

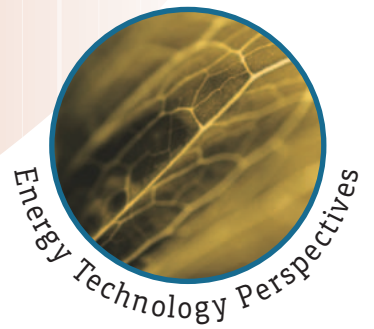


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Technology Roadmap

Solar Photovoltaic Energy

2014 edition

INTERNATIONAL ENERGY AGENCY

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Foreword

Current trends in energy supply and use are unsustainable – economically, environmentally and socially. Without decisive action, energy-related greenhouse-gas (GHG) emissions would lead to considerable climate degradation with an average 6°C global warming. We can and must change the path we are now on; sustainable and low-carbon energy technologies will play a crucial role in the energy revolution required to make this change happen. Energy Efficiency, many types of renewable energy, carbon capture and storage (CCS), nuclear power and new transport technologies will all require widespread deployment if we are to achieve a global energy-related CO₂ target in 2050 of 50% below current levels and limit global temperature rise by 2050 to 2°C above pre-industrial levels.

This will require significant global investment into decarbonisation, which will largely be offset by reduced expenditures on fuels. Nonetheless, this supposes an important reallocation of capital. To address this challenge, the International Energy Agency (IEA) is leading the development of a series of technology roadmaps which identify the steps needed to accelerate the implementation of technology changes. These roadmaps will enable governments, industry and financial partners to make the right choices – and in turn help societies to make the right decision.

Photovoltaic (PV) energy is one of the most promising emerging technologies. The cost of PV modules has been divided by five in the last six years; the cost of full PV systems has been divided by almost three. The levelised cost of electricity of decentralised solar PV systems is approaching or falling below the variable portion of retail electricity prices that system owners pay in some markets, across residential and commercial segments. For bulk power on grid, PV electricity can already be competitive at times of peak demand, especially in areas where peak electricity is provided by burning oil products. And there remains ample room for improvements, as this roadmap details.

Much has happened since our 2010 IEA technology roadmap for PV energy. PV has been deployed faster than anticipated and by 2020 will probably reach twice the level previously expected. Rapid

deployment and falling costs have each been driving the other. This progress, together with other important changes in the energy landscape, notably concerning the status and progress of nuclear power and CCS, have led the IEA to reassess the role of solar PV in mitigating climate change. This updated roadmap envisions PV's share of global electricity rising up to 16% by 2050, compared with 11% in the 2010 roadmap.

As PV spreads beyond Europe, where most deployment was concentrated until 2012, it faces a number of barriers, economic and non-economic. To help overcome such potential obstacles, this updated roadmap provides renewed proposals on technology, system integration, legislative and regulatory issues, based on analyses of the lessons learned by pioneering countries.

In mature PV markets – currently still only a handful of countries – greater market exposure is necessary as PV becomes more competitive. However, changes in legislative frameworks and support policies must be as transparent and predictable as possible. Like most renewable energy sources and energy efficiency improvements, PV is very capital-intensive: almost all expenditures are made up-front. Keeping the cost of capital low is thus of primary importance for achieving this roadmap's vision. But investment and finance are very responsive to the quality of policy making. Clear and credible signals from policy makers lower risks and inspire confidence. By contrast, where there is a record of policy incoherence, confusing signals or stop-and-go policy cycles, investors end up paying more for their finance, consumers pay more for their energy, and some projects that are needed simply will not go ahead.

I strongly hope that the analysis and recommendations in this roadmap will play a part in ensuring the continued success of PV deployment and, more broadly, a decarbonised energy system.

This publication is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven
Executive Director
International Energy Agency

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Key findings and actions

- Since 2010, the world has added more solar photovoltaic (PV) capacity than in the previous four decades. New systems were installed in 2013 at a rate of 100 megawatts (MW) of capacity per day. Total global capacity overtook 150 gigawatts (GW) in early 2014.
- The geographical pattern of deployment is rapidly changing. While a few European countries, led by Germany and Italy, initiated large-scale PV development, PV systems are now expanding in other parts of the world, often under sunnier skies. Since 2013, the People's Republic of China has led the global PV market, followed by Japan and the United States.
- PV system prices have been divided by three in six years in most markets, while module prices have been divided by five. The cost of electricity from new built systems varies from USD 90 to USD 300/MWh depending on the solar resource; the type, size and cost of systems; maturity of markets and costs of capital.
- This roadmap envisions PV's share of global electricity reaching 16% by 2050, a significant increase from the 11% goal in the 2010 roadmap. PV generation would contribute 17% to all clean electricity, and 20% of all renewable electricity. China is expected to continue leading the global market, accounting for about 37% of global capacity by 2050.
- Achieving this roadmap's vision of 4 600 GW of installed PV capacity by 2050 would avoid the emission of up to 4 gigatonnes (Gt) of carbon dioxide (CO₂) annually.
- This roadmap assumes that the costs of electricity from PV in different parts of the world will converge as markets develop, with an average cost reduction of 25% by 2020, 45% by 2030, and 65% by 2050, leading to a range of USD 40 to 160/MWh, assuming a cost of capital of 8%.
- To achieve the vision in this roadmap, the total PV capacity installed each year needs to rise rapidly, from 36 GW in 2013 to 124 GW per year on average, with a peak of 200 GW per year between 2025 and 2040. Including the cost of repowering – the replacement of older installations – annual investment needs to reach an average of about USD 225 billion, more than twice that of 2013.
- Utility-scale systems and rooftop systems will each have roughly half of the global market. Rooftop systems are currently more expensive but the value of electricity delivered on consumption sites or nearby is greater. However, as PV expansion is driven more and more by self-consumption – the use of PV electricity directly at the same site where it is generated – grids may carry smaller amounts of traded electricity, raising concerns over how to recover the fixed costs of grids. Grid operators, regulators and policy makers should monitor the impact of rapid expansion of distributed PVs on distribution networks. Rate changes ensuring full grid cost recovery and fair allocation of costs might be considered but should be carefully designed in order to maintain incentives for energy efficiency and the deployment of rooftop PV.
- The variability of the solar resource, as of wind energy, is a challenge. All flexibility options – including interconnections, demand-side response, flexible generation, and storage – need to be developed to meet this challenge so that the share of global electricity envisioned for PV in this roadmap can be reached by 2050.
- PV has to be deployed as part of a balanced portfolio of all renewables. In temperate countries, wind power tends to be stronger during winter and hence compensate for low solar irradiance. In hot and wet countries, hydropower offers considerable resource in complement to solar PV. In hot and arid countries, solar thermal electricity with built-in thermal storage capabilities can generate electricity after sunset, complementing the variability of PV and thus adding more solar electricity to systems – potentially making solar the leading source of electricity by 2040.¹
- Despite recent falls in the cost of PV electricity, transitional policy support mechanisms will be needed in most markets to enable PV electricity costs to reach competitive levels, as long as electricity prices do not reflect climate change or other environmental factors. The vision in this roadmap is consistent with global CO₂ prices of USD 46/tCO₂ in 2020, USD 115/tCO₂ in 2030, and USD 152/tCO₂ in 2040.
- In the last few years, manufacturing of PV systems has been concentrated in Asia, particularly in China and Chinese Taipei, mainly based on economies of scale in large new production facilities. Future progress is likely to be driven mainly by technology innovation, which keeps open the possibility of global deployment of manufacturing capabilities if research and development (R&D) efforts and international collaboration are strengthened.

1. See the companion *Technology Roadmap: Solar Thermal Electricity* (IEA, 2014a).

- Appropriate regulatory frameworks – and well-designed electricity markets, in particular – will be critical to achieve the vision in this roadmap. PV costs are incurred almost exclusively up-front, when the power plant is built. Once built, PV generates electricity almost for free. This means that investors need to be able to rely on future revenue streams so that they can recover their initial capital investments. Market structures and regulatory frameworks that fail to provide robust long-term price signals – beyond a few months or years – are thus unlikely to deliver investments in volumes consistent with this roadmap in particular and timely decarbonisation of the global energy system in general.

Key actions in the next five years

- Set or update long-term targets for PV deployment, consistent with national energy strategies and national contributions to global climate change mitigation efforts.
- Support these targets with predictable market structures and regulatory frameworks to drive investment.
- Address non-economic barriers. Develop streamlined procedures for providing permits.
- Identify the cost structure of current projects and any anomalies in comparison with projects in other jurisdictions. Implement specific actions to reduce anomalous costs.
- Work with financing circles and other stakeholders to reduce financing costs for PV deployment, in particular involving private money and institutional investors.
- Reduce the costs of capital and favour innovation in providing loan guarantees, and concessional loans in emerging economies.
- Strengthen research, development and demonstration (RD&D) efforts to further reduce costs.
- Strengthen international collaboration on RD&D and exchanges of best practices.
- In emerging PV markets:
 - Implement priority connection to the grid and priority dispatch of PV electricity.
- Implement support schemes with fair remuneration for investors but predictable decrease of the level of support.
- When parity with retail electricity prices is achieved in some market segments, provide incentives for distributed PV generation through net energy metering and/or tariffs for energy (total generation or only injections into the grid) based on a value of solar electricity determined through a transparent process open to all interested parties.
- In mature markets:
 - Progressively increase short-term market exposure of PV electricity while ensuring fair remuneration of investment, for example with sliding feed-in premiums and/or auctions with time-of-delivery and locational pricing.
 - Provide incentives for generation at peak times through time-of-delivery payments.
 - Provide incentives for self-consumption during peaks through time-of-use electricity rates.
 - Improve forecasts and reform energy-only electricity markets for better synchronisation of supply and demand.
 - Design and implement investment markets for new-built PV systems and other renewables, and markets for ancillary services.
 - Progressively reform rate structures to encourage generation and discourage consumption during peak times, ensuring the recovery of fixed costs of the transmission and distribution grids while preserving the incentives for efficiency and distributed PV.
 - Avoid retroactive legislative changes.
 - Work with financing circles and other interested parties to reduce financing costs for PV deployment, in particular involving private money and institutional investors.
- Strengthen research, development and demonstration (RD&D) efforts to further reduce costs.
- Improve quality via more diversified module qualification, and certification of developers, designers and installers.
- Strengthen international collaboration on RD&D and exchanges of best practices.
- Support best practices in developing economies, in particular for providing access to electricity based on off-grid and mini-grid PV systems.

Introduction

There is a pressing need to accelerate the development of advanced energy technologies in order to address the global challenges of clean energy, climate change and sustainable development. To achieve the necessary reductions in energy-related CO₂ emissions, the IEA has developed a series of global technology roadmaps, under international guidance and in close consultation with industry. These technologies are evenly divided among demand-side and supply-side technologies and include several renewable energy roadmaps (www.iea.org/roadmaps/).

The overall aim is to advance global development and uptake of key technologies to limit the global mean temperature increase to 2 degrees Celsius (°C) in the long term. The roadmaps will enable governments, industry and financial partners to identify and implement the measures needed to accelerate the required technology development and uptake.

The roadmaps take a long-term view, but highlight the key actions that need to be taken in the next five years, which will be critical to achieving long-term emission reductions. Existing conventional plants and those under construction may lock in CO₂ emissions, as they will be operating for decades. According to the *IEA Energy Technology Perspectives 2014 (ETP 2014)* (IEA, 2014b), early retirement of 850 GW of existing coal capacity would be required to reach the goal of limiting climate change to 2°C. Therefore, it is crucial to build up low-carbon energy supply today.

Rationale for solar photovoltaic power in the overall energy context

ETP 2014 projects that in the absence of new policies to accelerate the uptake of low-carbon solutions, CO₂ emissions from the energy sector would increase by 61% over 2011 levels by 2050 (IEA, 2014b). The *ETP 2014* model examines a range of technology solutions that can contribute to preventing this increase: greater energy efficiency, renewable energy, nuclear power and the near-decarbonisation of fossil fuel-based power generation. Rather than projecting the maximum possible deployment of any given solution, the *ETP 2014* model calculates the least-cost mix to achieve the CO₂ emission reduction needed to limit climate change to 2°C (the *ETP 2014* 2°C Scenario

[2DS]). The hi-Ren Scenario is a variant of the 2DS with slower deployment of nuclear and carbon capture and storage (CCS) technologies, and more rapid deployment of renewables, notably solar and wind energy.

Based on the *ETP 2014* hi-Ren Scenario, this roadmap envisions up to 16% of global electricity for solar PV with 6 300 TWh generated in 2050, up from the 4 500 TWh foreseen in the 2010 roadmap. This increase in PV compensates for slower progress in the intervening years in CCS and higher costs for nuclear power. It also reflects faster-than-expected rollout and cost reductions for solar PV.

Solar energy is widely available throughout the world and can contribute to reduced dependence on energy imports. As it entails no fuel price risk or constraints, it also improves security of supply. Solar power enhances energy diversity and hedges against price volatility of fossil fuels, thus stabilising costs of electricity generation in the long term.

Solar PV entails no greenhouse gas (GHG) emissions during operation and does not emit other pollutants (such as oxides of sulphur and nitrogen); additionally, it consumes no or little water. As local air pollution and extensive use of fresh water for cooling of thermal power plants are becoming serious concerns in hot or dry regions, these benefits of solar PV become increasingly important.

Purpose of the roadmap update

The solar PV roadmap was one of the first roadmaps developed by the IEA, in 2009/10. Since then, the world has added more PV capacity than it had in the previous four decades, and more rapidly than expected. The 210 GW of cumulative capacity expected to be reached by 2020 is now likely to be achieved five years earlier, and the capacity now expected for 2020 will be over twice what was foreseen in the 2010 roadmap. Moreover, the system cost milestones for 2020 in the original roadmap have already been reached in the most advanced markets, except for the smallest rooftop capacities.

This updated roadmap thus presents a new vision that takes into account this considerable progress of PV technologies, as well as changing trends in the overall energy mix. It presents a detailed assessment of the technology milestones that PV energy will need to reach to attain this

ambitious vision. The key objective is to improve PV technology performance and reduce costs in order to achieve the competitiveness needed for the large investments foreseen.

The roadmap also examines numerous economic and non-economic barriers that hamper deployment and identifies policy actions to overcome them. About half of overall capacity is likely to be deployed on buildings, so this roadmap considers critical issues arising from the complex relationships between PV generation, on-the-spot consumption and electricity networks.

This roadmap thus identifies actions and time frames to achieve the higher PV deployment needed for global emission reductions. In some markets, certain actions have already been taken, or are under way. Many countries, particularly in emerging regions, are only just beginning to develop PV systems. Accordingly, milestone dates should be considered as indicative of urgency, rather than as absolutes. Each country will have to choose which actions to prioritise, based on its mix of energy sources and industrial policies.

This roadmap is addressed to a variety of audiences, including policy makers, industry, utilities, researchers and other interested parties. As well as providing a consistent overall picture of PV power at global and continental levels, it aims at providing encouragement and information to individual countries to elaborate action plans, set or update targets, and formulate roadmaps for PV power deployment.

Roadmap process, content and structure

This roadmap was developed with the help of contributions from representatives of the solar industry, the power sector, research and development (R&D) institutions, the finance community and government institutions. An expert workshop was held in Paris in February 2014 at IEA headquarters in Paris, focusing on technology and “vision” for both solar PV and STE². A draft was then circulated to experts and stakeholders for further contributions and comments.

2. See www.iea.org/workshop/solarelectricity/roadmapworkshop.html.

The roadmap also takes into account other regional and national efforts to investigate the potential of PV, including:

- the SunShot initiative of the US Department of Energy
- the EU Strategic Energy Technology Plan (SET Plan)
- the international technology roadmap for PV (ITRPV)
- the Chinese 12th five-year plan for the solar PV industry.

This roadmap is organised into six major sections. First, the current state of the PV industry and progress since 2009 is discussed, followed by a section that describes the vision for PV deployment between 2015 and 2050 based on *ETP 2014*. This discussion includes information on the regional distribution of PV generation projects and the associated investment needs, as well as the potential for cost reductions.

The next three sections describe approaches and specific tasks required to address the major challenges facing large-scale PV deployment in three major areas: PV technology development; system integration; and policy frameworks, public engagement and international collaboration. The final section sets out next steps and categorises the actions in the previous sections that policy makers, industry, power system actors and financing circles need to take to implement the roadmap’s vision for PV deployment.

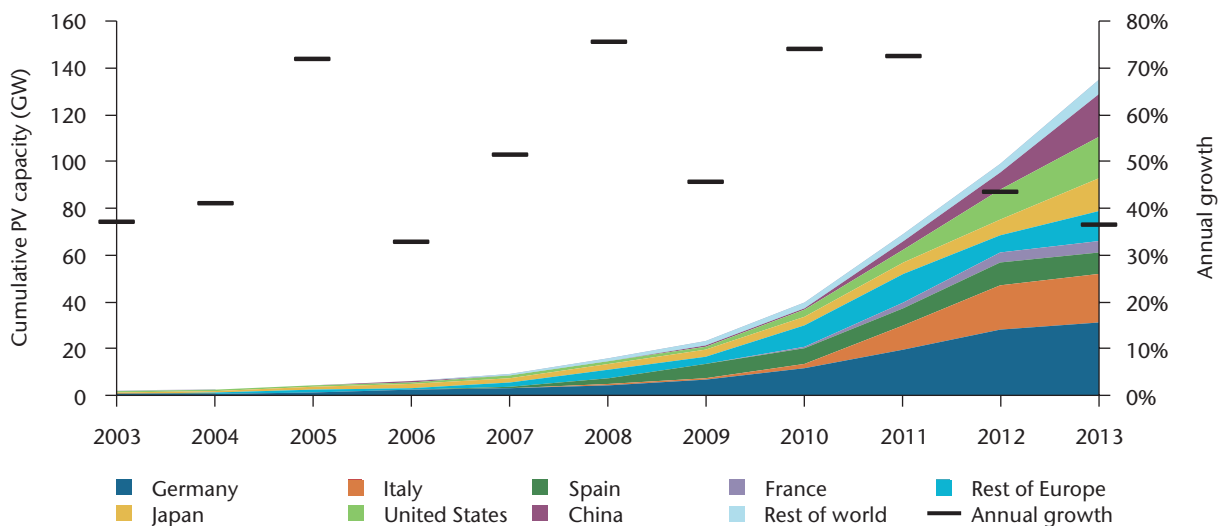
Progress since 2009

The PV industry has experienced a sea change in only five years, with considerable increases in manufacturing capacities, and a move of module manufacturing from European countries and the United States to Asia, notably China and Chinese Taipei. Market prices have been drastically reduced – by factor of five for modules, and by a factor of almost three for systems. The global rate of annual new-built capacities, which was 7 GW in 2009, was 5 times higher in 2013.

Recent market developments

In the last ten years, cumulative installed capacity has grown at an average rate of 49% per year (Figure 1). In 2013, about 37 GW of new PV capacity was installed in about 30 countries – or 100 MW per day – bringing total global capacity to over 135 GW. For the first time since 2004, more new capacity was installed in Asia than in Europe. China alone installed more than all of Europe, with over 11 GW. Japan ranked second with almost 7 GW, and the United States third with over 4 GW. New investment in PV capacity in 2013 was assessed at USD 96 billion.

Figure 1: Global cumulative growth of PV capacity



Source: Unless otherwise indicated, all tables and figures derive from IEA data and analysis.

KEY POINT: Cumulative PV capacity grew at 49%/yr on average since 2003.

Grid-connected PV systems continue to be built at all scales, from just a few kilowatts (kW) to hundreds of megawatts (MW). Off-grid systems can be even smaller while providing highly valued power far from electricity networks. At the opposite end, there are about 20 utility-scale plants of over 100 MW capacity in the world, mostly in China and in the United States.

In Germany, more than 1.3 million solar power plants generated almost 30 TWh in 2013, equivalent to 5.3% of German electricity

consumption (Burger, 2014), and total capacity was rated at 36 GW at the end of 2013. In Italy, PV systems generated 22 TWh in 2013, or 7% of electricity consumption, with total capacity rated at 17 GW at the end of 2013. PV generation has exceeded 3% of electricity demand in five other countries – Belgium, Bulgaria, Czech Republic, Greece and Spain (PVPS IA, 2014; RED, 2014).

Crystalline silicon (c-Si) modules, whether single-(sc-Si) or multi-crystalline (mc-Si), currently dominate the PV market with around 90% share.

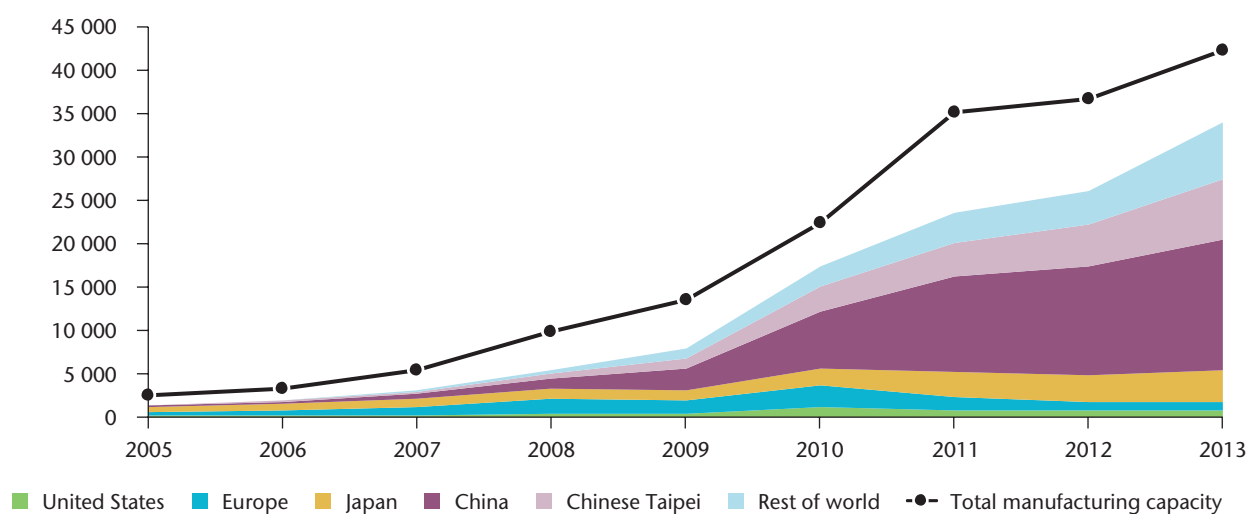
Thin films (TF) of various sorts now represent only about 10% of the market, down from 16% in 2009, and concentrating photovoltaics (CPV), although growing significantly, represent less than 1%. Decentralised systems represent approximately 60% of the global market, while centralised, utility-scale systems represent close to 40%. Off-grid systems, which once dominated a much smaller market, now account for 1% at most.

In the last few years, the PV module manufacturing industry has witnessed a dramatic shift, from Europe, particularly Germany, to Asia, mostly China and Chinese Taipei.

Table 1: Progress in solar PV markets and installation since 2009

	<i>End of 2009</i>	<i>End of 2013</i>
Total installed capacity	23 GW	135 GW
Annual installed capacity	7 GW	37 GW
Annual investment	USD 48 billion	USD 96 billion
Number of countries with >1 GW installed	5	17
Number of countries with >100 MW yearly market	9	23
PV electricity generated during the year	20 TWh	139 TWh
PV penetration levels	% of yearly electricity consumption	
Europe		2.6%
● Germany		5.3%
● Italy		7%

Figure 2: PV manufacturing by countries



Source: SPV Market Research (2014), *Photovoltaic manufacturer Shipments: Capacity, Price & Revenues 2013/2013*, Report SPV-Supply 2, April.

KEY POINT: The manufacturing of PV modules shifted from OECD to non-OECD countries over just a few years.

In 2012, the PV industry employed approximately 88 000 people in Germany to manufacture materials (silicon, wafers, metal pastes, plastic films, solar glass), and intermediate and final products (cells, modules, inverters, supports, cables, coated glass), and to build manufacturing plants and install PV systems. About a quarter of this production has since been lost, as the German PV market declined and as manufacturing moved to Asia. This shift was primarily a result of huge investments in production capacity in Asia. Labour costs only played a marginal role, as PV production is highly automated; other variable costs, including energy costs, played a more important role. Fast technology transfer was facilitated by the availability of turn-key production lines producing very good quality PV modules.

Manufacturing PV cells and modules now accounts for less than half the value chain, however, although it remains the largest single element. Upstream activities, from research and development (R&D) to building production lines, and downstream activities linked to installation and services, together account for the largest part. In many European countries, in particular those where PV manufacturing has never been important, such as Spain, thousands of PV-related jobs have been created and eliminated more because of on-again off-again renewable energy policies than because of competition from Asia.

At a global level, the PV industry has been estimated to represent about 1.4 million full-time jobs, including 300 000 to 500 000 in China, 312 000 in Europe, 112 000 in India and 90 000 in the United States (REN21, 2014), but these figures must be taken with caution as data collection is not homogenous and, more important, may change rapidly as markets evolve.

A detailed analysis of the cost trends of c-Si modules and the shift of manufacturing to China suggests that the historical price advantage of a China-based factory over a US-based factory is driven not by country-specific factors, but by scale, supply-chain development and access to finance. Technology innovations may result in effectively equivalent minimum sustainable manufacturing prices for the two locations (Goodrich et al., 2013) – and this may hold true for many other locations.

Technology improvements

PV cells are semiconductor devices that generate direct current (DC) electricity. Silicon cells are usually sliced from ingots or castings of highly purified silicon. The manufacturing process creates a charge-separating junction, deposits passivation layers and an anti-reflective coating, and adds metal contacts. Cells are then grouped into modules, with transparent glass for the front, a weatherproof material for the back and often a surrounding frame. The modules are then combined to form strings, arrays and systems.

PV can be used for on-grid and off-grid applications of capacities ranging from less than 1 watt to gigawatts. Grid-connected systems require inverters to transform DC power into alternating current (AC). The balance of system (BOS) includes inverters, transformers, wiring and monitoring equipment, as well as structural components for installing modules, whether on building rooftops or facades, above parking lots, or on the ground. Installations can be fixed or track the sun on one axis (for non- or low-concentrating systems) or two axes (for high-concentrating systems).

Alternative PV technologies, including thin films, had been expected to gain an increasing share of the market, but instead their share shrank from 15% in 2009 to about 10% in 2013. Thin films (TF) are based on cadmium telluride (CdTe), copper-indium-gallium-selenide (CIGS), or amorphous silicon (a-Si), plus some variants. They are usually manufactured in highly automated processes to produce complete modules, with no need to assemble modules from individual cells. Multi-junction cells, which are the standard PV technology in space applications, recently entered the terrestrial market in concentrating photovoltaics (CPV) systems with several large-scale plants (50 MW each) in operation or under construction. Some manufacturers also sell hybrid PV-thermal panels that deliver both heat and electricity.

Box 1: Efficiency and performance ratio

The output per watt (W) installed (sometimes termed “watt-peak”, or W_p) does not depend on nominal efficiency, which determines the required receptive area per watt. The nominal efficiency relates to the power generated under so-called “standard test conditions” (STC) – module temperature of 25°C, vertical irradiance of 1 000 W/m², air mass of 1.5 (distance travelled through the atmosphere 50% greater than when the sun is exactly overhead) and a specific irradiance spectrum. For example, modules of 1 m² would generate a maximum power of 150 W with 15% efficiency, and 200 W with 20% efficiency under the STC.

The actual output depends on the solar resource, the orientation of the modules and the “performance ratio” (PR) of the system, which

takes into account all efficiency losses resulting from actual module temperature, module mismatch, varying irradiance conditions, dirt, line resistance and conversion losses in the inverter. Well-designed PV plants achieve average PR of 80% to 90% throughout the year. A PV system receiving 1 200 kWh/m² per year would generate annually 1 020 kWh/kW with a PR of 85%, the equivalent of 1 020 full load hours, or a capacity factor of 11.6%. In regions with high insolation of 2 500 kWh/m² on the collector surface, the same system, assuming the same PR of 85%, would produce up to 2 125 kWh/kW, or a capacity factor of 24.3%.

The average efficiency of commercial silicon modules has improved in the last ten years by about 0.3% per year, reaching 16% in 2013. The best-performing commercial modules, based on back-junction, interdigitated back-contact (IBC) offer efficiencies of 21%, with heterojunction (HTJ) technologies close behind at over 19% efficiency, and excellent performance ratios. Modules are usually guaranteed for a lifetime of 25 years at minimum 80% of their rated output, and sometimes for 30 years at 70%. TF modules also saw increases in efficiencies, with commercial CdTe TF, in particular, reaching 15%. Moreover, CdTe modules, especially in hot and humid climates, and possibly CIGS TF modules, have higher performance ratios than average c-Si modules of similar prices. CPV modules offer efficiencies of 25% to 35%, but only make use of direct normal irradiance (DNI), which is lower than global normal irradiance (see Box 2). Therefore CPV performs best in high DNI locations.

Even more impressive progress has been made with respect to manufacturing. The amount of specific materials (silicon, metal pastes, etc.), the energy consumption and the amount of labour required to assemble modules were all significantly reduced.

Advances toward competitiveness

The emergence of the global PV market has coincided with rapid reductions in the costs of modules and systems. The levelised cost of energy (LCOE)³ from PV systems is already below retail electricity prices (per-kWh charge) in several countries, and rapidly approaching the level of generation costs from conventional alternatives, especially new coal with strict air pollutant emission standards, new nuclear plants with increased safety standards, or new gas plants in areas with high gas prices.

Investment costs

From 2008 to 2012, PV module prices were divided by five, and PV system prices divided by three in mature markets such as Italy (Figure 3). In 2013 and 2014, module prices more or less stabilised, indicating that prices were not fully reflecting underlying costs. As too many modules began

3. The LCOE represents the present value of the total cost (overnight capital cost, fuel cost, fixed and variable operation and maintenance costs, and financing costs) of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments, given an assumed utilisation, and expressed in terms of real money to remove inflation.

to be produced, many were sold at prices too low to recover investment, as the deterioration of the balance sheets of most PV companies (up to bankruptcy for some) demonstrated. But

improvements in technology and the scaling up of manufacturing were by far the main factors driving cost reductions.

Box 2: Solar radiation relevant for PV

Solar energy is the most abundant energy resource on earth, with about 885 million terawatt hours (TWh) reaching the surface of the planet every year – 6 200 times the commercial primary energy consumed by humankind in 2008, and 3 500 times the energy that humankind would consume in 2050 according to the *ETP 2014 6-degree Scenario* (IEA, 2011; 2014b).

The solar radiation reaching the earth's surface is about 1 kilowatt per square metre (kW/m²) in clear conditions when the sun is near the zenith. It has two components: direct or "beam" radiation, which comes directly from the sun's disk; and diffuse radiation, which comes indirectly after being scattered by the atmosphere. PV systems, with the exception of concentrating PV (CPV), make use of the "global" irradiance, which is the sum of direct and diffuse radiations.

All places on earth receive 4 380 daylight hours per year – i.e. half the total duration of one year. Different areas, however, receive different yearly average amounts of energy from the sun. When the sun is lower in the sky, its energy is spread over a larger area, and more is also lost when passing through the atmosphere, because of increased air mass; it is therefore weaker per horizontal surface area: inter-tropical areas should thus receive more radiation per land area than places north of the Tropic of Cancer or south of the Tropic of Capricorn. However,

atmospheric absorption characteristics affect the amount of this surface radiation significantly, and the sunniest places on Earth are usually arid and semi-arid areas close to the tropics but distant from the Equator.

The average energy received in Europe, measured in global horizontal irradiance (GHI), is about 1 200 kilowatt hours per square metre per year (kWh/m²/y). This amount compares with 1 800 kWh.m²/y to 2 300 kWh/m²/y in the Middle East. The United States, Africa, most of Latin America, Australia, most of India, and parts of China and other Asian countries also have good to excellent solar resource; these are broadly the regions where energy demand is expected to rise most in the coming decades.

Alaska, Northern Europe, Canada, Russia and Southeast China receive less solar energy. But tilting equator-facing modules can reduce disparities and increase the annual energy received on PV systems, especially at high latitudes, although this varies with meteorological patterns and the ratio of diffuse versus direct light. For example, modules in La Rochelle, in France, where the GHI is 1 300 kWh/m²/y, receive up to 1 500 kWh/m²/y if optimally tilted and oriented. Tracking the sun on one axis or two axes further increases the amount of energy received by the modules. Global normal irradiance (GNI) is the relevant resource for two-axis sun-tracking "1-sun" (i.e. non-concentrating) PV systems.

Production of PV modules in China has stimulated competition and reduced prices. In the United States, however, the installed price of Chinese and non-Chinese modules was roughly the same for any given module efficiency (Barbose et al., 2013). In the first half of 2014, Chinese Tier 1 module players were selling at USD 0.59-0.60/W in China,

and USD 0.67-0.79/W in other countries (Bnef, 2014). German modules were selling at EUR 0.69 (USD 0.95)/W.

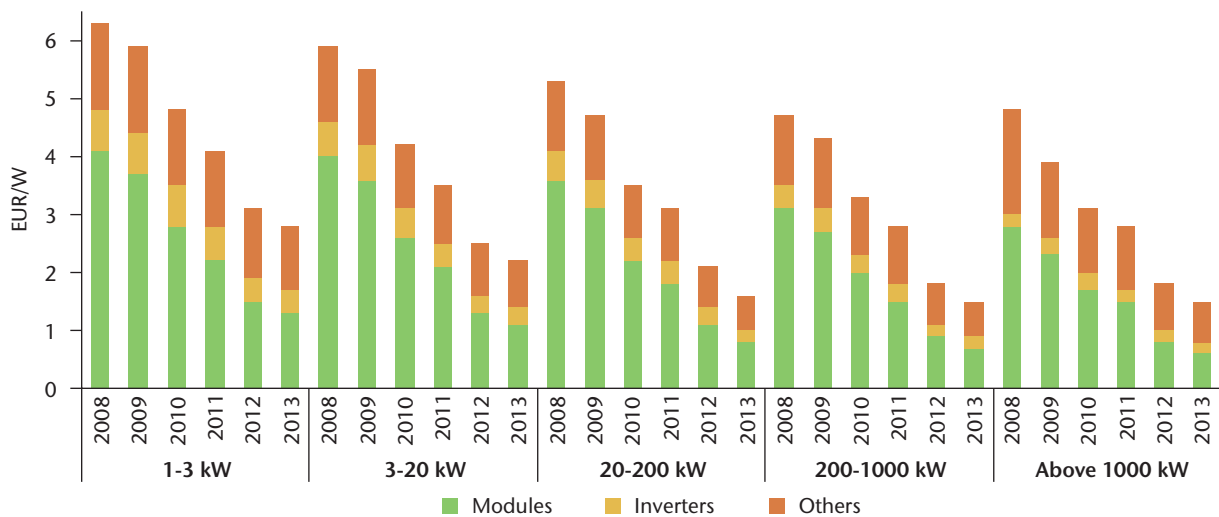
The learning experience for complete PV systems is usually considered slower than that for modules and other hardware parts (inverters, support structures,

cables, etc) – a phenomenon with both national and global dimensions. However, in emerging markets, non-module costs often shrink rapidly as installers gain experience – and also as project density increases, saving significant travel times for sales and marketing staff, and skilled workers.

The costs of PV systems have fallen considerably over the last six years in several markets. In Italy, prices for non-module components of PV systems dropped significantly (Figure 3). In other countries, notably in the United States, the reductions were much smaller, and the fall in module costs was the main driver of the decline in system costs up to 2012.

In 2013, the cheapest large-scale, ground-mounted PV systems could cost less than USD 1.50/W, a price that most market analysts expected, just two years previously, to apply in 2019 or 2017 at the earliest. Although module prices seem to have stabilised in 2013, system costs have continued to decline, with cost reductions in California, for example, ranging from 10% to 15% depending on system size in the first half of 2013 (Barbose et al., 2013). Both the investment cost difference and the output gap between fixed-tilted PV systems and one-axis sun-tracking systems have narrowed in the last few years. In Japan, costs of residential PV systems fell from USD 5.9/W in 2012 to USD 4.64/W in 2013 – a 21% reduction.

Figure 3: System prices in Italy, 2008-2013



Source: Gestore dei Servizi energetici (GSE) (2014), *PV in Italy: Generation Costs and Value Chain*, May, Rome.

KEY POINT: In 2013, PV systems in Italy cost 30% to 44% of what they cost in 2008.

Prices for entire PV systems range more widely than those of cells and modules, which tend to be global commodities. Small systems, such as rooftop systems, are usually more expensive than larger ones, especially ground-based, utility-scale systems (Australia and China being possible exceptions due to connection costs). Prices vary significantly among countries for similar system types (Table 2). Most of the gap comes from differences in “soft costs”, which include customer acquisition; permitting, inspection and interconnection; installation labour; and financing costs, especially

for small systems (Seel et al., 2013). Generous incentive frameworks in some countries keep prices higher than raw costs plus a reasonable margin. Even greater differences are evident in the costs of commercial PV systems from country to country; such systems are more than twice as expensive in the United States than in Germany.

Table 2: Typical PV system prices in 2013 in selected countries (USD)

USD/W	Australia	China	France	Germany	Italy	Japan	United Kingdom	United States
Residential	1.8	1.5	4.1	2.4	2.8	4.2	2.8	4.9
Commercial	1.7	1.4	2.7	1.8	1.9	3.6	2.4	4.5
Utility-scale	2.0	1.4	2.2	1.4	1.5	2.9	1.9	3.3

Sources: Friedman et al. (2014), *Comparing PV Costs and Deployment Drivers in the Japanese and U.S. Residential and Commercial Markets*, February, NREL/TP-6A20-60360; PV-PS IA (2014a), *PV Cost Data for the IEA*, personal communication, January.

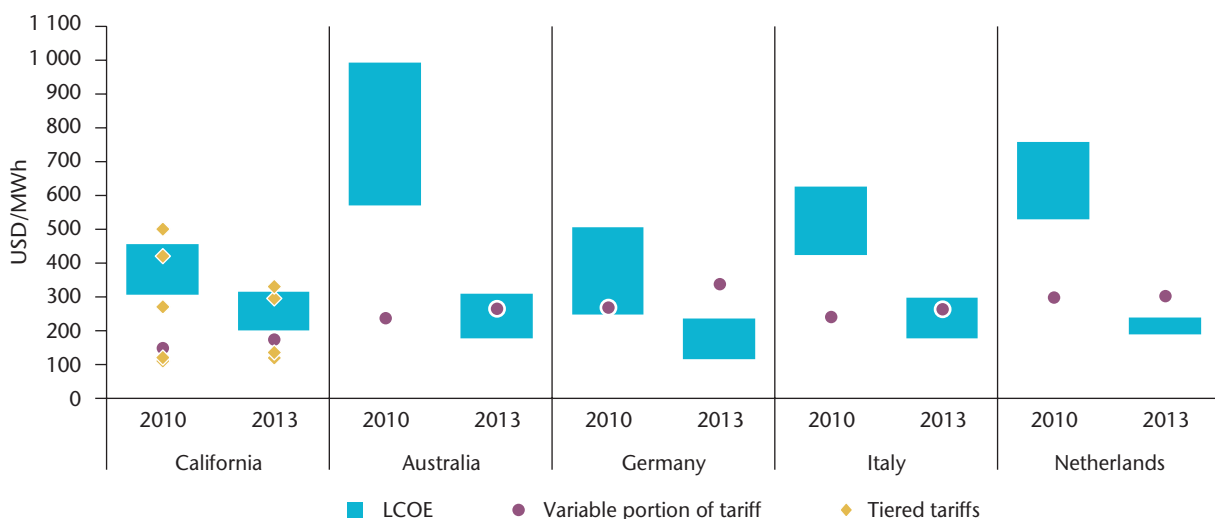
Levelised cost of electricity (LCOE)

PV power plants reached LCOE of EUR 78 (USD 110)/MWh to EUR 142 (USD 190)/MWh in the third quarter of 2013 in Germany, depending on the type of power plant and irradiance (Kost et al., 2013). At higher irradiation ranges (e.g. 1 450-2 000 kWh/m²/y), assuming same system costs but slightly higher costs of capital, the LCOE from PV in 2013 lies under EUR 120 (USD 162)/MWh for all PV power plant types. At 2 000 kWh/m²/y, PV utility-scale power plants under similar assumptions

relative to system costs and costs of capital would be already able to produce power for EUR 60 (USD 80)/MWh and therefore have a LCOE that is comparable to power generated from oil and gas, or even new-built coal (Kost et al., 2013). However, in countries where PV deployment has barely begun, PV system costs and costs of capital may be significantly higher, preventing PV from being immediately competitive.

PV can be built and operated in millions of small, decentralised systems, often characterised as “rooftop”. When the LCOE of decentralised solar

Figure 4: Grid parity was reached in 2013 in various countries



Note: Household electricity tariffs exclude fixed charges. LCOEs are calculated using average residential system costs (including value-added tax and sales tax in where applicable, and investment tax credit in California); ranges mostly reflect differences in financing costs. The tiered tariffs in California are those of Pacific Gas and Electric. Tiers 3 to 4 or 5 are tariffs paid on monthly consumption when it exceeds given percentages of a set baseline. All costs and prices are in 2012 USD.

KEY POINT: Grid parity underpins PV self-consumption in Germany, and net metering in California.

PV systems becomes lower than the variable portion of the retail electricity price (i.e. per kWh) (Figure 4), the situation is known as “grid parity” or “socket parity”. Grid parity provides an incentive to electricity customers to build a PV system and to generate part of the electricity they consume, and to consume part of the electricity they generate (as more extensively discussed in the System Integration section below). In virtually all power systems, the variable, per-kWh portion of retail prices covers energy costs, most transmission and distribution (T&D) costs, utility or grid operator margins, and various fees and taxes. Grid parity already drives part of the PV deployment in several countries. In the *ETP* model, the electricity from rooftop PV systems has to compete with bulk power costs from competitors, which is augmented by the T&D costs.

Barriers encountered, overcome or outstanding

The quality of PV products has generally increased over the last few years, with reduced variance in PR (Nowak, 2014), but as competition has intensified, some manufacturers have been able to sell lower-quality modules at very low costs. Most common defects were broken interconnections, solder bonds and diodes, or encapsulant discoloration or delamination. Other problems arose because local installers lacked the required skills or the initial design was poor. Conceiving and building PV systems requires a variety of skills, some very specific to PV.

Standards established by International Electricity Commission (IEC 61215 for c-Si, IEC 61646 for TF, IEC 62108 for CPV modules) have proven useful in reducing early failure – or “infant mortality” – of PV modules, but they were not designed to identify how modules wear out or fail in different climates and system configurations, or differentiate between products with short or long lifetimes, or quantify module lifetime for different applications or climates.

There are no widely recognised standards, norms or labels that would tell customers about the behaviour, performance and longevity of various PV products in specific environments. Most of today’s commercial modules pass qualification tests with minimum changes required, so the tests do not provide a means of rankings. Furthermore,

depending on the robustness of the quality assurance system, certification of a module type may only provide insurance with respect to one module out of millions.

In several countries, notably Germany and Italy, deploying PV rapidly has created technical issues (as well as policy cost issues, which are discussed below in the section on policy and finance). When the concentration of significant PV capacities in rural areas created “hot spots”, low-voltage grids needed to be strengthened to evacuate the power. To mitigate the problem, in 2012 Germany revised its Renewable Energy Sources Act to oblige new PV plants to allow remote curtailment, except for systems below 30 kW, which could instead opt for reducing feed-in to 70% of peak capacity (IEA, 2013a).

Grid codes have created other issues. The European power grid functions at a frequency of 50 Hertz (Hz). When more energy is fed in to the power grid than is removed from it, the grid frequency increases. Excessively high frequencies render the grid unstable. Until 2011, inverters for PV systems were equipped with an automatic switch-off function triggered at a fixed frequency of 50.2 Hz. As the number of PV systems in Germany increased, however, this requirement meant to protect the grid could have paradoxically put its stability at risk as PV systems switched off abruptly.

To ensure network security and handle the “50.2 Hz issue”, Germany’s System Stability Act of May 2012 scheduled the retrofit of PV systems until the end of 2014. Power inverters must be able to reduce output when frequency rises too high or to turn themselves off smoothly. If PV systems do not meet the technical requirements necessary to meet this obligation, the law requires that they be switched off at different frequencies. In March 2012, Italy required that PV systems over 50 kW and connected to the medium-voltage grid carry out retrofits by the end of March 2013 to solve a problem of under-frequency threshold for disconnection. This resulted in the saturation of the market for interface protection of medium voltage, leading to a suspension of incentives for plants that did not meet the deadline.

In March 2013, the European Network of Transmission System Operators for Electricity (ENTSO-E) released its latest network code on “requirements for generators”. When the new network code is formally approved and turned into laws, it will apply to all new generators and address the key issues of fault ride-through, frequency stability, voltage stability and remote control.

Obtaining permits and, more specifically, getting access to the grid has remained an obstacle for PV in many countries, because PV is not allowed at various voltage levels, or because grid operators have instituted complex, slow or expensive (or all of the above) connecting procedures. The replacement of feed-in tariffs (FiTs) by auctions has sometimes led to increases in overall costs, especially for low system sizes, as uncertain results increase development and financing costs.

Medium-term outlook

Based on a detailed analysis of all main PV markets, the IEA *Medium-Term Renewable Energy Market Report* (IEA 2014c) conservatively estimates that cumulative installed PV capacity will likely exceed 400 GW worldwide by 2020. China, which recently adopted a target of 70 GW PV capacity by 2017, would lead the world, with over 110 GW. Japan and Germany would each reach around 50 GW, followed by the United States at over 40 GW. Italy and India would rank fifth and sixth with 25 GW and 15 GW, followed by the United Kingdom, France and Australia, all nearing 10 GW.

With respect to annual markets, by 2020 China would be leading with about 14 GW/y, followed by the United States (5 GW/y) and Japan (3 to 4 GW/y). In 2020, global PV capacity that had been installed by the end of 2019 would be generating 530 TWh to 580 TWh, or about 2% of global electricity consumption. In the “enhanced case”, global installed capacity could reach 465 GW to 515 GW by 2020 (IEA, 2014c).

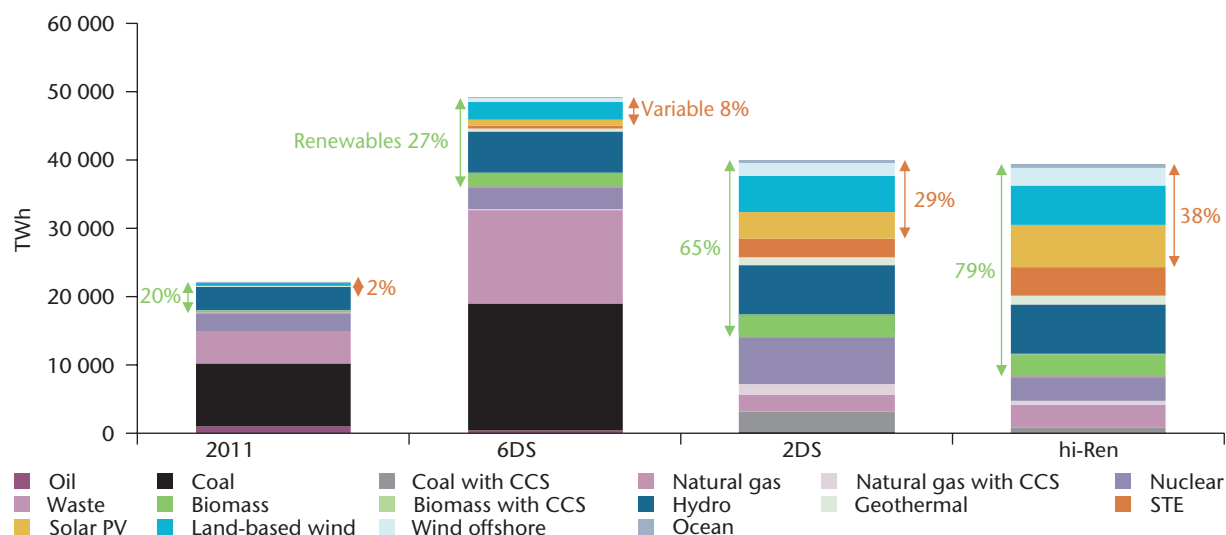
Vision for deployment

Since the IEA's original PV roadmap was published in 2010, technology has improved and costs have fallen more than expected, partly because PV systems have been rolled out faster than expected. Meanwhile, because of slower progress in carbon capture and storage (CCS) and persistent increased costs for nuclear power, *ETP 2014* envisages lower deployment of those technologies between now and 2050 than *ETP 2012* estimated (IEA, 2014b). While the original roadmap set a goal for PV of 11% of total electricity generation by 2050, this roadmap, based on the hi-Ren Scenario of *ETP 2014*, aims for as much as 16%. PV generation would contribute 17% to all clean electricity, and 20% of

all renewable electricity. In both variants of the 2DS, global electricity production in 2050 is almost entirely based on zero-carbon emitting technologies mostly renewables (65% in the 2DS, 79% in the hi-Ren), in sharp contrast with the unsustainable 6DS and 4DS (Figure 5).

It is also worth noting that the greater expansion of PV is not expected to harm the deployment of solar thermal electricity (STE) generated in concentrating solar power (CSP) plants; in this year's update of the 2010 STE/CSP roadmap, estimates of STE's share of total electricity generation have barely changed (IEA, 2014a).

Figure 5: Global electricity mix in 2011 and in 2050 in three *ETP 2014* scenarios



KEY POINT: in the hi-Ren Scenario, renewables provide 79% of global electricity by 2050, variable renewables provide 38%, and PV provides 16%.

CO₂ reduction targets from the *ETP 2014* hi-Ren Scenario

PV systems installed by the end of 2013 are generating 160 TWh/yr of clean electricity and thus avoiding about 140 million tonnes of CO₂ per year (MtCO₂/yr). Annual emissions from the power sector would increase from 13 GtCO₂ in 2011 to about 22 GtCO₂ in 2050 in the *ETP 2014* 6DS (IEA, 2014b, see Box 3). By contrast, in the hi-Ren Scenario, they

are reduced to a mere 1 GtCO₂ in 2050. Solar PV would be responsible for avoiding 4 GtCO₂/yr of emissions, or 19% of the total power sector emission reductions, by 2050, and 20% of cumulative emission reductions over the entire scenario period.

Box 3: ETP Scenarios: 6DS, 2DS, hi-Ren

This roadmap takes as a starting point the vision in the IEA *ETP 2014* analysis, which describes several scenarios for the global energy system in 2050.

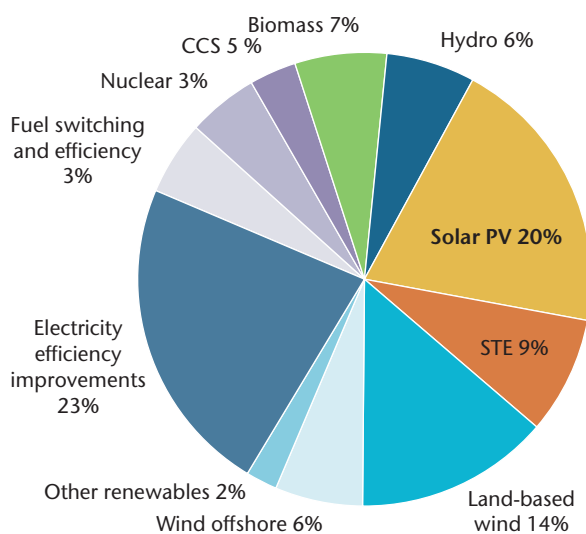
The 6°C Scenario (6DS) is a base-case scenario in which current trends continue. It projects that energy demand would increase by more than two-thirds between 2011 and 2050. Associated CO₂ emissions would rise even more rapidly, pushing the global mean temperature up by 6°C.

The 2°C Scenario (2DS) sees energy systems radically transformed to achieve the goal of limiting the global mean temperature increase to 2°C. The high-renewables Scenario (hi-Ren Scenario), achieves the target with a larger share of renewables, which requires faster and stronger deployment of PV, wind power and STE, to compensate for the assumed slower progress in the development of CCS and deployment of nuclear than in 2DS.

The *ETP 2014* analysis is based on a bottom-up TIMES* model that uses cost optimisation to identify least-cost mixes of energy technologies and fuels to meet energy demand, given constraints such as the availability of natural resources. Covering 28 world regions, the model permits the analysis of fuel and technology choices throughout the energy system, representing about 1 000 individual technologies. It has been developed over several years and used in many analyses of the global energy sector. The *ETP* model is supplemented with detailed demand-side models for all major end-uses in the industry, buildings and transport sectors.

* TIMES = The Integrated MARKAL (Market Allocation)-EFOM (energy flow optimisation model) System.

Figure 6: Cumulative technology contributions to power sector emission reductions in ETP 2014 hi-Ren Scenario, relative to 6DS, up to 2050

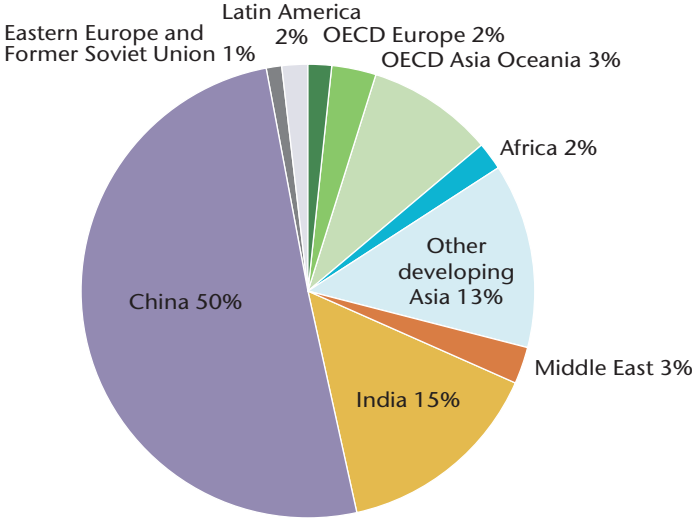


KEY POINT: Solar PV would equal wind power in cutting CO₂ emissions over the next 35 years.

Concerns have been raised about CO₂ emitted in the manufacturing of PV modules (see the Solar PV Technology Development section) and the possibility that the variable nature of PV power may hinder CO₂ emission reductions at power system level (see the System integration section). However, modelling by the IEA and others shows that the penalties incurred due to the manufacturing process and the variability of PV are minor compared with the emission reductions arising from fossil fuel displacement.

The regional distribution of additional CO₂ emission reductions due to PV in the hi-Ren Scenario (Figure 7) primarily reflects the share of PV in the electricity mix of each region (see below). However, it also depends on the carbon intensity of that mix in the 6DS. China, for example, has a carbon-intensive power mix today and in the 6DS. This explains why China alone accounts for half the additional emission reductions in 2050 due to the large PV deployment in the hi-Ren Scenario, while accounting for “only” 35% in the total PV generation.

Figure 7: Additional CO₂ emission reductions due to PV in 2050 in the hi-Ren Scenario (over the 6DS)



KEY POINT: China alone would account by 2050 for half the global emission cuts due to PV deployment.

Revised solar PV goals

To achieve the goals set out in the hi-Ren Scenario, this roadmap considerably increases the PV capacity deployment that was envisioned in the 2010 roadmap. The hi-Ren Scenario now sees a deployment of 1 700 GW of PV by 2030 (up from

870 GW in the 2010 roadmap), and of 4 670 GW by 2050 (up from 3 155 GW in the 2010 roadmap). This represents capacity additions of over 120 GW/yr on average, with a 15-year plateau above 200 GW/yr between 2025 and 2040 (Table 3). Including repowering, annual installed capacities would be 185 GW on average.

Table 3: PV capacities by region in 2030 and 2050 in the hi-Ren Scenario (GW)

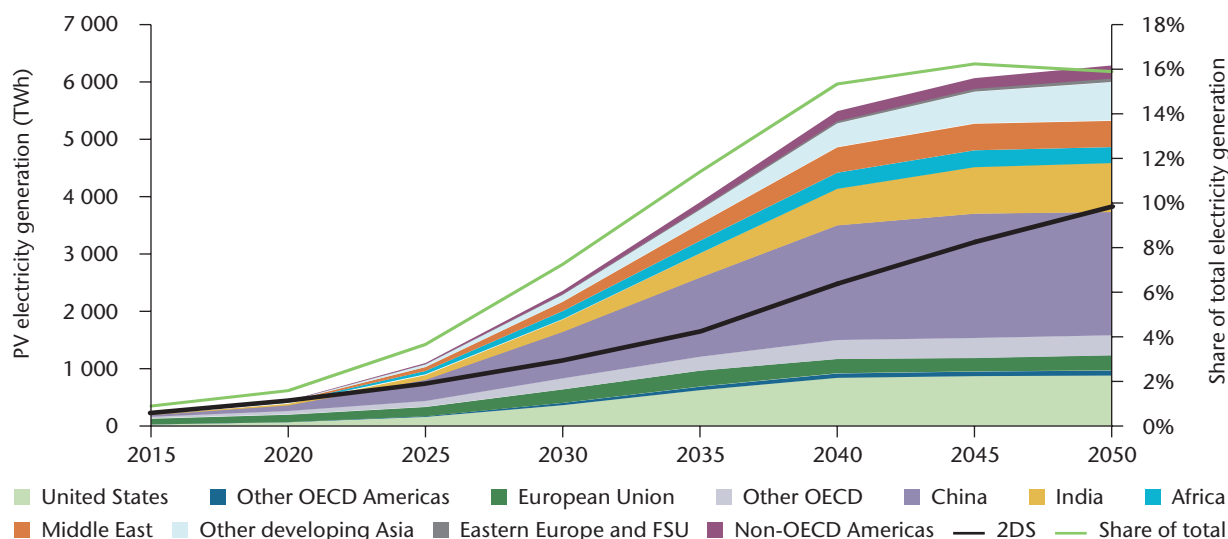
Year	US	Other OECD Americas	EU	Other OECD	China	India	Africa	Middle East	Other developing Asia	Eastern Europe and former Soviet Union	Non-OECD Americas	World
2013	12.5	1.3	78	18	18	2.3	0.3	0.1	1.4	3	0.2	135
2030	246	29	192	157	634	142	85	94	93	12	38	1721
2050	599	62	229	292	1738	575	169	268	526	67	149	4674

Notes. Some numbers in this table, especially for 2030, differ from those provided in ETP2014. The ETP model was re-run after the publication of ETP 2014 with slightly updated assumptions.

As for electricity generation (Figure 8), the hi-Ren Scenario foresees 2 370 TWh by 2030 and 6 300 TWh by 2050 (a 39% increase over the 2010

roadmap), so that PV achieves a 16% share in the global electricity mix (up from 11% in the 2010 roadmap or the *ETP 2014 2DS*).

Figure 8: Regional production of PV electricity envisioned in this roadmap



KEY POINT: in the hi-Ren scenario, PV provides 16% of global electricity by 2050, and China has a 35% share of the total PV electricity production.

China is expected to overtake Europe as the largest producer of PV electricity soon after 2020, with its share regularly increasing from 18% of global generation by 2015 to 40% by 2030 then slowly declining to 35% by 2050. From 2030 to 2050, the share of India and other Asian countries is expected to rise from 13% to 25%. By contrast, the United States' share is expected to remain at about 15% from 2020 on, and Europe's share to decrease constantly from 44% in 2015 to 4% in 2045.

This reflects widely different situations with respect to the power mix, and more specifically differences in the mix of renewables by 2050 (see Figure 9), based on the variety of resources available in different parts of the world, but also on different electricity load profiles. In non-OECD Americas, for example, the large availability of hydro power eases the integration of variable PV but combines with very competitive land-based wind power to limit PV penetration.

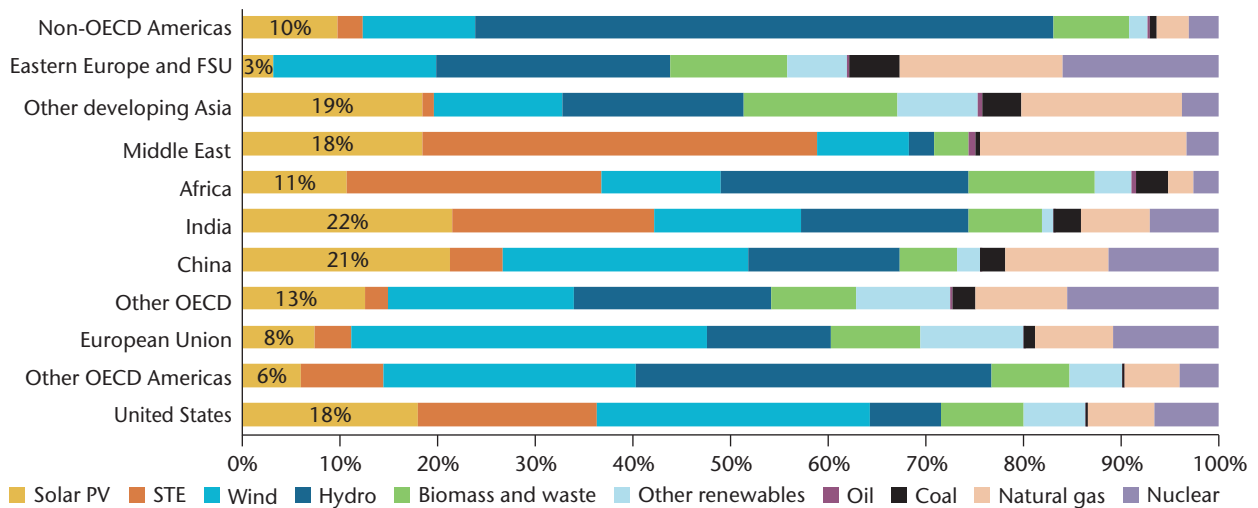
In Europe, the solar resource is high in the south but significantly lower in the north, while electricity demand is on average greater in winter than in

summer (IEA, 2011). Demand peaks often occur in late afternoon or early evening, so the “capacity credit”⁴ of PV at winter peak times is close to zero in most countries. Wind power in Europe offers a better match with daily and seasonal variations in demand, at competitive costs, and thus limits the penetration of PV to about 8% by 2050 in *ETP 2014* hi-Ren Scenario.

PV power could be more widely deployed in Europe if the costs of decentralised electricity storage (beyond transportation uses) fell significantly (IEA, 2014e). UBS estimates, for example, that if battery costs fell in line with the most optimistic assumptions, 14% to 18% of electricity demand in Germany, Spain and Italy could be met by self-produced solar electricity – with 6% to 9% of electricity demand replaced on these markets by 2020 (Hummel and Lekander, 2013)

4. The capacity credit of variable renewables is the reduction of peak capacity required to satisfy the power demand with the same loss-of-load probability, as a percentage of the variable renewable capacity installed.

Figure 9: Generation mix by 2050 in the hi-Ren Scenario by region (in annual energy)



KEY POINT: PV shares vary with the solar resource and electricity load.

Where the solar resource is high and electricity demand is largely driven during many months of the year by air-conditioning from noon (or even before) to evening, the match between resource and demand is much better. The economics of PV are improved if an actual capacity value is acknowledged and rewarded on electricity markets. When PV has a large share of electricity generation, however, the capacity credit of additional PV generation will diminish in the absence of demand side response or storage options (IEA, 2014d). PV systems can be deployed close to consumption centres, and even directly on consumption sites, which allows for lower grid losses and lower grid investments in some cases.

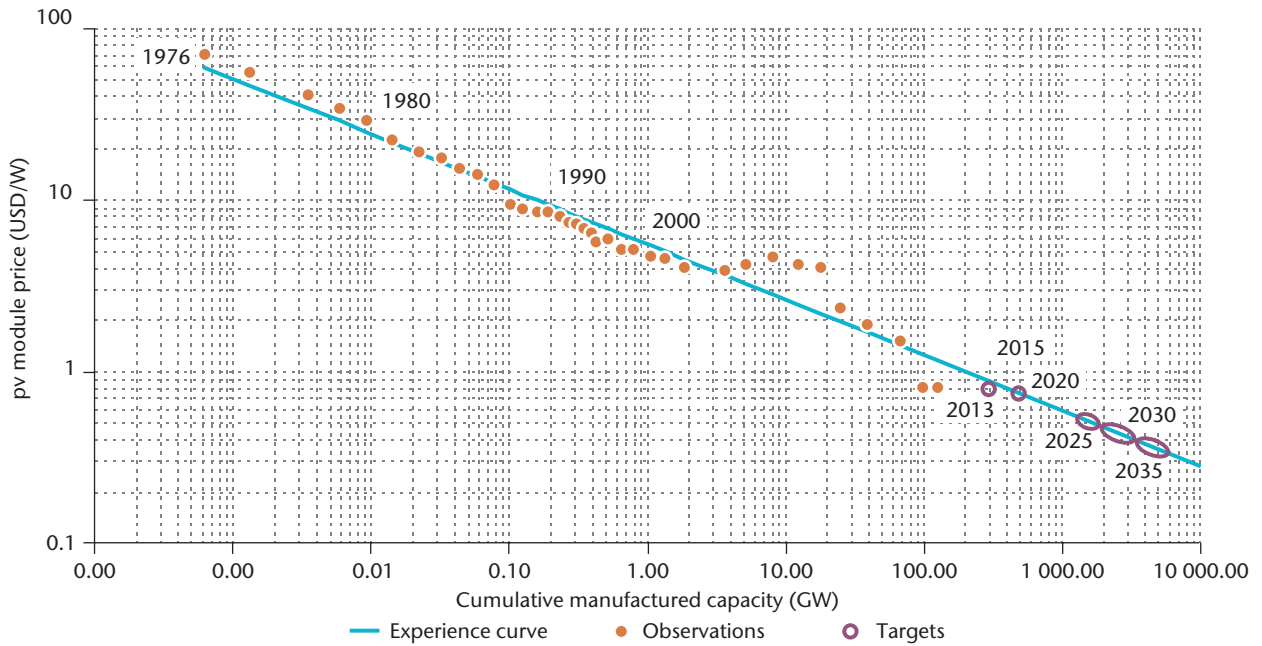
In countries or regions with strong sunshine and clear skies, CSP plants with built-in thermal storage capabilities may be better placed than PV with storage to capture a large share of electricity demand when the sun is not shining (IEA, 2014a). This explains why PV does not fare better in Africa, India, the Middle East or the United States than it does in China or other Asian developing countries, in the ETP 2014 hi-Ren Scenario. Rooftop PV represents half of PV capacities in this roadmap. An indicative-only possible repartition among main market segments could be about 2% off-grid systems and 98% grid-connected systems, of which 20% residential and 30% commercial rooftop systems, 10% industrial and 40% utility ground-based systems.

Potential for cost reductions

The prices of cells and modules fell rapidly from USD 4/W in 2008 to USD 0.8/W in 2012, but have since stabilised. Prices in 2008 were higher than expected, given the long learning trend, because of a shortage in c-Si capacities. The lowest market prices in 2012 and 2013 may have been below full costs, including return on investment. However, there is considerable body of evidence that the costs of cells and modules, whether of c-Si or TF, will decline further as deployment increases and technology improves in the next two decades. This roadmap expects module costs to fall to USD 0.3/W to USD 0.4/W by 2035 (Figure 10).

As local markets develop, system costs are likely to converge towards the current lowest values, except in places where “soft” costs, such as the cost of obtaining permits, are higher. The cost range will thus narrow significantly. Costs will fall further as technology improves, for both utility-scale and rooftop PV systems. Utility-scale capital expenditures cost would fall below USD 1/W by 2030 on average, but the cheapest systems would reach that mark by about 2020. Average costs would then reach a level of USD 700/kW by 2050. Rooftop prices would hit USD 1/W by 2025 for the cheapest systems and by 2040 on average (Figure 11).

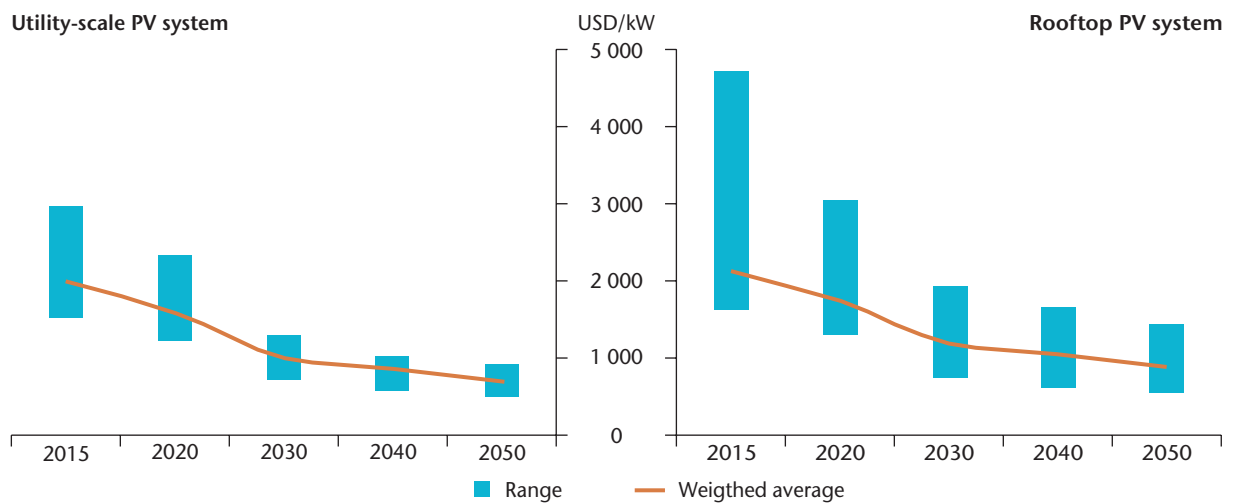
Figure 10: Past modules prices and projection to 2035 based on learning curve



Notes: Orange dots indicate past module prices; purple dots are expectations. The oval dots correspond to the deployment starting in 2025, comparing the 2DS (left end of oval) and 2DS hi-Ren (right end).

KEY POINT: This roadmap expects the cost of modules to halve in the next 20 years.

Figure 11: PV investments cost projections in the hi-Ren Scenario



KEY POINT: The price ranges of PV systems will narrow, and the average cost will be halved by 2040 or before.

As capital expenditures fall, performance ratios increase, and the bulk of PV moves from Europe to sunnier skies, the average PV LCOE will continue to diminish – and the range of LCOE across countries will continue to narrow. The average LCOE of

new-built, large-scale, ground-based PV plants is expected to fall on average below USD 100/MWh by 2025, and to gradually reach USD 60/MWh (Table 4).

Table 4: Projections for LCOE for new-built utility-scale PV plants to 2050 (USD/MWh) in the hi-Ren Scenario

USD/MWh	2013	2020	2025	2030	2035	2040	2045	2050
Minimum	119	96	71	56	48	45	42	40
Average	177	133	96	81	72	68	59	56
Maximum	318	250	180	139	119	109	104	97

Note: All LCOE calculations in this table rest on 8% real discount rates as in *ETP 2014* (IEA, 2014b). Actual LCOE might be lower with lower WACC.

Table 5: Projections for LCOE for new-built rooftop PV systems to 2050 (USD/MWh) in the hi-Ren Scenario

USD/MWh	2013	2020	2025	2030	2035	2040	2045	2050
Minimum	135	108	80	63	55	51	48	45
Average	201	157	121	102	96	91	82	78
Maximum	539	422	301	231	197	180	171	159

Note: All LCOE calculations in this table rest on 8% real discount rates as in *ETP 2014* (IEA, 2014b).

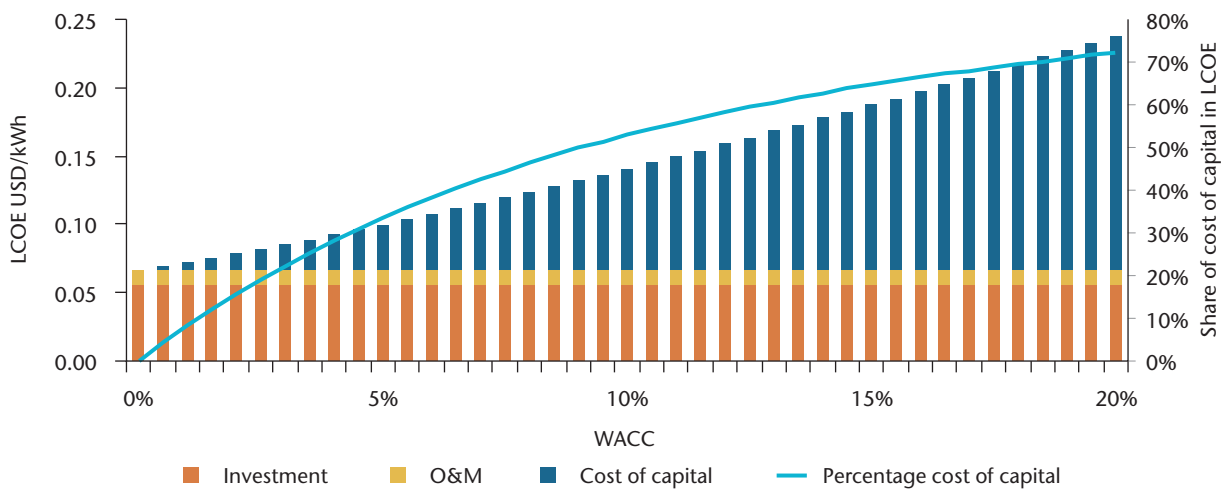
The LCOE of new-built rooftop PV systems will fall on average below USD 100/MWh soon after 2030, and gradually reach USD 80/MWh (Table 5).

For a given site and irradiation, setting aside performance ratio and its evolution over time, the most important levers for cost reductions are capital expenditures and costs of capital (Figure 12). When the weighted average capital cost (WACC) exceeds 9%, more than half the LCOE represents the burden of financing.

The LCOE projections in this roadmap rest on a WACC of 8%. More optimistic assumptions lead to lower costs. For example, a WACC of 2.4% to

2.8% in Germany and 4.7% in high solar irradiation countries could reduce the LCOE of PV power plants to EUR 55 to 94/MWh (USD 74 to 127/MWh) by 2020, so that “even small rooftop PV systems will be able to compete with onshore wind power and the increased LCOE from brown coal hard coal and combined cycle gas turbine (CCGT) power plants” (Kost et al., 2013). Where solar irradiation is high (2 000 kWh/m².m⁻².y⁻¹), the same study computes the LCOE of utility-scale PV at EUR 59/MWh (USD 80/MWh) today, and EUR 43 to 64/MWh (USD 58 to 87/MWh) by 2030.

Figure 12: The share of the costs of capital in the LCOE of PV systems



Notes: This example is based on output of 1 360 kWh/kW/y, investment costs of USD 1 500/W, annual operations and maintenance (O&M) of 1% of investment, project lifetime of 20 years, and residual value of 0.

KEY POINT: When the WACC exceeds 9%, over half the LCOE of PV is made of financial expenditures.

Box 4: Sustainable PV energy for all

Nearly 1.3 billion people did not have access to electricity in 2011, mostly in Africa and developing Asia. By 2050, although population growth will concentrate in cities, hundreds of millions of people will still live in sparsely-populated rural areas where off-grid solar systems would likely be the most suitable solution for minimum electrification. The IEA Energy for All case of the 2012 *World Energy Outlook* (IEA, 2012a) assumes grid extension for all urban zones and around 30% of rural areas, and for the remainder, mini-grids and stand-alone solutions.

In both on-grid and off-grid situations, solar PV has considerable merits, sometimes in combination with other energy sources. It can

improve life considerably for those who earn USD 1 to USD 2 per day and spend as much as USD 0.4 per day on dry batteries, kerosene and other energy products (IEA, 2011). PV could prove competitive if financing costs can be reduced, given the high share of up-front investment costs. This roadmap thus assumes by 2030 a PV capacity of 200 W per capita for 500 million people lacking other access to electricity. Mini-grids and off-grid PV capacity would thus total 100 GW, representing about 5% of total capacity by 2030 (2% by 2050), a significant increase from current trends.

Global investment to 2050

To decarbonise the entire energy system in the 2DS by 2050 will require about USD 44 trillion of additional spending. This investment is more

than offset by over USD 115 trillion in fuel savings, resulting in net savings of USD 71 trillion. Even with a 10% discount rate, the net savings are more than USD 5 trillion (IEA, 2014b).

The 2DS hi-Ren requires cumulative investments for power generation of USD 4.5 trillion more than in the 2DS, including notably PV but also wind power and STE. The lower consumption of fossil fuels in this variant saves USD 2.6 trillion, however, partly offsetting the additional investment needs, so that overall the 2DS hi-Ren variant results in additional costs of USD 1.9 trillion. This represents

a 3% increase in total cumulative costs for power generation compared with the 2DS, and only a 1% increase over the 6DS.

However, investments are more significant in the next two decades of the hi-Ren Scenario. This is reflected in the implicit carbon prices in both variants, which differ significantly by 2030 (Table 5).

Table 6: CO₂ prices in the climate-friendly scenarios of ETP 2014

USD/CO ₂	2020	2030	2040	2050
2°C Scenario	46	90	142	160
Hi-Ren Scenario	46	115	152	160

Total investments in PV over the modelling period of the hi-Ren Scenario would be about USD 7.8 trillion (undiscounted) for a total of 6 600 GW manufactured capacity, including repowering.

Beyond 2050

Limits to PV deployment mentioned above – such as 8% in Europe – depend on the modelling assumptions built into ETP modelling and (in part) on its time horizon of 2050, and may not be hard limits in a world that will strive to further reduce GHG emissions while ensuring energy security and access at affordable costs. The ultimate objective of the United Framework Convention on Climate Change (UNFCCC) is to stabilise GHG atmospheric concentrations at a level that would prevent dangerous anthropogenic interference with the

climate system. Whatever this exact level turns out to be, CO₂ stabilisation will require net emissions of zero or below to compensate for the rebound effect, i.e. the release in the atmosphere of CO₂ from natural reservoirs that accumulate some of current anthropogenic emissions (IPCC, 2014, chapters 6 and 12).

Longer-term climate change mitigation studies tend to show significantly higher PV deployment beyond 2050 – or even by 2050, due to their longer-term perspective. Germany alone could install 105 GW of PV without additional storage, to cover 19% of its electricity consumption (Giesler et al., 2013). A longer-term post-2060 hypothetical scenario envisages reducing global energy-related CO₂ emissions to about a tenth of current levels by installing 2.6 times as much PV capacity as this roadmap assumes by 2050 (IEA, 2011).

Solar PV technology development: Actions and milestones

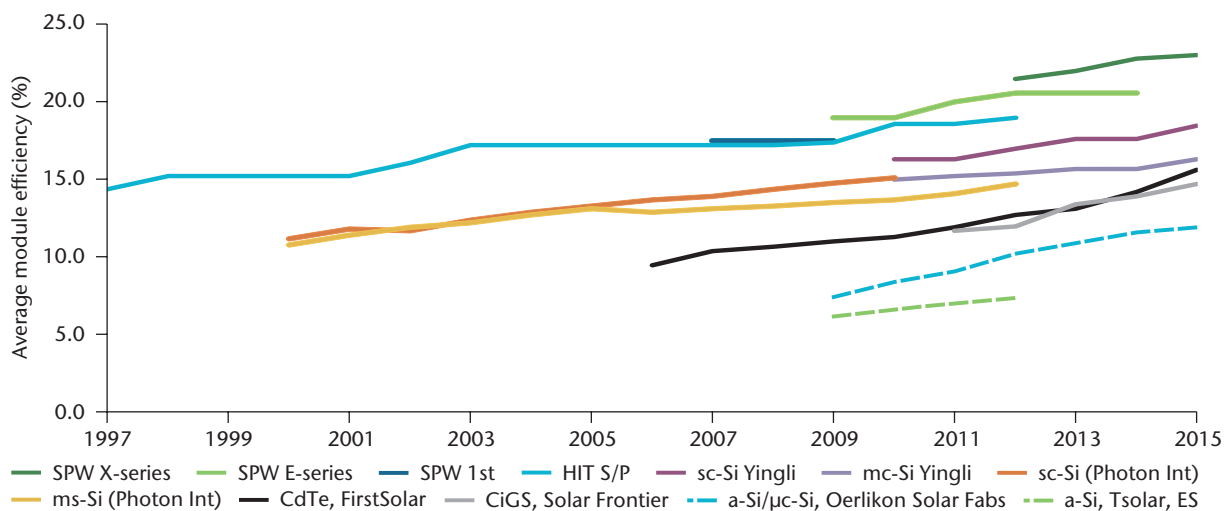
The era of rapid price decreases for PV cells and modules is probably over. All types of PV modules still have significant room for improvement, however, starting with c-Si modules, which dominate the market with a share of 90%. TF manufacturers plan to increase efficiencies and durability. Low- and high-concentrating PV providers strive to reduce costs and compete with “1-sun” PV (i.e. PV without concentration) in high-irradiance areas.

The lowest PV costs are not necessarily achieved with the highest efficiencies, and small improvements in efficiency can come at too high a cost to be worthwhile, even accounting for lower BOS costs driven by higher efficiencies. Record

cell efficiencies⁵ achieved on very small surface areas do not immediately translate into affordable commercial high-efficiency modules. Nevertheless, the PV industry has constantly demonstrated it can reduce costs while increasing the efficiency of commercial modules (Figure 13). Furthermore, while greater deployment has driven most cost reductions over the past decade, technology improvements are likely to return as a major factor behind future cost reductions (Zheng and Kammen, 2014).

5. See for example the well-known graph of best research-cell efficiencies that the NREL regularly updates and makes available at www.nrel.gov/ncpv/images/efficiency_chart.jpg.

Figure 13: Commercial 1-sun module efficiencies (actual and expected)



Note: SPW stands for SunPower, HIT S/P stands for Heterojunction Intrinsic Thin layer Sanyo/Panasonic.

Source: De Wild-Scholten, M. (2013), “Energy payback time and carbon footprint of commercial PV systems”, *Solar Energy Materials & Solar Cells*, No. 119, pp. 296-305.

KEY POINT: PV efficiencies have been rising constantly, and still have room for improvement.

Cells and modules

<i>This roadmap recommends the following actions</i>	<i>Time frames</i>
1. Increase module efficiencies to 40% (HCPV), 24% (sc-Si), 19%(mc-Si; CdTe; CIGS) or 12% (a-Si/ μ -Si; organic; dye-sensitised).	Complete by 2017.
2. Increase performance ratios and decrease degradation rates.	Complete by 2020.
3. Diversify module specifications for variable environments.	Complete by 2020.
4. Reduce Si consumption to 3 g/W while increasing module longevity. Reduce silver consumption.	Complete by 2020.
5. Enlarge wafer size. Generalise reusable moulds.	Complete by 2020.
6. Develop low-cost high-efficiency high-output bifacial 1-sun tandem cells, and design specific systems around them.	Complete by 2020.
7. Develop specific PV materials for building integration, road integration and other specific supports.	Complete by 2025.
8. Further reduce Si consumption below 2 g/W and increase efficiencies to 50% (HCPV), 28% (tandem cells), 22% (mc-Si, CdTe, CIGS), 16% (a-Si/ μ -Si; organic; dye-sensitised cells).	Complete by 2025.

c-Si modules

The efficiency of the best commercial c-Si modules now exceeds 21% and manufacturers such as US-based SunPower are targeting 23% efficiency by 2015, together with significant cost reductions. The major cost in c-Si PV cells is for pure poly-silicon feedstock, which dropped from USD 67 per kilogram (kg) in 2010 to USD 20/kg in 2012 and has remained below this price since then. Continued progress in the production processes, and reduction in the use of consumables, will keep the price under USD 20/kg in the next few years. Cost of ingot growth, wafer (cell precursors) sawing and cleaning will also improve. Efforts to reduce the amount of purified silicon in cells – which is now as low as 5 grams (g) per watt for the best cells – will continue towards 3 g/W or less, with thinner wafers. Diamond wire sawing and improved slurry-based sawing will reduce losses in slicing c-Si wafers, while kerf-less technologies may or may not offer an alternative to the traditional wafer-based c-Si process.

Manufacturers are also striving to use less silver and other expensive materials (maybe replacing silver with copper), while maintaining or even extending the technical life of cells and modules. Manufacturing automation is progressing for both

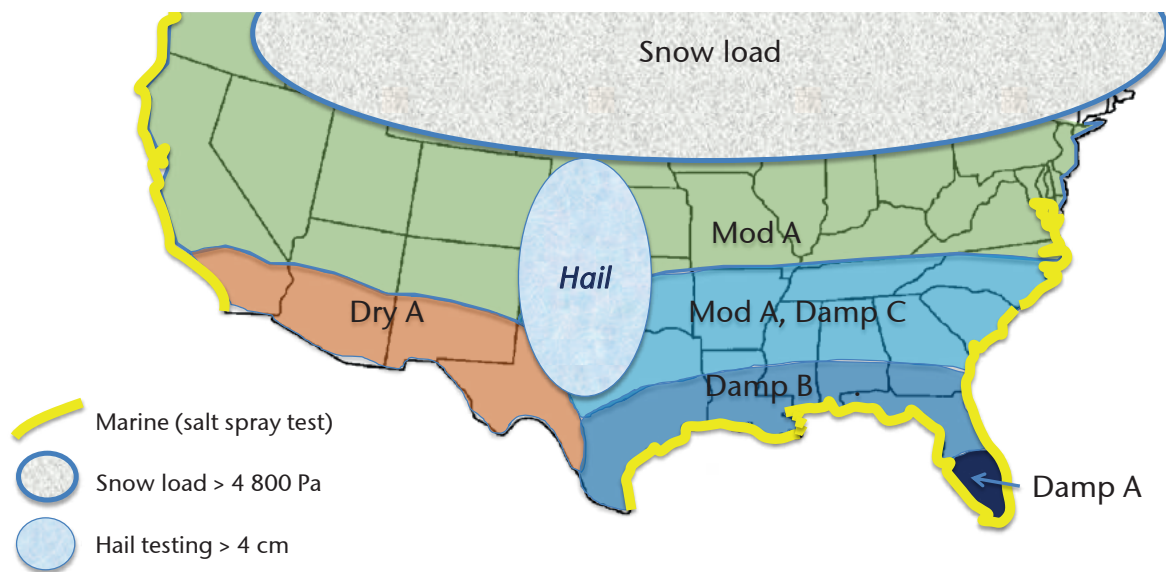
cells and modules. For modules, higher throughput could be achieved for the interconnection and encapsulation processes. Energy efficiency improvements over the whole manufacturing process are being sought. “Mono-like” mc-Si ingots, and reusable ingot moulds, could bring sc-Si performances at mc-Si costs. Back contact and metal wrap-through technologies, which reduce shading and electric losses, have been successfully introduced to markets by various manufacturers. The historical learning rate of 20% could be maintained over the next few years by introducing new double- and single-sided contact cell concepts with improved Si-wafers, as well as improved cell front and rear sides and better module technologies (IRTPV, 2014).

The heterojunction (HTJ) cell design combines two materials – often c-Si wafer and a-Si TF – into one single junction, resulting in higher efficiencies and performance ratios, thanks to a better resistance to high temperatures. The leader in HTJ technology, Sanyo/Panasonic, now develops HTJ cells with back contacts, and has announced a record efficiency of 25.6% in April 2014 on a research cell of “practical size” (over 100 cm²). Bifacial solar cells offer another emerging option, to be used in glass/glass modules enabling an increase in performance ratio and energy output of up to 15% using the light

reflected by the ground or buildings through the rear face. HJT technology, possibly combined with back-contact designs, may be further improved by using alternatives to amorphous silicon, in order to increase the overall spectral response (Sinke, 2014).

Costs could also be reduced by producing a greater variety of modules, adapted to a wider variety of conditions, including snow, hail, salt, humidity and heat. In the United States, for example risks vary greatly across the country (Figure 14).

Figure 14: How different climate zones in the United States affect the lifetime of PV modules



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Notes: Estimated minimum ratings needed for: 25 years estimated service life, open-rack mounting, retention of 80% power and pass high pot testing for 90% of modules. Climate ratings are indicated for Mod (Moderate), Damp (Warm damp, equable), Dry (Extremely warm dry).

Source: Kurtz, S. (2013), *Photovoltaic Module Reliability Workshop 2013*, NREL.

KEY POINT: Tailoring the resistance of PV modules and systems to their environment could reduce their cost without reducing their longevity.

Thin films

Three technologies dominate the TF area. The leading company in **CdTe** technology, First Solar, recently revised upward its efficiency objectives, targeting 25% for research cells and over 19% for commercial modules in three years. The US-based firm also claims that its latest generation of technology reduces degradation of performance to 0.5%/year in all climates.

Copper-indium-gallium-selenide (**CIGS**) technology, with efficiency of 12% to 14%, lags behind c-Si but offers a slightly higher performance ratio. The largest supplier, the Japanese firm Solar Frontier, which exceeded 20% efficiency in relatively large

research cells produced with mass production technology, aims to increase the efficiency of its commercial modules on this basis. It also aims to halve its costs from end-of-2012 levels by 2017.

a-Si technology offers traditionally the lowest efficiency among commercial modules, and its deployment has long been impeded by concerns about the longevity of its modules and degradation rates. When these issues were solved, the cost gap with c-Si was no longer sufficient to warrant strong deployment. The combination of amorphous and micro-crystalline silicon (**a-Si/μc-Si**) allows higher efficiencies.

Multi-junction cells

Multi-junction cell design involves superposing several cells in a stack. In the case of two cells, it will form a double junction, also called a tandem cell. Stacking more cells together forms a triple or a quadruple junction. In all cases, the upper cell(s) must be as transparent as possible to enable the lower cells to still be active. This approach enables a broader spectrum of sunlight to be captured, and overall efficiency to be increased. Record research-cell three-junction efficiencies of 38.8% under 1-sun exposure, and 44.4% under high concentration (>300 suns), have been achieved by Spectrolab, a Boeing subsidiary, and Sharp, respectively. Four- or five-junction cells could reach even higher efficiencies, such as the 44.7% achieved by Soitec and Fraunhofer ISE. Multi-junction cells have been so far mainly used for space applications and high-concentration solar cells (see below), reducing the semiconductor area to a small fraction and therefore allowing the use of more expensive materials. Niche markets exist however, for 1-sun multi-junction cells, such as unmanned aerial vehicles.

The rapid cost decline of c-Si, however, opens the door for mass-production of high-efficiency tandem cells, where TF would be deposited on c-Si wafers. Reviewing a broad range of material options – “III-V” alloys, chalcogenides and perovskites – and relevant production processes, Green et al. (2013) suggest that Si wafer-based tandem cells could represent a very cost-effective long-term combination. Such cells would probably be best used under 1-sun or low concentration with simplified tracking devices.

CPV

CPV technologies include low-concentrating PV (LCPV), which tracks the sun on one axis with a concentration ratio of around 10, and high-concentrating PV (HCPV), which tracks the sun on two axes with a concentration ratio in the hundreds. LCPV can be based on best-in-class c-Si cells. HCPV uses very high concentration factors, at or above 300, which allows the use of more expensive but highly efficient multi-junction cells. HCPV requires more precise tracking devices than LCPV or 1-sun devices. At locations with high DNI, both LCPV and HCPV already today compete with PV. Unlike dispatchable STE, CPV output varies like that of other sun-tracking PV systems while the higher efficiency significantly reduces the installed module surface per MW.

Advanced solar cells under development

Novel PV devices, such as quantum dots, dye-sensitised cells, organic cells and thermoelectric devices hold great promise for the future, but for mainstream applications they need to reach specific performance and cost levels to enter the market. That is why “stepping stones” in the form of markets that require specific properties (such as low weight, transparency, flexibility, colour and freedom of form) may help these new options to enter the market successfully. Efficiencies of 11% for organic cells and 12% for dye-sensitised cells have recently been achieved by Mitsubishi Chemical and Sharp, respectively.

Non-module costs

Non-module costs relate to non-module hardware, including fixed supports or tracking systems, cables, inverters and soft costs, including customer acquisition, permitting, installation, connection, and financing. The latter are investigated in the Policy and Finance section of this roadmap.

Inverters have followed an impressive learning curve, similar to that of PV modules. The reduction in material has been dramatic in the last ten years, from 12 kg/W to 2 kg/W. Manufacturers expect this trend to continue. Other hardware costs – materials, such as support and cables, or labour, such as installation – relate to the area of the solar PV systems and thus depend mostly on the efficiency of the modules. Increased efficiencies thus drive system cost reductions, which become progressively more important as the cost of PV modules diminishes and other costs rise above half the total system costs.

Systems designed to be integrated into the envelopes of buildings, or building-integrated PV (BIPV), currently cost more than standard rooftop systems. The BIPV concept raises the possibility, however, that a thin layer of PV-active material, possibly deposited as a paint, could become a standard feature of building elements such as roof tiles, façade materials, glasses and windows, just as double-glazed windows have become standard in most countries. Given that such elements comprise a large part of building envelopes, mass production could enable the cost of PV to almost vanish in this market segment where it currently costs the most.

Thin films and advanced solar cells are the primary candidates for such applications. Other integrated applications, such as PV materials for roads and similar surfaces, are also under development.

Life-cycle analysis

Manufacturing PV cells, modules and installing systems consumes energy and results in greenhouse gas emissions. Questions have been raised about the life-cycle assessment of PV systems with respect to climate change. Often-quoted estimates of energy pay-back times of two to five years, and GHG emissions of about 50 gCO₂-eq/kWh for mc-Si modules and 75 gCO₂-eq/kWh for sc-Si modules (e.g. IPCC, 2011, p.372) are already outdated and on steep downward trends. Technical improvements rapidly decrease energy consumption in the PV manufacturing process, while efficiency and performance ratios of new PV systems continuously increase. Recent studies show energy payback times of commercial PV systems under Southern Europe sunshine of 0.7 to 2.5 years, depending on technology and the power mix in manufacturing countries; the carbon footprint of PV electricity ranges from 20 to 81 gCO₂-eq/kWh, one order of magnitude below electricity from fossil fuels (de Wild-Scholten, 2013).

During the production of thin-film PV and flat screens, nitrogen trifluoride (NF₃) is still used by some manufacturers to clean the coating systems. Residues of this gas can escape into the atmosphere. NF₃ is more than 17 000 times as harmful to the environment as carbon dioxide. Current emission quantities are not known. As of 2013, NF₃ emissions are to be determined in 37 countries according to the revised Kyoto Protocol.

Some companies, such as FirstSolar, have long-established recycling schemes with facilities operational at all manufacturing plants and recovery rates of up to 95% of the semiconductor material and 90% of the glass. PV producers set up a manufacturer-independent recycling system in June 2010 (PV Cycle), which currently has more than 300 members. The version of the European WEEE Directive (Waste Electrical and Electronic Equipment Directive), which came into force on August 13, 2012, must be implemented in all EU states by the end of February 2014. This directive makes it compulsory for manufacturers to take back and recycle at least 85% of their PV modules free of charge.

Task 12 of the Implementing Agreement for a Co-operative Programme on Photovoltaic Power Systems of the IEA (PVPS IA) includes ongoing work on recycling of manufacturing waste and spent modules, as well as further work on life-cycle inventories and assessment.

System integration: Actions and milestones

PV generation is variable and uncertain. This does not create serious issues when PV has a low share of the power mix, but system-friendly deployment

is necessary to allow PV's share to progressively increase, as well as other measures that transform broader power systems.

Facilitate PV integration into electric grids	Time frames
1. Develop meteorological PV forecast, with feedback loop from PV power plant online data to weather forecasting.	2015-20
2. Elaborate and enforce grid codes that will drive inverters to provide voltage control and frequency regulation.	2015-30
3. Prevent PV hot spot emergence in ensuring geographical spread, e.g. through spatial remuneration differentiation.	2015-40.
4. Facilitate rapid market reactions by shortening gate closure times and trading block length.	2015-20
5. Incentivise generation during demand peaks through time-of-delivery payments and/or limitation to instantaneous injection except at peak times.	2015-30 depending on countries
6. Incentivise load management and flexibility from existing generating capacities; ensure fair remuneration of ancillary services.	2015-30 depending on countries
7. Investigate options for new PHS plants; anticipate the need for more flexible power capacities.	2020-30
8. Develop new storage capabilities.	2030-50

Variability and uncertainty

The output of solar PV depends on daylight patterns and the weather, notably the cloud cover and atmospheric turbidity. Clouds are only partially predictable over small areas, but the uncertainty regarding aggregate cloud coverage – which must be distinguished from variability – is reduced at larger geographic scales. Indeed, the generation of solar power is now easier to plan thanks to increasingly reliable forecasts. Changes in cloud cover are usually not able to create unpredicted sudden changes in generation at some level of aggregation (Figure 15) – this explains why the resource should be termed “variable” rather than “intermittent”. Unexpected episodes of fog can cause significant forecast errors, however.

Variability has two distinct effects on electric systems. Balancing effects, which relate to rapid short-term changes in load net of PV generation, from minutes up to a timescale of one or two days, must be addressed to avoid outages. Utilisation effects relate to how often a certain net load level

– defined as gross load minus variable generation from wind and PV – occurs over the course of a longer period of time. This relates to adequacy – the long-term transformation of the entire electrical system needed to keep pace with demand cost-effectively, i.e. re-arranging the shares of the different energy sources and electric-generating capacities to match likely utilisation rates, the various technologies and sources being best used for peak, mid-peak or base-load generation.

System-friendly PV deployment

Integrating low shares of PV power (of just a few percent) usually does not raise significant challenges, provided some pitfalls are avoided. For example, it is important to avoid concentrating PV capacities in areas with low power demand and relatively weak distribution grids, where variability may cause voltage problems, create reverse power flows, and lead to large grid congestions.

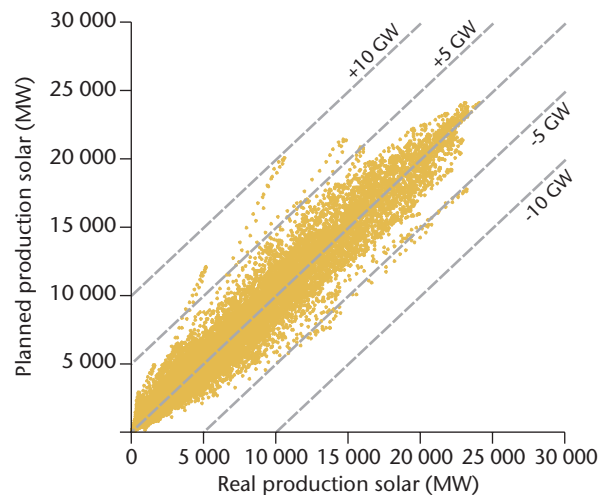
Modern electronics allow PV systems, via their inverters, to perform a number of tasks autonomously, however, such as riding through wide ranges of voltage and frequency fluctuations, actively counteracting voltage changes (voltage control) in providing reactive power, and reconnecting softly to avoid sharp spikes when disconnecting during power outages (SIWG, 2014). Telecommunication skills of modern inverters would greatly expand the possibilities and enable decentralised PV systems to support the grid. The system services capabilities of PV systems (and wind turbines), and the costs associated with providing these services, are the focus of the EU-funded REserviceS project (Kreutzkamp et al., 2013).

Changes in PV system design can better match supply and demand. PV developers can opt for sun-tracking systems. Developers can adjust the tilt and orientation of panels to maximise output at certain times of day or year, instead of maximising the annual output, if they receive appropriate time-of-delivery (TOD) price signals. Another option, which recent module cost cuts have made possible, is to design fixed-tilted PV systems with panels at different orientations and a greater DC/AC ratio – i.e. increased total capacity of modules (generating DC current) with respect to the capacity of the inverters (delivering AC current to the grid). Modules would not all face the equator; some could be oriented southeast and others southwest, thus delivering a more regular output throughout the day and increased capacity factors for the inverter.⁶ Multiple orientation systems, while not necessarily optimal, also offer additional opportunities for deployment on buildings.

System-friendly PV deployment should also be part of a broader system-friendly deployment of renewables, especially variable renewables. The balance between wind power and PV must be considered carefully, to take advantage of these complementary resources over time, as illustrated by the German case (Figure 16) – and possibly also the balance between PV and STE, if the latter is available at reasonable distance.

6. Wind power follows a similar path with higher hubs and greater swept area/capacity ratios (IEA, 2013b).

Figure 15: Hourly planned versus actual solar generation in Germany, 2013



Source: Burger, B. (2014), *Electricity Production from Solar and Wind in Germany in 2013*, Fraunhofer Institute for Solar Energy Systems, January, Freiburg, Germany.

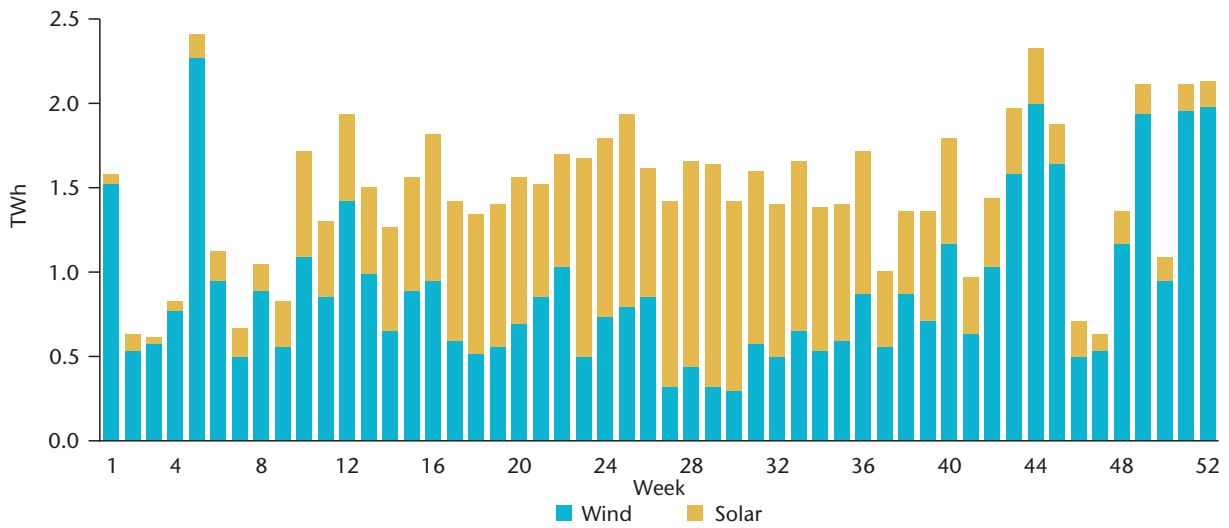
KEY POINT: Over country-sized areas, solar energy generation is largely foreseeable.

Integrating large PV shares

When PV makes up a large share of electricity generation, systems may require more reserves to ensure balancing than would otherwise be developed on the basis of the unpredictability and variability of electricity demand, and the risks of failures of some generating plants or connecting lines. The possibility of long periods with little solar resource – more frequent in winter – calls for adequate firm capacities. Eventually, integrating large shares of PV electricity requires technical and economic flexibility from the rest of the system (IEA, 2014). This need for flexibility can be illustrated by the foreseen evolution of the net load curve of spring days in California, nicknamed the “duck chart” (Figure 17), which reveals how PV is expected to modify the curve during daytime but keep almost unchanged the demand peak of the early evening – unless other measures, such as demand-side management, are taken (see e.g., Lazar, 2014).

Load management, including electricity efficiency improvements and load shifting, offers affordable options for integrating variable PV output. This strategy has great potential, but is not infinite – people will always need light at night. Electricity

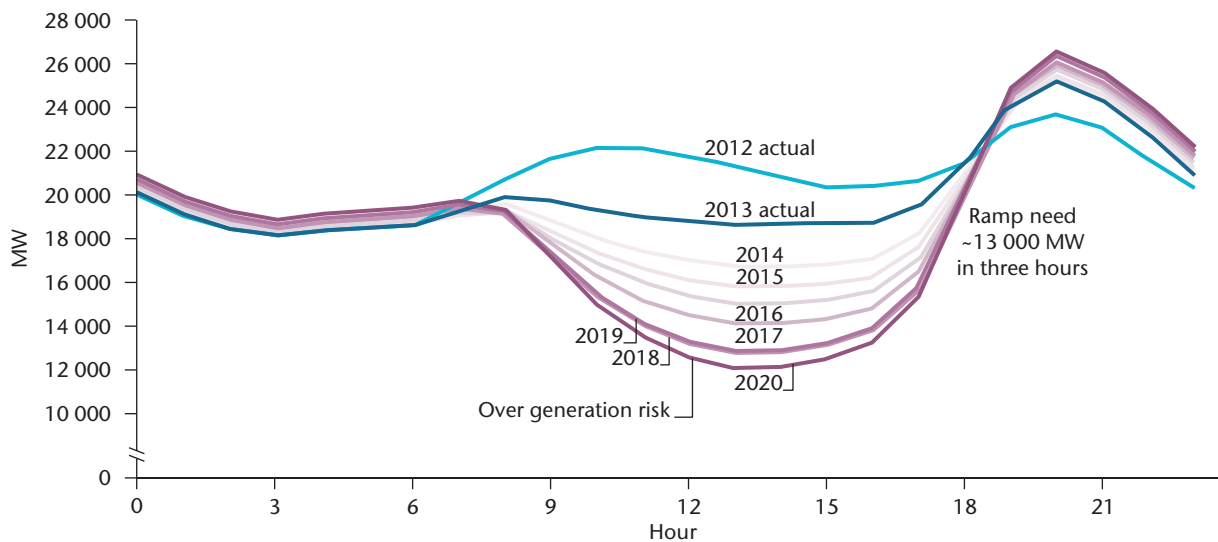
Figure 16: Weekly production of solar and wind in Germany in 2013



Source: Burger, B. (2013), *Electricity Production from Solar and Wind in Germany in 2013*, Fraunhofer Institute for Solar Energy Systems, January, Freiburg, Germany. Data: EEX Transparency Platform.

KEY POINT: Wind energy is often strong when sunshine is weak and vice versa.

Figure 17: Expected evolution of the net load of a typical spring day in California



Source: California ISO (Independent System Operator) (2013), *What the Duck Chart Tells Us About Managing a Green Grid*, Fast Facts, Folsom, CA, accessed 4 June 2014.

KEY POINT: The “duck chart” illustrates how large PV generation requires flexibility from the rest of the power system.

savings, especially targeting nocturnal peak consumption, would help integrate more PV in the mix. Load management would not only reduce the annual electricity demand that PV cannot supply, but also reduce the minimum load level, during daytime, of the conventional plants required to cover the peak at night, in particular if they have long starting times for hot starts. Savings on lighting is the obvious example.

Interconnections are important, because they allow smoothing out to some extent of the variability of PV plants over large areas, and enable the sharing of flexible generation, demand-side management and storage. Integration with other energy forms and energy networks, such as district heating or gas networks through hydrolysis and methanation, could also help increase PV shares in the electricity mix.

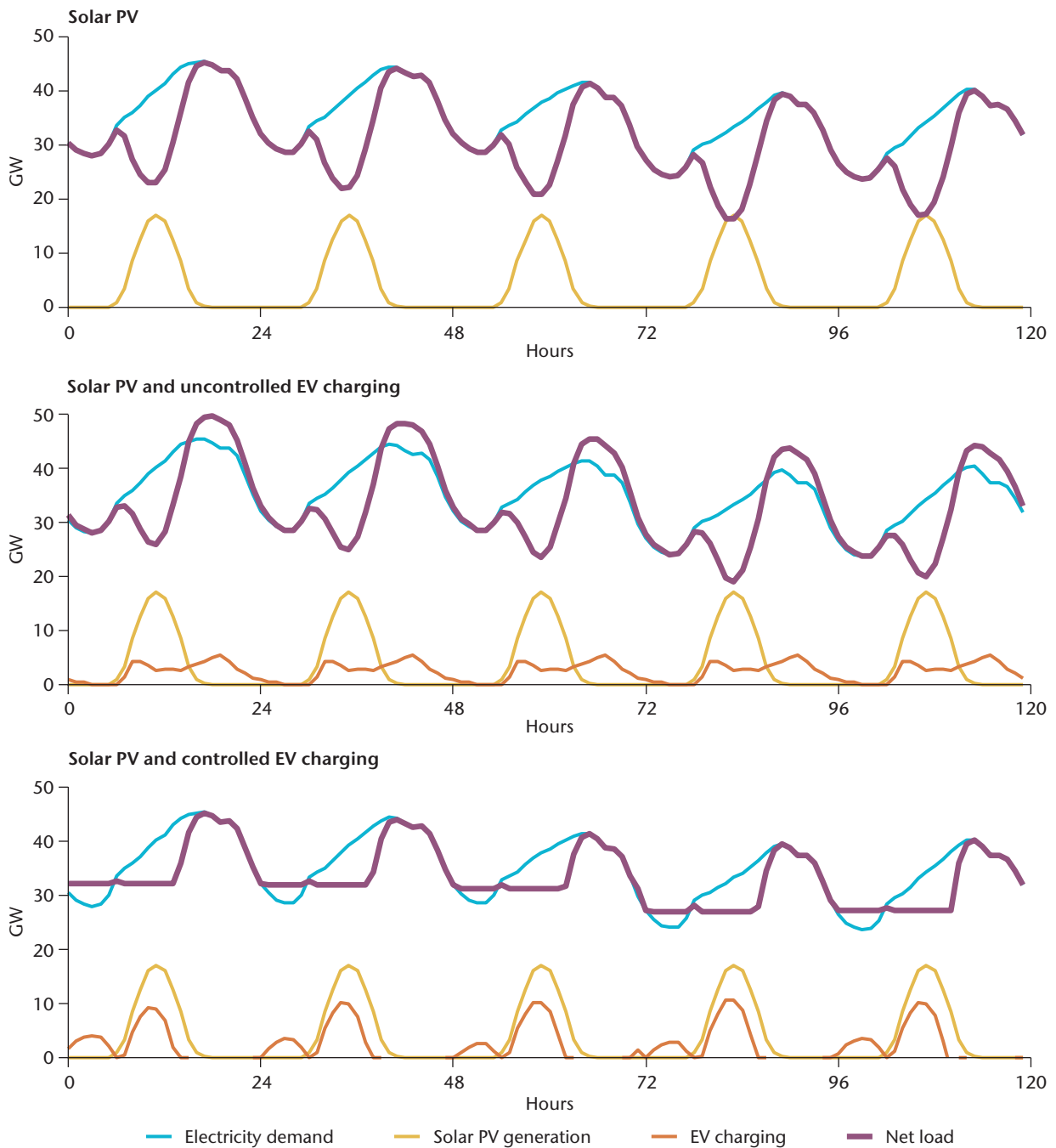
The flexibility of electricity-generating plants other than PV and wind has two aspects that are interlinked but distinct: one is purely technical, the other economical. Conventional thermal plants often take time to start or stop; not all can change pace quickly, and many have minimum loads in the 40%-50% range (in particular base-load plants, including older designs of CCGT power plants), but depending on plant design, minimum generation levels can be 25% or lower, even for coal-fired plants. Cold starts take a long time, especially for nuclear and coal plants. Economically, some technologies represent high investments, and their cost-effectiveness is contingent on continuous running; other plants are cheaper to build but usually burn more expensive fuels, and are preferably used as “peaking” or “mid-merit” plants. The business model takes into account the fact that they will operate with fewer full-load hours. Many plants run more economically at minimum load than if stopped for a few hours. Dispatchable renewables, such as reservoir hydropower and STE, where available, offer better prospects for complementing PV generation, because their electrical capacity can be adjusted by design, for a given energy input (solar or water inflows) to be run as mid-merit or peaking capacities.

Storage would be needed to shift more PV electricity to other consumption times. However, 99% of grid-tied electricity storage capabilities today are pumped-storage hydropower (PHS) plants, with 150 GW in service worldwide and another 50 GW under construction or in development. Global storage capacities are

estimated to reach 600 GW in the 2DS hi-Ren, with PHS providing most of the growth (IEA, 2014b). PHS will, in particular, be developed in areas with large penetration of wind power and little room for CSP plants, such as temperate regions. The potential for new PHS is important, because these plants do not require the large surface areas that characterise reservoir hydropower plants (IEA, 2012b; JRC, 2013). Storage at intermediate voltage levels can help address “hotspot” and grid congestion issues – providing these issues occur frequently enough to make sufficient use of the storage capacities. Decentralised battery storage is currently more expensive than PHS but may also have higher locational value, exactly like distributed PV generation, and for electricity storage competition with retail prices would be more favourable than with wholesale prices. Inevitably however, storage capacity optimisation would let some PV curtailment take place. California and Germany have already engaged in providing subsidies for distributed storage.

Further electrification of transport could also play a role in integrating variable PV output, because it offers storage (which is needed for driving autonomy in any case) and a potential means of reducing peak load (because most cars are stationary most of the time, offering time flexibility for charging). The external surface area of passenger cars and freight trucks is too small for embedded PV systems to provide a significant energy contribution. At present, these vehicles remain dependent on oil, a primary source of greenhouse gases (GHG) and other polluting emissions. Electric vehicles (EVs), whether partially electrified, such as plug-in hybrids, or full-fledged battery electric vehicles, are major options of reducing both oil dependence and environmental impacts. These vehicles offer electricity storage as an “absorbing capacity”, in what is termed the grid-to-vehicle (G2V) configuration. Provided charging can take place in the middle of the day, G2V could help flatten the net load curve, i.e. the load curve minus PV (Denholm et al., 2013). Otherwise, the risk is that uncontrolled EV charging may take place during evening peaks and increase the crest factor (i.e. the ratio of peak over average load) of the net load curve (Figure 18). Appropriate time-of-use (TOU) price signals could presumably provide incentives for appropriate behaviour. EV batteries connected to the grid may also have significant upward reserve value for the grid, even if the economics of routinely using them to provide energy to the grid are not favourable.

Figure 18: Controlled versus uncontrolled EV charging effects on load net of PV



Notes: stylised electricity system for a five-day period with PV generation (top figure), with additional uncontrolled PV charging (middle figure) and controlled charging (lower figure).

KEY POINT: Controlled charging of electric vehicles would reduce the volatility of net load and thus facilitate the integration of solar PV.

EV charging can increase PV self-consumption. Experiments in southeast France have shown that a PV system installed over the parking space for one car could produce enough electricity to run a

four-passenger car over 10 000 kilometres per year. Midday charging is more likely to happen at offices and other work sites using PV charging stations. Charging during daylight would also increase if

proposals were implemented to feed electricity into electric vehicles, notably heavy trucks, while they are on the move, via induction or trolleys (see transport chapter in IEA, 2014b).

A recent IEA publication, *The Power of Transformation* (IEA 2014d), investigates in detail the economics of integrating large shares of variable renewables such as wind power and solar PV into power systems. It shows that with timely re-optimisation of power systems, less inflexible base-load power, and more flexible mid-merit and peaking generation, total electricity costs at 45% of variable renewables would be increased by about 10% to 15% with current wind and PV technology costs. With assumptions relative to the decline of costs of these technologies consistent with the level of deployment in the hi-Ren Scenario, total electricity costs would eventually increase by about 3% only as a result of the expansion of solar PV (IEA, 2014b).

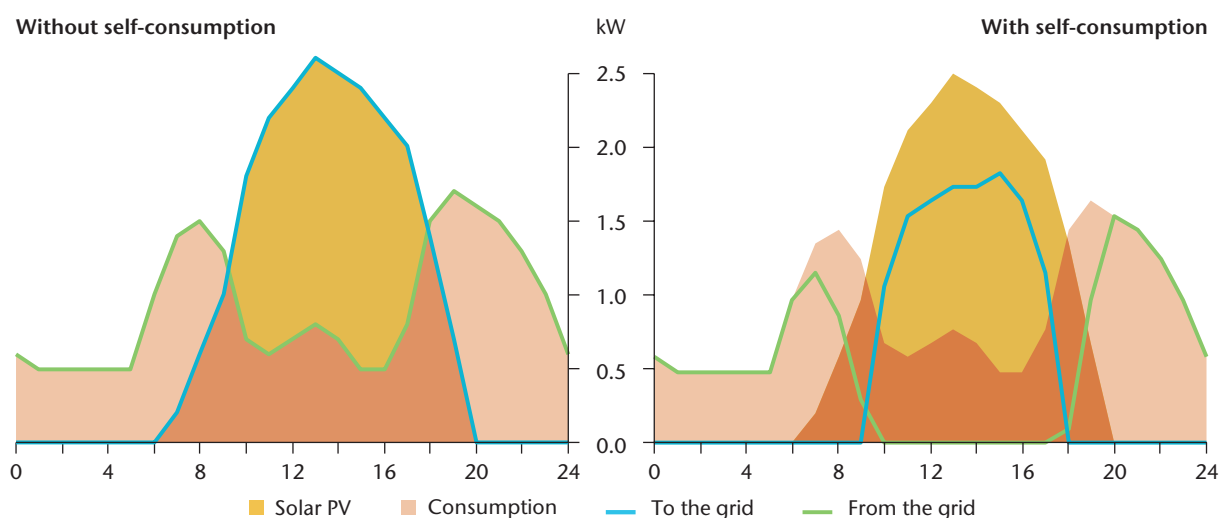
Decentralised PV generation

About half the large PV deployment considered in this roadmap would take place on buildings or nearby (such as over parking lots). It rests in part on the concept of grid parity – when the cost of distributed PV generation is equal or below the per-kWh component of retail electricity prices – and on self-consumption.

Grid parity holds potential but may also create illusions and raise concerns. The variability of the solar resource, together with the variability of electricity demand, limits self-consumption and its related benefits for electricity consumers who are also PV producers (known as “prosumers”), especially in the residential sector. For example, in temperate countries, most PV electricity generated in winter will be self-consumed, but the bulk of electricity consumption will still be drawn from the grid. On sunny summer days, the opposite holds true: less than half of PV electricity is self-consumed, but some electricity must still be drawn from the grid, especially during the evening peak (Figure 19). In practice, even reaching the suggested levels of self-consumption may require the development of “mini-grids” or “solar gardens”, where very short-term demand variations of dozens of customers would largely cancel out, while communities, including renters and owners, would share the investment in larger and cheaper, well-oriented, well-designed and well-managed PV systems.

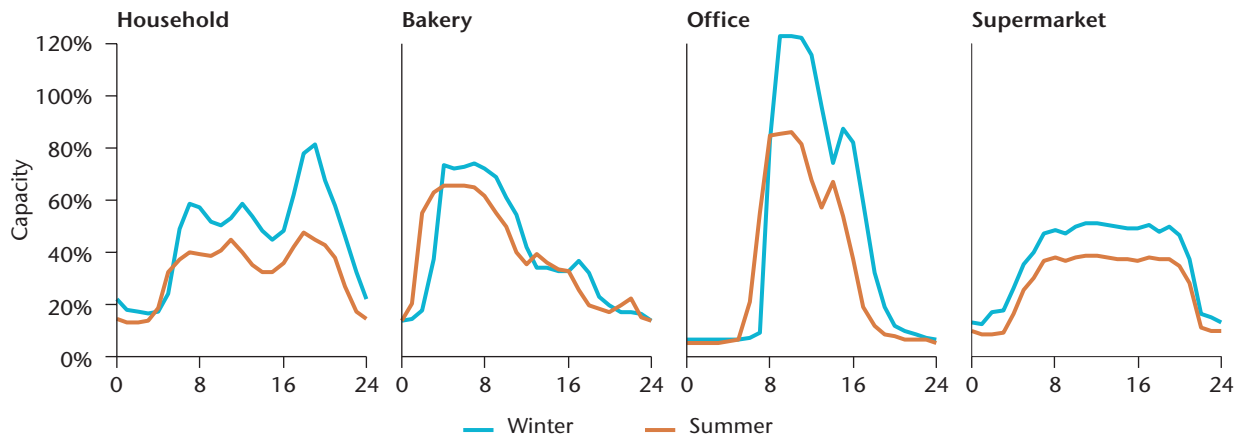
The prospects for self-consumption are higher in sunnier countries, where consumption is partly driven by air-cooling loads, and for buildings other than residential. The load profile of office buildings or supermarkets suggests a better match with the solar resource, which reaches its maximum in the middle of the day (Figure 20).

Figure 19: Self-consumption of stylised household and rooftop PV system during a sunny day



KEY POINT: Variability of both solar power and electricity demand limits self-consumption.

Figure 20: Hourly electricity consumption profiles for different building types in Germany



Note: The reported annual consumption of these buildings spans three orders of magnitude. To allow for an easy comparison of load profiles, these curves have been scaled down with respect to the annual consumption of a typical German household.

KEY POINT: Many buildings other than residential offer better prospects for self-consumption.

Load management offers a significant opportunity to increase self-consumption — simply by shifting the use of some devices to hours of high solar generation. Chilled water, ice and other frozen media can be produced during the sunniest hours, and cheaply stored for hours to provide air conditioning, or cold for food and beverage storage and display. Decentralised battery storage could further increase self-consumption, but its exact role in the span of the scenarios depends on cost reductions that remain uncertain. This is not a go or no-go issue, though. The value of each marginal kWh of storage capacity decreases with its utilisation rate, but as battery costs decline with mass production and experience, progressively greater storage capacities will find their business model. Building on the PV output and load profiles of Figure 19, Figure 21 illustrates how load management and small storage could each increase self-consumption by 10 percentage points. It also makes inflows to the grid more predictable.

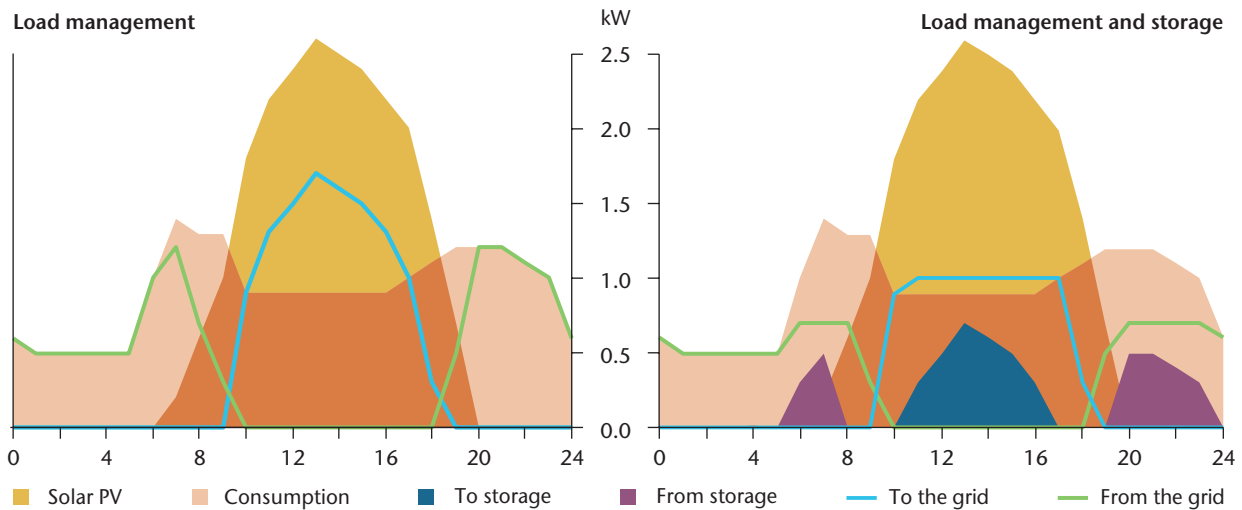
The economic viability of PV systems depends on both the value of electricity savings due to self-consumption, and the remuneration of injections into the grid. If the electricity injected into the grid were not remunerated at all, only small PV systems (e.g. of about 1 kW in Germany for a single-family household) would have a sufficient self-consumption ratio to be economically viable.

For apartment buildings in an urban environment, small PV systems may be close to what is possible given the available space, especially if limited to roofs. A five-storey building housing ten families, with an average apartment surface of 85 m², is likely to have a roof surface of about 170 m². Assuming that only one-quarter is free for PV systems with acceptable tilt and orientation, and assuming by 2030 an efficiency of 20% (already exceeded by the best commercial modules), the maximum power from a rooftop system would be about 8.5 kW — less than 1 kW per family. Neither the small capacity nor the small available surface area in urban environments should thus be considered obstacles from a system perspective; on the contrary, they fit very well with each other to support PV self-production and self-consumption. By 2050, one-third of 3 billion families with a 1 kW system would represent 1 000 GW, over 20% of global capacity in the 2DS hi-Ren.

In sum, in urban areas the available roof or façade surface area is likely to be the limiting factor, and all PV electricity generated will likely be either self-consumed or consumed in the immediate whereabouts of generation, whether through specific cables, “mini-grids”, or simply the existing distribution infrastructure.

In less densely populated areas, an appropriate framework for self-consumption may incentivise

Figure 21: Increasing self-consumption with load management (+10%) and small storage (+10%)



KEY POINT: Load management and decentralised storage can increase self-consumption.

load management and thus ease integration (see next section). Curtailment can help avoid excess injection in distribution grids – and avoid the need for grid strengthening that would only serve in a few occurrences (typically, during sunny summer Sundays). In Germany, new-built small-scale PV systems (<30 kW) should either be able to be curtailed remotely, or must permanently limit power injection into the grid to 70% of rated AC capacity, the rest being either self-consumed or curtailed.

System-level GHG emissions

Doubts have sometimes been cast on the efficacy of PV in reducing CO₂ emissions at the level of power systems, due to its variability and possible implications for emissions elsewhere in the system. Where short-term power plant dispatch is optimised, solar PV (as any other technology) will displace the generator at the margin. This generator may or may not be the most CO₂-intensive. In some cases in Europe, PV has displaced efficient combined-cycle gas turbines while not reducing the generation from lignite. In addition, the operational pattern of power plants that remain in the market will change in the presence of PV due to the known variability. This will include more frequent start-ups, part-load operations and increased changes in

outputs (ramping). There is thus a penalty in CO₂ emission reductions due to inefficient operation of the thermal plants, so-called cycling losses. However, the Western Wind and Solar Integration Study (NREL, 2013) found adverse effects to be marginal for 33% share of wind and solar in annual generation in the Western Interconnect, a region featuring a considerable amount of inflexible In addition, PV generation cannot be forecasted with perfect accuracy. This may increase reserve requirements and the frequency of calling on reserves. In effect, this means that plants with short start-up times, such as open-cycle gas turbines, will have to be used to the detriment of more efficient plants. Large forecast errors are infrequent, however, so the amount of energy that needs to be generated will be small, and resulting relative increases in CO₂ emissions be small compared with emission reductions, due to the displacement of fossil fuels by PV power.

In the longer term, a high share of PV (and wind) in the power system makes the rest of the generation mix “part-time workers”. The most cost-effective choice for a power plant operating part-time is one with low fixed costs, such as open-cycle gas turbines. This can lead to an increased share of generation from these less efficient plants. Again, the energy contribution is likely to remain limited (IEA, 2014d).

In some countries, the displacement by more flexible fossil-fuelled plants of capacities that are carbon-free but insufficiently flexible, from either a technical or economic standpoint – e.g. nuclear power in France or Germany – also raises concerns about increased CO₂ emissions from the “non-renewable” part of the electric systems. However, interconnections among countries, and other flexibility options such as demand-side management, hydroelectricity, solar thermal electricity and electricity storage, would limit the potential for emission increases that exist in few countries.

In sum, large emission reductions arising from the substitution of PV electricity for fossil fuel-based electricity generation are orders of magnitude more important than emission increases that the variability of PV may drive in the rest of power systems.

Policy, finance and international collaboration: Actions and milestones

As PV costs plummet, the need for high-cost subsidies per unit of energy recedes. However, the highly capital-intensive cost structure of PV is at odds with most current liberalised electricity markets. Strong and stable frameworks are needed, along with support to minimise investors' risks and reduce capital costs.

Deploying PV according to the vision of this roadmap requires strong, consistent and balanced policy support. The main areas of policy intervention include:

- Removing or alleviating non-economic barriers such as costly, lengthy and heavy permitting and connecting procedures; establishing internationally recognised standards and certification to increase customers' confidence in performance and durability of PV systems under a great variety of weather conditions.
- Creating or updating a policy framework for market deployment, including tailoring incentive schemes and reconsidering electricity market design to accompany transition to market competitiveness; policy frameworks should be based on targets for deployment set at country level; regulatory changes should be as predictable as possible, and avoid retroactive changes.
- Facilitating integration of larger shares of PV in electric systems by fostering their transformation toward greater flexibility.
- Providing innovative financing schemes to reduce costs of capital for a wide variety of potential customers.

Removing non-economic barriers

<i>This roadmap recommends the following actions</i>	<i>Time frames</i>
1. Ensure the legal framework authorises electricity generation by independent power producers at all scales and voltage levels (if not already implemented).	2015-20
2. Streamline permitting and connecting, including permissions on buildings. Phase out unnecessary bureaucratic administrative processes that add costs and waiting time.	2015-20
3. Elaborate and enforce performance standards for PV modules and systems in various climatic environments.	2015-20
4. Elaborate training and certification schemes for PV installers.	2015-20

Permitting and connecting remain two major issues in a wide number of jurisdictions – not to mention those countries that have yet to allow plant development by independent producers, or are restricting power injection into the grid to high-voltage levels, or high- and medium-voltage levels.

Administrative and transaction costs can be specially burdensome for small projects, unless or until particularly simple and rapid “fast-track” approval and connecting processes are put in place, such as in Germany, Italy and some US states, such as Vermont.

Box 5: “Soft costs” in the United States

This roadmap assumes a certain degree of convergence of “soft costs” – costs other than hardware such as panels, mounting systems and inverters – towards the lowest end of the range, represented by Germany, whose soft costs are themselves expected to decrease over time. However, in the United States, soft costs in 2012 were virtually unchanged since 2010, at USD 3.32/W for residential systems, USD 3.01/W for small commercial systems and USD 2.10/W for large commercial systems. They represented growing shares of the total system prices, from 52% for large commercial systems to 63.5% for residential systems, while hardware costs were almost cut by half (Friedman et al., 2013).

Ardani et al. (2013) have provided in the US context a specific soft cost reduction roadmap for the years 2013-2020, which aims at identifying the cost reduction opportunities to reach the targets of the SunShot Initiative with respect to soft costs by 2020, which are USD 0.65/W for residential systems, and USD 0.44/W for commercial systems. The interaction of significant market opportunities, such as for the entire United States, with the production of solar cells has significant feedback and benefits, of which assessment of the SunShot programme is an excellent example (Mileva *et al.*, 2013).

Certification and normalisation

Customers in a great variety of climatic situations should have confidence in the performance and the longevity of the PV systems they acquire. A greater coverage of internationally recognised standards would be needed, based on a wider variety of accelerated stress tests. Not all modules need to withstand snow, hail or extreme heat, but some do. In a large, mature global market, tailoring modules to different environments would help keep costs low while improving performance. This could include adding indications of actual performance in different ambient temperatures and different air masses. Certification of developers, designers and installers, regularly updated, may also improve customer confidence. Finally, grid codes and other regulation could facilitate smoother integration of PV systems into grids.

Industry associations, research institutes, government agencies and international collaboration, notably through the PVPS IA, all have important roles to play in certification and normalisation.

Setting predictable financial schemes and regulatory frameworks

Despite the recent cost reductions for PV systems, financial incentives are still needed in most markets to support the deployment of solar power technologies, but at significantly lower levels than just a few years ago: as the costs of systems plummet, the gap between market prices and LCOE of PV shrinks even faster. However, current electricity market designs may not be conducive to capital-intensive investments in power generation. PV is a capital-intensive technology, highly sensitive to investment risks, which are increased by a lack of long-term price visibility.

In countries where PV markets are already mature, however, a move towards greater market exposure would ease integration of variable PV power, by exposing PV systems to price signals that reflect the different values of electricity, which depends on time and location of generation, and on the level of PV deployment already achieved

The appropriate market design and policy framework must strike a delicate balance between these conflicting objectives. In any case, retroactive changes must be avoided.

Attract investment to solar PV and reduce soft costs in new or emerging PV markets	Time frames
1. Adopt or update medium and long term targets for PV deployment.	2015
2. Implement or update incentives and support mechanisms that provide sufficient confidence to investors; create a stable, predictable financing environment to lower costs for financing. These may notably include FITs and auctions for long term PPAs.	2015-20
3. Implement priority dispatch to jump-start PV deployment in new or nascent markets, until market maturity has sufficiently reduced costs for making greater market exposure compatible with sound deployment.	2015-30 depending on countries
4. Facilitate distributed PV generation, either using feed-in tariffs or net-metering.	2015-30 depending on countries
5. Identify the cost structure of current projects and anomalies by comparison with other jurisdictions, and implement specific actions to reduce anomalous soft costs, depending on country's circumstances.	2015-30
6. Work with financing circles and other stakeholders to reduce financing costs for PV deployment.	2015-30

Policy options

There is a great variety of policy options to consider. They might differ for large-scale, ground-based systems, and for smaller-scale systems on (or close to) buildings, as the latter tend to favour self-consumption. Some policy options may also entail transaction costs that are only acceptable for large projects.

For utility-scale PV plants, **feed-in tariffs (FiTs)**, **feed-in-premiums (FiPs)**, as well as **auctions** have prevailed in Europe, Australia, Canada, Japan; in the United States, **long-term power-purchase agreements (PPA)** have been signed by utilities to respond to **renewable energy portfolio standards (RPS)**, with or without solar carve-outs. They have been complemented with production and/or investment tax credits. Auctions are common in many emerging economies, from Brazil to South Africa.

For distributed PV, FiTs again, in Europe and Asia, and **net energy metering (NEM)**, notably in the United States, have been so far the most widely used policies, often in combination with various

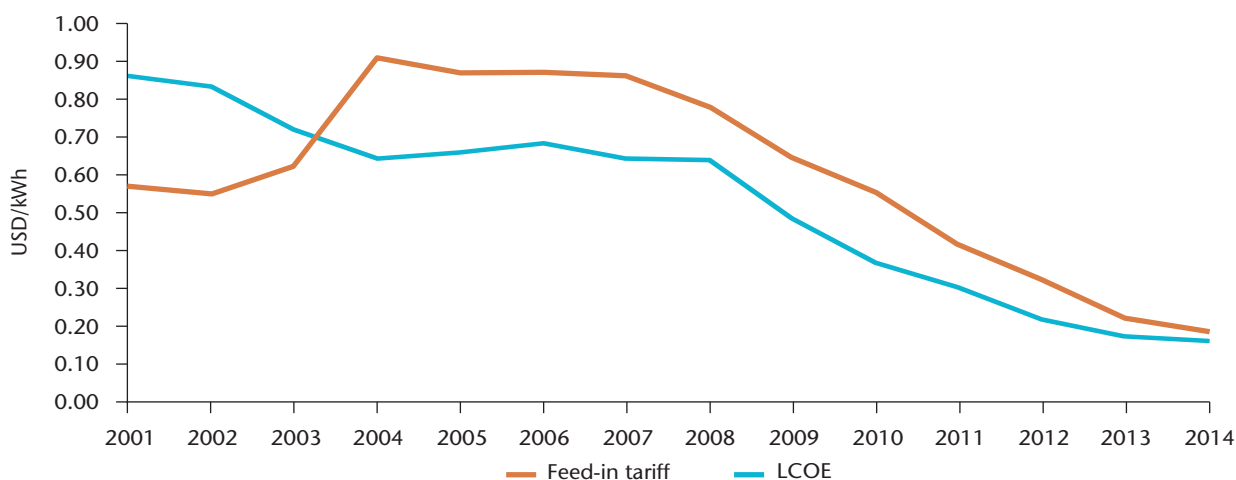
fiscal incentives such as **investment tax credits (ITC)** or **production tax credits (PTC)**. In some jurisdictions,⁷ **renewable energy certificates (REC)** or solar REC (SREC) are a driving force.

As the cost of PV electricity has plummeted and deployment volumes reached scale, both FiTs and net metering are now under scrutiny.

Well-managed **FiTs** have proven effective in stimulating deployment, while providing fair but not excessive remuneration to investors, especially in Germany, as suggests a comparison of the remuneration for PV electricity under the German FiT for small rooftops, and the LCOE of small system (Figure 22).

7. Notably a few European countries and some US states (Delaware, Massachusetts, Maryland, New Jersey, Ohio, Pennsylvania) and the District of Columbia.

Figure 22: Feed-in tariff levels and LCOE of small rooftop in Germany (USD/W)



Note: The German feed-in tariff applies to systems <30 kW to April 2012 and to systems <10 kW after that. LCOE assumptions: real discount rate 2.4%, annual O&M 1% of initial investment, 1040 full load hours. All prices are in 2013 USD.

KEY POINT: Feed-in tariffs, if well-managed, can deliver PV deployment providing fair remuneration to investors.

However, FiTs do not straightforwardly provide policy makers with precise control of the pace of deployment. The supply curve is relatively flat, reflecting considerable potential at a given cost. At any time, the incentive risks being either too high – driving more investment than desired – or too low, attracting much less investment than desired. Excessive remuneration and/or too rapid deployment have significantly impacted end-user electricity tariffs. Two options can keep deployment under control: rapid rate changes linked to effective deployment, as in Germany since June 2012 (IEA 2013a), or a limitation of the yearly new commitments through FiTs, either in capacity or (preferably) in financial support volume, as in Italy. This roadmap recommends that FiTs have degressive rates and quantitative limitations.

FiTs are also questioned on the grounds of integration, for they do not deliver any incentive to generate electricity when and where it is more useful for the entire electric system. **FiPs** are being implemented or suggested as possible transition tools toward greater market exposure. Premiums are added to the market prices to remunerate renewable electricity. One should however distinguish fixed (“ex ante”) FiPs from sliding (“ex post”) FiPs. Fixed FiPs are set once for all. The total remuneration thus depends on the market prices. Sliding FiPs are set at regular intervals, typically

months, to fill the gap between the average market price perceived by all generators of a given technology and a pre-determined strike price. The United Kingdom’s “contract for difference” can be considered as a sliding FiP.

With fixed FiPs, PV systems compete with all other generating technologies on wholesale markets. Their total remuneration is therefore more uncertain, which raises investors’ risk and ultimately increases the cost of capital and LCOE. With sliding FiPs, PV systems compete with one another. Those performing better than average in delivering power when the electricity prices are high get higher returns. Those performing worse than average get lower returns. The difference in returns is more modest than with ex ante FiPs, and the increases in risk and costs of capital are less pronounced.

Competitive auctions or requests for tenders are increasingly being chosen in both industrialised and developing economies as preferred support instruments for early deployment of renewable electricity. They offer full control over overall capacities, and allow for the market price to be reached through competitive bidding, but details of implementation must be carefully drafted. Tenders entail transaction costs and can seldom be adapted to small-scale projects unless project aggregators step in. They can result in prices that are too high if

cumbersome participation conditions – or worse, bribery or nepotism – limit competition. Tenders also run the opposite risk that aggressive bidding

by inexperienced – or speculating– developers might fail to deliver the capacity, precisely because contracted prices end up lower than actual costs.

<i>This roadmap recommends the following actions</i>	<i>Time frames</i>
1. Progressively increase short-term market exposure for PV electricity while ensuring fair remuneration of investment. This may include sliding FiPs and auctions with time-of-delivery and locational pricing.	2015-30 depending on countries
2. Facilitate distributed PV generation while ensuring T&D grid cost recovery. Remuneration may be based on net-metering, or self-consumption with remuneration of injection based on a fair assessment of the value of solar, or “pay all buy all” remuneration similarly based on a fair assessment of the value of solar.	2015-20 depending on countries
3. Avoid retroactive changes, which undermine the confidence of investors and the credibility of policies.	At all times
4. Work with financing circles and other stakeholders to reduce financing costs for PV deployment, in particular developing large-scale refinancing of PV (and other clean energy) loans with private money and institutional investors.	2015-30

In 43 US states, as well as several Australian states and territories, and Italy and other countries, the owners or users of PV systems who self-consume part of the electricity produced can “net” the electricity they inject into the grid against the amount they withdraw from the grid to cover their own needs. The netting period typically extends over long periods of time (one billing period), and often includes the opportunity to report excess as credits to the next period. Net energy metering (NEM) is attractive, easy to understand and administer.

However, NEM, effective for jump-starting local PV markets, raises concerns when large penetration levels are reached. It remunerates the injected electricity at a cost equivalent to the retail electricity price, which may not reflect its value for the system, being either above or below. Some utilities say the practice is inefficient and unfair: inefficient because utilities could buy electricity from other sources at a lower cost than the retail prices, which include T&D grid costs as well as various taxes and charges; and unfair, as the increase in costs resulting from inefficiency would be borne by other customers. NEM would thus entail cross subsidies. However, depending on the match between PV generation and peak demand, distributed PV systems may reduce grid costs or increase them, and their true value may be either greater or lower than retail

prices (Box 6). PV may also have a significant capacity value if it generates at peak times, avoiding to build more thermal plant to meet the demand, but with larger share the marginal capacity credit and value of new PV will vanish.

Grid costs, if not reduced by distributed generation, would have to be spread over a smaller amount of kWh sold, and the burden would fall disproportionately on the customers who do not generate electricity. This problem applies to self-consumption in general; NEM only compounds the issue. In any case cross subsidies never can be entirely avoided in practice in electric systems that have to deal with a great variety of customer profiles. It is thus not straightforward to determine what is acceptable and what is not.

Box 6: Value-of-solar tariffs in Minnesota

To reduce cross-subsidisation, and provide market signals for enhancing the value of electricity from PV, it has been suggested to replace net energy metering (NEM) with “pay all, buy all” systems. Producers also being consumers, or “prosumers”, would be remunerated for all energy produced, whether self-consumed or injected into the grid, while having to pay for all energy consumed, whether self-produced or drawn from the grid. This is at the root of so-called “value-of-solar” (VOS) tariffs, which were pioneered by the municipality-owned utility Austin Energy (Texas) and first implemented at state level in Minnesota in early 2014. However, the law finally enacted differs from the proposed legislation in several aspects, which makes it closer to NEM. Instead of true payments, PV owners would be credited against their electricity bills (in value, if not in energy, as in the Italian “Scambio sul Posto” system⁸). They may not produce more than 120% of on-site consumption. Furthermore, applying VOS is not mandatory, but left at the discretion of the utilities as an alternative to NEM.

The VOS components include “the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value”. Analyses are based on an hourly PV production time-series (Norris, Putnam and Hoff, 2014). As a final step, the methodology calls for the conversion of the 25-year levelised value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year to inflation. The preliminary VOS is higher than the retail price of the largest utility in the state – the difference reflects in particular the environment cost component,

8. See www.gse.it/it/Ritiro%20e%20scambio/Scambio%20sul%20posto/Pages/default.aspx

notably based on the federal social cost of carbon (from USD 42 in 2015 to USD 79 in 2050 in constant 2012 USD).

For some analysts, VOS could offer a way out of controversial NEM for the benefit of solar developers, utilities and electricity customers all together (e.g. Forrell, 2014). VOST is set for 25 years, giving greater certainty of return on investment to solar owners, reducing financing costs. Utilities may be better off as well, if their retail rates continue to increase. However, the opposite might hold true with more solar in the mix, especially if time-of-use (TOU) pricing is introduced (Darghouth, Barbose and Wiser, 2013). Other analysts or stakeholder groups see VOS tariffs more as a way to perpetuate a monopolistic business model of vertically integrated utilities by preventing its erosion through self-consumption (Smart, 2014).

If Minnesota’s utilities actually opt for VOST, an interesting precedent may be set for others and attenuate controversies about cross-subsidies. However, at least at current penetration levels, the largest difference between the level of remuneration for PV between VOS tariff and NEM may well be the inclusion of a carbon value in PV remuneration. As directly pricing carbon remains politically difficult, a negative carbon price for non-emitting CO₂ looks like a pragmatic option. There is also significant merit in the open public process of establishing and discussing the value of solar – but if it comes close to the retail price, it could paradoxically reinforce the legitimacy of NEM (Gilliam, 2014). Or it could help define a fair value for the electricity injected into the grid – a definition of “avoided costs” not limited to wholesale electricity market prices – taking self-consumption in account.

NEM raises another issue: as it is usually implemented with long netting periods, it does not encourage self-consumption, while self-consumption incentivises load management. NEM

puts the burden of managing PV variability onto the rest of the electricity system. Policy makers and regulators may want to implement progressive changes to the electricity tariff structure in order

to better recover fixed grid investment costs and decrease system costs. Nevertheless, evolutions should be conducted with care and strike a balance between various risks.

Reducing the variable tariff and increasing the fixed tariff on electricity bills is an option, but may unfairly burden poorer consumers. It may also lead some consumers to increase their electricity consumption at peak times, raising grid and system costs. Time-based pricing is preferable; it could more efficiently limit the penetration of variable renewables to what consumers can absorb, and incentivise demand-side management and storage. Just as TOU pricing could be used to incentivise load management, time-of-delivery (TOD) pricing could be used to incentivise the management of injected power (SEPA, 2013).

Whether through a combination of self-consumption and FiTs or FiPs, NEM or VOST, as the Department of Energy of the Republic of South Africa (RSA DOE, 2013) recently noted, “given the recent reduction in the cost of photovoltaic generation it has become highly probable that electricity consumers (commercial, residential, and to some extent industrial) will begin installing small-scale (predominantly roof-top) distributed generation to meet some or all of their electricity requirements. This penetration of distributed generation may occur with or without the support and approval of national and local government entities, but it may be prudent to incentivise the appropriate implementation in order to derive social benefits from this development rather than a potentially sub-optimal result because authorities only considered the risks rather than the benefits.”

Retroactive laws

Except for criminal laws, retroactive laws are not unconstitutional in most jurisdictions. With respect to fiscal decisions, they are even relatively common. Limited retroactivity usually gets approved by constitutional judges if the retroactive legislation has a rational legislative purpose and is not arbitrary, and if the period of retroactivity is not excessive.

However, changes in the rules applicable to investments already being made or in process can have long-lasting deterrent effects on future investment if they deeply modify the prospect for economic returns. In the last few years in Europe, many such retrospective legislative changes have been implemented, often specifically targeting PV (EPIA, 2013), either because governments realised

their support policies had not kept pace with rapid PV cost reductions, or because they wanted to protect the profitability of other players in energy markets in a context of economic and energy stagnation. Some were not exclusive to PV or even renewables, but affected them more as they could not pass new taxes or fees on to customers. Some were cancelled by judges, others confirmed, and other cases are still pending. Some changes strongly affected the revenues of asset-owners, pushing some to bankruptcy or loan-repayment default, while others were relatively minor. But all, arguably, affected the confidence of investors, and therefore they should be avoided.

Financing

The residential and, to a lesser degree, commercial markets in the United States have experienced a boom in third-party finance backed by tax equity; industry data suggest third-party finance supported nearly half of installed residential systems in 2011, and about three-quarters in 2012. This type of financing has a high cost of capital, which could impede the competitiveness of PV (Ardani et al., 2013). Costs of third party financing have been assessed at USD 780/kW for a residential portfolio and USD 670/kW for a commercial portfolio. On the other hand, while this may or may not be the best option from a customer viewpoint, third-party financing supports customer uptake and rapid market growth. As such it drives some PV cost reduction (Feldman et al., 2013).

The US DOE’s National Renewable Energy Laboratory (NREL) recently convened the Banking on Solar working group to work with lenders and other stakeholders to make it easier for homeowners and businesses to secure loans for installing rooftop PV systems. Banks, credit unions and other lenders are increasingly offering loans to enable homeowners and businesses to install rooftop solar systems; however, the NREL has found that significant barriers to accessing this growing market still remain. The group’s principal efforts centre on standardising contracts and underwriting processes, as well as educating banks and regulators about the risks and rewards of the solar asset class.

Re-financing PV assets from private money looking for long-term, safe but low-return investment could help accelerate the deployment of PV and other capital-intensive renewable energies (or energy efficiency improvements).

This roadmap recommends the following actions	Time frames
1. In countries (or smaller jurisdictions, such as islands) with highly subsidised retail electricity prices, progressively reduce these subsidies while developing alternative energy sources and implementing more targeted financial support to help the poor.	2015
2. In countries with large numbers of people without electricity access, work with stakeholders to develop and implement suitable business models for deploying off-grid and mini-grid PV.	2015-20

Box 7: Financing off-grid solar electrification

Small-scale solar electricity systems, most often PV, can bring considerable benefit to “base of the pyramid” consumers, i.e. the poor in poor countries. These people earn very small amounts of money on an irregular basis, and spend significant shares of it on dry batteries, kerosene and other energy products. According to some estimates, in rural areas those earning USD 1.25 per day may spend as much as USD 0.40 per day for energy.

Solar electricity is actually competitive, but up-front costs, ranging from USD 30 for very small PV systems to USD 75 000 for village mini-grids, are usually too high, even if off-grid systems of several MW are now economically and technically feasible. The financing dimension of solar energy deployment is perhaps most acute in this case. Access to finance to support the high up-front investment costs of solar systems for rural electrification is scarce. Transactions costs are very high, due to the disaggregated nature of the projects. The risks for potential third-party investors are also high, especially given that financial institutions have little experience on rural electrification projects, and are not compensated by high rates of return. The main risks are:

- commercial risks: overall uncertainty, very low experience and lack of specific information on the present state of the market make it hard to plan and deal with the future
- customer behaviour: fraud, default on the payment of bills
- operating risks: credit risk (default or protracted default on payment from end-user)

- economic risks: inflation risk (affecting end-user’s ability to pay), exchange rates
- risks affecting the distributor’s ability to correctly bill the end-user
- political risks: lack of political stability will affect the long-term assessment of policies to support rural electrification projects and the trustworthiness of investment contracts with states that might default on payments.

Public authorities need to develop and promote a clear political support scheme to draw on the support of the private sector and allow the development of a safe business environment for the dissemination of solar systems and mini-grid installations.

Once the risk is alleviated, equity funds and debt financiers from commercial banks and private funds can be tapped in decentralised rural electrification projects.

Two distinct business models can then be put in place, the retail model and the energy service model. In the retail model, best adapted to pico PV or solar home systems, the end-user buys the solar system from a private company. The cash or credit payment gives the buyer full ownership of the system. Public funds, multilateral or bilateral aid and the private banking sector can offer loans to support the banking institutions or the entity in charge of rural electrification. Supporting the purchase of the equipment by the private retailer and the end user is essential, as is expanding the network of retailers so they can supply the energy poor with affordable solar systems.

Helping end-users break down their payments into low monthly instalments is of paramount importance. In some countries, a large network of micro-financial institutions is present and established. These financiers can act as an efficient intermediary between governments, retailers and international institutions to promote and disseminate solar systems. They know the creditworthiness of their clients and can offer efficient end-user finance solutions through micro-credit loans (even if the interest rates are high, the default on payments is usually very low). In Bangladesh, Grameen Shakti was successful in offering micro loans to distribute more than one million solar home systems by November 2012 – twice the original target. Installations are continuing at a rate of 2 000 per day.

In the energy service model, best adapted to mini-grids, the company provides the equipment to the end-user, who pays for the

service rendered. The ownership of the system remains in the hands of the company. The private operating company will need capital to buy the necessary equipment. It can either buy it using loans from the public or the private sector or attract equity investors. To support this intermediary, multilateral and bilateral aid using concessional soft loans and grants from donor funds can help decrease the high-front investment of the private operating company and reduce the burden on the end client. If a fee is to be paid by the client, micro-financial institutions can help spread the first payment.

Policy support could take the form of grants to lower the price of systems to end-users in the retail model. In the service model, it could take the form of subsidies to the company or to the end-user to reduce the price of electricity and insure a minimum return on investment to the investor.

International collaboration

RD&D and normalisation

Greater co-ordination is needed between national PV energy RD&D actors across the globe. Increased collaboration among nations will ensure that important issues are addressed according to areas of national expertise, taking advantage of existing RD&D activities and infrastructure.

Long-term harmonisation of PV energy research agendas is also needed, as is the establishment of international testing facilities for materials and system components.

The current context of intense competition between manufacturers may make international R&D collaboration on PV cell and module technologies more difficult than in the past. However, there are many other areas in which international collaboration provides inestimable benefits, in particular those related to grid integration of both utility-scale and distributed PV.

One example of international PV energy technology collaboration is the IEA Implementing Agreement for a Co-operative Programme on Photovoltaic

Power Systems (PVPS IA). The PVPS IA includes technology experts from 24 countries and the European Union, as well as the European Photovoltaic Industry Association (EPIA), the International Copper Association and the US-based Solar Energy Industry Association (SEIA) and Solar Electric Power Association (SEPA). Together PVPS IA members have developed a research programme focused on accelerating the development and deployment of PV energy.

Its ongoing tasks include exchange and dissemination of information on PV systems (Task 1), very large-scale PV power generation systems in remote areas (Task 8), deploying PV services for regional development (Task 9), PV hybrid systems with mini-grids (Task 11), PV environmental health and safety (Task 12), performance and reliability of PV systems (task 13), and high penetration of PV systems in electricity grids (Task 14).

Support best practices in developing economies

Vast PV potential exists in many countries where deployment has not begun or has barely begun. OECD governments are encouraged to assist

developing economies in the early deployment of policy frameworks for renewable energy, and to exchange best practice in PV technology, system integration, support mechanisms, environmental protection and the dismantling of deployment barriers. Multilateral development banks are an important source of financing for joint development efforts. Financing facilities can be designed on a case-by-case basis to support differing needs. In Africa and Asia, where millions of people lack access to electricity, specific actions will be necessary to help develop access through off-grid and mini-grid PV systems.

The IEA secretariat is helping the Republic of South Africa to develop its own comprehensive, solar energy technology roadmap, with the support of the German government's development agency GIZ (Deutsche Gesellschaft für Internationale Zusammenarbeit). The IEA is also delivering recommendations to the government of Morocco

with respect to the deployment of PV and other renewables through an in-depth review of the kingdom's energy policy.

Assess and express the value of PV energy in economic development

The clear expression of the value of PV energy, in terms of climate protection and other development challenges, such as rural electrification, is important for accelerated PV deployment. Benefits in terms of innovation, employment and environmental protection should be accurately quantified and shared with developing economy partners, particularly in terms of their ability to contribute towards the fundamental questions of adequate energy provision and poverty alleviation.

Roadmap action plan

The main milestones to enable PV generation to reach a share of up to 16% of global electricity in 2050 are:

- Governments establishing or updating targets for PV deployment and ensuring a stable, predictable financing environment and striving to reduce “soft costs”.
- Industry further reducing PV costs through technology improvements.
- Power system actors anticipating the deployment of variable PV generation through evolution of transmission and distribution grids, and the rest of the power systems.

Near-term actions for stakeholders

The most immediate actions are listed below by lead actors.

Governments, including policy makers at international, national, regional and local levels, need to remove deployment barriers; establish frameworks that promote close collaboration between the PV industry and the wider power sector; and encourage private sector investment alongside increased public investment.

Governments, taking the lead, should:

- Set or update long-term targets for PV deployment, including short-term milestones consistent with their national energy strategy and with their contribution to the global climate mitigation effort.
- Ensure a stable, predictable financing environment. Where market arrangements and cost competitiveness do not provide sufficient incentives for investors, make sure that predictable, long-term support mechanisms exist; the level of support should, however, be progressively reduced as markets mature and PV system costs decrease.
- Address existing or potential barriers to deployment, in particular from permitting and connecting procedures.
- Ensure that a combination of self-consumption and fair remuneration of injections of electricity into the grids allows for deployment of

distributed PV generation, acknowledging the value of solar PV generation, and outreach to consumers about the options.

- Identify and provide a suitable level of public funding for PV R&D, proportionate to the cost reduction targets and potential of the technology in terms of electricity production and CO₂ abatement targets.
- Enable greater international R&D collaboration to make best use of national competencies.
- In mature PV markets, progressively modify the policy framework for new-built capacities, as greater market exposure favours better adaptation to the broader power system.
- In mature PV markets, consider progressive modification of the rate structure for electricity customers to ensure full recovery of fixed grid costs while preserving incentives for deployment of distributed PV generation, including time-of-use and locational pricing.

PV Industry includes module manufacturers, manufacturers of production lines and critical inputs (e.g. purified silicon), PV system developers, with strong collaboration with the research actors.

PV industry should:

- Further improve efficiency, performance ratios and robustness of PV modules and systems.
- Reduce inputs and energy consumption and identify substitutes for costly inputs, such as silver.
- Consider diversification of products to better suit various environments.
- Develop low-cost, high-efficiency, bifacial, 1-sun tandem cells.
- Train system designers and installers.

Power system actors include transmission companies, system operators and independent electricity sector regulators as established by governments, as well as vertically integrated utilities (where they exist). Their key role is to facilitate the evolution of transmission and distribution grids needed to connect utility-scale and distributed PV systems (and other generators) and move electricity to load centres. They also play a role in enabling physical power markets to evolve in a manner that

cost-effectively reduces the impact of variability and increases the value of PV electricity while ensuring security of supply.

Power system actors should:

- Develop wide-area transmission plans that support interconnection, anticipating PV deployment and the linking of regional power markets, to ensure security of supply.
- Where not already available, implement grid codes that will drive inverters to provide voltage control and frequency regulation; collaborate with neighbouring areas to enhance balancing.
- Advance progress on the evolution of market design and system operating practices to enable integration of large shares of variable renewable energy, shortening gate closure times and trading block length.
- Improve PV output forecasting and include online data in control rooms of system operators.
- Develop methods to assess the need for additional power system flexibility; carry out grid studies to examine costs and benefits of high shares of PV power.
- Exploit existing power system flexibility to increase the value of RES.
- Anticipate further PV deployment through increased flexibility of the rest of the system when additional capacity investments are required.

Implementation

The implementation of this roadmap could take place through national roadmaps, targets, subsidies and R&D efforts. Based on its energy and industrial policies, a country could develop a set of relevant actions.

Ultimately, international collaboration will be important and can enhance the success of national efforts. This roadmap update identifies approaches and specific tasks regarding PV research, development and deployment, financing, planning, grid integration, legal and regulatory framework development and international collaboration. It also updates regional projections for PV deployment from 2015 to 2050 based on *ETP 2014*. Finally, this roadmap details actions and milestones to aid policy makers, industry and power system actors in their efforts to successfully deploy PV.

The PV roadmap is meant to be a process, one that evolves to take into account new developments from demonstration projects, policies and international collaborative efforts. The roadmap has been designed with milestones that the international community can use to ensure that PV development efforts are on track to achieve the GHG emissions reductions required by 2050. As such, the IEA, together with government, industry and other interested parties will report regularly on the progress that has been achieved toward this roadmap's vision. For more information about the PV roadmap inputs and implementation, visit www.iea.org/roadmaps.

Abbreviations and acronyms

2DS	2°C Scenario	LCOE	levelised cost of electricity
6DS	6°C Scenario	LCPV	low-concentrating photovoltaic
AC	alternative current	mc-Si	multi-crystalline silicon
a-Si	amorphous silicon	MW	megawatt (1 000 kW)
a-Si/ μ c-Si	amorphous silicon/micro-crystalline silicon	MWh	megawatt hour (1 000 kWh)
BOS	balance of system	NEM	net energy metering
CCS	carbon capture and storage	NREL	National Renewable Energy Laboratory (United States)
CdTE	cadmium-telluride	NPV	net present value
CIGS	copper-indium-gallum-selenide	OECD	Organisation for Economic Co-operation and Development
cm ²	square centimetres	O&M	operation and maintenance
CO ₂	carbon dioxide	PHS	pumped hydroelectric storage
CO ₂ -eq	carbon dioxide equivalent	PPA	power purchase agreement
CSP	concentrating solar power	PTC	production tax credit
CPV	concentrating photovoltaic	PUC	Public Utility Commission
DC	direct current	PV	photovoltaic
ENTSO-E	European Network of Transmission System Operators for Electricity	R&D	research and development
ETP	<i>Energy Technology Perspectives</i>	RD&D	research, development and demonstration
EU	European Union	REC	renewable energy certificate
EUR	euro	REWP:	Renewable Energy Working Party
EV	electric vehicle	RPS	renewable energy portfolio standard
FiT	feed-in tariff	Sc-Si	single-crystalline silicon
FiP	feed-in premium	SREC	solar renewable energy certificate
FSU	Former Soviet Union	STC	standard test conditions
G2V	grid to vehicle	STE	solar thermal electricity
GHG	greenhouse gas(es)	T&D	transmission and distribution
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit (German Development Co-operation Agency)	TIMES	The Integrated MARKAL (Marketing and Allocation Model)-EFOM (energy flow optimisation model) System.
Gt	gigatonnes	TF	thin films
GW	gigawatt (1 million kW)	TOD	time of delivery
GWh	gigawatt hour (1 million kWh)	TOU	time of use
HCPV	high-concentrating photovoltaic	TWh	terawatt (1 billion kWh)
hi-Ren	high renewables (Scenario)	UNFCCC	United Nations Framework Convention on Climate Change
HTJ	heterojunction	USD	United States dollar
Hz	hertz, unit of frequency (one cycle per second)	US DOE	United States Department of Energy
IA	implementing agreement	Var	volt-ampere reactive
IBC	interdigitated back contact	VOST	value-of-solar tariff
IEA	International Energy Agency	vRE	variable renewables
IEC	International Electrotechnical Commission	WACC	weighted average cost of capital
IEEE	Institute of Electrical and Electronic Engineers		
ISO	independent system operator		
JRC	Joint Research Centre		
kW	kilowatt		
kWh	kilowatt hour		
kWh/kW/y:	kilowatt hour per kilowatt and per year		
kWh/m ² /y:	kilowatt hour per square meter and per year		

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