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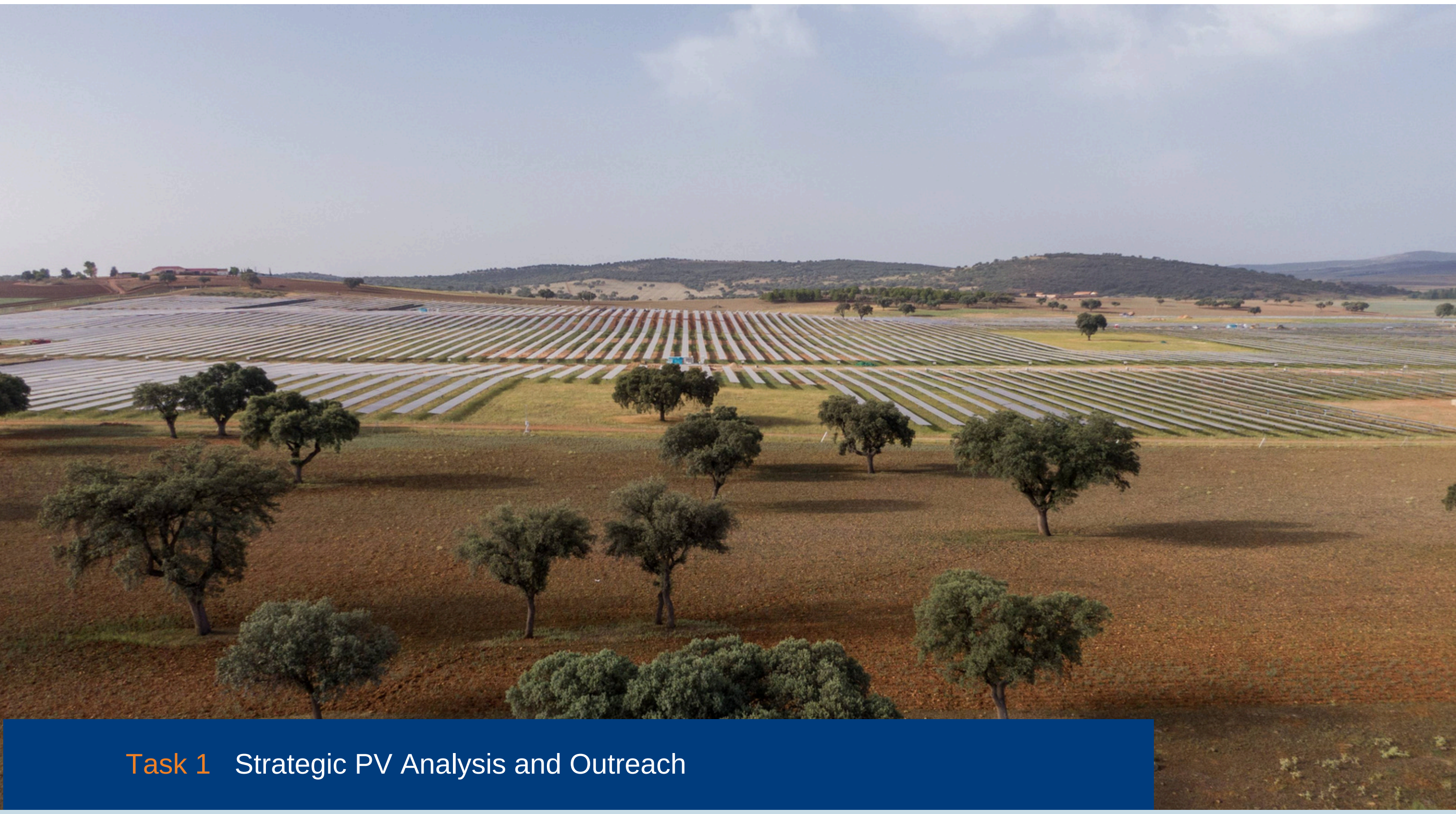
International Energy Agency
Photovoltaic Power Systems Programme



Task 1 Strategic PV Analysis and Outreach

PVPS

TRENDS IN PHOTOVOLTAIC APPLICATIONS 2026

Report IEA-PVPS T1-50:2026

PHOTOVOLTAIC POWER SYSTEMS TECHNOLOGY COLLABORATION PROGRAMME

WHAT IS IEA PVPS TCP?

The International Energy Agency (IEA), founded in 1974, is an autonomous body within the framework of the Organization for Economic Cooperation and Development (OECD). The Technology Collaboration Programme (TCP) was created with a belief that the future of energy security and sustainability starts with global collaboration. The programme is made up of 6.000 experts across government, academia, and industry dedicated to advancing common research and the application of specific energy technologies.

The IEA Photovoltaic Power Systems Programme (IEA PVPS) is one of the TCP's within the IEA and was established in 1993. The mission of the programme is to "enhance the international collaborative efforts which facilitate the role of photovoltaic solar energy as a cornerstone in the transition to sustainable energy systems." In order to achieve this, the Programme's participants have undertaken a variety of joint research projects in PV power systems applications. The overall programme is headed by an Executive Committee, comprised of one delegate from each country or organisation member, which designates distinct 'Tasks,' that may be research projects or activity areas.

This report has been prepared under Task 1, which deals with market and industry analysis, strategic research and facilitates the exchange and dissemination of information arising from the overall IEA PVPS Programme, with a contribution from Task 16.

The IEA PVPS participating countries are Australia, Austria, Belgium, Canada, China, Denmark, Finland, France, Germany, India, Israel, Italy, Japan, Korea, Lithuania, Malaysia, Morocco, the Netherlands, Norway, Portugal, South Africa, Spain, Sweden, Switzerland, Thailand, Türkiye, the United Kingdom and the United States of America. The European Commission, Solar Power Europe and the Solar Energy Research Institute of Singapore are also members.

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SUGGESTED CITATION
de l'Epine, M., Kaizuka, I., Mirata, A., Okazaki, J., Murata, A., Bosch, E., Martinez, J., Remund, J., Dominguez, G., (2026) Trends in Photovoltaic Applications 2026. IEA PVPS Task 1.

COVER PICTURE
Ground-mounted PV installation in Ciudad Real, Spain, Picon II. Image credits UNEF

ISBN 978-1-923734-15-9

DOI 10.69766/QAPR2899

REPORT SCOPE AND OBJECTIVES

The Trends report's objective is to present and interpret developments in the PV power systems market and the evolving applications for these products within this market. These trends are analysed in the context of the business, policy and nontechnical environment in the reporting countries. This report is prepared to assist those who are responsible for developing the strategies of businesses and public authorities, and to support the development of medium-term plans for electricity utilities and other providers of energy services. It also provides guidance to government officials responsible for setting energy policy and preparing national energy plans. The scope of the report is limited to PV applications of several dozen Wp or more. National data supplied are as accurate as possible at the time of publication. Data accuracy on production levels and system prices varies, depending on the willingness of the relevant national PV industry to provide data. This report presents the results of the 34th international survey. It provides an overview of PV power systems applications, markets and production in the reporting countries and elsewhere at the end of 2025 and analyses trends in the implementation of PV power systems between 1992 and 2025. Key data for this publication were drawn from member country information summaries supplied by representatives from each of the reporting countries information from the countries outside IEA PVPS are drawn from a variety of sources as indicated in the Methods Annex. While every attempt is made to ensure their accuracy, the validity of some of these data cannot be assured beyond the limits indicated.

ACKNOWLEDGEMENT

This report has been prepared under the supervision of Task 1 participants. A special thanks to all of them.

FOREWORD

The global photovoltaic market set another record in 2025, although growth slowed compared with the exceptional acceleration of the preceding years. Approximately 692 GW of new capacity was installed, 15% more than in 2024, bringing cumulative global capacity to almost 3 TW. This installed capacity could theoretically generate around 3 845 TWh annually, equivalent to approximately 12% of global electricity consumption.

China remained the dominant market, installing around 415 GW or 60% of global additions, while India added 54 GW and the USA approximately 43 GW. Deployment continued to broaden geographically, with 36 countries installing more than 1 GW during the year. Europe added approximately 79 GW, broadly stable compared with 2024, as growth in utility-scale installations increasingly compensated for slower development in some distributed-PV markets.

This deployment continued alongside significant industrial imbalance. Module production remained above annual installations, while nominal manufacturing capacity substantially exceeded both production and demand. Low utilisation rates, continuing price pressure and weak profitability affected manufacturers throughout the value chain. Industrial policies, trade measures, local-content requirements and supply-chain considerations continued to play a role in determining where PV products were manufactured and deployed, but did not significantly impact the regional balance of manufacturing capacity.

The scale of deployment is changing the relationship between photovoltaics capacity, electricity systems and electricity markets. Curtailment, negative prices, declining capture prices and grid-connection constraints are more increasingly visible in high-penetration markets. Storage, flexible demand, stronger networks, improved forecasting and appropriate market access are becoming essential to extending the contribution of PV beyond the hours in which it generates and providing bankable business models for new investment.

Electricity demand is increasing through transport, heating, cooling, industrial electrification and rapidly expanding data-centre loads. PV's modularity and relatively short construction times means it is well placed to contribute to this growth, but its value will increasingly depend on coordination with storage, networks, complementary generation and flexible consumption.

Photovoltaics is now a fundamental component of the world's economy, providing an estimated 8.2 million jobs for around USD 400 billion in market activity in 2025. It is also actively contributing to greening the energy sector, avoiding approximately 1.3 $GtCO_2eq$ of emissions.

PV development has moved to the next phase: it is now both about using almost 3 TW of cumulative capacity more effectively and enabling new capacity. As a major source of electricity, it is now necessary to ensure that it can contribute flexibility, resilience and system services to demonstrate the value of its continued expansion.

Melodie de l'Epine, Izumi Kaizuka - Co-Managers, IEA PVPS Task 1

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LARGE DEPLOYMENT AND A CHANGING SYSTEM ROLE

1 GLOBAL DEPLOYMENT SCALE

PV continued to expand rapidly in 2025, reaching 2.96 TW of cumulative capacity, with 0.69 TW added during the year, a 15% increase compared with 2024.

2.96 TW CUMULATIVE CAPACITY

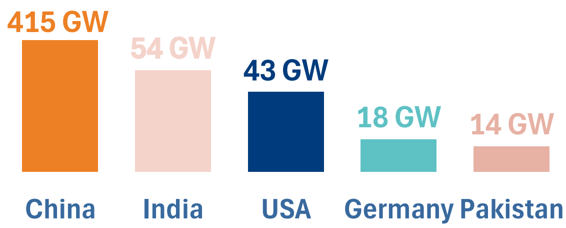
0.69 TW INSTALLED IN 2025

+15% YEAR ON YEAR

2 MARKET CONCENTRATION AND GEOGRAPHIC EXPANSION

China accounted for 60% of global additions in 2025. Deployment also broadened, with 36 countries installing more than 1 GW.

TOP 5 MARKETS: ANNUAL INSTALLATIONS IN 2025



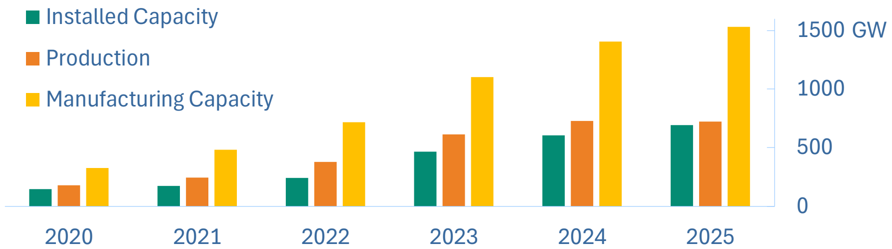
60% OF GLOBAL ADDITIONS IN CHINA

36 COUNTRIES INSTALLED OVER 1 GW

3 MANUFACTURING OVERCAPACITY AND WEAK UTILISATION

Global module production exceeded annual installations, but remained well below manufacturing capacity, pointing to continued overcapacity.

DEPLOYMENT AND INDUSTRIAL CAPACITY



4 STORAGE DEPLOYMENT ACCELERATED

Annual BESS energy-capacity additions in Europe and the USA combined rose from 2.9 GWh in 2020 to 79 GWh in 2025.

ANNUAL BESS ENERGY-CAPACITY ADDITIONS IN EUROPE AND USA

MORE THAN 27-FOLD INCREASE

5 CLIMATE AND ECONOMIC CONTRIBUTION

PV contributed to climate mitigation and the economy in 2025, avoiding emissions, supporting millions of jobs and generating substantial market activity.

1.3 Gt CO_2eq AVOIDED ANNUALLY

8.2 MILLION PV JOBS

400 USD BILLION IN MARKET ACTIVITY

12% THEORETICAL PV PENETRATION

SOURCE IEA PVPS AND OTHERS

one

INTRODUCTION TO THE CONCEPTS AND METHODOLOGY

PV TECHNOLOGY

Photovoltaic (PV) devices convert the energy in solar irradiation directly into electric energy and should not be confused with other solar technologies such as concentrated solar power (CSP) or solar thermal (ST) for heating and cooling. A PV power system combines photovoltaic modules with the equipment required to support, connect and operate them, including mounting structures, cabling and inverters for most applications. Depending on the configuration, systems may also include batteries, charge controllers, tracking systems or energy-management equipment. 1 GW

PV systems range from a few watts in small off-grid applications to multi-GW power plants. They can be installed on buildings and infrastructure, mounted on land or water, or combined with agricultural and other activities. Despite this diversity, most systems follow the same basic sequence: photovoltaic cells are interconnected to form modules, modules are assembled into arrays, and power-conversion equipment adapts their electrical output to the requirements of the load or electricity network.

CELLS, MODULES AND SYSTEMS

Photovoltaic cells represent the smallest unit in a photovoltaic power producing device. Cells can be classified as wafer-based crystalline silicon (c-Si), thin film semiconductor or emerging organic and hybrid technologies. Crystalline technologies account for more than 98% of the overall cell production. Monocrystalline has progressively replaced multicrystalline silicon in mass production although they are present in a large volume of already operational PV systems.

Wafer sizes, and hence cell sizes, have progressively increased, as this is considered by industrial actors to be an easy way to improve cell and module wattage. Several formats remain on the market, although current crystalline-silicon production is increasingly concentrated around larger formats based on the 182 mm and 210 mm wafer families, including rectangular formats. N-type wafers and cells have also increased their market share as manufacturers move towards technologies offering higher efficiencies and lower degradation. In 2025, n-type wafers represented around 82% of crystalline-silicon wafers used for cell manufacturing. The industrial evolutions on wafer formats, cell technologies and manufacturing are further discussed in Chapter 4.

Commercial crystalline-silicon module efficiencies are generally around 20% to 25%, depending on cell technology, module format and product design. Thin-film technologies such as cadmium telluride (CdTe), and copper indium-(gallium)-diselenide (CIGS or CIS) retain smaller specialised market shares, whilst perovskite and tandem technologies an important focal point of current research, pilot manufacturing and early demonstration.

Crystalline silicon modules consist of individual PV cells connected and encapsulated between a transparent front, usually glass, and a backing material, usually plastic or glass. Thin film modules encapsulate PV cells formed into a single substrate, in a flexible or fixed module, with transparent plastic or glass as the front material.

Bifacial PV modules collect light on both sides of the panel. Their additional power generation depends on site conditions, particularly ground reflectance, module height, row spacing and system configuration. Bifacial technology is now widely used in large-scale systems and can also be combined with tracking structures.

Commercial PV modules in 2026 commonly range from around 450 W for rooftop applications to above 700 W for large-format utility-scale products, with some commercial bifacial glass modules now exceeding 800 W. Larger formats and higher nominal powers are more frequently used in centralised ground-mounted systems, while residential and commercial products tend to use dimensions more compatible with roof layout, handling and installation requirements. Specialized products for building integrated PV systems (BIPV) exist, sometimes with higher nominal power due to their larger sizes.

A PV system consists of one or several PV modules, connected to either a connection point to an electricity network (grid-connected PV) or to a series of loads (off-grid), together with the electrical equipment required to adapt and control the electricity output. In grid-connected systems, an inverter is used to convert electricity from direct current (DC) generated by the PV array to alternating current (AC) that is injected into the electricity network. Modern inverters increasingly perform functions beyond power conversion, including monitoring, active- and reactive-power control and communication with energy-management or network-control systems. Their increasing role in electricity-system operation is discussed in Chapter 7.

A wide range of mounting structures have been developed — especially for BIPV — including PV facades, sloped and flat roof mountings, integrated (opaque or semi-transparent) glass-glass modules and PV tiles. Single or two-axis tracking systems are attractive for ground mounted systems, particularly for PV utilization in countries with a high share of direct irradiation, with an increase in energy yield from 15% to 35% for single axis and 25% to 50% for dual axis trackers compared with fixed systems.

PV APPLICATIONS AND MARKET SEGMENTS

PV systems are deployed across a wide range of applications and market segments. For the purposes of this report, the principal distinction is between distributed, centralised and off-grid PV. These classifications describe the function and connection of the system rather than applying a universal threshold based solely on system size.

DECENTRALISED OR DISTRIBUTED PV

Grid-connected distributed PV systems are installed to provide power to a grid-connected customer or directly to the electricity network — nearly always the distribution network but, for the largest utility scale systems, sometimes the transmission network. These systems may be on, or integrated into, the consumers premises — often on the demand side of the electricity meter, on residential, commercial or industrial buildings, or simply in the built environment on e.g., motorway sound-barriers, etc. Size is not a determining feature — while a 1 MW PV system on a rooftop may be large by PV standards, this is not the case for other forms of distributed generation. National reporting practices differ, and the harmonisation used for this report is described in the Methodological Annex.

When considering distributed PV systems on buildings, it is necessary to distinguish building applied photovoltaics (BAPV) and buildings integrated photovoltaics (BIPV) systems. BAPV refers to PV systems installed on an existing building as an addition to the existing building envelope while the definition of BIPV according to IEA PVPS Task 15 is that a BIPV module is both a PV module and a construction product together, designed to be a component of the building; and If the BIPV product is dismounted, it would have to be replaced by an appropriate construction product — which implies that the PV replaces conventional building materials such as roofing elements or facades.

CENTRALISED OR UTILITY SCALE PV

Grid-connected centralized PV systems (also called utility scale systems) perform the functions of centralized power stations. The power supplied is not physically associated with an electricity customer. These systems are generally ground-mounted and principally deliver electricity to the distribution or transmission network.

Centralised systems increasingly use large-format modules, tracking systems and high-capacity power-conversion equipment. They may also be co-located with battery storage, although storage capacity is reported separately from PV capacity. The contribution of PV in conjunction with storage and other flexibility resources is discussed in Chapter 7.

OFF-GRID PV

Off-grid domestic systems provide electricity to households and villages that are not connected to the utility electricity network. More generally, off-grid PV ranges from small solar home systems and pico-PV products providing basic lighting and communications to larger systems supplying commercial, industrial or community loads.

For most off-grid systems, a storage battery is required to provide energy during low-light periods. Some applications, such as water pumping, can operate without electrical storage. Hybrid systems can combine PV with batteries and dispatchable generators, with PV and storage increasingly reducing generator operating hours and fuel consumption.

Off-grid systems remain particularly important where extending the electricity network is technically difficult or economically unattractive. They are also among the more difficult market segments to quantify because installations may not be registered through utilities or national grid-connection databases.

OTHER PV APPLICATIONS

Floating PV systems are mounted on a structure that floats on a water surface and can be associated with existing grid connections, for instance when in the vicinity of a hydro power dam. They can reduce competition for land and are most commonly deployed on reservoirs and other artificial water bodies.

Agricultural PV combines crops and energy generation on the same site. System configurations range from conventional elevated or spaced ground-mounted systems allowing grazing or cultivation to more specialised structures designed to modify light, temperature or water conditions for crops. The balance between agricultural and electricity generation depends strongly on crop, climate and system design.

Vehicle integrated PV (VIPV) designates the integration of solar cells into the shell of vehicles to reduce emissions in the mobility sector. Solar cell technological developments allow new models to meet both aesthetic expectations for car design and technical requirements, such as light weight and resistance to load. Vehicle applied PV (VAPV) relates to the use of PV modules on vehicles without integration.

Infrastructure Integrated PV (IIPV) is when PV is integrated into infrastructure such as noise barriers, dam walls, pavement, roads, etc. New applications are being demonstrated regularly.

REPORTING CONVENTIONS AND DATA SOURCES

The rapid growth and diversification of PV deployment make international market statistics increasingly complex. National databases differ in their scope, units, registration requirements and treatment of distributed, off-grid, repowered and decommissioned systems. The objective of IEA PVPS reporting is to provide the most coherent possible comparison between markets while identifying where estimates, conversions or methodological assumptions are required.

The main conventions required to interpret the report are summarised below. Detailed definitions, source hierarchies, calculation methods and limitations are provided in the Methodological Annex.

PV CAPACITY IS REPORTED IN DC

This report counts all PV installations, both grid-connected and reported off-grid installations. By convention, the numbers reported refer to the nominal power of PV systems installed. These are expressed in W (or Wp) or Wdc. Unless specifically indicated otherwise, W, kW, MW and GW refer to nominal DC module capacity.

REPORTING CONVENTIONS AND DATA SOURCES / continued

Power capacity reported in AC is converted to DC (nominal) power when necessary to calculate the most precise installation numbers every year. Some countries report the power output of the PV inverter, or even the power of the grid connection, rather than module capacity. The DC/AC ratio varies according to system design and can be substantial in utility-scale plants where the PV array is deliberately oversized relative to the inverter.

For some countries, this means that this report publishes different values as compared to official data — for example, China's National Energy Administration (NEA) publishes in AC and PVPS applies a conversion ratio from AC to DC. Where the available data does not permit a single reliable conversion value, a range is used to reflect this uncertainty. The detailed conversion methodology, including the treatment of China, is provided in the Methodological Annex and identified in Chapter 2 where it materially affects national or global totals.

ANNUAL, CUMULATIVE AND OPERATING CAPACITY

Annual installed capacity refers to PV capacity considered commissioned during the reporting year. Cumulative installed capacity represents the total PV capacity recorded as installed at the end of the reporting period and is the principal indicator used in this report to describe the installed base.

Cumulative installed capacity should not necessarily be interpreted as identical to capacity currently in operation. National statistics differ in their treatment of systems that have been decommissioned, repowered or replaced. Some countries remove decommissioned systems from national totals, others report operating capacity, while others continue to report the historical sum of annual installations.

As cumulative installed capacity ages, repowering, component replacement and decommissioning will increasingly affect the relationship between cumulative and operating capacity. IEA PVPS does not currently construct a harmonised global operating-capacity series because national reporting of these developments is not sufficiently consistent.

MARKET SEGMENTS

There is no internationally harmonised system-size threshold separating distributed/decentralised and centralised PV. National definitions can depend on connection voltage, system size, customer relationship, support scheme or administrative category. For the purposes of this report, classification is primarily based on system function and connection, and not on a MW threshold.

Where national statistics use different segment definitions, data is mapped to the closest IEA PVPS category where sufficient information is available. Remaining inconsistencies are described where they materially affect comparisons.

TRACKING OF PV INSTALLED CAPACITY

Tracking PV installations in all the regions of the world can be challenging as many countries do not accurately keep track of the PV systems installed or do not make the data publicly available. Data published by IEA PVPS reports on new annual installed capacity and total cumulative installed capacity and is based on official data in reporting countries.

Depending on reporting practices, cumulative capacity (the sum of new annual capacity) may outstrip operating capacity as systems are decommissioned. Repowered capacities not only replace some decommissioned capacity but also generally increase operational capacity, as the repowered capacity is higher than the initial plant capacity due to PV module efficiency improvements.

There is no standardised reporting on these subjects across IEA PVPS countries. As the installed capacity ages, repowering, component replacement and decommissioning will increasingly affect the relationship between cumulative and operating capacity. Detailed treatment of national reporting practices, AC/DC conversion, repowering and decommissioning is provided in the Methodological Annex.

Module capacity that has been used to repower systems with defective or underperforming modules will appear in shipped volumes but not necessarily in new annual installations. The development of second-life markets also makes shipment data progressively less straightforward as a proxy for new installations.

IEA PVPS is following the dynamic evolution of decommissioning, repowering and recycling closely, but have not included quantified estimates of their impact on global operating capacity.

REPORTING CONVENTIONS AND DATA SOURCES / continued

SOURCES, ESTIMATES AND REVISIONS

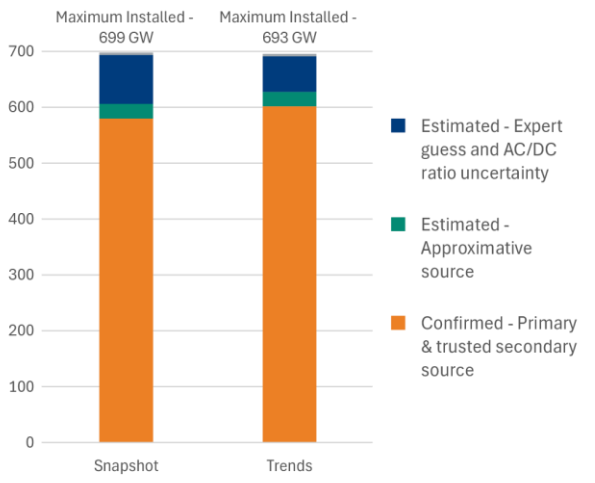
Global data should be considered as indications rather than exact statistics. IEA PVPS market data is primarily based on official statistics and information reported by member countries. National Survey Reports, government agencies, regulators, TSOs, DSOs and national statistical organisations provide the principal source material.

Where official reporting is incomplete or unavailable, recognised industry associations, market datasets, project information, trade data and other sources are used to complement national statistics. Expert estimates may be required where installations are known to exist but are not captured by registration or grid-connection databases.

As the PV market grows, reporting of PV installations is becoming more complex, in particular for rapidly growing distributed and off-grid markets, where imports or equipment sales can exceed the capacity visible in utility or government databases. In these situations, estimates may take into account trade flows, historical installation patterns and the time between import, installation and commissioning.

In this context, global PV totals should be understood as the best available estimate based on a combination of reported and estimated national data rather than as an exact census of all PV systems installed worldwide. Historical data may be revised between editions as final national statistics become available or as improved information modifies previous estimates.

FIGURE 1.1: GLOBAL ANNUAL CAPACITY 2025 - FIRST ESTIMATIONS AND CONSOLIDATED DATA



SMALL AND UNREGISTERED SYSTEMS

The rapid development of very small plug-and-play and balcony systems illustrates an increasing challenge for PV statistics. These systems may be sold through conventional retail channels and installed without the same registration processes used for larger rooftop installations. Although their individual capacity is small, aggregate volumes can become not insignificant in markets with large numbers of installations.

Other market evolutions such as off-grid applications are difficult to track even in member countries, and significant growth in installations in third countries without a robust reporting system is also a likely source of underreporting. The degree of uncertainty consequently differs between countries, and estimated volumes are identified where they materially influence national or global results.

GEOGRAPHICAL CONVENTIONS

Unless specified otherwise, the term Europe includes all countries on the continent. European Union totals refer specifically to EU Member States. Türkiye is included within Europe for regional reporting, Korea refers to the Republic of Korea, and Chinese Taipei refers to the economic region under the terminology used by IEA PVPS.

The European Commission participates in IEA PVPS; however, EU Member States are not automatically counted as individual IEA PVPS countries unless the relevant indicator explicitly uses the EU membership perimeter. The country lists and geographical groupings used for each aggregate are provided in the Methodological Annex.

OTHER METHODOLOGICAL INDICATORS

Indicators that require additional assumptions beyond installed-capacity reporting have methodologies consolidated in the Methodological Annex, but retain a short explanation of each indicator where required for interpretation.

These include the conversion between nationally reported AC capacity and nominal DC PV capacity; estimation of unreported installations; treatment of cumulative, operating, repowered and decommissioned capacity; theoretical annual PV generation; final electricity consumption used for theoretical PV penetration; module and system price comparisons; LCOE, tender and PPA comparisons; PV market business value; avoided greenhouse-gas emissions; and the treatment of preliminary data, estimates, revisions and uncertainty.

THEORETICAL PV GENERATION AND PENETRATION

The capacity installed at the end of a year may not have operated all year. A system commissioned in December, for example, contributes to year-end cumulative installed capacity but only a small amount to the electricity generated during that calendar year.

Chapter 7 distinguishes measured electricity generation from the theoretical annual generation of year-end cumulative PV capacity. The latter estimates the electricity that year-end installed capacity could produce over a complete year using representative national yields. It is an analytical indicator and should not be interpreted as measured PV generation during the reporting year.

Theoretical PV penetration is calculated by comparing this estimated annual generation with the most final electricity consumption. Final electricity consumption is preferred to electricity demand as a measure of potential PV electricity supplied at consumption sites by final consumers. More details are provided in the Methodological Annex.

The distinction is important (but increasingly difficult to calculate) as annual behind-the-meter generation, storage and self-consumption grow and reduce the visibility of electricity generation in conventional transmission-system statistics.

two

PV MARKET DEVELOPMENT TRENDS

Global cumulative installed PV capacity reached nearly 3 TW[1] at the end of 2025, with 0.69 TW installed during the year. Around 36 countries added more than 1 GW in 2025, confirming the expansion of the PV market. Market concentration remained high: China alone represented around 60% of global annual installations, and the ten largest national markets accounted for around 88% of new capacity.

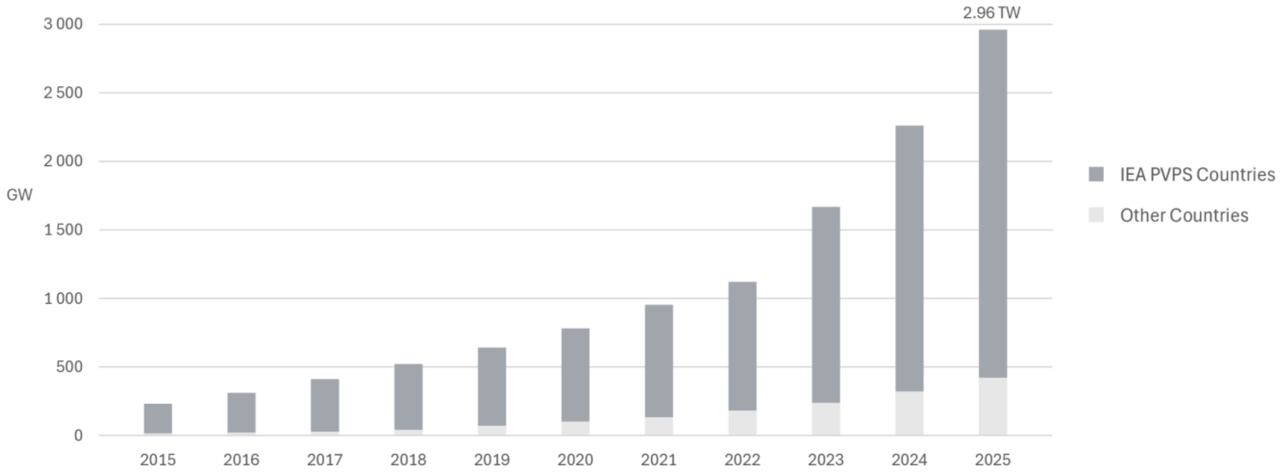
A large majority of PV installations are grid-connected and supply either a consumer's internal electrical system or the electricity network. Unless otherwise indicated, PV capacity is expressed as nominal DC module capacity. Where national statistics are reported in AC, values are converted to DC to improve consistency between markets; MW and GW therefore refer to MWdc and GWdc by default. The methodology and associated uncertainties are described in the Methodological Annex, including the specific treatment of China, where official utility-scale reporting is principally in AC.

THE GLOBAL INSTALLED CAPACITY

At the end of 2025, the cumulative global installed capacity reached 2.96 TW.

It appears that 0.69 TW represented the most probable capacity installed during 2025. This volume is a 15% increase compared to 2024, following the exceptional growth of the previous two years – resulting from a combination of increased action on climate imperatives, very low module costs and continued strong deployment in China and other major markets.

FIGURE 2.1: EVOLUTION OF CUMULATIVE PV INSTALLATIONS



SOURCE: IEA PVPS & OTHERS

[1] China's NEA reports official annual and cumulative capacities of 317 GW and 1,200 GW, respectively, both in AC, which are used as the benchmark. IEA PVPS converts these data to DC. Differences in the conversion assumptions applied result in estimates ranging from 197 GW to 256 GW DC centralised and from 107 GW to 113 GW DC for decentralised PV, an uncertainty of 59.2 GW. Full bars show the lower estimate and shaded bars the additional capacity included in the upper estimate. Unless otherwise specified, compiled data refer to the maximum estimate.

THE GLOBAL INSTALLED CAPACITY / continued

Among the trustable sources, the group of IEA PVPS[2] countries represented 2.62 TW of the global installed capacity. The IEA PVPS participating countries are Australia, Austria, Belgium, Canada, China, Denmark, Finland, France, Germany, India, Israel, Italy, Japan, Korea, Lithuania, Malaysia, Morocco, the Netherlands, Norway, Portugal, South Africa, Spain, Sweden, Switzerland, Thailand, Türkiye, the United Kingdom (UK), and the United States of America (USA). The European Commission is a member of IEA PVPS and, as such, in this report its member countries are counted in the IEA PVPS block. For the purpose of this report, IEA PVPS countries are those that are members in their own right – or, as occasionally mentioned explicitly those that are a member through the adhesion of the EC.

The other key markets that have been considered and which are not part of the IEA PVPS Programme represented a total cumulative capacity of 343 GW at the end of 2025. Amongst them, Brazil (65 GW), Pakistan (an estimated 36 GW) and Vietnam (26 GW) have the largest cumulative capacity. These countries represented from 8% (Vietnam) to 19% (Brazil) of the cumulative non-IEA PVPS capacity. Other non-IEA PVPS countries that have significant cumulative volumes include MENA countries, with world-record size systems coming progressively online, such as Saudi Arabia (13 GW) and the UAE (8.9 GW). In Europe, Poland (25 GW) and Greece (12 GW) are the largest cumulative markets outside IEA PVPS member countries, followed by Ukraine (8.6 GW), although here the market continues to be affected by the ongoing conflict. Nearly 25 non-IEA PVPS European countries now have cumulative capacity above 2 GW.

PV PENETRATION PER CAPITA

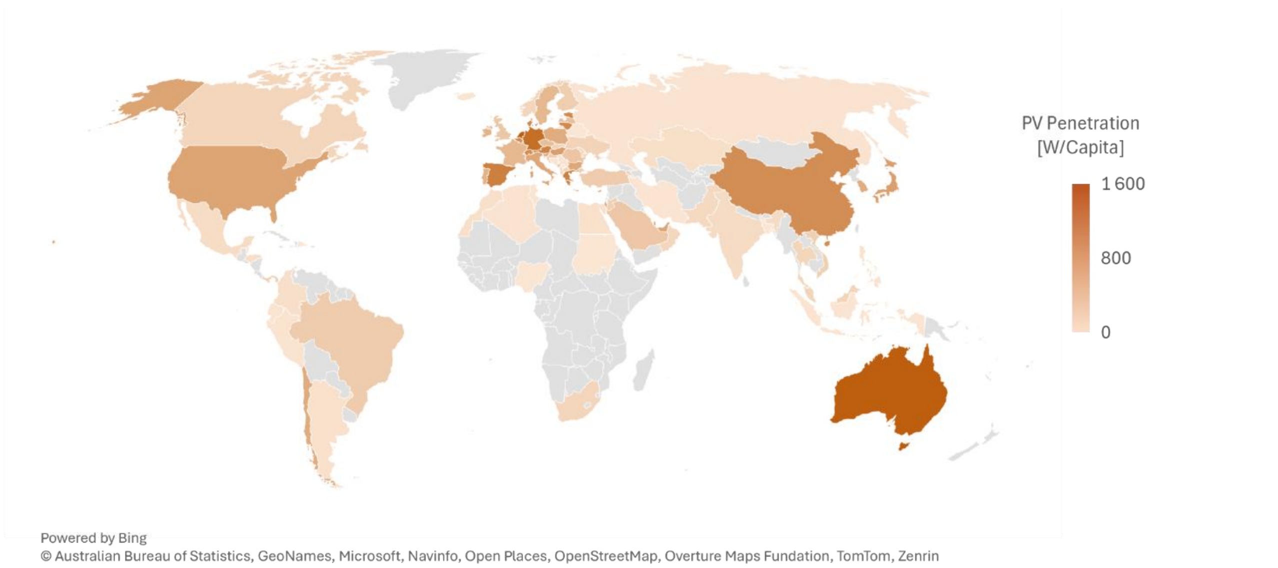
PV penetration can be measured either as a ratio of Wp per capita or kWh generated to meet a countries electricity demand – here we look at the volume of PV capacity relative to the country's population, indicating the relative efforts made by different countries.

AUSTRALIA, THE NETHERLANDS AND GERMANY HAVE MORE THAN 1 400 W/CAP INSTALLED.

In 2025, Australia surpassed the Netherlands to reach the highest cumulative installed PV capacity per inhabitant with 1 604 W/cap in IEA-PVPS and surveyed countries. The Netherlands is second with 1 584 W/cap and Germany (1 413 W/cap) third. Eight other European countries are above 1 000W/cap: Spain, Greece, Austria, Denmark, Lithuania, Estonia, Switzerland and Belgium. With once again large volumes installed in China, its penetration rate continued to increase, also passing the 1 kW/cap mark to reach 1 040 W/cap. Of the other largest country markets, Japan (835 W/cap) and the USA (778 W/cap) are close, however Brazil (310 W/cap) and India (122 W/cap) still lag behind.

Typical residential systems have modules with an individual power of anywhere from 500 Wp to 730 Wp. – and now more than 30 countries have the equivalent of 1 to 3 modules installed per person.

FIGURE 2.2: PV PENETRATION PER CAPITA IN 2025



SOURCE: IEA PVPS & OTHERS

[2]For the purpose of this report, IEA PVPS countries are those that are members in their own right – or, as occasionally mentioned explicitly those that are a member in their own right or through the adhesion of the EC.

THE GLOBAL INSTALLED CAPACITY / continued

EVOLUTION OF ANNUAL PV INSTALLATIONS

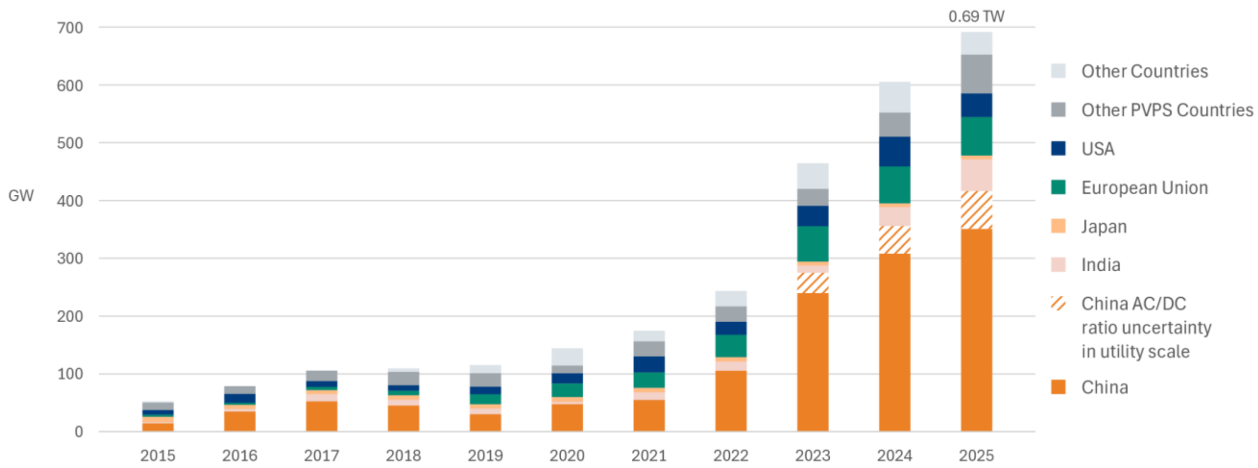
IEA PVPS countries installed close to 600 GW (an estimated 612 GW with all the EU included) in 2025, and Installations in non-IEA PVPS countries contributed an estimated 80 GW (although volumes here are more difficult to track). After the exceptional growth of 2023 and continued expansion in 2024, the annual market continued to grow in 2025 as consumer and investor confidence in the ability of PV to provide reliable and stable electricity generation costs as a shelter from electricity market costs and its eventual fluctuations was maintained.

The market in China continued to grow, with 415 GW installed during the year (+16% on 2024). Whilst there remains uncertainty around the nominal capacity installed in utility-scale plants because official reporting is in AC and the inverter/module ratio must be estimated, it is clear that the Chinese market was again driven by the centralised segment this year, with just over 38% of new capacity in the distributed segment. The Chinese market represented around 60% of global installations in 2025. This market dominance is similar to the role Germany played through the mid-late 2000's, and the long-term impacts of this concentration are difficult to judge. The cumulative capacity installed in China reached 1.46 TW in 2025.

India moved into second place with 54 GW installed in 2025, up strongly from the previous year's 32 GW, for a total cumulative capacity of 179 GW.

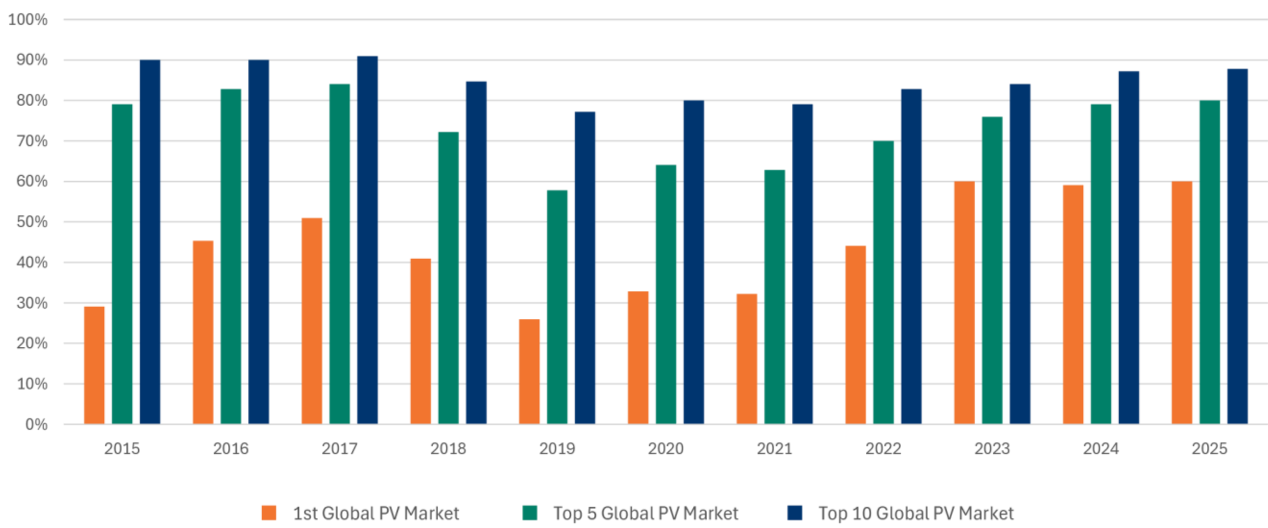
THE EUROPEAN UNION BLOC WOULD BE 2ND AFTER CHINA FOR ANNUAL INSTALLED CAPACITY. STILL A GROWTH MARKET (+5%), COMBINED ANNUAL NEW CAPACITY WAS 68 GW, JUST AHEAD OF INDIA AT 54 GW.

FIGURE 2.3: EVOLUTION OF ANNUAL PV INSTALLATIONS IN MAJOR MARKETS



SOURCE: IEA PVPS & OTHERS

FIGURE 2.4: EVOLUTION OF MARKET SHARE OF TOP COUNTRIES



THE GLOBAL INSTALLED CAPACITY / continued

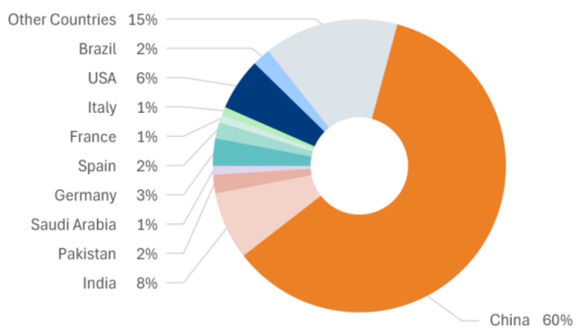
The United States market declined slightly from the 2024 record, reaching 43 GW in 2025. The market remains a utility-scale market, with 35 GW or around 80% of new capacity centralised. The decentralised market saw 7.6 GW installed, below 2024 volumes. By the end of 2025, the United States reached 266 GW of cumulative installed capacity. Germany was in fourth place with 18 GW installed in 2025, for a total cumulative capacity of 118 GW.

Whilst estimations of 2025 installed capacity in Pakistan vary, the IEA PVPS estimation of 14 GW puts Pakistan's annual market in 5th place (estimated 36 GW cumulative capacity),

With the dominance of the Chinese market, it is no surprise that the market share of the top countries remains elevated - smaller markets are contributing proportionally less to global installation numbers than the major markets. China has done much to absorb the results of its manufacturing capacity growth.

Whilst the market in Brazil did not maintain the high growth rates of the previous years, it remained a major market with 12 GW installed, reaching 65 GW cumulative capacity, confirming its place as a globally important market, in 6th place. Spain in 7th place (12 GW for 61 GW cumulative capacity) also remained a major market. France moved into 8th place with 7.4 GW new capacity for a cumulative capacity of 37 GW. Saudi Arabia, with some very large systems commissioned and more under construction entered the top 10 with 6.8 GW for 13 GW cumulative capacity, while Italy remained in the top 10, with 6.7 GW new capacity for a cumulative capacity of 44 GW.

FIGURE 2.5: ANNUAL GLOBAL PV MARKET IN 2025



SOURCE: IEA PVPS & OTHERS

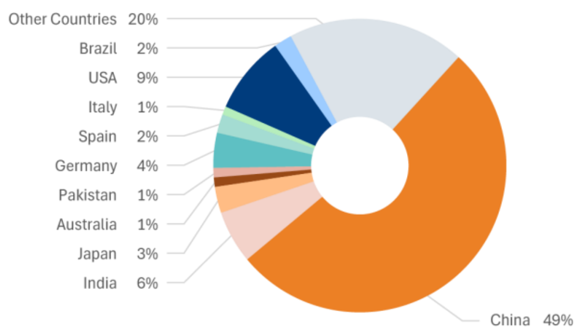
Together, these 10 markets cover about 88% of the 2025 annual world market, a sign that the growth of the global PV market has been driven by a limited number of countries once again. Market concentration has been fuelling fears for the market's stability in the past – in theory if one of the top three or top five markets experiences a slowdown, the whole market is impacted. However, the past years have shown that when one market slows, another is often in growth. As shown in Figure 2.4, the market concentration steadily decreased in 2019 before growing again in 2020 through to 2022 but has remained relatively stable over the past 3 years. As new markets emerge, the concentration of the global PV market minus China reduces, and therefore the risks to manufacturing of having a limited number of client countries. However, the size of the Chinese PV market continues to shape the evolution of the PV market as a whole and while manufacturers seem to be aggressively opening new markets with significant exports to Africa, overall volumes there were insufficient in 2025 to upset the largest markets positions and concentration.

The level of installations required to be included in the top 10 (country wise) has increased steadily since 2014: from 0.8 GW to 1.6 GW in 2018, to 6.7 GW in 2025. This reflects the global growth trend of the solar PV market, but also its variations from one year to another. Whilst this increase could be considered significant, it is still extremely low compared to the volume in China. Had all markets across the world grown at the same rate as in China, this minimum value would be closer to 10 GW than 5 GW.

Other countries that installed several GW in 2025 and were found in the top 10 countries in the past could not reach the volumes required this year but remained close: Japan left the Top Ten for the first time but still installed slightly more than last year with 5.9 GW. Others include Türkiye 4.7 GW, Australia 4.5 GW, Korea 4.3 GW and Poland 3.7 GW. Outside of the IEA PVPS countries, most of the smaller markets grew.

Around 36 countries (+ 3 compared to 2024) had more than 1 GW newly installed in 2025, spread across all continents, with the notable contribution of several countries in the Middle East and Africa.

FIGURE 2.6: CUMULATIVE PV CAPACITY END 2025



SOURCE: IEA PVPS & OTHERS

THE GLOBAL INSTALLED CAPACITY / continued

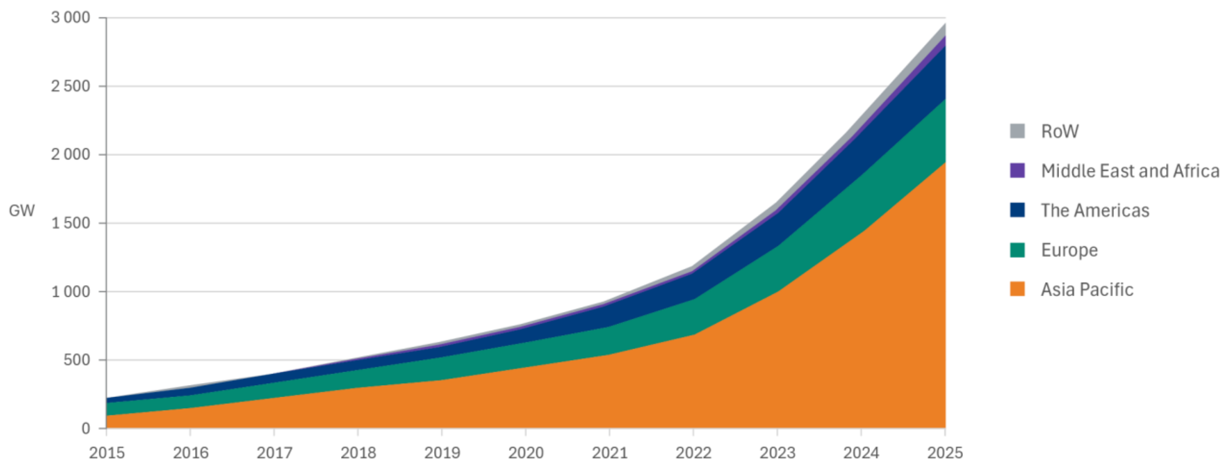
TABLE 2.1: EVOLUTION OF TOP 10 MARKETS

RANKING	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	China	China	China	China	China	China	China	China	China	China	China
2	Japan	USA	India	India	USA	USA	USA	USA	USA	USA	India
3	USA	Japan	USA	USA	India	Vietnam	India	India	Germany	India	USA
4	UK	India	Japan	Japan	Japan	Japan	Japan	Brazil	India	Pakistan	Germany
5	India	UK	Türkiye	Vietnam	Spain	Germany	Brazil	Spain	Brazil	Germany	Pakistan
6	Germany	Germany	Germany	Australia	Vietnam	Australia	Germany	Germany	Spain	Brazil	Brazil
7	Korea	Thailand	Korea	Türkiye	Australia	Korea	Spain	Japan	Japan	Spain	Spain
8	France	Korea	Australia	Germany	Korea	India	Australia	Poland	Italy	Italy	France
9	Australia	Australia	France	Mexico	Germany	Spain	Korea	Australia	Poland	France	Saudi Arabia
10	Canada	Türkiye	Brazil	Korea	Ukraine	Brazil	Poland	Netherlands	Türkiye	Japan	Italy
RANKING EU	3	4	4	2	2	2	2	2	2	2	2
	MARKET LEVEL TO ACCESS THE TOP 10										
	0.67 GW	0.81 GW	1.07 GW	2.27 GW	3.55 GW	3.78 GW	3.71 GW	4.20 GW	4.84 GW	5.62 GW	6.69 GW

Note: the positions in this table may change for past years as historical data is corrected

SOURCE: IEA PVPS & OTHERS

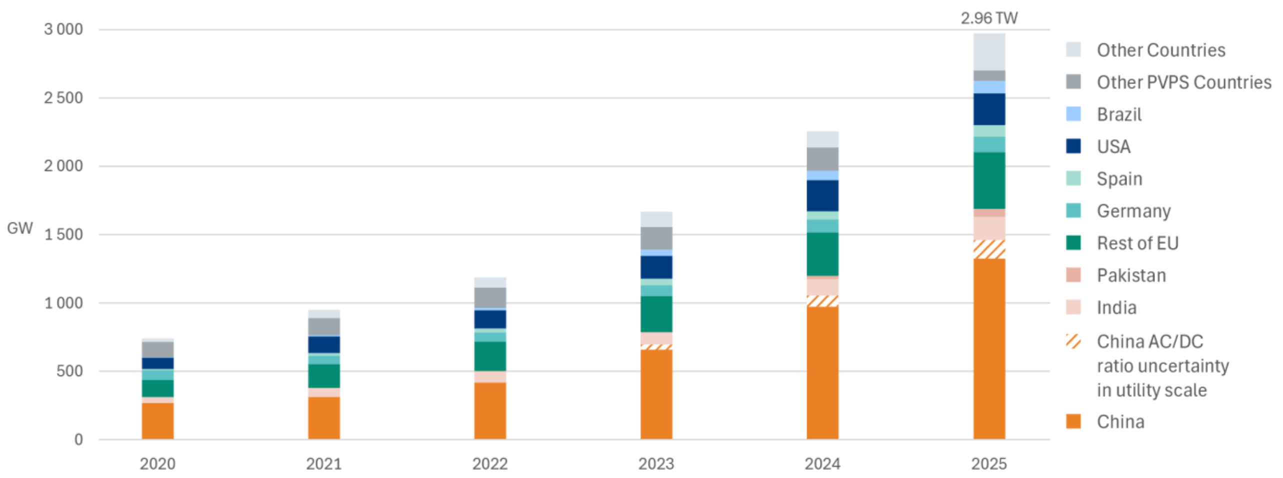
FIGURE 2.7: EVOLUTION OF REGIONAL PV INSTALLATIONS



SOURCE: IEA PVPS & OTHERS

THE GLOBAL INSTALLED CAPACITY / continued

FIGURE 2.8: 2020-2025 GROWTH IN MAJOR MARKETS



SOURCE: IEA PVPS & OTHERS

PV MARKET SEGMENTS

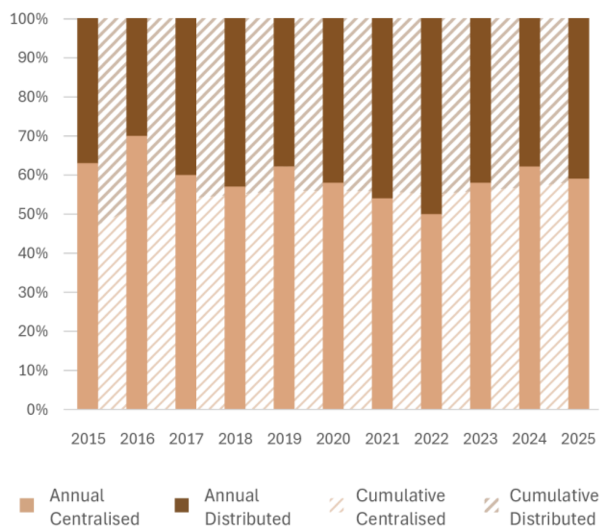
Three market segments are considered in this report; centralised (large systems above a few MW up to utility-scale and feeding electricity to the grid), distributed (anything below this connected to the grid and connected to a consumption point) and off-grid. Off-grid has been included in distributed volumes in market statistics. With different reporting systems from one country to another, there is no specific system size separating centralised from distributed. However, the segmentation is undertaken in most markets by governments, utilities and industry associations as the impacts are quite different, affecting grid connection, grid capacity, fiscality and taxation and the ability to properly count and evaluate capacities. Additionally, for some markets, the conversion of AC power to DC power is built on different conversion coefficients, in line with industry practices.

Overall, it is estimated that the centralised segment (59% or 410 GW) outweighed the distributed segment (41% or 282 GW) in new annual capacity in 2025. This result is on the one hand a reflection of the dominance of centralised systems in the largest markets (China, India, USA) but belies significant differences in other major markets.

Off-grid and edge-of-the-grid applications are increasingly integrated into distributed installations, and many countries do not track volumes. However, it is expected that the volume of annual off grid volumes will increase, under the combined effect of large government led solar pumping programmes (currently being deployed across India and likely to be replicated across Africa) and the continued drop in price of batteries for solar home systems and solar micro-grids.

Outside the European market that incentivized residential segments from the start, most of the major PV developments in emerging PV markets tended to come from utility-scale PV in the past. The drop in module prices and the increasing attractivity of self-consumption across the world is likely to change this, as was demonstrated in Brazil and Vietnam, and South Africa.

FIGURE 2.9: ANNUAL SHARE OF CENTRALISED AND DISTRIBUTED GRID CONNECTED INSTALLATIONS 2015-2025



SOURCE: IEA PVPS & OTHERS

THE GLOBAL INSTALLED CAPACITY / continued

DEVELOPMENT OF UTILITY-SCALE PV

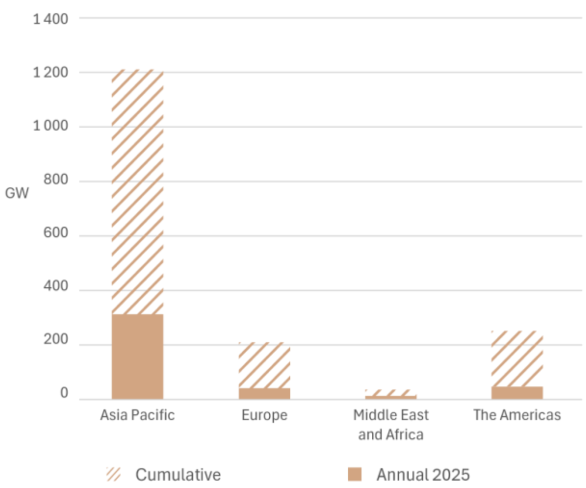
Utility-scale PV plants are in general ground-mounted (or floating) installations. In some cases, they could be used for self-consumption when close to large consumption centres or industries (mining sites), but generally they feed electricity directly into the grid. The development of utility-scale applications continues to grow in both new and established PV markets, and despite market competitiveness in many countries, competitive tendering processes are used to select the most competitive projects and to guide the types of land used or encourage other aspects.

Merchant PV, where PV electricity is directly sold to electricity markets and corporate PPAs, where it is directly sold to corporate consumers continues to grow in many countries. Trials conducted in the past years, especially in 2022 pulled by the high electricity markets costs, gave developers and investors' confidence in the ability to create viable projects. Whilst merchant PV is in its early phases, the impacts of negative prices and price cannibalisation are two subjects that will be closely monitored by investors over the next few years. In parallel, the limitations that are already being seen due to grid congestion, social acceptance or strict environmental impact study requirements remain important barriers. Experience has demonstrated that securing grid connection can lead project developers to tender very low bids just to secure grid connection capacity (Portugal, Spain) or propose multiple "dummy" projects in different locations just to secure grid connection capacity (USA), whilst some countries have had to specifically invest in and develop grid capacity to ensure the continued development of utility-scale systems (Australia, Austria, Brazil, France).

Utility-scale systems are providing a majority of new capacity in some key markets such as China, India, the USA and Spain. The commissioning of very large-scale utility systems in the MENA region – Saudi Arabia and the UAE ahead of a number of other countries in 2024 and 2025 – added new countries that are driven by centralised systems.

Utility scale plants are not homogeneous and vary in size from a few MW to over 1000 MW. Some may be installed on fixed tilt supports, others on single or dual axis trackers to maximise production. Systems installed on water bodies (floating PV) are becoming standardized, as is the development of lower density systems on grazing land. The use of bifacial PV modules is becoming standard. The addition of co-located storage (battery) systems is increasingly common, either pushed by specific rules in tenders, unattractive market prices for solar on its own or by attractive conditions for grid services and wholesale markets (Australia, Germany, USA). In 2025, centralised PV amounted to 410 GW (59% of new capacity) globally and the total installed capacity was to 1.7 TW, representing 58% of the cumulative installed capacity.

FIGURE 2.10: CENTRALISED PV - CUMULATIVE AND ANNUAL INSTALLED CAPACITY PER REGION 2025



SOURCE: IEA PVPS & OTHERS

TABLE 2.2: TOP 10 COUNTRIES FOR CENTRALIZED PV INSTALLED IN 2025

Country	GW
China*	256
India	42
USA	35
Spain	11
Germany	8.3
Saudi Arabia	6.8
Brazil	4.6
Korea	3.4
Italy	2.7
France	2,4

*includes AC/DC conversion uncertain volumes

SOURCE: IEA PVPS

TABLE 2.3: TOP 10 COUNTRIES FOR CUMULATIVE CENTRALIZED CAPACITY IN 2025

Country	GW
China*	930
USA	194
India	143
Spain	50
Japan	41
Germany	35
Korea	30
Brazil	22
Netherlands	16
France	15

*includes AC/DC conversion uncertain volumes

SOURCE: IEA PVPS

THE GLOBAL INSTALLED CAPACITY / continued

DEVELOPMENT OF DISTRIBUTED PV

Distributed PV (also called decentralised PV) are PV systems that are smaller, connected to the distribution grid (from a few hundred-kilowatt peak to a few MW), most often installed on buildings, or installed with the goal of supplying a local consumer (for example, directly through self-consumption). Historically, distributed PV launched the massification of the PV industry in **Germany** and other early adopting countries; now self-consumption is a market driver for distributed PV in many countries.

Countries where the distributed segment is driving overall market growth include **Pakistan**, **Germany**, **Brazil**, **France**, **Türkiye**, **Japan** and **Australia**, as well as most European countries.

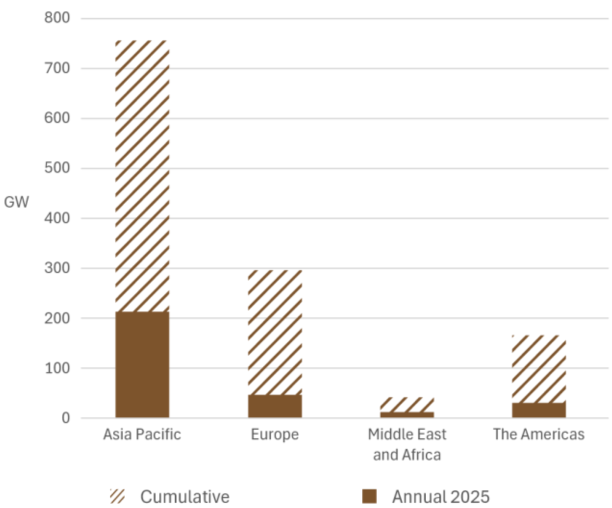
The distributed market was under 19 GW until 2016, when **China** succeeded in developing its own distributed market, roughly doubling distributed PV volumes from 2016 to 2018. In 2025, this market reached 282 GW, up from 228 GW in 2024 and 189 GW in 2023.

Table 2.4: TOP 10 COUNTRIES FOR DISTRIBUTED PV INSTALLED IN 2025

Country	GW
China	159
Pakistan	14
India	12
Germany	9.2
Brazil	7,9
USA	7,6
France	5,0
Türkiye	4,2
Italy	4,0
Japan	3,5

SOURCE: IEA PVPS

FIGURE 2.11: DISTRIBUTED PV - CUMULATIVE AND ANNUAL INSTALLED CAPACITY PER REGION 2025



SOURCE: IEA PVPS & OTHERS

TABLE 2.5: TOP 10 COUNTRIES FOR CUMULATIVE DISTRIBUTED CAPACITY IN 2025

Country	GW
China	533
Germany	83
USA	74
Japan	61
Brazil	43
India	36
Italy	29
Australia	29
Pakistan	29
France	22

SOURCE: IEA PVPS

DUAL USAGE AND EMERGING PV MARKET SEGMENTS

The installation of photovoltaic installations on infrastructure or land used for other purpose is a response to the competition for land implied by the massive development of new PV capacities, and the resulting need to ensure social acceptance. The availability of land surfaces and the acceptability of their usage for PV are key considerations in an increasing number of countries - typically where there is existing or spreading urbanisation with a consequent loss of biodiversity, sustained or regular loss of agricultural land or a strong push to preserve heritage buildings and natural landscapes for aesthetic and cultural reasons.

For utility scale PV and ground-mounted installations, competition has arisen between other uses and electricity production, dominated by conflict for agricultural land. By combining agricultural and energy production on the same surface, agrivoltaics seeks to propose a desirable acceptable alternative. Floating solar photovoltaics uses the available surfaces on natural and artificial lakes as well as reservoirs and is a particularly dynamic market segment in Asian regions where the tension on land use is strong. These market trends in the centralized segment are strong and underpinned by the same imperative to promote compatible dual land use. The use of other infrastructure such as canopies on canals or noise barriers along highways is also becoming more common, driven by the same motivating factors of access to land without generating conflict or opposition.

For distributed PV, integrating PV into and onto buildings has been a goal for many years and considered a natural solution to the imperative of reducing land use, bringing generation to the point of consumption and reducing social resistance to PV. Specific products have been developed for a long time – and encouraging PV on buildings has even been the mainstay of public policies for the distributed segment in the past in some countries (most notably France). In particular, the European Union is encouraging member states to develop ambitious targets. It can be attractive because it uses existing buildings but also can lead to a more harmonious integration in the environment, reducing social resistance.

AGRIVOLTAICS

Agrivoltaics has moved from an emerging application towards a more established segment of the PV market, although its level of maturity remains highly differentiated between countries and applications. The principle remains the combined use of agricultural land for food production and electricity generation, but the market is increasingly defined by the way agricultural activity is maintained, monitored and, in some cases, improved.

Agrivoltaic systems can take several forms. PV can be installed above crops, where module density, transparency, height or tracking is adapted to crop requirements; agricultural production or grazing can continue between rows of conventional or vertical PV systems; and PV can be integrated into greenhouses or other agricultural structures. The appropriate design depends on climate, agricultural activity, machinery requirements, water availability and the relative value given to electricity and agricultural production.

IEA PVPS AGRIVOLTAICS ACTION GROUP

IEA PVPS established an Agrivoltaics Action Group to strengthen international collaboration on the combined use of agricultural land and PV generation, bringing together expertise from the PV, agricultural and social-science communities. Its work focuses on improving consistency in terminology, performance indicators, modelling and monitoring approaches, and on developing shared resources that make agrivoltaic projects and research more comparable between countries. This work complements the 2025 Task 13 report *Dual Land Use for Agriculture and Solar Power Production*, which reviews agrivoltaic definitions, system configurations, performance assessment, operational experience and socio-economic aspects, and highlights the importance of harmonised metrics and continued agricultural performance. More at [IEA-PVPS.ORG](https://iea-pvps.org)

Food production and agricultural viability remain a central consideration in most regulatory frameworks. Environmental impacts, water use, social acceptance and the long-term economic balance of the agricultural activity are also becoming increasingly important. As a result, two broad categories continue to coexist: projects where electricity production remains the principal economic activity while agricultural use is maintained, and more advanced systems where the PV installation is designed around the needs of the agricultural activity and is expected to protect or improve its performance.

A first phase of policy development concentrated on definitions, eligibility criteria and dedicated support mechanisms. During 2025, attention increasingly shifted towards implementation, monitoring and procurement. In France, a technical instruction clarified implementation of the national agrivoltaic framework and the distinction between agrivoltaics and other ground-mounted PV on agricultural land. In Spain, agrivoltaic installations were recognised as potentially eligible agricultural surfaces under the Common Agricultural Policy where agriculture remains the principal activity, while the RENOINN programmes continued to support innovative projects, including systems combined with storage. In Italy, implementation of the PNRR agrivoltaic programme continued, alongside requirements to demonstrate the maintenance of agricultural activity. Germany continued to integrate agrivoltaics within competitive tender mechanisms, while in Japan policy increasingly focused on on-site verification and the possibility of withdrawing support where continued farming is not demonstrated.

Definitions nevertheless remain very different between countries, making international comparisons difficult. Some countries include relatively conventional ground-mounted PV where grazing or cultivation continues between rows, while others reserve the term agrivoltaics for systems designed specifically to maintain or improve agricultural production. This is particularly important when comparing very large reported project pipelines with elevated or highly engineered systems. Ongoing international work on terminology, classification and mapping is therefore becoming increasingly important.

The economic maturity of the sector is also developing unevenly. Many projects continue to rely on investment support, dedicated tenders or other public mechanisms, particularly where the PV structure is more expensive because it is designed around the needs of crops rather than electricity production alone. However, Germany now has some large

DUAL USAGE AND EMERGING PV MARKET SEGMENTS / continued

projects developed without direct investment support and financed through long-term electricity contracts. Agrivoltaics is becoming a distinct part of the portfolios of several European developers, while specialised developers and equipment suppliers, particularly tracker manufacturers, now treat the segment as a market in its own right.

Agrivoltaic systems are generally more expensive than conventional ground-mounted PV, particularly where elevated structures, greater row spacing, crop protection or active tracking are required. However, the value of maintaining access to agricultural land, of the electricity profile produced and benefits provided to agricultural production are increasingly being incorporated into business plans. East-west orientations, vertical bifacial systems, tracking and storage can alter the value of electricity generation, while shade, protection from hail or excessive heat, reduced evaporation and improved animal welfare can create additional value on the agricultural side.

Grassland and livestock, where additional structural requirements are relatively limited can allow very competitive systems. Sheep grazing around large PV plants is already common in several markets, including Australia and the USA, maintaining agricultural use while reducing vegetation-management costs. Crop-based systems generally require greater adaptation and remain more expensive, with elevated structures, movable modules or lower-density layouts increasingly focused on higher-value crops. In areas exposed to heat and water stress, agrivoltaics is consequently developing within a broader water-energy-food nexus, where the objective is to improve agricultural resilience while supplying electricity.

In India, the potential remains very large, but the market is still at an earlier stage of commercial development. Recent assessments estimate technical potential above 1 000 GW under different assumptions for system density, while several pilot and commercial projects are operating or under development. The organisation of the AgriVoltaics World Conference in Delhi in 2026 also reflects the growing interest of the Indian research, policy and development communities, as does the large-scale financing of solar pumping for agricultural purpose.

In Africa, agrivoltaics is increasingly considered as a combined response to access to electricity, water management and rural development rather than principally as an optimisation between agricultural and electricity revenues and competition for land. Here, one of the principal barriers remains access to finance, particularly for projects requiring irrigation, storage or other infrastructure in addition to the PV system.

Market development is moving to establish bankable project models, credible monitoring of agricultural performance and a wider use of regulatory frameworks that distinguish genuine dual-use systems from conventional PV with residual agricultural activity.

IIPV: INFRASTRUCTURE INTEGRATED PV

IIPV refers to PV implanted on or close to infrastructure; it is used as a term to cover PV installed on or directly associated with infrastructure other than buildings, including roads, railways, noise barriers, canals, dikes (often linear PV on linear infrastructure) and similar elements of the built environment.

There is significant potential in these spaces – and as another dual-use of land, they provide an opportunity for PV surface with better social acceptance. The rapid decline in PV prices in recent years has meant the linear PV systems or specifically adapted supports have increased their competitiveness and created new opportunities for these innovative deployment solutions.

Transport infrastructure has one of the largest potentials. Vertical PV installations along roads, motorways and railway corridors, including modules integrated into noise barriers, have been demonstrated for many years in Switzerland, Germany, Austria and the Netherlands, with new projects continuing to appear in other markets. A European Commission Joint Research Centre assessment estimated a technical potential of around 403 GW for vertical bifacial PV along EU roads and railways, corresponding to approximately 391 TWh of annual electricity production, to be compared with the 2030 deployment target of 750 GW in the EU Solar Energy Strategy of the European Green Deal.

In 2025 the European Commission addressed infrastructure-integrated solar and highlighted the importance of transport safety rules, permitting, ownership and technical standards. France, Germany and the Netherlands already provide routes for PV deployment alongside roads and railways, while Dutch railway infrastructure operator ProRail has developed technical guidance for installations along railway corridors and on noise barriers. New demonstrations in Lithuania on road and railway noise barriers provide operational experience with both new-build and retrofit configurations.

Other applications continue to be tested and deployed, including PV canopies above roads and cycle paths, systems on dikes, PV along railway corridors and shade structures over irrigation canals. Canal PV can combine electricity generation with reduced evaporation, making it particularly relevant in regions exposed to water stress. The different applications remain at very different levels of technical and commercial maturity, from relatively established PV noise barriers to more experimental systems integrated within road or railway structures.

The main challenges increasingly concern the infrastructure rather than the PV module itself. The original function of the structure (noise protection, transport safety or water management) must be maintained and still comply with demanding technical and liability requirements. Long, narrow sites also create specific electrical architecture and grid-connection constraints. The use of public infrastructure for electricity production raises additional questions concerning ownership, access, permitting and the allocation of revenues and responsibilities between infrastructure operators and project developers. These issues are likely to determine the pace at which the very large theoretical potential of IIPV can be converted into commercial deployment.

FLOATING PV: CONTINUED GROWTH

The floating PV market continued to expand in 2025, with the year marking an important step in the transition from individual demonstration projects towards larger-scale and more diversified deployment. In 2024, the market was characterised by a strong pipeline of large projects under construction or development, particularly in China, India and Southeast Asia. In 2025, several of these projects reached completion, while new applications also emerged in Europe such as offshore environments and industrial sites. The year therefore showed both continued growth in project scale and a broadening of the types of water bodies and energy systems in which floating PV can be deployed.

DUAL USAGE AND EMERGING PV MARKET SEGMENTS / continued

China remained at the forefront of the market and saw the commissioning of the 1 GW HG14 floating PV project off the coast of Dongying in Shandong Province in December 2025. Located in shallow coastal waters it combines floating PV with aquaculture and a 100 MW/200 MWh battery energy storage system. With more than 2 900 PV platforms covering approximately 1 223 hectares, it became the world's largest open-sea floating PV project in operation. Its scale also marks a significant step beyond the large inland reservoir projects that have traditionally dominated the floating PV market.

India also continued to expand its floating PV capacity. At the Omkareshwar Dam in Madhya Pradesh, a 120 MWp floating solar array was completed in May 2025. The installation covers approximately 210 acres of the reservoir and introduced new anchoring and platform solutions adapted to the conditions of the site. The project adds to the floating PV capacity already commissioned at Omkareshwar in 2024.

In Europe, France strengthened its position as one of the leading FPV markets. The 74 MWp Les Îlots Blandin project was inaugurated in June 2025 in Perthes, Haute-Marne, becoming the largest floating PV plant in Europe. The project is installed on flooded former gravel pits and comprises 72 MWp of floating PV, alongside a 2 MWp ground-mounted installation. The use of former extraction sites illustrates the role of floating PV in converting industrial land and water bodies with limited alternative uses into renewable energy assets.

2025 also saw floating PV expand into new geographical markets and applications. In Ghana, a 5 MWp floating PV system was completed on the Bui reservoir as part of the country's hydro-solar hybrid system, combined with a 30 MWh battery storage system. The project is the first floating PV installation of its kind in West Africa and demonstrates the potential for combining floating solar with existing hydropower infrastructure. In the Philippines, a 5MW installation at the Malubog Reservoir in Cebu became the country's first megawatt-scale floating solar project. The system supplies electricity directly to a copper mine, highlighting the potential for FPV to serve industrial loads rather than exclusively feeding large centralised power systems.

The technology also continued to move beyond conventional inland reservoirs. In Chile, a 300 kWp floating solar system was commissioned in March 2025 at a salmon farming site on Isla Huar. The system incorporates battery storage and is designed to reduce diesel consumption at the aquaculture facility. This type of deployment illustrates how floating PV can be adapted to remote or offshore applications where land availability is limited and replacing diesel generation can provide a direct economic benefit.

Overall, compared with 2024, the main evolutions in 2025 were an increase in project capacity and a diversification of applications. Large reservoir projects remained central to the market, but 2025 brought more examples of floating PV on former quarry sites, industrial reservoirs, hydroelectric reservoirs, coastal waters and aquaculture facilities. The integration of FPV with battery storage and hydropower also became increasingly visible. This suggests that the technology is moving beyond its initial application as an alternative to ground-mounted PV and is increasingly being considered as part of wider hybrid energy systems.

The long-term potential remains substantial. Research published in 2025 estimated that around 10% of the world's inland reservoirs could theoretically accommodate approximately 22 TW of floating PV capacity. The same assessment highlights additional benefits such as reduced water evaporation and the possibility of combining FPV with existing hydropower infrastructure. Although only a fraction of this theoretical potential is expected to be developed, the scale of the resource underlines the significant room for further growth as countries seek to expand solar generation while limiting competition for land.

BIPV: MATURE TECHNOLOGY, NICHE MARKET

Building-Integrated Photovoltaics (BIPV) is a specialised segment of the PV market, combining electricity generation with the functions of conventional building materials. Its development depends on PV economics, construction costs, architectural requirements, building regulations and acceptance by architects, developers and building owners.

The European market is amongst the most developed, led by France, Switzerland, Austria and Germany. Around 350 MW of BIPV was installed in Europe in 2024, representing less than 1% of annual distributed PV installations. By 2025, the majority of European markets for BIPV have stagnated or slightly contracted, reflecting limited construction activity and the scarcity of dedicated policy support. Switzerland remains the reference market for the segment and one of the few countries still providing investment support that can favour vertical installations. This tracking has allowed for the development of a specialized national industry in BIPV, allowing for better analysis and identification of trends specific to this technology. That monitoring also shows BIPV to be more sensitive than the wider distributed market to changes in public support.

China is emerging as the largest potential BIPV market and manufacturing base, though BIPV remains a small share of its very large distributed PV market. Realising this potential depends on the level of construction activity. However, since 2020 construction activity in China has decreased dramatically. Demand is consequently more likely to come from commercial, industrial and renovation projects than from new residential buildings.

In addition to increased construction activity in China, Chinese manufacturers are developing more standardised products and operate at significantly higher volumes than most European manufacturers. Some Chinese manufacturers can produce hundreds of megawatts of BIPV per year. This contrasts with Europe, where more than 90 manufacturers are active, but production is generally project-specific and concentrated in Italy, Switzerland, the Netherlands, Germany, Spain and Austria. This difference reflects two possible directions for the market: highly customised architectural products on the one hand, and increasingly standardised roofing and façade solutions that could benefit from industrial scale on the other. Competitive pressure currently favours the second: a number of European BIPV manufacturers have ceased operations over the last several years (e.g. Autarq in 2025), largely due to increasing competition from Chinese suppliers in the BIPV segment.

Outside Europe and China, Japan has made next-generation thin-film cells a national industrial priority, with domestic manufacturers developing perovskite building materials and the first megawatt-scale façade installations planned for the end of the decade. In Korea, mandatory zero energy building certification and a new national BIPV testing centre are expected to support demand. Market perspectives also remain positive in North America and parts of South East Asia.

DUAL USAGE AND EMERGING PV MARKET SEGMENTS / continued

BIPV has developed considerably more slowly than conventional rooftop PV. The principal barriers remain higher investment costs, demanding technical and building-code requirements, including fire safety, greater project complexity and the need to coordinate actors from both the construction and electricity sectors. BIPV products also compete directly with well-established conventional building materials. Falling conventional module prices have widened the cost gap between standard rooftop PV and more customised BIPV products.

Despite this, BIPV retains a different value proposition. As it replaces part of the building envelope rather than simply being added to it, it provides weather protection, shading, daylight control and architectural finish in addition to electricity generation. This keeps it attractive where roof space is limited, where façade surfaces represent a significant share of the available envelope, or where architectural and planning requirements constrain the use of conventional modules.

BIPV is increasingly technologically mature after more than two decades of deployment. Glass-glass modules dominate many façade and roofing applications, while improvements in coloured coatings, encapsulants, transparency and customised module dimensions are allowing greater architectural flexibility. The market is progressively moving towards finding a balance between aesthetics, electricity yield, construction performance and cost rather than maximising electricity generation alone.

Future growth will therefore depend primarily on stronger integration between the PV and construction industries, increased standardisation where possible and regulations requiring or encouraging renewable energy generation in buildings. BIPV is unlikely to represent a major share of global PV capacity in the short term, but it could become an increasingly relevant solution in high-value urban, façade and renovation markets where conventional rooftop PV cannot fully exploit the available building surface.

OFF-GRID MARKET DEVELOPMENT

Numbers for off-grid applications are generally not tracked with the same level of accuracy as grid-connected applications, and volumes are marginal but growing compared to the development of the utility scale grid-connected market. Rural electrification programmes in Africa and Asia remain important drivers, alongside growing markets for solar water pumping, refrigeration and other productive uses of electricity.

Two principal configurations can be distinguished:

Mini-grids, combine generation from one or more renewable energy (solar, hydro, wind, biomass), storage and small distribution grids to serve a limited number of consumers in isolation from national electricity transmission network.

Stand-alone systems, for instance solar home systems (SHS) that supply power for individual appliances, households or small businesses without connection to a public network. Batteries are also used to extend the daily duration of energy use.

PV represents a competitive alternative to providing electricity in areas where traditional grids have not yet been deployed. In the same way as mobile phones are connecting people without the traditional lines, PV is leapfrogging complex and costly grid infrastructure, especially to reach the “last miles”. Remote, lower-income and fragile regions characterise the remaining areas where grid extension can be particularly costly. The World Bank estimates 666 million people were still without electricity access in 2023, approximately 85% of them in Sub-Saharan Africa. World Bank and ESMAP analysis estimates that off-grid solar could represent the least-cost solution for over 40% of those requiring electrification to achieve universal access by 2030.

The challenge of providing electricity for lighting and communication, including access to the internet, is being met by PV and not just by mini grids and stand-alone systems.

Specific business models are developed (in Africa for instance) and large energy groups are targeting millions of people with such products. According to GOGLA, affiliated companies sold 10.2 million solar energy kits in 2025, the highest annual volume recorded and almost 10% above 2024. This included 2.5 million solar home systems and 2.7 million multi-light systems, while 1.8 million off-grid appliances were also sold during the year. GOGLA affiliates were providing improved energy access to around 148 million people worldwide at the end of 2025. Growth was particularly strong in East Africa and Nigeria and was supported by PAYGo financing, subsidies and results-based financing programmes.

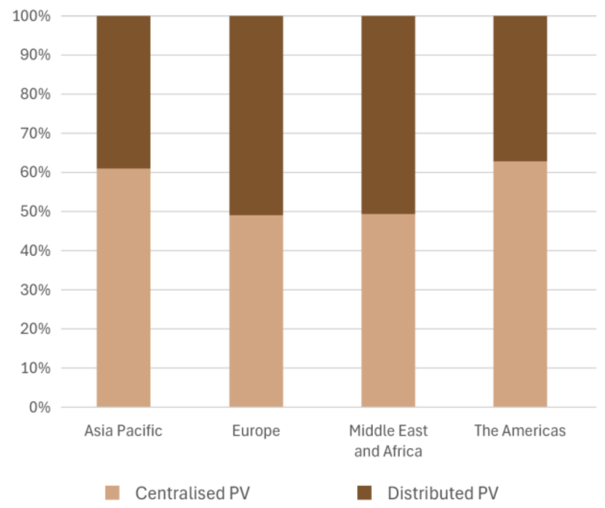
PV is going beyond basic lighting and communications towards productive uses of electricity. Solar-powered irrigation, refrigeration, cooling, communications and small commercial loads can increase agricultural productivity and local income while improving the use rates and economics of off-grid systems. This development is particularly important for mini-grids, where productive demand can improve load factors and project viability, and for solar home systems as appliance ownership increases.

Off-grid and edge-of-grid PV also serve a different role in more developed electricity systems. In Australia, for example, stand-alone power systems and local micro-grids are increasingly used in remote areas where maintaining long distribution lines is costly or exposed to bushfires, storms and other extreme events. In these cases, decentralised PV and storage are deployed primarily to improve resilience and reduce network costs rather than to provide first-time electricity access.

DETAILED INFORMATION ABOUT MOST IEA PVPS COUNTRIES CAN BE FOUND IN THE YEARLY NATIONAL SURVEY REPORTS AND THE ANNUAL REPORT OF THE PROGRAMME. IEA PVPS TASK 1 REPRESENTATIVES CAN BE CONTACTED FOR MORE INFORMATION ABOUT THEIR OWN INDIVIDUAL COUNTRIES.

PV DEVELOPMENT PER REGION

FIGURE 2.12: ANNUAL GRID-CONNECTED CENTRALISED AND DISTRIBUTED PV INSTALLATIONS BY REGION IN 2025

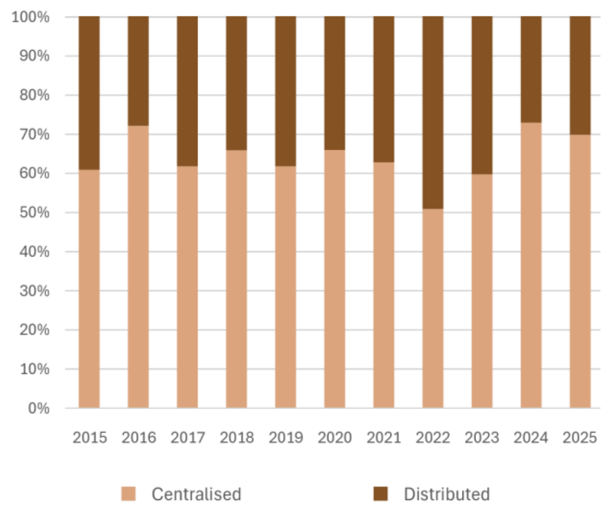


SOURCE: IEA PVPS & OTHERS

The global market grew slowly in the early 2000s, from around 200 MW in 2000 to around 1 GW in 2004, pulled by the introduction of incentives in Europe, particularly in Germany. Significant investments in Europe pushed the market faster after this and in 2008, Spain fuelled market development. Europe as a whole accounted for more than 80% of the global market until 2010, with 8 GW in 2006, booming to 17 GW in 2010.

From 2011 onward, the market shares of Asia and the Americas started to grow rapidly as some European markets contracted in a post-boom "bust" phase (Spain, France) and Asia taking the lead. This evolution has had Asia's annual market share oscillating between 50% and 75%; in 2025 it was 73%.

FIGURE 2.13: EVOLUTION OF PV INSTALLATIONS IN THE AMERICAS PER SEGMENT



THE AMERICAS

The Americas saw around 72 GW of PV installed in 2025 for a total cumulative capacity of around 415 GW. This represented around 10% of annual global capacity. As in previous years, most of these capacities were installed in the USA and Brazil, but several countries had annual capacity over the GW level (Mexico, Chile, Argentina) or continued to install several hundred MW per year (Canada, Peru, Colombia).

PV is developing in the Americas in both the distributed and centralised segments; the USA is pulled by the utility-scale segment, as is the market in Canada, running both on tenders and PPAs, whilst in Brazil distributed solar is the largest segment. The USA has by far the largest installed capacity, adding 43 GW to reach a cumulative capacity of 266 GW. The market declined slightly from the 2024 record, with around 35 GW of utility-scale PV and 7.6 GW of distributed PV installed in 2025. Evolving quite differently, Brazil continued to be the 2nd market in the Americas, adding 12 GW, of which around 7.9 GW was in the distributed segment. Its cumulative capacity is now 65 GW.

Mexico and Chile both slowed slightly with 1.3 GW of new capacity in Mexico, reaching 14 GW cumulative capacity and 1.1 GW in Chile to bring its cumulative capacity to 13 GW – high curtailment levels and the geographical distribution a real barrier to further development despite the extreme irradiation in the high-altitude deserts. The market in Colombia slowed to under 1 GW reaching a cumulative capacity of 4.6 GW.

Other South American markets remain comparably low, but hundreds of MW are still coming online in several countries as smaller centralised systems of a few dozen or hundred MW are planned. The acceleration in Argentina in 2025 is a sign that additional markets in the region can move towards the GW scale, while activity remained more modest in countries such as Peru, Panama and Ecuador.

ASIA-PACIFIC

The Asia-Pacific region installed around 515 GW in 2025 and the total installed capacity reached over 1.9 TW. The market remained strong across Asia-Pacific, despite very different trajectories from one country to another. The region represented nearly 75% of global annual capacity, and cumulative capacity in the region is now over 65% of the global total.

The size of the Chinese PV market makes it a dominant player in the Asian and global PV markets, while all other markets are lagging behind. Asia-Pacific is home to several GW-scale markets in 2025: China, India, Pakistan, Japan, Australia, Korea and Thailand.

China installed 415 GWdc (converted from China's National Energy Administration AC figures using the IEA-PVPS AC/DC conversion ratio as explained in this report), reaching a cumulative capacity of 1.46 TWdc. The distributed segment increased in market share in 2025 (38%) compared to 2023 and 2024 (35% and 33% respectively), although centralised systems still remain the larger part of the market. Volumes remain spread unevenly across the country, with very large utility-scale development continuing alongside a substantial distributed market.

Within the IEA-PVPS network, one of the largest markets in terms of installations and potential is India. With the world's largest population, significant investments in local manufacturing and support programmes that cover pumping, off grid and distributed systems and continued large scale tenders, the market in India is expected to

PV DEVELOPMENT PER REGION / continued

continue to grow. After the rapid acceleration observed in 2024, the market grew again in 2025, adding 54 GW and bringing cumulative installed PV capacity to 179 GW. Utility-scale PV remained dominant, representing around three quarters of the annual market, while the distributed market continued to grow but remained well behind utility-scale deployment; 1.7 GW off-grid systems was installed across of a range of applications.

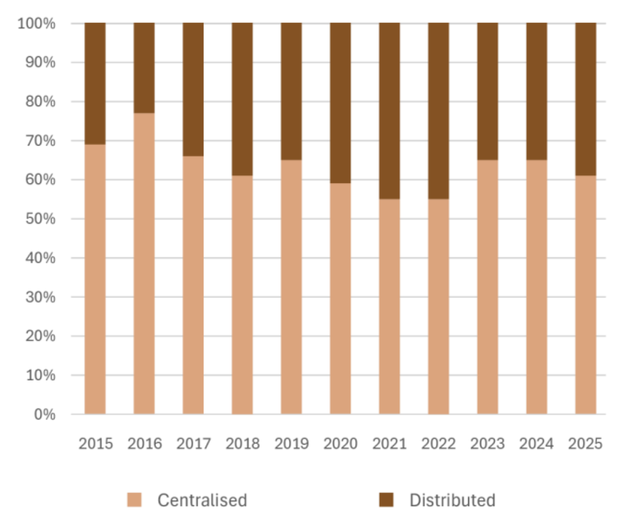
The PV market continued to develop in Pakistan, and whilst it is difficult to estimate installed volumes, the volume of imported modules and the containment of electricity consumption provides sufficient information to estimate that 14 GW new capacity was added in 2025, all in the distributed segment, for around 36 GW cumulative capacity.

The market in Japan remained broadly stable at 5.9 GW in 2025, reaching a cumulative capacity of 103 GW. The Japanese market had been slowly contracting from the much higher annual volumes of the previous decade, but a slight uptick in both the distributed and centralised segments has seen a small growth in the market volumes compared to 2024.

Both Korea and Australia remained important markets; Korea jumped back up to 4.3 GW, after a slow 2024 for a cumulative capacity of 35 GW, while Australia installed 4.5 GW for a cumulative capacity of 44 GW, below 2024's record breaking 5.3 GW. The two markets are dissimilar though – carried by centralised systems in Korea and the distributed segment in Australia. Australia continues to invest in new grid capacity to facilitate further development of utility-scale PV.

Thailand added 2.8 GW to reach 15 GW, Malaysia added 0.8 GW for a cumulative capacity of 8 GW. The markets across the rest of the Asia Pacific region remained below the GW level, although interest in commercial and industrial systems remains present.

FIGURE 2.14: EVOLUTION OF PV INSTALLATIONS IN ASIA PACIFIC PER SEGMENT



EUROPE

Europe led global PV deployment until the early 2010 s, but rapid market growth, falling module prices and costly support schemes were followed by abrupt policy changes in several countries, weakening investor and prosumer confidence. Growth slowed between 2013 and 2017 as deployment shifted towards Asia and the Americas. Since the early 2020s, European markets have returned to sustained growth, increasingly driven by distributed PV and residential, commercial and industrial self-consumption, reinforced by the high electricity prices experienced in 2022 and low module prices since 2024.

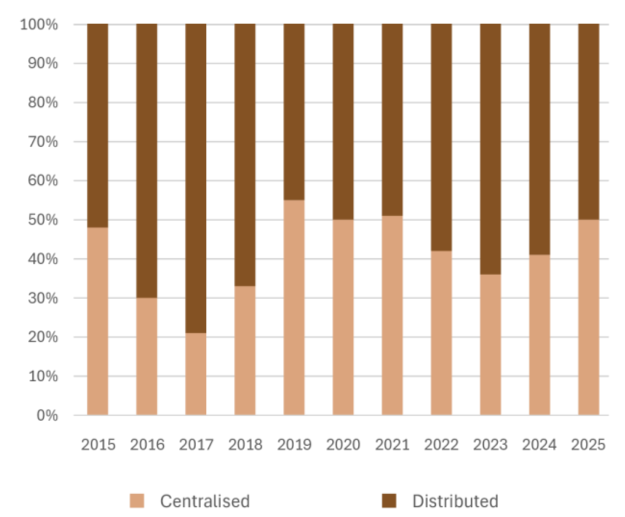
Annual capacity additions across Europe reached 79 GW in 2025, broadly stable compared to 2024 and representing around 11% of the global market. The cumulative capacity in Europe is now 482 GW, just 16% of the global cumulative capacity. Annual capacity was evenly spread across distributed and utility systems, and whilst the utility segment is growing as the distributed segment slows, it would take several more years for the cumulative capacity to reach the same equilibrium.

It is important to distinguish the European Union and its countries, which benefit from a common regulatory framework for part of the energy market, and other European countries which have their own energy regulations and are not part of the European Union. Outside EU countries, the most dynamic European market was Türkiye with a steady annual market of 4.7 GW. The UK saw a strong market with 3.2 GW in 2025, bringing cumulative capacity to around 25 GW and with the utility-scale segment taking a larger share of new installations. Switzerland continued to expand with 1.3 GW installed, once again overwhelmingly in the distributed segment, to reach 9.5 GW cumulative capacity. Ukraine also returned to higher installation levels, with around 1.5 GW added in 2025, although the market continues to be affected by the ongoing conflict.

EUROPEAN UNION

After adding 68 GW in 2025, the total installed capacity in the European Union reached 409 GW, or 85% of the capacity in Europe. As in the

FIGURE 2.15: EVOLUTION OF PV INSTALLATIONS IN EUROPE PER SEGMENT



PV DEVELOPMENT PER REGION / continued

wider European market, residential, commercial and industrial rooftops remain an important but shrinking segment, and annual utility-scale markets have grown from under 40% in 2023 to 54% in 2025.

Fourteen countries installed more than 1 GW, with Germany heading the list (18 GW), followed by Spain (12 GW), France (7.4 GW), Italy (6.7 GW), Poland (3.7 GW), Greece (2.7 GW), Romania (2.2 GW), the Netherlands (1.9 GW) and Austria (1.8 GW). Denmark, Bulgaria, Ireland, Portugal, Lithuania and Hungary installed between 1.0 GW and 1.4 GW of new capacity. The split between centralised and distributed generation varies from country to country. Utility-scale PV is an important market driver in Spain, Greece, Denmark and Bulgaria; on the opposite end, France, the Netherlands, and Belgium remained strongly driven by the distributed market. Several markets are moving towards a more equal market – generally by an increase in volume and proportion of utility scale PV, such as Germany, Italy and Poland.

The Netherlands continued to lead in terms of installed capacity per capita in the European Union with 1 584 Wp/capita, followed by Germany with 1 413 Wp/capita. Nine EU members have now passed 1 kW/cap.

MIDDLE EAST AND AFRICA

In Middle East and Africa countries, the development of PV remains modest compared to the larger markets, especially in many African countries. However, almost all countries saw some development of PV in recent years and several recorded significant increases in 2025. There is a clear trend in most countries to include PV in energy planning, to set national targets and to prepare the regulatory framework to accommodate PV. Regional additions reached around 22 GW in 2025 for a cumulative installed capacity of approximately 78 GW.

MIDDLE EAST

With high irradiation, the Middle East is amongst one of the most competitive places for PV installations, with PPAs granted through tendering processes among the lowest in the world, building on excellent irradiation levels, among others. The largest annual addition was in Saudi Arabia, with 6.8 GW installed to reach around 13 GW cumulative capacity. The UAE added 1.3 GW, and Israel also contributed 1.3 GW, reflecting continued market activity.

With a number of very large systems under construction across the Middle East, annual numbers are influenced by the commissioning dates of these utility systems, so annual capacity may not reflect the rhythm of deployment accurately,

In the region, energy prices are often supported by government spending, which limited the ability of PV to compete for years, however, countries such as Iran, Qatar, Kuwait, Saudi Arabia, Bahrain, Jordan, Oman and the United Arab Emirates have or are defining targets for renewable and solar energy for the coming years. Conditions are slowly changing for distributed PV, with net-metering or net-billing mechanisms in several countries including Egypt, the UAE, Bahrain and Jordan, and FiT or other mechanisms in Iran, Israel and Saudi Arabia, with plans to introduce similar schemes in other markets. The UAE is facilitating the connection of distributed generation to the network to help relieve peak loads. Another trend in the fast-developing region is the willingness for governments to develop brand new cities or neighbourhoods which aim at becoming showcases of renewable energies, such as Masdar City in the UAE or Spark and Neom in Saudi Arabia.

For centralised PV, tenders are an integral part of the plans for PV development in the short and long term in the region, with government and state-owned organisations tendering for single-site or multi-site projects as procurement exercises. The scale of commissioning in Saudi Arabia in 2025 illustrates the impact of these programmes. Projects for solar-powered green ammonia or hydrogen are underway in Jordan, Egypt and the UAE, while plans for new solar manufacturing capacity have also been announced in Saudi Arabia.

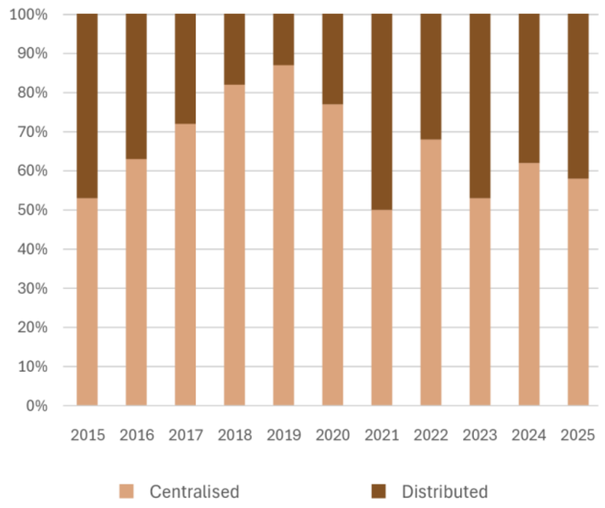
AFRICA

The African market is dynamic but remains difficult to follow, with market reports diverging in terms of capacity depending on their sources. On top of weak reporting standards and capabilities in many African countries, significant volumes of off-grid, micro and small-scale PV are probably not reported to authorities.

Africa remains by far the smallest regional market, with South Africa the largest contributor and a 2025 annual market of 3.4 GW for a cumulative capacity of 12 GW. Other countries continue to develop smaller utility-scale, commercial and industrial and off-grid projects.

The official or published installation figures probably understate the speed at which the market is changing. Imports of modules from China into Africa reached record levels in 2025 at an estimated 19 GW nearly 50% more than in 2024. Six countries logged more than 1 GW of module imports: South Africa (3.6 GW), Egypt (2.3 GW), Algeria (2.2 GW) and Nigeria, the DR Congo and Morocco also above 1 GW. Momentum continued during the first half of 2026, when Chinese module exports to Africa reached 12.5 GW, making Africa the fastest-growing regional destination for Chinese modules. China also exported approximately 11.6 GW of PV cells to Africa during the period, pointing to the rapid emergence of module-assembly activities in countries including Egypt, Morocco, Ethiopia and Kenya, with this domestic production targeting domestic and USA markets.

FIGURE 2.16: EVOLUTION OF PV INSTALLATIONS IN AFRICA AND THE MIDDLE EAST PER SEGMENT



PV DEVELOPMENT PER REGION / continued

Import statistics should nevertheless be treated as a leading indicator rather than a measure of annual installations. Modules may remain in inventories, be installed after a delay or be re-exported to neighbouring countries. The increase reflects both rapidly expanding African demand - particularly for distributed generation and alternatives to diesel generation - and the redirection of Chinese supply amid global manufacturing overcapacity, low module prices and growing trade barriers in several established export markets.

Large-scale systems remain an important contributor. In South Africa, the 273 MW Grootfontein plant entered commercial operation at the end of 2025, while a further 846 MW Kroonstad PV cluster was selected under the country's public procurement programme. In Egypt, financing advanced during the year for the 1 GW Obelisk PV project with a 200 MWh battery system, illustrating the increasing scale of solar-plus-storage development in North Africa. Smaller markets are also moving forward: financing was concluded for the 32 MW Ilute project in Zambia, while a further group of projects is intended to establish a pipeline of privately financed solar capacity.

At the same time, the distributed market is increasingly becoming one of the most significant characteristics of African PV development. Exceptionally low module prices, falling battery prices and unreliable or expensive grid electricity are making solar-plus-storage attractive to commercial users and to a growing number of urban households. As African cities expand rapidly, middle-class and wealthier consumers in countries such as South Africa and Nigeria are increasingly installing rooftop PV and batteries not only to reduce electricity bills but to obtain a more stable electricity supply and reduce dependence on diesel generators or unreliable grids. In South Africa, rooftop PV capacity had reached 8.5 GW by the end of 2025 with adoption particularly strong amongst wealthier households and businesses able to finance the upfront investment. Similar economics are increasingly visible elsewhere on the continent.

This bottom-up development is important because much of the 2025 increase in Chinese module imports appears to correspond to distributed rather than utility-scale installations. The rapid spread of imports across countries with relatively little announced utility-scale capacity suggests that homes, shops, factories, farms and other private consumers are becoming an increasingly important driver of African solar deployment alongside public procurement for government administrations, schools and health and social services. This resembles developments already observed in other markets where inexpensive modules and storage allow consumers to respond directly to high electricity prices or poor grid reliability without waiting for large power-sector investments.

Large-scale systems for low-carbon hydrogen projects have been announced, primarily looking to produce ammonia for fertiliser or export, taking advantage of the excellent irradiation available in many African countries. However, their contribution to actual PV installations remains relatively limited compared with the rapidly growing conventional utility-scale and distributed markets, and projects development seems to be a long process.

The question of African power infrastructure and markets remains essential since many countries have small, centralised electricity systems, sometimes with peak demand below 500 MW. In this respect, the challenge is not only to connect more PV to the grid but also to reinforce transmission and distribution infrastructure, add storage and increase interconnection with neighbouring countries. The growing importance of storage is particularly visible as solar penetration increases and users seek reliable electricity rather than PV generation alone.

Mini-grids remain an important tool for rural electrification. Projects continued to be announced or developed in 2025 in countries including Nigeria, Zambia, Senegal and others, supported in part by the World Bank and African Development Bank's Mission 300 initiative. In Zambia, for example, solar mini-grids and standalone systems are considered capable of providing electricity access to millions of additional people by 2030. This segment nevertheless remains strongly dependent on concessional finance, grants or subsidies while developers seek business models capable of attracting purely commercial finance.

One of the main difficulties remains attracting private investment, with investors wary of country risk, relatively high financing costs and the upfront capital requirements of power infrastructure. However, renewable markets are showing greater appeal to international and local investors, particularly where PV can replace expensive diesel generation or directly supply mines, factories, commercial facilities and households. In these applications, avoided fuel and unreliable grid electricity can make solar and storage commercially attractive without the support mechanisms historically required for utility-scale PV.

Early solar PV development was supported primarily by government and donor-backed rural electrification with micro and small systems, but an increasingly market-based development is now visible. Pay-as-you-go models remain important for lower-income consumers, while privately financed rooftop and captive systems are expanding at the other end of the market. The result is an increasingly diverse African PV market, ranging from small solar home systems and agricultural pumping to urban solar-plus-storage and multi-hundred-MW utility-scale plants.

Support policies, access to finance and facilitating regulation remain necessary to accelerate uptake ahead of the expected increase in electricity consumption resulting from population growth, urbanisation and socioeconomic development, as well as the electrification of industry and transport. Africa is already facing severe climate-change consequences including water stress and reduced food production, so emerging dual usages such as agrivoltaics and floating PV could also contribute to increasing food and water resilience whilst producing electricity.

Table 2.6: 2025 PV MARKET STATISTICS IN DETAIL

	2025 ANNUAL CAPACITY (IN GW)			2025 CUMULATIVE CAPACITY (IN GW)		
	DISTRIBUTED	CENTRALISED	TOTAL	DISTRIBUTED	CENTRALISED	TOTAL
Australia	2.8	1.7	4.5	29.2	15.1	44.3
Austria	1.5	0.4	1.8	9.5	1.3	10.7
Belgium	1.0	0.0	1.0	12.4	0.3	12.6
Canada	0.1	0.2	0.3	2.5	5.4	7.9
China	159	256	415	533	930	1464
Denmark	0.2	1.2	1.4	3.5	3.3	6.7
Finland	0.2	0.2	0.4	1.3	0.3	1.6
France	5.0	2.4	7.4	21.9	15.2	37.0
Germany	9.2	8.3	17.6	83.2	34.8	118
India	12.0	42.2	54.2	35.8	143	179
Israel	1.3	0.0	1.3	5.8	2.0	7.8
Italy	4.0	2.7	6.7	29.4	14.3	43.7
Japan	3.5	2.3	5.9	61.6	41.5	103
Korea	1.0	3.4	4.3	5.3	29.7	35.0
Lithuania	1.0	0.1	1.1	2.9	0.2	3.1
Malaysia*	0.3	0.1	0.4	3.0	2.6	5.6
Morocco*	0.9	0.2	1.1	3.2	1.3	4.5
Netherlands	1.3	0.6	1.9	12.6	16.0	28.6
Norway	0.1	0.0	0.1	0.9	0.0	0.9
Portugal	0.4	0.6	0.9	3.0	3.3	6.3
South Africa	2.7	0.7	3.4	8.5	3.7	12.1
Spain	1.4	10.7	12.1	11.1	49.8	60.9
Sweden	0.5	0.2	0.7	5.1	0.7	5.8
Switzerland	1.3	0.0	1.3	9.4	0.1	9.5
Thailand	0.9	1.9	2.8	4.6	10.1	14.7
Türkiye	4.2	0.5	4.7	21.3	4.9	26.2
UK	1.2	2.0	3.2	11.8	12.9	24.8
USA	7.6	34.9	42.5	74.1	194	266
Rest of EU	5.6	9.2	14.8	42.0	32.0	74.0
Total IEA PVPS (including EU)	230	383	612	1 048	1 568	2 614
Brazil	7.9	4.6	12	43	22	65
Pakistan	13.8	0.0	14	29	7	36
Total NON IEA PVPS	52	27	80	202	141	343
TOTAL	**282**	**410**	**692**	**1 250**	**1 708**	**2 958**

* Late data corrections not carried into totals or charts

SOURCE: IEA PVPS & OTHERS

three

POLICY SUPPORT FRAMEWORKS

PUBLIC POLICY DRIVERS AND SUPPORT SCHEMES

Public policy has accompanied the development of PV markets since the first large-scale deployment programmes were introduced in the late 1990 s (Germany) and early 2000s (Europe, USA). Feed-in tariffs, investment subsidies and tax incentives initially compensated for the higher cost of PV electricity compared with conventional generation. As PV generation costs declined during the 2010s and early 2020s, competitive tenders, self-consumption frameworks, Power Purchase Agreements and direct participation in electricity markets progressively replaced or complemented these mechanisms.

In markets with lower PV penetration, policy continued to focus on enabling investment and reducing financing barriers, using feed-in tariffs, tax incentives, capital subsidies and net metering as continued support for deployment, particularly in emerging markets and for specific consumer groups or applications. In markets with higher penetration, the role of public policy has evolved towards policy frameworks addressing the integration of growing PV volumes into electricity grids and markets. Grid access, the timing and value of electricity production, curtailment, negative wholesale prices, flexible consumption and storage became more prominent components of policy design. Governments also continued to use PV policy to pursue industrial development, supply-chain resilience, energy security, electricity access, land-use objectives and social participation.

Different priorities remained visible in many developing economies. During 2025, African countries continued to address electricity access, utility reform and mobilisation of private capital alongside utility-scale renewable procurement. At the Mission 300 Africa Energy Summit held in January 2025, 30 African governments endorsed the Dar es Salaam Energy Declaration and national reform programmes addressing electricity access, grid development, distributed energy and private investment. The World Bank Group and African Development Bank Group confirmed a target of connecting 300 million people in Africa to electricity by 2030. In many lower-access markets, electricity access, utility reform, grid expansion and mobilisation of private capital remained more immediate policy priorities than the market-integration questions observed in higher-penetration PV systems.

The policy environment during 2025 demonstrated several parallel transitions. Distributed PV policy continued to move from guaranteed export remuneration towards self-consumption, net billing, flexible exports and storage. Utility-scale policy continued to move from administered tariffs towards competitive tenders, Contracts for Difference, PPAs and increased market exposure. Industrial policy increasingly affected deployment conditions through local-content rules, supply-chain restrictions and procurement requirements. At the same time, land use, grid access and social participation played a larger role in determining where PV could be developed.

SUPPORT MECHANISMS AND REMUNERATION MODELS

FEED-IN TARIFFS, PREMIUMS AND MARKET-BASED REMUNERATION

Until recent years or specific circumstances (off-grid PV), PV generation costs exceeded the value of electricity available from conventional generation, and administratively determined schemes provided sufficient revenue to enable investment. Feed-in tariffs (FiT) were amongst the principal mechanisms used to establish early PV markets. They provide predefined remuneration for electricity injected into the grid over a contractual period, facilitating project financing. The mechanism reduced market risk and allowed a wide range of participants, including households, small businesses and independent generators, to invest in PV without exposure to wholesale electricity prices.

As PV costs declined, tariff levels were often progressively reduced, with degression mechanisms either embedded in tariff structures or applied on a regular basis, whilst other mechanisms such as system-size differentiation, capacity caps or restrictions based on installation type have also been used to limit over-remuneration or support specific segments and applications. This process has continued in several mature markets and is now often limited to smaller systems, particular building applications or surplus generation following self-consumption.

Changes to FiT policies during 2025, for example in France, Japan, Italy and Switzerland reflected this trend, with support increasingly differentiated according to size, application, location and market conditions. Larger projects are more frequently directed towards competitive tenders, market premiums or direct participation in electricity markets, while smaller rooftop systems often remained eligible.

The role of remuneration policies has evolved from a mechanism to ensure that the investment in PV was viable to a mechanism that limits overcompensation, increases self-consumption, reduces injections during periods of low electricity value and directs installations towards particular applications.

PUBLIC POLICY DRIVERS AND SUPPORT SCHEMES / continued

In China, reforms announced in February 2025 requires grid-injected wind and solar electricity to participate in electricity markets in principle, with a renewable-energy price-settlement mechanism established alongside market participation. The pricing reform applies to distributed PV (and larger scale systems) for electricity injected into the grid. Separate distributed-PV rules issued by the NEA in January 2025 encourage greater local consumption of generation. Residential systems retain the right to choose between several self-consumption and export configurations, while large commercial and industrial distributed systems face progressively stronger self-consumption requirements.

These reforms altered the basis on which renewable generation is remunerated in the world's largest PV market and increased the role of electricity-market signals in project revenues.

The Chinese reform also distinguished between existing and future projects. Existing projects retained mechanisms intended to preserve continuity of previously expected revenues, while mechanisms for later projects were more closely linked to competitive provincial processes and market conditions. The result is a remuneration framework that combines market participation with a form of revenue stabilisation.

Amongst IEA PVPS member countries, open-access feed-in tariffs remained available in 2025 for defined PV market segments in France, Germany, Israel, Italy, Japan and Switzerland, as well as under some state or local frameworks in the USA. Their scope differed considerably between markets and was increasingly restricted according to system size or application. In France, the March 2025 revision of the S21 framework changed the conditions applying to building-mounted PV, including residential systems and the end of open-access FiT support for part of the commercial and industrial segment. In Japan, FIT/FIP support continued in 2025, with differentiated treatment by system size and installation type. From the second half of FY2025, METI introduced an initial-investment support structure for rooftop PV, with higher remuneration during the first years of the support period and lower remuneration afterwards.

Feed-in premiums are a different mechanism. They supplement electricity-market revenues rather than replacing them. Depending on design, premiums can be fixed or variable (providing different levels of market exposure). In 2025, open-access market premiums or FiP-type support were reported in Austria, Israel, Italy and Japan, although eligibility differed by market segment. In Austria, the market premium remained the principal support mechanism for eligible PV following the end of the former FiT framework in 2021. In Israel, premium-based remuneration remained available across several PV segments. In Italy, FiP-type support applied to selected commercial and industrial and agrivoltaic systems, while other segments were supported through different mechanisms. In Japan, FiP support continued for selected commercial and industrial and agrivoltaic installations alongside the FIT framework for other categories.

Two-way Contracts for Difference (CfDs) provide another form of revenue stabilisation while participating in electricity markets. With a CfD, generators sell electricity on the market and receive an additional payment when the market reference price is below an agreed strike price. When the reference price rises above the strike price, the generator returns the corresponding difference. The mechanism reduces long-term revenue uncertainty by compensating the generator when electricity costs are low on the market while limiting excess revenues during periods of high market prices.

As PV generation costs have declined, support increasingly serves to reduce financing and market-price risk rather than to compensate for a cost disadvantage. Contract design, including the choice of reference price and treatment of negative prices or curtailment is now an increasingly important part of policy design.

The distinction between supported and market-based PV is becoming less distinct with these evolutions. A project can sell electricity directly into the market while still receiving additional support that helps stabilise its revenues.

Policy design is increasingly concerned with the distribution of market risk across the different actors. The main questions concern which (economic) risks are carried by generators, consumers, public authorities or electricity-system operators, and how those risks influence investment.

In the early development of PV, lower support tariffs generally indicated a reduction in required subsidy. In 2025, project remuneration increasingly depends on a combination of market exposure, contract structure, curtailment provisions, connection conditions and storage requirements. Direct comparison between nominal support prices therefore provides less information than in earlier phases of market development.

EUROPEAN PV MARKETS – FROM FIT TO MERCHANT PV

EU MARKETS WERE INITIALLY SUPPORTED THROUGH FEED-IN TARIFFS, BEFORE FALLING COSTS ACCELERATED THE SHIFT TOWARDS SELF-CONSUMPTION FOR DISTRIBUTED PV AND COMPETITIVE TENDERS AND PPAS FOR UTILITY-SCALE PROJECTS. MORE RECENTLY, MERCHANT AND OTHER MARKET-BASED REMUNERATION MODELS HAVE EXPANDED. THESE TRENDS ARE NOT UNIQUE TO EUROPE, ALTHOUGH HIGH RETAIL ELECTRICITY PRICES SUPPORTED FASTER DEVELOPMENT OF SELF-CONSUMPTION, INCLUDING INCREASINGLY COLLECTIVE AND VIRTUAL MODELS AS REGULATION EVOLVES.

BIPV HAS HISTORICALLY RECEIVED STRONGER SUPPORT IN EUROPE THAN ELSEWHERE BUT REMAINS A NICHE MARKET DESPITE SEVERAL GW OF INSTALLATIONS, WHILE MANDATORY SOLAR REQUIREMENTS IN BUILDING REGULATIONS ARE STILL BEING IMPLEMENTED UNEVENLY.

PUBLIC POLICY DRIVERS AND SUPPORT SCHEMES / continued

INVESTMENT SUBSIDIES, TAX CREDITS AND FISCAL SUPPORT

PV systems have relatively low operating expenditure but require capital investment at the beginning of the project. Capital subsidies, rebates and tax incentives therefore remained in use during 2025, particularly for households, small businesses and applications where access to finance remained a constraint.

These instruments may be targeted, not supporting all PV systems under identical conditions but specific fiscal measures can be directed towards defined consumer groups or applications. These included lower-income households, public buildings, batteries, BIPV, agrivoltaics and projects with specific social or industrial characteristics.

The declining cost of mainstream PV means that in many mature markets a general capital subsidy for rooftop modules is not necessary and redirected they can support specific segments where investment barriers remain higher or where governments seek additional system or social benefits.

In Australia, the Cheaper Home Batteries Program commenced in July 2025. In a market with high residential PV penetration, the programme supported battery deployment rather than rooftop PV modules, in line with a change in policy objectives. The programme sought to increase the local use and temporal shifting of distributed solar generation, particularly where midday export values had declined.

The relationship between PV and storage support in Australia is also linked to the structure of the existing distributed market. A large share of detached households already had PV systems by 2025. Additional modules therefore provide less incremental system value in some locations than increased flexibility, particularly where distribution networks experience high midday exports.

In Austria, the VAT exemption for smaller PV installations was terminated during 2025 earlier than initially foreseen, possibly due to a weaker residential market. Fiscal incentives can continue to influence consumer behaviour even where PV is already economically competitive. Changes in France during 2025 also showed increasing differentiation between operating support and fiscal support. While some remuneration levels were reduced, targeted fiscal treatment remained available for qualifying small residential installations (reduced VAT). Temporary preferential VAT treatment ended in Portugal during 2025, and in Canada there were changes to federal residential capital support.

Extensive fiscal-policy change during 2025 occurred in the USA. Federal clean-energy incentives had expanded from 2022 under the Inflation Reduction Act, supporting renewable deployment, domestic manufacturing and related supply-chain investments. The One Big Beautiful Bill Act (OBBBA) of July 2025 shortened the availability of several clean-electricity production and investment incentives for future solar projects and introduced additional conditions affecting eligibility and supply chains. The OBBBA did not affect all mechanisms in the same way or on the same timetable and the USA framework remained differentiated between residential, commercial, utility-scale and manufacturing activities with different tax provisions applying to different segments.

The changes nevertheless reinforced the interaction between deployment support and industrial policy. Access to financial incentives increasingly depends on factors related to supply-chain origin, supplier ownership and domestic manufacturing. This makes the distinction between a deployment policy and an industrial policy less clear than it was during earlier phases of PV market development.

Tax credits and tax reductions continued to form part of PV support frameworks in several countries during 2025, either as stand-alone incentives or alongside feed-in tariffs, direct subsidies and rebates. They can apply to equipment costs, installation labour or electricity supplied to the grid, although eligibility and calculation methods differ considerably between markets.

In Finland, the household-expense tax credit applies to eligible installation labour, although the maximum credit and eligible share of labour costs were reduced from January 2025. In Sweden, the Green Technology tax reduction for solar PV was reduced from 20% to 15% from 1 July 2025. Separate tax reductions for electricity supplied by qualifying micro-producers remained applicable through 2025 but were abolished from 1 January 2026. In the USA, the federal Residential Clean Energy Credit remained available at 30% during 2025 for qualifying residential solar expenditure and eligible battery storage. Federal legislation enacted in July 2025 brought forward the termination of the residential credit to the end of 2025, while business and utility-scale clean-energy incentives remained subject to separate provisions and timelines.

Tax incentives also continued to support business investment in some markets. In South Africa, the temporary residential PV rebate had already expired in February 2024, while the Section 12BA business renewable-energy deduction remained available during 2025 for qualifying assets brought into use before March 2026.

Elsewhere, tax credits and related fiscal measures remained part of PV support frameworks, but their design varied considerably between household, commercial and utility-scale segments. In several markets, 2025 changes focused less on introducing new tax credits than on reducing, phasing out or retargeting existing incentives.

Fiscal support also remains relevant in emerging markets, although often through different instruments. In some countries, import-duty exemptions, concessional loans, accelerated depreciation, reduced sales taxes or public financing can influence PV economics more than direct cash rebates.

For distributed systems, fiscal policy can also interact with social-policy objectives. Some programmes target low-income households or social housing, while others seek to reduce up-front investment barriers for small businesses or agricultural users. These programmes can increase access to PV even where the technology is competitive on a lifetime-cost basis.

The wider tendency during 2025 was for financial incentives to be increasingly targeted towards specific segments, complementary technologies or industrial objectives.

PUBLIC POLICY DRIVERS AND SUPPORT SCHEMES / continued

SELF-CONSUMPTION, PROSUMERS AND ENERGY COMMUNITIES

As PV generation costs declined, distributed-PV policy progressively evolved from remunerating electricity production towards enabling consumers to reduce their own electricity purchases. By 2025, self-consumption was a principal driver of distributed PV in many mature and emerging markets.

PV electricity generated and consumed behind the meter avoids electricity purchases from a supplier. The value of that electricity therefore depends on retail electricity prices, network tariffs, taxes and other charges avoided by the consumer. Policy determines the treatment of surplus generation, applicable grid charges, permitted ownership structures and whether generation can be shared between consumers.

A broad policy progression can be observed from historical feed-in tariffs towards self-consumption, net metering, net billing and more active management of generation and consumption. These mechanisms can coexist, and individual markets do not necessarily follow the same sequence.

The economic logic of self-consumption differs from that of feed-in tariffs. Under a classic FiT, the value of the PV system depends principally on the remuneration paid for generation. Under self-consumption, the value depends on the retail electricity price avoided by the consumer and the value received for surplus electricity.

This creates a closer link between distributed PV policy and electricity-tariff design. Changes to retail tariffs, fixed charges, time-of-use rates and export remuneration will influence PV economics even without changes to direct PV support.

INDIVIDUAL SELF-CONSUMPTION AND EXPORT REMUNERATION

Net metering remained in use in several markets during 2025 and continued to support distributed-PV deployment. Under conventional net metering, exported electricity is credited against later consumption, often at or close to the retail electricity price. This provides a simple investment signal and can support rapid market growth. As installed capacity increases, however, the difference between the retail value credited to exported electricity and its wholesale or system value can become a more prominent regulatory issue. This is one reason several mature markets have moved towards net billing, time-dependent export values or other forms of differentiated remuneration.

In China, distributed PV reached a scale where local grid conditions increasingly determine how much additional capacity can be connected. The regulatory response combines deployment policy with network planning. Revised distributed-PV management rules were issued in January 2025, applicable from May. The rules differentiate household and commercial and industrial projects, define permitted operating configurations and strengthen requirements for distributed systems to be observable, measurable, adjustable and controllable. Local authorities must also consider electricity demand, network hosting capacity and renewable-energy utilisation when planning distributed deployment.

The Chinese framework distinguishes between different operating models. Residential systems retain several options for self-consumption and export, while larger commercial and industrial systems face tighter conditions. Greater technical visibility gives system operators more information and control over distributed generation.

A similar evolution was visible in markets where exported PV electricity received a lower or more time-dependent value than electricity consumed behind the meter. During 2025, parts of Australia continued to use low export tariffs, smart inverters and dynamic export arrangements. In California, USA, export remuneration under the applicable distributed-generation framework varied according to the time at which electricity was supplied. In Greece, conventional net metering was closed to most new applicants in 2024 and replaced by a net-billing framework although projects approved under the previous net-metering scheme continued to be installed during 2025, while in France adjustments to surplus remuneration further differentiated self-consumed and exported electricity. In the Netherlands, the scheduled end to net metering from 2027 remained the reference point for the residential market.

Adjusting consumer incentives to complement electricity-system conditions is an important step in high market penetration countries. Where midday electricity has limited market value, high fixed export tariffs can encourage system sizes and operating patterns that increase network congestion without equivalent system benefit.

In markets that had expanded rapidly under net-metering frameworks, policy is increasingly adjusted to address the allocation of network costs and the value of surplus electricity. In Pakistan, low module prices, high grid electricity costs, supply-reliability concerns and favourable net-metering arrangements supported rapid consumer-led deployment during 2025. In March 2025, the Economic Coordination Committee approved a proposal to reduce the buyback rate for surplus electricity for future projects while protecting existing valid agreements, and NEPRA subsequently amended the distributed-generation and net-metering regulations in December 2025. These changes increased the relative value of self-consumption and, together with falling battery prices, strengthened the economics of storage – although investment motivations in Pakistan often include considerations on reliable supply and comfort, in particular for ventilation and air conditioning, rather than purely economic factors.

Across these markets, self-consumption policy increasingly favoured closer matching of generation and consumption. Under generous net metering, consumers can have an incentive to size systems above daytime demand. Under net billing, lower export tariffs or time-dependent remuneration, system sizing is more closely linked to local consumption unless storage is added.

NETWORK TARIFFS, GRID ACCESS AND COST ALLOCATION

As self-consumption becomes widespread, policy increasingly determines how prosumers contribute to network costs and under what conditions they may connect and export electricity. Three regulatory questions recur across markets: the connection and ongoing charges paid for use of the grid; the right to inject surplus electricity and receive remuneration; and whether a third party may own or operate a PV system on behalf of the consumer.

Network-tariff design becomes more important as self-consumption reduces electricity purchased from the grid. Where network costs are recovered mainly through charges on each kWh consumed, increasing self-consumption can reduce network revenues and shift a larger share

PUBLIC POLICY DRIVERS AND SUPPORT SCHEMES / continued

of costs towards consumers without PV. Regulatory responses include higher fixed or capacity-based charges, minimum contributions, time-dependent tariffs and differentiated network charges for electricity shared locally. The objective is to preserve incentives for efficient self-consumption while maintaining transparent and equitable recovery of network costs.

The choice of tariff structure can influence both PV economics and the distribution of network costs. In Austria, electricity exchanged within qualifying renewable energy communities benefits from reduced network charges, while in Australia full network charges generally remain applicable when locally generated electricity is transferred through the public grid, which can limit the economics of virtual sharing. In Sweden, small PV producers continued to benefit from reduced grid fees in 2025, while France introduced the TURPE 7 network-tariff framework in August 2025. In Europe, guidance issued in July 2025 encouraged network charges that better reflect how and when consumers use the grid, including the value of flexibility. These examples illustrate that tariff design increasingly affects distributed-PV economics even where no direct PV subsidy is involved.

The right to export is also increasingly conditional on local grid capacity. Automatic unrestricted injection can become difficult where distributed PV already exceeds local demand during parts of the day. Export caps, dynamic export limits and remotely controlled inverters allow additional systems to connect while limiting injections during constrained periods. These arrangements shift distributed-PV policy from a simple right to export towards managed access to the distribution network.

Connection and export rules are consequently becoming a distinct policy layer. A system may be economically viable but still depend on whether the distribution operator is required to connect it, whether reinforcement costs are paid by the project or shared across network users, and whether export rights are firm or conditional. Where networks are constrained, regulators can replace a binary choice between connection and refusal with managed connections that permit generation subject to export limits at specified times.

Third-party ownership adds a further regulatory question because leasing and solar-as-a-service models may involve electricity sales or contractual arrangements that fall under supplier or licensing rules. Together, connection charges, export rights and ownership rules form the basic regulatory architecture that determines whether consumer-led PV can develop once direct subsidies are reduced.

Third-party ownership also remains relevant to self-consumption. Leasing, rooftop rental and PV-as-a-service models can allow consumers to benefit from PV without making the full initial investment. The regulatory treatment of these models varies by country and depends on rules governing electricity resale, licensing and access to the grid.

CONSUMER PROTECTION AND INSTALLATION QUALITY

As distributed PV becomes increasingly consumer-led, policy may need to address the quality of installations and the contractual risks faced by households and small businesses. These issues become more relevant where consumers invest without the protection of a long-term guaranteed tariff, or where PV, batteries and electricity supply are bundled with finance, leasing or subscription contracts.

Policy approaches include installer accreditation, minimum electrical and product standards, approved-equipment lists, requirements for performance estimates and contractual disclosure, and formal complaint or dispute-resolution procedures. Public incentives can also be conditional on compliance with these requirements, allowing support schemes to reinforce technical and commercial quality standards.

In Australia, access to the Small-scale Renewable Energy Scheme requires accredited installers and approved PV modules and inverters, alongside consumer-law protections and complaint procedures. In the UK, the Microgeneration Certification Scheme provides certification requirements for small-scale renewable-energy installations, while associated consumer-code arrangements address quotations, cancellation rights, deposits, warranties and complaints.

As third-party ownership and long-term service contracts expand, consumer protection increasingly concerns the accuracy of savings claims, allocation of maintenance responsibilities, ownership of equipment, termination conditions and the treatment of contracts when properties are sold. These measures do not directly subsidise PV deployment, but they can reduce information asymmetry, improve installation quality and support confidence in expanding distributed-PV markets.

By 2025, the distinction between a prosumer and a conventional electricity consumer had become less clear in many markets. Households and companies can combine PV, batteries, electric-vehicle charging and flexible loads, while digital platforms and aggregators can manage these assets in response to tariffs or electricity-market conditions.

COLLECTIVE SELF-CONSUMPTION AND ENERGY COMMUNITIES

Collective self-consumption extends self-consumption beyond individual property owners. Electricity from one or more PV installations can be allocated physically or virtually among several consumers, using private networks or accounting mechanisms over the public grid.

These frameworks, also called Energy Communities, can extend access to PV to tenants, apartment residents and consumers without suitable roofs while allowing generation to be matched against the electricity demand of a wider group of consumers.

Collective self-consumption can take several forms. In some cases, a PV installation supplies several consumers within one building. In others, generation is virtually allocated among participants connected to the public distribution network. Energy communities can also own generation assets jointly or combine PV with storage and other technologies.

The European Union established the legislative basis for Renewable Energy Communities through the recast Renewable Energy Directive and for Citizen Energy Communities through the Electricity Market Directive. National implementation continued to develop during 2025. Several countries expanded the scale or geographic perimeter permitted for collective self-consumption. In France, the standard maximum cumulative generation capacity for extended collective self-consumption in mainland France was increased from 3 MW to 5 MW, while Italy, Austria, Spain and Switzerland continued to develop electricity-sharing frameworks supported by specific incentives,

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network arrangements or administrative procedures. The availability of smart meters and digital settlement systems is increasingly relevant to their implementation.

The effectiveness of these frameworks depends in part on different design choices including who is allowed to participate, the geographic or electrical perimeter over which electricity can be shared, and the network charges and taxes applied to those exchanges. A wider perimeter can improve the matching of generation and consumption and extend access to consumers without suitable roofs, but it also increases use of the public network. Tariff design therefore has a direct influence on whether collective self-consumption is economically viable and on how network costs are shared with other consumers.

Terminology differs between markets. In the USA, community solar generally refers to a shared or subscription-based solar project whose benefits are allocated to several customers, while the term energy community has also been used in federal tax policy for designated geographic areas. State community-solar programmes vary considerably, and some include requirements or incentives to extend participation to lower-income households. In Australia, shared-rooftop programmes for apartment residents, community batteries and community-led solar and battery initiatives are being developed as ways of extending participation beyond detached homeowners.

Collective self-consumption also has a role in matching local generation and consumption. A group of consumers with different load profiles can absorb a higher share of local solar generation than a single household, reducing the volume exported outside the local area.

The policy value of energy communities extends beyond social participation. In some contexts, they can support local flexibility and more efficient use of distribution networks. However, the effectiveness of these frameworks depends strongly on network tariffs and administrative design. If participants face the same full network charges as conventional electricity transfers, the economic benefit of local sharing can be limited. If network charges are reduced to much, cost allocation can become a concern for other consumers.

The policy challenge is to recognise the value of local generation while maintaining transparent and equitable network-cost allocation.

COMPETITIVE TENDERS AND PUBLIC PROCUREMENT

Competitive tenders became one of the principal mechanisms for guiding utility-scale PV deployment during the 2010s and early 2020s. Governments use them to control the timing, volume, location and characteristics of new capacity while developers compete for long-term remuneration, grid access or electricity procurement contracts.

Public procurement can influence PV deployment independently of electricity auctions. Public authorities may procure PV systems or renewable electricity for schools, hospitals, public buildings, transport infrastructure and other public assets, while procurement specifications can introduce requirements related to environmental performance, equipment origin, resilience, local participation or lifecycle impacts. Public purchasing can create demand for particular technologies or standards as well as add generating capacity.

Early tenders focused primarily on reducing the cost of renewable electricity, but now may incorporate electricity-system, industrial, environmental and social criteria in addition to price.

Procurement frameworks are also seeking electricity with defined characteristics related to timing, dispatchability, location, supply chains or land use.

Multi-GW PV tenders continued in 2025. Germany allocated more than 7 GW through three utility-scale PV tender rounds, while Italy allocated 7.7 GW in its first FER-X solar auction and Saudi Arabia awarded 3 GW. India remained one of the most active procurement markets, with around 44 GW of utility-scale solar tenders announced during the year across stand-alone solar, hybrid and solar-plus-storage formats, including a 2 GW solar tender and a 1.2 GW solar-plus-storage award. At least 4.4 GW of solar capacity was identified in Indian solar-plus-storage calls alone. Romania allocated around 1.4 GW, South Africa around 1.3 GW, and Türkiye also completed sizeable procurement rounds. Tender design increasingly incorporated storage, delivery profiles and supply-chain requirements alongside price, reflecting a gradual shift from procuring PV capacity alone towards more specific system and delivery characteristics.

EVOLUTION OF TENDER DESIGN AND REMUNERATION

Tender remuneration has progressively evolved from fixed feed-in tariffs towards feed-in premiums, Contracts for Difference and other revenue-underwriting arrangements. These mechanisms allow generators to participate in electricity markets while retaining sufficient revenue certainty to facilitate financing.

By 2025, grid access, land availability, regulatory risk and long-term revenue protection could all effect project economics alongside the nominal electricity price awarded through the tender.

The increasing complexity of tenders also reflects changing electricity-system needs. When PV represented a small share of electricity supply, additional midday generation could usually be absorbed without major operational effects. With higher penetration, the timing and location of generation became more relevant.

Storage is being incorporated more frequently into renewable procurement. In India, the government recommended in February 2025 that solar projects include co-located energy storage to improve grid stability and reduce system costs, while procurement rounds during the year increasingly combined PV and batteries. The objective was to procure renewable electricity able to contribute during evening demand periods, reduce network constraints or provide system services. Germany also completed a solar-plus-storage tender in October 2025, and related approaches were used through the Capacity Investment Scheme in Australia, storage-linked renewable procurement in Israel, and solar-plus-storage procurement in Middle Eastern markets during 2025.

In some tenders, storage requirements specify minimum duration or power capacity. In others, projects are required to meet a delivery profile or provide a defined level of firm capacity, leaving the developer to determine the optimal combination of PV and storage.

This reflects a transition from procurement centred on the lowest-cost renewable kWh towards procurement that also considers the timing and system value of renewable electricity.

Tender design also increasingly interacts with grid planning. Governments can designate zones where network capacity is available or include grid-connection conditions within procurement. This can

PUBLIC POLICY DRIVERS AND SUPPORT SCHEMES / continued

reduce uncertainty for developers and align renewable deployment with transmission investment.

In Australia, Renewable Energy Zones and the Capacity Investment Scheme illustrate this closer relationship between procurement and network planning. Similar approaches are emerging elsewhere where transmission access has become a constraint.

SELECTION CRITERIA BEYOND PRICE

Competitive tenders can be used to influence the physical, social and industrial characteristics of PV deployment in addition to the electricity price. Selection criteria may favour particular types of land or buildings, require storage, apply environmental or carbon-footprint requirements, include community participation, or specify local-content and supply-chain conditions.

Agrivoltaic or floating PV can be favoured where land-use constraints are relevant, while storage requirements can be used where greater flexibility or a defined delivery profile is required. Community or Indigenous participation can also form part of project selection where local economic participation is included in procurement objectives.

Industrial and supply-chain criteria are increasingly used in several major PV markets. In the European Union, the Net-Zero Industry Act established a common framework for non-price criteria in renewable-energy auctions. Secondary legislation adopted in May 2025 defined criteria covering resilience, environmental sustainability, cybersecurity, responsible business conduct and project-delivery capability. These provisions apply from 30 December 2025 to a defined share of renewable-energy auction volumes. Italy is the first EU markets to apply equipment-origin and resilience-related criteria in PV procurement in 2025 with a 1.1 GW PV auction concluded in December 2025 that applied equipment-origin requirements. In India, public procurement and government-supported PV programmes use the Approved List of Models and Manufacturers to determine eligible modules and, progressively, solar cells. In Türkiye, YEKA solar tenders apply domestic-content requirements; the 800 MW tender concluded in February 2025 required solar modules with a minimum 75% domestic-content rate. In the USA, domestic-content and supply-chain conditions also influence equipment selection in federally supported procurement and tendered projects.

The use of criteria beyond price affects the interpretation of tender results. A project required to include storage, use particular land, meet supply-chain conditions or provide community benefits cannot be compared directly with a project selected solely on generation price, and may have significant over-costs.

In 2025, eligibility and selection criteria in competitive tenders were used to differentiate projects according to:

- system size, including separate tender categories or thresholds in Korea, France and Poland;
- site or installation type, including buildings, parking structures and specified land categories in France and Germany;
- storage requirements or delivery profiles, particularly in India, Australia and Germany;
- carbon footprint or environmental performance, notably in France and Korea;
- local-content, supply-chain or domestic-participation requirements, including Türkiye, India and South Africa;
- domestic ownership, as in Malaysia;
- community or First Nations participation, particularly in Australia; and
- specific PV applications, including agrivoltaics and floating PV in Germany, Italy, India and Malaysia.

Tender outcomes are also affected by financing costs, grid-connection risk, equipment prices, permitting and expected curtailment. These factors influence both bid levels and project bankability. Where bids do not adequately reflect changes in these conditions between award and construction, projects can be delayed, renegotiated or cancelled. Indexation provisions, realistic delivery schedules and transparent grid-connection conditions can reduce these risks.

Tender programmes therefore increasingly combine deployment objectives with system planning, land-use policy and industrial-policy requirements.

BID PRICES REMAINED LOW IN 2025

LOWEST 2025 BIDS RANGED FROM:

- 11 USD/MWH IN SAUDI ARABIA
- 28 USD/MWH IN JAPAN,
- 29 USD/MWH IN INDIA AND SOUTH AFRICA

IN EUROPE, UTILITY-SCALE TENDER PRICES RANGED FROM

- LOWEST WINNING BIDS AT 39 USD/MWH IN GERMANY AND 50 USD/MWH IN ITALY
- AVERAGE BIDS AT 93 USD/MWH IN FRANCE

BUILDING-MOUNTED PV BIDS REMAINED HIGHER:

- 80 USD/MWH IN GERMANY
- > 100 USD/MWH IN FRANCE

DIFFERENCES REFLECT SOLAR RESOURCE, PROJECT SIZE, FINANCING AND GRID CONDITIONS, TECHNICAL AND OTHER REQUIREMENTS INCLUDED IN PROCUREMENT.

PPAS, MERCHANT PV AND NEW REVENUE MODELS

As PV generation costs declined, projects operating outside traditional public support schemes expanded in several markets.

CORPORATE RENEWABLE ELECTRICITY PROCUREMENT

Corporate renewable-electricity procurement extends beyond PPAs. Companies can invest directly in on-site or off-site PV, participate in energy communities, purchase renewable electricity through supplier contracts, or acquire renewable-energy certificates such as Guarantees of Origin. Policy determines how these certificates are issued, tracked and cancelled and therefore how reliably renewable-electricity claims can be demonstrated. However, PPAs remain one of the principal routes for linking long-term corporate demand to the financing of new renewable projects.

The contractual route determines what the buyer is actually purchasing. Under a physical PPA, electricity and its associated renewable attributes are delivered through the electricity system under a long-term contract; under a financial PPA, the parties settle financially against a reference market price while the electricity itself is traded separately. Supplier green tariffs and other retail contracts provide another route, particularly where direct contracting with a generator is not available. Renewable-energy attribute certificates, known as Renewable Energy Certificates in the USA and Guarantees of Origin in the European Union, can also be purchased together with or separately from electricity. Policy determines how these certificates are issued, transferred and cancelled so that the same renewable generation is not claimed more than once.

Corporate procurement is also moving towards more precise matching of electricity demand and renewable generation. Annual certificate matching remains widely used, but some large electricity buyers, particularly data-centre operators, are moving towards more granular procurement in which renewable or carbon-free electricity is matched with consumption in the same region and, increasingly, on an hourly basis. Google has adopted a 24/7 carbon-free energy approach based on hourly and regional matching, while Microsoft has also tested hourly matching of Guarantees of Origin in Europe. This can increase demand for storage, diversified renewable portfolios and time-specific certificates. The regulatory framework for certificates and electricity-market access influences whether corporate procurement primarily documents annual consumption or contributes to new generation and flexibility at the hours and locations where they are required.

POWER PURCHASE AGREEMENTS

Power Purchase Agreements provide long-term contracts between generators and electricity purchasers (consumers or re-sellers). During 2025, industrial companies, technology firms, retailers and data centres continued to procure renewable electricity through PPAs.

PPAs can be physical or financial and can include storage and flexibility. Their economics depend on the creditworthiness of the purchaser, the relationship between generation and consumption profiles, curtailment risk, grid conditions and future wholesale electricity prices.

Corporate PPAs can provide generators with long-term revenue certainty without direct public support. They can also allow electricity consumers to manage price risk and support renewable-energy procurement objectives.

The PPA market has become more complex as PV penetration has increased. A fixed-volume solar PPA exposes the buyer and seller to the fact that solar generation is concentrated during daylight hours. If daytime wholesale prices fall relative to average market prices, the economic value of the contracted generation can decline. In markets with high solar penetration, PV projects increasingly generated a large share of their electricity during periods of relatively low wholesale prices.

Contract design can reduce some of these risks. Under a pay-as-produced PPA (where the buyer purchases electricity whenever the PV plant generates), the buyer accepts the variability of solar output. In baseload or shaped PPAs (where the generator commits to supplying an agreed amount or profile of electricity), more of the risk associated with when electricity is produced remains with the generator. Financial PPAs (contracts that settle the difference between an agreed price and a market reference price rather than physically delivering electricity) can create a further risk when the reference market price differs from the price actually received by the PV plant.

Storage can also be incorporated into PPA structures to shift delivery towards higher-value periods or provide firmer supply profiles. This is particularly relevant for data centres and industrial consumers seeking higher levels of temporal matching.

Corporate PPAs are most prevalent in electricity markets with liquid wholesale trading, established renewable project pipelines and large corporate electricity buyers. The USA remains the largest market globally, with a reported 30 GW of corporate clean-energy PPAs signed in 2025 (20 GW of solar). In Europe, Spain was the most active PPA market in 2025, with around 4.5 GW contracted, while Germany and the UK also remained established markets. In Asia-Pacific, India and Australia were among the most active markets, with around 11 GW and 4 GW of corporate PPA announcements respectively, while activity is also developing in Japan, Korea, Malaysia and Vietnam as regulatory frameworks for direct renewable electricity contracting expand.

Corporate PPAs are also developing beyond the largest established markets. In Central Europe, Poland has become one of the more active markets, with around 2.5 GW of corporate PPA contracting in 2025, while activity is also developing in Romania, Hungary and Czechia. Across Europe, corporate PPAs continued to support utility-scale PV deployment particularly in Spain, Germany, Italy and Poland.

In South Americas largest PV markets Brazil and Chile, PPAs and other bilateral contracts are an established route for utility-scale renewable development, particularly for large commercial, industrial and mining consumers. In Chile, bilateral contracting remains an important driver of utility-scale renewable deployment, while Brazil continues to host corporate renewable transactions, including large solar PPAs.

In Africa, corporate PPAs are most developed in South Africa, where private generators can contract directly with large consumers and use the transmission or distribution networks to deliver electricity. Private PPA structures are also developing in Zambia, Namibia, Kenya, Ghana, Nigeria, Tanzania and Zimbabwe, although regulations for grid access and wheeling vary considerably. In many other African markets, PPAs remain predominantly contracts between independent power producers and utilities or other public off-takers rather than direct corporate procurement.

PPAS MERCHANT PV AND NEW REVENUE MODELS / continued

MERCHANT EXPOSURE AND HYBRID REVENUE MODELS

Merchant PV relies wholly or partly on electricity-market revenues. Low PV generation costs and high wholesale electricity prices increased interest in merchant projects during the early 2020s, particularly in parts of Europe and Australia.

Developments during 2024 and 2025 showed how increasing volumes of solar generation occurring at the same time can reduce project revenues. In several markets, the electricity price received by PV plants during the hours when they generate fell relative to the average market price (solar capture price), periods with electricity prices below zero became more frequent (negative process), and economic (economic curtailment) and grid constraints (technical curtailment) led to a larger share of potential PV generation being reduced or switched off.

In Brazil, curtailment became a regulatory and commercial issue during 2025, leading to work on compensation rules, grid development and storage. Similar pressures were observed during 2025 in Spain, Germany, Chile and Australia, although their causes and regulatory responses differed.

In some markets, curtailment results primarily from network constraints. In others, economic curtailment occurs when negative wholesale prices make generation unattractive. These causes have different implications for project design and compensation. Policy design could usefully distinguish between network and economic curtailment, and deliberate project or system optimisation

Project developers increasingly combined long-term PPAs, merchant exposure, CfDs or revenue floors, battery arbitrage, capacity remuneration, ancillary services and renewable energy certificates.

This “revenue stacking” can reduce dependence on a single electricity-market income stream. A battery co-located with PV can shift some electricity sales to higher-price periods while also earning revenue from balancing or ancillary services.

The distinction between supported, contracted and merchant PV therefore became less clear during 2025. Project revenues increasingly depended on combinations of electricity sales and system-service revenues.

This also affects project financing. Lenders generally prefer stable and predictable cash flows, while merchant exposure increases revenue uncertainty. Hybrid revenue structures can support bankability where pure merchant revenues are considered too volatile.

The evolution of PPAs and merchant PV is closely linked to the grid-integration issues discussed below. As PV penetration increases, market-based projects become more sensitive to capture prices, curtailment and the value of flexibility.

GRID INTEGRATION, FLEXIBILITY AND STORAGE POLICY

The rapid deployment of PV is creating electricity-system conditions that were less impacting when solar represented only a small share of generation.

By 2025, policy in several high-penetration markets increasingly addressed where and when PV electricity was produced. Large volumes of simultaneous generation can reduce daytime wholesale prices, create local or regional network congestion and result in curtailment.

The market and system value of additional unmanaged solar generation may decline as penetration increases, reducing uptake and investment as the value of additional new electricity depends increasingly on its timing, location and ability to respond to system conditions.

GRID ACCESS AND CONNECTION

Grid constraints can affect both utility-scale and distributed PV. Utility-scale projects may face long connection queues or requirements to finance network reinforcement. Distributed systems may face export limits where local feeders already experience high midday injections.

Policy responses included network reinforcement, spatial planning, connection-cost sharing, flexible grid connections, dynamic export limits and requirements for remote visibility and control.

Flexible connections allow projects to connect without full firm access to the grid, provided they accept curtailment during constrained periods. This can reduce waiting times and avoid some network reinforcement costs.

FROM CURTAILMENT TO FIRM PV POWER

At high shares of PV and variable renewables, avoiding all curtailment is not necessarily the lowest-cost system solution. IEA PVPS Task 16 analyses combinations of additional renewable capacity, storage, flexibility and controlled curtailment that can provide more predictable electricity supply. Its work indicates that some overbuilding and curtailment can form part of cost-optimised firm renewable-power configurations.

Remuneration based mainly on each kWh delivered may not fully recognise the value of capacity and flexibility in such configurations. Competitive procurement, capacity-based remuneration or requirements for defined delivery profiles can provide alternative approaches. The technical concept of Firm PV Power and the underlying Task 16 analysis are discussed in Chapter 7.

GRID INTEGRATION, FLEXIBILITY AND STORAGE POLICY / continued

Dynamic export limits perform a similar function for distributed PV. Rather than imposing one fixed export cap, network operators can vary the permitted export according to local grid conditions.

Smart inverters and advanced metering support these approaches by allowing network operators to monitor and control distributed generation more precisely.

Available network capacity became a growing constraint on PV deployment in several markets during 2025.

A range of policy responses have been applied. Australia continued investment in transmission and Renewable Energy Zones while developers faced lengthy connection procedures and technical requirements. In China, revised distributed-PV rules issued in January 2025 required grid operators to publish available connection capacity and establish warning mechanisms where distribution networks are becoming saturated, while new projects must be capable of being monitored and controlled by the grid operator. In Germany, legislation adopted in February 2025 strengthened incentives to limit injections during periods of excess generation, including restrictions on support during negative-price periods and temporary feed-in limits for some systems without suitable control equipment.

In France, the TURPE 7 network tariff framework entered into force in August 2025, increasing resources for grid investment, introducing stronger incentives to reduce connection delays and encouraging greater use of flexibility. In Spain, renewable generators were enabled from 2025 to provide dynamic voltage-control services, with participating plants receiving priority in dispatch, while technical curtailment increased as renewable capacity expanded. Italy's 2025 transmission development plan increased planned grid investment and introduced a territorial approach to connection planning intended to address the large volume of renewable connection requests and so-called virtual grid saturation. Regional grid constraints continued to affect project development in parts of Norway, while increased generator grid charges in Slovakia from January 2025 provide another example of network costs influencing PV project economics.

As PV equipment costs decline, the availability and cost of grid capacity represented a larger share of project development constraints in some markets. This creates a growing interaction between renewable-energy policy and electricity-network regulation. Deployment targets cannot be implemented efficiently if transmission and distribution planning do not evolve at a similar pace.

NEGATIVE PRICES AND CURTAILMENT

During 2025, negative wholesale electricity prices and curtailment affected PV revenues in several high-renewable electricity systems. Negative prices can occur when available generation exceeds demand and inflexible generators or subsidised generators continue producing. High PV output during periods of low demand can contribute to these conditions, particularly in spring and summer.

In Germany, amendments to the Energy Industry Act and EEG entered into force in February 2025[1] to address temporary generation surpluses. For affected PV systems commissioned from that date, state-supported remuneration is suspended during periods of negative wholesale electricity prices; the framework also expands control requirements and facilitates direct marketing of smaller PV systems.

The mechanism increases the financial incentive to self-consume, store or shift electricity use. It also reduces the extent to which support payments encourage generation during periods when market prices indicate low system value.

During 2025, periods of low or negative wholesale electricity prices were also relevant to PV revenues in Spain, France and the Netherlands. Policy and market responses included greater exposure to market prices, changes in remuneration structures, storage deployment and more active management of injections.

In Australia and Chile, network constraints and regional mismatches between renewable generation and electricity demand also contributed to curtailment. In Brazil, ANEEL opened a Public Consultation in February to refine procedures for calculating and paying compensation for curtailment from centrally dispatched PV plants. Transitional calculation rules were published by CCEE in March 2025 while the regulatory process continued.

The treatment of curtailed generation affects investment risk and can benefit from policies for an equitable management of lost revenue. If generators are compensated for all curtailment, the cost may be transferred to consumers or network users. If generators bear all curtailment risk, project financing costs can increase.

Transparency is important. Developers and lenders need information on the volume, location and cause of curtailment and compensation rules. For distributed PV, inverter-based voltage or export controls can affect some customers more frequently than others. Clear curtailment protocols, publication of available network capacity and consistent reporting can reduce uncertainty and facilitate investment.

Policy responses applied or developed during 2025 included price signals, dynamic export management, smart-meter and inverter requirements, flexible demand, batteries, network reinforcement and participation in balancing or ancillary-services markets.

Demand flexibility is increasingly relevant because shifting consumption towards solar-generation hours can increase the value of PV without requiring all surplus electricity to be stored. Industrial loads, electric-vehicle charging, water heating, heat pumps and other flexible demand can all contribute to PV integration. The interaction between PV and these sectors is discussed in Chapter 7.

[1] https://www.bundesregierung.de/breg-de/aktuelles/energiewende-2320072

GRID INTEGRATION, FLEXIBILITY AND STORAGE POLICY / continued

STORAGE AS A PV POLICY TOOL

Storage is increasingly treated as a policy tool for managing the consequences of higher PV penetration rather than as a stand-alone technology. Depending on the market, policy can use storage to increase self-consumption, reduce network congestion, shift generation towards periods of higher demand, provide balancing and grid-support services, or improve security of supply.

One policy choice is to reduce the cost of distributed storage where rooftop PV is already widespread. This can increase the share of solar electricity consumed locally and reduce exports during low-value midday periods. Australia's Cheaper Home Batteries Program, launched in July 2025, illustrates this approach. Similar objectives are reflected in parts of Europe, where distributed storage is developing alongside self-consumption, time-varying electricity prices and lower remuneration for surplus PV generation.

A second approach is to procure storage together with renewable generation, so that public procurement specifies characteristics of electricity supply rather than renewable capacity alone. This was increasingly visible in India during 2025, where solar-plus-storage and hybrid tenders required projects to provide electricity during defined periods or with specified storage capacity. Germany's innovation auctions provide another example of procurement favouring combinations of solar and storage.

Policy can also support large batteries as system infrastructure. Where conventional generators retire and variable renewable generation increases, batteries can provide frequency response, balancing, system strength and capacity during evening demand periods. The rapid development of utility-scale batteries in Australia illustrates this pathway: the Capacity Investment Scheme provides long-term revenue support for dispatchable capacity, while network and market reforms increasingly allow batteries to provide services previously supplied by conventional generators.

A related policy choice is to remove regulatory barriers to storage participation. Conventional electricity rules can treat a battery as a consumer when charging and a generator when discharging, potentially exposing the same stored electricity to network charges more than once or limiting access to electricity markets. Regulatory work in the European Union and Brazil during 2025 illustrates the increasing attention given to grid connection, market participation and network-tariff treatment for storage.

In isolated electricity systems, the policy objective can be different again. Islands have limited opportunities to export surplus renewable generation or import balancing power from neighbouring systems, increasing the value of storage. Policies can therefore promote PV-plus-storage to reduce dependence on imported fuels, provide reserves and maintain system stability. Hawaii illustrates this approach, combining distributed solar and batteries with procurement of larger hybrid renewable and storage projects.

Rapid growth in concentrated electricity demand such as for data centres, that can require very large grid connections in areas where network capacity or firm generation is already constrained is another reason for specific policies. Requiring or encouraging new loads to contribute their own flexibility or dispatchable capacity are being trialled. In Ireland, the 2025 data-centre connection framework linked new connections to the provision of generation and/or storage capacity sufficient to support the requested demand.

Storage can intersect with PV policy in different areas: investment support, renewable-energy tenders, capacity remuneration, electricity-market rules, network tariffs, grid-connection requirements or changes in export remuneration. The right instrument depends on the objective. Where the issue is excessive midday exports, distributed batteries may be encouraged; where evening sufficiency is the concern, procurement may require stored energy or firm delivery; where networks are constrained, storage can provide flexibility; and in isolated systems or around large new loads, it can contribute directly to security of supply.

Policy is increasingly not about whether storage should accompany PV, but which system problem storage is intended to address and how policy should remunerate the corresponding service.

The rapid acceleration of battery deployment in several mature PV markets is also discussed in Chapter 7.

SITING, PERMITTING AND LIFECYCLE POLICY

BUILDINGS AND LOW-CONFLICT SURFACES

Building regulations and support schemes can direct PV deployment towards roofs, façades, car parks and other already developed surfaces, reducing pressure on agricultural and natural land and potential conflict of usage and opposition. Policy approaches range from mandatory solar requirements for new buildings to investment support, differentiated remuneration and building-energy standards that encourage PV to be considered during construction or renovation.

This approach is becoming more explicit in several major markets. In the European Union, the revised Energy Performance of Buildings Directive establishes progressively expanding solar requirements for suitable public, commercial and residential buildings, with obligations extending to new roofed car parks later in the decade. In California, USA, the 2025 building-energy code continued requirements for PV on most new buildings and linked these increasingly with battery storage, while allowing carports and covered parking to contribute to the required solar area. In Japan, Tokyo's rooftop-solar requirements for qualifying new residential construction became applicable from April 2025.

SITING, PERMITTING AND LIFECYCLE POLICY / continued

Policies are also increasingly targeting surfaces beyond conventional rooftops. France continued to favour deployment on large car parks, while Switzerland introduced a dedicated bonus in 2025 for PV systems installed above qualifying permanent car parks. Japan also maintained support for solar carports, and local programmes in China promoted PV on industrial and public buildings, transport infrastructure and parking structures, including combinations of PV, storage and electric-vehicle charging.

BIPV remains a more specialised segment but continues to receive targeted policy support where PV can replace conventional building materials or where architectural, planning or heritage requirements make conventional systems less suitable. In China, national policy during 2025 promoted closer integration of PV into roofs and façades and advanced standards for BIPV products and systems. Japan continued support for wall- and window-integrated PV, while targeted incentives also remained in place in Belgium and Austria.

Plug-in or “plug-and-play” PV is also emerging as a means of using balconies, terraces and other small building surfaces, particularly for tenants and apartment residents without access to a suitable roof. Regulatory approaches remain uneven: Belgium authorised compliant plug-in systems in April 2025, while Utah, USA, exempted systems of up to 1.2 kW from utility approval and interconnection agreements, although the technical requirements limit the availability of compliant products. Such systems are already permitted under specific installation and safety guidelines in Korea and France while the UK launched a consultation in 2026 on regulatory changes to allow compliant systems to connect through a standard domestic socket. IEA PVPS is examining national regulations, deployment experience and remaining safety, registration and market barriers to support the development of appropriate frameworks for this emerging segment.

Policy objective may be broader than increasing rooftop PV capacity - building and parking-surface policies can reduce land-use conflicts, place generation close to electricity demand, support electric-vehicle charging and, where storage is included, improve the local use of solar electricity. The balance between mandatory requirements and targeted incentives nevertheless varies according to building type, ownership structure, available surface and local planning conditions.

LAND USE AND SOCIAL ACCEPTANCE

Land-use considerations and conflicts have resulted in more detailed regulation of ground-mounted PV in several markets. Projects facing strong local opposition can experience longer development timelines and higher costs, so clear land-use policy can reduce uncertainty for both communities and developers.

In Japan, the government adopted a package of measures for large-scale solar projects in December 2025. The package included review of environmental-impact-assessment coverage, third-party verification intended to address design-related safety issues, and consideration of ending FIT/FIP support for ground-mounted commercial PV from fiscal year 2027 while prioritising projects designed for coexistence with local communities. In France, agrivoltaic rules applied during 2025 sought to distinguish projects maintaining agricultural functions from projects primarily converting agricultural land to electricity generation. Denmark and Norway also have identified opposition to ground-mounted PV on agricultural or natural land during 2025.

As ground-mounted PV deployment expands, policy is increasingly concerned not only with whether projects can be built, but with where they are located and what functions the land must retain. Land availability, population density, agricultural value, environmental constraints, grid access and local planning rules vary substantially between markets, leading to different approaches to project eligibility, environmental assessment and local participation.

Agrivoltaics has become a policy category in several countries (Italy, France, Germany and several other markets) because it combines agricultural production and PV on the same land. Regulatory frameworks increasingly define minimum agricultural activity, crop protection or land-use requirements to distinguish genuine dual use from conventional ground-mounted PV.

Floating PV can reduce competition for land, but it raises separate questions concerning water ownership, environmental impacts and competing uses of reservoirs. Spain, for example, limits floating-PV coverage of federally managed reservoirs according to their ecological condition, while Germany restricts eligible projects to artificial or heavily modified water bodies. In India, states including Odisha and Kerala have developed specific procedures for identifying suitable water surfaces and protecting other reservoir uses.

Brownfields, former industrial or military land, landfills and transport infrastructure are increasingly prioritised in some markets because they reduce conflict with agriculture and natural ecosystems. France, Germany and the USA all have planning, procurement or incentive frameworks that favour previously developed or disturbed sites.

Citizen investment, local benefit-sharing and Indigenous or First Nations participation have also been incorporated into renewable-energy frameworks in Australia, Canada, the USA and parts of Europe. These mechanisms generally define how local communities participate in project ownership, consultation or economic benefits.

PERMITTING AND ADMINISTRATIVE REFORM

As technology costs have declined, permitting and administrative procedures have become a separate constraint from project economics and grid access. A financially viable project may still be delayed by land-use approvals, environmental assessment, multiple or fragmented administrative authorities or unclear responsibilities, while a fully permitted project may subsequently face a separate grid-connection constraint. Policy responses therefore increasingly distinguish between measures that improve project economics, measures that accelerate or clarify permitting, and measures that expand or manage network capacity.

Approaches to permitting reform include single contact points, electronic applications, statutory decision periods, standardised procedures for small rooftop systems and the designation of areas where renewable projects can be assessed more rapidly. In the European Union, the revised Renewable Energy Directive requires electronic permit-granting procedures from November 2025 and provides for renewable acceleration areas, with shorter permitting timelines and priority given to suitable artificial and built surfaces such as rooftops, parking areas, transport infrastructure, industrial sites and degraded land.

SITING, PERMITTING AND LIFECYCLE POLICY / continued

In the USA, automated tools such as SolarAPP+ illustrate a different approach for standardised residential solar and storage projects by allowing local authorities to automate code-compliance review and reduce permitting delays, while federal rules for renewable projects on public lands have also been revised to streamline applications and several jurisdictions have introduced shorter or more centralised approval procedures.

Faster procedures do not necessarily mean weaker environmental or social safeguards. In markets where rapid deployment has generated conflict, policy can instead strengthen siting, safety or environmental requirements while making responsibilities clearer. Japan's December 2025 package for large-scale solar, for example, proposed broader environmental review and additional third-party verification in response to concerns around project siting and safety. Elsewhere, reforms illustrate the need to balance acceleration with meaningful participation: in British Columbia, Canada, some projects can proceed with reduced environmental-assessment or consultation requirements, while in New York, USA, state-level approval can override local siting restrictions in defined circumstances. At EU level, permitting guidance adopted in 2024 paired faster procedures with recommendations to involve citizens, local authorities and societal stakeholders from policy development and spatial planning through project development and operation. Permitting policy may seek to reduce avoidable administrative delays while identifying unsuitable projects earlier and providing more predictable rules for developers, authorities and local communities, and ensure that consultation occurs early enough to influence siting, project design and local arrangements.

CIRCULARITY, REUSE AND END-OF-LIFE POLICY

As the installed PV capacity grows and earlier systems reach replacement or repowering, policy increasingly has to address equipment at the end of its first operating life. The policy questions extend beyond waste treatment to collection, financing, testing, reuse, repair, recycling and product design. Extended producer responsibility can transfer part of future collection and treatment costs to manufacturers and importers, while decommissioning requirements can oblige project owners to plan and finance equipment removal. Clear rules for testing, traceability and second-life use are also relevant where functioning modules are reused domestically or exported.

The European Union already includes PV modules within its waste electrical and electronic equipment framework, under which producers are responsible for financing collection and treatment for modules placed on the market from August 2012. Policy development is also moving further upstream. During 2025, European work on PV product policy advanced methods for assessing module carbon footprints and other product characteristics as part of the wider development of sustainability and eco-design requirements. In Japan, a government working group concluded in March 2025 that a more structured recycling framework would be required ahead of the larger volumes of PV waste expected from the 2030s, with continuing discussion over the allocation of collection, recycling and financing responsibilities.

Circularity policy can therefore influence PV deployment well before modules become waste. Requirements concerning durability, material information, recyclability, carbon footprint or end-of-life financing can affect product design, procurement and market access. Clear reuse rules can also help distinguish functioning second-life modules from waste, avoiding premature disposal while maintaining safety and performance requirements. As module prices remain low, the value of recovered materials may not by itself be sufficient to finance collection and recycling, increasing the role of regulatory frameworks in establishing viable treatment systems and recycling capacity.

For ground-mounted projects, end-of-life policy can extend beyond module recycling to the site itself. In the USA, decommissioning plans and financial guarantees are required for solar projects in several federal, state and local permitting frameworks, including requirements to restore agricultural land. In the UK, planning policy provides for removal of solar installations and restoration of the land after project closure, while New South Wales, Australia, includes decommissioning and rehabilitation requirements within its large-scale solar planning framework. Such provisions seek to ensure that future removal and restoration costs do not fall on landowners or public authorities.

The emerging policy approach is increasingly lifecycle-based: responsibilities are being considered for the manufacture and installation of PV equipment, as well as its operation, reuse, decommissioning and final treatment. PV policy is broadening to cover managing the long-term material and land-use consequences of a progressively larger installed capacity.

AGRICULTURAL AND PRODUCTIVE USES OF PV

PV can support electricity uses outside conventional grid supply. Solar-powered irrigation combines energy, agricultural and water policy and continued to be supported through dedicated programmes during 2025.

In India, the PM-KUSUM programme continued during 2025 to support the use of solar energy in agriculture. It provides support for small decentralised solar power plants, stand-alone solar-powered irrigation pumps, and the conversion of existing grid-connected agricultural pumps and electricity supply lines to solar power. The programme was scheduled to run until March 2026.

Solarisation can reduce diesel use and electricity purchases and, where export arrangements are available, allow agricultural consumers to sell electricity not required for pumping. The programme illustrates the interaction between PV policy and agricultural energy subsidies. In many parts of India, agricultural electricity has historically been subsidised or supplied under specific tariff structures. Solarisation can reduce utility subsidy requirements if programme design aligns incentives appropriately.

Lower pumping costs can increase groundwater abstraction beyond sustainable and conflict-free levels, requiring coordination between solar support, agricultural policy and water management. Allowing farmers to sell unused electricity can encourage reduced pumping, linking renewable-energy deployment with water conservation.

Solar pumping can reduce dependence on diesel in agricultural areas without reliable grid access. However, financing remains a barrier because the initial cost of pumps and PV systems can be high relative to farm incomes. Concessional finance, results-based financing, leasing and pay-as-you-go models can therefore influence uptake.

Productive uses of distributed or stand-alone PV were also part of electricity-access programmes in Africa. Mini-grids and stand-alone systems supported electricity supply for farms, small enterprises, health facilities, irrigation, refrigeration and agricultural processing.

Mission 300, launched in January 2025, combined electricity-access targets with grid expansion, distributed renewable energy and wider power-sector reform. In this context, PV policy addresses household electricity access and electricity use for productive activities. The economics of productive-use PV differ from those of household lighting systems. Irrigation, refrigeration and processing equipment require larger loads and can generate income, making financing and business-model design central components of policy.

In many African countries access to finance, regulatory frameworks, utility performance and local infrastructure remained principal determinants of PV deployment. The policy context varies between grid-connected and off-grid agricultural applications -in areas where the grid is available but unreliable, PV and batteries can provide backup and reduce electricity costs. In remote areas, stand-alone systems or mini-grids may provide the first reliable electricity supply.

INDUSTRIAL, MANUFACTURING AND TRADE POLICIES

PV manufacturing remained highly concentrated, and the manufacturing expansion of preceding years let to a lasting overcapacity situation that triggered unsustainable prices along the PV value chain. A few governments outside China continued to pursue domestic manufacturing capacity with ambition to reduce dependence on concentrated supply chains.

During 2025, policy instruments included production tax credits, capital subsidies, approved-manufacturer lists, local-content requirements, procurement criteria, resilience requirements, import tariffs and restrictions linked to supplier ownership or origin.

FROM MANUFACTURING SUPPORT TO MARKET ACCESS

The policy approaches of the principal manufacturing markets differed during 2025. Manufacturing incentives, deployment support and trade measures operated under different conditions and timelines across the manufacturing countries.

In China, manufacturing overcapacity and low product prices increased pressure on manufacturers. Policy discussions addressed production quality, technological upgrading, competition and industry consolidation rather than further expansion of manufacturing capacity alone. The Chinese manufacturing sector remains vertically integrated across most of the PV value chain, including polysilicon, wafers, cells and modules. This scale has contributed to low global PV prices but also to periods of oversupply and to negative margins. Industrial policy addresses market order, technology quality and, indirectly, consolidation. Measures affecting project deployment and renewable electricity pricing also influenced domestic demand for manufactured products.

In the USA, the Inflation Reduction Act continued to support domestic manufacturing during 2025, while federal legislation enacted in July modified deployment incentives and introduced additional supply-chain and entity restrictions, with the extension of foreign entity of concerns (renamed Prohibited Foreign Entity (PFE) restrictions to additional clean energy tax credits. Industrial policy combines production incentives with trade restrictions and sourcing conditions with the goal of supporting domestic manufacturing but impacts project costs and supply availability. In terms of trade restrictions and sourcing conditions, antidumping (AD) and countervailing duty (CVD) investigations were initiated in August 2025 on solar imports from India, Indonesia and Laos. This follows earlier ruling AD/CVD orders on other South-East Asian countries. The 2025 changes increased uncertainty for developers and manufacturers, temporarily slowing down market deployment and increasing the attractiveness of domestic manufacturing investments.

In India, implementation of the Production Linked Incentive programme continued during 2025, while the Approved List of Models and Manufacturers framework extended further upstream. The first ALMM List-II for solar cells was issued in July 2025, extending the approved-manufacturer framework upstream from modules to cells. The policy continued the push from module assembly towards greater domestic production of cells and other upstream components.

INDUSTRIAL, MANUFACTURING AND TRADE POLICIES / continued

The ALMM framework illustrates how industrial policy can operate through market access, as manufacturers must meet eligibility requirements for equipment to be used in specified projects. Domestic manufacturing policy in India is directly linked to public procurement and deployment programmes.

Australia used a different industrial-policy approach in a market that has historically relied heavily on imported PV equipment. The AUD 1 billion (approximately 700 million USD) Solar Sunshot programme, launched in 2024 and continued through additional funding rounds in 2025, supports manufacturing and innovation across the domestic PV supply chain. The programme is part of the Future Made in Australia agenda to establish manufacturing capability, not a specific policy to regulate access to an already large domestic manufacturing base.

In the European Union, implementation of the Net-Zero Industry Act advanced during 2025. Commission Implementing Regulation (EU) 2025/1176 (May 2025) specified pre-qualification and award criteria for renewable-energy auctions, including responsible business conduct, cybersecurity, project-delivery capability, sustainability and resilience.

Resilience and sustainability criteria increasingly entered renewable procurement. In Italy, renewable procurement during 2025 incorporated one of the strictest versions for equipment-origin and resilience criteria – and the procurement phase was oversubscribed.

The European approach relies less on direct domestic-content requirements and more on procurement criteria, sustainability and resilience objectives, reflecting the constraints of European trade and competition frameworks while still seeking to increase regional manufacturing capacity. The implementation of resilience criteria also means that industrial policy can affect tender outcomes even where imported equipment remains cheaper.

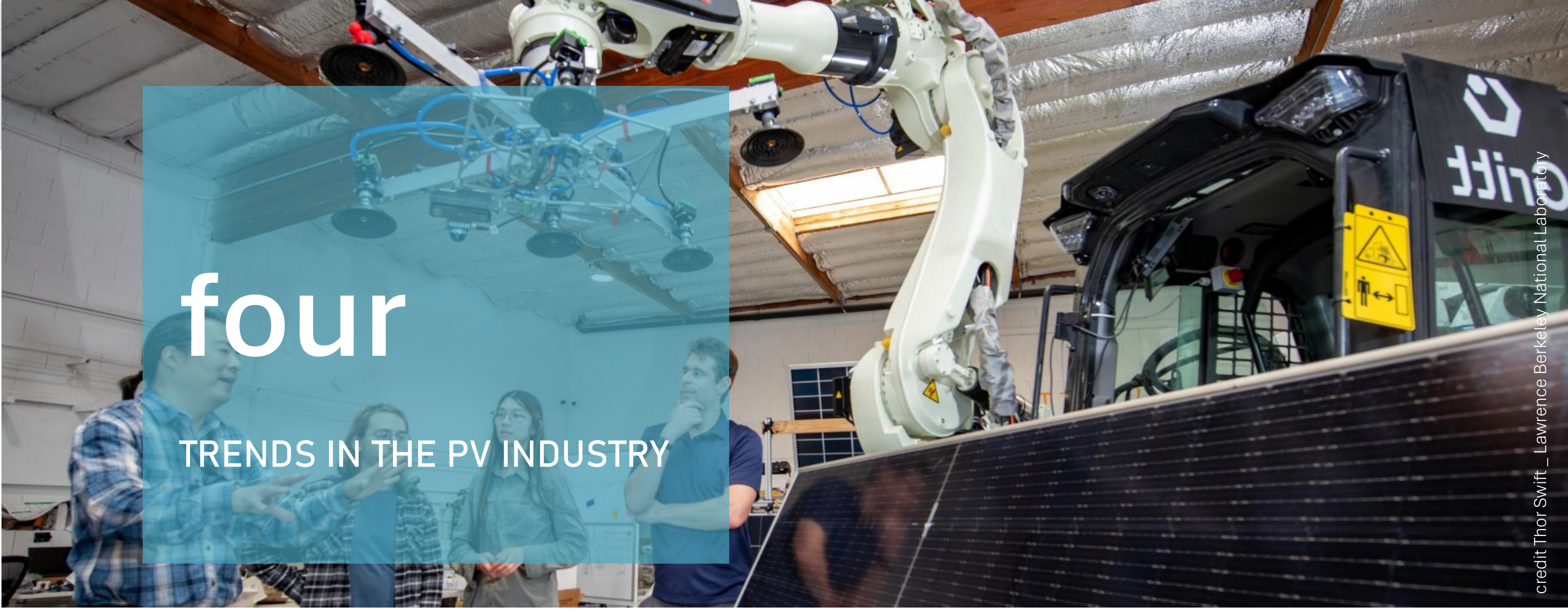
During 2025, module assembly and manufacturing activity also expanded in several African countries, including South Africa, Morocco, Nigeria, Egypt and Ethiopia. These initiatives were associated with employment creation, industrial development, energy security and, in some cases, access to export markets. Most of these facilities remained dependent on imported upstream components, particularly solar cells, and primarily concerned module assembly and downstream manufacturing capacity rather than a vertically integrated regional PV supply chain.

The scale and structure of African manufacturing varies considerably by country. South Africa has an existing industrial base and domestic renewable procurement market. Morocco combines domestic renewable deployment with industrial and export ambitions. Egypt, Nigeria and Ethiopia have pursued different forms of local assembly and industrial development. The economics of these plants often depend strongly on domestic market size (to the exception of Ethiopia's PV manufacturing, which mainly targets exports), access to imported cells and components, financing, electricity costs and trade policy.

Industrial policy also affects other emerging manufacturing markets. Türkiye, Saudi Arabia and other countries have used local-content requirements, industrial zones or procurement conditions to encourage domestic production.

Taken together, these developments show that in 2025 industrial policy increasingly addressed which products qualify for incentives, procurement advantages or access to domestic markets, a change from earlier industrial policy, which focused more directly on subsidising factory investment. These market-access instruments can create demand for domestic manufacturing without explicitly guaranteeing production volumes, but they can also increase project costs if compliant products are more expensive or less available, and the interaction between industrial and deployment policy requires balancing supply-chain objectives with electricity-cost and deployment targets.

Trade measures are another component of this interaction. Import duties, anti-dumping measures and customs restrictions can alter module prices and sourcing decisions; these measures can also support domestic manufacturers while increasing costs for project developers. The effect on total deployment will depends on the relative importance of equipment costs, financing, permitting and grid constraints.



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TRENDS IN THE PV INDUSTRY

credit Thor Swift _ Lawrence Berkeley National Laboratory

TRENDS IN THE PV INDUSTRY

This chapter provides an overview of the upstream and downstream sectors of the PV industry and highlights developments during 2025 and the first half of 2026. The first part provides manufacturing activities of the upstream sector of the PV industry from feedstocks (metallurgical grade silicon, (MG-Si), polysilicon, ingots, blocks/bricks and wafers) to PV cells and modules. The second part provides activities of the balance-of-system (BOS) sector that include components (inverters, mounting structures, charge regulators, storage batteries, and other equipment), and project development and operation and maintenance (O&M).

In 2025, global production of photovoltaic (PV) modules reached 722 GW, a 0.6% decrease from the previous year. This represents a significant slowdown compared to the 61.7% year-on-year growth recorded between 2022 and 2023.

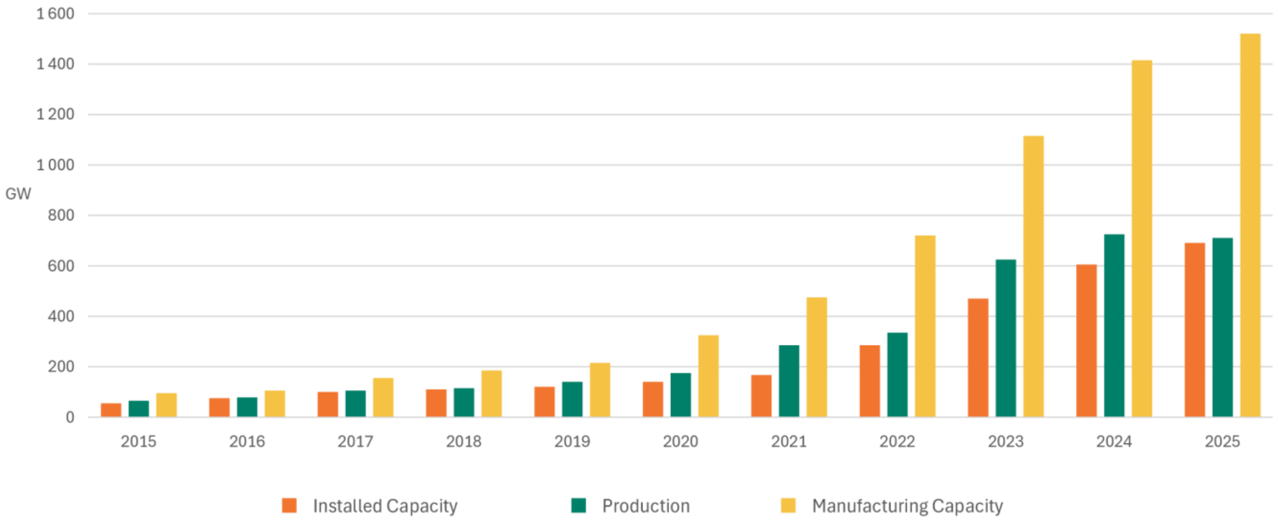
Among total PV module production, 94% was manufactured in IEA PVPS member countries, with China continuing to play an important role. China accounted for 79% of global PV module production. As manufacturing capacity expanded in India and the USA, China's share declined from 86% in 2024. Global PV module manufacturing capacity is estimated to have reached 1 531 GW/year, of which 71% was located in China. Beyond module manufacturing, China also retains a leading position in the inverter market. However, local-content requirements and cybersecurity-related regulations are expected to influence future deployment trends in the inverter sector.

As shown in Figures 4.1 and 4.2, manufacturing capacity (in GW) continued to exceed demand across the entire PV supply chain in 2025. As a result, PV product prices remained at low levels despite some fluctuations.

In China, a major PV manufacturing country, efforts have been intensified to address the challenging competitive environment (involution) by curbing overcapacity. The Chinese government revised the national standards (GB – effective January 2027) for PV manufacturing products in order to curb disorderly expansion in the industry. Manufacturers that are unable to supply products meeting the requirements specified in the GB standards, including energy consumption and conversion efficiency, may be phased out.

The trend toward manufacturing PV products in countries and regions where demand exists is expected to continue, reflecting the

FIGURE 4.1: YEARLY PV INSTALLATION, PV PRODUCTION AND PRODUCTION CAPACITY 2015-2025

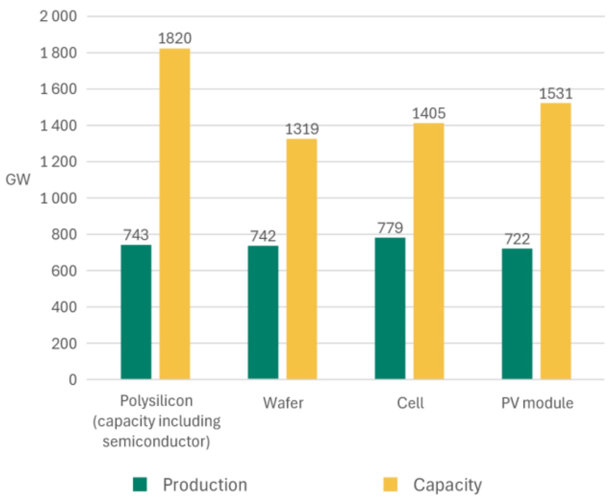


SOURCE: IEA PVPS, RTS CORPORATION

contribution of PV products to energy security and the energy transition.

In the USA and India, where manufacturing capacity has expanded, solar cell manufacturing capacity is expected to increase further in addition to PV module manufacturing. In the USA, the PV supply chain is being restructured through import tariffs and policy measures that provide preferential treatment for domestically manufactured products. Domestic wafer manufacturing capacity remains insufficient to meet domestic demand in the short term but is significant for its presence. In India, the development of the domestic PV industry continues to be supported by protectionist measures, including the Basic Customs Duty (BCD), the Production-Linked Incentive (PLI) scheme, and the Approved List of Models and Manufacturers (ALMM). India already possesses PV module manufacturing capacity that substantially exceeds domestic demand. In addition to solar cell manufacturing, plans for wafer and polysilicon manufacturing have also been announced.

FIGURE 4.2: GLOBAL PRODUCTION AMOUNT AND ANNUAL PRODUCTION CAPACITY ALONG THE VALUE CHAIN IN 2025



SOURCE: IEA PVPS, RTS CORPORATION

THE UPSTREAM PV SECTOR

METALLURGICAL-GRADE SILICON

Crystalline silicon (c-Si) solar cells are manufactured from polysilicon, which is produced by refining Metallurgical Grade Silicon (MG-Si) to a high level of purity. Global MG-Si production capacity reached 9.49 million tons/year in 2025, an increase of 6.4% from 8.92 million tons/year in 2024. China accounted for 83% of global production capacity, and the increase in production capacity in 2025 was due to capacity expansion in China. China's MG-Si production capacity reached 7.88 million tons/year in 2025. In terms of the distribution of production capacity, China, Brazil, the USA, Norway, France, Russia, and Germany remained the world's leading producers of industrial silicon. The top ten producing countries accounted for 95.6% of global production capacity.

China was also the world's largest producer of MG-Si, but its production in 2025 declined to 4.06 million tons, down 13.9% year-on-year and significantly lower than in 2024. This was mainly due to the sharp decline in MG-Si prices in the first half of 2025. As profit margins in the industry continued to shrink, many companies incurred losses and were forced to adjust their production pace through shutdowns and maintenance activities. In particular, the polysilicon industry for solar cells entered a period of capacity adjustment, resulting in increased inventories and constrained production. Historically, MG-Si production in China has been concentrated in the Xinjiang Uygur Autonomous Region, but in recent years, there has been a trend toward geographical diversification. In 2025, new production facilities commenced operation in Qinghai Province and the Inner Mongolia Autonomous Region.

POLYSILICON

At the end of 2025, global polysilicon production capacity, including semiconductor-grade polysilicon, reached 3.64 million tons/year, an increase of 11.7% from 3.26 million tons/year in 2024. Global polysilicon production in 2025, including semiconductor-grade polysilicon, amounted to 1.485 million tons, a decrease of 24% from 1.957 million tons in the previous year. Polysilicon production for solar cells was estimated at approximately 1.41 million tons in 2025. With regard to manufacturing processes, the majority of polysilicon for solar cells continued to be produced using the Siemens process. In 2025, polysilicon production for solar cells using the Siemens process amounted to 1.16 million tons (82%), while granular polysilicon production using the Fluidized Bed Reactor (FBR) process amounted to 269 000 tons (18%). Figure 4.3 shows global polysilicon production, and Figure 4.4 shows the share of polysilicon production by country.

China produced 1.37 million tons of polysilicon in 2025, accounting for 92% of global production. However, this represented a decline of approximately 25% compared with the 1.82 million tons produced in 2024. This was due to production being curtailed as a result of oversupply of polysilicon in the market. According to the China Photovoltaic Industry Association (CPIA), 16 companies produced polysilicon in China in 2025, and the average operating rate was 39.3%. Among the IEA PVPS member countries other than China, production was also reported in Germany, the USA, Malaysia, Korea, and Japan. However, polysilicon production in Korea and Japan is limited to semiconductor applications.

Despite the imbalance between supply and demand, global polysilicon production capacity is expected to continue expanding. If currently announced projects proceed as planned, global production capacity could increase from 3.64 million tons/year in 2025 to 5.76 million tons/year in 2026. New polysilicon production initiatives have been reported in India, Oman, Morocco, the USA, Europe, and Australia, supported by industrial policies aimed at strengthening domestic PV supply chains. In India, several companies have announced plans for vertically integrated projects covering the production of polysilicon through the manufacturing of PV modules. In Oman, construction progressed on the Middle East’s first polysilicon manufacturing facility of this scale, with an annual production capacity of 100,000 tonnes. In Morocco, the government announced the construction of a polysilicon plant with a production capacity of 30 000 tons/year in November 2025. In Europe, Resilicon, a Dutch start-up company, announced plans to produce polysilicon using renewable energy, which would be the first such production facility in Europe. In the USA, Highland Materials announced plans to establish a solar-grade polysilicon plant with a production capacity of 16 000 tons/year. In Australia, the Australian Renewable Energy Agency (ARENA) published the

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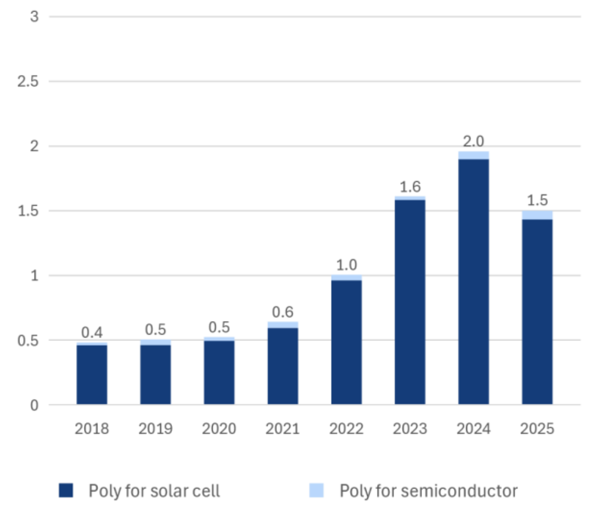
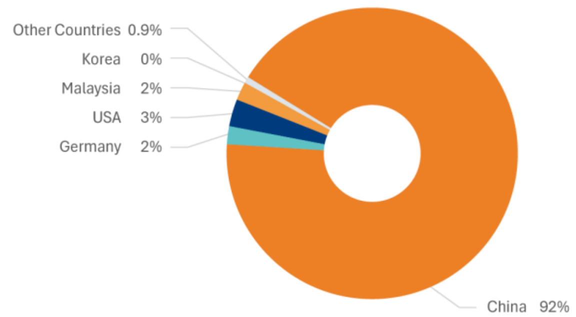
FIGURE 4.3: GLOBAL POLYSILICON PRODUCTION (IN MILLION TONS)



SOURCE: IEA PVPS, RTS CORPORATION

FIGURE 4.4: SHARE OF PV POLYSILICON* PRODUCTION BY COUNTRY IN 2025



* Including polysilicon for semiconductors

SOURCE: IEA PVPS, RTS CORPORATION

Australian Silicon (AusSi) Study, a preliminary feasibility study on establishing a polysilicon plant in Australia.

Polysilicon spot prices in 2025 changed due to China's policies. At the beginning of January 2025, the spot price was USD 4.83/kg. Thereafter, despite some fluctuations, prices remained in the USD 4/kg range (USD 4.2 - 4.9/kg) through August. From September onward, prices increased as the Chinese government clarified its policy to regulate disorderly price competition in July 2025 and prohibited sales below production cost. Polysilicon spot prices remained in the USD 6/kg range through the end of December 2025, reaching USD 6.5/kg at the end of December.

To address low-price competition, ten Chinese polysilicon producers established the joint venture Beijing Guanghe Qiancheng Technology (Guanghe Qiancheng) on December 9, 2025. The company was reportedly intended to function as an inventory storage platform to alleviate the oversupply of polysilicon, and was expected to play a role in accelerating the phase-out of less advanced production capacity facing long-term losses and increasing debt. However, the State Administration for Market Regulation (SAMR) considered that the company could potentially control the production and sales of polysilicon, allocate market shares according to the ownership stakes of its shareholders, and seek to control prices. As there was a risk that these activities could violate the Anti-Monopoly Law, SAMR requested corrective measures. As a result, the company no longer appears to be fulfilling the role that had been expected of it. Meanwhile, the Chinese government established new national standards as a measure to curb excess production capacity by eliminating low-productivity companies. For polysilicon production, the standards for energy consumption per unit were tightened. The energy consumption levels for polysilicon production were set at 5.0 kgce/kg for tier-1, 5.5 kgce/kg for tier-2, and 6.3 kgce/kg for tier-3 (kgce: kilogram of standard coal equivalent), compared with the current standards of 7.5 kgce/kg, 8.5 kgce/kg, and 10.5 kgce/kg, respectively. As a result, less productive production facilities are expected to be phased out.

Specific silicon consumption in 2025 is estimated to have declined from 2.1 g/W in 2024 to 2.0 g/W. This reduction can be attributed to several factors, including thinner wafers, reduced kerf loss, and improvements in conversion efficiency. According to the 17th edition of the International Technology Roadmap for Photovoltaics (ITRPV), specific silicon consumption of n-type TOPCon cells is projected to decline further to 1.27–1.41 g/W by 2035 to 2036.

INGOTS & WAFERS

Global wafer production capacity at the end of 2025 is estimated at 1 319 GW/year, a decrease of 5.4% from 1 384 GW/year in the previous year. Wafer production also declined, falling from 804 GW in 2024 to 742 GW in 2025, a year-on-year decrease of approximately 7.6%. Figure 4.5 shows recent trends in global wafer production.

As shown in Figure 4.6, China maintained its dominant position in wafer manufacturing within the PV value chain. In 2025, China produced 719.3 GW of wafers, accounting for approximately 96.6% of global wafer production, supported by a production capacity of 1 271 GW/year. Similar to the polysilicon sector, wafer production in China declined year-on-year, falling by 7.3% compared with 2024.

In addition to China, wafers were also produced in countries such as Vietnam, Thailand, Malaysia, and Türkiye. These countries and regions have attracted investments from major Chinese manufacturers seeking to establish overseas production bases in order to circumvent tariffs on Chinese products imported into the USA. Nonetheless, production volumes in these countries remain relatively limited in scale. In addition to these countries, wafer manufacturing is planned in several countries seeking to establish domestic PV supply chains. In India, wafer manufacturing plans are gaining momentum, supported by targeted policy measures aimed at developing a domestic PV industry. In 2025, wafer manufacturing capacity reached 2.2 GW/year, and further capacity expansion is planned. According to the National Solar Energy Federation of India (NSEFI), c-Si wafer manufacturing capacity is expected to reach 100 GW/year by 2030.

In the USA, Corning commenced operations at a crystalline silicon ingot and wafer manufacturing facility in the third quarter of 2025. Additionally, Qcells, a subsidiary of Hanwha Solutions (Korea), is establishing a vertically integrated plant in Cartersville, Georgia. The

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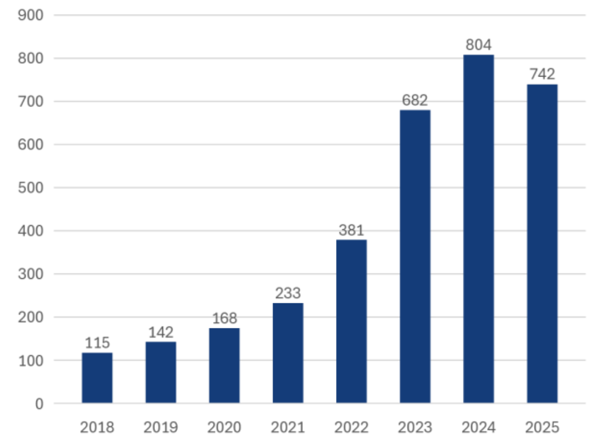
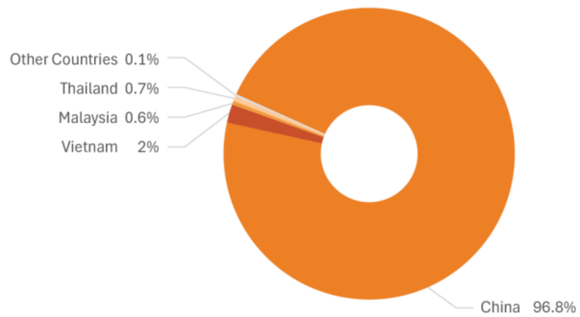
FIGURE 4.5: GLOBAL WAFER PRODUCTION (IN GW)



SOURCE: IEA PVPS, RTS CORPORATION

FIGURE 4.6: SHARE OF PV WAFER PRODUCTION BY COUNTRY IN 2025



SOURCE: IEA PVPS, RTS CORPORATION

facility will have a production capacity of 3.3 GW/year and will include the manufacturing of ingots, wafers, solar cells, and modules.

In addition to these countries, new plans for wafer manufacturing have been reported in Indonesia, Laos, Spain, and Australia. In Spain, Sunwafe is planning to establish a wafer manufacturing facility with a production capacity of 20 GW/year. In Australia, Stellar PV plans to construct a wafer manufacturing plant in Queensland with a production capacity of 2 GW/year.

In 2025, nearly all c-Si wafers used in solar cell manufacturing were single-crystalline (sc-Si) silicon wafers. Approximately 82% of these were n-type wafers. The share of n-type products is expected to continue increasing, while the share of p-type products used for PERC solar cells is projected to decline to 1.5% in the 2030s. For p-type wafers, the market for space application is expected to expand as p-type cells have superior radiation resistance in space.

The pace of wafer thinning has slowed compared with previous years. For p-type sc-Si wafers, there is little remaining incentive for further thickness reduction, and the average wafer thickness has remained at approximately 150 µm. The average thickness of n-type silicon wafers used for TOPCon cells was 130 µm, while silicon wafers used for heterojunction (HJT) cells averaged 110 µm, both broadly unchanged from the previous year. Some manufacturers of n-type solar cells are planning further reductions in wafer thickness in the coming years.

Wafer size and format are also evolving. Rectangular wafers have become the dominant product in the market. According to the China Photovoltaic Industry Development Roadmap (2025-2026) published by the China Photovoltaic Industry Association (CPIA), a variety of wafer sizes, including wafers of 166 mm or smaller, are available in the market. Since 2023, the market share of rectangular wafers has expanded rapidly, reaching 48% in 2025. The market share of M10 wafers (182 mm × 182 mm) was approximately 11%, while G10 wafers (182 mm × 182 mm) accounted for around 19% and G12 wafers (210 mm × 210 mm) for approximately 21%. In contrast, the market share of M6 (166 mm × 166 mm) wafers fell to below 1%.

Wafer price trends varied somewhat depending on wafer format and size. However, wafer price trends continued to be influenced primarily by persistent overcapacity and cell demand. In January 2025, the price of an n-type sc-Si wafer with dimensions of 182.2 mm × 183.75 mm (G10L format, 130 µm thickness) was USD 0.142 per piece. The price increased slightly to USD 0.147 per piece in March 2025. Subsequently, continued oversupply and elevated inventory levels led to a decline in prices, which fell to USD 0.105 per piece by July. In addition, government tightening measures contributed to a recovery in wafer prices, which reached USD 0.168 per piece in October 2025. However, prices declined again toward the end of 2025, falling to around USD 0.14 per piece.

Driven by continued cost-reduction pressure, diamond wire saws used for silicon wafer slicing are increasingly being replaced by tungsten wire. According to the CPIA, tungsten wire had replaced diamond wire in more than 90% of wafer slicing applications by 2025. At the same time, the wire diameter was reduced to 29 µm.

Similar to polysilicon, the Chinese government also revised the national standards for wafer manufacturing. Under the revised standards, energy consumption for c-Si wafer production is set at 5 900 kgce per million wafers for Tier 1 facilities, 7 005 kgce per million wafers for Tier 2 facilities, and 9 525 kgce per million wafers for Tier 3 facilities. The industry-average energy consumption in 2024 was reported at 9 704 kgce per million wafers. If these standards are strictly applied to domestic production, some production facilities may be phased out.

SOLAR CELLS

Global solar cell manufacturing capacity, including thin-film technologies, is estimated to have reached 1,405 GW/year at the end of 2025. This represents a decrease of approximately 1.5% compared with the global manufacturing capacity of 1,427 GW/year at the end of 2024. Despite the decline in manufacturing capacity, global solar cell production increased by approximately 3.5% year-on-year, reaching 779 GW in 2025. Figure 4.7 shows recent trends in global solar cell production, including thin-film technologies. Compared with the exceptionally strong growth of 62% recorded between 2022 and 2023, the rate of production growth slowed in 2025. The pace of expansion also moderated relative to the 19% growth recorded between 2023 and 2024.

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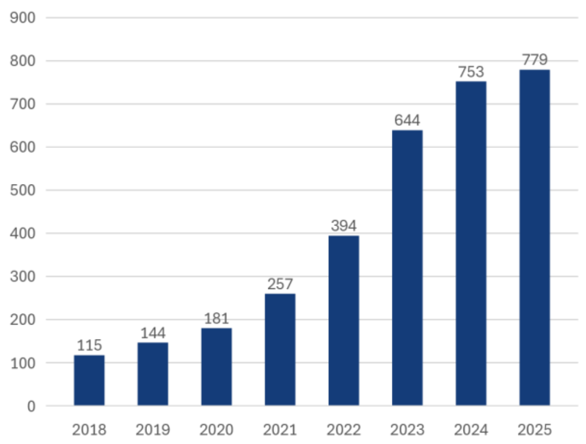
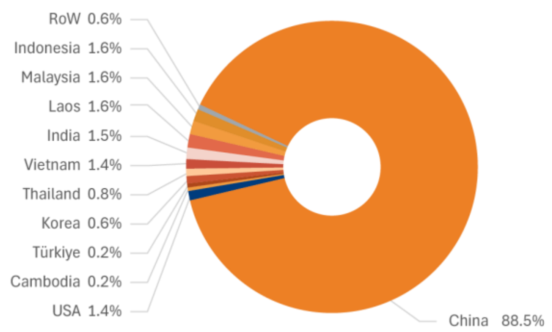
FIGURE 4.7: GLOBAL PRODUCTION AMOUNT OF SOLAR CELL INCLUDING THIN-FILM (IN GW)



SOURCE: IEA PVPS, RTS CORPORATION

FIGURE 4.8: SHARE OF PV CELL PRODUCTION BY MAJOR COUNTRIES IN 2025



SOURCE: IEA PVPS, RTS CORPORATION

Figure 4.8 shows the national shares of global solar cell production. China had a manufacturing capacity of 1 214 GW/year and produced 689 GW in 2025. While the pace of new cell manufacturing capacity expansion in China has slowed, many companies continue to upgrade existing cell production facilities. As shown in Table 4.1, the world's top five companies in terms of production were all Chinese companies. Outside China, solar cell-producing countries include India, Vietnam, Thailand, Malaysia, Laos, and the USA. In Southeast Asia, particularly in Vietnam, Thailand, and Malaysia, solar cell production for the USA market was active, but production volumes have declined following the decision to impose anti-circumvention tariffs. In India, solar cell manufacturing capacity reached 27 GW/year at the end of 2025. In India, the requirement to use solar cells listed under the Approved List of Models and Manufacturers (ALMM) List-II for solar cells began in June 2026. PV systems using net-metering and open-access schemes that commence operation on or after June 1, 2026 are required to use solar cells and modules listed under ALMM Lists I and II. As a result, solar cell production in India is expected to continue increasing in the coming years. In the USA, solar cell manufacturing capacity reached 20 GW/year at the end of 2025, with more than 28 GW/year of additional capacity expected to be added. Current USA production is insufficient to meet demand, and the USA continues to import solar cells, mainly from India and Southeast Asia. However, as anti-circumvention tariffs have come to apply to products from Southeast Asia, solar cell manufacturing has begun in new production locations, including Ethiopia. In addition, major Chinese companies have invested in solar cell production in Egypt and Türkiye.

Additional plans for cell manufacturing have also been announced in Indonesia and several Middle Eastern countries, indicating growing interest in localizing the PV value chain within the region. The dominant solar cell technology shifted from p-type PERC to n-type TOPCon in 2024. TOPCon accounted for approximately 75% of the market in 2025 and is expected to maintain a dominant market position over the next decade. Silicon heterojunction (SHJ/HJT) technology represented around 5% of the market, while back-contact (XBC)-based cells with planar electrodes accounted for approximately 6%. Although the share of p-type technologies continues to decline, p-type cells continue to be used in space applications, where demand is expected to increase in the future. In addition, several manufacturers in the USA are pursuing the production of p-type PERC cells. The reasons cited for this technology choice include higher manufacturing productivity compared with TOPCon technology, the risk of patent infringements and established reliability.

For TOPCon solar cells, laser-assisted firing technologies, including Laser-Induced Firing (LIF) and Laser Enhanced Contact Optimization (LECO), have become widely adopted. These technologies reduced contact resistance between the metal contacts and the silicon wafer, contributing to improvements in cell conversion efficiency. In addition, optimization of Al2Ox and SiNx layers also advanced technologies for improving resistance to ultraviolet-induced degradation. In XBC technologies, the optimization of rear-side interdigitated electrode layouts and finger widths enabled a significant reduction in silver paste consumption. Efforts to reduce metallization costs through copper-plated metallization were also introduced into mass-production processes. In addition, technologies integrating bypass diodes directly into the solar cell were developed to prevent module power loss and hotspot formation. In HJT solar cell technology, the adoption of silver-coated copper paste advanced rapidly and became the mainstream technology for HJT solar cells.

In terms of pricing, n-type TOPCon sc-Si solar cells were priced at USD 0.035/W at the beginning of 2025. Prices increased and reached a peak in March, supported by a surge in demand at the beginning of the year. Subsequently, weakening demand led to a sharp decline in prices. As supply-demand conditions deteriorated further, prices fell below USD 0.030/W by June, and shipment prices from some manufacturers dropped below cash-cost levels. Following the Chinese government's efforts to enforce provisions of the Anti-Unfair Competition Law prohibiting below-cost sales, prices gradually recovered from July onward and reached USD 0.038/W in October. In December, cell prices increased further, supported by a sharp rise in silver prices.

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PV MODULES

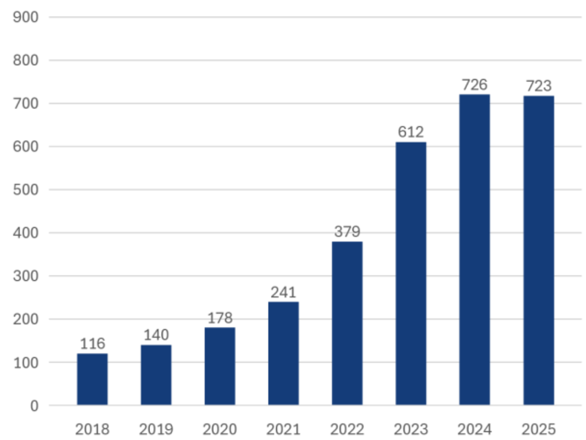
Global PV module manufacturing capacity is estimated to have reached 1 531 GW/year in 2025, representing an increase of approximately 9% from 1 405 GW/year in the previous year. The expansion in manufacturing capacity was driven primarily by the continued development of domestic PV supply chains in **India** and the **USA**. In contrast, global PV module production declined slightly, falling from 726 GW in 2024 to 722 GW in 2025. Table 4.2 shows recent trends in PV module production and manufacturing capacity.

As with other segments of the PV value chain, **China** remained the global leader in PV module production in 2025. The country had a manufacturing capacity of 1 089 GW/year and produced 575 GW of PV modules, representing approximately 79% of global production.

As shown in Table 4.1, the world's five largest PV module manufacturers, in terms of both production volume and shipment volume, were all Chinese companies.

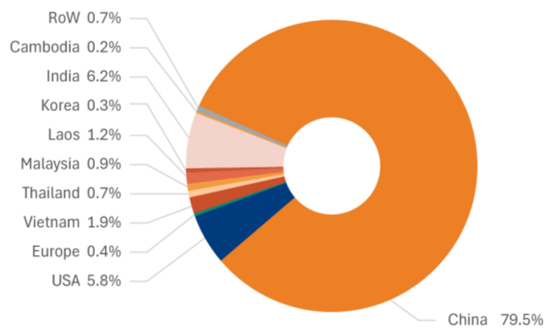
Notable developments were also observed in module manufacturing outside **China**. **India** recorded the largest PV module production volume, reaching 45 GW in 2025, followed by the **USA** with 42 GW. Production in **Vietnam** amounted to approximately 14 GW, while Indonesia and Laos produced 8.36 GW and 8.35 GW, respectively. Module production in **Malaysia** was approximately 7 GW. In addition, PV modules were manufactured in **Canada, Japan, Cambodia, Chinese Taipei, Mexico**, and several European countries, principally **Türkiye**. Figure 4.9 shows global PV module production from 2018 to 2025, while Figure 4.10 shows the share of PV module production by country in 2025.

FIGURE 4.9: GLOBAL PV MODULE PRODUCTION (IN GW)



SOURCE: IEA PVPS, RTS CORPORATION

FIGURE 4.10: SHARE OF PV MODULE PRODUCTION BY COUNTRY IN 2025



SOURCE: IEA PVPS, RTS CORPORATION

TABLE 4.1: GLOBAL TOP FIVE MANUFACTURERS (BRANDS) IN TERMS OF PV CELL/MODULE PRODUCTION AND SHIPMENT VOLUME (2025)

Rank	Solar cell production (GW)		PV module production (GW)		PV module shipment (GW)	
1	Tongwei Solar	102.4	JinkoSolar	83.8	JinkoSolar	86.8
2	JinkoSolar	83.4	LONGi Green Energy Technology	72.6	LONGi Green Energy Technology	86.6
3	Trina Solar	68.8	Trina Solar	69.5	Trina Solar	67.9
4	LONGi Green Energy Technology	59.8	JA Solar Technology	65.8	JA Solar Technology	66.7
5	JA Solar Technology	53.8	Tongwei Solar	44.9	Tongwei Solar	43.3

NOTE: Production volumes are manufacturers' own production, whereas shipment volumes include commissioned production and OEM procurement

SOURCE: RTS CORPORATION

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TABLE 4.2: EVOLUTION OF ACTUAL MODULE PRODUCTION AND PRODUCTION CAPACITIES (MW)

YEAR	ACTUAL PRODUCTION			PRODUCTION CAPACITIES			
	IEA PVPS COUNTRIES	OTHER COUNTRIES	TOTAL	IEA PVPS COUNTRIES	OTHER COUNTRIES	TOTAL	UTILIZATION RATE
1993	52		52	80		80	65%
1994	0		0	0		0	0%
1995	56		56	100		100	56%
1996	0		0	0		0	0%
1997	100		100	200		200	50%
1998	126		126	250		250	50%
1999	169		169	350		350	48%
2000	238		238	400		400	60%
2001	319		319	525		525	61%
2002	482		482	750		750	64%
2003	667		667	950		950	70%
2004	1 160		1 160	1 600		1 600	73%
2005	1 532		1 532	2 500		2 500	61%
2006	2 068		2 068	2 900		2 900	71%
2007	3 778	200	3 978	7 200	500	7 700	52%
2008	6 600	450	7 050	11 700	1 000	12 700	56%
2009	10 511	750	11 261	18 300	2 000	20 300	55%
2010	19 700	1 700	21 400	31 500	3 300	34 800	61%
2011	34 000	2 600	36 600	48 000	4 000	52 000	70%
2012	33 787	2 700	36 487	53 000	5 000	58 000	63%
2013	37 399	2 470	39 869	55 394	5 100	60 494	66%
2014	43 799	2 166	45 965	61 993	5 266	67 259	68%
2015	58 304	4 360	62 664	87 574	6 100	93 674	67%
2016	73 864	4 196	78 060	97 960	6 900	104 860	74%
2017	97 942	7 200	105 142	144 643	10 250	154 893	68%
2018	106 270	9 703	115 973	165 939	17 905	183 844	63%
2019	123 124	17 173	140 297	190 657	28 530	219 187	64%
2020	156 430	23 044	179 474	289 581	37 095	326 676	55%
2021	213 032	29 346	242 378	410 500	71 500	482 000	50%
2022	329 842	48 758	378 600	611 124	105 476	716 600	53%
2023	550 992	61 208	612 200	1 030 500	72 500	1 103 000	56%
2024	686 140	39 760	725 900	1 321 278	84 027	1 405 305	52%
2025	678 624	43 843	722 467	1 442 765	88 322	1 531 087	47%

Note: Although China joined IEA PVPS in 2010, data on China's production volume and production capacities in 2006 onwards are included in the statistics.

Source IEA PVPS & RTS Corporation

Among module-producing countries, the USA and India recorded particularly significant expansions in manufacturing capacity during 2025. By the end of the year, PV module manufacturing capacity had reached 73 GW/year in the USA, up from 42.1 GW/year in 2024, and 191 GW/year in India, compared with 61 GW/year in 2024. In both countries, manufacturing capacity expanded to levels exceeding domestic demand, supported by industrial incentives and policy measures favouring domestically produced products.

In Southeast Asia, PV module production increased in Indonesia and Laos. PV modules manufactured in Vietnam, Thailand, Malaysia, and Cambodia were primarily produced for the USA market. However, USA authorities determined that PV products imported from these four

THE UPSTREAM PV SECTOR / continued

countries were circumventing existing trade duties on Chinese products, and anti-dumping (AD) and countervailing duties (CVD) came into effect on June 6, 2024. As a result, new manufacturing facilities were established in Indonesia and Laos, contributing to increased production in these countries.

Standard PV module prices for industrial applications were traded at around USD 0.078/W in January and February 2025. Prices temporarily increased to USD 0.085/W in March and April, driven by strong demand associated with market-oriented trading policies, before declining again in May. Following the passage of the Anti-Unfair Competition Law at the end of June, including the prohibition of below-cost sales, module prices recovered to around USD 0.08/W from September onward. By the end of the year, module prices were pushed up by rising cell costs resulting from a sharp increase in silver prices, reaching USD 0.085/W in January 2026. Prices subsequently increased further, reaching around USD 0.11/W, but later declined as solar cell prices fell and have remained at around USD 0.10/W since June 2026.

Figure 4.11 shows the distribution of module production by technology type. C-Si modules accounted for approximately 98% of global production in 2025. Thin-film technologies represented the remaining 2%, with most being cadmium telluride (CdTe) modules manufactured by First Solar in the USA. Production volumes of other technologies such as amorphous silicon, CIGS, and organic PV remain small.

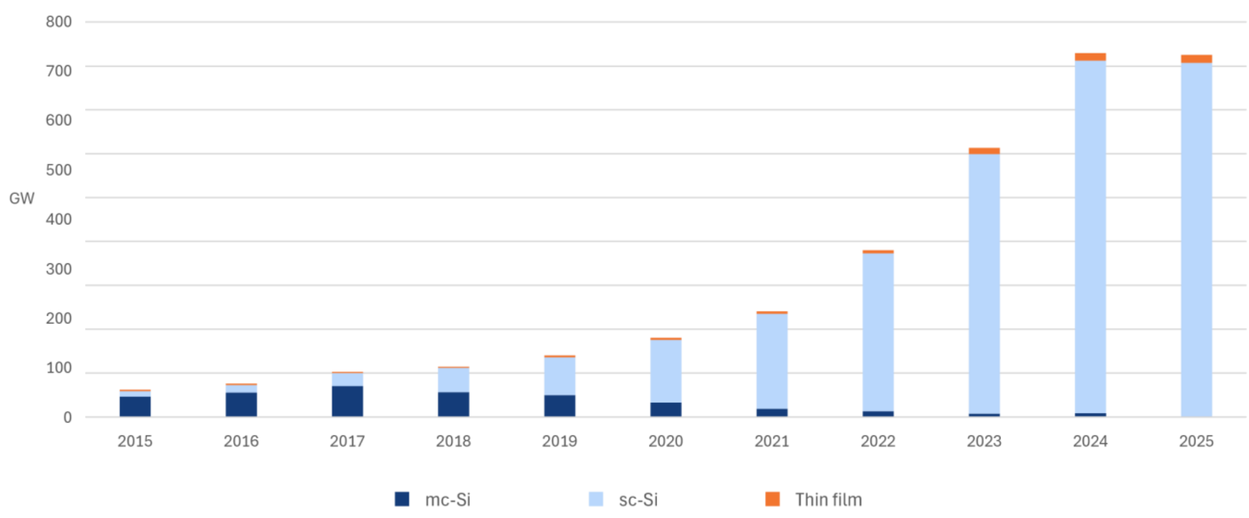
TECHNOLOGY TRENDS

C-Si PV modules continue to achieve higher power outputs through a range of technological innovations. While half-cut cells were previously the dominant configuration, the industry has increasingly adopted one-third-cut and quarter-cut cell designs. Quarter-cut cells can further reduce current and losses, although this approach involves a trade-off in the form of higher manufacturing complexity and laser-cutting costs. To minimize performance losses associated with cell cutting, manufacturers introduced advanced techniques such as non-destructive cutting, which prevents laser-induced damage, and side passivation, which treats the cut edges to prevent efficiency losses. In cell interconnection design, Super Multi-Busbar (SMBB) technology, typically employing 15 to 20 busbars, has become the mainstream solution for TOPCon and heterojunction (HJT) cells, replacing conventional Multi-Busbar (MBB) designs with 15 or fewer busbars. Further efforts to reduce silver consumption led to the adoption of busbar-free technologies, including 0BB (zero busbar) technologies, which use densely arranged fine ribbons instead of conventional busbars. Other technologies, such as SmartWire, Integrated Film Covering (IFC), and dispensing technologies, are also being used to reduce metallization material consumption. Significant progress has been made in technologies aimed at minimizing the spacing between cells. In addition to modules using back-contact cells, new approaches have been developed to significantly reduce optical and electrical losses by eliminating conventional busbars and ribbons and placing conductive seed layers and conductive wires on the cell surface. Other technologies maximise the active area by dividing cells into smaller segments and overlapping them using conductive adhesives, eliminating inter-cell gaps and maximising light-receiving areas.

Double-glass bifacial products continued to dominate the market for module structures in 2025, accounting for approximately 70% of the market, as in 2024. The significant increase in the market share of double-glass (bifacial) modules has made 2.0 mm-thick glass the mainstream configuration. For front glass, coated glass with anti-reflective (AR) properties is widely used due to its superior anti-reflection performance, soiling resistance, and ageing resistance.

In terms of encapsulation materials, CPIA reported that EVA-based encapsulants accounted for 53.4% of the market in 2025. The market share of EPE laminates (co-extruded EVA-POE-EVA composite sheets) continued to increase, rising from 37% in 2024 to 41% in 2025. In heterojunction (HJT) solar cell technology, wavelength-converting encapsulation materials that convert ultraviolet (UV) radiation into blue light have been adopted. These materials improve power conversion efficiency by approximately 1.2% to 1.5% while also mitigating UV-induced degradation.

FIGURE 4.11: PV MODULE PRODUCTION PER TECHNOLOGY



SOURCE: IEA PVPS, RTS CORPORATION

Although efforts to improve the power output of c-Si PV modules through the adoption of various technologies described above are progressing, China is also promoting improvements in product performance through government-led standards. The Chinese government revised the national standards (GB) for PV modules. The standards specify minimum conversion efficiency requirements for TOPCon, heterojunction (HJT), and back-contact technologies, while building-integrated PV (BIPV) and perovskite/silicon tandem solar cells are excluded from the scope of the standards. For example, the conversion efficiency requirements for TOPCon solar cells are set at ≥ 24.0% for Tier 1, ≥ 23.7% for Tier 2, and ≥ 23.2% for Tier 3. When applied to a TOPCon PV module of 1,134 mm × 2,382 mm, these requirements mean that modules with a power output of 630 W or less would not comply with the standard. If the standards are strictly applied to domestically manufactured products, some production facilities may be phased out. As the requirements for conversion efficiency and degradation rate of PV modules have been tightened, the quality of PV products is expected to improve. In China, manufacturers are expected to streamline their existing product lineups and dispose of inventories in preparation for January 2027. Products that do not comply with the new standards may face price reductions.

EMERGING TECHNOLOGIES

In several IEA PVPS member countries such as China, Japan, Korea, USA, Germany, the Netherlands and Sweden, R&D efforts on emerging PV technologies are underway. In particular, since the conversion efficiency has been rapidly improved in a short period of time, efforts toward the practical application of perovskite technology have been continued in 2025. Perovskite solar cells have the potential for high conversion efficiency, low material costs, and a low carbon footprint process. Furthermore, the use of flexible substrates enables the production of lightweight and flexible PV modules, making it possible to install them on low-load-bearing roofs and curved surfaces and raising expectations that the range of potential installation sites for PV systems can be expanded, including to spatial applications.

Several companies, primarily in China, have established pilot production lines for perovskite PV modules and have begun operating GW-scale production lines. In February 2025, UtmoLight reported the commencement of operations at a GW-scale production line. In addition, Microquanta announced plans to bring a GW-scale production line into operation in the second half of 2026. Based on the combined production capacity of the announced projects, China's perovskite module manufacturing capacity is expected to reach approximately 5 GW/year by the end of 2026. However, as of the end of 2025, single-junction perovskite solar cells had not yet reached large-scale commercial production and were shipped primarily for demonstration projects. Demonstration activities have also been expanding in Japan, as well as in China. In addition, demonstration tests for space applications have also been reported.

The practical application of tandem technology using perovskite solar cells and c-Si solar cells is also actively being carried out around the world. Oxford PV (UK) started production of tandem cells using M6 (166 mm wafers) in their German factory. Progress toward the commercialization of perovskite/ c-Si tandem technologies has continued to be reported. In China, GCL Perovskite commissioned a 500-MW/year perovskite PV module production line in 2025 and announced plans to commence mass production in 2026, with shipments expected to begin by the end of the third quarter of 2026. First-year shipments are projected to reach approximately 50-70 MW. Trina Solar reported a power output of 907 W and a full-area module conversion efficiency of 29.2% for a perovskite/silicon tandem module based on the 210 mm wafer format. In April 2025, Oxford PV signed a patent licensing agreement with Trina Solar covering perovskite/silicon tandem PV products. In June 2026, Trina Solar announced its first commercial order for high-efficiency perovskite/silicon tandem modules for a project in New Zealand. In the USA, Tandem PV opened a pilot facility in April 2026 with a manufacturing capacity of 40 MW/year for four-terminal perovskite/ c-Si tandem modules. In parallel, major Chinese PV manufacturers have continued to report efficiency improvements in tandem solar cell technologies. LONGi Green Energy Technology achieved a world-record conversion efficiency of 35.2% for a two-terminal perovskite/silicon tandem solar cell (active area: 0.9994 cm^2) in May 2026. JinkoSolar reported a conversion efficiency of 34.82% for a perovskite/TOPCon tandem solar cell. Risen Energy announced a conversion efficiency of 31.95% and an open-circuit voltage of 1.988 V for a perovskite/silicon heterojunction (HJT) tandem solar cell with an area of 1 cm^2 in February 2026; however, field data show that high-efficiency perovskite devices combining comparable performance with long-term (> 1 year) outdoor stability remain rare. In addition, companies that initially entered the market with single-junction perovskite solar cells have increasingly expanded their activities into perovskite/ c-Si tandem technologies as well as all-perovskite solar cells, reflecting growing efforts to develop next-generation high-efficiency PV technologies.

For perovskite solar cells, both single-junction and tandem technologies still require further improvements in the conversion efficiency of commercial-scale products, particularly to reduce the gap between small-area cells and large-area modules. In addition, long-term durability and stability need to be verified, and further progress is needed in standardization efforts. To date, only a limited number of case studies have reported outdoor performance data from commercial-scale perovskite PV modules. In addition to overcoming these challenges, the successful commercialization of perovskite PV technologies will require the identification of target markets that can capitalize on their unique characteristics, as well as the optimization of system-level product design, including integration with power conversion systems (PCS) and installation methods. Furthermore, ensuring environmental safety and addressing recycling will also be necessary.

Advanced III-V compound semiconductor technologies, such as gallium arsenide (GaAs)-based and Ga-compound-based multijunction solar cells, remain specialized for space applications. Meanwhile, the use of c-Si PV modules in space applications has also expanded as module costs have continued to decline, particularly in the context of satellite miniaturization and the increasing number of satellite launches.

TECHNOLOGY TRENDS / continued

BALANCE OF SYSTEM

PV INVERTERS

According to Wood Mackenzie, global shipments of inverters for PV systems reached 523 GWac in 2025, representing a year-on-year decline of approximately 2%. Global inverter manufacturing capacity exceeded 1 TW/year, and overcapacity persisted throughout 2025. As a result, inverter prices continued their downward trend.

China continues to play a dominant role in inverter manufacturing, supported by its position as the world's largest PV market. In 2025, Huawei and Sungrow, the two leading Chinese manufacturers, accounted for more than 55% of the global inverter market.

Inverters used in PV systems can be broadly classified into three categories: string inverters, central inverters, and Module-Level Power Electronics (MLPE). String inverters perform independent maximum power point tracking (MPPT) for each PV string. While they were originally used mainly in distributed PV applications, they have become the dominant technology in utility-scale ground-mounted power plants. Their market share is estimated to have reached approximately 75-80% in 2025.

Central inverters aggregate electricity from a large number of strings and convert it in a single high-capacity unit. This technology offers the lowest initial investment cost and continues to be widely deployed in very large utility-scale PV projects, particularly those located on flat terrain. However, its market share has gradually declined as string inverters have gained market acceptance. MLPE place power conversion equipment at the level of individual modules or small groups of modules. MLPE solutions are primarily used in residential PV markets, especially in the USA, where safety functions such as arc-fault detection are highly valued. They have also begun to be deployed in plug-in solar systems for balcony applications.

Key trends in inverter technology include:

Higher voltage and higher power ratings: As the power output of c-Si PV modules has increased, 1,500 V system architectures have become standard for PV systems. In line with this trend, the power rating of string inverters has increased to 300-400 kW per unit. At international PV trade exhibitions held during the first half of 2026, several manufacturers showcased inverter products with power ratings exceeding 500 kW.

Modular architectures: Modularization has been adopted in central inverters to reduce costs. For example, configurations combining eight 800 kW inverter units to achieve a total capacity of 6.4 MW are being used.

Introduction of next-generation power semiconductor devices: To improve conversion efficiency to over 99% while reducing system size and weight, the transition from conventional silicon (Si)-based insulated gate bipolar transistors (IGBTs) to SiC (next-generation power semiconductor) devices capable of high-frequency switching is accelerating.

Grid-forming technology: In regions where the share of variable renewable energy sources in electricity generation has increased, fluctuations in grid voltage and frequency have become a significant challenge. As a result, demand is growing for grid-forming inverters, which actively maintain voltage and frequency and contribute to grid stability, in contrast to conventional grid-following inverter technologies.

Hybrid inverters: The increasing deployment of PV systems for self-consumption, together with the need to accommodate curtailment and other operational requirements, is driving inverter manufacturers to shift from stand-alone inverter products toward hybrid inverter products combining batteries and PCS. Hybrid inverters have become mainstream products in distributed PV applications, particularly in the residential sector.

Use of artificial intelligence (AI): AI is being used to optimize and enhance inverter operation and control.

China, which is also the world's largest supplier of PV inverters, promulgated a mandatory national standard (GB standard) for PV inverters on June 27, 2026. The standard specifies maximum conversion efficiency levels according to inverter capacity classes. Products that fail to meet these requirements will gradually be phased out of the market. For example, for inverter products with a rated power of 200 kW < P ≤ 500 kW, the required conversion efficiencies are specified as 99.00% for Tier 1 products, 98.85% for Tier 2 products, and 98.65% for Tier 3 products.

Since 2025, cybersecurity risks associated with communication functions integrated into PV inverters have emerged as a major concern, prompting the strengthening of regulatory frameworks in a growing number of countries and regions. For example, in May 2026, the European Commission (EC) decided that PV, wind power, and energy storage projects using inverters originating from "high-risk countries" would no longer be eligible for financing from the European Investment Bank (EIB) and the European Investment Fund (EIF). In Italy, tenders requiring the use of non-Chinese products were conducted in 2025.

In the USA, the Federal Communications Commission (FCC) announced in July 2026 that grid-connected power inverters had been added to the list of "Covered Equipment and Services" that may pose risks to national security. As a result, the introduction of new models from certain foreign manufacturers into the USA market could be effectively restricted, although products that had already obtained FCC certification remain unaffected. Looking ahead, further revisions to relevant regulations and the introduction of new compliance requirements in public procurement and tendering processes are expected. As these regulatory frameworks become more widely adopted, market share may increasingly shift toward domestically manufactured products and certified equipment.

PV TRACKING SYSTEMS

The market for tracking systems in utility-scale PV applications continued to grow in 2025. According to Wood Mackenzie, global shipments of PV tracking systems reached 134 GW in 2025, representing a 19% increase compared to the previous year.

As the USA remained the world's largest market for PV tracking systems, manufacturers headquartered in the country continued to maintain a strong market presence. Nextracker (now Nextpower) ranked first in global shipments, with approximately 40 GWdc shipped in 2025, marking its eleventh consecutive year as the global market leader. It was followed by GameChange Solar, Arctech Solar, Array Technologies, and PV Hardware, which ranked among the leading suppliers for the third consecutive year. Shipments in the USA. market exceeded 40 GWdc for the first time in 2025, representing year-on-year growth of more than 25%. Nextracker accounted for more than 50% of the USA market, while Nextracker, Array Technologies, and GameChange Solar together represented approximately 90% of total shipments. Chinese manufacturers have been operating manufacturing facilities in countries such as Saudi Arabia and India and have strengthened their presence in markets such as Saudi Arabia. The European PV tracker market also continued to expand in 2025, reaching a record shipment volume of 25 GWdc. Spain-based Axial achieved the largest market share in the European market, partly due to its involvement in agrivoltaic projects.

PV mounting structure manufacturers are responding to the increasing adoption of large-area modules and bifacial PV modules by enhancing the structural strength of mounting structures, including improved wind-load resistance and torsional rigidity. In addition, technological developments are underway in areas such as algorithms for utilizing diffuse irradiance under cloudy conditions, asynchronous tracking systems adapted to uneven and complex terrain, and smart control technologies that automatically move trackers into a safe stow position upon detection of sandstorms, high-wind or hail events.

For mounting structures, policies aimed at strengthening domestic supply chains are increasingly introducing local-content requirements. In some markets, the use of locally produced steel and mounting structures has become a condition for obtaining tax incentives or gaining market access. As a result, the geographical distribution of manufacturing facilities may continue to evolve in response to these policy measures.

five

SOCIETAL IMPLICATIONS OF PV AND ACCEPTANCE

PV is bringing profound changes to modern society with impacts across economic sectors, communities and the environment. It is a fundamental pillar without which the energy transition could not go ahead. As deployment expands, the societal implications of PV extend to employment, the creation and transformation of companies, financial flows, electricity costs, and impacts on land, the environmental and local communities. Understanding these impacts of PV is important for governments as photovoltaic generation represents a growing part of electricity supply and investment.

As penetration rates increase and utility-scale and building-integrated systems become more visible, acceptance can vary between national policy objectives and individual projects. The distribution of costs and benefits, participation in project decisions and access to PV savings are visible subjects besides decarbonisation, climate mitigation and electricity supply. These subjects are becoming more important as PV moves from a relatively specialised technology to a major component of electricity infrastructure.

ACCEPTANCE OF PV DEPLOYMENT

Acceptance can be defined as the willingness of stakeholders to approve, support, and engage themselves. In the early days of PV development, systems were predominantly small-scale and distributed, with limited impacts on land use and local infrastructure. As installed volumes and individual project sizes increased, the range of stakeholders affected by PV deployment widened.

Three dimensions of acceptance can be distinguished: socio-political acceptance concerns the place of PV within energy policy and among institutions, stakeholders and the wider public, community acceptance concerns the response of people and organisations affected by individual projects and finally market acceptance concerns the willingness and ability of households and companies to adopt PV systems and services. These three aspects of acceptance can evolve differently: broad support for solar can coexist with opposition to a specific project, while consumers can support PV without having the capital, roof or contractual conditions required to install it

The most recurring concerns with regards to acceptance of PV depend on the country and market segment, but common themes remain:

- competition with agriculture and other land uses;
- impacts on biodiversity;
- the appearance of PV in natural or heritage landscapes;
- the distribution of project revenues and economic benefits;
- concerns over materials and end-of-life treatment;
- installation quality and safety;
- whether developers take community interests into account during project design

In earlier phases of PV development, socio-political acceptance was often closely linked to the cost and pace of support-driven market growth. Rapid expansion under feed-in tariffs in several European markets between 2007 and 2012 was followed by abrupt reductions in support as governments sought to contain programme costs. As PV costs declined and deployment expanded, the emphasis of acceptance progressively shifted towards land use, grid integration, local participation and the distribution of economic benefits. These issues now coexist with, rather than replace, questions over the allocation of policy and network costs.

This distinction between technology acceptance and project acceptance is present in many countries – for example, in **France,** there is broad support for solar across the population, but project-level concerns remain. **Norway** reports stronger acceptance for rooftop PV than for ground-mounted projects and preferences in some municipalities for roofs, car parks and other already developed surfaces. In **Denmark** there is visible debate around large solar parks on agricultural land, while environmental and siting concerns remained relevant for large projects in **Japan**.

These examples indicate that acceptance is increasingly linked to project location and design rather than to the PV technology itself. Public support can remain high while individual projects face opposition where land, landscape, biodiversity or local economic concerns are not resolved. Policy measures aimed at improving general information would have little impact on siting rules, environmental assessment or local participation.

LAND USE, AGRIVOLTAICS AND ACCEPTANCE

Competition between ground-mounted PV, agriculture, biodiversity and landscape values is becoming more visible as project pipelines expand. Several countries are consequently giving greater attention to roofs, car parks, infrastructure corridors and other previously developed surfaces, while agricultural PV is developing where electricity generation can be combined with continued agricultural use.

In **France** 2025 saw continued debate over the use of agricultural land and a more tightly defined framework for agrivoltaics; in **Norway**, some municipalities have explicitly preferred previously developed “grey” surfaces over farmland and forests.

ACCEPTANCE OF PV DEPLOYMENT / continued

Land use competition also affects the way large projects are discussed locally. In Denmark, opposition to solar parks on agricultural land became sufficiently visible in public debate that the expression “iron fields” entered public usage in 2025. In Japan, concerns surrounding a large project near Kushiro Marsh National Park contributed to a government package announced in December 2025 that combined stronger safety and compliance measures with greater coordination with local initiatives and support for community-integrated projects.

Agrivoltaics, combining agricultural activity and electricity production on the same land, is one approach to avoid conflict. IEA PVPS publications emphasise the need for clear definitions, comparable agricultural and electrical performance metrics and early involvement of farmers and other stakeholders. The IEA PVPS Agrivoltaics Action Group has published a report on Dual Land Use for Agriculture and Solar Power Production for further details that addresses these varied subjects.

PRODUCT QUALITY, HEALTH CONCERNS AND CONSUMER CONFIDENCE

Product and installation quality can influence market acceptance, particularly in distributed and off-grid markets where a solar system represents a material household investment. Poor performance, weak warranties or limited repair services can increase consumer costs and reduce confidence in suppliers. Quality standards, installer competence and after-sales service are an important component of durable market development. Past experiences in off-grid markets have demonstrated that early product failure can weaken confidence in solar, making consumer protection important where households purchase systems through instalment or PAYGo arrangements.

Concerns around module materials can also enter public debate. IEA PVPS Task 12 has developed methods for assessing potential human-health risks associated with chemical releases during building fires and following rainwater exposure of broken modules. This work provides a technical basis for evaluating specific exposure pathways and for distinguishing assessed risks from broader concerns regarding PV materials. (See the IEA PVPS Task 12 reports on Human Health Risk Assessment Methods for PV, Part 1 – Fire Risks, Part 2 – Breakage Risks and Part 3 – Module Disposal Risks for further details).

THE BUILT ENVIRONMENT AND VISUAL ACCEPTANCE

For building-integrated PV (BIPV), visual acceptance is linked to architectural integration as well as energy performance. Colour, transparency, façade treatment and indoor visual comfort can influence the perception of BIPV by building owners, architects and users. The landscape impacts associated with ground-mounted PV are substantially different to those when the PV system becomes part of the building envelope and must respond to architectural, construction and energy requirements simultaneously. IEA PVPS Task 15 addresses these questions through its work on BIPV design and multi-dimensional evaluation; detailed technical treatment is provided in a variety of Task 15 publications including the Building Integrated Photovoltaics Technical Guidebook.

COMMUNITY PARTICIPATION, FAIRNESS AND LOCAL VALUE

In many countries there is a gap between national socio-political acceptance and community acceptance. Community acceptance is related to acceptance by local stakeholders and includes concerns over participation in administrative and permitting procedures, revenue and benefit sharing, and recognition of local values:

- Procedural fairness concerns who receive information and can participate in decision making.
- Distributional fairness concerns how revenues, employment and other benefits are distributed relative to local land, visual, environmental or infrastructure impacts.
- Recognition concerns whether rights, local knowledge and cultural values are incorporated into decision-making.

These dimensions are closely related in practice: local opposition can reflect the project itself, the way decisions were taken, or a perception that costs and benefits are distributed unevenly.

COMMUNITY ENGAGEMENT AND CO-DESIGN

Stakeholder engagement can improve acceptance of PV projects. This can include consultation on project siting and permitting, participation in land-use planning, opportunities for local investment, and involvement through citizen or energy communities. These approaches give local stakeholders a clearer role in how projects are developed and how some of the benefits are shared.

Early engagement can allow project design, environmental measures and local benefit arrangements to be discussed before the main decisions are fixed. Several countries reported measures to strengthen this participation and indicate that strong community engagement can reduce project cancellations. In Canada, meaningful consultation for large projects, including the involvement of neutral organisations where appropriate is considered important. In the USA, the Department of Energy’s R-STEP programme supports state and local authorities in planning for large renewable projects and developing approaches based on community engagement. Austria continues to use municipal planning and citizen-participation models to involve local communities in decisions on ground-mounted PV.

Faster permitting can change when and how local stakeholders participate in project development. It is important to understand whether consultation occurs early enough for local communities to influence siting, project design and local arrangements. Streamlined procedures can reduce unnecessary delay, but weak or late participation can increase opposition where local concerns over land, environment or benefit distribution remain unresolved. Policy approaches to permitting and administrative reform are discussed in Chapter 3.

LOCAL BENEFIT SHARING, INVESTMENT AND OWNERSHIP

Citizen participation in energy communities or investment and governance of solar projects can empower residents to initiate projects and retain part of the economic flows within local communities. Models include community-benefit funds, local procurement, municipal participation, citizen investment and shared ownership. These mechanisms vary in the degree of influence they provide: a one-off

COMMUNITY PARTICIPATION, FAIRNESS AND LOCAL VALUE / continued

community payment differs materially from long-term revenue sharing, equity participation or a cooperative structure in which local actors take part in ownership and governance.

Austria has established citizen-investment and regional cooperative models to retain a greater share of investment and electricity value locally, while France has used tender incentives to encourage citizen participation in projects. In Australia, community solar and community battery programmes were expanded in 2025 to include apartment residents and community groups without access to an individual rooftop system, while Queensland requires social-impact assessments and community-benefit arrangements for relevant large renewable projects. Policy frameworks are using citizen and cooperative investment, municipal participation, community-benefit agreements and tender criteria rewarding local ownership or benefit sharing to increase the economic participation of host communities.

These mechanisms are particularly relevant for large projects in rural areas where livelihoods depend on agriculture, grazing or other land-based activities. Local employment and procurement, access to project revenues and the duration of benefits can influence acceptance, but financial benefits do not remove the need for appropriate siting and environmental assessment. The quality and durability of local participation remains an important factor.

INDIGENOUS AND FIRST NATIONS PARTICIPATION

The development of utility-scale PV in remote or sparsely populated areas has been accompanied by discussion on local acceptability, energy justice and the distribution of project revenues. Where projects affect Indigenous or First Nations lands and communities, participation also concerns land rights, cultural heritage, consent, governance and long-term economic participation. These considerations are closely connected to the wider questions of procedural, distributional and recognition fairness discussed above.

In Australia, the First Nations Clean Energy Strategy provides a framework for participation in the energy transition, including opportunities for economic participation and stronger involvement in project development. Canada has developed loan-guarantee and financing approaches intended to support Indigenous equity participation in major energy and natural-resource projects. These approaches reflect a broader progression from consultation and benefit sharing towards participation in ownership and governance.

The use of renewable energy projects as a tool to support reconciliation does not in itself guarantee reconciliation outcomes. Studies have found that benefit-sharing arrangements, revenue-sharing mechanisms and equity participation can provide different levels of long-term involvement for Indigenous communities. More durable outcomes are generally associated with arrangements that provide a continuing role in ownership or governance, although their effectiveness remains dependent on land rights, project design and the

Guidance developed by the First Nations Clean Energy Network in Australia emphasises early respectful engagement, protection of cultural heritage and Country, accessible information and the sharing of economic and social benefits. These principles provide a practical complement to financing and ownership mechanisms by focusing on how projects are developed over their full lifetime. The 2025 edition of the IEA PVPS Trends in PV Applications takes a more in depth look at this subject.

INFORMATION, TRANSPARENCY AND MISINFORMATION

Information and guidance platforms can facilitate citizen engagement in self-consumption, guide consumers through administrative procedures and provide independent information on technology, costs and installation. Such tools have been used for many years in Australia, France, Spain and the USA and more recently in Israel and Switzerland.

The tools increasingly address different audiences. Israel has a central government renewable-energy platform for citizens, developers and municipalities, together with implementation material for local authorities, Switzerland a platform explaining local electricity-sharing models and an energy dashboard providing public information on electricity supply, prices and weather whilst Canada provides federal and industry planning guides for households and commercial users.

Information is most useful where concerns result from uncertainty over performance, safety, materials or project procedures. It has a more limited role where disagreement concerns land use, environmental impacts or the distribution of economic benefits, where planning and decision-making processes are more directly relevant.

CLIMATE CHANGE MITIGATION AND HEALTH IMPACTS

CLIMATE CHANGE MITIGATION

Climate change has become one of the key challenges that society has to address, and PV is one of the primary technologies for reducing greenhouse-gas emissions in the energy sector. Increasing the share of PV in the electricity-generation mix reduces emissions where solar electricity displaces generation with higher lifecycle emissions.

Global energy-related CO2 emissions increased by around 0.4% in 2025 to nearly 38.4 Gt. Over the same year, the global CO2 intensity of electricity generation was around 435 g CO2/kWh, continuing a downward trend as renewable generation expanded, and reduces power sector emissions.

The lifecycle greenhouse-gas emissions associated with PV depend on module technology, manufacturing, system configuration, irradiation and operating conditions, and have continued to drop as wafers decrease in thickness and module size increases. Manufacturing dominates the lifecycle footprint of most PV systems, while the emissions per kWh decline where systems operate at higher yields and over longer lifetimes. IEA PVPS Task 12 maintains detailed lifecycle inventory and assessment work; its 2026 Life Cycle Inventories of Photovoltaic Systems provides updated datasets for current crystalline-silicon and thin-film technologies, balance-of-system components and representative residential, commercial and utility-scale systems.

EMISSIONS AVOIDED BY PV GENERATION

The total CO_2 emissions avoided by PV on a yearly basis are estimated from the electricity that could have been produced by the cumulative PV capacity installed at the end of 2025. For each country, annual PV generation is calculated from cumulative installed capacity and a

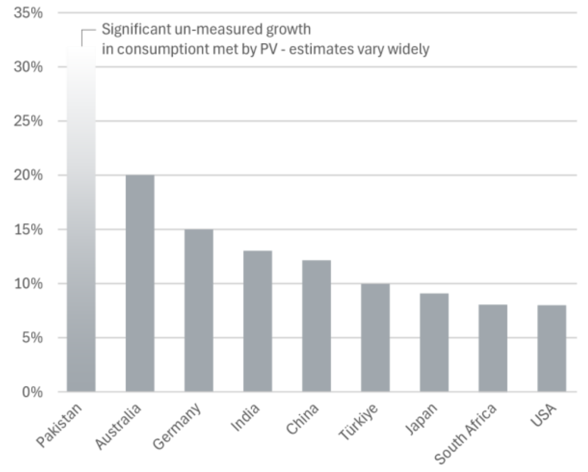
CLIMATE MITIGATION AND HEALTH IMPACTS / continued

country-specific yield reflecting typical irradiation and system performance. The resulting volume of PV electricity is then compared with an equivalent amount of electricity produced at the carbon intensity of the national electricity mix.

This method follows the general approach used in previous editions, while updating the assumptions applied to the most recently installed capacities. Capacity installed up to the end of 2021 retains the lifecycle emissions factors previously used for the corresponding national PV capacity. For capacity installed from 2022 onwards, a common lifecycle factor of 35.8 g CO_2eq/kWh is applied, representing contemporary monocrystalline silicon modules manufactured in China. The emissions attributed to the cumulative PV capacity in each country are calculated from the relative shares of older and more recently installed capacity and are deducted from the emissions associated with the equivalent volume of grid electricity.

The methodology uses the average national electricity mix rather than assuming that PV displaces the most carbon-intensive marginal generator. At low penetration rates, an additional unit of solar production may frequently displace flexible fossil generation operating at the margin, however, as PV reaches a material share of annual electricity generation it affects a broader range of generation and increasingly forms part of the normal electricity mix. Using average national carbon intensity provides a consistent basis for comparison across countries. The calculation remains an annual accounting estimate rather than an hourly power-system simulation. It does not identify the generator displaced by PV in each hour and therefore does not fully capture changes in marginal emissions across the day or year. Electricity imports and exports are represented only to the extent that they are reflected in the national emissions factors used. Storage charging and discharging are not explicitly modelled, and, for continuity with previous editions, curtailed PV volumes are not deducted systematically from the estimated annual PV production. The resulting values should therefore be interpreted as an estimate of the emissions associated with the annual PV production calculated from the installed capacity, rather than as a direct measurement of realised hourly displacement.

FIGURE 5.2: AVOIDED CO_2 EMISSIONS AS PERCENTAGE OF TOTAL EMISSIONS OF ELECTRICITY SECTOR* IN 2025



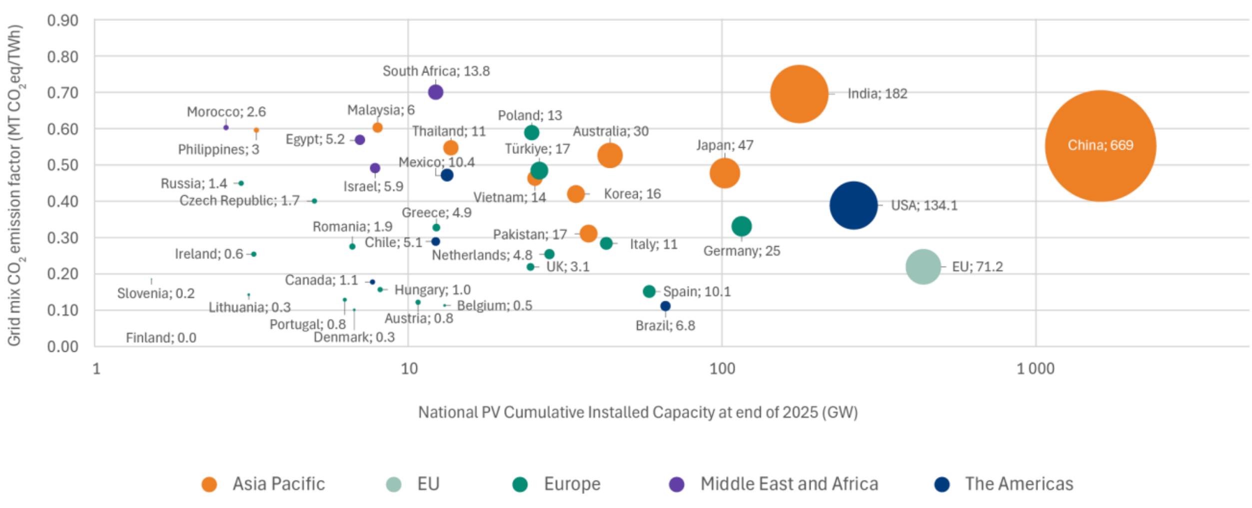
*Emissions of final electricty demand

SOURCE: IEA PVPS, OTHERS

This methodology also means that the avoided emissions associated with each additional kWh of PV tend to decline as electricity systems decarbonise. In a system dominated by coal- or gas-fired generation, an additional unit of PV replaces electricity with a relatively high carbon content. In a system with a high share of hydro, nuclear, wind or solar generation, the average electricity displaced already has a lower carbon intensity. At the same time, continued growth in the volume of PV generation can increase total avoided emissions even where the avoided emissions per kWh decline.

Using this methodology, the PV capacity installed globally at the end of 2025 is estimated to avoid around **1.3 Gt CO_2eq per year**, compared with around **1.0 Gt CO_2eq** for the cumulative capacity installed at the

FIGURE 5.1: CO_2 EMISSIONS AVOIDED BY PV [MT], SELECTED COUNTRIES



SOURCE: IEA PVPS FROM IEA PVPS, GLOBAL SOLAR ATLAS, EMBER

CLIMATE MITIGATION AND HEALTH IMPACTS / continued

end of 2024. The increase of around 254 Mt CO_2eq, or approximately 23%, is a direct result of the substantial growth in cumulative installed capacity over 2025.

Global energy-related CO_2 emissions reached nearly 38.4 Gt in 2025 according to the IEA. On this basis, the estimated annual emissions avoided by the global PV capacity correspond to approximately 3.4% of global energy-related CO_2 emissions, compared with approximately 2.8% using the equivalent calculation for 2024. The two quantities are not directly equivalent accounting categories, since the numerator represents estimated electricity-sector emissions displaced by PV whereas the denominator includes emissions from the entire energy sector, but the comparison provides an indication of the scale reached by the global PV capacity.

The geographic distribution of avoided emissions remains highly concentrated. **China** accounts for an estimated 700 Mt CO_2eq, or just over half of the global total, reflecting the combination of the world's largest installed capacity and an electricity mix that remains relatively carbon intensive. **India** follows at around 180 Mt CO_2eq, while the **USA** accounts for approximately 135 Mt CO_2eq. Together, these three countries represent around 77% of the calculated global total.

The next-largest contributions are estimated for **Japan** at around 47 Mt CO_2eq, **Australia** at around 30 Mt CO_2eq and **Germany** at around 25 Mt CO_2eq. **Pakistan, Türkiye, Korea, South Africa, Vietnam** and **Poland** each contribute around 13 –17 Mt CO_2eq. The first 10 countries in the ranking represent approximately 89% of estimated global avoided emissions, while the first 30 represent approximately 99%.

Figure 5.1 shows the countries with the largest calculated avoided emissions as a function of their cumulative installed PV capacity and national grid carbon intensity. The comparison illustrates the two principal factors for high avoided emissions: countries with very large volumes of PV generate large volumes of solar electricity, while countries with more carbon-intensive electricity mixes avoid more emissions for each TWh of PV generation. Similar cumulative capacities can produce substantially different calculated emissions benefits depending on the composition of the electricity system.

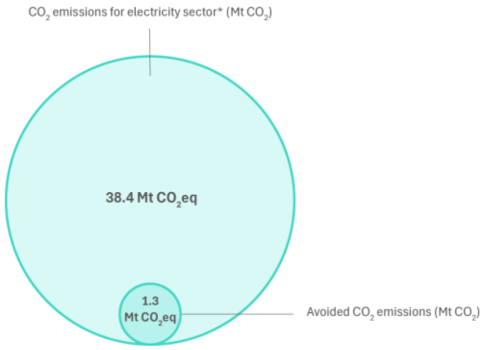
AROUND 1.3 GT CO_2EQ AVOIDED ANNUALLY

This principle can be seen clearly when comparing **Korea** and **France**. The grid carbon intensity in Korea is close to the world average at 417 g CO_2/kWh, whereas in **France** it is just 41 g CO_2/kWh, reflecting the much lower-carbon French electricity mix. Despite both countries having similar volumes of cumulative capacity, the estimated annual avoided emissions are 17 Mt CO_2eq in **Korea**, while they are close to zero in **France** once the lifecycle emissions of PV are taken into account. This does not imply that PV has no system value in those markets with already low grid mix emission factors; many other services are rendered by the installed PV capacity.

Figure 5.2 expresses the calculated avoided emissions relative to estimated electricity-sector emissions and provides a complementary view of the effect of PV penetration. Among the countries shown, **Australia** is at around 20%, followed by **Germany** at around 15%, **India** at around 13% and **China** at around 12%.

Pakistan has the highest ratio, with estimated PV-related avoided emissions around 31% of calculated electricity-sector emissions, however this result should be interpreted with particular caution. Both the estimated cumulative PV capacity and the associated PV generation are subject to considerable uncertainty, reflecting the rapid expansion of distributed and behind-the-meter systems that are only partially visible in official power-sector statistics. The grid emissions factor used in the calculation is based on reported national generation, which includes substantial hydro and nuclear generation alongside thermal power. However, analysts consider that a large share of distributed PV generation is effectively invisible to the grid and may be meeting additional electricity demand that is also not captured in conventional utility data. At the same time, the amount of PV curtailment is uncertain, particularly given network constraints and the fragility of parts of the power system. The estimate of around 17 Mt CO_2eq of avoided emissions for an equivalent of 30% total electricity sector emissions should therefore be treated as indicative only. The high share shown in Figure 5.2 reflects the interaction between very rapid estimated PV growth and the recorded electricity-sector emissions base, but the underlying uncertainties are substantially greater than for countries with more complete PV and grid-generation statistics.

FIGURE 5.3: AVOIDED CO_2 EMISSIONS AS PERCENTAGE OF ENERGY SECTOR TOTAL EMISSIONS



* Energy related CO_2 emissions from power sector

SOURCE: IEA PVPS, IEA

COOLING AND HEAT RESILIENCE

PV can contribute to adaptation to higher temperatures because cooling demand is often elevated during hot, sunny periods. This creates a degree of coincidence between air-conditioning demand and PV production and can reduce daytime grid demand. Cooling loads can remain high after solar output declines, so building efficiency, storage and flexible demand remain relevant. Solar for cooling is particularly relevant in hot-climate markets where extreme heat coincides with high electricity demand or unreliable supply. In **Pakistan** and **India**, for example, rapid distributed-PV deployment increasingly overlaps with rising cooling needs. Access to rooftop PV, storage and efficient cooling can improve household and business resilience, while differences in access to these technologies introduce a distributional dimension.

ECONOMIC CONTRIBUTION OF PV

PV MARKET BUSINESS VALUE

The turnover of the PV sector has been evaluated based on the size of the PV market - annual installations and cumulative capacities - and the average price value for installation and Operation & Maintenance (O&M) specific to the different market segments and countries.

For this report, market business value is estimated from installed volumes and market prices and should be read as a comparative market indicator, not as national value added.

Based on 2025 market volumes and prices used in this report, the global PV market business value remained around 400 billion USD. Record capacity additions were partly offset in value terms by lower equipment and system prices. This illustrates an increasingly important distinction between physical market growth and monetary turnover: a market can install substantially more capacity without a proportional increase in business value when system prices fall.

The growing cumulative capacity also increased recurring O&M activity. This estimate remains a lower-range value because maintenance practices differ substantially between residential, commercial and utility-scale systems and because replacement equipment, repowering and recycling are not comprehensively included. As the installed capacity matures, these recurring activities are expected to account for a larger share of PV-related economic activity.

PV MARKET VALUE RELATIVE TO NATIONAL GDP

Figure 5.4 shows the estimated business value of the PV sector in selected IEA PVPS countries as compared with their national GDPs. These values are determined from domestic PV market activity and do not fully account for imports, exports or all stages of the PV value chain.

The ratio should be interpreted as the scale of PV market activity relative to the national economy rather than as a direct contribution to GDP.

Gross market turnover is not equivalent to national value added because imported equipment and intermediate expenditure are included in market expenditure.

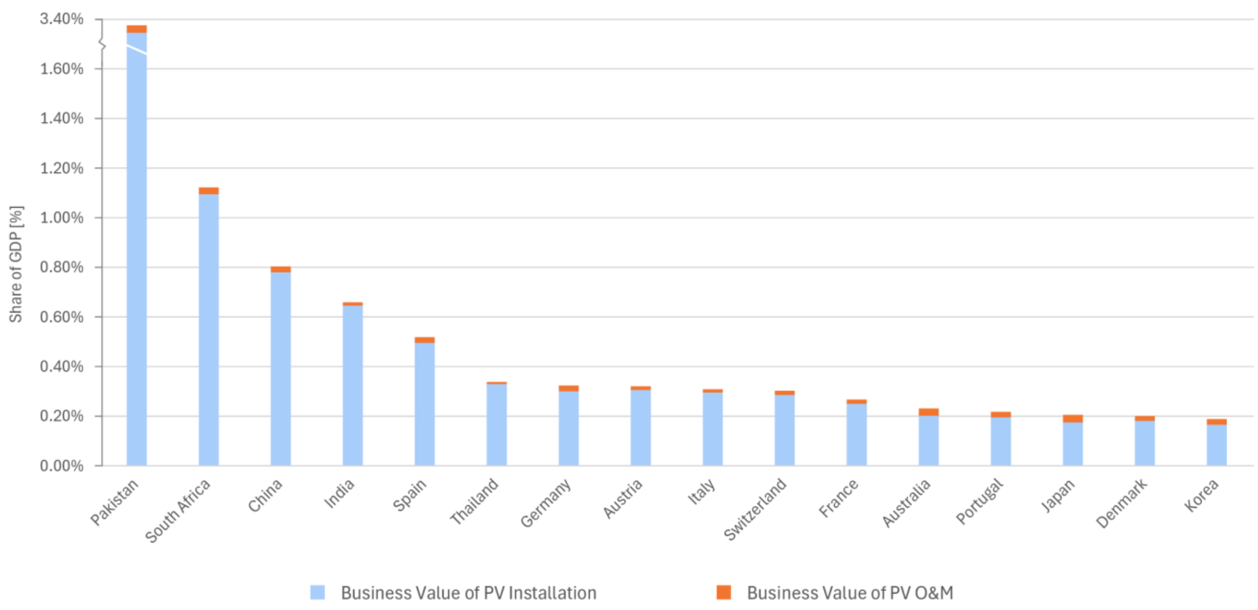
The updated 2025 ranking places China first at around 160 billion USD, followed by the USA at 50 billion USD, India at 27 billion USD, Germany at 17 billion USD and Pakistan at 14 billion USD. Spain was close to 10 billion USD, while Japan, France, Italy and South Africa completed the top ten among the markets assessed. The ranking reflects both installation volumes and market-segment prices: a country with a larger share of residential and commercial systems can generate more market turnover per MW than a market dominated by utility-scale installations.

TURNOVER PV 383 BILLION USD

O&M 27 BILLION USD

GLOBAL BUSINESS VALUE WAS IN SLIGHT DECLINE FOR 2025

FIGURE 5.4: BUSINESS VALUE OF THE PV MARKET IN 2025 IN SELECTED IEA PVPS COUNTRIES



SOURCE: IEA PVPS

ECONOMIC CONTRIBUTION OF PV / continued

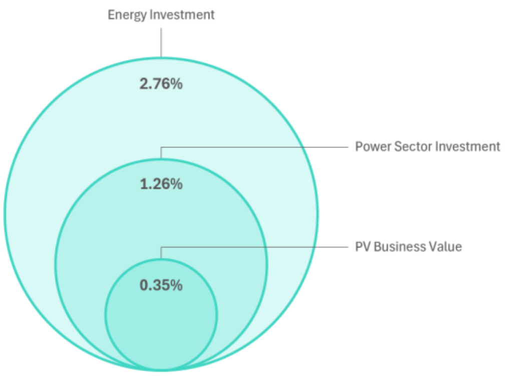
TABLE 5.1: TOP 10 RANKING OF PV BUSINESS VALUES IN SELECTED IEA PVPS COUNTRIES

1	China	160	billion USD
2	USA	50	billion USD
3	India	27	billion USD
4	Germany	17	billion USD
5	Pakistan	14	billion USD
6	Spain	10	billion USD
7	Japan	9.4	billion USD
8	France	9.3	billion USD
9	Italy	7.9	billion USD
10	South Africa	4.9	billion USD

Note: estimates include business value from installation and O&M

SOURCE: IEA PVPS

FIGURE 5.5: CONTRIBUTION TO GLOBAL GDP OF PV BUSINESS VALUE AND ENERGY SECTOR INVESTMENTS



Energy: Fuels, Power, End-use
Power Sector: Generation, Batteries and Grids

SOURCE: IEA PVPS, IEA, OTHERS

INDUSTRIAL VALUE AND LOCAL ECONOMIC ACTIVITY

Even though assessing the detailed contributions of the different parts of the whole PV value chain is complex due to the level of market integration, an approximate evaluation of the industrial business value of PV has been performed for the major PV manufacturing countries.

The evaluation is based on production volumes and manufacturing shares for polysilicon, wafers, cells and modules, including thin-film technologies, as detailed in Chapter 4, together with an estimated average price for each of these four segments. Balance-of-system equipment, including inverters, is not included.

The 2025 figures indicate an industrial business value of around 80 billion USD for the selected manufacturing stages. Physical output and industrial revenue can move in different directions: continued growth in production can coincide with lower gross sales value when polysilicon, wafer, cell and module prices fall. China remained predominant across the crystalline-silicon value chain, while manufacturing activity was also visible in India, the USA, Malaysia, Thailand and other markets.

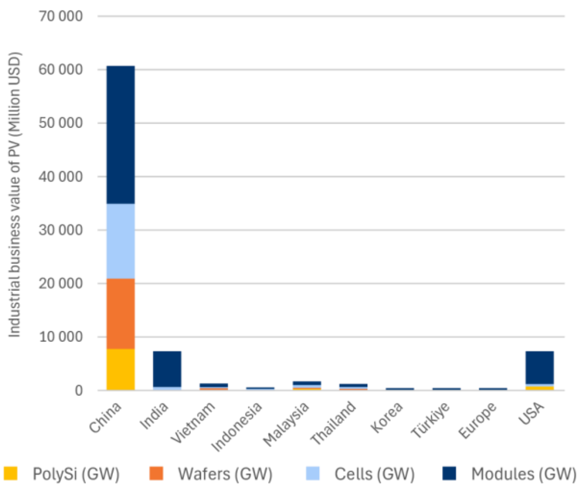
Although China dominates in absolute industrial value, PV manufacturing represents a comparatively larger share of economic activity in some smaller export-oriented economies, particularly Malaysia and Vietnam. This increases their exposure to changes in international prices, trade conditions and factory utilisation. The difference between production volume and business value was particularly visible during the period of manufacturing overcapacity and price compression. For countries with large export-oriented manufacturing bases, employment and industrial turnover can be influenced by international prices and trade conditions even when domestic PV deployment remains strong.

For balance-of-system activities, the industry is more distributed. Local manufacturers and suppliers of structures, cabling, electrical equipment, project development, civil works, installation and grid

connection can retain economic value even where cells and modules are imported. O&M and system monitoring create additional local activity over the operating lifetime of the installed capacity. The local economic footprint of deployment is therefore broader than module manufacturing alone.

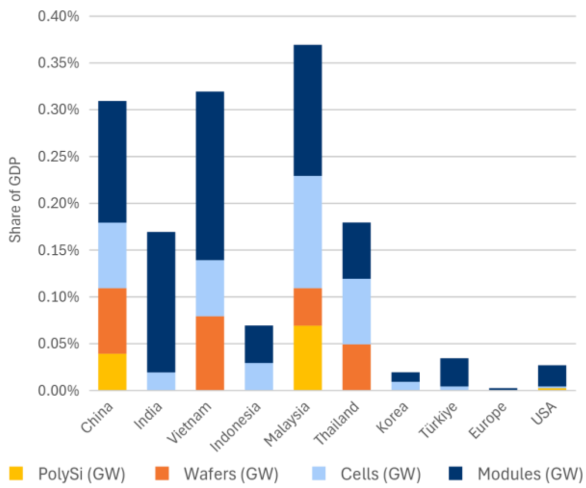
ECONOMIC CONTRIBUTION OF PV / continued

FIGURE 5.6: ABSOLUTE PV INDUSTRIAL BUSINESS VALUE IN 2025



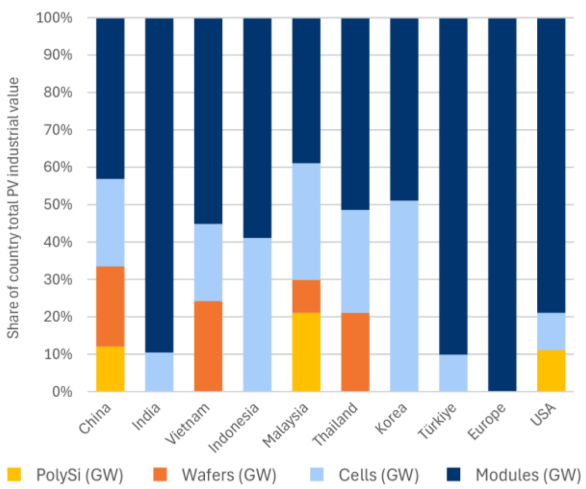
SOURCE: IEA PVPS, RTS CORPORATION

FIGURE 5.8: PV INDUSTRIAL BUSINESS VALUE AS SHARE OF GDP IN 2025



SOURCE: IEA PVPS, RTS CORPORATION

FIGURE 5.7: PV INDUSTRIAL BUSINESS VALUE ALONG THE VALUE CHAIN IN 2025



SOURCE: IEA PVPS, RTS CORPORATION

CONTRIBUTION TO EMPLOYMENT

EMPLOYMENT IN PV

Annual construction activity can create large numbers of temporary jobs in rapidly growing markets, or permanent employment in markets with strong perennial volumes of distributed PV. O&M employment grows with the cumulative capacity. Manufacturing employment can move independently of domestic deployment where production serves export markets.

Figure 5.9 gives an overview of estimated full-time-equivalent jobs in major IEA PVPS and other markets. The methodology uses data provided by reporting countries in National Survey Reports on upstream industrial employment and downstream development, installation and O&M, and extrapolates to other markets according to their respective market and manufacturing volumes.

The estimate should be interpreted with care because national accountings differ in their treatment of headcount and FTE, temporary construction jobs, indirect employment and the boundaries of upstream and downstream activities. Some countries report employment in the wider solar industry, while others provide only direct jobs associated with installation or manufacturing.

There was an estimated 8.2 million FTE in PV in 2025. There is a clear concentration of employment. China remains the largest national PV workforce by a wide margin, reflecting its manufacturing base and installation market, while India, the USA, Brazil and perhaps Pakistan form a second group of large employment markets. In Europe and several mature Asian markets, employment is increasingly distributed between installation and O&M.

JOB INTENSITY AND PRODUCTIVITY

Generally, in good correlation with market evolution, PV employment expands where markets develop. Development and installation of distributed systems remain more labour intensive per MW than utility-scale deployment because each project requires customer acquisition, design, permitting and installation.

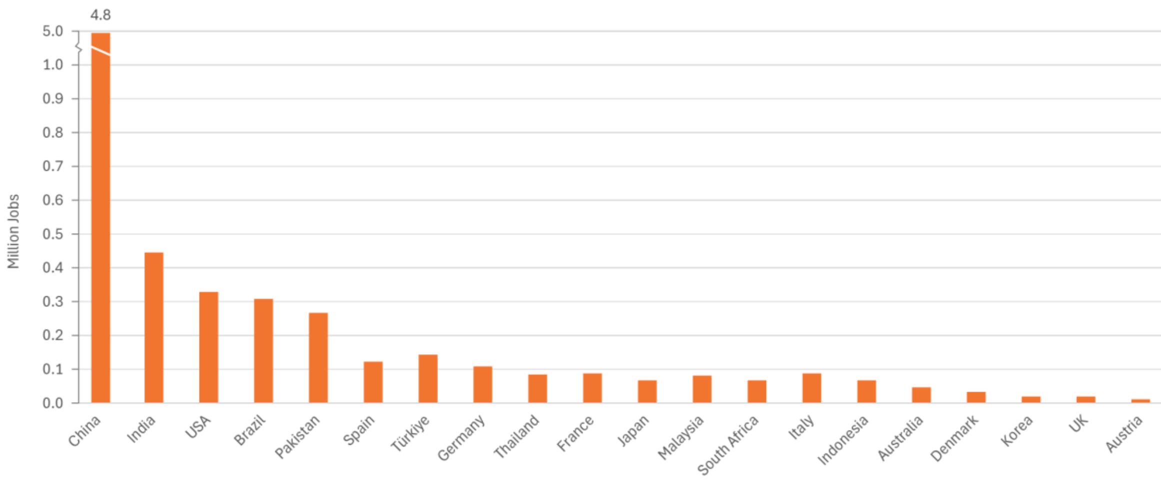
Increased deployment does not necessarily result in proportional employment growth. Competency and training-based productivity improvements, increasingly automated installation processes and more powerful modules for similar sizes reduce the labour required for each installed MW.

Expansion of the cumulative capacity increases recurring activity in O&M, monitoring, inverter replacement and repowering. In mature markets, this gradually shifts part of the employment base from new construction towards operation of the installed capacity, however the adoption of digital tools and assistants is expected to constrain growth per MW in these fields.

As the scale of manufacturing increases, automation and larger production lines reduce job intensity per GW in the manufacturing sector. Export-oriented manufacturing is more exposed to international demand and trade conditions - manufacturing employment remains particularly important in China, Vietnam, Thailand and Malaysia, while additional manufacturing capacity has increased industrial employment in India, the USA and Türkiye.

PV SECTOR EMPLOYED AN ESTIMATED 8.2 MILLION PEOPLE IN 2025

FIGURE 5.9: GLOBAL EMPLOYMENT IN PV SELECTED COUNTRIES



ELECTRICITY COSTS, ACCESS AND EQUITY

HOW PV AFFECTS ELECTRICITY CONSUMPTION COSTS

The impact of PV on electricity costs evolves as deployment increases. In the early stages of market development, support mechanisms can add to public expenditure or electricity bills, particularly where deployment is driven by feed-in tariffs, tax incentives or other forms of guaranteed remuneration. As PV becomes more competitive, these support costs generally decline relative to the volume of electricity produced. Their direction can also reverse: during high-price periods in Europe, two-way support arrangements in France and the UK required renewable generators to return revenues when wholesale prices exceeded contractual reference levels, while Austria temporarily suspended levies used to finance renewable support. The effect on consumers depends on both scheme design and market prices.

At higher penetration, PV increasingly influences wholesale electricity markets. Large volumes of low-marginal-cost solar generation can reduce daytime prices and lower energy-purchase costs for suppliers and, over time, consumers. In Australia, AEMO reported that average wholesale prices in the National Electricity Market fell by 27% year-on-year in the third quarter of 2025 and by 44% in the fourth quarter, with increased renewable generation contributing to the decline. In the western USA, CAISO also reported lower wholesale prices in 2025 despite higher natural-gas prices, partly reflecting increased renewable generation. Analysis of the UK similarly found a measurable downward effect of solar generation on wholesale prices, although the effect weakens as penetration rises.

The same market effect can reduce revenues earned by PV generators during the hours in which they produce. At high penetration, very low or negative prices, lower capture prices and curtailment can weaken merchant project economics. This increases the value of storage, flexible demand, interconnection and market arrangements that shift electricity from low-value solar hours to periods of higher demand. Australia illustrates this transition, with batteries increasingly charging during periods of high renewable output and supplying electricity later in the day. For generators, flexibility can improve capture prices and reduce exposure to curtailment and negative pricing; for consumers, it can extend the benefit of low-cost solar electricity across a wider part of the day. The overall impact on electricity costs then depends increasingly on how network and flexibility costs are allocated and on whether market arrangements allow these resources to respond efficiently to periods of surplus and scarcity.

IMPACT ON NETWORK COSTS

Distributed PV can alter the allocation of network costs. PV self-consumer purchase fewer kWh from the grid but generally continue to rely on network capacity at other times. Where network charges are predominantly volumetric, rising self-consumption can shift a greater share of network-cost recovery towards consumers without PV. The issue becomes more visible as rooftop PV moves from a niche activity to a material share of electricity supply.

Regulatory responses include fixed or capacity-based charges, time-dependent tariffs and differentiated arrangements for electricity shared locally. From a societal perspective, this raises questions on the balance between maintaining incentives for self-consumption and allocating the fixed costs of the electricity system transparently between participating and non-participating consumers.

PV FOR LOW INCOME CONSUMERS

PV can assist low-income households and communities in managing electricity needs, including in countries with stable electricity networks and close to total electrification. Programmes have been introduced to assist lower-income households to install grid-connected systems, while energy communities and shared solar are also used to extend access to consumers who cannot install an individual system.

Access to PV savings nevertheless remains uneven because of up-front investment requirements, access to finance, property ownership, roof suitability and building type. Policy responses increasingly distinguish between households able to finance an individual rooftop system and consumers who require alternative access routes. National and sub-national programmes in Australia, Italy, Korea, the USA and the UK have used targeted rebates, concessional finance or social-housing installations, while collective self-consumption and energy-community models in markets including Italy and Portugal provide access to locally generated electricity without requiring an individual roof.

ELECTRICITY ACCESS, RELIABILITY AND PRODUCTIVE USE

PV can be a competitive alternative for increasing electricity access in remote areas not connected to power grids and for improving supply where grid electricity is unreliable. Solar home systems, mini-grids and larger decentralised systems can support households, farms, health facilities, schools and small businesses, while productive uses such as irrigation, refrigeration and processing can increase the economic value of electricity access. In these applications, reliability and the service delivered are at least as relevant as the existence of a connection.

The societal outcome depends on affordability, reliability, equipment quality and access to finance, maintenance and local operating capacity. Distributed PV can complement grid expansion in remote areas and reduce dependence on diesel generation where conventional supply is unreliable. IEA PVPS Task 18 addresses the technical and operational conditions for durable off-grid and edge-of-grid systems; its 2025 work on digitalisation highlights monitoring,

SOLAR IRRIGATION AND WATER USE

In India, the PM-KUSUM programme supports stand-alone solar irrigation pumps, solarisation of grid-connected agricultural pumps and decentralised renewables. 2.2 million farmers had benefited by the end of 2025. Solar pumping reduces diesel or purchased-electricity expenditure and provides predictable daytime energy for irrigation.

Lower pumping costs can also increase pressure on groundwater where extraction is insufficiently constrained. Solar-irrigation programmes therefore need to be considered together with irrigation efficiency and groundwater management. Where farmers can earn revenue from electricity not used for pumping, electricity exports can provide an alternative value for solar generation. The example illustrates the interaction between energy, agricultural and water policy.

CIRCULARITY, REUSE AND END OF FIRST LIFE

The volume of PV modules reaching the end of their useful first lifetime is still marginal compared to the volumes of new PV modules deployed in the market. However, as the PV market develops rapidly, the same is expected for future waste volumes. A module can leave its first installation because of degradation, premature failure, damage, insurance claims, repowering or revamping. The timing of these flows is determined by economic and project decisions as well as technical lifetime.

A module removed from its first installation is not necessarily at the end of its technical life. Second-life markets can extend equipment use, but require testing, traceability and information on remaining performance to distinguish functioning equipment from waste. These requirements are particularly important where used modules move between countries, since weak quality control can transfer future treatment liabilities to buyers and markets with limited recycling capacity.

RESPONSIBILITY FOR COLLECTION AND TREATMENT

Depending on the country and region, end-of-life PV modules may be treated under PV-specific regulations or under general waste and disposal-related regulations. In the European Union, end-of-life PV module streams have been regulated by the WEEE Directive since 2012, based on extended producer responsibility.

Approaches remain diverse outside the European Union. The IEA PVPS Task 12 report Status of PV Module Recycling in IEA PVPS Task 12 Countries, published in September 2025, reviews regulatory developments and recycling practice across participating countries and provides detailed references for national recycling frameworks. The review shows that collection and treatment systems are developing under different combinations of PV-specific rules, general waste regulation and voluntary industry activity.

National approaches illustrate different ways of allocating end-of-life responsibility. Japan introduced mandatory reserves for dismantling and removal costs for larger FIT-supported systems; several Australian jurisdictions restrict disposal of PV modules to landfill and have developed stewardship approaches; China has supported demonstration recycling lines and dedicated industry infrastructure; and the USA has developed a network of specialised recyclers alongside state and industry initiatives. These approaches differ in whether responsibility is placed on producers, system owners, waste rules or dedicated financing mechanisms.

Who carries future collection and treatment costs and whether adequate infrastructure exists as larger volumes reach end of life is an important question with both economic and societal implications. Recycling economics remain sensitive to material values, process costs, transport distances and the price of new modules. Extended producer responsibility, recycling obligations and financial reserves can support collection and treatment capacity and reduce the risk that future costs fall on landowners or public authorities.

The economics also affect the hierarchy between continued use, repair and recycling. Very low new-module prices can weaken the incentive to repair or redeploy older equipment, while higher recovery rates and improved separation of valuable materials can improve recycling outcomes. Detailed process and lifecycle analysis is covered by IEA PVPS Task 12 reports.

DECOMMISSIONING AND SITE RESTORATION

For ground-mounted PV, end-of-life responsibility may extend to the project site. Decommissioning can require removal of modules, structures, foundations, cables and other equipment and restoration of land for agricultural or other uses. Planning requirements and financial guarantees can provide greater certainty that these future costs remain with project owners and clarify the condition in which land will be returned after project closure. Clear responsibilities for removal, site restoration and financing can reduce uncertainty for landowners and local authorities at the time a project is approved, particularly for projects occupying agricultural or leased land.

As PV deployment increases, societal outcomes increasingly depend on where systems are installed, who participates in decisions and economic benefits, how electricity-system costs are distributed and how responsibilities are managed over the full project lifecycle. These considerations increasingly form part of the conditions under which PV can continue to expand while maintaining public confidence and distributing benefits across consumers and host communities.

six

COMPETITIVENESS OF PV ELECTRICITY IN 2025

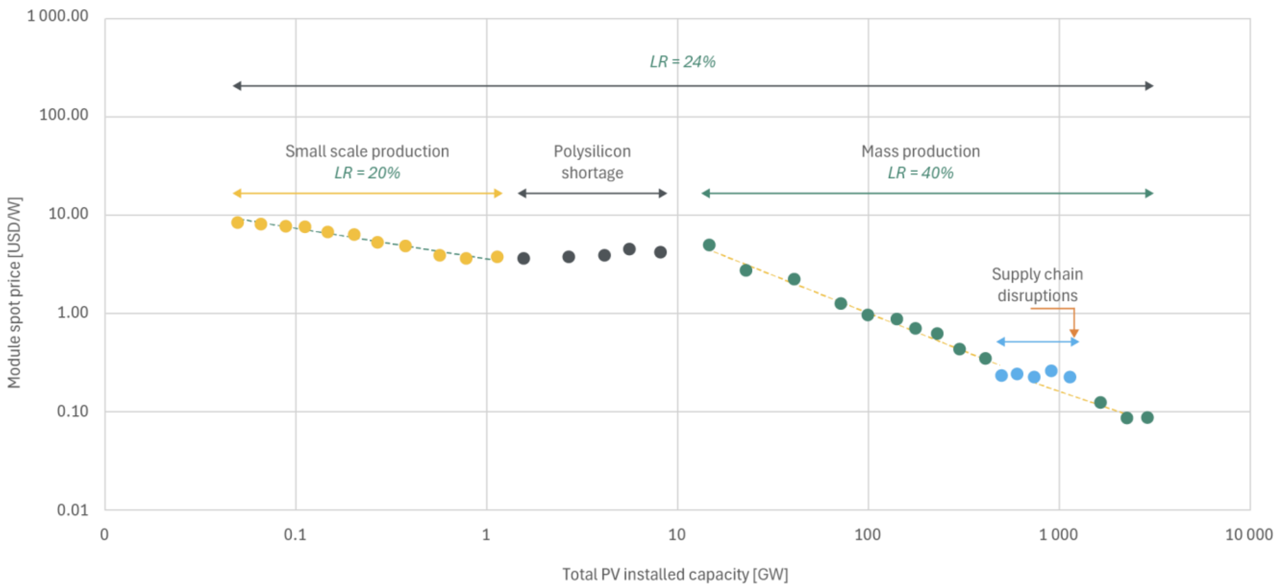
PV system prices remained at low levels in 2025, while module prices broadly stabilised after the sharp reductions of the previous two years. Continued manufacturing overcapacity maintained these low prices and have placed considerable pressure on manufacturer profitability. Competitiveness, however, depends on more than system costs - financing conditions, solar resource, grid connection, self-consumption level, export remuneration, curtailment and electricity-market prices can all influence the economics of a project.

Different indicators may be used to assess competitiveness depending on the type of project. System price or CAPEX represents the investment required to install a PV system, while the levelised cost of electricity (LCOE) represents the lifetime cost of the electricity produced.

Residential and commercial PV compete mainly with retail electricity prices and are strongly influenced by self-consumption and tariff structures. For self-consumers, the main economic value comes from the retail electricity cost avoided and the remuneration received for the electricity exported to the grid. Utility-scale projects are more directly exposed to financing conditions, wholesale market prices and grid access. Tender and power purchase agreement (PPA) prices represent remuneration under specific commercial contracts. In wholesale markets, the capture price corresponds to the average market price received during the hours in which PV generates electricity. Off-grid systems compete with the cost of alternative electricity supply, including fuel, transport and maintenance.

MODULE PRICES

FIGURE 6.1: PV MODULE SPOT PRICE LEARNING CURVE (1992-2025)



MODULE PRICES / continued

The evolution of PV module prices can be divided into three main phases. Early small-scale production, up to around 2 GW of cumulative PV capacity, as manufacturing volumes increased and production processes improved (price learning rate of about 20%). A period of slower price reductions (up to around 10 GW manufacturing capacity) followed, with limited polysilicon availability constraining supply and prices at relatively high levels. Mass manufacturing, particularly in China, launched a third phase, with economies of scale, technology improvements and increasingly integrated supply chains for a price learning rate of around 40%. Temporarily interrupted in 2021 and 2022 by supply-chain, raw material and transport constraints, recent large additions of polysilicon, wafer, cell and module manufacturing capacity have supply growing faster than demand. The industrial causes and consequences of this overcapacity are discussed in Chapter 4.

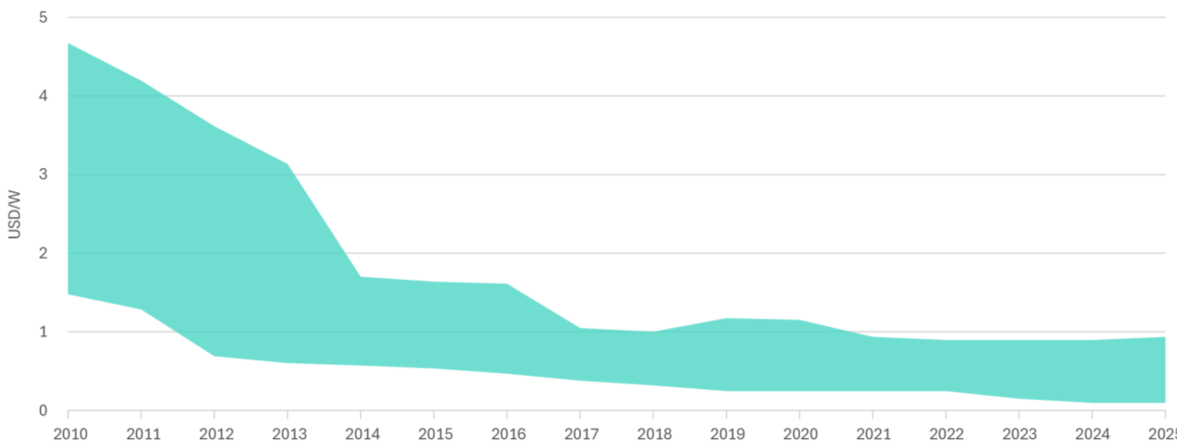
Module prices remained at very low levels in 2025, although the prices in national markets varied according to technology, market segment and distribution channels. At the lower end, module prices were around USD 0.09-0.10/W in **China**. European market prices for large order TOPCon modules were in a similar range, at approximately USD 0.10-0.12/W, as did **Korea**, where the upper range was around USD 0.18/W. Upper ranges were higher in **India**, and many European markets (**Belgium, Germany, Spain** and **Italy**, for example) from USD 0.28-0.44/W. Module prices seem to have had a larger spread in **Australia** and **Japan,** extending above USD 0.71/W or even USD 0.85/W.

These higher values (that represent a minority of the market volumes) include different module categories and technologies and are not directly comparable with bulk utility-scale procurement, with tariffs, trade measures, transport, taxation, local-content provisions and national distribution structures all affecting delivered prices. In addition, the position of the buyer on the value chain (as a distributer, installer or end user) materially affects the price, and reporting conventions differ from country to country. As a result, very low manufacturing prices are not transmitted uniformly between markets.

After the sharp declines observed in 2023 and 2024, module prices did not fall materially further during 2025 and remained at low levels. These prices reflected persistent manufacturing overcapacity. As production capacity is rationalised and manufacturers seek to restore viable margins, module prices may increase from these lows rather than continue past declines, at least for several years. This would not fundamentally alter the competitiveness of PV electricity because as module prices have declined, they represent a smaller share of total system cost in many applications. This is particularly visible in distributed PV, where inverters, mounting structures, electrical equipment, labour, customer acquisition, permitting and other soft costs can represent a substantial part of the installed price. Further reductions in module prices consequently have a smaller effect on the total cost of these systems.

FIGURE 6.3: INDICATIVE MODULE PRICES IN REPORTING COUNTRIES

FIGURE 6.2: EVOLUTION OF PV MODULE PRICES RANGE IN USD/W



SOURCE: IEA PVPS & OTHERS

SYSTEM PRICES

PV system prices[1] vary considerably according to system size, location, customer type, technical specifications, grid-connection requirements and the scope of costs included. The values presented here should be considered as indicative national price ranges and are for a selection of IEA PVPS countries only. Further detail is available in the IEA PVPS National Survey Reports.

The 2025 data continue to show a clear relationship between system size and installed price. Residential systems generally remain the highest-cost grid-connected segment, while commercial, industrial and centralised systems benefit progressively from economies of scale.

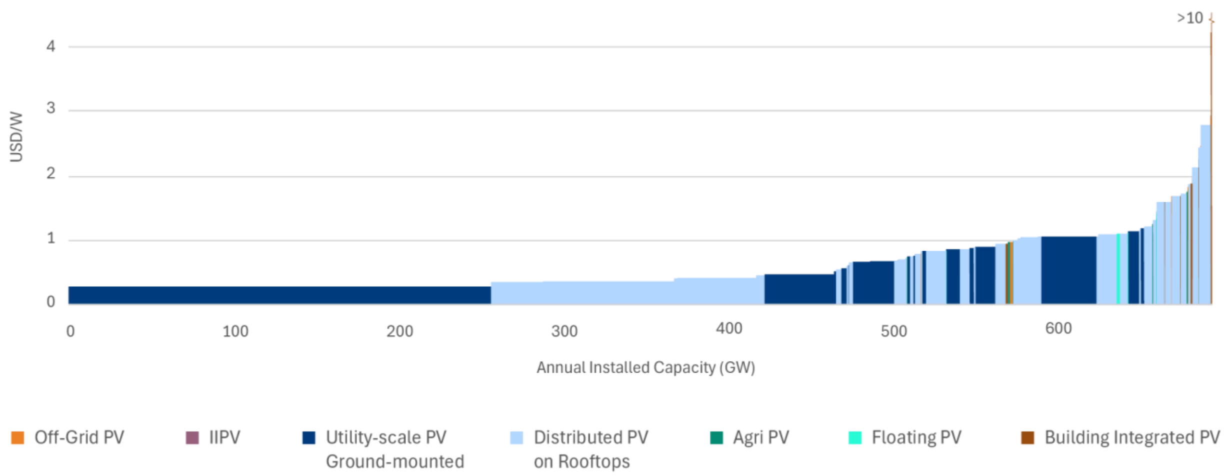
Residential system prices were particularly dispersed, with some of the lowest prices in China (around 0.46 USD/W), while many European and Asian markets were situated broadly between 1 USD/W and 2 USD/W. The USA, (2.9 USD/W) and Switzerland (3.55 USD/W) have some of the highest average end user system prices. With modules representing a smaller part of total residential system prices, differences in labour, balance-of-system components, administrative requirements and market structures are likely to account for the variation between countries.

Commercial and industrial system prices were generally lower and more concentrated. Indicative prices in China and India were around 0.4-0.5 USD/W, while many European and Asian reporting markets were situated in an approximate 0.6-1.0 USD/W range. Higher values remained in some markets where labour, development and other local costs were greater.

For the lowest-cost utility-scale segment, PV modules accounted for just 1/4 to 1/3 of the total installed system price. In China, utility-scale TOPCon module prices of around 0.09–0.10 USD/W compared with utility scale ground-mounted system prices of approximately 0.28–0.39 USD/W. Centralised utility scale PV were in the vicinity of 0.39 USD/W in India (with variations depending on the use of imported module vs Indian made modules), while a group including Brazil, Denmark, Portugal, Israel, Austria, Norway and Korea reported system prices at broadly between 0.5 USD/W and 0.7 USD/W. Higher values remained in markets including France, Italy, the USA and Japan.

Most commercial, industrial and centralised capacity represented in the reporting dataset of IEA PVPS countries was installed at system prices below 1 USD/W. Residential prices showed a wider distribution because local labour, administration, customer acquisition and other soft costs account for a larger share of the total price.

FIGURE 6.4: 2025 PV MARKET COSTS RANGES



Note: Utility and distributed PV are distributed according to volumes and costs. Floating, Linear, AgriPV and Offgrid PV are indicative average maximum/ minimum price points; the real costs are spread between these two points with outliers.

SOURCE: IEA PVPS

[1] System-price data are provided through IEA PVPS national reporting and converted to USD using yearly average exchange rates. System boundaries, system sizes and the inclusion of taxes, development expenditure, grid-connection costs and other components can differ between countries. Cross-country values should be interpreted as indicative market ranges rather than harmonised engineering-cost benchmarks.

SYSTEM PRICES / continued

FIGURE 6.5: EVOLUTION OF RESIDENTIAL AND GROUND-MOUNTED SYSTEMS PRICE RANGE 2014-2025 (USD/W)

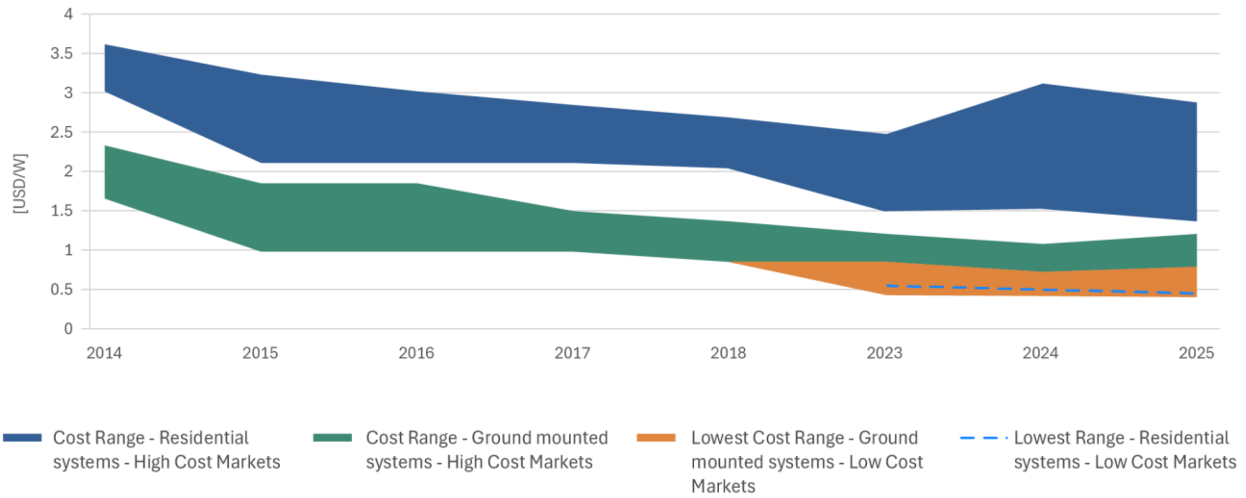


FIGURE 6.6: INDICATIVE INSTALLED SYSTEM PRICES IN SELECTED IEA PVPS REPORTING COUNTRIES IN 2025

Some applications have structurally different cost profiles. Floating PV requires anchoring and electrical designs adapted to water conditions; parking canopies require additional structural components; agrivoltaic systems range from relatively simple configurations used with grazing to elevated or mobile systems above crops; and installations along transport or other infrastructure can require additional engineering and connection works. BIPV can also involve higher PV-specific costs, although part of the investment can replace conventional roofing or facade materials.

The lowest installed price does not necessarily result in the lowest electricity cost. Trackers, higher-quality components, additional grid equipment or design features can increase initial investment while improving electricity yield or lifetime performance. Comparisons between projects are consequently more meaningful when based on lifetime electricity production and revenues rather than installed USD/W alone.

COST OF PV ELECTRICITY

The lowest system price does not always correspond to the lowest LCOE. The cost of PV electricity depends on investment cost, financing, operating costs, lifetime and electricity yield. Solar resource remains one of the main physical determinants: a similar system will produce more electricity in a location with higher irradiation, reducing the cost per MWh. Availability (time when repairs or faults have not taken the system offline), degradation and O&M also affect lifetime production. Comparisons between projects need to take into account yield, the cost of capital, operating performance and expected curtailment.

Financing conditions can create large differences between projects with similar equipment costs. Most capital outlays occur before electricity production begins, making the cost of capital an important component of PV economics. Higher interest rates, country risk, currency risk or uncertain project revenues can offset part of the benefit of low equipment prices. This effect is particularly relevant in markets where higher financing costs reflect greater economic, currency or project-related risks.

As equipment prices fall, project development, grid costs and financing conditions account for a larger share of differences in PV competitiveness between projects and markets. Land, permitting, network studies and connection infrastructure can materially affect total investment, while long connection queues can increase financing costs and expose projects to changes in equipment prices, contracts and policy conditions before energisation. Financing conditions can therefore outweigh differences in equipment costs: a project with low-cost, long-term finance may achieve a lower LCOE than an otherwise similar project with cheaper equipment but a higher cost of capital. Revenue uncertainty reinforces this effect, as exposure to volatile wholesale prices, curtailment or uncertain connection conditions increases investor and lender risk and can raise financing costs.

GRID PARITY, SELF-CONSUMPTION AND COMPETITIVENESS OF DISTRIBUTED PV

Grid parity refers to the point at which the cost of PV electricity falls below the retail electricity price paid by the consumer. It remains a useful indicator but no longer captures all aspects of distributed-PV competitiveness.

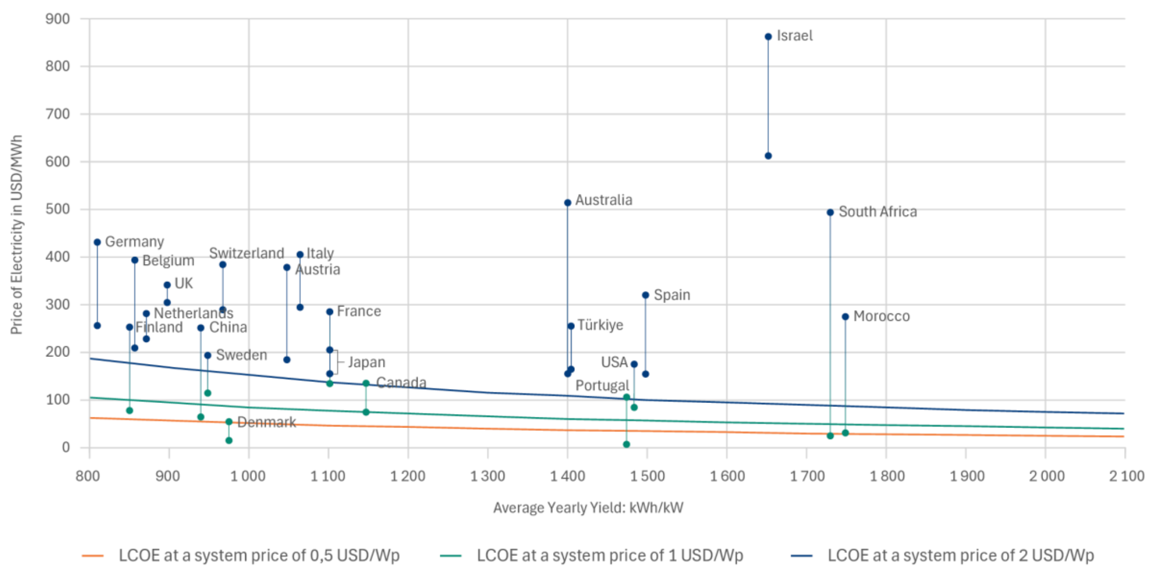
The value of a rooftop system depends on the share of generation self-consumed, the retail tariff components avoided, and the remuneration received for exports. Consumers with substantial daytime demand generally achieve higher self-consumption than households whose demand is concentrated after sunset.

Residential system prices also vary widely. In 2025, they ranged from below 0.50 USD/W in China to around 2.9 USD/W in the USA, while many reporting countries were between approximately 1 USD/W and 2 USD/W. Similar retail electricity prices can thus produce different levels of competitiveness depending on local system costs.

Electric-vehicle charging, water heating, heat pumps, batteries and other forms of demand management can increase self-consumption, while appropriate system sizing, collective self-consumption and energy communities can broaden the use of locally generated electricity.

If only part of PV generation can be self-consumed, the remainder must be exported where technically possible. Small systems are often remunerated through feed-in tariffs, net-billing or other export arrangements. Where grids are constrained or local generation exceeds demand, exports may instead be curtailed or receive substantially lower remuneration, as increasingly observed in parts of Australia, Austria and the USA.

FIGURE 6.7: LCOE OF PV ELECTRICITY AS A FUNCTION OF SOLAR IRRADIANCE COMPARED TO RETAIL PRICES IN KEY MARKETS*



* Note: the country yield (solar irradiance) here shown must be considered as an average.
The lowest electricity prices displayed per country should be seen as an average value for industrial consumers.
The highest electricity prices displayed per country should be seen as an average value for residential consumers.

GRID PARITY, SELF-CONSUMPTION AND COMPETITIVENESS OF DISTRIBUTED PV / continued

Retail electricity prices generally include four components: the electricity procurement price and supplier margin; grid costs and fees; taxes; and levies used for renewable-energy support, social programmes or other policy objectives. Self-consumption does not necessarily avoid all of these. Fixed network charges and some taxes or levies remain payable, while greater self-consumption can reduce revenues collected through volumetric network tariffs. Regulators are responding through fixed, capacity-based or time-dependent charges. The policy treatment of these questions is discussed in Chapter 3 and their societal implications in Chapter 5.

Export remuneration should be considered in the same context. Where local solar production exceeds demand, exported electricity may have lower market value than self-consumed electricity and may also face network limits. Self-consumption, export value, tariff structure and flexibility consequently provide a more complete indication of distributed-PV competitiveness than grid parity alone.

The same distinction between production cost and electricity value is increasingly important for utility-scale PV. For distributed systems, value depends primarily on avoided retail purchases and export remuneration; for market-exposed utility-scale projects, it depends on the wholesale prices occurring when PV produces and on the contractual arrangements used to stabilise those revenues.

For BIPV, the comparison differs where the PV component replaces conventional roofing, façade or shading materials. In these cases, the relevant cost is the incremental cost of the integrated PV solution compared with the building component it replaces.

Figure 6.7 above compares retail electricity prices in selected countries with indicative PV electricity costs across different solar resources and three assumed system prices of 0.5 USD/W, 1 USD/W and 2 USD/W. Blue dots indicate markets where PV is competitive across most of the assumed system-cost range, while green dots indicate cases where competitiveness remains more dependent on local system prices and retail electricity tariffs.

The comparison shows that grid parity remains broadly established across most IEA PVPS reporting countries, although the margin of competitiveness varies by market segment. In most countries, the lower electricity-price range corresponds to commercial and industrial consumers and the upper range to residential consumers, with France remaining an exception. Electricity-price increases during 2022 strengthened the competitiveness of distributed PV, while subsequent reductions in commercial electricity prices in several European markets during 2023-2025 were partly offset by lower PV system and module costs. Grid parity consequently remains widespread, although self-consumption levels, export remuneration and tariff structure increasingly determine the actual economics of distributed PV.

COMPETITIVENESS OF PV ELECTRICITY WITH WHOLESALE ELECTRICITY PRICES

In markets with wholesale electricity trading, the price received when PV generates is becoming an important factor in the competitiveness of utility-scale PV. In important distinction has then to be made between the cost of PV generation and the market value of that generation. A project can have a low system price and low LCOE while obtaining weaker revenues if a large share of its generation occurs during periods of very low or negative prices. Merchant projects are more exposed to this risk (usually referred to as price cannibalisation) than projects with long-term contracted revenues.

When a wholesale market does not exist as such, the comparison point (generation-cost competitiveness) is the production cost of electricity from coal-fired power plants.

Merchant and market-exposed PV business models carry more revenue risk than long-term contracted schemes, largely because rising PV penetration is pushing prices toward zero or below during midday peaks. In Germany, roughly a quarter of solar generation now occurs during negative-price periods; in Queensland and Victoria (Australia), that share has passed 40%. Utility-scale solar capture rates, the ratio between what solar actually earns and the average wholesale price, have fallen accordingly: from over 100% in 2018 to below 60% by 2025 across several major European markets including France, Spain, Germany and the Netherlands, and even more steeply across Australia's National Electricity Market, where Victoria and Queensland have dropped from around 100% in 2018 to under 30%, and South Australia to under 50%. Greater flexibility, especially paired with storage, can help restore the market value of solar by shifting output toward higher-priced hours.

Government-supported schemes have tightened their rules in response. In the UK, Contracts for Difference awarded from the fourth Allocation Round no longer pay out during negative day-ahead price hours. Germany's EEG originally withheld the market premium only after six consecutive hours of negative prices; a 2025 reform cut this threshold to a single hour. Both changes push developers further into direct wholesale price exposure. Rising balancing costs, up to eightfold in some markets over five years, add further uncertainty, with negative prices now recorded across Australia, the USA and numerous European countries.

SOLAR + STORAGE COMPETITIVENESS

As solar penetration increases, the competitiveness of PV increasingly depends on when electricity can be delivered for consumption. Storage allows part of daytime production to be transferred to periods of higher demand and higher prices, that often occur in the early evening. The economics of a combined solar-plus-storage system depend on the additional storage cost compared with the value recovered through energy shifting, reduced curtailment, capacity or balancing revenues and other grid services.

The IEA estimates that average utility-scale battery-storage project costs fell by around 40% in 2024 to approximately USD 150/kWh, and that battery-pack prices continued to decline in 2025. Whilst complete solar-plus-storage costs depend on battery duration (generally anywhere from 2h in emerging battery markets to 6h to 8h in the more mature battery markets such as Australia and in some parts of the USA and China), system configuration, shared equipment, grid connection arrangements and financing.

Storage co-location is becoming the default response where capture rates have collapsed, both to shift output in time and to unlock a wider stack of grid-service revenues for the combined asset and capabilities. The complementary risk profiles of solar PV and storage can also improve financing conditions (e.g., gearing ratios), making co-located projects bankable where standalone PV face important prohibitive financing constraints. But standalone PV can still access services and revenue beyond simple energy sales.

Storage is most valuable where electricity prices vary substantially during the day or where PV output is exposed to curtailment. Charging during periods of high solar generation and low prices and discharging later can increase the capture price of the combined system, although additional investment and operating costs, conversion losses and degradation must be balanced against the current and future benefits of changing the time and value at which electricity is delivered.

For distributed PV, storage can increase self-consumption and reduce grid purchases during higher-priced periods, particularly when time-of-use structures exist for consumption from the grid (either for commodity component or network tariffs component of retail electricity prices).

The value of co-location depends on battery duration, connection capacity, charging arrangements and access to electricity, balancing and ancillary-service markets.

Operating a solar-+-storage system can require increasingly complex optimisation between several possible actions: exporting PV generation directly to the grid, charging the battery, discharging stored electricity, retaining available battery capacity for later periods, or temporarily doing nothing where prices or grid conditions are unfavourable all of which while complying with eligibility rules for PV support schemes. The most economic choice can change over the course of the day according to electricity prices, forecasts of PV generation and demand, battery state of charge, degradation costs, network constraints and the availability of balancing or ancillary-service revenues. A range of optimisation, aggregation and energy-management services is developing to manage these automatically and maximise the combined revenues of PV and storage assets.

This increasingly active management of PV and storage is supported by the evolution of inverter and control technologies. PV systems have moved from passive grid users, which fed in maximum power and disconnected at the first sign of disturbance, to active participants offering grid-support functions such as Volt-VAR and Frequency-Watt control under both normal and disturbed conditions. Most regulatory frameworks now still treat this participation as a connection requirement rather than a paid service. Under IEEE 1547-2018 in the USA, distributed energy resources must be able to inject or absorb reactive power. The EU's Network Code on Requirements for Generators (Regulation (EU) 2016/631) similarly obliges reactive power and frequency-stabilisation support, transposed into national codes. Comparable obligations apply in China, Brazil, Australia and Egypt. Genuine additional revenue, distinct from these obligations for standalone PV, remains limited but does exist in specific markets.

From a competitiveness perspective, mandatory grid-support functions represent a connection requirement, while separately procured ancillary services can provide additional revenue. The same battery capacity cannot necessarily be used simultaneously for energy shifting and other services, so revenue streams should be assessed together.

TENDERS, PPAS AND CONTRACTED PV PRICES

Tenders and PPAs remain widely used to secure long-term revenues for PV projects. Tender and PPA prices reflect the allocation of project and remuneration risks as well as generation cost. Contract duration, indexation, currency, financing, land, grid connection, curtailment provisions and guarantees can all influence the contract price and price structure. Government auctions, utility PPAs and corporate PPAs can consequently result in different remuneration even for projects with similar generation costs.

Tender prices reached record-low levels in 2020 and 2021, before higher electricity-market prices and financing costs contributed to higher contracted prices in Europe, the USA and Australia during 2022 and 2023. Prices moderated again in 2024, with several contracts below 40 USD/MWh and a tender in Saudi Arabia at 12.9 USD/MWh, the second-lowest value in the reported historical series in Table 6.1, after the 10.4 USD/MWh Saudi Arabian result in 2021. The historical lowest bids also show the importance of regional conditions: values below 20 USD/MWh have been recorded in the Middle East, Europe and Latin America, while the lowest values recorded for Asia, Africa and North America remain higher.

Government-supported solar procurement (i.e., competitive tenders) in 2025 continued to produce a wide range of prices across markets. In Saudi Arabia, competitive procurement resulted in some of the lowest long-term solar PPA prices globally, at around 11 USD/MWh, while government tenders in Ireland and France resulted in substantially higher support prices, around 100 to111 USD/MWh.

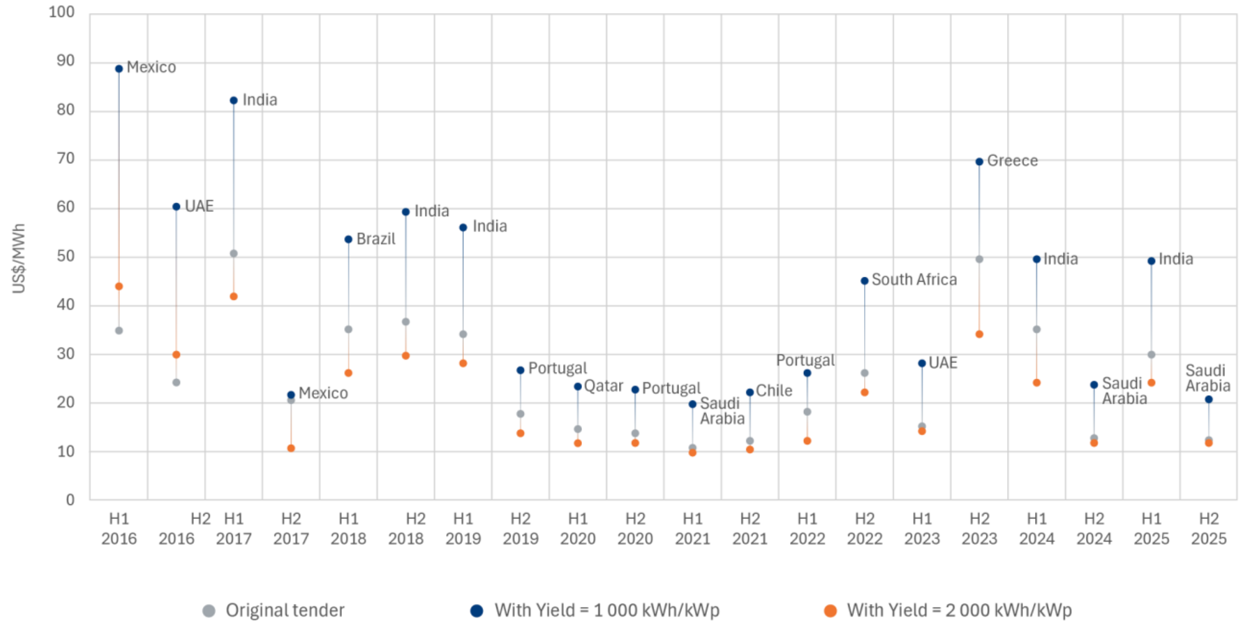
TABLE 6.1: TOP 10 LOWEST WINNING BIDS IN PV TENDERS FOR UTILITY SCALE PV SYSTEM

Region	Country	USD/MWh	Year
Middle East and Africa	Saudi Arabia	10,40	2021
Middle East and Africa	Saudi Arabia	12,90	2024
Europe	Portugal	13,20	2020
The Americas	Chile	13,32	2021
Middle East and Africa	UAE	13,53	2020
Middle East and Africa	Qatar	14,49	2020
Europe	Spain	14,98	2021
Europe	Portugal	16,02	2019
Middle East and Africa	UAE	16,20	2023
The Americas	Brazil	17,50	2019

Values are nominal and not adjusted to 2025 currency

SOURCE: IEAPVPS

FIGURE 6.8: REPORTED SOLAR TENDER/PPA PRICES NORMALISED FOR REFERENCE SOLAR YIELD, 2016-2025



* Based on lowest PPA prices per semester

SOURCE: IEA PVPS & OTHERS

TENDERS, PPAs AND CONTRACTED PV PRICES / continued

In Southeast Asia, government procurement prices were also varied, at approximately 34 to 39 USD/MWh in **Malaysia**, around 76 USD/MWh for ground-mounted solar under the **Philippines** auction ceiling, and approximately 38 to 53 USD/MWh in **Vietnam** under regional generation-price ceilings, although these values are should not be directly compared because they reflect different procurement structures, contract terms and risk allocation.

Private PPA markets showed a different pattern. In **North America**, solar PPA offer prices generally increased during 2025, with some market indicators ending the year almost 9% higher year-on-year. Upward pressure was particularly strong in California, while eastern **USA** markets also remained relatively strong amid grid-connection constraints, development costs and sustained corporate demand. This contrasted with **Europe**, where reported solar PPA offer prices declined during 2025 as increasing solar penetration and low midday wholesale prices reduced the value of unshaped solar generation.

The range illustrates the continuing influence of financing, contract design, grid conditions and project requirements in addition to solar resource and system cost. Figures 6.8 and 6.9 normalise reported prices to reference solar yields to facilitate comparison between markets; this normalisation does not represent the LCOE of the underlying projects.

Long-term contracts remain attractive because of the greater certainty they provide over future electricity revenues and expenditure. For generators, they reduce exposure to wholesale-price and capture-price volatility; for commercial and industrial buyers, they can provide greater visibility over future electricity costs after the market volatility observed in 2022 and 2023. The high level of certainty when it comes to solar generation levels and operating costs also facilitates long-term contracting, although buyers and generators may value this stability differently depending on expected wholesale-market prices.

As cumulative installed capacity ages, contracting is also beginning to concern systems reaching the end of initial feed-in tariffs, support mechanisms and first PPAs. Whilst most early solar PPAs were for new projects, refinancing, repowering and new contracts for operating projects are expected to represent a growing share of contracting activity alongside PPAs for new capacity.

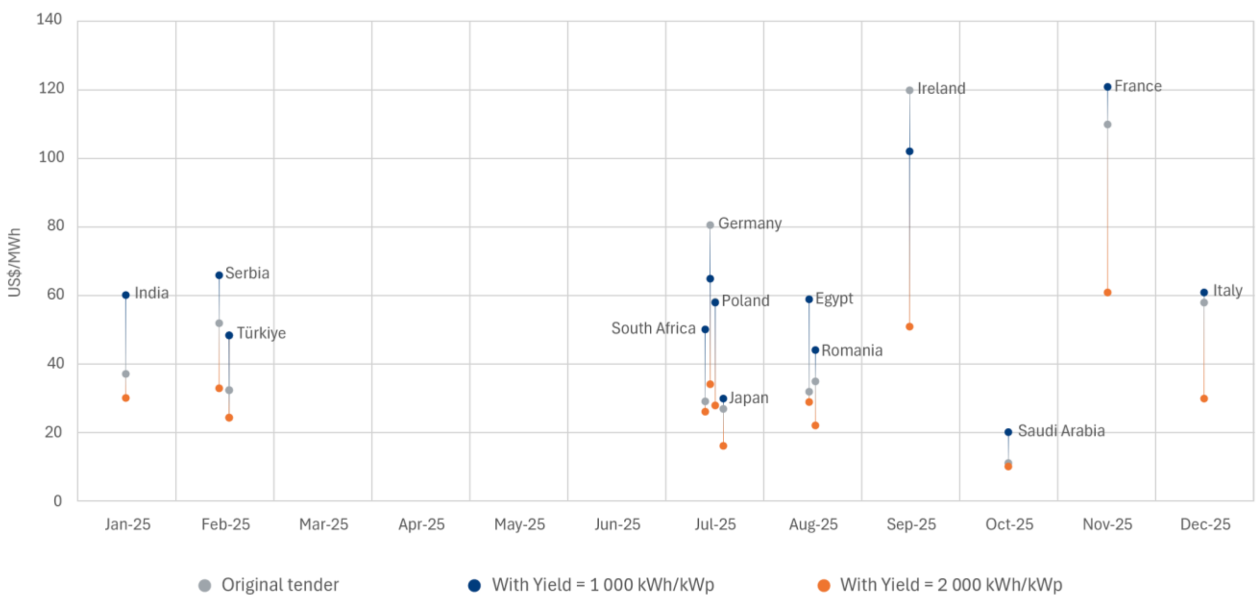
TABLE 6.2: LOWEST WINNING BIDS IN PV TENDERS FOR UTILITY SCALE PV SYSTEM PER REGION

Region	Country/State	USD/MWh	Year
Asia	Uzbekistan	17,9	2021
Africa	Tunisia	24,4	2019
Europe	Portugal	13,2	2020
Latin America	Chile	13,3	2021
North America	Mexico	20,6	2017
Middle East	Saudi Arabia	10,4	2021

Values are nominal and not adjusted to 2025 currency

source: IEA PVPS

FIGURE 6.9: REPORTED 2025 SOLAR TENDER/PPA PRICES NORMALISED FOR REFERENCE SOLAR YIELD



SOURCE: IEA PVPS & OTHERS

FUEL PARITY AND OFF-GRID COMPETITIVENESS

Off-grid PV and hybrid PV-diesel systems have a different benchmark for competitiveness. The relevant alternative is generally the delivered cost of diesel-generated electricity or another local supply option rather than the wholesale or retail grid price.

Off-grid systems remain more expensive on a USD/W basis than the lowest-cost grid-connected systems. Reported 2025 prices are broadly around 0.9-1.3 USD/W in India and Morocco, around 0.9-1.1 USD/W in Korea, and higher for some configurations in Australia. These prices can include differences in storage, power electronics, scale and the additional transport and installation requirements of remote sites.

Fuel parity describes the point at which avoided fuel expenditure can finance the PV investment. In remote applications, avoided fuel transport and generator maintenance can also contribute to the economic value. Lifetime delivered electricity cost and reliability give a more complete comparison than the installed PV price.

This is particularly relevant for remote mining sites, where electricity has traditionally been supplied by isolated diesel or gas power systems. PV is increasingly moving beyond incremental fuel displacement and becoming a major determinant of the design and operation of these systems. In Australia, for example, early mining projects used PV primarily to reduce daytime diesel consumption, whereas larger hybrid systems now combine PV, batteries and thermal generation and can supply most or, for periods, all daytime electricity demand. The 60 MW Fortescue solar project in Western Australia, combined with a 35 MW battery and existing thermal generation, illustrates this progression towards renewable generation becoming the central operating resource rather than an auxiliary fuel-saving measure.

Where off-grid PV provides electricity to a location that previously had little or no electricity supply, no existing generation cost may be available for direct comparison. These systems are more appropriately assessed against alternative electrification options. Their wider societal implications are discussed in Chapter 5.

seven

PV IN THE ENERGY SECTOR

At the end of 2025, cumulative global installed PV capacity reached approximately 2.96 TW, adding 0.69 TW during the year. At this scale, PV is no longer a marginal source of electricity in a growing number of markets: Its contribution increasingly extends beyond annual energy production to the timing and location of electricity supply, system adequacy, grid services and resilience.

PV ELECTRICITY PRODUCTION

ESTIMATING PV PRODUCTION

Estimating PV electricity production is easy to measure at a power plant but much more complicated to compile for an entire country. Installed capacity must be accurately tracked, which requires an effective and consistent approach and the commissioning date of new capacity impacts the electricity actually generated during the year. A system installed at the end of the year will have produced only a small fraction of its theoretical annual electricity output. Estimates also differ from actual production because of system orientation, shading, degradation, availability and curtailment.

For these reasons, the electricity production from PV per country in this report is an estimate of what the minimal theoretical production should be the following year, when all the PV systems installed at the end of the year have generated electricity for one year.

To calculate this "next year's minimal theoretical PV production", an average solar yield in the country is used. Depending on the country, this value is either provided through National Survey Reports and is calculated as the total solar generation divided by total solar capacity, or is a representative value taken from geographical irradiance atlases – The assumptions and limitations are detailed in the Methods Annex.

Nationally produced statistics on solar generation will in general reflect real production injected into the grid – consequently, in years with high new capacity additions, especial late in the calendar year, the theoretical value used here can be well above official statistics for the current year. Behind-the-meter generation and batteries further complicate this comparison because part of PV production may not be directly visible to transmission-system statistics. This incomplete visibility is increasingly relevant not only for statistics but also for load forecasting and network planning.

PV PENETRATION

PV electricity penetration can be two different indicators – either the installed capacity per capita, as seen in Chapter 2; or, as used here, the share of electricity consumption supplied by PV generation. For the purposes of this chapter, the theoretical penetration rate is the ratio between theoretical annual PV production and electricity consumption.

The PV penetration rates here are an estimate and are likely to differ from official PV production and penetration numbers in many countries for the reasons detailed above - they should be considered as indicative, providing a reliable estimation for comparison between countries and do not replace official data.

As demonstrated in Table 7.1, 26 countries have potential theoretical PV penetration rates above 10%, 17 over 15% and five are above 20%.At the top, Greece and Spain over 27%, Australia and the Netherlands at 21%[1].

For Pakistan the theoretical value of 35% is subject to substantially greater uncertainty because installed capacity, grid outages, behind-the-meter production and curtailment are not fully observed. It should not be interpreted as a measured national generation share.

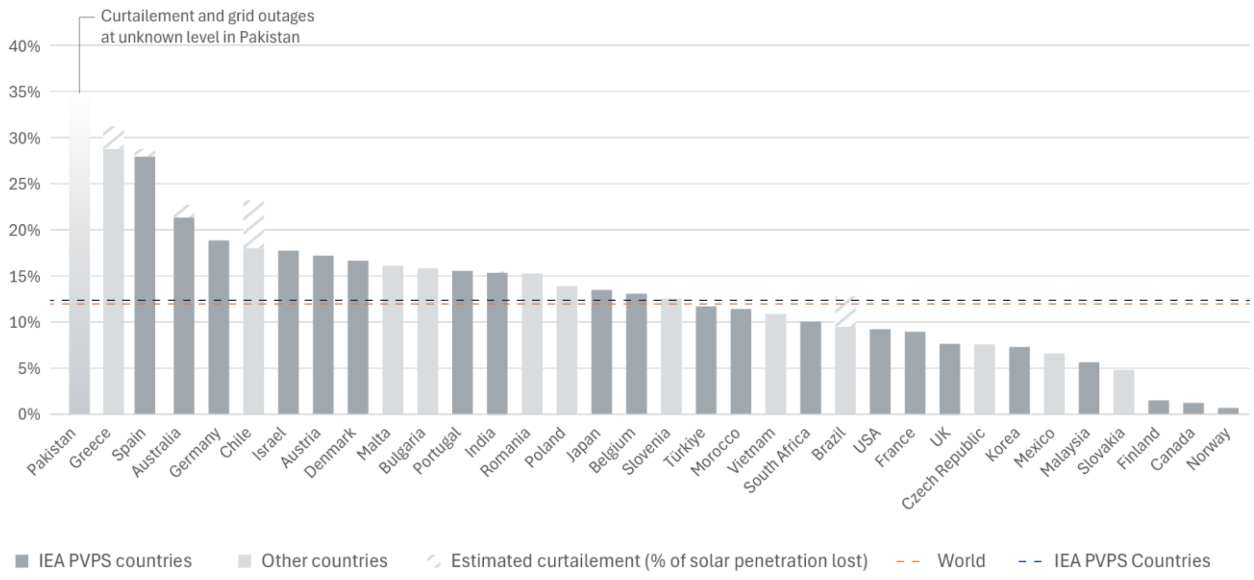
Concerning global PV penetration, with around 2.96 TW installed worldwide, PV could produce approximately 3 846 TWh of electricity on a yearly basis if an average yield of 1 300 kWh/kWp is considered. This represents around 12% of global electricity consumption.

PV accounted for approximately 6.9% of measured global electricity generation in 2025, while renewable sources together accounted for about 31.9%, according to IEA data (Figure 7.3). The share in annual *generation* is mechanically lower than the 12% theoretical penetration in consumption because it is calculated from end-2025 cumulative capacity but also because final electricity consumption is lower than total electricity generation as it has electricity used within the power system and losses in transmission and distribution deducted.

[1] See the Methodological Annex for an explanation of the methodology used. Official statistics may differ significantly depending on their scope and denominator. For example, the Spanish transmission system operator reports PV at 18.4% of recorded electricity generation in 2025, rising to 21.3% when estimated self-consumption is included. These figures do not fully capture small-scale systems and are not directly comparable with the consumption-based penetration indicator used in this report.

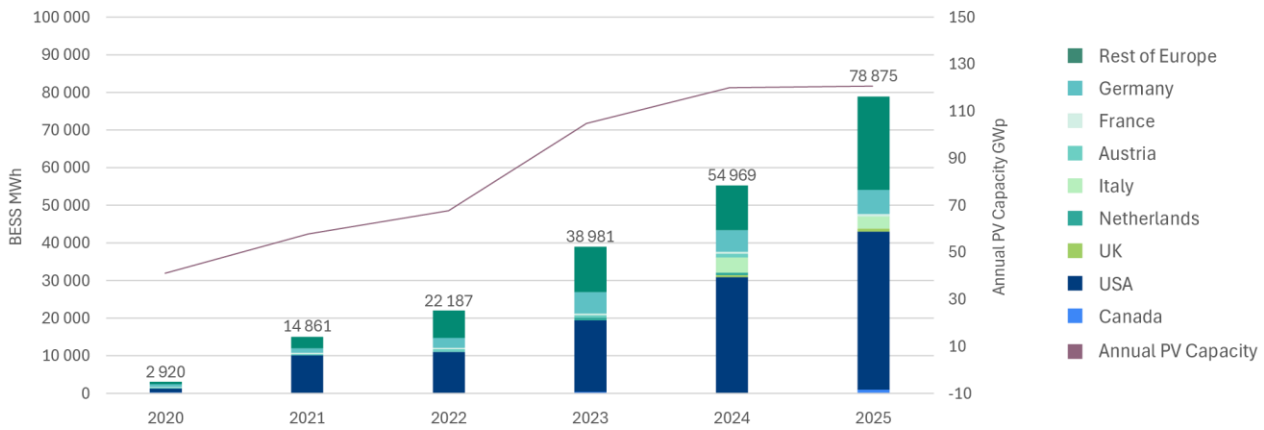
PV ELECTRICITY PRODUCTION / continued

FIGURE 7.1: PV CONTRIBUTION TO ELECTRICITY CONSUMPTION 2025



SOURCE: IEA PVPS COUNTRIES

FIGURE 7.2: ANNUAL BATTERY ENERGY STORAGE SYSTEM (BESS), SELECTED COUNTRIES



SOURCE: IEA PVPS, SPE, PVAUSTRIA, CANREA, ENEDIS, BATTERY CHARTS .DE, TERNA, CBS, SISTEMAELECTRICO, GOV.UK

FROM ELECTRICITY PRODUCTION TO A BROADER SYSTEM CONTRIBUTION

PV penetration measured over a year does not describe the timing of production or the conditions experienced by the electricity system at individual hours. As PV generation and penetration increases, daytime demand after self-consumption can fall substantially with remaining demand peaking in the late afternoon or evening, when PV production is declining. In this context, the contribution of additional P-only systems to the system overall can decrease.

Storage, flexible demand, interconnection and complementary generation can extend the contribution of PV beyond solar-production hours. IEA PVPS Task 16 work on Firm Power Generation shows that firm supply from systems with high shares of solar and wind can be achieved through cost-optimised combinations of complementary renewable resources, short-term storage, demand flexibility and, where appropriate, limited dispatchable generation. Overbuilding renewable capacity with controlled curtailment can also reduce the requirement for long-duration storage. This changes the interpretation of curtailment at high penetration. Whilst curtailment caused by network constraints represents electricity that could not be delivered, controlled overbuilding can also be part of an economically optimised system where additional PV capacity is less costly than storing every surplus kWh.

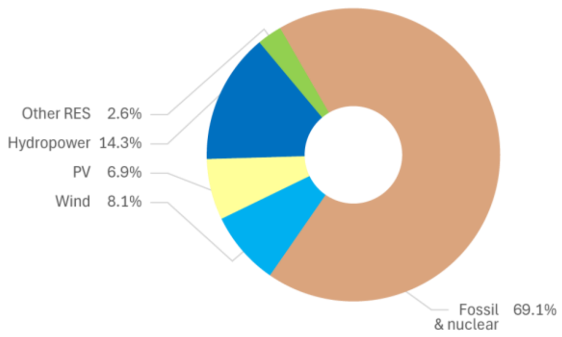
STORAGE AND THE TIMING OF PV SUPPLY

Storage is one flexibility option among several and need not be the preferred solution where demand can be shifted directly towards solar hours. Despite the presences of alternatives (electrolysis for hydrogen, demand side management, pumped hydro, thermal storage....) battery costs are dropping fast and deployment is increasing rapidly alongside PV. Across the selected countries represented in Figure 7.2, annual BESS energy-capacity additions increased from 2.9 GWh in 2020 to 79 GWh in 2025, whilst annual PV additions in the same group of markets also increased substantially.

Storage changes the contribution of PV to an energy system. Batteries can shift part of PV production into later hours, reduce peak injections and curtailment, and provide fast-response services independently of instantaneous solar production. Consequently, the role of storage differs according to local system needs. In Australia, more than 165 000 household batteries were installed in the second half of 2025, adding around 4.3 GWh of storage and beginning to influence evening peak demand. In Japan, a 1 MW PV plant combined with a 500 kW / 1.9 MWh battery and an energy-management system is being demonstrated as a microgrid providing local supply, congestion relief and continuity of supply during large outages.

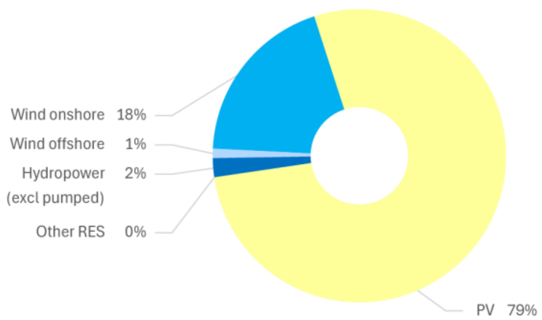
The form of integration constraints also differs between markets. In Canada, PV penetration remains low enough in many regions that grid congestion or curtailment is not yet a major issue. In the USA, both system-wide curtailment during periods of oversupply and local curtailment caused by transmission congestion are increasingly relevant. In Austria and Switzerland, constraints are also visible at distribution level through voltage rise, limited connection capacity or restricted export rights

FIGURE 7.3: SHARE OF RENEWABLES IN THE GLOBAL ELECTRICITY PRODUCTION IN 2025



SOURCE: IEA

FIGURE 7.4: NEW RENEWABLE INSTALLED CAPACITY 2025



SOURCE: IEA PVPS, GWEC, IHA, REN21

PV INVERTERS AND GRID SERVICES

The system contribution of PV is not limited to energy production or peak capacity. Modern PV inverters can adjust active and reactive power and contribute to voltage control where plant configuration and operating rules permit. Better integration requires not just accommodating variable generation, but also adapting operating rules so that available inverter capabilities can be used by system operators to the benefit of the grid and its users as a whole.

The April 2025 blackout in continental Spain and Portugal illustrates this evolving context. The ENTSO-E Expert Panel concluded that the event resulted from a combination of interacting factors, including oscillations, gaps in voltage and reactive-power control, differences in voltage-regulation practices, rapid output reductions and generator disconnections. It did not attribute the event to a single technology.

Following the event, implementation of the revised Spanish P.O. 7.4 voltage-control arrangements was accelerated, extending participation to renewable generation able to demonstrate the required reactive-power and voltage-control capabilities. This illustrates how operating rules developed around conventional generation may need to evolve as inverter-based generation becomes more significant.

FROM ELECTRICITY PRODUCTION TO A BROADER SYSTEM CONTRIBUTION / continued

FIRM POWER

Grid-connected solar power generation, either distributed or centralised, has developed and grown at the margin of a core of dispatchable and baseload conventional generation. As in many countries PV production comes close to, or is even higher than demand load, running PV under the “generate and forget” mode is no longer feasible.

The challenge ahead for grid-connected solar is to go beyond the margin and the context of underlying conventional generation management. As for wind, the transformation of intermittent variable solar power generation into firm, effectively dispatchable, power generation is a prerequisite to the gradual displacement of the underlying conventional generation core.

In principle the Task 16 firm power approach is to calculate cost optimal LCOE by optimising different renewable options, curtailment and storage (Figure 7.5).

It may be contra-intuitive, but curtailing renewables – not using every kWh – is making renewable energy systems much cheaper, and are a prerequisite to run electricity systems with very high shares of renewables.

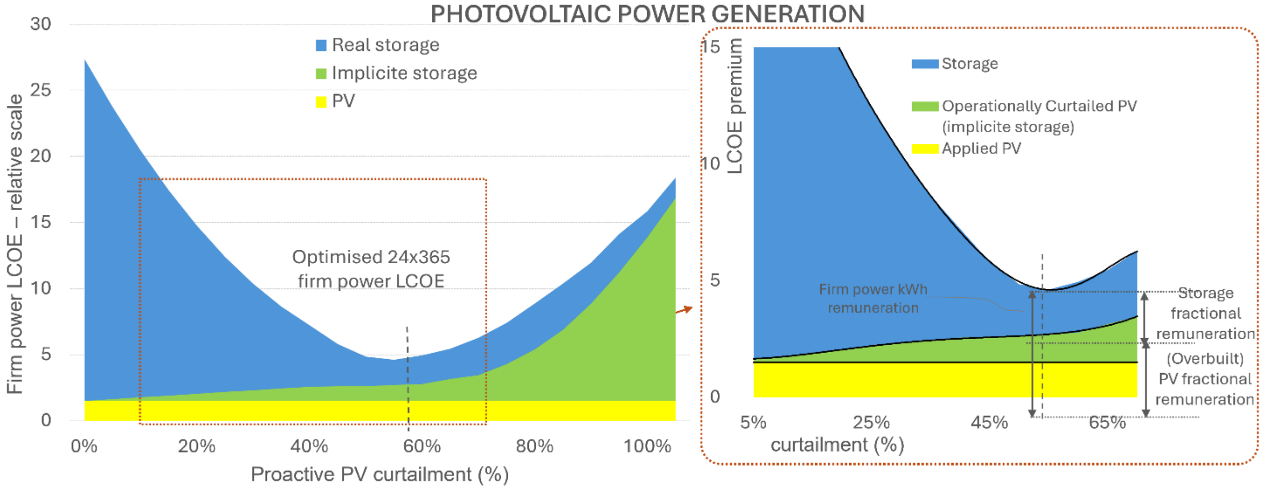
In February 2026 Task 16 published its latest Firm Power Generation 2026 report[2]. This updated report incorporates over 25 examples of firm power studies and reinforces the existing findings:

- Analyses of hourly supply–demand balancing across diverse regions finds that fully renewable VRE systems can economically provide year-round electricity.
- VRE Overbuilding and curtailment are essential key drivers, showing that firm power can be supplied at low cost, even without seasonal storage or large cross-continental grid expansion
- Limited dispatchable thermal generation using e-fuels can lower overall system costs.
- Market reforms are crucial to unlocking the least-cost firm power configurations.

Firm renewable power is not only technically achievable but also economically competitive. Realizing this vision requires advanced modelling, strategic system design, and—most importantly—market reforms to support new configurations.

Optimal firm power configurations – particularly the amount of VRE overbuilding – depend on local resources, strategic assumptions, and system capabilities - such as access to low-cost supply-side flexibility or sector coupling. The studies presented span a range of scenarios, from 'tabula rasa' models with VRE-only generation and new e-fuel flexibility, to configurations integrated into regional systems with existing flexible renewable generation or mature sector coupling options.

FIIGURE 7.5: COST OPTIMIZATION AND REMUNERATION STRATEGY FOR FIRM PHOTOVOLTAIC POWER GENERATION



NOTE: Left panel shows how proactive curtailment minimizes LCOE; right panel illustrates a possible capacity-based remuneration model for PV and storage [note: a similar proportional revenue distribution strategy could be applied for firm power configurations including wind and flexibility in addition to PV and storage]

SOURCE: Marc Perez / Richard Perez IEA PVPS TASK 16

[2] https://iea-pvps.org/key-topics/t16-firm-power-generation-2026/

FROM ELECTRICITY PRODUCTION TO A BROADER SYSTEM CONTRIBUTION / continued

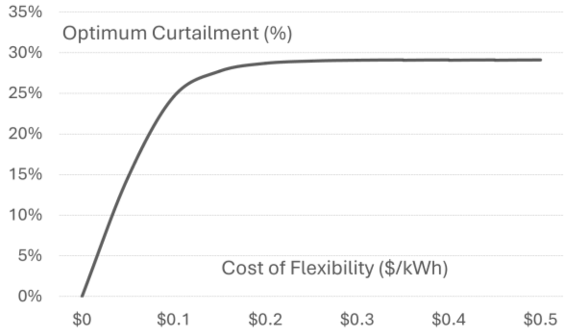
The results show that overbuilding and curtailment are essential parts of a new renewable energy system. Only in cases with very high and cheap shares of flexibility (e.g., flexible hydro power) are optimal curtailment levels small (a few percent). In Task 16's most recent publications, the relation between costs of storage and flexibility levels versus curtailment rates were analysed (Fig. 7.6). The assumptions regarding costs of flexibility are also the reason for strongly varying outcomes regarding curtailment levels in different studies.

However, curtailment isn't rewarded in today's market and subvention schemas. The economics are still mostly dependent on energy delivery. Due to the – effectively natural effect of – price cannibalisation in the energy-based spot market of solar (and wind) will deliver only marginal and highly variable incomes. Incentivizing the potential generation by supporting capacities (e.g., by auctions) could be an effective incentive.

Without changes in the subvention schema the risk is high that investments security will be too low to obtain the needed PV and wind fleets.

The Task 19 Energy Economy Subtask is working on market questions. A first paper about different market and subvention schemas in Europe has been published[3] and the analyses of reasons and effects of negative prices has begun.

FIGURE 7.6: COST-OPTIMAL CURTAILMENT AS A FUNCTION OF FLEXIBILITY'S OPEX



SOURCE: Marc Perez / Richard Perez IEA PVPS TASK 16

IEA PVPS TASK 16 – SOLAR RESOURCE FOR HIGH PENETRATION AND LARGE-SCALE APPLICATIONS

As PV penetration increases, higher-quality solar-resource data and improved spatial and temporal resolution are needed to optimise PV performance and power-system operation. Task 16 develops improved assessment and forecasting methods, including the use of AI.

The Task focuses on:

1. Solar resource assessment, including long-term climate impacts on applications such as bifacial PV, floating PV and agrivoltaics.
2. Solar forecasting for reliable and cost-effective operation of grids with high PV penetration and utility-scale PV-plus-storage, from minute-ahead to seasonal horizons.

Current priorities include sub-seasonal and seasonal forecasting, extreme events and climate change including *Dunkelflauten*, and best practices for the application of AI. Beyond meteorological and climate data, Task 16 also addresses grid integration through its Firm PV Power activity

See the Task publications on the IEA PVPS website: https://iea-pvps.org/research-tasks/solar-resource-for-high-penetration-and-large-scale-applications/

[3] M. McCulloch et al., "Integrating Solar PV into Energy, Capacity and Balancing Markets: An International Comparative Analysis of Market Design and Regulation," 2026 22nd International Conference on the European Energy Market (EEM), Trondheim, Norway, 2026, pp. 1-8, doi: 10.110 9/EEM68581.2026.11589789

FROM ELECTRICITY PRODUCTION TO A BROADER SYSTEM CONTRIBUTION / continued

RELIABILITY, AVAILABILITY AND RESILIENCE

As PV supplies a larger share of electricity, the predictability of supply from the installed capacity becomes increasingly important. Output can be affected by module and inverter degradation, component failures, soiling, vegetation and extreme conditions including cyclones, hail, snow, dust and sandstorms, heatwaves, floods and wildfires. Monitoring, data analytics and predictive maintenance can help identify faults and changes in performance, while drones, imaging techniques and automated inspection are increasingly used to support operation and maintenance of large-scale systems.

Improved resource assessment and forecasting are also central to IEA PVPS Task 16 work on high-penetration PV, where regional forecasts can support scheduling, reserve sizing and congestion management

Siting, component selection and system design can also improve performance under local environmental conditions. In Austria and Switzerland, vertical Alpine installations have demonstrated high yields at elevated sites, supported by high albedo, low temperatures and limited fog, while dual-axis tracking has been deployed in selected high-irradiation projects in Spain, the south-western USA and Chile's Atacama Desert to maximise generation.

Beyond reliable operation under normal conditions, PV can also contribute to electricity-system resilience during disruptions. Distributed PV benefits from geographic dispersion and proximity to demand, and whilst conventional grid-connected systems do not continue supplying local loads during an outage, storage, suitable controls, islanding capability or microgrid configurations can allow continued functioning. This value is already visible in several markets: load shedding contributed to rapid behind-the-meter PV deployment in South Africa and Pakistan, for example, but also across many other countries in Africa, while some consumers in Canada install batteries primarily for security of supply. In Ukraine, distributed PV and battery storage are contributing to a more decentralised electricity system where centralised infrastructure is exposed to repeated physical disruption, complementing network restoration, interconnection and other dispatchable resources.

VISIBILITY, FORECASTING AND ACTIVE CONTROL

As distributed PV becomes more significant at a system level, accurate forecasting and visibility of generation behind the meter also become more important. DSOs and TSOs may have incomplete information on the location, capacity and operation of PV and battery systems, affecting load forecasting, connection planning and real-time operation.

In Austria, new requirements are moving to qualifying PV systems towards remote controllability, supported by widespread smart-meter deployment and a shift from fixed limits towards operation that responds more closely to grid conditions. In China, revised distributed-PV rules similarly strengthen requirements for distributed generation to be observable, measurable, adjustable and controllable.

Greater controllability and connectivity also increase requirements for secure communications and system governance. In Europe, attention is increasingly focused on cybersecurity risks related to remote inverter access, software updates and the large number of individually owned devices connected through different platforms. Cybersecurity is therefore becoming an element of operational reliability as PV, batteries and flexible loads are increasingly managed as active system resources.

PV AND GROWING ELECTRICITY DEMAND

The changing contribution of PV to energy systems is taking place during a period of renewed growth in electricity consumption. The International Energy Agency (IEA) indicates that global electricity demand grew by around 3% in 2025, more than twice as fast as total energy demand, supported by increasing use of air conditioning, electric vehicles, heat pumps, industry and data centres. The IEA expects global electricity demand to grow by an average 3.6% per year between 2026 and 2030, and renewable output is forecast to increase by around 1 000 TWh per year over the same period[4].

This growth increases the importance of the cost of new generation, but also of the time required to deploy it. The modularity and comparatively short deployment times of PV allow new generation to be added from individual buildings to multi-GW plants, whilst major network reinforcement and other large energy infrastructure can require longer development periods.

Electrification can also create flexible demand that improves the use of PV production. Electric-vehicle charging, water heating, heat pumps, cooling, refrigeration, pumping and selected industrial processes can be shifted towards solar hours, where operational requirements permit using flexibility where it can to reduce curtailment, storage requirements or network peaks.

DATA CENTRES AND RAPIDLY GROWING LOADS

Data centres are a particular challenge – as new electricity demand that is developing faster than the generation and networks needed to supply them. Global data-centre electricity consumption is projected to more than double to around 945 TWh by 2030, increasing by around 15% per year from 2024[5].

PV is well positioned to contribute to this additional demand because it can be deployed relatively quickly through installations on buildings, nearby utility-scale plants and corporate procurement. Renewables are projected to meet nearly half of the growth in data-centre electricity demand to 2030, supported by this relatively short lead times and corporate procurement strategies.

[4] IEA, Global Energy Review 2026 - https://www.iea.org/reports/global-energy-review-2026/electricity-demand]

[5] IEA, Energy and AI - https://www.iea.org/reports/energy-and-ai/energy-demand-from-ai

PV AND GROWING ELECTRICITY DEMAND / continued

In the USA, technology companies and data-centre operators are major corporate renewable-electricity purchasers. In Spain, the national data-centre association identified around 5.0 GW of viable projects in the permitting pipeline, with part of this development expected to incorporate self-consumption PV. Portugal similarly identifies new data centres, together with electrification of buildings and industrial processes, as emerging drivers of electricity demand.

Building-mounted PV can contribute rapidly where suitable roof, façade or parking surfaces are available and has the advantage of locating generation close to demand. However, the high and continuous load of large data centres means that on-site PV alone will generally provide only part of their electricity requirements – but its contribution is already being seen as an enabling factor in some countries.

OUTLOOK

PV has moved from a marginal source of electricity towards a major component of electricity supply in a growing number of countries. As cumulative capacity increases, its contribution is broadening beyond annual energy production.

Simple grid connected PV remains primarily an energy source and currently its contribution to energy systems decreases as residual demand moves outside solar production hours. However, storage, demand flexibility, interconnection, complementary generation and deliberate modulation can extend the useful contribution of PV, while modern inverters can provide additional system services where technical requirements and operating rules allow them to do so.

Experiences in IEA PVPS member countries show that there is no single model or rhythm for the transition of PV as a marginal component to a fundament energy and service provider. Canada remains at a stage where PV-related curtailment is limited in much of the system; Austria is increasingly managing local voltage and export constraints; Australia combines very high distributed PV penetration with rapidly growing storage; and Spain is extending the participation of inverter-based renewable generation in voltage control.

At the same time, electricity demand is increasing through transport, heating, cooling, industrial electrification and data centres. PV's modularity and speed of deployment make it particularly well suited to contribute to this growth, but the value of additional capacity will increasingly depend on how effectively generation, networks, storage, system services and flexible demand are coordinated.

The next phase of PV development concerns not only installing additional capacity, but using cumulative PV capacity more effectively through appropriate grid rules, reliable operation, system services, resilience and flexibility.

TABLE 7.1: 2025 PV ELECTRICITY STATISTICS IN IEA PVPS COUNTRIES *

COUNTRY	FINAL ELECTRICITY CONSUMPTION	HABITANTS	GDP	SURFACE	AVERAGE YIELD	ANNUAL INSTALLED PV CAPACITY	CUMULATIVE INSTALLED PV CAPACITY	THEORETICAL PV ELECTRICITY GENERATION	ANNUAL CAPACITY PER CAPITA	CUMULATIVE CAPACITY PER CAPITA	CUMULATIVE CAPACITY PER KM²	THEORETICAL PV PENETRATION
	TWh	Million	B USD	1000 km²	kWh/kWp	GW	GW	TWh	W/Cap	W/Cap	kW/km²	%
Australia	273	27.6	1 799	7 690	1 400	4.5	44.3	62.0	163	1 604	5.8	22.7%
Austria	64	9.2	579	84	1 050	1.8	10.7	11.3	198	1 165	128	17.5%
Belgium	80	11.9	725	31	853	1.0	12.6	10.8	82	1 059	412	13.5%
Canada	618	41.7	2 320	9 985	1 150	0.35	7.9	9.1	8	191	0.8	1.5%
China	10 013	1 407	19 498	9 634	940	415	1 464	1375.7	295	1 040	152	13.7%
Denmark	38	6.0	463	44	975	1.4	6.7	6.6	238	1 119	153	17.3%
Finland	82	5.6	317	338	850	0.38	1.6	1.4	67	288	4.8	1.7%
France	451	68.7	3 366	552	1 100	7.4	37.0	40.7	107	539	67.2	9.0%
Germany	493	83.5	5 051	358	808	17.6	118	95.4	211	1 413	330	19.3%
India	1 788	1 463.9	3 956	357	1 625	54.2	179	290.5	37	122	500	16.2%
Israel	72	10.1	611	21	1 650	1.3	7.8	12.9	127	775	378	17.9%
Italy	289	58.9	2 552	302	1 117	6.7	43.7	46.6	113	741	145	16.1%
Japan	820	123.4	4 435	378	1 100	5.9	103	113.3	48	835	273	13.8%
Korea	604	51.7	1 872	100	1 261	4.3	35.0	44.1	84	677	349	7.3%
Lithuania	11	2.9	95	331	1 022	1.1	3.1	3.2	371	1 088	10	28.6%
Malaysia	186	36.0	472	331	1 314	0.41	5.6	7.4	11	156	17.0	4.0%
Morocco**	39	38.4	182	711	1 750	1.06	4.5	7.9	28	118	6.4	20.2%
Netherlands	116	18.1	1 333	42	875	1.9	28.6	25.1	106	1 584	690	21.6%
Norway	132	5.6	531	324	760	0.13	0.92	0.7	21	162	2.8	0.5%
Portugal	54	10.8	347	92	1 407	0.94	6.3	8.9	87	584	68.4	16.4%
South Africa	213	64.7	427	1 219	1 733	3.4	12.1	21.0	52	187	9.9	9.9%
Spain	265	49.4	1 906	506	1 500	12.1	60.9	91.4	246	1 235	120	27.8%
Sweden	127	10.6	669	410	950	0.73	5.8	5.5	69	548	14.2	4.3%
Switzerland	58	9.1	1 044	41	970	1.3	9.5	9.2	146	1 045	230	15.9%
Thailand	209	71.6	577	1 219	1 522	2.8	14.7	22.4	39	205	12.1	10.7%
Türkiye	323	85.9	1 597	784	1 471	4.7	26.2	38.5	55	305	33.4	11.9%
UK	290	69.5	4 003	1 054	902	3.2	24.8	22.4	46	357	23.5	7.7%
USA	4 282	341.8	30 770	9 147	1 483	42.5	266	394.2	124	778	29.1	9.2%
IEA PVPS (excluding rest of EU)	21 992	4 183	91 497	48 936	1 300	598	2 541	2 778	143	607	51.9	12.6%
Brazil	762	212.8	2 280	31	1 506	12	65	97.3	59	304	2115	12.8%
Pakistan	178	255.2	407	907	1 708	14	36	61.9	54	142	40.0	34.9%***
NON IEA PVPS	9 708	4 032	26 853	85 389	1 300	94	417	1 067	23	103	4.9	11.0%
World	**31 700**	**8 215**	**118 350**	**134 325**	**1 300**	**692**	**2 958**	**3 845**	**84**	**360**	**22.0**	**12.1%**

*See Annex for methodological notes; capacity, consumption, generation and penetration are calculated IEA PVPS values and may differ to national reporting data. **Late data corrections not carried into totals or charts ***Grid outages and curtailment at unknown level in Pakistan - PV penetration in 2025 is estimated to be between 20% and 30%, depending on the source and hypotheses used.

SOURCE: IEA PVPS, OTHERS

Annexes

METHODOLOGICAL ANNEX

DATA CONVENTIONS, CALCULATED INDICATORS AND SOURCE HIERARCHIES

The Trends in Photovoltaic Applications report combines national statistics, information supplied through the IEA PVPS reporting network and complementary market information to provide a coherent view of global PV deployment, industry development, economic activity and contribution to the energy system.

National statistical systems differ in their definitions, reporting periods, units, market classifications and coverage of distributed and off-grid installations. Some indicators presented in this report are therefore direct national statistics, while others require conversion, estimation or calculation to improve comparability between markets.

This Annex describes the principal conventions and calculation methods used in the report. Individual chapters retain a short explanation of the relevant indicator; the detailed assumptions, source hierarchy and principal limitations are consolidated here.

GENERAL DATA SOURCES, ESTIMATES AND REVISIONS

APPLIES PRINCIPALLY TO CHAPTERS 2, 4, 5, 6 AND 7

Key data are drawn primarily from IEA PVPS National Survey Reports and information supplied by IEA PVPS member countries, supplemented by national PV associations, government agencies, energy regulators, transmission and distribution system operators, statistical offices and other official sources. Information for countries outside the IEA PVPS reporting network is drawn from a wider range of sources and cannot always be assured with the same degree of confidence. This approach continues the methodology used in previous editions of Trends.

Where official reporting is incomplete or unavailable, recognised industry associations, market datasets, project information, trade data and other sources are used to complement national statistics. Becquerel Institute analysis is used to consolidate national datasets, identify differences in statistical perimeter, undertake conversions and produce estimates where direct data are incomplete.

Global PV totals should therefore be understood as the best available estimate based on a combination of reported and estimated national data rather than as an exact census of every PV system installed worldwide. Historical values may be revised between editions as final national statistics become available or as improved information modifies previous estimates.

[Sources: IEA PVPS member countries; National PV associations, TSOs/DSOs, energy regulators and government data; Becquerel Institute analysis; IEA PVPS, Trends in Photovoltaic Applications 2025]

DATA CONFIDENCE AND UNCERTAINTY

The degree of certainty varies between indicators and countries. Direct official statistics and national IEA PVPS submissions generally provide the highest confidence. Recognised national or industry sources, transparent proxies and estimates based on well-established underlying series provide a second level. Values derived from broader proxies, incomplete registration or indirect market information should be considered indicative.

Where uncertainty materially changes a national or global total, a range or specific note is provided rather than implying greater precision than the underlying data allow. The level of confidence can also change between editions as provisional values are replaced by final national statistics.

CHAPTER 2 - PV MARKET DEVELOPMENT

INDICATOR: ANNUAL INSTALLED PV CAPACITY

Annual installed capacity refers to PV capacity considered installed or commissioned during the reporting year. The report seeks to count all PV installations, including grid-connected and reported off-grid systems. This follows the convention used in previous editions, where IEA PVPS stated that all PV installations are counted when reported and that estimates are made for remaining unreported installations.

[Sources: IEA PVPS member countries; Becquerel Institute analysis; IEA PVPS, Trends in Photovoltaic Applications 2025]

INDICATOR: NOMINAL PV CAPACITY - DC vs AC

Unless specifically indicated otherwise, W, kW, MW and GW in this report refer to the nominal DC module capacity of the PV system. Some national authorities report inverter output or grid-connection capacity in AC rather than nominal module capacity. These values are converted to DC where required to maintain consistency between countries.

The DC/AC ratio varies according to system design and can be substantial in utility-scale plants where the PV array is deliberately oversized relative to inverter or connection capacity. The appropriate conversion can therefore be materially greater than a simple inverter-loss adjustment. Where information on actual national DC/AC ratios is available, that information is used preferentially; otherwise, representative ratios derived from national market information, industry practice, and press releases from commissioned projects are applied.

DC capacity = AC capacity × DC/AC ratio

[Sources: IEA PVPS member countries; *Becquerel Institute analysis*; *IEA PVPS, Trends in Photovoltaic Applications 2025]*

INDICATOR: CUMULATIVE INSTALLED CAPACITY

Cumulative installed capacity represents the total PV capacity recorded as installed at the end of the reporting period and is the principal indicator used in this report to describe the installed base. It should not necessarily be interpreted as identical to capacity currently in operation. National statistics differ in their treatment of systems that have been decommissioned, repowered or replaced.

[Sources: IEA PVPS member countries; *Becquerel Institute analysis]*

DEFINITION: REPOWERING, COMPONENT REPLACEMENT AND DECOMMISSIONING

Repowering can increase the capacity of an existing PV project by replacing older modules or other principal components while retaining part of the original infrastructure. National reporting practices differ, and repowering may be recorded as new capacity, equipment replacement, capacity reduction followed by re-registration, or no change in published capacity statistics. Module shipment, second-life market, and recycling data therefore cannot be used consistently to identify repowering or decommissioning.

IEA PVPS therefore does not currently quantify a global annual decommissioning or repowering adjustment unless supported by sufficiently robust national statistics.

[Sources: IEA PVPS member countries; *Becquerel Institute analysis]*

INDICATOR: PV CAPACITY PER CAPITA

PV capacity per capita is calculated as year-end cumulative installed PV capacity divided by national population.

PV CAPACITY PER CAPITA = CUMULATIVE INSTALLED PV CAPACITY / POPULATION

The indicator expresses the quantity of nominal installed PV capacity relative to population and is useful for comparing the scale of deployment between countries of different sizes. It is not an indicator of electricity production or of the share of national electricity supplied by PV.

[Sources: IEA PVPS member countries; *Becquerel Institute analysis*; [World Bank - Population, total (SP.POP.TOTL)](#)*]*

CHAPTER 4 - TRENDS IN THE PV INDUSTRY

DEFINITION: MANUFACTURING PRODUCTION AND MANUFACTURING CAPACITY

Production is the estimated quantity of material or equipment manufactured during the year. Production capacity is the maximum or nominal annual output that manufacturing facilities could produce and does not represent actual production. Differences may be significant when factories operate below full utilisation. Capacity expressed in GW/year refers to annualised nominal manufacturing output capability, not electricity-generating capacity.

[Sources: IEA PVPS member countries; *RTS Corporation*; *Becquerel Institute analysis]*

CHAPTER 5 - SOCIETAL IMPLICATIONS AND ECONOMIC CONTRIBUTION

INDICATOR: ANNUAL CO2 EMISSIONS AVOIDED BY PV

The total CO2 emissions avoided by PV on a yearly basis are estimated from the electricity that could be produced by the cumulative PV capacity installed at the end of the reporting year. For each country, annual PV production is calculated from cumulative installed capacity and a representative country yield.

ESTIMATED ANNUAL PV PRODUCTION = CUMULATIVE INSTALLED PV CAPACITY X REPRESENTATIVE COUNTRY YIELD

The resulting electricity volume is compared with an equivalent amount of electricity produced at the carbon intensity of the national electricity mix. The lifecycle emissions associated with PV are deducted from the emissions associated with the equivalent quantity of grid electricity.

AVOIDED CO2 = ESTIMATED PV PRODUCTION X (NATIONAL GRID CARBON INTENSITY - APPLICABLE PV LIFECYCLE INTENSITY)

The 2026 methodology retains capacity installed up to the end of 2021 with the lifecycle emission assumptions previously attributed to the corresponding national installed capacity, and for capacity installed from 2022 onwards, a common lifecycle value of 35.8 g CO2eq/kWh for contemporary monocrystalline silicon modules manufactured in China. The lifecycle intensity attributed to cumulative capacity is calculated from the relative shares of older and more recently installed capacity.

[Sources: IEA PVPS member countries; *Becquerel Institute analysis*; *IEA PVPS Task 12 lifecycle inventory work]*

AVERAGE RATHER THAN MARGINAL ELECTRICITY EMISSIONS

The methodology uses the average national electricity mix rather than assuming that PV always displaces the most carbon-intensive marginal generator. At low PV penetration an incremental unit of PV production may frequently displace flexible fossil generation; at higher penetration, however, PV increasingly forms part of the normal generation mix and affects a broader range of generation. Using national average carbon intensity provides a consistent annual comparison between countries.

The calculation remains an annual accounting estimate rather than an hourly power-system simulation. It does not identify the generator displaced by PV in each hour and therefore does not capture hourly variation in marginal emissions. Electricity imports and exports are represented only to the extent that they are reflected in the national carbon-intensity datasets used. Battery charging and discharging are not modelled separately and curtailed PV volumes are not systematically removed from theoretical production.

The result should be interpreted as an estimate of the emissions associated with theoretical annual PV production from cumulative installed capacity, rather than a direct measurement of realised hourly displacement.

NATIONAL GRID CARBON INTENSITY

National electricity-mix carbon intensities are derived from recognised electricity datasets and national sources. Ember Yearly Electricity Data is used as a principal harmonised cross-country source where appropriate, complemented by national data where a more suitable or more recent value is available.

[Sources: Ember - Yearly Electricity Data; National electricity statistics; Becquerel Institute analysis]

COUNTRY SPECIFIC PV YIELD

Country-specific PV yields follow the same source hierarchy as the theoretical-production calculation in Chapter 7. National IEA PVPS yield information is preferred where representative; otherwise the Global Solar Atlas is used to establish or validate a representative solar-resource value.

[Sources: IEA PVPS member countries; World Bank Group / Solargis / ESMAP - Global Solar Atlas; Becquerel Institute analysis]

GLOBAL REPRESENTATIVE YIELD

Where a single global theoretical production estimate is presented, a simplified global representative yield is applied to cumulative global PV capacity. For the 2025 calculation in Chapter 7, the indicative value used is 1 300 kWh/kWp/year.

INDICATOR: PV MARKET BUSINESS VALUE

The turnover of the PV sector is estimated from annual market volumes, annual and cumulative installed capacity and representative prices for installation and operation and maintenance in the different market segments and countries.

ANNUAL INSTALLATION BUSINESS VALUE = ANNUAL INSTALLED CAPACITY X REPRESENTATIVE INSTALLED SYSTEM PRICE

National installation volumes and price information are derived primarily from IEA PVPS member-country reporting, national PV associations and other recognised market sources. Becquerel Institute analysis is used to consolidate market segments and calculate the resulting business value. Values expressed in local currency are converted to USD using average annual exchanges rates.

Recurring O&M activity is estimated from cumulative installed capacity and representative annual O&M values. O&M estimates vary considerably by system scale, contract structure and country and should therefore be interpreted as indicative.

The resulting PV market business value is a gross market-activity indicator. Imported modules and other components can be included within the price paid for an installation even though part of that value is created outside the country. Conversely, domestic manufacturing for export may create economic activity not represented in domestic installation expenditure.

[Sources: IEA PVPS member countries; National PV associations; Becquerel Institute analysis; Federal Reserve - G.5A Annual Foreign Exchange Rates]

INDICATOR: PV MARKET VALUE RELATIVE TO GDP

The ratio compares estimated PV market business value with national nominal GDP.

PV MARKET VALUE RELATIVE TO GDP = ESTIMATED PV MARKET BUSINESS VALUE / NOMINAL GDP

GDP is taken at current USD values to maintain consistency with the nominal USD market-value calculation. The ratio indicates the scale of PV-related market turnover relative to the national economy and should not be interpreted as the direct contribution of PV to GDP, since gross market turnover includes imported equipment and does not correspond to domestic value added.

[Sources: Becquerel Institute analysis; World Bank - GDP (current US$), NY.GDP.MKTP.CD]

INDICATOR: INDUSTRIAL BUSINESS VALUE OF PV

Industrial PV business value is estimated for the principal manufacturing stages of the crystalline-silicon value chain: polysilicon, wafers, cells and modules. Representative value at each production stage is derived from market-price and supply-chain cost information.

Becquerel Institute analysis combines these elements to estimate the gross industrial value associated with production in each country. The resulting values represent gross production value rather than value added. Inputs purchased from the preceding manufacturing stage are embedded in the value of subsequent products and the figures should not be summed across the value chain as though each stage represented additional GDP.

[Sources: IEA PVPS; RTS Corporation; Becquerel Institute analysis; Clean Energy Ministerial (CEM), Solar PV Supply Chain Cost Tool, 2026; IRENA, Solar PV Supply Chain Cost Tool: Methodology, results and analysis, 2026; IEA - Solar PV manufacturing costs per component and origin, 2024]

INDICATOR: PV EMPLOYMENT

Employment estimates combine national IEA PVPS reporting with external employment datasets and Becquerel Institute analysis. National Survey Reports provide upstream industrial employment and downstream development, installation and O&M employment where available. For countries without sufficiently complete reporting, estimates are derived using market and manufacturing volumes, supported by external national or regional employment benchmarks and job intensities.

Definitions vary between headcount and full-time equivalents, direct and indirect employment, temporary construction employment and the boundaries of the wider solar sector.

[Sources: IEA PVPS member countries; Becquerel Institute analysis; SolarPower Europe, EU Solar Jobs Report 2025; Fingerhut, J. and Wink, R. (2026), Beschäftigung in den erneuerbaren Energien: Entwicklung und politische Reformen, Bertelsmann Stiftung; Renewables First, The Many Dividends of Solar Rush in Pakistan, 2025]

CHAPTER 6 - COMPETITIVENESS OF PV ELECTRICITY

INDICATOR: MODULE PRICES

Module prices are compiled from national IEA PVPS reporting and complementary market sources. Depending on the country and source, these may represent wholesale transaction prices, large-order prices or representative national market ranges. Consequently, module-price observations should not be considered fully harmonised quotations.

Technology, order size, tariffs, trade measures, transport, taxation, local-content rules and distribution channels can materially affect the delivered price. Chapter 6 therefore presents ranges and country comparisons rather than treating every observation as an equivalent global spot price. Unless otherwise indicated, prices are expressed in USD/W of nominal DC module capacity.

[Sources: IEA PVPS member countries; *National PV associations and industry sources*; *Becquerel Institute analysis]*

INDICATOR: INSTALLED SYSTEM PRICES

PV system prices vary according to system size, location, customer type, technical specifications, grid-connection requirements and the scope of costs included. System-price data are provided through IEA PVPS national reporting and converted to USD using the currency-conversion convention applied in the underlying dataset.

System boundaries, system sizes and the inclusion of taxes, development expenditure, grid-connection costs and other components differ between countries. Cross-country values should therefore be interpreted as indicative market ranges rather than harmonised engineering-cost benchmarks. Where national reporting provides minimum and maximum values rather than a single representative value, these are retained as a range.

Prices for specialised applications such as floating PV, agrivoltaics, BIPV, carports or infrastructure-integrated PV should not be directly compared with conventional rooftop or ground-mounted systems without considering the additional structures or functions included.

[Sources: IEA PVPS member countries; *Becquerel Institute analysis*; Federal Reserve - G.5A Annual Foreign Exchange Rates*]*

INDICATOR: LEVELISED COST OF ELECTRICITY - LCOE

The levelised cost of electricity represents the discounted lifetime cost of electricity produced by a PV system.

LCOE = DISCOUNTED LIFETIME PROJECT COSTS / DISCOUNTED LIFETIME ELECTRICITY PRODUCTION

Project costs include initial investment and applicable operating expenditure. Lifetime electricity production depends on irradiation, system yield, degradation, availability and project lifetime. Financing assumptions, particularly the cost of capital, can materially alter LCOE even where equipment costs are similar.

[Sources: IEA PVPS member countries; *Becquerel Institute analysis]*

DEFINITION: CAPTURE PRICE

Where used, PV capture price refers to the average wholesale-market price received during the hours in which PV generates. It differs from the simple annual average wholesale electricity price because the production profile of PV is concentrated in daylight hours. At higher PV penetration, increasing simultaneous solar production can reduce prices during these hours and cause the PV capture price to decline relative to the market average.

PV CAPTURE RATE = PV CAPTURE PRICE / AVERAGE WHOLESALE ELECTRICITY PRICE

The metric describes market value and should not be confused with LCOE or project revenue under a fixed PPA or support contract.

CHAPTER 7 - PV IN THE ENERGY SECTOR

INDICATOR: THEORETICAL ANNUAL PV PRODUCTION FROM YEAR-END CUMULATIVE CAPACITY

PV electricity production can be measured accurately at an individual plant but is more difficult to compile for an entire country, particularly where distributed generation and self-consumption are significant. The commissioning date of new capacity also matters: a system installed late in the year contributes to year-end cumulative capacity but only a small fraction of its full-year electricity production.

Chapter 7 therefore distinguishes measured annual production from the annual production potential of year-end cumulative installed capacity.

THEORETICAL ANNUAL PV PRODUCTION = YEAR-END CUMULATIVE INSTALLED CAPACITY X REPRESENTATIVE ANNUAL YIELD

Representative national yield is expressed in kWh/kWp/year. Where sufficiently representative national PVPS production and capacity data are available, these are used to derive or validate the national yield. Where national information is incomplete, representative irradiation and PV-output data from the Global Solar Atlas are used.

Theoretical production is an analytical comparison indicator. It is not measured electricity generation during the reporting year. Actual production can differ because of commissioning date, annual irradiation, orientation and inclination, shading, system availability, degradation, temperature, clipping, grid or market curtailment and technical failures. These factors are not modelled individually at national level.

[Sources: IEA PVPS member countries; World Bank Group / Solargis / ESMAP - Global Solar Atlas; *Becquerel Institute analysis]*

INDICATOR: FINAL ELECTRICITY CONSUMPTION

For theoretical PV penetration, the preferred denominator is electricity consumed by final users. The target perimeter excludes electricity used by the energy or power sector and transmission and distribution losses where the national energy balance permits. Behind-the-meter and self-consumed electricity is included where it is captured in national final-consumption accounts. Consequently, the country-level electricity consumption dataset includes countries with differing perimeters.

This differs from electricity demand that is generally calculated from generation adjusted for net imports and can include electricity that is lost in networks and power-sector own use and therefore exceed electricity actually consumed by final users.

The hierarchy used for the 2025 dataset is: (1) final electricity consumption reported by the PVPS country; (2) where unavailable, an estimate based on electricity demand minus network losses, plus self-consumption where reported; and (3) where neither consumption nor demand is provided by the PVPS country, an alternative electricity-demand source may be used.

Ember Yearly Electricity Data is used as a comparison and cross-check during compilation of the electricity dataset, but the Ember electricity-demand series is not used automatically as the denominator for theoretical PV penetration. The preferred denominator in this report is electricity consumed by final users, and national final-consumption sources are used where available.

Where final electricity consumption is estimated, the following formulas are applied:

Final electricity consumption = Electricity demand − Network losses + Self-consumption

NETWORK LOSSES = ELECTRICITY DEMAND × TRANSMISSION AND DISTRIBUTION LOSS RATE

The transmission and distribution loss rate is taken from the World Bank indicator “Electric power transmission and distribution losses”, where available.

[Sources: IEA PVPS member countries; *National energy balances and electricity statistics*; *Becquerel Institute analysis*; Ember - Yearly Electricity Data; World Bank Group - Electric power transmission and distribution losses (% of output) EG.ELC.LOSS.ZS*]*

INDICATOR: THEORETICAL PV PENETRATION

THEORETICAL PV PENETRATION = THEORETICAL ANNUAL PV PRODUCTION / FINAL ELECTRICITY CONSUMPTION

The result expresses the annual electricity that year-end PV capacity could produce over a complete representative year relative to electricity used by final consumers. It is an indicative comparative indicator, not the measured share of PV generation during 2025.

The indicator can differ materially from official annual PV-generation shares because part of the capacity was installed during the year; distributed and self-consumed PV can be incompletely captured; theoretical production does not systematically remove curtailed electricity; and the representative yield differs from actual annual solar conditions.

[Sources: IEA PVPS member countries; *Becquerel Institute analysis]*

INDICATOR: PV SHARE OF MEASURED GLOBAL ELECTRICITY GENERATION

The measured global share of PV and other generation technologies shown in Chapter 7 is based on IEA electricity-generation statistics and is separate from the IEA PVPS theoretical penetration calculation. The contribution of PV production to electricity generation is mechanically lower than the contribution to electricity consumption as consumption is equal to generation +/- imports – network, storage and curtailment losses.

[Sources: IEA - Breakdown of global electricity generation by source, 2019-2027*]*

DATA-CENTRE ELECTRICITY DEMAND

Estimates of global data-centre demand, expected growth and the 2030 outlook are taken from the IEA Energy and AI analysis.

[Sources: IEA - Energy and AI: Energy demand from AI*]*

REPORT-WIDE CONVENTIONS

GEOGRAPHICAL CONVENTIONS

Unless specified otherwise, Europe includes countries geographically situated on the European continent. European Union totals refer specifically to EU Member States. Türkiye is included within Europe for regional reporting, Korea refers to the Republic of Korea, and Chinese Taipei refers to the economic region under the terminology used by the IEA PVPS Programme.

The European Commission participates in IEA PVPS, but EU Member States are not automatically counted as individual IEA PVPS countries unless the indicator explicitly uses the EU membership perimeter. The list of countries included in each aggregate should be maintained consistently in the report data workbook.

[Sources: IEA PVPS reporting conventions]

UNITS, CURRENCIES

PV power capacity is reported in W, kW, MW or GW of nominal DC module power unless specifically identified as AC. Electricity production and consumption are generally reported in GWh or TWh. Battery storage requires two separate indicators: MW or GW for instantaneous power capacity and MWh or GWh for stored energy capacity.

Financial data are generally expressed in nominal USD unless otherwise indicated. Where national values are converted from local currencies, the exchange-rate convention used for the relevant indicator is applied consistently. Calculations are performed using the underlying unrounded dataset and rounded only for publication.

SUMMARY OF PRINCIPAL CALCULATED INDICATORS

Indicator	Principal calculation	Interpretation	Principal limitation
Annual installed PV capacity	National reported/estimated commissioned capacity, converted to DC where necessary	New capacity during reporting year	Registration and commissioning conventions differ
Cumulative installed PV capacity	National year-end installed capacity	Recorded installed base	Decommissioning and repowering treatment differs
PV capacity per capita	Cumulative capacity / population	Relative deployment scale	Does not measure electricity contribution
Theoretical PV production	Cumulative capacity x representative yield	Full-year production potential of year-end capacity	Not realised reporting-year generation
Final Electricity Consumption	Electricity demand − Network losses + Self-consumption	Electricity consumption considering network losses and self-consumption	Consumption perimeter and estimation methods differ across countries.
Theoretical PV penetration	Theoretical PV production / final electricity consumption	Comparative potential contribution to end-user electricity use	Consumption perimeter and production assumptions differ
Avoided CO2	Theoretical PV production x difference between grid and PV lifecycle emissions	Annual accounting estimate	Not an hourly marginal-displacement model
Installation business value	Annual capacity x representative system price	Gross annual installation-market turnover	Not domestic value added
LCOE	Discounted lifetime cost / discounted lifetime production	Lifetime electricity cost	Sensitive to financing and performance assumptions
Capture price	Generation-weighted wholesale price	Market value of PV production profile	Applies only to market-exposed production

PRINCIPAL EXTERNAL DATASETS AND THEIR USE

Dataset	Main report use	Methodological role
World Bank - Population, total	Chapter 2	Population denominator for PV capacity per capita
World Bank - GDP (current US$)	Chapter 5	GDP denominator for PV market value relative to GDP
World Bank Group - Electric power transmission and distribution losses (% of output)	Chapter 7	Final electricity consumption as the denominator of the Theoretical PV penetration
Ember - Yearly Electricity Data	Chapters 5 and 7	Grid carbon intensity; electricity-data comparison and validation
Global Solar Atlas	Chapters 5 and 7	Representative national solar yield where national PVPS data are incomplete
Federal Reserve G.5A	Chapters 5 and 6	Currency conversion for business-value and price comparisons
IEA - World Energy Investment 2026	Chapter 5	External comparison with wider energy investment
IEA - Solar PV manufacturing costs	Chapters 4 and 5	Manufacturing cost structure and industrial value analysis
IEA - Global electricity generation by source	Chapter 7	Measured global electricity-generation shares
IEA - Global Energy Review 2026	Chapter 7	Electricity-demand growth and electrification context
IEA - Energy and AI	Chapter 7	Data-centre electricity-demand outlook

ANNEXE 1: CUMULATIVE INSTALLED PV CAPACITY (GW) FROM 1992 TO 2025

COUNTRIES	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Australia	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.05	0.05	0.06	0.07	0.08	0.10	0.19	0.6	1.4	2.4	3.2	4.1	5.1	6.0	7.1	11.6	16.4	21.1	26.1	30.4	34.5	39.8	44.3
Austria										0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.05	0.1	0.2	0.4	0.6	0.8	0.9	1.1	1.3	1.5	1.7	2.0	2.8	3.8	6.4	8.9	10.7
Belgium															0.01	0.02	0.11	0.67	1.1	2.2	2.9	3.1	3.2	3.4	3.5	3.9	4.3	5.1	6.3	7.1	8.2	10.7	11.7	12.6
Canada								0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.09	0.3	0.6	0.8	1.2	1.8	2.5	2.7	2.9	3.1	3.4	3.7	5.8	6.5	7.3	7.6	7.9
China									0.01	0.02	0.03	0.04	0.05	0.06	0.07	0.09	0.13	0.29	0.8	3.5	6.7	17.7	28.3	43.5	78.0	131	175	205	254	309	414	691	1 049	1 464
Denmark																			0.0	0.0	0.5	0.7	0.8	1.0	1.1	1.1	1.3	1.4	1.6	2.3	4.1	4.6	5.3	6.7
Finland																			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.7	1.0	1.2	1.6
France						0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.04	0.08	0.22	0.44	1.4	3.6	4.9	5.7	6.8	7.9	8.6	9.7	10.8	11.9	13.1	16.7	19.7	23.7	29.7	37.0
Germany	0.01	0.01	0.01	0.02	0.03	0.04	0.05	0.07	0.11	0.18	0.30	0.44	1.11	2.06	2.90	4.17	6.12	10.57	18.0	25.9	34.1	36.7	37.9	39.2	40.7	42.3	45.2	49.0	54.6	60.3	67.9	83.2	100	118
India																			0.1	0.3	1.3	2.4	3.2	5.4	9.5	22.6	33.4	43.4	47.8	61.5	79.6	92.6	125	179
Israel																		0.02	0.1	0.2	0.3	0.4	0.6	0.8	0.9	1.0	1.4	2.0	2.4	3.3	4.5	5.7	6.6	7.8
Italy	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.05	0.10	0.50	1.28	3.6	13.1	16.8	18.2	18.6	18.9	19.3	19.7	20.1	20.9	21.6	22.6	25.1	30.3	37.0	43.7
Japan	0.02	0.02	0.03	0.04	0.06	0.09	0.13	0.21	0.33	0.45	0.64	0.86	1.13	1.42	1.71	1.92	2.14	2.63	3.6	4.9	6.6	13.6	23.3	34.2	42.0	49.5	56.2	63.2	71.9	78.4	84.9	91.2	97.2	103
Lithuania																		0.10	0.2	0.3	0.4	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1.0	1.1	1.2	2.1	3.1
Malaysia																		0.00	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4	0.9	1.4	1.8	2.1	3.1	4.2	5.2	5.6
Morocco																											0.2	0.2	0.2	0.7	1.0	2.0	3.5	4.5
Netherlands							0.00	0.00	0.01	0.01	0.02	0.02	0.04	0.04	0.05	0.05	0.06	0.07	0.1	0.2	0.4	0.8	1.1	1.5	2.1	2.9	4.6	7.2	10.7	14.3	18.5	23.3	26.7	28.6
Norway								0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.6	0.8	0.9
Portugal										0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.07	0.11	0.1	0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.7	0.9	1.1	1.7	2.6	3.9	5.4	6.3
South Africa																					0.0	0.3	1.4	1.5	2.1	2.1	2.2	2.7	4.0	4.4	4.5	7.5	8.7	12.1
South Korea											0.01	0.01	0.01	0.01	0.04	0.08	0.36	0.52	0.7	0.7	1.0	1.6	2.5	3.6	4.5	5.8	8.1	12.7	17.3	21.2	24.5	28.2	30.7	35.0
Spain										0.00	0.01	0.01	0.03	0.05	0.15	0.74	4.02	4.07	4.6	5.1	5.4	5.6	5.6	5.7	5.7	5.9	6.3	11.6	15.9	21.9	30.5	39.6	48.8	60.9
Sweden																0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.7	1.1	1.6	2.5	4.1	5.1	5.8
Switzerland	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.05	0.08	0.1	0.2	0.4	0.8	1.1	1.4	1.7	1.9	2.2	2.5	3.0	3.7	4.7	6.4	8.2	9.5
Thailand														0.02	0.03	0.03	0.03	0.04	0.0	0.2	0.4	0.8	1.3	1.4	2.4	3.1	3.5	3.5	3.6	4.1	4.3	8.9	11.9	14.7
Türkiye																		0.00	0.0	0.0	0.0	0.0	0.1	0.4	1.2	4.2	7.3	8.6	9.4	10.9	12.5	17.4	21.5	26.2
UK												0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.1	1.0	1.8	3.1	6.3	11.4	13.7	14.7	15.0	15.4	15.7	16.4	17.3	18.8	21.6	24.8
USA													0.11	0.19	0.30	0.46	0.75	1.19	2.0	3.9	7.1	12.1	18.3	25.8	41.0	51.8	62.5	75.9	95.1	119	141	176	223	266
TOTAL IEA PVPS (with EU)	0.05	0.07	0.08	0.11	0.14	0.20	0.26	0.37	0.56	0.77	1.1	1.6	2.7	4.1	5.5	8.0	14.9	23.0	40.1	71.2	100.5	137.4	176.7	225.5	298.5	395.7	488.7	580	696	841	1 049	1 469	2 001	2 614
Brazil																				0.0	0.0	0.1	0.1	0.1	0.1	1.2	2.4	4.7	8.5	14.5	25.4	37.8	52.1	64.6
Pakistan																		0.00	0.0	0.0	0.0	0.1	0.2	0.2	0.5	1.0	1.1	1.6	1.9	2.6	3.2	4.5	22.4	36.3
TOTAL NON IEA PVPS	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.03	0.05	0.07	0.08	0.11	0.14	0.24	0.82	2.9	4.5	7.3	10.8	12.7	15.9	20.3	26.8	33.3	56.4	86.4	114.2	147.7	190.9	263.4	343.0
TOTAL	0.05	0.07	0.09	0.12	0.15	0.21	0.27	0.38	0.57	0.79	1.16	1.59	2.73	4.16	5.62	8.11	15.03	23.29	40.6	72.3	102.3	140.3	181.2	232.9	309.9	413.3	522	636	782	955	1 197	1 660	2 264	2 958

ANNEXE 2: ANNUAL INSTALLED PV CAPACITY (GW) FROM 1992 TO 2025

COUNTRIES	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Australia																	0.02	0.08	0.4	0.8	1.0	0.8	0.9	1.0	0.9	1.1	4.5	4.8	4.7	5.0	4.2	4.2	5.3	4.5
Austria																		0.02	0.0	0.1	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.7	1.0	2.6	2.5	1.8
Belgium																0.02	0.09	0.56	0.4	1.1	0.7	0.3	0.1	0.1	0.2	0.3	0.4	0.8	1.1	0.9	1.1	2.5	1.0	1.0
Canada																		0.06	0.2	0.3	0.2	0.4	0.6	0.7	0.1	0.2	0.2	0.3	0.3	2.0	0.7	0.8	0.3	0.3
China											0.02					0.02	0.04	0.16	0.5	2.7	3.2	11.0	10.6	15.2	34.6	52.9	44.3	30.3	48.2	54.9	106	277	357	415
Denmark																				0.0	0.5	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.3	0.7	1.8	0.5	0.7	1.4
Finland																									0.0	0.0	0.1	0.1	0.1	0.1	0.3	0.3	0.2	0.4
France																0.04	0.14	0.22	1.0	2.1	1.3	0.8	1.1	1.1	0.7	1.1	1.0	1.2	1.2	3.6	3.0	4.0	6.0	7.4
Germany								0.02	0.04	0.06	0.12	0.14	0.67	0.95	0.84	1.27	1.95	4.45	7.4	7.9	8.2	2.6	1.2	1.3	1.5	1.6	2.9	3.8	5.6	5.7	7.6	15.3	17.2	17.6
India																			0.1	0.2	1.0	1.1	0.9	2.2	4.1	13.0	10.8	10.1	4.4	13.7	18.1	13.0	31.9	54.2
Israel																		0.02	0.0	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.4	0.6	0.5	0.9	1.2	1.2	0.9	1.3
Italy																0.05	0.40	0.78	2.3	9.5	3.7	1.4	0.4	0.3	0.4	0.4	0.4	0.8	0.8	0.9	2.5	5.3	6.7	6.7
Japan	0.02				0.02	0.03	0.04	0.08	0.12	0.12	0.18	0.22	0.27	0.29	0.29	0.21	0.23	0.48	1.0	1.3	1.7	7.0	9.7	10.8	7.9	7.5	6.7	7.0	8.7	6.5	6.5	6.3	5.9	5.9
Lithuania																		0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.9	1.1
Malaysia																					0.0	0.1	0.1	0.1	0.1	0.0	0.5	0.5	0.4	0.4	1.0	1.1	1.0	0.4
Morocco																											0.2			0.5	0.3	1.0	1.5	1.1
Netherlands													0.0						0.0	0.1	0.2	0.4	0.3	0.5	0.5	0.9	1.7	2.6	3.5	3.6	4.2	4.8	3.4	1.9
Norway																												0.0	0.0	0.0	0.2	0.3	0.2	0.1
Portugal																	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.2	0.2	0.6	1.0	1.3	1.5	0.9
South Africa																						0.3	1.1	0.1	0.6	0.1	0.1	0.5	1.3	0.5	0.1	3.0	1.2	3.4
Korea															0.0	0.0	0.3	0.2	0.1	0.1	0.3	0.5	0.9	1.1	0.9	1.3	2.3	4.6	4.7	3.9	3.3	3.7	2.5	4.3
Spain														0.0	0.1	0.6	3.3	0.0	0.5	0.5	0.4	0.1	0.1	0.0	0.1	0.2	0.4	5.3	4.3	6.0	8.6	9.1	9.2	12.1
Sweden																						0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.5	0.8	1.7	0.9	0.7
Switzerland																		0.0	0.0	0.1	0.2	0.3	0.3	0.3	0.3	0.2	0.3	0.3	0.5	0.7	1.1	1.6	1.8	1.3
Thailand														0.0						0.2	0.1	0.4	0.5	0.1	1.0	0.6	0.5	0.0	0.0	0.5	0.2	4.6	3.0	2.8
Türkiye																						0.0	0.0	0.3	0.8	3.0	3.1	1.2	0.9	1.5	1.6	4.8	4.1	4.7
UK																			0.1	0.9	0.8	1.3	3.2	5.1	2.4	1.0	0.3	0.4	0.3	0.6	0.9	1.5	2.8	3.2
USA													0.1	0.1	0.1	0.2	0.3	0.4	0.8	1.9	3.2	4.9	6.2	7.5	15.1	10.8	10.7	13.4	19.3	23.6	22.7	34.9	47.1	42.5
TOTAL IEA PVPS (with EU)	0.05	0.02	0.02	0.02	0.03	0.05	0.06	0.11	0.19	0.21	0.36	0.42	1.13	1.42	1.44	2.46	6.88	8.16	17.1	31.1	29.3	36.9	39.3	48.8	73.0	97.2	93.0	91.1	116	145	208	420	532	612
Brazil																				0.0	0.0	0.0	0.0	0.0	0.0	1.1	1.3	2.3	3.8	6.0	10.9	12.4	14.3	12.5
Pakistan																					0.0	0.1	0.1	0.1	0.3	0.5	0.1	0.5	0.3	0.7	0.7	1.3	18.0	13.8
TOTAL NON IEA PVPS	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.04	0.10	0.2	0.6	0.7	1.1	1.6	2.9	4.0	6.2	15.7	23.1	30.0	27.8	33.5	43.3	72.4	79.6
TOTAL	0.05	0.02	0.02	0.02	0.04	0.06	0.07	0.11	0.19	0.22	0.37	0.43	1.14	1.43	1.46	2.49	6.92	8.26	17.3	31.7	30.0	38.1	40.9	51.7	77.0	103	109	114	146	173	242	464	604	692

ANNEXE 3: 2025 EXCHANGE RATES

COUNTRY	CURRENCY CODE	EXCHANGE RATE IN 2025 (1 USD =)
AUSTRALIA	AUD	1.550
AUSTRIA	EUR	0.884
BELGIUM	EUR	0.884
BRAZIL	BRL	5.589
CANADA	CAD	1.397
CHILE	CLP	0.000
CHINA	CNY	7.188
DENMARK	DKK	6.614
FINLAND	EUR	0.884
FRANCE	EUR	0.884
GERMANY	EUR	0.884
INDIA	INR	87.147
ISRAEL	ILS	3.451
ITALY	EUR	0.884
JAPAN	JPY	149.569
KOREA	KRW	1421.396
MALAYSIA	MYR	4.281
MEXICO	MXN	19.205
MOROCCO	MAD	9.346
NETHERLANDS	EUR	0.884
NORWAY	NOK	10.381
PAKISTAN	PKR	0.000
PORTUGAL	EUR	0.884
SOUTH AFRICA	ZAR	17.878
SPAIN	EUR	0.884
SWEDEN	SEK	9.806
SWITZERLAND	CHF	0.831
THAILAND	THB	32.862
TÜRKIYE	TRY	39.578
UK	GBP	0.758
USA	USD	1.000

ANNEXE 4: COUNTRY AND MARKET GROUPINGS

COUNTRY/MARKET	SUB REGION	REGION
ALBANIA	RoW	Other countries
ALGERIA	Middle East and Africa	Other countries
ARGENTINA	The Americas	Other countries
AUSTRALIA	Asia Pacific	Other IEA PVPS countries
AUSTRIA	Europe	European Union
BANGLADESH	RoW	Other countries
BELARUS	RoW	Other countries
BELGIUM	Europe	European Union
BOSNIA HERZEGOVINA	RoW	Other countries
BRAZIL	The Americas	Other countries
BULGARIA	Europe	European Union
CANADA	The Americas	Other IEA PVPS countries
CHILE	The Americas	Other countries
CHINA	Asia Pacific	China
CHINESE TAIPEI	Asia Pacific	Other countries
COLOMBIA	The Americas	Other countries
CROATIA	Europe	European Union
CYPRUS	Europe	European Union
CZECH REPUBLIC	Europe	European Union
DENMARK	Europe	European Union
ECUADOR	The Americas	Other countries
EGYPT	Middle East and Africa	Other countries
ESTONIA	Europe	European Union
FINLAND	Europe	European Union
FRANCE	Europe	European Union
GERMANY	Europe	European Union
GREECE	Europe	European Union
HONDURAS	The Americas	Other countries
HUNGARY	Europe	European Union
ICELAND	Europe	Other countries
INDIA	Asia Pacific	India
INDONESIA	Asia Pacific	Other countries
IRAN	Middle East and Africa	Other countries
IRELAND	Europe	European Union
ISRAEL	Middle East and Africa	Other IEA PVPS countries
ITALY	Europe	European Union
JAPAN	Asia Pacific	Japan
JORDAN	Middle East and Africa	Other countries
KAZAKHSTAN	Asia Pacific	Other countries
KOREA	Asia Pacific	Other IEA PVPS countries
KOSOVO	RoW	Other countries
LATVIA	Europe	European Union
LITHUANIA	Europe	European Union
LUXEMBOURG	Europe	European Union
MALAYSIA	Asia Pacific	Other IEA PVPS countries
MALTA	Europe	European Union
MEXICO	The Americas	Other IEA PVPS countries
MONTENEGRO	RoW	Other countries
MOROCCO	Middle East and Africa	Other IEA PVPS countries
NETHERLANDS	Europe	European Union
NORTH MACEDONIA	RoW	Other countries
NORWAY	Europe	Other IEA PVPS countries
PAKISTAN	Asia Pacific	Other countries
PANAMA	RoW	Other countries
PERU	The Americas	Other countries
PHILIPPINES	Asia Pacific	Other countries
POLAND	Europe	European Union
PORTUGAL	Europe	European Union
QATAR	RoW	Other countries
MOLDOVA	RoW	Other countries
ROMANIA	Europe	European Union
ROW	RoW	Other countries
RUSSIA	Europe	Other countries
SAUDI ARABIA	Middle East and Africa	Other countries
SERBIA	Europe	Other countries
SINGAPORE	Asia Pacific	Other countries
SLOVAKIA	Europe	European Union
SLOVENIA	Europe	European Union
SOUTH AFRICA	Middle East and Africa	Other IEA PVPS countries
SPAIN	Europe	European Union
SUDAN	RoW	Other countries
SWEDEN	Europe	European Union
SWITZERLAND	Europe	Other IEA PVPS countries
THAILAND	Asia Pacific	Other IEA PVPS countries
TUNISIA	RoW	Other countries
TÜRKIYE	Europe	Other IEA PVPS countries
UAE	Middle East and Africa	Other countries
UK	Europe	Other countries
UKRAINE	Europe	Other countries
USA	The Americas	USA
VIETNAM	Asia Pacific	Other countries

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