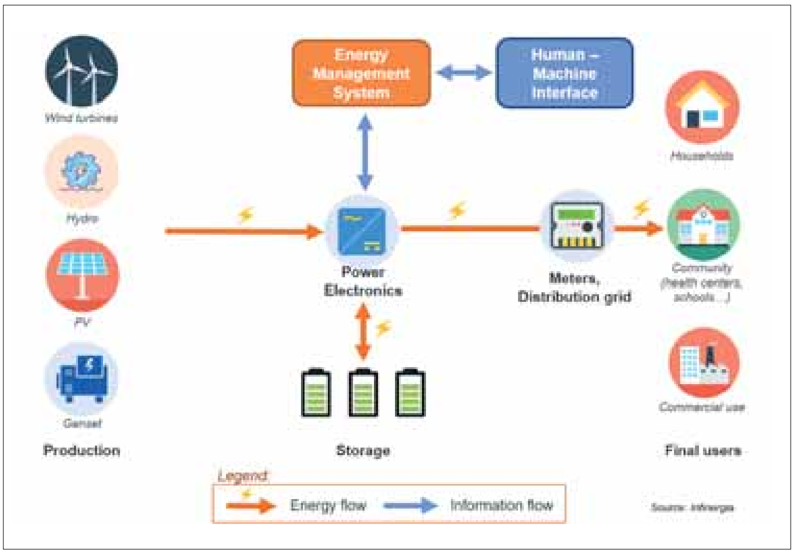
Mini-grids, local and isolated networks, have started to gain momentum in the last five to 10 years. They can offer a lower cost than solar home systems in cases where population is dense enough and a similar quality of service than grid extension.

At Infinergia, we focused on 31 African and Asian countries where mini-grids are relevant for regulatory, historic or economic reasons. We also analysed the upstream mini-grid industry (component manufacturers and integrators), the regulatory frameworks of those countries and the associated projects.

Upstream industry's main trends: technological innovation and containerisation

Mini-grids/Micro-grids/Nano-grids?

Vocabulary can be tricky, and it is difficult to find two definitions of mini-grids that are similar. Based on REN21, UNFCCC and ARE's definitions, we choose to define a mini-grid as one or several decentralised energy generation sources with a combined peak power between 10kW and 10MW connected to multiple customers through a local network. Those systems are completely isolated from the main grid. If they are not, we call such a system a micro-grid. If the peak power is smaller (<10kW), we call it a nano-grid.



Credit: Infinergia

Figure 1. Main components of a mini-grid

Most of those installations produce and distribute electricity at a community level (usually a village) but can also be used for commercial, industrial, military or agricultural applications.

Even though the first mini-grids were solely based on diesel or hydraulic power, the drop in photovoltaic prices over the last 10 years has favoured the development of PV-based mini-grids. Now, the typical installation includes PV panels, batteries, a back-up diesel generator, an energy management system (EMS) and, of course inverters, meters and a local grid as illustrated in Figure 1.

Batteries: a key component for the total cost of the mini-grid

In a typical PV-based mini-grid the battery is the key component in terms of both CAPEX and OPEX. Concerning village electrification, the first requirement is reliability. The complexity of having a technician on site means most EPC choose a proven and low-cost technology. Therefore, for small to medium systems (e.g. less than one megawatt), lead-acid batteries are still the most commonly used technology today. They offer a lower cost per nominal kWh, are known and mainstream on the market and, as such, easier to maintain or to find spare parts. However, their high sensitivity to temperature and low depth-of-discharge plus low lifetime often make them the weak link of the system.

The harshness of most off-grid environments gives opportunities for innovation. Lithium batteries are more and more used for mini-grids and new storage technologies have been trialled over the last years (e.g. flow batteries, zinc-air, sodium-nickel, sodium-ion…) with varying success rates. According to several interviewed mini-grid developers and EPCs, there is still a need for a more reliable technology that could lower the systems' total cost of ownership, even if only a handful of developers are willing to take the risk.

Energy management system: the system's brain

The hybridisation of power sources (diesel genset, PV, batteries, hydro…) adds complexity to the system that must be managed by a local intelligence, an EMS that consists of a software and hardware control solution. Those systems vary broadly from controllers to local computers with forecasting and advanced optimisation algorithms. More intelligence is not always better. The mini-grid designer must find a compromise between efficient management of resources, a low cost and high resilience. For most projects, experience is key to determining the most relevant EMS for a given project.

Integration: the path to standardisation

Most mini-grids today are custom-made. Once the project is financed and the community's needs have been established, an EPC is chosen to design the most relevant system. A specific room is then built to host the inverters and the batteries. Every component is assembled on-site by the local workforce.

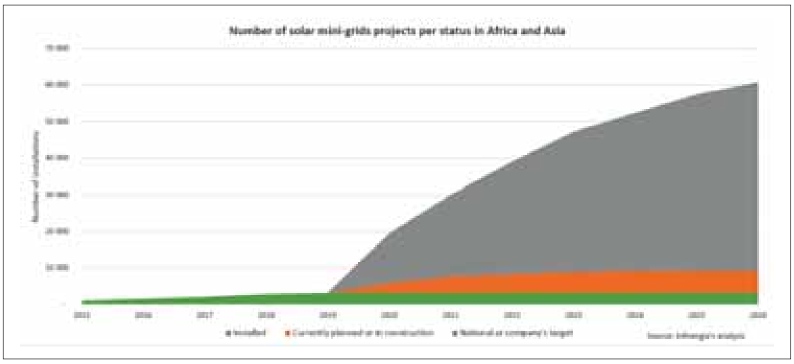
While achieving a very low CAPEX, such solutions often have a significant failure rate. For instance, only 25% to 35% of the mini-grids installed in Senegal between 1996 and 2011 are still functional today [2].

New solutions have emerged over recent years to tackle this issue, such as containerised standardised systems in which every component is pre-assembled at factory (even the solar panels are bundled with a folding/unfolding system) and the container just needs to be transported on-site and unfolded. Those systems secure most of the hidden costs that often appear in custom-made projects (e.g. pieces missing, theft, the supply of various components, low quality of installation…). On the other hand, they need a production scale effect to reduce their CAPEX. By analysing the main integrators' projects (e.g. Redavia, Schneider Electric, Winch Energy, Africa Greentec…), we have identified 30 of such projects installed (not only rural electrification) representing 119 installed containers globally by end 2019 [3].

The regulatory framework for mini-grids is strengthening

At Infinergia, we have developed an indicator to compare the development stage of the mini-grid market over 30 countries. By analysing the regulatory framework [3], the announced and existing

Figure 2. Past and forecast development of mini-grid projects in Africa and Asia.



Source: Infinergia

projects, the countries' economic status and the local presence of mini-grid actors, we can compare, year after year, those countries' evolution.

Mini-grids have grown in 2019 in Africa

Eight African countries (including Ethiopia, Kenya, and Nigeria) have reached a higher maturity stage [4]. Over 75 public tenders for mini-grid projects have been published in the last two years, new regulations framing the development of mini-grids were released (e.g. tariffs, subsidies, private operators licenses, possibility to connect the mini-grid to the main grid…). National targets for rural electrification have been defined and include the development of mini-grids (e.g. in Ethiopia and Nigeria). International funding to promote the development of off-grid solutions has been increased (e.g. FEI OGEF, International Solar Alliance, World Bank…).

Regulatory changes less visible in Asia

India still has the highest potential for mini-grids globally but lacks a better framework to move forward. For instance, a draft mini-grid policy was edited in 2016 but has not evolved since then. Myanmar, the Asian country with the lowest electrification rate, is considered by many as the most promising Asian country for mini-grids in the short term but still requires a more established framework to allow a full-scale development of its potential.

Projects: market potential but with high uncertainties

We have identified over 400 announcements, tenders, national or private targets, projects and installations, globally that represent altogether a potential for around 63,000 mini-grids by 2026 globally [4]. In order to characterise the level of certainty of those projects, we have decided to distinguish three main categories:

Installed projects have been identified as such and should remain so in the next years. It should be noted that depending on the countries and developers, an unquantified part of those projects might encounter technical failures.

Currently planned or in construction projects have been financed, tendered and most of the time awarded to an EPC. They have a very high probability of ending up installed (even though delays may occur compared to the announced

Credit: IRENA

Mini-grids show substantial promise in unelectrified communities, but still rely on subsidies

commissioning date).

National or companies' targets are engagements (usually not completely financed) that have been made by companies or countries to develop a certain number of mini-grids, usually with no precise location identified. They show ambition but should be considered cautiously.

Considering those categories, two scenarios can be defined: a realistic (even a little pessimistic) one in which over 9,000 mini-grids would be installed globally (compared to 3,200 today), and an optimistic one where 60,000 new mini-grids could be built by 2026.

It is important to consider that only three countries (India, Nigeria and Myanmar) account for 95% of the national and companies' targets. Their capability to translate those announcements into real projects will be key for the development of the market.

A strong future with short-term uncertainties

Even taking only into account our realistic scenario, we can estimate that the mini-grid market should at least experience a 20% CAGR over the next six years. The growth of this market is not limited by its potential or by companies' and countries' willingness to develop those systems but rather by technical and financial issues. The business model for privately operated mini-grids has not been proven yet and most of the projects rely on national or international subsidies. They are therefore strongly impacted by political instability and international programmes. In 2019 for instance, 236 new projects have been identified as commissioned while 1,260 new ones have been planned.

Furthermore, the harsh environment for most mini-grids raises a need for more reliable solutions that can lower the project's maintenance without increasing its CAPEX. New component technologies (e.g. batteries, EMS..) and new integration models (e.g. containerised standardised mini-grids) are the main drivers to solve those issues today.

Turn to p.66 for further insights into the how micro-grids are helping shape the smart neighbourhoods of the future

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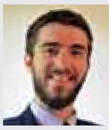

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Smart neighbourhood, smart micro-grid

Credit: DHYBRID

Micro-grids | Micro-grids can offer a resilient and secure alternative for both rural and city communities. Molly Lempriere looks at some of the micro-grids around the world that are transforming the way neighbourhoods produce and consume electricity

Around the world, communities and companies alike are increasingly looking to micro-grids, to help increase resiliency and energy security. In particular, as people turn to intermittent renewables such as solar PV to decarbonise electricity networks, micro-grids offer an exciting new alternative to conventional energy networks.

They have proved particularly successful in rural and remote communities, as an economic alternative to expanding national grids. But they are popping up in cities too, often to help secure generation against outages caused by extreme weather such as hurricanes, and to allow people to take greater advantage of self-generation.

In a Global Innovation Report report by Hitachi America, the biggest growing microgrid markets were examined, predicting that worldwide there is likely to be 7,500MW of capacity and a US$35,000 million market by 2024.

As senior vice president and general manager of the Energy Solutions Division of Hitachi America, Alireza Aram, explained in the report: "Against a background of successive natural disasters and terror threats around the world, a steady supply of electricity including measures against power outages is a common social issue for all countries, from the viewpoint of the safety and security of their residents.

"As the introduction of renewable energy proceeds as a measure against global warming, micro-grids are looked to as a promising solution to various issues."

How are micro-grids developing though, and how 'smart' can a neighbourhood become?

Micro-grids: not such a micro trend

As a concept micro-grids are not particularly new, they have functioned around the world using fossil-fuel generation for decades. But as renewable generation technologies have developed along with digitisation, the possibilities they offer have expanded.

In the US there were 2,250 micro-grids in 2018 according to Wood Mackenzie, with 545MW of capacity added that year alone. The majority of these micro-grids still use standalone fossil-fuel generation, but this is changing as communities and companies take advantage of technologies such as solar and blockchain.

For example, the Brooklyn Microgrid project that was established in 2016 takes advantage of blockchain to allow a collection of homes in the New York suburb to generate power using solar panels, and then use peer-to-peer trading. It was the first project of its kind in the US and has continued to expand and receive acclaim over the last few years.

Now there are over 50 homes and businesses within the grid, which is run by LO3 Energy. The desire for a micro-grid in the area came after Storm Sandy caused widespread blackout in New York in 2012, calling the security of the electricity supply into question for many.

Micro-grids like this are popping up in communities around the US and Europe, but they are also helping communities in energy-poor countries in Sub-Saharan African and Asia. A Navigant report produced in 2018 showed that the Middle East and Africa region was forecast to have

Islands are one of the settings where micro-grid technologies could be most beneficial

the world's fastest market for micro-grids. It suggested that there would be a compound annual growth rate of 27% in these regions, which could represent almost 1,145 by 2027.

In these communities the technology can offer electrification where there hasn't been any before, bringing a huge range of benefits. Not least among them, such grids can support lighting that allows people to move away from hazardous kerosene lamps, which pose a number of health risks from producing harmful gases to being a fire risk.

The Alabama Smart Neighbourhood: the newest test ground

In Alabama, a micro-grid pilot project has been launched to test and trial the neighbourhood of the future. Completed in 2018, the project consists of 62 homes built with advanced energy efficiency measures, home automation and connected to its own micro-grid, all integrated together.

While the micro-grid can work together with the national grid, it can also be islanded, functioning completely separately, and relying purely on its own generation and storage technologies.

Todd Rath, marketing services director for Alabama Power, who is running the project, explains: "We wanted to create a neighbourhood that would be what we think a standard neighbourhood in the state of Alabama and the southeast would probably look like in the year 2040, and that would include building envelope requirements as well as technologies within the home with appliances and other connected technologies. And using an energy source that may be different than a traditional grid, such as a micro-grid with solar, battery storage and those kind of things."

The neighbourhood is the Southeast's first community-scale micro-grid, according to Alabama Power, and is designed to be a true testing ground, allowing the utility to understand the changing needs and opportunities of those living in Alabama and beyond. Alabama Power is a subsidiary of the Southern Company; a second subsidiary, Georgia Power, is now also running a micro-grid project to trial smart technologies.

The Alabama Smart Neighbourhood uses solar panels, battery storage and a backup natural gas generator to create a complete energy system.

The micro-grid has around 1MWp of electrical output, separated between three

Alabama Power's micro-grid could be a prototype of the smart neighbourhood of the future

Credit: Alabama Power

components; a 333kW fixed-tilt array, comprising 11 rows of solar modules with string inverters at the end of each row, a lithium-ion battery system provided by Samsung with a capacity of 333kW, and a 400kWp natural gas-fired turbine.

The neighbourhood was specifically modelled before it was built to use a third of a megawatt at peak power. As such, throughout the research project Alabama Power can vary the supply, testing the system both when islanded and utilising the wider grid, and how the different technologies perform.

Southern Company research and development engineer Jim Leverette adds that the generator was included predominantly as backup, as the battery system included in the project could not see the whole neighbourhood through 12 hours. As such, it was unlikely to last through a night, meaning that a backup source is needed for a few hours over night before the sun rises and solar power can once again take over.

Along with the technology making up the grid itself, the Alabama Smart Neighbourhood has tested how homes can interact and become more efficient within the micro-grid.

It uses a piece of software called Complete System-Level Efficient and Interoperable Solution for Microgrid Integrated Controls (CSEISMIC), developed by the US Department of Energy's Oak Ridge National Laboratory.

"The system basically sits out at the micro-grid, and it sees the generator, the battery and the solar," says Leverette. "It has a forecast of what the weather is going to be, a forecast of the predicted electric usage in the neighbourhood, and then it makes decisions about which assets to run. We can set different objectives, we can set it to just minimise costs, we can try to minimise carbon output, we can preconfigure it so it has additional savings and energy for backup power, a lot of different configurations.

"And that control system is also communicating to devices in the home, and it can actually adjust the set point on the thermostat and the set point on the water heater. So, it's able to look at those devices as possible control options as well as the battery, the solar and the generator.

"So really, it's looking at five or six different things and it can make decisions about what is the least impactful to the customer, what's the most cost-effective thing to do at any given moment in time."

Each home within the micro-grid can set parameters within which this software can make changes, such as maximum and minimum temperatures it will allow its heating, ventilation, and air conditioning (HVAC) to be adjusted to. This is particularly significant as HVAC is one of the most energy intense aspects of a home, and one that is set to continue to grow in coming years.

A report by the International Energy Agency in 2018, entitled *The Future of Cooling*, found that air conditioning and fans account for a fifth of the total electricity consumption in buildings globally, or about 10% of all electricity consumption now. As the world continues to get hotter due to global warming this is likely to increase, tripling by 2050.

If this rings true, new electricity capacity will be required that is the equivalent to the combined electricity capacity of the United States, the EU and Japan today, the report concludes. As such, in a hot and humid state like Alabama, being able to effectively manage HVAC systems could greatly benefit both supplier and the grid.

As Leverette says, "there [are] millions of smart thermostats in the US and elsewhere. If there was a low-cost way to integrate them to the grid without impacting customers, you could potentially have a really big win-win for customers and utilities."

One of the biggest learnings that has come from the project is the impact a degree or two can make upon the grid and energy usage. This is particularly pertinent when looking at water heaters, as people rarely notice a degree's difference but collectively it can have an impact on grid capacity.

Following the construction of the micro-grid, the system was modelled post-installation using software developed by HOMER Energy.

Dr. Peter Lilienthal, founder at HOMER, says that micro-grid decision makers such as planners and engineers, can use modelling to understand precisely how new technologies can perform and interact. This also expands to further verifying that systems are operating as expected after their energisation.

"As the electric power industry starts implementing new technologies and combining them in new ways, such as these hybrid renewable micro-grids, the design simulation and optimisation capabilities of the HOMER software shows the economic impact of different configurations. We are glad to see this activity beginning to happen in every region of the country and the world."

This modelling, together with the constant monitoring of the micro-grid, is allowing Alabama Power to continue to learn from the micro-grid. The company is planning to continue to run the project, with the majority of those in the homes currently electing to continue to take part as it moves into another year.

DHYBRID: a global tech

Not all micro-grids are made the same, however, and German company DHYBRID offers a distinctly different approach. Specialising in rural and island communities, the company provides an energy management system that can run hybrid micro-grid systems, using its Universal Power Platform (UPP).

"Basically, we understand our UPP to be like the foundation when it comes to building smart grids and micro-grids for renewables," says DHYBRID CEO Benedikt Böhm.

"All the renewable assets, such as solar, batteries and also the existing generators in the micro-grid, are all built on top of that platform. And since our solution is manufacturer independent and technology neutral, the client or the operator does not have any issues when it comes to extendibility in the future, and scalability," he says.

DHYBRID's software now supports over 75 projects in 25 countries, as increasingly communities turn to micro-grids as a resilient alternative to national grids. One of the company's most recent projects was in Senegal, working together with the national utility company Senelec, which implemented seven hybrid projects scattered throughout the remote region of Ile du Saloum (pictured below). Its aim was to provide electricity to remote villages, with the option of eventually connecting them to the state grid should they require expansion.

"Three of these are so-called fuel-saving applications, meaning a direct combination of diesel generators and solar. And then four out of the seven are actually with storage. So, they are fully automated when it comes to the operation mode and switching between generators and battery operation," says Böhm.

Elsewhere the company has another project in the Maldives, where it is implementing its energy management system across 26 separate micro-grids, on 26 separate islands. These involve diesel generators, battery storage and solar.

According to Böhm, the interest in micro-grids is growing, fuelled by a number of different advances in the energy sector globally.

"I think the competitiveness of renewable energy is key, because a decade ago you had to pitch solar mostly about the environmental impact and the social impact that it would bring. But now renewable energy is much more competitive, solar is more competitive than most unsubsidised fuels," Böhm says, indicating that the scalability of micro-grids is being at least partly driven by how cost-competitive renewables are now with fossil fuels.

Technologies such as solar, that are often chosen for micro-grids have undoubtedly matured, bringing operational and cost benefits. The cost of solar power has fallen by 99% over the last four decades, according to MIT.

Hand in hand with this, Böhm says, is what he labels the "operation philosophy", with energy management maturing and leading to "a lot more reliability and professionalism when it comes to energy supply."

Moving forwards, it is clear that micro-grids offer an exciting opportunity to both small islanded communities and the smart communities of the future.

Böhm predicts that a key part of this will be continued growth in the size of a micro-grid, as well as continued integration of smart technologies. Instead of the current Master/Slave mode most micro-grids use, where different forms of distributed generation have different functions, with one the master source of generation and the others reacting to it, the micro-grids of the future will be hybrid systems, with generators and batteries seamlessly transitioning in what's accepted as "Master/Master" mode.

Such a system could offer an appealing alternative to today's national grids, providing a resilient and reliable solution to the integration of technologies such as solar, blockchain and management software, making microgrids a smart choice.

DHYBRID is testing its micro-grid technologies in a remote part of Senegal

Credit: DHYBID

Utility-scale PV surges onward in the United States

Project economics | As utility-scale PV projects continue to spread across the United States, Mark Bolinger, Joachim Seel, and Dana Robson of the Lawrence Berkeley National Laboratory cover key technology and market trends in this synopsis of their annual "Utility-Scale Solar" report series

Credit: BHE Renewables

Only a little more than a dozen years old, the utility-scale PV sector in the United States has grown rapidly. Just five years after the first two utility-scale projects achieved commercial operations in late 2007, the utility-scale sector became the largest segment of the overall US PV market (in terms of new capacity) in 2012, and has since shown no signs of relinquishing its market-leading position. In 2018, the utility-scale sector accounted for nearly 60% of all new PV capacity built in the United States, and more than three quarters of all states were home to one or more utility-scale PV projects (defined here as any ground-mounted project larger than $5MW_{AC}$).

Figure 1 plots the 690 utility-scale PV (and in some cases, PV plus battery) projects totaling $24,586MW_{AC}$ that were operating in the United States at the end of 2018 by location and technology configuration. While the sector got its start in sunny southwestern states like Nevada, Arizona, and California, declining installed costs have enabled it to expand to less-sunny regions of the country—even recently including northerly states like Washington, Minnesota, Michigan, and Vermont. Some of these more-recent northerly projects are even using single-axis tracking, which in earlier days had been reserved primarily for the sunniest sites (i.e., where the solar resource was strong enough to justify tracking it).

The US utility-scale PV sector is maturing and expanding outside of its traditional comfort zones

Since 2015, though, single-axis tracking has become the dominant mount type in most parts of the country, and was used for nearly 70% of all new capacity—including virtually all new thin-film (primarily CdTe, but with some CIGS) capacity—added in 2018 (Figure 2). Fixed-tilt projects are increasingly only built in less-sunny regions, even while tracking projects continue to push into those same regions.

Meanwhile, the median inverter loading ratio ("ILR")—i.e., the ratio of the DC capacity of a project's PV array

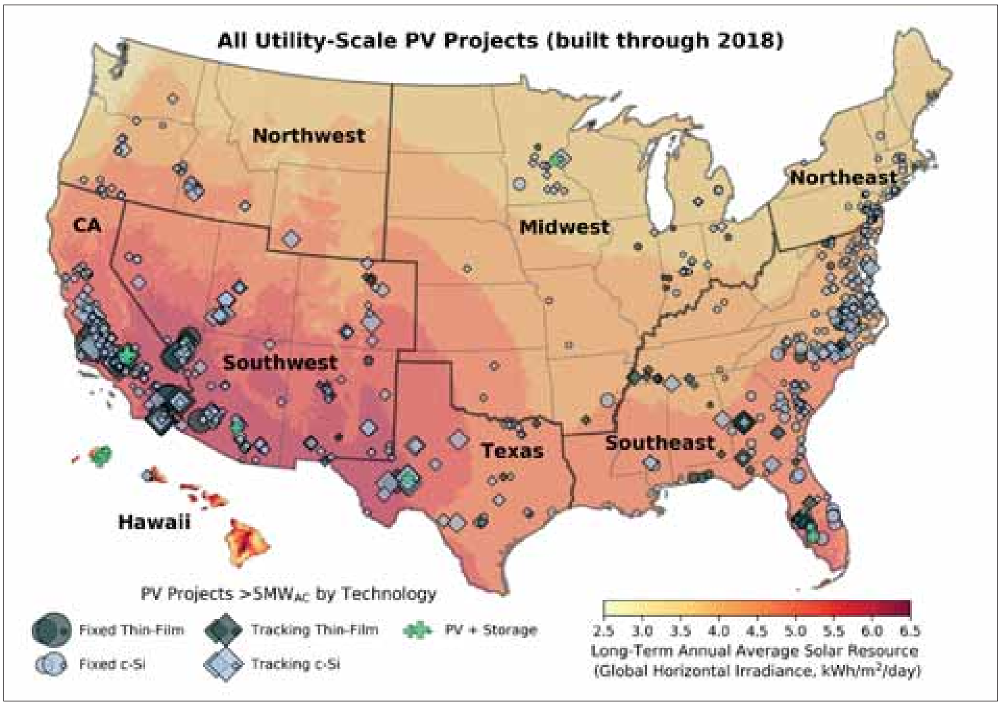

Figure 1. Utility-scale PV projects (>5MW$_{AC}$) in the United States

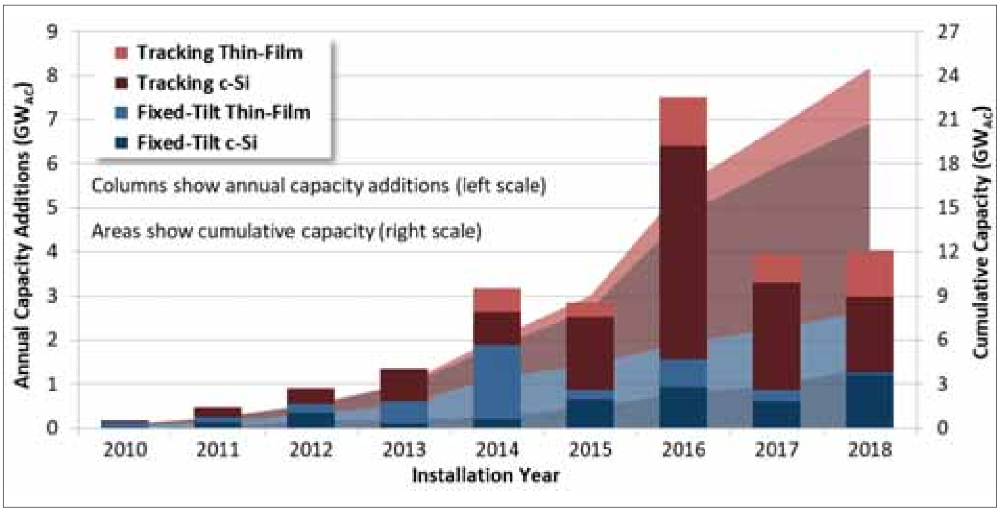

Figure 2. Annual and cumulative utility-scale PV capacity by module and mounting type

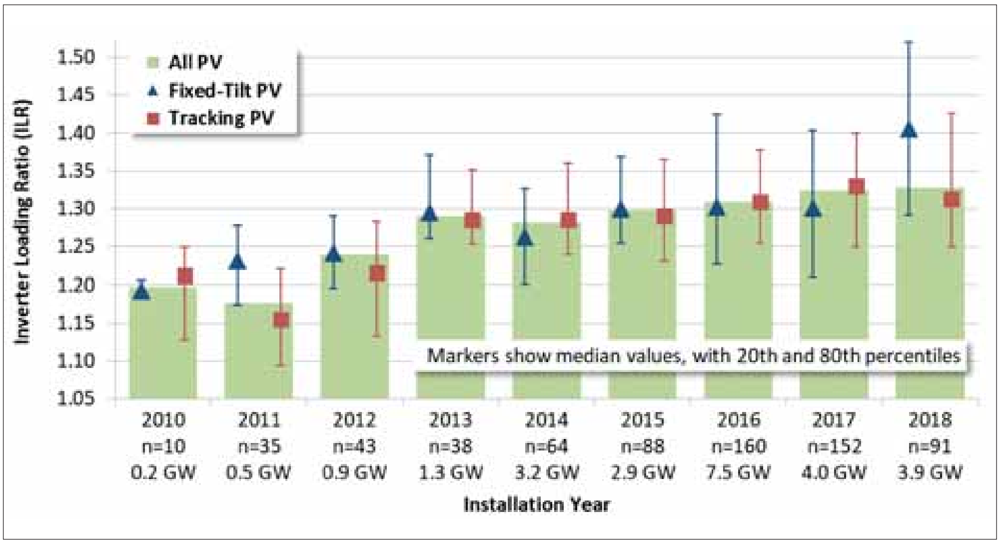

Figure 3. Trends in inverter loading ratio by mounting type and installation year

relative to the AC capacity of its inverters—has risen steadily, from around 1.2 in the early days of the sector to more than 1.3 in 2018 for both tracking and fixed-tilt projects (Figure 3). Higher ILRs allow inverters to operate closer to (or at) full capacity for more of the day, but as the DC:AC ratio increases, the extra generation during the morning and evening "shoulder hours" must be balanced against any mid-day power clipping that occurs to ensure that there is a net gain in production. For a standalone PV project, an ILR in the range of 1.3-1.4 seems to be the sweet spot, but this ratio could go significantly higher (e.g., to 2.0 or more) with the addition of a DC-coupled battery that is able to capture and store mid-day solar generation that would otherwise be clipped.

Median installed prices have steadily fallen by nearly 70% since 2010, to US\$1.6/W$_{AC}$ (US\$1.2/W$_{DC}$) among 60 utility-scale projects (totaling 2.5GW$_{AC}$) completed in 2018 (Figure 4). In a sign of a maturing market, price dispersion across the sample has narrowed in each year since 2013—e.g., the standard deviation of installed prices declined from US\$0.9/W$_{AC}$ in 2013 to US\$0.5/W$_{AC}$ in 2018.

To assess how these projects have performed, we rely on capacity factors—a measure of the amount of electricity generated in a given period relative to how much electricity could have been generated if the generator was operating at full capacity for the entire period. Because solar generation varies seasonally, capacity factor calculations for solar are typically performed in full-year increments. Figure 5 shows that the capacity factors of individual projects in our sample vary widely, from 12% to 35% (in AC terms), with a sample median of 25% and a capacity-weighted average of 27%. A good deal of this project-level variation can be explained by the three primary drivers of capacity factor that are tracked in Figure 5: the average quality of the solar resource at the site (broken out into quartiles), whether the project tracks the sun or is mounted at a fixed-tilt, and the ILR (also divided into quartiles). Curtailment and degradation—both of which are baked into the capacity factors shown in Figure 5—can also play a role, and may be partly responsible for some of the apparent outliers.

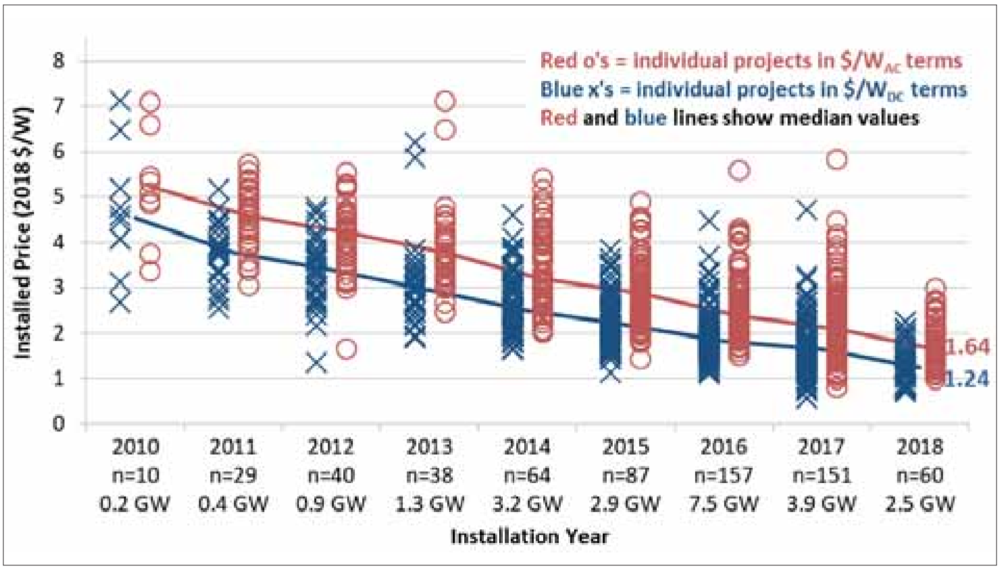

Figure 4. Installed price of utility-scale PV projects by installation year

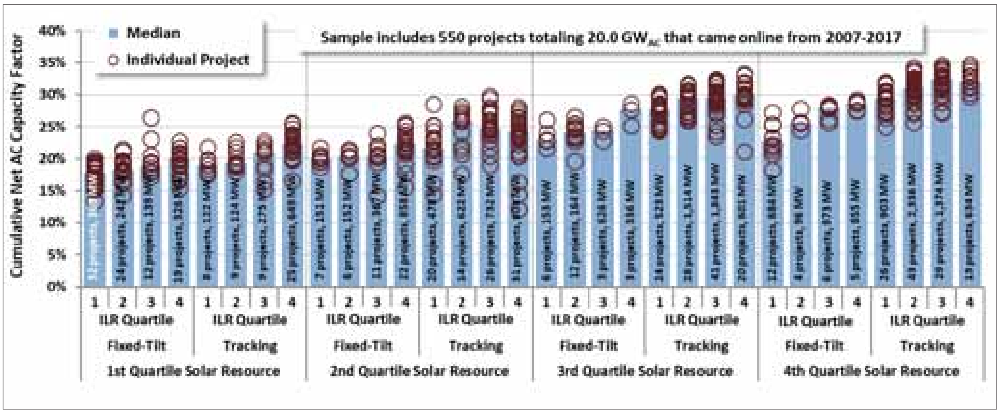

Figure 5. Cumulative capacity factor by resource strength, fixed-tilt vs. tracking, and inverter loading ratio

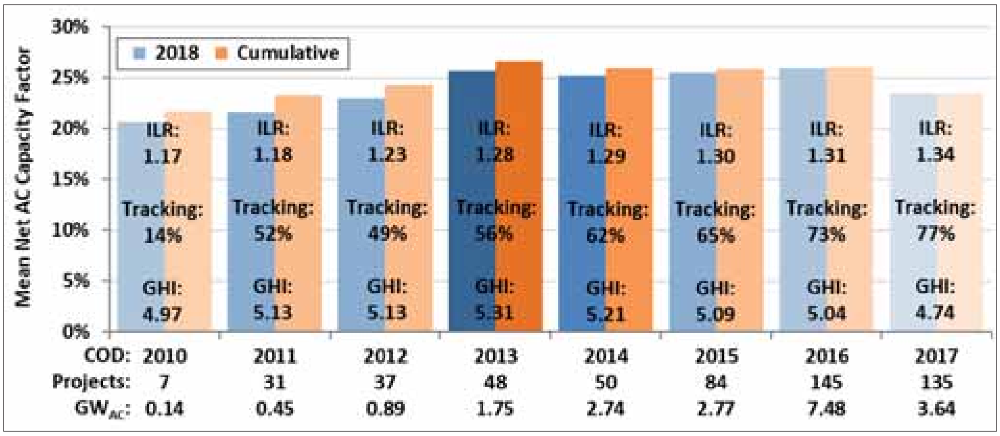

Figure 6. Cumulative and 2018 capacity factor by project vintage: 2010-2017 projects

Figure 6 breaks out average capacity factor by project vintage (based on commercial operation date, or COD). The steady improvement from 2010-vintage through 2013-vintage projects was driven by increases in all three of the drivers shown in Figure 5 and again in Figure 6—long-term average global horizontal irradiance (GHI) at each site, the prevalence of tracking, and the average ILR. Since 2013, though, average ILRs have held fairly steady around 1.3, while the two other drivers—prevalence of tracking and long-term average GHI—have moved in opposite directions, largely canceling each other out and resulting in stagnant capacity factors among more-recent project vintages. The lower long-term average GHI since 2013 (indicated numerically but also visually by the fading intensity of the blue and orange shading) reflects the geographic expansion of the market from California and the Southwest into less-sunny regions of the United States—this is a positive trend, despite having a negative impact on average fleet-wide capacity factor.

Figure 7 graphs both the median (with 20th and 80th percentile bars) and capacity-weighted average "irradiance-normalised" (i.e., to correct for inter-annual variability in the strength of the solar resource) capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values). The dashed red line approximates the slope of both the median and capacity-weighted average and depicts a straight-line degradation rate of -1.2%/year—i.e., worse than the -0.5%/year to -0.8%/year range that often serves as conventional wisdom. It is important to recognise, however, that Figure 7 is capturing plant-level degradation from all possible degradation pathways—including (but not limited to) module degradation, balance of plant degradation (e.g., from trackers), soiling, and downtime (e.g., due to outages, scheduled maintenance, or curtailment)—and so should not be confused with the more-commonly measured (and typically more modest) module degradation rate.

Driven by lower installed project prices and, at least through 2013, improving capacity factors, levelised power purchase agreement (PPA) prices for utility-scale PV projects in the United States have fallen dramatically over time, by US$20-30/MWh per year on average from 2006 through 2012, with a smaller price decline of ~US$10/MWh per year evident in most years since 2013 (Figure 8). Aided by the 30% federal investment tax credit (ITC), most recent PPAs in our sample—including many outside of sunny California and the Southwest—are priced below US$40/MWh levelised (in real 2018 dollars), with many priced below US$30/MWh and a few even priced below US$20/MWh.

Particularly within higher-penetration

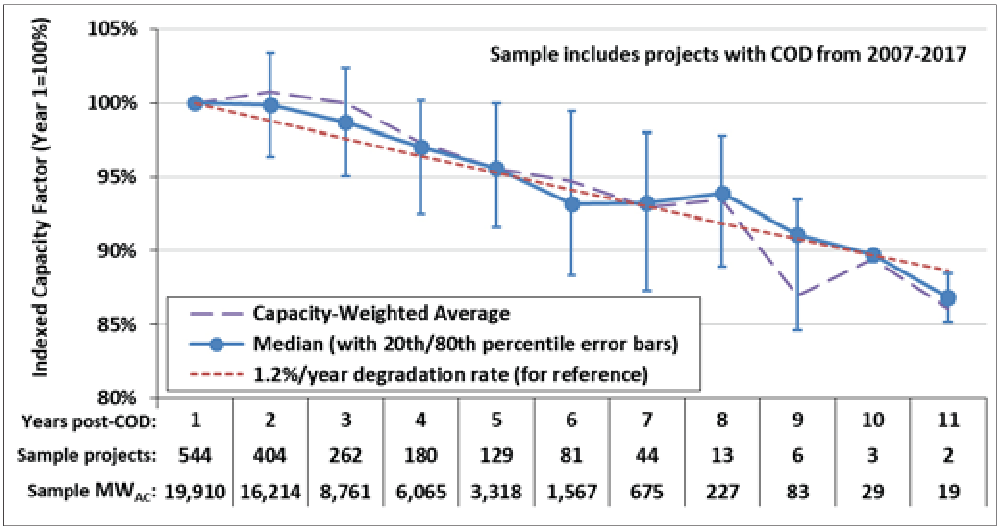

Figure 7. Fleet-wide performance degradation

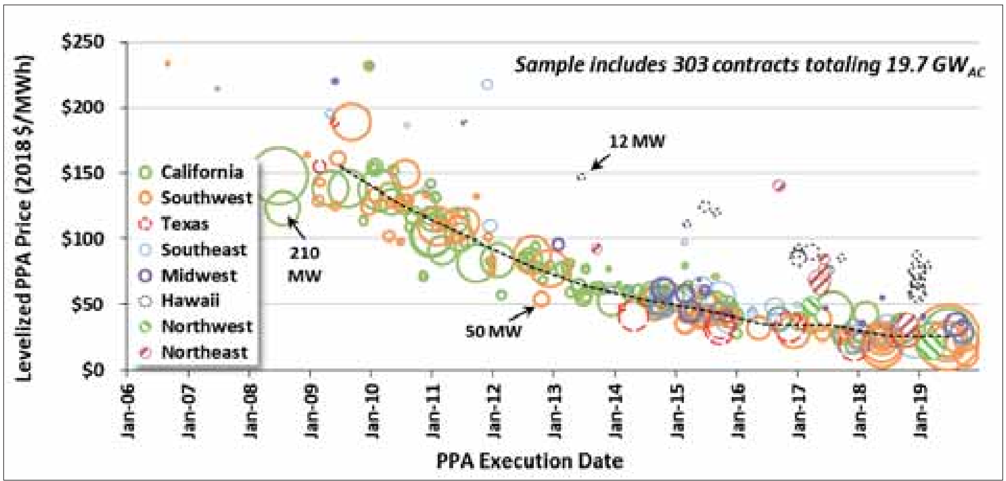

Figure 8. Levelised PPA prices by region, contract size, and PPA execution date

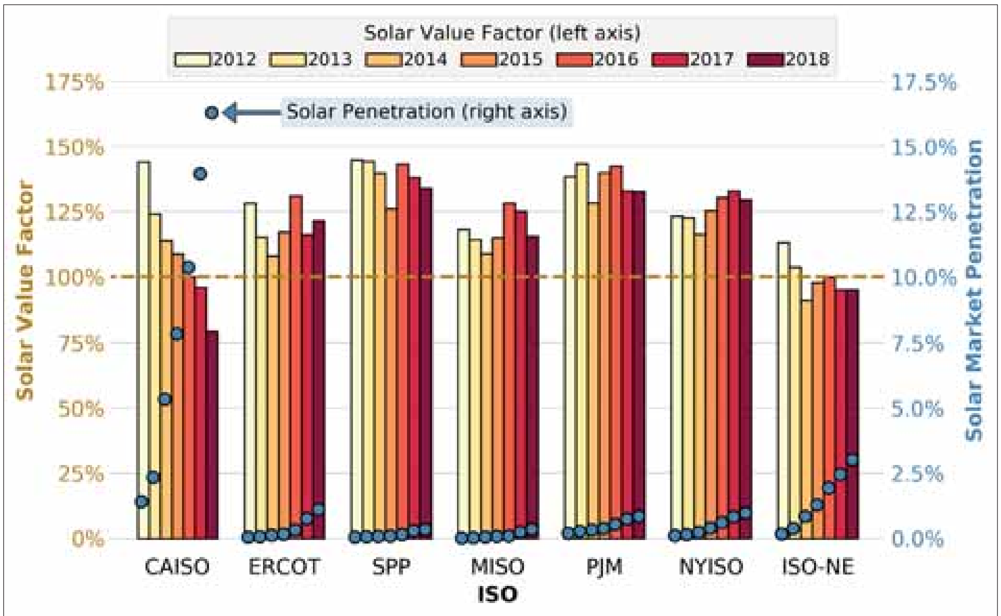

Figure 9. Solar's "value factor" and market penetration by independent system operator (ISO)

solar markets like California, these falling PPA prices have been matched, to some degree, by a decline in the wholesale market value (i.e., the energy and capacity value) of solar. Due to an abundance of solar energy pushing down mid-day wholesale power prices, solar generation in California earned just 79% of the average energy and capacity value within the California Independent System Operator's (CAISO's) wholesale power market in 2018—down from 146% back in 2012 (Figure 9). However, in five of the six other independent system operator (ISO) markets analysed—all of which still have solar penetration rates of 1% or less, compared to California's 16%—solar still provides above-average value (i.e., solar's "value factor" remains above 100%). The exception is in New England (ISO-NE), where the highest wholesale power prices typically occur during winter cold snaps when the heating and power sectors compete for a tight supply of natural gas, driving up both natural gas and wholesale power prices. In the depths of a dark and snowy New England winter, PV is often not in a good position to capitalise on these price spikes, which, in turn, results in below-average market value (at least when measured over the course of a full year).

To date, falling PPA prices have largely kept pace with the dramatic decline in solar's market value in California, thereby maintaining solar's relative competitiveness over time. In the other six ISOs, solar offers higher value yet, in some cases, similar or even lower PPA prices than in California—which is perhaps the primary reason why the market has been expanding beyond California and into these other regions.

Adding battery storage is one way to increase the market value of solar, and there has been a notable proliferation of PV plus battery PPAs (e.g., 23 of the PPAs shown in Figure 8 include battery storage) and project announcements in the United States over the past few years. Data from 38 completed or announced PV hybrid projects totaling 4.3GW$_{AC}$ of PV and 2.6GW$_{AC}$ of battery capacity (and with storage duration ranging from two to five hours, with four hours being by far the most common) suggests that sizing of the battery capacity relative to the PV capacity varies widely, depending on the application and specific situation.

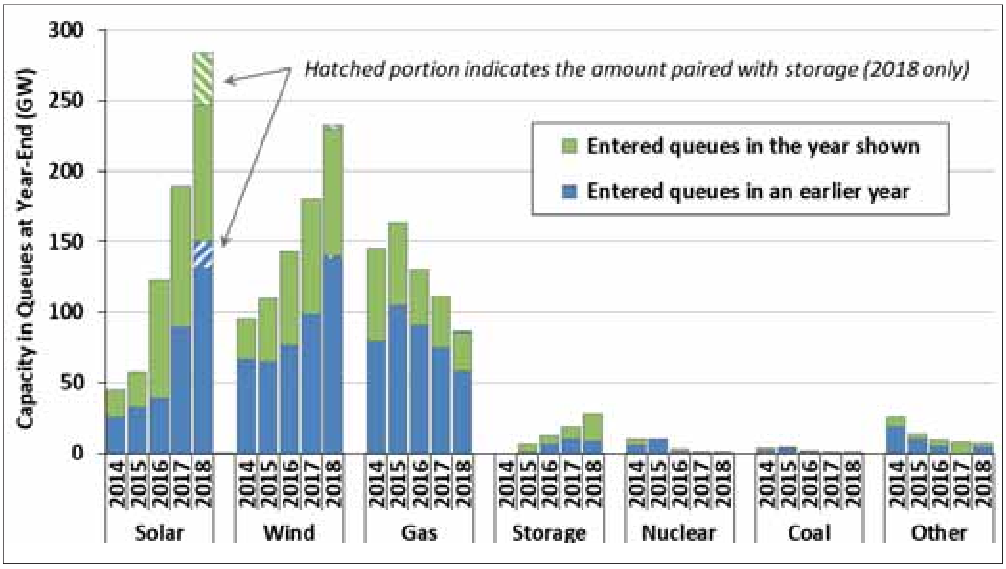

Figure 10. Solar and other resource capacity in 37 selected interconnection queues across the US

For example, in Hawaii—an isolated island grid grappling with a high PV penetration rate—this ratio is typically 1:1 so that all mid-day PV generation can be stored and shifted into the evening and overnight hours, whereas in the continental United States, batteries are more-commonly smaller, sized from 25-50% of the PV capacity. Moreover, data suggest that the incremental PPA price adder for four-hour storage varies linearly with this ratio, ranging from ~US$5/MWh for batteries sized at 25% of PV capacity up to US$15/MWh for batteries sized at 75% of PV capacity. As battery storage becomes more cost-effective, many developers now offer it

> "Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry in future years. At the end of 2018, there were at least 284GW of utility-scale solar power capacity within the interconnection queues across the nation"

as a standard upgrade to standalone PV, and many project owners are revisiting their existing fleets of standalone PV projects in search of opportunities to retrofit a battery.

Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry in future years (Figure 10). At the end of 2018, there were at least 284GW of utility-scale solar power capacity within the interconnection queues across the nation, 133GW of which first entered the queues in 2018 (with 36GW of this 133GW including batteries). Solar is now the largest resource within these queues, ahead of both wind and natural gas (though as recently as 2016, solar was in third place, behind the other two).

Moreover, the growth of solar within these queues is widely distributed across all regions of the country, and is most pronounced in the up-and-coming Midwest region, which accounts for 26% of the 133GW that first entered the queues in 2018, followed by the Southwest (21%), Southeast and Northeast (each with 15%), California (10%), Texas (9%), and the Northwest (5%). Though not all of these projects will ultimately be built as planned (i.e., entering the queues is a necessary but not a sufficient condition for development success), the ongoing influx and widening geographic distribution of solar projects within these queues is as clear a sign as any that the utility-scale PV sector in the United States is maturing and expanding outside of its traditional high-insolation comfort zones. ■

LNBL's 2019 "Utility -Scale Solar" report is available at utilityscalesolar.lbl.gov

Acknowledgement

This material is based upon work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under Solar Energy Technologies Office (SETO) Agreement Number 34158 and Contract No. DE-AC02-05CH11231. The U.S. Government retains, and the publisher, by accepting the article for publication, acknowledges that the U.S. 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 U.S. Government purposes. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

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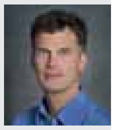

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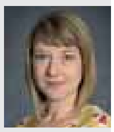


Dana Robson is a programme manager within the Electricity Markets & Policy Department at the Lawrence Berkeley National Laboratory. She has worked in nonprofit and government administrative support for more than 20 years, and previously worked for the David & Lucile Packard Foundation's Conservation & Science Program and the California Academy of Sciences Research Division.

Turn to p.75 for analysis of how the step-down of the solar investment tax credit is expected to affect the US industry.

Life after the ITC

Policy | On 1 January this year, the solar investment tax credit, responsible for fuelling the rapid growth of the US market, began its decline. Cecilia Keating assesses what impact it will have


Credit: Wikimedia Commons

Federal tax provisions set out by members of Congress one week before Christmas did not bring good tidings to the US solar industry.

While the wind industry wrangled an extra year of federal incentives in the tax package, the US$1.37 trillion budget omitted the extension of the solar investment tax credit (ITC) industry groups had lobbied for throughout the year.

The only federal incentive for solar installations, the solar ITC (which extends to storage, when co-located and co-developed) started its decline on 1 January.

The incentive, signed into law by President George W Bush in 2005 and renewed three times since, allowed solar system owners to recoup 30% of a project's total cost from their taxes. The subsidy dropped to 26% on 1 January of this year and will depreciate further next year to 22% before leveling at 10% for utility and commercial solar projects and expiring entirely for the residential market in 2022.

The Solar Energies Industries Association (SEIA), which has fronted the lobby to get the credit extended, has said that a 10-year extension of the full credit until 2030 would spur more than US$87 billion in investment and generate 81.8GW of deployment above the baseline.

Developers and analysts approached by *PV Tech Power* agreed that while an extension would turbocharge growth and level a federal tax code many believe to be biased towards fossil fuels, the utility-scale segment of the industry will weather any subsequent dip in growth. This is largely due to ever-declining materials costs, improving technology efficiencies and the maturity of financing models. The depreciation of the credit may have a bigger impact in the smaller-scale solar segments, where system costs are higher, and in the storage industry, where the technology is greener and the economic case for a subsidy is stronger.

Annual capacity is set to steadily increase in the US between 2020 and 2022 in the utility-scale, residential and commercial segments, BloombergNEF figures show. The firm estimates that new solar additions will leap from 11.1GW_{DC} at the end of 2019 to 14.9GW_{DC} in 2020, 16.1GW_{DC} in 2021 and nearly 18GW_{DC} in 2022.

A hoped-for extension to the US solar ITC has been rejected by Congress

The rush to safe harbour

In 2020, the capacity of new installations is set to eclipse the 12-month record set in 2016 when 14.1GW_{DC} was installed, or double the 7.3GW_{DC} the year prior. The boom was due to the scheduled step-down of the solar ITC from 30% to 10% (a plan that was ultimately nixed) in 2016.

A similar phenomenon is at work once again, with a rush of project developments announced at the tail end of 2019 as developers met the conditions needed to qualify them for the full 30% credit before it started depreciating. In December 2019, analyst Wood Mackenzie noted that 21.3GW of new utility PV projects were announced from Q1 to the end of Q3 of 2019, bringing the contracted utility PV pipeline to a record high of 45.5GW_{DC}

The US Internal Revenue Service deems a project's construction to have officially "begun" when either "physical work of a significant nature" has started, or 5% of a project's total cost has been spent. Purchasing – or safe harbouring – inverters and panels is one of the simplest ways developers can meet that benchmark and qualify their project for the existing ITC rate.

In December, residential and commercial developer Sunnova secured US$150 million of financing to purchase safe-harbour equipment, following in the footsteps of SunPower who purchased 200MW of safe-harboured panels, or enough to satisfy its residential lease customers and commercial PPAs through to 2022. Texas utility-scale developer 7X Energy revealed that it had purchased 2GWAC-worth of inverters.

"It's a call to action from a selling perspective," says Daniel Marino, chief commercial officer at BayWa r.e. Solar Systems LLC, the firm's distribution, residential and commercial and industrial business. The step-down "is helping solar companies sell more solar in the short-term because of the threat of an impending charge".

Icing on the cake

Benoit Allehaut, managing director of Capital Dynamics' Clean Infrastructure Fund, says that he is "not convinced that, over the very long term, the industry needs the 30% ITC in perpetuity". "Solar is priced extremely competitively," Allehaut says. "We're at a very different stage of the growth cycle of the industry, compared to where we were five or 10 years ago."

Capital Dynamics is the largest private owner of solar assets in the US and owns four of the 15 largest solar projects in the the country. In 2019, the firm acquired 2,249MW of solar capacity. While it entered the commercial and industrial segment in 2019 with the acquisition of Sol Systems and through a partnership with Johnston Controls, its bread and butter has always been large, utility-scale projects – "plain vanilla" projects, according to Allehaut, with "good-quality, long-term cash flow, long-term PPAs" that appeal to institutional investors.

"We're not advocating for or against subsidies, we leave that to trade associations," he says. "But when you look at the levelised cost of energy of utility-scale solar, without the ITC or with an ITC at 10% only, it is still extremely good value for money for customers, which is really at the end of the day what matters," he says.

The step-down might "push some capacity out" in its core segment, he says, but utility-scale solar will largely weather the tax change.

Figures from the US Department of Energy's Lawrence Berkeley National Laboratory published in late December show that PPA prices for utility-scale PV have fallen by US$10 per MWh annually in most years since 2013. Another metric of price decline – the median installed PV price – fell 70% since 2010 (see p.70).

"An extension of the solar investment tax credit at this point would have really been the icing on the cake. We still have a very good technology that can stand on its own without a tax incentive to bolster it," Colin Smith, senior solar analyst for Wood Mackenzie, says. Utility-scale developers, he adds, "tend to be more concerned by tariffs, simply because a 10c tariff has a bigger impact on the lower system costs in terms of raising the overall percentage and eating in to their margin".

President Trump's tariffs on imported solar cells and modules turned two years old on 22 January, and late 2019 saw an unpredictable back and forth between his administration and the courts on whether bifacial modules would be included in the suite of tariffs.

For Fred Robinson, executive vice-president of Baywa r.e. Solar Projects LLC, the firm's utility-scale business, it's a matter of making the federal tax code fairer and more environmentally friendly.

"From a utility-scale perspective, every power plant benefits from subsidy or tax relief of some form or another. We want to have a level playing field," he says. "That's our first objective. The second objective is that we want a price on carbon […] I think the ITC does a decent job of at least getting close to valuing that component [carbon], and it's probably the most politically viable. We want to see the ITC get extended."

Smaller-scale developers will feel the tax rule change more acutely, according to WoodMackenzie's Smith, given that the dollar-per-watt figure is higher and the tax incentive goes "a lot further" to make solar attractive to consumers.

"With the ITC going away, it doesn't necessarily put the existing states where solar is now developing rather prolifically in jeopardy, but it certainly might make it harder for developers to find new clients and make an attractive, compelling offer for building solar on the homes," he adds.

At BloombergNEF, the in-house view is that the step-down could bring down costs in the residential and commercial segment. The cost of a solar system in the US ranges "between US$3 to US$4 per watt" or about three times more than a customer would pay in Australia, and significantly more than in Europe, BloombergNEF solar analyst Tara Narayanan explains.

"We believe a large portion of the inflated costs are simply because of high customer acquisition costs, overheads and marketing," she says. "And to an extent that's supported because providers and distributors are able to tell customers they are going to get a rebate on the system. And so, once the tax credit rolls off, we think prices will actually come down, which will be a good thing."

Baywa r.e.'s Marino says his long-term view is "bullish" for the firm's commercial, residential and distributed business despite anticipating a "little dip in growth" when it steps down to 10% for commercial and industrial and expires for residential in 2022.

"I'm seeing trends of declining materials costs and rising utility rates offsetting, at least from a residential, commercial and industrial perspective, a lot of the negative of the ITC decline. Solar costs will keep going down," he says.

Marino predicts that over the longer term the industry will see "significant growth rates and lower customer acquisition costs, which is one of the main headaches in the residential segments", regardless of the step-down.

While there used to be a handful of states driving the market, there are now "more than 20" states driving growth, he says.

US solar advocates have vowed to continue the fight for continued federal support for the sector

Credit: SunPower

Push from corporates and states

While the federal administration has made it clear that decarbonisation is not a priority, states and companies are picking up the slack.

California's solar homes mandate came into effect on 1 January and will turbocharge rooftop solar in the state. Twenty-nine states, Washington, D.C., and three territories now have renewable energy standards.

The US corporate PPA market is flourishing, too, triggered by falling technology costs and the security offered by fixed-price and long-term energy deals. BloombergNEF figures published in January note that the volumes of corporate PPAs hit 9.6GW in 2019, a sharp increase on the 5.4GW recorded in 2018.

"The states have done a tremendous job of pushing in light of the step-down to make sure the markets are strong, and corporates and cities are doing it as well," says Baywa r.e. Solar Projects' Robinson.

A credit for storage

The shrinking of the solar ITC will be felt in the storage industry, where the tax credit has been key in driving the commercialisation of storage in both utility-scale and small-scale segments.

"It forced the solar industry to think about how to finance and assess the risk of storage," explains BloombergNEF's Narayanan. "It reflects the early days of solar, where everyone is asking the same questions: What is technology risk? How likely is the system to fail? Which hardware provider can I trust?"

"Solar has become a safe thing, fixed-income, long-term contracts and revenue streams. [The ITC encouraged industry] to try to see how it can make storage look like that and get projects off the ground," she says.

The Energy Storage Association says that more than 1GW of grid battery systems have been deployed so far, and that there are more than 7GW included in utility resource plans. The group is calling for a standalone storage ITC, in particular as an increasing number of utilities and residents turn to storage to circumvent the grid instability showcased after wildfires in California this year.

The group told *PV Tech Power's* sister website, *Energy Storage News* that lobbying for the credit was a "priority" in December and that the subsidy would "allow the US to maintain its lead in the advanced energy economy" and "offset some of the uncertainty with ongoing trade disputes and tariff threats."

Gregory Whetstone, president of the national American Council on Renewable Energy (ACORE) says that "storage is a real priority that really does not have a tax incentive in the code today, and should". "That's a real priority for us because we need more energy storage to accommodate higher levels of penetration and to make our grid more resilient," he says.

Battle stations

The fight for better federal tax relief for the solar industry is far from over, according to trade groups.

"The decision not to extend the ITC last year was a missed opportunity to add jobs and economic growth this year, and reduce carbon emissions in a meaningful way," says Dan Whitten, vice-president of public affairs for the SEIA. "We'll continue advocating for policy at the state and federal level that supports solar and helps us meet our economic and climate goals, and we will be working with members of Congress on a legislative approach that addresses those important goals."

ACORE's Whetstone says that the group will be "picking up where it left off last year" in order to address an "unlevel playing field in the tax code".

The presidential election in November, of course, could see the election of a decarbonisation-friendly administration keen to resuscitate the ITC. ("It certainly presents the opportunity to have a friendlier policy environment in which to address these issues," Whetstone notes.) Democratic candidate Elizabeth Warren was one of 20 Democratic senators to write a letter urging policymakers to extend the solar ITC extension in June 2019. Joe Biden, Bernie Sanders and Warren have pledged to implement carbon-neutral electricity or net-zero emissions targets if elected.

Wood Mackenzie's Smith muses that, after a tumultuous year marked by a trade war, solar tariffs and the uncertain future of the ITC, policy certainty is more important than all else.

"I think that most developers – whether they are in favour or against current administration – most agree that it has presented a lot of uncertainty, which inherently comes with risk," he says.

"As long as developers really understand what the landscape looks like, they are going to be relatively happy about it. It's really the certainty aspect they are looking for." ■

Presented to you by: Energy Storage News

STORAGE & SMART POWER

Introduction

Welcome to another edition of 'Storage and Smart Power', brought to you by Energy-Storage.news.

My introduction to the last issue's excellent feature articles and technical papers were an attempt at fighting climate despair, but, being honest, it feels like things have just got worse in some parts of the world in a very short time.

It would be quite cheap of me therefore to try and pretend that Australia's horrific bushfires – to give just one example – have at least stirred much of that country and the rest of the world into action and recognition of the problems at hand.

And in other countries, politicians are going all-out to try and protect increasingly uneconomical – or at best short-term – interests in the fossil fuel industry, even if renewable energy is actually cheaper and more investable than stranded assets and diminishing returns on oil and gas exploration.

On the other hand, it's easy to think that just because of the headlines and the very worst-case scenarios that are already happening, these things are *all* that is happening.

Some of us didn't even get into this industry to try and save the world, we just thought it was exciting technology and a natural progression to try and find better ways to generate – and now store and integrate – electricity. Yet we are truly part of an international business community now that is rapidly changing the world faster sometimes than even we realise. This edition includes topics from different continents and very different areas within the smart and clean energy spaces.

Safety is without a doubt of paramount importance in any industry, while efficiency comes in a closely connected second place. This issue, Robert Puto and Gerhard Klein at TÜV SÜD have written for us an in-depth examination of the manifold, vital technical assessments that must take place to ensure that systems are not only safe to install and operate, but that they will do exactly what their manufacturers and designers claim that they can.

Then, we have interviewed some of North America's leading developers of solar-plus-storage and standalone storage projects. Each told us what they have learned from 2019, what technologies they are using and what they are most excited, ambitious or even apprehensive about going forwards into 2020. That article is part of our #SmartSolarStorage2020 series, running throughout the year – check the website for more exclusive content and you can also use the hashtag to join the discussion online.

Consultancy EnAppSys has contributed an article on the role of storage and smart power technologies to help balance Europe's electricity infrastructure. From how things are currently done across the continent, to the roles that different kinds of batteries could play, to the business case for enabling renewable and low or zero carbon technologies on the grid.

Following my look at Japan's changing solar and storage markets in the main magazine, we also have a preview of the forthcoming PV Expo show and an interview with Kiwi Power, one of the winners of the recent Japan Energy Challenge.

We can't really talk about international cooperation, or indeed the clean energy industry, without also extending our thoughts and best wishes to all of those in China and elsewhere affected by the coronavirus. At the time of going to publication, it was casting an uncertain shadow over much activity in the industry and elsewhere so we hope that wherever you are, you remain safe.

Andy Colthorpe
Solar Media

Highview Power launches liquid air energy storage into the US with 400MWh Vermont project

Highview Power - one of the companies profiled in last edition's long-duration storage 'contenders' feature article - has announced the first installation of a long-duration liquid air energy storage (LAES) system in the United States.

Set to be a minimum of 50MW/400MWh, the project is being jointly developed by Highview and Encore Renewable Energy and is to provide in excess of eight hours of storage.

Highview's LAES uses excess of off-peak electricity to clean and compress air which is then stored in liquid form in insulated tanks, with temperatures closing in on 320 degrees below zero Fahrenheit (-196 C). The pressurised gas is then allowed to warm, turning a turbine as it expands.

Credit: Highview Power

Highview Power has announced a 50MW/400MWh minimum capacity project in Vermont, a scaled-up version of the grid-scale 'demonstrator' pictured

Navigant: Li-ion for ESS to exceed 28GW globally by 2028

While pumped hydro plants still account for around 96% of installed capacity of stationary energy storage worldwide, there will be more than 28GW of lithium batteries deployed for stationary storage applications by the year 2028, Navigant Research has predicted.

Navigant said 2019 had been a "transformative year" in energy storage, with the sheer numbers and scale of systems deployed surpassing anything seen in previous years, while batteries – and other technologies for storage – are also being deployed to serve a wider range of applications than ever before.

Lithium-ion industry 'disruptor' 24M's thick electrodes power Kyocera's new energy storage systems

Kyocera has launched a residential energy storage system using an advanced manufacturing process that supplier 24M claims can reduce some of the key costs of lithium battery manufacturing by as much as 50%.

The Japanese company's new product, Enerezza, is aimed at the booming market in its homeland and is available in 5kWh, 10kWh and 15kWh capacities. Kyocera began pilot production of battery cells and systems in June using 24M's proprietary production process, which uses electrodes typically three to five times thicker than in other lithium-ion batteries.

"Full-scale mass production" is set to begin in autumn 2020, with 24M hinting at initial production volumes of around 100MW in previous interviews with Energy-Storage.news.

First utility-scale battery joins Ireland's DS3 flexibility market

Statkraft is laying claim to the first utility-scale battery in the Republic of Ireland with the completion of an 11MW project.

The Norwegian state-owned utility has completed its 11MW Kerry battery in Ireland, partnering with systems technology supplier Fluence for the project, using LG Chem battery modules.

It is to be fully operational in early 2020, with Statkraft to enter into a contract with Irish transmission operator EirGrid through its DS3 flexibility market, providing reserves to the national electricity grid.

Virtual power plants: Enel X's aggregated home storage goes into action in Italy

A regulatory framework put in place by Italy's grid operator TERNA has enabled Enel X to aggregate residential energy storage systems to pool their capabilities, including their use as 'virtual power plants' to help balance the network.

The innovation and digital solutions division of European energy company Enel was a major awardee in competitive tender processes held by the transmission system operator (TSO).

Terna confirmed that its national Grid Development Plan had resulted in the award of more than 120 contracts for so-called UVAM (Virtually Aggregated Mixed Units) in just the first seven months since the programme's launch, between November 2018 and June 2019, totalling 820MW of capacity.

Li-Cycle: Recycled lithium battery materials sent to first commercial customer

A new lithium battery recycling facility has been established by operator Li-Cycle on a commercial basis at the well-known Eastman Business Park in New York State.

Eastman Business Park in Rochester, New York, is also host to a number of other battery industry operations, including Kodak's battery production centre. Li-Cycle representatives said via email that the announced facility will be a "spoke" of the company's operations (as opposed to a "hub"), with capacity to process 5,000 tonnes of spent lithium-ion batteries per year.

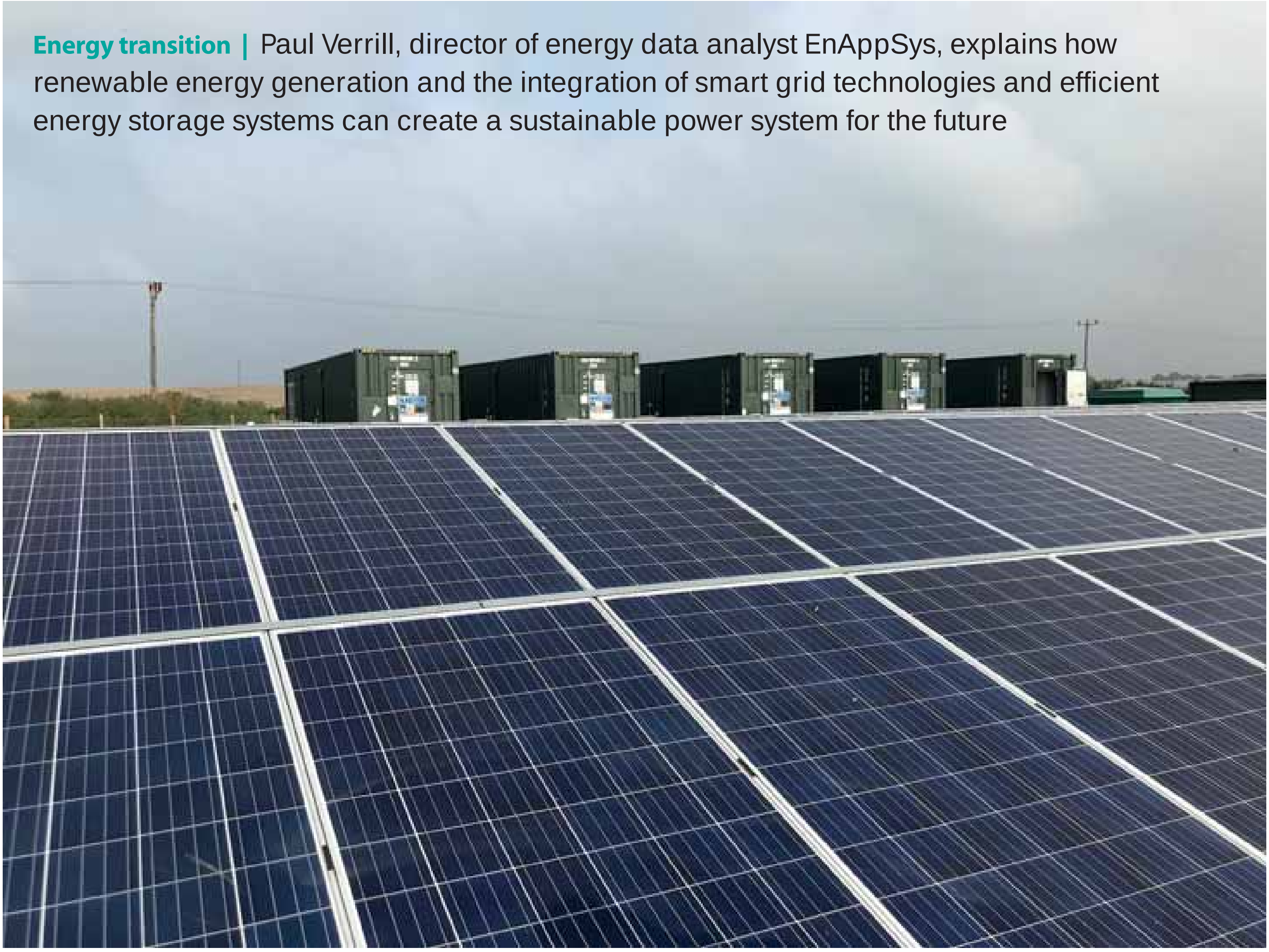
Korean flow battery company signs JV agreement for 200MWh US factory

KORID Energy Company Limited, a South Korea headquartered developer of VRBs, has signed a joint venture (JV) agreement with Canada-headquartered Margaret Lake Diamonds, a "technology and strategic metals exploration company" for the possible siting and construction of a vanadium redox flow battery (VRB) factory in the northeastern US.

Margaret Lake Diamonds is looking to conduct vanadium exploration in the US as well as constructing the batteries, offering an opportunity for value chain vertical integration. The initial Phase 1 of the factory is planned for 50MW annual output at 200MWh capacity.

Creating a sustainable power system for the future

Energy transition | Paul Verrill, director of energy data analyst EnAppSys, explains how renewable energy generation and the integration of smart grid technologies and efficient energy storage systems can create a sustainable power system for the future



Credit: Anesco

Electricity markets across Europe are seeing the growth of renewables within their mix, with levels of generation from renewables overtaking those from fossil fuels across Europe in 2019. Whilst the pace has slowed in recent years, each new year sees records being broken in respect of the proportion of electricity demand met by renewable energy.

Predominantly the growth of renewable generation is coming from increased levels of generation from wind farms – and historically from solar sources – although hydro remains the primary source of renewable generation in European markets.

This growth can lead to problems in security of supply, but the most significant are maintaining stable operation of power grids that were designed for large centralised thermal power stations. This also means ensuring that there is enough generation to meet demand in periods when output from renewables is low.

In most countries in Europe, the solution to date has been to introduce reserve and/or availability payments via capacity payment mechanisms to supplement the income of existing power stations and incentivise the build of new power stations that are able to meet demand in periods when renewable output is low. These mechanisms in the main provide support to thermal power stations and enable the management of the energy transition but slow down the closure of carbon-emitting assets.

Storage has the ability to hasten the transition to a zero-carbon energy system

Drivers created by these mechanisms (which are often closed to high-polluting stations) and the European carbon market are increasing the switch from coal to gas but do not yet drive transition to a 'net zero' world.

Some markets, Ireland and Great Britain, for example, are approaching the point where renewables are exceeding 50% of the fuel mix in some periods, which causes challenges for grid operation.

Some of the transmission system operators (TSOs) publish forward

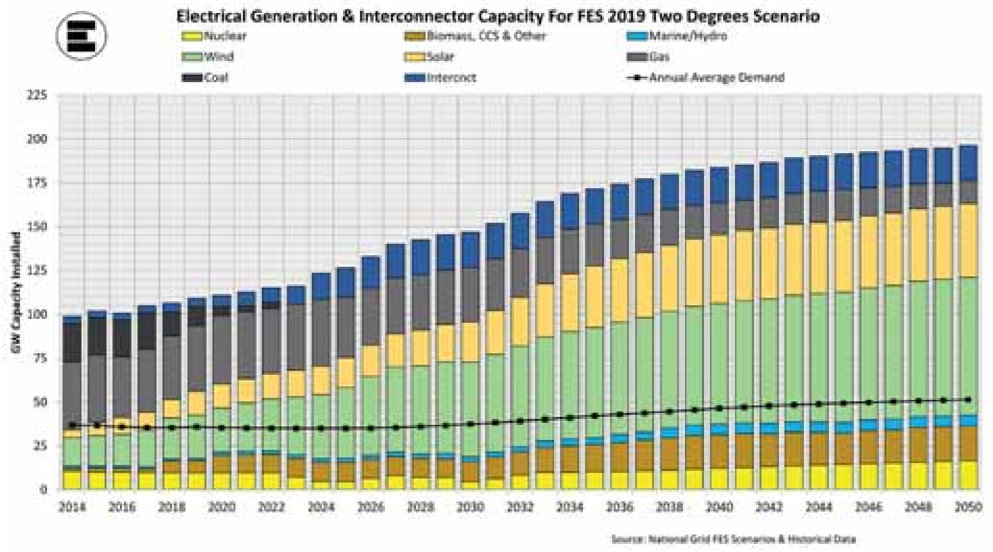


Figure 1. A projection of likely demand versus possible supply of electricity with an increasingly low-carbon fuel mix. Source: National Grid

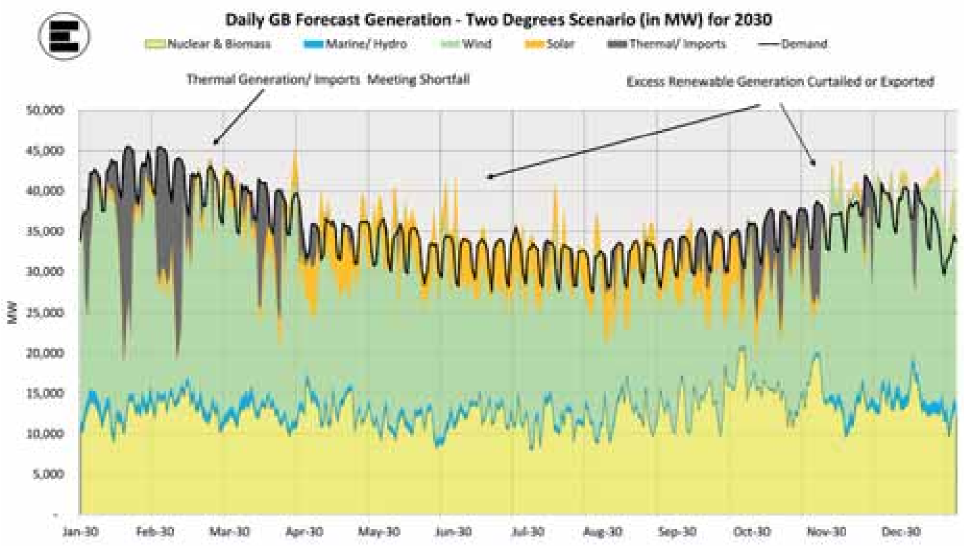


Figure 2. EnAppSys's generation forecast for Britain in 2030 under National Grid's 2 Degree Future Energy Scenario

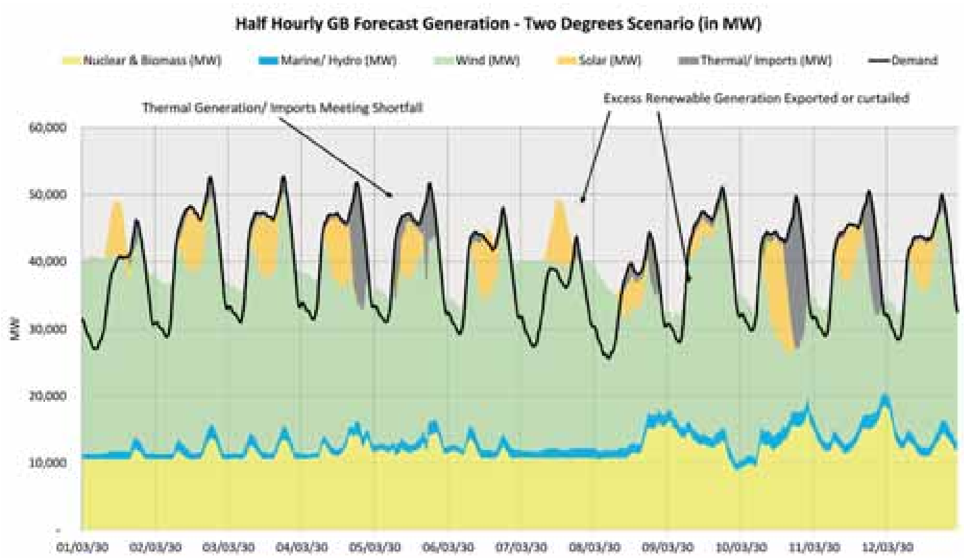


Figure 3. EnAppSys's generation forecast for Britain over a two-week period in 2030 under National Grid's 2 Degree Future Energy Scenario

energy scenarios to look at potential fuel mixes going forward, most notably GB's National Grid, which publishes its Future Energy Scenarios. The chart in Figure 1 shows its high renewable scenario with the forecast of average demand plotted on it. This graphic highlights that installed renewables will have the capability at peak output to more than exceed required demand and, whilst export via interconnectors can deal with this excess, it is likely that there may be excess in neighbouring countries as well.

The charts in Figures 2 & 3 show a projection of GB generation fuel mix in 2030 and for a summer two-week period. These have been produced using the EnAppSys forward model and assumes National Grid's 2 Degree Future Energy Scenario. Periods of excess renewable generation and periods of low renewable generation can be seen. In these scenarios, thermal generation is used to meet demand in the shortfall periods and excess renewable generation is curtailed (i.e. turned down).

Energy storage systems and smart grid technologies are ideally placed to work within this type of fuel mix to reduce the use of fossil fuels, limit the curtailment of zero-carbon generation and contribute to grid stability services – overall, providing progress to meet the net zero target.

The smart grid technology that provides these benefits has features that enable it to measure in real-time energy usage, be combined with some model determining future demand at the point of metering and have some level of control either through demand user action or automatically to change that energy use. Certain demand sites that have generation and/or storage behind the meter would also be able to provide export as part of the response.

To truly decarbonise would require differing types of energy storage that offer a combination of short-term, medium-term and longer-term zero-carbon energy storage technologies. Periods when renewable output is low, or high for extended periods, would not be able to be managed by smart grid technology and/or short duration energy storage.

In addition, when renewable output is low for sustained periods (i.e. days) then long-term (strategic reserve)

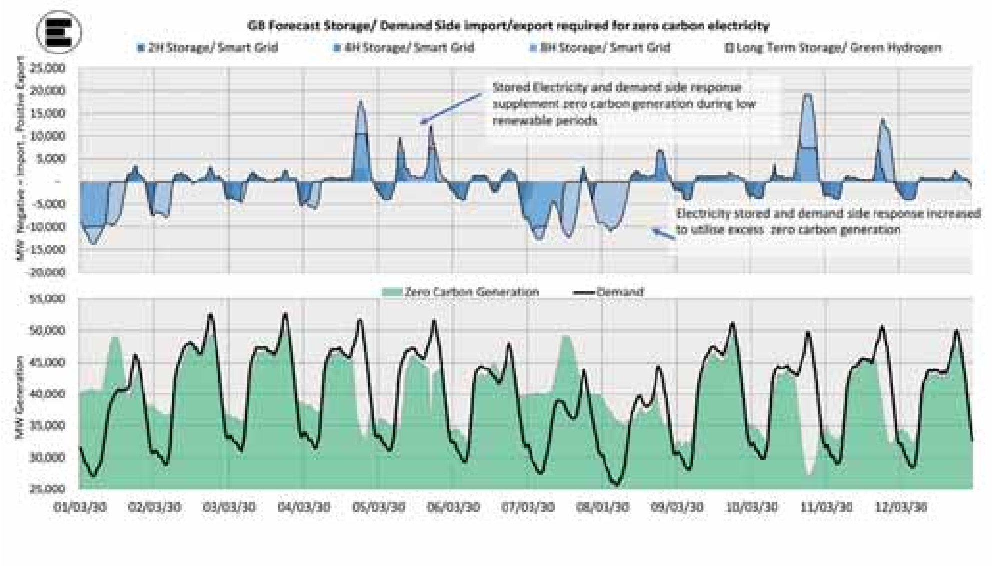


Figure 4. The same fuel mix as in Figures 2 & 3 but with a combination of storage and smart grid technology to optimise the zero-carbon generation

storage would be required.

Figure 4 shows the previous fuel mix with a combination of energy storage and smart grid technology varying both demand and supply to maximise the use of zero-carbon generation.

A combination of front-of-meter storage and behind-the-meter storage enables the demand curve to be matched more closely with the generation curve. Peaks of renewable generation are either stored for use in periods of high demand or else peaks of demand are flattened by moving non-time-critical electricity usage to periods of high renewable output. This is already happening but not yet at the scale that is anticipated.

These charts use GB market forecast for 2030 with a high renewable fuel mix and assumes no interconnector export of excess renewable energy. To enable all zero-carbon energy that could be produced by a combination of storage and demand response, that is around five times the import capacity of current GB storage and represents more than 1,000 times the storage capacity. Whilst the scenario used is the highest renewable build scenario, it illustrates the requirement for a significant build of low-cost 'bulk' storage capacity in a market with high wind and solar generation mix.

Technologies

Currently the majority of energy storage deployment is via lithium-ion batteries, with the advances driven by growth of portable electronic devices feeding into the automotive sector and now driving improved batteries into grid-scale energy storage.

The GB market has perhaps seen the greatest deployment of batteries in the last five years through the construction of a number of lithium-ion battery projects with close to 1GW in operation or being completed. It should be noted that in the main these projects have been constructed to meet the former issue with increased renewable deployment, i.e. grid stability.

> "Energy storage systems and smart grid technologies are ideally placed to reduce the use of fossil fuel, limit the curtailment of zero-carbon generation and contribute to grid stability services"

The installed projects to date are typically fast (sub-one second), short duration (less than one hour) projects and are designed to provide frequency support to maintain supplies. The primary reason for this is that the current capital cost of this technology and degradation means that it requires a higher price differential between import and export than is currently the case in European electricity markets for them to be economic in pure time shifting/pure arbitrage operation. A premium for their speed is currently required but with falling capital costs and improved technical performance this is likely to change.

Lithium-ion batteries are suited to deployment at domestic scale, and commercial products already exist, such as the Tesla Powerwall. With the growth of EV vehicles, a battery installation can share key infrastructure (inverters etc.) with charging infrastructure, making them complementary and delivering powerful smart grid capability.

Flow batteries, typically non-solid-state energy storage devices, are being developed but the level of R&D spend is significantly lower than for lithium ion as they do not yet have the same consumer application as lightweight, energy-dense storage devices. The technology has the capability for long-duration storage and for certain technologies employing rotating machinery to provide grid inertia, reactive power and fault tolerance stability services to grid, which the majority of grid systems in Europe were designed for.

Going forward, the potential for hybrid storage involving solid state batteries for speed, coupled with flow batteries for duration and potentially with certain technologies to provide grid inertia is an option for the future. Technology-wise, all of the elements are there, but the drivers are not as developed for this combination of abilities.

The oldest storage on the system both in GB and across Europe is pumped hydro. These are typically fast-acting (sub-two-minute assets), long-duration assets, offering anywhere from four hours of sustained output to more than 12 hours for some projects in planning. Across Europe the average age of stations is around 30 years and whilst new units are coming online it is rare as they require large upfront capital investment and therefore ideally long-term revenue certainty.

A means of energy storage that would also drive decarbonisation of heating systems as well as using existing generation infrastructure is hydrogen, ideally produced from excess renewable energy or from carbon capture technologies. This has the advantage of being able to use established gas storage infrastructure and gas-fired generation assets to

provide flexible and, more importantly, sustained generation in periods of low renewable output, which simplifies the journey towards net zero. In the case studies above, the production, use and storage of green hydrogen in existing natural gas storage and transmission infrastructure would enable the decarbonisation of thermal generation and heating.

Smart grid capability on the demand side is growing across Europe with the roll-out of smart meters. 'Agile' tariffs now exist in GB where price signals are communicated to consumers; they pay on a real-time price basis and this drives behaviour on their use of energy.

Barriers

The primary barrier to the deployment of energy storage and smart grid technology to deliver a sustainable power system is the level of investment required. The development needs certainty of revenues for an investment community and needs to be affordable for the consumer in the case of domestic applications.

Mechanisms for rewarding energy storage and smart grid technology are not well developed. Most of the investment in this technology requires the major proportion of its revenue to be obtained through merchant markets, which can be difficult to finance against. In the consumer market, the smart meter roll-out is assisting the market but the use of this capability is still limited.

As investment in storage technologies increases and the more it acts to enable the transition to net zero, the lower the returns for the assets if operating on pure merchant returns. The reason for this is that they derive their revenue from the price spread between periods of high demand and low demand; and the more demand is matched to generation, the lower this price spread. For assets also deriving revenue from providing grid stability services, the amount of installed assets required to balance supply and demand could create excess competition for the provision of these services, driving prices very low.

Enablers

Recognising certain medium/long-term storage assets as grid infrastructure would enable TSOs to build and/or procure storage as part of their overall network investment programme or else to have support through cap and floor mechanisms in a similar way to interconnectors. This would help the more strategic deployment of energy storage to either reduce transmission flows or cover long duration reserve.

In some markets, further deployment of weather-dependent renewable technologies requires the developers to build a proportion of energy storage to match and support their technologies.

> "The emphasis currently is on the transition from the old world to the new and not so much on what the end system ideally would look like. We must decide on a destination before a truly effective map can be made of how to reach that point"

This creates a market for these projects and a share of the support given to renewables.

Currently, processes to support renewable/zero carbon can be technology-targeted and centrally the government retains the requirement to balance out any of the negative aspects of the technology deployed. For example, in GB offshore projects are supported by the CfD (Contracts for Difference) mechanism, the government then has a capacity market mechanism to counter the impact of high renewables and the TSO procures alternative flexible generation to meet grid stability requirements.

There is the potential to extend this, and tender processes that seek to procure zero or low-carbon electricity generation able to match supply and demand would allow developers to team up and innovate to deliver solutions with a portfolio approach. This would find the most complete solution to delivering net zero power and could even include an element of demand response within it. Smart grid-enabled consumers could help a group of technologies to deliver zero carbon dispatchable generation similar to a nuclear project.

Capacity market mechanisms that target energy storage could alternatively provide the type of investment support that is driving investment in conventional generation. Currently, energy storage is positively discouraged in capacity mechanisms through the way in which derating factors are calculated.

Conclusion

Energy storage and smart grid technologies are developing rapidly and projects that provide positive benefits to the system are being deployed across Europe. The potential contribution they can make to a sustainable energy supply is recognised, and most system operators and governments are encouraging it through roll-out of smart meters and modification of system operation to recognise the changing fuel mix.

Despite this, the progress made so far is arguably 'behind the curve', as evidenced by the issues identified in the GB power cut of August 2019.

In our view, the market structures to allow energy storage and smart grid technologies to fulfil their potential and play their part in delivering a sustainable energy supply in Europe are not there yet. Whilst there are initiatives, trials and schemes that are supporting investment, it is not clear that these are scalable and that a consensus exists for the European market to adopt a whole-system approach. The emphasis currently is on the transition from the old world to the new and not so much on what the end system ideally would look like. It may well be that we must decide on a destination before a truly effective map can be made of how to reach that point.

Author

Paul Verrill is a director of EnAppSys, an energy information business providing energy data analysis and consultancy to both government departments, traders and operators active in the UK and European energy markets. Paul is a chartered engineer and has held senior posts in asset management and development with Enron and more recently px limited.

A developers' eye view on North America

#SmartSolarStorage2020 | Last year saw large-scale storage come of age in the USA and Canada, with some heavyweight storage portfolios starting to take shape. Speaking to four leading North American developers, Andy Colthorpe takes the pulse of a market poised for growth

There is no doubt 2019 was a massive year in the US and Canada for energy storage. One of the biggest drivers was the advent of economically competitive solar-plus-storage, where business models and savvy policy came together to heat up a market that has long been simmering. Not forgetting too that ancillary services and capacity, utility resource planning and other drivers kept standalone storage in the spotlight.

Considerations around the best battery chemistries, the best-designed incentive programmes, the existence or absence of supportive regulatory programmes and well-designed market structures are among the many factors that can make or break a project or pipeline of projects.

For both solar-plus-storage and standalone energy storage, nothing happens without developers ready and willing to take on those questions and get projects built and commissioned. So, who better to ask than four of North American's fast-rising players about the state of the region's storage market as it stands, seemingly, on the cusp of rapid expansion?

8minute Solar Energy – Tom Buttgenbach, CEO, president, co-founder

***PV Tech Power:* What are some of your most significant accomplishments in in 2019, and what were some of the challenges along the way?**

Tom Buttgenbach: Last year was a big year for 8minute's solar-plus-storage projects. We're extremely proud of The Eland Solar Centre, which will deliver up to 400MW of clean energy to the grid, with the additional capability of storing up to 300MW/1,200MWh, dispatchable for use when the sun is not shining (typically in the evening and night-time hours, when the load is still high). Eland, which holds the price record for solar-plus-storage in the US is a game-changer for the renewable energy industry and a huge win for California.

But big projects are happening outside of California as well. We also announced the Southern Bighorn Solar & Storage Centre, which includes a 475MW_{DC} (300 MW_{AC}) solar array with 540 MWh of Li-Ion battery energy storage and will be built in Clark County on the Moapa River Indian Reservation, about 30 miles north of Las Vegas, Nevada. Together, projects such as Eland and Southern Big Horn's advanced dispatch capabilities, are dispelling misconceptions about the availability, reliability, and long-term viability of clean solar power.

In all, I think 2019 will be remembered as the year that large-scale solar-plus-storage arrived in force.

What sort of technologies are you using at the moment, and what's exciting about future technology development and innovations?

8minute is technology-neutral as a company, but there are obviously exciting technological innovations in hardware throughout the entire industry. But one of the under-covered aspects of large-scale solar-plus-storage is software.

Earlier this year, we partnered with Doosan GridTech to develop an advanced energy software control solution for dispatching energy from advanced PV solar-plus-storage centres (PVS). We're using the new software first at the Springbok 3 Solar Farm, in Kern County, California.

This partnership pairs Doosan's flexible software platform and energy storage expertise with our forward-thinking PVS dispatch approach to maximise asset value creation. This new control solution will improve PVS plant output predictability and unlock additional value streams.

Credit: 8minute Solar Energy

8minute Solar Energy's Eland Solar Centre features a 300MW/1,200MWh storage facility

I believe that dispatchable large-scale solar paired with energy storage will be the backbone of the 21st-century grid. Smart, innovative software that communicates with the grid is a hugely important part of that future.

What do you expect to see this year and beyond 2020?

We're at the beginning of one of the most massive economic and technological transformations in history: the transition away from fossil fuels. The transition will happen much faster than most people realise because renewables, and solar in particular, have economics on our side. Fossil fuels are in decline, and once industries and technologies go into decline, it can become a rapid process even if incumbents are seemingly entrenched.

I can already beat a gas peaker anywhere in the country today with a solar-plus-storage power plant. Who in their right mind today would build a new gas peaker?

Ultra-low-cost large-scale 'solar-plus-storage centres' are changing the equation on the grid much faster than most people realise. We are a factor of two cheaper. We can cut the head and tail off the so-called duck curve, which will be a memory as more storage comes online. The fact is that storage can be both centralised and distributed in a way that will make the grid more resilient and efficient – not to mention cleaner and cheaper.

I think solar and storage will continue to grow on the grid. All the great things the industry accomplished in the last decade are just the beginning. Solar will be nearly free in the coming decades. As a result, it becomes economically beneficial to design the entire system around those cheap electrons.

GlidePath – Sean Baur, engineering manager

***PV Tech Power:* What are some of your most significant accomplishments in in 2019, and what were some of the challenges along the way?**

Sean Baur: GlidePath added more than 250MW to its portfolio in 2019 – that number includes construction of self-developed storage projects and acquisitions of both storage projects and renewable energy assets that will be paired with storage in the future. GlidePath has also grown its development portfolio to about 1.6GW of similar projects across a variety of markets.

We are seeing a major proliferation of battery OEMs and integrators providing viable products in the space, increasing competition and pressuring the more established firms.

Regulations and fire codes are forcing standardisation across the industry. Battery safety has always been a top priority and we hope it won't take incidents or negative headlines to keep the industry focused on safety going forward.

What sort of technologies are you using at the moment, and what's exciting about future technology development and innovations?

We are primarily focused on projects using lithium-ion batteries and are seeing a mix of more established nickel manganese cobalt (NMC) suppliers and newer-to-the market lithium iron phosphate (LFP) OEMs. LFP appears to be well-positioned this year, with more certainty around tariffs – as most of the major players are in China – allowing them to really showcase their price competitiveness and increasingly dependable technical performance.

On a forward-looking basis, we see that integrators are thinking more creatively about [battery] augmentation as project lives are extended and project-owners look for longer performance guarantees. One of the most exciting areas of growth here, also applicable to solar-plus-storage, is the scale-up of DC-DC converter technology. This will be vital as battery systems age and need to be augmented, especially with some of the modular augmentation strategies that we are seeing proposed from suppliers.

We are happy to see more thought around the technical aspects of battery augmentation, and especially the push towards truly agnostic augmentation regimes where the augmentation battery vendor (or even chemistry) can be different than the original installation. This is being promised by some integrators, so we look forward to seeing how this is implemented across power electronics, switching and protection, communications and controls.

What do you expect to see this year and beyond 2020?

We are happy to see serious discussion of the value of limited-energy duration projects to serve in wholesale markets. We predict that this will be resolved this year for markets such PJM and NYISO, but the actual resolution is harder to predict. What we would like to see is an immediate transition to valuing storage projects at or near their current penetration levels, with a longer-term discussion surrounding the potentially declining ability to supply capacity services as the resource mix on the grid changes over time.

Implementation of fast frequency response in ERCOT is a good step to expanding out the ability of storage projects to provide more ancillary services, not just PJM RegD. This, combined with the Fast AGC developments in MISO, indicate that more market operators are starting to recognise and implement programmes to value the unique capabilities of storage.

GlidePath's Prospect Storage project in Texas looks set to compete in the ERCOT market

Key Capture Energy – Jeff Bishop, CEO and co-founder

***PV Tech Power:* What are some of your most significant accomplishments in in 2019, and what were some of the challenges along the way?**

Jeff Bishop: We kicked 2019 off by starting operation of our first project, KCE NY 1, the largest operating battery storage project in New York. KCE NY 1 serves the state's electrical system by enhancing power grid performance and reliability and will help reduce greenhouse gas emissions.

The 20MW energy storage system supports Governor Andrew M. Cuomo's Green New Deal, the most aggressive climate change initiative in the nation, which mandates New York's energy storage target of 3,000MW by 2030.

We also were awarded the Orange & Rockland award for a Non-Wires Alternative (NWA) to be deployed in 2020 and were pleased to start construction on three Texas battery projects. We ended the year with over 1,000MW of battery storage projects in development, ranging from 5MW to 200MW in New York, Texas and in New England.

What sort of technologies are you using at the moment, and what's exciting about future technology development and innovations?

We work with leading system integrators such as NEC Energy Solutions (NEC) and Powin Energy Corporation (Powin). Our KCE NY 1 project is using NEC's end-to-end grid storage solution and its AEROS proprietary energy storage controls software. The system includes a flexible design to accommodate wholesale market opportunities in the NYISO market. NEC's grid storage solution architecture offers parallel redundancy for better system reliability with high availability and field serviceability.

We have partnered with Powin on several projects, currently under construction or in development. Powin provides provide fully integrated battery energy storage systems including cells, enclosures,

Credit: Key Capture Energy

Key Capture Energy's 20MW entry into New York in 2019 showed the state's concrete ambitions for cleaner energy, Jeff Bishop says

cabling, transformers, inverters, and all software and controls systems. Powin will be responsible for commissioning the battery energy storage systems and for scheduling the systems.

KCE uses lithium-ion batteries and continues to work with a large swath of vendors to assess the best technology for each solution that we are developing. It is exciting to see the decline in battery costs and we believe that we will see more and more large-scale energy storage projects competing in non-traditional markets.

What do you expect to see this year and beyond 2020?

At the close of 2019 there were 528MW of storage projects operating across the country. However, we are seeing strong development interest in storage with a total of more than approximately 45GW of projects in queues across CAISO, PJM, NYISO, ISO-NE, ERCOT, SPP and MISO. When a state sets a goal, like California, Massachusetts or New York have done, that gives developers like us a clear framework to operate in and confidence that the inevitable challenges we will face as an emerging technology solution (market access, development soft costs, clear timelines and structures) will be figured out.

For the industry to mature and those ~45GW of projects to go from being under development to operational, the wholesale electricity markets will need to be designed to take full advantage of energy storage's potential. Storage can provide a wide range of services to the grid, but only if storage has a seat at the table – across stakeholder processes at the wholesale level, through proceedings before the Federal Energy Regulatory Commission, and through regulatory policies enacted by legislatures and state commissions.

Productive discussions with regulatory bodies and ISOs, as policies and markets are formed, will be essential. If we can work together with regulators and generators to allow for technology neutral compensation to the products a generator provides to the electric grid, storage will play a key role in the clean energy transformation.

Convergent Energy + Power – Frank Genova, CFO/COO

PV Tech Power: What are some of your most significant accomplishments in solar-plus-storage and/or standalone energy storage in 2019, and what were some of the challenges along the way?

Frank Genova: We were acquired by Energy Capital Partners (ECP), a private equity and credit investment firm with greater than US$20 billion in capital commitments. This provides us with a flexible and scalable capital structure that will allow us to grow our pipeline in the rapidly evolving energy storage sector. Also, we completed, to our knowledge, the first solar-plus-storage tax equity closing for three projects on the Delmarva peninsula on the East Coast.

We also set a new industry record for the largest behind-the-meter battery energy storage system (10MW/20MWh), matching our previous record set in 2018. This system was developed as part of a joint venture with Shell New Energies, designed to reduce their facility's peak consumption of energy by one third while increasing reliability and long-term sustainability of the grid. Our energy storage solutions are also now available to existing Shell Energy North America customers in Canada.

Last but not least, 2019 was a year in which we really grew the M&A side of business, acquiring around US$70 million of new projects; these acquisitions are for both standalone storage and solar and storage projects, with varying levels or merchant and contracted revenue streams.

On the challenges front, the lack of familiarity with storage—or misconceptions about it—continues to hold back development and growth in certain instances. Projects not coming to fruition, particularly after being awarded and announced, is not uncommon in the sector and can breed customer scepticism. Another challenge is the tax equity process for solar and storage. At distributed scale, it's an expensive, time-consuming, one-off process. Lastly, safety-related issues that occur do hurt the overall reputation of the industry.

What sort of technologies are you using at the moment, and what's exciting about future technology development and innovations?

For us, anything in the one- to six-hour range is going to be lithium-ion, a combination of lithium iron phosphate (LFP) and nickel manganese cobalt (NMC) depending on pricing, available area, etc. We are seeing opportunities outside of that range, but based on our strategic focus they're still few and far between.

There are some interesting flow battery technologies out there that we're following but it's a smaller subset of our total opportunity set. Looking forward, we're somewhat bullish on certain flow technologies and zinc-based chemistries due to the fact that their primary performance characteristics such as cost, safety, abundance of raw materials, commercialisation process and so on, align well with where we see value in the market. Although these chemistries are not being manufactured at scale, the developers have the right viewpoint on the market and could be well positioned as they continue commercialising their products.

What do you expect to see this year and beyond 2020?

In 2020 we're expecting to see continued price declines on battery storage technologies, a greater understanding and adoption from stakeholders and off-takers (on both the C&I and utilities side), a broadening of the opportunity set – pricing comes down, the opportunity set increases – and ultimately, more favourable market conditions and market treatment for storage.

Some other things we expect to see include a consolidation of developers and assets – we're already seeing a lot of developers flipping and/or selling their platforms. [Also], more educated customers, a greater demand for storage across customer segments, and a focus on storage as a part of corporate social sustainability efforts. ■

Safety and efficiency first in solar-plus-storage

Technical due diligence | Ensuring battery systems used in conjunction with solar perform safely and optimally is essential in ensuring the continued roll-out of storage technology. Robert Puto and Gerhard Klein of TÜV SÜD examine independent technical assessments that must be undertaken before a storage system is built

It is obvious that the purpose of generating solar energy is essentially its transformation into useable electric power. Because of its fluctuating nature, the timing and the magnitude of this generation cannot be controlled, nor can it be managed in correspondence to high or low demand from consumers.

The rise of solar and wind (and the concurrent decline of fossil fuel) generation demands a stable integration into existing power grids. In addition, smart grids offer the flexibility to store energy during periods of surplus and low demand/low price, and consume it during peak-demand/high price. The solution is energy storage.

On the one hand, this solution must be efficient and fast enough to prevent grid instability; on the other, it must operate safely for users and without causing negative impact on the environment. These are necessary conditions for public acceptance.

In technical terms, storage systems should have the following properties:

(1) So-called "four quadrant operation", i.e. full operation for all combinations of active and reactive power.

(2) Renewable firming, i.e. provision of backup power to tighten the output of a PV system and ensure a continuous power supply.

(3) Reactive power control to establish reactive power supply to meet any grid requirements.

(4) Peak-shaving and -shifting in power production to shave, store and deliver energy when needed.

(5) Ramp rate control to buffer output changes of intermittent renewable energy sources.

(6) Active power management as frequency-dependent control to support the grid.

(7) Fault ride through (FRT) properties, i.e. the capability of staying connected during short network voltage dips, must comply with local requirements.

On 19 August 2019, a lightning strike triggered a series of events that led to the disruption of the UK's power grid resulting in power loss for one million consumers for up to 45 minutes and 1GW of disconnected electricity demand. This is a clear example of how critical it is to design a well-balanced and stable grid, where generators, protective devices, suitable backup power (from energy storage systems), power management systems, etc., provide enough inertia to prevent critical voltage and frequency instability.

Beyond the societal and ecological aspects, renewable energy combined with energy storage must also prove economically viable, i.e. competitive when compared to fossil, or nuclear power generation.

TÜV SÜD offers a holistic approach, consisting of combined top-down and bottom-up analyses for a most comprehensive ESS assessment. Top-down analysis come from system-level considerations, whereas bottom-up from component level. In this article we present our approach to utility-scale PV plants combined with electrochemical battery storage solutions, as one of the most interesting applications.

Technical due diligence (TDD)

Generally, investment projects require a due diligence (DD) process based on a thorough assessment of legal (LDD), financial (FDD) and commercial aspects (CDD). It has evolved to become a quasi-standard for project financing and financial transactions. In the case of projects driven by new technology, it is necessary to have a sound evaluation of technical feasibility, opportunities and risks associated with the technological solution proposed.

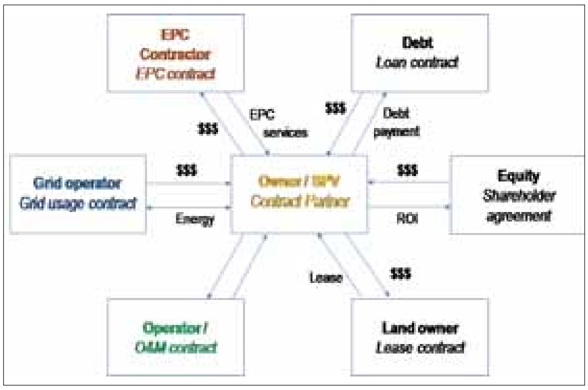


Figure 1. Typical stakeholders in a utility-scale PV and storage power plant. Source: TÜV SÜD.

Third parties are engaged in technical due diligence (TDD) activities to identify critical issues or risks, and for technical advisory concerning possible mitigation measures. It is important to note that such a technical due diligence is not only an engineering exercise. It also takes into consideration the interactions between different project stakeholders shown in Figure 1.

In other words, technical evaluations during the TDD assessment are relevant to LDD, FDD and CDD work streams.

Below is a description of the main activities performed under top-down and bottom-up technical due diligence.

Top-down TDD activities

Amongst various system-level assessments made, particular attention shall be paid to:

System design and profitability

Although different designs are possible from a technical point of view, the benefit/cost ratio may depend on other factors as well. In [1], different connec-

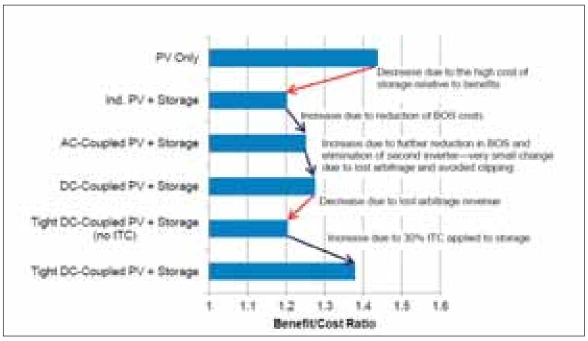


Figure 2. Benefit/cost ratio for different PV-storage combinations [1]

tions to the grid of a PV plant plus storage systems have been considered for a system model located in California (independent PV and storage system, AC-coupled PV plus storage system, DC-coupled system with flexible charging and DC-tightly-coupled with PV-only charging). Depending on whether there is an investment tax credit (ITC), either the "DC-coupled system with flexible charging", or the "DC-tightly-coupled with PV-only charging" will result being the "best solutions" from a benefit/cost perspective.

Figure 2 shows how sensitive the benefit/cost is ratio to factors such as system location and support policies in place, on top of design-related factors, such as AC-coupled versus DC-coupled PV + storage models.

Criteria for battery technology

Careful criteria for the selection of a suitable battery type for the storage shall be defined during the early feasibility stage. Lithium-ion (Li-ion) batteries are currently widely used in stationary utility-scale storage applications, with several technologies available [2]. It's important to note that the combination of different types of electrolytes with different electrode materials can result in very different battery characteristics. Therefore, the first selection criterion is based on the assessment of the maturity of the technology.

The next selection criterion we use is based on safety considerations. Given the high energy levels involved (currently between 200Wh/l to 350Wh/l, in uptrend towards 250Wh/l to 550Wh/l by 2030) in combination with highly flammable nature electrolytes, intensive R&D is ongoing focused on optimisation of different layouts and cell designs. One of the "worst case scenarios" that needs to be prevented is the so-called "thermal runaway". This might be the consequence of external events causing overloading of cells thus overheating, or even worse, short circuits in the cell structure which can trigger uncontrollably high temperature rises leading to hazards like burning, fire and explosion of the cells. Deep discharge is another phenomenon that should be controlled as it may cause corrosion.

Cost is obviously a very important factor to be considered for Li-ion systems. Its current learning curve is on a steep decline, which is a very good news. According to BNEF's Long-Term Energy Storage Outlook, the capital cost of a utility-scale lithium-ion battery storage system is expected to decrease by around 52% between 2018 and 2030 [3].

Another significant development we will witness in the short to medium term is the application of second- life batteries. This will further accelerate the downward trend of Li-Ion battery price. In fact, according to recent studies, second-life battery supply from used EV batteries of electric vehicles could exceed 200 GW-hours per year by 2030 for stationary applications, which might even exceed the demand for Lithium-Ion utility-scale storage for low- and high-cycle applications combined [4]. However, due to different designs of EV-battery packs, fragmentation of volume in the automotive sector and a gap in standardisation addressing second-life batteries, there is no guarantee today regarding their quality and performance. Furthermore, nascent but immature regulations might create uncertainties for OEMs, second-life battery companies, and potential users. Technical developments are underway on second-life battery safety standards, involving all industry stakeholders. The final goal is twofold: on the one hand, creating transparency into product supply and market demand [4], on the other, matching battery performance potential with storage application requirements through a classification method for both.

Figure 3. Predicted price outlook for lithium-ion batteries [3]

Criteria for battery management system

The battery management system (BMS) is essential to the safety and performance of the entire ESS system: it has a controlling and monitoring function, hence its specifications and functions need to be checked, tested and validated.

Controlling and monitoring the state of charge (SoC) of the battery cell through its parameters (current, voltage, temperature) during charging and discharging is a critical function based on which functional safety for fault protection is designed.

In addition, BMS does fault recording and connection/disconnection of the battery system, and acts as a balancing function by optimising the usable system capacity. These functions are necessary because of differences in cell capacity and internal resistance due to manufacturing methods and modes of use. When the cells are connected, they will charge and discharge differently, which in turn can lead to deep discharge or overcharging of cells. Cell balancing allows for usable capacity to be maximised, and at the same time for an increased service life. The state of health (SoH) defines the residual capacity at a given time and is used for the characterisation of the remaining usable capacity.

Finally, the BMS has the function of controlling thermal management, as the efficiency and ageing of the cells are highly dependent on temperature. Increased temperatures lead to more rapid degradation of the materials and faster ageing of the battery, while lower temperatures impede the flow of current as the conductivity of the electrolyte is reduced. In order to ensure normal operation, optimum power output and service life, the system will require cooling at high temperatures and heating in cold weather.

Bottom-up TDD activities

For a comprehensive, overall validation, also component-level requirements shall be met.

Hereby we would like to highlight the importance of the following:

Battery testing

Safety, performance, reliability and environmental tests are conducted in the laboratory.

Test methods are in accordance with international and local battery standards as listed in Table 1. Above all, we would

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IEC 62619:2017	Secondary cells and batteries containing alkaline or other non-acid electrolytes – Safety requirements for secondary lithium cells and batteries, for use in industrial applications	Safety testing
IEC 62620:2014	Secondary cells and batteries containing alkaline or other non-acid electrolytes – Performance requirements for secondary lithium cells and batteries, for use in industrial applications	Performance testing
IEC 61427-1:2013	General Requirements and Test Methods for Renewable Energy Storage Batteries and Battery Units. Part 1: Photovoltaic Off-grid Applications	Performance, lifecycle testing
IEC 61427-2:2015	General Requirements and Test Methods for Renewable Energy Storage Batteries and Battery Units. Part 2: Grid Connection Applications	Performance and lifecycle testing
VDE-AR-E 2510-50:2017	Stationary battery energy storage systems with lithium batteries – Safety requirements	*Safety, reliability, environmental*
UL 1973:2018	Batteries for Use in Stationary, Vehicle Auxiliary Power and Light Electric Rail (LER) Applications	*Safety, environmental, reliability testing*
JIS 8715-1:2019	Secondary Lithium cells and batteries for use in industrial applications- Part 1 : Tests and requirements of performance	*Performance testing*
JIS 8715-2:2019, J62619	Secondary Lithium cells and batteries for use in industrial applications- Part 2 : Tests and requirements of safety	*Safety testing*
KBIA-10104-03-7312 (2018), KC62619, KC 62620	Secondary lithium-ion battery system for battery energy storage systems — performance and safety requirements	*Safety, Performance testing*
GB/T 36276-2018	Lithium-ion Battery for electrical energy storage	*Safety, lifecycle, reliability testing*
UN 38.3 (Ver.6 + A1)	Battery Transport Requirements (UN Handbook, Recommendations, Tests and Standards for the Transport of Dangerous Goods)	Environmental, reliability testing

Table 1. International and national battery standards

like to highlight the importance of the following three standards:

1) IEC 62619 - Safety requirements for secondary lithium cells and batteries, for use in industrial applications; 2) UN 38.3- Battery Transport Requirements; 3) IEC 62620 - Performance requirements for secondary lithium cells and batteries, for use in industrial applications. (Worth noting, too, are the country-specific regulations: VDE-Germany, UL-USA, JIS-Japan, KBIA-South Korea, GB-China.)

Examples of test failures

Impact test. Is defined in clause 7.2.2 of IEC 62619 - Safety requirements for secondary lithium cells and batteries, for use in industrial applications. Figure 4 shows the effect of the failure of the battery under the specified test conditions. The overheating phenomenon, called "thermal runaway", is triggered within the battery cell structure. The sequence of cause-effect events leading to fire starts with mechanical pressure applied on the battery, finally leading to fire (mechanical pressure => damaged cell structure => internal short-circuit => overheating => fire). The root-cause for the failure is the solidity of the separator between the two electrolytes inside the battery. The separator, if too thin, or made of inadequate material, may get punctured under the applied crushing pressure, hence giving rise to an internal short circuit, and consequently to uncontrollable overheating and burning. Although the impact test does not feature among those with the highest failure rates in laboratory testing, it is very important to execute it correctly given the disruptive risk associated with it. In the test, a cell (or cell block) is first discharged at a constant current of 0.2It A to 50% SOC. A stainless steel bar is placed across the centre of cell, thus 9.1kg rigid mass is dropped on the sample from a height of 0.6m. The acceptance criterion is that the impact shall not cause fire or explosion.

Credit: TÜV SÜD

Figure 4. Cell burning during impact test

External short-circuit test. Is defined in clause 38.3.4. of UN 38.3 - Battery Transport Requirements. It can result in a "thermal runaway" inside modules of cells without adequate protection. Normally modules are equipped with an internal protective device called CID (current interruption device) designed to intervene during the short-circuit test. If this doesn't happen reliably, burning can occur (Figure 5), and thus the failure of the test. Redundancy in protection levels might be necessary.

Credit: TÜV SÜD

Figure 5. A module of cells burns during external short-circuit test.

Functional safety. Failure of the control system is more frequently encountered during the following safety tests of the above mentioned IEC 62619:
1) clause 8.2.2 Overcharge control of voltage (battery system); 2) clause 8.2.3 Overcharge control of current (battery system); 3) clause 8.2.4 Overheating control (battery system).

Performance tests. Covered by IEC 62620 - Performance requirements for secondary lithium cells and batteries, for

use in industrial applications. Attention shall be paid to endurance tests according to: 1) clause 6.6.1 Endurance in cycles and 2) clause 6.6.2 Endurance in storage at constant voltage (permanent charge life).

Risk assessment and validation for PCS, BMS and EMS

Power conversion system (PCS), battery management system (BMS) and energy management system (EMS) are the main pillars on which the entire system, its controls and protections rely. Our guiding principle for a final judgement is a thorough risk assessment of the three pillars mentioned above. It starts with hazard identification, continues with risk analysis and finally evaluates the measures implemented for risk reduction. The following standards are applied throughout the risk assessment:

IEC TS 62933-5-1: 2017 – Electrical Energy Storage, Safety considerations for grid-connected EES systems. Is used to classify hazards in eight categories: electrical, mechanical, explosion, fire, temperature, chemical, exposure to electric/magnetic/electromagnetic fields, and unsuitable working conditions. Different technologies present different hazards. Clause 7 of this standard provides detailed guidance on risk assessment procedures, risk reduction measures and damage propagation for grid-connected applications.

IEC TS 62933-4-1: 2017 - Electrical Energy Storage, Guidance on environmental issues. Provides guidance to environmental reliability. ESS shall be capable of withstanding severe environmental conditions per its intended use, under conditions such as water, dust, humidity, salt mist, exposure to solar irradiation of enclosures, low/high temperatures, seismic vibrations.

IEC 62933-2-1: 2017 - Electrical Energy Storage, Unit parameters and test methods. Provides methods for checking main system parameters per intended use, such as nominal energy capacity, input/output power ratings, roundtrip efficiency, expected service life, system response, self-discharge, etc. In addition, performance parameters related to grid compliance, such as duty-cycle round-trip efficiency, fluctuation reduction, black start output voltage, grid connection compatibility, etc, shall also be tested.

Dedicated programme for utility-scale, containerised ESS systems

TÜV SÜD PPP 59044A is a verification, testing and validation procedure for utility-scale, containerised battery storage systems. It is performed after the battery testing and is mainly based on the above mentioned standards (IEC 62933-5-1, -4-1, -2-1). It consists of three activities, two of which conducted on-site:

1) Documentation review: System diagrams, BMS, PCS, ESS, container, lighting, air-conditioning & ventilation, fire protection systems, etc.
2) Construction checks (on-site): Coinsistency of materials/parts (BOM), fixing methods/installation of components/parts, functionl checks of all sub-systems, wiring system, fire-protection system, isolation/overcurrent protection devices, protection against electric shock, etc. (Figure 6, left.)
3) Safety tests (on-site): Insulation resistance, voltage test, earth continuity, verification of protection by automatic disconnection of supply, ingress protection (IP rating), door fan integrity, noise level, etc. (Figure 6, right, & Figure 7.)

Particular attention shall be paid to the insulation system coordination between all parts of the ESS system in order to prevent total breakdown. It is therefore essential that it is inspected and tested during the project. In case of systems with multiple PV power sources, the insulation stress caused by the system voltage, working voltage, temporary and impulse overvoltage on the other circuits and components connected to the PV sources shall be tested. For example, for a PV source rated 1,000 VDC with overvoltage category II, all circuits connected shall withstand a working voltage test on the insulation between the PV source and earth of 1,600 VDC (1 min) and 4,464 Vpeak impulse test.

Additional TDD activities

Beyond the engineering judgement, we are also involved in the assessment of contracts, permits and licences (related to legal due diligence).

Contracts are the basics of a project. As far as they include technical specifications, the following aspects shall be assessed from a technical perspective. This holds especially true for EPC and O&M contracts:

- Is the scope of supply and services defined sufficiently?
- Are prices and pay-out mechanisms according to industry standards?

Construction tests

Safety tests on containerized Battery ESS

Credit: TÜV SÜD & Greensmith/Wartsila

Fig. 6 TÜV SÜD experts during on-site construction checks (left) and safety tests (right)

Credit: TÜV SÜD

Figure 7. On-site testing of "enclosure integrity" of door fan as required by NFPA 2001 regulation (USA: National Fire Protection Association: Clean Agent Fire Extinguishing Systems)

- Have arrangements regarding amendments been made in a transparent way?
- Have periods of performance/supply been defined reasonably (e.g. hand-over conditions)?
- Are the provisions on warranties and guarantees as expected (liability, performance guarantee for battery cells)?
- Do the provisions on penalties cover the project needs?
- Are all permits, certifications and qualifications available or can we expect they will be available in time (considering the experience of the project partners involved)?
- Are there remarkable political or country risks (higher level of security measures required?)

Considering Li-ion cells, e.g., major ethical concerns were raised in different countries with respect to quarrying cobalt or lithium under conditions of child labor or forced labor. This issue might lead to a more restrictive legislation or even prohibition on the use of such materials.

Market expectations (related to commercial due diligence)

The market development determines the revenue streams, but also possible competitive technologies coming up during the lifetime of the project must be considered:

- What is the main source of revenue? (feed-in tariffs? Renewable Portfolio Standards? Capacity charge or working price?)
- What is the off-take and sales risk?
- How has it developed in the past? What are expectations for the future?
- Will the project be able to master future challenges?

Investor expectations (related to financial due diligence)

In order to fully capture the economic opportunities of combined PV-energy generation and ESS on the one hand, and on the other mitigating the risk of failing to generate adequate income, a thorough evaluation of the financial planning is needed also from a technical perspective:

- Are LCOE and IRR realistic?
- Are CAPEX and refurbishment expenditures planned reasonably?
- What is included in OPEX and are the assumptions well-founded?
- Finally, is the business plan (revenues and expenditures) realistic?

Final considerations

Applying system-level technical due diligence from an early design phase is key to building a solid business case. Applying component-level technical due diligence during project implementation is key to securing efficient operations and therefore the expected financial returns. Ignoring or overlooking the safety aspects, or lack of expertise in risk assessment activities, can lead to very harmful consequences from a legal, financial and commercial perspective.

Clear examples of the type and scale of damages incurred are the fire accidents in South Korea from August 2017 involving 23 lithium-Ion ESS systems and resulting in the shutdown of 533 ESS units with US$32 million losses. The investigation committee formed by the Ministry of Industry identified four root causes: insufficient battery protection systems against electric shock; inadequate management of operating environment; faulty installations due to faulty wirings and damage to batteries; and deficiencies in ESS integration. In particular, deficiencies regarding the battery management system (BMS), energy management system (EMS), and power management system (PMS) were the root causes which led to fire. ■

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Japan Energy Challenge: An invitation to innovators

Smart energy | With Japanese companies keen to learn from their counterparts in deregulated energy markets such as the UK, the Japan Energy Challenge provided the ideal forum for exchanging ideas. Andy Colthorpe reports

The 2019 edition of the Japan Energy Challenge, launched by analytics and AI company SMAP Energy, got significant buy-in from many influential businesses in Japan, including established players such as Tokyo Gas and innovative start-ups such as PV company Looop.

Companies from around the world were invited to share their knowledge and solutions for building a 'smarter' energy world, built around decarbonisation and digital innovation. One of the winners was UK-based Kiwi Power and Connected Energy, whose international market development leader, Nima Tabatabai, tells PV Tech Power what lessons Japan can learn from the UK

***PV Tech Power:* I've heard that Japanese companies are very interested to see what UK companies can offer them, having experienced its own energy market deregulation in the previous decades. Was that the case for Kiwi Power?**

Nima Tabatabai: The UK was one of the first to open up flexibility markets. The US, or some parts of it, was first, it's now happening in Europe but in terms of accumulating years of experience, UK flexibility aggregators like Kiwi are some of the most experienced companies in the world because this [type of distributed flexibility platform] has really only existed for about 10 years.

We have a platform that can handle any type of flexibility assets, so for example it can manage demand response, generation assets, battery storage assets, it's agnostic to the technology.

It's basically a platform for connecting any type of distributed energy resource and allowing it to respond to a signal or price or whatever you want it to respond to. We have one platform but it can be deployed in many different ways, and in different types of assets, whether it's commercial demand response, or any kind of aggregation.

There's always been an expectation that Japan's FiT programme would end in the early 2020s. There seems to be a general shift in Japan market from deployment of renewables in its own right and on to smart technologies that help to integrate them. Does that tally with what you've seen?

It's a natural transition as well for a market. So usually, renewables are always the easiest point of entry, with investable projects. In almost every market, if you look at the US and Europe, renewables happen first, but really renewables introduce intermittency into the energy system. And it's kind of the downstream effect of that which then drives the change into energy storage and smart grid technologies.

It's really how to manage the impacts of renewables that I think leads to these other types of solutions being demanded in the market. What I think is really interesting is how renewables have become economically competitive, outcompeting almost every other form of generation, so it's less politicised now. It's less about political buy-in and subsidies in almost every market. Whether people like renewables or not, it doesn't really matter anymore.

The downstream effect is that renewables start scaling up and you need the suite of technologies that will help manage the grid to integrate more than a certain threshold of renewable into any energy system.

So there are areas of knowledge and expertise that UK companies might have, that Japanese industry players may want to leverage. Are there any other similarities there, and conversely, any areas that appear to be 'new' challenges?

Credit: Japan Energy Challenge

Kiwi Power's Nima Tabatabai (second from right) accepts the Japan Energy Challenge award, one of four winning companies

Japan is an island, and an island grid is quite different than a continental grid to manage.

That encourages them to look at the UK more than perhaps the size of the UK market might warrant otherwise. The fact you have an isolated grid and you need to balance the grid at every moment in time… doing that on an isolated system is more challenging than on a well-interconnected system, so a European network is not a good analogy for the Japanese grid – which also has two frequencies, 50Hz (East Japan) and 60Hz (West Japan).

Some of the challenges are the land mass and topography. It's mountainous and the seas around Japan are deep, they're not on a continental shelf, like the UK. So the offshore wind technology that currently exists basically needs continental shelves. That's why the UK and Europe are really leading the deepwater wind technology which could be a good 10 to 15 years away – that's what's needed in Japan to drive offshore wind.

Until that's ready, there will be a natural constraint on deploying renewables. On the consumption and asset side, Japan is perfectly positioned because they have a high amount of personal electrification, they have highly developed industries that are all grid-connected.

What to expect at Tokyo's PV Expo, part of World Smart Energy Week

Event preview | Andy Colthorpe looks at some of the highlights in the forthcoming PV Expo, part of World Smart Energy Week in Tokyo

World Smart Energy Week, which hosts the popular PV Expo show, alongside smart grid, battery, wind and other industry-specific, but closely connected segments, is attended annually by tens of thousands of visitors from all over the world.

Here are some of the highlights, topics and expected trends that will be put to the fore at this year's conference and exhibition, taking place at Big Sight, Odaiba, Tokyo from 26-28 February 2020.

Large-scale power plants and investment

While there has been downward pressure on expectation for new contracts for large-scale, ground-mounted solar power plants, the segment itself will be full of activity.

The conference on Wednesday 26 February includes a presentation on 'Growing Solar Power Generation as the Main Power Source in the 2020s' from Juntaro Shimizu, a director at the government Ministry of Economy, Trade and Industry (METI). He will be joined by Japan Photovoltaic Energy Association (JPEA) chairman Kimikazu Sugawara.

JPEA's Sugawara will discuss solar's role in decarbonising society and battling climate change, presenting solar as a potential 30% of Japan's energy mix by 2050. METI director Juntaro Shimizu will discuss challenges associated with supporting the growth of PV and the government's long-planned "fundamental review of the FIT system in Japan".

The next day, Masaya Okuyama, director, Climate Change Policy Division for the Global Environment Bureau at the Ministry of the Environment will discuss the 'Spread of Solar Power Generation in the 2020s', followed by a presentation from RTS Corporation CEO, Osamu Ikki.

Credit: 3R Energy co

In a mountainous country where land is at a premium, finding the right site location can be a challenge

Meanwhile, at the exhibition, the likes of EPC company ECOLABO Co, will present their services to builders of the many gigawatts of already awarded projects and to those vital, but limited, new opportunities to develop and build power plants, including maintenance, design proposals and public relations and engagement.

With limitations on land and tricky-to-negotiate topography, 3R Energy Co will present suitable properties for development, aimed at investors, power producers and construction and EPC firm customers alike.

Zero Energy Homes and self-consumption of PV

With the shift from selling energy to the grid(s) to smart creation and consumption, exhibitors will be offering everything from simulation and modelling services to battery energy storage and complete home systems including management and control suites.

As well as international names including Tesla, domestically headquartered companies will be on hand at the exhibition, such as Nipron, which claims its new product PV Oasis is a "revolutionary storage battery-type self-consumption system with no reverse power flow", and new home battery product launches from Nagase & Co's 'all-in-one' HEMS system, including a 2.3kWh/4kWh li-ion battery with hybrid power conditioner architecture, to an energy storage system suitable for home to light industrial use from Yamabishi Corporation, including peak shaving. Also of interest will be carport PV structure providers, including Nichiei Intec (pictured).

The conference supports this area with a presentation from Masamitsu Kawanaka, director in areas including renewable energy policy at the Ministry of Agriculture, Forest and Fisheries (MAFF), at the session on Friday morning (28 February), 'Full-scale Expansion of Solar Power Generation Systems'. Also on the stage at that session will be Takashi Ikeuchi, managing officer for the urban business unit at Tokyu Land Corporation, a stock exchange-listed Japanese real estate company.

Credit: Nichiei Intec

Providers of smart energy solutions such as this carport PV structure from Nichiei Intec will be on display

Operations and maintenance

The 7GW+ annual PV market in Japan since at least 2013 means that there is no shortage of businesses competing to look after and operate existing ground-mounted solar assets.

Everything from specially designed ride-on mowers to cut grass around PV arrays in open field sites to robotic brushes and cleaning systems, to on-site yield forecasting, string-level solar panel checkers, to all-in-one, fully wrapped O&M strategy designers and providers will be at this year's exhibition.

At the conference, Naoyuki Taniguchi, senior VP and board member at NTT Anode Energy, a recently-established division of major Japanese telecoms provider NTT targeting the growing 'smart energy' business sector, presents new strategies and products at the Friday (28 February) afternoon session, O'utlook of Solar Power Generation Business for Social Change'. Following up is Atsushi Ito, president and CEO at Next Energy and Resources, sharing a "view for radical change in energy industries," driven by solar PV, focusing on market competitiveness and promoting "rapid expansion" of renewable energy. ■

For full information on PV Expo website https://www.pvexpo.jp/en-gb

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